Endgame

A zero-carbon electricity plan for Ireland

June 2021

Version History

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Commissioned by Wind Energy Ireland

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Foreword from Wind Energy Ireland

Now, it is a choice.

If there is one thing this piece of research shows it is that the amount of CO_2 that will be emitted from our electricity system in December 2030 is a choice – perhaps more a series of choices – which we will make between that day and this.

Decarbonising Ireland's electricity system to fewer than 2 million tonnes of CO_2 a year or even, potentially, to zero is not a question of resources. We have the investment, private and public, to develop the renewable energy and the infrastructure we need, and we can do it at a good price for the electricity consumer.

We lack neither expertise nor skill. We are world leaders in the integration of renewable power, we have more than 5,000 men and women working in an onshore wind energy industry that can compete with the best in the world and growing international experience attracted to our offshore wind opportunities.

And, most fundamentally, it is not a question of technology. This report makes clear we will be relying on proven technologies. Wind energy already – just with onshore wind farms – provides a greater share of our electricity demand in Ireland – 36% – than anywhere else in the world. We also have some of the best offshore wind resources in the world.

Globally, the price of wind and solar is continuing to plummet and, with the right policy choices, prices will fall here too.

We have the tools we need to decarbonise our electricity system if we choose to use them.

Or we can make the other choice, the one that in Ireland we traditionally make.

Where we choose to aim for the minimum, as little as we can get away with, and then still choose to fall short.

Where we choose to take the easy option, to leave it to the next government to fix, the next generation, passing the ball further and further down the line until it is eventually too late. Where we take comfort knowing the responsibility for our collective failure can always be represented as someone else's fault.

When we choose only to see the barriers and not the opportunities, only the reasons why we cannot do things and never the case for why we must.

We can choose more plans, more reviews, more consultations or we can choose to act.

We, the Irish people in making a collective decision, can choose to dramatically decarbonise our electricity system within nine years and even to eliminate carbon from it entirely.

This report sets out in detail the choices we must make over the next 9-10 years but, in essence, there are five key requirements.

First, we must deliver the targets set out in the Climate Action Plan and the Programme for Government. We need an additional 4,000 MW of onshore wind, 5,000 MW of offshore wind and 5,000 MW of solar power. We know we have the pipelines to deliver these targets.

Next, we need to replace our fossil fuel based back-up generation with zero-carbon technologies like battery storage, demand side response and synchronous condensers. This report shows that we can ensure the stability of our electricity system with cheaper and cleaner zero-carbon alternatives.

Then we need to ensure that the price of carbon reflects the damage it does to our planet. Setting the carbon price floor to €100 per tonne of CO_2 by 2030 will transform the market, reflect the real cost of fossil fuels and will enable renewables to push the final remaining fossil fuel, natural gas, out of the electricity market.

We know better than anyone that the wind does not always blow nor the sun always shine. We need a reliable source of power that can deliver when it is needed. This will be long-duration energy storage along with green hydrogen. Our existing gas generator fleet must be retrofitted to run on green hydrogen and any new fossil fuel plant built this decade must be designed to make conversion easy.

Finally, and most importantly, we need an electricity grid that is strong enough to achieve this. We cannot run a 21st century economy with a 20th century electricity grid. We need to build critically needed new grid infrastructure like the North-South Interconnector and we must invest in EirGrid's DS3 programme to ensure that the system can, when the wind and solar is available, operate with 100% renewables.

These are real and valid choices facing us but they are not easy ones.

They will require the transformation of our electricity system, the rapid development of new renewable energy projects and real leadership stretching from the meeting rooms in Government Buildings on Merrion Square into the heart of every community, big and small, on this island.

And now we know that if we fail, it will be because we chose to fail, because we preferred the easy option, to make more excuses, to quietly hope that someone else would fix a problem we created.

But now we also know that if we make the right choice, for ourselves and for our children, we will build an Ireland that is energy independent, delivering warmer homes, cleaner air and tens of thousands of new jobs, a leader in the fight against climate change, a better country in which to grow old and in which to raise our families, one which now enters the endgame for CO_2.

For our members, that is the choice we make.

Noel Cunniffe,

CEO, Wind Energy Ireland

Executive Summary

In this study, Baringa has sought to bring its landmark 2018 ‘70 by 30’ study into 2021, by accounting for significant market and policy developments in Ireland, and to determine the necessary steps to achieve a zero-carbon power sector in Ireland.

Key findings

- Reducing power sector CO_2 emissions in Ireland from around 9 million tonnes today to a target of **less than 2 million tonnes of CO_2** per year is very achievable by 2030, using the approach currently underway to achieve the ‘70 by 30’ target, and implementing more of **existing and proven technologies**.
- The current Programme for Government renewable capacity targets of **8.2 GW of onshore wind** and **5 GW of offshore wind** by 2030 should be maintained, with an additional target of **5 GW of solar PV**.
- This target can be achieved at a **lower cost to the end consumer** in Ireland, compared to delivery of the less ambitious ‘70 by 30’ target.
- A **zero-carbon power system is possible** by 2030 and represents an achievable target in the 2030s.
- Realising this target requires incremental investment in a **suite of technologies new to Ireland**, and the implementation of a **carbon price floor** in the I-SEM.

Our analysis

We have performed two phases of analysis:

- **Phase 1** considers how a ‘more of the same’ approach can enable the delivery of renewable electricity beyond the current 70% target by 2030 using existing policy along with proven and readily available technology, reducing power sector emissions below 2 million tonnes of CO_2 per year. We have utilised zero-carbon system services to remove the reliance on fossil gas-fired plant to meet Irish DS3 limits (operational constraints) and enable delivery of enough wind and solar generation capacity to achieve 85% renewable electricity (RES-E) in the Republic of Ireland (ROI) by 2030 in the **‘Less than 2 $MtCO_2$’** scenario. We have measured the costs and benefits of this scenario to the end consumer relative to an updated scenario that achieves the 70% target, considering developments in the Irish market since 2018 – the **‘70 by 30 (3.3 $MtCO_2$)’** scenario.
- **Phase 2** explores the impact of new policy actions, and technologies yet to be explored in Ireland, on the achievable deployment of renewable generation capacity – reducing power sector emissions below the levels seen in Phase 1. We consider the incremental power sector CO_2 emission savings associated with **alignment of the ETS carbon price with the planned non-ETS price** of 100 €/tCO_2, as well as emerging technologies such as **long-duration energy storage** and **green hydrogen**. We construct a viable pathway of investment that combines these solutions to deliver **a zero-carbon power sector** in 2030.

In each phase, we have used our in-house power market and system modelling capability to analyse the impact on the Irish power sector of each assumption, and have calculated the net costs and benefits to end consumers of the scenarios.

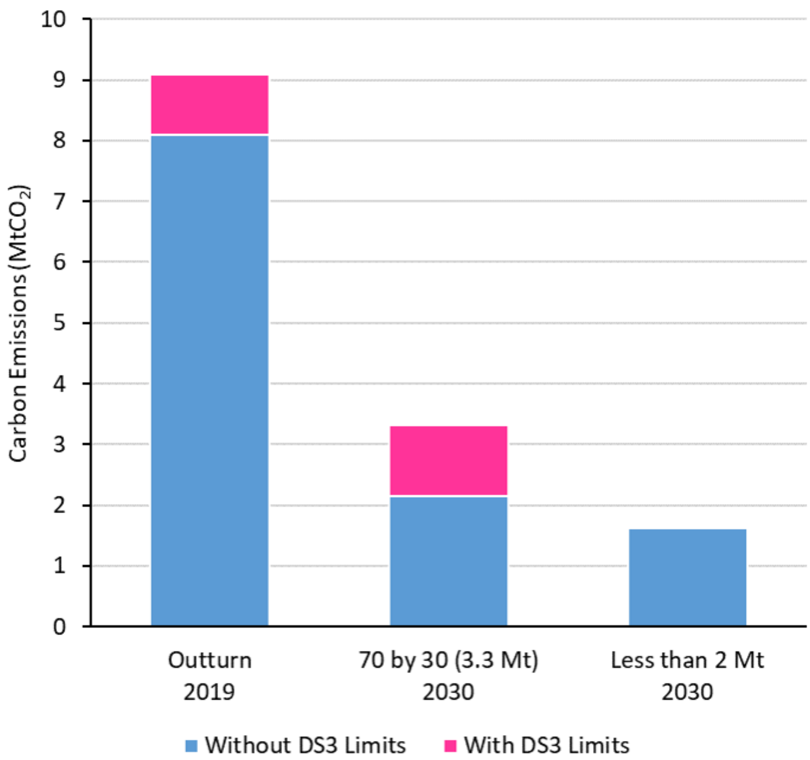
Phase 1 – achieving less than 2 million tonnes of CO_2

Table 1 and Figure 1 below present the key Phase 1 scenario assumptions, and resulting Irish power sector CO_2 emissions from dispatch of plant in each scenario.

Table 1: Key Phase 1 scenario assumptions

Phase 1 Key Scenario Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Installed ROI RES Capacity			
Onshore wind	*MW*	6,270	6,900
Offshore wind	*MW*	2,530	3,340
Solar PV	*MW*	2,550	3,350
I-SEM DS3 Limits (Operational Constraints)			
SNSP limit	*%*	95%	100%
RoCoF limit	*Hz/s*	1.0	1.0
Minimum inertia	*MWs*	0	0
System stability minimum units - I-SEM	*#*	4	0
System stability minimum units - ROI	*#*	0	0
System stability minimum units - NI	*#*	2	0

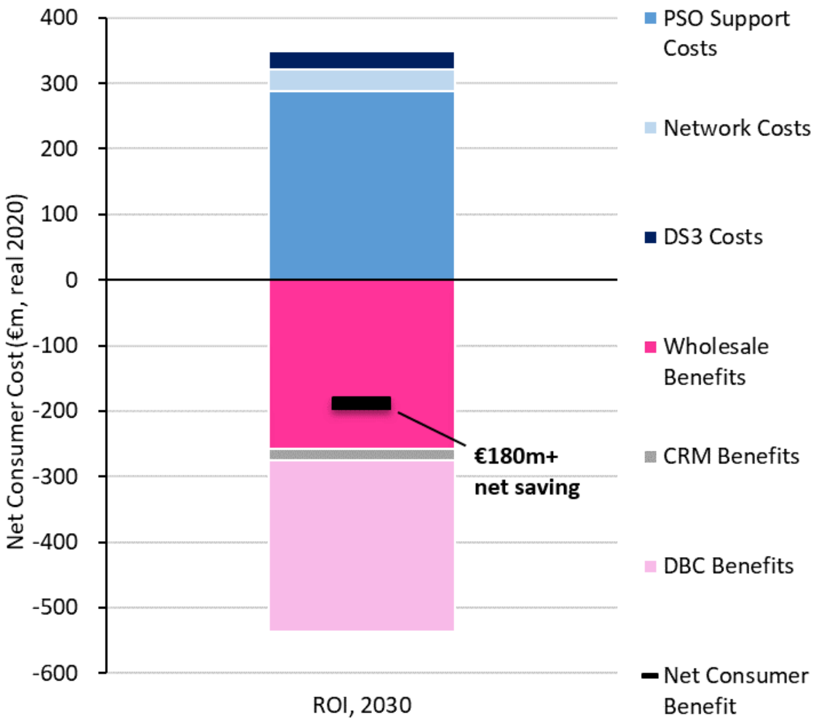
Figure 1: ROI power sector CO_2 emissions in the Phase 1 scenarios



Emissions are significantly reduced from historical levels in both scenarios due to substantial build-out of renewable generation technologies such as onshore and offshore wind, and solar PV capacity – enabled by investment in the network, and zero-carbon solutions to DS3 limits (operational constraints). Irish power sector emissions total 2.1 million tonnes of CO_2 ($MtCO_2$) from the day-ahead schedule positions of plant in the '70 by 30 (3.3 $MtCO_2$)' scenario, with re-dispatch of plant to meet DS3 limits adding a further 1.2 $MtCO_2$ from fossil gas-fired generation. Incremental renewable capacity build and zero-carbon system services reduce emissions to 1.6 $MtCO_2$ in the 'Less than 2 $MtCO_2$' scenario. Renewable generation as a proportion of demand (RES-E) reaches 70% in the former scenario, and 85% in the latter.

Our analysis shows that the deployment of incremental wind and solar capacity and investment in zero-carbon system services in the 'Less than 2 $MtCO_2$' scenario results in a net cost saving to the end consumer in Ireland of over €180m in 2030. The breakdown of this saving is shown in Figure 2.

Figure 2: End consumer cost-benefit analysis of the 'Less than 2 $MtCO_2$' scenario



A cost is incurred to the end consumer in Ireland to support renewable capacity through the PSO levy, as well as additional costs to reinforce the network and secure DS3 services. However, the €288m savings associated with lower wholesale power prices, and the elimination of over €250m of dispatch balancing costs (DBC) – much of which are paid to turn on gas-fired power stations to enable them to provide system services – result in a large overall net saving to end consumers.

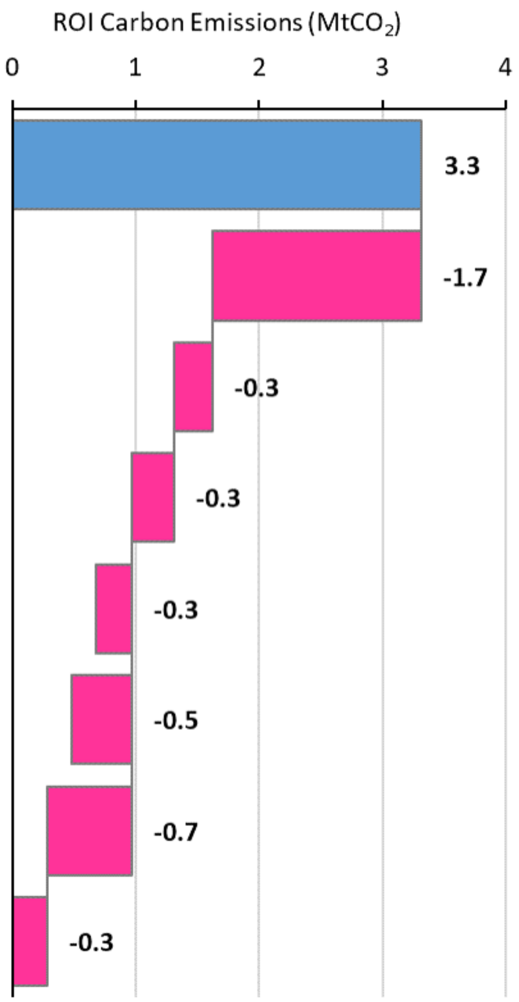
Our analysis of the Phase 1 scenario indicates that a target of **less than 2 million tonnes of CO_2 emissions** per year from the Irish power sector is very achievable using **proven technologies that exist today**. Realisation of this target would result in a **decrease in the cost to end consumers** relative to the existing and less ambitious '70 by 30' target.

Phase 2 – achieving a zero-carbon power sector

In Phase 2 of this study, we considered the incremental reduction of power sector emissions in 2030, beyond the 'Less than 2 $MtCO_2$' scenario, offered by a series of innovative policy and technology levers. We have modelled each scenario as an extension of 'Less than 2 $MtCO_2$', with additional measures achieved by 2030. We present a summary of the resulting renewable electricity (RES-E) % and CO_2 emission savings achieved using these solutions in Table 2.

Table 2: ROI power sector RES-E and CO_2 emission savings of Phase 2 solutions

Scenario	ROI RES-E Percentage	ROI CO_2 Emissions
70 by 30 (3.3 $MtCO_2$)	70%	3.3 $MtCO_2$
Less than 2 $MtCO_2$	85%	1.6 $MtCO_2$
80% of PfG Targets*	94%	1.3 $MtCO_2$
Aligned Carbon Price	94%	1.0 $MtCO_2$
Long-Duration Storage	97%	0.7 $MtCO_2$
Green Hydrogen	89%	0.5 $MtCO_2$
Storage & Hydrogen*	90%	0.3 $MtCO_2$
Zero Carbon (100% of PfG)	101%	0 $MtCO_2$



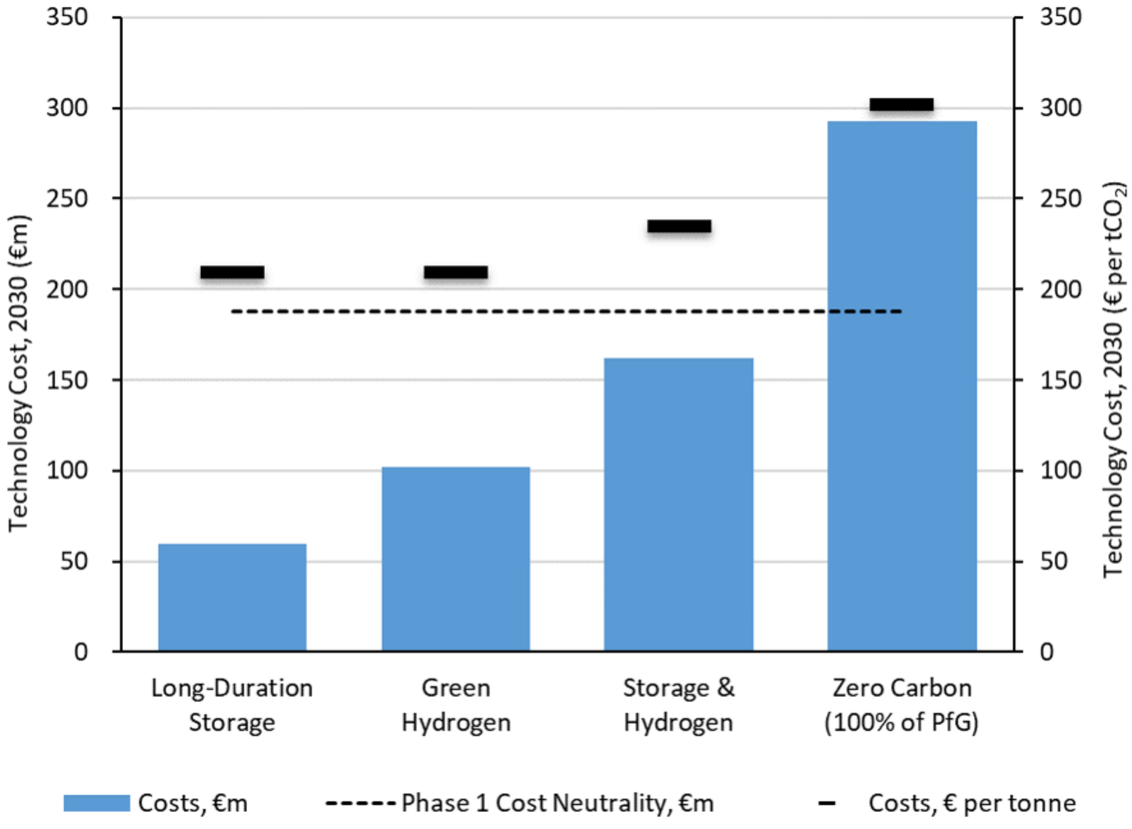
The 1.6 $MtCO_2$ emitted from electricity generation in the Irish power sector in the 'Less than 2 $MtCO_2$' scenario can be reduced by 0.3 $MtCO_2$ by increasing build-out of renewable capacity to 80% of the new-build renewable targets presented in the recent Programme for Government (PfG) (7.4 GW of onshore wind, and 4.0 GW of both offshore wind and solar PV) and by a further 0.3 $MtCO_2$ by implementing an ETS carbon price of 100 €/tCO_2 in Ireland, in-line with the current trajectory of the non-ETS price in Ireland (the 'Aligned Carbon Price' scenario). Deployment of 640 MW of long-duration energy storage technologies in ROI results in a further 0.3 $MtCO_2$ reduction, with 1,300 MW of electrolysers able to displace 0.5 $MtCO_2$ by producing green hydrogen, utilised in retrofitted gas-

fired power stations. Using these solutions in combination achieves a saving of 0.7 $MtCO_2$ (in the 'Storage & Hydrogen' sensitivity).

In the final step, the 'Zero Carbon' scenario employs a combination of the 100 €/tCO_2 ETS carbon price, long-duration storage assets, electrolyser capacity, and a comprehensive retrofit of fossil gas-fired capacity to provide enough system flexibility to enable the build-out of the full Programme for Government renewable targets (8.2 GW of onshore wind, 5.0 GW of offshore wind, and 5.0 GW of solar PV) and reduce Irish power sector emissions to zero.

The calculated technology cost to the end consumer of delivering each of the Phase 2 solutions is shown in Figure 3 below. We present the absolute technology costs in 2030, along with the cost per avoided tonne of CO_2. The net end consumer savings of over €180m delivered through the Phase 1 measures offset many of the additional technology costs in Phase 2. Our analysis covers the costs incurred to deliver the assets, excluding any benefits or additional costs. Potential cost savings associated with these technologies include reductions in network reinforcement costs from strategic location of storage and electrolysis assets behind grid constraints.

Figure 3: Technology costs of the Phase 2 solutions



Phase 2 of our study therefore demonstrates that a **zero-carbon power sector in Ireland is possible**, and can be achieved with concurrent investment in a series of **technologies new to Ireland** such as long-duration storage and green hydrogen, and a **carbon price floor** of 100 €/tCO_2 in I-SEM. Although modelled in 2030, we acknowledge that the investment necessary to deliver the pathway to a zero-carbon power sector in Ireland could extend beyond this timeframe into the 2030s.

1 Introduction

Baringa in collaboration with Wind Energy Ireland (formerly the Irish Wind Energy Association) carried out the landmark '70 by 30' study[1] in 2018 that established how 70% of Ireland's power consumption could be met by renewables in 2030, at zero net cost for end consumers. Since then, there have been significant market and policy developments, both in the Republic of Ireland (ROI) and throughout Europe.

A new 'Programme for Government' (PfG)[2] has been agreed with a commitment to reduce carbon emissions by an average of 7% per year over the next decade in Ireland across all sectors, which corresponds to more than a 50% absolute reduction in CO_2 emissions in that timeframe. As part of this release, government targets have been set for the total wind generation capacity installed by 2030; namely 8.2 GW of onshore wind and 5 GW of offshore wind. Industry is responding and is actively developing pipelines to meet these targets. There is also a growing indication that market players aim to deliver up to 5 GW of solar PV capacity over the same timeframe.

From a system operational perspective, EirGrid has committed to a more ambitious 'DS3+' programme than anticipated in 2018. In the 70 by 30 study a maximum SNSP[3] limit of 90% was assumed viable by 2030, but in EirGrid's recent publication 'Shaping our Electricity Future'[4] it set a target of at least 95% SNSP by 2030, with the potential for 100%, stating that "Reaching the 2030 targets will require close to 100% instantaneous non-synchronous RES penetrations". Forecasts of Irish demand in 2030 have grown significantly, from an anticipated 39 TWh in the 70 by 30 report to around 43 TWh in recent publications.

This study aims to update the 70 by 30 analysis by taking into account these developments to establish the contribution that renewable generation could provide to the Irish power sector, and determine the corresponding reduction in carbon emissions. The same methodology is applied in this study as in the 70 by 30 analysis, with appropriate updates to input assumptions to reflect changes that have occurred since 2018. At each stage of the analysis in this study, we have utilised our in-house PLEXOS[5] pan-European power market model to simulate the hourly plant dispatch on the island of Ireland (the I-SEM). The outputs of this model have been analysed in detail to determine the holistic impact on the Irish power sector, including a thorough end consumer cost-benefit analysis.

Phase 1 – achieving less than 2 million tonnes of CO_2

Two distinct phases of analysis have been performed as part of this study. In Phase 1 we explore two scenarios surrounding deployment of renewable generation capacity that could be enabled using a 'more of the same' approach towards policy and technology solutions. The two scenarios in this phase assume that moderate volumes of well understood and immediately available technologies are deployed in order to support renewable capacity additions beyond existing installed levels, with

[1] https://windenergyireland.com/images/Article_files/Final_Baringa_70by30_Report_web.pdf

[2] https://www.gov.ie/en/publication/7e05d-programme-for-government-our-shared-future/

[3] System Non-Synchronous Penetration represents a metric approximately equal to the instantaneous share of renewable generation meeting total domestic demand, taking into account interconnector flows; https://www.eirgridgroup.com/site-files/library/EirGrid/SNSP-Formula-External-Publication.pdf

[4] https://www.eirgridgroup.com/site-files/library/EirGrid/Full-Technical-Report-on-Shaping-Our-Electricity-Future.pdf

[5] PLEXOS is a third-party modelling platform extensively used for energy sector studies.

the ultimate aim of power sector decarbonisation in Ireland. Each scenario is modelled over the year 2030. The two scenarios considered in this phase are:

- **'70 by 30 (3.3 $MtCO_2$)'**: A baseline scenario that represents a direct update to the 'Renewable Energy' scenario considered in the original 70 by 30 study. The 2019 Climate Action Plan[6] target of 70% renewable share of electricity generation (RES-E) is achieved in 2030 using moderate deployment of proven technologies, and 50% of the new-build wind and solar capacity required to hit the PfG targets[7] (6.2 GW of onshore wind, and 2.5 GW of both offshore wind and solar PV). Enabling technologies modelled include synchronous condensers that provide zero-carbon system services, and energy market batteries that provide system flexibility. Residual DS3[8] limits (operational constraints) retain some reliance on fossil gas-fired generation capacity, though zero-carbon solutions have reduced this relative to the original study, e.g. we have included synchronous condensers to provide system inertia.
- **'Less than 2 $MtCO_2$'**: A scenario in which increased investment in demonstrated technologies allows DS3 limits to be met solely by zero-carbon solutions, removing the necessity for re-dispatch of fossil gas-fired plant from their ex-ante positions in the day-ahead schedule (dispatch balancing). These solutions enable increased penetration of renewable generation capacity into the Irish market, reaching 85% RES-E by 2030 using 67% of the PfG new-build targets (6.9 GW of onshore wind, 3.3 GW of offshore wind and 3.4 GW of solar PV). Power sector emissions in ROI fall below 2 million tonnes of CO_2 annually by 2030.

Phase 2 – achieving a zero-carbon power sector

In Phase 2 of the study, we explore a series of additional levers that can be utilised to increase deployment of wind and solar capacity, and reduce power sector emissions in Ireland beyond the levels observed in Phase 1. The range of solutions explored in this phase represents a menu of options that go beyond existing policy, or make use of technologies new to Ireland. Several potential solutions have been modelled across four key scenarios and a series of sensitivities, each considered within the year 2030. The Phase 2 scenarios represent independent steps along a pathway to a zero-carbon power sector that are not specific to the order presented, and simultaneous investment in multiple solutions may be necessary. We do not comment on the timelines necessary to deploy the technologies detailed in these scenarios, instead we present each scenario as representative of an incremental erosion of CO_2 emissions from the Irish power sector in 2030. Each Phase 2 scenario builds upon the key assumptions of the 'Less than 2 $MtCO_2$' scenario, with zero-carbon system services meeting the DS3 limits without the need for re-dispatch of plant. The key scenarios presented in detail are:

[6] https://assets.gov.ie/25419/c97cdecddf8c49ab976e773d4e11e515.pdf

[7] Throughout this study we have use the term 'Programme for Government targets' to refer to 8.2 GW of onshore wind (stated in the 2019 Climate Action Plan and repeated in the PfG), 5 GW of offshore wind (stated in the PfG) and 5 GW of solar PV capacity (a consistent figure derived from the ISEA 'The Value of Solar in Ireland' publication).

[8] DS3 (Delivering a Secure, Sustainable Electricity System) is EirGrid's overall programme of changes required to accommodate high levels of renewable generation. DS3 limits arise from the need maintain at all times adequate volumes of ancillary services such as reserve, inertia, reactive power and ramping, which are critical to grid stability. Wind and solar generation capacity can provide some, but not all of these services.

- **'Aligned Carbon Price'**: A scenario in which the ETS[9] carbon price in I-SEM, as well as the equivalent price in the neighbouring British (GB) and French markets, are moved into alignment with the current non-ETS target price of 100 €/tCO_2 for Ireland in 2030. This movement discourages domestic fossil gas-fired generation, with import of lower cost generation from neighbouring markets moving to replace it during peak demand periods; however, despite this, wholesale market prices rise as a result of the carbon price increase. This incentivises build-out of 80% of the PfG new-build targets (7.4 GW of onshore wind, 4.0 GW of offshore wind, and 4.0 GW of solar PV).
- **'Long-Duration Storage'**: Investment in long-duration energy storage technologies deployed throughout I-SEM increases system flexibility during day-ahead actions. Renewable output that would otherwise have been turned-down as oversupply during hours of low demand is instead utilised during hours of high demand, displacing fossil gas-fired generation. The 100 €/tCO_2 carbon price and 80% of the PfG target wind and solar capacity are retained from the 'Aligned Carbon Price' scenario. While not modelled explicitly in this analysis, it is worth noting that if long-duration storage technologies are deployed in suitable locations on the network, these also have the potential to address local network constraints, reducing the need for investment in new grid infrastructure.
- **'Green Hydrogen'**: Electrolysis of hydrogen gas powered by renewable energy ('green hydrogen') in I-SEM reduces oversupply of renewable generation during hours of excess. A fleet of fossil gas-fired assets retrofitted to generate using this hydrogen displace fossil gas-fired generation in the hours of highest price, in which the carbon intensity of the system would otherwise be highest. The 100 €/tCO_2 carbon price and 80% of the PfG target wind and solar capacity are retained from the 'Aligned Carbon Price' scenario. Similarly to the storage assets above, strategic deployment of electrolysis sites would help to alleviate potential network constraints.
- **'Zero Carbon'**: Combined deployment of long-duration energy storage and electrolysis assets throughout I-SEM, along with an ETS carbon price of 100 €/tCO_2, provides sufficient system flexibility to enable deployment of the full 100% of the PfG renewable targets (8.2 GW of onshore wind, and 5.0 GW of both offshore wind and solar PV). A comprehensive retrofit of the remaining fossil gas-fired fleet to enable it to run on hydrogen allows complete decarbonisation of the Irish power sector during all hours of 2030.

CO_2 emission offset sensitivities

In addition to the key scenarios introduced above, we have modelled two sets of sensitivities that quantify the net CO_2 emission savings achievable using renewable electricity generated in the Irish power to decarbonise other sectors in Ireland and GB. These solutions are presented in Appendix A, and have been modelled as sensitivities on the 'Aligned Carbon Price' scenario, but can be combined with any of the Phase 1 or Phase 2 scenarios:

- **'Electrification of Heat'**: A series of three sensitivities in which low-carbon electricity generated in the Irish power sector is used to meet flexible heat demand in the industrial sector. This transition brings the dual benefits of displacement of fossil gas CO_2 emissions by electrified and hydrogen-fired heating implements in the heat sector, and the reduction of renewable oversupply in the power sector.

[9] Emissions Trading Scheme; in Europe, the European Union ETS includes emissions from power stations, industrial facilities, aviation within the European Economic Area, and other energy-intensive installations.

- **'GB Power Sector'**: Irelands wind resource is used to reduce day-ahead CO_2 emissions in the neighbouring GB power market, with the saving attributed to ROI in the form of carbon offset credits. We consider an offshore wind site in Irish waters as directly connected to the GB network. The output of the wind farm displaces the marginal generator in the GB day-ahead schedule, reducing the emissions associated with this plant. The PfG has identified the potential for Ireland to export its wind resource by setting a long-term target of 30 GW for offshore wind; this scenario quantifies the initial potential of this initiative in terms of decarbonisation.

Each scenario and sensitivity input assumption is based on publicly available sources where possible, as well as Baringa analysis. We present these assumptions in detail, along with the analytical methodology used and the ultimate findings of the study.

The remainder of this report is structured as follows:

- **Section 2** presents the assumptions, methodology and results of the Phase 1 scenarios;
- **Section 3** details each of the key Phase 2 model scenarios;
- **Section 4** presents the key conclusions that can be drawn from this study; and
- The **Appendix** sections present the emission offset sensitivities, as well as further detail on the modelling methodology and assumptions, and an overview of Baringa.

All monetary figures presented in this report are in real 2020 currency.

2 Phase 1 – achieving less than 2 million tonnes of CO_2

2.1 Scenario assumptions

2.1.1 Overview

The key assumptions for each Phase 1 scenario, '70 by 30 (3.3 $MtCO_2$)' and 'Less than 2 $MtCO_2$', are presented in the tables below. Table 3 below details the key system-level assumptions, with Table 4 and Table 5 below presenting the ROI and NI assumptions respectively. Each value is based either on publicly available sources, or from Baringa analysis. In the remainder of Section 2.1 we explore the sources and reasoning underlying each assumption.

Table 3: Key Phase 1 scenario assumptions for the Integrated Single Electricity Market (I-SEM)

I-SEM Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Commodity & Carbon Prices			
Coal CIF ARA	*$/tonne*	73	73
Gas NBP	*p/therm*	61	61
Oil Brent	*$/bbl*	78	78
Carbon EUA	*€/tonne*	50	50
I-SEM DS3 Limits (Operational Constraints)			
SNSP limit	*%*	95%	100%
RoCoF limit	*Hz/s*	1.0	1.0
Minimum inertia	*MWs*	0	0
System stability minimum units - I-SEM	*#*	4	0
System stability minimum units - ROI[10]	*#*	0	0
System stability minimum units - NI	*#*	2	0
Interconnection Capacity			
Import limit	*MW*	2,150	2,150
Export limit	*MW*	2,200	2,200

[10] Although we have assumed that the minimum unit for system stability (Min Gen) constraint for ROI becomes an all-island constraint with the commission of the North-South interconnector, in practice there are no hours in the '70 by 30 (3.3 $MtCO_2$)' scenario in which less than 2 contributing units are on-load in ROI.

Table 4: Key Phase 1 scenario assumptions for the Republic of Ireland (ROI)

ROI Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Demand			
Total annual demand[11]	*GWh*	44,310	44,230
Total peak demand	*MW*	7,320	7,320
EV number	*#*	1,000,000	1,000,000
HP number	*#*	600,000	600,000
Installed Generation Capacity			
Onshore wind	*MW*	6,270	6,900
Offshore wind	*MW*	2,530	3,340
Solar PV	*MW*	2,550	3,350
Battery	*MW*	1,360	1,360
Fossil gas	*MW*	4,560	4,380
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*[12]	8,000	14,080

Table 5: Key Phase 1 scenario assumptions for Northern Ireland (NI)

NI Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Demand			
Total annual demand	*GWh*	10,750	10,730
Total peak demand	*MW*	1,780	1,780
EV number	*#*	371,700	371,700
HP number	*#*	158,500	158,500
Installed Generation Capacity			
Onshore wind	*MW*	1,970	2,240
Offshore wind	*MW*	270	380
Solar PV	*MW*	750	950
Battery	*MW*	340	340
Fossil gas	*MW*	1,600	1,600
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	2,000	3,520

[11] Total annual demand includes business as usual demand, demand from electric vehicles (EVs) and heat pumps (HPs), and energy storage demand. Imports and exports are excluded from this figure. Variations in this value between the Phase 1 scenarios arise from different energy storage patterns in the model runs.

[12] Megawatt-seconds (MWs) are the units of inertia, and are not synonymous with Megawatts (MW). 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 from the grid to power it.

2.1.2 Commodity and carbon prices

We have derived our commodity and carbon price assumptions from the Stated Policies scenario of the International Energy Agency (IEA) World Energy Outlook (WEO) 2020 publication. We have aligned our 2030 CIF ARA[13] coal and Brent Crude[14] oil prices with the Stated Policy scenario values of 73 $/tonne and 78 $/bbl respectively (real 2020 money). We have assumed that 2030 NBP[15] gas prices are set by the cost of fossil gas traded at HH[16] prices, imported as liquefied natural gas (LNG) from the United States (US). The cost of delivered LNG from the US includes the cost of HH fossil gas based on the Stated Policies scenario cost of 3.6 $/MMBtu, and costs for liquefaction, transport and regasification, each an in-house Baringa assumption. The final cost of NBP fossil gas is calculated as a time-weighted average price of 61 p/therm. We include a monthly seasonality on this price, calibrated by analysis of historical seasonal variation in North-West European gas prices.

We include annual (per kW) and short-term (per MWh) gas capacity charges in our modelling of fossil gas-fired plant in ROI and NI, sourced from Gas Networks Ireland[17] and Gas Market Operator (GMO) NI[18] releases respectively. We assume that the low load factors of the fossil gas-fired plant in each jurisdiction in these scenarios incentivises the switch from annual to short-term gas capacity charges.

We have calculated the carbon indifference price, the carbon price at which the short-run marginal costs (SRMC) of gas-fired and coal-fired plant are equal, based on the assumed NBP fossil gas and coal CIF ARA prices detailed above. We have assumed that the EUA[19] and UKA[20] carbon prices are each aligned with this value in 2030; 50 €/tCO_2.

2.1.3 I-SEM DS3 limits

In the '70 by 30 (3.3 MtCO_2)' scenario, we have taken EirGrid and SONI's latest views on DS3 limit (operational constraint) relaxations in I-SEM from the Tomorrow's Energy Scenarios (TES) 2019[21] and SONI TESNI 2020[22] documents respectively:

- We assume that the EirGrid TES target of a 95% simultaneous non-synchronous penetration (SNSP) limit is reached as in their Centralised Energy and Coordinated Action scenarios. This is higher than the 90% SNSP limit assumed in the original 70 by 30 study conducted in 2018, and represents a marked increase from the 75% limit today (under trial since 22nd April 2021)[23];

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13 North-West European hard coal price (Amsterdam-Rotterdam-Antwerp) including cost, insurance, and freight.
14 North-West European crude oil hub based in the North Sea.
15 National Balancing Point, a virtual trading hub for fossil gas based in the United Kingdom.
16 Henry Hub, a physical trading and distribution hub for fossil gas based in Louisiana, US.
17 https://www.gasnetworks.ie/corporate/gas-regulation/tariffs/transmission-tariffs/Short-term-capacity-examples.pdf
18 http://gmo-ni.com/assets/documents/Tariffs/2019-20/Daily-Gas-Prices/NI-Forecast-Tariff-Publication-GY2021.pdf
19 European Union Allowances, carbon credits used within the EU Emissions Trading System (EU ETS).
20 United Kingdom Allowances, carbon credits used within the UK Emissions Trading System (UK ETS).
21 http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-Report.pdf
22 https://www.soni.ltd.uk/media/documents/TESNI-2020.pdf
23 https://www.eirgridgroup.com/site-files/library/EirGrid/Operational_Constraints_Update_May_2021.pdf

- The present rate-of-change-of-frequency (RoCoF) limit of 1 Hz/s, under trial since 17th June 2020, is retained in the '70 by 30 (3.3 $MtCO_2$)' scenario;
- EirGrid's intent as stated in the TES is to relax the constraint around the minimum inertia required from conventional plant, currently active at 23,000 MWs. We assume that 10,000 MWs of inertia can be met by synchronous condensers across the all-island system (8,000 MWs in ROI and 2,000 MWs in NI) fitted with flywheels to provide large amounts of inertia in the '70 by 30 (3.3 $MtCO_2$)' scenario. These assets are a new assumption following the intent of the SEM Committee to procure low-carbon inertia[24], and were not present in the original 70 by 30 study;
- The Minimum Generator Units for System Stability (Min Gen) constraint for ROI (currently 5 units) is removed, being replaced by an equivalent all-island constraint of 4 units on-load at all times. The primary NI Min Gen constraint is retained with 2 units required, down from the 3 units currently required;
- The local Dublin and South generation constraints are retained, with the Moneypoint and North West constraints assumed to be met by zero-carbon solutions including network reinforcement.

In the 'Less than 2 $MtCO_2$' scenario, we have assumed that the bulk of the key DS3 limits have been resolved using zero-carbon solutions, with any inertia requirement met by synchronous condensers:

- We assume that an SNSP limit of 100% is achieved;
- The RoCoF limit of 1 Hz/s is retained from present trial levels;
- EirGrid's stated ambition in the TES to relax the constraint around the minimum inertia required from conventional plant is achieved. We assume that the 17,500 MWs required (all-island) for the Celtic Interconnector to meet the 1 Hz/s RoCoF constraint in all hours can be met entirely by dedicated synchronous condensers fitted with flywheels throughout I-SEM;
- The Min Gen constraints are relaxed in both ROI and NI;
- The local Dublin, South, Moneypoint and North West generation constraints are assumed to be met by grid reinforcements and/or deployment of voltage stability assets;
- Operating reserve requirements are met entirely by dedicated battery capacity. Ramping requirements, though not modelled explicitly, are not considered to be binding as detailed below.

Today synchronous condensers can be obtained with capacities up to ~4000 MWs; with around 5 units of this size required to provide the 17,500 MWs of combined inertia in ROI and NI assumed in the 'Less than 2 $MtCO_2$' scenario. We have sourced our I-SEM reserve requirements from EirGrid's Operation Constraints Updates.

Operating reserves and ramping

Beyond these assumptions, we have assumed that the primary operating reserve (POR) and secondary operating reserve (SOR) requirements are each increased to 100% of the largest infeed by 2030. This is a conservative assumption, derived from previous EirGrid statements; a recent

[24] https://www.semcommittee.com/sites/semc/files/media-files/SEM-21-021%20System%20Services%20Future%20Arrangements%20-%20Decision%20Paper%201.pdf

consultation with the aim of reducing DS3 tariffs[25] implied that there will be sufficient, and potentially surplus, POR and SOR provision available from batteries earlier than previously expected, possibly as soon as 2022.

It is becoming clear therefore that provision of reserves, as well as inertia and reactive power services, can be met with mature zero-carbon technologies that are either operational or in the construction and planning stages of development in both the Irish and British power sectors. One ancillary service that has not been the subject of detailed public analysis is the provision of zero-carbon ramping services. This requirement is expected to increase with the addition of non-dispatchable renewable generation capacity. Interconnectors (both existing and new-build), curtailed wind and solar capacity, batteries, long-duration storage, controllable electrolysers, demand-side flexibility, and hydrogen-fired thermal plant are each capable of providing zero-carbon ramping capability. Preliminary analysis conducted by Baringa indicates that zero-carbon ramping capability is either not a binding constraint, or can be resolved for a small cost, in a system of high renewable penetration. It is recommended that EirGrid sets out their ramping policy and projected requirements over the coming decade in order for market players to factor this capability into development plans.

2.1.4 Interconnection and external markets

In the market modelling framework of this study, the I-SEM day-ahead market is coupled directly with the neighbouring British and French markets via a series of interconnectors. Interconnectors are typically private self-funded business ventures that seek to recover costs through cross-border wholesale power market arbitrage, capacity market revenues and ancillary service revenues. Unlike transmission or distribution network assets, the capital expenditure and maintenance costs of interconnectors are not recovered directly from consumers in the form of network charges unless market revenues prove insufficient. Based on the outcome of feasibility assessments of multiple interconnectors in Europe, in many of which Baringa was directly involved, we have validated that the business cases for the 500 MW Greenlink (to GB) and 700 MW Celtic (to France) interconnectors are sufficient to include them within our modelling in this study.

In addition, we assume that the Moyle interconnector export capacity to Scotland is increased to 500 MW[26] in line with EirGrid's Generation Capacity Statement (GCS) 2020[27]. Moyle's import capacity is assumed to remain at 450 MW. We model the East-West HVDC[28] interconnector at its current maximum capacity of 500 MW in each direction. Finally we assume that the North-South interconnector between ROI and NI is commissioned prior to the horizon of this study. Each of these assumptions is held consistent across all scenarios.

The installed generation capacity assumptions of both neighbouring markets are based on the Baringa Reference Case[29] assumptions, which in-turn are sourced from a combination of market

[25] http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-System-Service-Tarrif-Review-Consultation_28-05-2021.pdf
[26] An additional new-build interconnector would be required to meet the export capacity considered in this study if the Moyle export capacity does not increase to 500 MW.
[27] https://www.eirgridgroup.com/site-files/library/EirGrid/All-Island-Generation-Capacity-Statement-2020-2029.pdf
[28] High-Voltage Direct Current
[29] The Reference Case is the 'central' scenario in Baringa's in-house pan-European market modelling framework.

intelligence and internal analysis. However, compared to the Reference Case we have increased the renewable deployment in both GB and France, to reflect consistent ambitions with I-SEM in the Phase 1 scenarios.

We have assumed that:

- 20 GW of onshore wind, 35 GW of offshore wind, and 15 GW of solar PV capacity is commissioned in GB; and
- 40 GW of onshore wind, 9 GW of offshore wind, and 41 GW of solar PV is deployed in France by 2030.

This deployment of offshore wind in GB exceeds the Reference Case assumption, and assumes that the GB market will be closer to achieving the 40 GW target announced by the UK Government in October 2020[30]. The French capacity assumptions are derived from the Baringa High Commodities Case, an in-house scenario in which consistently high commodity and carbon prices induce rapid investment in renewable generation capacity.

2.1.5 Demand

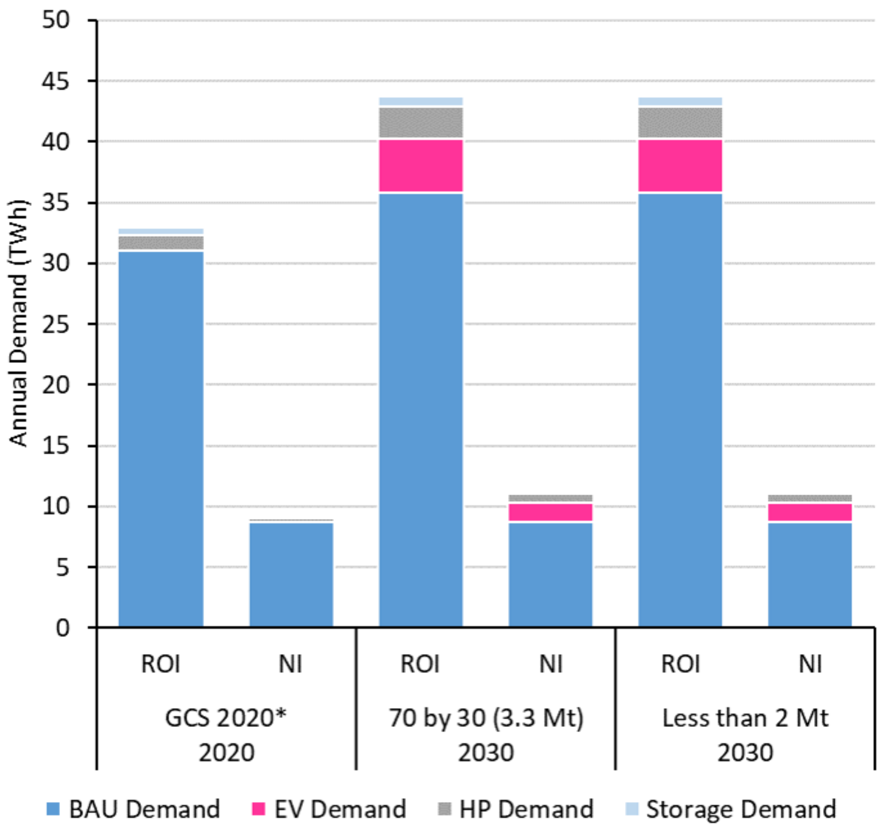
We have aligned our electricity demand assumptions for both ROI and NI, including the breakdown into fixed and flexible contributions, between the 'Less than 2 $MtCO_2$' and '70 by 30 (3.3 $MtCO_2$)' scenarios. Figure 4 below shows the 2030 annual demand projections in each scenario in addition to the 2020 projection from the GCS 2020*.

*The GCS 2020 projection does not account for the impact of COVID-19 on outturn consumer demand. We have included internal Baringa assumptions to adjust the projection, as well as differentiate between business as usual (BAU) demand, storage demand, and demand from electric vehicles (EVs) and heat pumps (HPs). Storage demand in the projected scenarios is an optimised model output resulting rather than a model input.

We have sourced our ROI and NI BAU demand figures from the median scenario of the GCS 2020, by calculating the load projections net of flexible demand, extending each of the projections out to 2030. These BAU demand projections include EirGrid's assumptions regarding data centre demand as stated in the GCS 2020; up to 30% of the all-island BAU demand in 2030.

[30] https://www.gov.uk/government/news/new-plans-to-make-uk-world-leader-in-green-energy

Figure 4: Annual demand projections in ROI and NI



Demand-side flexibility

In addition to this inflexible component of demand, we have considered the 2019 Climate Action Plan targets for EV and HP uptake in ROI, and the analogous projections for NI from the SONI TESNI 2020 Accelerated Ambition scenario. The flexible demand projections correspond to:

- 1,000,000 EVs (4.4 TWh) and 600,000 HPs (2.7 TWh) in ROI; and
- 370,000 EVs (1.6 TWh) and 160,000 HPs (0.7 TWh) in NI.

The demand associated with these levels of EV and HP deployment exceed that assumed in the GCS, and so our total demand projections exceed that of the GCS median scenario. We assume that 25% of the EV demand in both ROI and NI is flexible, and can react to pricing signals within each day, according to hourly limits. This corresponds to around 250,000 flexible EVs in ROI, and 90,000 in NI. We do not consider vehicle-to-grid (V2G) flows from EVs back onto the electricity network. The flexibility of HP demand is assumed to be limited. In addition to flexible EV capacity, we assume based on a European Commission study[31] that around 360 and 120 MW of BAU demand-side capacity in ROI and NI respectively is able to be curtailed in hours in which generation is limited, and a further 160 and 50 MW of demand is flexible, being able to shift load profile. This projection represents an increase in BAU flexible demand-side capacity from today, representative of smart

[31] https://ec.europa.eu/energy/sites/ener/files/documents/demand_response_ia_study_final_report_12-08-2016.pdf

meter roll-out in the residential sector and the increasing exploration of demand-side flexibility in the industrial and commercial sectors. Suitable demand-side assets include heating, ventilation and air conditioning of commercial buildings, refrigeration, dishwashers, laundry driers, washing machines and other residential home automation applications, as well as flexible load in heavy industry. Appendix A.1 presents a series of sensitivities that explore extensive electrification of heat demand in the industrial sector.

Although advances in consumer technology offer a pathway to achieve the penetration of demand-side flexibility, e.g. through smart EV home charging, policy will need to be developed to encourage widespread adoption.

In aggregate, these assumptions provide an approximately 80:20 split of total I-SEM annual demand between ROI and NI. This demand-weighted ratio has been used throughout this study to divide deployment of capacity providing system services, e.g. synchronous condensers, and system-side consumer costs and benefits such as capacity provision and imperfection charges (in-line with current policy).

2.1.6 Installed generation capacity

Renewable generation capacity

Our renewable energy source (RES) capacities are based around the 2019 Climate Action Plan (ROI), the Programme for Government (ROI) and SONI TESNI 2020 Accelerated Ambition (NI) targets for onshore and offshore wind capacity. The Programme for Government (PfG) does not state explicit targets for solar PV capacity. Considering the pipeline of projects in development, the results of the RESS 1 auction, and the likely take-up of domestic solar capacity following the introduction of the upcoming domestic feed-in tariff, we have concluded that the 5 GW figure from the 'Higher Solar Ambition' scenario of the 'The Value of Solar in Ireland'[32] report from the Irish Solar Energy Association (ISEA) represents a target consistent with the PfG. In aggregate these targets comprise:

- 8,200 MW of onshore wind, 5,000 MW of offshore wind, and 5,000 MW of solar PV in ROI; and
- 2,540 MW of onshore wind, 500 MW offshore wind, and 1,170 MW of solar PV in NI.

These target capacities are too high to integrate into I-SEM without excessive levels of oversupply and curtailment, based on our demand assumptions and today's power system. Therefore, we have pro-rated equally the new-build RES capacities required to reach these targets in the '70 by 30 (3.3 $MtCO_2$)' and 'Less than 2 $MtCO_2$' scenarios to the maximum levels that can be accommodated using solutions that reflect 'more of the same'. In Section 3, we explore new approaches that could allow more renewable capacity to be integrated, but these solutions require additions to the current approach.

The '70 by 30 (3.3 $MtCO_2$)' scenario assumes a build of 50% of the Programme for Government (PfG) new-build target and around 55% of the NI TES target. In the 'Less than 2 $MtCO_2$' scenario, we have commissioned 67% of the new-build capacity required to meet the PfG targets in ROI, and just over 75% of the NI TES targets. These installed capacity assumptions are summarised in Table 6 below.

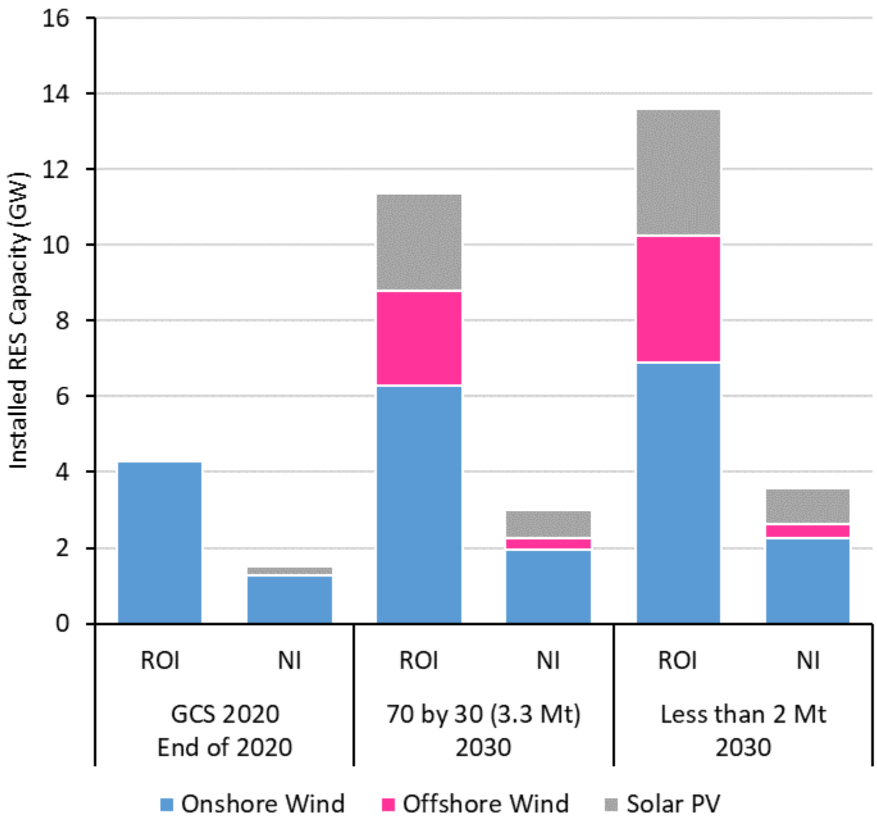
[32] https://irishsolarenergy.org/wp-content/uploads/2021/03/AFRY_ISEA_The-Value-of-Solar-in-Ireland_v300.pdf

Table 6: Phase 1 installed renewable generation capacity assumptions in ROI and NI

RES Capacity Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Proportion of New-Build Targets			
Programme for Government (ROI)	*%*	50%	67%
SONI TES 2020 Accelerated Ambition (NI)	*%*	55%	75%
Installed ROI RES Capacity			
Onshore wind	*MW*	6,270	6,900
Offshore wind	*MW*	2,530	3,340
Solar PV	*MW*	2,550	3,350
Installed NI RES Capacity			
Onshore wind	*MW*	1,970	2,240
Offshore wind	*MW*	270	380
Solar PV	*MW*	750	950

The projected RES capacity in each scenario is presented, in comparison to the installed capacity at the 'end of 2020' as stated in the GCS 2020, in Figure 5 below.

Figure 5: Installed ROI and NI RES capacity projections



Network constraints are not accounted for in this study, and the installed capacity of renewables presented above are sufficient to deliver the renewable generation (RES-E) levels and carbon savings detailed in Section 2.3 without dispatch-down from constraint actions. **Therefore, once grid constraints are accounted for, higher renewable generation capacities could be required to achieve the renewable generation reported in this study.**

Energy storage and residual thermal capacity

In each scenario we consider 500 MW of energy market battery capacity with a 2 hour duration throughout I-SEM, and 500 MW of capacity with a 3 hour duration. In addition, we model 700 MW of 0.5 hour duration 'DS3-only' battery capacity in I-SEM. These battery units are unable to participate in the day-ahead market, but are able to meet the projected 700 MW operating reserve requirement in I-SEM (100% of the largest infeed, the Celtic interconnector). The three tranches of battery capacity are split between ROI and NI on a demand-weighted basis.

In the '70 by 30 (3.3 $MtCO_2$)' scenario, we have used our in-house capacity market model to simulate the Capacity Remuneration Mechanism (CRM) auctions to determine the new-build fossil gas-fired capacity required to maintain a 4-5% de-rated capacity margin (DRCM) in I-SEM in 2030. We have aligned stated short-term new-build capacity and decommissioning of existing capacity with the GCS 2020. Although it is assumed that wind and solar capacity does not participate in the CRM auction directly, the expected contribution to meeting peak demand of this capacity is netted off the CRM procurement target in accordance with their assumed auction de-rating factors in the T-4 2024/25 auction final information pack[33]. In ROI, this results in a total of 4,600 MW of installed fossil gas-fired capacity. This includes new-build open cycle gas turbine (OCGT) and gas engine capacity, in addition to residual existing combined cycle gas turbine (CCGT) capacity. 200 MW of biomass-fired capacity is modelled in ROI, in addition to 220, 290, and 90 MW of existing conventional hydro, pumped hydro energy storage, and waste-to-energy capacity respectively. In NI, the CRM auction methodology results in 1,600 MW of installed gas-fired capacity, along with 30 MW of existing waste-to-energy capacity.

The incremental build of renewable capacity in the 'Less than 2 $MtCO_2$' scenario decreases the requirement on procurement of new-build fossil gas-fired capacity to maintain a DRCM of 4-5% in I-SEM. To achieve this in this scenario we consider 4,380 MW of fossil gas-fired capacity in ROI, with the 1,600 MW of capacity in NI retained.

2.2 Modelling methodology

2.2.1 Wholesale electricity market 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 hourly demand profiles, commodity prices, plant build and retirement, and hourly 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 30 interconnected

[33] https://www.sem-o.com/documents/general-publications/Final-Auction-Information-Pack_FAIP2425T-4.pdf

European markets to produce hourly dispatch for the generators and hourly market prices taking full consideration of plant operational constraints (ramp rates, start time, availability etc.).

The hourly input 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 plant, with the latter assumed to have a higher load factor. We consider repowering of legacy wind plant towards the tail-end of their economic life.

The representation of the all-island system in the model 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 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 I-SEM DS3 limits are active. These include system-wide limits such as the SNSP and RoCoF limits, and Min Gen and minimum inertia constraints, as well as localised limits such as the Dublin and South generation constraints. A comprehensive list of reserve requirements is also modelled in this run. Grid constraints are not explicitly considered in the power market model during either run.

In alignment with the I-SEM market arrangements, wholesale electricity price projections in this report are derived from the outputs of the 'unconstrained' run (representative of the day-ahead schedule), and generator dispatch schedule from the 'constrained' run (representative of position after dispatch balancing to meet DS3 limits). The incremental cost paid to generators in the 'constrained' run is the dispatch balancing cost (DBC) and is considered in the cost-benefit analysis completed in Phase 1.

2.2.2 Capacity Remuneration Mechanism (CRM) modelling

As described in Section 2.1.6, we assume that the CRM auctions target a long-term DRCM of between 4 and 5%. This figure is based on Baringa analysis surrounding historical outturn provision requirements, and is designed to be representative of a suitable margin above a central peak demand forecast to cover an exceptionally high peak demand event.

Around 1,100 MW of the fossil gas-fired generation capacity in ROI in the '70 by 30 (3.3 $MtCO_2$)' scenario is new-build capacity. This projection includes build-out of OCGT and gas engine capacity in the early 2020s as detailed in the GCS 2020, as well as further OCGT build as determined in the DRCM calculation. Around 850 MW of this capacity is assumed to be built in the 'Less than 2 $MtCO_2$' scenario, with around 600 MW of new-build OCGT and gas engine capacity built in NI in both scenarios.

To enable investment in this new-build capacity, we have considered the increase in auction clearing price required to deliver these assets. We assume that the CRM clearing price in both scenarios is 70 €/kW, de-rated, based-on high-level missing money calculations. This represents an increase in price compared to previous auctions, which have cleared at prices around 46 €/kW, de-rated[34]. This increase accounts for the depression in wholesale market revenues received by fossil gas-fired plant in the Phase 1 scenarios relative to those received historically. The penetration of renewable capacity in both scenarios discourages baseload operation of fossil gas-fired plant in the day-ahead schedule, forcing them to operate in a more 'peaky' manner, capturing revenue only during hours of peak demand, or low RES output. Revenues captured during hours of high price are relatively insulated from the incremental build of RES capacity in the 'Less than 2 $MtCO_2$' scenario and so no additional increase in clearing price beyond the '70 by 30 (3.3 $MtCO_2$)' scenario has been considered.

This clearing price has been used in the Phase 1 cost-benefit analysis to determine the impact of incremental renewable capacity on the cost of CRM provision as detailed in Section 2.2.8 below.

2.2.3 Cost-benefit analysis overview

In calculating the net cost or benefit to the consumer of achieving the 'Less than 2 $MtCO_2$' scenario, we have considered the following costs and benefits relative to the '70 by 30 (3.3 $MtCO_2$)' scenario:

- **PSO support costs**: the net Public Service Obligation (PSO) levy cost of subsidising incremental renewable capacity build, and any increase in cost to support existing plant due to reduced captured prices;
- **Network costs**: the cost of reinforcing the transmission network to allow incremental wind and solar capacity onto the I-SEM;
- **DS3 costs**: the additional cost of deploying the technology necessary to meet DS3 limits and reserve requirements with zero-carbon system services;
- **Wholesale benefits**: the savings associated with the reduced 'cost to load' of the day-ahead schedule, the payments made to generation assets, from lower wholesale prices;
- **CRM benefits**: the net reduction in the cost of provision of dispatchable capacity due to incremental de-rated capacity of wind and solar plant;
- **DBC benefits**: the savings associated with the reduction in dispatch balancing costs from the provision of zero-carbon system services.

The costs and benefits calculated in the analysis apply for the year of the modelling horizon only, 2030, and do not include any preceding or subsequent costs or benefits incurred or received in other years. For example, the total cost associated with the build-out of infrastructure is assumed to be annuitized across its economic lifetime, according to a weighted average cost of capital (WACC); the cost calculated is that incurred by consumers in the year 2030.

2.2.4 Public Service Obligation (PSO) support costs

The Renewable Electricity Support Scheme (RESS) in ROI subsidises wind and solar capacity by providing a two-way contract-for-difference (CfD)[35] at a fixed strike price. We assume that the incremental new-build RES capacity in ROI in the 'Less than 2 $MtCO_2$' is supported by RESS, or an analogous support mechanism. The cost associated with new-build RES capacity under this

[34] https://www.eirgridgroup.com/newsroom/t-4-2324-final/

[35] In the RESS two-way CfD, the generator receives a set value per MWh produced, the 'strike price', which is not indexed by CPI and is a fixed nominal price for the term of the contract. When the reference price falls below the strike price, the generator receives top-up payments to supplement the market income. When the reference price exceeds the strike price, generators pay back the difference.

mechanism is conservatively assumed to be secured from end consumers via the PSO levy. If the 2019 Climate Action Plan ambition of delivering 15% RES-E using corporate power-purchase agreements (CPPAs) is achieved, this cost will be reduced below the levels presented in Section 2.3.2. The strike price for each RES technology in 2030 is assumed to converge with the LCOE for that technology:

- New-build onshore wind capacity is assumed to have an LCOE of 50 €/MWh and a load factor of 35%;
- New-build offshore wind capacity is assumed to have an LCOE of 65 €/MWh and a load factor of 45%; and
- New-build solar PV capacity is assumed to have an LCOE of 60 €/MWh and a load factor of 11%.

The 'cannibalisation effect'[36] of renewable deployment on captured prices adds an additional cost element to the PSO levy to support existing renewable capacity in ROI under Renewable Energy Feed-in Tariff (REFIT) contracts, a one-way CfD[37] mechanism. We assume the onshore wind capacity under this scheme has an average load factor of 30%. The incremental contributions to the PSO levy are independent of the REFIT strike price.

In NI, we assume that new-build RES capacity is supported under the UK CfD scheme, a two-way support mechanism analogous to the RESS, or a similar mechanism. The same LCOE and load factor assumptions are used as in the ROI calculation. Existing renewable capacity in NI has been supported by the legacy Northern Ireland Renewables Obligation (NIRO) scheme, under which support is made to RES generators on a per MWh basis[38]. The nature of this scheme means that no incremental cost is incurred to the end consumer from captured price movements.

2.2.5 Network costs

The EirGrid and SONI Shaping our Electricity Future publication provides quantitative projections of the cost incurred to reinforce the transmission network in ROI and NI to accommodate renewable build. These costs represent investment required to 'uprate' and 'upvoltage' existing circuits, as well as build new circuits and new network equipment. We have conservatively taken the 'Developer-Led' scenario as the basis of our assumptions, calculating a 'per MW of renewable capacity' cost from the assumed renewable build in this scenario. This value equates to around 0.25 €m/MW in ROI, and 0.29 €m/MW in NI. The 'Developer-Led' scenario assumes that wind and solar capacity is deployed in locations requested by developers, necessitating the highest costs of the scenarios in the publication.

The costs detailed above represent the 'deep' reinforcement costs associated with the transmission network. 'Shallow' transmission costs, and both 'deep' and 'shallow' connection costs on the

[36] As RES plant bid into the day-ahead market at prices of around 0 €/MWh, wholesale prices tend to be lower during hours of high wind or solar output than other hours. This causes the prices captured by these plant to be lower than the average wholesale price by a certain 'captured price discount'. This discount increases as the capacity of correlated RES output increases; 'cannibalising' captured prices.

[37] In the REFIT one-way CfD, the generator receives a set value per MWh produced, the 'strike price', which is indexed by CPI. When the reference price falls below the strike price, the generator receives top-up payments to supplement the market income. When the reference price exceeds the strike price, generators do not have to pay back the difference, and secure additional income.

[38] In the NIRO subsidy payments, renewable generators are provided with a certain number of Renewables Obligation Certificates (ROCs) for each MWh produced, which can be sold to suppliers. This represents a 'top-up payment' per MWh, independent of the wholesale price.

distribution network level are included in the LCOE cost assumptions for wind and solar capacity. Any incremental costs associated with these are therefore included in the PSO levy cost detailed above.

The costs per MW, differentiated by ROI and NI, are applied to the incremental RES build in the 'Less than 2 $MtCO_2$' scenario assuming an economic lifetime of 40 years at a WACC of around 5%. This annuitization is more conservative than the assumption of 3.8% WACC over a 50 year lifetime used in the Price Review 5 (PR5) Determination Papers[39]. This conservative approach reflects the potential for inflated costs in a network with high renewable penetration beyond 70% RES-E.

2.2.6 DS3 costs

In the 'Less than 2 $MtCO_2$' scenario we have considered the investment necessary to meet DS3 limits using zero-carbon system services. We have assumed that the incremental build-out of synchronous condenser capacity relative to the '70 by 30 (3.3 $MtCO_2$)' scenario is divided by jurisdiction in proportion to the total annual demand split. An indicative all-in cost of a synchronous condenser is around €50m for a 4000 MWs asset[40]. We have used this figure to provide a 'per MWs' cost of this capacity, and annuitized the cost over an economic lifetime of 15 years with a WACC of 12%. This cost of capital assumes a perceived level of risk surrounding asset revenues. Procurement of system services via long-term contracts would mitigate this risk premium by increasing revenue certainty, and contribute to lower costs.

In the '70 by 30 (3.3 $MtCO_2$)' scenario, a proportion of the operating reserve requirement is met by fossil gas-fired plant that are required to be on-load to meet the residual Min Gen constraints. The zero-carbon solutions to these constraints in the 'Less than 2 $MtCO_2$' necessitate additional remuneration to the 'DS3-only' 0.5 hour duration batteries for provision of these services. We model the associated DS3 cost as the net 'missing money' of the assets after CRM revenue, assuming an annuitized technology cost of around 55 €/kW and de-rating factors as found in the T-4 2024/25 auction final information pack. We assume that this cost is incurred by end consumers in ROI and NI according to the ratio of domestic demand in each jurisdiction.

We have assumed that any incremental voltage requirements can be met by renewable generation, synchronous condensers, and the transmission network reinforcement detailed above. The associated costs are therefore divided between PSO support costs, network costs, and DS3 costs.

2.2.7 Wholesale benefits

By bidding at a price of 0 €/MWh (or at negative prices as is incentivised for RES assets under legacy support schemes) into the day-ahead market, wind and solar capacity acts to lower the average annual wholesale price in I-SEM. The incremental RES build in the 'Less than 2 $MtCO_2$' increases the downward pressure on price. This reduces the 'cost to load', i.e. the value of the total payments made to generators in the day-ahead market to meet domestic demand, reducing cost for the end consumer. This benefit equates to the product of the domestic consumer demand in ROI or NI, (excluding storage demand) and the demand-weighted wholesale price.

[39] https://www.cru.ie/document_group/price-review-5-electricity-networks/

[40] https://www.esb.ie/tns/press-centre/2021/2021/04/09/esb-announces-green-atlantic-@-moneypoint

2.2.8 CRM benefits

In our modelling of 2030 we consider the Irish CRM as acting to ensure that that the DRCM in I-SEM remains around 4-5%. Renewable generation capacity, although not participating in the CRM auctions directly[41], acts to reduce the fossil gas-fired capacity provision required by the CRM. We consider the net benefit to the consumer that arises from the incremental RES build in the 'Less than 2 $MtCO_2$' scenario, using the corresponding de-rating factors in the T-4 2024/25 auction final information pack; around 9% and 13% for wind and solar capacity respectively. The benefit that results from this decreased provision is assigned to ROI and NI according to the ratio of domestic demand, in-line with current policy.

In both scenarios we assume that the CRM clearing price in both scenarios is 70 €/kW, de-rated, as detailed in Section 2.2.2.

2.2.9 DBC benefits

In the 'constrained' model run of the '70 by 30 (3.3 $MtCO_2$)' scenario, the PLEXOS model is forced to re-dispatch plant away from their ex-ante position in the day-ahead market in order to meet the I-SEM DS3 limits. This incurs an additional cost to the system relative to the cost-optimised day-ahead market dispatch, known as the dispatch-balancing cost. In the 'Less than 2 $MtCO_2$' scenario, zero-carbon provision of system services reduces the need for this re-balancing of plant, avoiding some of the dispatch balancing cost component incurred by end consumers. In accordance with current policy we assume that this cost would be included as part of the 'imperfections charge' included in end consumer bills. The benefit from its avoidance is divided between consumers in ROI and NI by the ratio of domestic demand in the two jurisdictions.

2.3 Results and discussion

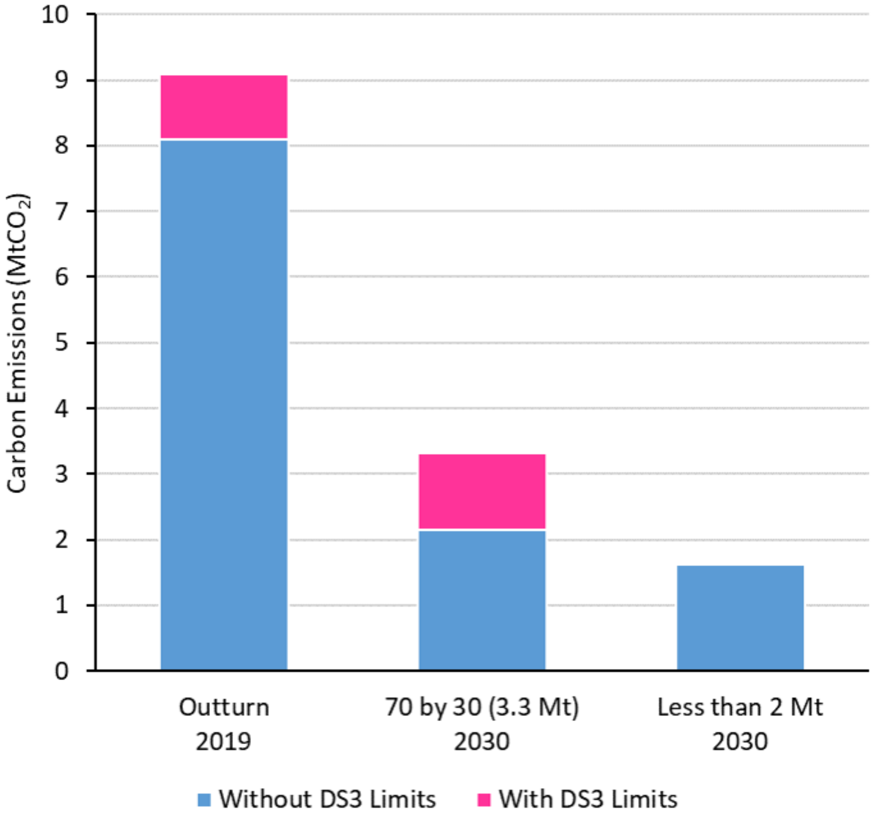
2.3.1 Power sector CO_2 emissions

In 2019, emissions from the ROI power sector totalled around 9 million tonnes of CO_2[42] ($MtCO_2$). Around 1 $MtCO_2$ emissions[43] resulted directly from re-dispatch of plant from their day-ahead positions to meet DS3 limits (dispatch balancing).

Figure 6 below presents the ROI power sector emissions in the '70 by 30 (3.3 $MtCO_2$)' and 'Less than 2 $MtCO_2$' scenarios. 'Without DS3 Limits' refers to emissions that result from the ex-ante positions of plant in the day-ahead schedule. 'With DS3 Limits' emissions represent incremental emissions from re-dispatch of plant to meet I-SEM DS3 limits but does not consider any deviation from ex-ante position to meet grid constraints.

[41] Renewable plant backed by RESS or UK CfD subsidies can participate in the CRM auction, but this is not mandatory and without incentive, as CRM revenues offset support payments.
[42] https://www.seai.ie/publications/Energy-in-Ireland-2020.pdf
[43] Estimated based on Baringa analysis.

Figure 6: ROI power sector emissions from day-ahead plant position and dispatch balancing



Growth in RES penetration in the '70 by 30 (3.3 $MtCO_2$)' scenario results in a decrease to 2.1 and 1.2 $MtCO_2$ emissions in ROI in 2030 from day-ahead positions and dispatch balancing actions respectively. The combined 3.3 $MtCO_2$ emissions is significantly below the 5 $MtCO_2$ determined in the original 70 by 30 study. ROI emissions in this scenario are also below the 4-5 $MtCO_2$ projected in the 2019 Climate Action Plan 70% RES-E adherent scenario. These comparisons are reflective of the increased ambition towards zero-carbon solutions to residual DS3 limits captured in this study, including the implementation of a 95% SNSP limit and deployment of 8,000 MWs of inertia providing synchronous condensers in ROI and 2,000 MWs in NI. The Baringa 'Store, Respond and Save'[44] study showed that zero-carbon system services can account for 2 $MtCO_2$ alone in 2030.

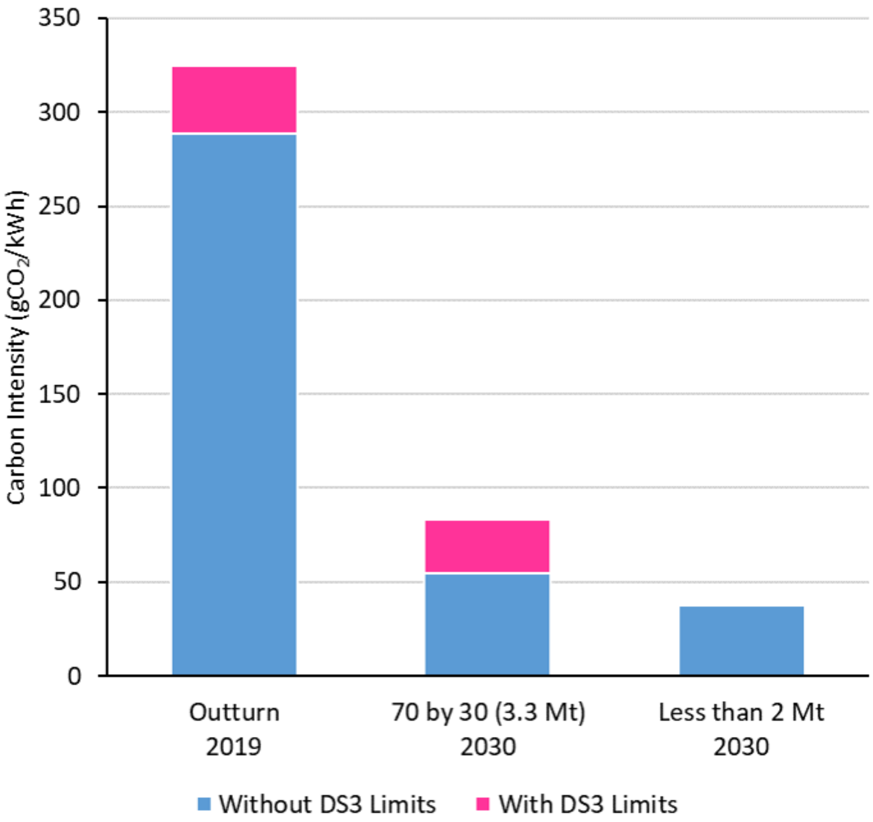
In the 'Less than 2 $MtCO_2$' scenario, ROI emissions total 1.6 $MtCO_2$, entirely from fossil gas-fired generation of CCGTs, OCGTs and gas engines remaining in the generation fleet. Zero-carbon solutions to I-SEM DS3 limits remove any incremental emissions associated with re-dispatch of plant.

The emission intensity of the ROI power sector, a measure of the CO_2 produced per unit of domestic generation, are significantly below those seen historically in each scenario as presented in Figure 7 below. In 2019, the emission intensity of the ROI power sector totalled 324 grams of CO_2 per kWh generated including emissions from re-dispatch of plant to meet DS3 limits. Conversely, the '70 by 30 (3.3 $MtCO_2$)' and 'Less than 2 $MtCO_2$' scenarios achieved intensities of 84 and 38 gCO_2/kWh in 2030 respectively in ROI. The greatly reduced carbon intensity in the 'Less than 2 $MtCO_2$' scenario also acts

[44] https://windenergyireland.com/images/files/iwea-baringastorerespondsavereport.pdf

to decarbonise the heat and transport sectors due to the penetration of electric vehicles and heat pumps assumed.

Figure 7: CO_2 emission intensity of ROI electricity generation

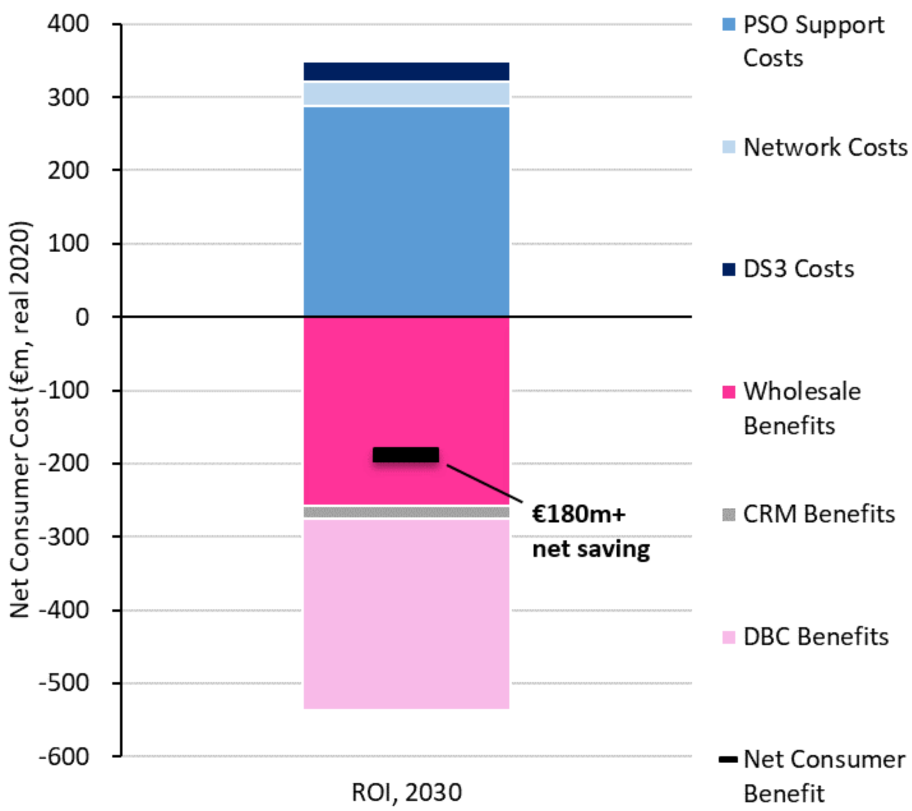


The 'Less than 2 $MtCO_2$' scenario represents the first step along the pathway to reach a zero-carbon power system. Section 3 of this report explores further steps along this pathway, which may not be fully concluded by 2030 but could be delivered early into the decade.

2.3.2 Costs and benefits to the end consumer

The results of the end consumer cost-benefit analysis of the 'Less than 2 $MtCO_2$' scenario are presented below in Figure 8. Each of the consumer costs and benefits presented is calculated relative to the costs of the '70 by 30 (3.3 $MtCO_2$)' scenario, and represent costs and benefits for the year 2030 alone, i.e. they do not include any costs or benefits that are incurred or received from investment in the years prior to 2030.

Figure 8: Costs and benefits to the end consumer of the 'Less than 2 $MtCO_2$' scenario



The 'Less than 2 $MtCO_2$' scenario results in a net saving for end consumers in ROI of over €180m versus the '70 by 30 (3.3 $MtCO_2$)' scenario in 2030. This net benefit is conferred from the following costs and benefits:

- Increased renewable deployment in the 'Less than 2 $MtCO_2$' scenario necessitates greater contributions to the PSO levy to support the incremental new-build renewable capacity. Additionally, depressed wholesale prices increase the support required for the residual capacity under REFIT contracts in ROI. This incremental cost amounts to around €288m in 2030.
- Additional cost is incurred from reinforcement of the network required to enable greater renewable penetration, e.g. from uprating of circuits and the cost of new equipment, as well as from the DS3 cost associated with incremental synchronous condenser build and support of reserve providing batteries. These costs amount to around €32m and €28m in ROI respectively. Additional costs may be incurred to alleviate DS3 limits such as the localised Dublin and South generation constraints if the synchronous condensers and batteries are not strategically placed within the network.
- Renewable assets bidding into the day-ahead market at zero marginal cost act to reduce the wholesale power price in I-SEM in the 'Less than 2 $MtCO_2$' scenario to 46 €/MWh in 2030, down from 52 €/MWh in the '70 by 30 (3.3 $MtCO_2$)' scenario. This depression reduces the 'cost to load', the total payment given to generation assets, in the system by approximately €259m, providing a net benefit to the end consumer.

- We have considered the effect of new-build renewable capacity on the procurement of thermal capacity required under the Capacity Remuneration Mechanism in I-SEM. Reductions in the de-rated capacity procurement required benefit the consumer by around €17m in ROI in 2030.
- Zero-carbon solutions to DS3 limits have reduced the dispatch balancing costs incurred to re-dispatch plant to meet these limits in the '70 by 30 (3.3 $MtCO_2$)' scenario. The associated saving amounts to around €262m in ROI in 2030. The cost savings associated with addressing the final DS3 limits in the 'Less than 2 $MtCO_2$' scenario are relatively large as they include the embedded cost savings associated with system operational improvements made over two decades to be able to operate the system at 100% SNSP and without fossil fuel-fired generation; the full benefit of this is only realised when the final limit is addressed.

2.3.3 Renewable electricity generation (RES-E)

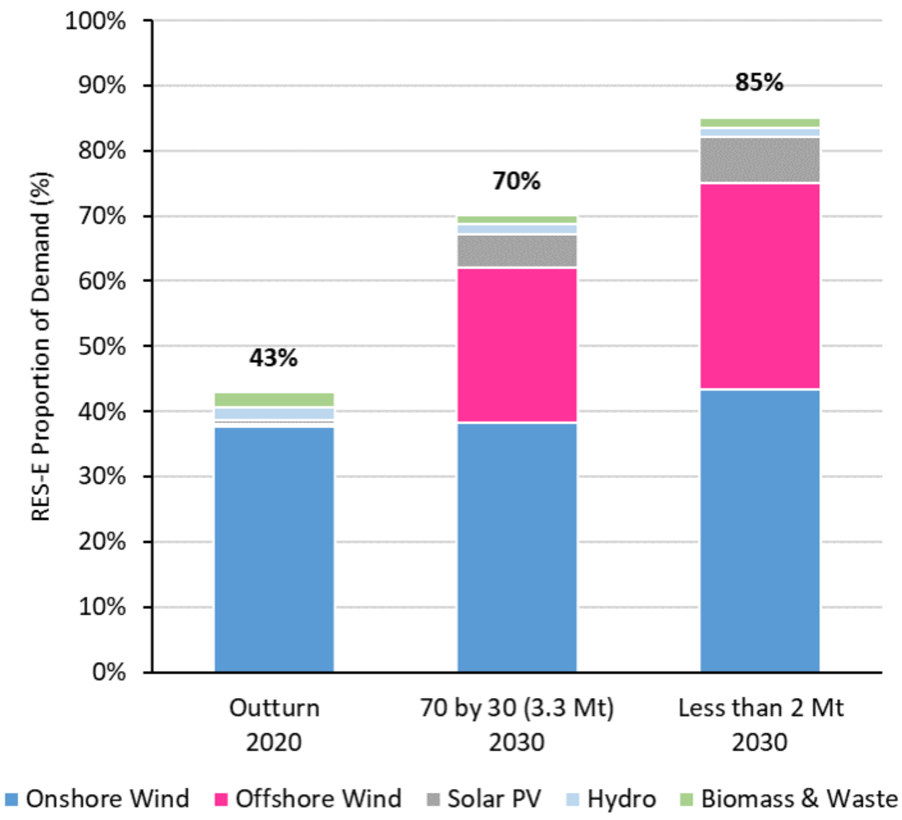
In the GCS 2020, EirGrid defines the RES-E percentage as the sum of the outturn generation from wind, solar, hydro and biomass plant, in addition to half the outturn generation from waste-to-energy plant, divided by total domestic consumer demand, i.e. electricity demand excluding storage load and exports. A prorated proportion of co-firing biomass/peat generation is included in this definition.

Under this methodology, domestic renewable generation in ROI totalled around 43% in 2020[45]. The majority of this electricity was generated by onshore wind capacity, with the remainder comprised of solar, hydro, waste and co-firing biomass/peat generation, as well as output from the 25 MW Arklow bank offshore wind demonstration project. Depression of electrical demand from national lockdowns associated with the COVID-19 outbreak increased the 2020 RES-E proportion relative to previous years.

The RES-E percentages in ROI in the '70 by 30 (3.3 $MtCO_2$)' and 'Less than 2 $MtCO_2$' scenarios are presented in Figure 9 below.

[45] http://www.eirgridgroup.com/newsroom/electricity-consumption-f/index.xml

Figure 9: Proportion of domestic ROI demand met by renewable generation (RES-E)[46]



The deployment of renewable energy source (RES) capacities of the '70 by 30 (3.3 $MtCO_2$)' scenario increases the RES-E proportion of demand in ROI to 70% by 2030. Onshore wind, offshore wind, and solar PV capacity meet 38%, 24% and 5% of domestic ROI demand respectively. This equates to around 17, 10, and 2 TWh of generation. Hydro, biomass and renewable waste generation make up another 3%, or around 1 TWh.

In the 'Less than 2 $MtCO_2$' scenario, 85% of domestic ROI demand is met by renewable generation. 43% of the domestic ROI demand is met by 19 TWh of onshore wind generation. 14 TWh of offshore wind generation provides the next largest share of domestic demand, around 32%. Another 7% of demand is met by solar PV, from 3.TWh of generation, and 3% from hydro, biomass and renewable waste generation, around 1 TWh.

The remaining power sector demand in ROI is met by net imports from neighbouring markets, non-renewable waste generation, and fossil gas-fired generation in both scenarios.

[46] The total 2020 RES-E proportion of 43% is sourced from an EirGrid announcement. The individual split into renewable technologies in Figure 9 is derived from analysis of Baringa PLEXOS modelling.

2.3.4 DS3 limit outturn

Outturn in the '70 by 30 (3.3 $MtCO_2$)' scenario

Figure 10 below presents a duration curve (hourly values stacked from highest to lowest from left to right) of the all-island inertia delivered by synchronous condensers in the '70 by 30 (3.3 $MtCO_2$)' scenario, and a second independent duration curve[47] of the combined total inertia provided by all generation assets in addition to the condensers. Additional inertia is met by generation technologies including pumped hydro storage, biomass and waste, and fossil gas-fired plant.

Despite no explicit minimum inertia constraint being modelled in this scenario, the PLEXOS optimisation can act to turn-up thermal plant to meet the inertia requirement associated with the RoCoF constraint. The largest infeed contingency considered by the model is the 700 MW Celtic interconnector. An infeed of this capacity requires 17,500 MWs of inertia according to the 1 Hz/s RoCoF constraint. Although this value represents the largest inertia necessary to meet the I-SEM DS3 limits in each scenario, there is no absolute upper inertia limit imposed by the model optimisation; in peak demand hours in which multiple fossil gas-fired plant are dispatched, the total system inertia reaches in excess of 30,000 MWs.

During periods in which the largest infeed considered by the model is small, the optimisation permits a schedule with low inertia. The model does not consider individual windfarms as contingencies for the largest infeed, only considering thermal plant and interconnectors. In reality, an individual wind farm may become the largest single infeed during hours without import through interconnectors or large thermal output, necessitating the turn-up of synchronous condensers. Figure 10 therefore represents a lower bound to the output of synchronous condensers towards the tail-end of the duration curve.

The outturn all-island RoCoF and SNSP levels in the '70 by 30 (3.3 $MtCO_2$)' scenario are presented as independent duration curves in Figure 11. The 1 Hz/s RoCoF constraint binds in 2,230 hours. The SNSP limit of 95% binds in less than 10 hours. Figure 12 below shows independent duration curves of the number of large thermal plant on-load in I-SEM and NI. The all-island (4) and NI (2) Min Gen constraints bind in 1,270 and 5,960 hours respectively. Although no explicit ROI Min Gen constraint is modelled, there are no hours with less than 2 large thermal plant on-load in ROI in this scenario.

[47] Each profile is sorted from high to low independently in Figure 10 for the purposes of the chart. It is likely that the hours of lower total inertia are the hours in which it is sourced primarily from synchronous condensers.

Figure 10: Duration curves of all-island inertia in the '70 by 30 (3.3 $MtCO_2$)' scenario

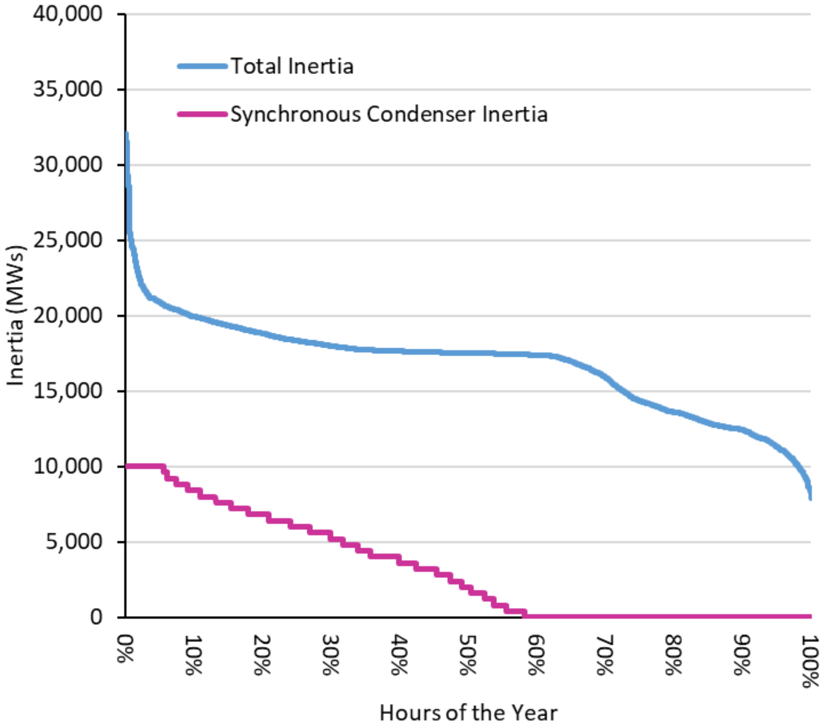


Figure 11: Duration curves of I-SEM RoCoF and SNSP levels in the '70 by 30 (3.3 $MtCO_2$)' scenario

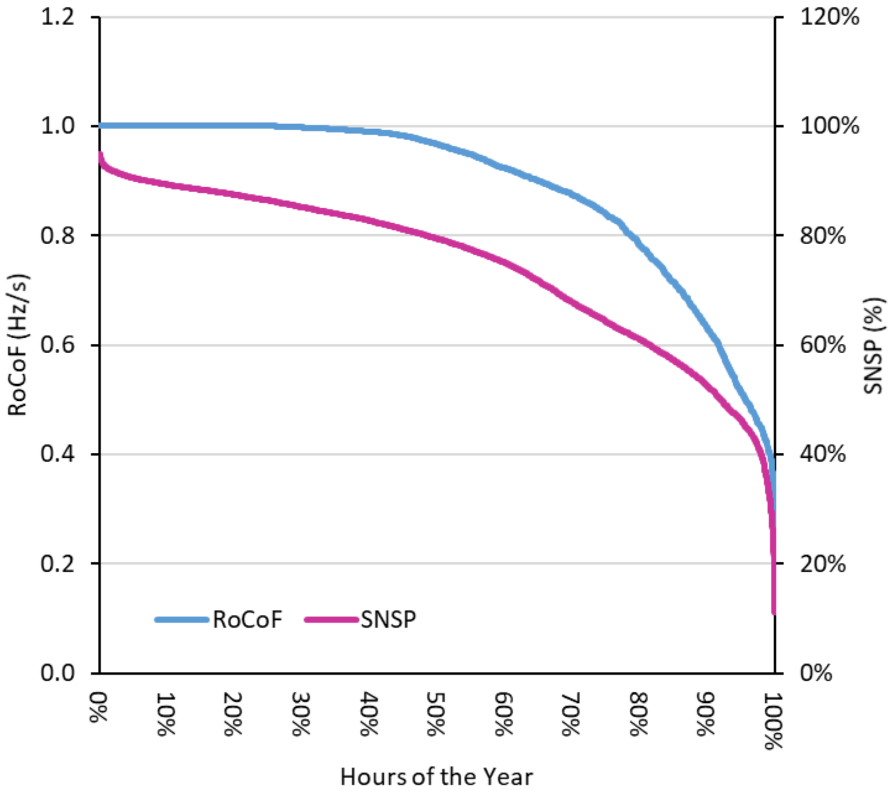
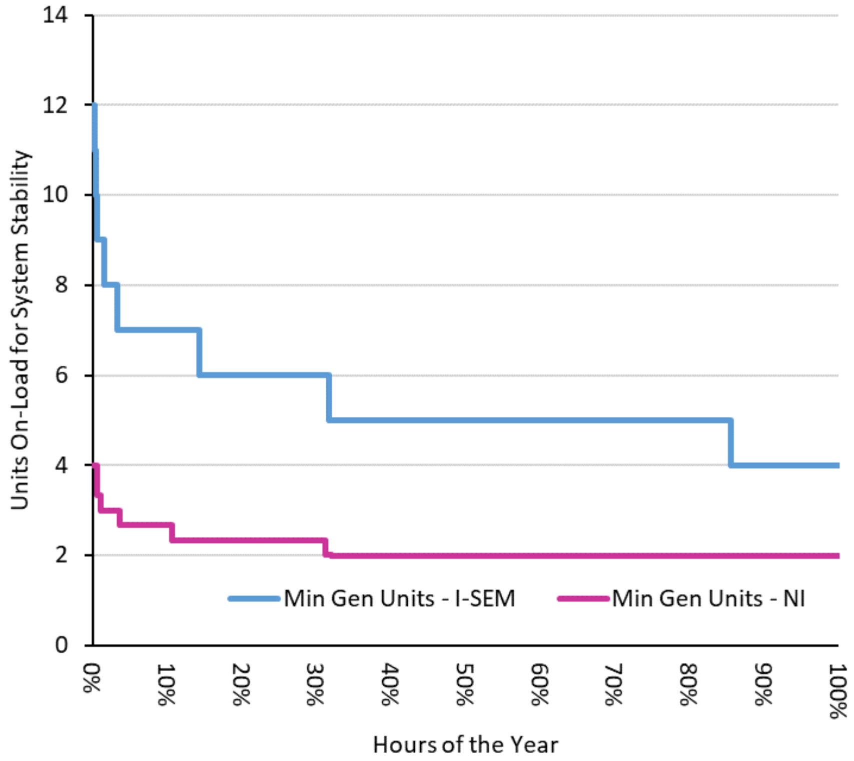


Figure 12: Duration curves of I-SEM and NI units on-load in the '70 by 30 (3.3 $MtCO_2$)' scenario



Outturn in the 'Less than 2 $MtCO_2$' scenario

Greater RES penetration in the 'Less than 2 $MtCO_2$' scenario necessitates increased investment in zero-carbon solutions to DS3 limits, with SNSP and Min Gen levels going beyond the extremes seen in the '70 by 30 (3.3 $MtCO_2$)' scenario.

Figure 13 below presents the total inertia, as well as inertia provided by synchronous condenser assets, as independent duration curves. The 17,500 MWs of available inertia from synchronous condensers is enough to allow Celtic to adhere to the 1 Hz/s RoCoF constraint.

As in the '70 by 30 (3.3 $MtCO_2$)' scenario, the model does not consider individual windfarms as contingencies for the largest infeed in the 'Less than 2 $MtCO_2$' scenario and so the right-hand side of the total inertia duration curve in Figure 13 represents a lower bound to that required in these hours.

Figure 14 shows the RoCoF and SNSP levels modelled in the 'Less than 2 $MtCO_2$' scenario. The RoCoF limit constraint binds in 3,930 hours, around 1,700 more hours than in the '70 by 30 (3.3 $MtCO_2$)' scenario. SNSP levels reach 100% in 800 hours. The number of simultaneous units on-load in I-SEM in each hour is shown as the duration curve in Figure 15 below. The relaxation of the I-SEM and NI Min Gen constraints to zero allows 5,190 hours without operation of large thermal plant.

Figure 13: Duration curves of all-island inertia in the 'Less than 2 $MtCO_2$' scenario

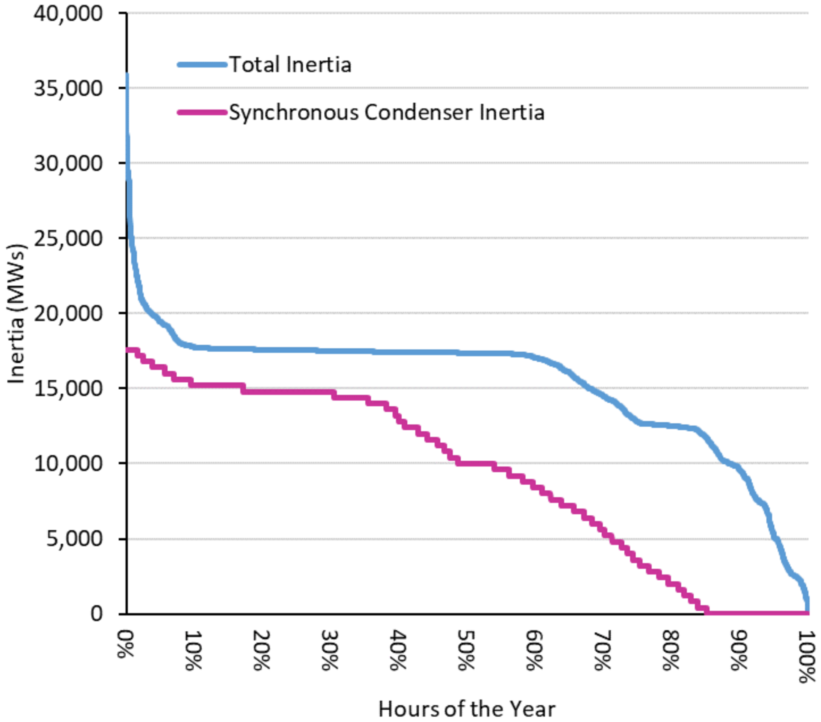


Figure 14: Duration curves of all-island RoCoF and SNSP levels in the 'Less than 2 $MtCO_2$' scenario

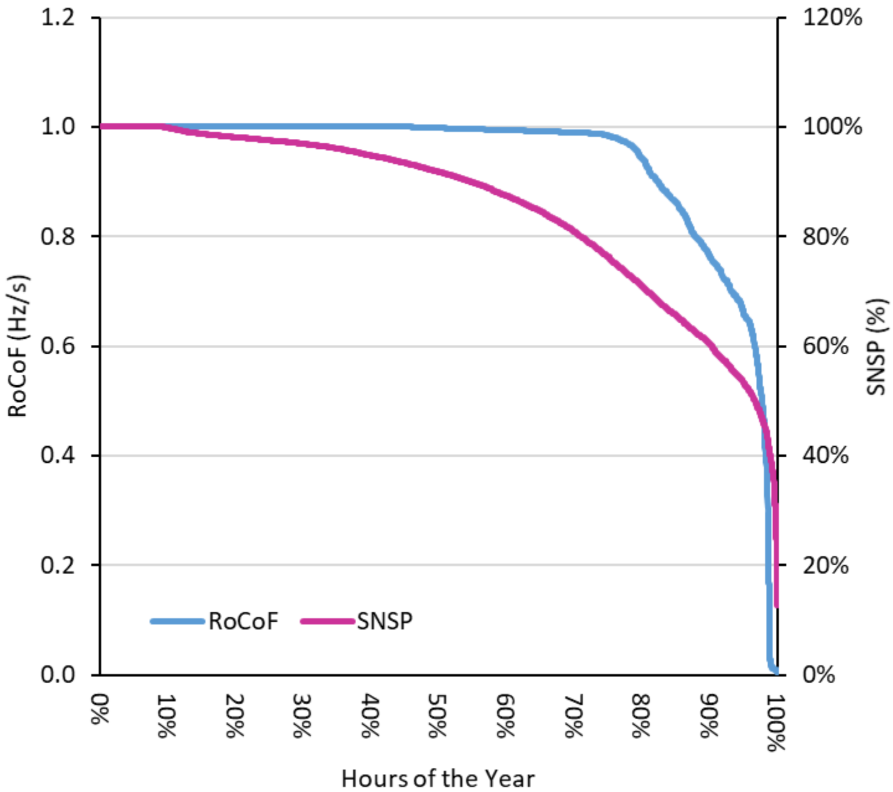
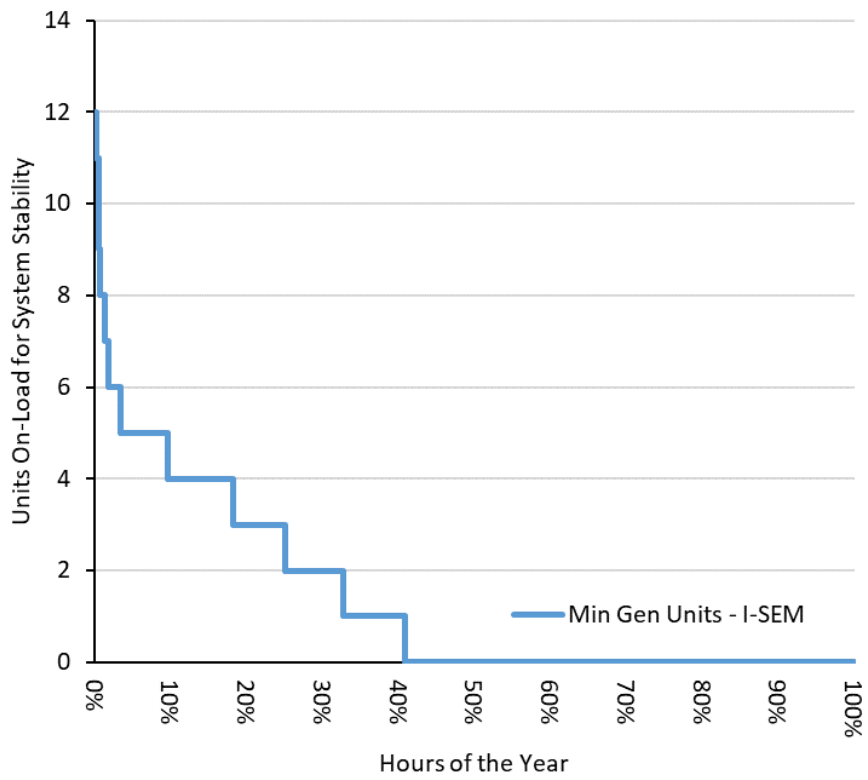


Figure 15: Duration curve of I-SEM units on-load in the 'Less than 2 $MtCO_2$' scenario



2.3.5 Generation mix and interconnector flows

The residual thermal fleet in ROI in the '70 by 30 (3.3 $MtCO_2$)' scenario produces 8.4 TWh of fossil gas-fired generation and 0.3 TWh of non-renewable waste-to-energy generation. Around 5.8 TWh of fossil gas-fired generation is present in the day-ahead schedule, before dispatch balancing to meet DS3 limits, representing an average load factor of 14% across the fleet in ROI. Re-dispatch of thermal plant to account for DS3 limits increases this output by 2.6 TWh; an increase of 6% to the average load factor.

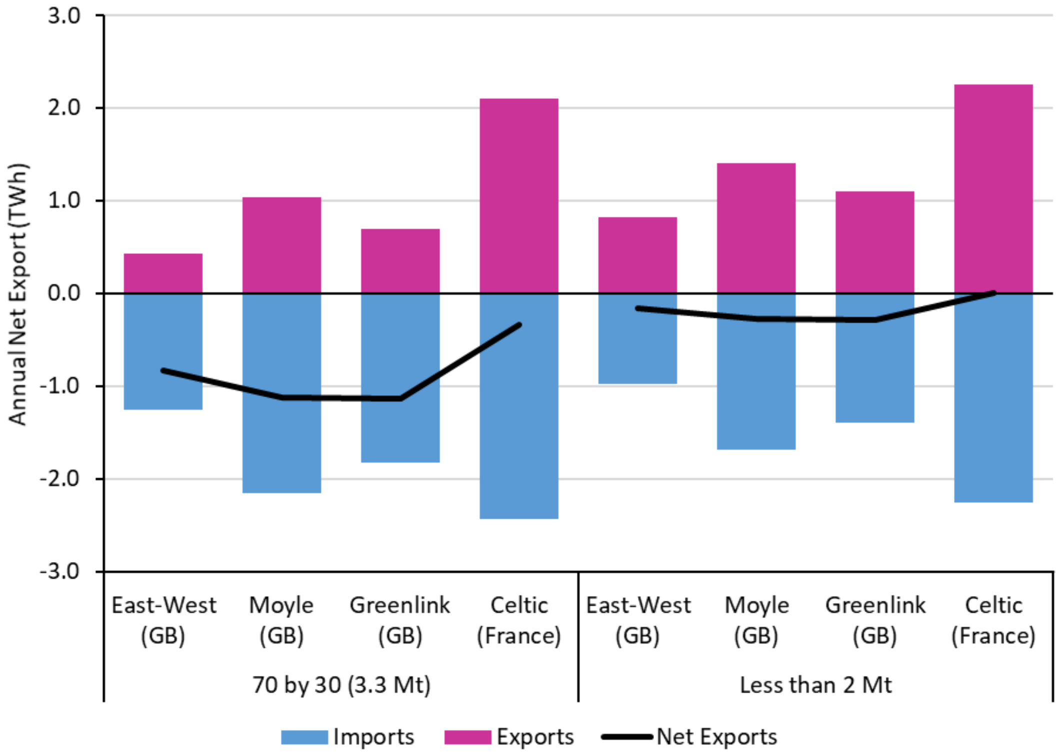
Displacement of out-of-merit plant by additional renewable capacity, and the relaxation of DS3 limit requirements on conventional thermal plant in the 'Less than 2 $MtCO_2$' scenario decrease fossil gas-fired generation to 4.4 TWh in ROI, an average load factor of 11%. 0.3 TWh of non-renewable waste-to-energy generation is observed in ROI.

In both scenarios, fossil gas-fired plant contribute to system adequacy in peak demand hours, and periods of limited RES output; sometimes termed 'Dunkelflaute' events. These events manifest as extended periods of low wind output during the winter months, in which solar generation is at a minimum. In both scenarios, there is sufficient dispatchable capacity to cater for these events over the modelling horizon. The gross demand requirement is met by domestic generation, interconnector flow, or demand-side flexibility in every settlement period within each scenario. During extended periods of low renewable output, output of fossil gas-fired assets dominates the I-SEM generation mix, along with import of nuclear and fossil-gas fired generation from GB and France, and release of electricity from domestic storage technologies including energy market batteries, pumped hydro storage assets, and flexible demand-side response. Fossil gas-fired plant dispatch during these events contributes to Irish power sector emissions. Longer periods of limited RES output than are seen in the 'P50 weather year' modelled in this study would result in greater emissions than the 1.6 $MtCO_2$ produced in the 'Less than 2 $MtCO_2$' scenario in this study; this scenario has been named conservatively to account for additional emissions that could arise from more extreme weather years.

In the '70 by 30 (3.3 $MtCO_2$)' scenario, the baseload wholesale price in I-SEM averages higher than that of neighbouring markets, with an average annual price of 52 €/MWh exceeding 47 €/MWh in both GB and France. This spread is reflected in the potential for infra-marginal rent for interconnector assets between I-SEM and neighbouring markets in the day-ahead schedule. The residual I-SEM DS3 limits act to increase the total fossil gas-fired generation in I-SEM in this scenario relative to the optimal dispatch in the day-ahead schedule. This additional generation acts to move interconnectors to decrease imports and increase exports from their ex-ante positions. Net imports from GB and France of around 3.1 and 0.3 TWh respectively are observed after this re-dispatch.

Increased RES deployment in I-SEM in the 'Less than 2 $MtCO_2$' brings wholesale prices closer to parity with neighbouring markets; 46 €/MWh in I-SEM relative to 46 and 47 €/MWh in GB and France respectively. Correspondingly the magnitude of net annual imports is small, around 0.7 TWh in total, compared to the total I-SEM demand of around 54 TWh excluding storage load. The balance of imports and exports through each interconnector in both scenarios is presented in Figure 16 below.

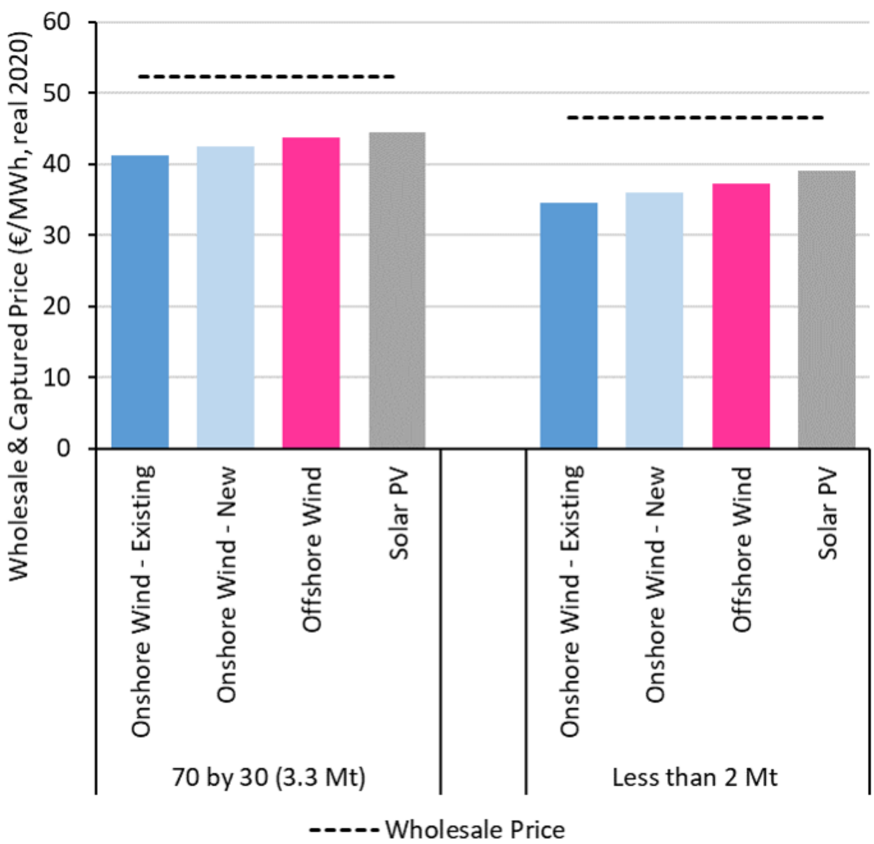
Figure 16: Annual imports and exports through interconnectors to GB and France



2.3.6 Baseload and renewable captured wholesale prices

The baseload (time-weighted average) wholesale prices in the two scenarios, presented as black dotted lines in Figure 17 below reflect the degree of renewable penetration in I-SEM in each scenario. As mentioned in the previous section, the annual average wholesale price observed in the '70 by 30 (3.3 $MtCO_2$)' scenario is 52 €/MWh in real 2020 money. Increased downward pressure on wholesale prices from wind and solar generation in the 'Less than 2 $MtCO_2$' scenario reduces the annual average I-SEM wholesale price to 46 €/MWh.

Figure 17: Baseload and captured wholesale prices of RES technologies in ROI



Renewable energy sources act to cannibalise their respective captured prices. As the volume of correlated generation increases, the price captured by renewables decreases. Correspondingly, the captured discount of onshore wind is the largest of renewables in ROI in the '70 by 30 (3.3 $MtCO_2$)' scenario, with a 21% discount captured by existing plant, and 19% by new-build plant with greater load factors. Offshore wind and solar capacity capture smaller discounts; 16% and 15% respectively, due to their lower penetration in the I-SEM generation mix.

Increased renewable capacity in the 'Less than 2 $MtCO_2$' scenario depresses captured prices to a greater extent than baseload prices, increasing renewable captured discounts. Onshore wind assets capture at discounts of 22-26%, with discounts of 20% and 16% captured by offshore and solar technologies respectively.

Prices and discounts presented above are captured after renewable oversupply and curtailment to account for DS3 limits.

The addition of further flexibility mechanisms such as demand side management (DSM), additional flexible generation, energy storage and interconnection would act to improve capture prices. A number of these options are considered in Phase 2 of this study in Section 3 of this report.

Dispatch-down of renewable generation

In Shaping our Electricity Future, EirGrid and SONI define three distinct dispatch-down actions that may act to reduce the output of renewable generators below their maximum output. These actions are summarised in Table 7 below and consist of:

- Oversupply;
- Curtailment; and
- Constraint.

This study accounts for dispatch-down of RES output from oversupply and curtailment actions and excludes actions taken to account for grid constraints ('constraint'). Additional deployment of grid infrastructure and 'smart' network devices will be needed by 2030 to minimise constraint levels in the scenarios considered.

Dispatch-down of wind and solar generation due to oversupply and curtailment actions in I-SEM total around 5% in the '70 by 30 (3.3 $MtCO_2$)' scenario. This figure is moderated by demand-side flexibility (including from EVs), energy market battery deployment, and the assumption of efficient trading arrangements with neighbouring jurisdictions through four interconnectors.

Zero-carbon solutions to DS3 limits remove the curtailment of RES entirely in the 'Less than 2 $MtCO_2$' scenario. The flexibility of the I-SEM system allows oversupply to remain below 5% for each of onshore wind, offshore wind, and solar PV generation. Additional dispatch-down from grid constraints is likely to have some overlap with the levels of renewable oversupply that is captured in the modelling.

Table 7: Dispatch-down actions in I-SEM

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 area where the constraint occurs.
When?	In the day-ahead schedule.	In the balancing market.	In the balancing market.
2020 outturn[48]	0.6%	5.9%	6.2%

[48] https://www.eirgridgroup.com/site-files/library/EirGrid/2020-Qtrly-Wind-Dispatch-Down-Report.pdf

3 Phase 2 – achieving a zero-carbon power sector

3.1 Scenario assumptions and methodology

3.1.1 Overview

In Phase 1 of this study (Section 2) the 'Less than 2 $MtCO_2$' scenario demonstrated that deployment of 67% of the new-build renewable capacity from the Programme for Government (PfG) targets and 75% of the SONI TESNI 2020 Accelerated Ambition new-build figures (presented in Table 6, on page 8), supported by zero-carbon solutions to the I-SEM DS3 limits, would allow power sector carbon emissions to be reduced to 1.6 $MtCO_2$ in ROI in 2030. The methods of achieving this result represent 'more of the same'; leveraging proven technologies and existing policy to a greater extent than in the '70 by 30 (3.3 $MtCO_2$)' scenario.

In Phase 2 of this study, we consider a range of further technology and policy investments to allow more of the renewable capacity targeted in the PfG and TESNI 2020 onto the I-SEM, and reduce emissions below 'Less than 2 $MtCO_2$' levels. The Phase 2 solutions are presented sequentially, but do not need to be made in a specific order and can be made concurrently, or in a different order. We do not present representative timescales for these solutions, instead presenting the result of each in the year 2030.

In this section we present the following scenarios in detail:

- **'Aligned Carbon Price'**: We assume that the ETS carbon price in I-SEM and the neighbouring British and French markets are moved into alignment with the targeted Irish non-ETS sector carbon price of 100 €/tCO_2;
- **'Long-Duration Storage'**: We consider 640 and 160 MW of energy storage capacity in ROI and NI respectively with an average duration of 100 hours, in addition to the 100 €/tCO_2 carbon price;
- **'Green Hydrogen'**: We model 1,290 and 310 MW of hydrogen electrolysers in ROI and NI respectively, and 1,200 MW of retrofitted hydrogen-fired generation capacity throughout I-SEM, with the 100 €/tCO_2 carbon price.

Each of the scenarios above includes 80% of the PfG new-build capacity targets (7.4 GW of onshore wind, and 4.0 GW of both offshore wind and solar PV), and 95% of the SONI TESNI 2020 Accelerated Ambition targets (2.5 GW of onshore wind, 480 MW of offshore wind, and 1.1 GW of solar PV).

We consider a fourth scenario, with 100% of the PfG and TESNI targets (8.2 GW of onshore wind and 5.0 GW of both offshore wind and solar PV in ROI, and 2.5 GW of onshore wind, 500 MW of offshore wind and 1.2 GW of solar PV in NI), and the 100 €/tCO_2 carbon price:

- **'Zero Carbon'**: A combination of the 800 MW long-duration storage capacity and 1,600 of hydrogen electrolysis capacity throughout I-SEM, and a comprehensive retrofit of the residual fossil gas-fired generation capacity in both ROI and NI.

We have modelled two additional sensitivities in PLEXOS: '80% of PfG Targets', a sensitivity with assumptions aligned to the 'Less than 2 $MtCO_2$' scenario but with 80% of the new-build PfG renewable capacity targets; and 'Storage & Hydrogen', a sensitivity that combines the solutions of the 'Long-Duration Storage' and 'Green Hydrogen' scenarios. The results of these sensitivities have been used to isolate the impact on power sector emissions and RES-E percentage from each of the technology and policy solutions considered in Phase 2. The two sensitivities are indicated with asterisks (*).

A summary of the key assumptions of the Phase 2 scenarios and sensitivities is presented in Table 8 below. We have aligned the other scenario assumptions (fixed and flexible demand, commodity prices, interconnection capacity, DS3 limits, external market generation capacity, and residual I-SEM non-RES capacity) with the 'Less than 2 $MtCO_2$' scenario of Phase 1.

Table 8: Phase 2 key scenario and sensitivity assumptions

Scenario	PfG RES Target Proportion	ETS Carbon Price	I-SEM LDS Capacity	I-SEM H_2 Electrolyser Capacity	I-SEM H_2 Generation Capacity
70 by 30 (3.3 $MtCO_2$)	50%	50 €/tCO_2	-	-	-
Less than 2 $MtCO_2$	67%	50 €/tCO_2	-	-	-
80% of PfG Targets*	80%	50 €/tCO_2	-	-	-
Aligned Carbon Price	80%	100 €/tCO_2	-	-	-
Long-Duration Storage	80%	100 €/tCO_2	800 MW	-	-
Green Hydrogen	80%	100 €/tCO_2	-	1,600 MW	1,200 MW
Storage & Hydrogen*	80%	100 €/tCO_2	800 MW	1,600 MW	1,200 MW
Zero Carbon (100% of PfG)	100%	100 €/tCO_2	800 MW	1,600 MW	5,980 MW

For each Phase 2 scenario, we have completed an 'unconstrained' PLEXOS power market model run over the 2030 horizon. For the 'Green Hydrogen' and 'Zero Carbon' scenarios, as well as the 'Storage & Hydrogen' sensitivity, we have overlaid the PLEXOS results with Excel calculations.

In addition to the scenarios and sensitivities detailed above, Appendix A presents two sets of sensitivities that explore the potential decarbonisation impact of flexible industrial heat demand and export of offshore wind generation to GB via a direct connection.

3.1.2 Renewable generation capacity

In Phase 1 of this study we explored the extent to which 'more of the same', i.e. utilising proven technologies and extending existing policy, can enable ambitious renewable deployment in Ireland. In the 'Less than 2 $MtCO_2$' scenario, 67% of the Programme for Government new-build RES targets were deployed in ROI (6.9 GW of onshore wind, and 3.3 GW of both offshore wind and solar PV), and 75% of the SONI TESNI 2020 Accelerated Ambition capacity was installed in NI (2.2 GW of onshore wind, 0.4 GW of offshore wind, and 1.0 GW of solar PV).

In the initial Phase 2 scenarios ('Aligned Carbon Price', 'Long-Duration Storage', and 'Green Hydrogen'), we have modelled a greater proportion of the PfG new-build renewable capacity, 80%, as well as 95% of the SONI TESNI 2020 Accelerated Ambition capacity. In the 'Zero Carbon' scenario, in which we model the combined impact of multiple technology and policy solutions, we deploy 100% of the new-build capacity associated with the PfG targets, and 100% of the SONI TESNI 2020 Accelerated Ambition scenario targets. A summary of these renewable generation capacities is presented in Table 9 below (see Table 6 for the installed renewable capacities in the Phase 1 scenarios).

Table 9: Phase 2 installed renewable generation capacity assumptions in ROI and NI

RES Capacity Input Assumptions	Units	80% of PfG	Zero Carbon
Proportion of New-Build Targets			
Programme for Government (ROI)	*%*	80%	100%
SONI TES 2020 Accelerated Ambition (NI)	*%*	95%	100%
Installed ROI RES Capacity			
Onshore wind	*MW*	7,420	8,200
Offshore wind	*MW*	4,010	5,000
Solar PV	*MW*	4,010	5,000
Installed NI RES Capacity			
Onshore wind	*MW*	2,480	2,540
Offshore wind	*MW*	480	500
Solar PV	*MW*	1,120	1,170

The levels of renewable penetration in the 'Less than 2 $MtCO_2$' scenario induce around 1,500 hours of zero price in the day-ahead market. With 80% of the PfG target capacity, this figure increases to over 2,000 hours. Zero price hours arise when wind and solar plant, bidding at zero cost, are able to provide enough generation to meet demand levels in the day-ahead market. Any excess RES generation must either be exported to neighbouring markets via interconnectors or curtailed as oversupply. Demand-side flexibility provided by storage or electrolysis assets can utilise the excess electricity during hours of high renewable output, and release it during hours of tight DRCM in which the least efficient and most emission intense plant would otherwise be active.

3.1.3 Carbon pricing

In each of the Phase 2 scenarios, we assume that the ETS carbon price in I-SEM is brought into alignment with the non-ETS price of 100 €/tCO_2 by 2030 in Ireland targeted in the 2019 Climate Action Plan. We have also made the conservative assumption that the neighbouring British and French markets adopt the same 100 €/tCO_2 carbon price. An asymmetric carbon price, i.e. a greater price in I-SEM than in GB and France, would result in larger emissions savings in the Irish power sector as imports of fossil gas-fired generation from neighbouring markets would outcompete domestic fossil gas-fired generation.

3.1.4 Long-duration storage (LDS)

In the 'Long-Duration Storage' and 'Zero Carbon' scenarios we consider 800 MW of long-duration storage capacity deployed throughout I-SEM, split by ROI and NI on a demand-weighted basis; 640 MW in ROI, and 160 MW in NI. We model these assets as connected to a total of 80 GWh of storage volume, giving them an average storage duration of 100 hours. Turlough Hill, the existing pumped hydro storage plant in ROI, is modelled as having a duration of just over 5 hours.

The assets are modelled with an average round-trip efficiency of 60%. This capacity is representative of several emerging technologies including:

- Long-duration pumped hydro energy storage;
- Compressed air energy storage;
- Liquid air energy storage[49];
- Thermal energy storage (e.g. liquid salt, 'hot rocks'[50]); and
- Novel battery compositions, e.g. vanadium redox flow, NaS and $NaNiCl_2$ batteries.

Strategic deployment of long-duration storage capacity in areas of grid constraints would act to reduce the levels of constraint dispatch-down of renewable generation in these areas. These assets would act as additional localised demand in hours in which the network cannot accommodate the export of RES generation from congested regions, and would release the zero-carbon electricity in hours of lower RES output.

We have not included Lithium-ion batteries as an option for long-duration storage. Despite significant reductions in costs, we do not consider them likely to be competitive for the durations considered in this study in 2030. They are included in our shorter-duration (0.5 hour, 2 hour, and 3 hour) storage capacity assumptions however, which provide reserve services alongside participation in the wholesale market.

[49] https://www.environmentalleader.com/2021/04/construction-to-begin-on-worlds-largest-liquid-air-energy-storage-project/
[50] https://www.rechargenews.com/energy-transition/stiesdal-hot-rocks-energy-storage-technology-stoked-by-andel-funding-boost/2-1-998021?utm_content=buffer82f9d&utm_medium=social&utm_source=linkedin.com&utm_campaign=buffer

3.1.5 Green hydrogen

In the 'Green Hydrogen' and 'Zero Carbon' scenarios we have assumed that 1,600 MW of electrolyser capacity has commissioned throughout I-SEM by 2030. This capacity is split into ROI and NI on a demand-weighted basis; 1,290 MW in ROI and 310 MW in NI. These electrolysers are configured to produce hydrogen when day-ahead prices fall below 50 €/MWh. At this price, the marginal molecule of hydrogen retains approximate price parity with that of fossil gas under an ETS carbon price of 100 €/tCO_2, assuming some insulation from transport charges from strategic locational deployment of electrolysers, with the average molecule of hydrogen being considerably lower in cost than the fossil gas equivalent. The electrolyser capacity is assumed to have a power-to-hydrogen efficiency of 70%, i.e. 100 MWh of electricity can produce 70 MWh of hydrogen.

We assume that the hydrogen produced is utilised in hydrogen-ready fossil gas-fired generation assets built before 2030, retrofitted to become hydrogen-fired. In the 'Green Hydrogen' scenario we consider 900 MW of retrofitted fossil gas-fired capacity in ROI and 300 MW in NI. In the 'Zero Carbon' scenario we model a complete retrofit of the remaining I-SEM fossil gas-fired fleet; 4,380 MW of hydrogen-fired generation capacity in ROI, and 1,600 MW in NI.

Retrofitting the I-SEM fossil gas fleet is considered technically achievable according to suppliers such as GE[51], Siemens[52] and Mitsubishi[53]. It should be noted however that all gas customers, as well as the gas transmission and distribution system, would need to convert to a hydrogen blend (or 100% hydrogen) at the same time. It is outside the scope of this study to determine the feasibility, economics or timing of such a change.

The volume of hydrogen produced by the electrolysers during the model horizon is assigned to hours of highest to lowest price, with hydrogen offtake limited in each hour by the installed retrofitted capacity in each jurisdiction. Fossil gas offtake is displaced in these hours, until the hydrogen volume is consumed. This calculation has been performed in Excel, using the hourly results of the PLEXOS market model. To allow this flexible and targeted hydrogen offtake, we have assumed that storage volumes are not a limiting factor in these scenarios, with 3.0 and 1.0 TWh of hydrogen storage available in ROI and NI respectively in the 'Green Hydrogen' scenario, and 4.5 TWh of storage deployed throughout I-SEM in the 'Zero Carbon' scenario (0.5 TWh more than in the 'Green Hydrogen' scenario). Hydrogen can be stored cryogenically or in high pressure tanks, or more economically, in underground caverns where the geology permits. This methodology assumes that suitable cavern locations are employed for storage of hydrogen. Without these sites the available storage volume may become a limiting factor in the deployment of green hydrogen infrastructure in I-SEM. This would result in a 'less targeted' use of hydrogen offtake for generation, in hours of lower emission intensity.

In both scenarios, we assume that an equal volume of hydrogen is used in hydrogen-fired generation capacity within the power sector as is produced by the modelled electrolysers, i.e. the power sector hydrogen use is net neutral in 2030. This does not assume that the hydrogen infrastructure in the power sector is isolated, only that there is no net gain/loss of hydrogen within it in 2030. Green

[51] https://www.ge.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines
[52] https://assets.new.siemens.com/siemens/assets/api/uuid:ddb422e8-3079-452b-a6bd-0f662e1f9309/version:1596631992/hydrogencapabilitesgt-april-2020.pdf
[53] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/090320-mitsubishi-lands-33-gw-of-new-us-hydrogen-compatible-gas-turbine-orders

hydrogen could alternatively be used to decarbonise the heating, industrial, or transport sectors, sometimes known as 'sector coupling'[54].

Hydrogen can also be used as a raw material step in the production of 'electrofuels' such as ammonia, methanol, electromethane, 'e-petrol' and 'e-diesel'. These fuels may have applications in shipping and aviation, both domestically and for export to other markets. The infrastructure required to produce and store hydrogen could be shared between the electricity system and these end-uses, with resulting economies of scale, but evaluation of the interactions between sectors is outside the scope of this study.

The additional demand brought by electrolysers would offer additional system benefits if deployed behind grid constraints. Renewable generation that would otherwise be turned-down as constraint would be utilised to produce green hydrogen that could be transported to provide generation in areas of localised demand.

3.2 Results and discussion

3.2.1 CO_2 emission savings in ROI

The model scenarios in this study indicate that the residual CO_2 emissions in ROI in the '70 by 30 (3.3 $MtCO_2$)' scenario can be progressively eroded by investment in incremental solutions. Table 10 below details the CO_2 savings made by each Phase 2 solution, as well as the RES-E proportion enabled in all scenarios. The two sensitivities, which have been modelled to isolate the impact of each solution, are indicated with asterisks (*).

As demonstrated in Phase 1 of this study, zero-carbon system services are able remove the need to re-dispatch thermal assets to meet DS3 limits. These solutions alleviate the reliance on fossil gas-fired generation to meet inertia and Min Gen limits, and allow increased renewable capacities onto the I-SEM without curtailment to meet an SNSP constraint. Emissions totalling 1.7 $MtCO_2$ can be saved from this 'more of the same' investment by implementing the 'Less than 2 $MtCO_2$' scenario.

Commissioning of 80% of the PfG renewable target capacity can reduce CO_2 emissions further, by 0.3 $MtCO_2$. However, increased wind and solar generation results in greater levels of renewable oversupply and reduced captured prices. An initial mitigation solution considered was the potential of increased new-build interconnection. However, several test scenarios modelled showed that the optimised dispatch of current, and planned new-build, interconnection does not act to substantially mitigate the above factors. Rather than increasing new-build interconnection, we applied an ETS carbon price of 100 €/tCO_2 in I-SEM, with aligned prices in GB and France. This discourages dispatch of fossil gas-fired plant within the model, forcing more effective optimisation of interconnector flow between markets. This carbon pricing policy is able to reduce emissions in ROI by a further 0.3 $MtCO_2$, down to 1.0 $MtCO_2$, and improve renewables integration. In each scenario it has been assumed that GB and France align their carbon pricing policy with Ireland; an asymmetric carbon price, lower in neighbouring markets, would result in larger CO_2 emission savings in Ireland.

640 MW of long-duration storage assets and 1,290 MW of hydrogen electrolysers have been considered individually in ROI. Each is able to utilise renewable output that would otherwise be curtailed as oversupply. Around 0.3 and 0.5 $MtCO_2$ can be saved in ROI from these solutions

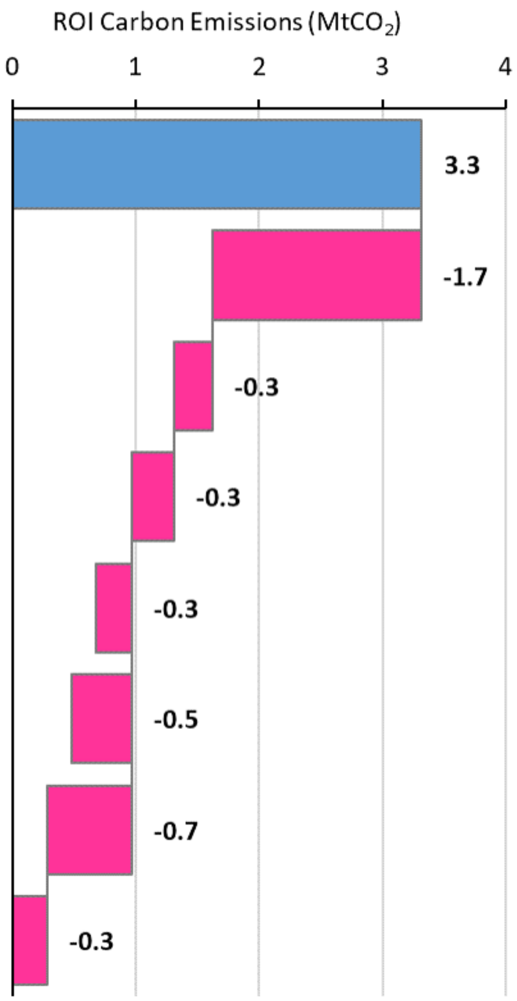
[54] https://windenergyireland.com/images/files/our-climate-neutral-future-0by50-final-report.pdf

respectively. Long-duration storage and green hydrogen technologies have different merits in the Irish power sector. Long-duration storage has a greater initial build capital cost but a round-trip efficiency of 60% offers advantage over the end-to-end efficiency of around 30% for green hydrogen. Under the assumptions of this study, the hydrogen pathway can store much longer durations for a much lower cost per unit of storage, and retrofit of the existing fossil gas fleet offers cost savings. When combined in a single model scenario, they are able to reduce emissions by 0.7 $MtCO_2$, down to a total of 0.3 $MtCO_2$ in ROI. In addition to the direct emissions savings from day-ahead market dispatch considered in this study, strategic deployment of each of the above technologies offers further benefit to the network, reducing the level of required network investment to achieve the RES penetration in these scenarios.

100% of the Programme for Government target wind and solar capacity, in combination with 640 MW of long-duration storage, 1,290 MW of electrolyser capacity, and a 4,380 MW of retrofitted fossil gas-fired generation capacity in ROI results in a zero-carbon power system.

Table 10: Power sector RES-E[55] and CO_2 emission savings[56] of Phase 2 solutions in ROI in 2030

Scenario	ROI RES-E Percentage	ROI CO_2 Emissions
70 by 30 ($3.3\ MtCO_2$)	70%	$3.3\ MtCO_2$
Less than $2\ MtCO_2$	85%	$1.6\ MtCO_2$
80% of PfG Targets*	94%	$1.3\ MtCO_2$
Aligned Carbon Price	94%	$1.0\ MtCO_2$
Long-Duration Storage	97%	$0.7\ MtCO_2$
Green Hydrogen	89%	$0.5\ MtCO_2$
Storage & Hydrogen*	90%	$0.3\ MtCO_2$
Zero Carbon (100% of PfG)	101%	$0\ MtCO_2$



3.2.2 Technology costs of Phase 2 solutions

Presented in Figure 18 below are the total technology costs associated with each Phase 2 solution. The technology cost represents the annuitized capital cost of the assets in each scenario. We have not attempted to evaluate any additional costs or benefits in Phase 2 of this study. Under these scenarios, the Irish power sector is very different from today, and will require elements of new electricity market design. Each technology cost and carbon saving is measured relative to the 'Aligned Carbon Price' scenario, and represents the costs for the year 2030 alone.

On a cost per tonne of CO_2 basis, the long-duration storage assets in the 'Long-Duration Storage' scenario have a similar cost to the hydrogen solution in the 'Green Hydrogen' scenario, at around 210 €/tCO_2. The long-duration storage assets are assumed to be a blend of technologies with varying

[55] RES-E is systematically lower in scenarios that include hydrogen electrolysers, as they contribute additional demand to the Irish power system.
[56] For comparison, power sector emissions in ROI totalled around 9 $MtCO_2$ in 2019.

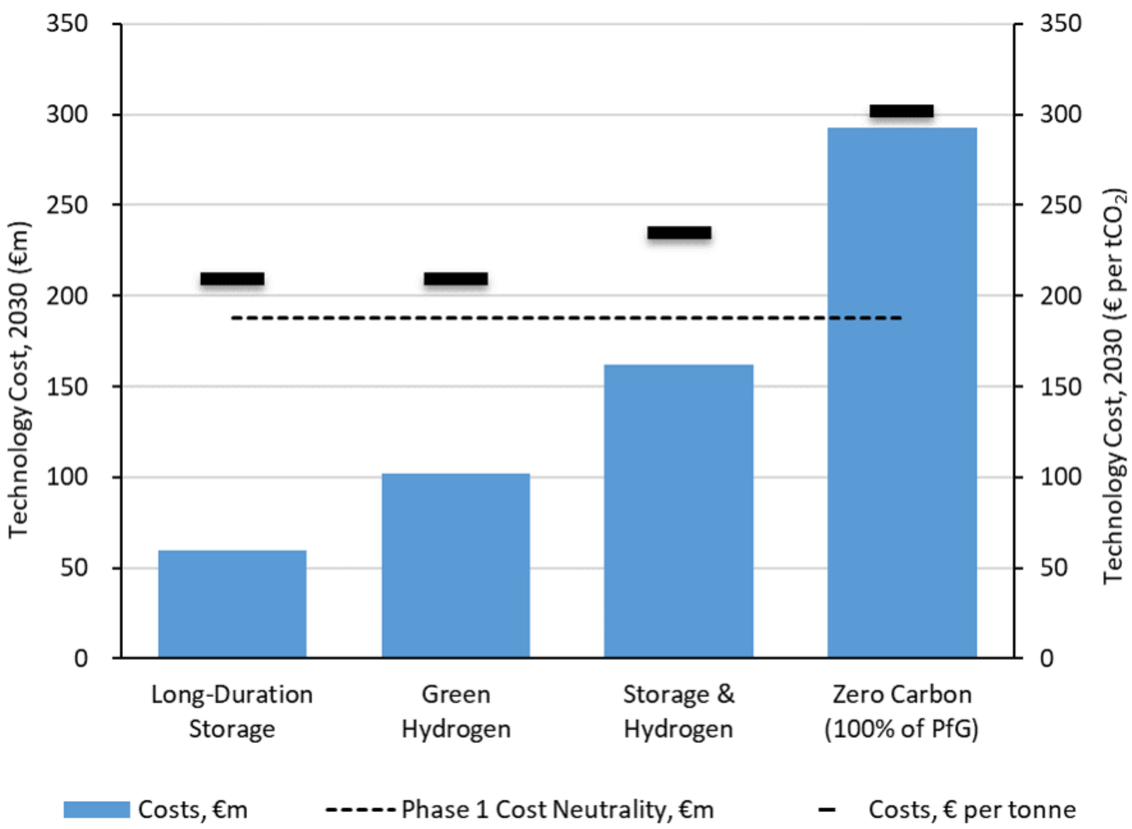
efficiencies. The costs associated with the ‘Green Hydrogen’ scenario include the cost of hydrogen storage facilities, assumed to be suitable caverns, in addition to the electrolysis assets and the cost of retrofitting fossil gas-fired plant. Around €60m of the technology cost in this scenario results from the electrolysis assets, with around €40m and €10m required for the installation of storage volume and retrofit of generation capacity respectively.

‘Storage & Hydrogen’ represents the combined technology cost of the two solutions. The incremental cost of the ‘Zero Carbon’ scenario relative to this is indicative of the increased hydrogen storage volume and retrofitted generation capacity required, and the cost of the final 20% of the PfG renewable capacity target. The total technology cost in ROI in the ‘Zero Carbon’ scenario amounts to €290m in 2030, or 300 €/tCO_2, around €100m net of the cost saving of the ‘Less than 2 MtCO_2’ in Phase 1.

‘Phase 1 Cost Neutrality’ refers to the technology cost incurred to end consumers from a Phase 2 scenario that would equal the net consumer benefit provided by the ‘Less than 2 MtCO_2’ scenario relative to the ‘70 by 30 (3.3 MtCO_2)’ scenario, as calculated in the Phase 1 cost-benefit analysis.

This result shows a practical combination of long-duration storage and green hydrogen technologies, combined with high renewable capacity build-out, can enable Ireland to achieve a zero-carbon power sector. This study did not seek to calculate the ‘optimum portfolio’; there may be less expensive solutions, and other technologies that can contribute.

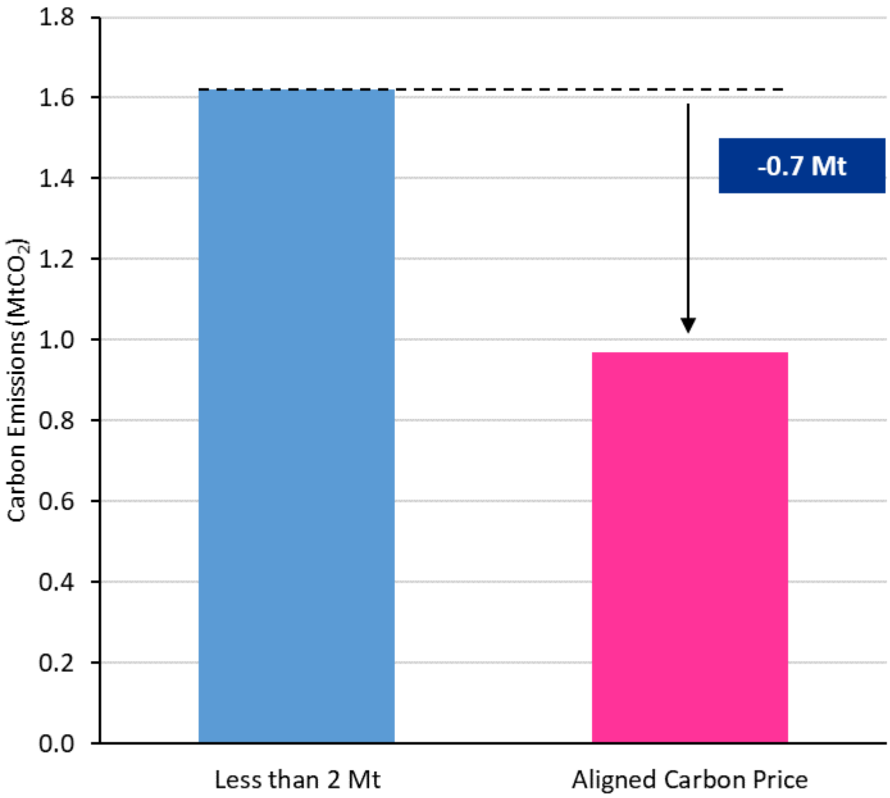
Figure 18: ROI technology costs of Phase 2 solutions (excludes benefits)



3.2.3 Aligned CO_2 price in ETS and non-ETS sectors

The incremental RES capacity in the initial Phase 2 scenarios, totalling 1,850 MW in ROI displaces fossil gas-fired generation and reduces 2030 power sector emissions by 0.3 $MtCO_2$ relative to the 'Less than 2 $MtCO_2$' scenario.

Figure 19: CO_2 emissions from ROI plant dispatch in the 'Aligned Carbon Price' scenario



The carbon price movement acts to increase the SRMC of a 46% fossil gas-fired plant by around 20 €/MWh, further out of merit in the I-SEM system. As a result, domestic fossil gas-fired generation in ROI is decreased from 3.5 to 2.6 TWh from the carbon price movement alone. Imports to I-SEM act to replace the displaced domestic fossil gas-fired generation; net exports from I-SEM decrease from 2.8 to 1.6 TWh.

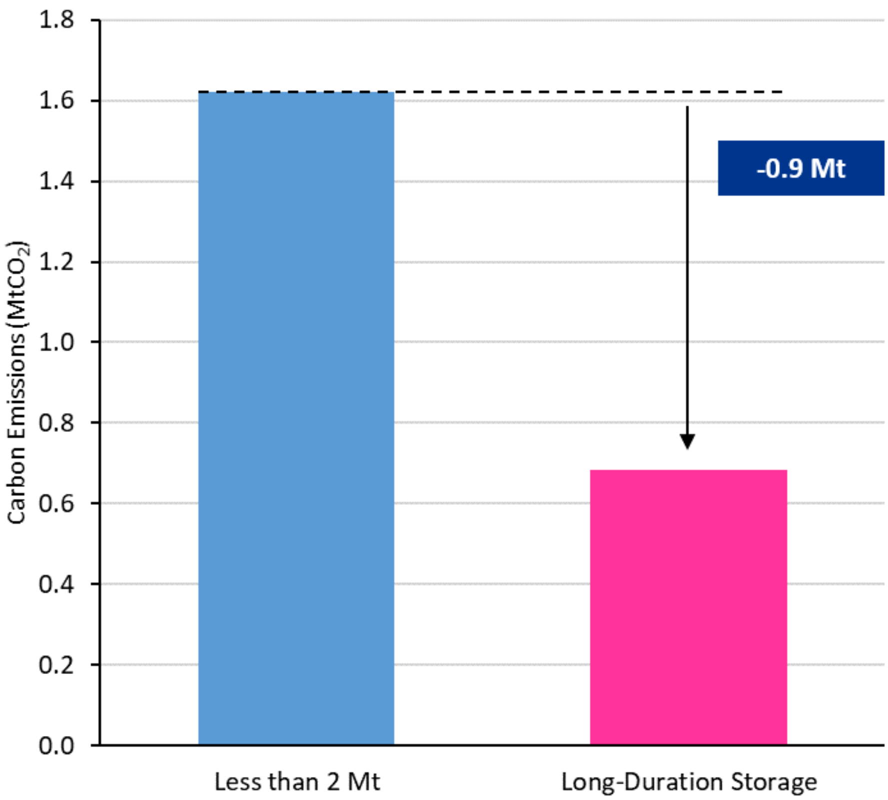
The movement in carbon price acts to reduce ROI power sector emissions by 0.3 $MtCO_2$. In combination with the incremental RES build, emissions fall by 0.7 $MtCO_2$ relative to the levels seen in the 'Less than 2 $MtCO_2$' scenario, to around 1.0 $MtCO_2$ in the 'Aligned Carbon Price' scenario.

3.2.4 Long-duration storage technologies

Around 3.1 TWh of renewable generation in the 'Aligned Carbon Price' scenario was turned-down due to oversupply. In the 'Long-Duration Storage' scenario we explore the effect of introducing long-duration energy storage assets to the all-island system to enable the volume of RES capacity on the system with reduced oversupply.

The 100 hour duration of the storage assets provides them with the flexibility to take in excess renewable generation during low demand hours, and export that energy when it is most needed during hours of low renewable output. Correspondingly the volume of RES oversupply in I-SEM is reduced to around 1.8 TWh in the 'Long-Duration Storage' scenario.

Figure 20: CO_2 emissions from ROI plant dispatch in the 'Long-Duration Storage' scenario[57]



Generation from the storage assets displaces domestic thermal plant, reducing fossil gas-fired generation to 1.8 TWh in ROI, down from 2.6 TWh in the 'Aligned Carbon Price' scenario. Power sector emissions are reduced in proportion to fossil gas-fired generation; down to 0.7 $MtCO_2$ as shown in Figure 20 above.

The 60% efficient assets are able to take in 1.8 TWh of low cost, primarily renewable generation during hours of low demand, and provide 1.1 TWh of generation during peak demand hours. The storage units are able to capture an average generation price of 85 €/MWh, giving a spread of 68 €/MWh above the average cost of pumped volume; 17 €/MWh. Wholesale market revenues captured at this spread imply that operation of these assets is economic, when combined with CRM payments and indicative DS3 revenue. Figure 21 below shows the duration curve of the net generation (generation is positive and pump load is negative) of the long-duration storage assets throughout I-SEM in the 'Long-Duration Storage' scenario.

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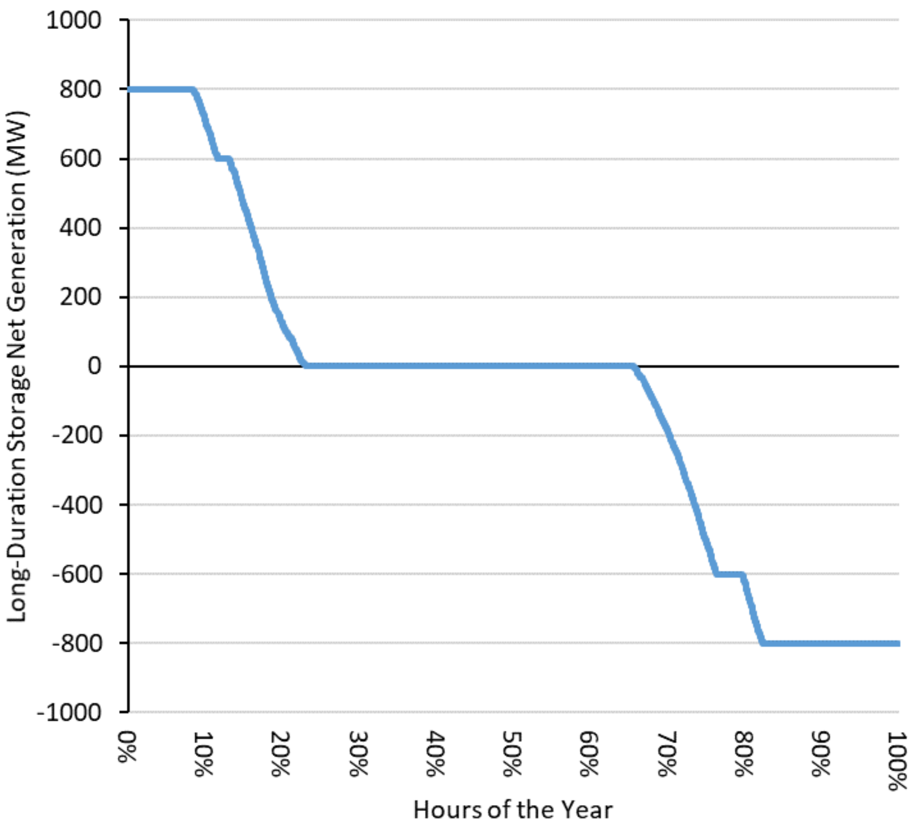
[57] This total emission saving relative to the 'Less than 2 $MtCO_2$' scenario includes that from the implementation of the 'Aligned Carbon Price' scenario, i.e. from the deployment of 80% of the PfG renewable target capacities, and the ETS carbon price of 100 €/tCO_2. This is also the case in Figure 22.

In the ‘Long-Duration Storage’ scenario we model interconnector flows to and from GB and France as fixed in their optimised flow from the ‘Aligned Carbon Price’ scenario.

Figure 21: Duration curve of I-SEM LDS asset net generation in the ‘Long-Duration Storage’ scenario



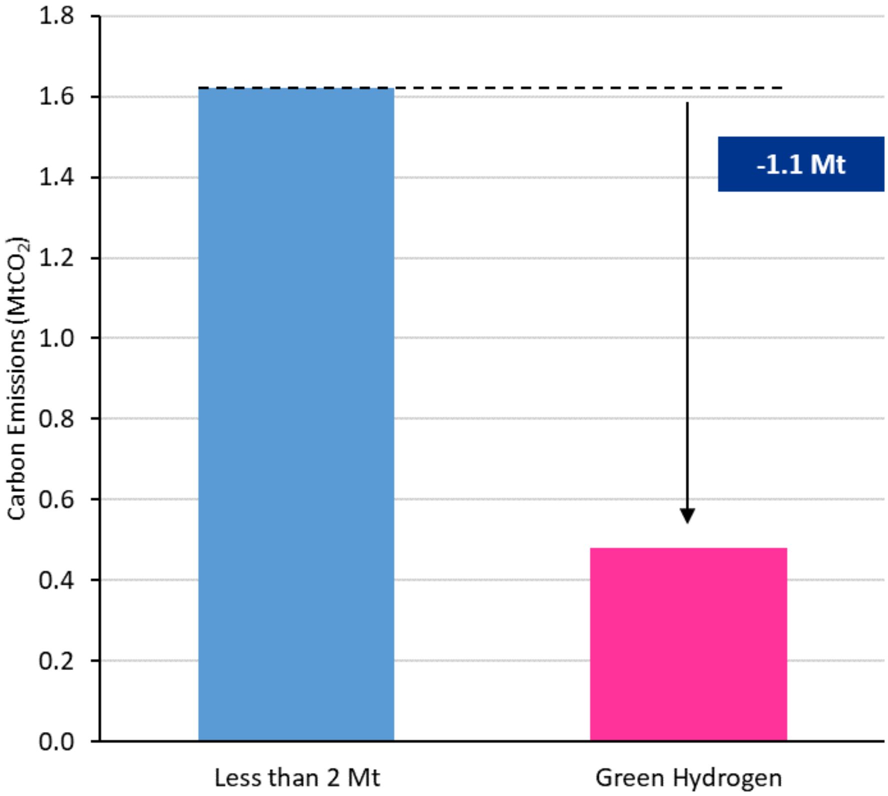
3.2.5 Green hydrogen production

In the ‘Green Hydrogen’ scenario, the 1,600 MW of hydrogen electrolysis capacity installed throughout I-SEM produces 3.9 TWh of hydrogen from 5.6 TWh of electricity during hours with a day-ahead price below 50 €/MWh. The electrolysis-weighted cost of production of this hydrogen, i.e. the average cost of electricity used for electrolysis, is around 15 €/MWh. Electricity generation using green hydrogen produced at these power prices is highly cost-competitive relative to fossil gas-fired generation under an ETS carbon price of 100 €/tCO_2[58].

All hydrogen produced by the electrolysers is utilised for generation within 900 MW of retrofitted fossil gas-fired capacity in ROI, and 300 MW in NI. The hydrogen-fired units are dispatched when day-ahead prices exceed 80 €/MWh, displacing fossil gas-fired generation during these hours. Figure 22 below presents the emissions savings in ROI in the ‘Green Hydrogen’ scenario.

[58] In this calculation we have considered recovery of the capital cost of electrolysers. The operational cost is dependent on applied network charges, which could be either positive or negative depending on the incentives offered by regulators to encourage strategic locational deployment of these electrolysers, given their potential to avoid or defer new network investment.

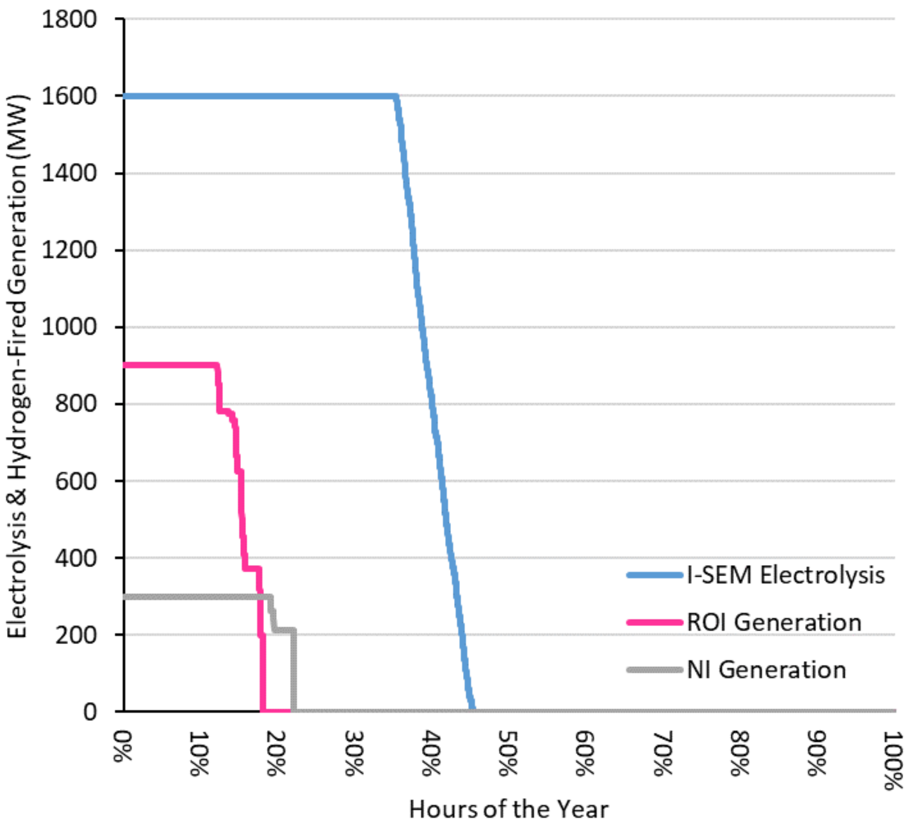
Figure 22: CO_2 emissions from ROI plant dispatch in the 'Green Hydrogen' scenario



Of the 2.6 TWh of gas-fired generation in ROI in this scenario, around 1.3 TWh is hydrogen-fired. Power sector emissions are correspondingly reduced by 0.5 $MtCO_2$ in ROI from this displacement of fossil gas relative to the 'Aligned Carbon Price' scenario. The electrolysers act to increase the domestic I-SEM demand during low price hours, reducing renewable oversupply to 1.2 TWh.

Figure 23 below presents the independent duration curves of the electricity demand of electrolyser assets in I-SEM, and generation from hydrogen-fired plant in ROI and NI in the 'Green Hydrogen' scenario.

Figure 23: Electrolysis and hydrogen generation duration curves in the 'Green Hydrogen' scenario



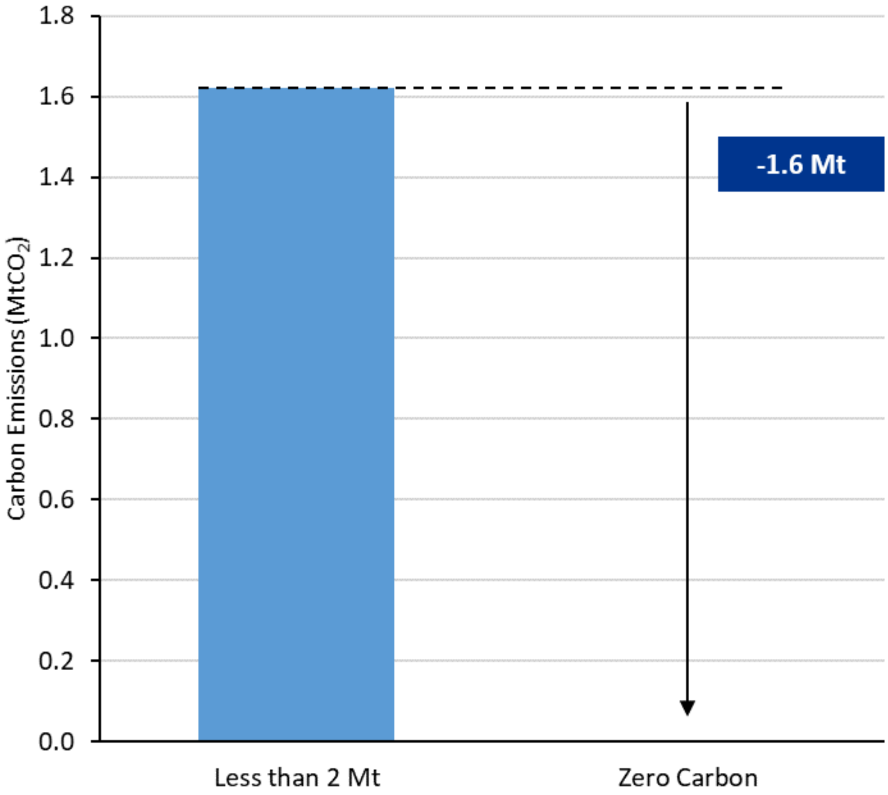
3.2.6 A zero-carbon Irish power sector

The 'Zero Carbon' scenario explores a 2030 I-SEM system with long-duration storage assets, complemented by hydrogen electrolysers and a comprehensive suite of hydrogen-fired generation capacity. In this scenario the increased system flexibility provided by these assets allows the deployment of the full Programme for Government new-build renewable capacity and SONI TESNI Accelerated Ambition capacity.

800 MW of long-duration storage capacity, and 1,600 MW of electrolysers throughout I-SEM provide demand flexibility to moderate RES oversupply despite the combined 18,200 and 4,200 MW of RES capacity in ROI and NI respectively.

The incremental RES capacity provides low-cost generation for the production of 4.5 TWh of green hydrogen in this scenario. 4,380 MW of hydrogen-fired generation capacity in ROI is able to provide 1.4 TWh of zero-carbon thermal generation respectively, displacing fossil gas-fired generation in all hours. Figure 24 below presents the emission reduction relative to the 'Less than 2 $MtCO_2$' scenario.

Figure 24: CO_2 emissions from ROI plant dispatch in the 'Zero Carbon' scenario



The 60 TWh of domestic all-island demand in this scenario is met by 58 TWh of wind and solar generation, 2 TWh of biomass, waste and hydro generation, and 2 TWh from hydrogen-fired assets. Net exports to neighbouring markets total around 2 TWh.

The independent duration curves presented in Figure 25 and Figure 26 below show the hourly dispatch of the long-duration storage and electrolysis assets (throughout I-SEM), and hydrogen-fired plant (in ROI and NI) in this scenario.

Figure 25: Duration curve of I-SEM LDS asset generation/pump load in the 'Zero Carbon' scenario

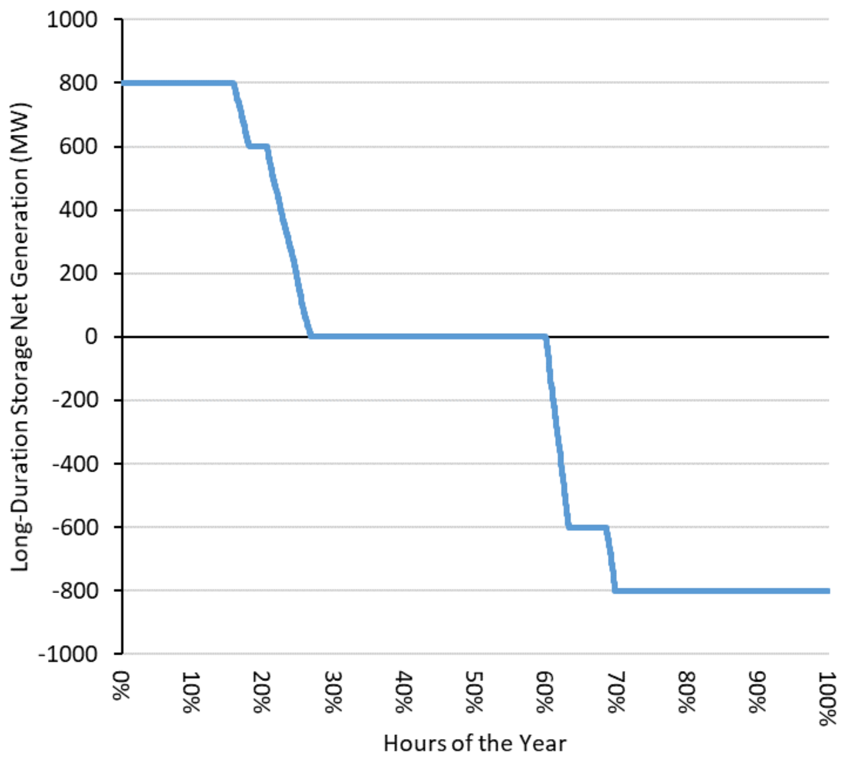
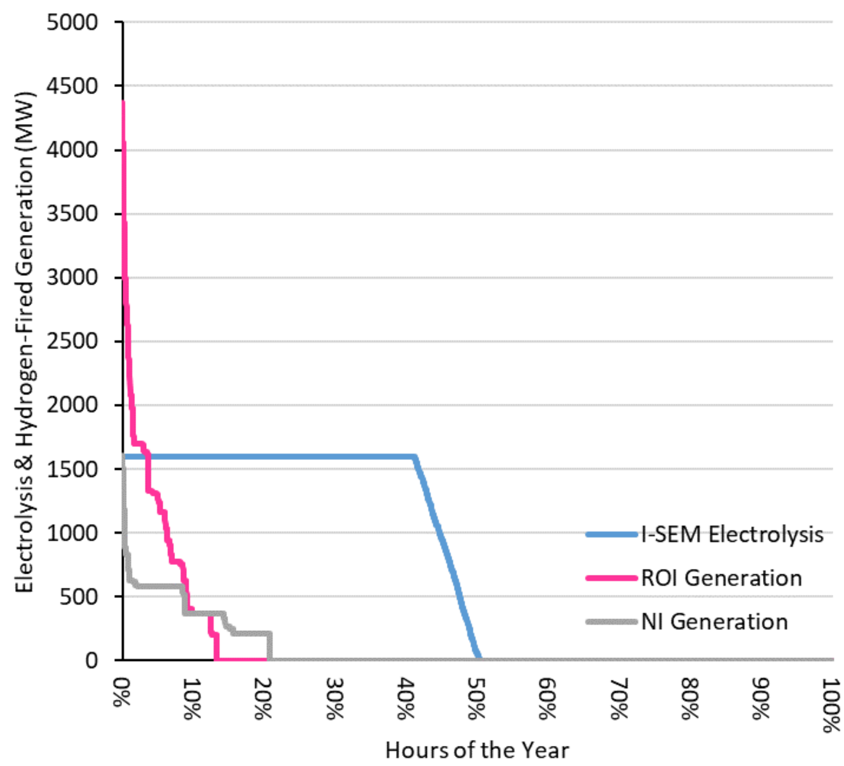


Figure 26: Duration curves of hydrogen electrolysis and generation in the 'Zero Carbon' scenario



3.2.7 Security of supply considerations

As in the Phase 1 scenarios, the gross domestic demand requirements of the Irish power system are met in every hour by renewable generation, imports from GB and France, and fossil gas and hydrogen-fired generation. In order to stress-test the Irish power system further under the 'Zero Carbon' scenario, we have performed a high-level calculation in Excel to determine the duration of event that the system could sustain without wind or solar output.

Between the 22nd February and the 5th March 2018, Ireland was hit with a 12-day storm known as the 'Beast from the East'. We have analysed the outturn I-SEM demand levels during this event to determine the system adequacy if such an event were to occur in 2030 in a period with very low RES output.

Over the 12 days of the storm in 2018, the average demand level increased to around 11% above the annual average. We have assumed that the corresponding electricity demand in a 2030 event increases proportionally to the annual average according to this ratio. We have assumed that a similar event hits the British and French markets, and so the interconnectors do not flow in either direction. Under these conditions, assuming that the installed biomass, waste and hydro plant operate at their average load factors, the 4.5 TWh of hydrogen storage volume in the 'Zero Carbon' scenario would last around 13 days without any wind or solar output. Therefore, it would have continued to supply electricity securely during an extreme event like the 'Beast from the East', even with limited RES output. This calculation assumes that that the energy storage capacity, including the long-duration assets, act to generate alongside the hydrogen-fired capacity during the peak demand hours over this period, using excess hydrogen generation in hours of below-average demand. The hydrogen-fired fleet is assumed to be fully available over this period.

Periods of limited RES output longer than 13 days would require additional hydrogen storage volume; each additional TWh of storage volume would add a further 3 days of security of supply. Any wind or solar output during this event would act to extend the duration of system adequacy. If additional security is required on a capacity basis, e.g. if plant availability is the limiting factor rather than supply of hydrogen, overbuild of hydrogen-fired generation capacity would be required. Any reserve hydrogen stored at the plant sites would increase the length of system adequacy under these conditions.

4 Conclusions

In this study we have set out to update the analysis we undertook for the 70 by 30 study in 2018, taking into account the market and policy developments seen in the years since. Increasing investment in zero-carbon system services within Ireland have brought the prospect of reducing emissions below 2 million tonnes of CO_2 by 2030 into reality with reliance only on existing and demonstrated technologies and current policy.

Beyond this scenario, we have demonstrated a viable pathway towards delivery of a zero-carbon power sector in Ireland, by investing in a series of policy and technology solutions new to Ireland, and deployment of the renewable capacity targets stated in the Programme for Government.

The results of this study indicate five key findings regarding the future of the electricity sector in the Republic of Ireland:

- Reducing power sector emissions in Ireland from around 9 million tonnes today to a target of **less than 2 million tonnes of CO_2** per year is very achievable by 2030, using the approach currently underway to achieve the '70 by 30' target, and implementing more of **existing and proven technologies**.
- The current Programme for Government renewable capacity targets of **8.2 GW of onshore wind** and **5 GW of offshore wind** by 2030 should be maintained, with an additional target of **5 GW of solar PV**.
- This target can be achieved at a **lower cost to the end consumer** in Ireland, compared to delivery of the less ambitious '70 by 30' target.
- A **zero-carbon power system is possible**, and represents an achievable target in the early 2030s.
- Realising this target requires incremental investment in a **suite of technologies new to Ireland**, and the implementation of a **carbon price floor** in the I-SEM.

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Appendix A Emission offset sensitivities

A.1 Electrification of the Irish heat sector

As detailed in the Sustainable Energy Authority of Ireland (SEAI) 'Energy in Ireland 2020' report, around 37 $MtCO_2$ of energy-related emissions were produced in ROI in 2019. Of these, 13 $MtCO_2$ were emitted as a result of energy use in the heat sector, 34% of the total energy-related emissions, and over a third more than in the electricity sector. Heat demand in Ireland has been principally met by combustion of oil and fossil gas.

Electrification through the use of electric industrial boilers[59], hydrogen-fired heat production and air source heat pumps, offers an opportunity for decarbonisation of the Irish heat sector using renewable electricity. The viability of these technologies is often linked to the temperature required at the point of use. The Irish industrial sector uses approximately 20 TWh of heat each year[60] across the following temperature bands:

- 6.5 TWh at temperatures <100°C;
- 5.0 TWh at temperatures of 100-400°C; and
- 8.5 TWh at temperatures >400°C.

Electrifying these end-use applications creates additional electrical demand, but also creates an opportunity to integrate renewable generation that would otherwise be turned-down as oversupply. The relative flexibility of these technologies allows them to target their offtake in hours of low price, in which the proportion of wind and solar generation is highest. Additional demand in hours of zero price acts to reduce RES oversupply. To quantify the impact that the Irish power sector can have on the heat sector, we have modelled three sensitivities that explore different penetration of electrified heat demand in ROI, each modelled as an extension of the 'Aligned Carbon Price' scenario:

- **'3 TWh – Electrode'** (~15% of industrial heat demand): In this sensitivity we have considered the impact on the Irish power and heat sectors of an additional 3 TWh tranche of flexible electrified industrial heat demand, representative of 'electrode boilers' for use in heavy industry such as aluminium production. These electrode boilers are typically suitable for applications in the 100-400°C range.
- **'5 TWh – Electrode & Hydrogen'** (~25% of industrial heat demand): In addition to the industrial demand above, we assume that 2 TWh of flexible hydrogen electrolysis demand is deployed in the ROI power sector. The hydrogen produced by these assets is used for heat production in industry. Hydrogen offers an alternative to fossil fuels for very high-temperature applications that require temperatures of >400°C.
- **'7 TWh – Electrode, Hydrogen & Heat Pump'** (~35% of industrial heat demand): Along with the 5 TWh of electrified heat demand detailed above, a further 2 TWh of low-temperature industrial heat demand (<100°C) is electrified using flexible heat pumps. This heat pump demand could alternatively be used to further decarbonise residential heating.

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[59] https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_industrial_process_heat_and_cc.pdf

[60] https://renewableenergyireland.ie/wp-content/uploads/2021/05/Renewable-Energy-Ireland_Renewable-Heat-Plan_-Final.pdf

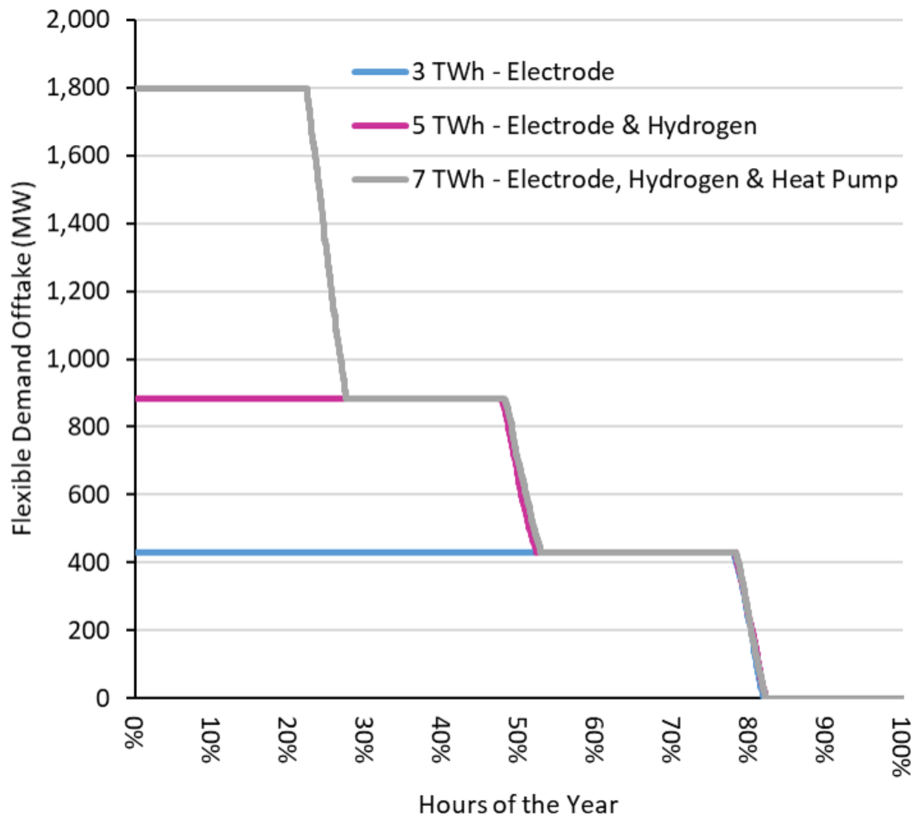
The 2 TWh of industrial heat pump demand modelled in this sensitivity is additional to the approximately 3 TWh of relatively inflexible heat pump demand in ROI assumed in the 'Aligned Carbon Price' scenario.

We have used our PLEXOS power market model to assess the impact of this additional flexible demand on the Irish power sector, and calculated in Excel the displaced CO_2 emissions in the heat sector.

Each tranche of heat demand is modelled as having a monthly required offtake but with flexibility to shift demand profile within month. The 3 TWh electrode tranche is assumed to require an average load factor of 80%, offering limited flexibility of offtake. The 2 TWh of hydrogen electrolysis demand is assumed not to be triggered directly by a certain wholesale price as is assumed for the electrolysers in Section 3, which produce hydrogen for use in the power sector, but to maintain a 50% load factor on average. 2 TWh corresponds to around 35% of the electrolyser demand in the 'Green Hydrogen' Phase 2 scenario. The industrial heat pump demand in the '7 TWh' sensitivity is assumed to require a 25% load factor on average, allowing targeted offtake in hours of excess renewable power generation.

The offtake of incremental heat sector demand determined by the model optimisation is presented as independent duration curves in Figure 27 below.

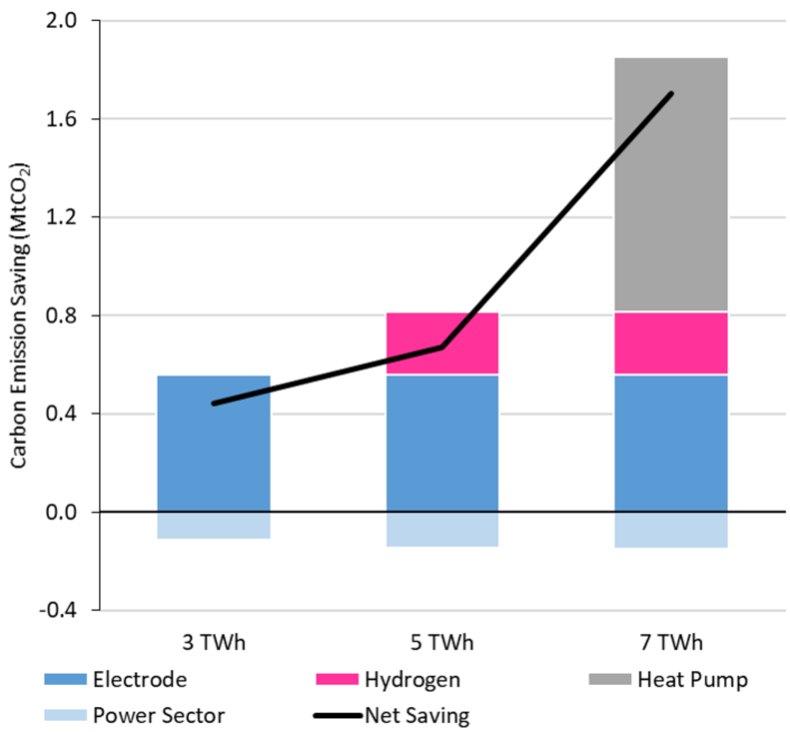
Figure 27: Duration curves of flexible heat sector demand offtake



Increased electricity demand in hours of high wind and solar generation acts to incrementally reduce RES oversupply in ROI. The electrified industrial demand reduces RES oversupply by around a quarter in the ‘3 TWh’ sensitivity relative to the ‘Aligned Carbon Price’ scenario, with a two-third reduction seen in wind and solar oversupply in the ‘7 TWh’ sensitivity. The load factor limits applied to the industrial and hydrogen demand tranches force the use of electricity in hours with some fossil gas-fired generation, i.e. hours of non-zero price in the day-ahead market. This demand acts to increase power sector emissions by 120 and 150 ktCO_2[61] in the ‘3 TWh’ and ‘5 TWh’ sensitivities respectively. The 25% load factor limit applied to the industrial heat pump demand component allows them to use renewable electricity almost exclusively (around 25% of hours have zero price) and results in a negligible increase in power sector emissions in the ‘7 TWh’ sensitivity relative to ‘5 TWh’.

We have calculated the displaced CO_2 emissions in the heat sector as a result of electrification in each sensitivity using the relative efficiencies of heat production methods in the industrial sector. The net emission savings in each sensitivity relative to the ‘Aligned Carbon Price’ scenario are presented in Figure 28 below. The ‘3 TWh’ sensitivity results in a net CO_2 emission reduction of 0.4 MtCO_2 in ROI. The use of green hydrogen in supply of heat demand in the ‘5 TWh’ sensitivity reduces net emissions by a further 0.2 MtCO_2. The relative efficiency of industrial heat pumps[62] results in the largest displacement of emissions, with a further 1.0 MtCO_2 displaced in the ‘7 TWh’ sensitivity. In each calculation, we have assumed that the electrified heating assets displace fossil gas-fired equivalents. If residual oil-fired industrial heat production is displaced, the CO_2 saving figures would be around one third larger.

Figure 28: Net CO_2 emission savings across the power and heat sectors in ROI



[61] Thousand tonnes of CO_2.

[62] Heat pumps are typically described as having a ‘coefficient of performance’ (COP), a measure of the ratio of heat delivered relative to the electrical energy consumed. HPs typically have a COP greater than 1. In this study, we have used the 2030 COP projection of 2.54 from the SONI TESNI 2020.

A.2 Displacement of emissions from the GB power sector

We have also explored an alternative sensitivity in which we consider additional renewable capacity in I-SEM as reducing CO_2 emissions in the GB market using Ireland's wind resource. This sensitivity has been performed in Excel based on the hourly PLEXOS results of the 'Aligned Carbon Price' scenario, but represents a CO_2 mitigation solution compatible with any Phase 1 or Phase 2 scenario.

In this sensitivity we consider a 700 MW offshore wind farm in Irish waters as being connected directly into the GB market, displacing emissions in the GB day-ahead schedule. Such direct connected projects are likely to be required if Ireland is to utilise the 30 GW of offshore wind potential stated in the Programme for Government. Any reduction in emissions is attributed to ROI in the form of carbon offset credits. To calculate this offset we assume that all generation from the offshore site, subject to connection losses and availability, acts to displace the output of the marginal plant in GB, and contributes to the carbon offset at the emission intensity of the marginal generator. We assume that the 700 MW connection includes line losses of around 4%, with an additional 3% outage rate.

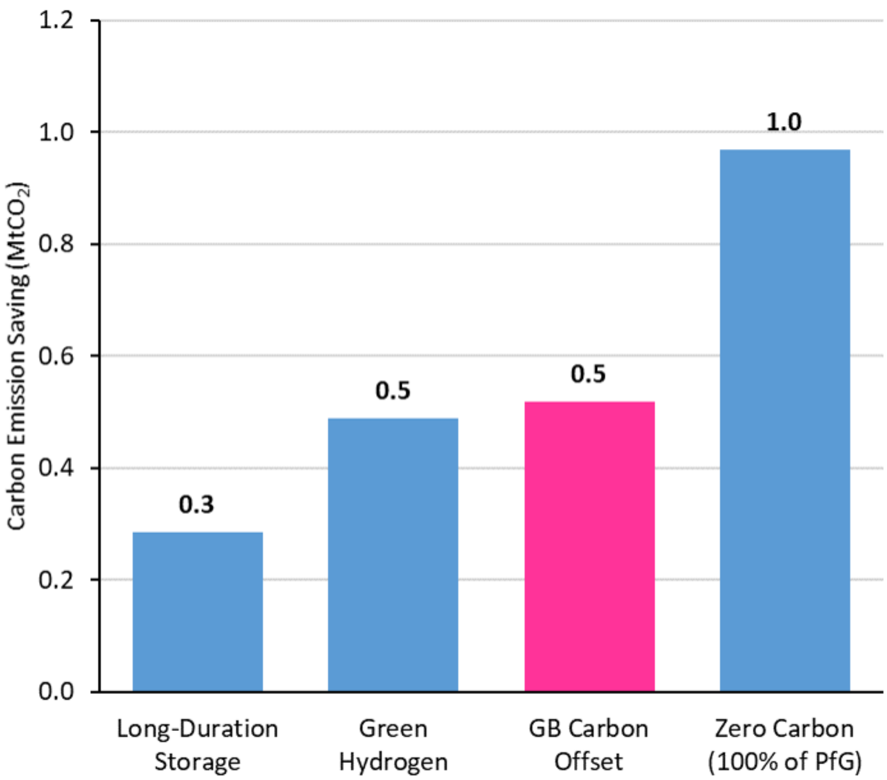
The 2030 GB market in the 'Aligned Carbon Price' scenario emits around 15 $MtCO_2$, at an average emission intensity of 46 tCO_2/MWh, greater than the 27 tCO_2/MWh in the I-SEM. The average emission intensity of the marginal plant in GB however is around 210 tCO_2/MWh. The offshore site is assumed able to displace generation in the GB day-ahead schedule, at the emission intensity of the marginal plant in each hour.

The modelled offshore wind site is able to offset 0.5 $MtCO_2$ from the GB day-ahead schedule. This carbon saving relative to the 'Aligned Carbon Price' scenario is comparable to that provided by the fleet of electrolysers and retrofitted generation capacity in the 'Green Hydrogen' scenario as shown in Figure 29 below. This sensitivity proves competitive with the key Phase 2 scenarios on a 'per tonne of CO_2' basis at around 140 €/tCO_2.

As the offshore site is independent for the I-SEM network, the emission saving available from a carbon offset is relatively invariant to the degree of decarbonisation in I-SEM, i.e. comparable emission offsets can be achieved in combination with each of the Phase 1 or 2 scenarios.

A carbon offset of this nature would also be initially scalable. Results show that in 2030, 1 $MtCO_2$ could be displaced from the GB market with an offshore site of approximately 1,360 MW under conditions of the 'Aligned Carbon Price' scenario. This solution would not be limitless however, as the emission intensity of the marginal plant in GB would decrease as the capacity of the offset increases. Beyond 2030 the emission saving would be expected to decrease as the GB market decarbonises further.

Figure 29: ROI CO_2 emission reduction relative to the 'Aligned Carbon Price' scenario



Appendix B Technologies not considered

Numerous alternative zero-carbon generation technologies exist, either in a theoretical or test state, or are being considered for deployment in other energy markets.

Prevalent examples of these technologies include:

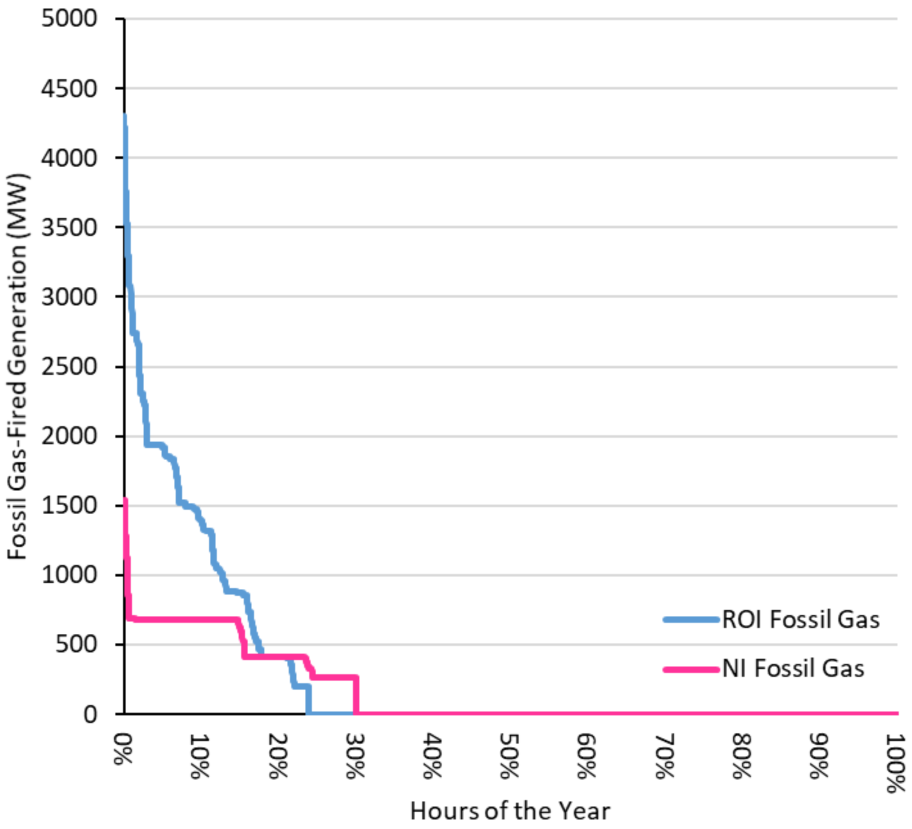
- Nuclear energy;
- Geothermal energy;
- Fossil gas-fired assets abated with Carbon Capture and Storage (CCS);
- Biomass-fired power plant;
- Biogas-fired power plant.

Under RES penetration levels seen in Phase 2 of this study, residual fossil gas-fired plant act with a highly ‘peaky’ profile as presented in the independent duration curves in Figure 30 below. In the ‘Aligned Carbon Price’ scenario around 4.6 and 1.6 GW of installed fossil gas-fired generation capacity in ROI and NI generate at load factors of 6% and 10% respectively.

Gas-fired plant abated with CCS, and nuclear and geothermal plant are primarily suited for baseload or mid-merit generation profiles rather than the highly ‘peaky’ and low load factor production complementary to the high RES deployment in the scenarios modelled. We have not considered these technologies within this study.

Biogas-fired generation assets are more suited to ‘peaky’ generation profiles. However, given the potentially valuable application of biogas within the heat and transport sectors, and the likely limits on available resource volumes, we have not considered the use of biogas in the Irish power sector in this study.

Figure 30: Duration curves of fossil gas-fired generation in the 'Aligned Carbon Price' scenario



Appendix C Tabulated input assumptions

C.1 Phase 1 scenario assumptions

I-SEM Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Commodity & Carbon Prices			
Coal CIF ARA	*$/tonne*	73	73
Gas NBP	*p/therm*	61	61
Oil Brent	*$/bbl*	78	78
Carbon EUA	*€/tonne*	50	50
I-SEM DS3 Limits (Operational Constraints)			
SNSP limit	*%*	95%	100%
RoCoF limit	*Hz/s*	1.0	1.0
Minimum inertia	*MWs*	0	0
System stability minimum units - I-SEM	*#*	4	0
System stability minimum units - ROI	*#*	0	0
System stability minimum units - NI	*#*	2	0
Interconnection Capacity			
Import from GB	*MW*	1,450	1,450
Export to GB	*MW*	1,500	1,500
Import from France	*MW*	700	700
Export to France	*MW*	700	700

External Market Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
GB RES Capacity			
Onshore wind	*MW*	19,640	19,640
Offshore wind	*MW*	35,000	35,000
Solar PV	*MW*	15,100	15,100
France RES Capacity			
Onshore wind	*MW*	40,000	40,000
Offshore wind	*MW*	9,010	9,010
Solar PV	*MW*	41,240	41,240

ROI Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Total & BAU Demand			
Total annual demand	*GWh*	44,310	44,230
Total peak demand	*MW*	7,320	7,320
BAU annual demand	*GWh*	35,780	35,780
BAU peak demand	*MW*	5,910	5,910
EV & HP Demand			
EV number	*#*	1,000,000	1,000,000
EV total demand	*GWh*	4,430	4,430
EV flexible demand	*GWh*	1,110	1,110
HP number	*#*	600,000	600,000
HP total demand	*GWh*	2,670	2,670
HP flexible demand	*GWh*	0	0
Demand Side Response			
Demand side capacity able to be curtailed	*MW*	360	360
Demand side capacity able to shift load	*MW*	160	160
Installed RES Capacity			
Onshore wind	*MW*	6,270	6,900
Offshore wind	*MW*	2,530	3,340
Solar PV	*MW*	2,550	3,350
Installed Battery Capacity			
0.5 hr battery (DS3-only)	*MW*	560	560
2 hr battery	*MW*	400	400
3 hr battery	*MW*	400	400
Other Generation Capacity			
Biomass	*MW*	200	200
Fossil gas	*MW*	4,600	4,380
Hydro	*MW*	220	220
Pumped hydro storage	*MW*	290	290
Waste	*MW*	90	90
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	8,000	14,080

NI Input Assumptions	Units	70 by 30 (3.3 Mt)	Less than 2 Mt
Total & BAU Demand			
Total annual demand	*GWh*	10,750	10,730
Total peak demand	*MW*	1,780	1,780
BAU annual demand	*GWh*	8,680	8,680
BAU peak demand	*MW*	1,430	1,430
EV & HP Demand			
EV number	*#*	371,700	371,700
EV total demand	*GWh*	1,650	1,650
EV flexible demand	*GWh*	410	410
HP number	*#*	158,500	158,500
HP total demand	*GWh*	700	700
HP flexible demand	*GWh*	0	0
Demand Side Response			
Demand side capacity able to be curtailed	*MW*	120	120
Demand side capacity able to shift load	*MW*	50	50
Installed RES Capacity			
Onshore wind	*MW*	1,970	2,240
Offshore wind	*MW*	270	380
Solar PV	*MW*	750	950
Installed Battery Capacity			
0.5 hr battery (DS3-only)	*MW*	140	140
2 hr battery	*MW*	100	100
3 hr battery	*MW*	100	100
Other Generation Capacity			
Biomass	*MW*	0	0
Fossil gas	*MW*	1,600	1,600
Hydro	*MW*	0	0
Pumped hydro storage	*MW*	0	0
Waste	*MW*	30	30
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	2,000	3,520

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C.2 Phase 2 assumptions ('Aligned CO_2' and 'LDS')

I-SEM Input Assumptions	Units	Aligned CO_2	LDS
Commodity & Carbon Prices			
Coal CIF ARA	*$/tonne*	73	73
Gas NBP	*p/therm*	61	61
Oil Brent	*$/bbl*	78	78
Carbon EUA	*€/tonne*	100	100
I-SEM DS3 Limits (Operational Constraints)			
SNSP limit	*%*	100%	100%
RoCoF limit	*Hz/s*	1.0	1.0
Minimum inertia	*MWs*	0	0
System stability minimum units - I-SEM	*#*	0	0
System stability minimum units - ROI	*#*	0	0
System stability minimum units - NI	*#*	0	0
Interconnection Capacity			
Import from GB	*MW*	1,450	1,450
Export to GB	*MW*	1,500	1,500
Import from France	*MW*	700	700
Export to France	*MW*	700	700

External Market Input Assumptions	Units	Aligned CO_2	LDS
GB RES Capacity			
Onshore wind	*MW*	19,640	19,640
Offshore wind	*MW*	35,000	35,000
Solar PV	*MW*	15,100	15,100
France RES Capacity			
Onshore wind	*MW*	40,000	40,000
Offshore wind	*MW*	9,010	9,010
Solar PV	*MW*	41,240	41,240

ROI Input Assumptions	Units	Aligned CO_2	LDS
Total & BAU Demand			
Total annual demand	*GWh*	44,350	45,630
Total peak demand	*MW*	7,320	7,320
BAU annual demand	*GWh*	35,780	35,780
BAU peak demand	*MW*	5,910	5,910
EV & HP Demand			
EV number	*#*	1,000,000	1,000,000
EV total demand	*GWh*	4,430	4,430
EV flexible demand	*GWh*	1,110	1,110
HP number	*#*	600,000	600,000
HP total demand	*GWh*	2,670	2,670
HP flexible demand	*GWh*	0	0
Demand Side Response			
Demand side capacity able to be curtailed	*MW*	360	360
Demand side capacity able to shift load	*MW*	160	160
Installed RES Capacity			
Onshore wind	*MW*	7,420	7,420
Offshore wind	*MW*	4,010	4,010
Solar PV	*MW*	4,010	4,010
Installed Battery Capacity			
0.5 hr battery (DS3-only)	*MW*	560	560
2 hr battery	*MW*	400	400
3 hr battery	*MW*	400	400
Other Generation Capacity			
Biomass	*MW*	200	200
Fossil gas	*MW*	4,380	4,380
Hydro	*MW*	220	220
Pumped hydro storage	*MW*	290	290
Waste	*MW*	90	90
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	14,080	14,080

NI Input Assumptions	Units	Aligned CO_2	LDS
Total & BAU Demand			
Total annual demand	*GWh*	10,760	11,070
Total peak demand	*MW*	1,780	1,780
BAU annual demand	*GWh*	8,680	8,680
BAU peak demand	*MW*	1,430	1,430
EV & HP Demand			
EV number	*#*	371,700	371,700
EV total demand	*GWh*	1,650	1,650
EV flexible demand	*GWh*	410	410
HP number	*#*	158,500	158,500
HP total demand	*GWh*	700	700
HP flexible demand	*GWh*	0	0
Demand Side Response			
Demand side capacity able to be curtailed	*MW*	120	120
Demand side capacity able to shift load	*MW*	50	50
Installed RES Capacity			
Onshore wind	*MW*	2,480	2,480
Offshore wind	*MW*	480	480
Solar PV	*MW*	1,120	1,120
Installed Battery Capacity			
0.5 hr battery (DS3-only)	*MW*	140	140
2 hr battery	*MW*	100	100
3 hr battery	*MW*	100	100
Other Generation Capacity			
Biomass	*MW*	0	0
Fossil gas	*MW*	1,600	1,600
Hydro	*MW*	0	0
Pumped hydro storage	*MW*	0	0
Waste	*MW*	30	30
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	3,520	3,520

ROI Input Assumptions	Units	Aligned CO_2	LDS
Long-Duration Storage			
Installed generation capacity	*MW*	-	640
Storage duration	*hrs*	-	100
Round-trip efficiency	*%*	-	60%
Green Hydrogen			
Installed electrolysis capacity	*MW*	-	-
Electrolyser $P2H_2$ efficiency	*%*	-	-
Installed storage volume	*GWh*	-	-
Installed generation capacity	*MW*	-	-

NI Input Assumptions	Units	Aligned CO_2	LDS
Long-Duration Storage			
Installed generation capacity	*MW*	-	160
Storage duration	*hrs*	-	100
Round-trip efficiency	*%*	-	60%
Green Hydrogen			
Installed electrolysis capacity	*MW*	-	-
Electrolyser $P2H_2$ efficiency	*%*	-	-
Installed storage volume	*GWh*	-	-
Installed generation capacity	*MW*	-	-

C.3 Phase 2 assumptions ('Green H_2' and 'Zero Carbon')

I-SEM Input Assumptions	Units	Green H_2	Zero Carbon
Commodity & Carbon Prices			
Coal CIF ARA	*$/tonne*	73	73
Gas NBP	*p/therm*	61	61
Oil Brent	*$/bbl*	78	78
Carbon EUA	*€/tonne*	100	100
I-SEM DS3 Limits (Operational Constraints)			
SNSP limit	*%*	100%	100%
RoCoF limit	*Hz/s*	1.0	1.0
Minimum inertia	*MWs*	0	0
System stability minimum units - I-SEM	*#*	0	0
System stability minimum units - ROI	*#*	0	0
System stability minimum units - NI	*#*	0	0
Interconnection Capacity			
Import from GB	*MW*	1,450	1,450
Export to GB	*MW*	1,500	1,500
Import from France	*MW*	700	700
Export to France	*MW*	700	700

External Market Input Assumptions	Units	Green H_2	Zero Carbon
GB RES Capacity			
Onshore wind	*MW*	19,640	19,640
Offshore wind	*MW*	35,000	35,000
Solar PV	*MW*	15,100	15,100
France RES Capacity			
Onshore wind	*MW*	40,000	40,000
Offshore wind	*MW*	9,010	9,010
Solar PV	*MW*	41,240	41,240

ROI Input Assumptions	Units	Green H_2	Zero Carbon
Total & BAU Demand			
Total annual demand	*GWh*	48,880	51,500
Total peak demand	*MW*	7,320	7,320
BAU annual demand	*GWh*	35,780	35,780
BAU peak demand	*MW*	5,910	5,910
EV & HP Demand			
EV number	*#*	1,000,000	1,000,000
EV total demand	*GWh*	4,430	4,430
EV flexible demand	*GWh*	1,110	1,110
HP number	*#*	600,000	600,000
HP total demand	*GWh*	2,670	2,670
HP flexible demand	*GWh*	0	0
Demand Side Response			
Demand side capacity able to be curtailed	*MW*	360	360
Demand side capacity able to shift load	*MW*	160	160
Installed RES Capacity			
Onshore wind	*MW*	7,420	8,200
Offshore wind	*MW*	4,010	5,000
Solar PV	*MW*	4,010	5,000
Installed Battery Capacity			
0.5 hr battery (DS3-only)	*MW*	560	560
2 hr battery	*MW*	400	400
3 hr battery	*MW*	400	400
Other Generation Capacity			
Biomass	*MW*	200	200
Fossil gas	*MW*	4,380	0
Hydro	*MW*	220	220
Pumped hydro storage	*MW*	290	290
Waste	*MW*	90	90
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	14,080	14,080

NI Input Assumptions	Units	Green H_2	Zero Carbon
Total & BAU Demand			
Total annual demand	*GWh*	11,860	12,490
Total peak demand	*MW*	1,780	1,780
BAU annual demand	*GWh*	8,680	8,680
BAU peak demand	*MW*	1,430	1,430
EV & HP Demand			
EV number	*#*	371,700	371,700
EV total demand	*GWh*	1,650	1,650
EV flexible demand	*GWh*	410	410
HP number	*#*	158,500	158,500
HP total demand	*GWh*	700	700
HP flexible demand	*GWh*	0	0
Demand Side Response			
Demand side capacity able to be curtailed	*MW*	120	120
Demand side capacity able to shift load	*MW*	50	50
Installed RES Capacity			
Onshore wind	*MW*	2,480	2,540
Offshore wind	*MW*	480	500
Solar PV	*MW*	1,120	1,170
Installed Battery Capacity			
0.5 hr battery (DS3-only)	*MW*	140	140
2 hr battery	*MW*	100	100
3 hr battery	*MW*	100	100
Other Generation Capacity			
Biomass	*MW*	0	0
Fossil gas	*MW*	1,300	0
Hydro	*MW*	0	0
Pumped hydro storage	*MW*	0	0
Waste	*MW*	30	30
Installed Synchronous Condenser Capacity			
Synchronous condenser	*MWs*	3,520	3,520

ROI Input Assumptions	Units	Green H_2	Zero Carbon
Long-Duration Storage			
Installed generation capacity	*MW*	-	640
Storage duration	*hrs*	-	100
Round-trip efficiency	*%*	-	60%
Green Hydrogen			
Installed electrolysis capacity	*MW*	1,290	1,290
Electrolyser P2H_2 efficiency	*%*	70%	70%
Installed storage volume	*GWh*	3,000	3,250
Installed generation capacity	*MW*	900	4,380

NI Input Assumptions	Units	Green H_2	Zero Carbon
Long-Duration Storage			
Installed generation capacity	*MW*	-	160
Storage duration	*hrs*	-	100
Round-trip efficiency	*%*	-	60%
Green Hydrogen			
Installed electrolysis capacity	*MW*	310	310
Electrolyser P2H_2 efficiency	*%*	70%	70%
Installed storage volume	*GWh*	1,000	1,250
Installed generation capacity	*MW*	300	1,600

C.4 Technology cost assumptions

I-SEM Technology Cost Assumptions	Units	All Scenarios
RES LCOE Assumptions		
Onshore wind	*€/MWh*	50
Offshore wind	*€/MWh*	65
Solar PV	*€/MWh*	60
Phase 2 Annuitized Technology Costs		
Pumped hydro storage	*€/kW per year*	76
Compressed air storage	*€/kW per year*	140
Hydrogen electrolyser	*€/kW per year*	43
Hydrogen storage (cavern)	*€/kWh per year*	13
Hydrogen-fired generator (retrofit-only)	*€/kW per year*	8

C.5 Emission offset sensitivity assumptions

Emission Offset Sensitivity Assumptions	Units	All Sensitivities
Electrified Industrial Heat Demand		
Fossil gas-fired boiler efficiency (>100°C)	*%*	98%
Fossil gas-fired boiler efficiency (<100°C)	*%*	90%
Electrode boiler efficiency (100-400°C)	*%*	99%
Hydrogen-fired boiler efficiency (>400°C)	*%*	98%
Heat pump COP	*#*	2.54
GB Connected Offshore Wind		
Offshore Wind LCOE (GB Connected)	*€/MWh*	70
Connection losses	*%*	4%
Connection outage rate	*%*	3%

Appendix D About Baringa

Baringa Partners is an independent business and technology consultancy. We help businesses run more effectively, navigate industry shifts and reach new markets. We use our industry insights, ideas, and pragmatism to help each client improve their business. Collaboration is central to our strategy and culture, ensuring we attract the brightest and the best. And its why clients love working with us.

Baringa launched in 2000 and now has over 900 members of staff and 92 partners across our practice areas Energy & Resources, Financial Services, Products & Services, and Government & Public Sector. These practices are supported by cross-sector teams focused on Customer & Digital; Finance, Risk & Compliance; People Excellence; Supply Chain & Procurement; Data, Analytics & AI; Intelligent Automation & Operations Excellence; and Technology Transformation. We operate globally and have offices in the UK, Europe, Australia, US and Asia.

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.

Baringa Partners have been voted as the leading management consulting firm in the Financial Times' UK Leading Management Consultants 2021 in the categories Energy, Utilities & the Environment, and Oil & Gas. We have been in the Top 10 for the last 14 years in the small, medium, as well as large category in the UK Best Workplaces™ list by Great Place to Work®. We are a Top 50 for Women employer, and are recognised by Best Employers for Race.

Baringa. Brighter Together.