# Saving Power

## 70 by 30
## Implementation Plan

August 2020

## Delivering the *Climate Action Plan*

## Executive Summary

Ireland is a world leader.

Though our challenges and failures in the fight against climate change are widely known, there is less of a focus on our achievements.

EirGrid and SONI, as the operators of Ireland's electricity transmission system, have led the way in integrating large volumes of renewable electricity to provide clean power to homes and businesses across the country.

They have done this by working together to identify and deploy innovative systems and technologies to support our electricity grid.

Their success has made ours possible.

In 2019 the Irish wind energy industry provided almost a third of Ireland's electricity and over the first five months of 2020 this rose to just over 40%. We are number one in Europe for the level of electricity demand met by onshore wind.

Wind energy cuts our CO2 emissions by more than three million tonnes a year and annually saves our economy hundreds of millions of euro in fossil fuel imports, keeping jobs and investment at home.

But the increased deployment of onshore wind and the planned development of new solar farms and offshore wind farms will create greater challenges in integrating renewable electricity.

Already wind farms are being dispatched down – instructed to reduce the amount of power they generate – because the system is unable to cope with the large volumes of clean power available.

In 2019 alone more than 710,000 MWh of renewable electricity, enough to power the city of Galway for a year, was lost.

When wind farms are dispatched down they are replaced by fossil fuel generators. Every time a wind farm is told to reduce its generation, Ireland's CO2 emissions rise.

There are two main causes of dispatch down.

The first is curtailment. To ensure the safe and secure operation of the transmission system EirGrid sets a limit on the amount of demand that can be met by renewable electricity. This is currently set at 65% which means that even when it is possible for wind farms to provide more, to meet 70 or 75% of our electricity needs for example, they cannot do so.

Instead, they are curtailed, and that demand is met by fossil fuel generators. Increasing this limit, known as the System Non-Synchronous Penetration (SNSP) limit is essential if we are to achieve the Climate Action Plan's target of a 70% renewable electricity system by 2030.

The second main cause of dispatch down is constraints. Unlike the system-wide phenomenon of curtailment, a constraint is localised in nature. It means that the transmission system in a specific part of the country is unable to transport power from where it is generated to where it is needed.

Constraints are already a serious problem in the west, north-west and south-west of Ireland. As more wind farms – on and offshore – and solar farms are developed in the coming decade it is expected constraints will increase in those areas and also start to rise rapidly in the midlands and the east coast.

Put simply, we are approaching the moment when the greatest barrier to achieving our 2030 targets is not building new wind farms but the challenge of strengthening our electricity system to integrate the renewable electricity we need.

*Saving Power* is one part in a series of four reports produced by the Irish Wind Energy Association that together provide a detailed plan to enable Ireland to achieve the Climate Action Plan's target.

It sets out how we can minimise dispatch down and maximise the use of renewable electricity on our grid by 2030. Implementing the recommendations in Table 1 is essential to building a modern electricity system, one designed for an Ireland powered by wind and solar rather than coal and gas, and will create a firm foundation on which to build a zero-carbon Irish energy system.

These changes will cut CO2 emissions, cut the price of renewable electricity and cut fossil fuel imports.

Reducing dispatch down will require our system operators – EirGrid and ESBN – to work with the CRU and industry to design a power system for 2050 and beyond.

It will also mean deploying new technologies that have not been a significant feature of Ireland's electricity system to date such as battery storage, demand side response and synchronous condensers to replace our reliance on fossil fuel generators to provide system stability.

We know we can do this. We have the technology, the resources and the skills.

Our engineers, researchers and policymakers have already shown the world how to achieve what was previously thought impossible in integrating renewable electricity.

Together, we are ready to take the next step, not simply towards achieving our 2030 targets, but towards our true shared vision – a 100% renewable Irish power system.

**David Connolly**

**CEO**

**Irish Wind Energy Association**

Table 1: Summary of Policy Recommendations to Minimise Renewable Dispatch Down.

| Policy Improvement | Description | Aim | Lead Stakeholders | Target Date | Impact in 2030 if not implemented |
|---|---|---|---|---|---|
| **Policy Improvements to Minimise Curtailment** | | | | | |
| DS3+ | Enhance the DS3 programme to facilitate 2030 RES-E objectives | Develop a DS3+ programme to relieve existing operational constraints in line with EirGrid's strategic objectives to run the system with up to 95% non-synchronous generation | EirGrid, CRU, ESBN | 2020 | 16.4% Extra Curtailment |
| Interconnection Capacity | Provide additional interconnection capacity i.e. deliver Celtic and Greenlink interconnectors and put in place an enduring interconnection policy regime | Deliver Greenlink Interconnector by 2023 and Celtic Interconnector by 2026<br>Develop an enduring interconnection policy regime by Q4 2020 | CRU, EirGrid, Greenlink Developer | Develop enduring interconnection regime - 2020<br>Greenlink – 2023<br>Celtic – 2026 | 19.1% Extra Curtailment |
| Interconnection Operation | Introduce Single Intraday Coupling (SIDC) and maximise countertrading as an interim measure to ensure that the market design is incentivising the right behaviour on the interconnectors on a first principles basis (least cost / least emissions). | Enhance interconnector operation so that they able to export approximately 90% of their capacity during curtailment events | EirGrid, SEMO, CRU | Max countertrading - 2020<br>Intro SIDC - 2023 | 12.4% Extra Curtailment |
| **Policy Improvements to Minimise Constraints** | | | | | |
| Increase Transmission Grid Capacity for Existing & New Lines | Progress grid reinforcements based on future renewable development pipeline along with alternative network solutions using best-in-class community engagement. Streamline EirGrid's 'six-step' process and create a Grid Capacity Advisory Council.<br>Maximise the capacity of the existing grid via alternative network solutions such as Smart Wires, energy storage, demand side response | Minimise constraints to the greatest extent possible and, where appropriate and reasonable, provide an indicative solution and timeline so renewable electricity generation can continue to develop with the certainty that constraints will be minimised in future. | EirGrid, ESBN, CRU | 2020: Identify grid development requirements; Establish Grid Capacity Advisory Council; Initiate design & consent of required grid reinforcements.<br>Develop PR5 grid development programme of work. | 1,750 MW Less Onshore Wind<br><br>2,000 MW Less Offshore Wind<br><br>8% Increase in cost of wind energy |

| Major Long-Term Changes to Consider | | | | | |
|---|---|---|---|---|---|
| **Policy Improvement** | **Description** | **Aim** | **Lead Stakeholders** | **Target Date** | **Impact in 2030 if Policy Measure not implemented** |
| Market Redesign | Today's electricity market is designed around marginal-cost energy, backup capacity and a small amount of system services. In the future, renewable electricity will need long-term energy contracts, power plants will likely rely on capacity contracts and the grid will need much more system services. There is a consensus change is coming, but analysis is required to establish the nature of this change. | The market operator, SEMO via EirGrid and the CRU, should put in place a dedicated team to solely focus on what the electricity market design should be in 2030 to facilitate a 70by30 power system.<br>Ireland should also seek to engage and lead at a European level in the design of future markets appropriate for very high RES-E levels. | CRU, SEMO, EirGrid | 2021 | N/A |
| Dispatch down Certainty | CRU should implement dispatch down compensation for variable renewable generators, which is paid for by EirGrid and ESBN, who can then justify investments in solutions to reduce this compensation and thus reduce dispatch down. The compensation mechanism will need to ensure that generators are also not incentivised to build capacity in unwanted locations. | This could be implemented in the short-term while transposing Article 12 and 13 of the Electricity Regulation in the Clean Energy Package. If not, the CRU should establish a roadmap that will explain how dispatch down will be managed over the next decade at the lowest cost to the consumer, while also incentivising investment in renewable electricity to achieve 70by30. At present, without dispatch down compensation, it is very likely that the 2030 targets will not be met or, alternatively, they will be met at unnecessarily high costs to the consumer. | SEMO, CRU, EirGrid, ESBN | 2020 | N/A |
| Grid 2050 | The power system will be very different in 2050 so whatever path we take towards 2030 should bring us on the journey to full decarbonisation of the economy before 2050. This will ensure we can 1) use wind energy for renewable heat and transport and 2) minimise dispatch down due to Energy Balancing. | EirGrid and ESB Networks should begin planning for the power system needs for a fully decarbonised electricity system which can support the electrification of heat and transport with the goal of a decarbonised economy by 2050. | EirGrid, ESBN, CRU | 2020 | N/A |

# Table of Contents

# 1 Introduction

The Irish Wind Energy Association (IWEA) is the representative body for the Irish wind industry, working to promote wind energy as an essential, economical and environmentally friendly part of the country's low-carbon energy future. We are Ireland's largest renewable energy organisation with more than 150 members who have come together to plan, build, operate and support the development of the country's chief renewable energy resource.

In 2018 IWEA commissioned Baringa Partners LLP to undertake a fully costed study of a 70% renewable electricity system in Ireland. While it shows this target was possible it did not identify the policy changes needed to achieve it. Following the publication of Ireland's Climate Action Plan in June 2019, where Government endorsed the 70% target, IWEA has undertaken a body of work to set out in detail how the target can be achieved.

This body of work, which we refer to as the 70by30 Implementation Plan consists of four separate reports:

- *Saving Money;*
- *Saving Power;*
- *Building Onshore Wind;*
- *Building Offshore Wind.*

This report, *Saving Power*, sets out how we can minimise dispatch down and maximise the use of renewable electricity on our grid by 2030.

If a system security issue can be addressed by dispatching down any renewable generator across the entire national grid, then this dispatch down is referred to as curtailment. Curtailment is used to manage challenges which impact the entire system and are not locational in nature. For example, at the time of writing the maximum percentage of electricity that can be provided by wind power in Ireland for system security reasons is 65% of demand and electricity exports, so when wind farms produce more than this, it has to be curtailed. Dispatch down for a local network limitation is referred to as constraint. For example, if a power line in a certain area of Ireland does not have enough capacity to transfer the power from the renewable generator to where it is needed, then there is a constraint and the renewable generator must be dispatched down to solve the local capacity issue.

Figure 1 provides an illustrative example of how dispatch down for curtailment and constraint works in practice. Taking a hypothetical daily electricity generation and demand scenario, the blue line shows electricity demand and interconnector exports while the orange line shows the SNSP limit. When wind generation rises above the SNSP limit the yellow highlighted areas show where curtailment is occurring. Where there is a local network constraint, the red highlighted area shows where wind generation is dispatched down for constraint reasons. The grey highlighted area on the right of the graph where dispatch down occurs because wind generation exceeds demand is an example of excess generation and is not a power system issue. In this case excess wind generation is dispatched down for energy balancing reasons as there is not enough demand to meet the level of wind generation at the time. This excess wind generation situation is rare at present but will become much more prevalent towards the second half of the decade with increasing levels of onshore wind and the connection of the first offshore wind projects. It is discussed in Section 4 as part of the 'Major Long-Term Changes' that will be required.

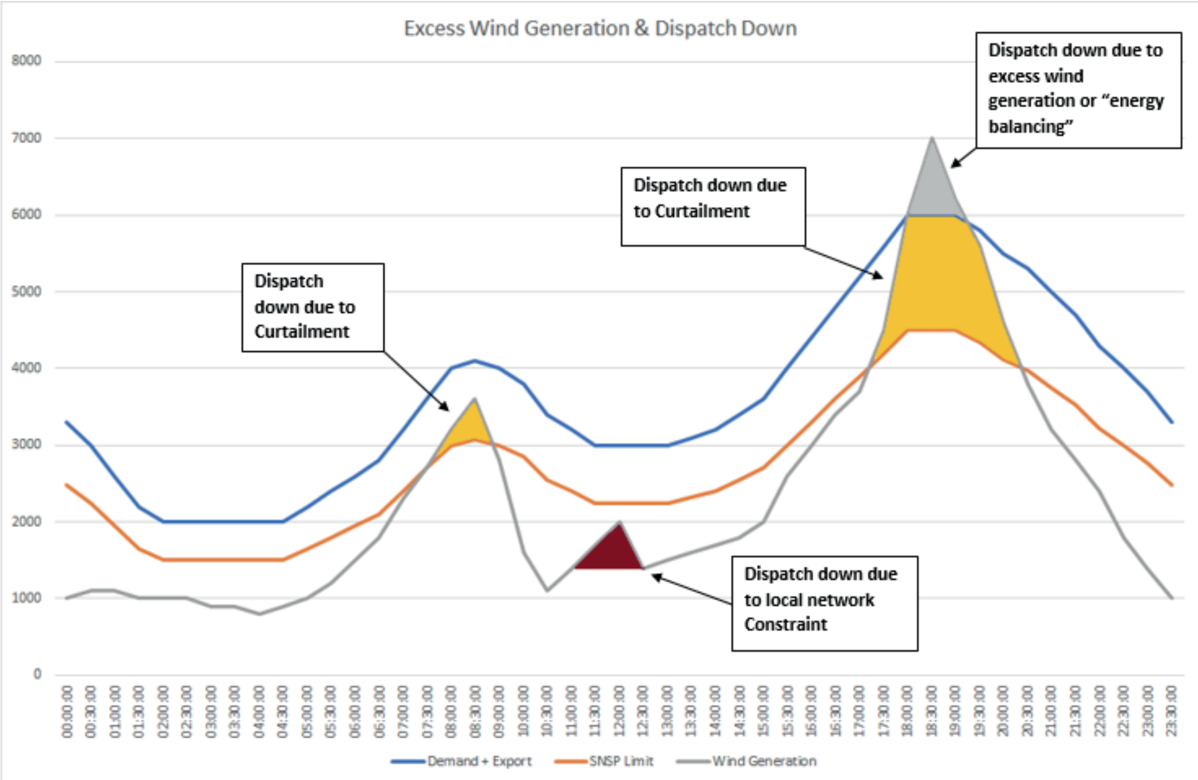


Figure 1: Example dispatch down scenarios for Renewable Generation.

The latest full year of data from EirGrid, which is for the year 2019, shows that dispatch down in Ireland is now at 6.9%, with 3.1% from curtailment and 3.8% from constraints.[1] In total, this equated to 710,591 MWh of renewable electricity could not be used in 2019. This would have been enough to power the entire city of Galway for the year.[2] Analysis carried out by MullanGrid estimates that, for 2019, this dispatch down cost wind farms approximately €50 million in lost revenue in Ireland. This also led to more of Ireland's electricity demand being met by fossil fuel generation which meant higher power sector emissions and system costs (detailed further in Section 2.2.2).

Figure 2 below provides an overview of historical wind dispatch down percentages for Ireland. Constraint levels saw a significant increase in 2019, partly due to issues with the Moneypoint transformer, and this is something that is projected to increase due to network limitations in many parts of the country where renewable projects are planning to connect. While

[1]http://www.eirgridgroup.com/site-files/library/EirGrid/2019-Qtrly-Wind-Dispatch-Down-Report.pdf

[2] The approximate energy usage of Galway City is 712,000 MWh which is calculated using assumptions and information from EirGrid's most recent Transmission Forecast Statement.

curtailment has so far been kept at manageable levels of under 4%, this is also projected to increase unless system level measures are introduced to accommodate more renewable generation.

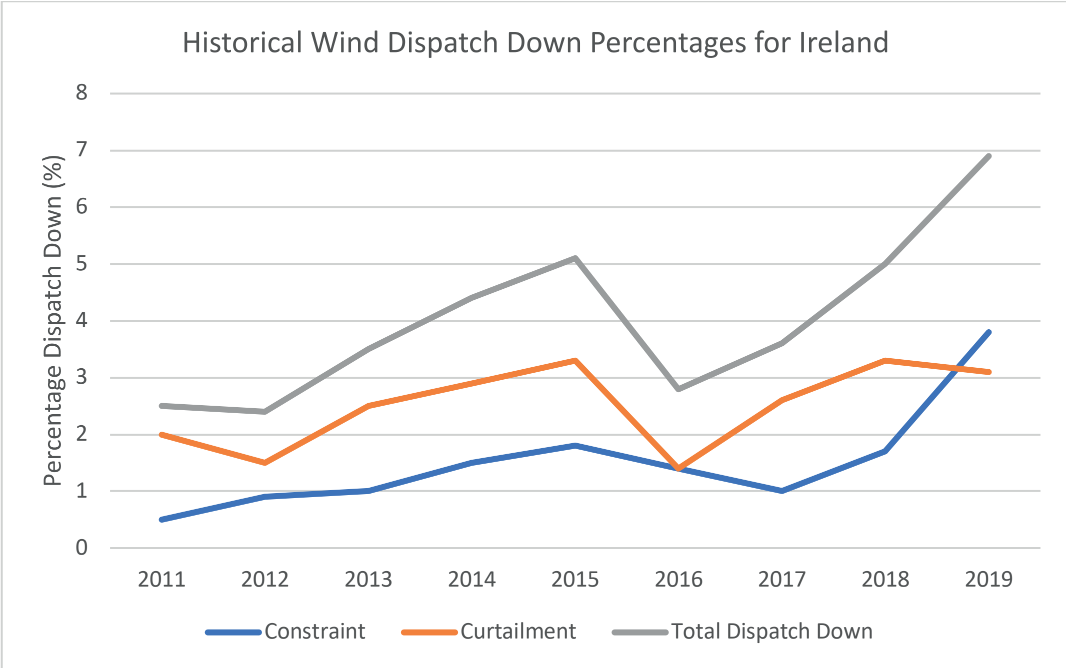


Figure 2: Historical wind dispatch down percentages for Ireland.

The goal of *Saving Power* is to identify how we can minimise dispatch down and maximise the use of renewable electricity on our grid by 2030. The following sections set out in detail how to implement each policy that will:

- Minimise curtailment (Section 2).
- Minimise constraints (Section 3).
- Major long-term changes to consider (Section 4).

These measures are summarised in the conclusion in Section 5, which includes an overview of all the policies proposed along with the key stakeholders responsible for implementing these Policy Improvements (PIs) to minimise dispatch down (Table 3).

# 2 Policy Improvements (PIs) to Minimise Curtailment

## 2.1 Introduction

EirGrid and SONI, the Transmission System Operators (TSOs), must continuously ensure that electricity is able to flow safely and securely on the all-island power system from generators to homes and businesses when and where it is needed. To enable this to happen, the TSOs must adhere to specific system security standards at all times.

The electricity system works by running at a stable frequency of 50Hz where supply (electricity generation) and demand are perfectly balanced. If the frequency becomes unbalanced, and is not contained and restored to normal, then this can cause the system to destabilise and can lead to blackouts. The system frequency can become unbalanced when a large fossil fuel generator runs into an issue and has to shut down at short notice or when there is a sudden unforecasted change in wind generation and there is not enough generation to meet demand.

Traditionally, electricity generation mostly consisted of a handful of large fossil fuel or hydro generators that were able to be dispatched (i.e. turned on/off or up/down) by the TSOs when the need arose. For system security, the TSOs had to ensure that sufficient generation was available to meet demand, that the electricity system was able to carry the needed electricity and that sufficient generation was available in reserve at short notice in case of an issue or fault with an operating generator.

However, as the levels of variable renewable generation on the system have increased in recent years, and will be our main source of electricity going forward, this brings about certain challenges which must be addressed if we are to achieve our RES-E goals. One of the main challenges is that renewable generators such as wind and solar are variable (i.e. their output is dependent on weather conditions thus they cannot be turned on or off on demand and so are non-dispatchable). This means the TSOs must manage this variability to ensure that there is always enough generation to meet demand. The ability of the power system to quickly and reliably respond to this variability is known as system flexibility and there are a number of technologies such as demand side response, energy storage and interconnectors that can help manage this. These technologies will be discussed in more detail in later sections.

The other big challenge is that wind and solar are non-synchronous technologies. To put this simply, large fossil fuel generators are directly connected to the grid and run in synchronism, producing electricity at 50Hz. As these generators produce electricity, their spinning turbines inherently provide what is known as 'inertia' which is like a type of stored energy that helps manage deviations in generation and demand and keeps the system frequency stable. However, wind and solar are not synchronously connected to the grid in the same manner due to their technical characteristics and do not provide this same 'inertia' to help manage system frequency. As wind and solar replace traditional fossil fuel generators in providing our electricity, this brings about system stability challenges which are being addressed through programmes such as DS3, which will be discussed in more detail in Section 2.3.

In 2010, EirGrid and SONI completed the *All-Island TSO Facilitation of Renewables* study which examined the amount of non-synchronous wind and solar generation that the electricity system could safely accommodate at any one time while maintaining system security.[3] This is referred to as the System Non-Synchronous Penetration limit (SNSP) and in simple terms it refers to the maximum percentage limit of electricity demand and electricity exports that can be met by wind/solar generation at any given time. If the available wind/solar generation is above this limit at any time it must be dispatched down to at, or below, the SNSP level and this is known as curtailment.

There are a number of system operational considerations that influence and interact with the SNSP limit such as minimum generation levels, inertia levels, voltage support and operating reserves. These are discussed further in Section 2.2.2.

The 2010 study identified a 50% SNSP limit at the time and, based on this, EirGrid and SONI began a programme of work in 2011 known as 'Delivering a Secure, Sustainable Electricity System' (DS3) with the goal of delivering the system level changes required to increase the SNSP limit to 75% by 2020. The programme has so far successfully delivered the tools, policies and system services needed to allow the current SNSP operational limit to be increased to 65% as of the time of writing.

## 2.2 Supporting Studies

### 2.2.1 Managing Curtailment in 2030

A study carried out by Mullan Grid, ABO Wind, Dublin City University and Coillte, which was co-funded by SEAI, identified the most important curtailment mitigation measures required to manage high levels of renewable electricity by 2030. It is called 'Identifying the relative and combined impact and importance of a range of curtailment mitigation options on high RES-E systems in 2030 & 2040', but it is referred to here as the *Managing Curtailment in 2030* study.[4]

The study estimates that curtailment will become a significant issue without the development of new mitigation measures to manage increasing levels of renewable generation. Achieving the 70% RES-E target is theoretically possible without these mitigation measures but curtailment levels could increase to 44% (see Figure 8) and we would need over 21 GW of installed wind capacity, due to these high curtailment levels, to meet 70% RES-E.

Results from this work, which are displayed in Table 2, outline how it is possible to reach 70% renewable electricity in 2030 with manageable levels of curtailment. This is called the 'Climate Action Plan' scenario in the report and it includes a range of measures which, if implemented together, will result in approximately 5.5% curtailment in 2030. This is not a huge jump from existing levels of 3.7%[5]. However, the analysis also demonstrates how this could be significantly larger if the three critical measures outlined are not implemented. If this occurs, the results

[3] http://www.eirgridgroup.com/site-files/library/EirGrid/Facilitation-of-Renewables-Report.pdf
[4] https://www.seai.ie/data-and-insights/seai-research/research-projects/details/identifying-the-relative-and-combined-impact-and-importance-of-a-range-of-curtailment-mitigation-options-on-high-rese-systems-in-2030--2040
[5] http://www.eirgridgroup.com/site-files/library/EirGrid/2019-Qtrly-Wind-Dispatch-Down-Report.pdf

show that curtailment increases from 5.5% to 44%, which would make it very challenging and expensive to continue building renewable electricity in Ireland. Even failing to implement one of these measures would have significant curtailment impacts.

Table 2: Failure Impact Analysis for 70% RES-E System Integration (text in red highlights the specific failure under each policy measure compared to the Climate Action Plan scenario).

| Scenario | SNSP | Min Gen | Interconnector Capacity | Average Interconnector Exports* | Curtailment in 2030 with 70% RES-E | Stakeholders Responsible for Individual Policies |
|---|---|---|---|---|---|---|
| 'Climate Action Plan' Scenario i.e. All Measures Successfully Implemented | 90% | 700MW | 2,030MW | 90% | 5.5% | EirGrid/ ESBN /CRU |
| Impact of Failure for Each Policy Measure Individually | | | | | | |
| DS3+ Failure | 75% | 1,400MW | 2,030MW | 90% | 16.4% | EirGrid/ ESBN /CRU |
| Interconnection Export Capacity Failure | 90% | 700MW | 580MW | 90% | 19.1% | EirGrid/ CRU |
| Interconnection Market Failure | 90% | 700MW | 2,030MW | 50% | 12.4% | SEMO/ EirGrid/ CRU |
| Impact of Failure for All Policy Measures Combined | | | | | | |
| DS3+ Failure, Interconnection Capacity & Market Failure | 75% | 1,400MW | 580MW | 50% | 44% | EirGrid/ ESBN /CRU |

*This is the average capacity used on the interconnectors during times where curtailment occurs.

### 2.2.2 *Store, Respond and Save*

The second piece of analysis referred to extensively in this report was carried out by Baringa Partners LLP entitled *Store, Respond and Save – Cutting two million tonnes of CO2* and was published in December 2019.[6] This investigates the benefits to the power system of procuring all system services from zero carbon sources such as battery energy storage, demand side response, synchronous condensers and renewable generators in place of traditional fossil fuel sources.

The TSOs on the all-island system must ensure that they hold a sufficient quantity of available system services provision at all times. There are broadly four types of system services, which are:

- **Reserve:** 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 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, the reserve services require power to be delivered from seconds up to 20 minutes depending on the different service type.
- **Inertia:** this stored kinetic energy from the rotating turbines of synchronous generators, which traditionally have been hydro, gas and coal-fired generators, ensures the power system remains stable during frequency events on the system. If there is not enough inertia, then the frequency will drop rapidly if a generator or interconnector trip occurs. If it drops too quickly this can lead to loss of customer demand on the grid or, in the worst case, a blackout. EirGrid monitors the level of inertia on the system in real-time to ensure this does not occur.
- **Reactive Power:** makes sure that voltage levels across the system remain stable and within safety limits. It is important to stay within limits as this ensures power can flow across the grid from generators to where it is consumed. All generators, including renewables, can either provide or absorb reactive power to help the system stay within limits. Other network devices can also help with this.
- **Ramping:** this ensures that there is always sufficient generation available to meet longer-term unforecasted changes in demand or generation, covering timeframes up to 8 hours ahead. With variable renewable generation that may experience a change in output due to unforecasted weather conditions. These services ensure the TSO has adequate generation available to ramp up ahead of time in response to potential changes.

[6] https://www.iwea.com/images/files/iwea-baringastorerespondsavereport.pdf

Currently, the TSOs meet their system service requirements largely from a combination of gas and coal-fired generators, along with some pumped storage and hydro power stations. So that fossil-fuelled power stations can provide these services they typically need to be turned on and generating at a certain minimum output. This provides 'headroom' for output to be increased quickly. 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.

The TSOs pay compensation to generators, almost exclusively power plants, to cover the costs of this pre-positioning. On an all-island basis, current methods of meeting power system operational constraints cost consumers over €190 million per year, recovered as part of the 'imperfections' charge which is levied on electricity suppliers and passed through to consumers as part of their bills. 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.[7]

Two major drawbacks of power plants providing these system services are firstly, the carbon emissions associated with these as it requires the power plants to use more coal or gas, and secondly, but more significantly in the long-term, these power plants must produce electricity to provide these system services. In other words, although the purpose is to ensure the grid has sufficient system services, the fact that power plants must produce electricity to provide these system services means that they are taking up supply or 'space' on the grid which could be provided by renewables such as wind and solar.

The *Store, Respond and Save* assessment leverages previously completed work carried out as part of Baringa's *70 by 30* analysis which examined a variety of scenarios with the Ireland and Northern Ireland power system reaching 70% renewable electricity by 2030.

Baringa modelled scenarios with system service constraints in place for the years 2021, 2023, 2025, 2027 and 2030, and then removed these constraints in turn – reflecting provision of system services (i.e. inertia, reserves, voltages) from 'non-energy market' zero-carbon sources such as battery energy storage, demand side response and synchronous condensers.

The modelling results show a potential system cost saving of €90 million per annum by 2021, increasing to €117 million by 2030 when all system services are sourced from zero-carbon sources instead of system services from fossil fuel i.e. power plants. Figure 3 below highlights the system cost savings under these different scenarios.

[7] These costs are additional to the payments made for the provision of system services under the current DS3 regime.

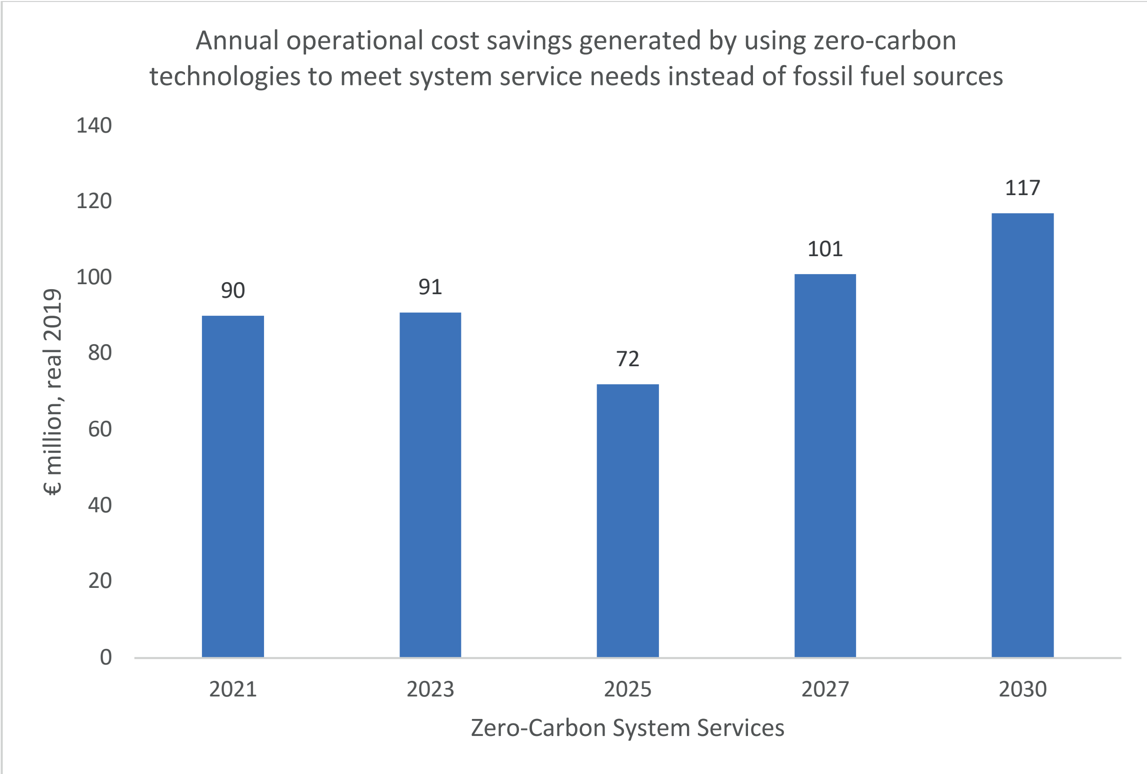


Figure 3: System Cost Savings from Zero-Carbon System Services Provision.

The Baringa analysis also shows that there is a huge benefit from avoided CO2 emissions from full zero-carbon provision of system services, equating to almost 2 million tonnes of CO2 avoided annually by 2030. To put this in context, Baringa estimates that this would be equivalent to around one third of total power sector emissions that could be avoided annually by 2030. Figure 4 highlights the annual avoided emissions from zero-carbon service provision under this zero-carbon system services scenario.

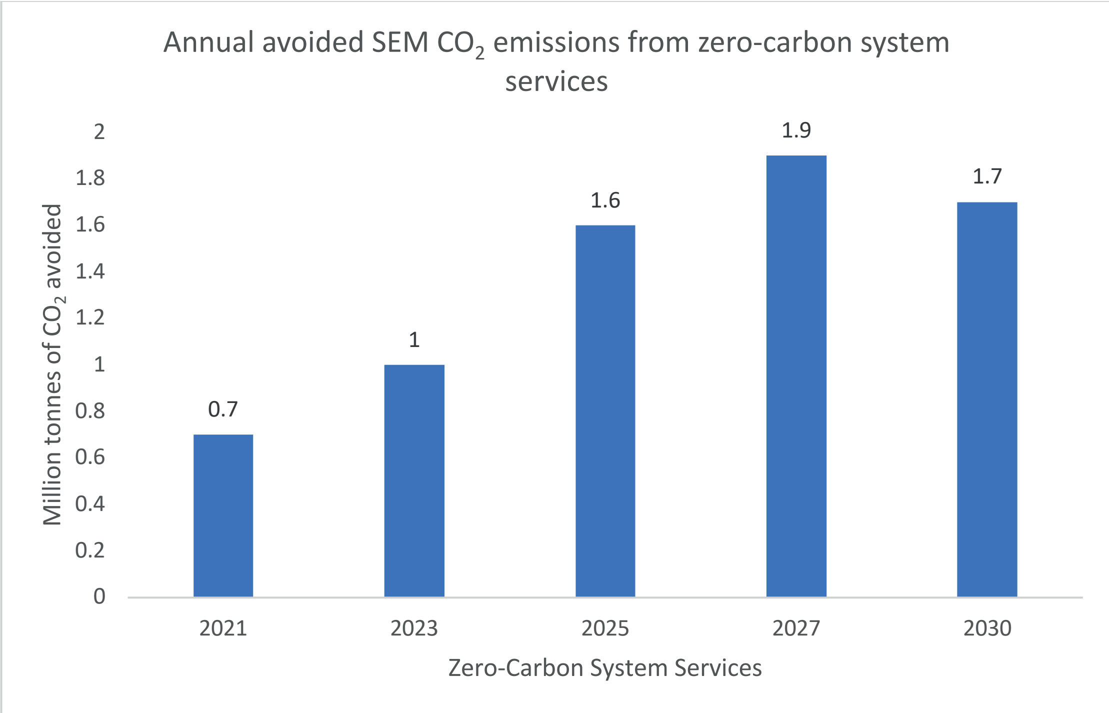


Figure 4: Annual avoided emissions by Zero-Carbon System Services Provision.

Baringa's Zero-Carbon System Services analysis has also analysed the potential benefits for renewable curtailment in a 70% RES-E scenario where all system service constraints are met using zero-carbon service providers. Baringa's analysis assumes several existing system constraints have already been alleviated, an operational SNSP limit above 90% and approximately 2,000 MW of interconnector export capacity by 2025. Baringa estimates a reduction in curtailment from around 8% to 4% in 2030, when meeting all system constraints using zero-carbon providers, which allows more space on the system for wind generation by removing the need to constrain on fossil fuel generation for system service provision (Figure 5).

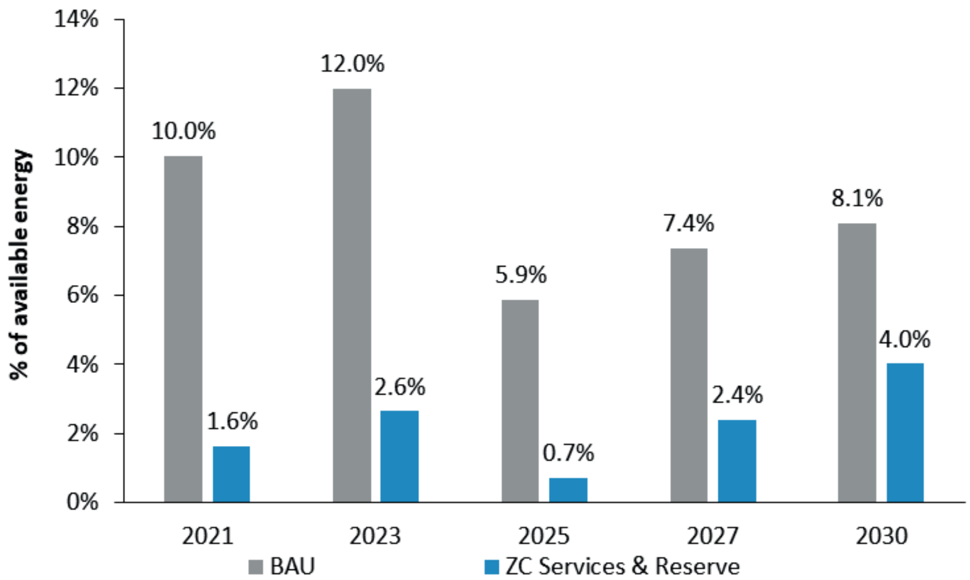


Figure 5: Impact of Zero-Carbon System Services on Renewable Curtailment.

New zero-carbon technologies will be required that can provide these system services and which can supplement the electricity generated by wind and solar power. An estimate of the volumes of services required and examples of the technologies that will be able to provide these system services is outlined in Figure 6.

| 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 |

Figure 6: Estimated levels of each system service required on the Irish Electricity Grid.

The service volumes outlined above should only be used as a guide as fully quantifying the system needs would require a very detailed analysis of the Irish electricity system. More analysis will be required to get a full understanding of how Ireland can lead the world in the transition from fossil-fuel based system services to zero-carbon based system services. It is expected this modelling will be carried out through the EU-SysFlex project and EirGrid's DS3+ programme.[8]

## 2.3 Curtailment Policy Improvement 1: DS3+

## Aim: Increase SNSP from 75% to >95% and reduce 'Min Gen' from approximately 1,400 MW to 300 MW

### 2.3.1 Introduction and Quantifying the Impact

Meeting the ambitious 2030 targets for renewable energy and decarbonisation will require a fundamental re-think of how the power system has been operated up until this point and will require new operational procedures, policies and control centre tools to help manage the system. It will also require commercial frameworks to incentivise the development of new flexible capability in order to remove current system operational constraints.

The *Managing Curtailment in 2030* study does not model each system service operational constraint individually (i.e. inertia, voltage, reserves), but instead models two key limitations on the power system which reflect the level of system services that are available. These limitations are:

- **System Non-Synchronous Penetration (SNSP):** refers to the amount of renewable generation that the electricity system can safely accommodate at any one time. Currently at 65% with plans to increase this to 75% in 2021. EirGrid has also set a goal of reaching 95% SNSP by 2030 in their most recent strategy, but the specifics on how to do this are yet to be defined.[9]
- **Minimum Generation (Min Gen):** refers to the amount of conventional fossil fuel generation that the TSOs must keep on at all times to maintain system security (i.e. to maintain security standards such as minimum inertia levels and voltage stability. This is currently set at approximately 1,400 MW and there is no defined target to reduce this but, if SNSP is to increase to 95%, then this will have to be significantly reduced as otherwise there would not be enough 'space' on the system for the 95% SNSP limit to be achieved.

By adjusting these limits (SNSP and Min Gen), it was possible in the *Managing Curtailment in 2030* study to model the impact of providing more or fewer system services. The challenge of integrating 70% RES-E on the system was first quantified by taking the system as it is anticipated to exist in 2020 (i.e. a 75% SNSP and 1,400 MW Min Gen) and attempting to reach 70% RES-E simply by adding more wind generation without any changes. This resulted in curtailment levels of 44% (as shown in the red circle in Figure 7 below).

[8] EU-SysFlex - Work Package 2 - http://eu-sysflex.com/workpackages/wp2-development-of-new-approaches-for-system-operation-with-high-res-e/

[9] EirGrid Strategy 2020 - 25 - http://www.eirgridgroup.com/about/strategy-2025/

Figure 7 illustrates that approximately two-thirds of this curtailment is removed through the implementation of a 95% SNSP limit and a 300 MW Min Gen limit (highlighted in the purple circle). As such reducing these limits by the provision of sufficient system services is the single most important measure required to integrate 70% RES-E on the Irish system. The continuation and enhancement of EirGrid/SONI's existing 'Delivering a Secure, Sustainable Electricity System' (DS3) programme is essential to achieving this. It is this programme that will introduce the required system level changes and identify and procure the suitable technologies required to provide the necessary system services, so it is the first policy improvement (PI) recommended here to reduce curtailment.

Figure 8 demonstrates the volume of installed wind generation capacity which would be required to meet 70% RES-E in various SNSP and minimum system conventional generation scenarios. The benefits of transitioning to 95% SNSP with a minimum system generation conventional generation level of 300 MW has an enormous impact on the quantity of generation required to meet 70% RES-E.

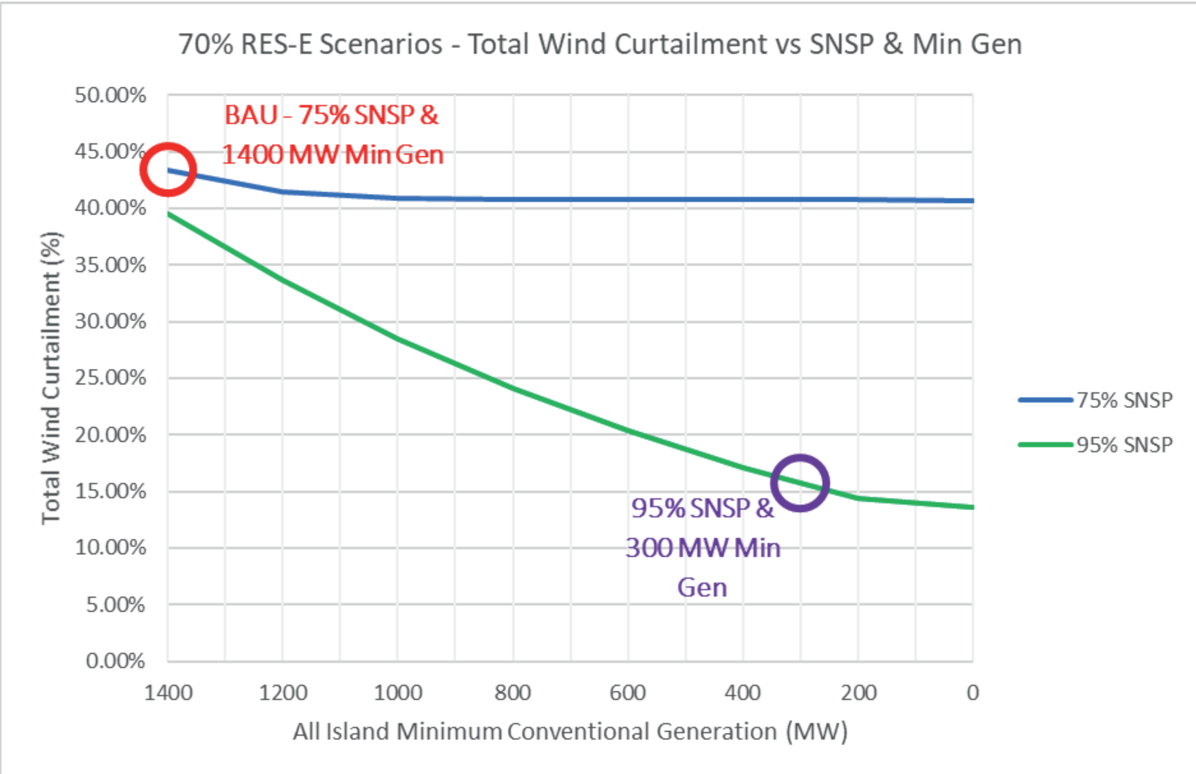


Figure 7: Curtailment vs minimum system conventional generation for 75% and 90% SNSP limits for 70% RES-E systems (Both lines represent a 70% RES-E system with the level of curtailment related to changes in Min Gen levels, all other system assumptions based on 2020 system).

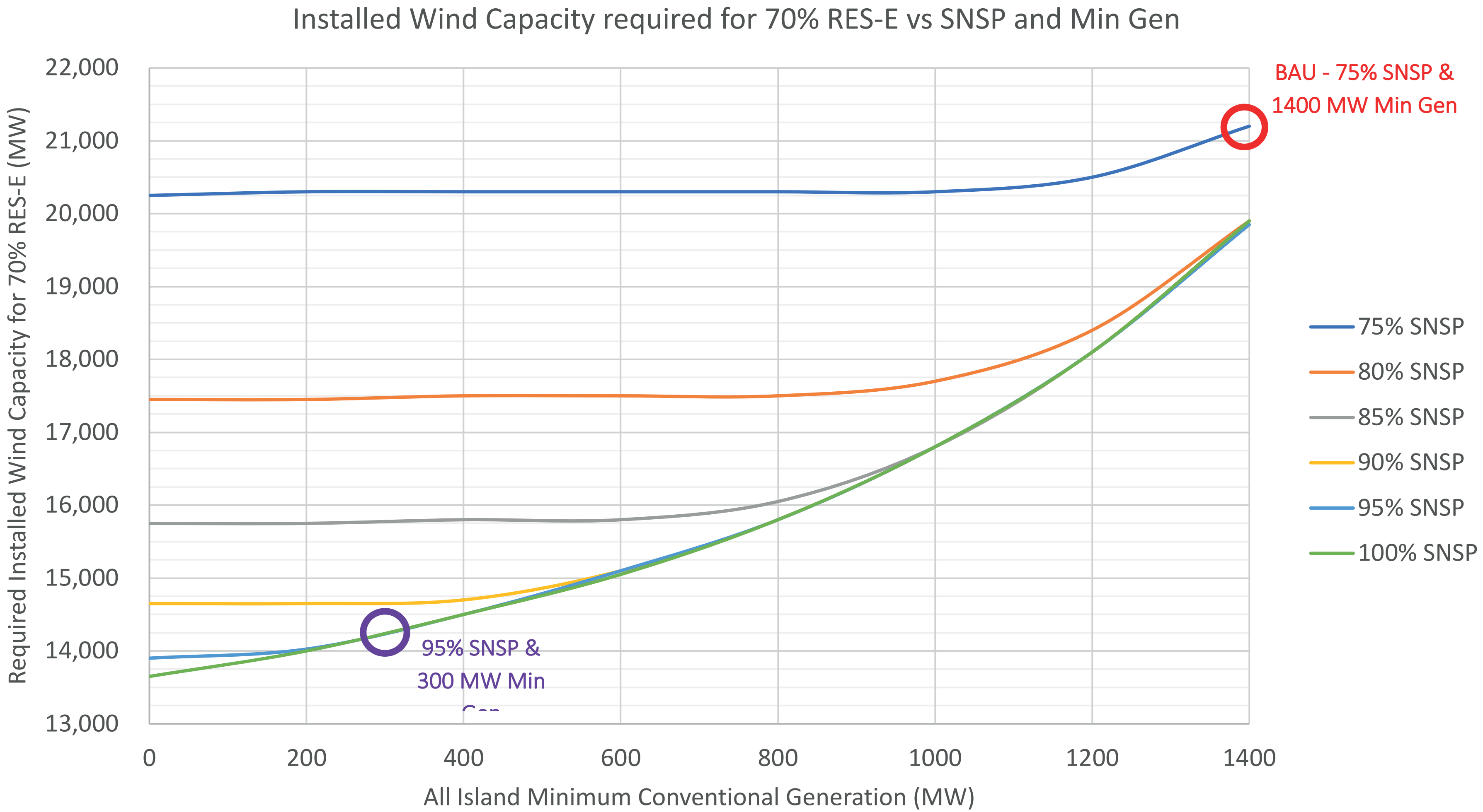


Figure 8: Required Installed Wind Capacity for 70% RES-E vs minimum system conventional generation for various SNSP limits (Each line represents a 70% RES-E system, all other system assumptions based on 2020 system).

### 2.3.2 Implementation

#### 2.3.2.1 Summary of Current Policy

The DS3 programme has been an extremely successful initiative that has enabled Ireland to be a world leader in the integration of renewable electricity onto the grid.

The DS3 programme began in 2011 and was established with the goal of delivering the system level changes required to operate the network at 40% RES-E by 2020. The programme has so far successfully delivered the tools, policies and system services needed to allow the current SNSP operational limit to be increased to 65%, up from a 50% limit when the programme began. Further trials to increase SNSP to 70% and 75% respectively are expected in 2020/2021.

#### 2.3.2.2 Shortcomings of Current Policy

Going forward, achieving a 70% renewable electricity target will require the continued development of the DS3 programme (referred to as DS3+ for the purposes of this report) as delivering even higher levels of renewable integration will bring significant system challenges that must be addressed. As such it is important that the System Operators (EirGrid, SONI, ESBN and NIE Networks) have the resources and support needed to ensure Ireland continues as a world leader in this area and that a comprehensive programme of work is put in place to allow the system to accommodate the volumes of renewables needed to reach 70by30.

It is extremely likely that operating a system capable of achieving 70by30 will require increasing the SNSP operational limit to 95%, or above, and removing many of the other existing operational constraints which limit the penetration of renewable generation on the system. The DS3 programme has so far maintained curtailment at manageable levels of less than 5% but, as the volume of renewables connecting to the system continues to grow, it is certain that without a strong DS3+ programme and further SNSP increases, curtailment levels will increase substantially. *Managing Curtailment in 2030* estimates that with current system constraints, and no new mitigation measures, curtailment levels could increase to 44% (see Figure 8) and we would need over 21 GW of installed wind capacity, due to these high curtailment levels, to meet 70% RES-E.

Uncertainty regarding future curtailment levels also significantly impacts the commercial viability of renewable projects and will lead to higher costs for consumers via RESS auction bids as developers will price in this added uncertainty and anticipated curtailment. This was highlighted in the *Saving Money* volume of the 70by30 Implementation Plan, where it was shown that if curtailment increases bid prices by approximately 10%, this would add billions of euro to the cost of meeting Ireland's future renewable electricity targets.

#### 2.3.2.3 Proposed New Policy

Meeting the ambitious 2030 targets for renewable energy and decarbonisation will require a fundamental re-think of how the power system has been operated up until this point. DS3+ will require new operational procedures, policies and control centre tools to help manage the system but will also require commercial frameworks to incentivise the development of new flexible capability in order to remove current system operational constraints. An area of work under the DS3 programme which has greatly improved the flexibility of the operating fleet and already delivered huge value to the consumer is that of System Services. It is also an area which can deliver greater system flexibility, further savings and emissions reductions over the next decade as highlighted in Baringa's *Store, Respond and Save* report.

The design of System Services has contributed to conventional fossil fuel generators transforming their operation and substantially reducing their Min Gen levels from what was seen at the beginning of this decade. This reduction in Min Gen allows for more 'space' for renewable generation on the system and, alongside increases in operational SNSP limits, is essential to minimising curtailment.

If we are to achieve our 70% RES-E target in the most cost-efficient manner, the power system will need to accommodate non-synchronous renewable penetration levels of over 95% at any one time. This will likely mean that, at these times, all System Services requirements will need to be met by zero carbon service providers, such as wind, solar, demand side response, storage and synchronous condensers, as there will be no room on the system for fossil fuel generators. Technologies which can provide Zero Carbon System Services, including potential capacities required by 2030, were outlined previously in Figure 6.

In order to deliver the required changes, IWEA proposes the following measures for the System Operators and Regulatory Authorities (CRU and NIAUR):

1. Develop and implement a comprehensive programme of work to achieve SNSP of >95% and the removal of fossil fuel system constraints (e.g. Min Gen, RoCoF).
2. Ensure adequate resourcing and expertise is in place to deliver DS3+ programme objectives.
3. Work with industry to identify and break down the existing barriers to achieve DS3+ and ensure continued industry involvement via frameworks such as the DS3 Advisory Council.
4. Measure and report on energy market and non-energy market emissions as part of the existing quarterly dispatch down reports. The TSOs often position units away from the energy market schedule to meet system service requirements. These are known as non-energy actions. The recommendation is for the TSOs to model electricity system CO2 emissions to compare energy market emissions and actual electricity generation emissions to calculate the non-energy market emissions contribution. Or in other words, the emissions solely related to actions that are required to ensure the electricity system remains stable.

5. Prioritise the procurement and dispatch of sources of System Services from low or zero-carbon sources, with the goal of bringing emissions from System Services to zero.
6. Ensure that sufficient System Services are procured to efficiently integrate the 70% renewable electricity targeted by 2030 and enable SNSP levels of >95%.
7. Begin the scoping and analysis needed to achieve long-term decarbonisation goals (e.g. 100% RES-E and 100% SNSP).

#### 2.3.2.4 Implementing new Policy

Who is the decision maker?

EirGrid/SONI will design and lead the implementation of the DS3+ programme.

The CRU/NIAUR will decide on the enduring System Services Procurement framework and approve the System Operators' allowed spend on the DS3+ programme.

Who has a supporting role?

ESBN/NIEN will oversee the development of DS3+ from a distribution system perspective.

Industry will work with the System Operators and Regulators on DS3+ programme objectives and development of zero-carbon system support technologies.

Budget or resource requirements:

The required resourcing and spend on the operational aspects of the DS3+ programme will be determined by the System Operators, with the final decision on allowed spend made by the Regulatory Authorities. The System Operators are currently developing their system needs analysis for 2030 which will inform the level of resources/funding required.

System Operator spend on System Services will be dictated by the Regulatory Authorities' decision on the enduring procurement framework which is expected to be developed by Q1 2021.

Target date for achieving policy change:

- Q2 2020 – CRU consultation on PR5 revenue allowance and incentives
- Q2 2020 – CRU/NIAUR high-level consultation on System Services enduring procurement framework
- Q3 2020 – CRU decision on PR5 revenue allowance and incentives (Note: Important for NIAUR to allow for similar level of revenue allowance and incentives for SONI and NIEN in their Price Control also)

- Q4 2020 – CRU/NIAUR detailed design consultation on System Services enduring procurement framework
- Q4 2020 – Completion of TSOs' analysis on DS3+ technical analysis and plan of work
- Q1 2021 – 70% SNSP implemented
- Q1 2021 – CRU/NIAUR decision on DS3 System Services enduring procurement framework
- Q2 2021 – 75% SNSP implemented

## 2.4 Curtailment Policy Improvement 2: Interconnection Capacity

### Aim: Deliver the Greenlink Interconnector by 2023 and Celtic Interconnector by 2026 to enable an export market for surplus renewable generation and develop an enduring interconnection policy regime by Q4 2020.

#### 2.4.1 Introduction and Quantifying the Impact

Systems with high levels of distributed variable renewable generation need flexibility to respond to changes in generation and demand to maintain the stability of the power system. Interconnection is a proven and mature technology that can provide this flexibility along with many other benefits. Physically it comprises a High Voltage Direct Current (HVDC) cable linking Ireland with one of its neighbouring electricity markets which allows electricity to be traded. This helps to smooth variations in production from wind and solar generation sources as Ireland can export excess wind power at times of high production and import power from other markets at times of low wind production.

Power flows on the interconnector are a result of market signals i.e. whether an interconnector exports or imports is dependent on the difference in electricity prices between markets. Interconnection helps drive competition by allowing markets access to other generation sources, which lowers costs to consumers, particularly by allowing markets to share low-cost power plants (which has shown to be the case in Denmark[10]) and by reducing renewable curtailment by enabling an export market for surplus renewable generation. It also brings security of supply benefits by sharing generation across markets thus reducing our need for conventional fossil fuel generation capacity.

Interconnectors expose the Irish power system to larger GB and EU markets, which is good if they are competitive and the market is driving efficient flows. With well designed, well-functioning markets, interconnection, at the optimum size and location, is very beneficial for Irish consumers.

The Baringa 70by30 report envisaged Ireland having two new interconnectors, Celtic and Greenlink, as well as the North-South interconnector built in the mid-2020s. EirGrid's Tomorrow's Energy Scenarios 2019 report[11] set outs two scenarios which meet 70% RES-E that include both Greenlink and Celtic interconnectors being delivered on time (2023 and 2026 respectively). The National Climate Action Plan[12] also sets out a Marginal Abatement Cost Curve for Ireland to achieve 70% RES-E by 2030, which shows increasing onshore and offshore wind capacity are the most economical options for electricity production, and assumes that the two planned interconnectors are delivered by the mid-2020s.

Adherence to these delivery timelines and development of this additional interconnection as early as possible is therefore essential to minimising curtailment and integrating increased

[10]https://vbn.aau.dk/ws/portalfiles/portal/38593365/Danish_Wind_Power_Export_and+Cost.pdf
[11] EirGrid TES 2019 report http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-Report.pdf
[12] Ireland's Climate Action Plan
https://www.dccae.gov.ie/documents/Climate%20Action%20Plan%202019.pdf

renewable generation on the grid. Clear timelines and certainty of delivery on additional interconnection also sends a positive signal to the market regarding future curtailment mitigation which will likely reduce RESS auction prices for support contracts that will be in place for up to 15 years. Interconnection projects often have very long development times of >10 years so consideration should be given now to facilitating increased interconnection post 2030 in view of our long-term decarbonisation goals. This section also provides recommendations for enduring interconnection policy in this regard.

The potential impact of additional interconnection on wind curtailment is illustrated in Figure 9 below which is from the *Managing Curtailment by 2030* study.[13] If we assume that the Celtic and Greenlink interconnectors perform in an ideal way (i.e. use 100% of their capacity to export when curtailment occurs), then as a single measure this will reduce curtailment by approximately a quarter from 44% in the BAU case (circled in red) to approximately 20% (circled in purple) by 2030.

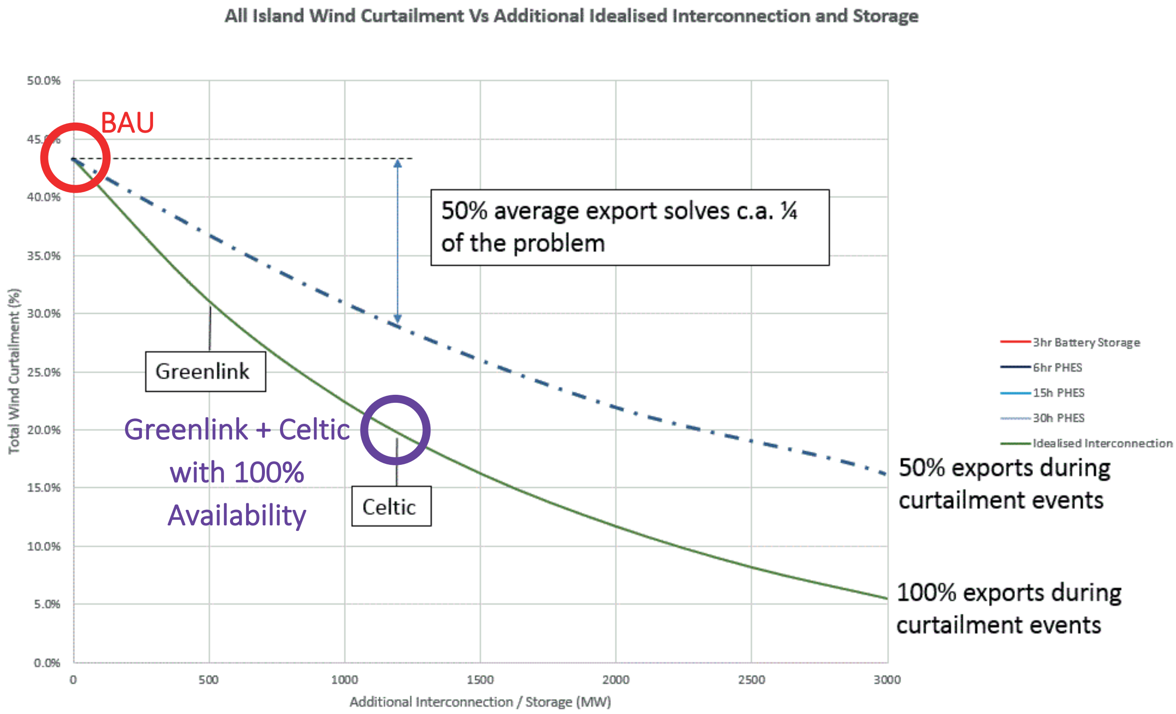


Figure 9: Curtailment vs additional interconnector capacity for varying average IC exports (every point on each line represents a 70% RES-E system, all other system assumptions are as at 2020).

[13]https://www.seai.ie/data-and-insights/seai-research/research-projects/details/identifying-the-relative-and-combined-impact-and-importance-of-a-range-of-curtailment-mitigation-options-on-high-rese-systems-in-2030--2040

### 2.4.2 Implementation

#### 2.4.2.1 Summary of Current Policy

The EU views interconnection as critical infrastructure for integrating European energy markets and supports interconnector projects via the EU Projects of Common Interest (PCI) process.[14] PCIs are key infrastructure projects that link the energy systems of EU countries. To become a PCI, a project must have a significant impact on energy markets and market integration in at least two EU countries, help the EU's energy security by diversifying generation sources and contribute to the EU's climate and energy goals by integrating renewables. PCIs also have the right to apply for funding from the Connecting Europe Facility (CEF). Both Celtic and Greenlink interconnectors have PCI status.

PCIs may benefit from accelerated planning and permit granting, a single national authority for obtaining permits, improved regulatory conditions and lower administrative costs due to streamlined environmental assessment processes.

The PCI process also establishes the role of a Competent Authority (CA) for PCIs in each Member State to coordinate and schedule the permit granting process and put in place a 'one-stop-shop' to streamline the permit granting process. An Bord Pleanála is the designated CA in Ireland and is responsible for facilitating and co-ordinating the permit granting process for PCIs here.

The EU's 2014 European Energy Security Strategy sets a target for each Member State to achieve interconnection of at least 10% of installed electricity production capacity by 2020 and 15% by 2030 and designates PCIs as the main means of delivering this. Ireland's only current operational interconnector is the East-West interconnector (EWIC) and we are currently well below our 2030 target with a level of interconnection at 7.4% of installed capacity in 2017.[15]

Further to this, the EU's "Communication on strengthening Europe's energy networks"[16] published in November 2017 refined the 15% interconnection target to include a target of interconnection capacity of at least 30% of installed renewable generation capacity by 2030.

In July 2018, the Irish Government published a National Policy Statement on Electricity Interconnection[17] to help provide clarity to potential developers on the decision-making process for proposed interconnection projects.

In September 2018, the CRU published its policy on assessment criteria for electricity interconnection applications[18] which sets out a high-level approach for how the CRU will assess interconnector applications going forward. The CRU assesses each application based on criteria

[14] PCI Process: https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest
[15] https://ec.europa.eu/commission/sites/beta-political/files/energy-union-factsheet-ireland_en.pdf
[16] https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf
[17] National Policy Statement on Electricity Interconnection: https://www.dccae.gov.ie/en-ie/energy/publications/Documents/19/National%20Policy%20Statement%20on%20Electricity%20Interconnection.pdf
[18] CRU Policy on Interconnector Applications: https://www.cru.ie/wp-content/uploads/2018/09/CRU18221-Policy-for-Electricity-Interconnectors-Assessment-Criteria-for-Electricity-Interconnection-Applications-Decision-Paper.pdf

such as costs to the consumer, facilitation of integration of renewables and security of supply to determine whether it is in the public interest to proceed.

Interconnectors derive most of their revenues from sales of interconnection capacity to users who wish to move electricity between markets with different prices. These are known as congestion revenues. Interconnector projects can be built under fully or partly regulated mechanisms or can be fully private (merchant) projects.

The majority of interconnector projects develop under either fully or partly regulated models. In the fully regulated model, it is the electricity consumer that pays the investment costs in full via Use of System (UoS) charges and receives all the revenues from sales of interconnection capacity. These projects are usually TSO led, for example, EWIC and Celtic fall under the fully regulated model.

Under the partly regulated model, projects can be developed privately but partly supported by UoS from electricity consumers. For instance, Greenlink is a private enterprise that is developing under the UK regulatory cap and floor regime. Under this regime the relevant Regulatory Authorities set a maximum (cap) and minimum (floor) level to the revenues that can be gained by interconnector developers. Developers will receive a top-up from electricity consumers if interconnector capacity revenues fall below this floor while developers must hand back revenues above the cap, thus ensuring consumers are protected against excess costs. This mechanism allows developers to receive reasonable but not excessive revenues and incentivises private development of interconnector projects.

However, in a merchant model the interconnector is fully reliant on its congestion revenues and bears all the risks of not being able to recover its investment.

#### 2.4.2.2 Shortcomings of Current Policy

Development timelines for new interconnector projects are often very long due to difficulties in aligning processes and different regulatory regimes between jurisdictions (e.g. cost benefit assessments, regulatory regime design, grid connections and planning systems). As a result, projects typically take 10 years or more from first being considered to operational delivery.

Greenlink and Celtic have delivery timelines of 2023 and 2026 respectively. Failure to meet these timelines will have a negative impact on renewable curtailment levels while significant delays will impact the renewable project pipeline and increase the costs of renewable deployment as projects factor this uncertainty into their financial models.

As for potential additional interconnection projects, a clear policy framework is needed as well as signals for further interconnection needs. Most significant interconnectors in Europe develop under the PCI process which can take time to obtain approval. A project must first apply and be approved onto ENTSO-E's European Ten-Year Network Development Plan (TYNDP) schedule before application to the PCI process for selection on the next available list (every two years). Once selected, they can then approach their national energy regulator for the necessary approvals to enable construction.

Whether developing under a regulated or merchant model, the interconnector project is required to demonstrate to the CRU that its development will bring wider socio-economic benefits in order to gain regulatory approval for investment in areas such as the necessary grid reinforcement or UoS charges (where the project is fully or partly underwritten by electricity consumers).

The CRU will assess each application on a case by case basis using criteria set out in its high-level approach paper referenced above. They may then carry out their own cost-benefit analysis and will publish a consultation on each interconnector application they receive.

The overall Irish policy regime around interconnection is not well defined. Projects can be initiated by both private developers (Greenlink by Element Power) and State entities (Celtic by EirGrid). Fully merchant projects are rare due to the large investment costs and development times required coupled with the lack of revenue support guaranteed by either fully TSO-led projects or partly-regulated projects. A clear policy framework with high-level agreements between jurisdictions at an early stage to streamline and coordinate development processes would likely reduce development timelines and uncertainty for both public and private developers.

The TSO should also keep a clear separation of roles, firstly as a developer of interconnector projects and secondly as a transmission system operator. It may be appropriate to keep all the options open in the current regime, but this should be explicitly stated and decided, so that both public and private developers are clear on the regime in which they are operating over the next 15 years.

#### 2.4.2.3 Proposed New Policy

Both Greenlink and Celtic interconnectors have achieved PCI status and are in different stages of development. Both have submitted development applications to the CRU and a cost/benefit analysis has been completed with both projects passing the public interest test.

Greenlink is in the planning phase with a delivery timeline of 2023 while Celtic is in the pre-planning consultation phase with an estimated delivery timeline of 2026.

It is important that both projects are prioritised, resourced and supported in order to meet their delivery timelines. Key stakeholders such as DCCAE, DHPLG, the CRU, EirGrid and the relevant planning authorities such as An Bord Pleanála must support the progression of these projects via the various planning, licensing and grid connection/delivery (both onshore and offshore) frameworks in order to ensure they meet their development milestones.

It is therefore essential that policy improvements set out in *Building Onshore Wind* in relation to planning and grid are implemented in order to facilitate these interconnector projects.

Regarding future projects, Ireland needs to send a formal message to its neighbours that it is "open for interconnection business". Prior to that policymakers should ensure they can clearly set out the policy regime, so that neighbours can assess the merits of additional interconnection:

- EirGrid should indicate the likely advantages and disadvantages of locating interconnectors at various points in Louth, Dublin, Wicklow, Wexford, Waterford and Cork. EirGrid should also comment on the 500 MW or 700 MW sizing choices, and likely future direction of travel on the Largest Loss of Infeed sizing (as this sets the upper limit for future interconnection).
- The connection regime should continue to allow interconnection offers to be processed on a case by case basis, recognising that interconnection is a mix of demand, generation and network reinforcement, and has different needs to standard generator connections.
- The Department of Communications, Climate Action and Environment should commission and publish a study setting out the likely economic scale of interconnection on each of its borders (presumably France and GB).
- The CRU should publish a high-level summary of acceptable regulatory regimes, with as much detail as possible to provide clarity to developers going forward.
- Government and diplomatic services should be scoped to discuss, promote and negotiate the nature of likely future trading relationships with France and GB.
- The foreshore licencing regime is outdated and cumbersome and should be improved (this applies to more than just interconnection and is covered in more detail in the forthcoming *Building Offshore Wind* report which makes up part of our 70by30 implementation plan).

The PCI process is intended to streamline the delivery of projects but the key challenges to delivering Greenlink and Celtic are the potential delays via lengthy planning and grid delivery timelines. It is therefore imperative that decisions on these projects are resourced and prioritised by the relevant stakeholders.

#### 2.4.2.4 Implementing new Policy

Who is the decision maker?

The CRU will develop and oversee the regulatory framework for interconnector applications and revenue mechanisms, including funding for EirGrid to progress interconnector applications and grid reinforcements via PR5.

Who has a supporting role?

- DCCAE will define the strategic direction of future interconnection policy including guidance for other policy makers such as the CRU in its consideration of project applications.
- EirGrid will process the relevant grid connections and reinforcements for Celtic and Greenlink. They will also assess future system needs, including new interconnector opportunities and relevant grid reinforcement needs.
- ESBN will support in the development of the necessary grid infrastructure as TAO.
- Developers will work with EirGrid and the CRU to identify further interconnection opportunities and means of progression.

Budget or resource requirements

Greenlink and Celtic have PCI status so they can avail of EU funding and they are either partly or fully regulated so their investment costs can be underwritten to an extent by electricity consumers.

However, it is important that appropriate EirGrid and ESBN resourcing for their respective functions in the delivery of the Greenlink and Celtic interconnectors is provided for in the PR5 revenue allowance and programme of work.

As for future projects, the work being done currently to progress Celtic and Greenlink will help define many of the decisions and policies in order to produce a set of generic guidance and policy papers for future interconnector development. These suggested policy changes are not resource or capital intensive, rather they require more transparency and direction on interconnection policy and development regimes for new projects.

Target date for achieving policy change

- Q2 2020 – CRU consultation on ESBN/EirGrid PR5 revenue allowance
- Q3 2020 – CRU PR5 decision
- Q2/3 2020 – EirGrid assessment of future system needs and additional interconnector opportunities for 2030 and beyond (with support of developers)

- Q4 2020 – CRU to publish a high-level summary of acceptable regulatory regimes, with as much detail as possible.
- 2023 – Delivery of Greenlink interconnector
- 2026 – Delivery of Celtic interconnector

## 2.5 Curtailment Policy Improvement 3: Interconnector Operation

Aim: Improve the current market design and enhance interconnector operation so that they are able to export approximately 90% of their capacity during curtailment events

### 2.5.1 Introduction and Quantifying the Impact

The previous section outlined the benefit of interconnection, but assumed they operated as intended. However, the existing interconnectors have typically been exporting approximately 50% of their capacity during curtailment events under the current market design and operational framework. Therefore, instead of reducing curtailment to approximately 20% when Greenlink and Celtic are complete, it would only reduce to approximately 30% if they are operated like Ireland and Northern Ireland's interconnectors today (see Figure 9).

As mentioned in the previous section, the *Managing Curtailment in 2030* study illustrates that further significant renewable curtailment reductions would be possible if these interconnectors were able to export 100% of their capacity during curtailment events. However, it is possible that it may not be appropriate or possible to have 100% of interconnector capacity available for exports for a variety of reasons.

The question posed in this document is whether it is possible to achieve better outcomes and close the gap between idealised curtailment mitigation from interconnectors (i.e. 100% capacity availability) and real-world outcomes (i.e. 50% availability at present) through implementation of better market design or operation so that the existing and new interconnectors export approximately 90% of their capacity during curtailment events.

This section proposes two policy recommendations for improving interconnector operation:

1. Implement Single Intraday Coupling (SIDC):
2. Maximise SO countertrading until SIDC is implemented.

### 2.5.2 Implement Single Intraday Coupling (SIDC)

#### 2.5.2.1 Implementation

##### 2.5.2.1.1 Summary of Current Policy

Some of the most important tools for minimising dispatch down are the interconnectors. In perfectly coupled markets, interconnectors should be scheduled to flow efficiently according to price signals. However, the Irish market is not yet fully integrated with European markets and so the interconnectors are at present not operating as efficiently as possible.

IWEA has analysed the performance of the interconnectors since the introduction of I-SEM and noted that often the interconnectors are not performing efficiently during curtailment events due to the current market design. For example, Figure 10 demonstrates that in the period from 01/10/2018 to 19/05/2020, interconnector flow was in the opposite direction to the price signal in the balancing market 34% of the time i.e. the interconnectors were not dispatched efficiently 34% of the time meaning available renewable generation was not utilised and curtailment actually increased, even though they were scheduled to operate correctly in the Day-Ahead Market (DAM).

In SEM, interconnectors are scheduled in the Day-Ahead Market, 24 hours in advance of dispatch and adjusted in the intraday markets IDA-1 and IDA-2. The Day-Ahead Market is coupled with the rest of Europe via the pan-European trading platform (EUPHEMIA) while the IDA-1 and IDA-2 markets are just coupled with Great Britain.

IDA-2, the later IDA auction, closes a maximum of 15 hours ahead of dispatch and runs for the last 12 hours of the day. Due to the unpredictability of wind and electricity system dynamics, interconnectors are often scheduled to flow inefficiently by the time of actual dispatch. This means that, up to 15 hours in advance, the interconnectors can be scheduled to flow in the balancing market in a manner that actually leads to increased curtailment, with less ability to adjust flows closer to real-time.

There is a third intraday market, IDA-3, which opens after the closure of IDA-2, closes a maximum of 9 hours ahead of actual dispatch and runs for the last 6 hours of the day. However, IDA-3 is a local SEM market only meaning that it is not coupled with GB, thus there is no trading across the interconnectors in this market.

There is also an intraday continuous market which is an ex-ante trading market that closes on a rolling basis one hour before the start of the relevant trading period. This allows market participants to adjust their positions as close to real time as possible. However, currently it is a SEM only market, meaning trading does not take place across the interconnectors with other jurisdictions.

There is a pan-European trading platform known as Single Intraday Coupling (SIDC) that links the intraday continuous markets of Member States, thus allowing trading across the interconnectors much closer to real time, but Ireland is not yet a part of this.

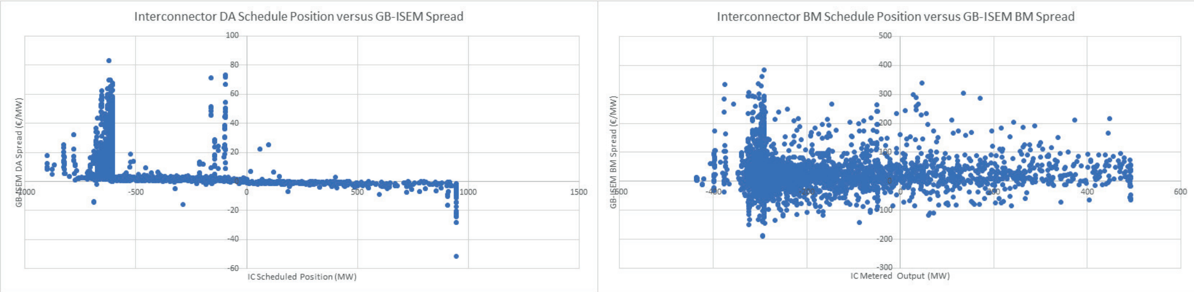


Figure 10: Interconnector flows and GB-ISEM Price spread during curtailment events between 01/10/2018 and 19/05/2020. Day-ahead Market on top and Balancing Market on bottom.

***Graph Explanation:*** *When plotted in the above graph format, an efficient interconnector should see points in the top-left and bottom-right quadrants indicating the interconnector is flowing with the price signal. Points in the top-right and bottom left quadrants signal inefficient interconnector scheduling where flow is against the price signal. We can see from the above graphs that during curtailment events between 01/10/2018 and 19/05/2020, the interconnector was generally flowing with the Day-Ahead Market price signal but by the time of dispatch there was often a price signal for the interconnector to change its operation. This means that the curtailment of wind during these days could have been alleviated by a late adjustment to the interconnector schedule.*

#### 2.5.2.1.2 Shortcomings of Existing Policy

The fact that the continuous intraday market is a SEM market only means that capacity on the interconnectors cannot be used to trade closer to real-time. This limits the flexibility of the interconnectors/market to respond to changes in wind forecasts and help minimise curtailment closer to real-time.

#### 2.5.2.1.3 Proposed New Policy

Implementing SIDC in Ireland would involve the SEM coupling with the EU intraday continuous market and allow pan-European trading based on available interconnector capacity one hour in advance of real-time dispatch. Forecast errors one hour in advance of dispatch are low and so SIDC will vastly improve interconnector efficiency meaning more up to date wind and market conditions can be taken into account in interconnector trading.

SIDC was not implemented at the outset of I-SEM due to resource and time constraints in achieving the market go-live date. An interim solution, the three intraday markets and some coupling with GB, was put in place instead until such a date that SIDC could be implemented. The work required to implement SIDC would require significant resourcing and regulatory support and would span 1-2 years implementation.[19] However, SIDC is mandated by the EU regulation on Capacity Allocation and Congestion Management and SEMO have recently produced a roadmap for its development.[20]

The potential impacts of Brexit are unclear at this stage and how this will affect the coupling of SEM to the European market via current interconnection with GB. Close regulatory alignment between GB and Europe will alleviate this potential issue as well as delivery of the Celtic interconnector which will link the SEM directly to the European market.

#### 2.5.2.1.4 Implementing new Policy

Who is the decision maker?

EirGrid/SONI, via SEMO, will lead the development of SIDC.

Who has a supporting role?

CRU/NIAUR will support the TSOs and market operators in terms of policy design/resourcing for implementing SIDC.

Budget or resource requirements

SEMO will lead the implementation work for SIDC including relevant resource allocation and funding requirements from the Regulatory Authorities. As this is an EU regulation, its implementation should be provided for under the regulatory cost recovery mechanisms. We would encourage the Regulatory Authorities to consider the implementation of this in future SEMO Price Controls.

Target date for achieving policy change

- 2021-2022 Development of SIDC in SEM (as per timelines in the SEMO market development roadmap published in November 2019)
- 2023 – Introduction of SIDC and EU coupled intraday auctions.

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[19] SEMO Roadmap for Market Development - https://www.semopx.com/documents/general-publications/ROADMAP_Nov_2019.pdf
[20] https://www.semopx.com/documents/general-publications/ROADMAP_Nov_2019.pdf

### 2.5.3 Maximise SO countertrading until SIDC is implemented

#### 2.5.3.1 Implementation

##### 2.5.3.1.1 Summary of Current Policy

It is widely accepted that the introduction of SIDC will greatly improve the operation of the interconnectors. However, the prospect of SIDC and a SEM that is closely integrated with European markets is several years away. Brexit places further risks on market.

As a result, IWEA believes an interim solution is required where EirGrid/SONI trade to adjust interconnector schedules before dispatch (i.e. SO countertrading) based on up to date wind forecasting and system information.

In decision 11-062, the SEM Committee decided on a dispatch hierarchy that allowed priority dispatch for renewables while being 'a reasonable balance of the various requirements on the TSOs'. In 11-062 the SEM Committee decided to:

*"Adhere to an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations and where this can be done in a manner that does not threaten the delivery of renewables targets."*

This hierarchy in 11-062 sets out that interconnectors should be re-dispatched after renewables (Figure 11). IWEA interprets this as meaning there is an obligation on TSOs to countertrade on interconnectors closer to the time of dispatch in order to minimise system curtailment.

1. re dispatch price making generation and SO counter trading on the interconnector after Gate Closure;
2. re dispatch price taking generation:
   a. Peat
   b. Hybrid Plant
   c. High Efficiency CHP/Biomass/Hydro
   d. Windfarms, and within windfarms
      i. windfarms which should be controllable but do not comply with this requirement/are not derogated from same;
      ii. windfarms which are controllable;
      iii. windfarms which are not required to be controllable/are derogated from this requirement/those in commissioning phase.
   e. Interconnector re-dispatch;
   f. Generation the dispatch down of which results in a safety issue to people arising from the operation of hydro generation stations in flooding situations

Figure 11: SEMC decision 11-062 dispatch hierarchy.

#### 2.5.3.1.2 Shortcomings of existing policy

Current TSO operational procedures, as set out in the Weekly Operational Constraint Update, is to only SO countertrade to resolve system security issues i.e. not to minimise curtailment. This is re-enforced in the *2018 EirGrid Annual Constraint and Curtailment Report*[21] which notes the following:

*"Post-ISEM (October 2018 onwards), countertrading has not been used by the Control Centres, as it was decided it would be better to allow the new market bed-in without TSO interference. The flows on EWIC and Moyle are driven by price differentials between GB and the all-island system, and the consensus is that the market is getting the flows correct – high wind conditions (with corresponding low market prices in ISEM) generally lead to high exports on the Interconnectors, and vice-versa. In the future, countertrading will only be used to resolve system security issues, and thus is not expected to be used often."*

#### 2.5.3.1.3 Proposed New Policy

To implement this solution, EirGrid/SONI would need to explicitly update operational procedures and policies to use SO countertrading to minimise renewable dispatch down.

We understand anecdotally that this seems to occur but there is no transparency as to when countertrades on the interconnectors are currently requested and subsequently rejected by Britain's National Grid. Providing this information would increase transparency and provide reassurance that this practice is being followed.

Furthermore, TSOs should monitor and report on interconnector performance during curtailment events to allow the market to identify opportunities for improvement. Currently the TSOs are incentivised to reduce their dispatch balancing costs against forecast projections. There is a risk that this may impact the incentives on the TSOs to countertrade to minimise dispatch down, particularly as there may be instances where countertrading may increase dispatch balancing costs. IWEA believes the incentives on the TSOs should be to maximise renewable generation and reduce the emissions from the scheduling and dispatch process, in line with EU and national policies. This should be the objective when seeking to countertrade to minimise dispatch down, until such time as more real-time market solutions such as SIDC come into effect.

It is also possible that the SOs might believe that SIDC will be introduced in a relatively short timeframe and so there is no need to change policies to maximise SO countertrading. This is no longer the case as SIDC implementation is still some years away, as per the November 2019 SEMO market development roadmap.

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

#### 2.5.3.1.4 Implementing new Policy

Who is the decision maker?

EirGrid and SONI.

Who has a supporting role?

CRU and UR.

Budget or resource requirements

This would entail a change to current operational policy and procedure rather than a resource intensive project.

Target date for achieving policy change

Q2 2020

# 3 Policy Improvements (PIs) to Minimise Constraints

## 3.1 Introduction

Ensuring that the electricity network has the capacity to deliver the volumes of renewable electricity needed to deliver our 70by30 goals will be a significant challenge. There is currently a lack of network capacity in areas of the country where large numbers of renewable projects are planning to connect. For instance, many connected renewable generators are already seeing constraint levels over 5%, particularly in the west, north-west and south-west due to network limitations.[22] There is a high risk these constraint levels will reach into double figures, for both existing and future projects, if the grid is not reinforced in time for the future pipeline. For instance, EirGrid's ECP-1 constraint reports project constraint levels of between 11-12% in Galway, 26-28% in Mayo[23] and 12-14% in Donegal[24] by 2022 with increasing levels of renewable generation connecting in these areas. In addition, EirGrid's *Tomorrow's Energy Scenarios 2019 System Needs Assessment* report identified the need for grid development in all scenarios analysed, with the highest need evident in areas such as the east coast where large volumes of offshore wind are planning to connect and in the west, north-west and midlands to accommodate increases in onshore wind.[25]

Considering these reports, the pipeline of renewable projects under development and the recent timelines needed to deliver grid infrastructure, e.g. up to 10-15 years for a new transmission line, it is clear that the current methods of delivering large-scale network reinforcements will need to be improved and mechanisms introduced to ensure the most efficient use of existing grid capacity. If the System Operators take the traditional approach of only beginning to examine grid reinforcement options once a generator project has been consented or a new generation customer has signed a connection offer, this will mean the new generator is likely to be operational for several years before any grid reinforcement materialises.

This is likely to result in high constraints being incurred by both existing and new renewable generators, which will mean significant volumes of renewable energy cannot be used. This will also affect the commercial viability of projects entering the development pipeline, as some projects may not be able to connect to the system until the relevant grid reinforcements are in place, which could take several years. This will lead to higher costs to the consumer as developers will price anticipated constraint levels into their RESS bids, or simply choose not to enter auctions until such time as they can make competitive bids. In *Saving Money*, Everoze estimated that constraints could increase the typical cost of a wind farm by approximately 8%, which would add over a billion euro to the cost of meeting Ireland's 2030 electricity target.

Therefore, it is imperative that EirGrid begins to design and consent grid reinforcement projects at an early stage based on the volumes and locations of the future renewable

[22] http://www.eirgridgroup.com/site-files/library/EirGrid/2019-Qtrly-Wind-Dispatch-Down-Report.pdf
[23] http://www.eirgridgroup.com/site-files/library/EirGrid/ECP-1-Solar-and-Wind-Constraints-Area-B-v1.1-April-2020.pdf
[24] http://www.eirgridgroup.com/site-files/library/EirGrid/ECP-1-Solar-and-Wind-Constraints-Area-A-v1.0.pdf
[25] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-TES-2019-System-Needs-Assessment-Report_Final.pdf

generation pipeline and progress these projects in parallel with renewable project development. ESBN and EirGrid should also develop and introduce measures where possible to ensure the most efficient use of existing grid capacity such as dynamic line ratings, Smart Wires and network solutions such as energy storage and demand side response. The aim here is to minimise constraint levels for existing and new renewable generation, and maximise the number of renewable projects able to connect to the grid without delay by ensuring sufficient grid capacity is in place.

## 3.2 Constraint Policy Improvement 1: Increase Transmission Grid Capacity

Aim: Minimise constraints to the greatest extent possible and, where appropriate and reasonable, provide an indicative solution and timeline so renewable electricity generation can continue to develop with the certainty that constraints will be minimised in future.

### 3.2.1 Introduction and Quantifying the Impact

The *Building Onshore* volume of IWEA's 70by30 Implementation Plan assessed the impact of failing to ensure sufficient grid capacity for new renewable projects connecting to the system. The analysis assumed a business as usual scenario such that, on average, 74% of projects face some degree of transmission system delay before being able to connect (47% of all projects face a 2-year delay, while 27% of projects face a 4-8 year delay). The report then looked at a policy improvement scenario with early transmission reinforcement in parallel with renewable project development such that 70% of projects are able to connect immediately with no transmission system delay and the number of projects facing 2-year delays is reduced from 47% to 20% and those facing 4-8 year delays is reduced from 27% to 10%. This results in a significant improvement in renewable capacity able to deliver by 2030 and contribute to the 70% RES-E target. The analysis estimated that failing to deliver these changes would result in a shortfall of 1,750 MW of onshore wind against the Climate Action Plan target which aims to deliver an additional 4,000 MW of onshore wind.

Offshore wind in Ireland will start at scale on the east coast as this is where the projects are located which are furthest along the development pipeline. EirGrid carried out a provisional assessment of the grid capacity available for offshore wind on the east coast of Ireland, which suggests that there is capacity available, but upgrades will be required to accommodate 800 MW of capacity in various locations.[26] Although not directly stated in the analysis, it would suggest that major upgrades will be required to achieve the 2030 target of 3,500 MW as it is likely substantial work would be required to connect anything more than 1,600 MW of offshore wind. Therefore, we estimate that there could be a significant impact on 1,500-2,000 MW of offshore wind generation, out of the 3,500 MW offshore wind target, in terms of constraint

[26] http://www.eirgridgroup.com/site-files/library/EirGrid/East-Coast-Generation-Opportunity-Assessment.pdf

levels and potential delays if grid capacity is not resolved. This is discussed in more detail in the *Building Offshore Wind* volume of the 70by30 Implementation Plan.

Finally, for both onshore and offshore wind, the *Saving Money* volume of this 70by30 Implementation Plan calculated that constraints could add 8% to the price of wind energy in Ireland. This would add over a billion euro to the cost of wind energy in Ireland so it is more likely that many projects will not materialise rather than progress with this additional cost burden, or the consumer will pick up the additional costs through higher renewable auction prices.

This section proposes two policy recommendations to increase transmission grid capacity:

1. Early transmission development;
2. Maximise existing grid capacity.

### 3.2.2 Early transmission development

#### 3.2.2.1 Implementation

##### 3.2.2.1.1 Summary of Current Policy

Lack of transmission capacity is likely to be the biggest barrier to meeting our 2030 targets. Traditionally, EirGrid has brought forward grid reinforcement projects, via their six-step framework for grid development,[27] once a need to develop the grid has been identified. This has typically been once projects have been consented or have received a connection offer. However, it is not possible to wait for this milestone before progressing with grid development if we are to meet the 2030 renewable electricity target.

A high-level summary of EirGrid's six-step grid development process and timelines is as follows:

- Step 1 – Identifying the future needs of the electricity grid (up to 12 months)
- Step 2 – Assessing the technologies that can meet these needs (up to 6 months)
- Step 3 – Deciding on the best option and location (up to 12 months)
- Step 4 – Deciding exactly where to build the project including detailed route or site (up to 12 months)
- Step 5 – The planning process (up to 18 months)
- Step 6 – Construction and energisation (6 to 36 months depending on the type of project)

The indicative timelines set out above are EirGrid's own, assume a relatively smooth process and can thus be viewed as best case scenarios; however, timelines to reinforce the grid can vary considerably depending on the extent of works required and the potential for legal

[27] EirGrid - Have Your Say - http://www.eirgridgroup.com/__uuid/7d658280-91a2-4dbb-b438-ef005a857761/EirGrid-Have-Your-Say_May-2017.pdf

challenges. New network infrastructure will be required in order to deliver the renewable volumes needed for 2030 and beyond. Historically, the complete development timeline for a new overhead line can be as much as 10-15 years.

#### 3.2.2.1.2 Shortcomings of Current Policy

There is currently a lack of transmission capacity in areas of the country where large numbers of renewable projects are planning to connect. Many connected renewable generators are already seeing constraint levels over 5%, particularly in the west, north-west and south-west due to network limitations. There is a high risk these constraint levels will reach into double figures, for both existing and future projects, if the grid is not reinforced in time for the future pipeline. In the *Saving Money* volume of this Delivery Plan, Everoze estimated that constraints could increase the typical cost of a wind farm by approximately 8%, which would add over a billion euro to the cost of meeting Ireland's 2030 electricity target.

If the system operators wait until renewable projects have been consented, or have received a connection offer, before starting to design and consent grid reinforcement projects, then there will be insufficient network capacity to accommodate the volume of renewables needed for 2030.

As we look at the pipeline of renewable projects under development, and the recent timelines needed to deliver transmission infrastructure, the traditional model of beginning to examine grid reinforcement options once a project has been consented or a new generation customer has signed a connection offer will mean the new generator is likely to be operational for several years before any grid reinforcement materialises. As outlined in EirGrid's six-step grid development process, the first five steps can take approximately 4-5 years, assuming everything goes to plan, which all need to take place before construction even begins.

This is likely to result in high constraints being incurred by new generators, which will affect the commercial viability of projects entering the development pipeline. It will also lead to lower renewable energy levels for Ireland and higher costs to the consumer as developers will price anticipated constraint levels into their RESS bids, or simply choose not to enter auctions until such time as they can make competitive bids. In the *Saving Money* volume of this Delivery Plan, Everoze estimated that constraints could increase the Levelised Cost of Energy (LCoE) of a typical wind farm by approximately €6/MWh, which would add over a billion euro to the cost of meeting Ireland's 2030 electricity target.

Furthermore, the planning permission for the renewable project may expire before the network has developed sufficiently to carry this additional capacity. This would mean the project either must re-enter the planning process or terminate - thus adding further costs to the project development.

### 3.2.2.1.3 Proposed New Policy

Begin Early Transmission Development based on the Future Renewable Generation Pipeline

EirGrid needs to progress grid reinforcements through their grid development process based on the strength and certainty of the future renewables pipeline rather than waiting for projects to obtain planning consent and accept connection offers.

IWEA has carried out a detailed survey of its membership to establish the status of the wind energy projects that they are currently working on (referred to as IWEA's Pipeline Survey), including a county-by-county breakdown of projects at all development stages and estimates of planning submission dates for early stage projects. A high-level summary of the results of this survey for onshore wind are included in Figure 12 and a survey template illustrating the detailed supporting data is included in Appendix 1.


Figure 12: High-level summary of IWEA's onshore wind pipeline survey as of October 2019.

It may be argued that early transmission development could potentially lead to stranded assets and wasted resources where the expected renewable projects do not materialise. However, early progression of network reinforcement projects would not entail speculative development of the grid, rather only the scoping and planning process (i.e. the first five steps of EirGrid's framework) should not wait until renewable generation is through planning or has entered the connection process.

These first five steps are relatively cheap compared to the final step of construction and energisation but they take a large amount of time. IWEA members estimate that obtaining planning permission for a large infrastructure project like a transmission line takes up less than 10% of total project costs but, under the EirGrid process, can take four years to complete. Therefore, the CRU should ensure that the consenting of grid infrastructure is progressed immediately by resourcing the SOs in PR5 so they deliver the necessary infrastructure on time for 2030.

A summary of the offshore wind development pipeline is shown in Figure 13. Altogether there is over 12 GW of offshore wind projects currently in various stages of development.

| Wind Farm | Capacity (MW) | Developer | Foundation |
|---|---|---|---|
| Arklow Banks 2, Wicklow | 520 | SSE Renewables | Fixed |
| Codling Wind Park, Wicklow | 1100 | Fred Olsen, EDF | Fixed |
| Oriel, Louth | 330 | Oriel, Parkwind, ESB | Fixed |
| Codling Wind Park Extension, Wicklow | 1000 | Fred Olsen, EDF | Fixed |
| Dublin Array, Dublin | 600 | Innogy, Saorgus | Fixed |
| Skerd Rocks, Galway | 400 | Fuinneamh Sceirde Teoranta | Fixed |
| Braymore Point, Louth | 800 | SSE Renewables | Fixed |
| Celtic Sea Array, Waterford | 800 | SSE Renewables | Fixed/ Floating |
| Clogherhead, Louth | 500 | ESB, Parkwind | Fixed |
| Cooley Point, Louth | 500 | ESB | Fixed |
| Helvick Head, Waterford | 1000 | Energia | Fixed |
| Kilmichael Point, Wexford | 500 | ESB | Fixed |
| NISA, Louth/Meath | 750 | Statkraft | Fixed |
| Inis Ealga, Cork | 700 | DP Energy | Floating |
| Clare Offshore Wind Farm | 700 | DP Energy | Floating |
| Sligo Offshore Wind Farm | 500 | DP Energy | Floating |
| South Irish Sea | 1000 | Energia | Fixed |
| Block 30 (Off Shore Wind), Clare | 600 | Lightfield Limited | Floating |

Figure 13: List of offshore wind projects currently in development.[28]

EirGrid needs to signal solutions and timelines to address the needs of the grid at an earlier stage (e.g. via publications such as their System Needs Assessment, Transmission Development Plan and Transmission Forecast Statement) to provide more certainty to participants on future grid development which can then be factored in RESS auction bids, leading to lower costs.

It is important that a programme is established for every grid reinforcement once the need has been established. This would be a joint TSO/TAO programme of work. Step 1 of the six-step process is covered off by EirGrid's Tomorrow's Energy Scenarios and System Needs Assessment but once a need has been established, EirGrid should then be incentivised to complete the

[28] https://iwea.com/images/files/final-harnessing-our-potential-report-may-2020.pdf

optioneering phase within a fixed time period. After Step 2 the project should have enough definition to allow a high-level programme to be developed mapping out how long it will take for the project to pass through each of the remaining steps until it is handed over to the TAO. The TSO should be incentivised to meet or better these timelines.

The same process and incentives should be applied to existing projects and ATRs. EirGrid and ESB should set out a 5-year programme at the outset of PR5 with projected progress through each of the six grid development steps. They should then report quarterly on project progress through these six steps, similar to how ATR updates are currently reported. However, more transparency would be required in this reporting than is currently available. Where timelines are missed or projected to be missed, reasons for delays should also be included. This would be a means of tracking progress against expected performance through each of the six steps. At the end of each calendar year it will then be possible to measure EirGrid's performance against the grid reinforcement objectives at the beginning of the year, based on the 5-year programme already set out.

It is important that the programme of work strikes the right balance between being achievable while also being ambitious enough to deliver on national renewable policy aims and it should be consulted on before commencement in January 2021.

Improve EirGrid's Six-Step Framework for Grid Development

EirGrid/ESBN's grid development process can also be streamlined and timelines for individual steps improved as follows:

- EirGrid resources during steps 1 to 5 could be increased. Projects with dedicated project teams progress quicker. Dedicated teams would be particularly beneficial to drive projects through steps 3, 4 and 5 to carry out public engagement and get projects to and through planning more rapidly.
- As it is EirGrid's role as TSO to design, develop and operate the transmission network, but ESBN's role as TAO to maintain and construct network assets, there is an Infrastructure Agreement between the two companies that sets out the rules and operating procedures regarding the delivery of transmission projects. This ESBN/EirGrid Infrastructure Agreement process adds additional layers and timelines to project delivery and could be streamlined. IWEA propose that ESBN, EirGrid and industry conduct a joint review of the Agreement processes to determine where and how it could be simplified and streamlined to improve project delivery timelines.

Create a New Grid Development Strategy

EirGrid's corporate strategy for 2020-25 contains goals to connect 10,000 MW of new renewable generation and operate a system with 95% SNSP, however there is little detail on how the grid will be developed to deliver these targets.

Therefore, there is a need for a new EirGrid strategy and plan specifically for grid development (based on IWEA's pipeline survey analysis and the Climate Action Plan targets). This would be particularly relevant for areas such as the north-west, south-west, west, midlands and east coast where large amounts of new renewable generation are expected to connect.

### Third-Party Network Build

There is an opportunity to work with industry to see where third-party network solutions may be appropriate. There are several recent examples of third-party investment in transmission infrastructure development through new regulatory models in a number of countries, such as the Regulatory Investment Test for Transmission (RIT-T) process in Australia.[29] In these models, if third-party developers can provide the same level of reinforcement outcome for the transmissions system, but at a cheaper cost to the consumer than the transmission system operator is proposing, then the regulatory authority allows the third party to develop the solutions. Similar processes are being trialled in the UK and the US.

### Establish a Grid Capacity Advisory Council

IWEA propose that the CRU/SOs establish a Grid Capacity Advisory Council (similar to the DS3 Advisory Council) as a mechanism for the SOs, Regulators, industry and other stakeholders, including planning authorities and relevant Government Departments, to engage and work collaboratively on these matters.

### Support for New Grid Infrastructure

Getting public and planning authority support, as well as local community buy-in, for new grid infrastructure will also be essential. EirGrid and ESBN should engage with IWEA and other industry associations on the rationale and messaging for grid consenting and the need for pro-active transmission development with planning authorities. EirGrid and ESBN should also work with industry on community engagement/mechanisms to promote the need for, and benefits of grid development, and how these are linked to renewable energy policies and climate action.

The net impact of these policy measures will ensure that sufficient grid capacity is available for projects in the development pipeline such that, after having secured a route to market, 70% of projects will be able to connect without delay while the remainder will only suffer minimal delays. This significantly increases the number projects able to energise before 2030 and also reduces the uncertainty and cost of renewable development.

[29] Australian Energy Regulator - RIT-T Overview - https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-transmission-rit-t-and-application-guidelines-2010

#### 3.2.2.1.4 Implementing new Policy

Who is the decision maker?

- EirGrid, as TSO, will design and consent the appropriate network reinforcement.

Who has a supporting role?

- ESBN, as TAO, will carry out the necessary construction and energisation works.
- CRU, as the Regulatory Authority, will determine the allowed spend on network reinforcement projects.
- An Bord Pleanála and other relevant local planning authorities are the planning consent decision makers for the relevant new grid infrastructure.
- Industry can work with the SOs to provide information on the future renewable pipeline, potential third-party network solutions, where these may be appropriate, and messaging/rationale for new grid development.

What budget or resource implications there may be?

The SOs will need adequate resources, in terms of the development and operating spend required for the design and consenting of grid reinforcement solutions and the capital spend required for new network build to deliver the required grid reinforcements. If these resources are not provided for in the upcoming PR5 period, then the SOs will not be able to deliver the necessary grid infrastructure. It is therefore important that the CRU supports the approach of developing grid reinforcements based on the strength of the renewable pipeline in their PR5 decision.

Baringa's 70by30 report assumed that approximately €2.1 billion of additional investment is required in the electricity network to achieve a 70% RES-E penetration on the island of Ireland (Baringa estimated that these costs would be recovered through TUoS over a 40-year period).[30]

Figure 14 below shows Baringa's estimate of the total costs and benefits in a 70by30 scenario. For example, this included benefits such as wholesale energy market savings compared against costs such as network development and DS3 System Service requirements. Their analysis indicated that a reduction in LCoEs to an average of €60/MWh for onshore wind, €70/MWh for offshore wind and €80/MWh for solar would result in delivering a 70% RES-E scenario at no additional cost to consumers (from a 40% RES-E baseline in 2020).

We are seeing that onshore and offshore wind are delivering well below these strike prices in other countries. For example, the LCoE for onshore wind in the Nordics is now as low as €30/MWh[31] and the recent Contracts for Difference (CfD) auctions in the UK resulted in

[30] https://www.iwea.com/images/files/70by30-report-final.pdf
[31] https://www.iwea.com/images/Article_files/10._14.30_Cathrine_Torvestad.pdf

offshore wind projects clearing as low as £39.65/MWh.[32] Analysis carried out by Everoze has estimated that this is also possible in Ireland, provided the right policy measures are in place which is the focus of the *Saving Money* volume of the 70by30 Implementation Plan.

The Baringa analysis has shown that onshore wind at strike prices of €60/MWh and offshore at €70/MWh is a no regrets option, i.e. there is no net cost to the consumer for achieving 70by30.

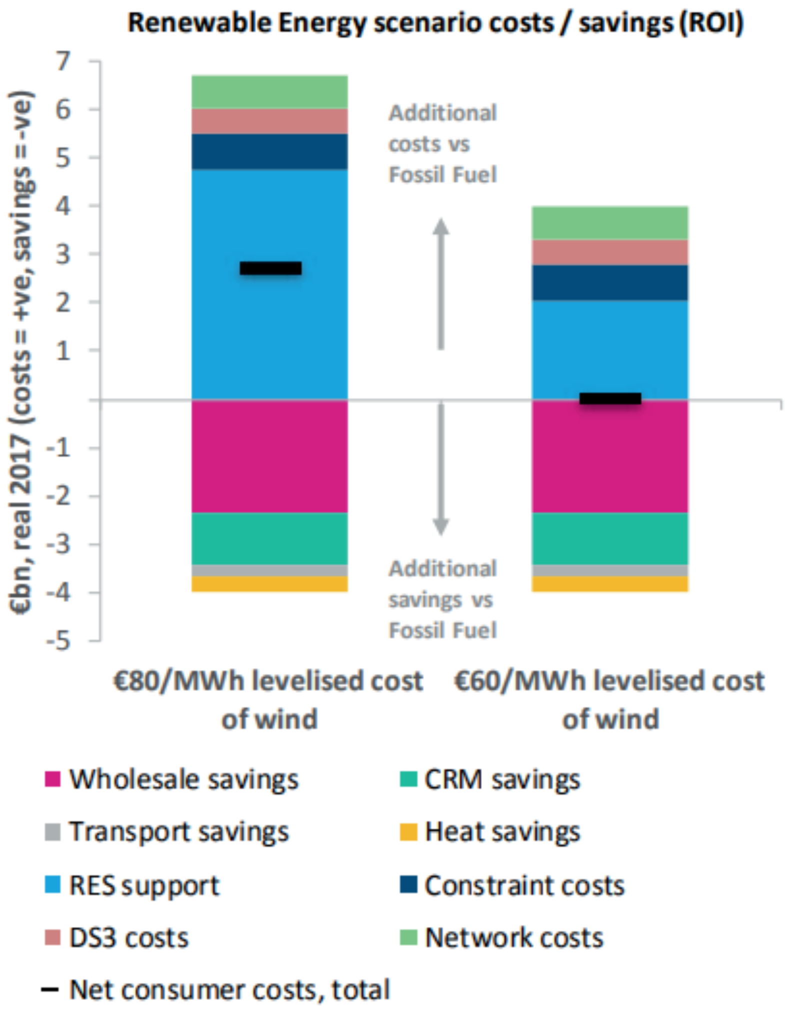


Figure 14: Baringa 70by30 summary of total 70 per cent RES-E costs and benefits.

IWEA has also commissioned Pöyry Management Consulting, (now AFRY), to analyse the net consumer value of Contracts for Difference (CfD) at various potential strike prices in the upcoming RESS auctions.

[32] https://www.gov.uk/government/news/clean-energy-to-power-over-seven-million-homes-by-2025-at-record-low-prices

Their analysis suggests that if CfD strike prices come in at €60/MWh over the fifteen-year period from 2025 to 2040, consumers in both Northern Ireland (NI) and the Republic of Ireland (ROI) could benefit by around €2.6 billion. Under this assumption, the cost of providing stability to CfD-supported generators would be around €3.2 billion. However, reduced wholesale market electricity prices due to the downward price pressure of zero-marginal cost renewable generation would more than offset this stabilisation cost, benefitting consumers by around €5.8 billion, resulting in the €2.6 billion net benefit to the consumer as demonstrated in Figure 15 below.

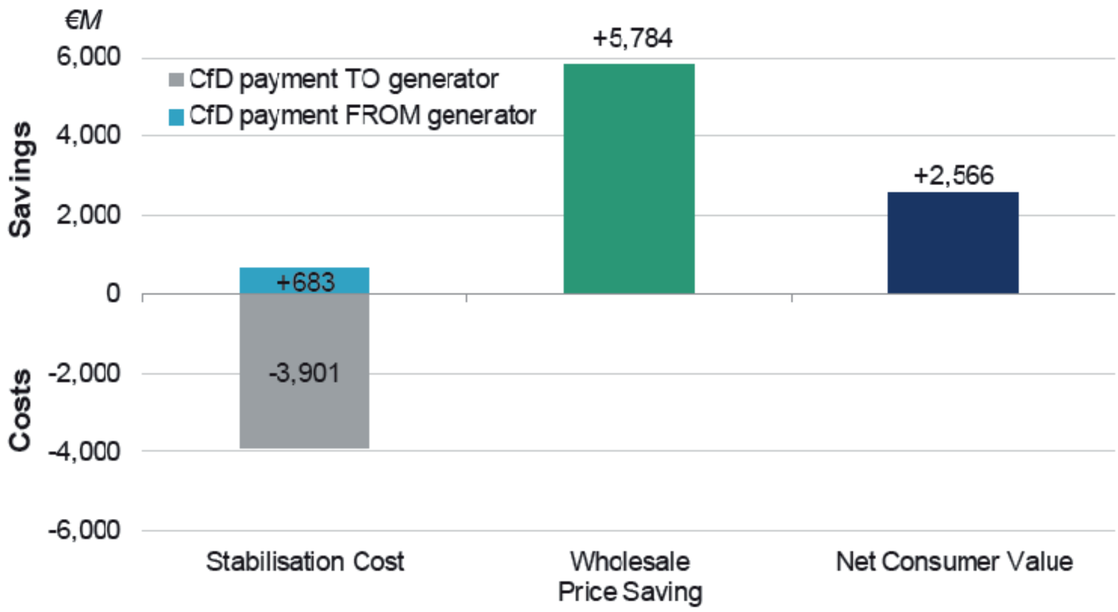


Figure 15: Net Consumer Value estimate assuming a CfD strike price of €60/MWh (€M, real 2017 money).

AFRY has also analysed the net consumer value at strike prices from €50/MWh up to €65/MWh, as shown in Figure 16 below.

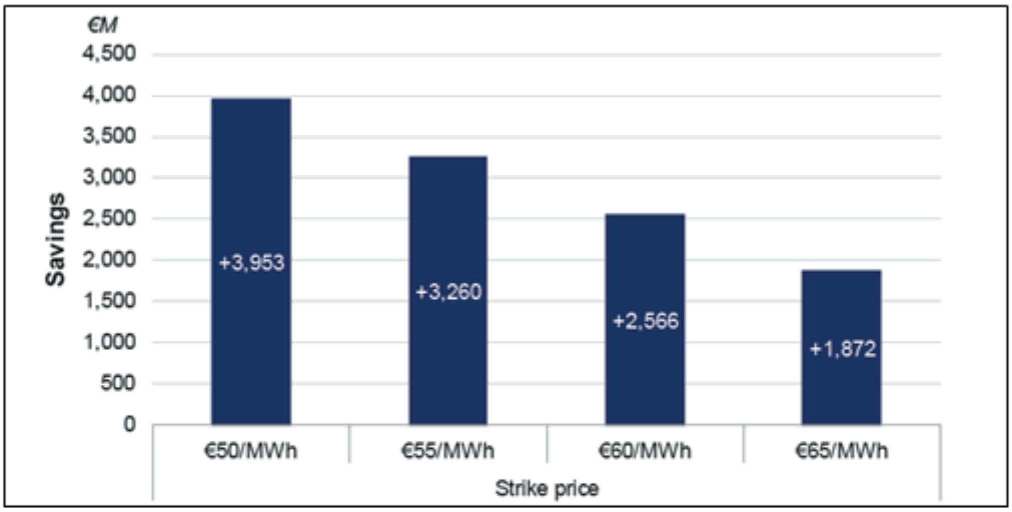


Figure 16: Net consumer value at various CfD strike prices (€m, real 2017 money).

The AFRY analysis highlights the significant consumer benefits that can be gained from policy measures that help reduce the levelised costs of renewable energy. The analysis has not included any potential costs related to grid reinforcement or other system costs that may be required to operate a system capable of handling renewables penetration of 70%.

The figures provided by AFRY can be viewed as a 'budget' for delivering the power system needed to achieve our RES-E ambitions. In order to unlock these wholesale price saving benefits, spend will be required in areas such as grid development and System Services.

The results from the AFRY analysis were published in October 2019 in a full report titled *Cheaper and Greener*.[33]

<u>Target Date for Achieving Policy Change</u>

- Q4 2019 – EirGrid/ESBN to begin scoping of grid reinforcements/network solutions based on renewable pipeline and Tomorrow's Energy Scenarios System Needs Assessment
- Q4 2019 – SOs' PR5 submission to the CRU
- Q2 2020 – Consultation on PR5
- Q3 2020 – EirGrid/ESBN to develop and publish new grid development strategy
- Q3 2020 – Establish an all-island grid capacity forum
- Q3 2020 – CRU PR5 decision
- Q4 2020 – Consult on grid development programme of work for PR5
- Q1 2021 – Initiate PR5 grid development programme of work

[33] https://www.iwea.com/images/files/iwea-cheaper-and-greener-final-report.pdf

### 3.2.3 Maximise Existing Grid Capacity

#### 3.2.3.1 Implementation

##### 3.2.3.1.1 Summary of Current Policy

After assessing and identifying the future needs of the grid in step 1 of the six-step grid development process, in steps 2 & 3 EirGrid will analyse a range of technical options which might be appropriate to meet those needs. Broadly speaking, these options can be divided into two categories:

1. Develop new grid infrastructure such as a substation or overhead line;
2. Use alternative network solutions and new technologies to enhance the capacity of the existing grid.

The previous section highlighted the need to develop new grid infrastructure at an early stage to meet the needs of the future renewable pipeline. This section will look at alternative solutions that, in certain cases, can help reduce or replace the need for new overhead lines or other capital-intensive grid infrastructure. These solutions can sometimes be a quicker and cheaper means of unlocking additional grid capacity and making the most efficient use of the existing grid.

EirGrid's 2015 discussion paper on Ireland's grid development strategy *Your Grid, Your Views, Your Tomorrow*[34] sets out a range of technologies, which are available or ready for trial use, that could provide an alternative to new grid infrastructure development.

**Existing Technologies**

<u>High-Temperature Low-Sag (HTLS) overhead line conductors</u>

This technology allows lines to operate at higher temperatures with lower sag characteristics while maintaining security standards. These have been used by EirGrid and ESBN since 2011 and EirGrid noted in the 2015 discussion paper that they have achieved a 60% increase in capacity on over 500km of existing lines.

<u>Series Compensation</u>

This technology is used to boost electricity flows on very long transmission lines and has been more traditionally used in parts of the world with transmission systems spread over large geographical areas. However, EirGrid noted in 2015 that recent advances in technologies and control systems may allow smaller systems to benefit.

<u>Dynamic Line Ratings</u>

The capacity of an overhead line is influenced by conditions such as temperature, wind speed, wind direction and other factors. Dynamic line rating involves the installation of devices to monitor these conditions and allow higher power flows when conditions permit. This can be

[34] http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Draft-Grid-Development-Strategy.pdf

used in the short-term to reduce potential network bottlenecks while awaiting delivery of grid development projects. Prior to 2015, EirGrid trialled this on several lines and noted that they will continue to evaluate its use in other cases.

Reactive Power Management Devices

Technologies such as STATCOMS (Static Synchronous Compensator) can be introduced in areas to help provide voltage support to the network. These devices can help to manage the greater volatility in system voltage from high levels of renewables in weaker parts of the network.

### New Technologies ready for trial use (as per EirGrid's 2015 discussion paper)

Power Line Guardian

This is a type of power management technology that can be rapidly deployed onto existing overhead lines and allows power flows to be diverted from heavily loaded overhead lines or cables to more lightly loaded ones. This allows the existing grid to be used more effectively.

Voltage Uprating

It is possible to increase the capacity of an existing line by increasing its operating voltage. While doing this generally requires significant modifications or a new substation or overhead line, EirGrid noted they are actively supporting research and development efforts into new voltage uprating technologies that would involve less structural modifications. This makes the uprating quicker to complete and lowers costs.

New HTLS Conductors

EirGrid noted that new HTLS conductors that could potentially double line capacity are undergoing field trials and if they do become available their application is likely to be restricted to voltage levels greater than 110kV.

New overhead line structures / new tower designs

There is also the potential to incorporate new designs, structures and materials (e.g. composite polls) to existing assets that could increase their capacity. EirGrid noted they were actively considering these in their 2015 paper.

#### 3.2.3.1.2 Shortcomings of Current Policy

Once technologies have been trialled and have been approved as ready for use, they then move into a 'toolbox' of potential solutions available to EirGrid and ESBN when assessing options to meet the needs of the system.

However, it does not appear that the technologies available to EirGrid are being utilised to their full potential and there is little transparency on the options being assessed for many projects in the early grid development process. It is also not clear what the timelines are for technologies moving from a trialling phase to a ready for use stage and it appears that some trial projects have not progressed or have seen delays without explanation.

#### 3.2.3.1.3 Proposed New Policy

There is the potential for existing and new alternative technologies to substantially improve the capacity and efficiency of the existing grid and this can often complement or reduce the need for new grid reinforcements.

EirGrid and ESBN should look to implement these alternative solutions where possible and where these may provide a more efficient and effective option to help deliver our RES-E targets and minimise dispatch down.

Under PR5, the System Operators should look to set out a programme of work with timelines to trial and bring successful technologies to a ready for use phase. More transparency is also required on the early stages of the grid development process, particularly options being assessed under steps 2 & 3 and IWEA has suggested quarterly reporting and the establishment of a Grid Capacity Advisory Council to help manage and engage on this.

EirGrid/ESBN need to investigate alternative third-party network solutions (e.g. Smart Wires, energy storage, demand side response, congestion products) where this may prove a cheaper and more efficient option than could be put forward by the System Operator. This would also involve locational signalling via transparent network information and long-term commercial frameworks to incentivise these third-party solutions where relevant. National Grid in Great Britain have implemented such third-party solutions for constrained locations on the grid.[35]

[35] https://www.nationalgrideso.com/transmission-constraint-management

#### 3.2.3.1.4 Implementing new Policy

Who is the decision maker?

- EirGrid, as TSO, will assess the various network solutions and progress these via the six-step grid development process

Who has a supporting role?

- ESBN, as TAO, will carry out the necessary construction and energisation works.
- CRU, as the Regulatory Authority, will determine the allowed spend on network projects.
- An Bord Pleanála and other relevant local planning authorities are the planning consent decision makers for the relevant new grid infrastructure.
- Industry can work with the SOs to provide information on the future renewable pipeline, potential third-party network solutions, where these may be appropriate, and messaging/rationale for new grid development.

What budget or resource implications there may be?

The potential budget and spend available to the System Operators for grid development has been set out previously in section 3.2.2.1.4.

Target Date for Achieving Policy Change

- Q4 2019 – EirGrid/ESBN to begin scoping of grid reinforcements/network solutions based on renewable pipeline and Tomorrow's Energy Scenarios System Needs Assessment
- Q4 2019 – SOs' PR5 submission to the CRU
- Q2 2020 – Consultation on PR5
- Q3 2020 – EirGrid/ESBN to develop and publish new grid development strategy
- Q3 2020 – Establish an all-island Grid Capacity Advisory Council
- Q3 2020 – CRU PR5 decision
- Q4 2020 – Consult on grid development programme of work for PR5
- Q1 2021 – Initiate PR5 grid development programme of work

# 4 Major Long-Term Changes to Consider

Ireland is a world leader at integrating variable renewable electricity onto a power system as recognised by the International Energy Agency (see Figure 17).

In order to deliver on our longer term decarbonisation ambitions we will have to innovate in ways no other power system has before, which means step changes like those proposed in chapters 2 and 3 are unlikely to be sufficient in the long term.

Major changes take a lot of time, so it is important that the steps we take over the next decade do not simply resolve the issues of 2030, but bring us along a path which is in line with where we want to be in 2040 and 2050. Some examples are presented here of the major changes that Ireland will need to consider to achieve our future decarbonisation targets, particularly in the context of maximising the vast wind energy resource available in our country.

Examples of areas requiring major change are:

1. Market redesign
2. Dispatch down certainty
3. Grid 2050

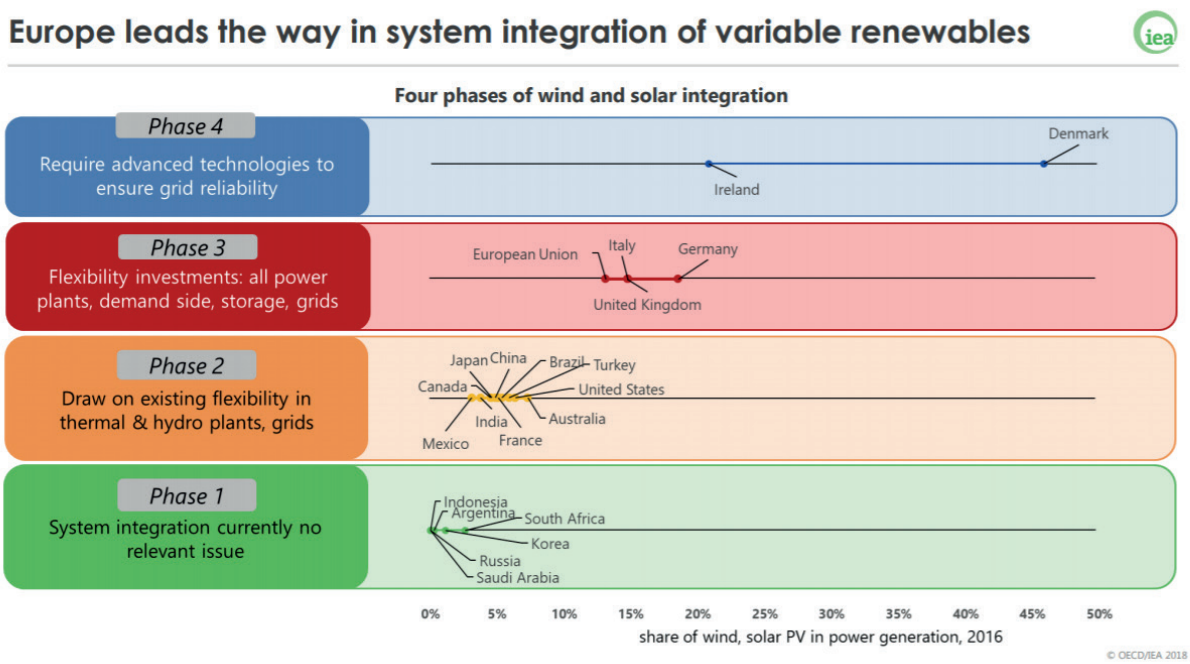


Figure 17: World leaders in system integration of variable renewables according to the International Energy Agency (IEA).[36]

## 4.1 Market Redesign

In Ireland's existing electricity market, the Single Electricity Market (SEM), there are three primary types of markets: capacity, energy and system services (via DS3). At present the energy

[36] https://www.iea.org/media/presentations/180925_Wind_Europe.pdf

market is the largest in terms of value for participants followed by the capacity market and then the system services market. The energy market was designed around the short-term marginal cost of production since it was originally conceived with fossil-fuelled power plants in mind, where marginal costs (i.e. the price of fuel) were typically the most significant expense driven by coal, gas and oil prices. This means that the price of commodities such as coal and gas have typically determined the price of electricity in Ireland and the Irish market is therefore exposed to volatility in the international prices for these commodities. These fossil fuel plants typically have lower capital costs relative to their marginal or operating costs, so they rely on the energy market for most of their revenue to cover costs.

However, wind energy is different in that it has relatively high capital costs but has no marginal costs (as there is no fuel or carbon cost) so when wind energy participates in the electricity market it effectively enters with a bid of zero, thus driving down the price of electricity on the market as it displaces more expensive forms of fossil fuel generation via the merit order effect.

For example, in 2018, the wholesale price of electricity was approximately 20% less due to wind energy being present.[37] So what happens when Ireland's power system can facilitate 95% wind energy at a single point in time (as will be required for 70by30 – see section 2.3)? A market design based on the marginal cost of the generators participating in it is not fit for purpose in a world where 95% of the electricity is being produced by zero-marginal cost renewable electricity. It is likely to lead to a lot of negative pricing in the market and volatile price swings, which is unlikely to provide the revenue certainty required for investments to continue in either renewable or thermal generators.

So, if the current electricity market is not fit for purpose, then what is? At present, there is no clear market design in place for a power system with more than 50% variable renewable electricity, so if Ireland wants to achieve 70by30, it will need to play a leading role in designing and implementing the market of the future to support this.

Fossil fuel power plants will be pushed out of the energy market as renewable electricity grows to 70% of electricity supply and they are also likely to be pushed out of the system services market, as zero-carbon solutions evolve.[38] However, they will still be important for back-up power when the wind and solar generators are not available, so it is likely that the capacity market will need to provide sufficient revenue to maintain enough generation capacity on the power system for the times when wind and solar are not available. Technologies such as demand side response, energy storage, interconnectors and even renewable generators can contribute to generation capacity requirements and reduce our reliance on fossil fuel plants for this purpose.

Renewable electricity will provide the majority of the energy in the market (i.e. 70%), but unlike today's market in Ireland where electricity prices for participants are set one day in advance, renewable electricity typically requires price certainty for 10-15 years in advance to be financeable due to its relatively high up front capital costs. So how can our energy market

[37] https://www.iwea.com/images/files/baringa-wind-for-a-euro-report-january-2019.pdf
[38] https://www.iwea.com/images/files/iwea-baringastorerespondsavereport.pdf

evolve to provide the price certainty required to stimulate more investment in renewable electricity? At present there is a clear market failure as although the power system wants more renewable electricity, the current market design is not incentivising this and the government has to provide an alternative route to market via REFIT and RESS (backed by the PSO) to create investments in renewable electricity. In the future, could there be 10-15-year contracts in the Irish energy market so the Government no longer has to intervene? Corporate PPAs, carbon price floors and renewable electricity obligations on suppliers could all be ways to stimulate a market for 10-15-year contracts in the energy market.

Finally, system services via DS3 is a relatively new part of the Irish electricity market as, in the past, the cost of system services were effectively included in the energy price of power plants. As variable renewable electricity grows and less energy is supplied by power plants, the system services market will need to grow to support the solutions outlined in Figure 6 earlier.

In summary, the electricity sector will change rapidly over the next decade and so the electricity market needs to keep pace with these changes. The energy market is moving from one based predominantly on fossil fuel plants and recovering short-term marginal costs to one based on renewable electricity with little to no short-term marginal costs but with a need for longer-term price supports. Capacity markets will also become critical to ensure sufficient generation capacity is available as a backup for low wind/low solar days and new system services and technologies need to be incentivised to support a system with high levels of variable renewable electricity. At present, there is a clear consensus that change is coming, but very little consensus on what the market design of 2030 looks like in order to send the correct signals for the investments that are required to achieve 70by30.

**Recommendation: The market operator, SEMO, via EirGrid and the CRU, should put in place a dedicated team to solely focus on what the electricity market design should be in 2030 to facilitate a 70by30 power system. Ireland should also seek to engage and lead at a European level in the design of future markets appropriate for very high RES-E levels.**

## 4.2 Dispatch down certainty

Dispatch down via curtailment and constraints is growing as documented earlier in Figure 2 and likely to continue to grow over the next decade without major interventions, which have been discussed in detail in sections 2 and 3. One common theme across all of the solutions presented so far is that they require a 'system-wide approach' to be resolved.

Building infrastructure such as new power lines and interconnectors or incentivising flexibility such as batteries, synchronous condensers and demand side management will require the 'system' to send the right investment signals. The individual wind farms which are creating the variable renewable electricity will typically not be able to incentivise the solutions that are required to resolve dispatch down. A wind farm cannot build a new transmission line or put the revenue stream in place to reward demand side management. However, at present, it is wind farms which pay for the price of dispatch down. This is a market failure as those best placed to resolve dispatch down are not paying the price for the problem and as a result, are not incentivised to resolve it.

The current context for wind farms in the development pipeline that are looking to secure a route to market via RESS or CPPAs is significantly different to those that developed under the previous REFIT framework.

For REFIT projects, forecasts of constraint and curtailment levels were a lot more manageable and less volatile. In the context of a 40% RES-E target for 2020, the DS3 programme set out how to deliver the system level changes required to integrate this level of renewables and manage curtailment levels. There was also a lot more constraint certainty with firm grid access policy and Associated Transmission Reinforcement (ATR) timelines identified with a project's connection agreement. As a result, the modelled constraint and curtailment levels for most projects remained within relatively narrow bands, considering a plausible range of assumptions. In any event, the REFIT tariff price was set by the Government and not wind farm developers so the constraint and curtailment risk was with the developers, who had to absorb any cost within the available REFIT tariffs, and not with consumers.

However, the current context is very different as going forward it is wind farm developers that will be determining the price of renewable development via their RESS auction bids and CPPA prices. There is now a much higher RES-E target of 70% (with significant upward pressure on this target anticipated within the lifetime of a typical project and major system changes required to deliver this target) and a non-firm connection policy (with no ATRs or timelines for firmness). As such there is a lot less certainty on future constraint and curtailment levels. Wind farms in the development pipeline which are looking to secure a route to market via RESS or CPPA have to take a 25-30 year view of future constraint and curtailment levels to factor into their financial models and come up with a price under which they can build.

Future constraint and curtailment levels are extremely difficult to project, and wind farms must factor in a certain amount of additional risk in their calculations to account for volatility. As has been highlighted in sections 2 and 3, curtailment levels could increase significantly if certain measures are not implemented and constraint levels in many parts of the country are forecast to rise considerably, to varying degrees under different scenarios, as more renewables connect to the system. This leads to considerable uncertainties that developers need to consider when trying to make provisions for future constraint and curtailment and modelling results are likely to be over a much wider risk band when a plausible range of input assumptions are considered.

In the Terms and Conditions for RESS 1, renewable generators are expected to include the cost of curtailment into their bid prices, with a safeguard in place to provide some support should curtailment exceed 10% for two consecutive years.[39] There is no similar measure for projects entering CPPAs and this does not account for dispatch down as a result of constraints or energy balancing. Renewable generators will therefore be charging consumers for a cost, via their auction bids, which they are very poorly placed to find solutions for. These costs will then be locked in for up to 15 years under the term of the RESS support. It is highly unlikely that the

[39]https://www.dccae.gov.ie/documents/RESS_1_Terms_and_Conditions.pdf

cost factored into a wind farm's bid to take account of this uncertainty will reflect the true cost of constraint and curtailment. In the future, consumers will be paying for this either directly (through some form of constraint/ curtailment compensation) or indirectly (where onshore and offshore developers incorporate their assumptions into auction bids).

Commercially efficient contracts allocate risk to the parties best placed to manage them. Developers have almost no ability to manage these risks post RESS auction bid or CPPA contract initiation, whereas those who are ideally placed to reduce and even remove dispatch down are the CRU, EirGrid and ESBN by either adjusting the electricity market rules to incentivise solutions or by building the solutions directly. Therefore, the CRU should place the cost of dispatch down on EirGrid and ESBN which would incentivise the solutions required to minimise it. For example, dispatch down cost renewable generators approximately €50 million in 2019, so if EirGrid/ESBN had to compensate generators for this, then they could justify investments in solutions to prevent this from happening in the future. They could construct a new power line, upgrade a line, or incentivise the development of a battery in the ideal location - all of which could be justified on the basis that it would reduce the cost of compensating dispatch down in future years. Without this incentive, renewable generators will continue to bear the cost of dispatch down without being able to resolve it, while those who are ideally placed to resolve it (EirGrid/ESBN) will not be incentivised to prevent it from occurring.

It is important to acknowledge that generators should not be incentivised to build renewable capacity where it is not required or where costs to the consumer from dispatch down compensation would be excessive (e.g. a non-firm generator in a highly constrained area of the country). It is important that strong locational signals are sent to generators but these should only be at a point in a project lifecycle where they can respond to such signals i.e. when they choose a location or choose to invest/construct. After this, it is only ESBN, EirGrid and the CRU that can manage dispatch down costs. It is important that mechanisms are developed that take account of appropriate locational signals for renewable generators while incentivising the delivery of firm capacity by EirGrid and ESBN.

**Recommendation: Certainty on future dispatch down levels will be needed over the coming years in order to deliver new renewable generation at the best possible price to the consumer. In the short term, this could be implemented through the CRU's implementation of Article 12 and 13 of the Electricity Regulation in the Clean Energy Package, which relate to the removal of priority dispatch and compensation for dispatch down. As per the Articles, the CRU should implement dispatch down compensation for variable renewable generators, which could be paid for through Imperfections Costs. This places the management of the curtailment and constraint levels in the hands of the System Operators, who can then justify investments in solutions such as grid development or programmes such as DS3+ to reduce these compensation levels and minimise dispatch down. The compensation mechanism will need to ensure that generators are also not incentivised to build capacity in unwanted locations or lead to excessive costs for consumers.**

**In the longer term, the CRU should establish a roadmap that will explain how dispatch down will be managed over the next decade in order to give certainty to renewable developers, who**

**can then deliver renewable energy at the lower cost to the consumer. At present without dispatch down compensation or certainty on dispatch down levels in the future, it is very likely that the renewable generation required to achieve 2030 targets will not be delivered at the lowest possible cost to the consumer.**

## 4.3 Grid 2050

To date, curtailment and constraints have been the key challenges in Ireland while integrating variable renewable electricity, as outlined in Figure 2. However, there is a third type of dispatch down which was presented in Figure 1 that is likely to become another major challenge in the coming decade – Energy Balancing.

Achieving 70% RES-E will necessitate installing higher volumes of renewable generation than can be met by demand/exports at any one time. For instance, Ireland's Climate Action Plan has set out targets of 8.2 GW of onshore and 3.5 GW of offshore wind in order to reach 70by30. These volumes will be in excess of all-island peak demand which is projected to reach between 6-7 GW by 2030, with potential interconnector exports of approximately 2 GW on top of this.[40] This means that, on high wind days, excess renewable generation would have to be dispatched down for 'energy balancing' reasons i.e. where generation exceeds demand, unless mechanisms are found such as creating new forms of demand for wind energy, incentivising flexible demand that can respond to variations in renewable generation, developing additional interconnection or developing long-term storage to avoid this excess renewable power being wasted.

### 4.3.1 Creating new forms of demand for wind energy

There are a number of opportunities in a low-carbon energy system to use this excess wind energy particularly in the heat and transport sectors. To date, increasing renewable energy in heat and transport has been very slow and Ireland is very unlikely to meet its 2020 targets in these areas.[41] In contrast renewable electricity has been a huge success, not only in Ireland but globally, which has led to a general consensus that this clean electricity should be used in future to supply clean heat and transport also, primarily via heat pumps, electric cars and hydrogen (a form of electrofuel). As outlined in Figure 18, this this will create a new type of demand for wind energy in Ireland by connecting it to the heat and transport sectors, which will completely transform how the power system operates.

[40] EirGrid Generation Capacity Statement 2019-2028: http://www.eirgridgroup.com/site-files/library/EirGrid/EirGrid-Group-All-Island-Generation-Capacity-Statement-2019-2028.pdf

[41] SEAI - Renewable Energy in Ireland report - April 2020 - https://www.seai.ie/publications/2020-Renewable-Energy-in-Ireland-Report.pdf

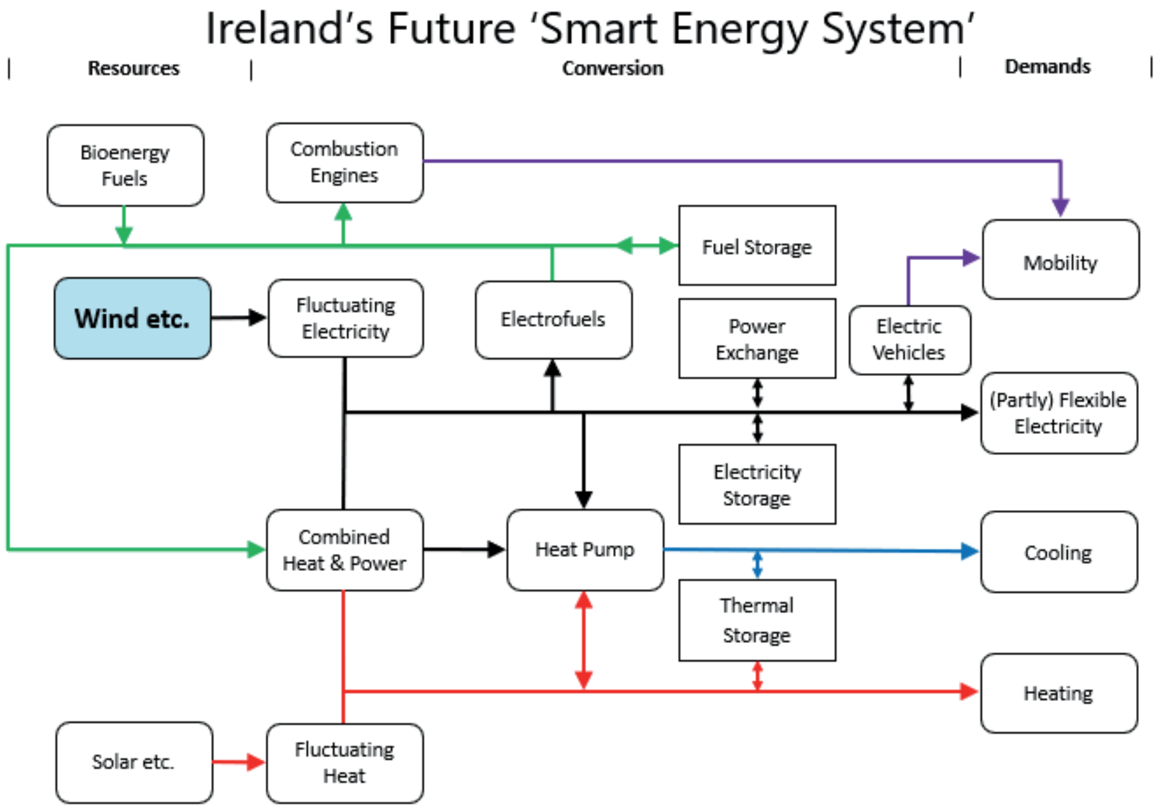


Figure 18: Smart Energy System.[42]

Today, the primary energy supply for electricity, heat and transport is approximately 60 TWh per year each (~5 Mtoe).[43] Therefore, when electricity is expected to supply a large proportion of heat and transport, it will be a very large increase in the electricity demand compared to today, thus offering a significant opportunity to solve two key issues: 1) supply renewable energy to heat and transport and 2) create extra demand to reduce dispatch down from Energy Balancing. In addition, the demand itself, connecting the electricity sector to heat and transport will also connect the electricity sector to low-cost energy storage. As outlined in Figure 19, thermal storage is approximately 100 times cheaper per unit of stored energy than direct electricity storage, while fuel storage (i.e. gas and oil) is approximately 100 times cheaper than thermal storage. Therefore, by using wind to power heat pumps, electric cars and create electrofuels (see Figure 18), it is connecting wind power to very low-cost and high volume energy storage. In this world the electricity grid will be very different than today.

[42] https://www.youtube.com/watch?v=eiBiB4DaYOM
[43] https://www.seai.ie/publications/Energy-in-Ireland-2019-.pdf

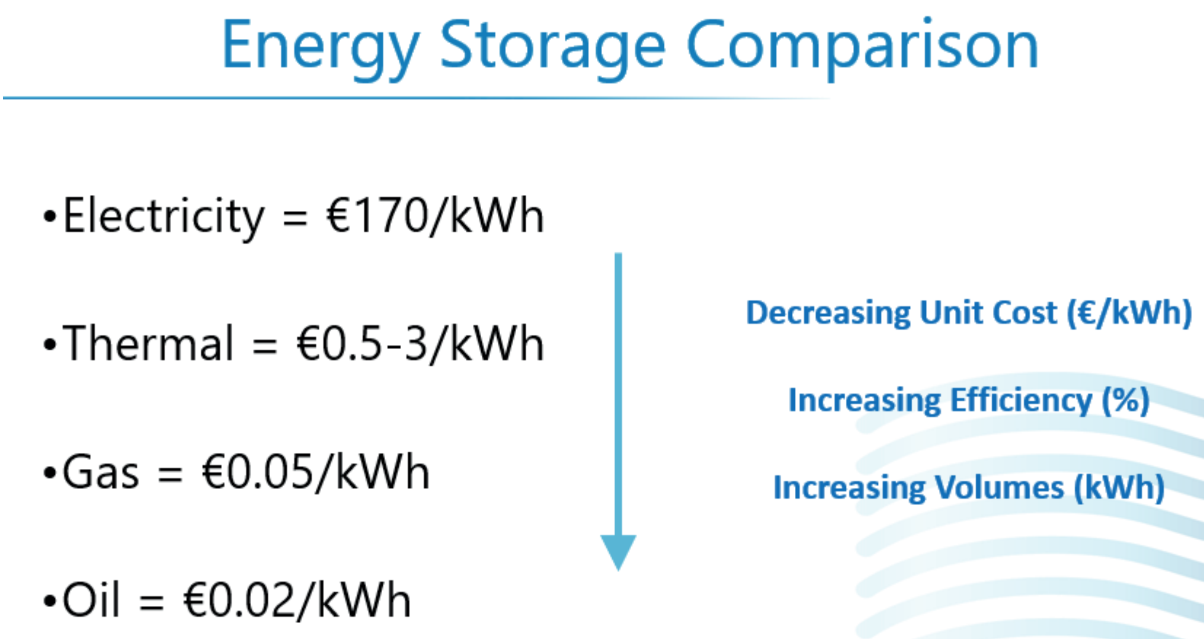


Figure 19: High-level comparison of various forms of energy storage.

When the electricity sector is meeting additional demand for heat and transport than is required for conventional electricity demand, then it is likely to operate in a very different way compared to today. The weather and seasons are strongly linked to heat demand and the daily commute to transport, so these will start to play a much more significant role in electricity demand. The volumes of heat in water tanks around the country, charge in batteries of electric cars and hydrogen volumes in tanks will become vital components of how the electricity system is managed as well as the variability of wind energy. The Paris Agreement at COP21 has set the planet on a trajectory to very low-carbon energy systems, something which is likely to be solidified in Irish law via the new Climate Action Act. Grid infrastructure has a 40-50-year lifetime so when designing the grid for 2030, it seems prudent to consider the longer-term future of 2050 and beyond also.

### 4.3.2 Flexible Demand

Incentivising flexible demand that can respond to variations in renewable generation is also a means of minimising dispatch down for energy balancing reasons. For example, mechanisms such as real-time pricing or system service incentives to ensure demand sources such as EV charging and domestic water heating can optimise their demand profile to match times of high renewable generation, when electricity prices are typically at their lowest, can bring benefits to consumers and to renewable energy production.

### 4.3.3 Long-term Storage

Longer-term storage technologies that can store excess renewable generation, or can be used in conjunction with dedicated renewable generators, for use in electricity, transport and heat can help minimise dispatch down due to energy balancing. For example, renewable generation could be used to produce hydrogen gas via electrolysis, which can then be stored and transported via the existing gas network and used to provide electricity or in other sectors such as heat or transport. Hydrogen electrolysis is a process that splits water into hydrogen and oxygen using electricity, and can be generated by zero-carbon sources, like wind or solar PV.

Longer duration storage technologies, such as hydrogen electrolysis or power to synthetic gas from renewable generation, are still at an early development stage and require dedicated frameworks and incentives to scale up and become commercially viable. For instance, over 95% of hydrogen production today is fossil-fuel based. Only around 4% of global hydrogen supply is produced via electrolysis from renewable generation, with the large capital costs of this technology being the main barrier at present.[44]

Energy Storage Ireland[45] has developed a report (*Our Energy Storage Future – Recommendations for an All-Island Energy Storage Roadmap)* which sets out a number of recommendations for developing energy storage on the island of Ireland in the short to long-term including the development of technologies such as hydrogen electrolysis.[46]

In the longer term, Government support and regulation via price signals such as new market mechanisms, new tariff structures and new system services will be required to unlock the potential of longer duration energy storage technologies and to increase their commercial viability.

A recommended first step would be the establishment of a dedicated forum or advisory body that seeks to define and develop approaches to removing barriers to longer-duration storage. This body could be composed of government policy makers, Regulators, System Operators and industry representatives.

### 4.3.4 Additional Interconnection

Additional interconnection, beyond the development of Celtic and Greenlink, can help with this problem by exporting excess renewable generation on high wind days, and can support capacity adequacy requirements on low wind days, but as has been shown this must be developed with the right market design to minimise dispatch down. Furthermore, as neighbouring power systems increase their own renewable sector development and move to full decarbonisation, the benefits of interconnection for renewable curtailment in Ireland may diminish over time.

**Recommendation: The power system will be very different in 2050 so whatever path we take towards 2030 should bring us on the journey to full decarbonisation of the economy before 2050. This will ensure we can 1) use wind energy for renewable heat and transport and 2) minimise dispatch down due to Energy Balancing.**

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[44] WindEurope Report 'Wind to X' https://windeurope.org/policy/position-papers/wind-to-x/
[45] www.energystorageireland.com
[46] https://www.energystorageireland.com/wp-content/uploads/2020/02/All-Island-Energy-Storage-Roadmap.pdf

## MAJOR LONG-TERM CHANGES TO CONSIDER

There are a number of measures such as creating new forms of electricity demand for wind energy, incentivising flexible demand that can respond to variations in renewable generation, developing additional interconnection and long-term storage technologies that can store and re-use renewable electricity in other sectors.

EirGrid and ESB Networks should begin planning for the power system needs for a fully decarbonised electricity system which can support the electrification of heat and transport with the goal of a decarbonised economy by 2050.

# 5 Conclusion

Ireland is a world leader when it comes to integrating variable renewable electricity onto the power system. However, achieving a 70% renewable electricity target will require almost tripling the amount of renewable generation connected to the system by 2030 which will bring significant challenges that must be addressed to fully integrate this volume of renewables on our grid.

Without policy measures to improve the capability of the system to manage and accommodate this level of renewables, dispatch down levels will increase significantly which will make it very challenging and expensive to continue developing renewable generation in Ireland.

In *Saving Power*, IWEA has identified the measures needed over the next decade to minimise dispatch down and maximise the use of renewable electricity on our grid by 2030, thus reducing the cost of renewable deployment and bringing benefits to electricity consumers. These measures are summarised in Table 3.

## Recommendations to Minimise Curtailment

The following three key system level policy measures, when implemented together, will maintain curtailment of renewable generation at manageable levels of around 5% out to 2030.

- Develop a DS3+ programme to relieve existing operational constraints in line with EirGrid's strategic objectives to run the system with up to 95% non-synchronous generation.
- Deliver the Greenlink Interconnector by 2023, the Celtic Interconnector by 2026 and develop an enduring interconnection policy regime by Q4 2020.
- Enhance interconnector operation through improved market design measures such as the introduction of Single Intraday Coupling (SIDC) so that they able to export approximately 90% of their capacity during curtailment events.

## Recommendation to Minimise Constraints

The recommendation to reduce constraints is to create more grid capacity by developing the grid at an early stage based on the strength and certainty of the renewable pipeline and maximising the efficiency of the existing grid by using alternative network solutions and new technologies. There are a number of steps to achieve this:

- Begin early transmission development (designing and consenting) based on the future renewable pipeline.
- Improve EirGrid's six-step framework for grid development.
- Create a new grid development strategy.

- Establish a Grid Capacity Advisory Forum to take feedback from industry and update stakeholders on the work that is underway to resolve constraints (in a similar manner to how the DS3 Advisory Forum does this for curtailment).
- Build public support for new grid infrastructure.
- Maximise the capacity of the existing grid via alternative network solutions such as Smart Wires, energy storage, demand side response.

## Major Changes to Consider

In order to deliver on our longer-term decarbonisation ambitions, we will have to innovate in ways no other power system has before. This will mean major changes in how the current electricity market and power system is designed to work. Areas which will need to be addressed are those such as market redesign, dispatch down certainty and Grid 2050. IWEA's recommendations are to begin developments in these areas as follows:

- Market Redesign – The market operator, SEMO, via EirGrid and the CRU should put in place a dedicated team to solely focus on what the electricity market design should be in 2030 to facilitate a 70by30 power system. Ireland should also seek to engage and lead at a European level in the design of future markets appropriate for very high RES-E levels.
- Dispatch Down Certainty – The CRU should implement dispatch down compensation for variable renewable generators, which is paid for by EirGrid and ESBN, who can then justify investments in solutions to reduce this compensation and thus reduce dispatch down. The compensation mechanism will need to ensure that generators are also not incentivised to build capacity in unwanted locations.
- Grid 2050 – EirGrid and ESB Networks should begin planning for the power system needs for a fully decarbonised electricity system. It should support the electrification of heat and transport and create new forms of demand for wind energy. It should also incentivise flexible demand that can respond to variations in renewable generation and develop additional interconnection or long-term storage to avoid excess renewable power being wasted.

Table 3: Summary of Policy Recommendations to Minimise Renewable Dispatch Down.

| Policy Improvement | Description | Aim | Lead Stakeholders | Target Date | Impact in 2030 if not implemented |
|---|---|---|---|---|---|
| **Policy Improvements to Minimise Curtailment** | | | | | |
| DS3+ | Enhance the DS3 programme to facilitate 2030 RES-E objectives | Develop a DS3+ programme to relieve existing operational constraints in line with EirGrid's strategic objectives to run the system with up to 95% non-synchronous generation | EirGrid, CRU, ESBN | 2020 | 16.4% Extra Curtailment |
| Interconnection Capacity | Provide additional interconnection capacity i.e. deliver Celtic and Greenlink interconnectors and put in place an enduring interconnection policy regime | Deliver Greenlink Interconnector by 2023 and Celtic Interconnector by 2026<br>Develop an enduring interconnection policy regime by Q4 2020 | CRU, EirGrid, Greenlink Developer | Develop enduring interconnection regime - 2020<br>Greenlink – 2023<br>Celtic – 2026 | 19.1% Extra Curtailment |
| Interconnection Operation | Introduce Single Intraday Coupling (SIDC) and maximise countertrading as an interim measure to ensure that the market design is incentivising the right behaviour on the interconnectors on a first principles basis (least cost / least emissions). | Enhance interconnector operation so that they able to export approximately 90% of their capacity during curtailment events | EirGrid, SEMO, CRU | Max countertrading - 2020<br>Intro SIDC - 2023 | 12.4% Extra Curtailment |
| **Policy Improvements to Minimise Constraints** | | | | | |
| Increase Transmission Grid Capacity for Existing & New Lines | Progress grid reinforcements based on future renewable development pipeline along with alternative network solutions using best-in-class community engagement. Streamline EirGrid's 'six-step' process and create a Grid Capacity Advisory Council.<br>Maximise the capacity of the existing grid via alternative network solutions such as Smart Wires, energy storage, demand side response | Minimise constraints to the greatest extent possible and, where appropriate and reasonable, provide an indicative solution and timeline so renewable electricity generation can continue to develop with the certainty that constraints will be minimised in future. | EirGrid, ESBN, CRU | 2020: Identify grid development requirements; Establish Grid Capacity Advisory Council; Initiate design & consent of required grid reinforcements.<br>Develop PR5 grid development programme of work. | 1,750 MW Less Onshore Wind<br><br>2,000 MW Less Offshore Wind<br><br>8% Increase in cost of wind energy |

| Major Long-Term Changes to Consider | | | | | |
|---|---|---|---|---|---|
| **Policy Improvement** | **Description** | **Aim** | **Lead Stakeholders** | **Target Date** | **Impact in 2030 if Policy Measure not implemented** |
| Market Redesign | Today's electricity market is designed around marginal-cost energy, backup capacity and a small amount of system services. In the future, renewable electricity will need long-term energy contracts, power plants will likely rely on capacity contracts and the grid will need much more system services. There is a consensus change is coming, but analysis is required to establish the nature of this change. | The market operator, SEMO via EirGrid and the CRU, should put in place a dedicated team to solely focus on what the electricity market design should be in 2030 to facilitate a 70by30 power system.<br>Ireland should also seek to engage and lead at a European level in the design of future markets appropriate for very high RES-E levels. | CRU, SEMO, EirGrid | 2021 | N/A |
| Dispatch down Certainty | CRU should implement dispatch down compensation for variable renewable generators, which is paid for by EirGrid and ESBN, who can then justify investments in solutions to reduce this compensation and thus reduce dispatch down. The compensation mechanism will need to ensure that generators are also not incentivised to build capacity in unwanted locations. | This could be implemented in the short-term while transposing Article 12 and 13 of the Electricity Regulation in the Clean Energy Package. If not, the CRU should establish a roadmap that will explain how dispatch down will be managed over the next decade at the lowest cost to the consumer, while also incentivising investment in renewable electricity to achieve 70by30. At present, without dispatch down compensation, it is very likely that the 2030 targets will not be met or, alternatively, they will be met at unnecessarily high costs to the consumer. | SEMO, CRU, EirGrid, ESBN | 2020 | N/A |
| Grid 2050 | The power system will be very different in 2050 so whatever path we take towards 2030 should bring us on the journey to full decarbonisation of the economy before 2050. This will ensure we can 1) use wind energy for renewable heat and transport and 2) minimise dispatch down due to Energy Balancing. | EirGrid and ESB Networks should begin planning for the power system needs for a fully decarbonised electricity system which can support the electrification of heat and transport with the goal of a decarbonised economy by 2050. | EirGrid, ESBN, CRU | 2020 | N/A |

# 6 Appendix 1 – IWEA Pipeline Survey - Data Available Upon Request

## 6.1 Onshore Wind Pipeline by County and Stage of Development

| Includes REFIT Projects at Risk, existing CPPAs and all projects for future CPPAs/RESS | | | | | |
|---|---|---|---|---|---|
| **County** | **With Planning** | **In Planning** | **In Advanced Pre-Planning** | **Feasibility Stage** | **Grand Total** |
| Carlow | | | | | |
| Cavan | | | | | |
| Clare | | | | | |
| Cork | | | | | |
| Donegal | | | | | |
| Galway | | | | | |
| Kerry | | | | | |
| Kildare | | | | | |
| Kilkenny | | | | | |
| Laois | | | | | |
| Leitrim | | | | | |
| Limerick | | | | | |
| Longford | | | | | |
| Mayo | | | | | |
| Meath | | | | | |
| Monaghan | | | | | |
| Offaly | | | | | |
| Roscommon | | | | | |
| Sligo | | | | | |
| Tipperary | | | | | |
| Waterford | | | | | |
| Westmeath | | | | | |
| Wicklow | | | | | |
| **Grand Total** | | | | | |

## 6.2 Onshore Wind Pipeline by County and Year to Enter Planning

| Includes REFIT Projects at Risk, existing CPPAs and all projects for future CPPAs/RESS | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| County | Sum of Capacity (Net MWs) | | | | | | | | | | |
| | | | Going Into Planning | | | | | | | | |
| | With Planning | In Planning | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Grand Total |
| Carlow | | | | | | | | | | | |
| Cavan | | | | | | | | | | | |
| Clare | | | | | | | | | | | |
| Cork | | | | | | | | | | | |
| Donegal | | | | | | | | | | | |
| Galway | | | | | | | | | | | |
| Kerry | | | | | | | | | | | |
| Kildare | | | | | | | | | | | |
| Kilkenny | | | | | | | | | | | |
| Laois | | | | | | | | | | | |
| Leitrim | | | | | | | | | | | |
| Limerick | | | | | | | | | | | |
| Longford | | | | | | | | | | | |
| Mayo | | | | | | | | | | | |
| Meath | | | | | | | | | | | |
| Monaghan | | | | | | | | | | | |
| Offaly | | | | | | | | | | | |
| Roscommon | | | | | | | | | | | |
| Sligo | | | | | | | | | | | |
| Tipperary | | | | | | | | | | | |
| Waterford | | | | | | | | | | | |
| Westmeath | | | | | | | | | | | |
| Wicklow | | | | | | | | | | | |
| Grand Total | | | | | | | | | | | |

## 6.3 Onshore Wind Pipeline by Type of Planning Application: SID?

| Includes Projects in Advanced Pre-Planning & Feasibility Stage | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Using SID? | Going Into Planning | | | | | | | | |
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Grand Total |
| **Yes** | | | | | | | | | |
| **No** | | | | | | | | | |
| **Grand Total** | | | | | | | | | |

## 6.4 Onshore Wind Pipeline by Type of Grid Connection: TSO/DSO

| Includes Projects With Planning (but no grid offer), In Planning, at Advanced Pre-Planning & Feasibility Stage | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Projects that Require a Grid Offer (MW) | With Planning | In Planning | Going into Planning | | | | | | | | |
| | | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | Grand Total |
| Distribution System | | | | | | | | | | | |
| Transmission System | | | | | | | | | | | |
| Grand Total | | | | | | | | | | | |