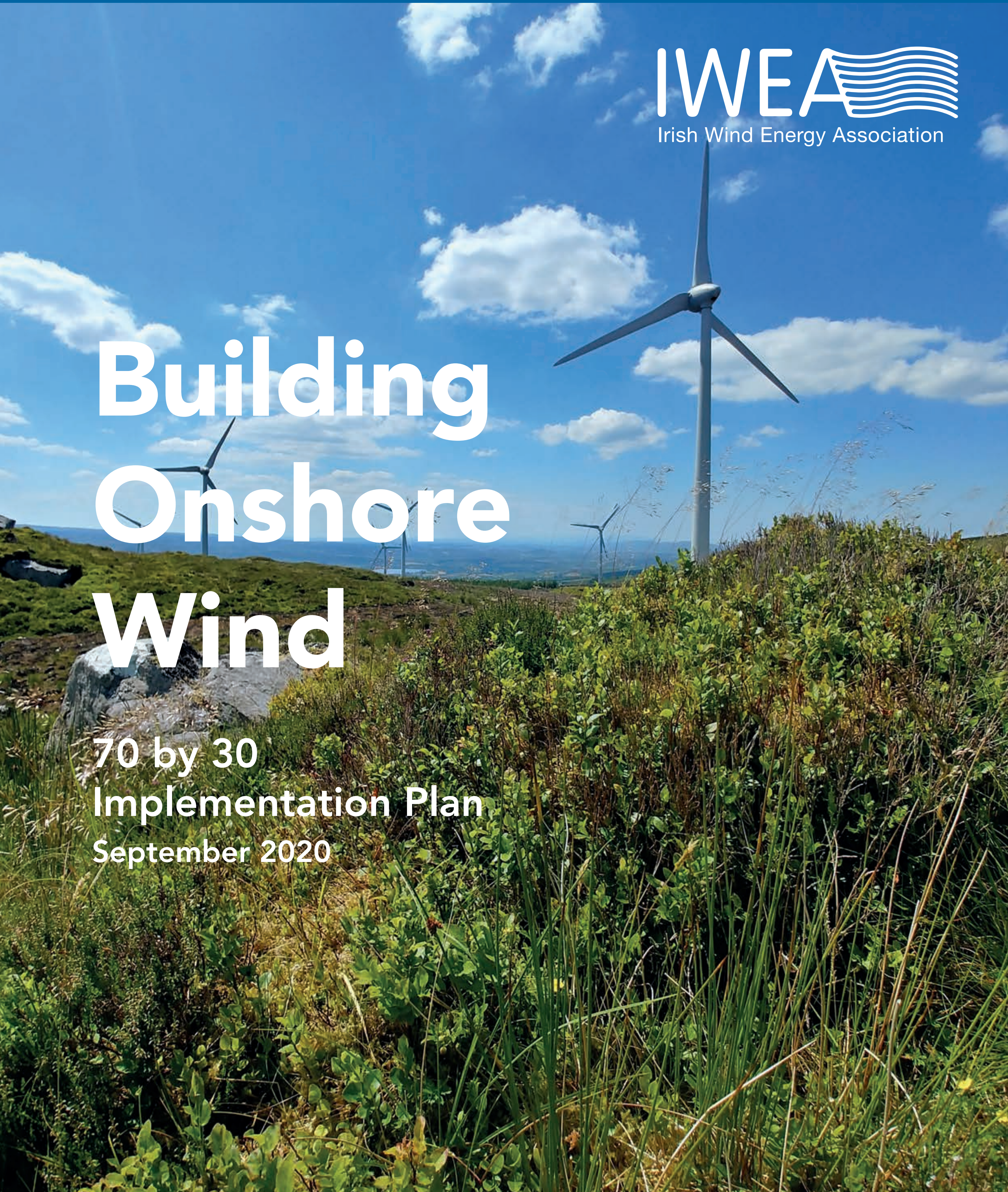
Irish Wind Energy Association



Building Onshore Wind

70 by 30 Implementation Plan

September 2020

Delivering the *Climate Action Plan*

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Foreword from the Chair

As a father of three young children I have been reading ongoing reports and research on climate change with a growing sense of alarm. A recent chart published by NASA shows just how far atmospheric CO_2 levels currently sit above their normal historic variations (see Figure 1). The increases seen in the last 70 years are almost double those seen at any time in the previous 800,000 years with few signs of this stabilising.

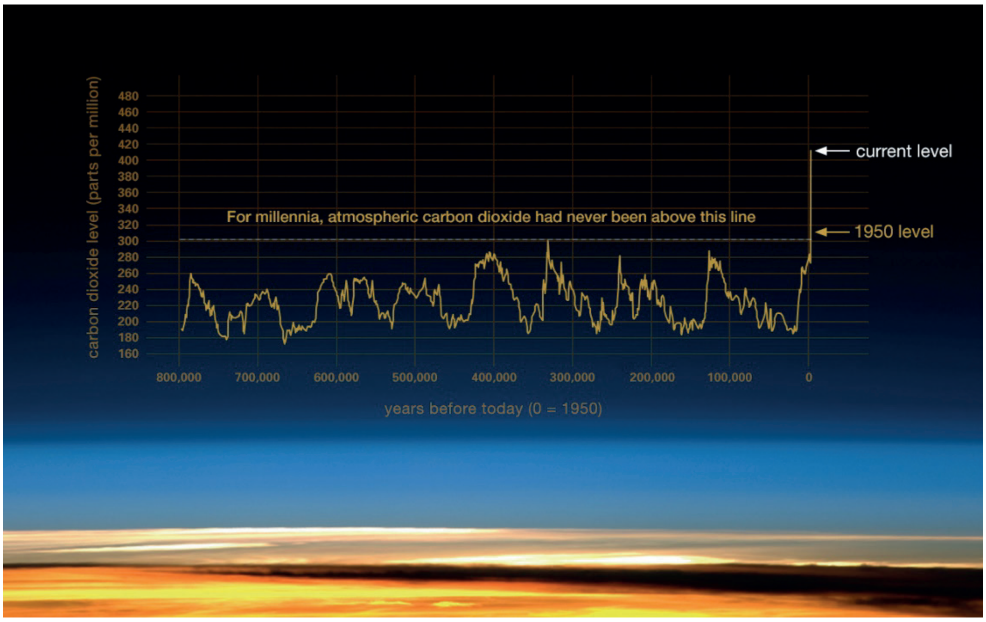

Figure 1: Atmospheric CO_2 concentrations for last 800,000 years.

In recent times we are also hearing more direct and extreme warnings from the scientific community that we are running out of time to address the problem. As recently as November 2019 there was a fresh warning from an international consortium of more than 11,000 scientists that the Earth is now facing a climate emergency.[1]

This was followed by another warning later that month that Earth's climate system may be crossing irreversible tipping points and that this possibility is "an existential threat to civilization".[2]

The authors of the latest report from the UN Intergovernmental Panel on Climate Change indicated we have 12 years to limit global warming to a maximum rise of 1.5 °C noting that **urgent and unprecedented** changes are needed to achieve this target. That warning came almost two years ago.

The IEA's recently published World Energy Outlook[3] also highlights just how far off track we currently are as shown in Figure 2 below.

[1] https://www.irishtimes.com/news/environment/irish-academics-among-11-000-scientists-declaring-climate-emergency-1.4073664
[2] https://www.nationalgeographic.com/science/2019/11/earth-tipping-point/
[3] https://www.iea.org/media/publications/weo/WEO2019-Launch-Presentation.PDF

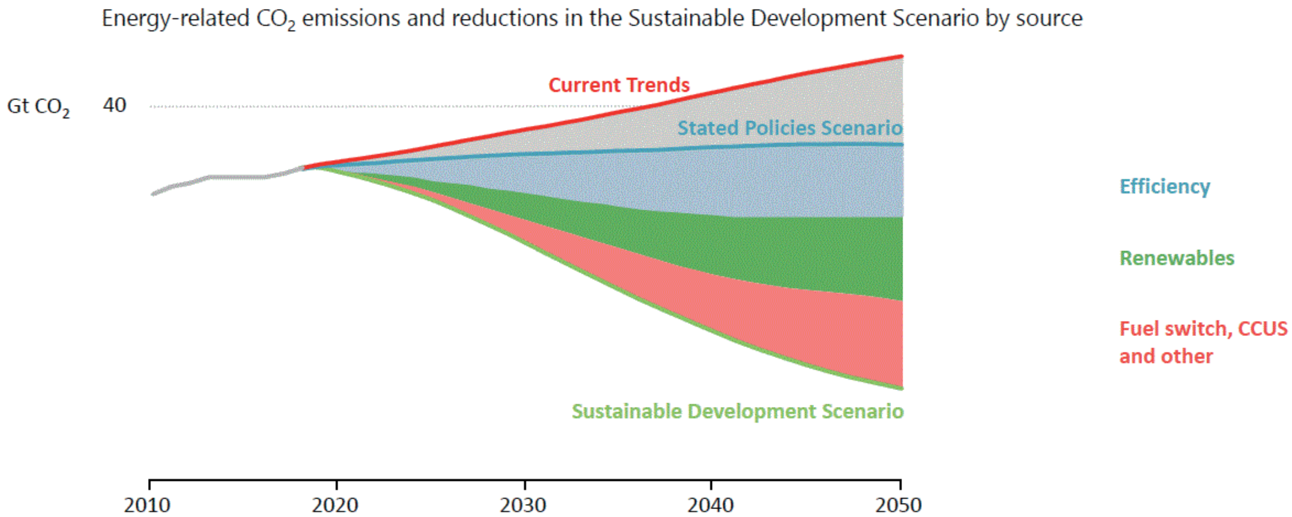

Figure 2: Energy related CO_2 emissions: trends, policies and sustainable scenario requirements.

The clear message from all of these warnings is that globally we are under-promising and under-delivering on those same promises.

In this regard, Ireland has recently shown positive leadership on the international stage, particularly in terms of the proposed de-carbonisation of the power generation sector. In March 2019, the Joint Oireachtas Committee on Climate Action published its cross-party report entitled, *Climate Change: A Cross-Party Consensus for Action*, which set out 42 priority recommendations in the area of climate action, including a target for 70 per cent renewable electricity in Ireland by 2030.[4] What was heartening about this publication is that it was a cross-party initiative. As we look at the polarising politics emerging in many countries around the world, it was inspiring to see Irish politicians work together towards a goal that is of national and global importance.

This was followed by Minister for Communications, Climate Action and Environment Richard Bruton TD publishing Ireland's Climate Action Plan which formally adopted the 70 per cent renewable electricity target.[5] The leadership that Ireland is showing in de-carbonising electricity has the potential to be of global significance and evidence of this is already emerging. Last September EirGrid signed a Memorandum of Understanding with the state of New York to support them in their decarbonisation objectives. New York Governor, Andrew Cuomo, confirmed that the collaboration with EirGrid will enable New York state "to remain at the forefront of technological advancement".[6]

[4] https://data.oireachtas.ie/ie/oireachtas/committee/dail/32/joint_committee_on_climate_action/reports/2019/2019-03-28_report-climate-change-a-cross-party-consensus-for-action_en.pdf
[5] https://www.dccae.gov.ie/en-ie/climate-action/publications/Documents/16/Climate_Action_Plan_2019.pdf
[6] https://www.governor.ny.gov/news/during-climate-week-governor-cuomo-announces-partnerships-ireland-and-denmark-improve-power

Ireland already has some of the best power systems engineers in the world. They are meeting the challenges of operating a synchronous grid system at renewable penetrations of up to 75 per cent. Reaching a 70 per cent renewable electricity target will involve running the power system at instantaneous renewable penetration levels of between 90-95 per cent and the solutions to the technical challenges presented by this level of penetration will be ground-breaking.

In addition to overcoming the technical challenges of integrating this volume of renewables at a system level, this mandate also puts an onus on all stakeholders to ensure that we deliver the other enabling measures required. This report has been prepared by a dedicated working group within IWEA's 70by30 committee. We are attempting to identify and quantify the impact of existing bottlenecks in the system and make constructive proposals to eliminate them. As an industry, we look forward to engaging and working with all key stakeholders to develop this further in the coming months and years.

A significant challenge in achieving the ambition set out in the Climate Action Plan which is not dealt with in this report, is the responsibility of industry and Government to bring the citizens of this country with us on the journey. For most people, electricity is something only considered when there is a power cut or the bill arrives.

To truly empower people to be energy citizens we need to do a better job of explaining these new renewable technologies like wind and solar power, battery storage and the need for grid reinforcement. We must not only engage earlier with local communities but we must listen to, and strive to address, their concerns. And we can ensure that the commercial opportunities presented by the shift to renewable energy are more widely shared through community benefit programmes, opportunities to invest in projects and supporting community owned renewable energy.

While there is a lot to be positive about Ireland's Climate Action Plan, it is probably fair to say that it still falls short of the "urgent and unprecedented" changes that the climate science demands. We are not yet on a trajectory to zero emissions by 2050 and the Climate Action Plan must be understood not as the destination, but as a step on the journey towards that goal. It is important however that even as we work towards this challenging goal, that we are already considering how we can go even further across all sectors of the economy.

I would like to conclude with a few words about my colleagues in the wind industry and the wider renewable energy sector in Ireland. After 10 years working in wind energy development, it is clear to me that almost everyone in this industry puts in hours far beyond the normal working week because they believe absolutely in the importance of what they are doing.

A special note of thanks in this regard goes out to all the members of the working group that helped to write this report. I know each of us is rightly concerned about what the future holds and, while what we do in Ireland certainly will not be enough on its own, I know everyone working to support and grow renewable energy in Ireland will be able to look their children in the eyes and tell them we hear the warnings and we are playing our part to tackle what is without doubt the challenge of our generation.

It is with this in mind that, rather than using pictures of the working group in the foreword as would be traditional, we decided to include pictures of the children of our working group members, just to remind us all who we are doing this for!

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Paul Blount, BE CEng,
Portfolio Director, Coillte.
Chairperson of the IWEA 70by30 Committee.

Executive Summary

The target set out in the Climate Action Plan is that 70 per cent of Ireland's electricity should be coming from renewable sources like wind and solar by 2030.

It is not, currently, achievable.

We have the technology to achieve it. Ireland is a leader in integrating renewable energy onto our electricity system; we have one of the world's most successful onshore wind industries, enormous offshore wind potential and a growing solar sector.

We know we have the resources, the skills, the technology and the experience.

What we lack – the missing piece – is a policy system which will enable the successful, cost-effective and rapid deployment of renewable electricity.

This can change.

If we are to achieve our 2030 targets make no mistake; it must change.

To support policymakers in their efforts to design a framework that will make the Climate Action Plan achievable we established a working group to analyse how the volumes of renewable electricity required by the plan could be developed and connected.

The two key building blocks to this analysis were:

1. A detailed survey of the IWEA membership to establish the current wind energy pipeline summarised in Figure 3 below and set out in more detail in Appendix 1;

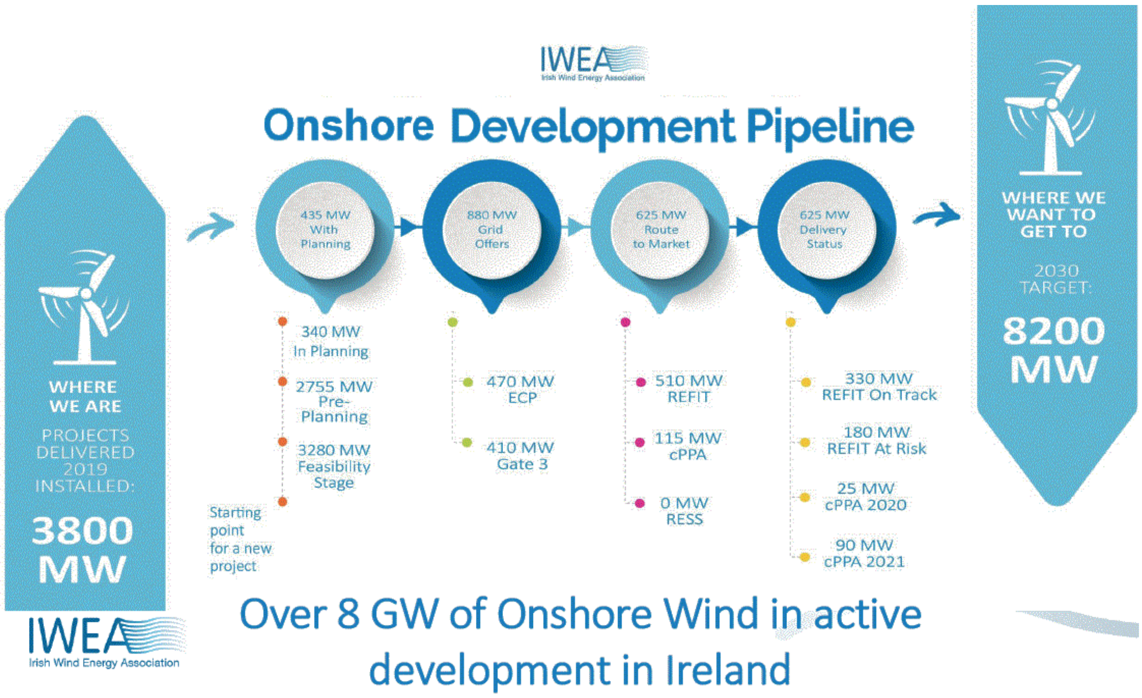


Figure 3: High level summary of IWEA's Onshore Wind Pipeline survey (Dated: October 2019).

2. An IWEA pipeline analysis tool (i-PAT) that can model this pipeline as it moves through the development process.

Using these two tools we were able to create a business as usual (BaU) scenario based on the existing timelines in Ireland which see project development take a minimum of eight years. These BaU scenario assumptions are set out in the main body of the report.

The results of this BaU are summarised in Figure 4 below. It is absolutely clear that in a BaU scenario Ireland will fall far short of the installed capacity required to deliver on the Climate Action Plan. Only 5.4 GW is energised by the end of the decade compared to a target of 8.2 GW in the Government's Climate Action Plan.

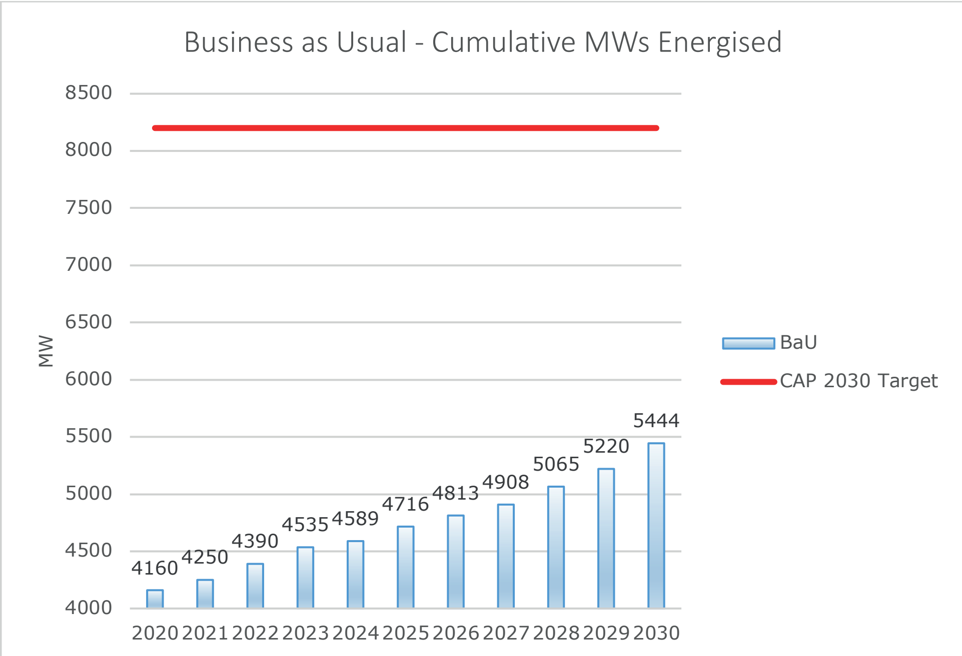


Figure 4: Business as Usual onshore wind energisation.

These figures set the challenge – how do we change the existing regulatory and policy framework to meet the onshore wind target of 8.2 GW by 2030.

Using the pipeline analysis tool IWEA has identified nine Policy Improvements (PIs) that can enable Ireland to deliver the Climate Action Plan. These policy improvements are summarised in Table 1 below.

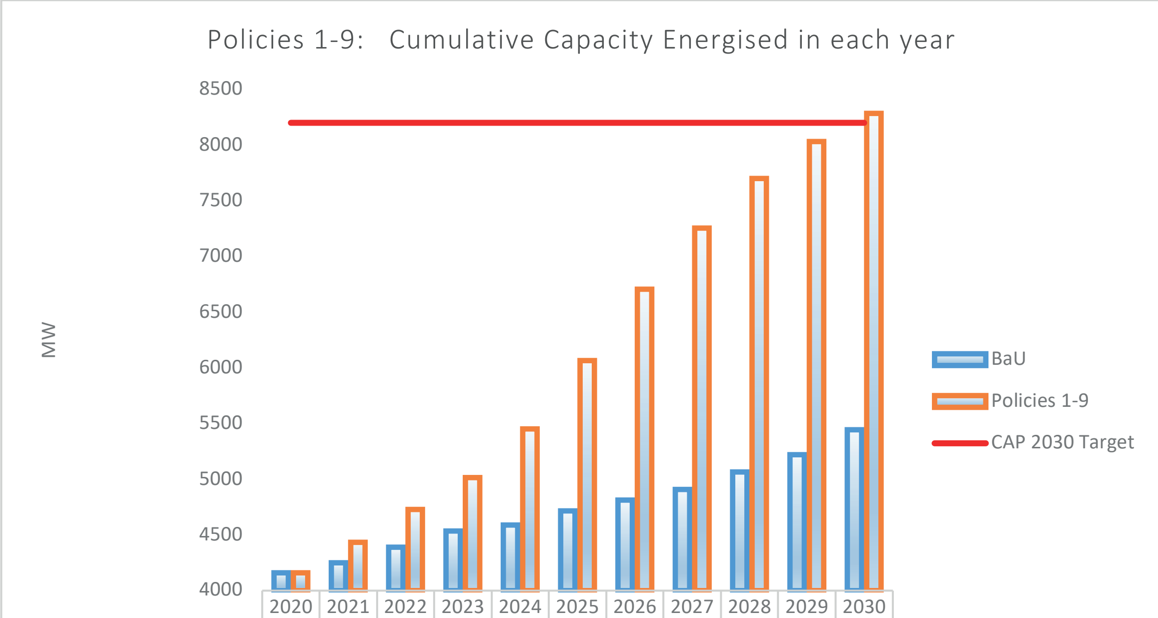
Table 1: Summary of Policy Improvements (PIs) required to deliver 8.2 GW of onshore wind by 2030.

Policy Improvement (PI)	Description	Aim	Lead	Supporting Role	Next Step	Target Date	Impact of Delay in 2030
1. Pre-Planning Success	Higher Pre-Planning Success via enhanced Community Engagement & Regional Planning (REPDF).	Halve the pre-planning attrition rate from 33% in BaU to 15%.	DHPLG	Regional assemblies, DCCAE	Appoint consultants to prepare the Regional Renewable Energy Strategies on behalf of the three Regional assemblies, and the associated Strategic Environmental Assessments (SEA) and Habitats Directive Assessments (HDA). DHPLG to brief and instruct Regional assemblies on urgency of proceeding with Regional Renewable Energy Strategies, and outline proposed approach for preparation, funding, etc.	2021, 2022	-593MW -3.9% RES-E +794kt CO_2
2. SID Success	Higher SID Success via improved planning applications and more extensive ABP-industry engagement.	Double the current SID success rate from 38% in BaU to 75%.	DHPLG	ABP	DHPLG legislates for the suggested new SID pre-application stage in a revision to the Planning and Development Act. To begin, DHPLG seeks formal or informal input from An Bord Pleanála and industry stakeholders on need for change to SID process.	2021	-916MW -6% RES-E +1227kt CO_2
3. ABP Decision Timelines	ABP Decision Timelines via mandatory decision timelines similar to SHD.	Improve ABP decision timelines by reducing them to 18 weeks for all decisions. Current decision timelines in ABP are 66 weeks for Local Authority Appeal, 89 weeks for JR referrals and 32 weeks for SID decisions.	DHPLG	ABP, OPR	DHPLG legislates for the suggested new ABP decision timeframes in a revision to the Planning and Development Act for SID decisions, JR referrals and appeals. To begin, DHPLG should seek formal or informal input from An Bord Pleanála and/or industry stakeholders on how to change the SID decisions, JR referrals and appeals processes/timelines.	2021	-95MW -0.6% RES-E +127kt CO_2
4. Grid Offers	SOs offer sufficient grid offers to meet targets & have sufficient competition via grid offer regulations e.g. Prioritise Large Projects in ECP or implement Grid Following Funding (GFF).	SOs move from 'order of planning grant' for grid offers to processing minimum of 50 offers per year, prioritising first 25 for largest, or move to Grid Following Funding model.	CRU	EirGrid, ESBN	CRU to design and decide on the enduring connection policy framework, including the treatment of firm/non-firm access, and on the allowed PR5 spend for the SOs. EirGrid and ESBN will process the connection offers as per the ECP framework.	2020	-1969MW -13% RES-E +2638kt CO_2

5. Transmission Grid Capacity	Parallel Transmission Development via PR5 and resourcing	- Increase from 27% to 70% proportion of projects which face no transmission system delay - Reduce from 48% to 20% proportion of projects which face a 2-year delay - Reduce from 24% to 10% proportion of projects which face a 4-year delay or longer	EirGrid, ESBN	CRU, ABP	EirGrid to design and consent the appropriate network reinforcement and ESBN to carry out necessary construction and energisation works. CRU to determine the allowed spend on network reinforcement projects.	2020	-1750MW -11.5% RES-E +2344kt CO_2
6. Grid Consenting	a) Parallel Grid Consenting via PR5; b) resourcing and early engagement with SOs on connection methods via a new Project Development Support and Tracking office.	Increase parallel grid consenting from 30% of projects to 80% and obtain early engagement with SOs.	a)DHPLG, DTTAS, CRU; b)EirGrid, ESBN	a)EirGrid, ESBN; b)CRU	a) DHPLG to update the Planning and Development Regulations. DTTS to make necessary amendments to the Roads Act; b) SOs to create a new Project Development Support and Tracking Office.	2020	-77MW -0.5% RES-E +103kt CO_2
7. Grid Offer Longstop Dates	ECP Long-Stop enables entry to three RESS auctions via grid offer regulations or RESS entry requirements or a Grid Following Funding (GFF) model.	Grid offers allow projects to enter three annual RESS auctions rather than one.	CRU	DCCAE	CRU to design and decide on ECP framework.	2020	-832MW -5.5% RES-E +1114kt CO_2
8. Grid Delivery	Strict Grid Delivery Timelines via PR5 and penalties for late delivery.	Reduce finance and build period from 2.5 years to 1.5 years.	ESBN, EirGrid	CRU	ESBN and EirGrid, as parties to the Infrastructure Agreement, to develop connection design specifications and grid delivery programmes.	2020	-253MW -1.7% RES-E +338kt CO_2
9. Route to Market via RESS/CPPAs	Annual route to market for 66% of projects via a) RESS or b) Corporate PPAs (CPPAs)	BaU case assumed 66% of projects found route to market each year. Impact quantified by removing this and assuming onshore wind is excluded beyond RESS-1 and CPPA market is limited to 100 MW per year.	DCCAE, SEAI, DoF, DPER	DHPLG, CRU, EirGrid, ESBN, Large Energy Users, IDA, ESRI	RESS: First auction to be completed in July 2020 with annual auctions for onshore wind to follow thereafter. Update RESS timeline and volumes to reflect this. CPPAs: New policy to pass some of the savings due to CPPAs to corporates who sign CPPAs. Both: Task force to be set up with a focus on reducing the cost of renewable electricity in Ireland.	2020	-2817MW -18.5% RES-E +3774kt CO_2

The resulting improvements have been modelled as the 'Climate Action Plan' scenario in i-PAT to quantify the additional capacity from the onshore wind pipeline that can be energised in each year to 2030 when each of these policies are implemented. The results are summarised in Figure 5 below and indicate that for 2030, all nine policy improvements will be required to achieve the 2030 target of 8.2 GW onshore wind.

Even if one is missed, then Ireland cannot meet this target.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
Policies 1-9	4160	4434	4729	5015	5452	6065	6706	7255	7700	8032	8285
CAP 2030 Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 5: "Climate Action Plan" scenario with all Policy Improvements (PIs) implemented.

The changes required to deliver each policy are outlined in the main body of the report (section 4) under the following headings:

- Summary of current policy;
- Shortcomings of the current policy;
- Proposed new policy;
- Implementing the new policy, including:
  - Who is the decision maker?
  - Who has a supporting role?
  - Budget/resource requirements
  - Key steps
  - Target date for delivery

The targets in the Climate Action Plan will not be achieved if even one of these policies is not implemented. Figure 6 below outlines the onshore wind capacity that will be lost in 2030, along with the additional carbon emissions that will be created, if any policy fails.

The three policies with the greatest impact on achieving the 8,200 MW target for onshore wind in 2030 are:

1. **Providing an annual route to market via the Renewable Electricity Support Scheme (RESS) auctions or Corporate Power Purchase Agreements (CPPAs);**
2. **Providing enough grid connection offers; and**
3. **Developing the transmission grid in parallel with the wind farms.**

Failing to deliver parallel consenting of the shallow connection assets (PI6) and failure to improve ABP timelines (PI3) do not have a significant impact on the capacity energised in 2030, however there is a material impact in 2025 and 2027, which will be important for meeting the interim renewable energy targets in these years (see Figure 7).

It will be extremely challenging to deliver the volume of renewables required in these intermediate years, which must be reported to the European Commission (via the National Energy & Climate Plan) and so these PIs still make a significant contribution.

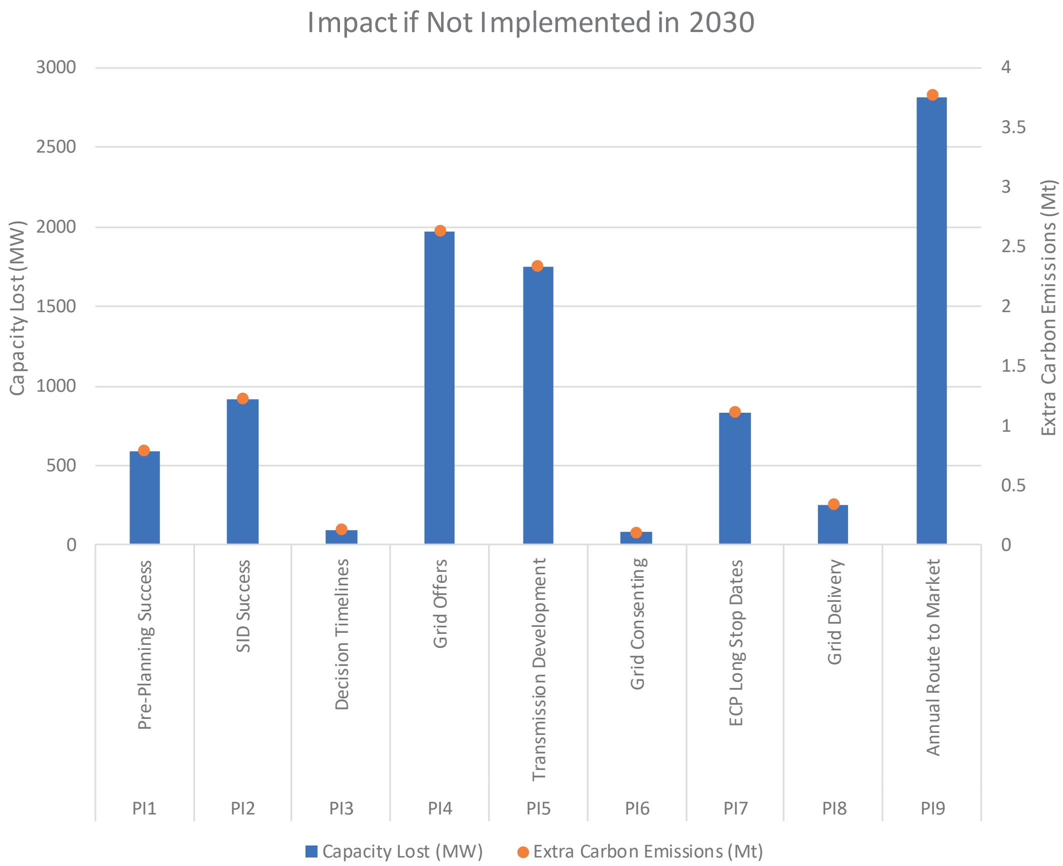


Figure 6: Onshore wind capacity lost and additional CO_2 emissions in 2030 if individual policies are not implemented.

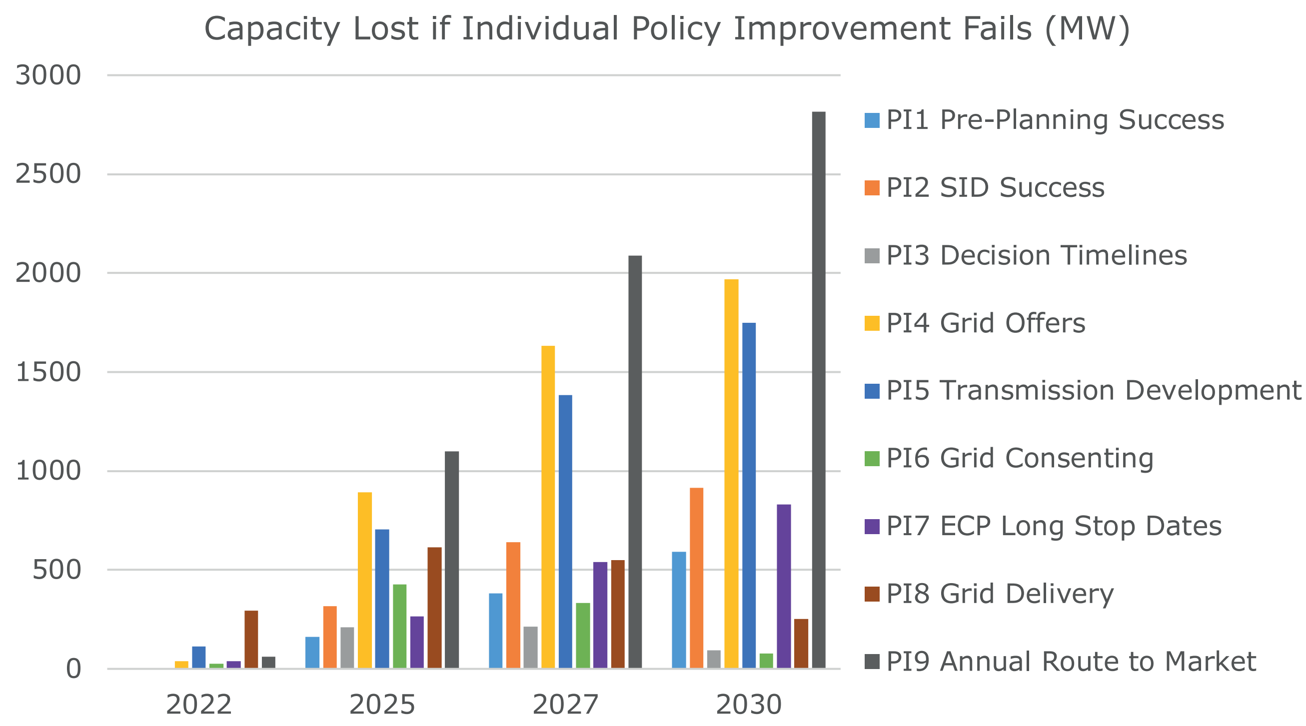


Figure 7: Onshore Wind Capacity lost in 2022, 2025, 2027 and 2030 if individual Policy Improvements (PI) fail. This analysis was carried out by removing a single PI while keeping all of the others, which then revealed the impact of the failure.

The findings of this analysis are clear – Ireland simply cannot afford a 'Business as Usual' approach over the next ten years.

We are conscious that the timelines for what we are proposing are extremely short. We are aware that carrying out these kinds of substantial legislative, policy and regulatory changes within the next two years is unprecedented.

But an unprecedented threat requires an unprecedented response.

We know our industry can deliver.

We are ready to play our part.

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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 per cent 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 per cent 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, *Building Onshore*, sets out how to ensure we can reach the Climate Action Plan target of 8.2 GW of installed onshore wind by 2030.

1.1 Typical Timeline to Develop an Onshore Wind Farm

To understand the challenge, it is useful to first understand a "business as usual" wind farm development timeline in Ireland. This is summarised in simplified form in Figure 8 below but a full report describing the process is available on the IWEA website.[7] Taking each phase in turn, the typical wind farm development process, and associated timelines, are described below.

Planning application preparation (2-3 years): Once a site has been identified and land agreements have been secured there is a minimum requirement to undertake two years of bird survey work. After this Environmental Impact Assessment reports need to be produced prior to submitting a planning application.

Planning decision (1-2 years+): Wind farm developments are relatively complex. It is common for planning authorities to request further information on development applications. Not all applications are consented so there is generally some attrition at this stage. Positive decisions are often appealed and/or judicially reviewed resulting in lengthy consenting timelines.

Grid offer (3 years+): Projects that successfully obtain planning permission join a queue for grid offers. Between 2008 and 2018 there was no grid offer process to issue new connection offers and so many projects that received planning permission during this period were unable to gain

[7] https://iwea.com/images/files/iwea-onshore-wind-farm-report.pdf

access to the grid. Depending on future rules on batch processing, projects potentially face a lengthy wait before being eligible to receive a grid connection offer.

Planning for grid connection (2 years+): Many projects may only learn of their actual connection method once they have sight of their grid connection offer. In the event that a project requires a further planning consent for their grid connection this will result in a number of years work to carry out the required environmental studies, submit the planning application and face the possibility of judicial review.

Transmission System Development – Deep reinforcements (0-10 years+): Depending on the location of the project it may be necessary for the transmission system to be reinforced before the project can be connected to the grid. Timelines to re-enforce the grid can vary considerably. In some locations it may be possible to uprate existing lines, in other locations new HV overhead lines (HV OHL) can be required. The complete development timeline for a new HV OHL can be as much as 10-15+ years. Therefore, if the system operators wait until renewable projects have been consented before starting work, the planning permission for the wind farm may time out before the network is reinforced.

Financing and construction (2-3 years): Once a project has all of these earlier consents in place, it then needs to secure a route to market through either a Renewable Electricity Support Scheme (RESS) auction or a Corporate PPA (CPPA), and then obtain project finance and construct the project. Depending on the timing of the next auction process, it may be up to 1.5 years before a route to market is secured and then a further 4-6 months to secure project finance and 12-18 months to construct the project.

Cumulative Timelines: As can be seen from the timelines above, in the existing policy/regulatory environment, a project currently could take anywhere from 8.5 years to 20+ years to go from initial site identification to energisation (Figure 8).

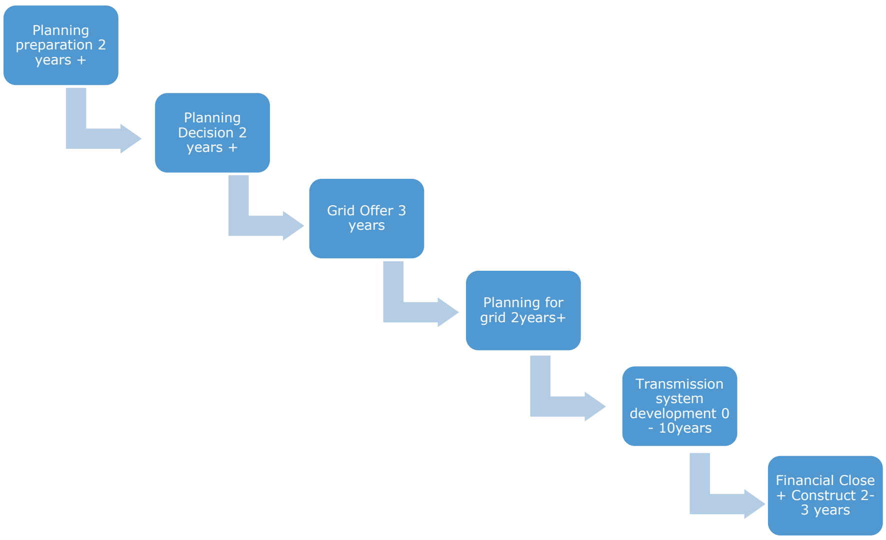


Figure 8: Simplified development timelines for a typical wind farm.[8]

[8] https://www.iwea.com/images/files/iwea-onshore-wind-farm-report.pdf

1.2 Need to reduce timelines to meet Ireland's 2030 Target

To assess the impact of the existing timelines on our ability to deliver on a 70 per cent RES-E target we need to grapple with some of the key questions below:

- Planning:
  - What is the current pipeline of projects and when will they be ready to go into the planning system?
  - What level of planning attrition can we expect?
  - How soon will these projects have planning permission?
- Grid:
  - Where are all these new projects located, how much space is there on the transmission system in these locations and how long might it take for the transmission system to be reinforced if necessary?
  - How many projects are already consented and have grid offers; and what level of attrition might apply to these projects if they have old consents and waited a long time for their connection offers?
  - How many grid offers can the system operators process every year and how will they be prioritised?
- Markets:
  - How frequently will we have RESS auctions and will there be a minimum level of oversubscription required to protect consumers from higher PSO costs?
  - How many auction losers might be in a position to improve their bids and enter a subsequent auction?
  - Will there be a Corporate Power Purchase Agreement (CPPA) market?

Using the pipeline analysis tool (i-PAT) we look to create a "counter factual / BaU" scenario which is based largely on historic development timelines.

We then compare this counterfactual with the targets set out in the Government's Climate Action Plan (see Table 2). The ultimate objective of this report is to identify a series of **policy improvements (PIs)** required to achieve these targets.

While we apply these measures in sequence in order to try to identify the individual contribution of each measure, it is important to note that the full benefit of any individual measure may not be realised until it is combined with some subsequent measure.

Table 2: Climate Action Plan 2030 renewable targets.

Technology	Target
Onshore Wind	8,200 MW
Offshore Wind	3,500 MW
Solar	1,500 MW

2 Methodology

2.1 IWEA Pipeline Survey

In October 2019, IWEA updated a survey of its membership to understand the status of the wind energy pipeline in Ireland (see Appendix 1). The full survey included county-by-county data on:

- Capacity Installed (MW) to Oct 2019;
- Capacity (MW) of REFIT Projects on track to deliver in 2019/2020;
- Capacity (MW) of REFIT Projects at risk of non-delivery;
- Capacity (MW) of projects which had secured a CPPA and expect delivery in 2020;
- Capacity (MW) of projects which had secured a CPPA and expect delivery in 2021;
- Capacity (MW) of projects with planning and grid (either Gate 3 or in ECP-1 process) but no route to market secured;
- Capacity (MW) of projects with planning only that are waiting for the next ECP batch;
- Capacity (MW) of projects in the planning process;
- Capacity (MW) of projects in advanced pre-planning including estimated planning submission year and breakdown or those expected to make local authority applications vs those that would submit under the SID process;[9]
- Capacity (MW) in feasibility stage including estimated planning submission year and breakdown or those expected to make local authority applications vs those that would submit under the SID process.[10]

A high-level summary of the survey results is provided in Figure 9. The full detailed breakdown of this survey can be made available on a confidential basis to key stakeholders if it is required to support the development of enabling policy measures.

[9] To be considered at the 'advanced pre-planning phase', a project had to have its initial environmental assessment work completed.

[10] To be considered at the 'feasibility phase' projects had to have their land rights secured.

Figure 9: High level summary of IWEA's onshore wind pipeline based on a survey of members which was completed in October 2019. It is important to note that this survey was carried out before the publication of the Draft Revised Wind Energy Development Guidelines in December 2019[11] which, depending on the final outcome of this consultation, could potentially reduce this pipeline significantly.

[11] https://www.housing.gov.ie/sites/default/files/public-consultation/files/draft_revised_wind_energy_development_guidelines_december_2019.pdf

2.2 IWEA Pipeline Analysis Tool (i-PAT)

We developed a pipeline analysis tool to analyse this data and estimate how this pipeline would convert into annual MW capacity of onshore wind achieving:

- Planning permission;
- Grid connection offers;
- Route to market; and
- Energisation

2.2.1 Defining the Starting Point

The starting point for all modelling work is assumed to be the end of 2020. All figures cited in this report under each year from 2020 to 2030 should be read as being the figure anticipated for the end of the relevant year.

The IWEA Pipeline Survey provided most of the starting point assumptions, but the following initial assumptions were also required to define the anticipated system status at the end of 2020:

- Target: the IWEA Pipeline Survey indicated that approximately 4,200 MW of onshore wind would be installed by the end of 2020, so an additional 4,000 MW is required by 2030 to meet the Climate Action Plan’s target of 8,200 MW.

- Expected pre-auction attrition rate of existing projects with planning and grid with legacy issues (e.g. planning running out & project located inside a Special Protection Area). The exact assumptions are provided in Table 3.

- For each location specialist grid consultants within the working group have made assumptions to estimate the amount of capacity that is currently available on the transmission system and how much capacity could become available through either smart network strategies, line upgrades or new transmission lines. Further engagement with the SOs would be required to refine these estimates. Projects that can fit within the existing capacity and do not require any planning permission for their grid connection are categorised as Tier 1. Once the amount of capacity seeking connection in each county exceeds this limit, subsequent capacities are moved into Tier 2, 3 or 4. For each of these tiers we build in a different delay period between the time they have planning permission and a grid connection offer and when they could bid into a RESS auction or enter into a CPPA contract.

    - Tier 2 projects could expect modest delays (2 years) in connecting to the transmission system. This can be because of a need to secure planning for the shallow connection method or perhaps a smart network solution is required (e.g. Special Protection Schemes)

- Tier 3 projects can expect substantial delays (4 years) e.g. they might trigger the need for a line uprate or some other significant upgrade works.
- Tier 4 projects are projects that can expect major delays (8 years) e.g. they would be relying on new transmission system lines.

It is important to understand that the projects would not require these works to be completed in advance of entering an auction; they would simply need to have sufficient confidence that the necessary works would be completed in advance of energisation.

2.2.2 How i-PAT works

Once the starting point has been defined, the first item the model accounts for is the pre-planning attrition. This then generates a capacity in MW entering the planning system through the local authority and SID routes each year. The model then applies a success rate and consenting duration to these capacities to determine the MW capacity in each year that would be expected to secure a planning permission and join a queue for a grid connection offer.

The next step is to consider the grid connection offer process. The model applies a batch size, batch frequency, offer issue timeline and prioritisation ruleset to determine the capacity in each year with planning and grid.

Following this we consider whether there are any further grid related delays before the project would be considered ready to bid into an auction. To determine this, we examined the MW capacity of "space" on the transmission system available in each county in each year and compared this with the estimated capacity with planning and grid emerging that year. Where space is available, this was allocated to the project with planning and grid and as this space is used up in the model, subsequent capacities were moved into one of several subsequent tiers.

The model then accounts for a percentage of projects that would require a second planning consent for their grid connection method before being ready to bid into an auction. This generates a MW capacity in each year that is available to bid into an auction.

For the auction process the model allows the user to define a minimum amount of oversubscription to determine the capacity securing a route to market in each year and also to identify losing bidders that can bid into the next auction. The final step is to apply a finance and build period to the capacity with a route to market to determine the MW capacity energised in each year. This process is summarised in Figure 10.

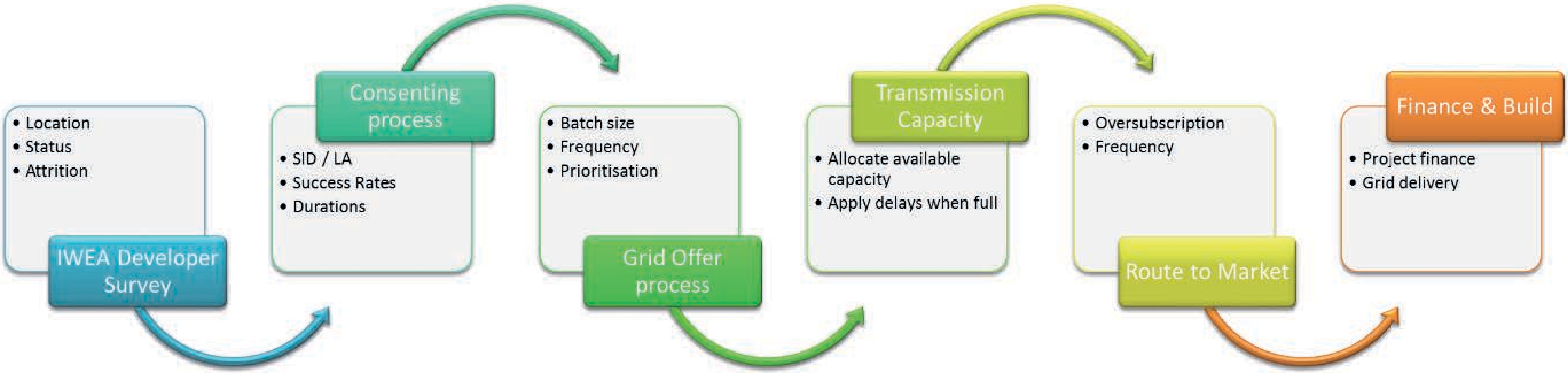


Figure 10: Illustration of the operation of the i-PAT model.

3 Business as Usual Analysis

3.1 Business as Usual (BaU) Assumptions

The BaU assumptions applied in the i-PAT tool are as summarised in Table 3 and Table 4 below.

Table 3: BaU Input assumptions excluding transmission grid.

Assumption	Value Applied	Unit
Planning Process Assumptions		
Pre-planning attrition	33	%
SID success rates	38	%
Local Authority success rates	80	%
SID Process Consenting Duration	44	Weeks
Local Authority Process Consenting Durations	142	Weeks
Blended Average Consenting Duration	1.90	Years
Grid Offer Process		
Batch size (capacity)	1,000	MW
Batch size (number of projects)	50	Offers
Batch frequency	Annual	
Complete Offer Process timeline	12	Months
Prioritisation Criteria (onshore wind and solar)	Date order of planning grant	
Impact of Longstop dates	0% of losers in auctions bid into next auction	
Grid Connection Planning		
Percentage of capacity (MW) that would require a second consent for their grid connection method from 2022 and would face a 2-year delay between securing a grid offer and being ready to bid into an auction.	70	%
Transmission System Delays applied between receiving a grid offer and being ready to bid into an auction (see Table 4).		
Capacity (MW) in Tier 1	0	Years
Capacity (MW) in Tier 2	2	Years
Capacity (MW) in Tier 3	4	Years
Capacity (MW) in Tier 4	8	Years
Route to Market		
Percentage of capacity (MW) ready to enter an auction that secure a contract each year. (Assumes annual auctions either through RESS or CPPA).	66	%
Pre-auction attrition of consented projects	25%/5%	2020/2021+
Finance & Build		
Wind farm financial close post auction win	4	Months
ESB/EirGrid interface agreement and capital approval processes post 2nd stage grid payment.	8	Months
Non-contestable grid delivery	18	Months

Table 4: Grid Delay Threshold Capacity (MW) which represent the capacity post-2020 that can fit on the grid in each county within each tier of delay. Once the threshold for a Tier is reached, the next wind farm seeking access to the grid is allocated to the subsequent Tier and the associated delay period is applied in the analysis.

County	Tier1 (MW)	Tier2 (MW)	Tier3 (MW)	Tier 4 (MW)
Offaly	134	252	296	296+
Donegal	86	172	172	172+
Cork	157	258	258	258+
Mayo	0	100	100	100+
Kerry	83	166	166	166+
Waterford	32	65	65	65+
Clare	25	50	50	50+
Leitrim	0	0	81	81+
Galway E	128	128	128	128+
Galway W	29	29	29	29+
Tipperary N	0	0	0	0+
Tipperary S	0	98	98	98+
Laois	78	156	156	156+
Kildare E	46	91	91	91+
Kildare W	0	0	0	0+
Westmeath	166	332	332	332+
Roscommon N	0	0	28	28+
Roscommon S	12	23	23	23+
Kilkenny	13	27	27	27+
Longford	8	17	17	17+
Wicklow	55	110	110	110+
Carlow	46	92	92	92+
Cavan	23	46	75	75+
Other	0	102	202	202+
Totals	**1,122**	**2,315**		

3.2 Business as Usual (BaU) Results

The results of the BaU analysis are presented in Figures 11 to 15. It is clear that in a BaU scenario there are shortcomings in every part of the development cycle.

Planning Figure 11: To achieve a target of 8,200 MW of onshore wind by 2030 requires an absolute minimum of 4,000 MW of projects to be consented over the decade. But in a BaU scenario we only reach a cumulative consented volume of 3,880 MW. This means that currently we cannot even get sufficient projects through the planning system to achieve the 2030 target, let alone get enough through to survive the formidable attrition rates at the next stage.

This poor outcome is driven primarily by low success rates in the SID process, high pre-planning attrition and relatively long consenting durations. It is also important to note that the 2020 figure includes the cumulative consented wind up to 2020 that will not be built under REFIT. We are forecasting a relatively high pre-auction attrition of 25 per cent on these capacities due to legacy issues for these projects.

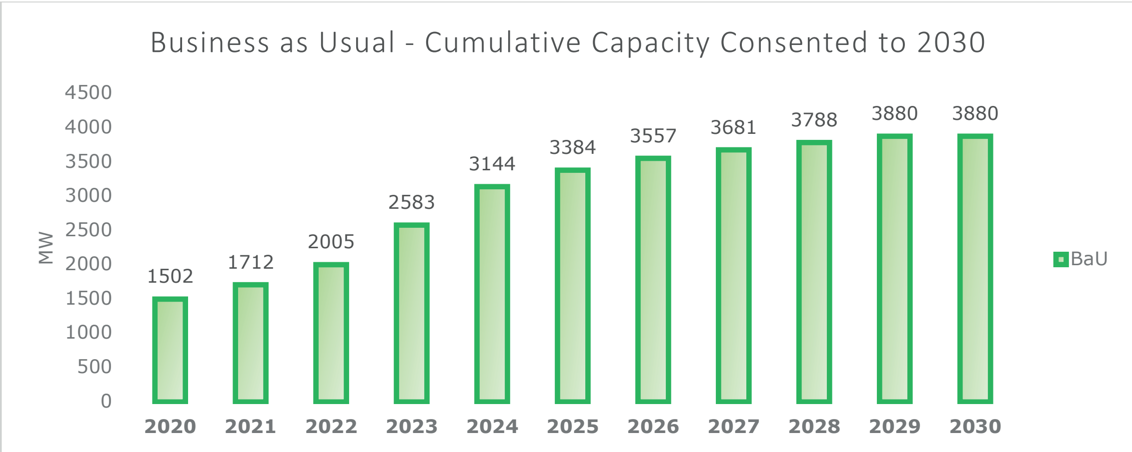


Figure 11: BaU cumulative capacity (MW) with planning consent 2020 to 2030 (2020 figure includes all capacity consented but not constructed at the end of 2020).

Grid Offer Process Figure 12: Similarly, an absolute minimum of 4,000 MW of grid offers must be available over the decade if the target is to be reached and significantly more if we are to see competitive auctions. In the Business as Usual scenario we only reach 3,161 MW by 2030. This is primarily driven by an assumed "date order of planning grant" prioritisation which results in large numbers of smaller capacity offers being issued and imposes significant waiting times on larger wind farms.

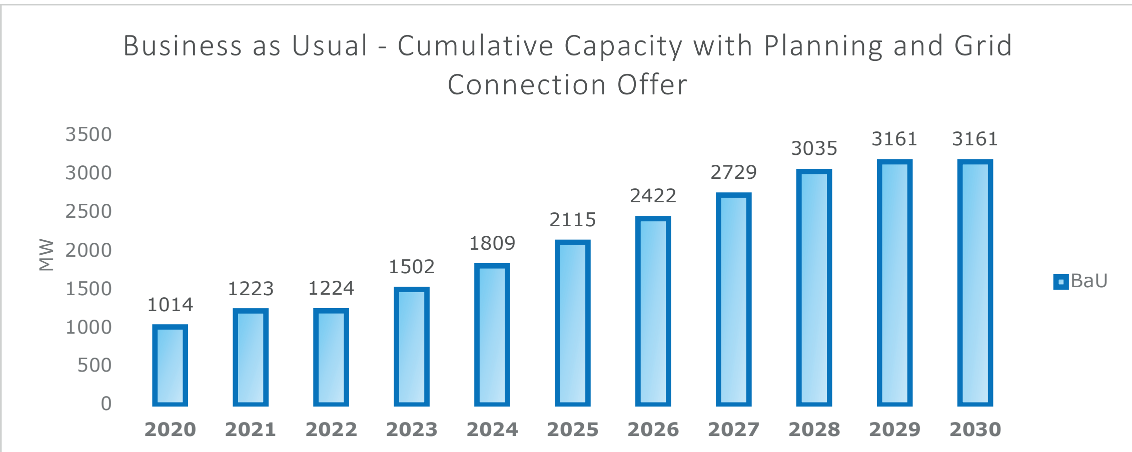


Figure 12: BaU cumulative capacity with planning consent and grid connection offer 2020 to 2030 (2020 figure includes all capacity with planning and grid but not constructed at the end of 2020).

This means that the capacity available to enter auctions is relatively low (Figure 13) and, when the minimum level of competition is applied, it means there are only ~1,300 MW with a RESS offer or CPPA by 2027 (Figure 14) so the total capacity energised by 2030 only reaches 5,444 MW (Figure 15).

In the BaU scenario other factors such as the transmission system capacity are less damaging due to the relatively low volumes of projects coming forward with planning permission and a grid offer.

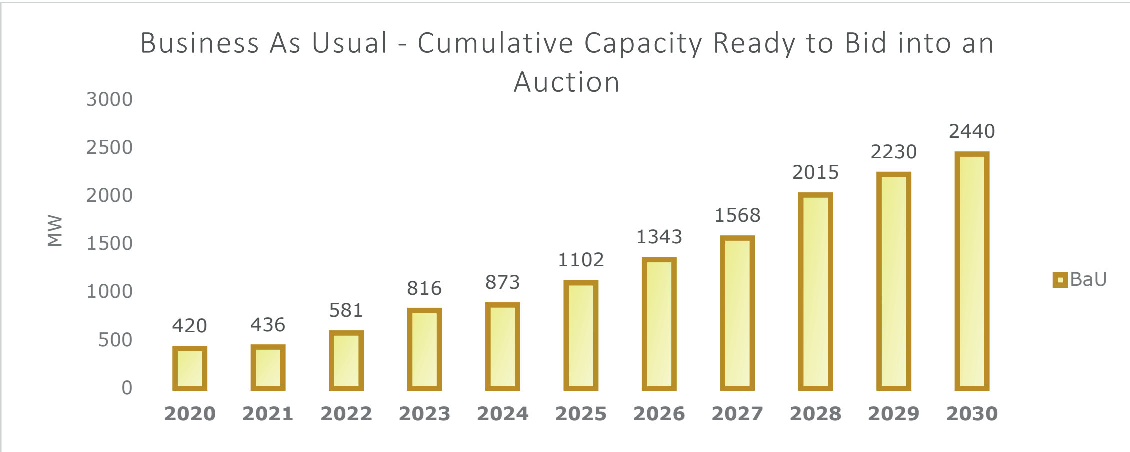


Figure 13: BaU cumulative capacity ready to bid into an auction 2020 to 2030 (2020 figure includes all capacity with planning permission, grid offer, no transmission system delays, grid connection planning and bankable at the end of 2020).

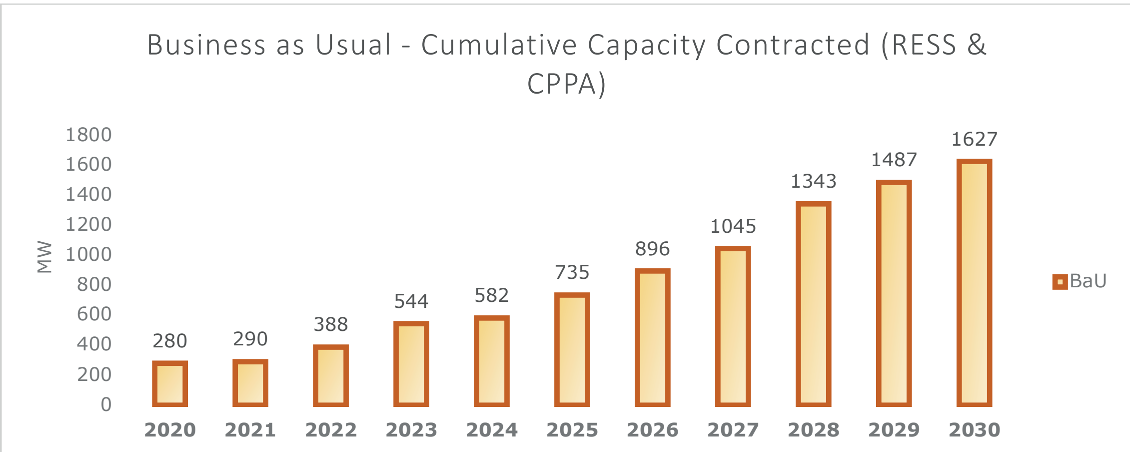


Figure 14: BaU cumulative capacity contracted under RESS or Corporate PPA in each year 2020 to 2030. (Corporate PPA contracts signed in 2019 are not included in these figures).

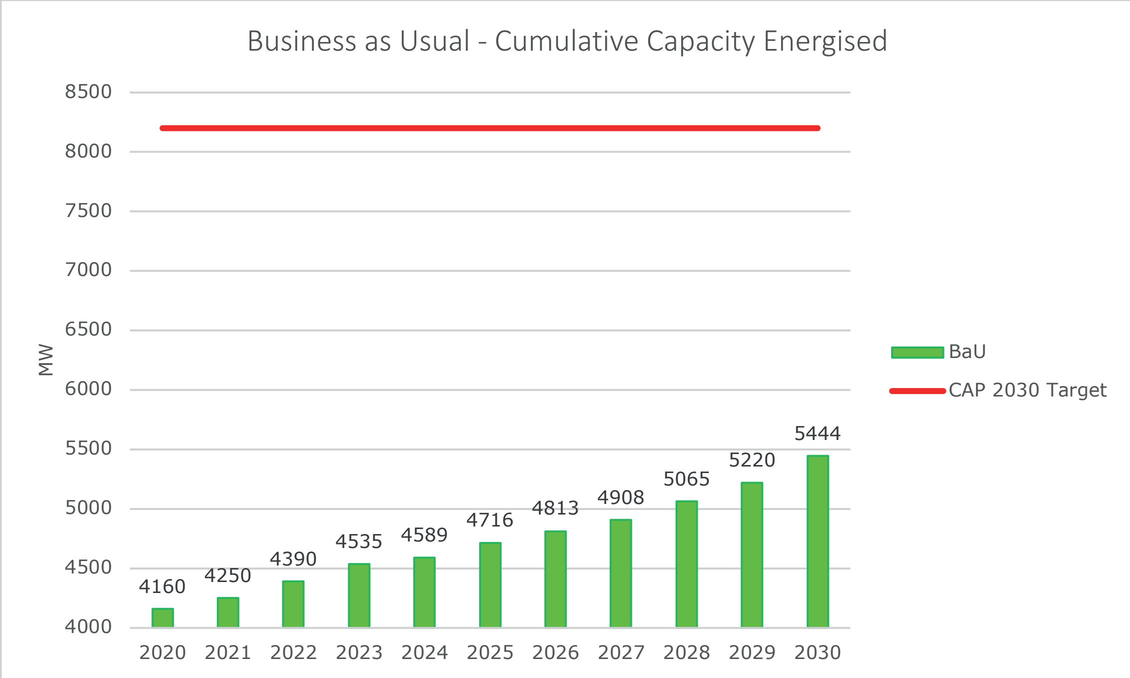


Figure 15: BaU cumulative capacity of onshore wind energised in each year from 2020 to 2030.

4 Policy Improvements to deliver 8.2 GW Onshore Wind by 2030

This section presents a list of Policy Improvements (PIs) which have been identified to accelerate the development of onshore wind in Ireland between 2020 and 2030. In total, nine PIs have been identified, which are:

1. Halve the pre-planning attrition rate by reducing the BaU assumption from 33 per cent to 15 per cent;
2. Double SID Success Rates in the BaU from 38 per cent to 75 per cent;
3. Speed up ABP decision timelines by reducing BaU from 32-89 weeks across local authority appeals, JR referrals and SID decisions to 18 weeks;
4. Increase the number of grid offers in ECP from to at least 50 (ideally 125) with priority for the largest projects;
5. Design and consent the transmission system in parallel to the overall wind energy pipeline so that 70 per cent of projects have no delay (compared to 26 per cent in the BaU), 20 per cent of projects have a two year delay (compared to 47 per cent in the BaU), and 10 per cent of projects have a four year delay (compared to 27 per cent in the BaU);
6. Allow parallel consenting of shallow grid connections for individual wind farms by facilitating grid installations along public roads and early engagement with the SOs on connection methods, so that the percentage of projects that consent their grid connection in parallel with the wind farm increases from 30 per cent to 80 per cent;
7. Increase competition in RESS/CPPAs by allowing longer grid offers by increasing grid offer 'longstop dates' from one auction/year to three auctions/years;[12]
8. Reduce construction and grid delivery timelines from 2.5 to 1.5 years;
9. Ensure an annual route to market via RESS or CPPAs.

Each section in this chapter covers a separate PI by firstly quantifying the impact it has for each year between 2020 and 2030 in terms of either:

- Additional capacity of onshore wind that is consented and/or
- Additional capacity of onshore wind energised

After quantifying the impact of the PI, we then describe how to go about implementing the PI by breaking it down into the following sub-headings:

- Summary of Current Policy;
- Shortcomings of Current Policy;
- Proposed New Policy;
- Implementing New Policy.

[12] Due to PI9 it is assumed that auctions are annual so three years equates to three auctions.

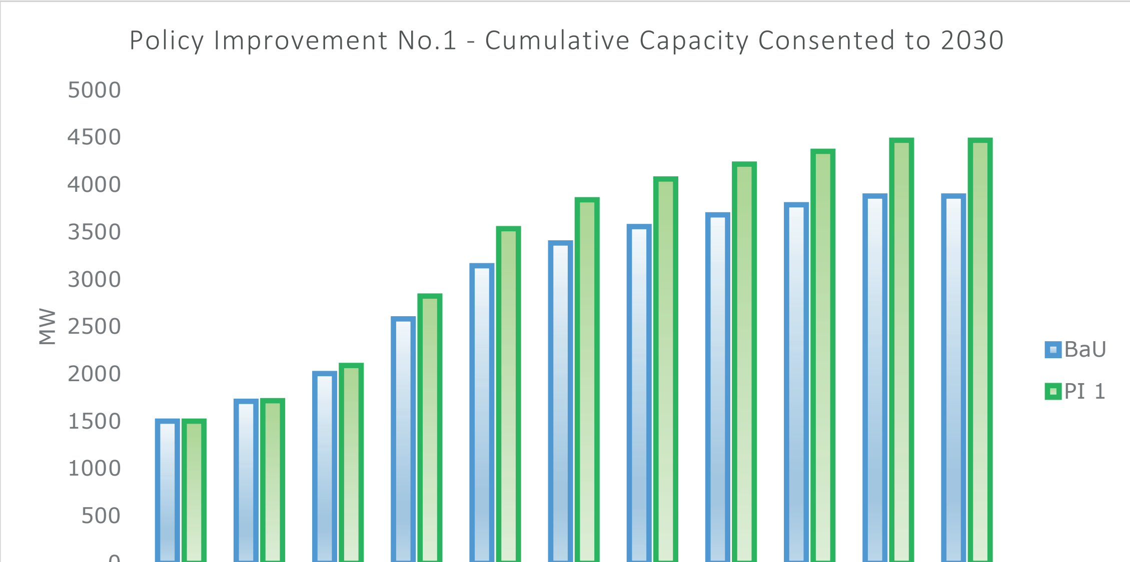
It is hoped that this will offer the stakeholders responsible for each PI a roadmap to implement each proposal.

It is important to note that all improvements are inter-related. In some cases, the full benefit of an individual improvement will not be realised until combined with some subsequent improvement. To address this we have included a separate impact analysis in section 5 which analyses the impact of the failure of each policy improvement.

4.1 PI1: Halve the pre-planning attrition rate

4.1.1 Introduction and Quantifying the Impact

By halving the pre-planning attrition rate assumed in BaU scenario from 33 per cent to 15 per cent, there is an improvement on the capacity consented over the decade, as outlined in Figure 16 below. By 2030 the cumulative capacity consented increases from 3,880 MW to 4,469 MW, however due to other bottlenecks in the system (e.g. grid offers, grid capacity, etc.) no additional capacity is energised by 2030 compared to the BaU scenario.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	1502	1712	2005	2583	3144	3384	3557	3681	3788	3880	3880
PI 1	1502	1718	2090	2823	3535	3841	4060	4217	4352	4469	4469

Figure 16: Impact of a reduction in the pre-planning attrition rate on the capacity consented in each year.

4.1.2 Implementation

The changes required to reduce the pre-planning attrition rate are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.1.2.1 Summary of Current Policy

The spatial planning and identification of suitable areas for wind energy development is a function of local authorities, typically achieved through their County Development Plans or specific Renewable Energy Strategy documents.

The Department of Communications, Climate Action and Environment (DCCAE) is currently preparing a Renewable Electricity and Policy Development Framework (REPDF). This will provide guidance to An Bord Pleanála, planning authorities, other statutory authorities, the general public and project developers.

It is intended that REPDF will seek to broadly identify suitable areas in the State where large scale renewable electricity projects (defined as a capacity of 50 MW or more) can be developed in a sustainable manner.

The recently adopted Regional Spatial and Economic Strategies (RSES), prepared by the three Regional Assemblies, have some supportive policies and objectives relating to renewable energy, particularly around preparing regional renewable energy strategies and identifying potential renewable energy sites.

It is unclear how the current and future policy frameworks for the spatial planning for wind energy development will be integrated and how the various policy documents will be aligned and ordered in hierarchy.

4.1.2.2 Shortcomings of Current Policy

Some wind farms have attracted opposition in recent years and while the levels of opposition have fallen steadily from a peak several years ago, the nature of the planning system is that small numbers of objectors to renewable energy can have a disproportionate impact.

In some cases this opposition has led to changes, or proposed changes, to local planning policies or County Development Plans. Some such policy changes have required intervention by the Minister of Housing, Planning and Local Government, to bring local policy back into line with national policy.

The proposed REPDF and the objectives of the RSES are very much welcomed and urgently required. But they must be aligned within a policy framework that clearly assigns responsibility for spatial planning for wind energy development at a national or regional level, rather than at local level.

As shown in Figure 17 the current approach is leading to major differences in landscape classification for wind energy along county boundaries. These four counties all have very different approaches to classifying landscape which creates challenges for renewable energy projects that cross – or are even within sight of – county borders.

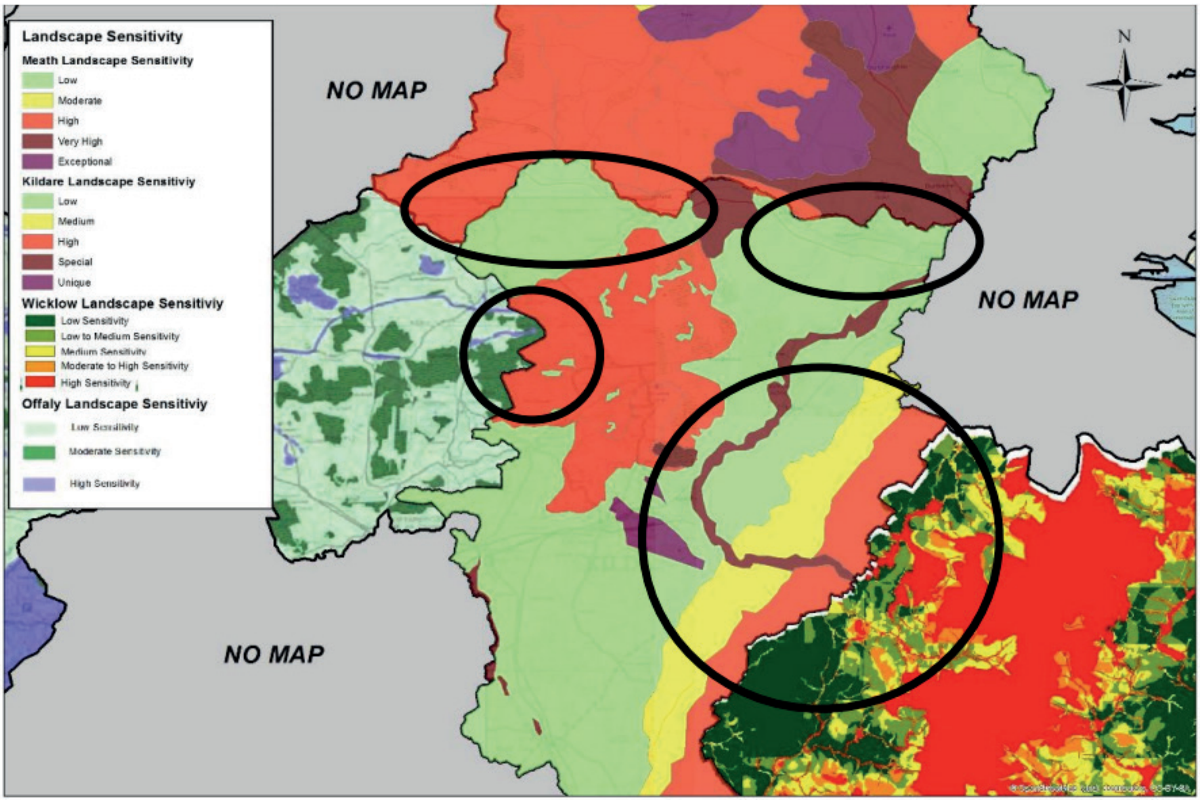


Figure 17: Landscape classification for wind energy across Meath, Kildare, Wicklow and Offaly which outlines the misalignment at county boundaries for wind energy at present, which a regional approach would overcome.[13]

4.1.2.3 Proposed New Policy

IWEA believes the spatial planning of wind energy should be carried out on a national and regional basis.

To complement the REPDF currently being prepared by DCCAE, IWEA urges that each Regional Assembly should be given the resources to prepare Regional Renewable Energy Strategies.

These would ensure that a sufficient amount of land within each region is identified as suitable for wind energy to meet the national targets. Analysis completed by MKO planning consultants indicates that sufficient suitable development land is available for the volumes of renewable energy we need to deliver the Climate Action Plan.[14] [15] The Regional Renewable Energy Strategies could integrate the output of the REPDF and ensure that the full potential of each region is identified. This would fill the policy and spatial planning gap for projects less than 50 MW in scale, particularly community energy projects.

[13] https://iwea.com/images/Article_files/Donal_OSullivan_Powerpoint_Slides_IWEA_Spring_Conference_2019.pdf
[14] https://iwea.com/images/Article_files/Brian_Keville_Powerpoint_slides_-_IWEA_Spring_2019.pdf
[15] https://www.youtube.com/watch?v=w7F1tXi3kMg&list=PLDsqLyqa3iQRqmwUGJjBkx-nOyuLiabPy&index=18

The preparation of the Regional Renewable Energy Strategies by the three Regional Assemblies should be coordinated by, and directly funded by, the Department of Housing, Planning and Local Government.

Once the Regional Renewable Energy Strategies are published, the County Development Plans of individual local authorities would no longer be used to identify areas as suitable or unsuitable for renewable energy development.

The Regional Assemblies and the RSES that is being prepared for each region provide a more appropriate platform for ensuring national policy can be transposed effectively and that a consistent approach is applied across the entire country that reflects Government policy.

A regional approach could be used to strategically designate areas within each region for the development of wind energy. This would help address some of the significant planning challenges facing the wind energy sector including inter-county differences in landscape classification as outlined in Figure 17.

Rather than trying to advance national policy through 31 different local authority areas and uncoordinated County Development Plans we believe national policy should be integrated and developed strategically across the three Regional Assemblies (Figure 18).

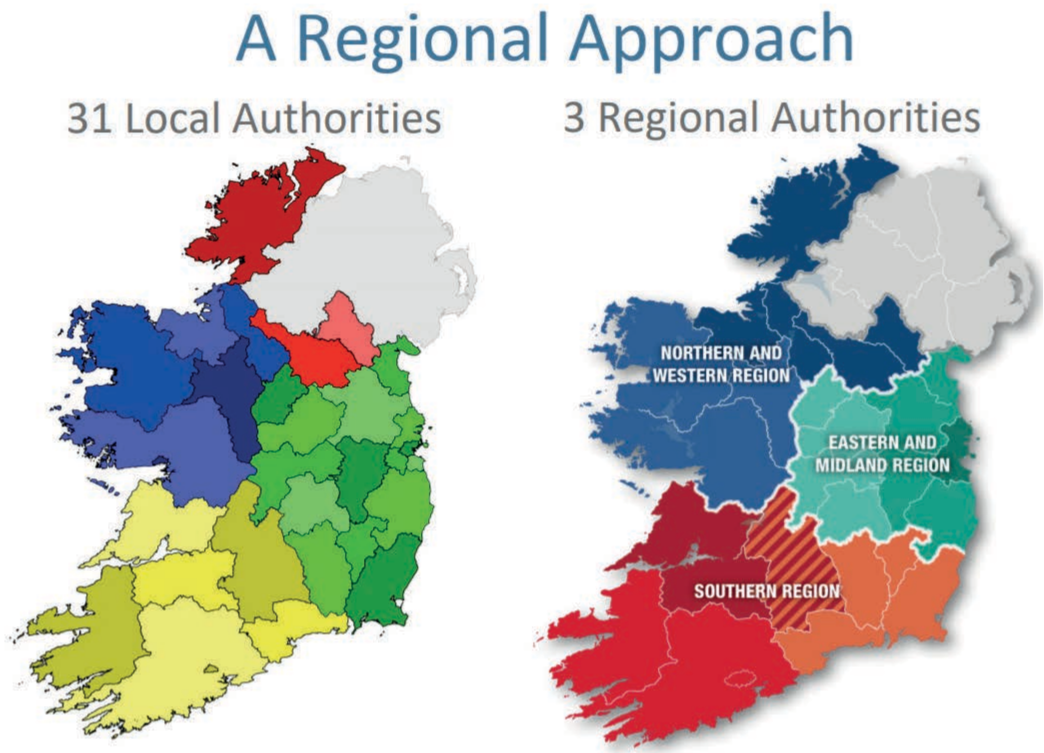


Figure 18: A Regional Approach to renewable energy planning will mean the transposition of national policy via three Regional Assemblies instead of 31 Local Authorities which will streamline resources, approaches and expertise.

4.1.2.4 Implementing new Policy

Key Non-Industry Stakeholders

Roinn Cumarsáide, Gníomhaithe ar son na hAeráide & Comhshaoil
Department of Communications, Climate Action & Environment

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

Tionól Reigiúnach Oirthir agus Lár-Tíre
Eastern and Midland Regional Assembly

Northern & Western Regional Assembly

Tionól Réigiúnach an Deiscirt
Southern Regional Assembly

Who is the decision maker?

The Department of Housing, Planning and Local Government would have responsibility for driving the delivery of the Regional Renewable Energy Strategies by the Regional Assemblies.

Who has a supporting role?

The Department of Communications, Climate Action and Environment would have a supporting role as the department responsible for delivering the REPDF, which will be incorporated into the Regional Renewable Energy Strategies.

Budget or resource requirements:

To appoint consultants to prepare the Regional Renewable Energy Strategies on behalf of the three Regional Assemblies, and the associated Strategic Environmental Assessments (SEA) and Habitats Directive Assessments (HDA), is likely to require a budget of approximately €300,000. Cost and resources efficiencies could be availed of by preparing the three strategies for the three Regional Assemblies in parallel.

Key steps:

- DHPLG to brief and instruct Regional Assemblies on the urgency of proceeding with Regional Renewable Energy Strategies and outline proposed approach for preparation, funding, etc.
- DHPLG to draft a tender to be used by the three Regional Assemblies to appoint consultants to prepare the regional strategies and associated assessments.
- DCCAE and DHPLG to quantify the amount of land required nationwide to provide the capacity of renewable generation required to meet the 2030 targets and future ambitions.
- Regional Assemblies to appoint consultants.
- Regional Renewable Energy Strategies to be adopted by Regional Assemblies as variations to, or addendums of, RSES.

- DHPLG to transfer responsibility for identifying areas as suitable or unsuitable for renewable energy development to the Regional Assemblies as part of their Regional Renewable Energy Strategies.

Target date for achieving policy change:

2021/2022

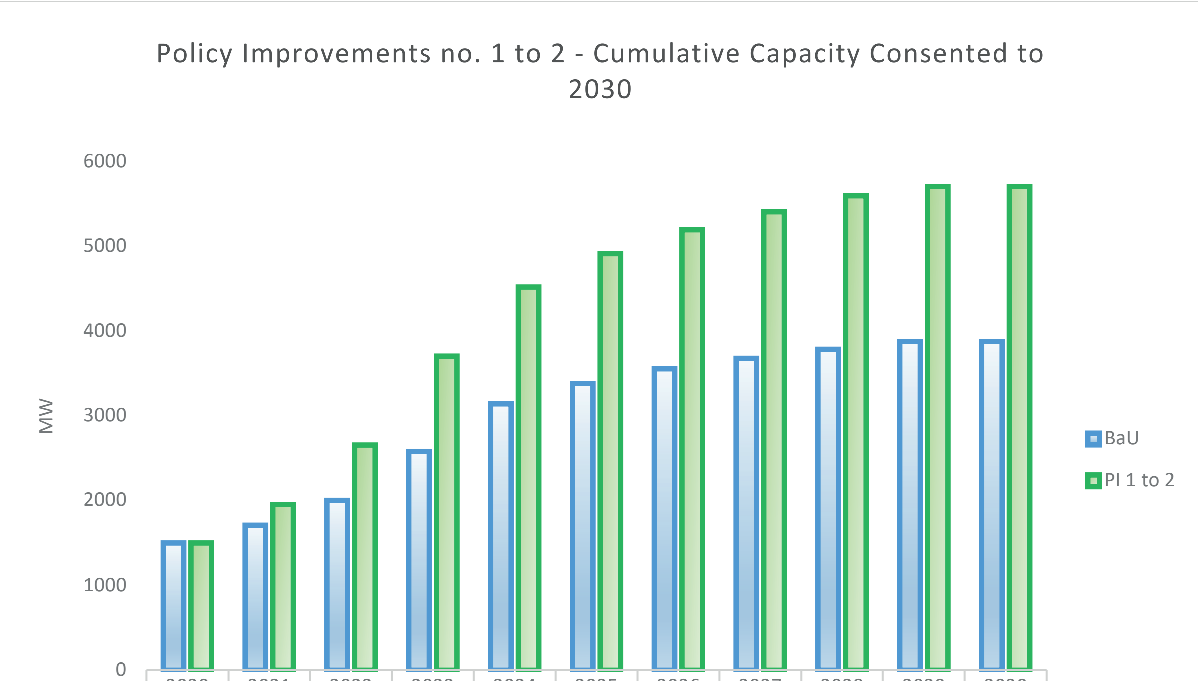
4.2 PI2: Double SID Success Rates

4.2.1 Introduction and Quantifying the Impact

Our survey data indicates that approximately 58 per cent of all capacity in the onshore development pipeline will be progressing through the SID process. Here we increase the SID success rate from 38 per cent to 75 per cent which significantly increases the capacity consented each year to 2030 as noted in Figure 19 below.

The additional benefit of this increased success rate is that the blended average consenting duration of projects proceeding through the local authority process and SID processes reduces from 1.90 years to 1.59 years due to the quicker overall decision times for SID decisions, JR referrals and appeals.

Implementing Policy Improvements 1 & 2 results in a total forecast of 5,708 MW of projects with planning consent by 2030. However, again due to other bottlenecks in the system, no additional capacity is energised in 2030 compared to the BaU results.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	1502	1712	2005	2583	3144	3384	3557	3681	3788	3880	3880
PI 1 to 2	1502	1956	2658	3707	4523	4917	5198	5411	5600	5708	5708

Figure 19: Impact of earlier Policy Improvements combined with an increase in the SID success rates from 38 per cent to 75 per cent on capacity consented each year to 2030.

4.2.2 Implementation

The changes required to double the SID success rate from 38 per cent to 75 per cent are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.2.2.1 Summary of Current Policy

Wind energy projects with a proposed capacity of 50 MW or greater must apply to An Bord Pleanála for planning permission via the Strategic Infrastructure Development (SID) process. The success rate of SID wind farm applications and decision timeframes have both improved in recent years. However, there remains significant room for improvement, particularly during the “pre-determination” stage.

4.2.2.2 Shortcomings of Current Policy

Before an application for planning permission can even be submitted, it can regularly take more than 12 months for a determination to be made that a project can be classed as an SID project even though the criteria set out in legislation is extremely clear. There is no reason of which we are aware to explain why the SID determination process cannot be made within two weeks.

Once classed as an SID the project can proceed with submitting a planning application. Many SID applications have been refused for reasons that should have been identified for applicants much earlier in the process. Examples include refusals for reasons such as inappropriate site selection (e.g. first National Children’s Hospital application), a lack of policy to support the development (e.g. on a number of large-scale wind farm developments), or the expectation to follow new requirements or guidelines that had not been identified earlier (e.g. new best practice guidelines for surveying and assessment).

Applicants, planning authorities, An Bord Pleanála and third parties all expend significant time and resources on such applications which, if unsuccessful, do nothing to help deliver strategic national infrastructure. Pre-application consultation with An Bord Pleanála is currently limited to discussions around determining whether the proposal is SID or not. There is no meaningful engagement on the detail of a project that can be relied upon in the later stages of the application process.

4.2.2.3 Proposed New Policy

The pre-planning consultation stage of SID projects should be split into two distinct parts.

The first is a quick, streamlined, process for confirming whether a project is SID. The second is a meaningful pre-planning consultation phase, modelled on the SHD (Strategic Housing Development) process. This requires An Bord Pleanála to determine at the end of the pre-planning stage whether there is a reasonable basis for the planning application to be made.

The process of determining and confirming whether a proposed project constitutes SID should be greatly simplified. A simple form (preferably online) could be submitted to An Bord Pleanála in which the applicant provides the project's details which allow a decision to be made on whether it satisfies the SID project criteria. A two-week timeframe is short but is considered reasonable given the decision should be Yes/No based on the very clear SID project definitions set out in legislation.

A formal and meaningful pre-application consultation process for SID projects, akin to that in place for Strategic Housing Development (SHD) applications, would be of great benefit. An Bord Pleanála would engage with applicants, the local planning authority and other Statutory consultees, on a formal statutory basis, as per the SHD process. The pre-application consultation should conclude when the Board has formed an opinion that documents, details, consultation and discussions undertaken on the project constitute a reasonable basis for an application.

Such a process is proving very effective for strategic housing developments in identifying material issues at an early stage and providing applicants an opportunity to address them before submitting an application.

4.2.2.4 Implementing new Policy

Key Non-Industry Stakeholders

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

An Bord Pleanála

Who is the decision maker?

The Department of Housing, Planning and Local Government would have to legislate for the suggested new SID pre-application stage in a revision to the Planning and Development Act.

Who has a supporting role?

The Department of Housing, Planning and Local Government may wish to discuss the merits of the suggested change with An Bord Pleanála in advance of bringing forward the legislative change.

Budget or resource requirements:

Resource requirements in the form of time for personnel in the Department of Housing, Planning and Local Government required to draft the required legislative amendment. Once the change is implemented, ABP will also need additional resources to meet the SID success rates.

Key steps:

1. DHPLG seeks formal or informal input from An Bord Pleanála and industry stakeholders on the need for changes to the SID process.
2. DHPLG drafts a suggested legislative amendment.
3. The suggested legislative amendment is inserted into the next Planning Bill or an alternative Bill that can give effect to the changes to the Planning and Development Act.

Target date for achieving policy change:

2021

4.3 PI3: Speed up ABP decision timelines

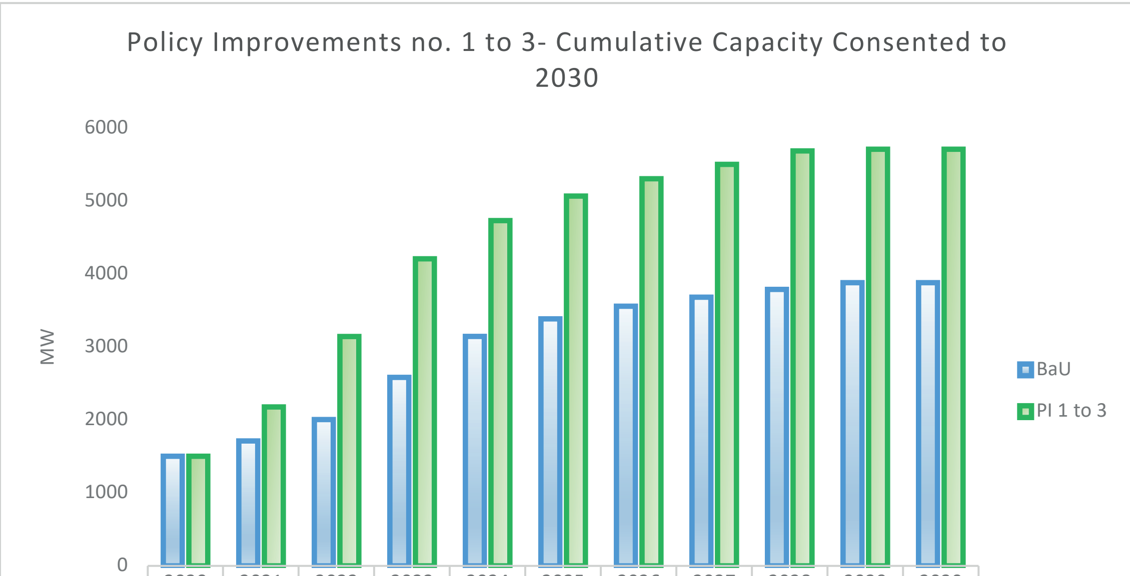
4.3.1 Introduction and Quantifying the Impact

The BaU assumptions for ABP decision timelines, based on an analysis of historic timelines, are as follows:[16]

- Local Authority Appeal = 66 weeks
- Judicial Review Referral = 89 weeks
- SID decisions = 32 weeks

Here we reduce all of these timelines to 18 weeks which increases the capacity consented each year to 2030 as noted in Figure 20 below. The additional benefit of this increased success rate is that the blended average consenting duration of projects proceeding through the local authority process and SID processes reduces from 1.59 years to 1.13 years, due to the quicker overall decision times across SID decisions, JR referrals and appeals.

Implementing Policy Improvements 1 to 3 results in material improvements in the capacity consented in the years 2020 to 2024 which are the critical years for 2030 energisations. Again, due to other bottlenecks in the system no additional capacity is energised in 2030 compared to the BaU results.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	1502	1712	2005	2583	3144	3384	3557	3681	3788	3880	3880
PI 1 to 3	1502	2178	3143	4207	4730	5066	5304	5501	5685	5708	5708

Figure 20: Impact of earlier Policy Improvements combined with a reduction in ABP decision timelines to 18 weeks on capacity consented each year to 2030.

[16] https://iwea.com/images/Article_files/Brian_Keville_D1.pdf

4.3.2 Implementation

The changes required to speed up ABP decision timelines by reducing the BaU timelines from 32-89 weeks across various streams to 18 weeks for all are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.3.2.1 Summary of Current Policy

An Bord Pleanála currently has a statutory objective to decide or dispose of appeals within 18 weeks. However, where the Board does not consider it possible or appropriate to reach a decision within 18 weeks (e.g. because of delays arising from the holding of an oral hearing), it informs the parties and states when it intends to make the decision.

4.3.2.2 Shortcomings of Current Policy

According to An Bord Pleanála's Annual Report for 2018 a target was set at the beginning of the year to decide between 60-70 per cent of planning appeals within the statutory objective period of 18 weeks. This was lower than the previous year's target, given the backlog generated that year. By year's end, the compliance rate for appeals was down to 39 per cent., However, in the month of December this improved to 50 per cent. The average timeframe to decide planning appeals was just over 22 weeks in 2018 (compared to 17 weeks in 2017).

The appeal decision timeframes experienced by wind farm projects differ greatly from the average figures for all appeals as reported in the 2018 An Bord Pleanála Annual Report.

An analysis of wind farm appeals decided by An Bord Pleanála between 2017 and mid-2019 found that the average period that appeals were under consideration by An Bord Pleanála to be 66 weeks. For wind farm grid connections between 2018 and mid-2019 the average period that appeals were under consideration by An Bord Pleanála was 67 weeks.

These are far in excess of the 18-week statutory objective period, and three times the average period for all appeals decided by An Bord Pleanála in 2018.

4.3.2.3 Proposed New Policy

The statutory objective of 18 weeks for An Bord Pleanála to decide on appeals should become a statutory decision period.

Statutory decision periods were introduced for SHD (strategic housing developments) applications submitted directly to An Bord Pleanála. An Bord Pleanála has proven its ability to meet these statutory deadlines for making decisions on SHD applications when assigned the necessary resources to do so.

An Bord Pleanála should equally be sufficiently resourced to ensure it can meet an 18-week statutory decision period on all appeals or at the very least on infrastructure projects such as renewable energy developments that are essential to the State's fight against climate change.

4.3.2.4 Implementing new Policy

Key Non-Industry Stakeholders

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

An Bord Pleanála

OPR Oifig an Rialaitheora Pleanála
Office of the Planning Regulator

Who is the decision maker?

The Department of Housing, Planning and Local Government (DHPLG) would have to legislate for the suggested new An Bord Pleanála decision timeframes in a revision to the Planning and Development Act.

Who has a supporting role?

DHPLG may wish to discuss the merits of the suggested change with An Bord Pleanála in advance of bringing forward the legislative change.

Budget or resource requirements:

Resource requirements in the form of time for personnel of the Department of Housing, Planning and Local Government, required to draft the required legislative amendment. Once the change is implemented, ABP will also need additional resources to meet the new 18-week decision timeline.

Key steps:

1. DHPLG seeks formal or informal input from An Bord Pleanála and/or industry stakeholders on the need for changes to the SID process.
2. DHPLG drafts a suggested legislative amendment.
3. Incorporate the amendment into the next Planning Bill or an alternative Bill that can give effect to the changes to the Planning and Development Act.

Target date for achieving policy change:

2021

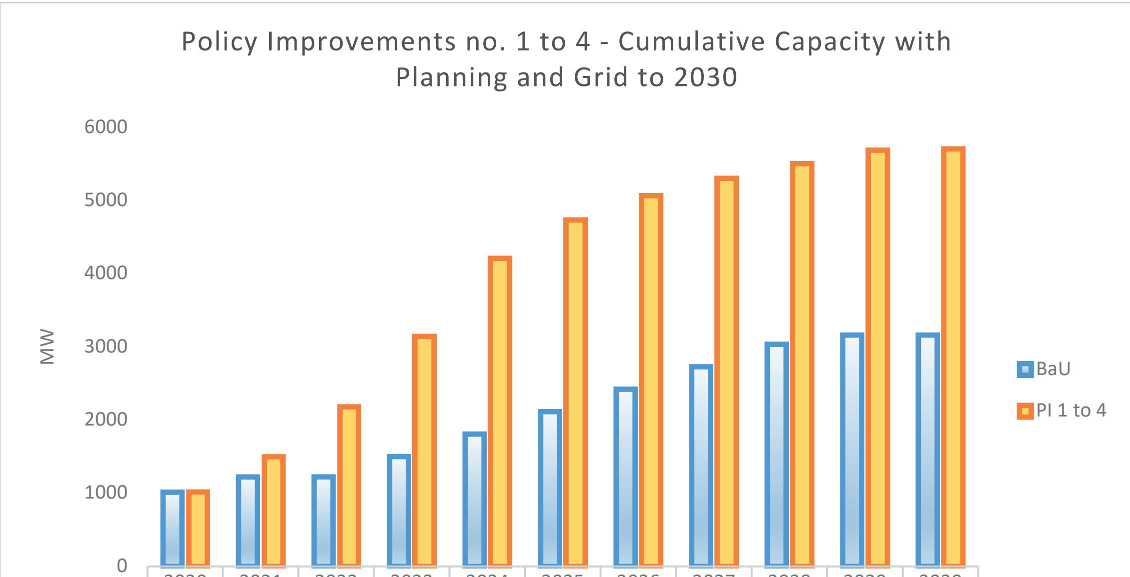
4.4 PI4: Increase Grid Offers in ECP

4.4.1 Introduction and Quantifying the Impact

It is assumed here that the System Operators (SOs) EirGrid and ESBN will process a minimum of 50 offers per annum (although this would ideally be 125 to clear the backlog) and prioritise the first 25 offers projects based on project scale or move to a Grid Following Funding model.

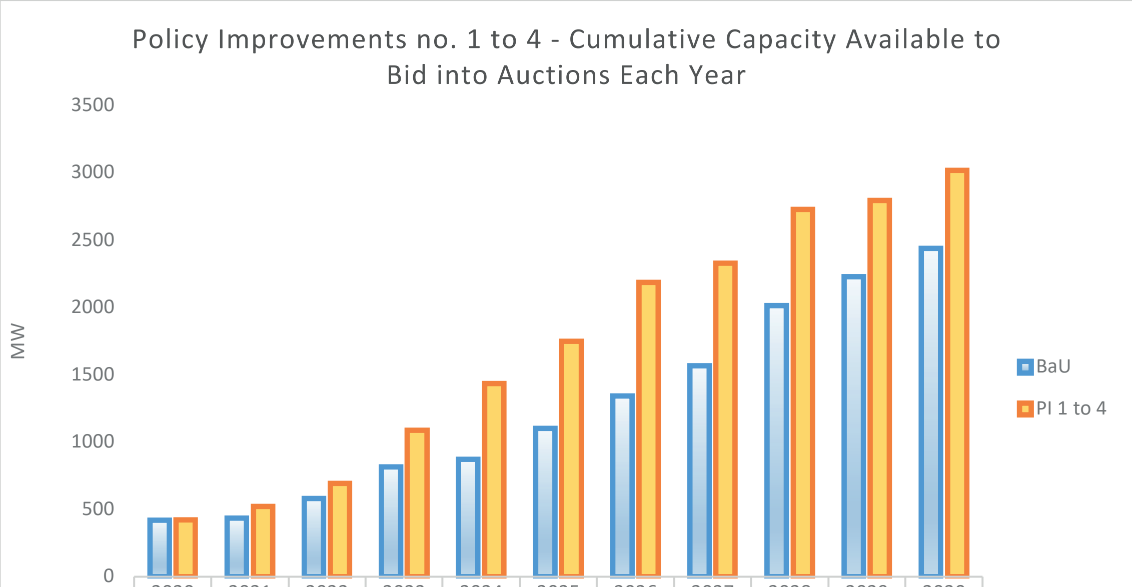
Given that this is an improvement to the grid offer process it has no effect on the volume of capacity receiving planning consents in each year. However, we do see material improvements in the volume of capacity with planning ***and*** a grid connection offer each year to 2030.

We also see improvements in the capacity available to contract in auctions, the capacity contracted in auctions and the capacity energised in each year as illustrated in Figure 21, Figure 22, Figure 23 and Figure 24 below.



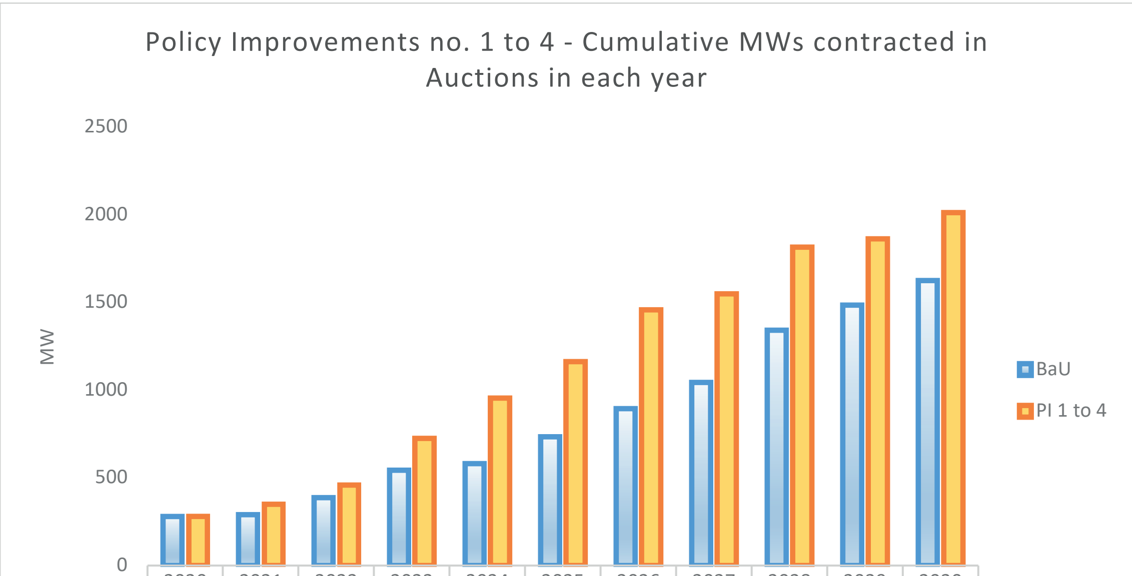
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	1014	1223	1224	1502	1809	2115	2422	2729	3035	3161	3161
PI 1 to 4	1014	1502	2178	3143	4207	4730	5066	5304	5501	5685	5708

Figure 21: Impact of earlier Policy Improvements combined with changes to ECP prioritisation criteria on the cumulative capacity with planning and grid in each year to 2030.



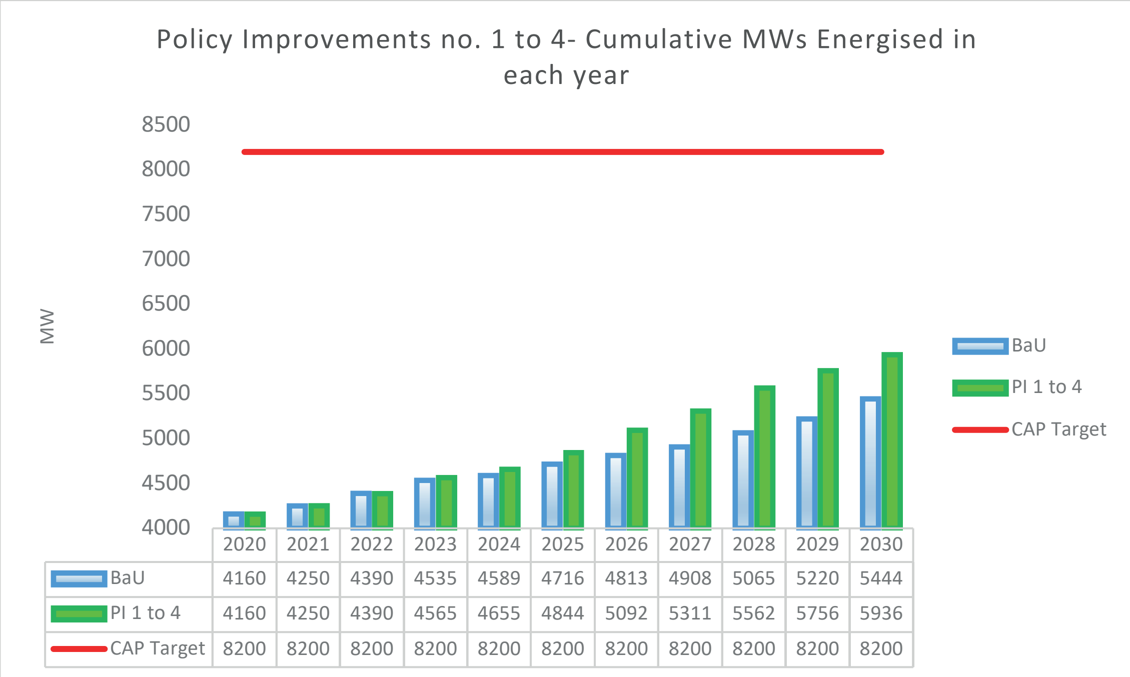
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	420	436	581	816	873	1102	1343	1568	2015	2230	2440
PI 1 to 4	420	524	692	1089	1435	1748	2189	2328	2729	2796	3021

Figure 22 : Impact of earlier Policy Improvements combined with changes to ECP prioritisation criteria on the cumulative capacity available to bid into auctions each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	280	290	388	544	582	735	896	1045	1343	1487	1627
PI 1 to 4	280	349	461	726	957	1165	1459	1552	1819	1864	2014

Figure 23: Impact of earlier Policy Improvements combined with changes to ECP prioritisation criteria on the cumulative capacity contracted each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
PI 1 to 4	4160	4250	4390	4565	4655	4844	5092	5311	5562	5756	5936
CAP Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 24: Impact of earlier Policy Improvements combined with changes to ECP prioritisation criteria on the cumulative capacity energised each year to 2030.

4.4.2 Implementation

The changes required increase the number of grid offers to at least 50 per annum while prioritising the first 25 offers projects based on project scale are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.4.2.1 Summary of Current Policy

The CRU's Enduring Connection Policy Stage 1 (ECP-1) decision, published in 2018, was the first step in establishing an enduring connection policy framework for new generators to connect to the system.[17] This was long overdue as almost a decade had passed since the end of the gate process which allowed large renewable projects to obtain a grid connection.

[17] https://www.cru.ie/wp-content/uploads/2017/04/CRU18058-ECP-1-decision-FINAL-27.03.2018.pdf

The key ECP-1 policy decisions were to mandate planning permission as a pre-requisite for a connection application, to process at least 1,000 MW of new connection offers in the first batch and to prioritise projects by date of planning expiry.

Furthermore, all offers from this batch are to be issued on a non-firm basis. It is expected that all connection offers under this first batch will be issued by Q2 2020.

4.4.2.2 Shortcomings of Current Policy

Batch Frequency

The renewable energy industry welcomed the commencement of the ECP-1 batch process but the pace at which offers have been processed has been very slow given the volume. It is expected that it will be over two years from the closure of the application window in May 2018 to the final connection offers being issued in Q2 2020. If we assume comparable timelines for future batches this will limit the amount of projects able to enter early RESS auctions and lead to knock-on delays in the number of projects able to connect on time for 2030.

Prioritisation

The grid connection batch process is generally heavily oversubscribed with projects seeking to obtain a connection offer. The current ECP-1 prioritisation rule processes projects based on the date of planning expiry, up to a limited number of offers or capacity that can be progressed in each batch.

This is not the most efficient use of the batch offer process and of limited SO resources as prioritisation based on planning date alone may lead to over-subscription of smaller projects, with lower MWh contributions to RES-E targets, and inefficient allocation of limited connection offers.

Firm Access

ECP-1 offers are also issued on a non-firm basis with no guarantee of when or if a connection will be made firm via the necessary network reinforcements. Currently generators are not compensated for curtailment, regardless of firmness, while non-firm generators are also exposed to the imbalance price for constrained energy. A complete non-firm connection policy where firmness is not delivered in a timely manner is simply not sustainable.

There is also a lack of transmission capacity in areas of the country where large numbers of renewable projects are planning to connect. This is likely to lead to high constraint levels if the grid is not reinforced in time for the future pipeline and would place additional risk on projects for something which is outside of their control.

Continuation of this non-firm connection policy in future ECP batches will impact the commercial viability of projects and means that developers will have to account for this uncertainty and added cost in their RESS auction bids. Consistency is needed between connection policy and the Clean Energy Package Electricity Regulation in relation to compensation for dispatch down and the renewable electricity ambitions set out in the Climate Action Plan.

4.4.2.3 Proposed New Policy

Batch Frequency

It is important that the enduring connection framework provides for frequent and efficient processing of batches to enable projects to enter RESS auctions and deliver the renewable capacity essential for 70 per cent RES-E.

Annual ECP batches with a maximum 12-month turnaround time between batch opening and issuing connection offers would greatly facilitate the number of projects able to enter RESS auctions without delay, and receive connection offers on time to deliver for 2030. Annual batch processing and opening of subsequent batches must be allowed to run in parallel, with the first batch application window opening in Q3 2020.

Prioritisation

Changing the ECP prioritisation rule so that at least 25 of the offers processed in each round are prioritised by size (as defined by their annual GWh generating capacity) would allow for more effective allocation of capacity in the batch process. The Clean Energy Package requires significant progress towards 2030 through check-in points in 2022, 2025 and 2027. It will be very difficult to demonstrate progress in the absence of prioritising large volumes of renewables. Additionally, the entry of larger projects into the RESS auctions should allow for greater economies of scale and for a more competitive outcome with lower costs for the electricity consumer. These offers should also be for renewable projects only.

A Grid Following Funding model, where only projects with planning permission and a defined route to market (e.g. RESS auction or CPPA) receive connection offers, was raised as a potential future connection policy option by the CRU in its ECP Future Options – Call for Evidence paper, published on 29 November 2019[18].

The CRU has proposed that this could be implemented post RESS-2. IWEA supports the principle of a grid following funding model and would encourage further development of this proposal as an efficient mechanism for delivering the necessary grid offers. However, we note that that this will require significant work and thought to prevent potential gaming, where projects are securing a route to market outside of RESS, and in relation to early and reliable connection cost information from the SOs so projects can factor this into their financial models.

[18] https://www.cru.ie/wp-content/uploads/2019/11/CRU19144-ECP-Future-Options-Call-for-Evidence.pdf

Firm Access

Article 13 of the Clean Energy Package Electricity Regulation, which came into force on 1 January 2020, states that generators should be compensated for non-market redispatch i.e. constraint and curtailment, including at the level of any financial support, unless they have accepted a connection offer with no guarantee of the firm delivery of power.

It is noted that the expression “a connection agreement under which there is no guarantee of firm delivery of energy” is also open to interpretation. It could be understood to only mean a permanently non-firm connection agreement. IWEA is also in receipt of correspondence from the European Commission’s Directorate-General for Energy (DG ENER), received via Wind Europe, which indicates that non-firm access should be the exception rather than the expectation.

That said, as non-firm wind farms in Ireland normally operate with levels of constraint comparable to firm wind farms, determining firmness is less important. This means non-firmness unnecessarily becomes a material financing risk for wind farms, which ends up costing the consumer more, particularly within the context of pay-as-bid renewable support auctions.

The importance of firmness for compensation for non-market redispatch brings greater scrutiny on the current definition of firm access. We believe that the current methodology for the determination of firmness should be changed under the enduring connection policy regime. It should take greater cognisance of the principle that a generator should be considered non-firm only where there are potentially high costs to the consumer arising from material, enduring, constraints.

Curtailment is not related to the firmness of a grid connection as it is a system wide issue that impacts all wind farms on a pro rata basis. Article 13 only requires firm generation to be compensated, but it is within the gift of Member States to compensate non-firm generators if appropriate to do so. Compensation for curtailment for both firm and non-firm generators should be implemented as it would strip away this uncertainty risk from RESS auction bids, thus benefiting consumers, and it would also level the playing field between generators competing in RESS.

A review of the existing non-firm connection policy, including the definition of firm access, should be carried out by the CRU. The review should include:

- Efficiency of connection offer process to improve timelines including the interactions between the TSO and DSO;
- Strategies for early engagement and information sharing between the generators and System Operators before and during the connection offer process;
- Processes for processing different renewable and supporting technologies; and
- Resources required to deliver grid offers for 2030 targets.

Our recommendations in relation to transmission development are set out in section 8.

4.4.2.4 Implementing new Policy

Key Non-Industry Stakeholders

Who is the decision maker?

The CRU will design and decide on the enduring connection policy framework, including the treatment of firm/non-firm access. The CRU will also decide on the allowed PR5 spend for the SOs.

Who has a supporting role?

EirGrid and ESBN will process the connection offers as per the ECP framework.

What budget or resource implications there may be?

Processing the required volumes of connection offers per year and opening subsequent batches in parallel will put a strain on SO resources which are already struggling to process and issue connection offers under ECP-1. There is a risk that the SOs will not be able to process the required connection volumes which will limit the number of projects able to enter RESS auctions without delays. It is therefore essential that the SOs assign adequate resources, and the Regulatory Authorities allow sufficient SO spend in PR5, to deliver the required connection offers.

The SOs' PR5 submissions and resource requirements must consider the volume of connections needed to achieve the targets under the Climate Action Plan. Resource requirements should also be informed by the pipeline data from the IWEA developer survey. Increased early engagement with developers is also important regarding connection method, connection costs and expected constraints. This may mean reassigning existing personnel or bringing in additional resources to handle this increased workload.

On top of this, we estimate that an independent review of the connection offer process in 2020 would require a budget of approximately €100,000. Now is the opportune time to commence this review and implement changes to the grid offer process in advance of the beginning of the next ECP batch in the second half of 2020.

Key steps and target dates for achieving the policy change

ECP:

- Q4 2019 – CRU consultation on ECP-2 proposals (to include firm access policy)
- Q2 2020 – CRU decision on ECP-2
- Q3 2020 – Connection process review by independent consultant
- Q3 2020 – ECP-2 batch application window opens (with annual batch openings going forward and a maximum 12-month turnaround time between batch opening and issuing of connection offers)
- Q4 2020 – SOs implement recommendations arising from connection process review

PR5:

- Q4 2019 – SOs' PR5 submission to the CRU
- Q2 2020 - Consultation on PR5
- Q3 2020 - CRU PR5 decision

4.5 PI5: Design and consent the transmission system in parallel

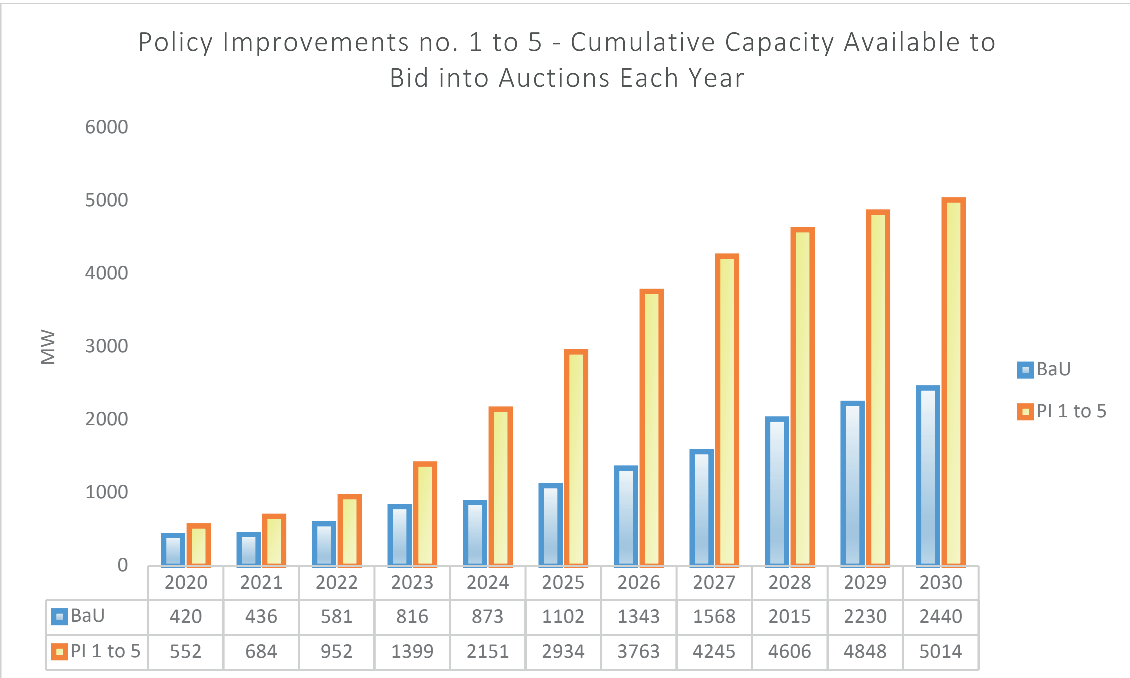
4.5.1 Introduction and Quantifying the Impact

Before bidding into an auction, projects need visibility of a commercially viable level of transmission constraints at the time of anticipated energisation and the necessary reinforcements need to be completed by the time the projects are energised.

In this section we assume that by implementing parallel design and consenting of the transmission system, EirGrid is able to demonstrate this to 70 per cent of projects at the time they receive their connection offers (compared to 26 per cent in the BaU).

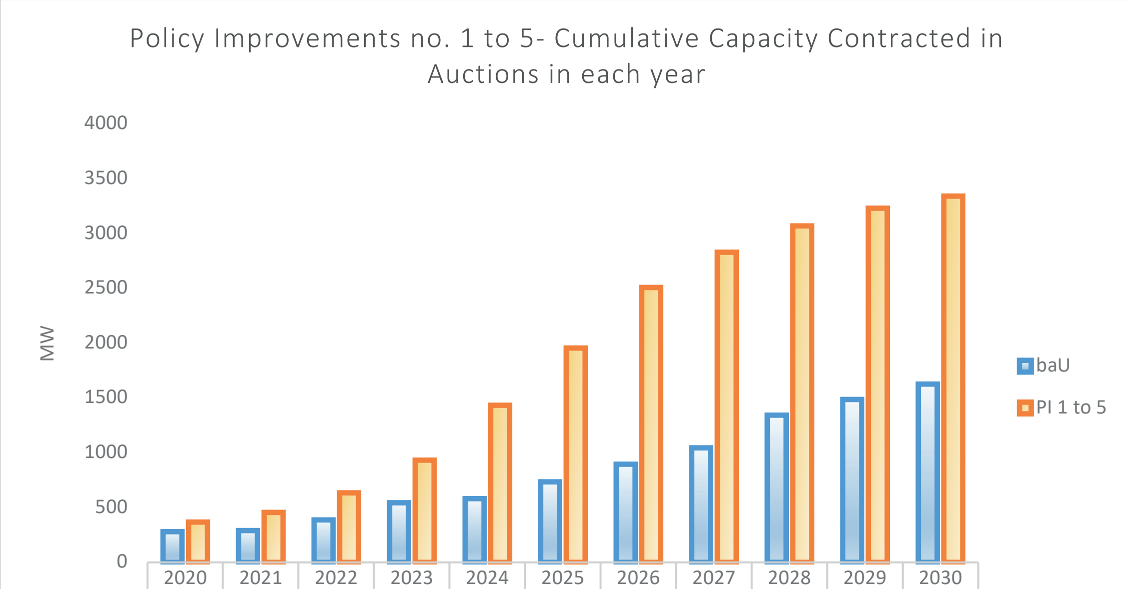
For 20 per cent of projects we assume that this cannot be achieved for a further two years (compared to 47 per cent in the BaU), and for 10 per cent of projects for a further four years (compared to 27 per cent in the BaU). The delay periods are applied as a delay between the connection offer being issued and the date on which the project is ready to bid into an auction. Further engagement with EirGrid is required to understand the specific project level measures that would be required to deliver this outcome.

Given that this step occurs after the ECP offer process, this does not result in any improvement to the capacity receiving planning consents or grid connection agreements. However, we do see significant improvements in the capacity available to bid into auctions each year and in the capacity energised in each year as can be seen in Figure 25, Figure 26 and Figure 27 below.



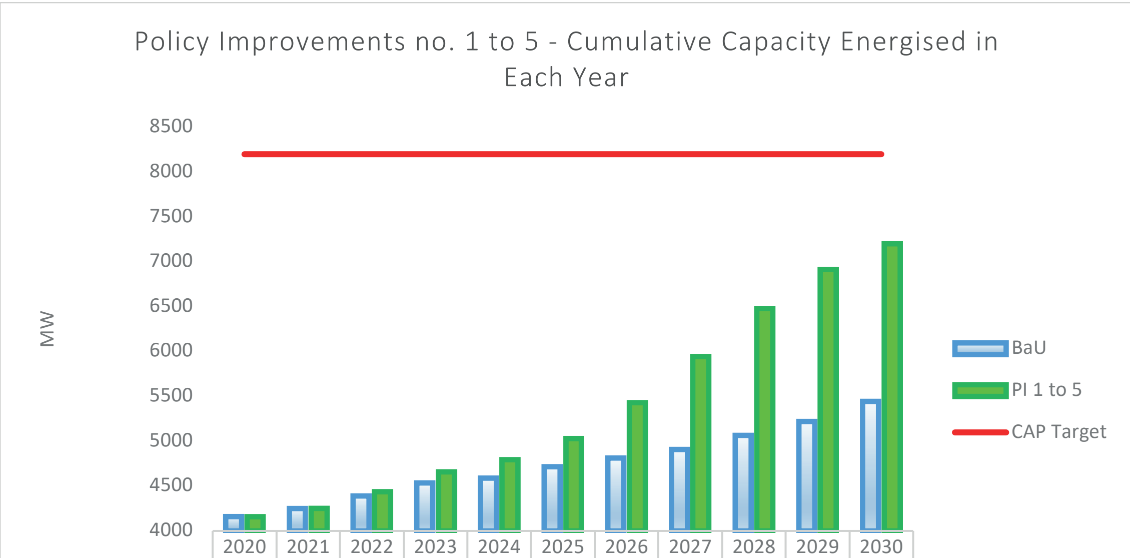
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	420	436	581	816	873	1102	1343	1568	2015	2230	2440
PI 1 to 5	552	684	952	1399	2151	2934	3763	4245	4606	4848	5014

Figure 25: Impact of earlier Policy Improvements combined with parallel development of the transmission system on the cumulative capacity available to contract in each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
baU	280	290	388	544	582	735	896	1045	1343	1487	1627
PI 1 to 5	368	456	635	933	1434	1956	2509	2830	3071	3232	3342

Figure 26: Impact of earlier Policy Improvements combined with parallel development of the transmission system on the cumulative capacity contracted in each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
PI 1 to 5	4160	4250	4434	4662	4795	5034	5433	5945	6482	6919	7200
CAP Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 27: Impact of earlier Policy Improvements combined with parallel development of the transmission system on the cumulative capacity energised in each year to 2030.

4.5.2 Implementation

The changes required to design and consent the transmission system in parallel to the overall wind energy pipeline are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.5.2.1 Summary of Current Policy

Lack of transmission capacity is likely to be the biggest block to meeting our 2030 targets. Traditionally, EirGrid has brought forward grid reinforcement projects, via their six-step framework for grid development,[19] once a demonstrated need to develop the grid has been identified. This has typically been once projects have been consented or have received a connection offer. A high-level summary of EirGrid's six-step grid development process and timelines is:

- 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 above are EirGrid's own and assume a relatively smooth process, however, timelines to reinforce the grid can vary considerably depending on the extent of works required and the potential for legal challenges. New network infrastructure will be required to deliver the renewable volumes needed for 2030 and beyond. Historically, the complete development timeline for a new overhead line or substation can be as much as 10-15 years.

4.5.2.2 Shortcomings of Current Policy

There is not enough 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 per cent, particularly in the west, north-west and south-

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

west, due to network limitations. There is a high risk these constraint levels will reach double figures, for both existing and future projects, if the grid is not reinforced in time for the future pipeline.

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 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 the new generator, 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 they can make competitive bids.

Furthermore, the planning permission for the renewable project may often time out before the network has developed sufficiently to carry this additional capacity, meaning the project will either have to re-enter the planning process or terminate.

4.5.2.3 Proposed New Policy

<u>Early Transmission Development</u>

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

EirGrid also 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 Tommorrow's Energy Scenarios and System Needs Assessment, but once a need has been established, EirGrid should then be incentivised to complete the 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 6 grid development steps. They should then report quarterly on project progress through these 6 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 6 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 achievable and ambitious enough to deliver on national renewable policy aims and it should be consulted on before commencement in January 2021.

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 per cent 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 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, West, Midlands and East Coast where large amounts of new renewable generation are expected to connect.

Alternative Network Solutions

EirGrid/ESBN need to investigate alternative network solutions (e.g. smart wires, storage, congestion products) where this may prove a cheaper and more efficient outcome. There is also an opportunity to work with industry to see where third-party solutions may be appropriate.

Improvements in 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 quicker.
- As it is EirGrid's role as TSO to design, develop and operate the transmission network but ESBN carry out the TAO licensed activities in maintaining and constructing 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. We propose that ESBN, EirGrid and the industry conduct a joint review of the Infrastructure Agreement processes. This is also relevant to the proposal for a Project Development Support and Tracking Office concept which is outlined further in section 4.6.3.3.

Grid Capacity Forum

We also propose that the CRU/SOs establish an all-island Grid Capacity Forum (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 going forward.

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 per cent of projects will be able to connect without delay while the remainder will only suffer minimal delays. This significantly increases the number of projects able to energise before 2030, and also reduces the uncertainty and cost of renewable development.

4.5.2.4 Implementing new Policy

Key Non-Industry Stakeholders

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.
- 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.

IWEA commissioned AFRY (formerly Pöyry) Management Consulting to carry out an analysis on the net consumer value of Contracts for Difference (CfD) at various potential strike prices in the upcoming RESS auctions.[20]

Their research 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 €2.5 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, as demonstrated in Figure 28 below.

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

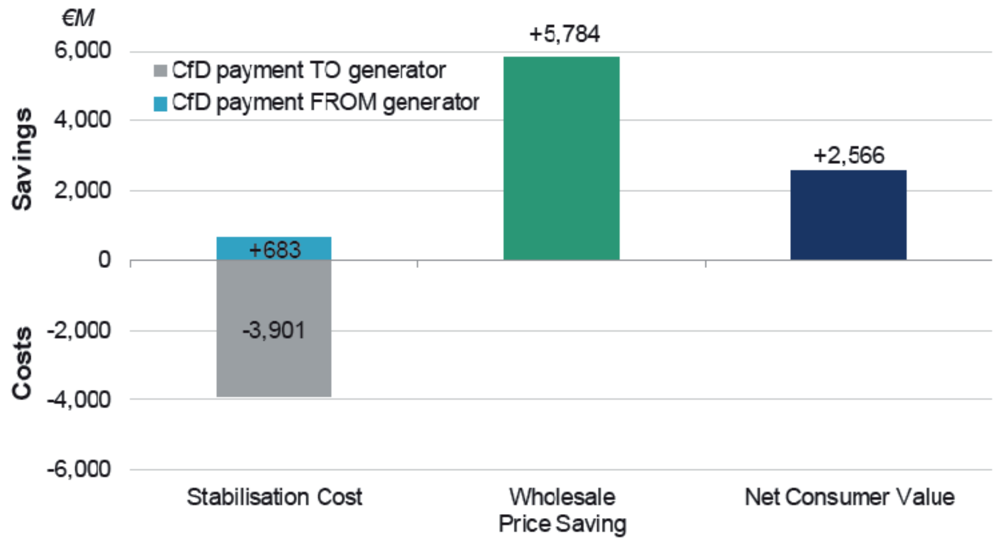


Figure 28: Net Consumer Value estimated assuming a CfD strike price of €60/MWh (€M, real 2017 money).[21]

AFRY has also analysed the net consumer value at strike prices from €50/MWh up to €65/MWh, as shown in Figure 29 below.

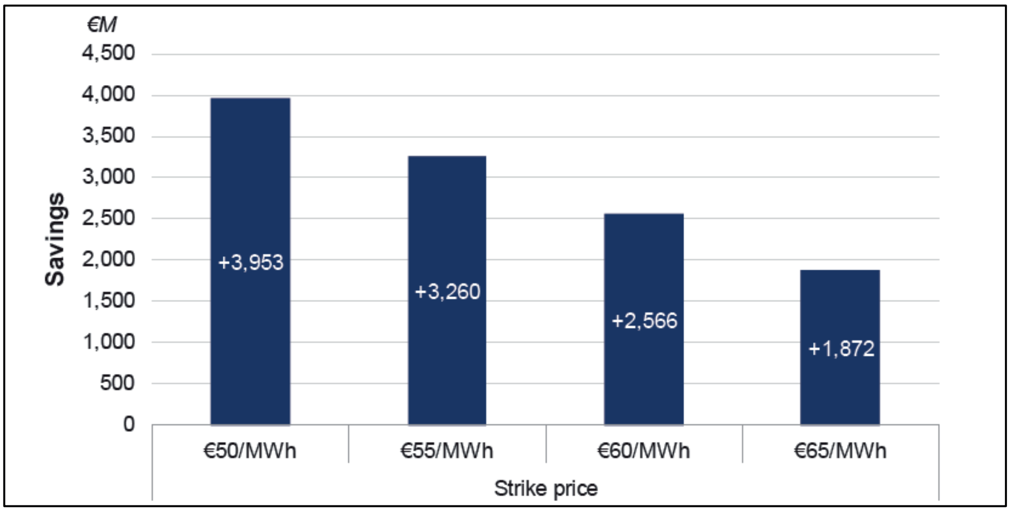


Figure 29: Net consumer value at various CfD strike prices (€m, real 2017 money).

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 per cent.

However, we note that Baringa's 70by30 report assumed that approximately €2.1 billion of additional investment is required in the electricity network to achieve a 70 per cent RES-E

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

penetration on the island of Ireland (Baringa estimated that these costs would be recovered through TUoS over a 40-year period).

The analysis 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.

Figure 30 below shows Baringa's estimate of the total costs and benefits in a 70by30 scenario. 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 per cent RES-E scenario at no additional cost to consumers (from a 40 per cent 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[22] and the recent Contracts for Difference (CfD) auctions in the UK resulted in offshore wind projects clearing as low as £39.65/MWh.[23] 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 in a separate volume of the 70 by 30 Implementation Plan titled *Saving Money*.

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.

[22] https://www.iwea.com/images/Article_files/10._14.30_Cathrine_Torvestad.pdf
[23] https://www.gov.uk/government/news/clean-energy-to-power-over-seven-million-homes-by-2025-at-record-low-prices

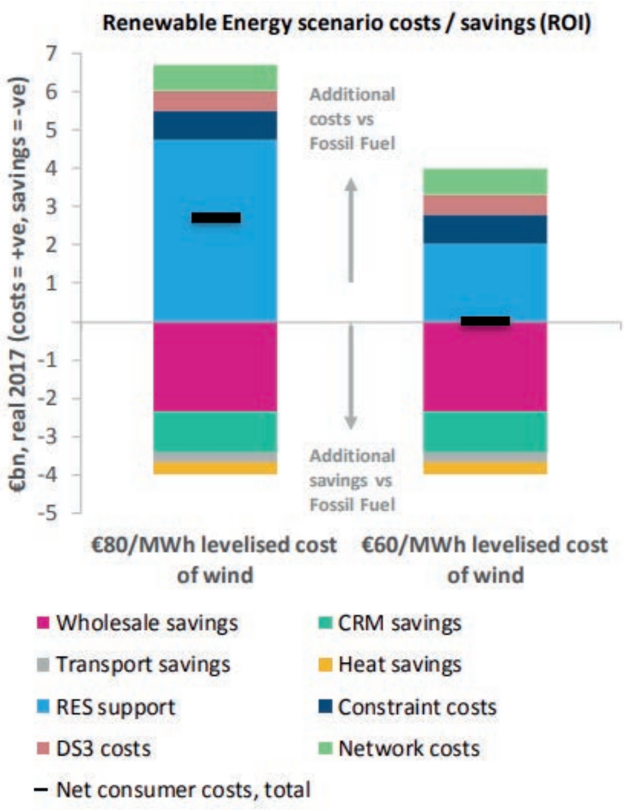


Figure 30: Baringa 70by30 summary of total 70 per cent RES-E costs and benefits.

<u>Key steps and target dates for achieving the policy change</u>

- Q4 2019 – EirGrid/ESBN to begin scoping of grid reinforcements/network solutions based on renewable pipeline and system needs assessment
- Q4 2019 – SOs' PR5 submission to the CRU
- Q2 2020 - Consultation on PR5
- Q2 2020 – EirGrid/ESBN to develop and publish new grid development strategy
- Q2 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

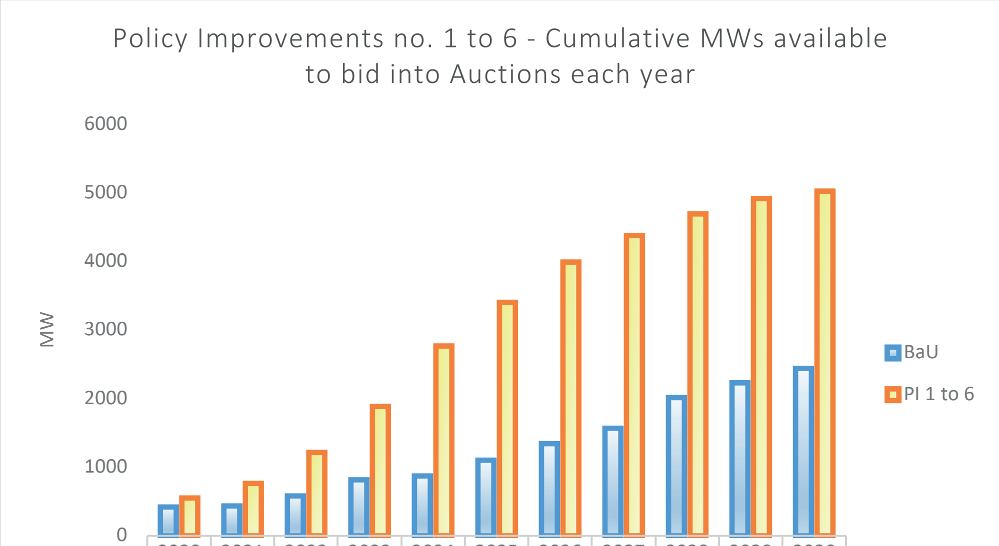
4.6 PI6: Allow parallel consenting of shallow grid connections for individual wind farms

4.6.1 Introduction and Quantifying the Impact

Today only projects that have grid connection points relatively close to the wind farm and have relatively clear connection methods can include their grid connection in their planning application for the wind farm. Projects with longer connections in public roads cannot reasonably get the required private landowner consents (where the folio boundary extends to the centre of the road). Projects with unclear/multiple potential connection methods probably also need some SO engagement to improve the likelihood of consenting the correct method.

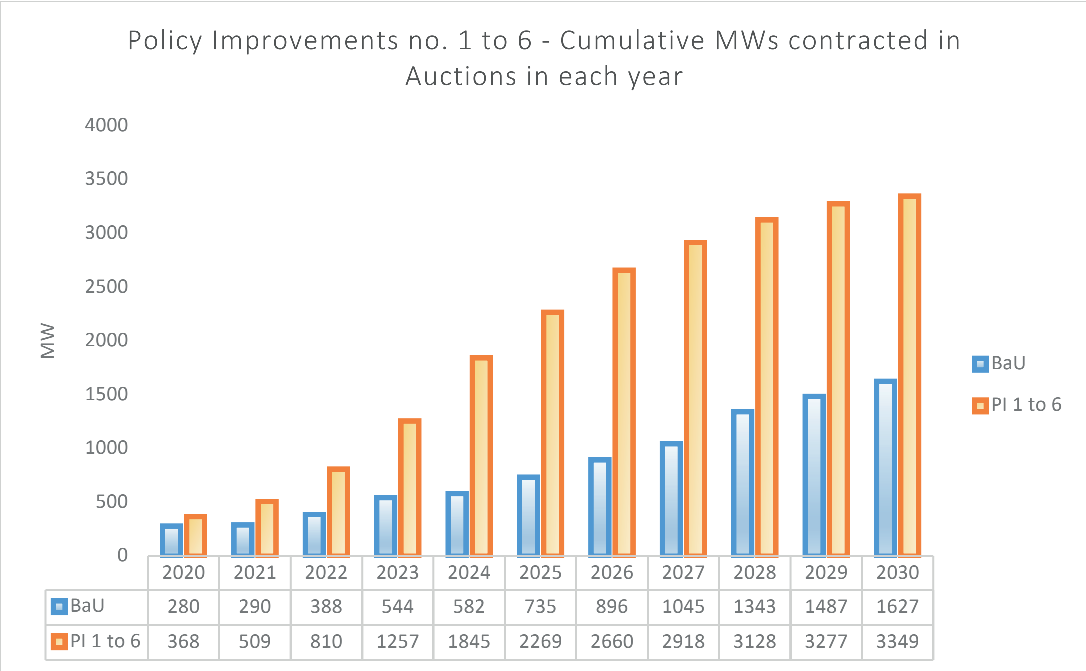
By providing early SO engagement on potential grid connection methods and solving the challenge created by private ownership of public roads, a much larger percentage of projects will be able to obtain planning permission for their grid connections in parallel with the parent wind farm application.

In the analysis here, we assume the percentage of projects that consent their grid connection in parallel with the wind farm increases from 30 per cent in the BaU to 80 per cent. This results in material improvements in the capacity available to bid into auctions and the capacity energised in each year, particularly the intermediate target years of 2025 and 2027, as noted in the Figures below.



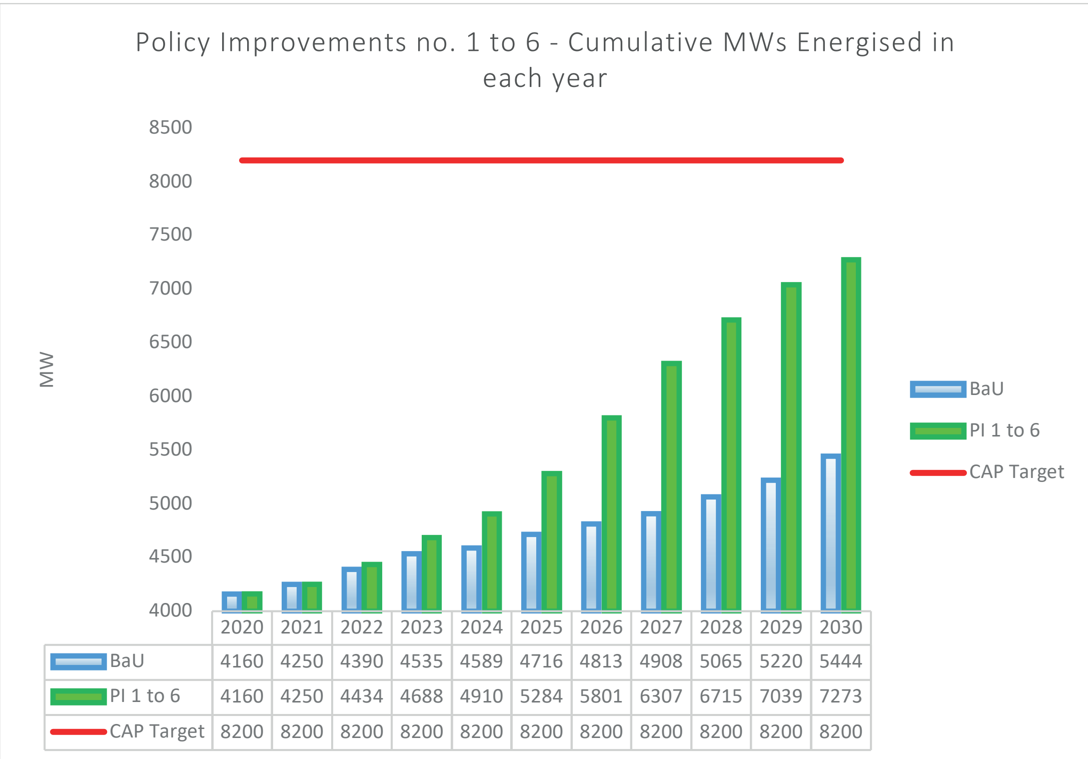
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	420	436	581	816	873	1102	1343	1568	2015	2230	2440
PI 1 to 6	552	764	1215	1886	2767	3403	3990	4377	4692	4916	5024

Figure 31: Impact of earlier Policy Improvements combined with parallel consenting of the shallow connection assets on the cumulative capacity available to contract in each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	280	290	388	544	582	735	896	1045	1343	1487	1627
PI 1 to 6	368	509	810	1257	1845	2269	2660	2918	3128	3277	3349

Figure 32: Impact of earlier Policy Improvements combined with parallel development of the shallow connection assets on capacity contracted in each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
PI 1 to 6	4160	4250	4434	4688	4910	5284	5801	6307	6715	7039	7273
CAP Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 33: Impact of earlier Policy Improvements combined with parallel development of the shallow connection assets on capacity energised in each year to 2030.

4.6.2 Implementation of grid installations along public roads

The changes required to allow parallel consenting of shallow grid connections for individual wind farms by facilitating grid installations along public roads are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.6.2.1 Summary of Current Policy

As a result of changes to long-standing custom and practice it is estimated that in the case of 70 per cent of wind farm projects in recent years, a separate and subsequent planning permission was required for the wind farm's grid connection, after planning permission had already been secured for the wind farm project.

An analysis of wind farm planning consent decision timeframes decided by An Bord Pleanála between 2017 and mid-2019 determined that the average period for planning application decisions was 38 weeks and the average time that appeals were under consideration by An Bord Pleanála was 66 weeks. This amounts to a total of 104 weeks (i.e. 2 years).

A corresponding analysis of planning consent decision timeframes for wind farm grid connections decided by An Bord Pleanála between 2018 and mid-2019 determined that the average period for grid connection planning application decisions was 45 weeks and the average decision time for appeals was 67 weeks. This amounts to a combined 112 weeks (i.e. >2 years).

If a wind farm project must first secure planning permission for the wind farm itself (average period 104 weeks) and then it must apply for a separate planning permission for its grid connection (average period 112 weeks), the project could be a combined 216 weeks (4+ years) in the planning process.

4.6.2.2 Shortcomings of Current Policy

Two specific shortcomings of current policy are highlighted below that require urgent responses from the relevant Government departments.

The first relates to the current requirements for lodging a planning application for a linear development along a public road, such as a wind farm grid connection. The second relates to the right to install utility services, such as wind farm grid connections, in or under a public road corridor.

Requirements to lodge a planning application

The consent of the landowner is necessary if planning permission is required for any development. For linear developments along public roads such as wind farm grid connections, the consent of dozens or hundreds of landowners would potentially be necessary to submit a valid planning application and applicants would very rarely secure the consent of every landowner.

Powers are available under the Electricity Acts, Gas Acts, Water Services Acts and other legislation giving statutory bodies or utility providers the right to carry out works to provide utility services, without landowner consent, once planning permission is secured. However, landowner consent remains a requirement to submit a valid planning application for the works.

It is therefore a serious contradiction to require landowner consent to apply for planning permission, when undertaking the works does not require landowner consent. This anomaly must be rectified as a matter of urgency.

Right to install utility services under in the public road corridor

The second issue relates to who owns the land under a public road in which utility services are typically installed. Public road corridors play a vital role as utility corridors carrying electricity, phone, broadband, gas, water and cable TV services and infrastructure.

Although the road corridor is within the control of the Roads Authority, which is responsible for maintenance and upkeep of the road, unless the land under the road has been acquired by the Roads Authority ownership of the road generally rests with the owners of the lands adjoining the road corridor. The adjoining landowners on either side of a road generally own the land to the middle of the road.

This presents a difficulty when private or semi-state entities need to install new utility services along a public road corridor. While a Road Opening Licence allows a road to be opened and reinstated, it does not convey any rights to the soil or subsoil under the road corridor in which the utility services are typically installed. The installation of such utility services could be said to be a trespass on private property and therefore the owners of adjacent lands would, in effect, be able to veto the installation of new utility services along public road corridors.

4.6.2.3 Proposed New Policy

Requirement to lodge a planning application

The proposed new policy to deal with the current shortcomings and inability to lodge a planning application along public road corridors involves an amendment to the Planning and Development Regulations 2001.

This is necessary to change the required contents of a planning application. The amendment would remove the requirement for landowner consent for planning applications for such utility services along public roads. The suggested amended Article 22 (2) (g) is outlined below in, with the amendment highlighted in blue.

> *Article 22. Content of planning applications generally.*
>
> *(2) A planning application referred to in sub-article (1) shall be accompanied by –*
>
> > *(g) where the applicant is not the legal owner of the land or structure concerned, the written consent of the landowner to make the application, except in the case of any part of the development that will be carried out by a Statutory Undertaker to provide gas, electricity or telecommunications services on, in, over or under a public road, and*

Schedule 3 of the Regulations also prescribes the planning application form to be used for planning applications under section 34 of the Planning and Development Act 2000. Section 10 of the prescribed form (Form no.2) is entitled 'Legal Interest of Applicant in the Land or Structure'. It requires the applicant to identify whether they are Owner/Occupier/Other by ticking the appropriate box. It further states:

> *'If you are not the legal owner, please state the name and address of the owner and supply a letter from the owner of consent to make the application as listed in the accompanying documentation.'*

This consent should not be required in respect of any gas, electricity or telecommunications services on, in, over or under the public road. Applicants should be able to tick the 'Other' box as an option and state that any works to provide such utility services along the public road will be carried out by a Statutory Undertaker.

To take account of projects that are already in the planning process by the time this amendment takes effect the suggested solution should apply to both live planning applications at the time the amendment is made and to future planning applications.

<u>Right to install utility services under in the public road corridor</u>

The proposed new policy to deal with the current policy shortcomings around the inability to install utility services in the public road corridor is modelled on the Water Services Act 2007, which is clear on the rights of landowners with land registered to the centre of the public road. Section 41 of that Act covers the installation of pipes in the public road as follows:

> *(3) Any person authorised by a water services authority to provide water services or any person providing water services jointly with or on behalf of that person, may, in respect of the provision of those services, carry pipes through, across, over, under or along a public road, or place intended for a public road, or under or over any cellar or vault which may be under the pavement or carriageway of any public road, or from time to time repair, alter, remove or replace the same, subject to the consent of the road authority for that road.*
>
> *(11) For the purposes of this Act, where a person (other than a road authority) claims an interest in or under any road –*
>
> *(a) it shall be for the person concerned to prove such interest, and*
>
> *(b) the value of such interest shall be taken to be nil unless it is shown to be otherwise by the person.*

An amendment to the Roads Act section 13 (10) as set out below and similar to the Water Services Act's sections 3 and 41(11) (a) & (b), would strengthen the road opening licensing process. The suggestion is to add the following new clauses (in blue) to Section 13(10) of the Roads Act 1993:

> *(d) Any person authorised by the Minister or granted planning permission by a planning authority or An Bord Pleanála to lay ducts, cables, pipelines, connections to existing infrastructure may in respect of that authorisation or permission, carry and lay ducts, cables, pipes, connections to existing infrastructure, through, across, over, under or along a public road or from time to time repair, alter, remove or replace same, subject to the consent of the road authority for that road.*
>
> *(e) for the purposes of the consent to excavate the road under paragraph (b), where a person (other than a roads authority) claims an interest in or under the road*
>
> *(i) it shall be for the person concerned to prove such interest.*
>
> *(ii) the value of such interest shall be taken to be nil unless it is shown otherwise by the person.*

4.6.2.4 Implementing new Policy

<u>Key Non-Industry Stakeholders</u>

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

An Roinn Iompair, Turasóireachta agus Spóirt
Department of Transport, Tourism and Sport

Who is the decision maker?

- The DHPLG is the decision maker with responsibility for the necessary update to the Planning and Development Regulations.
- The DTTAS is the decision maker with responsibility for the necessary amendment to the Roads Act.

Who has a supporting role?

N/A

Budget or resource requirements:

Resource requirements in the form of time for personnel of the Department of Housing, Planning and Local Government and Department of Transport, Tourism and Sport required to draft the required legislative amendments.

Target date for achieving policy change:

2021

4.6.3 Implementation of early engagement with System Operators (SOs) on connection methods

The changes required to allow parallel consenting of shallow grid connections for individual wind farms by facilitating early engagement with the SOs on connection methods are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.6.3.1 Summary of Current Policy

To complete their permitting process, all wind and solar projects need to know their grid connection method. Under current policy, projects are not able to apply for a grid connection offer until they have first received planning for the main facility (e.g. the wind turbines).

Grid applications are batched together (the last batch being known as ECP-1). EirGrid and ESB, taking into account grid policy, choose a connection method and, where efficient to do so, create sub-groups sharing certain assets. The first time a developer officially learns the likely connection method is at a meeting mid-way through the offer process.

After the developer receives and accepts a connection offer, the system operators will then start to wayleave and permit the (non-contestable parts of the) connection method. Developers can speculate on the connection method, and perhaps secure wayleaves or planning permission in advance of this point, but there is a risk that the connection method differs from that offered.

4.6.3.2 Shortcomings of Current Policy

There are three key shortcomings of the current policy:

- The main drawback is the entirely sequential nature of the steps involved. A typical critical path could comprise two years for the wind farm planning, then a further two years before a grid offer is received and another two years for planning for the grid itself. If it was possible to know the grid connection method during the early development stage, then the grid planning permission could run in parallel, reducing the critical path by a third.

- The O'Grianna judgement requires that the environmental impact of both the grid connection and the wind farm are assessed cumulatively. The only way to achieve this is if both are known at the submission of the wind farm planning. Currently developers assess multiple connection methods to try to cover all bases, but the approach is complex and time consuming. Planners are sometimes concerned about "project splitting" and it can cause confusion within the local community as well if the developer is unable to be clear how their project will connect to the grid.

- By only looking at grid connection methods for projects late in the development process (i.e. which have already received planning), the system operators are not able to take into account projects which are in development, thus forgoing the opportunity to come up with shared and grouped connections that could be more cost efficient for everyone. Late knowledge of the grid connection method means developers do not know the full costs of developing their project and so they cannot participate in early auction or CPPA planning. For example, if Grid Following Funding is to be introduced, system operators will need to issue some form of connection method report with estimated costs.

4.6.3.3 Proposed New Policy

We propose a new Project Development Support and Tracking Office is created across the two system operators. Its key objective would be to make sure that system operators maintain a database of the size, location, technology and state of development of all new or extension generation projects.

Developers would submit quarterly updates indicating their project maturity (e.g. land secured, bird surveys underway, EIS completed, planning submitted, further information, planning appeal, judicial review, planning grant). Using this information, the system operators would maintain a specific multi-year grid development plan which would enable developers (or groups of developers) to option/wayleave/permit much earlier and in parallel with their generation projects' timelines.

There is often at this point talk of assigning probabilities to MW of capacity at each stage of development. There is of course a very fine line between sensible strategic long-term system planning and speculative development. However, if a group of developers have secured lands for a series of wind/solar projects, and are actively developing them, then it seems reasonable that the system operator should also be designing a connection method and developing it (i.e. optioneering/routing/securing land/planning) in parallel with the projects. In due course, all the projects are ultimately likely to be built; the only uncertainty is over timelines. Thus, the task is to speed up or slow down the routing, wayleaving, permitting and construction of the grid solutions so that they progress in parallel with the wind farm projects.

In this context we are referring specifically to shallow connections but there can be some interaction with deep works. For example, a new 110kV substation may be needed by multiple projects in a region and that substation may later be looped with a third 110kV circuit. Neither the grid reinforcement project nor the generators can route their connection until a location for that substation is fixed.

Under the current policy, that would not happen until one or more projects accepted their connection offers. Under the proposed policy, the system operators would choose this location as soon as there was a critical mass of wind/solar projects that had lands secured. Then the system operators (and/or developers) would secure the substation lands, carry out the ecology surveys and submit for planning. The pace of each of these steps would match that of the generation projects in the region depending on it. Only the decision to construct would be contingent on signed connection agreements; all earlier development steps would proceed independently.

There would be full "contestability" in permitting. Developers could individually or as a group permit the shared assets. The System Operators Support Office would supply as required functional specifications, sample layouts, trench specifications and give feedback on key parameters (how many bays, what busbar configuration, what future expansion needs to be provided for etc.) so as to ensure that the connection method going into planning permission reflects the ultimate connection offer. Developers could also contract the system operator to do the routing/wayleaving/planning work on a "non-contestable" basis, but this choice would be in advance of, and independent of, any decisions to construct the connection method on a contestable or non-contestable basis.

There may be a risk of freeloading in groups, if a majority of group members are prepared to fund the early development of grid, but a few are not. The majority here could for example be over 66 per cent if determined by number of projects or over 50 per cent if determined by capacity. A possible mitigation here would be to allow the majority to proceed to design and permit a shared connection method without input from the non-paying late joiners. Then, once the late joiners finally do catch up, when they accept their grid offer, they would incur a late surcharge, for example 30-50 per cent to the cost of permitting the shared assets, with this surcharge being recycled to the majority that moved. This would encourage groups to work together earlier, but still allow late joiners to defer big expenditure if they were unable to fund early development works.

4.6.3.4 Implementing new Policy

Key Non-Industry Stakeholders

Who is the decision maker?

The main parties who would be responsible for delivering this new policy are the System Operators – EirGrid and ESBN.

Who has a supporting role?

There would need to be full buy-in from the industry, but we would expect this to be forthcoming. The industry would need to be prepared to fund the development work in advance of receiving a connection offer.

Budget or resource requirements:

If all we're doing is bringing forward in time the same work that would have happened anyway post offer acceptance, then it could be argued that there's no change in resourcing requirement. But practically, the IWEA Pipeline Survey shows a very high level of activity over the coming three years. This is of course the right time to do this work if we are to have a chance of meeting 2030 targets, but it may require reallocation of resources within the system operators. In contrast, there will be less work required post offer acceptance, as much of the grid will be already permitted. In theory, more efficient grid connections will result in less work overall, so this policy change may only require a reallocation of resources within the System Operators rather than additional budget/resources.

The revised policy would see an increase in expenditure prior to connection offer acceptance. It would be reasonable for the System Operators and regulators to consider amending the charging structure to ensure the SOs have sufficient funds to complete the work without putting consumers at risk. The current policy sets out an application fee of €2-3k/MW (depending on project size) prior to offer issuance, with around €10k/MW "first stage payment" to accept the offer. With the connection method design and planning permission work moving from after offer acceptance to before, it would be sensible to consider an increased application fee and reduced first stage payment, or some equivalent restructuring to give the same effect.

Key steps and target dates for achieving policy change:

It is not definite that the new policy set out above would require a consultation. The new policy would not actually change the wording of grid offers nor the grid allocation process (such as ECP). The only change is the addition of a new early development service, which developers can take up if they find useful.

Connection charging could also remain unchanged. The offer process already allows rebates/offsets/credits where, for example, planning permission does not need to be prepared because it was done earlier in the process.

As such, we believe this change could be implemented as soon as there was agreement on it between the industry, EirGrid and ESBN. In fact, EirGrid has already experimented with offering ad-hoc support to early stage development projects. This is to be commended and should now be expanded to the scope set out above.

We do not think it is unreasonable to implement this before the end of 2020.

4.7 PI7: Longer grid offer 'longstop date' to increase RESS/CPPA competition

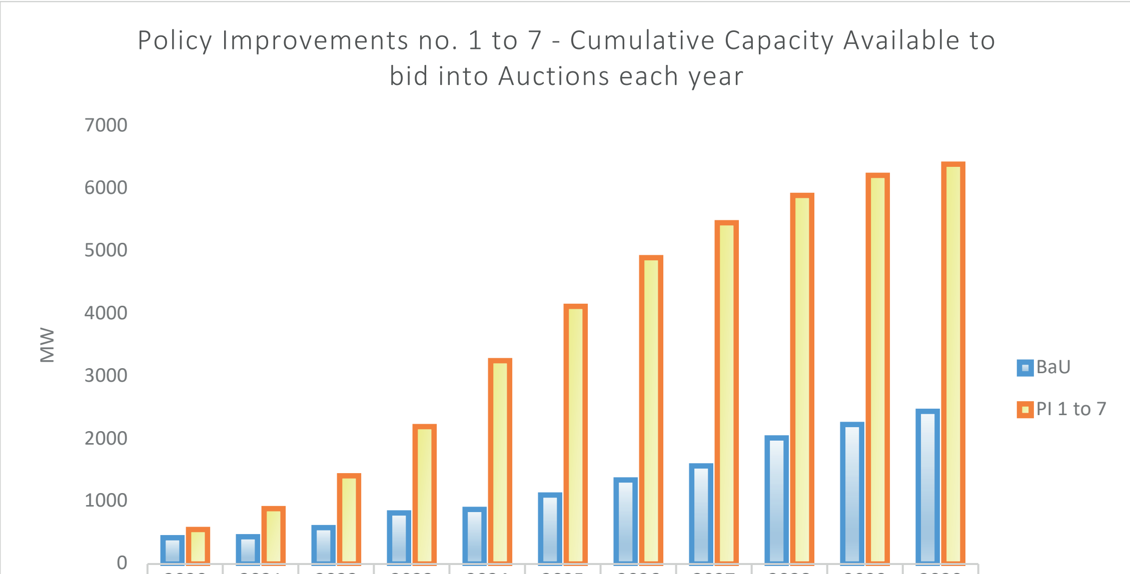
4.7.1 Introduction and Quantifying the Impact

If the CRU imposes relatively onerous longstop dates in connection agreements this will mean that projects that fail to secure a route to market in a single auction will likely see their connection agreements terminated before being able to bid into the next auction.

By applying less onerous longstop dates, projects that will have taken as many as 6-10 years to develop will be in a position to refine their bids and bid into multiple auctions. In the analysis, the grid offer 'longstop dates' are increased so projects can bid into at least three annual RESS auctions instead of just one. The same effect, in terms of increased competition, would be observed in relation to other potential routes to market such as CPPAs.

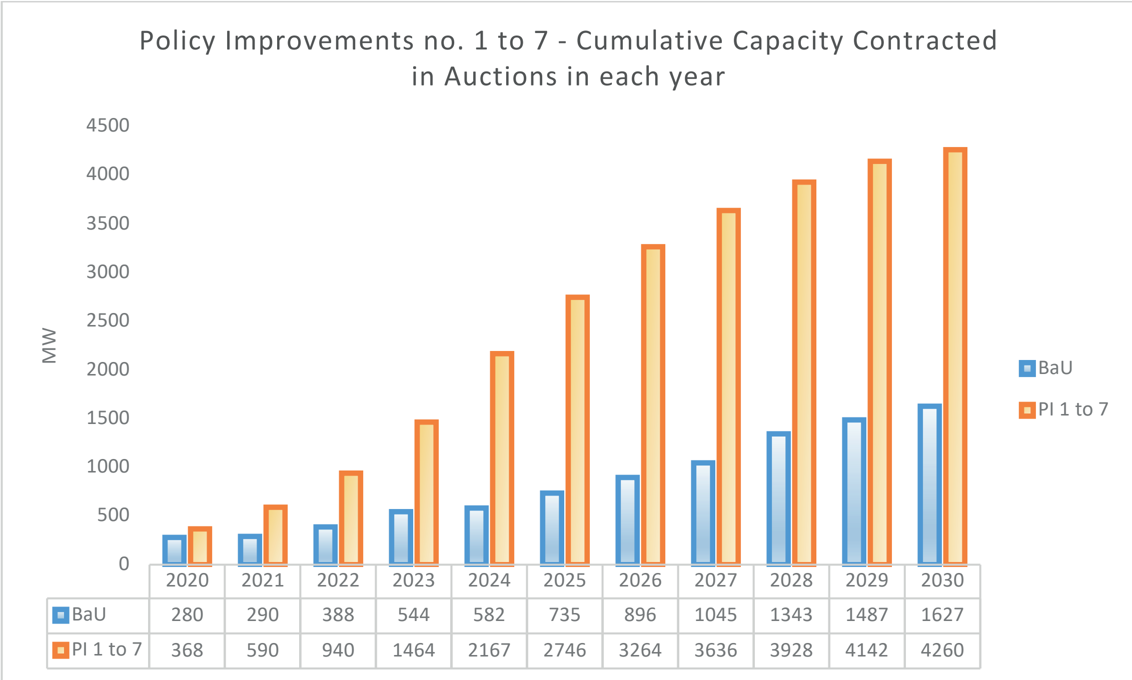
In the modelling, this equates to longstop dates which are three years instead of one, as the model has a built in assumption that there is an annual route to market, which is a key PI and is discussed in detail in section 4.9. However, if RESS auctions do not take place each year, then the longstop dates would need to be longer than three years to facilitate entry into three auctions.

These longer longstop dates have a very positive impact on the capacity available to bid into each auction and on the capacity energised in each year as noted in Figure 34, Figure 35 and Figure 36 below.



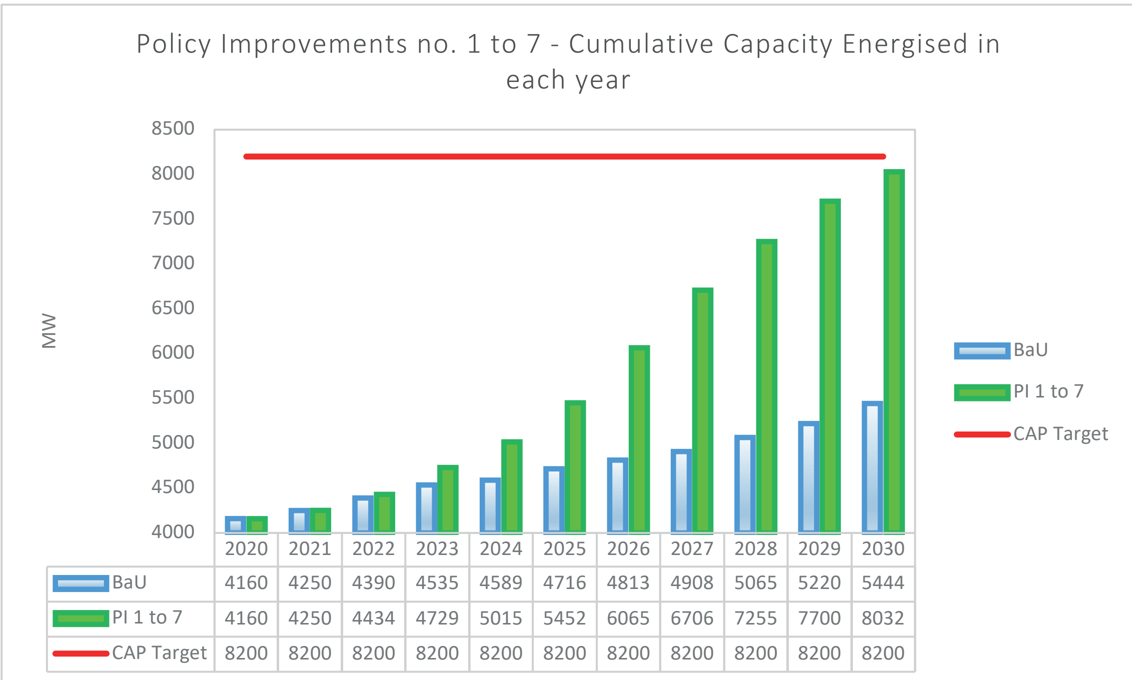
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	420	436	581	816	873	1102	1343	1568	2015	2230	2440
PI 1 to 7	552	885	1410	2196	3250	4118	4896	5454	5892	6212	6391

Figure 34: Impact of earlier Policy Improvements combined with less onerous ECP longstop dates on capacity available to contract in each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	280	290	388	544	582	735	896	1045	1343	1487	1627
PI 1 to 7	368	590	940	1464	2167	2746	3264	3636	3928	4142	4260

Figure 35: Impact of earlier Policy Improvements combined with less onerous ECP longstop dates on capacity contracted in each year to 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
PI 1 to 7	4160	4250	4434	4729	5015	5452	6065	6706	7255	7700	8032
CAP Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 36: Impact of earlier Policy Improvements combined with less onerous ECP longstop dates on capacity energised in each year to 2030.

4.7.2 Implementation

The changes required to allow longer grid offer 'longstop dates' are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.7.2.1 Summary of Current Policy

The CRU decided in its ECP-1 decision in March 2018 to reduce the connection longstop dates from 36 months to 24 months after scheduled consents and operational dates. Their rationale for this was to enable the connection of 'shovel ready' projects and prevent hoarding of grid capacity.

4.7.2.2 Shortcomings of Current Policy

Shorter ECP longstop dates do not align with the expected scheduling of RESS auctions, which may be every two years, as projects that are unsuccessful in an auction will be unlikely to be able to enter subsequent auctions and may have to terminate, or apply for a later ECP round. This has the impact of reducing competition in RESS auctions, potentially leading to a less efficient outcome for consumers.

Furthermore, projects that have been processed under ECP would have already sunk considerable costs into the pre-planning, planning and connection processes and will have already obtained consents which should be taken as a statement of their intention to deliver. The requirement for planning permission to obtain a grid connection offer has significantly reduced the risk of speculative projects hoarding grid capacity.

Shorter ECP longstop dates lead to wasted SO/developer time and resources, as well as sunk development costs, which then impact developer project portfolios and the overall cost of renewable deployment.

4.7.2.3 Proposed New Policy

In terms of ensuring a competitive RESS outcome and delivering the renewable capacity needed for 70 per cent RES-E by 2030, it is important that appropriate longstop dates are set that allow projects the flexibility to enter multiple auctions or find an alternative path to market within a reasonable timeframe, without the threat of connection offer termination.

For example, a simple policy change of setting longstop dates such that projects can bid into a minimum of three RESS auctions would greatly increase the number of projects able to enter multiple RESS auctions, increasing competition and potentially lowering costs to consumers. Again, this equates to longstop dates of three years instead of one in this analysis, as the model assumes there is an annual route to market (section 4.9). However, if RESS auctions do not take place each year, then the longstop dates would need to be longer than three years to facilitate entry into three auctions.

Similarly, IWEA proposes that there should be a capacity release and refund mechanism for projects that are unsuccessful in RESS and wish to terminate. IWEA recommends a principle that allows the recycling of capacity, and more effective use of the grid, without penalising those who wish to remain to enter subsequent auctions.

4.7.2.4 Implementing new Policy

Key Non-Industry Stakeholder

CRU

Who is the decision maker?

The CRU will design and decide on the ECP framework.

Who has a supporting role?

N/A

Budget or resource requirements:

No additional budget or resources are required, this is a simple policy design measure.

Key steps and target dates for achieving policy change:

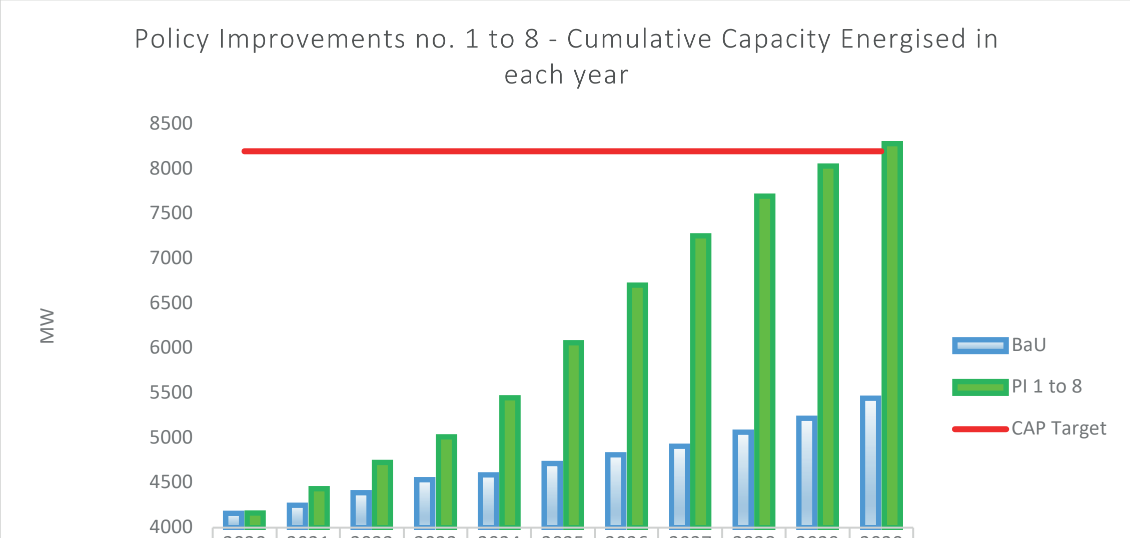
Q2 2020 - CRU decision on ECP-2 framework

4.8 PI8: Reduce construction and grid delivery timelines

4.8.1 Introduction and Quantifying the Impact

Once projects have secured planning, a grid connection offer and a route to market, non-contestable grid delivery is typically the critical path to project energisation.

Here the non-contestable grid delivery timeline is reduced to 14 months from the date a second stage grid payment is made (compared to a BaU timeline of approximately 2.5 years), which results in a substantial improvement in capacity energised in each year, particularly in the intermediate target years of 2022, 2025 and 2027, as noted in Figure 37 below.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
PI 1 to 8	4160	4434	4729	5015	5452	6065	6706	7255	7700	8032	8285
CAP Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 37: Impact of earlier Policy improvements combined with improved finance and build periods on capacity energised in each year to 2030.

4.8.2 Implementation

The changes required to reduce construction and grid delivery timelines by reducing the BaU from 2.5 to 1.5 years are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.8.2.1 Summary of Current Policy

As the standard development timeline in Figure 8 shows, the timeframe to finance, build and energise a wind farm after securing a route to market can take between 2-3 years. The critical path in this is grid delivery and IWEA has continued to raise issues with both ESBN and EirGrid as regards grid delivery delays and the impact this has on renewable project timelines and financing.

4.8.2.2 Shortcomings of Current Policy

Grid delivery delays push out the number of projects that can energise each year, impacting the ability to reach our 2030 targets.

As we move to RESS auctions, it is important to note that developers will account for the risks and costs of delays and uncertainty in grid delivery timelines in their auction bids, and that these costs will ultimately be borne by consumers.

There are several areas where grid delivery issues exist and where improvements can be made:

<u>ESBN and EirGrid Infrastructure Agreement</u>

For transmission projects, EirGrid must work with ESBN via the mechanisms set out in their Infrastructure Agreement (IA) to contract ESB Networks to build the necessary connections (also discussed earlier in section 4.5.2).[24] There are several key problems arising from this structure:

- There are rigid and defined timelines in the IA for documentation to be sent back and forth between EirGrid and ESB Networks to define the project (documents such as Committed Project Parameters and Project Implementation Plans).

[24]The infrastructure agreement between ESBN and EirGrid is not an agreement between the undertakings for the purpose of avoiding competition.

The fixed timelines apply whether the project is complex or simple. They generally add 9-12 months to the timeline before the project is formally handed to an ESB Networks delivery team.

- There is an additional layer of review to all decisions, drawings, designs and functionality. EirGrid uses both internal and external engineers, as do ESB Networks and wind farm developers. The sign-off process can be excessive, with comments flowing back and forth on multiple iterations of a design. The difference between the same 110kV connection delivered directly with ESB or via EirGrid and the Infrastructure Agreement adds at least 50 per cent more time to all design processes, as well as significant engineering risk and cost to the project.

Grid Delivery Delays

In many cases, grid delivery dates as set out by EirGrid and ESBN in their programme of work slip and projects are left stranded suffering significant delays to project energisation dates.[25] Programmes, when provided, lack any detail for scrutiny and are treated as a broad indication of timescales instead of a construction programme to which there is a contractual obligation to adhere.

There does not seem to be sufficient resourcing available or priority placed on addressing delays when they occur. It is important that when an activity or step on the critical path is delayed for any reason that additional resources are applied to recover lost time.

It is also important that processes are better integrated and coordinated between departments within ESBN and EirGrid so there is a focus on delivering grid delivery programmes on time.

Connection Design Specifications

There is a need for clarification of design specifications. It is appreciated that the System Operators are the lead for developing and deciding on these designs; however, IWEA and its members have raised concerns multiple times that changes are being made by the System Operators with little or no interaction with industry. It is not expected that all specification changes are discussed with industry but specifications that directly impact on shallow connection assets should be.

Over the past five years there have been positive examples of how interactions with industry has helped to improve specifications. Interactions on moving to containerised substations for distribution connections is ongoing and shows how ESBN have been interacting with industry, developers and contractors with substantial experience in this area.

[25] These grid delivery dates set out by EirGrid and ESBN in their programme of work can slip, and projects and their processes are not informal or formal arrangements to avoid competition.

Similarly, recent experience with the EirGrid's functional cable specifications have been a positive experience in how comments from industry can improve functional specifications and make them more workable for all parties.

However, the ongoing changes to the specification of looped 110kV substations by EirGrid is an example where the System Operator is unilaterally making material changes to onsite substation specifications without any discussions with the renewable industry. As these substations are located on the generator sites, and the proposed changes are imposing massive increases in the substation sizes and consequently costs, planning and community engagement risk, it would seem only reasonable and appropriate that EirGrid consult with industry on these changes.

Many projects with planning consents for substations which were designed to previously accepted standards find themselves returning to communities and the planning process with significant changes in design. This can add two years in design and consenting for a project which appeared fully consented. Design changes have added significant cost without any oversight or due process. Raising connection cost without consultation is at odds with the standard pricing approach and the CRU obligation to consult on cost increases.

4.8.2.3 Proposed New Policy

With grid delivery process improvements, the timeline for energisation following route to market can be reduced by up to one year. This would allow projects to connect quicker and greatly facilitate the delivery of the renewable volumes needed to meet our 2030 targets. Improvements can be made in the following areas:

<u>ESBN and EirGrid Infrastructure Agreement</u>

Grid delivery timelines can be significantly improved with process improvements in the ESBN/EirGrid infrastructure agreement. As mentioned in the previous section, IWEA proposes that the CRU, ESBN, EirGrid and the industry conduct a joint review of the infrastructure agreement processes to determine where and how the agreement could be simplified and streamlined to improve grid delivery timelines and add value for customers.

<u>Grid Delivery Delays</u>

We recommend that EirGrid and ESBN create a Project Development Support and Tracking Office to track and schedule all renewable connection projects and the resources required to deliver them (presented earlier in section 4.6.3). The programme office would coordinate the relevant work between teams and ensure updates are issued regularly by the delivery teams and that any delays are immediately identified.

This office should issue formal programmes to customers so they are able to track the progress, resourcing and costs in the management of connection delivery which ultimately impacts on them. We note that ESBN and EirGrid have significantly raised the costs of the client engineer and connection management roles although there has been no improvement in the process. There is a need for open and transparent monitoring of EirGrid and ESB Networks timelines for the delivery of grid connections. Without appropriate measures and monitoring of performance, there is no proper way to determine process and efficiency improvements in the grid delivery area.

We also recommend that a Project Delay Committee is formed within the Project Development Support and Tracking Office within ESB Networks and EirGrid (presented earlier in section 4.6.3). Any delays escalated up from the Programme Office are immediately communicated to the project developer. The Project Delay Committee has sufficient authority within the SOs to look at innovative remedial actions that can bring the project back on track e.g. bringing in additional resources or facilitating a temporary connection arrangement.

Connection Design Specifications

IWEA propose that the System Operators should be required to interact with industry on specification changes that directly impact on the connection of renewable generators. There should be a standardised approach to these consultations, possible through a System Operator/Industry working group. This consultation needs to be appropriately resourced as it cannot be a reason for the delay in the delivery of connections.

Any design changes which significantly add to the space requirements or costs for connection works must be proven to be technically necessary, in line with best international practice, and have a complete cost benefit analysis justification. IWEA also proposes that the System Operators perform a review of all current specifications with the CRU to identify where reductions and optimisations to current specification requirements are progressed.[26]

4.8.2.4 Implementing new Policy

Key Non-Industry Stakeholders

[26] The proposed connection design specifications and grid delivery programmes which IWEA advise should be improved by way of policy as referred to and not an agreement between the undertakings for the purpose of avoiding competition.

Who is the decision maker?

ESBN and EirGrid are parties to the Infrastructure Agreement and are in charge of developing connection design specifications and grid delivery programmes.

Who has a supporting role?

- The CRU as regulator for the SOs' licenced activities, including oversight of the Infrastructure Agreement, grid delivery processes and SO cost recovery.
- Industry can provide input and work with the SOs/CRU on grid delivery process reviews and connection design specifications.

Budget or resource requirements:

Most of the proposed policy changes involve process improvements and are not resource intensive. A review of the ESBN/EirGrid Infrastructure Agreement will require dedicated resources to work with the CRU and industry for the length of the review.

Creating formal programme offices for grid delivery will require either reallocation of existing SO resources or additional resourcing, which should be considered under PR5.

Key steps and target dates for achieving policy change:

- Q3 2020 – CRU, ESBN, EirGrid and industry conduct a joint review of the infrastructure agreement processes
- Q3 2020 – Creation of formal SO grid delivery programme offices and project delay committee
- Q4 2020 – Creation of SO/Industry working group on connection design specifications
- Q1 2021 – Implementation of improved grid delivery processes following IA review

4.9 PI9: Annual Route to Market via RESS or CPPAs

4.9.1 Introduction and Quantifying the Impact

Every project will need to decide a 'route to market' which is effectively how a project will earn its income once it is constructed. For the majority of projects in the next decade, this is likely to happen via the Irish Government's Renewable Electricity Support Scheme (RESS) or via a deal with large energy user via a Corporate PPA.

It is also possible for a wind farm to build as a 'merchant' project which simply relies on income from the electricity market, but considering the risks associated with this at the time of writing, it is unlikely without major changes to the current market design that this will be a prominent route to market in the coming decade.

From the outset, our modelling had a built-in assumption that 66% of the onshore wind projects which have planning and a grid offer will find a 'route to market' each year. The 66% figure was based on the assumption that a RESS auction will need some level of oversubscription to ensure competition in the auction. Assuming a 50% oversubscription, or in other words a competition ratio of 1.5, means 66% of the total projects available are successful.

More importantly though is the 'annual' assumption, which assumes 66% of onshore wind projects that are ready to take up a 'route to market' do so. As this was a built-in assumption from the outset, the impact of fewer projects finding a route to market each year has been assessed differently to the previous Policy Improvements.

Instead of adding this as a new policy, since it was already included, the impact was assessed by assuming there would be fewer opportunities for these projects to obtain a route to market, which stems from two major concerns:

1. Inconsistency of messaging in the RESS auction timelines presented;
2. Concerns about the volumes feasible via the Corporate PPA market.

DCCAE published the RESS High Level Design in July 2018.[27] The high-level design sets out a trajectory of timelines and delivery dates for up to five RESS auctions which would see up to 13.5 TWh of new renewable energy being delivered onto the grid over the next decade.

Since the RESS High Level Design document was published, the Government released the Climate Action Plan 2019 which set an alternative trajectory for how these auctions could be delivered.[28] This update raised questions as to whether the auctions would allow onshore renewables to participate. They also do not align with the initial dates proposed in the RESS High Level Design paper (see Figure 38: Comparison of RESS timelines presented in DCCAE's High Level Design Paper [left] and All of Government Climate Action Plan 2019 [right].).

[27] DCCAE RESS High Level Design - https://www.dccae.gov.ie/documents/RESS%20Design%20Paper.pdf
[28] Climate Action Plan 2019 - https://www.dccae.gov.ie/en-ie/climate-action/publications/Documents/16/Climate_Action_Plan_2019.pdf

The Climate Action Plan 2019 also sets out many targets for offshore wind including an explicit target of “at least 3.5GW of offshore wind”. Given that 3.5 GW of offshore wind alone would deliver the entire 13.5 TWh target in the RESS High Level Design, investors are understandably unsure about whether post RESS-1 auctions will be technology neutral or whether they will be exclusively for offshore.

2019 - 10,000 MWh renewables

	MWh	Auction Year	Delivery
RESS 1	1,000 to 3,000	2019	2020
RESS 2	3,000	2020	2022
RESS 3	3,000	2021	2025
RESS 4	4,000	2023	2027
RESS 5 (Possible)	2,500	2025	2030

	MWh	Auction Year	Delivery
RESS 1	1,000 to 3,000	2020	2023
RESS 2	?	2021	?
RESS 3	?	2022	?
RESS 4	?	2024	?
RESS 5 (Possible)	?	?	?

2030 - 23,500 MWh renewables

Figure 38: Comparison of RESS timelines presented in DCCAE's High Level Design Paper [left] and All of Government Climate Action Plan 2019 [right].

If onshore wind is excluded from RESS auctions, it will very likely rely on the Corporate PPA route to market. The Climate Action Plan has a target of 15% of electricity being supplied by CPPAs in 2030, which equates to approximately 2,000-2,500 MW of onshore wind.

However, to date, there are only two CPPAs in Ireland with a combined capacity of 115 MW (see section 4.9.3). This market will need to grow by approximately 20 times its current size in the next decade to achieve this. Again, for context, the entire EMEA region signed 2,600 MW of CPPAs in 2019.[29] The onshore wind sector in Ireland is concerned about the prospects of finding 2,500 MW of CPPAs for Ireland by 2030, particularly when considering some of the extra policy costs for onshore wind currently in Ireland (this is the focus of the *Saving Money* volume of the 70 by 30 Implementation Plan).

To demonstrate these concerns and the importance of an annual route to market in the modelling, the ‘annual route to market for 66% of projects’ assumption was replaced with the assumption that onshore wind will not be able to participate in future RESS auctions beyond RESS-1 and the CPPA market is limited to 100 MW per year.

[29] http://taiyangnews.info/business/19-5-gw-corporate-clean-energy-contracts-in-2019/

The result in Figure 39 shows that this would result in 2,817 MW less onshore wind capacity in 2030, meaning that accommodating an annual Route to Market is the most important part of the this 70by30 Implementation Plan.

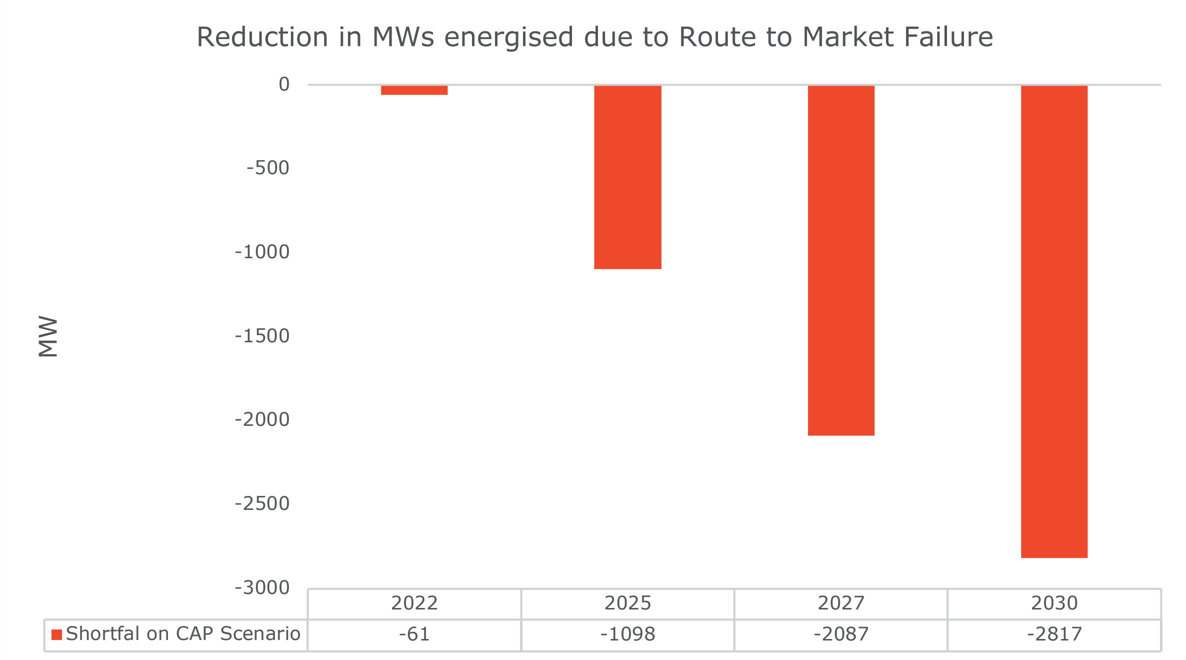


Figure 39: Impact of going from '66% of projects finding a route to market Annually' to assuming that onshore wind is excluded from RESS beyond RESS-1 and the CPPA market is limited to 100 MW per year.

Considering the bigger picture also demonstrates how important both the RESS and CPPA routes to market are. A review of the overall target of 70% renewables in the context of EirGrid's 'Median Demand Scenario' suggests Ireland will require all 13.5 TWh of the proposed RESS volumes plus the full 15% target for Corporate PPAs set out in the Climate Action plan to come close to achieving the 70% target (see Figure 40).

Regular and well set-out RESS auctions in parallel to an active CPPA market will both be essential for Ireland to meet the 2030 renewable electricity target, but particularly the interim targets which are required under the Clean Energy Package's (CEP) Renewable Electricity Directive.[30]

A summary of the renewable target trajectory, coupled with the expected outcomes of RESS-1, and CEP milestones, is set out in Figure 40. The CEP requires Ireland to meet interim targets of 45% RES-E in 2022, 53% in 2025 and 59.5% in 2027. Given the lead time on delivering sufficient offshore wind generation to meet the 3.5 GW target by 2030, it will be particularly important that onshore renewable generation has a regular route-to-market through RESS and CPPAs to help meet the 2022 and 2025 targets.

[30] EU Commission - Renewable Electricity Directive - https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN

Considering the importance of both routes to market, this section outlines how both RESS (section 4.9.2) and CPPAs (section 4.9.3) could facilitate more onshore wind in Ireland.

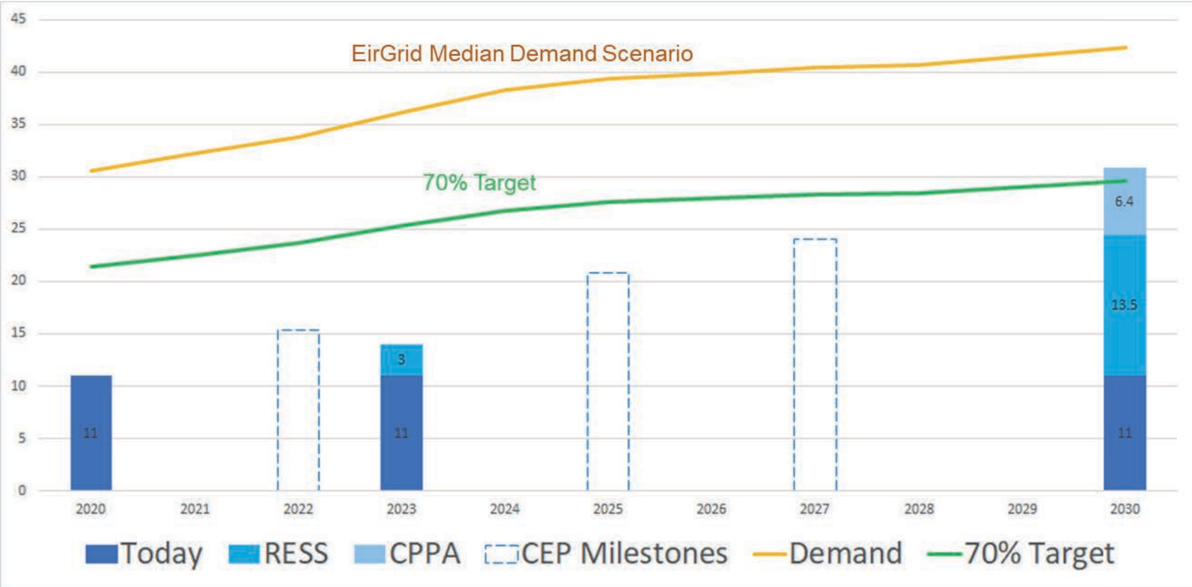


Figure 40: Summary of renewable electricity trajectory required to meet 70% target by 2030, combined with interim renewable electricity targets from the Clean Energy Package.

4.9.2 Implementation of RESS

The changes required to ensure an annual route to market via RESS are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements
- Key steps
- Target date for delivery

4.9.2.1 Summary of Current Policy

Contracts for Difference (CfD) and specifically 2-way CfDs are being adopted in many European markets as the main structure for supporting new capacity from large-scale renewable electricity generation technologies. Typically, these take the form of government backed contracts, although they can also be found in some (i.e. financial) CPPAs.

The new RESS is one such 2-way CfD scheme. It is intended that all generators successfully clearing in the RESS auctions will ultimately receive the auction clearing price or their bid price[31] (i.e. the Strike Price), with generators making and receiving payments based on how the Strike Price compares to a market reference price (expected to be the Day-Ahead price) during times of generation.

When the Day-Ahead price is lower than the Strike Price, generators will receive a payment from the PSO Levy; when the Day-Ahead price is higher than the Strike Price, generators will make a payment into the PSO Levy. This is shown graphically in Figure 41.

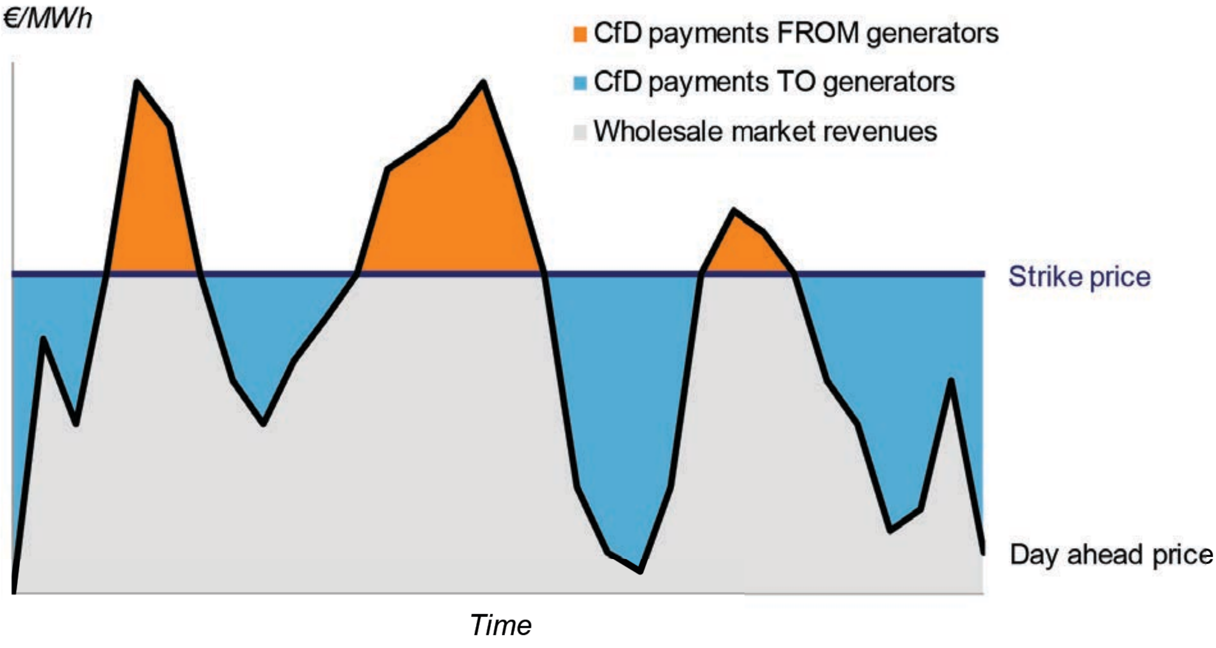


Figure 41: Financial structure of a 2-way Contract for Difference.[32]

The RESS High Level Design paper set out the following timelines and volumes to be procured over the course of four to five RESS auctions as outlined in Figure 42.

[31] The auction design can be either 'Pay-as-Clear' where all participants receive the same clearing price or 'Pay-as-Bid' where each participant receives their bid price. In the case of RESS 1 it will be 'Pay-As-Bid'.
[32] Image from 'Cheaper and Greener' report by AFRY (formerly Pöyry) - https://www.iwea.com/images/files/iwea-cheaper-and-greener-final-report.pdf

	Auction Capacity (GW/hrs)	Auction Year	Delivery Year (end of)	Single Technology Cap
RESS 1	1,000	2019	2020	No
RESS 2	3,000	2020	2022	Yes
RESS 3	3,000	2021	2025	tbc
RESS 4	4,000	2023	2027	tbc
RESS 5 (possible)	2,500	2025	2030	tbc

Figure 42: Table from the RESS High Level Design Paper setting out the timelines and volumes for four to five RESS auctions to help meet Ireland's renewable electricity targets.

The Climate Action Plan 2019 subsequently set out the milestones to be delivered for RESS auctions, which contradict with the volumes and timelines set out in the RESS High Level Design Paper (see Figure 43 and Figure 44).

Action 28: Design and implement the RESS. Increase the volumes and frequencies of RESS auctions to deliver on the 70% renewable electricity target by 2030 ensuring an appropriate community/enterprise mix to achieve an efficient delivery of renewables.			
Steps Necessary for Delivery	**Timeline by Quarter**	**Lead**	**Other Key Stakeholders**
Finalise the Detailed Design of the RESS including state aid notification	Q3 2019	DCCAE	
Establish the Community Framework to accompany the RESS and engage with the Standing Committee on Climate Action on this. Put measures in place to ensure that community benefit fund is equitable and there is strong citizen participation in renewable projects	Q4 2019	DCCAE	
Begin Qualification Process for RESS 1 Auction	Q4 2019	DCCAE	EirGrid, CRU,
Finalise design and implementation of RESS 2 and RESS 3	2021/2022	DCCAE	EirGrid, CRU

Figure 43: Action 28 of the Climate Action Plan is focused on designing and implementing RESS with a specific focus on RESS 1 and achieving state aid notification.

Action 25: Facilitate the development of Offshore Wind, including the connection of at least 3.5 GW of offshore wind, based on competitive auctions, to the grid by 2030. We will establish a top team to drive this ambition			
Steps Necessary for Delivery	**Timeline by Quarter**	**Lead**	**Other Key Stakeholders**
Finalise State Aid Notification to include Offshore Wind as a category in RESS Auctions (Date subject to DG Competition timing)	Q3 2019	DCCAE	
Secure Government approval for offshore specific auction	Q3 2020	DCCAE	
Publish Terms and Conditions of Offshore RESS Auction	Q1 2021	DCCAE	EirGrid
Open Qualification Process for Offshore RESS Auction	Q2 2021	EirGrid	
Evaluate whether sufficient competition in applications received to hold an offshore wind RESS auction. If not, consider alternative options	Q2 2021	DCCAE	CRU
Hold Offshore RESS Auction	Q2 2021	DCCAE	EirGrid
Hold further RESS Auctions to facilitate offshore renewables (subject to Government approval)	Q3 2022, 2024	DCCAE	EirGrid
Monitoring of projects to ensure they abide by Terms and Conditions of the auction including construction deadlines	Ongoing in advance of construction	DCCAE	EirGrid

Figure 44: Action 25 of the Climate Action Plan is Focused on delivering at least 3.5 GW of offshore wind and includes details on offshore RESS auctions.

4.9.2.2 Shortcomings of Current Policy

The objective of procuring 13.5 TWh of renewable energy through the RESS is the correct policy given present demand projections. However, the lack of certainty regarding an annual or regular route to market will add to costs and timelines to deliver projects as described in section 4.9.1.

4.9.2.3 Proposed New Policy

DCCAE should publish a new RESS timeline which promotes annual RESS auctions that are sized according to the volume of renewable generation available to participate in them each year.

IWEA recommends that indicative auction quantities should be set using pipeline surveys for onshore, offshore and solar generation which are compiled by relevant industry bodies. An annual route to market will significantly reduce the timeline to deliver renewable projects and reduce project failure rates.

DCCAE should also make clear what auctions will have technology specific preference categories for different technologies. At present there is a lack of clarity in the renewables industry as to whether RESS 2, RESS 3 and RESS 4 (as set out in the Climate Action Plan Action 25) will also include onshore renewables. IWEA's analysis indicates that onshore renewables will need to compete in annual RESS auctions, particularly to assist in meeting the 2022 and 2025 interim renewable electricity targets.

4.9.2.4 Implementing new Policy

Key Non-Industry Stakeholders

Roinn Cumarsáide, Gníomhaithe ar son na hAeráide & Comhshaoil
Department of Communications, Climate Action & Environment

CRU

EIRGRID GROUP

Who is the decision maker?

DCCAE decide on the timeline and volume for each RESS auction, as well as the technology specific elements of each auction.

Who has a supporting role?

CRU and EirGrid advise DCCAE on the design and timelines for each RESS auction as part of the RESS Oversight group.

Budget or resource requirements:

DCCAE, EirGrid and CRU have created RESS auction design teams to help project manage RESS 1. Auction systems have also been developed by EirGrid to run the RESS-1 auction. An annual budget and resource allocation would be required for teams to continue running RESS auctions.

Specialist support may also be required to provide financial and legal advice to the teams. A specialist consultant may also be required to provide input on terms and conditions for offshore renewables.

Key steps:

DCCAE and the rest of the RESS Oversight Group to agree timelines and proposed volumes for future RESS auctions. Industry acknowledges that volumes may need to be tailored closer to the time based on the progress of the renewable pipeline through preceding steps in the development process.

Target date for achieving policy change:

2020

4.9.3 Implementation of Corporate PPAs

Globally, large multi-national companies are actively entering into CPPAs to help meet their Environmental, Social and Governance (ESG) goals. Ireland is home to more than 60% of the RE100 signature list including major data centre owners, large multi-national pharmaceutical producers and manufacturing entities with significant electricity load here in Ireland.

IWEA believes that it is in the interests of consumers to have an active Corporate PPA market. Every euro invested by corporate companies into new build renewable energy projects will directly offset a euro from the consumer needed to meet 2030 renewable energy targets.

Corporate PPAs offer an opportunity to create a win-win situation for a number of stakeholders:

- Consumers benefit from lower costs of achieving 2030 renewable energy targets;
- Renewable generators reduce reliance on consumer backed revenue stabilisation mechanisms;
- Corporates can demonstrate true 'additionality' in delivering new build renewable projects to meet ESG goals;
- Ireland's attractiveness for Foreign Direct Investment (FDI) from large multi-nationals is increased.

When a corporate entity is considering how it procures power, the primary consideration is expected to be the price the corporate must pay for its electricity, but it will not be the only one.

Managing risk will play a role and securing a fixed price may well have advantages from a budgeting and planning perspective. This is particularly true if one expects significant increases in the cost of carbon and the upward effect that would have on wholesale power prices. As outlined by AFRY (previously Pöyry) in *Cheaper and Greener* report, corporates who sign a CPPA will also benefit from:

- **Hedging against future price increases:** In the SEM, annual average baseload electricity prices have ranged between €40/MWh and €80/MWh over the last decade so a CPPA provides a corporate with a fixed electricity price into the future rather than being exposed to this volatility.

- **Meeting their Corporate Social Responsibilities:** There is also a trend for shareholders to require corporates to demonstrate their green credentials and a well-structured CPPA that delivers new renewables capacity – is a good way to demonstrate such intentions.

The changes required to ensure an annual route to market via CPPAs are outlined here under the following headings: Summary of current policy; Shortcomings of the current policy; Proposed new policy; and Implementing the new policy which is further broken down by:

- Who is the decision maker?
- Who has a supporting role?
- Budget/resource requirements

- Key steps
- Target date for delivery

4.9.3.1 Summary of Current Policy

At present, individual generators and corporates typically engage in bilateral discussions to create a CPPA in Ireland. Two CPPAs have been announced in Ireland to date covering 115 MW of onshore wind capacity with Amazon,[33,34] although the type of CPPA structure that has been used is not publicly known. Before this there were other deals between renewable generators and corporates in Ireland, but these were for wind farms which were also in receipt of some form of support scheme, so the two projects with Amazon are the first pure CPPAs and evidence that such deals can be developed in Ireland.

The Irish Government has indicated that they see a major role for CPPAs over the next decade. The Climate Action Plan[35] would like 15% of electricity demand in 2030 to come from renewable electricity procured by CPPAs in 2030.

[33] Amazon Web Services, Amazon Announces New Renewable Energy Project in Ireland to Support AWS Global Infrastructure, 8 April 2019.

[34] Cork Beo, Amazon to invest in major new wind farm in Cork, 1 August 2019.

[35] https://www.dccae.gov.ie/en-ie/climate-action/topics/climate-action-plan/Pages/climate-action.aspx

Table 5: Actions in the Climate Action Plan relating to Corporate PPAs.

Action 29: Ensure that 15% of electricity demand is met by renewable sources contracted under Corporate PPAs			
Steps Necessary for Delivery	**Timeline by Quarter**	**Lead**	**Other Key Stakeholders**
Initial scoping work on Corporate PPAs including identification of barriers and policy options	Q2 2019	SEAI	CPPA Advisory Group, DCCAE, CRU
Consultation workshop(s) with industry and relevant government or state agencies (CRU, DFin, Revenue, IDA etc.)	Q3 2019	SEAI	DCCAE, CRU
Complete consultancy report on Renewable Electricity Corporate PPAs including set of policy recommendations	Q4 2019	SEAI	CPPA Advisory Group, DCCAE
Follow-up workshop with relevant entities (CRU, EirGrid, revenue etc.) to discuss and analyse in detail the proposed recommendation(s)	Q2 2020	DCCAE	SEAI, CRU
CPPAs Policy Paper based on consultancy study and Advisory Group Recommendations Paper	Q3 2020	DCCAE (with input from relevant Government Departments and Agencies	
Implementation of approved recommendation(s)	Q4 2020	DCCAE	CRU, SEAI, Other relevant State Entities

4.9.3.2 Shortcomings of Current Policy

Based on EirGrid's median demand scenario, 15% of electricity demand will equate to 6.4 TWh of electricity in 2030, which is equivalent to approximately 2,000-2,500 MW of onshore wind. Achieving this target would require a significant increase in CPPAs from the current level of 115 MW.

However, without changes to commercial and regulatory structures in Ireland, Corporate PPAs are unlikely to deliver at significant scale in the short term. This is evident from the UK experience where even though there had been a buoyant Corporate PPA market while the Renewable Obligation subsidy scheme was in place, the removal of subsidies without steps being taken to incentivise the corporate purchasing of renewable electricity has meant that only one project has since closed with a Corporate PPA – and that is an extension to an existing project.

IWEA sees two major types of barriers for CPPAs in Ireland at present:

- **Commercial Barriers:** Ireland has lagged behind in developing Corporate PPAs to date partly because it is competing in a global market with renewable generators in other countries where the costs are lower. Some of these markets benefit from either tax incentives or renewable certificates reducing the incremental contribution required from Corporate offtakers.

For example, some CPPAs in Scandinavia are being procured at €30 per MWh[36] while the outlook for wind energy prices in Ireland over the next decade currently ranges from €40-100 per MWh. Therefore, in Ireland, there is a commercial gap between what corporates are prepared to pay and what is required by renewable generators to form a viable investment. Furthermore, now that the Government has committed to a 70% renewable electricity target in Ireland, in the absence of new policies the wholesale price of electricity is likely to fall in the coming decade making the commercial gap for CPPAs even wider.

- **Regulatory Barriers:** IWEA members have identified a number of regulatory barriers that act to restrict Corporate PPA activity in Ireland including:
    - Under REFIT generators are not able to cancel or transfer GoOs to offtakers under Corporate PPAs, preventing those offtakers being able to satisfy their Greenhouse Gas Scope 2 reporting requirements to the necessary level of transparency to claim their use of green electricity.
    - The use of private wire generation for large industrial users is prevalent in many other countries such as Germany. In Ireland there are regulatory barriers preventing the use of private wire generation.

Ireland already has the highest share of onshore wind in Europe and second highest share of wind energy in Europe, so playing a leading role globally in the integration of variable renewable electricity increases the uncertainty associated with these barriers compared to other countries.

4.9.3.3 Proposed New Policy

Resolving the Commercial Barrier: Solutions to bridge the commercial gap require navigation of various national and EU policies and so would need detailed consideration with key stakeholders. Potential solutions that merit investigation can broadly be categorised as follows:

(i) Reduce the cost of developing renewable electricity in Ireland so it is more competitive with a) fossil fuels in Ireland and b) renewable electricity in other markets. IWEA has dedicated a separate volume of this 70by30 Implementation Plan called *Saving Money*, which identifies how the cost of wind power in Ireland could be reduced by over 50%.[37] We propose a task force is established across policymaking, the regulator, the System Operators and renewable electricity generators with a focus on reducing the cost of renewable electricity in Ireland.

[36] https://iwea.com/images/Article_files/10._14.30_Cathrine_Torvestad.pdf
[37] https://iwea.com/images/Article_files/Simon_Bryars_-_Revised_slides_2019-009_IWEA_70_by_30_putting_a_pricetag_on_policy.pdf

(ii) Layering of revenue streams such as Guarantees of Origin (GoO) and Corporate PPAs with consumer backed revenue stabilisation mechanisms

(iii) Government guarantees or backstop prices to de-risk Corporate PPAs from low commodity price environments.

(iv) Government guarantees or government-supported credit insurance for smaller corporate offtakers to reduce credit risk for lenders and investors. These long-term stabilisation schemes help with contract duration and creditworthiness like the Norwegian Export Credit Agency Guarantee.

(v) Expand the 'Accelerated Capital Allowance for Energy Efficient Equipment' scheme to CPPAs.

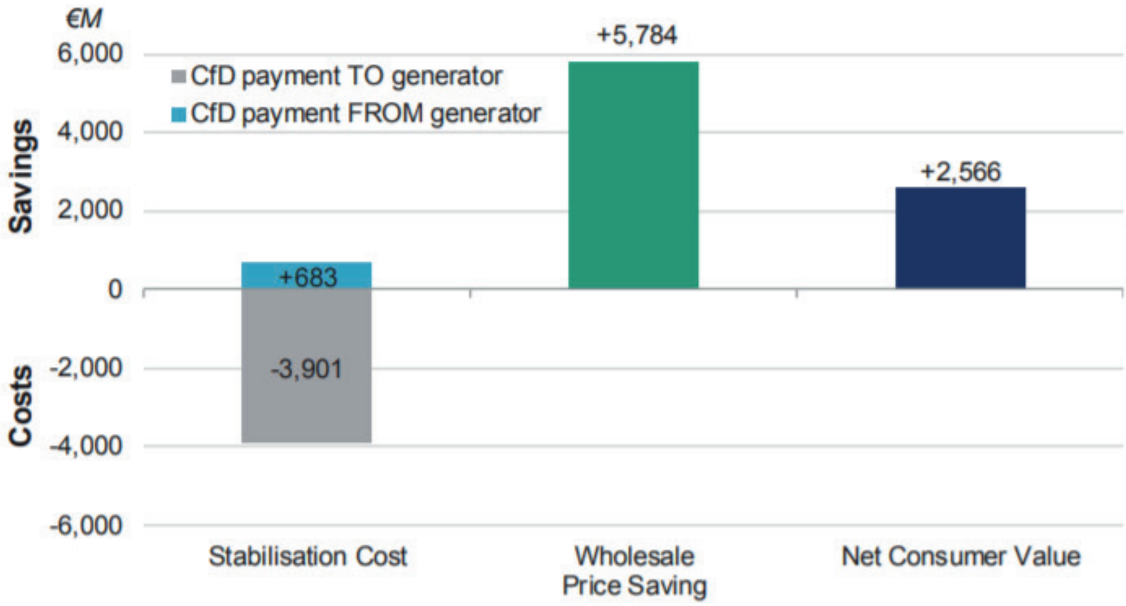
(vi) Levy exemptions (e.g. removal of the PSO for Corporate with PPAs) or tax incentives (e.g. remove electricity tax) to reduce the cost of renewable energy in Ireland.

(vii) Increase carbon prices in the electricity sector e.g. carbon floor price (as recommended by the Joint Oireachtas Committee on Climate Action). This would remove concerns that locking into a CPPA price now will lead to competitive disadvantages for a corporate in the future.

Implementing these changes would likely need to meet various criteria under Irish Government policy, energy regulation, consumer interests and EU State Aid and so would require engagement with many stakeholders. Hence, a single state entity such as Department of Taoiseach, SEAI, ESRI or the IDA should be asked to coordinate the implementation of these solutions.

There is a very strong economic case for policymakers to provide financial incentives to corporates that sign a CPPA. Achieving 15% renewables by CPPAs would materially reduce wholesale prices on the electricity market in Ireland to the benefit of all consumers, but the corporates who sign these CPPAs would take all the costs and risks associated with a CPPA. This concept was quantified in a study by energy experts, AFRY (previously Pöyry), called *Cheaper and Greener,* see Figure 45.

It shows that 70% renewable electricity in Ireland will save consumers €2.5 billion compared to a scenario where Ireland maintains the 2020 level of 40% renewable electricity. If RESS is used to finance this increase in renewable electricity then all consumers will pay the 'stabilisation costs' and receive the 'wholesale price saving'. However, if CPPAs are used, then a corporate will take the 'stabilisation costs' and all consumers will receive the 'wholesale price savings.' Therefore, to stimulate CPPAs, it would seem reasonable to take some of the commercial solutions proposed here to pass on some of the savings to stimulate the CPPA market.



Note: A discount rate of 6% was used to calculate the net present value.

Figure 45: Net Consumer Value over a 15-year period for a 70% renewable electricity scenario in Ireland compared to a 40% renewable electricity scenario assuming the additional renewable electricity is procured under a CfD with an average strike price of €60/MWh (€M, real 2017 money).[38] This CfD could be either via a RESS auction or CPPA. If RESS is used then all consumers will pay the 'stablisation costs' and receive the 'wholesale price saving'. However, if CPPAs are used, then a Corporate will take the 'stabilisation costs' and all consumers will receive the 'wholesale price savings.'

Resolving the Regulatory Barrier: solutions to bridge the regulatory barriers also require due consideration but IWEA proposes the following for consideration:

(i) Government confirmation that GoO will be available to generators to transfer to offtakers under a Corporate PPA, as proposed by the 17 January 2018 amendment to the recast Renewable Energy Directive.

(ii) The CRU to provide clarity on the use of Private Wires in Ireland and if it cannot currently accommodate the needs for CPPAs, then amendments should be made to section 37 of the Electricity Regulation Act.

(iii) Make it a condition of planning permission or a grid connection offer that a Large Energy User with a demand in excess of 5 MW must procure a CPPA with a renewable electricity generator in Ireland.

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

4.9.3.4 Implementing new Policy

Key Non-Industry Stakeholders

Who is the decision maker?

DCCAE: Establish a task force that identifies how to implement solutions that reduce the cost of renewable electricity in Ireland as part of their ongoing work on CPPAs in the Climate Action Plan.

Department of Finance/DPER: Implement financial incentives for corporates that sign a CPPA, in line with the savings that the CPPAs create for consumers on the wholesale electricity market (see Figure 45), including indirect incentives such as a carbon tax floor price for the electricity sector.

Who has a supporting role?

SEAI, ESRI, IDA or an external consultant to administer the task force. SEAI is ideally placed due to their current work on CPPAs under the Climate Action Plan.

Budget or resource requirements:

Allocate €100,000 to organise and lead the task force on cutting costs for renewable electricity in Ireland and identifying financial incentives for corporates to sign CPPAs.

Key steps:

DCCAE, DoF, or DPER to establish the task force (most likely within SEAI).

Target date for achieving policy change:

2020

5 Quantifying the impact of each individual Policy Improvement

As noted earlier, in the analysis to this point, the benefits of some measures do not fully materialise until combined with some subsequent measure. To better understand the individual benefit, we need to apply all improvements required to deliver on the Climate Action Plan ambition and then remove the one that we want to isolate. In this section we summarise the impact of failure to deliver on each Policy Improvement individually.

The figures below summarise the results of this analysis and Appendix 2 includes a detailed breakdown for each PI. The critical years that we have examined are the intermediate target years provided in the CEP Governance Directive i.e. 2022, 2025, 2027 and 2030.

The results in Figure 46 show that in 2030, the amount of onshore wind capacity that is lost from highest to lowest is:

- PI9: Annual Route to Market via RESS/CPPAs = 2,817 MW
- PI4: Grid Offers = 1,969 MW
- PI5: Transmission Development = 1,750 MW
- PI2: SID Success = 916 MW
- PI7: Grid Offer Longstop Dates = 832 MW
- PI1: Pre-Planning Success = 593 MW
- PI8: Grid Delivery = 253 MW
- PI3: ABP Decision Timelines = 95 MW
- PI6: Grid Consenting = 77 MW

However, an important qualitative consideration is also how easy or difficult it is to actually implement the PI required.

For example, increasing the number of grid offers (PI4) could avoid the loss of almost 2 GW of onshore wind, which could be carried out by changing the parameters of the existing grid offer regulation i.e. ECP, and recruiting a relatively small number of additional resources in the System Operators.

However, in contrast, transmission development (PI5) can take years and even decades to complete, as witnessed with the North-South interconnector between Ireland and Northern Ireland. So even though the analysis suggests that transmission development will deliver less renewable energy, in IWEA's view this is the most significant barrier to meeting the 2030 target of 8.2 GW of onshore.

It is also important to recognise that some of the PIs will help more with Ireland's interim targets than with the final 2030 target. For example, Grid Delivery (PI8) is towards the bottom of the list for 2030, but for 2022 it is the most significant PI as it could potentially allow an extra 295 MW to become energised in that year.

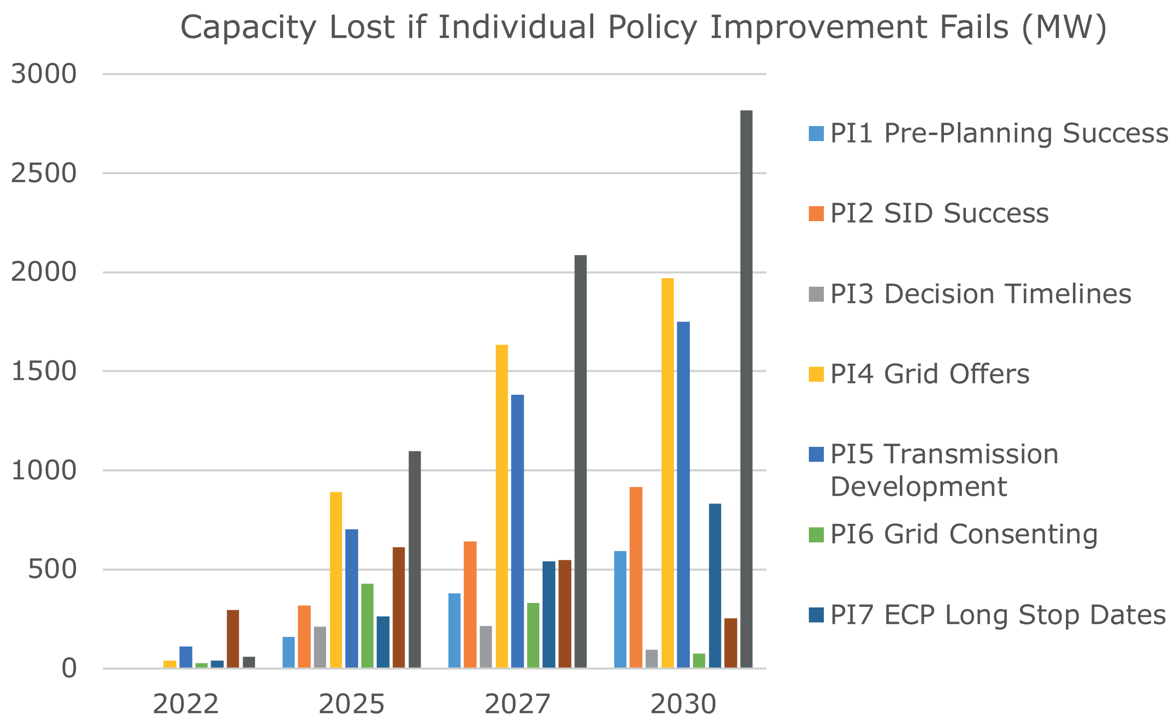


Figure 46: Onshore wind capacity lost in 2022, 2025, 2027 and 2030 if individual Policy Improvements (PI) fail. This analysis was carried out by removing a single PI while keeping all of the others, which then revealed the impact of the failure.

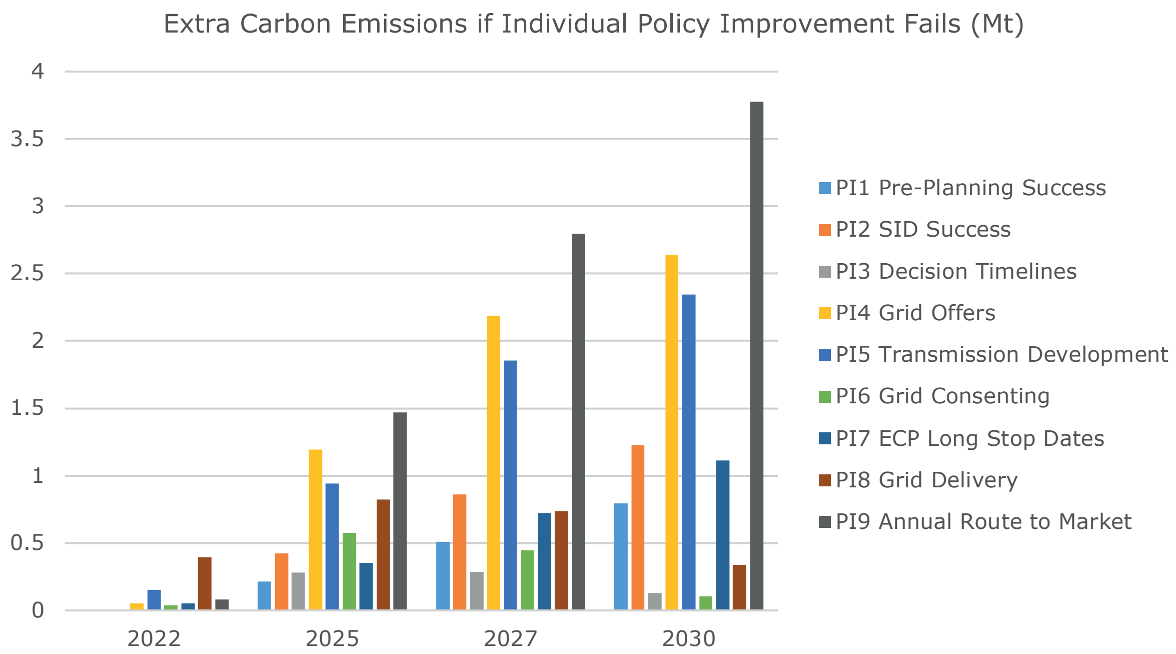


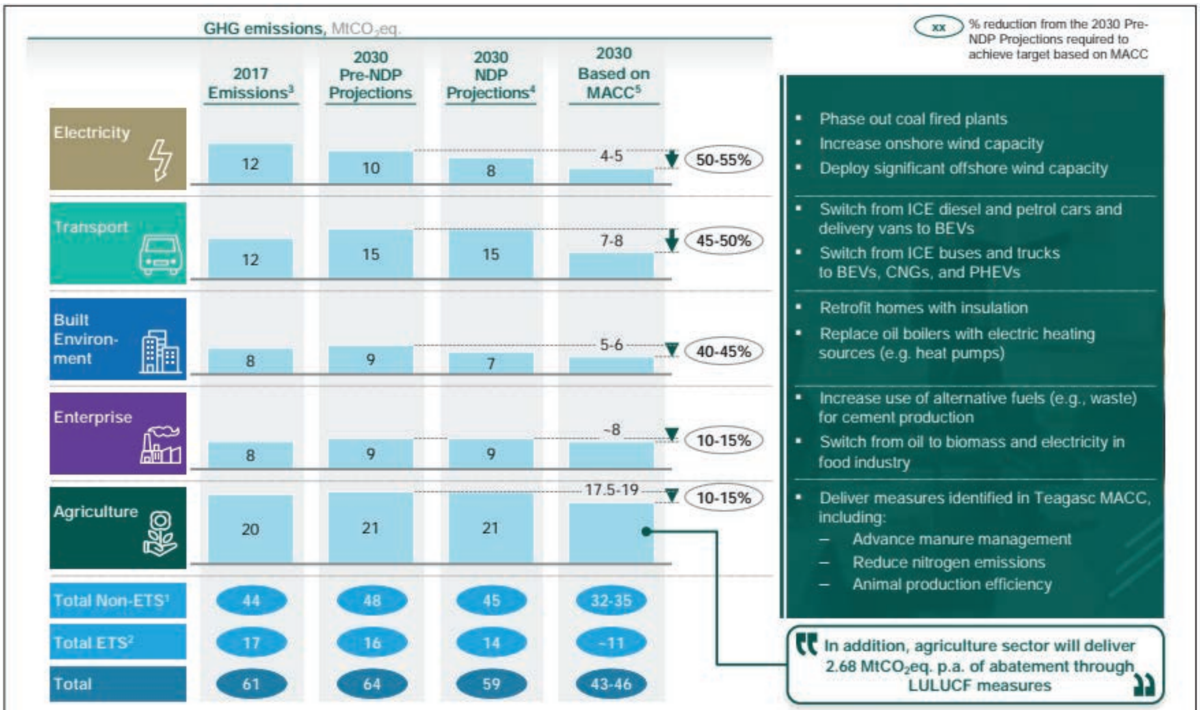
Figure 47: Additional CO_2 Emissions in 2022, 2025, 2027 and 2030 if individual Policy Improvements (PI) fail. This analysis was carried out by multiplying the onshore wind capacity that is lost by the assumed average emissions of the remaining fleet of 437kg / MWh.[39]

[39] https://www.seai.ie/publications/Energy-in-Ireland-2018.pdf

Ultimately the aim of Ireland's Climate Action Plan and the reason for developing onshore wind in Ireland is to reduce the carbon emissions from electricity production. Therefore, the carbon emissions impact is shown in Figure 47.

The order of magnitude for each PI is the same as for the onshore wind capacity that is lost (see Figure 46), but these results really highlight how important these PIs are in the overall context of Ireland's decarbonisation journey rather than specifically for the wind sector.

The overall aim in current Climate Action Plan is to save ~16 Mt of CO2 annually by 2030. Failure to implement any of the top three PIs proposed here alone (i.e. annual route to market, grid offers and transmission development) could each result in over 2 Mt of additional CO2 annually, which is more than all of the measures combined for the 'Built Environment' in the Climate Action Plan. Implementing the PIs proposed here is therefore vital for the overall success of the Climate Action Plan as well as for the success of the onshore wind target.



1 Non-ETS emissions are made up of all emissions from Transport, Built Environment, and Agriculture, these summed up to 42 Mt in 2017. In addition, non-ETS includes 0.5 Mt from electricity, 1.2 Mt from industry, 0.5 Mt from waste, 0.2 Mt IPPU (industrial processes), and 0.8 Mt of F-Gases. NDP includes emission reduction of 0.8 $MtCO_2$ by 2030 from these segments
2 ETS emissions are made up of emissions from Electricity and Industry (which summed up to 17 Mt in 2017) minus the Non-ETS components of these sectors listed above
3 Based on provisional estimates from the EPA
4 NDP figures assume implementation of all measures in the National Development Plan 2018-20275 Reduction is based on MACC results, it excludes abatement from biofuels usage in energy/heat production

Figure 48: Carbon Emission reductions across all sectors in the Government's Climate Action Plan.

6 Summary of Results

The resulting improvements have been modelled as the 'Climate Action Plan' scenario in i-PAT to quantify the additional capacity from the onshore wind pipeline that can be energised in each year to 2030 when each of these policies are implemented.

The results are summarised in Figure 49 below and indicate that all nine Policy Improvement proposals will be required to achieve the 2030 target of 8.2 GW onshore wind. Even if one is missed, then Ireland will not meet this target.

Importantly, the main benefits of the 'planning' PIs are not truly visible from the energisation results, so Figure 50 presents the amount of onshore wind that is consented rather than energised in each of these years, which demonstrates the benefits of these PIs more appropriately.

The targets in the Climate Action Plan will not be achieved if any one of these policies is not implemented. Figure 51 outlines the onshore wind capacity that will be lost in 2030 along with the additional carbon emissions that will be created if any individual policy fails.

The three policies with the greatest impact on achieving the 8,200 MW target for onshore wind in 2030 are: providing enough grid connection offers, developing the transmission grid in parallel with the wind farms and providing an annual route to market via RESS auctions or Corporate PPAs.

Finally, failing to deliver parallel consenting of the shallow connection assets (PI6) and failure to improve ABP timelines (PI3) do not have a significant impact on the capacity energised in 2030, however there is a material impact in 2025 and 2027, which will be important for meeting the interim renewable energy targets in these years.

It will be extremely challenging to deliver on the volume of renewables required in these intermediate years, which must be reported to the European Commission (via the National Energy & Climate Plan), and so these PIs still make a significant contribution.

In conclusion, the findings of this report clearly demonstrate that a "Business as Usual" approach to the development process is simply preparing to fail.

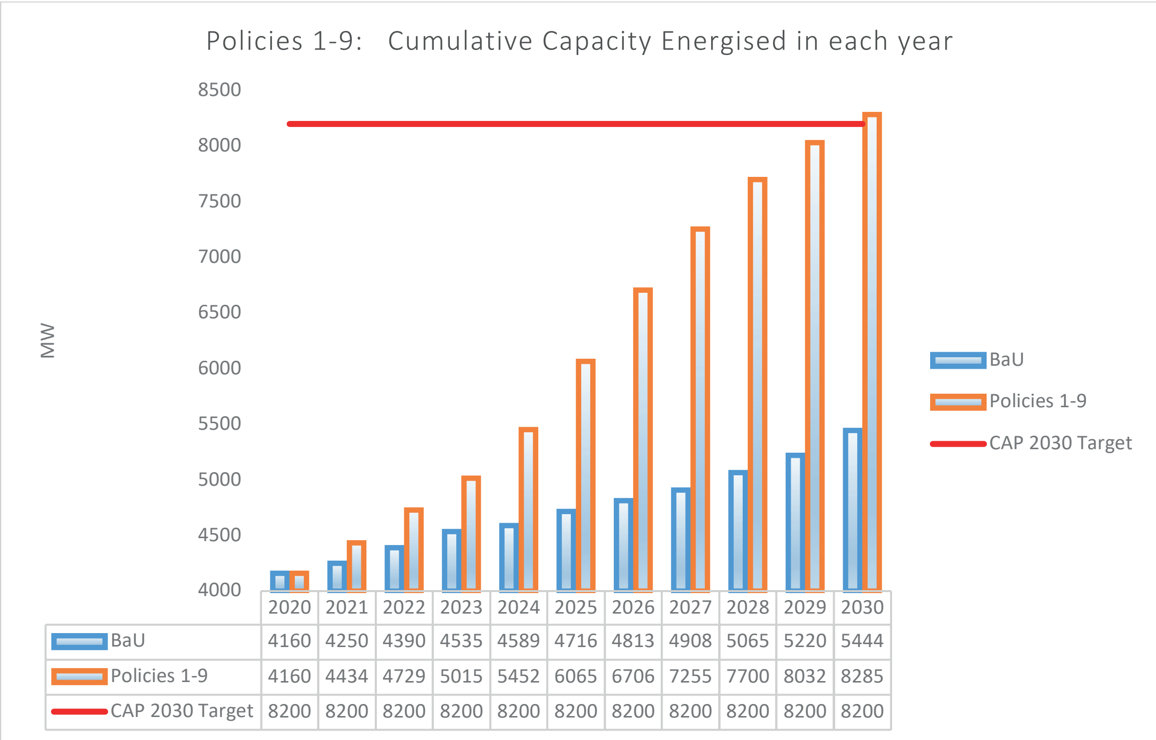
Given the timelines associated with certain categories of transmission system reinforcement projects, IWEA would strongly recommend priority be given to the longer-term renewables trajectory such as the 2040 and 2050 projections towards full de-carbonisation with considerable further electrification of heat and transport.

In some ways, this report is a cause for optimism. It shows that we **can** develop the additional 4,000 MW of onshore wind to hit the 2030 target. We **can** get those projects through the planning system. We **can** get them connected to the grid and we **can** find routes to market.

In the next ten years we **can** build on a record of achievement to develop Ireland's onshore wind industry to a point where it can decarbonise our electricity system to a greater extent than any other technology.

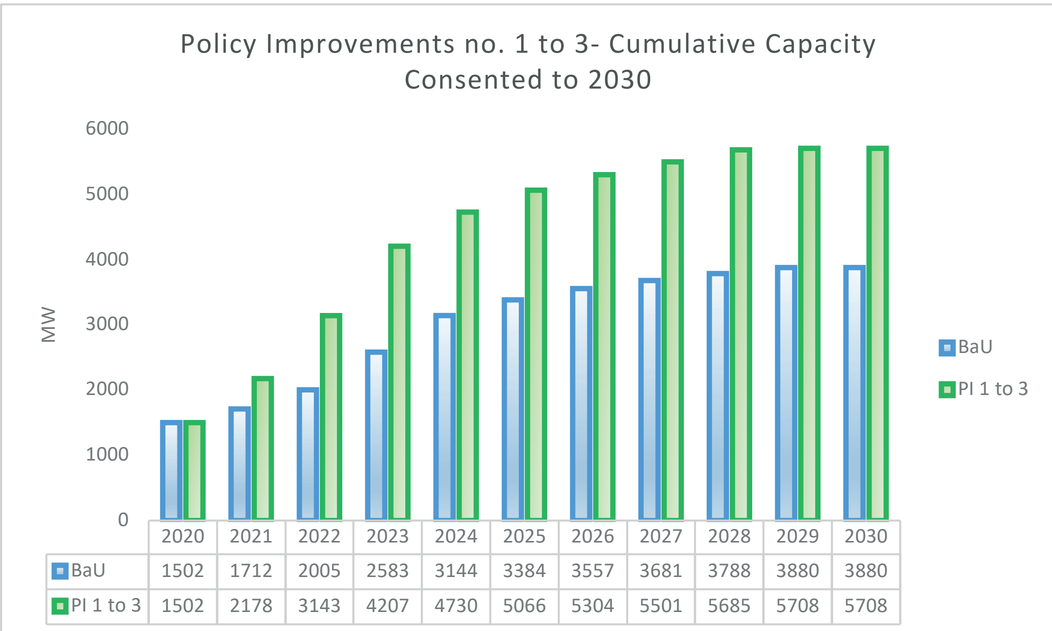
The question – for ourselves as developers but even more for policymakers and Government – is whether we will.

In *Building Onshore Wind* we set out the changes and improvements necessary to make it the Climate Action Plan a thing of substance, a reality for Ireland in 2030.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	4160	4250	4390	4535	4589	4716	4813	4908	5065	5220	5444
Policies 1-9	4160	4434	4729	5015	5452	6065	6706	7255	7700	8032	8285
CAP 2030 Target	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200	8200

Figure 49: Onshore wind energised in each year between 2020 and 2030 under the “Climate Action Plan” scenario with all Policy Improvements Implemented.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BaU	1502	1712	2005	2583	3144	3384	3557	3681	3788	3880	3880
PI 1 to 3	1502	2178	3143	4207	4730	5066	5304	5501	5685	5708	5708

Figure 50: Onshore wind consented in each year between 2020 and 2030 under the “Climate Action Plan” scenario with all Policy Improvements Implemented.

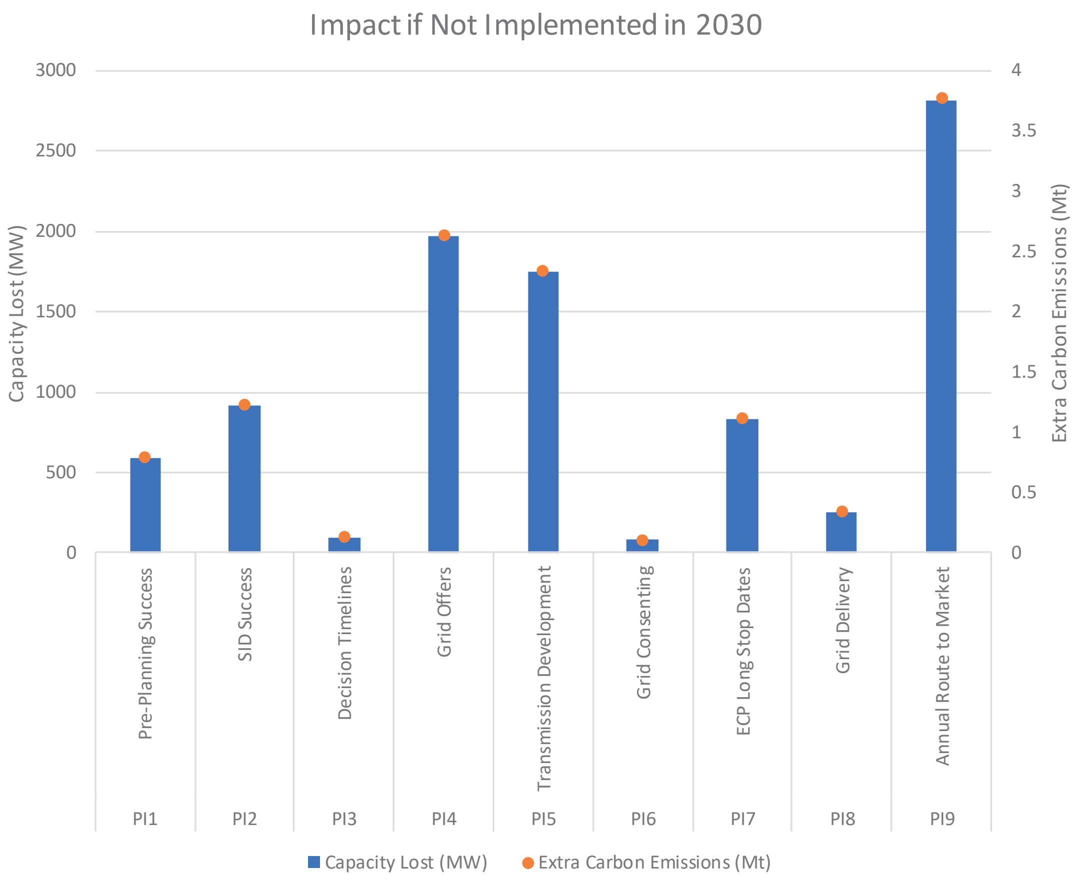


Figure 51: Onshore wind capacity lost and additional carbon emissions in 2030 if individual policies are not implemented.

7 Monitoring and Governance to Track the Impact of the Policy Improvements (PIs)

The year end 2030 is only 10 years away, which is extremely short in the context of developing sufficient renewable energy.

To govern, monitor and track the progress of the 70by30 Implementation Plan, it is proposed to keep track of the volume of projects that are passing through each of the critical milestones in a project's life-cycle.[40]

By tracking these milestones, it will be possible to identify if sufficient volumes of renewable energy are progressing to meet the 70 per cent target and also to identify where the bottlenecks are occurring, so these can be resolved early.

Below is a list of the critical milestones that would enable this progress to be tracked, ordered from nearest to furthest from completion:

1. Installed Capacity
2. In Project Construction and Grid Delivery
3. Has a Route to Market
4. Has a Grid Offer
5. Has Planning/Consent for the project
6. In Advanced Pre-Planning: defined as having two years of bird surveys completed
7. At Feasibility Stage: defined as having at least the required land secured

The closer a project is to the top of the list, the closer a project is to completion. By tracking the volume of projects that pass through each of these milestones, stakeholders in both Government and industry will be able to evaluate how the 70by30 Implementation Plan is progressing.

To demonstrate how it could work, IWEA has prepared a template, see Table 6, and populated this template with the data currently available. At a glance, presenting the data in this format indicates that:

- A large proportion of onshore wind projects that are in the final phase of development are at risk, 180 MW, which is primarily due to the deadlines associated with REFIT.
- A lot of projects will be available for the first RESS auction, with almost 900 MW of both onshore wind and solar currently waiting for a Route to Market.
- A large volume of projects will enter the planning system very soon as there are 2,755 MW of onshore wind in advanced pre-planning, so An Bord Pleanála and Local Authorities will likely see a significant increase in activity within the next 6-18 months.

[40] https://iwea.com/images/files/iwea-onshore-wind-farm-report.pdf

- Offshore wind needs clarity on the consenting regime required to develop a project, as there is approximately 12 GW of projects currently in the pipeline, but it is not clear what phase they are at.

To supplement the high-level overview in Table 6, a detailed year-by-year set of targets for each of the milestones is provided in

Table 7. Using these annual targets would ensure that any delay is identified early, so there is enough time to react and fix the issue before it is too late.

Implementing these solutions will require collaboration across a wide range of stakeholders, so to facilitate this also, IWEA has created an overview of those responsible for each of the PI identified in this report in Table 8.

Each PI includes the key stakeholder responsible, other stakeholders which will play a supporting role, the next step required to progress this solution and a summary of the impact this solution will have by 2030.

IWEA recommends that the lead stakeholder identified for each PI in Table 8 engages with the supporting stakeholders and industry to ensure that a solution can be identified that keeps onshore development on track to meet the annual targets set out in Table 7.

IWEA proposes that the PIs identified here are included in the next iteration of the Climate Action Plan. We are available to provide inputs where suitable and required about how each of these PIs can be progressed.

Table 6: Status of project pipeline for onshore wind, offshore wind and solar in October 2019.

	Status			Technology		
	Planning	Grid	Route to Market	Onshore Wind	Offshore Wind	Solar
Installed Capacity	Yes	Yes	Yes	3,800	25	0
REFIT On Track: 2019/2020	Yes	Yes	Yes	330		
REFIT At Risk: 2020	Yes	Yes	Yes	180		
CPPA 2020	Yes	Yes	Yes	25		
CPPA 2021	Yes	Yes	Yes	90		
With Planning & Grid & Market	Yes	Yes	Yes	625	0	0
With a Route to Market	Yes	Yes	REFIT	510		
	Yes	Yes	RESS			
	Yes	Yes	CPPA	115		
	Yes	Yes	Merchant			
With Planning & Grid	Yes	Yes	Waiting	880	330	900
With Grid	Yes	ECP1	Waiting	470		360
	Yes	Gate3	Waiting	410	330	540
With Planning Only	Yes	Waiting		435	1,620	850
In Planning	Waiting			340		800
Advanced Pre-Planning				2,755	10,350	Unknown
Feasibility Stage				3,280		Unknown
Pipeline Subtotal (excluding installed)				8,310	12,300	2,550
Total (including installed)				12,110	12,325	2,550

Table 7: Targets for the onshore wind project pipeline to reach the 2030 target in the Climate Action Plan.

Metric	Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Capacity in Planning (MW)	Target	616	1347	1390	578	417	293	251	238	0	0	0	5130
	Actual												
	Delta												
Capacity Consented (MW)	Target	1502	675	965	1065	523	336	237	197	184	23	0	5707
	Actual												
	Delta												
Capacity in Grid Process (post ECP-1)	Target	488	675	965	1065	523	336	237	197	184	23	0	4693
	Actual												
	Delta												
Capacity with Grid Offers (Post REFIT)	Target	1014	488	675	965	1065	523	336	237	197	184	23	5707
	Actual												
	Delta												
% of these MWs with planning for grid connection	Target	100%	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%	
	Actual												
	Delta												
% of these MWs with Sufficient Grid Capacity for Grid Connection	Target	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	
	Actual												
	Delta												
Capacity with All Planning & Grid (i.e. ready to contract in RESS / CPPA including losers from previous auctions)	Target	552	333	525	786	1054	868	778	558	437	321	178	6390
	Actual												
	Delta												
Capacity Contracted (MW)	Target	368	222	350	524	703	579	519	372	291	214	119	4261
	Actual												
	Delta												
Capacity Energised (MW)	Target	4160	274	295	286	437	613	641	549	445	332	253	8285
	Actual												
	Delta												

MONITORING AND GOVERNANCE TO TRACK THE IMPACT OF THE POLICY IMPROVEMENTS (PIS)

Table 8: Summary of Policy Improvements (PIs) required to deliver 8.2 GW of onshore wind by 2030.

Policy Improvement (PI)	Description	Aim	Lead	Supporting Role	Next Step	Target Date	Impact of Delay in 2030
1. Pre-Planning Success	Higher Pre-Planning Success via enhanced Community Engagement & Regional Planning (REPDF).	Halve the pre-planning attrition rate from 33% in BaU to 15%.	DHPLG	Regional assemblies, DCCAE	Appoint consultants to prepare the Regional Renewable Energy Strategies on behalf of the three Regional Assemblies, and the associated Strategic Environmental Assessments (SEA) and Habitats Directive Assessments (HDA). DHPLG to brief and instruct Regional Assemblies on urgency of proceeding with Regional Renewable Energy Strategies, and outline proposed approach for preparation, funding, etc.	2021, 2022	-593MW -3.9% RES-E +794kt CO2
2. SID Success	Higher SID Success via improved planning applications and more extensive ABP-industry engagement.	Double the current SID success rate from 38% in BaU to 75%.	DHPLG	ABP	DHPLG legislates for the suggested new SID pre-application stage in a revision to the Planning and Development Act. To begin, DHPLG seeks formal or informal input from An Bord Pleanála and industry stakeholders on need for change to SID process.	2021	-916MW -6% RES-E +1227kt CO2
3. ABP Decision Timelines	ABP Decision Timelines via mandatory decision timelines similar to SHD.	Improve ABP decision timelines by reducing them to 18 weeks for all decisions. Current decision timelines in ABP are 66 weeks for Local Authority Appeal, 89 weeks for JR referrals and 32 weeks for SID decisions.	DHPLG	ABP, OPR	DHPLG legislates for the suggested new ABP decision timeframes in a revision to the Planning and Development Act for SID decisions, JR referrals and appeals. To begin, DHPLG should seek formal or informal input from An Bord Pleanála and/or industry stakeholders on how to change the SID decisions, JR referrals and appeals processes/timelines.	2021	-95MW -0.6% RES-E +127kt CO2
4. Grid Offers	SOs offer sufficient grid offers to meet targets & have sufficient competition via grid offer regulations e.g. Prioritise Large Projects in ECP or implement Grid Following Funding (GFF).	SOs move from 'order of planning grant' for grid offers to processing minimum of 50 offers per year, prioritising first 25 for largest, or move to Grid Following Funding model.	CRU	EirGrid, ESBN	CRU to design and decide on the enduring connection policy framework, including the treatment of firm/non-firm access, and on the allowed PR5 spend for the SOs. EirGrid and ESBN will process the connection offers as per the ECP framework.	2020	-1969MW -13% RES-E +2638kt CO2

5. Transmission Grid Capacity	Parallel Transmission Development via PR5 and resourcing	-Increase from 27% to 70% proportion of projects which face no transmission system delay Reduce from 48% to 20% proportion of projects which face a 2-year delay Reduce from 24% to 10% proportion of projects which face a 4-year delay or longer	EirGrid, ESBN	CRU, ABP	EirGrid to design and consent the appropriate network reinforcement and ESBN to carry out necessary construction and energisation works. CRU to determine the allowed spend on network reinforcement projects.	2020	-1750MW -11.5% RES-E +2344kt CO2
6. Grid Consenting	a) Parallel Grid Consenting via PR5; b) resourcing and early engagement with SOs on connection methods via a new Project Development Support and Tracking office.	Increase parallel grid consenting from 30% of projects to 80% and obtain early engagement with SOs.	a)DHPLG, DTTAS, CRU; b)EirGrid, ESBN	a)EirGrid, ESBN; b)CRU	a) DHPLG to update the Planning and Development Regulations. DTTS to make necessary amendments to the Roads Act; b) SOs to create a new Project Development Support and Tracking Office.	2020	-77MW -0.5% RES-E +103kt CO2
7. Grid Offer Longstop Dates	ECP Long-Stop enables entry to three RESS auctions via grid offer regulations or RESS entry requirements or a Grid Following Funding (GFF) model.	Grid offers allow projects to enter three annual RESS auctions rather than one.	CRU	DCCAE	CRU to design and decide on ECP framework.	2020	-832MW -5.5% RES-E +1114kt CO2
8. Grid Delivery	Strict Grid Delivery Timelines via PR5 and penalties for late delivery.	Reduce finance and build period from 2.5 years to 1.5 years.	ESBN, EirGrid	CRU	ESBN and EirGrid, as parties to the Infrastructure Agreement, to develop connection design specifications and grid delivery programmes.	2020	-253MW -1.7% RES-E +338kt CO2
9. Route to Market via RESS/ CPPAs	Annual route to market for 66% of projects via a) RESS or b) Corporate PPAs (CPPAs)	BaU case assumed 66% of projects found route to market each year. Impact quantified by removing this and assuming onshore wind is excluded beyond RESS-1 and CPPA market is limited to 100 MW per year.	DCCAE, SEAI, DoF, DPER	DHPLG, CRU, EirGrid, ESBN, Large Energy Users, IDA, ESRI	RESS: First auction to be completed in July 2020 with annual auctions for onshore wind to follow thereafter. Update RESS timeline and volumes to reflect this. CPPAs: New policy to pass some of the savings due to CPPAs to corporates who sign CPPAs. Both: Task force to be set up with a focus on reducing the cost of renewable electricity in Ireland.	2020	-2817MW -18.5% RES-E +3774kt CO2

8 Appendix 1 – IWEA Pipeline Survey - Data Available Upon Request

8.1 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					

8.2 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											

8.3 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									

8.4 Onshore Wind Pipeline by type of grid connection: TSO/DSO

Includes Projects Wwith 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											

9 Appendix 2 – Impact of Individual Failure

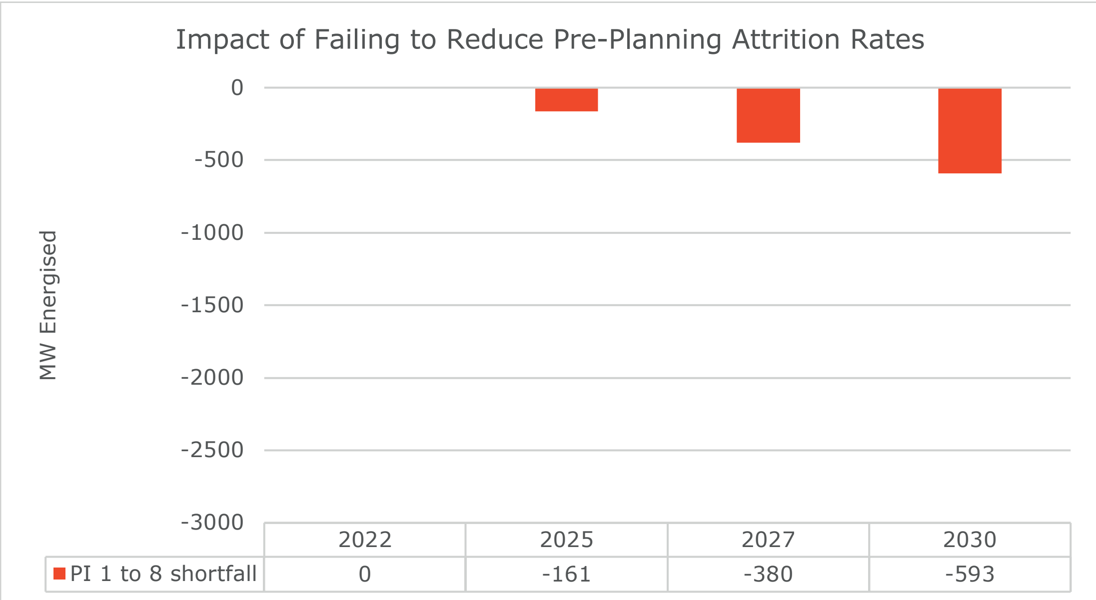
9.1 Failure of PI1: Reduce pre-planning attrition rate

Failure 1 Failure to reduce pre-planning attrition rate from 33% to 15%

- Avoid failure by providing for spatial planning for renewable energy on a national and regional basis rather than at the local authority level.

Impact of potential failure 1:

Year	2022	2025	2027	2030
MW Shortfall	0MW	-161MW	-380MW	-593MW
% RES-E Shortfall	0.0%	-1.1%	-2.6%	-3.9%
CO_2 emissions increase (ktonnes p.a.)	0 kt	+216kt	+509kt	+794kt



Key Non-Industry Stakeholders to prevent failure:

Roinn Cumarsáide, Gníomhaithe ar son na hAeráide & Comhshaoil
Department of Communications, Climate Action & Environment

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

Tionól Reigiúnach Oirthir agus Lár-Tíre
Eastern and Midland Regional Assembly

Northern & Western Regional Assembly

Tionól Réigiúnach an Deiscirt
Southern Regional Assembly

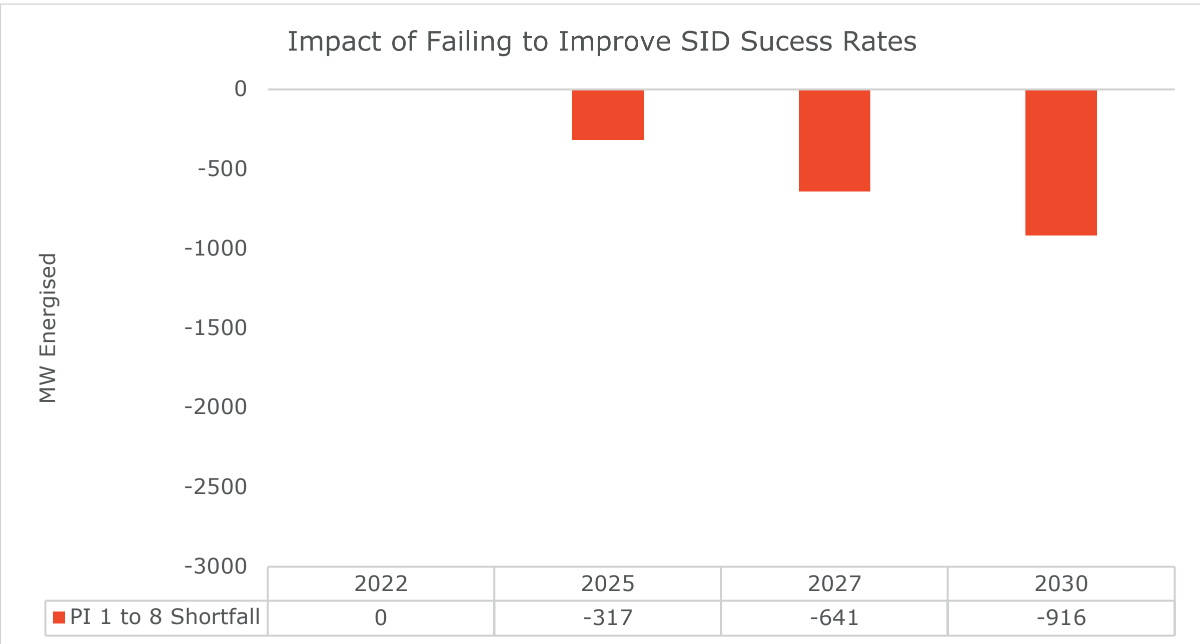
9.2 Failure of PI2: Double SID Success Rates

Failure 2 Failure to increase SID sucess rates from 38% to 75%

- Avoid failure by:
  - Simplifying the process for determining whether a proposed project constitutes SID.
  - Introducing a meaningful pre-application consultation process similar to the Strategic Housing Development application process.

Impact of potential failure 2:

Year	2022	2025	2027	2030
MW Shortfall	0MW	-317MW	-641MW	-916MW
% RES-E Shortfall	0.0%	-2.2%	-4.3%	-6.0%
CO2 emissions increase (ktonnes p.a.)	0 kt	+424kt	+859kt	+1227kt



Key Non-Industry Stakeholders to prevent failure:

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

An Bord Pleanála

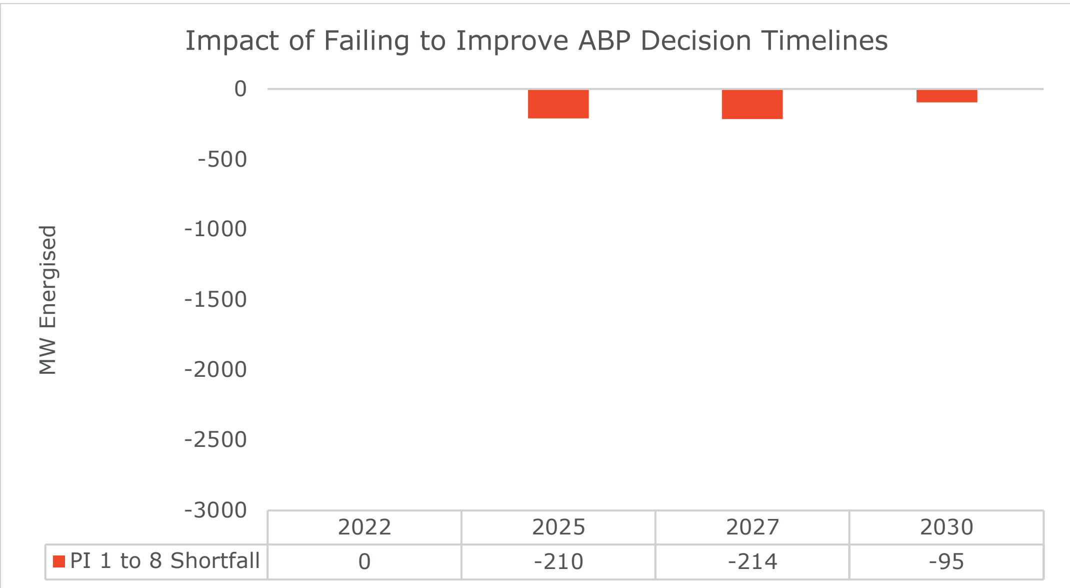
9.3 Failure of PI3: Improve ABP decision timelines

Failure 3 Failure to reduce ABP decision timelines

- Avoid failure by introducing a statutory decision period of 18weeks for An Bord Pleanala similar to Strategic Housing Developments

Impact of potential failure 3:

Year	2022	2025	2027	2030
MW Shortfall	0MW	-210MW	-214MW	-95MW
% RES-E Shortfall	0.0%	-1.5%	-1.4%	-0.6%
CO2 emissions increase (ktonnes p.a.)	0 kt	+282kt	+286kt	+127kt



Key Non-Industry Stakeholders to prevent failure:

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

An Bord Pleanála

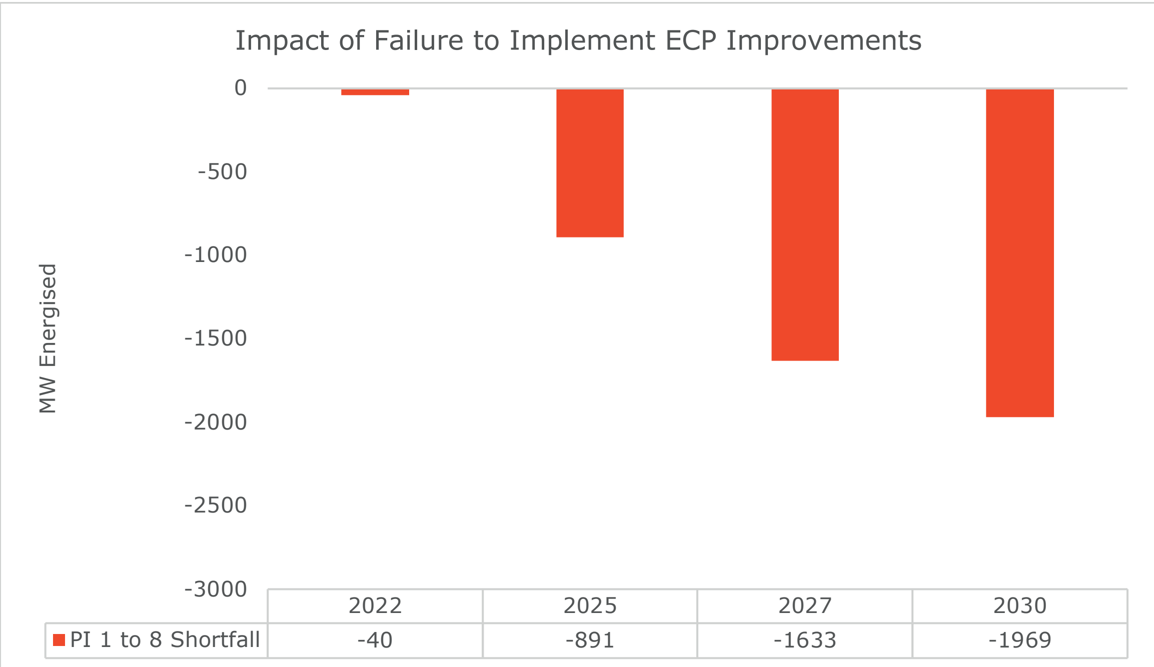
9.4 Failure of PI4: Increase Grid Offers

Failure 4 Failure to issue sufficient grid connection offers

- Avoid failure by processing a minimum of 50 offers per year (ideally 125) with the first 25 offers being prioritised based on MWh p.a. scale.

Impact of potential failure 4:

Year	2022	2025	2027	2030
MW Shortfall	-40MW	-891MW	-1633MW	-1969MW
% RES-E Shortfall	-0.3%	-6.2%	-11.1%	-13.0%
CO_2 emissions increase (ktonnes p.a.)	+54 kt	+1193kt	+2189kt	+2638kt



Key Non-Industry Stakeholders to prevent failure:

CRU EIRGRID GROUP ESB

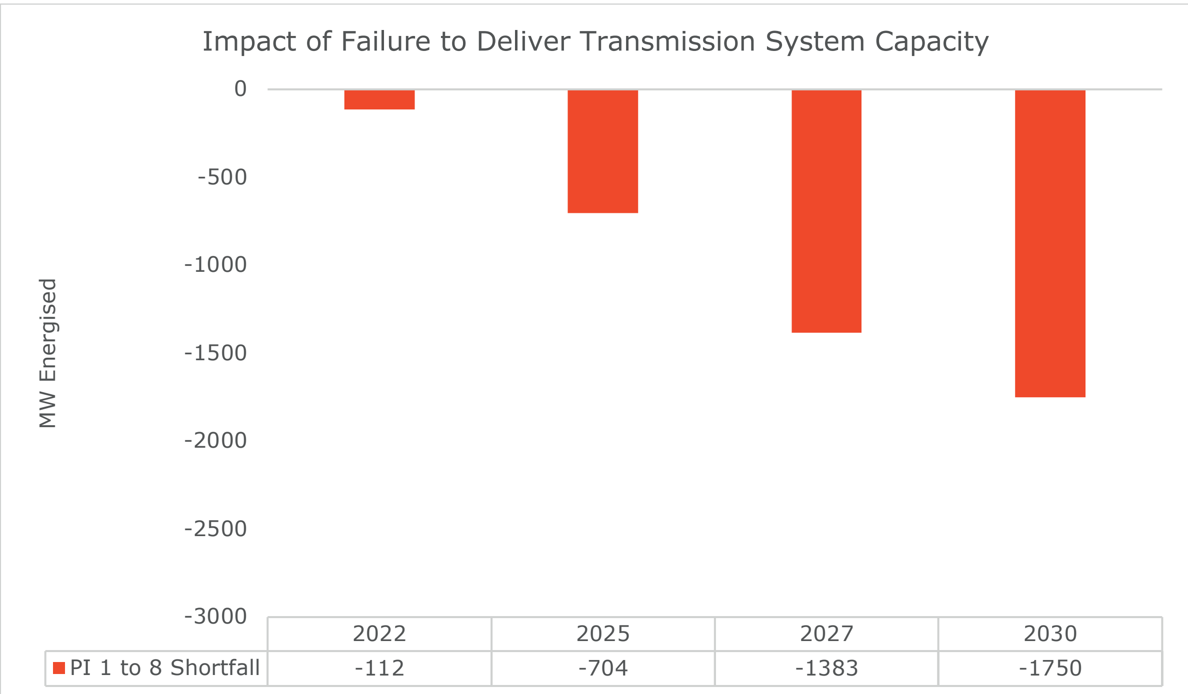
9.5 Failure of PI5: Parallel design and consent of the transmission system

Failure 5 Failure to provide sufficient capacity on the transmission system

- Avoid failure by developing the transmission system in parallel such that:
  70% of projects face no transmission system delay
  20% of projects face a 2 year delay
  10% of projects face a 4 year delay

Impact of potential failure 5:

Year	2022	2025	2027	2030
MW Shortfall	-112MW	-704MW	-1383MW	-1750MW
% RES-E Shortfall	-0.9%	-4.9%	-9.4%	-11.5%
CO2 emissions increase (ktonnes p.a.)	+151 kt	+943kt	+1853kt	+2344kt



Key Non-Industry Stakeholders to prevent failure:

CRU EIRGRID GROUP ESB An Bord Pleanála

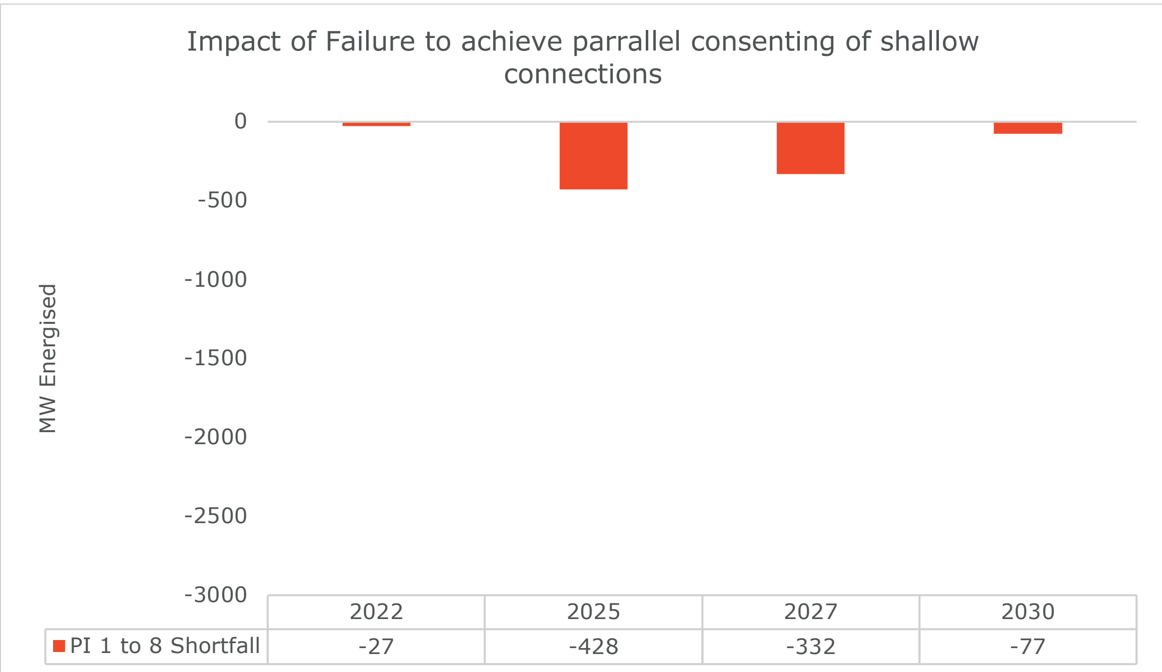
9.6 Failure of PI6: Parallel consenting of individual grid connections

Failure 6 Failure to obtain planning permission for grid connection methods at the same time as the wind farm on more than 20% of projects

- Avoid failure by:
  - Providing early and reasonably reliable connection method information.
  - Address the issue of private ownership of public roads

Impact of potential failure 6:

Year	2022	2025	2027	2030
MW Shortfall	-27MW	-428MW	-332MW	-77MW
% RES-E Shortfall	-0.2%	-3.0%	-2.3%	-0.5%
CO2 emissions increase (ktonnes p.a.)	+36 kt	+574kt	+445kt	+103kt



Key Non-Industry Stakeholders to prevent failure:

An Roinn Tithíochta, Pleanála agus Rialtais Áitiúil
Department of Housing, Planning and Local Government

CRU

EIRGRID GROUP

ESB

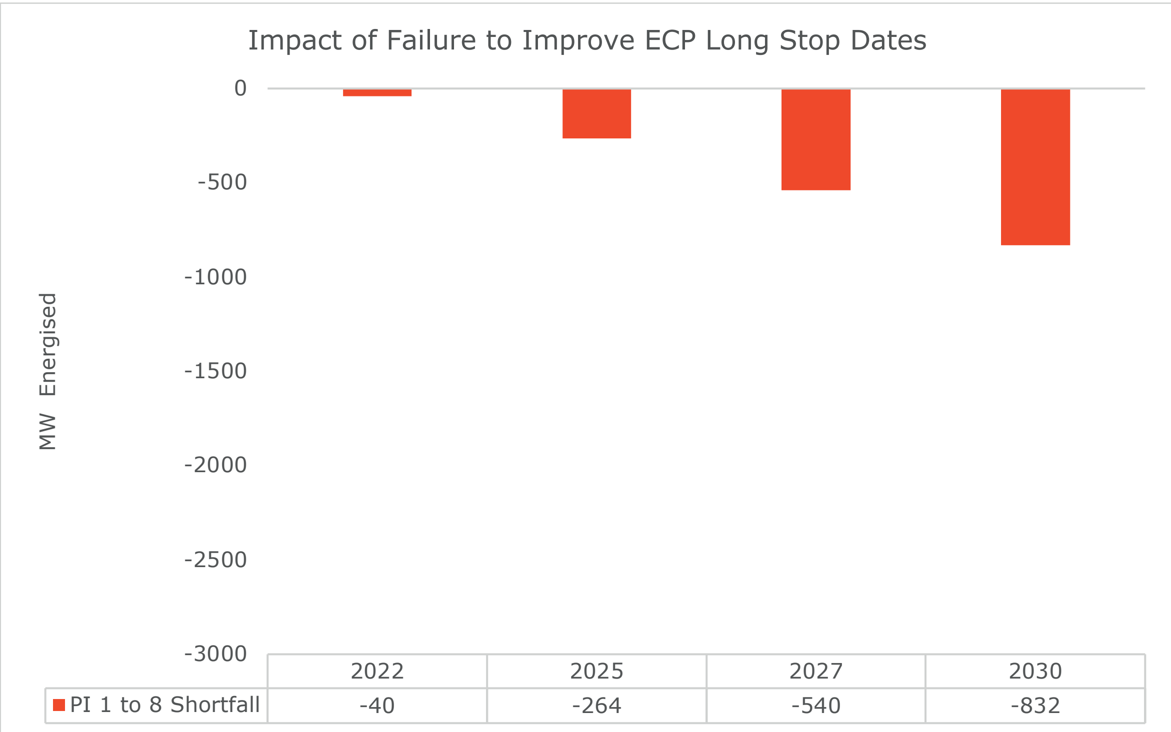
9.7 Failure of PI7: Longer ECP 'longstop dates' for Grid Offers

Failure 7 Failure to increase ECP Long stop dates such that projects can bid into at least 3 annual auctions

- Avoid failure by increasing ECP Long stop dates

Impact of potential failure 7:

Year	2022	2025	2027	2030
MW Shortfall	-40MW	-264MW	-540MW	-832MW
% RES-E Shortfall	-0.3%	-1.8%	-3.7%	-5.5%
CO2 emissions increase (ktonnes p.a.)	+54 kt	+354kt	+723kt	+1114kt



	2022	2025	2027	2030
PI 1 to 8 Shortfall	-40	-264	-540	-832

Key Non-Industry Stakeholders to prevent failure:

CRU

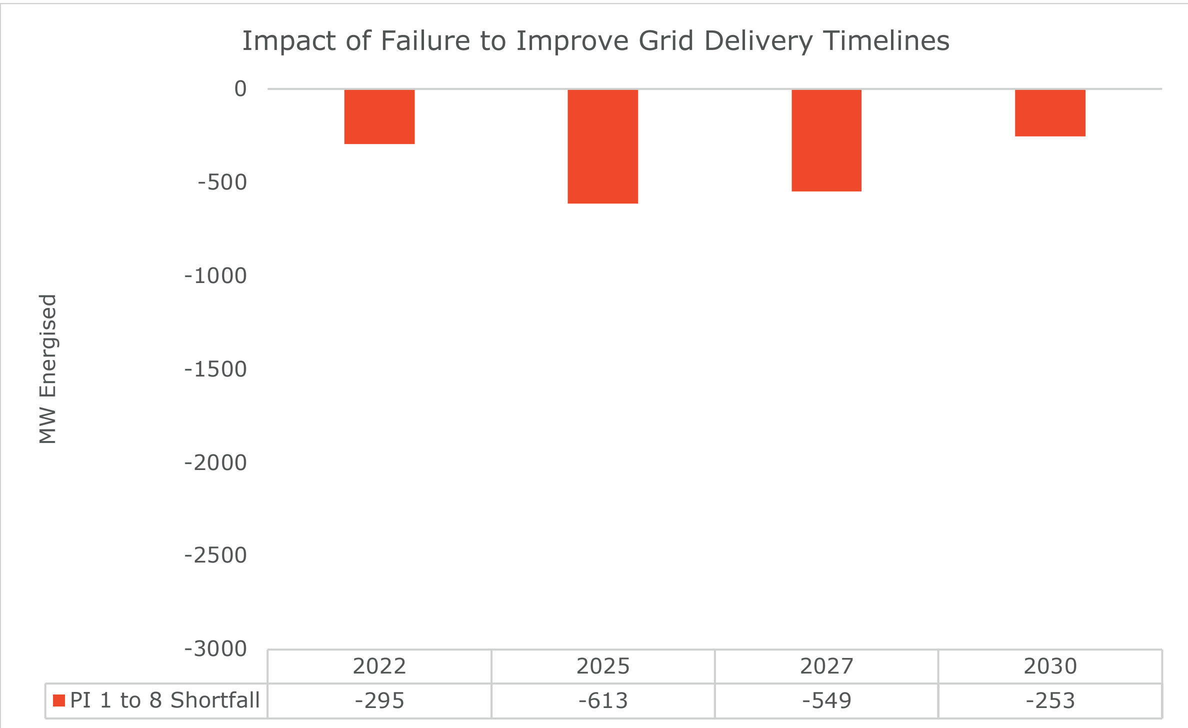
9.8 Failure of PI8: Reduce grid delivery timelines

Failure 8 Failure to reduce finance and build periods from 2.5 to 1.5 years

- Avoid failure by improving delivery of non-contestable grid connection works such that projects are energised within 14months of making a second stage payment.

Impact of potential failure 8:

Year	2022	2025	2027	2030
MW Shortfall	-295MW	-613MW	-549MW	-253MW
% RES-E Shortfall	-2.3%	-4.3%	-3.7%	-1.7%
CO2 emissions increase (ktonnes p.a.)	+395 kt	+822kt	+735kt	+338kt



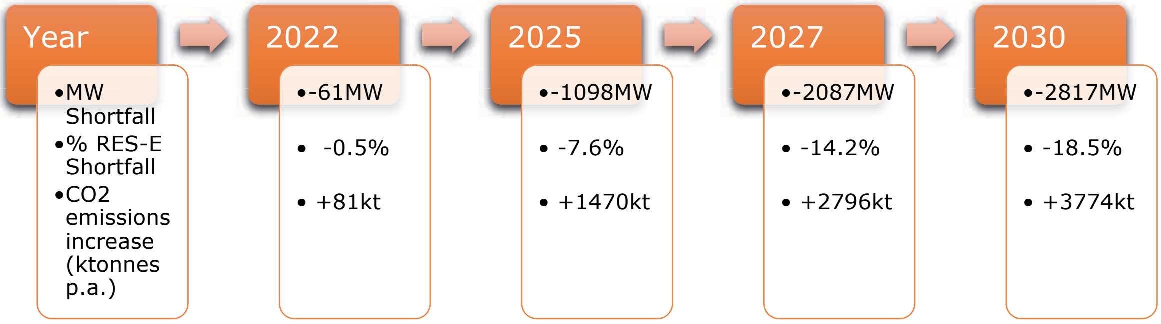
Key Non-Industry Stakeholders to prevent failure:

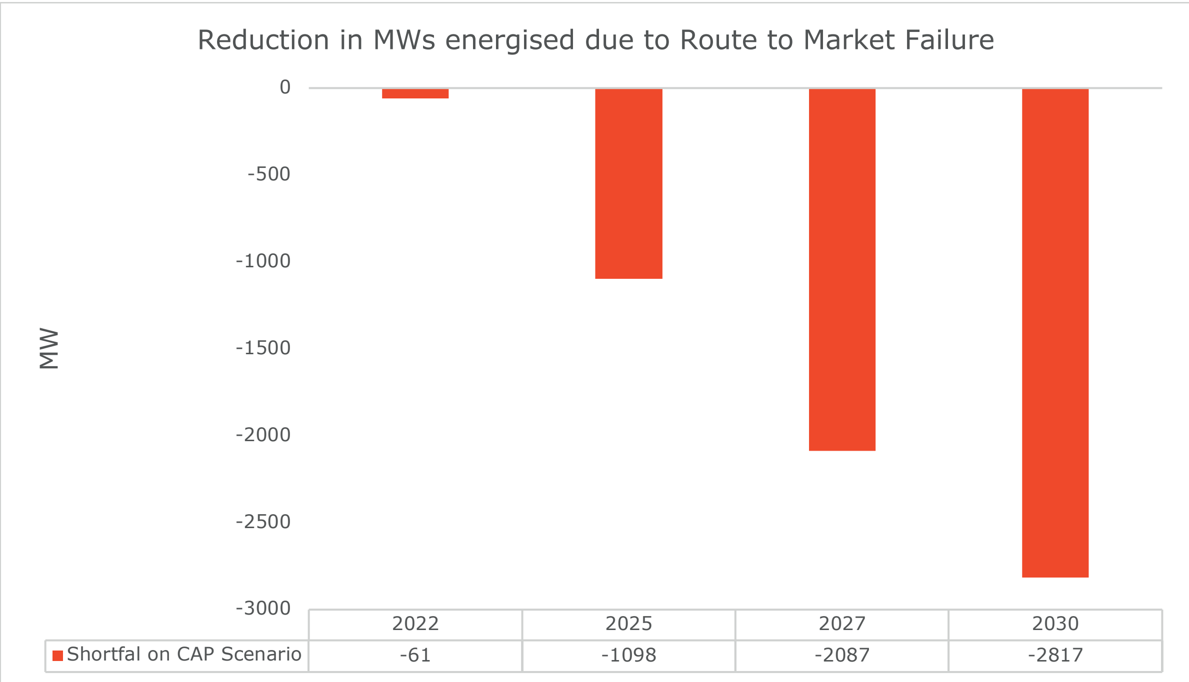
9.9 Failure of PI9: Annual Route to Market

Failure 9 Route to Market failure - 66 % of eligible projects are contracted in RESS 1 only, 100MW p.a. contract through CPPA's after RESS 1

- Avoid failure by ensuring the delivery of an active CPPA market and / or by delivering annual RESS auctions.

Impact of potential failure 9:





Key Non-Industry Stakeholders to prevent failure: