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December 2019

Version History

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Contents

Executive Summary

1. Baringa's '70 by 30' report demonstrated that 70% renewable electricity by 2030 in Ireland can be achieved at a net financial benefit to end consumers[1]. This report played an important role in influencing Ireland's renewable energy ambitions and in March 2019 the Irish government pledged a binding target of 70% renewable electricity by 2030. Further to this, both the Irish[2] and UK[3] governments have set a goal of net-zero emissions by 2050 and decarbonisation has also been made a primary goal in the strategies of key all-island stakeholders such as the Commission for Regulation of Utilities, Water and Energy (CRU)[4], the Utility Regulator in Northern Ireland[5], and the Transmission System Operators (TSOs) EirGrid[6] and SONI[7].

   One of the key observations from '70 by 30' is that the provision of 'flexibility' on the Irish power system is essential for the successful and efficient integration of renewables. An important aspect of this flexibility is the provision of system services that are required by EirGrid and SONI to ensure the electricity system remains stable. There are different types of system services which reflect the various products that the TSOs require, such as the provision of reserve, inertia, ramping and voltage support.

2. Currently, the TSOs apply limits, known as 'constraints', to the operation of power stations and power demand to ensure there are sufficient system services available on the grid at all times to maintain the safe and secure flow of electricity.

3. Traditionally, system services have been provided in large part by fossil-fuelled power stations that often must be turned on or 'positioned' by the TSOs, when they otherwise would not be running, so they are available to provide these services. These power stations receive compensation to cover the additional fuel and carbon costs they need to operate in order to provide these services. This also results in increased CO_2 emissions and the curtailment of renewable generation[8].

4. One important and potentially valuable role that 'zero-carbon' flexible technologies such as battery storage, demand side response, synchronous condensers and renewable generators could play is in the provision of system services – avoiding the need to source them from fossil-fuelled generators.

5. This study looks at an alternative approach to meeting all system services provision via a 'Zero-Carbon Model'. We have analysed the societal benefits – in terms of CO_2 emissions reduction, operational cost savings and reduced renewable curtailment – of procuring all system services

[1] https://www.iwea.com/images/files/70by30-report-final.pdf
[2] https://www.dccae.gov.ie/en-ie/climate-action/publications/Pages/Climate-Action-Plan.aspx
[3] https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law
[4] https://mk0cruiefjep6wj7niq.kinstacdn.com/wp-content/uploads/2019/03/CRU19030a-CRU-Strategic-Plan-2019-2021-English-Version.pdf
[5] https://www.uregni.gov.uk/news-centre/corporate-strategy-2019-24-and-forward-work-programme-2019-20-published
[6] http://www.eirgridgroup.com/about/strategy-2025/
[7] http://www.soni.ltd.uk/newsroom/press-releases/soni-strategy-2020-2025/
[8] Curtailment occurs when renewable power stations, that would otherwise have been running, have their output reduced by the TSO to accommodate the additional generation from power stations which are being turned on to meet system constraints.

from zero-carbon technologies, compared with an alternative scenario where fossil fuels continue to be the predominant provider.

6. **Our analysis shows that:**

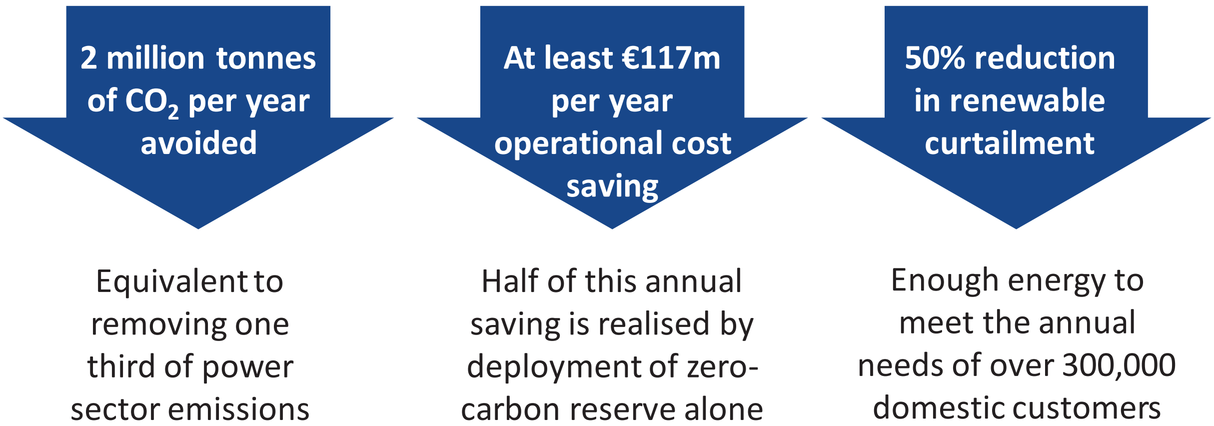
   - **Procuring system services from zero-carbon providers could reduce all-island power sector emissions by almost 2 million tonnes of CO_2 per year by 2030. This is equivalent to one third of total 2030 power sector emissions that could be avoided by transitioning to a Zero-Carbon Model.**

   - **There are significant operational cost savings associated with sourcing all system services from zero-carbon sources, with up to €90m per year of savings by 2021, increasing to €117m per year by 2030, primarily from avoided fuel and carbon costs. We project an annual operational cost saving of €57m per year by 2030 if reserve requirements alone are met by zero-carbon technologies.**

   - **There is a significant reduction in renewable curtailment if system operational constraints are met using zero-carbon service providers. In 2030, our analysis suggests a greater than 50% reduction in renewable curtailment from 8.1% to 4.0%. This reduction in the curtailment of zero-marginal cost renewables results in lower electricity generation costs as it displaces more expensive, typically fossil-fuelled, generators in the production of electricity.**

7. In this study, we have not considered the market design and commercial framework under which zero-carbon service providers could be remunerated but we consider that long-term frameworks that provide investment certainty for zero-carbon providers to deliver may be beneficial. We have also not modelled other possible benefits that a zero-carbon model could bring such as lower wholesale energy prices, or a reduction in the cost of renewable deployment as a result of reduced curtailment levels.

Figure 1 Summary of the key benefits of the Zero-Carbon Model by 2030[9]



[9] Average annual domestic customer electricity demand is reported by the Commission for Regulation of Utilities, Water and Energy: https://www.cru.ie/wp-content/uploads/2017/07/CER17042-Review-of-Typical-Consumption-Figures-Decision-Paper-1.pdf

1 Introduction

1.1 Objectives

This study builds off Baringa's '70 by 30' report which was published in October 2018[10]. In that study, we showed that 70% renewable electricity can be achieved by 2030 in Ireland at a net financial benefit to end consumers, if Ireland can match over the period 2020-2030 the renewable energy costs already achieved elsewhere in Europe. The conclusions of the '70 by 30' report played an important role in shifting the ambitions for power sector decarbonisation in Ireland, and in March 2019 the Irish government pledged a binding target of 70% renewable electricity by 2030.

EirGrid and SONI, the Transmission System Operators (TSOs) of Ireland and Northern Ireland, apply operational limits to the power system in order to make sure it remains stable during times of stress. This ensures that power can continue to flow from supply to demand in a safe fashion where all technical limits of the power system are met. These limits are maintained by applying 'constraints' to the operation of generation and demand to ensure there are sufficient 'system services' available on the grid to maintain safety standards. There are different types of system services which reflect the various products that the TSOs require to keep the system stable, such as the provision of reserve, inertia, ramping and voltage support. Constraints ensure that there are enough providers of system services available to react if an issue arises on the system, such as a trip of a transmission circuit or a generator. Traditionally system services have been provided in large part by fossil-fuelled power stations.

We found as part of our '70 by 30' study that the provision of 'flexibility' on the Irish power system was one key to the successful and efficient integration of renewables. One important and potentially valuable role that 'zero-carbon' flexibility providers such as battery storage, demand side response, synchronous condensers and renewable generation could play is in the provision of system services – avoiding the need to source these services from fossil-fuelled generators.

As the contribution from renewable electricity increases on the power system in Ireland and Northern Ireland, it is vital to understand how the cost of meeting power system constraints such as reserves, inertia and voltage is likely to evolve, and what role new technologies can play in maintaining a robust power grid at the lowest cost, and with the smallest carbon footprint.

On an international stage we are witnessing the emergence of new 'zero-carbon' technologies and approaches to provide reserve, which do not rely on running gas and coal-fired generators. The two most well-known examples are battery storage and demand side response such as the controllable reduction in industrial power consumption. These technologies are beginning to emerge in the all-island market. There is around 580 MW of demand side response currently contracted, and there are battery storage projects currently under development primarily focussed on the provision of system services under the current 'DS3' ancillary services regime.

The objective of this zero-carbon system services study is to determine the societal benefit – in terms of CO_2 emissions reduction, operational cost savings and reduced renewable curtailment – of using new zero-carbon technologies to ensure the all-island power grid remains strong and secure, rather than current fossil-fuel powered methods.

[10] https://www.iwea.com/images/files/70by30-report-final.pdf

The analysis for this study takes place within the scenario set out in our '70 by 30' report. We have kept key assumptions relating to electricity demand, generation capacities, and electrification largely unchanged and consistent with the '70 by 30' study.

1.2 Background to system services

The TSOs on the all-island system must ensure that they hold a sufficient quantity of available system services provision at all times. In the case of reserves, this back-up power is held for use in the event of sudden and unexpected disruptions to sources of power generation or demand on the power system, such as a failure of a power station, or a piece of grid infrastructure. Reserve typically consists of additional sources of generation, or demand reduction, which the TSOs hold in a state of readiness. These can be called upon at short notice to deliver additional power by increasing output or reducing demand. There are different types of reserve services, which are categorised according to how quickly they can be activated, and for what duration they are able to sustain their operation. For instance, these reserve services require power to be delivered from seconds up to 20 minutes depending on the different service type.

Currently, the TSOs meet their reserve requirements largely from a combination of gas and coal-fired generators, along with some pumped storage and hydro power stations. In order for fossil-fuelled power stations to provide the fastest reserve services, such as primary operating reserve that must be delivered in seconds, they typically need to be turned on and generating at a certain minimum output. This provides 'headroom' for output to be increased quickly, at short notice. This means that, currently, the TSOs routinely pre-position fossil-fuelled generators by either asking them to

- turn on and run at minimum output, when they otherwise would not be running, or
- turn down to a part-loaded state, when they otherwise would be running at maximum output.

This is also the case for other system services such as inertia and voltage control, where fossil-fuelled generators generally must be operating to provide these services and are often turned on or run inefficiently at less than their full generation output solely to ensure their availability to provide this support.

The TSOs pay compensation to generators in order to cover the costs of this pre-positioning. On an all-island basis, current methods of meeting power system operational constraints:

- Cost consumers over €190m per year, recovered as part of the 'imperfections' charge on consumer bills[11]. This covers the costs that generators incur by being turned on or the compensation costs of turning them down to provide system services, including additional fuel and carbon costs. These costs are additional to the payments made for the provision of system services under the current DS3 regime.

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[11] Forecast Total Constraints costs for the year 2018/19 were €190.44m and this is recovered through the Imperfections Charge on end customer bills https://www.semcommittee.com/sites/semc/files/media-files/SEM-18-047%20Imperfection%20Charge%20October%202018%20-%20September%202019%20and%20Incentive%20Outturn%20October%202016%20-%20September%2020017.pdf

- Result in the curtailment of 445 GWh of renewable electricity per year. This is because the available 'space' on the system for renewable generation is reduced by the need to turn on fossil-fuelled generators for service provision. This curtailed renewable electricity could meet the annual power requirements of 105,000 domestic customers[12].
- Increase power sector CO_2 emissions through the use of gas and coal-fired generators.

1.3 Our analysis of the Zero-Carbon Model

In this study, we looked at an alternative approach to meeting all system services provision via a 'Zero-Carbon Model'. Under the Zero-Carbon Model, system services procurement occurs outside the energy market, through a specialist technology fleet that is constantly available to provide reserve and other system services. These zero-carbon providers do not have to be generating in order to provide the necessary services, but rather they maintain a state of 'readiness' at all times.

We began the study by analysing the benefits of procuring all reserve services from zero-carbon sources such as battery storage and demand side response, in comparison to an alternative scenario where fossil fuels continue to be the predominant provider of reserve. Such zero-carbon sources of reserve do not need to be 'pre-positioned' in the same way as fossil-fuelled sources of reserve, and do not incur the financial cost or CO_2 emissions of burning gas and coal in order to be in a state of readiness.

We then analysed the benefits of removing all system service constraints, reflecting the fact that these services are being provided by zero-carbon providers that are outside the energy market. In our analysis, we do not prescribe the exact technologies to be deployed under the Zero-Carbon Model. The results of this study are therefore entirely technology agnostic. However, zero-carbon technologies which are currently available to provide reserve and other system services include demand side response units, battery storage, synchronous condensers, flywheels and renewable generation. A future model for zero-carbon system services could envisage a range of such technologies deployed across the all-island system at strategic positions, ready to provide the necessary energy, inertia, or voltage upon request of the TSOs.

Our analysis in this report is focussed on the fundamental societal value of the Zero-Carbon Model in terms of reducing system operation costs, emissions and the curtailment of renewables. This study does not provide commentary on the market design or commercial model under which zero-carbon service providers could be remunerated by 2030. We have therefore not modelled the costs related to any payments made for the provision of system services.

In this study, we have analysed four scenarios for the provision of reserve and system services on the island of Ireland:

[12] EirGrid Annual Renewable Energy Constraint and Curtailment Report 2018 states 707 GWh of renewable dispatch-down, of which an estimated 63% was attributed to curtailment. Average annual domestic customer electricity demand is reported by the Commission for Regulation of Utilities, Water and Energy: http://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2018-V1.0.pdf
https://www.cru.ie/wp-content/uploads/2017/07/CER17042-Review-of-Typical-Consumption-Figures-Decision-Paper-1.pdf

- In the '**Base Case'**, system services are met in a 'business as usual' fashion where for a substantial percentage of the year fossil-fuelled plant are moved 'out of merit' to maintain system security.
- In the '**Zero-Carbon Reserve Case'** all reserve is met by a fleet of zero emissions technology (notionally demand side response / battery storage) purely focussed on reserve provision. Meeting reserve in this manner using technology not participating in the energy market means that the final dispatch of energy generating plant moves significantly closer to market optimal levels.
- In the '**50% Zero-Carbon Reserve Case**' half of reserve requirements are met in this fashion.
- In the fourth scenario, '**Zero-Carbon Services & Reserve**' sees all reserve and all other system service constraints met by non-energy market participating zero emissions technology, which results in an optimal dispatch in the power market.

We have used our advanced, in-house model of the all-island power system, based on PLEXOS, to capture the impact of system services provision on system operation cost. System operation cost is defined for this study as:

- the additional fuel cost associated with running less efficient plants or by bringing online thermal plant and curtailing zero marginal cost renewables
- the carbon cost associated with additional CO_2 emissions, and
- charges associated with the re-dispatch of interconnectors.

Primarily the cost of reserve and grid service provision falls upon the all-island system, however given the interconnected nature of power markets we also take into account the impacts on Great Britain and other European markets.

The operational cost of providing system services is dependent on the extent and magnitude of system operational constraints. Our assumptions of the trajectory of system operational constraints have been informed by current EirGrid and SONI policy, public announcements on the future direction of travel, and a broader understanding of what may be necessary for Ireland to meet its target of 70% renewable electricity by 2030. We assume that many of the existing system operational constraints will be removed or reduced by 2030. To the extent that the actual reduction in constraints is less than we have assumed, then this would increase the reported operational cost savings (outlined further in Section 2.4).

1.4 Report structure

The remainder of this report is structured as follows:

- **Section 2** presents the scenario input assumptions
- **Section 3** explains the methodology used in our analysis
- **Section 4** discusses the key results, and
- **Section 5** summarises the main conclusions of the study.

The Appendix includes further detail on the modelling approach and scenario assumptions.

All monetary values in this report are presented in real 2019 money, unless otherwise stated.

2 Scenario assumptions

2.1 Market assumptions

Key input assumptions such as capacity mix, demand and commodity prices are consistent across all four modelled scenarios and are based upon the assumptions in our ’70 by 30’ report. Since the ‘70 by 30’ analysis was undertaken in 2018, the market has inevitably shifted in some areas. For example, demand growth expectations have increased, and near-term fuel and carbon price expectations would also be higher than assumed in the ’70 by 30’ study. Other recent developments include the policy announcements associated with the Climate Action Plan 2019 in Ireland regarding greater EV and heat pump ambitions. Directionally, the majority of these developments would strengthen the findings of the ‘70 by 30’ report. Furthermore, it is the relative difference between scenarios that is important in our analysis, rather than the specific numerical outcomes of each scenario. In the interests of consistency, we have therefore opted to leave the ’70 by 30’ scenarios assumptions unchanged. The key ‘universal’ scenario assumptions used in the study are presented in Table 1.

Table 1 Key universal assumptions in 2030

	ROI	NI	All-Island
% RES-E	70%	70%	70%
% RES	25%	25%	25%
Total Electricity Demand (TWh)	38.8	10.6	49.4
Wind Power (MW)	8,000	2,190	10,190
Solar Power (MW)	2,500	400	2,900
Interconnection (MW) – All Island	2,030	2,030	2,030
Electric Vehicles (nr)	426,000	203,398	629,398
Heat Pumps (nr)	279,000	117,302	396,302
Small Scale Battery Storage[13] (MW)	400	100	500
Large Scale Battery Storage[13] (MW)	960	240	1,200

There is over 580 MW of demand side response units currently contracted in the SEM and the potential of flexible demand response from domestic, commercial and industrial users is expected to increase over time (outlined in Section 3.4). A full description of the ’70 by 30’ scenario market assumptions can be found in Appendix A.

2.2 Provision of reserve

As part of maintaining system security, the TSOs seek to ensure there is a sufficient amount of ‘back-up power’ available at all times. There are six reserve categories which the TSOs maintain – Primary

[13] This is battery storage capacity that operates in the energy market, and excludes capacity associated with the Zero-Carbon Model.

Operating Reserve (POR), Secondary Operating Reserve (SOR) and Tertiary Operating Reserve 1&2 (TOR 1 & TOR2), Negative Reserve and Replacement Reserve. One key distinction between these reserve categories is the speed at which back-up power must be made available, and the duration over which the power must be sustained. Table 2 presents the key characteristics for POR through to TOR2.

Table 2 Reserve definition

	Delivered By	Maintained Until
Primary Operating Reserve	5 seconds	15 seconds
Secondary Operating Reserve	15 seconds	90 seconds
Tertiary Operating Reserve 1	90 seconds	5 minutes
Tertiary Operating Reserve 2	5 Minutes	20 minutes

The volume of reserve that the TSOs maintain is related to the largest possible single loss of power at a given point in time, referred to as the Largest Infeed Loss or LIFL. LIFL is measured in MW and will typically be set by a large generator or an importing interconnector. Currently the maximum LIFL is set by the East-West Interconnector at around 500 MW. For POR & SOR the TSOs currently maintain a reserve level equal to 75% of LIFL, while for TOR1 & TOR2 the volume of reserve procured is 100% of LIFL. The reason that the TSOs currently only hold 75% of LIFL for the faster response/shorter duration reserve is that a quantity of additional reserve is typically available from fossil-fuelled generators which are able to increase their output above the nominal maximum for a time, if required.

Reserve has historically been provided mainly by thermal plant and pumped storage. These plant contribute to reserve provision by generating at less than full load and having the ability to quickly ramp up output at short notice. Such units are said to have 'headroom'. Given the rapid delivery window of POR, SOR & TOR1 generally only plant that are actually operating at the time and have headroom can contribute to meeting reserve. For TOR2, the five-minute window for provision of energy means that in addition to units with headroom, plants that are not generating but are able to start-up relatively quickly (such as gas engines or open-cycle gas turbines) are also considered as available to provide reserve.

In the 'Base Case' scenario reserve is provided in the same manner as it is currently, with the TSOs re-dispatching plant to ensure there is sufficient headroom on the system (bearing in mind the capacity of fast starting plant to meet TOR2). However, in the other three scenarios, reserve is provided wholly or partially by a specialist fleet of zero-carbon reserve providers that do not otherwise participate in the wholesale energy market.

A new service, Fast Frequency Response (FFR), which requires delivery of energy within 2-10 seconds has been procured by the TSOs as of 2018 via the DS3 system services framework. Operating requirements for this service are not yet set out in the TSOs' operational constraints, and we have not modelled FFR provision in this study. However, we note that zero-carbon providers such as demand side response and battery storage are capable of providing this service and are already being contracted under the existing DS3 regime to do so.

2.3 Provision of other grid services

There are currently a number of system operational constraints in the SEM, in addition to reserve provision, that relate to maintaining the stability and resilience of the power grid. These include:

- A floor on the number of large power generation units operating at any one time. This is often referred to as the 'Min Gen' constraint. Today this is set at 5 units in the Republic of Ireland (ROI) and 3 units in Northern Ireland (NI). We assume that the North-South interconnector will be in place by 2024, and that this constraint is then set on an all-island basis at 5 units, dropping to 4 units by 2030.
- A limit on the maximum System Non-Synchronous Penetration (SNSP). The SNSP is a ratio of the volume of renewables plus interconnector imports and the volume of demand plus interconnector exports. Today the SNSP limit is set at 65% although we project this to increase to 90% by 2030 which is an objective outlined in the Climate Action Plan.

While Min Gen and SNSP constraints are two of the key system constraints, there also exist more targeted constraints focussed on parameters such as the rate of change of frequency (ROCOF), inertia levels, and locational voltage support. A full list of system constraints is presented in Table 4 and in the Appendix.

In the scenario 'Zero-Carbon Services & Reserve', we have assumed that a fleet of zero-carbon technologies is available to meet all reserve <u>and all other system operational constraints</u>, while sitting outside of the wholesale energy market. We have made no assumptions on the exact zero-carbon technology that is deployed. Possible examples could include battery storage, synchronous condensers, or flywheels. An estimate of the volume of system services that would be required is provided in Table 3 below. In such circumstances where all reserve and system constraints are met by non-energy market participating plant, there would be no need for the TSOs to re-dispatch plant at all to meet system-level constraints.

Table 3 Zero-carbon system service providers and potential capacities required in a 2030 70% RES-E power system

System Service	Potential Capacity Required	Example zero-carbon technologies
Reserve	700-1,000MW of Reserves – 500ms to 1 hour	Battery storage, domestic and large energy user demand-side response, renewables
Inertia	20,000 MWs	Synchronous condensers
Reactive Power	±3,600 Mvar	STATCOMs, renewables, battery storage
Ramping	1,500 MW – 1 hour, 3000 MW – 3 hours, 4,000 MW – 8 hour	Long-duration storage, pumped hydro, demand-side response

2.4 System constraint assumptions

The assumptions on the future evolution of system operational constraints (reserves and grid services) are shown in Table 4 and are universally applied across all four scenarios. Operational constraint assumptions are informed by the TSOs' current policy, combined with the direction of travel signalled by ongoing trials and announcements, as well as a broader understanding of likely changes required to support the delivery of 70% renewable electricity by 2030. We assume that many of the existing constraints will be removed or reduced by 2030. To the extent that the actual reduction in constraints is less than we have assumed, then this would increase the reported cost savings.

Table 4 Main system constraint assumptions

	2021	2023	2025	2027	2030
POR/SOR requirements MW (% largest infeed loss)	75%	75%	75%	75%	75%
TOR1/TOR2 requirements MW (% largest infeed loss)	100%	100%	100%	100%	100%
Minimum POR, SOR, TOR1, TOR2 (MW)	184 day, 124 night	184 day, 124 night	184 day, 124 night	184 day, 124 night	184 day, 124 night
Negative Reserve (MW)	150	150	150	150	150
Rate of Change of Frequency Limit (Hz/s)	1	1	1	1	1
Min Inertia (MWs)	20,000	20,000	NA	NA	NA
System Non-Synchronous Penetration Limit	75%	75%	75%	80%	90%
Minimum Large Generators ROI	5	5	NA	NA	NA
Minimum Large Generators NI	2	2	NA	NA	NA
Minimum Large Generators All – Island[14]	NA	NA	5	5	4

See appendix for full list of system constraints

Where the four modelled scenarios do differ is in the amount of non-energy market, zero-carbon reserve or grid service technologies that exist, as shown in Table 5. In our analysis, we do not prescribe which zero-carbon reserve technologies are deployed. The results of this study are therefore entirely technology agnostic. Our zero-carbon reserve assumptions cover Primary, Secondary and Tertiary Operating Reserve. We have not modelled Replacement Reserve. To account for planned and unplanned outages and other redundancy considerations, additional Replacement Reserve capacity may be necessary to ensure that reserve is only met through the zero-carbon model under all circumstances. However, Replacement Reserve is not generally held in a state of readiness, and therefore does not materially contribute to CO_2 emissions and system operational costs.

[14] We assume that 'Minimum Large Generators' moves from being country-specific to an all-island constraint by 2025, once the North-South interconnector is commissioned, increasing the network capacity between NI and ROI.

Table 5 Non-energy market reserve and grid service technology volumes

	2021	2023	2025	2027	2030
Base Case					
Non-energy market reserve (MW)	0	0	0	0	0
% other grid services from non-energy market technology	0	0	0	0	0
Zero-Carbon Reserve					
Non-energy market reserve (MW)	500	500	700	700	700
% other grid services from non-energy market technology	0	0	0	0	0
50% Zero-Carbon Reserve					
Non-energy market reserve (MW)	250	250	350	350	350
% other grid services from non-energy market technology	0	0	0	0	0
Zero-Carbon Reserve & Grid Service					
Non-energy market reserve (MW)	500	500	700	700	700
% other grid services from non-energy market technology	100%	100%	100%	100%	100%

3 Modelling methodology

3.1 General assumptions

We have carried out all modelling in real 2019 money terms unless otherwise stated. When considering costs or savings in multiple years, we have not considered the time value of money (i.e. a discount rate of zero was used).

The study period covers the period to 2030 through the modelling of the spot years 2021, 2023, 2025 2027 and 2030, all of which were modelled at hourly granularity. The scope of this study covers the wholesale electricity market and constraint payments.

3.2 Wholesale electricity market modelling

Baringa has developed in-house a Pan-EU power market model covering Ireland, Great Britain and most countries in 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. The Baringa Pan-EU model takes key inputs and scenario assumptions such as hourly demand profile, commodity prices, plant build and retirement, hourly wind and solar profiles, and has detailed representations of generator technical parameters and interconnection between countries. The model engine carries out least cost optimisation to produce hourly dispatch for the generators and hourly prices for the markets taking full consideration of the operational constraints.

The representation of the ROI and NI 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 cost, taking start fuel offtake, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes into account.

3.3 Constraint modelling

Two runs take place in the model. In the initial unconstrained run, no system operational constraints are in place and plants are dispatched on a merit-order basis. This is analogous to the unconstrained clearing of the day-ahead market. In the constrained run, system operational constraints are applied, including reserve, SNSP, minimum number of generating units, and locational voltage support.

Under I-SEM market arrangements, wholesale electricity prices are set in a day-ahead auction, equivalent to the unconstrained PLEXOS run. However, in order to meet system operational constraints, the TSOs will re-dispatch assets by turning them up or down from their unconstrained market positions. The TSOs do this by accepting incremental offers or decremental bids in the balancing market, and will provide compensation for these TSO system actions. Such 'constraint payments' are regulated to be cost reflective and largely consist of fuel and carbon costs. The end result of this re-dispatch is equivalent to our constrained PLEXOS model run.

For this study, we have calculated the cost of meeting system constraints, often referred to as dispatch balancing costs, by assessing the difference in fuel, carbon, other variable operating, and interconnector re-dispatch costs incurred in the constrained run over that which is incurred in the unconstrained model run. Invariably, the constrained run is more expensive, driven by the additional costs of meeting system constraints, which stem from more expensive, less efficient units being called to generate instead of cheaper alternatives.

It is important to note that the methodology we have applied to estimate constraint costs is likely to be conservative for five reasons:

1. We assume that many existing constraints have already been alleviated or substantially reduced by 2030 in the modelled scenarios. System balancing costs would be much higher otherwise.
2. We do not include opportunity costs that could be included in the 'bids' and 'offers' of plant to 'turn up' or 'turn down'.
3. Our I-SEM PLEXOS model does not capture the demand for system balancing actions that are triggered by operational network issues, for example power line outages.
4. Interconnectors are modelled with considerably greater flexibility than is currently observed. For example, we have set no limit on the degree to which interconnectors can alter their position. We have also assumed a re-dispatch 'cost' or penalty of 25 €/MWh up to 2025, and 10 €/MWh thereafter. This is substantially lower than the current cost of SO-SO trades[15] which frequently exceeds 100 €/MWh.
5. Commodity and carbon prices for this study are consistent with those adopted in the '70 by 30' report. However, since the assumptions were made for that study, both gas and carbon price projections have increased materially. This would increase the cost difference between more and less efficient thermal generators and increase the bidding prices of all thermal plant compared to zero short run marginal cost renewables.

3.4 Flexible demand modelling

We model in detail the dynamics of flexible demand in the system such as demand side response which is often provided by large energy consumers, electric vehicles (EVs), heat pumps (HPs). Flexible demand can be optimised across the year, subject to operational and technical constraints such as assumed EV charging regimes and minimum range requirements.

The demand in each hour in the PLEXOS market model is the sum of the inflexible demand and the flexible demand in the system. The basis of the inflexible portion of demand varies by type:

- 'Business as Usual' (BAU) demand based on historical demand profiles.
- Transport – fixed load profiles for unmanaged charging of electric vehicles, based on standard weekday and weekend profiles.
- Heating – fixed load profiles for inflexible heat demand from heat pumps, based on seasonal standard profiles.

The basis for the flexible portion of demand is as follows:

- BAU demand – both load shifting (i.e. shifting load from periods with high prices to periods with lower prices) and load curtailment from demand side response providers (i.e.

[15] The position of interconnectors is altered via an 'SO-SO trade' between the TSOs on either side of the link, which has an associated price. This price is in addition to the fundamental change in generation costs on either side of the interconnector associated with the change in interconnector flow.

curtailing some load if it is more economic to do so) are considered in our modelling. The potential of flexible BAU demand is assumed to increase over time in line with smart meter roll-outs in the residential sector and the increasing use of demand side flexibility in the industrial and commercial large energy user sectors. This can come from heating, ventilation and air conditioning of commercial buildings, refrigeration, dishwashers, laundry driers, washing machines and other residential applications, plus flexible loads in heavy industry and data centres.

- Transport – EVs plugged to the grid may be charged based on prevailing power price signals. However, the demand side flexibility provided by EVs is constrained in the model to account for considerations such as timing, battery capacity, and the number of EVs that can be charged at the same time.
- Heating – flexible heating demand due to heat pump installations, subject to constraints such as storage and heat pump capacity, maximum withdrawal/injection rates, and efficiency losses. The model needs to meet a total amount of heat over a certain period but shifts flexible heating demand to ensure that this is generated in a price optimal manner.

4 Results

4.1 Economic benefits of zero-carbon services and reserve

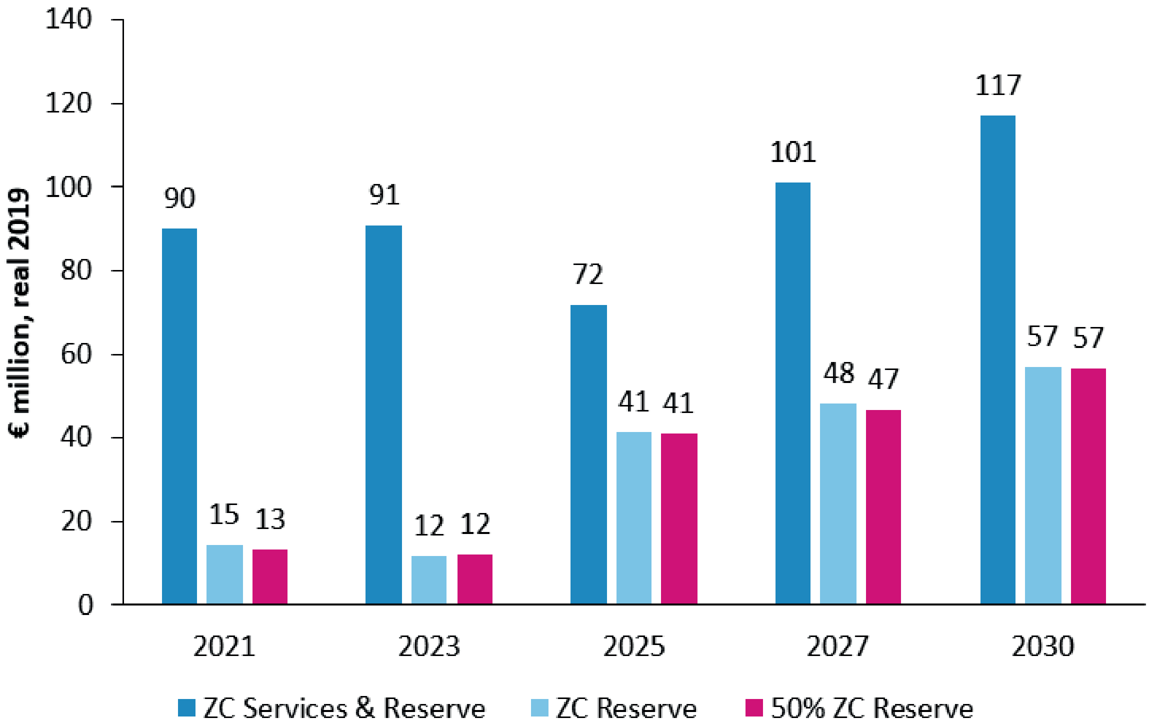
Figure 2 presents a summary of our projected annual system operation cost savings over the period to 2030 for the following scenarios:

- '**ZC Reserve**' – 100% of reserve requirements met by zero-carbon sources
- '**50% ZC Reserve**' – 50% of reserve requirements met by zero-carbon sources
- '**ZC Services & Reserve**' – 100% of reserve requirements and all other system constraints met by zero-carbon sources

Our analysis shows that there are significant cost savings associated with providing reserve and grid services in a manner that does not disrupt the optimal dispatch of generation in the wholesale energy market, with up to €117m per year of savings by 2030. We project an annual cost saving of €57m per year by 2030 if reserve requirements alone are met by zero-carbon providers.

The cost savings presented in Figure 2 represent the fuel, carbon emissions, operational and interconnector costs which are avoided by the use of zero-carbon reserve providers, compared to the alternative of the TSOs bringing online more expensive fossil-fuelled generation to ensure that reserve and constraint requirements are met.

Figure 2 **Annual operational cost savings generated by using zero-carbon technologies to meet reserve and system services**



Our results show a general trend of increasing cost savings from the zero-carbon provision of reserve and grid services, from €90m per year in 2021 to €117m by 2030. The 'dip' in projected savings in 2025 to €72m per year is associated with the assumed relaxation of the SNSP and other constraints in that year (see Section 2.4 for a description of these assumptions). Factors such as increasing gas and carbon prices, and a greater need to turn on gas-fired generators which would otherwise not be running, then lead to further increases in the cost savings from zero-carbon reserve and grid service provision.

Our analysis shows a substantial increase in cost savings between meeting reserve requirements alone versus meeting all system constraints from zero-carbon sources. In the 'Zero-Carbon Reserve' case, there are still substantial system constraints in place which alter the optimal functioning of the energy system[16]. However, our analysis shows that there are only marginal additional cost savings when moving from 50% to 100% 'zero-carbon reserve' provision, with conventional plant still providing non-reserve system services. The reason for this result is that a substantial proportion of the reserve requirement is being simultaneously provided by plant which is already required to generate in order to meet other operational constraints. Therefore, removing the final 50% of the reserve requirement results in minimal cost savings while other binding system constraints are still in place, as essentially reserve is being provided for 'free' in these circumstances as a by-product of meeting other constraints. This emphasises the importance of considering the provision of the wider set of system constraints from zero-carbon sources, in addition to reserve, in order to maximise the cost savings to end consumers.

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[16] Note we assume a partial relaxation of system constraints (e.g. SNSP, Min Units) in 2025, accounting for the reduced savings under the 'ZC Services & Reserve' scenario between 2023 and 2025.

When considering the savings generated by an individual unit of zero-carbon reserve or system services it is necessary to first evaluate the capacity required to satisfy the scenarios. Estimating the capacity of technologies needed to meet all system service requirements through the zero-carbon model is complex due to multitude of interdependencies between services. Given the intricate nature of system service provision and the rapid evolution of technical capability in this space, we have opted not to pursue quantification of the size of the zero-carbon system service fleet. By contrast, computing the volume of reserve is straightforward and readily quantifiable.

The zero-carbon reserve technology fleet must be able to provide enough power to replace maximum annual LIFL, (maximum LIFL is currently 504 MW from the East West interconnector, however with the assumed commissioning of the Celtic interconnector this increases to 700MW in 2025). The volume of reserve required for the Zero-Carbon Reserve scenarios is therefore a function of the maximum annual LIFL and the percentage of reserve to be provided through the Zero-Carbon Model (100% in ZC Reserve and 50% in 50% ZC Reserve).

The methodology for the calculation of the required size of the zero-carbon fleet is similar to the manner by which EirGrid and SONI currently determine the volume of reserve they procure. However, for the faster response reserve services (POR & SOR) the TSOs currently only procure enough reserve to meet 75% of LIFL. This is acceptable because fossil fuel generators can briefly exceed their nameplate capacity for the short duration over which POR & SOR occur. As there is no fossil fuel reserve provision in the Zero-Carbon Model we assume that 100% of LIFL must be procured (or 50% in the 50% ZC Reserve scenario).

Table 6 Modelled capacity of the zero-carbon reserve fleet[17]*

	Zero-Carbon Reserve Fleet	50% Zero-Carbon Reserve Fleet
2021	504 MW	252 MW
2023	504 MW	252 MW
2025	700 MW	350 MW
2027	700 MW	350 MW
2030	700 MW	350 MW

Based on the capacity of zero-carbon reserve presented in Table 5 and the conservative projected savings from the deployment of zero-carbon reserve presented in Figure 2, we have quantified the savings associated with each kW of reserve provision operating under the Zero-Carbon Model and these are shown in Figure 3. If zero-carbon reserve could be deployed for a cost which is lower than the €/kW values shown below, then this would result in financial savings for end consumers versus current methods of reserve provision.

[17] Our zero-carbon reserve capacity covers Primary, Secondary and Tertiary Operating Reserve, assuming that the zero-carbon technologies provide all three simultaneously, as is typical of fossil fuel plant today. We have not modelled Replacement Reserve. To account for planned and unplanned outages and other redundancy considerations, additional Replacement Reserve capacity may be necessary to ensure that reserve is only met through the zero-carbon model under all circumstances. However, Replacement Reserve is not generally held in a state of readiness, and therefore does not materially contribute to CO_2 emissions and system operational costs.

Figure 3 Cost savings produced by each kW of reserve operating under the Zero-Carbon Model

4.2 Avoided carbon emissions

Our analysis indicates that procuring reserve and grid services from zero-carbon providers could reduce all-island power sector emissions by almost 2 million tonnes of CO_2 per year, as shown in Figure 4. This is equivalent to around one third of power sector emissions by 2030, as shown in Figure 5. By deploying zero-carbon providers, EirGrid and SONI can avoid the need to displace renewable generation by thermal generation, or displace efficient gas-fired plants with less efficient alternatives. This has the potential to make a material contribution towards reducing power sector emissions and the operation of the power system – a clearly stated goal of both the ROI[18] & UK[19] governments, and the strategies of EirGrid[20], SONI[21], the Northern Irish Utility Regulator[22] and CRU[23].

The savings associated with emissions reductions from adopting the Zero-Carbon Model are factored into the cost savings presented in our economic analysis above. We note that the financial savings attributed to emissions reductions are conservative, as the assumed cost of carbon used for this study is as low as €15/tCO_2 in 2021, which is consistent with the assumptions used in our previous '70 by 30' study. At the time of writing (November 2019), EU ETS carbon credits are trading at

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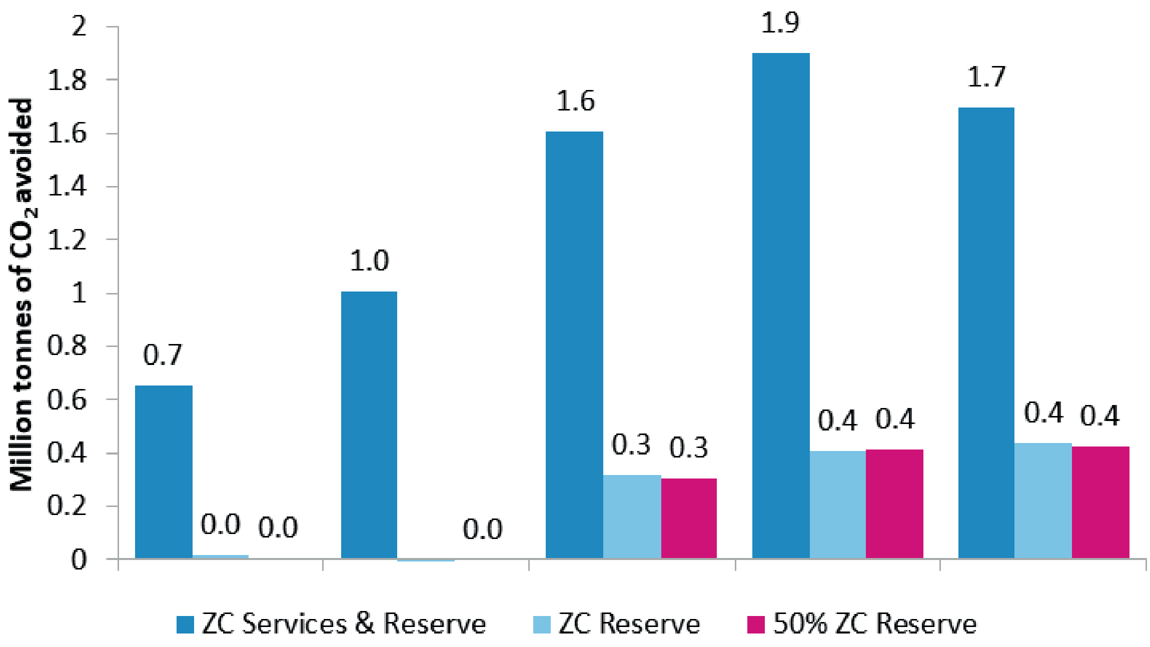
[18] https://www.dccae.gov.ie/en-ie/climate-action/publications/Pages/Climate-Action-Plan.aspx
[19] https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law
[20] http://www.eirgridgroup.com/about/strategy-2025/
[21] http://www.soni.ltd.uk/newsroom/press-releases/soni-strategy-2020-2025/
[22] https://www.uregni.gov.uk/news-centre/corporate-strategy-2019-24-and-forward-work-programme-2019-20-published
[23] https://mk0cruiefjep6wj7niq.kinstacdn.com/wp-content/uploads/2019/03/CRU19030a-CRU-Strategic-Plan-2019-2021-English-Version.pdf

€25/tCO_2, and the Climate Action Plan outlines a 2030 cost of carbon for ROI of €65/tCO_2 in real 2019 money.

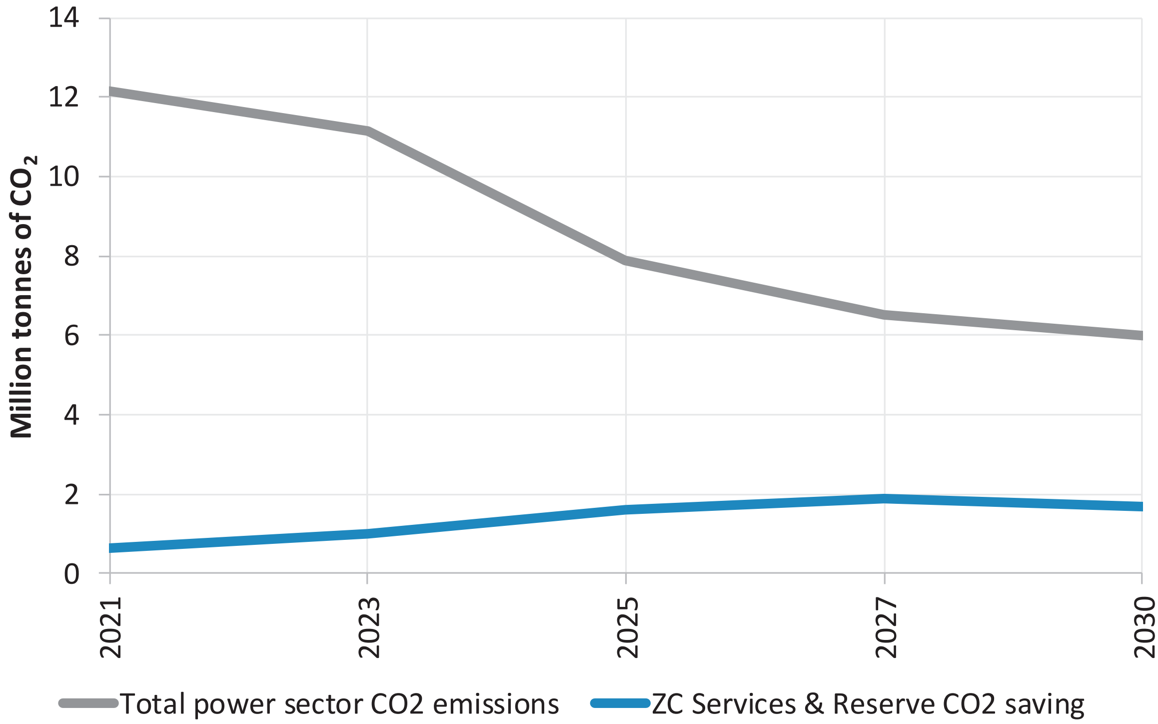
Figure 4 Annual avoided SEM CO_2 emissions from zero-carbon system services



The emissions savings generated by implementing a zero-carbon system services model increase substantially through 2020s, and reach levels of up to 1.9 million tonnes of CO_2 in 2027. This potential abatement opportunity is equivalent to taking over 600,000 fossil-fuel powered cars off the road which is around 20% of the all-island passenger vehicle fleet[24].

[24] ROI passenger vehicle fleet in 2017 was 2.06 million. https://www.gov.ie/en/press-release/7609bf-bulletin-of-vehicle-and-driver-statistics/?referrer=/press-releases/2018/bulletin-vehicle-and-driver-statistics/ NI vehicle fleet (2016) 1.13 million, assume GB average vehicle split (82.7%) cars, 0.94 million passenger vehicles. all-island passenger vehicle fleet 3 million.

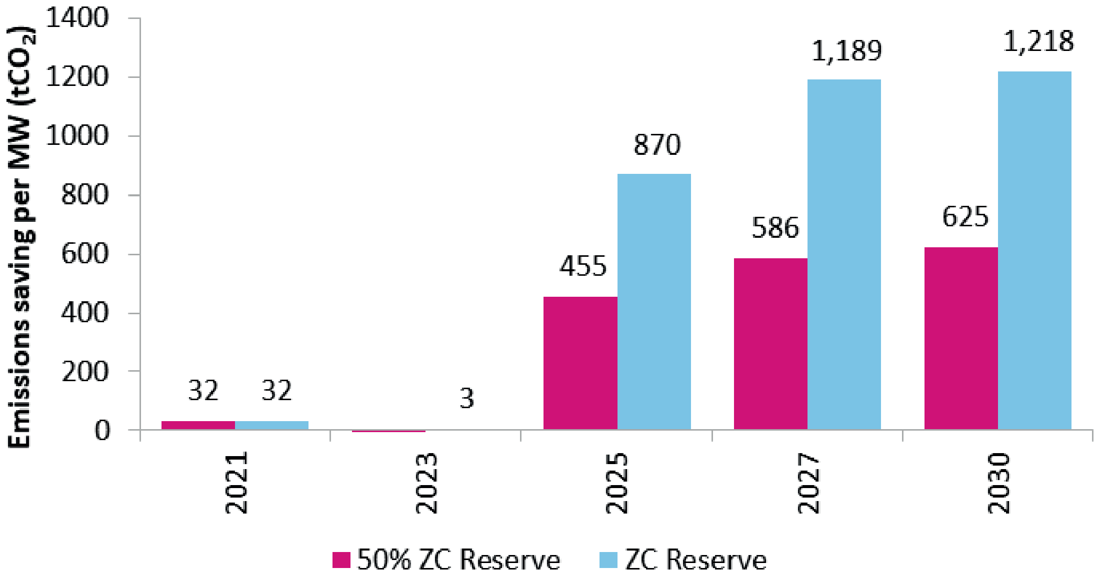
Figure 5 Total annual power sector CO_2 emissions vs zero-carbon system services saving



In Figure 6, we present the emissions saving per MW of zero-carbon reserve deployed. A single MW of zero-carbon reserve reduces CO_2 emissions by as much as 1,218 tonnes per year by 2030. For context, a single tree requires 40 years to sequester up to one tonne of carbon[25]. In other words, deploying 1 MW of zero-carbon reserve from 2025 to 2030 would be at least equivalent to planting over 6,000 broadleaf trees and ensuring their survival for the next 100 years.

[25] https://granthaminstitute.com/2015/09/02/how-much-co2-can-trees-take-up/

Figure 6 Annual CO_2 emissions saving per MW of zero-carbon reserve deployed



4.3 Renewable curtailment reductions

Curtailment describes a situation when a generator is forced to reduce output below planned levels due to external system factors. Minimising renewable curtailment is an important part in achieving Ireland and Northern Ireland's renewable energy targets at least cost to end consumers, and maintaining investor confidence in the island's renewable energy sector. In recent years, renewable curtailment levels have been around 4% of available energy[26]. Curtailment is largely driven by system constraints such as Min Gen and the SNSP limit. With substantial renewable capacity additions required to achieve 2030 targets there is likely to be upward pressure on curtailment unless mitigating steps are taken.

Figure 7 shows the projected level of curtailment under a BAU setting as Ireland moves towards 70% renewable electricity by 2030. The projections are substantially above current levels and are concerning for consumers for multiple reasons:

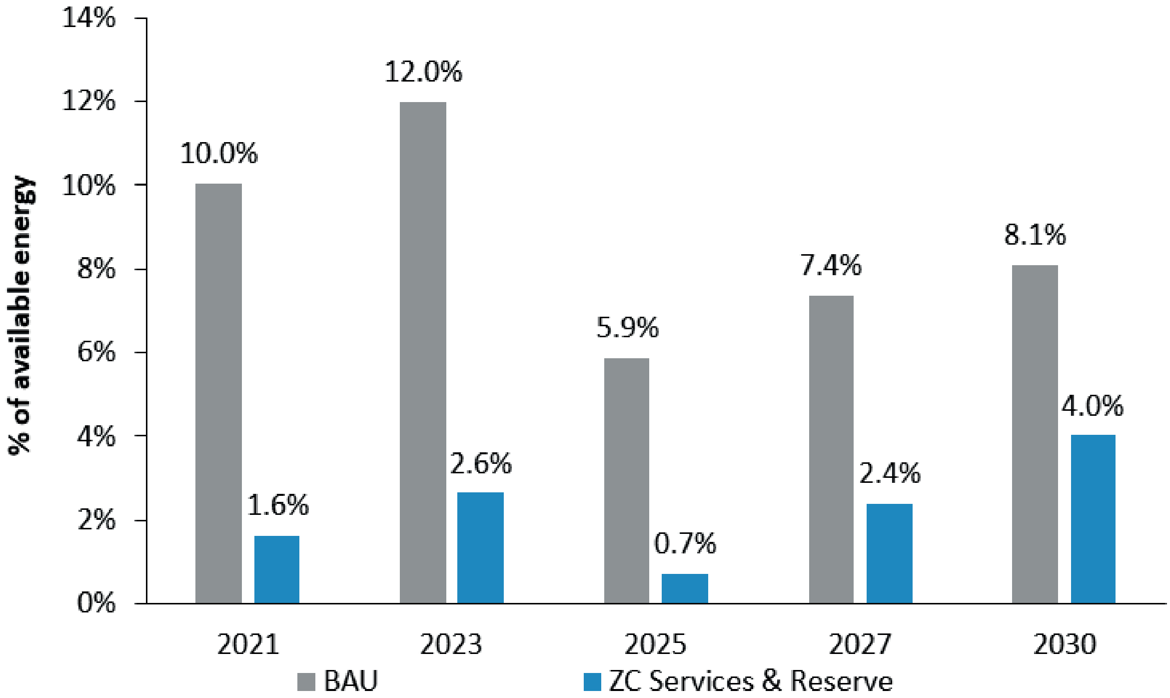
- Curtailment of zero-marginal cost renewables results in using more expensive, typically fossil-fuelled, plant to generate electricity. The cost of this flows through to customer bills.
- Curtailment of renewables in order to turn up fossil-fuelled plant results in additional CO_2 emissions.
- Should curtailment exceed investor expectations renewable energy project returns may be reduced, which could potentially raise the cost of capital for future renewable investment.

[26] http://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2018-V1.0.pdf

- Curtailment levels will be factored in to bidding strategies of new renewable projects participating in the upcoming Renewable Electricity Subsidy Scheme (RESS) auction, or those developed without subsidy under corporate PPAs, which could drive up clearing prices.

Our analysis suggests a significant reduction in renewable curtailment if system constraints are met using zero-carbon service providers. For example, in 2030, our analysis suggests a greater than 50% reduction in renewable curtailment from 8.1% to 4.0%[27].

Figure 7 Projected renewable curtailment levels under modelled scenarios



[27] We are aware of higher curtailment forecasts in some recent studies such as EirGrid's 'Tomorrow's Energy Scenarios 2019' publication, as a result of the higher renewable generation volumes which are now being assumed to be required given increases in expected demand growth.

5 Conclusion

1. In this study we have analysed the significant societal benefits that moving to a zero-carbon system services model would bring – in terms of CO_2 emissions reductions, operational cost savings and reduced renewable curtailment – compared with an alternative scenario where fossil fuels continue to be the predominant provider of system services.
2. **Our analysis shows that:**
   - **Procuring system services from zero-carbon providers could reduce all-island power sector emissions by almost 2 million tonnes of CO_2 per year by 2030. This is equivalent to one third of total 2030 power sector emissions that could be avoided by transitioning to a Zero-Carbon Model.**
   - **There are significant operational cost savings associated with sourcing all system services from zero-carbon sources, with up to €90m per year of savings by 2021, increasing to €117m per year by 2030, primarily from avoided fuel and carbon costs. We project an annual operational cost saving of €57m per year by 2030 if reserve requirements alone are met by zero-carbon technologies.**
   - **There is a significant reduction in renewable curtailment if system operational constraints are met using zero-carbon service providers. In 2030, our analysis suggests a greater than 50% reduction in renewable curtailment from 8.1% to 4.0%. This reduction in the curtailment of zero-marginal cost renewables results in lower electricity generation costs as it displaces more expensive, typically fossil-fuelled, generators in the production of electricity.**
3. The results of this study are entirely technology agnostic, but we note that zero-carbon providers such as demand side response units, battery storage, synchronous condensers, flywheels and renewable generation are already available today. A future model for zero-carbon system services could envisage a range of such technologies deployed across the all-island system at strategic positions, ready to provide the necessary reserves, inertia, or voltage upon request of the TSOs.
4. In this study, we have not considered the market design and commercial framework under which zero-carbon service providers could be remunerated. However, we consider that long-term frameworks that provide investment certainty for zero-carbon providers to deliver may be beneficial in achieving all-island power sector decarbonisation goals.

Figure 8 Summary of the key benefits of the Zero-Carbon Model by 2030[28]

2 million tonnes of CO_2 per year avoided

Equivalent to removing one third of power sector emissions

At least €117m per year operational cost saving

Half of this annual saving is realised by deployment of zero-carbon reserve alone

50% reduction in renewable curtailment

Enough energy to meet the annual needs of over 300,000 domestic customers

[28] Average annual domestic customer electricity demand is reported by the Commission for Regulation of Utilities, Water and Energy: https://www.cru.ie/wp-content/uploads/2017/07/CER17042-Review-of-Typical-Consumption-Figures-Decision-Paper-1.pdf

Appendix A Common scenario assumptions

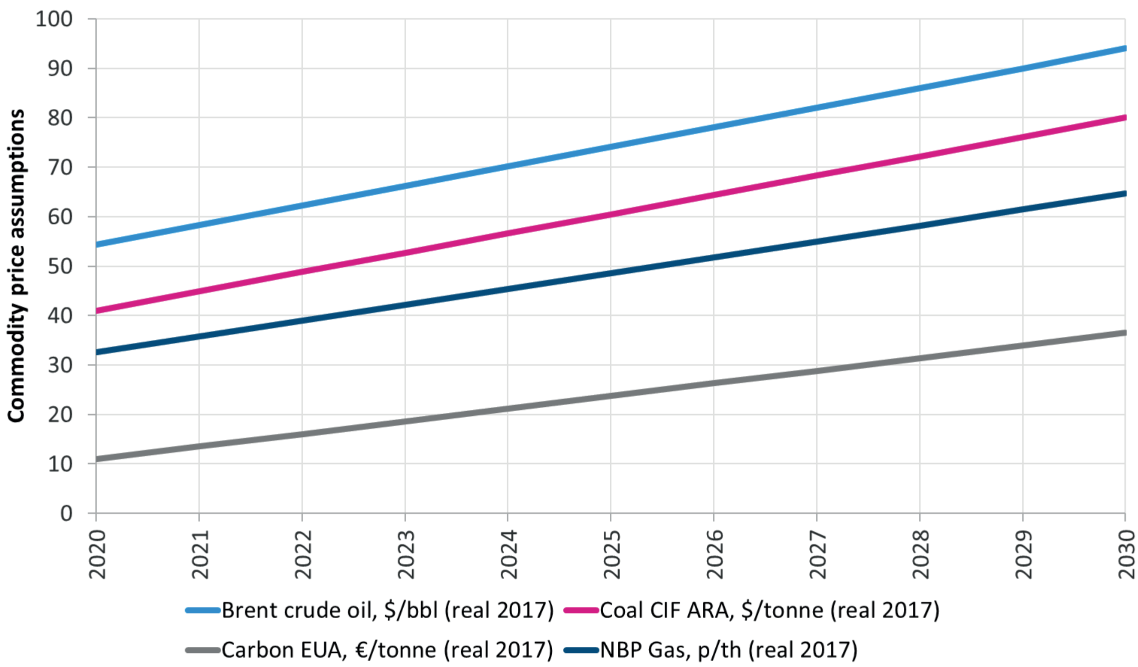
A.1 Commodity prices and exchange rates

The fuel and carbon prices used for this study are a blend of UK government, DCCAE and International Energy Agency (IEA) assumptions. The 2020 assumptions are taken from UK Department for Business, Energy and Industrial Strategy (BEIS) fossil fuel price projections[29]. The 2030 assumptions are based on the IEA World Energy Outlook (WEO) 2017 'New Policies' scenario. The 2020 carbon price was taken from the DCCAE's Public Spending Code[30], and the 2030 assumption was based on the IEA WEO 2017 'New Policies' scenario.

Fuel and carbon prices between 2020 and 2030 were derived using a simple linear interpolation. The assumptions are presented in Figure 9 and were used consistently across both the Fossil Fuel and Renewable Energy scenarios.

Commodity and carbon prices increase steadily between 2020 and 2030 in real terms, with UK National Balancing Point (NBP) gas prices broadly doubling from around 33 p/th in 2020 to around 63 p/th in 2030. Carbon prices rise from around 11 €/tCO_2 in 2020 to reach around the IEA's forecasted price in the 2017 World Energy Outlook of 36 €/tCO_2 in 2030 (note: no price was provided for 2030 explicitly, so this is the average of the price provided across 2025 and 2040).

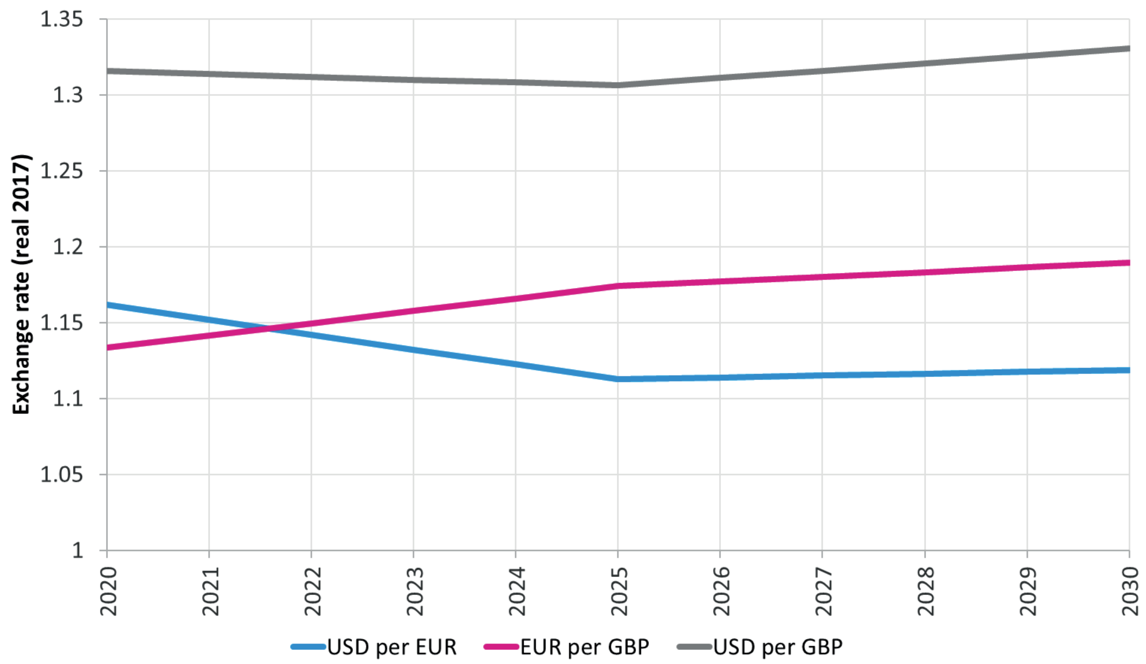
Figure 9 Commodity and carbon price assumptions



The exchange rate assumptions for this study are shown in Figure 10, which stay relatively flat in real terms over the study period.

[29] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/576542/BEIS_2016_Fossil_Fuel_Price_Assumptions.pdf
[30] https://publicspendingcode.per.gov.ie/wp-content/uploads/2015/09/E5.pdf

Figure 10 Exchange rate assumptions



Commodity price and exchange rate assumptions are tabulated in the following section.

A.2 Demand

Demand is uniform across all scenarios and is based upon the Median scenario in EirGrid's 2017 Generation Capacity Statement (GCS)[31], with the 2021-2026 growth rate extrapolated to 2030. However, demand is greater than that of the GCS in both NI and ROI as we adopt more aggressive assumptions on electric vehicle (EV) and heat pump (HP) uptake.

Demand growth is linear between 2020 and 2030, reaching 36.3 TWh in ROI, 9.6 TWh in NI, and around 46 TWh on an all-island basis. Much of the demand growth over this period is associated with the roll-out of new data centres in Ireland. By 2030 there is 629,398 EVs across the Ireland of Island (equivalent to 19% of cars being EVs) and 396,302 heat pump installations, covering 14% of homes, (this is in line with EirGrid's Low-Carbon Living forecasts in the Tomorrow Energy Scenarios 2017 publication (Figure 13)[32]). EVs & HPs contributes 2.5 TWh and 1.0 TWh to the total annual demand in ROI and NI respectively in 2030.

[31] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf
[32] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Tomorrows-Energy-Scenarios-Report-2017.pdf

Figure 11   Scenario demand assumptions (ROI)

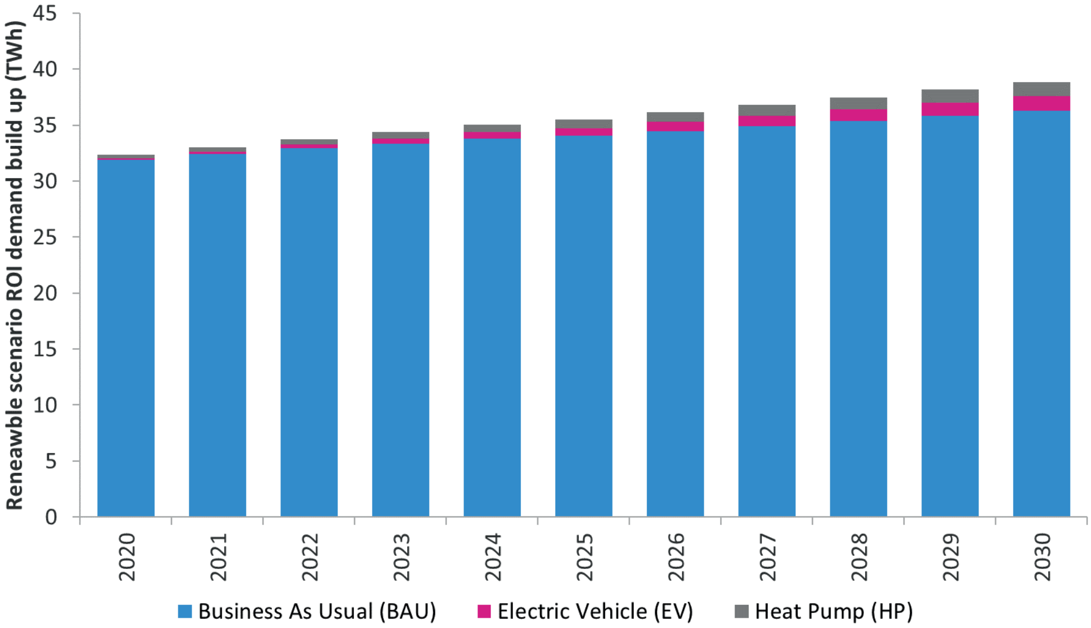


Figure 12   Scenario demand assumptions (NI)

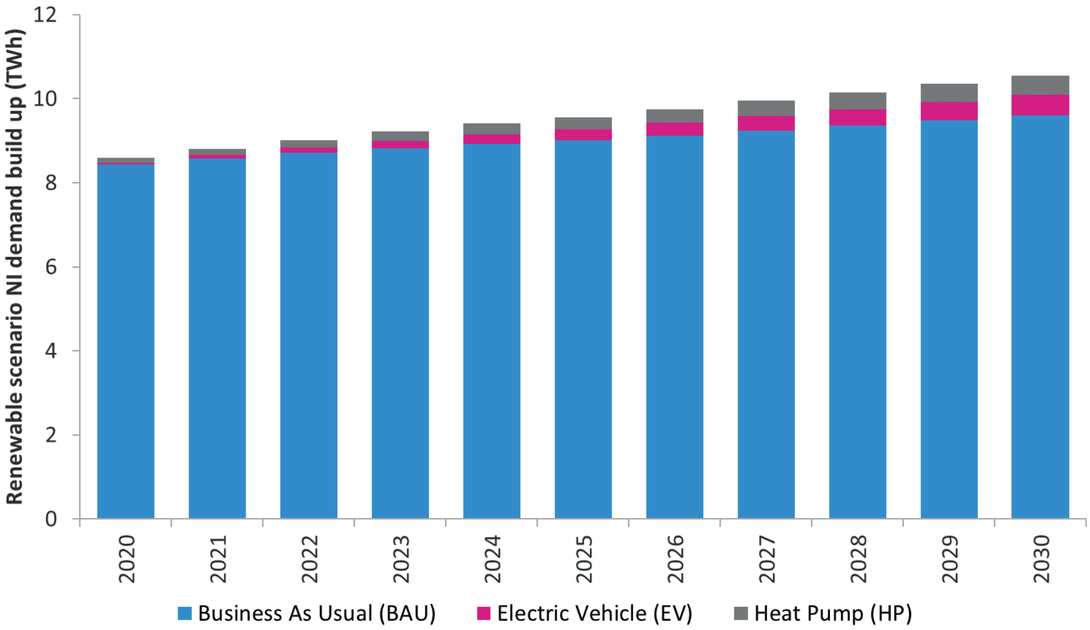
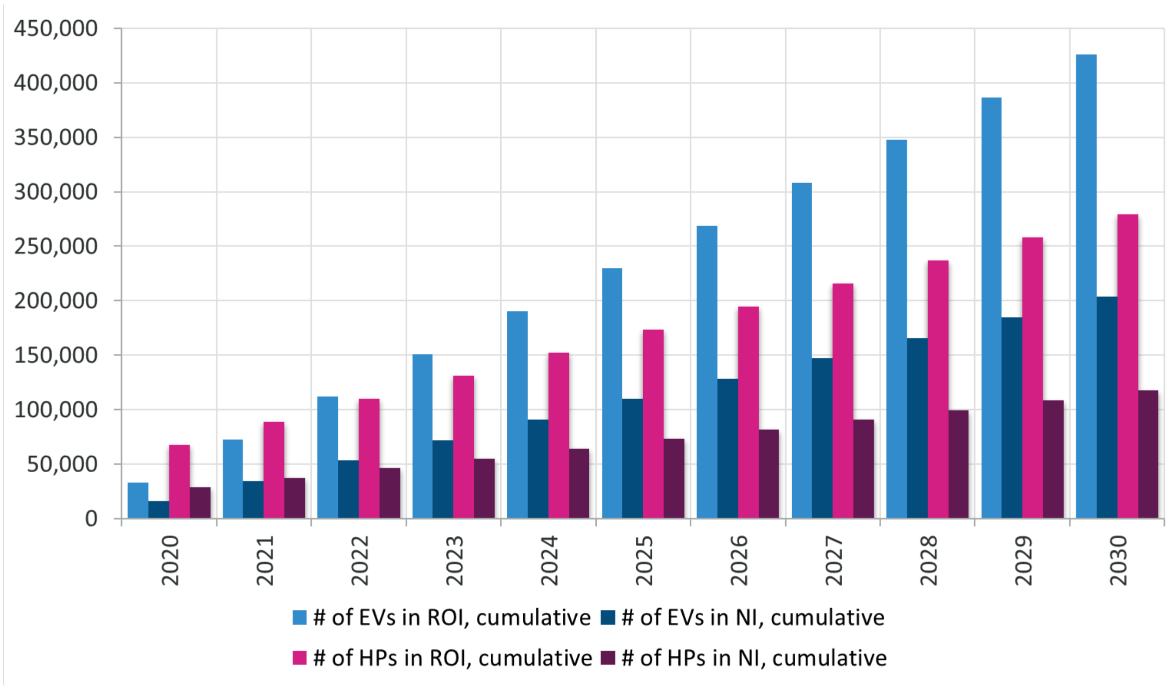


Figure 13 Assumed deployment of electric vehicles (EVs) and heat pumps (HPs)



A.3 Generation capacity

Assumptions on energy market participating generation capacity are uniform across all four modelled scenarios, and are largely unchanged from our ’70 by 30’ Renewable Energy scenario. Wind and solar capacity is commissioned to reach a level in 2030 that is sufficient for the whole island to achieve 70% renewable electricity target, after curtailment of renewables is taken into account. Note that the market outlook has evolved since the ’70 be 30’ study was undertaken, and there is now a higher volume of renewables required to meet the 70% target because of demand growth.

The modelled energy generating capacity on an all-island, ROI and NI basis is presented in Figure 14, Figure 15 and Figure 16 below. The total additions and retirements of fossil fuelled and renewable capacity over the period of the study are shown in Figure 17.

Figure 14 Installed capacity assumptions (All-Island)

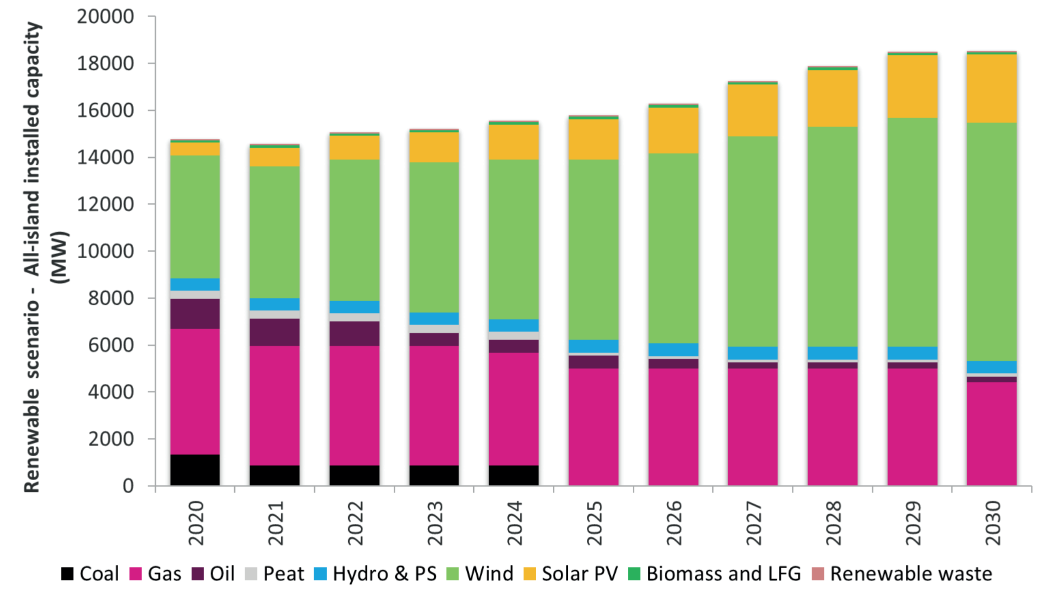


Figure 15 Installed capacity (ROI)

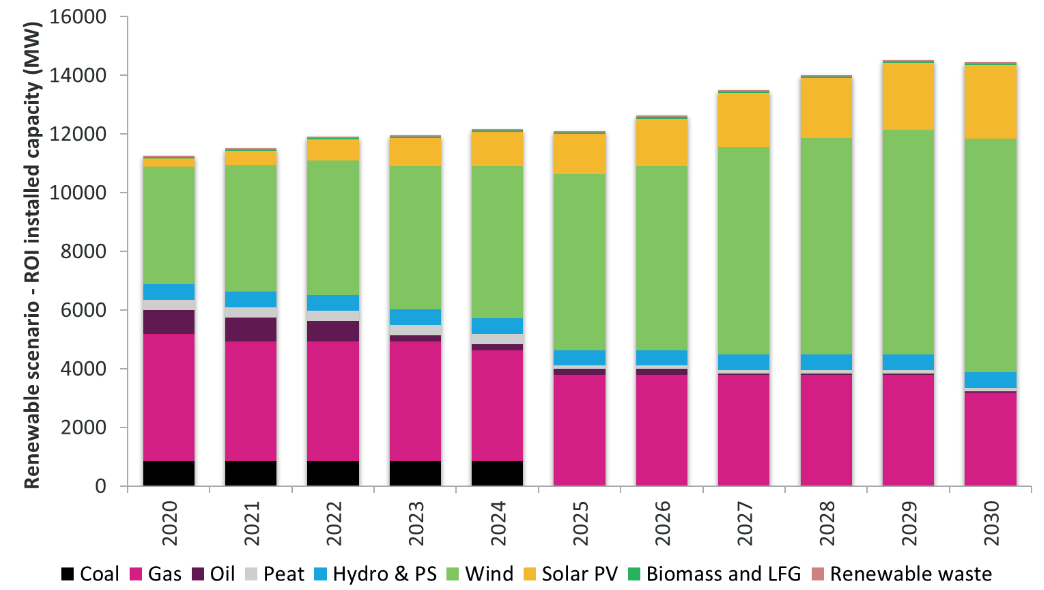


Figure 16 Installed capacity (NI)

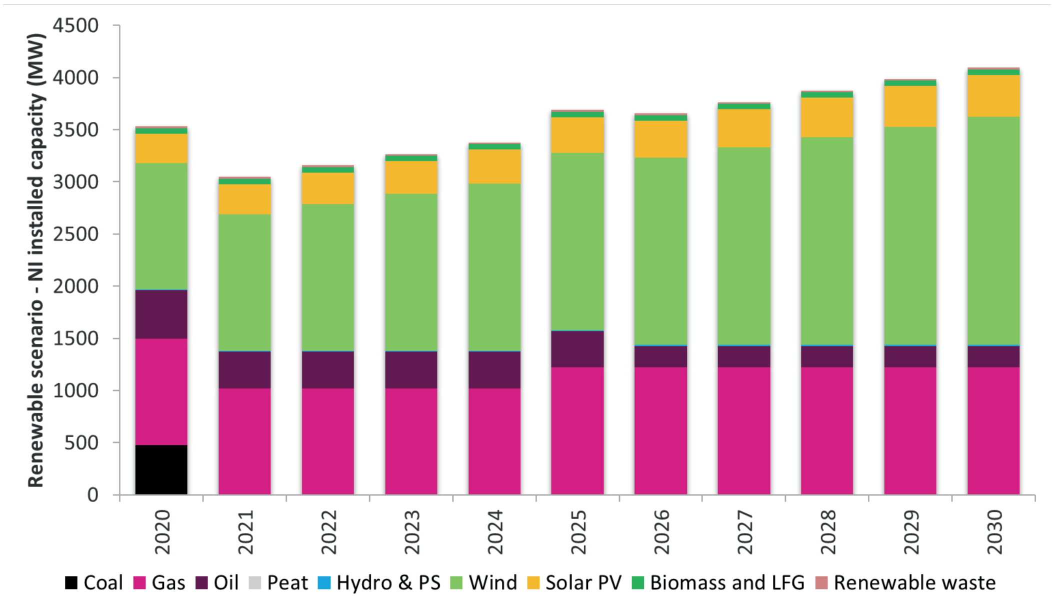
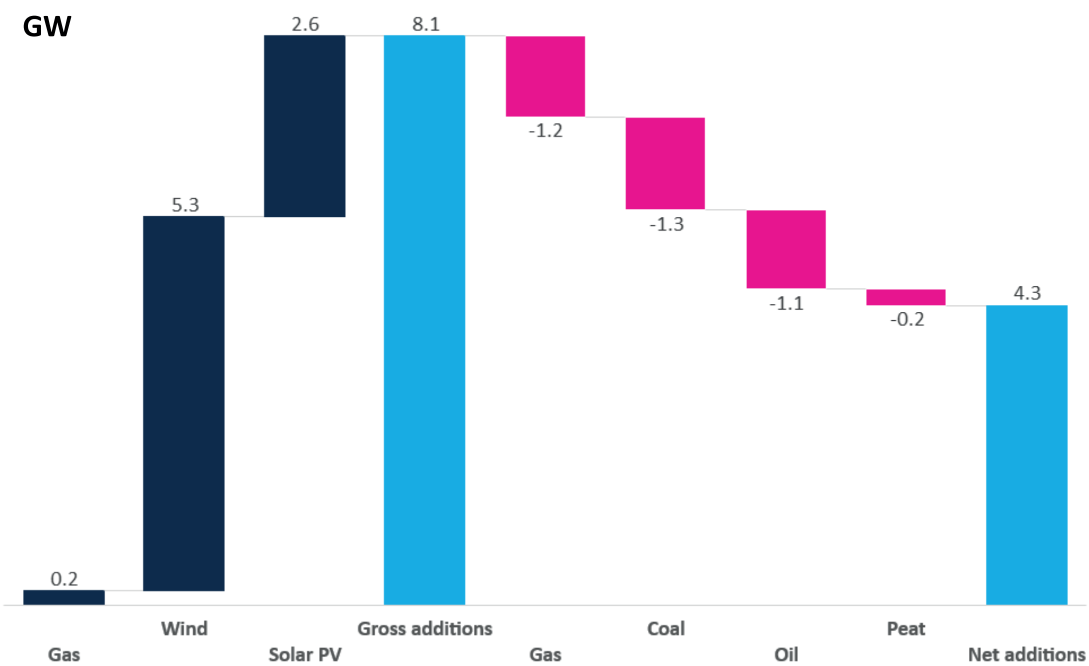


Figure 17 Summary of total additions and retirements of fossil fuel and renewable capacity over the period 2020-30 (All-Island)

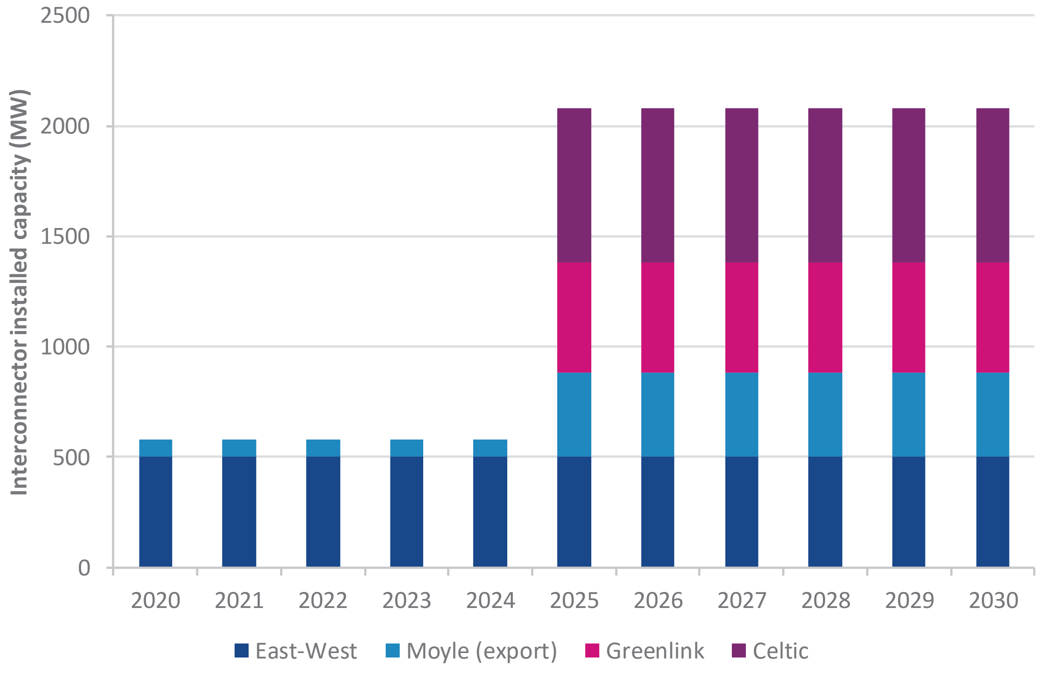


A.4 Interconnection

The capacity of interconnection is uniform across all scenarios. In 2025 we relax the Moyle export limit from 80 MW (as currently constrained by EirGrid) to 380 MW. We also commission two new interconnectors totalling 1200 MW of installed capacity by 2025, in the form of Greenlink to GB and

Celtic to France. We assume that the North-South interconnector between ROI and NI is commissioned in 2024.

Figure 18 Interconnector capacity assumptions



* Moyle import capacity is assumed to be 450 MW for all scenarios.

Baringa has undertaken the modelling for this study using its pan-European wholesale electricity market model, which is described in detail in Section 3. Interconnected markets have been co-optimised with the all-island market, and have been modelled at the same level of granularity (hourly), in order to capture the impact of cross-border flows and interactions in detail. Scenario assumptions for interconnected markets, including Great Britain and France, were based on the Baringa Reference Case[33]. Under the Reference Case, there is continued growth in renewable capacity across European markets. For example, in Great Britain:

- onshore wind capacity increases from 13.1 GW in 2020 to 15.3 GW in 2030
- offshore wind capacity increases from 8 GW in 2020 to 15.5 GW in 2030, and
- solar PV capacity increases from 12.9 GW in 2020 to 17.9 GW in 2030.

Similarly, in France:

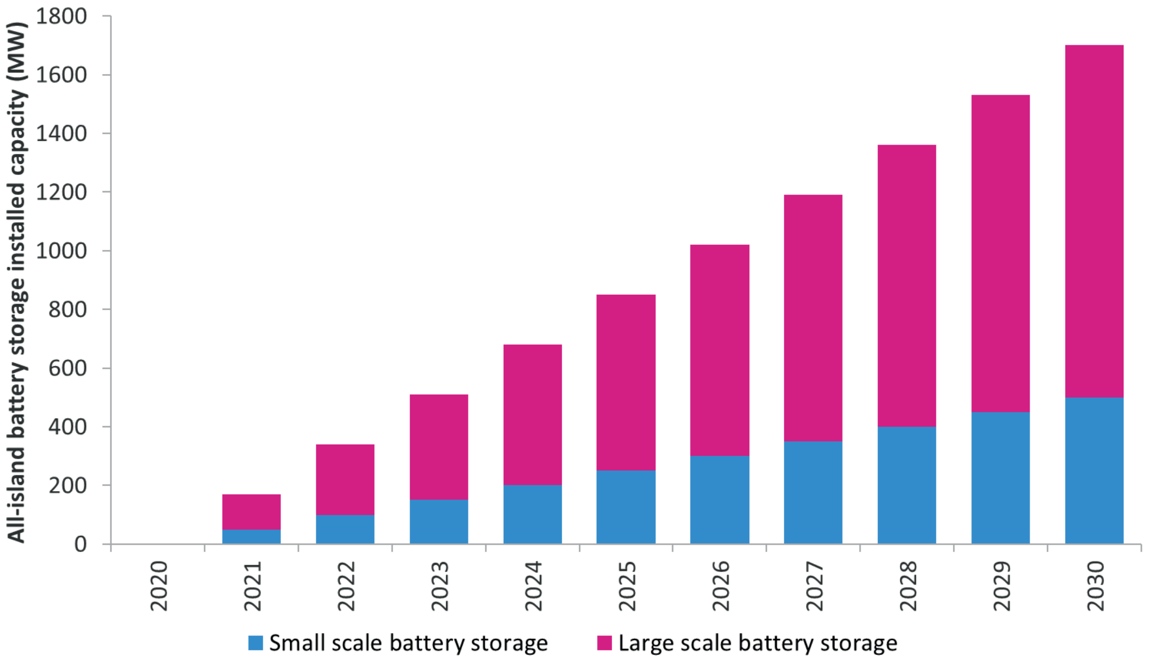
- onshore wind capacity increases from 18.0 GW in 2020 to 31.0 GW in 2030
- offshore wind capacity increases from 1.0 GW in 2020 to 4.2 GW in 2030, and
- solar PV capacity increases from 13.2 GW in 2020 to 36.0 GW in 2030.

[33] The Reference Case is Baringa's in-house 'central' market scenario

A.5 Storage

All scenarios assume a linear increase in energy market battery capacity from zero to 1.7 GW installed battery capacity from 2020 to 2030. This is shown in Figure 19. We have assumed that this battery storage has a two-hour storage duration to avail of wholesale price arbitrage opportunities, and does not contribute towards the provision of system reserve. We assume that these batteries are self-funded and recover their costs through energy arbitrage, capacity market payment and ancillary service revenues excluding reserve provision. Based on Baringa's battery cost assumptions, we have verified that these batteries are commercially viable under the modelled scenarios.

Figure 19 Battery storage capacity assumptions



Appendix B Tables of assumptions

B.1 Demand assumptions

Annual Demand Assumptions	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
All Island	*TWh*	40.9	41.8	42.8	43.6	44.4	45.1	45.9	46.8	47.6	48.5	49.4
ROI	*TWh*	32.3	33.0	33.7	34.3	35.0	35.4	36.1	36.7	37.4	38.0	38.7
NI	*TWh*	8.6	8.8	9.1	9.3	9.5	9.6	9.8	10.0	10.3	10.5	10.7

B.2 Commodity price and FX assumptions

All scenarios		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Brent crude oil	$/bbl (real 2017)	54.3	58.3	62.3	66.2	70.2	74.2	78.1	82.1	86.1	90.0	94.0
Coal CIF ARA	$/tonne (real 2017)	41.0	44.9	48.8	52.7	56.6	60.5	64.4	68.3	72.2	76.1	80.0
Carbon EUA	€/tonne (real 2017)	11.0	13.5	16.1	18.6	21.2	23.7	26.3	28.8	31.4	33.9	36.5
NBP Gas	p/th (real 2017)	32.6	35.8	39.0	42.2	45.4	48.6	51.8	55.0	58.2	61.4	64.6

All scenarios	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EUR/USD	1.162	1.152	1.142	1.132	1.122	1.113	1.114	1.115	1.116	1.117	1.119
GBP/EUR	1.133	1.141	1.150	1.158	1.166	1.174	1.177	1.180	1.183	1.186	1.189
GBP/USD	1.316	1.314	1.312	1.310	1.308	1.306	1.311	1.316	1.321	1.326	1.331

B.3 Interconnector assumptions

	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Interconnector Capacity	*Total MW operational (export)*	950	950	950	950	950	2,080	2,080	2,080	2,080	2,080	2,080
East-West	*MW operational*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*	*500*
Moyle (import)	*MW operational*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*	*450*
Moyle (export)	*MW operational*	*80*	*80*	*80*	*80*	*80*	*380*	*380*	*380*	*380*	*380*	*380*
Greenlink	*MW operational*						*500*	*500*	*500*	*500*	*500*	*500*
Celtic (France)	*MW operational*						*700*	*700*	*700*	*700*	*700*	*700*

B.4 Thermal capacity assumptions

Installed capacity: ROI	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coal	*MW*	855	855	855	855	855	-	-	-	-	-	-
Gas	*MW*	4,332	4,074	4,074	4,074	3,780	3,780	3,780	3,780	3,780	3,780	3,181
Oil	*MW*	810	810	694	208	208	208	208	52	52	52	52
Peat	*MW*	351	351	351	351	351	118	118	118	118	118	118
Hydro & PS	*MW*	530	530	530	530	530	530	530	530	530	530	530
Installed capacity: NI	**Units**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Coal	*MW*	476	-	-	-	-	-	-	-	-	-	-
Gas	*MW*	1,022	1,022	1,022	1,022	1,022	1,222	1,222	1,222	1,222	1,222	1,222
Oil	*MW*	464	348	348	348	348	348	206	206	206	206	206
Peat	*MW*	-	-	-	-	-	-	-	-	-	-	-
Hydro & PS	*MW*	8	8	8	8	8	8	8	8	8	8	8

B.5 Renewable capacity factor assumptions

Capacity Factors	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Onshore wind	*%*	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Offshore wind	*%*	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
Solar PV	*%*	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%

B.6 Renewable capacity assumptions

Modelled installed capacity (Republic of Ireland)	Units	2020	2025	2030
Wind	*MW*	4,006	5,985	7,965
Solar PV	*MW*	273	1,386	2,500
Hydro	*MW*	238	238	238
Biomass and LFG	*MW*	52	52	52
Renewable waste	*MW*	43	43	43

Modelled installed capacity (Northern Ireland)	Units	2020	2025	2030
Wind	*MW*	1,210	1,700	2,190
Solar PV	*MW*	282	341	400
Hydro	*MW*	8	8	8
Biomass and LFG	*MW*	52	52	52
Renewable waste	*MW*	17	17	17

Modelled installed capacity (All Island)	Units	2020	2025	2030
Wind	*MW*	5,216	7,685	10,155
Solar PV	*MW*	555	1,727	2,900
Hydro	*MW*	246	246	246
Biomass and LFG	*MW*	104	104	104
Renewable waste	*MW*	59	59	59

B.7 Heat pump assumptions

Key input assumptions	Units	2030
Conventional heating: Oil		
Upfront cost per unit	*€*	3,000
Power output per unit	*kW*	22
Efficiency	*%*	79%
Fuel cost	*€/GJ*	18.6
Other running cost: Distribution	*€/GJ*	4.1
FOM	*€/year*	270
HP		
Upfront cost per unit	*€*	10,000
Power output per unit	*kW*	10
Efficiency	*%*	260%
Fuel cost	*€/GJ*	Electricity Production & Distribution Is Modelled
Other running cost	*€/GJ*	
FOM	*€/year*	150

B.8 EV assumptions

Key input assumptions	Units	2030
Conventional vehicle: Average of Diesel/Petrol		
Upfront cost per vehicle	*€*	20,560
Fuel consumption	*GJ/km travelled*	0.00169
Fuel cost	*€/GJ*	41.8
FOM	*€/year*	842
EV		
Upfront cost per unit	*€*	27,777
Fuel consumption	*GJ/km travelled*	0
Fuel cost	*€/GJ*	Electricity Is Modelled
Other running cost	*€/GJ*	
FOM	*€/year*	614

B.9 Flexibility assumptions

Annual demand (Republic of Ireland)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electric vehicles (EVs)												
Fixed Demand	*GWh*	23	51	79	106	134	162	189	217	245	272	300
Flexible Demand	*GWh*	70	153	236	319	402	485	568	651	734	817	900
Electric heating (HP)												
Fixed Demand	*GWh*	73	96	118	141	164	186	209	232	255	277	300
Flexible Demand	*GWh*	218	287	355	423	491	559	627	696	764	832	900

Annual demand (Northern Ireland)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electric vehicles (EVs)												
Fixed Demand	*GWh*	11	24	38	51	64	77	90	104	117	130	143
Flexible Demand	*GWh*	33	73	113	152	192	232	271	311	350	390	430
Electric heating (HP)												
Fixed Demand	*GWh*	31	40	50	59	69	78	88	98	107	117	126
Flexible Demand	*GWh*	92	121	149	178	207	235	264	293	321	350	379

Annual demand and Battery Storage (All Island)	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Battery storage												
Small scale battery storage	*MW*	0	50	100	150	200	250	300	350	400	450	500
Large scale battery storage	*MW*	0	120	240	360	480	600	720	840	960	1080	1200
Electric vehicles (EVs)												
Fixed Demand	*GWh*	34	75	116	157	198	239	280	321	361	402	443
Flexible Demand	*GWh*	103	226	349	471	594	717	839	962	1084	1207	1330
Electric heating (HP)												
Fixed Demand	*GWh*	103	136	168	200	233	265	297	329	362	394	426
Flexible Demand	*GWh*	310	407	504	601	698	795	891	988	1085	1182	1279

B.10 Constraint assumptions

Reserve constraints

	TSO Reference	2021	2025	2027	2030
POR/SOR requirements MW (% largest infeed loss)	S_PRM_TOT, S_SEC_TOT	75%	75%	75%	75%
TOR1/TOR2 requirements MW (% largest infeed loss)	S_TR1_TOT, S_TR2_TOT	100%	100%	100%	100%
Min Reserve (POR,SOR,TOR)		184MW Day / 124MW Night	184MW Day / 124MW Night	184MW Day / 124MW Night	184MW Day / 124MW Night
Negative Reserve MW	S_NEG_ROI, S_NEG_NI	150MW	150MW	150MW	150MW

System-wide constraints

	TSO Reference	2021	2025	2027	2030
SNSP Limit (%)	S_SNSP_TOT	75%	75%	80%	90%
RoCoF Limit (Hz/s)	S_RoCoF	1Hz/s	1Hz/s	1Hz/s	1Hz/s
Min Inertia (MWs)	S_INERTIA_TOT	20,000 MWs	NA	NA	NA

Minimum Generation constraints

	TSO Reference	2021	2025	2027	2030
Min Units ROI	S_NBMIN_ROImin	5	NA	NA	NA
Min Unit NI	S_NBMIN_MINNI1	2	NA	NA	NA
Min Units All-Island		NA	5	5	4

Locational constraints

	TSO Reference	2021	2025	2030
Dublin Generation 1	S_NBMIN_DubNB2	1 of DB1, HNC, HN2	1 of DB1, HNC, HN2	1 of DB1, HNC, HN2
Dublin Generation 2	S_NBMIN_Dub_NB	2 of DB1, HNC, HN2, PBA, PBB	2 of DB1, HNC, HN2, PBA, PBB	2 of DB1, HNC, HN2, PBA, PBB
Dublin Generation 3	S_NBMIN_DUB_L1	2 of DB1, HNC, PBA, PBB (ROI demand > 4000 MW)	2 of DB1, HNC, PBA, PBB	1 of DB1, HNC, PBA, PBB
Dublin Generation 4	S_NBMIN_DUB_L2	3 of DB1, HNC, HN2, PBA*, PBB* (ROI demand > 4700 MW)	3 of DB1, HNC, HN2, PBA*, PBB*	2 of DB1, HNC, HN2, PBA, PBB
South Generation 1	S_NBMIN_STHLD1	1 Gas Unit (ROI demand > 1500 MW)	1 Gas Unit	1 Gas Unit

	TSO Reference	2021	2025	2030
South Generation 2	S_NBMIN_STHLD2	2 Gas Units (ROI demand > 2500 MW)	2 Gas Units	2 Gas Units
South Generation 3	S_NBMIN_STHLD2	3 Gas Units (ROI demand > 3500 MW)	2 Gas Units	2 Gas Units
South Generation 4	S_NBMIN_STHLD5	3 Gas Units (ROI demand > 4200 MW)	2 Gas Units	2 Gas Units
MoneyPoint	S_NBMIN_MP_NB	1 of MP1, MP3, TYC	NA	NA
NorthWest Generation	S_NBMIN_CPS	Coolkeeragh on load if NI Demand > 1608 MW & NI wind generation < 450 MW	NA	NA

B.11 Technology cost assumptions

Technology	Economic Life (years)	WACC	FOM (€/kW)	Overnight CAPEX (€/kW)		
				2020	2025	2030
CCGT	20	8.7%	32.0	653	627	597
OCGT Large	20	8.7%	20.0	386	367	349
Battery Storage 2hr	10	11.0%	10.0	618	449	380