CORNWALL INSIGHT

CREATING CLARITY

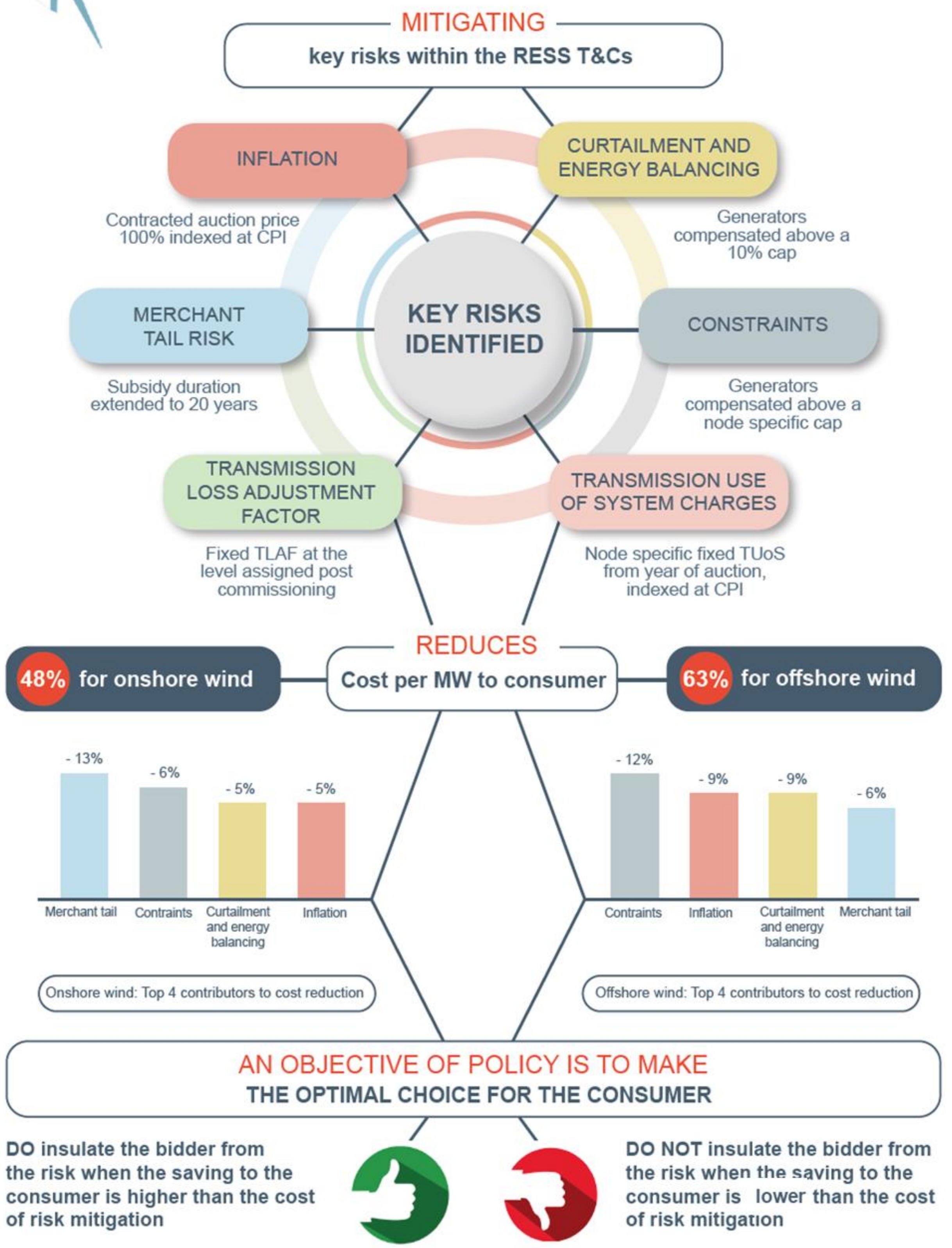
Green Tech Skillnet

Improving revenue certainty and risk allocation for new renewable generators

28 April 2022

RESS for LESS

Mitigating the risks to developers in the RESS auction design will reduce the price end use consumers pay for the addition of new renewable energy capacity



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1. Executive Summary

The addition of renewable energy to generation portfolios in Ireland and internationally is paving the way to net zero and a cleaner energy future. Through the Climate Action (Amendment) Bill of 2021 and the associated Climate Action Plans, Ireland has set ambitious renewable targets for 2030. These are onshore wind up to 8GW, offshore wind at least 5GW & solar PV of between 1.5 GW & 2.5 GW. In order to achieve these targets, Ireland has established the Renewable Electricity Support Scheme (RESS) auction mechanism. This is a competitive auction process that seeks to drive auction bid prices downwards, therefore delivering a lower cost to consumers and aid the promotion of a mix of technologies.

Competitive renewable auctions are the go-to method for the addition of renewable generation internationally. We assessed the contracted auction prices across Europe in recent years and found that the auction prices in Ireland were higher than the European norm. This could be attributed to the fact that there was less competition than was expected in the first RESS auction, but upon investigation the terms and conditions of the auction design appear to be the biggest contributor to the high prices.

If the auction design does not insulate developers from enough risk, especially those risks that they have no ability to manage and limited ability to predict, the bid price submitted by those developers will be higher. This will result in higher contracted auction prices and costs to the consumer. Economic theory tells us that the above statement holds true and, specifically related to the RESS terms and conditions (RESS T&Cs), bidding behaviour and the role that WACC plays in both bid price discovery and consumer costs is a function of the auction structure.

With the goal of testing this hypothesis we reviewed the RESS T&Cs to assess how a renewable developer considers risk management of certain externally managed risks within their RESS auction bids and the impact it has on the cost of power to the consumer. The objective of the study is to guide policy decisions on risk allocation for RESS such that risks are transferred to those best placed to manage them and costs to the consumer are optimally reduced. Work underpinning the study was segmented into two phases. We focused on the behaviour of the pragmatic bidder who typically allocates a premium or buffer to their bid price, albeit pared to the minimum level they can live with (a walk-away bid considering the risk), given the auction context. It is key for the success of an auction mechanism that the pragmatic bidder can lower their risk perception to an extent that they can lower their bid price.

Phase 1 looked at how developers bid into the RESS auction considering different levels of risk perception amongst them, the various types of externally managed risks[1] that developers face, an explanation of these risks and how they are considered nationally for RESS in Ireland and in other types of renewable schemes internationally. Based on this comprehensive review mitigation measures for each risk were identified for inclusion in Phase 2.

Phase 2 used a cost benefit analysis to assess the impact of implementing the identified risk mitigation measures. Three elements were considered and presented; the expected required weighted average cost of capital (WACC) of a project by the developer, the related bid price submitted for that project, and the per MW cost to the consumer associated with the RESS auction. This was completed using two scenarios: the first used a Pragmatic Bidder's[2] approach to the RESS auction considering specific externally managed risks, whilst the second used a pragmatic bidder's[7]

1 Risks that cannot be managed by the bidder, but are managed or controlled by a separate stakeholder, such as the Regulator, the Transmission System Operator (TSO), policy makers, etc.
2 The definition of a Pragmatic bidder assumed in this report is provided in Section 4.1

approach to that same RESS auction, where these externally managed risks have been mitigated as per Phase 1; 'Pragmatic Bidder with risk Mitigation'.

If we start with the hypothesis that the aim of the auction design should be to de-risk all factors to the extent where the "saving" to the consumer from lower bids is higher than the costs to the consumer of the specific risk mitigation measure should the risk crystalise, then:

- DO insulate the bidder from the risk when the saving to the consumer from lower bids is higher than the cost of risk mitigation.
- DO NOT insulate the bidder from the risk when the saving to the consumer from lower bids is lower than the cost of risk mitigation.

A pragmatic bidder is exposed to several risks across their project. However, it is the externally managed risks that are important in this study. These are risks that fall outside the control of the developer but can be managed by a different stakeholder, for example the System Operators, Regulators, or Policy Makers. We have limited the externally managed risks identified to those risks that could be mitigated within the RESS Terms and Conditions (T&Cs) and which bidders rate as significant and material, therefore driving their bidding behaviour. These risks are: constraint risk, curtailment and energy balancing risk, TLAF[3] risk, TUoS[4] risk, merchant tail risk, and inflation risk.

To understand how they are managed in Ireland and internationally, we proposed some appropriate mitigation measures using evidence from other markets with similar challenges and goals to Ireland. Those mitigation measures were then fed into the cost benefit analysis modelling study (CBA). **We observed that there is a definite reduction in costs to the consumer when the identified risks are mitigated.** While certain risk mitigation measures have a higher impact than others, there is also an additional combination effect[5] causing increased savings when all the identified risks are mitigated together. The CBA considered not only the direct levy savings to the consumer as a result of implementing the risk mitigation measure, but also the cost of the risk mitigation measure to the consumer.

Overall, the impact of the risk mitigation measures is greater for offshore wind projects than onshore wind projects. Notwithstanding the higher capacity factor, the larger overall magnitude of offshore wind versus onshore wind projects modelled in this analysis gives rise to the greater impact on the consumer cost experienced. As such, in Table 1, we have presented the results on a per MW basis to ensure a like for like comparison between onshore and offshore wind projects. The combination effect is also higher and assists in the higher cost to consumer reduction than for onshore wind projects. This can also be attributed to the different distributive weighting of, or exposure to, different risks to each technology.

Table 1: Summary of savings for consumers as per CBA

Risk	Reduction in Cost to Consumer- Onshore wind	Reduction in Cost to Consumer- Offshore wind
Constraint	6%	12%
Curtailment and Energy Balancing	5%	9%
Inflation risk (Indexation)	5%	9%
Merchant Tail Risk	13%	6%
TLAF	3%	5%
TUoS	4%	3%
Combination effect	12%	20%
Total savings for consumers	~48%	~63%

[3] Transmission Loss Adjustment Factor
[4] Transmission Use of System Charges
[5] Additional savings due to all the risks being mitigated together, discussed in Section 6

From our evaluation it is clear that adopting risk mitigation measures for externally managed risks would result in beneficial savings for consumers. The greatest single impacts would arise from the mitigation of merchant tail risk for onshore wind and constraints for offshore wind projects. However, efficiencies arising from mitigation measures across the entire basket of risks considered in this study are meaningful and the combination effect of addressing all of them are profound in terms of reducing consumer costs.

Considering the ease of implementation of mitigation measures, we recommend the following to be considered noting the time scales suggested:

Table 2: Key recommendations

Risk	Risk Mitigation method	Recommendation	Action element(s)	Timeline	Action owner(s)
Dispatch Down Risk – Curtailment & EB	10% cap on Curtailment & EB.	Current RESS T&Cs already include a 10% cap for curtailment related dispatch down. We recommend that this is extended to energy balancing related actions, especially as there is still lack of clarity around the implementation of Article 12 and Article 13 of the EU Electricity Regulation, despite the SEMC decision paper published.	Changes made to RESS T&Cs to include compensation for energy balancing related actions.	Quick win	• DECC • CRU
Dispatch Down Risk – Constraints	A nodal cap for constraints.	Further assessments need to be carried out before this risk mitigation method can be put into place.	First, design methodology to assign nodal caps. Second, nodal caps to be assigned to every node after node wise assessment is carried out	Medium term	• EirGrid • DECC • CRU

Risk	Risk Mitigation method	Recommendation	Action element(s)	Timeline	Action owner(s)
TLAF Risk	Fixed TLAF at the level assigned post commissioning.	Further assessments need to be carried out before this risk mitigation method can be put into place. Other countries did not mitigate this risk through auction design (the exception being Belgium). The long-term impact if this is implemented in the RESS T&Cs need to be assessed.	Assessment of long-term impact of fixing TLAF.	Long term	• CRU
TUoS Risk	Fixed TUoS charges at each individual node at the year of auction and indexed to inflation.	Further assessments need to be carried out before this risk mitigation method can be put into place. Other countries studied did not mitigate this risk within their auction design and therefore lessons cannot be learnt from them regarding the long-term impact of fixing TUoS charges.	Assessment of long-term impact of fixing TUoS charges.	Long term	• CRU
Merchant Tail Risk	Extending the length of the subsidy to 20 years.	No restrictions within the EU state aid documents, on the basis of which RESS was approved, which prevents a 20-year subsidy period. However, approvals for changes will have to be taken from the European Commission as currently a maximum support period of 16 years has been approved.	Application to extend state aid for a period of 20 years for future RESS rounds.	Medium Term	• DECC • CRU • European Commission

Risk	Risk Mitigation method	Recommendation	Action element(s)	Timeline	Action owner(s)
Inflation Risk	Contracted auction price fully indexed against the Irish CPI.	Reducing the risk of inflation through indexation has a dual benefit: first, to reduce the bid price by lowering interest rates. Second, to bring in additional sources of investment such as institutional investors and pension funds who otherwise may not bear the risks of investing under the current RESS T&Cs. This will contribute considerably to expanding the investor base, which is key considering Ireland's RE targets.	Include 100% indexation against the CPI in RESS T&Cs.	Quick win	• DECC • CRU

2. Introduction

This study looks to review the Renewable Electricity Support Scheme (RESS) to assess how a renewable developer considers risk management of certain externally managed risks within their RESS auction bids and the impact this can have on the cost to the consumer associated with the RESS auction. The key objective of the study is twofold: First, to determine what mitigation measures could be put in place to address these externally managed risks with the aim of moving the burden of risk away from the developer to the party best placed to manage them; Second, to determine what the associated impact on the cost to the consumer is. This report considers both onshore and offshore wind projects and is broken into two distinct phases.

Phase 1 looks at how developers bid into the RESS auction considering different levels of risk perception amongst them, the various types of externally managed risks[6] that developers face, and an explanation of these risks and how they are considered nationally for RESS in Ireland and in other types of renewable schemes internationally. Based on this comprehensive review mitigation measures for each risk are identified for inclusion in Phase 2.

Phase 2 uses a cost benefit analysis to assess the impact of implementing the identified risk mitigation measures. Three elements are considered and presented:

- the expected required weighted average cost of capital (WACC) of a project by the developer,
- the related bid price submitted for that project, and
- the cost to the consumer associated with the RESS auction.

This is completed by using two scenarios. The first is a 'Pragmatic Bidders'[7] approach to the RESS auction considering specific externally managed risks, or risks which cannot be managed by the developer during the lifetime of the RESS project. The second is a pragmatic bidders[7] approach to that same RESS auction when these externally managed risks have been mitigated as per Phase 1, namely the 'Pragmatic Bidder with Risk Mitigation' scenario.

This report has the following sections:

- **Section 3** Background: Renewable Auction Mechanisms
- **Section 4** Phase 1: Risk Perception and Bidding Behaviour
- **Section 5** Phase 1: Externally Managed Risk
  - Identification of Risks
  - Treatment of identified risk in Ireland and internationally
  - Summary of Risk Mitigation Measures
- **Section 6** Phase 2: Cost Benefit Analysis
  - Methodology and Assumptions
  - Results of implementation of risk mitigation measures
- **Section 7** Key Findings

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[6] *In this document externally managed risks are those risks which cannot be managed by the developer during the lifetime of the RESS project, such as the risk of revenue loss due to dispatch down, risk of TUoS and TLAFS being charged, uncertainties around future inflation rates and earnings after the subsidy period i.e., the merchant tail. This has been explained further in Section 5.*

7 The definition of a Pragmatic bidder assumed in this report is provided in Section 4.1.

3. Background

The addition of renewable energy to generation portfolios both in Ireland and internationally is paving the way to net zero and a cleaner energy future. In 2016, the European Union (EU) along with 191 other countries signed the Paris Agreement, a legally binding treaty ensuring countries put measures in place to deal with climate change. In 2019, the EU created directives and regulations for its member states to follow. The Clean Energy Package (CEP) sets out targets for energy efficiency (32%), shares of renewable energy (32%), increased interconnection between member states (15%), and the reduction in global greenhouse gas (GHG) emissions (40% from 1990 levels) by 2030. These targets are expected to be increased further as the EU strives for a 55% reduction in GHG emissions under the ‘Fit for 55 Package’.

Ireland has set its own ambitious target in line with EU requirements. In its 2019 Climate Action Plan, it committed to reaching 70% of renewable electricity by 2030. In its 2021 Climate Action Bill, that target was increased to 80% renewable electricity by 2030. The targets in the Climate Action Plan of 2021[8] (CAP2021) have accordingly been adjusted to reflect the following capacity addition targets for various renewable energy technologies in line with their potential on the island:

1. Onshore wind: Up to 8GW
2. Offshore wind: At least 5GW
3. Solar PV: Between 1.5 GW to 2.5 GW

Internationally, renewable auctions have been the go-to method for policy makers to drive this addition of renewable capacity as they aim to: drive efficient and lower auction bid prices, drive lower cost to consumers for the addition of renewable capacity, and aid in the promotion of a certain mix of technologies as required. CAP2021 specifies ‘Electricity technologies will compete with each other on cost through competitive auctions’[9] and this ideology has been incorporated within Ireland’s Renewable Electricity Support Scheme (RESS) high level design since 2018.

RESS has been set up in Ireland to achieve the additional renewable capacity targets through a competitive auction process which:

1. Seeks to drive auction bid prices downwards through the reverse auction structure: Under the RESS mechanism the bids are stacked according to the bid price, from lowest to the highest, with capacity being allocated to bidders in an ascending order until the set target under that round is reached.
2. Drives a lower cost to consumers who bear the ultimate burden for adding this capacity: The cost of supporting the RESS Auction output is passed on to the consumer via the PSO levy.
3. Aids promotion of a certain mix of technologies as required: In RESS 1, there were specific carve outs for Solar PV, due to it being at a nascent stage in Ireland at that point, and the future ORESS is an auction specifically set up to promote and drive offshore wind capacity. In RESS 2, the introduction of the Evaluation Correction Factors (ECF) aims to level the playing field between more mature and less mature technologies.

In Ireland so far, the competition has not been as robust as expected, with ~88% of the total capacity that bid into RESS 1 being offered contracts. This has led to the auction strike price (clearing price) being on the higher side as compared to other international countries. Table 3 gives

8 Based on the 2021 Climate Action Bill
9 Climate Action Plan 2021, 04 November 2021 (https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/)

examples of recent strike prices at renewable auctions.

Table 3 Renewable Auction Strike Prices Internationally

Country	Technology	Timeline	Average price
Germany	Onshore wind	May 2021	€/MWh 59.10
	Solar PV	March 2021	€/MWh 50.30
	Innovative wind/solar/storage	April 2021	€/MWh 42.90
	Offshore wind	April 2018	€/MWh 46.60
	Onshore wind and solar combined	November 2020	€/MWh 53.30
France	Onshore wind	February 2021	€/MWh 59.50
	Solar PV	February 2021	€/MWh 60.10
	Offshore (Dunkirk)	June 2019	€/MWh 44
Great Britain	Offshore wind	October 2019	~€/MWh 53.7
	Onshore remote Island	October 2019	~€/MWh 52.8
Denmark	Onshore wind	December 2019	€/MWh 2 + market revenues
Finland	Onshore wind	November 2018	€/MWh 2.4 + Market reference price
Spain	Onshore wind	October 2021	€/MWh 25.3
Netherlands	Onshore wind	2020	€/MWh 24.7
Italy	Onshore wind	June 2019	€/MWh 68.5
Ireland	Solar PV	August 2020	€/MWh 72.92
	All projects (Onshore wind and solar PV)		€/MWh 74.08

While some of the delta between Ireland and its peers may be attributed to general investment sentiment being affected by COVID-19, the design and terms of the auction play the key role in determining bid prices and the associated auction dynamics.

This report investigates how the RESS auction mechanism design could be modified through the T&Cs to reduce the strike price for Ireland and ensure a more efficient and cost-effective price for the end consumer.

4. Phase 1: Risk Perception and Bidding Behaviour

Developers play an important role in the auction mechanism as it is their investment decisions that drive the bid price discovery and the auction strike price.

Under an auction structure there are two main drivers to bid price discovery:

1. Level of competition: If the level of competition in an auction is high, developers will aim to bid more aggressively. This will result in a lower bid price discovery.
2. Risk perception: If externally managed risks need to be considered by the developer, they will take a conservative view in order to secure their return. This will result in higher bid price discovery regardless of a competitive auction being in place.

The aim of an auction design should be to de-risk all factors to the extent where the "saving" to the consumer from lower bids is higher than the costs to the consumer of the specific risk mitigation measure should the risk crystalise. Policy makers need to understand fully the premium attached to risk perception and make the right choice for the consumer:

- DO insulate the bidder from the risk when the saving to the consumer from lower bids is higher than the cost of risk mitigation, should the risk crystalise.
- DO NOT insulate the bidder from the risk when the saving to the consumer from lower bids is lower than the cost of risk mitigation, should the risk crystalise.

To explore these statements and take the appropriate policy decisions it is important to understand:

1. Economic Theory of Bidding Behaviour.
2. WACC and its role in bid price discovery and cost to consumers.

4.1 Economic Theory of Bidding Behaviour

Established economic theory and decades of observed investor behaviour tell us that when making an investment if the expected risk is high, then there needs to be a high expected return attached to compensate for such risk whilst still satisfying the investment objectives of the provider of capital. In economic theory, this decision is termed the *risk-return conundrum*.

When the costs of unpredictable or externally managed risks are absorbed by bidders it can give rise to different kinds of bidding behaviour; the two extremes being:

- High bid price discovery by a bidder more focused on conservative risk management and high return on investment.
- Low bid price discovery by a bidder more focused on winning a project and not pricing in risks leading to so called winner's curse and projects not being built.

The latter type of bidding behaviour can be cause for concern as higher levels of contracted projects not being built in the long-term lowers investor appetite, potentially causing setbacks to the achievement of targets. We are already seeing some of the RESS 1 contracted solar projects dropping out and thought should be given as to why this is happening and how to mitigate against it in the auction design.

For this report however, we do not consider either of the two bidding behaviours presented above, but a bidding behaviour which is a direct and rational reflection of the auction design and the risks a bidder is expected to account for over the lifetime of the plant – the '**Pragmatic Bidder'**. This type of bidder allocates a premium or buffer to their bid price, albeit pared to the minimum level they can live with (a walk-away bid considering the risk), given the auction context.

It is key for the success of an auction mechanism that the Pragmatic Bidder can lower their risk perception to a feasible extent where they can lower their bid price while adding capacity to the grid. A study of 23 EU Member states and GB found that most countries identified the risks caused by policy design to have been the most important[10] in setting WACC.

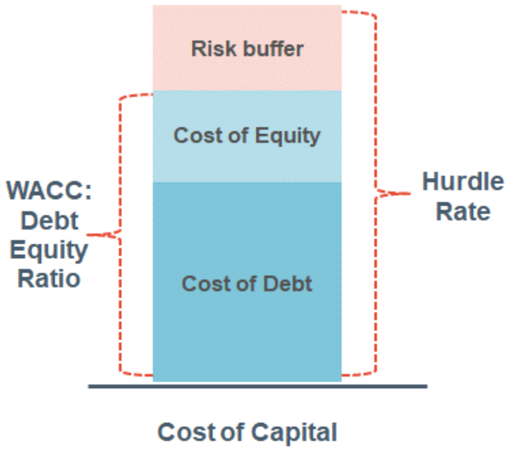
If a policy is built in such a way where unsuitable externally managed risks are assigned to developers (i.e., developers must assess the level of risk they face over the project life cycle) it will drive up the WACC. Reassigning those risks to the stakeholder most appropriately placed to manage those risks can result in an overall lower cost to the consumer so long as the savings from the lower bid prices outweigh the possible cost to the consumer of accepting or mitigating the risk for an auction participant.

4.2 WACC & its role in Bid Price Discovery & Cost to Consumers

A renewable project has a different business case as compared to most conventional electricity generation projects. They have high capital costs and low operational costs, making the recovery of the high upfront investment the key focus of any investment case. This leads to a need for a higher return to counter the higher risk of making upfront investment on the renewable electricity project before it is operational. Before an investment decision is made a risk analysis is carried out. If the risk perception is high, this is reflected in a higher fee for making the initial investment capital available i.e., a higher cost of capital. The cost of capital is a function of two key concepts: the Weighted Average Cost of Capital (WACC) and hurdle rates. Figure 1 shows the factors that input into the cost of capital.

The ratio between the cost of debt and cost of equity in an investment, i.e., the debt-equity ratio, makes up the WACC. The lower the cost of debt and equity, the lower will be the required WACC. The hurdle rate is the minimum rate of return that an investment needs to make. Therefore, the risk perception, or risk buffer that needs to be built into an investment, is directly reflected in its hurdle rate and WACC[11], and impacts overall investability.

Figure 1: Cost of Capital Factors



Source: Cornwall Insight analysis

[10] *DiaCore(Ecofys, Fraunhofer, Elareon, EPU NTUA, Energy Economics Group, LEI); The impact of risks in renewable energy investments and the role of smart policies, 2016*
[11] *Aures (Augustan Roth, Eclareon), Renewable energy financing conditions in Europe: survey and impact analysis, 2021*

"An auction mechanism could both help improve and deteriorate planning risk".[12] An auction mechanism containing clearly defined auction parameters, whether they be around pre-bid risks (auction frequency, dates, volumes, etc.) or operational risks (de-risking market-based uncertainties, fixed thresholds for unpredictable factors such as dispatch down, transmission charges and losses, merchant tail, etc.), can drive down costs of capital. By contrast, auctions that do not have these features can drive up costs of capital.

A higher cost of capital translates to a higher bid price driving up the cost to consumers.

In 2018, AURES-E II (Auctions for Renewable Energy Support II) funded by the EU's Horizon 2020 Framework Programme, published the report 'Trends and evolution of the Costs of Capital in RE Financing'. This included details of the WACC for onshore wind across Europe

Figure 2). In most countries with a low WACC we can observe that the bid price is lower than that discovered during RESS 1 in Ireland. This can be seen in Figure 3.

Figure 2: WACC for onshore wind across Europe[13]

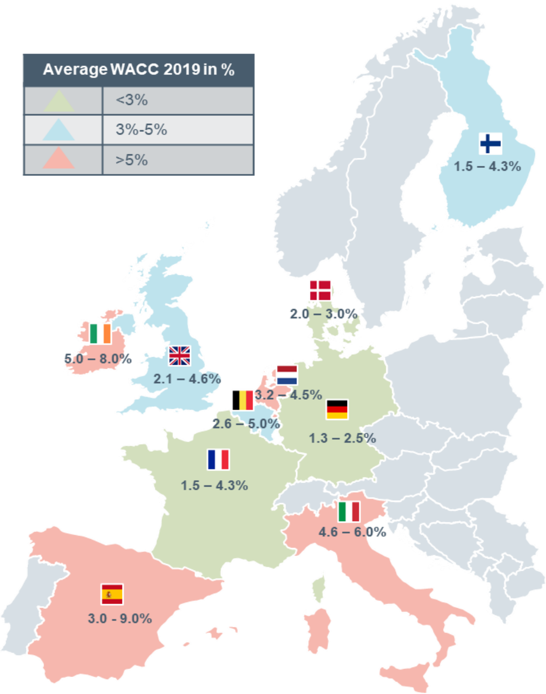
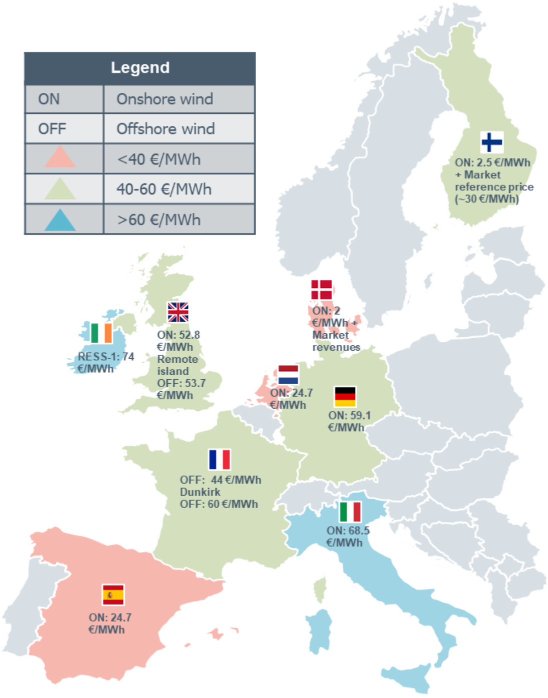


Figure 3: Auction Clearing Prices Across Europe[13]



Source: AURES, EU

Table 4 lists the auction prices for recent onshore and offshore renewable auctions across Europe, including 2019 unlike the figures above.

Table 4 Auction Prices for Recent onshore and offshore Renewable Auctions across Europe

Country	Technology	Year	Price
Denmark	Onshore	2019	2 €/MWh + market revenues
England	Onshore remote Island & Offshore	2019	52.8 €/MWh on / 53.7 €/MWh off

[12] *Mak Dukan, Lena Kitzig, The impact of auctions on financing conditions and cost of capital for wind energy projects, 2021*

[13] *Aures (Augustan Roth, Eclareon), Renewable energy financing conditions in Europe: survey and impact analysis, 2021(https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5daaba9f4&appId=PPGMS)*

Finland	Onshore	2018	2.4 €/MWh + Market refence price
France (Dunkirk)	Offshore	2019	44 €/MWh (Dunkirk) & 60 €/MWh off
Germany	Onshore	2020	59.1 €/MWh
Ireland	Onshore	2020	74 €/MWh
Italy	Onshore	2019	68.5 €/MWh
Spain	Onshore	2021	25.3 €/MWh
The Netherlands	Onshore	2020	24.7 €/MWh

Source: Cornwall Insight research

The AURES-E II report highlights that the average WACC is higher in Ireland for onshore wind investments as compared to other key European countries. This implies that investors perceive a higher risk when investing in onshore wind in Ireland. This relates back directly to the auction design or policy environment under which the investment is made in the country.

For example, in the Nordic countries of Denmark, Sweden, and Finland the WACC in Sweden is significantly higher than in Denmark. This difference can be tied back to the difference in risk perception associated with both auction policy designs. Denmark's near shore wind auction design places the burden of site evaluation, clearances, permits, etc. on the Government. This results in a reduction of required WACC as less risks need to be considered by the developer in Denmark.

Similarly, when the Department of Energy and Climate Change (DECC) in GB moved from a Renewable Obligation (RO) scheme to a Contract for Difference (CfD) scheme there was an investor survey and analysis of investor reports carried out as part of the study.[14] This acknowledged the principle that lowering expected price risk reduces rate of return risk. As a result, there was a 0.5 – 1.0% reduction in required WACC due to increased certainty in the CfD price. Table 5 shows the impact on hurdle rates caused by the difference in risk perception under both schemes.

Table 5: RO and CfD hurdle rate differences as per NERA report

NERA Assessment- Total risk impact on hurdle rates			
	Offshore wind	Biomass conversion	Onshore wind
DECC RO WACC	10.2%	11.6%	8.3%
DECC CfD WACC	9.6%	10.9%	7.9%

Source: DECC UK

It can be concluded from our analysis above that the countries with lower WACC have lower risks assigned to the developers under their auction design. The question remains: since consumers are exposed to several different types of costs related to the addition of renewable capacity (such as infrastructure cost, auction clearing price, risk mitigation costs), does a lower WACC lead to a lower cost burden on consumers?

There are several examples of studies highlighting countries that share risk management optimally between consumers and developers to lower the cost to consumers.

[14] *NERA, Department for Energy and Climate Change DECC) UK, 2013*

For example, the UK's Regulated Asset Based (RAB) model for adding on nuclear capacity. Nuclear projects have high construction risks with timelines and costs often overrunning. The RAB model tries to minimise the burden of this risk by sharing the burden of the risk with consumers. There are expected cost savings to the tune of £30billion to consumers because of this model. The model has already been used successfully for other infrastructure projects such as The Thames Tideway Tunnel and Heathrow Terminal 5.[15]

It follows then that policy makers need to be conscious of the following when designing an auction mechanism in an optimal manner:

1. Identifying risks that drive up the cost of capital.
2. Identifying the risks that cause the greatest increase in WACC.
3. Understanding whether the application of risk mitigation measures will result in an overall lower cost to the consumer.

[15] *BEIS, New Story, Future funding for nuclear plants-An explanation of the Regulated Asset Base (RAB) model option, 2021*

5. Phase 1: Externally Managed Risk

This section makes use of the information in section 4 on risk perception and bidding behaviour to identify the key risks that could be mitigated within the RESS T&Cs with the intention of lowering costs to consumers. A comprehensive national and international review of these identified risks is presented alongside the proposed risk mitigation measures that will be applied in section 6.

The risk mitigation measures that will be discussed in Section 5.3 were finalised for this study using the following methodology:

1. All options for risk mitigation measures were collated from international comparators, Irish market expertise, and previous analysis and reports[16] on this topic.
2. All options were then analysed and ranked for the following factors:
    a. Complexity: Measures with easier implementation and lower expected institutional costs are ranked higher.
    b. Value to consumer: Measures where the cost to consumer is lower considering the cost of the mitigation and cost of the auction are ranked higher.
    c. International Review: Measures where multiple countries are using it are ranked higher.

5.1 Identification of Risks

A renewable generator bidding into RESS is exposed to several types of risks during the operational lifetime of their plant. While these risks can be of various types (delivery risk, technical risk, revenue risk, political risk, volume risk, operational risk, etc.), what is important to understand is whether the bidder can or cannot manage that risk. The bidder may include an appropriate buffer into their bid price in line with their view of the level of risk they expect to bear i.e., their risk perception. But such a buffer or premium is likely to be higher for unmanageable risks.

- Manageable risk: Risks where the bidder can to a large extent, predict or manage the risk, and its variability can be predicted or controlled. In this case, the bidder will not build in a buffer but price the risk at actuals.
- Un-manageable risk: Risks such as political risks, weather related risks, force majeure, etc., over which no stakeholder in the auction process has any control. These risks will have a buffer built in related to their risk perception which can be subjective and often prudent.
- Externally managed risk: Risks that cannot be managed by the bidder but are managed or controlled by a separate stakeholder such as the Regulator, the Transmission System Operator (TSO), policy makers, etc. In this case, the bidder also builds in a buffer dependant on their perception of that risk, historical trends, and often conservative future projections.

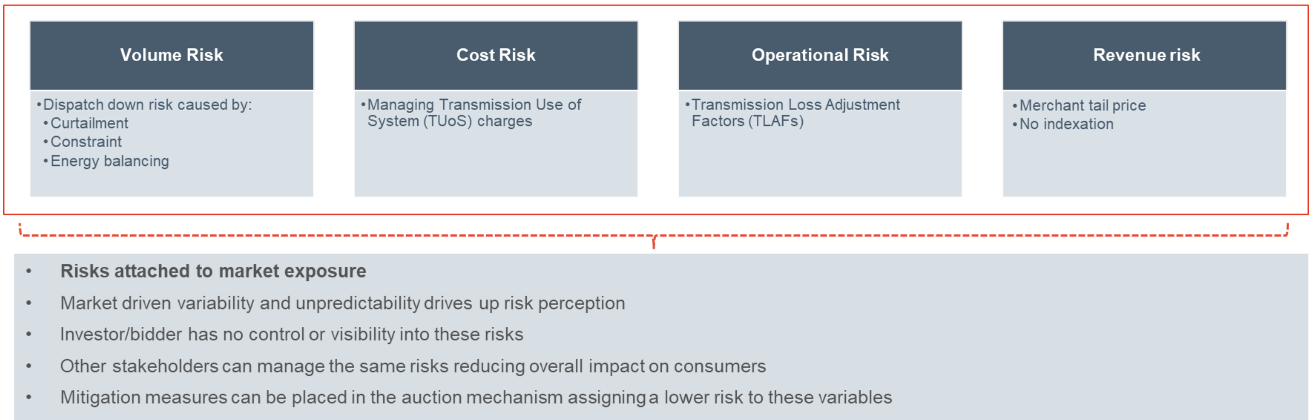
It is important to remember that the focus of a bidder is to ensure their project is viable and their return is secure despite the risks to their project. While it is the policy makers' focus to ensure that their policy goals are met at the least possible cost to the consumer.

As discussed, there are various types of risks that can impact different aspects of a renewable project. This report focuses on those risks for which mitigations can be built into the RESS T&C, namely externally managed risks. These risks affect risk perception within the auction mechanism

[16] *WEI Submission to DECC on Reducing RESS Auction Bidding Risk*

and drive up the WACC, in turn driving up bid price and costs to consumers. Figure 4 outlines some of the key external risks that drive up the overall costs of a renewable projects under the current RESS auction mechanism through lack of predictability, visibility, and certainty.

Figure 4: Externally Managed Risks Assessed in this Report



Source: Cornwall Insight analysis

5.2 Treatment of Identified Risks in Ireland & Internationally

5.2.1 Dispatch Down Risk

5.2.1.1 Dispatch Down in Ireland

In this report there are three types of dispatch down definitions:

- Curtailment: If renewable generation is reduced or dispatched down due to a system wide limit of SNSP (system non-synchronous penetration) we classify this as curtailment of renewable generation.
- Energy Balancing: If generation is reduced or dispatched down due to an oversupply of generation on the grid to ensure a balance between demand and generation we classify this as energy balancing dispatch of renewable generation.
- Constraint: If generation is reduced or dispatched down due to a locational technical limitation on the network that can be directly impacted by the export of a generator in that area we classify this as constraint of renewable generation.

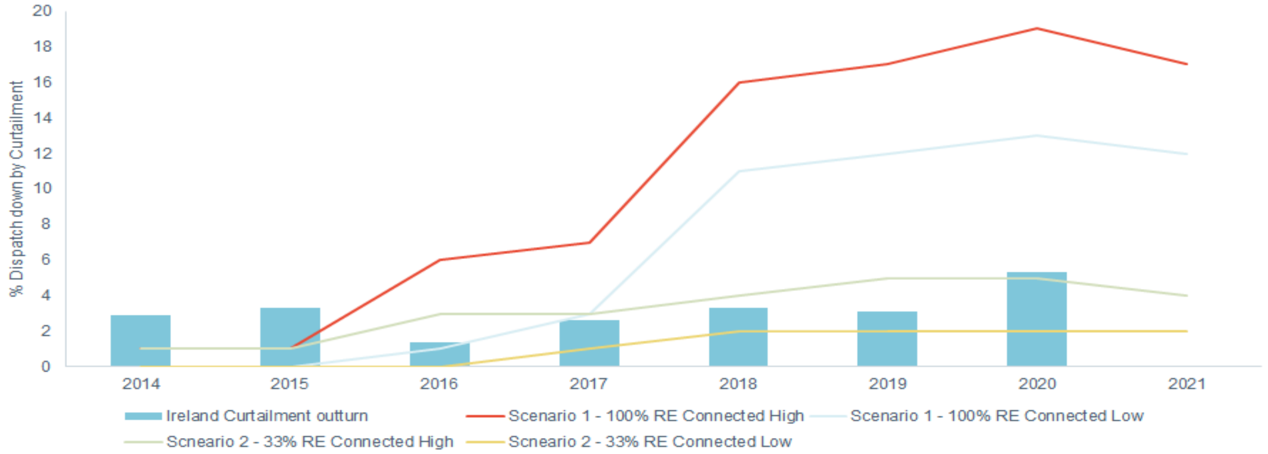
5.2.1.1.1 Curtailment in Ireland

As stated above, curtailment is defined in this report as when renewable generation is reduced or dispatched down due to a system wide limit of SNSP (system non-synchronous penetration).

Projects entering RESS will look at curtailment as a risk which will then be factored into their bid price. Curtailment is outside the realm of control of a bidder. Therefore, to counter its downside they must price in the risk of curtailment reaching a certain level. Currently, bidders are not protected from curtailment by RESS T&C until curtailment reaches 10%. When curtailment reaches 10% for two consecutive years a mechanism is in place to protect revenues for bidders. The RESS T&C state that compensation will not be provided if curtailment is being compensated by another party and/or through another mechanism. Other mechanisms, whereby a generator may be compensated, are not clear at this point. However, the Article 13 of the Electricity Regulation (Clean Energy Package) directs its member states to build a mechanism for redispatch of renewable generation into its market design. While a decision paper has been published by the SEM Committee[17] for Ireland's transposition of this article, further clarity is needed to understand the compensation mechanism for dispatch down of renewable generators in the future.

Looking at EirGrid's Gate 3 Constraint Reports 2020[18], which also includes curtailment projections, there is a large variability for a bidder depending on how much renewable generation is expected to get connected at each node. Figure 5 highlights how curtailment out turned in practice from 2014 to 2020 versus two other scenarios (33% and 100% of projects connected respectively). Although curtailment was not as high on the system over this time period as projected, there is a direct correlation between increasing renewable generation and increased curtailment levels.

Figure 5: Curtailment projections from EirGrid Gate 3 constraint reports (Line) vs actual outturn data (Bar)

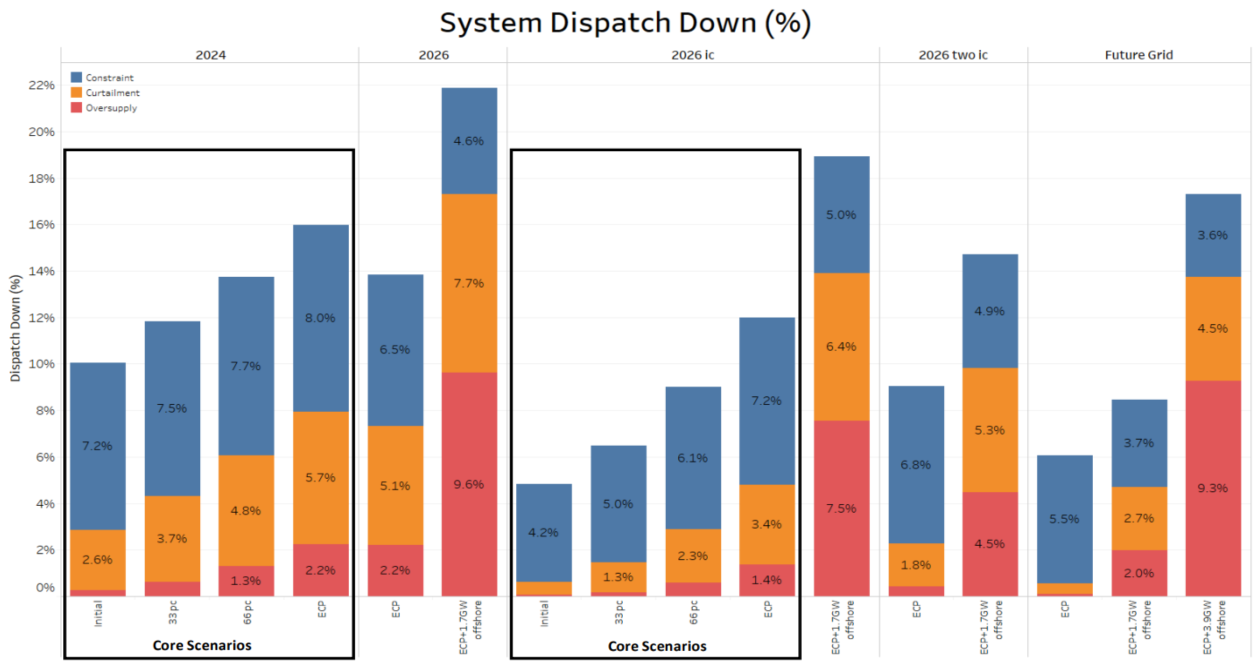


Source: EirGrid Gate 3 constraint reports and EirGrid Annual Renewable Energy Constraint and Curtailment report 2020[18]

More recently, EirGrid released their ECP 2.1 constraints report which gives a projection for all three types of dispatch down based on the level of ECP projects that may connect. Focusing on curtailment here, Figure 6 shows the level of curtailment across a range of scenarios relating to the deployment of renewables. For a bidder, the trend is towards significant increase in curtailment levels in 2026 (7.7% in worst case scenario outlined) as more renewables are connected (33%-Full ECP+1.7GW offshore). The risk of curtailment is difficult to quantify for a bidder as they look quite high from this forecast out to 2026 but could change depending on pipeline and infrastructure build out. It is also significant for bidders that the forecast does not look past 2026 but the RESS timeframe is 15 years.

[17] *SEM Committee Decision Paper on Dispatch, Redispatch and Compensation Pursuant to Regulation EU202019943*
18 EirGrid Annual Renewable Energy Constraint and Curtailment Report 2020

Figure 6 System wide dispatch down % for Ireland based on ECP 2.1 Constraints report – Curtailment Focus



Source: Enduring Connection Policy 2.1 Constraints Report for Area A Solar and Wind

As mentioned above, the CEP (per Article 12 and Article 13 of the Electricity Regulation) will require dispatch-down to be compensated when the action is based on re-dispatch, so this compensation will be a factor for renewable generators when forming their risk perception. However, this is only for non-market-based dispatch (firm generators[19]) and will only be up to the level of the day ahead market price at the time they are curtailed[20], therefore maintaining uncertainty in revenues for renewable generators. This could result in higher required WACCs for bidders, pushing bid price discovery higher resulting in higher consumer costs. It is important to note that how this will be implemented in Ireland is still not clear.

Who Manages the risk – who has it in their control?

EirGrid as Transmission System Operator (TSO) schedules generators and issues all dispatch instructions, including dispatch down instructions. The TSO controls the level of SNSP that are allowed on the grid at any one time based on technical limitations. Increasing SNSP, as we travel towards 2030, will need to be a focus for the TSO as well as incentivising zero carbon technologies to provide system services. As allowed SNSP levels increase, curtailment levels will reduce.

5.2.1.1.2 Energy Balancing in Ireland

As stated above, energy balancing is defined in this report as when generation is reduced or dispatched down due to an oversupply of generation on the grid to ensure a balance between demand and generation. This delivers a demand supply balance, i.e., energy balance.

At present, the impact of energy balancing hasn't been felt as the total installed capacity for

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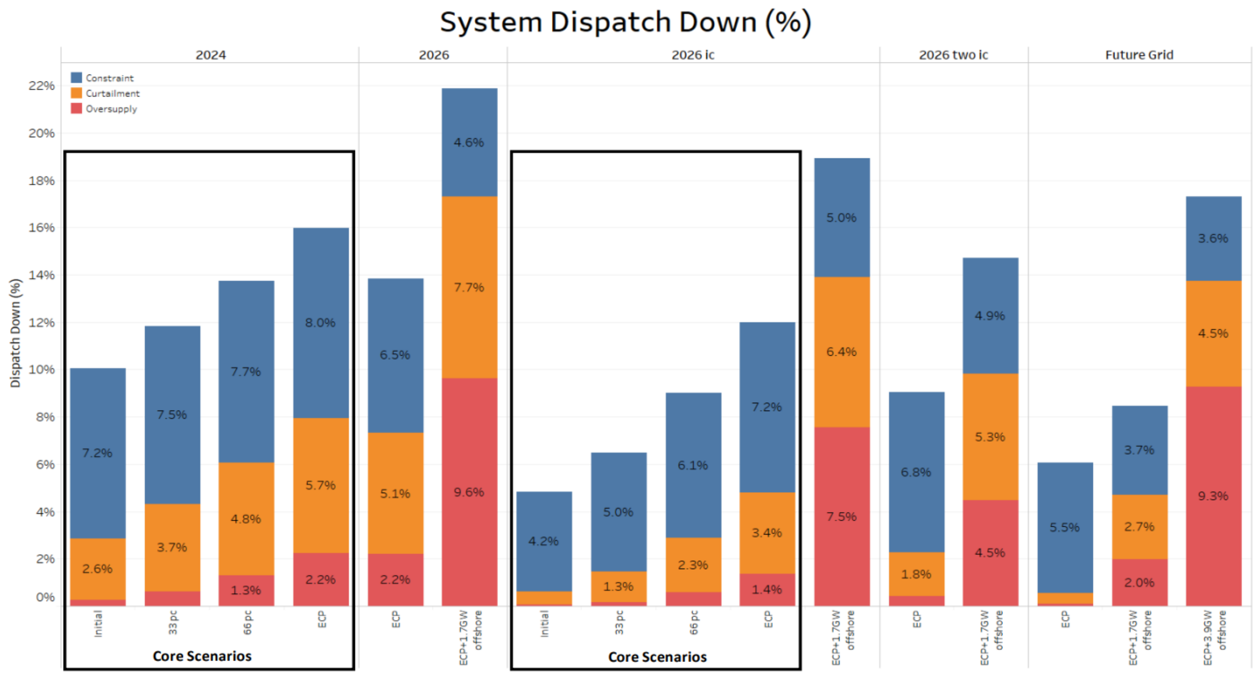
[19] The level of firm financial access available in the transmission network for a generator is that generator's Firm Access Quantity or 'FAQ'. Firm financial access means that if a generator is constrained on or off, it is eligible for compensation in the manner set out in the Trading & Settlement Code. (Source: EirGrid)

20 SEMC - Consultation on Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943 renewables in Ireland, which consists primarily of 4,309 MW of onshore wind[21], hasn't outstripped demand. Additionally, before RESS, renewable generators had priority access and as such were one of the last types of generators to be dispatched down due to oversupply. However, as targets are achieved, RESS capacity is commissioned, and SNSP limits are increased, energy balancing dispatch down will become increasingly evident. There are multiple external factors that can impact the level of energy balancing dispatch down. For example, the building of interconnectors, infrastructural development, and large energy user activity like data centres or pharmaceuticals, increases electricity demand. All these factors add to the uncertainty around this risk. Delays or deferrals in infrastructure development cannot fully be controlled by the government either. Thus, the best way to address this risk is to build in assurance and certainty within the auction design for compensation for energy balancing dispatch down. If certainty is not built in, especially for later RESS rounds, uptake may fall as the risk of energy balancing dispatch down rate increases.

Figure 7 (same as Figure 6) is taken from the EirGrid ECP 2.1 Constraints Report and gives developers a view of energy balancing dispatch down levels, particularly if significant volumes of offshore wind are added to the system. Pragmatic bidders will then price this risk into their bids with the potential for significant volumes of capacity to be lost or for bid price discovery to be higher.

For a bidder, the trend is towards an increase in energy balancing levels out to 2026 (9.6% in worst case scenario outlined) as more renewables are connected (33%-Full ECP+1.7GW offshore). Again, the risk of energy balancing is hard to quantify as levels could change depending upon the pipeline of both generation and demand projects. It is also significant for bidders that the forecast does not look past 2026, but the RESS timeframe is 15 years.

Figure 7 System wide dispatch down % for Ireland based on ECP 2.1 Constraints report – EB Focus



Source: Enduring Connection Policy 2.1 Constraints Report for Area A Solar and Wind

Who Manages the risk – who has it in their control?

EirGrid as the TSO manages this risk for developers and with a large volume of offshore wind in particular planned, the future impact on the grid will be significant. To reduce the level of energy

[21] *EirGrid Installed Capacity Report September 2021*

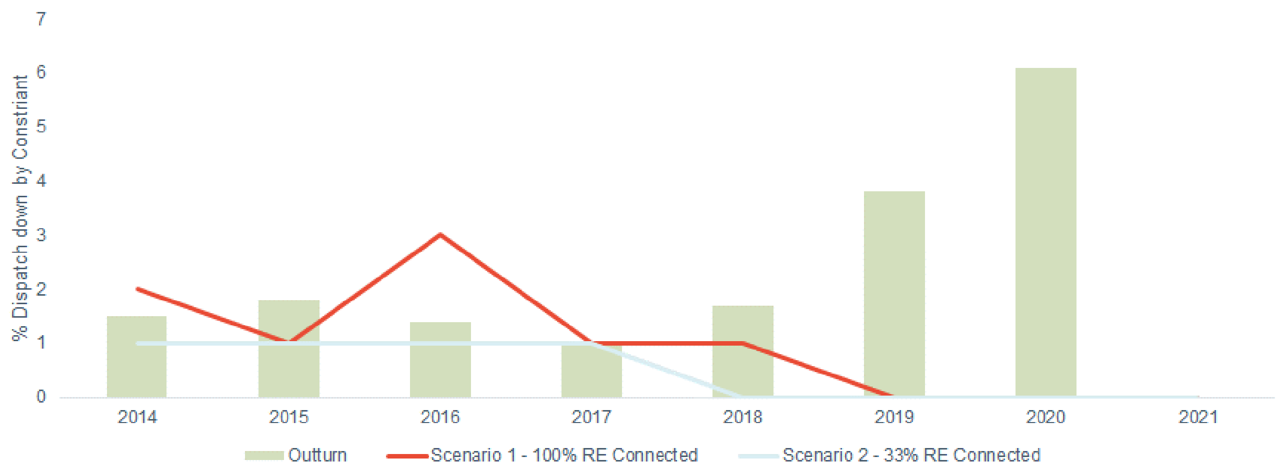
balancing dispatch down the TSO needs to ensure that: electricity markets are designed with the future of renewables on the grid in mind, current interconnector projects are delivered in a timely manner, storage is increased on the system, and future grid requirements are modelled and implemented at the earliest stage. The role of the SEMC as well, considering post BREXIT arrangements, where there are bilateral trading arrangements between GB and Ireland for import and export on the interconnectors needs to be understood. This is so that the capacity added in Ireland is dispatched efficiently in the coupled markets (Intraday 1 and Intraday 2 markets only at present) and not stranded due to limitations in market arrangements.

5.2.1.1.3 Constraint in Ireland

We define constraint as when generation is reduced or dispatched down due to a locational technical limitation on the network that can be directly impacted by the export of a generator in that area. The RESS T&C's do not currently compensate for network constraints.[22]

In Ireland, the level of constraint has risen steadily over the last four years to 6.2% on average with a range between 3.3% and 8.9% depending on the area of the country in which the renewable project is located. The risk of constraint is a volume related risk for the bidder over the lifetime of the project. As this risk is currently not addressed in the RESS T&Cs, developers must forecast future constraints at their project location and factor the risk into their bid price over the project's lifetime (25- 30yrs). This risk analysis requires internal or market expertise as constraint forecasts over a 15-year horizon (the current duration of a RESS contract) are currently not publicly available. Figure 8 shows projected constraints by EirGrid for 2014 -2019 vs actual outturn. As can be seen, the 2019 and 2020 outturn has been significantly higher than forecasted where it was predicted that constraints would disappear. This contrasts with the curtailment forecast in Figure 5, where historically the System Operator has achieved a more accurate forecast of future curtailment levels. These trends will increase uncertainty among bidders as to the future level of constraint on the grid and erode confidence that the grid reinforcements to alleviate this risk will fully come to fruition.

Figure 8 Constraint projections from EirGrid Gate 3 constraint reports (Line) vs actual outturn data (Bar)



Source: EirGrid Gate 3 Constraint reports and EirGrid Annual Renewable Energy Constraint and Curtailment report 2020[23]

Figure 9 is an illustration of the theoretical impact an additional 50MW wind farm can have on a particular 110kV line. This illustration has been used to demonstrate how sharply constraints can

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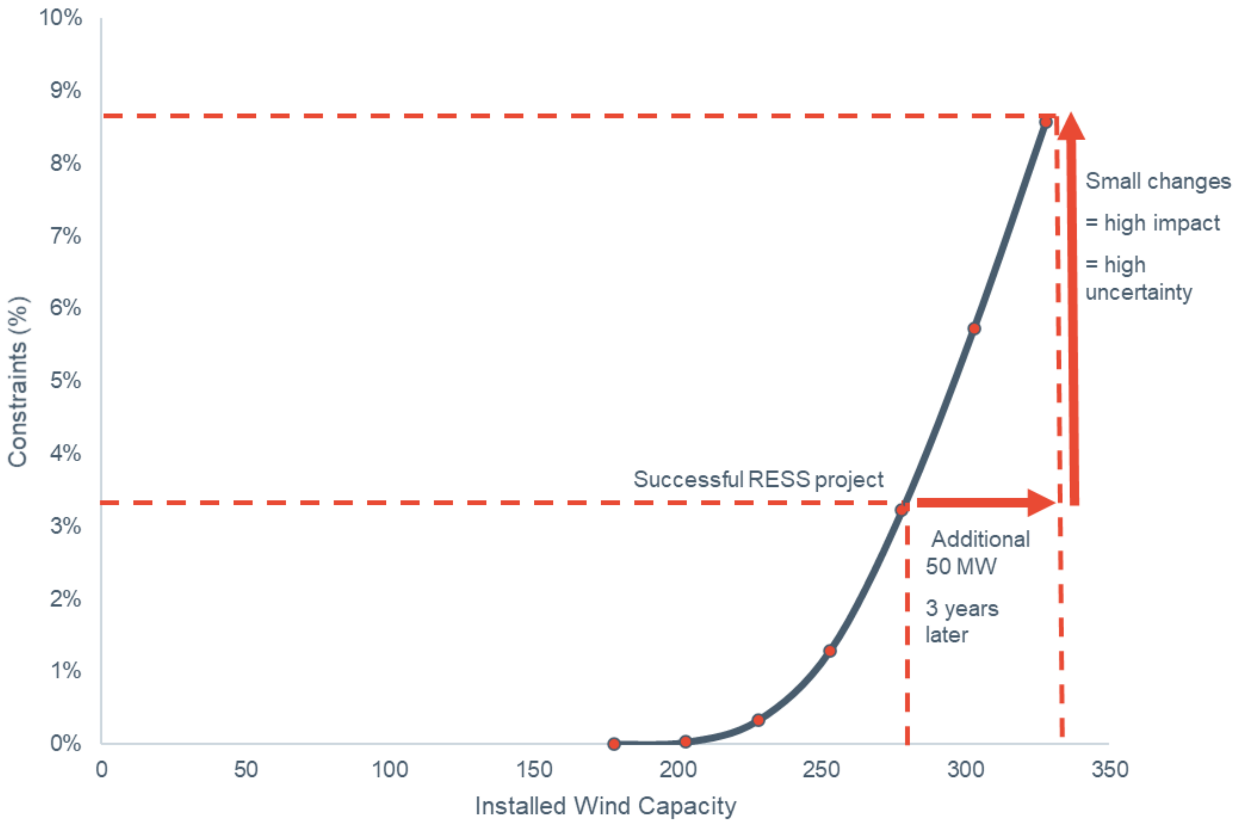
[22] *Terms and Conditions for the Second Competition under the Renewable Electricity Support Scheme RESS 2October 2021*
23 *EirGrid Annual Renewable Energy Constraint and Curtailment Report 2020*

increase if new generation comes online at a particular node where the network may not have the capacity to accommodate it.

In this example, Developer A was successful in a RESS Auction and at that time the constraint level at this location was 3%. Developer B then adds a new 50MW project to the same node which almost triples constraint levels at this location to 9%. For the historic wind farm, they are now penalised for an action that was beyond their control or ability to predict, i.e., addition of capacity.

This uncertainty and sensitivity to change may lead developers to form conservative predictions on constraints, increasing their bid price discovery. Consumers will pay the increased cost in RESS contracted auction prices based on this but the conservative constraints forecast might not materialise. Meaning, the consumer will have paid the price for something that never happened.

Figure 9: Illustrative Example of Changes to Constraints based on Additional Capacity at a Particular Location



Source: Cornwall Insight analysis

<u>Who Manages the risk – who has it in their control?</u>

EirGrid, as TSO, is responsible for grid development on the transmission network and at present there is a more reactive approach taken to grid development. To assist in reducing constraint levels the TSO needs to do the following:

- Pro-active grid reinforcements to develop a fit for purpose future grid.
- Alternative network solutions which avoid the need for costly reinforcements.
- An increased grid capacity where renewable generation pipeline is likely to be strongest.
- Ensure grid reinforcement projects progress in a timely fashion.

These actions will help reduce the level of constraint on the network and ensure that the maximum levels of renewable generation can connect to the network. Whilst the EirGrid's Shaping the Electricity Future report is welcome, it is the actual delivery of these projects that is important.

5.2.1.2 International Review of Dispatch Down Risk

Table 6 looks at how dispatch down is managed in several European countries and the lessons that could be learned for the Irish market.

Table 6: International Review of Dispatch Down Risk

Country	Approach towards risk	Mitigation included in support scheme design?
Denmark	In Denmark's Thor offshore wind project, **curtailment is fully compensated by the TSO** for loss of revenue. The auction documents compensation for **constraint and energy balancing led dispatch down are not** mentioned. However, the Danish Energy Agency mentions that the risk is borne by the TSO rather than the bidder. [24]	✓
Finland	Wind farm developers are **not compensated for loss of revenue caused by curtailment, constraint, or energy balancing** driven dispatch down.[25]	✗
France	**Compensation arrangements for curtailment, constraint, and energy balancing driven dispatch down are not referenced** in the tender documentation for the Dunkirk auction documents.[26]	✗
GB	In GB, generators are **compensated for dispatch-down related to constraints and**	✓

[24] Sources: Denmark 2017 Review; International Energy Agency; 2018 & Danish Energy Agency - Experience of offshore wind development; & 2017 *Danish Energy Agency; De-risking offshore wind power in Denmark); 2018*
[25] *Source: energiavirasto.fi*
[26] *Source: Electricity at sea in an area offshore Dunkirk - specifications; Energy Regulatory Commission; 2018*

Country	Approach towards risk	Mitigation included in support scheme design?
	curtailment. The compensation is **based on the inputs to the balancing market** from bidders (developers) for dispatch down.[27]	
Belgium	In Belgium, the **curtailment rules and associated conditions for curtailment depend on the regional government** and are a part of the permitting process. From 2020, the limits for curtailment are included in the auction documents. [28]	✓
Netherlands	The Dutch subsidy scheme (**SDE++ scheme) does not include compensation** for curtailment, constraints, or energy balancing. Compensation is **handled outside the subsidy scheme for dispatch down via application** to the TSO by the bidder (developer).[29]	✗
Spain	The **SO is responsible for compensating "incorporated programme modifications" which include curtailment and re-dispatch**. Curtailment is compensated at 15% of the market price. [30]	✓
Germany	In Germany, wind farm operators are **compensated for 95% of**	✓

[27] *Source: DECC UK*
[28] Source: RES Legal EU & *The regulatory framework for wind energy in EU Member States; European Union 2015*
Note on the construction support mechanism offshore wind farms after 2020; CREG; 2018
[29] *Source - RVO - Netherlands Enterprise Agency*
[30] Source: *Spain 2021 Energy Policy Review; International Energy Agency; 2021*
Wind Europe; 2016 & *Status of renewable energy support schemes in Europe for 2016 and 2017 ; CEER; 2108*

Country	Approach towards risk	Mitigation included in support scheme design?
	the incurred losses of revenue due to curtailment. Curtailment when there is a threat to security of supply and to prevent grid overload due to infrastructure challenges is considered, and there are additional requirements related to receipt of data, etc. that need to be fulfilled. [31]	
Italy	In Italy, a method of zonal marginal pricing is used to address constraint issues. The TSO **does not compensate for curtailment, constraint, and energy balancing** related dispatch down via its auction structure.[32]	✗

5.2.1.3 International Case Study: GB

Curtailment

One of the risks perceived by developers in GB is that high amounts of curtailment on the system will lead to a loss of revenue to generators, greater system inflexibility, a lack of grid optimisation, and a disproportionately large allocation of risks to the developers. When renewable generators are curtailed by the National Grid ESO (Electricity System Operator), they lose money by not being able to operate when they otherwise should.

As outlined in GB's Allocation Round 3 (AR3) T&C's, curtailment is defined as:

"The prevention or restriction by, or on the instruction of, the NETSO of the export from the facility to the national electricity transmission system of all (but not less than all) of the electricity which the facility is otherwise able to generate and export during the relevant period, and the period of any curtailment shall include, subject as provided below, the minimum period of time (determined by reference to a Reasonable and Prudent Standard) that the Facility takes to ramp up and down in response to the relevant prevention, restriction or instruction, as the case may be provided that:

- *There shall be no curtailment during any period in which the export of electricity from the facility is prevented or restricted as a result of:*
    - *Any unplanned Transmission System outage or Black Start or any Emergency De-energisation instruction.*
    - *A breach or default by the Generator or any of its Representatives of the Contract for*

[31] Source: Germany 2020; Energy policy review; International Energy Agency; 2020 & EWEA position paper on priority dispatch of wind power; European Wind Energy Association; 2015 & *Status review of renewable support schemes in Europe for 2018 and 2019; CEER; 2021*
32 Wind Europe; 2016

Difference, any Law or Directive, any Industry Document or any Required Authorisation.

- *A failure by the generator or any of its representatives to act in accordance with a Reasonable and Prudent Standard; or*
- *Any matter relating to health, safety, security or environment at or with respect to the facility (but not as a result of any such matter at or with respect to the national electricity transmission system)"*[33]

The ESO defines constraint management as being *"required where the electricity transmission system is unable to transmit power to the location of demand, due to congestion at one or more parts of the transmission network."*[34] In March 2021, National Grid ESO published its five-point plan to deal with network constraints in the years ahead. These include clearer forecasts on Balancing Services Use of Systems (BSUoS) costs, developing intertripping capability through their pathfinder, working with regional networks on a whole-system approach, exploring storage potential in a heavily constrained network, and continuing to improve the existing network. This work compliments other projects by the ESO and BEIS on constraint and curtailment mitigation including an energy storage technical feasibility assessment, a longer duration energy storage demonstration funding scheme, and a competition and incentive scheme to manage costs to consumers in line with the ESO regulatory and incentive frameworks.

In GB, the largest amount of curtailment generally happens in the north around Scotland as the transmission infrastructure is not yet in place to deliver large levels of generation to the demand centres in England and Wales. In the case of wind energy (which is the most curtailed source of energy in GB), the ESO curtails the wind farm for limited transfer capability. If the lack of available transmission infrastructure is known by the ESO in advance then they will sign a contract with the relevant windfarm (known as Inter-Trip) where the windfarm is prepared to be curtailed only when there are circumstances or situations that lead to limited transfer capability.

Due to the increasingly fast development of renewable generation a system known as "Connect and Manage" was introduced to help compensate the generator for any loss of revenue they might experience if the network is not yet ready for use.[35] Generators can also choose to have a 'non-firm connection', meaning that they agree to be curtailed with no anticipation of compensation in return for a cheaper connection fee to the grid.[36] However, generally, any dispatch down related actions are treated as balancing actions. Both curtailments and constraints are paid for in GB and are addressed in the balancing market. Renewable generators are able to submit bids to dispatch down that can be accepted regardless of the cause of the dispatch down action. The revenue to fund this is gathered from consumer bills via the BSUoS tariff.

As the development of renewable energy continues to increase and more and more renewables are connected to the grid, the costs of compensating those generators and balancing the grid increase as well. According to the Brighton & Hove Energy Services Co-op (BHESCo), "*in 2020, when consumer demand fell as a result of the Coronavirus lockdown, National Grid spent an unprecedented £826 million balancing the grid, primarily in the form of payments to wind farm producers to cease generation."*[37]

Although the costs are high, National Grid stated: *"The cost of these constraint payments is*

33 *https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/799137/AR3-Standard-Terms-and-Conditions.pdf*
34 *https://www.nationalgrideso.com/balancing-services/system-security-services/transmission-constraint-management*
35 *Connect and manage – the establishment of constraint payments is part of a regulatory framework called connect and manage, introduced by the UK government in 2010. It has been put in place to allow the development of electricity generation projects and their connection to the transmission system*
36 *https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Priority-Dispatch-and-Curtailment.pdf*
37 *https://bhesco.co.uk/blog/national-grid-constraint-curtailment-electricity-network*

continually weighed up against the cost of building new infrastructure, to ensure we keep the costs of running the system as low as possible. To date, these constraint payments have been the most cost-effective option to operate the electricity system securely.”[38] Despite this method being optimal for GB, as the development of renewable energy continues to increase and as the government works toward achieving its decarbonisation targets, this will likely not always be the case and eventually the grid will need to be upgraded, expanded, and reinforced and these compensation methods re-evaluated.

The ESO defines constraint management as being “required where the electricity transmission system is unable to transmit power to the location of demand, due to congestion at one or more parts of the transmission network.”[39] In March 2021, National Grid ESO published its five-point plan to deal with network constraints in the years ahead. These include clearer forecasts on BSOuS costs, developing intertripping capability through their pathfinder, working with regional networks on a whole-system approach, exploring storage potential in a heavily constrained network, and continuing to improve the existing network. This work compliments other projects by National Grid ESO and BEIS on constraint and curtailment mitigation including an energy storage technical feasibility assessment, a longer duration energy storage demonstration funding scheme, and a competition and incentive scheme to manage costs to consumers in line with the ESO regulatory and incentive frameworks.

The key takeaway here is that as constraints and curtailment are so difficult to predict there is a ratio between the cost to the consumer of the compensation for the constraint or curtailment and the cost to the consumer of higher bid prices when the developer is factoring in a risk premium.

5.2.1.4 Proposed Risk Mitigation Measure for Cost Benefit Analysis

Curtailment and Energy Balancing

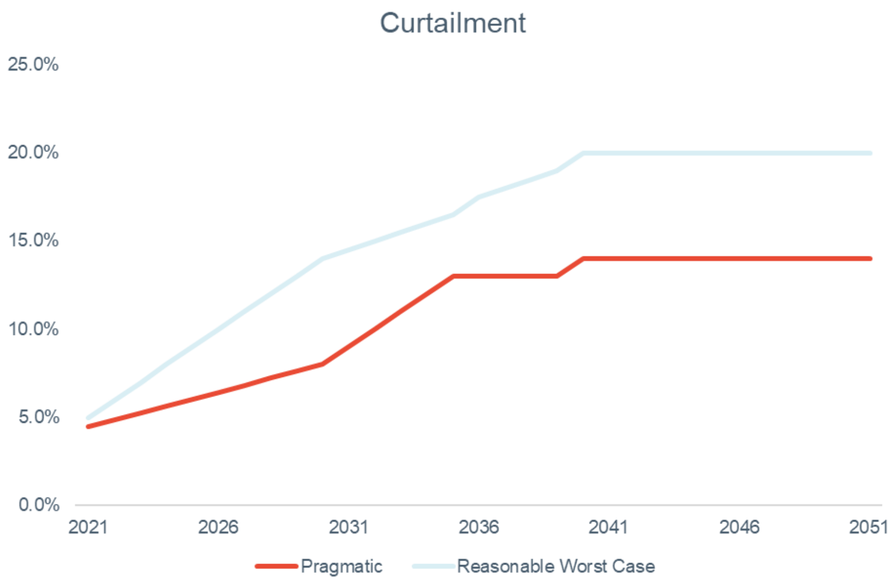
Denmark, GB, Belgium, Spain, and Germany compensate their renewable energy generators partially or fully for curtailment. In several instances there is no differentiation made between curtailment and energy balancing. In Ireland, this risk is ultimately planned to be addressed via arrangements made under Article 12 and Article 13 of the EU Electricity Regulation (Clean Energy Package). In 2022, the SEMC decision paper published did not add enough clarity around how dispatch down would be compensated for new renewable energy projects. It is therefore key that there is clarity around the current arrangements under the RESS T&Cs to mitigate the risk around curtailment and energy balancing.

To investigate the benefit to consumers of insulating bidders from the risk of dispatch down via curtailment and energy balancing we combine both and describe it all as ‘Curtailment & EB’. For the risk mitigation measure we take lessons from Germany where curtailment is compensated for up to 95% of revenue loss and propose a 10% cap on not just curtailment but for EB as well. This means that once Curtailment & EB levels hits 10% renewable developers would start to receive compensation payments. For the purposes of our CBA in Section 6 we have modelled a 10% cap.

Figure 10 illustrates the possible outturn for curtailment & EB out to 2051 from both a pragmatic and a reasonable worst-case point of view.

38 https://www.hartreesolutions.com/market-insights/uk-wind-record-14-month-sooner/

Figure 10 Curtailment & EB Forecasts for CBA modelling[40]



Source: Wind Energy Ireland

Constraint

GB, Belgium, Netherlands, and Germany compensate in different ways for constraints. For the risk mitigation measure we take lessons from Germany and Belgium and have analysed a nodal cap for constraints whereby each node would be assigned a cap on constraints prior to the specific RESS auction commencing.

For the purposes of our CBA in Section 6, to illustrate a locational nodal cap we assumed that constraints are compensated when constraint levels exceed 2% during a given year over the duration of the RESS contract. This means the generator will be reimbursed when constraint exceeds 2% during a given year.

Figure 11 illustrates the possible outturn for constraints out to 2051 from both a pragmatic and a reasonable worst-case point of view.

[40] *All numbers used in this example are for illustrative purposes only.*

Figure 11 Constraint Forecasts for CBA modelling[41]

Source: Wind Energy Ireland

5.2.2 Transmission Loss Adjustment Factor (TLAF) Risk

5.2.2.1 TLAF in Ireland

When a project gets connected to the grid it is then assigned a transmission loss adjustment factor (TLAF). These are set by the TSO on an annual basis and are designed to account for the energy losses associated with the transport of electricity across the grid, which means that not all of a generator's power is transferred. These TLAFs are a part of what is described in the RESS 2 consultation document as implicit signals for generators connecting across different locations. Although these can be predicted by the developer in advance of receiving a connection offer for that year, the ability of a developer to locate a project in a certain area is not always within their power. Further to this however, whilst a locational signal is presented by these TLAFs that signal only lasts as long as nothing changes at the node. If a new generator or demand project locates there or if the grid changes, the TLAF can increase or decrease at a node. Whilst reasonable demand forecasts are available for locations from the TSO the ability of a developer to predict if other generators will locate at the same, or nearby node of the transmission system is not. This can have a significant impact on their view of the future for their TLAF.

To illustrate this, a specific node, Bellacorrick, was examined from 2018-present day. In 2018, the TLAF at the node averaged at 0.986 across all periods of the year. In 2019, a new 93MW generator was connected at the node and the TLAF dropped to 0.957 before rising slightly to 0.964 in 2021. This example illustrates that TLAFs can increase as well as decrease as changes happen on the network.

This potential for negative change to assigned TLAFs is of concern for offshore developers off the east coast for example, who are looking to connect near the large demand centre of Dublin. Uncertainty around the number of generation projects connecting at particular nodes is likely to result in changes to annual TLAFs assigned. This uncertainty can result in higher bid price

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[41] All numbers used in this example are for illustrative purposes only.

discovery.

Who Manages the risk – who has it in their control?

EirGrid, as TSO, is responsible for creating and updating TLAF charges annually. They use TLAFs to recover costs of transporting electricity from high generation areas to the load centres, providing an implicit locational signal to developers as well. Whilst this is necessary, the lack of forecast of future TLAFs makes this a risk for developers. This lack of predictability of TLAFs year to year could be improved by the TSO. Further to this, new generation or demand projects will be assigned appropriate TLAFs based on the network they are connecting into and will be able to factor that into their project plan, whilst existing generators can do nothing to mitigate against any new TLAF that they are assigned at the same time.

This annual change in TLAFs is a risk that the pragmatic bidder will factor into their bid price discovery increasing the cost to consumers. Again, this could mean the consumer is paying for a risk that does not materialise.

5.2.2.2 International Review of TLAF Risk

Table 7 looks at how transmission losses are managed in several European countries and the lessons that could be learned for the Irish market.

Table 7 International Review of TLAF Risk

Country	Approach towards risk	Mitigation included in support scheme design?
Denmark	For the Thor offshore wind farm there is **no reference to transmission losses within the tender documentation**. The network tariffs and the costs are (in most cases) during the operational phase and are fully covered by a single transmission tariff charged by the TSO.[42]	✘
Finland	Finland's "Premium Help" document for those accepted into the bonus system provides necessary measurement arrangements for calculation of share of electricity and differentiates from losses. There is **no visibility of actual transmission losses in the auction process**. There is a fixed capacity fee per MWh and energy-based charge for use of the transmission network and input onto the transmission network.	✘
France	In France, **transmission losses are paid for via a tariff charged by the transmission system operator by generators** through injection charges. For the Dunkirk Model[43], a**ny losses which were a result of a delay in completing the grid connection is borne by the TSO** (if not a force majeure or as a result of the wind farm	✘

42 Source: ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019
43 Dunkirk model refers to the Dunkirk offshore Renewable Auction Design in 2018, see section 5.2.5.3

Country	Approach towards risk	Mitigation included in support scheme design?
	operators own doings). [44]	
GB	Losses on the transmission system are allocated across BSC[45] Parties using Transmission Loss Multipliers (TLMs). Transmission loss factors (TLF) exist for each TLF zone (aligning with the existing Grid Supply Point Groups) for each BSC season to **allocate transmission losses on a geographical basis**. The TLM calculation uses a parameter called the Generation/Demand (G/D) split which **divides transmission losses between generators and demand users in a 45%:55% split.**	✗
Belgium	In Belgium, there is compensation for losses at HV levels by the TSO and these are recovered through tariffs. For **offshore wind, grid losses are considered when calculating renewable energy support payments**. [46]	✓
Netherlands	**Transmission losses are not considered as part of the conditions of the SDE++ scheme**. The costs of losses are recovered by a transmission user, paid by consumers, or various network users.[47]	✗
Spain	Transmission losses are **not included in the tariffs charged by the TSO directly to developers**, instead, they are recovered through the energy market. **Suppliers buy not only the energy from developers, but also the losses**. The standard losses are determined by the National Regulatory Authority and published on an annual basis. [48]	✗
Germany	Losses in Germany are **recovered through tariffs**.[49]	✗
Italy	**Costs associated with transmission losses are not covered by any tariff or charge**, the **producers pay-in-kind for losses** (through injection of additional energy), which may be	✗

44 Source; ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019 & French Energy Code
45 A BSC Party is any company that has acceded to the Balancing and Settlement Code in GB
46 Source: Note on the support mechanism for the construction of offshore wind farms after 2020; CREG; 2018
ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019
47 Source; ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019
48 Source; ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019
49 Source; ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019

Country	Approach towards risk	Mitigation included in support scheme design?
	passed through to the buyers of their products and/or services (end consumer). Losses on the Italian transmission network are purchased by load service entities based on standard losses factors.	

5.2.2.3 International Case Study: GB

Losses on the transmission system are recovered by the ESO through Balancing Services Use of System (BSUoS) charges allocated across BSC Parties. In the calculation of BSUoS charges, transmission losses are allocated by scaling up or down (depending on whether the user imports or exports electricity) the metered MWh volume of each BSUoS user. These scaling factors are called Transmission Loss Multipliers (TLMs), which are:

- Zone specific, and there are 14 geographic zones.
- Vary at different times of year due to different flows and the weather.
- Are produced by Elexon using transmission loss factors (TLF) for each node and a generation/demand split of 45% / 55% respectively.
- The Transmission Loss Factor Agent (TLFA) annually calculates the TLFs for each zone and season for use in the TLM calculation.

Losses on the distribution networks are allocated through the use of Line Loss Factors (LLFs).

Whilst the calculation of the BSUoS charges associated with transmission losses appear to be fairly straightforward and transparent, there are no significant regulatory incentives in place to try and reduce losses or costs related to losses across the transmission and distribution networks.

5.2.2.4 Proposed Risk Mitigation Measure for Cost Benefit Analysis

In Belgium, transmission losses are considered while calculating support payments for offshore wind. Generators in GB have to bear 45% of transmission losses and under the Dunkirk auctions in France unpredictable costs due to grid connection delays or issues are borne by the TSO driving predictability. For our risk mitigation measure we draw lessons from these countries, and to enhance predictability we have proposed a fixed TLAF which is fixed at the level of TLAF assigned to the generator post commissioning.

For the purposes of our CBA in Section 6, this risk mitigation measure will be implemented using a fixed value TLAF of 0.99 for the duration of the RESS contract.

5.2.3 Transmission Use of System Charge Risk

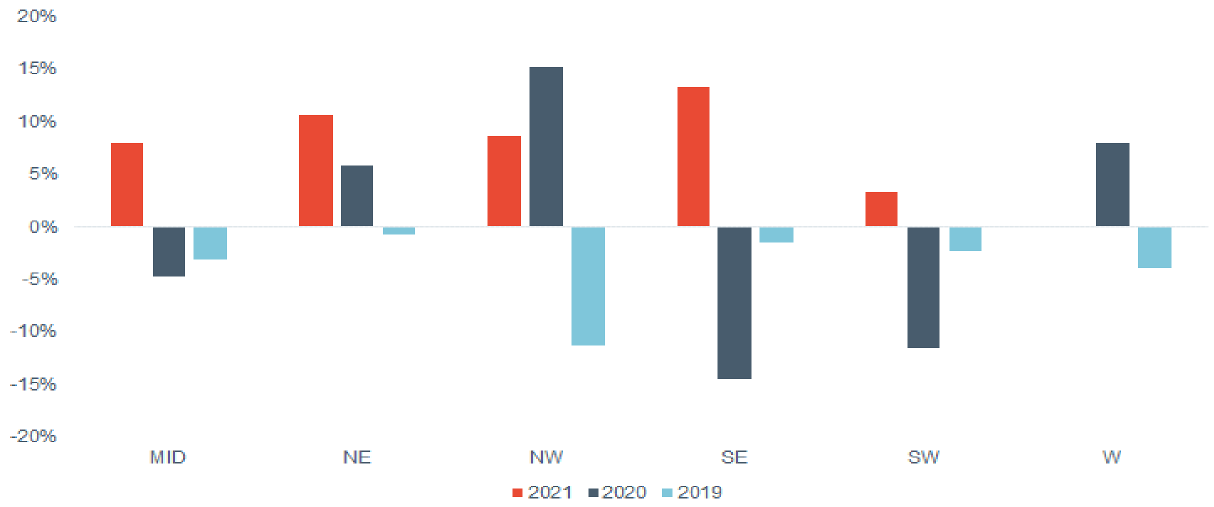
5.2.3.1 TUoS in Ireland

TUoS charges are levied on generators in Ireland to pay for the use of the system to transport electricity. The charges are designed to recover the costs of operating, maintaining, and developing the transmission system. TUoS provides a locational signal that incentivises installation of generation capacity where it is of most benefit to the overall electrical grid. TUoS charges are reviewed annually, similar to TLAF charges, and significant volatility occurs with 1 -15% swings annually in TUoS charges around the country. Figure 12 highlights the annual percentage change in TUoS per node between 2019 – 2021.

To illustrate this, we again use a specific node, Bellacorrick. There has been a 20% swing in TUoS charges from 2020 to 2021 alone from €6.67 to €8.30.

This lack of predictability and volatility creates uncertainty for developers which can result in higher bid price discovery.

Figure 12 Annual percentage change in TUoS charge per Node



Source: EirGrid Statement of Charges

Who Manages the risk – who has it in their control?

EirGrid, as TSO, is responsible for creating and updating TUoS charges annually. Factors such as future targets, future connection policy, auctions, and Transmission Development Plans can impact TUoS charges annually. Again, although this is a necessary element of grid management, the ever-changing nature of TUoS charges due to changes on the network is outside of the developer's control.

Again, this lack of predictability of TUoS charges year to year could be improved by the TSO. Further to this, new generation or demand projects will be assigned appropriate TUoS charges based on the network they are connecting into and will be able to factor that into their project plan, whilst existing generators can do nothing to mitigate against any new TUoS charge that they are assigned at the same time.

The change in TUoS charges annually is a risk that the pragmatic bidder will factor into their bid price discovery increasing the cost to consumers, which could mean the consumer is paying for a risk that does not crystallise.

5.2.3.2 International Review of TUoS Risk

Table 8 looks at how transmission use of system charges are managed in several European countries and the lessons that could be learned for the Irish market.

Table 8 International Review of TUoS Risk

Country	Approach towards risk	Mitigation included in support scheme design?
Denmark	For the Thor offshore windfarm project**, as part of the tender documentation, establishment costs are borne by the winning tender and should be included in the bid price**. In Denmark, **costs associated with first connection charges for a renewable power plant is socialised** via a tariff and the bidder (developer) is not directly charged. **They must pay charges once they begin injecting electricity onto the grid**. [50]	✘
Finland	Grid users pay for the infrastructure connecting its installation to the transmission grid (line/cable and other necessary equipment). Finland's **"premium help" document does not refer to transmission use of system charges**.[51]	✘
France	RTÉ, the **TSO, is responsible for grid connection costs for successful bidders for the Dunkirk model**[52]. The Energy Regulatory Commission sets tariffs. For first connection costs generators pay 100 % of the cost and consumers pay 70 % of the cost of their main connection. **Grid users pay for the infrastructure** connecting generators to the transmission grid (line/ cable and other necessary equipment). For **all generators connected at 150 - 400kV, there is a generation component** to be paid as part of their tariff. These grid users must also **pay for start-up charges** [53]to connect their infrastructure to the transmission network. This may include lines, cables etc.	✘
GB	Charges apply to generators, suppliers, directly connected transmission demand, and embedded generators. Generators are charged according to TEC (Transmission Entry Capacity) and **have a bespoke TNUoS tariff calculated by the ESO**. The **total amount that can be charged to**	✘

50 Sources: Overview of Transmission tariffs in Europe 2019; ENTSOE; 2020 & *Annex 3.9; Subsidy scheme, award criterion and costs to be included in the tender, Thor Offshore Wind Farm; 2021*
ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019
51 Source: *ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019*
Premium Help; Instructions for those who are accepted into the bonus system to the electricity produce; 2020
52 Dunkirk model refers to the Dunkirk offshore Renewable Auction Design in 2018, see section 5.2.5.3
53 Source: *ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2019; ENTSOE; 2019*
ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019

Country	Approach towards risk	Mitigation included in support scheme design?
	generators for use of the transmission system is capped by law at €2.5/MWh.[54]	
Belgium	In Belgium, **generators pay approximately 5% of transmission costs**. Transmission tariff values are set four years in advance, but the value may differ each year. Furthermore, the tariff methodology may change during the regulatory period. For **first connection charges, grid users generally pay for the infrastructure** connected to the transmission network. Specifically for **onshore connections, all components are socialised**, except for all installations between the grid user and the connection bay at the substation. For **offshore wind farms that have a direct onshore connection there is a support mechanism in place** to foresee additional subsidies for the cable connection up to 25 M€.[55]	✗
Netherlands	**Costs of connecting the wind farm to the transmission network are borne by the project developer**. There are two types of tariffs, and initial connection tariff and a periodic connection tariff. Tariff values are updated annually and are based on a pre-defined methodology.[56]	✗
Spain	The **wind farm operator is responsible for the cost of the infrastructure to connect to the transmission network**. All reinforcements required for this connection as subsequently paid for by the consumer via socialised tariffs. In Spain, tariff values are updated annually by the National Regulatory Authority. As with many other countries in the EU. Generators pay approximately 7.6% of transmission costs[57]	✗
Germany	Charging is generally based on actual costs. General reinforcements of the grid are socialised via tariffs. **Since 2019, offshore wind farms connected to the grid pay all offshore grid connection costs**. This has replaced the	✗

[54] Source: *DECC*
[55] Source: *ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2019; ENTSOE; 2019*
ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019
[56] Sources: SDE++ 2021 Stimulation of Sustainable Energy Production and Climate Transition; Ministry of Economic Affairs and Climate Policy; 2021 & *ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019*
[57] Source: *ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2019; ENTSOE; 2019*
ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019

Country	Approach towards risk	Mitigation included in support scheme design?
	transmission tariff that was previously charged.	
Italy	The **transmission tariff in Italy has a two-tier structure** based on the connection capacity and based on the energy at point of delivery to end consumer. The transmission tariff for any particular year is determined by the Italian Regulatory Authority for Energy, Networks, and Environment (ARERA) by 30 November of the year before.[58]	✗

5.2.3.3 International Case study

Most countries, including the countries we have studied, do not have any specific arrangements within their renewable auction design which removes the risk arising from TUoS charges as they see these charges as a locational signal. The methodology used for charging TUoS differs from country to country. However, some countries such as France, Belgium, and Spain have arrangements where the developer does not have to bear the full impact of TUoS charges, thus removing some of their risk burden. GB has a cap on their Transmission Network Use of System (TNUoS) charges, limiting this risk. There is no example within the countries that we have studied where the uncertainty and burden of predicting future TUoS charges is completely shifted away from the developer through that country's renewable auction process.

5.2.3.4 Proposed Risk Mitigation Measure for Cost Benefit Analysis

Germany accounts for costs upfront and does not charge a tariff driving predictability, while Belgium partially subsidises offshore wind and fixes transmission charges for 4 years. GB, who we draw part of our proposed mitigation method from, has a specific tariff for every generator and has a cap on the transmission charges.

To investigate the benefit to the consumer of improving certainty around TUoS charges for renewable generators we propose investigating the benefit of fixing TUoS charges at each individual node as per the year of auction and indexing it to inflation.

For the purposes of our CBA in Section 6, to illustrate a fixed TUoS charge at each individual node indexed to inflation we assumed that the TUoS charge was based on an average of the TUoS charge at all nodes in 2020/21 and indexed it to the Irish CPI.

5.2.4 Merchant Tail Risk

5.2.4.1 Merchant Tail in Ireland

When developers consider the lifetime revenue of a generation plant they typically consider the subsidy revenue as their primary revenue stream. As RESS contracts last 15 years this results in a large revenue gap towards the end of the useful lifetime of the plant, which is typically 25 years in Ireland. After the end of the subsidy period the developer will look to utilise a forward price

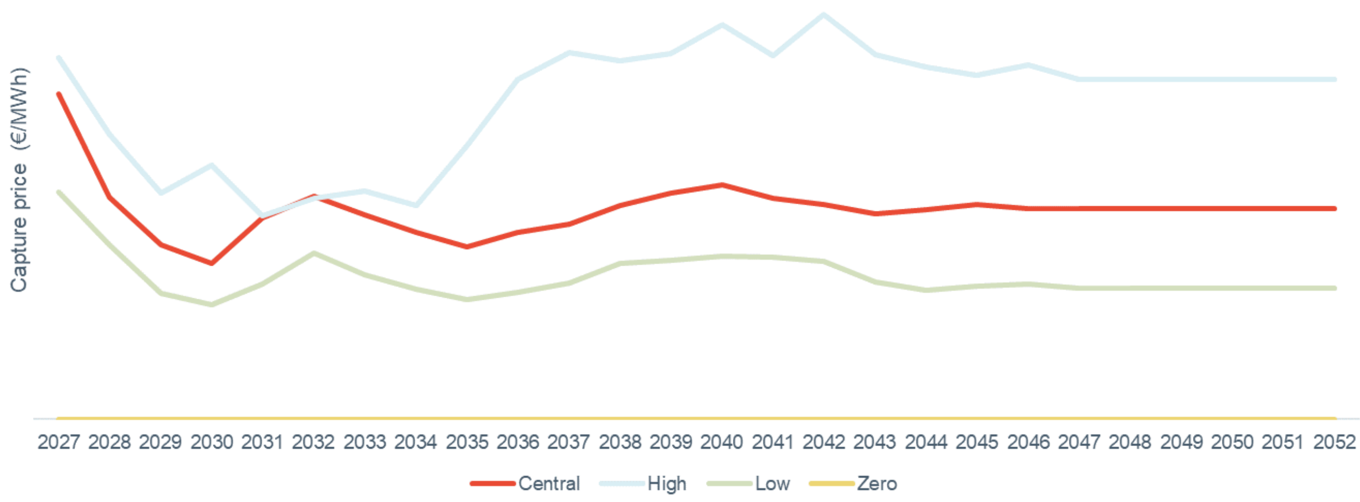
[58] Source: *ACER Practice Report on Transmission Tariff Methodologies in Europe; ACER; 2019 & Integrated text of the provisions for the provision of the services of transmission and distribution of electricity; ARERA; 2020*

projection to estimate the potential revenues that could be earned post subsidy. The level of conservatism taken by a developer in this period can have a large impact on bid price in RESS auctions as the assumed revenues will directly impact their cost of financing which can impact on bidding behaviour. Considering the current market volatility and unpredictability, especially in the price of fossil fuels, a long term 2-way CfD, such as the RESS offers hedging options on the predicted rise or fall of their renewable asset offering the developer leverage for their investment, which would otherwise have been difficult to attain.

Figure 13 illustrates a forward price projection for onshore wind in Ireland. The level at which a developer chooses its merchant tail for onshore or offshore wind will have an impact on the bid price that they submit. The design of our wholesale energy markets in 2040 and beyond is difficult to predict. This fact may impact pragmatic bidders who expect very low revenue from their asset (<€10/MWh) in the future due to competition in the market, for example, highlighted as the zero case below.

Please note, for offshore wind there is an expectation that the revenues, post subsidy, will be marginally higher than for onshore wind due to their high-capacity factors and steady wind speeds but the merchant tail risk, however, is much the same as for onshore wind. Their build price and relative novelty in the Irish market can increase this risk to developers.

Figure 13 Illustrative forward price projection for onshore wind in Ireland



Source: Cornwall Insight All-Island Forward Curve

To date, the most popular way of accounting for long-term merchant risk has been the corporate power-purchase agreement (PPA). However, over the past couple of years PPA terms have plummeted. 'A list of project PPAs supplied by Bloomberg New Energy Finance (BNEF) shows typical contract lengths falling from 20-25 years in 2017 to 12-15 years in 2019, with a 10- or 12-year term being the lower bound for PPAs reported'[59]. PPA contracts becoming shorter in length poses a risk to developers as it is very difficult to predict what the wholesale market is going to be in the future. This in turn increases the risk for developers that they must try and factor into their bid prices, ultimately increasing costs to consumer.

[59] *https://pv-magazine-usa.com/2019/10/08/beyond-the-ppa/*

Who Manages the risk – who has it in their control?

The policy makers set the term for the RESS subsidy duration as part of the RESS T&Cs. Policy makers could adjust the contract length to reduce the premium bidders place on revenue post subsidy.

A developer will most likely use a long-term price forecast from a market model to determine what risk premium to assign to merchant tail risk. A pragmatic bidder will factor this into their bid price discovery increasing the cost to consumers.

5.2.4.2 International Review of Merchant Tail Risk

Table 9 looks at how merchant tail risk is managed in several European countries and the lessons that could be learned for the Irish market.

Table 9 International Review of Merchant Tail Risk

Country	Approach towards risk	Mitigation included in support scheme design?
Denmark	**Support period of 20 years exists** in Denmark under their renewable energy support scheme for the Thor offshore wind project. The support begins from the date of commissioning of the final turbine of the project and continues for 20 years.	✓
Finland	Projects that were successful in the 2018 tender were **awarded a 12-year support contract**. It should be noted that many projects in Finland are owned by public entities, which in turn have a lower interest rate and a lower rate of expected return. Furthermore, **many projects do not receive government support and entered PPA agreements**. [60]	✗
France	The **successful bid into the Dunkirk scheme has a duration of 20 years** from the effective completion date of the entire installation, and 12 months after the longstop date imposed by the TSO. **For onshore wind farms the support period is also 20 years.** [61]	✓
GB	The **Contract for Difference (CfD) has a support period of 15 years for all technologies** awarded a contract under it.[62]	✗
Belgium	For **onshore wind the renewable energy support scheme has a duration of 20 years.** [63]	✓

[60] Source: Aures; Renewable energy financing conditions in Europe: survey and impact analysis; 2021
[61] Source: Electricity at sea in an area offshore Dunkirk - specifications; Energy Regulatory Commission; 2018 Renewable energy financing conditions in Europe: survey and impact analysis; Aures; 2021
[62] Source; Renewable energy financing conditions in Europe: survey and impact analysis; Aures; 2021
[63] Source; Renewable energy financing conditions in Europe: survey and impact analysis; Aures; 2021

Country	Approach towards risk	Mitigation included in support scheme design?
Netherlands	For **both onshore and offshore wind** the subsidy scheme in the Netherlands has a **support duration of 15 years**. [64]	✗
Spain	For **both onshore and offshore wind** the support duration in Spain is 15 years.	✗
Germany	For the auction for **onshore wind held in 2020 a support duration of 20 years is provided** for those successful in the renewable energy support scheme. For **offshore wind**, the support period as approved by the European Union in March 2020 **will also have a duration of 20 years**.[65]	✓
Italy	**Short-term CPPAs are most common for existing renewable generation projects** and they usually cover around 1-5 years. Longer-term CPPAs for new/developing renewable generation plants cover a long period of time of around 10-15 years. The PPA market is slowly developing in Italy.	✗

5.2.4.3 International Case Study

There are several countries, which have a support term longer than in Ireland. Some of the countries offering 20 years of support are Denmark, France, Belgium, and Germany. GB, Netherlands, and Spain in the meanwhile match Ireland's support period under RESS with a 15 year subsidy. However, in some countries there is a shift away from the traditional subsidy model. For example, in GB, merchant or 'quasi-merchant' projects are becoming more commonplace and are expected to increase in the upcoming Allocation Round 4 (AR4) auction. This will likely include projects in which capacity is only partly funded by a contract for difference (CfD) and others that are the subject of a PPA, or in which storage and/or the production of green hydrogen play a growing role mitigating risk and reducing the effect on prices of a fast-growing amount of wind energy in the UK power market.

Wood Mackenzie research director for offshore wind, Rolf Kragelund, said: *"Merchant exposure is already inevitable for a number of projects that will come out of a CfD and increasingly likely for new projects and for extensions to existing projects. Subsidised projects in the UK, will on average have 29.6 years left on their lease terms, allowing for lifetime extension and repowering, which would further extend the merchant tail of offshore wind projects"*[66] As an example, Kragelund cited SSE's Seagreen project of which only 42% of the output is covered by a CfD, the rest of which will be farmed down to investors, including, potentially, well known oil companies interested in offshore wind.

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[64] Source; Renewable energy financing conditions in Europe: survey and impact analysis; Aures; 2021
65 Source: Renewable energy financing conditions in Europe: survey and impact analysis; Aures; 2021
EEG 2017 - Reform of the Renewable Energy Law (as revised) Germany 2020; Energy policy review; International Energy Agency; 2020
66 https://www.rivieramm.com/news-content-hub/news-content-hub/despite-short-term-concerns-merchant-projects-lsquowill-become-commonplacersquo-in-uk-market-58793

5.2.4.4 Proposed Risk Mitigation Measures for Cost Benefit Analysis

Denmark, France, Belgium, and Germany all provide support to onshore and/or offshore wind for a period of 20 years. For our risk mitigation measure we draw lessons from them and propose to mitigate the risk of merchant tail for developers by extending the length of the subsidy to 20 years.

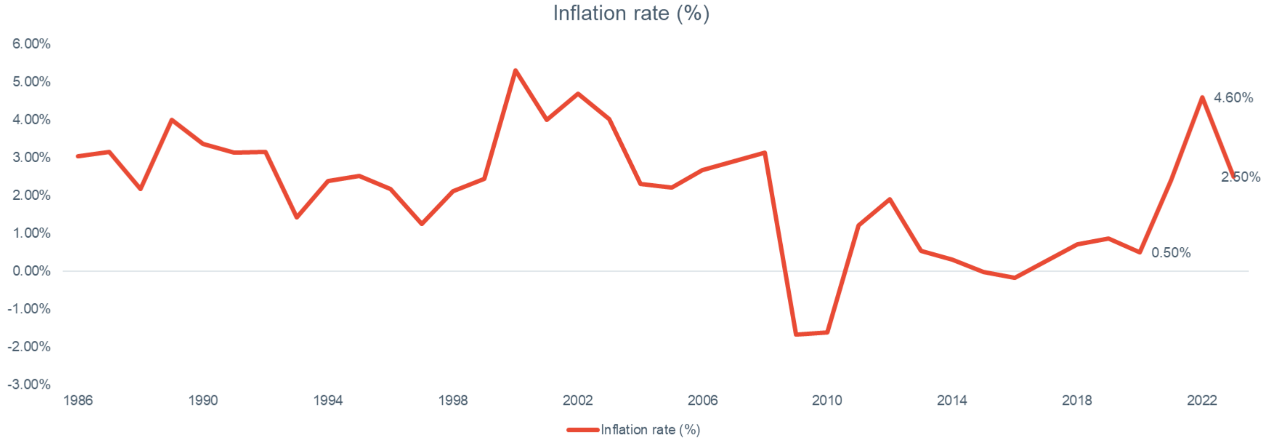
This has been modeled in the Cost Benefit Analysis carried out in Section 6.

5.2.5 Inflation Risk

5.2.5.1 Inflation Risk in Ireland

Inflation rates have been trending upwards, not accounting for the dip seen in 2020 due to COVID-19 lockdowns. Between February 2021 and February 2022, the inflation rates in Ireland have risen to a 20 year high of 5.6%[67]. In 2021, as per the European Economic Forecast for Ireland (2022) as shown in Figure 14, the estimated inflation in Ireland is 2.4% and is expected to rise to 4.6% in 2022 before falling again to 2.5% in 2023. Governor Makhlouf of the Central Bank of Ireland in his remarks on their 'The economic outlook for the year ahead' said in February 2022, "Having reached highs of 5 per cent in December, inflation across the euro area is expected to remain elevated in the near term. We expect it to remain above 2 per cent for most of this year but our forecasts project it to settle below our 2 per cent target in 2023 and 2024." Since generation projects under subsidy mechanisms are expected to recover their cost over a longer time span, it is expected that they will be subject to inflation. This is critical, especially in countries where inflation is expected to rise over time. The RESS support is currently for a period of 15 years, with auctions occurring at regular intervals within this current decade. This will expose RESS projects to inflation rates up to and beyond 2050, the estimations and projections for which are murky at best and unavailable at worst, especially at a country level. It becomes almost impossible for a developer to be firm about the kind of inflation levels their investment will be exposed to in the long run. This risk makes them err on the side of caution and build in a buffer for unexpected, or maximum levels of inflation into the future, thus driving up bid prices.

Figure 14 Ireland's Inflation Rates 1986 – 2021 and Projection to 2023



Source: Statistica, 2021(historical), European economic forecast February 2022 (projections)

67 Source: Central Statistics Office, Ireland

One of the key methods to reduce the risk caused by inflation is indexation. This allows for an adjustment to the price of a good or service, in this case RESS bid prices, based on changes in prices of a comparable, or standard good or service. Currently the RESS bid prices are not indexed. For ORESS T&C, indexation, particularly partial indexation, is being considered against the Irish Consumer Price Index (CPI) or indices such as the Steel Index.

Indexation can lower the required WACC of a project through the type of investor it will attract. A non-indexed project is likely to attract private equity players, who have a high risk – high return threshold, therefore driving up the required WACC. However, an indexed project is likely to attract institutional funds and pension funds, who typically have lower required WACC, therefore driving down bid price discovery.

Who Manages the risk – who has it in their control?

Inflation is a function of demand-pull and cost-push in the overall economy. The government can control it to an extent with overall economic decisions. However, measures such as indexation built into a mechanism allows the bidders to access financing at a cheaper cost and from a wider range of investors as it builds in the impact of inflation into the auction mechanism. This is within the control of policy makers.

5.2.5.2 International Review of Inflation Risk and Indexation

Table 10 looks at how inflation risk and indexation is managed in several European countries and the lessons that could be learned for the Irish market.

Table 10 International Review of Inflation Risk and Indexation

Country	Approach towards risk	Mitigation included in support scheme design?
Denmark	**Indexation is not accounted for** as part of the renewable energy support scheme.	✘
Finland	**Indexation is not accounted for** as part of the renewable energy support scheme. It should be noted that many projects in Finland are owned by public entities.	✘
France	The Dunkirk model[68] in France offers **partially indexed support** for the successful tender under their renewable energy support scheme.	✓
GB	In GB, the strike price is **100% index-linked to the Consumer Price Index** in the UK under the Contract for Difference (CfD) mechanism (RE support scheme). The number is updated annually.	✓
Belgium	**Indexation is not accounted for** as part of the renewable energy support scheme.	✘

[68] *Dunkirk model refers to the Dunkirk offshore Renewable Auction Design in 2018, see section 5.2.5.3*

Country	Approach towards risk	Mitigation included in support scheme design?
Netherlands	**Indexation is not accounted for** as part of the renewable energy support scheme.	✘
Spain	**Indexation is not accounted for** as part of the renewable energy support scheme.	✘
Germany	**Indexation is not accounted for** as part of the renewable energy support scheme.	✘
Italy	**Indexation is not accounted for** as part of the renewable energy support scheme.	✘

5.2.5.3 International Case Studies – France and GB

France – Partial Indexation

The Dunkirk model is a partial indexation model introduced in 2018 as part of a competitive tender procedure to promote the development of offshore wind at Dunkirk, France. The wind farm will comprise approximately 45 turbines and will have a capacity of 600 MW.

Partial indexation in the Dunkirk model relates to two phases of the project lifecycle: the construction phase and the operational phase.

The Dunkirk model considers a range of different developer costs during the construction phase. Some developer costs which are partially indexed include the length deviation of the submarine link and installation costs because of excess depth. The inflation risks of these costs are adjusted in line with certain indexes, such as the copper index published by the London Metal Exchange and the revised labour cost index. There are different levels of support for each of these indices, ranging from 2% to 66%.

During the operational phase, there is a compensation rate of 30%. This is made up of a 15% compensation rate based on the revised hourly labour cost index and a 15% compensation rate based on the French producer price index.

However, although this method was successful in France, the complexity and scale of the investment are very different to individual RESS projects in Ireland. RESS is not location specific and individual projects have a much smaller installed capacity compared to the 600 MW of the Dunkirk offshore project. To fully implement this model would require site specific assessments which could require significant resources from both developers and System Operators. However, the theory does make sense and should be considered in more detail.

GB – Full Indexation

In the GB Contract for Difference (CfD) scheme inflation is de-risked by indexing the auction strike price to inflation over the term of the contract. The CfD scheme is the government's main mechanism for supporting investment and development of renewable energy in GB. CfDs are designed to incentivise investment in renewable energy by providing developers of projects with high upfront costs and long lifetimes with direct protection from volatile wholesale prices. There have currently been three auctions, or allocation rounds (AR), which have seen a variety of renewable energy technologies participating in the competitive auction. Successful projects enter into a private law contract with the Low Carbon Contracts Company (LCCC). The AR T&Cs outline exactly how the indexation adjustment is applied to the Strike Price during the Strike Price Adjustment Calculation Period in each calendar year of the Term.[69]

Developers are paid a flat (indexed) rate.[70] The flat rate is the difference between the strike price and the market reference price. The budgets and Strike Prices for each AR are published in 2012 prices, allowing direct comparison between each AR. The actual budgets are then calculated using the Consumer Price Index (CPI) Inflator. For AR3, the Inflator used for calculating the actual available budget was 1.0193.[71]

Indexing the Strike Price to inflation helps provide more clarity and certainty around the income generators can expect to receive over the lifetime of their contract. Additionally, because it is indexed to inflation, the Strike Price holds its value over time rather than decreasing as it would if it were not indexed to inflation. By providing greater certainty to developers the bid price discovery can be lower as can the required WACC.

5.2.5.4 Proposed Risk Mitigation Measures for Cost Benefit Analysis

GB offers full indexation of the strike price against CPI, while France partially indexes its bids in the Dunkirk auctions against multiple indices.

For our risk mitigation measure we draw lessons from GB and to drive predictability we proposed using total indexation against the Ireland CPI.

This has been modelled in the Cost Benefit Analysis carried out in Section 6.

[69] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/799137/AR3-Standard-Terms-and-Conditions.pdf
[70] The flat rate is indexed with CPI
[71] BEIS 2019

5.3 Summary of Risk Mitigation Measures for CBA

A summary of the proposed Risk Mitigation Measures for the CBA identified in Section 5.2 is provided in Table 11

Table 11: Summary of Risk Mitigation Measures for CBA

Risk	Current measure in RESS T&Cs	Who manages the risk?	Risk Mitigation Measure
Dispatch Down Risk – Curtailment & EB	10% cap on Curtailment, for 2 consecutive years	TSO	10% cap on Curtailment & EB.
Dispatch Down Risk – Constraints	No measure	TSO	A nodal cap for constraints.
TLAF Risk	No measure	TSO	Fixed TLAF at the level assigned post commissioning.
TUoS Risk	No measure	TSO	Fixed TUoS charges at each individual node at the year of auction and indexed to inflation.
Merchant Tail Risk	Subsidy period of 15 years	Policy makers (DECC)	Extending the length of the subsidy to 20 years.
Inflation Risk	No measure	Market function, can be managed through indexation	Contracted auction price fully indexed against the Irish CPI.

6. Phase 2: Cost Benefit Analysis

A cost benefit analysis has been used to assess the impact of implementing the identified risk mitigation measures from Section 5.3. Three elements are considered and presented:

- the expected required WACC of a project by the developer,
- the related bid price submitted for that project, and
- the cost to the consumer associated with the RESS auction.

This is completed through a comparison of two scenarios (pragmatic Bidder and Pragmatic Bidder with Risk Mitigation), details of which are show below with the considerations for these two scenarios presented in Figure 15.

- **Pragmatic Bidder**: As per section 4.1, the Pragmatic Bidder is one that allocates a premium to their bid price, albeit pared to the minimum level they can live with (a walk-away bid considering the risk), given the auction context. However, under a mechanism where they are expected to take variable prices and uncertainty related decisions around the known risks, it will drive up contracted auction prices. This scenario considers the impact to bid price, WACC, and consumer cost when a pragmatic bidder must consider certain external risks.
- **Pragmatic Bidder with Risk Mitigation**: This case again uses the pragmatic bidder but considers the impact to bid price, WACC, and Consumer Cost when certain risks are mitigated and need not be considered by the pragmatic bidder.

The underlying theory behind this CBA is that when developers can lower the WACC required for financing a project they can lower the bid price they submit, and by doing this a lower cost is achieved for RESS which ultimately results in lower costs being passed through to consumers.[72]

6.1 CBA Methodology

This section explains the methodology used to calculate the impact of implementing risk mitigations.

Figure 15 details the methodology used for this CBA analysis. Constraints are used as an illustrative example here but the logic is similar for all risk mitigation measures referred to in this report. All numbers used in this example are for illustrative purposes only. An explanation of Figure 15 is provided here.

Pragmatic Bidder

A developer calculates the required WACC they have for a project considering costs. They also need to consider the risk management in this case of constraints. They can then calculate a bid price that will cover costs and a risk premium to cover the risk of constraints. There is a lot of uncertainty in what constraints will outturn at over the lifetime of the plant but the developer must make an assumption. As a result, the developer takes a pragmatic view which covers some but not all risk, assuming their generation will be reduced by 7% due to constraints on the network. With these assumptions the bid price they calculate is €100/MWh. However, it is quite possible that the constraint level could be higher than expected, for example, 9%. In this reasonable worst-case scenario the developer makes a lower rate of return.

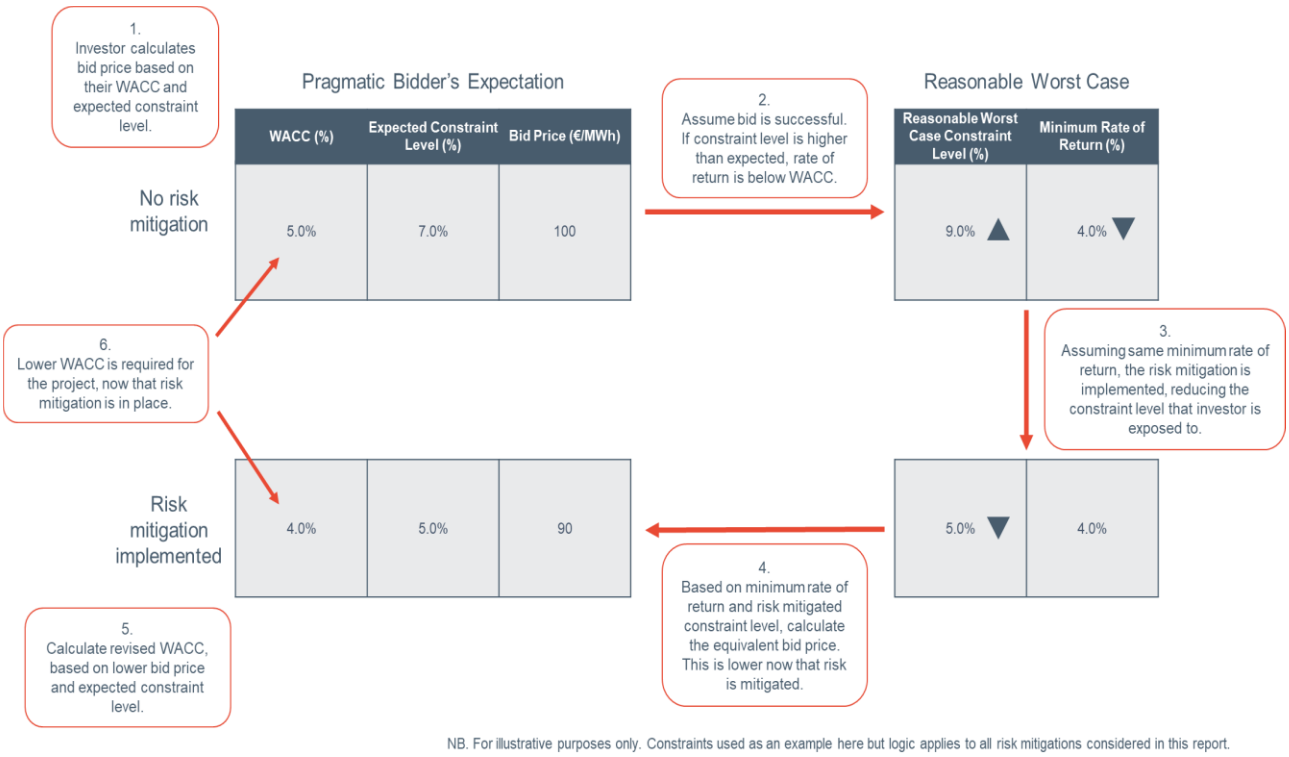
[72] *Note: Different type of investors will require different returns (WACC), so changing the WACC will change the type of investors and bring in additional investors such as pension funds, who typically have lower cost of capital.*

Pragmatic Bidder with Risk Mitigation

The reasonable worst-case scenario is then considered with the risk mitigation measure in place to see how it would impact the developer's required WACC and bid price. In this illustrative example a risk mitigation measure of a cap of 5% on constraints is introduced. The developer is only exposed to lost revenue for constraint levels up to 5% and if the actual constraint level is higher, e.g., 9%, the developer will be compensated for their losses.

From this, it is possible to reverse calculate the bid price based on a reduced risk premium requirement because the risk mitigation measure is in place. The required WACC can then be re-calculated by taking the reduced bid price and what the developer expected the constraints level to be. In this example, the result is that the required WACC for the project has reduced from 5.0% to 4.0%. This demonstrates that by implementing risk mitigation measures developers can lower their required WACC, thereby reducing their bid price discovery which will result in lower costs to the consumer.

Figure 15: CBA Methodology

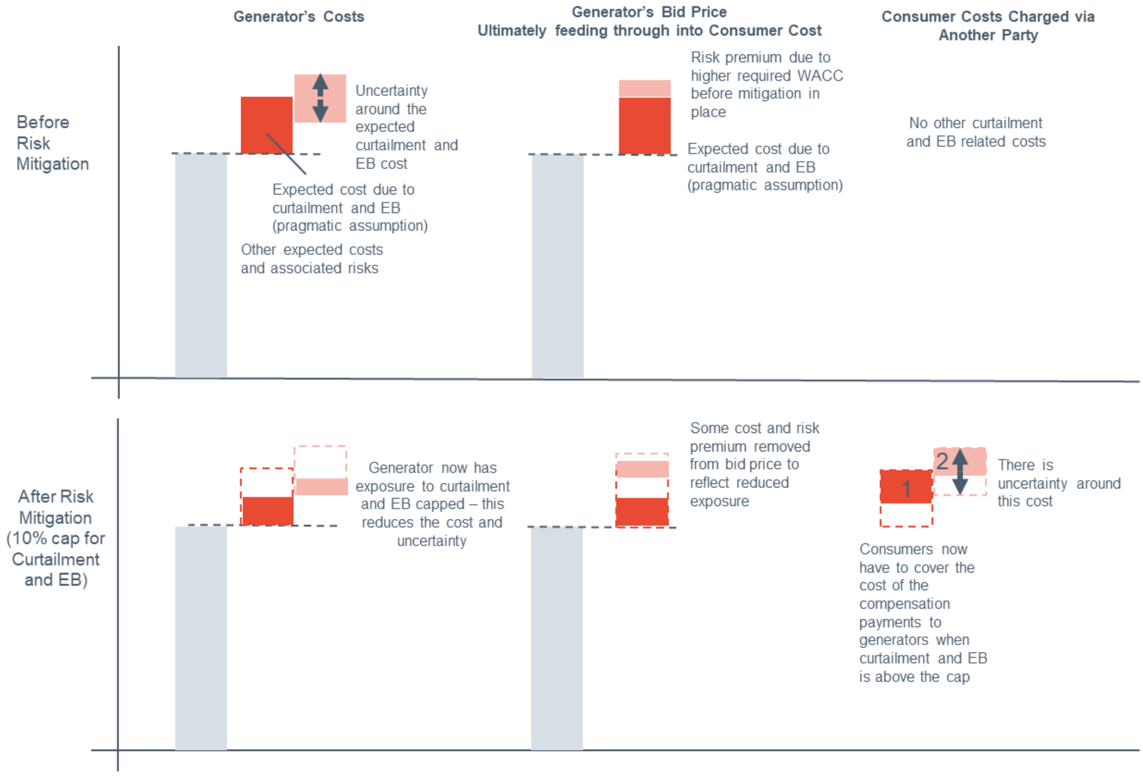


Source: Cornwall Insight

6.1.1 Consumer Impact

It is important to note that there are two aspects to the reduction in consumer costs that are modelled in this CBA. Firstly, the risk mitigation measures result in a reduction in bid price that in turn results in a saving to the consumer in terms of the contracted auction prices. However, some of the risk mitigation measures that are implemented here actually pass the risk on to the consumer, increasing other costs that they face, for example, the payment of constraint compensation. This CBA takes this into account so that **the saving to the consumer is based on both the reduction in cost based on lower contracted auction prices, but also the increase in cost of the risk mitigation measure.** In Figure 16 below, the example of curtailment and EB has been used to demonstrate how the CBA has accounted for the costs that have been passed to the consumer as a result of the risk mitigation method in addition to the bid price impact. Due to the risk mitigation method passing some of the burden of the risk to the consumers, the risk premium incorporated into the bid price can be reduced. By allocating the risk to the consumer, the consumer has avoided crystallising the risk in advance, however they are now exposed to a variable cost. In our calculation of consumer cost, we have included the additional payments that consumers would have to pay to compensate generators based on the expected cost due to curtailment (represented by box 1 in Figure 16). We have not modelled scenarios of the risk around the expected cost now that it sits with the consumer (represented by box 2 in Figure 16). An example of curtailment and EB has been shown, but this methodology has been used to find the consumer cost impact for all risk mitigation methods.

Figure 16: Example Curtailment and EB: accounting for the shift in consumer cost burden due to risk mitigation method implemented



The key takeaway is that by assigning the risk to those better placed to manage it, there is the possibility to reduce the cost to the consumer of the risk mitigation measure. Whereas assigning a risk to developers that they cannot control results in them factoring in higher risk premiums into their bid which exposes the consumer to higher costs regardless of whether the risk crystallises or not.

6.1.2 Modelling Assumptions

This section looks at the inputs to the CBA including how the risk mitigation measures identified in Section 5.3 are modelled in the CBA.

Table 12: Modelling Assumptions – Risk Mitigation Measures

Risk	Risk Mitigation Measure	CBA Assumption
Dispatch Down Risk – Curtailment & EB	10% cap on Curtailment & EB.	10% cap for all curtailment and EB related dispatch-down.

Risk	Risk Mitigation Measure	CBA Assumption
Dispatch Down Risk – Constraints	A nodal cap for constraints.	2% cap for constraint related dispatch down.
TLAF Risk	Fixed TLAF at the level assigned post commissioning.	Fixed TLAF at 0.99
TUoS Risk	Fixed TUoS charges at each individual node at the year of auction and indexed to inflation	Fixed TUoS charge based on the average of the TUoS charge at all nodes in 2020/21 and indexed against Irish CPI
Merchant Tail Risk	Extending the length of the subsidy to 20 years	20 years of subsidy under RESS
Inflation Risk	Contracted auction price fully indexed against the Irish CPI	Contracted auction price fully indexed against the Irish CPI

Table 13: Modelling Assumptions – Other Inputs

Other Inputs	CBA Assumption
Onshore wind capacity	30 MW
Offshore wind capacity	500 MW
Constraint Levels to 2050	Market Model Forecast
Curtailment & EB Levels to 2050	Market Model Forecast

6.1.3 Result Presentation

The results of the CBA are presented in three sections:

- Impact of Risk Mitigation Measures on required WACC – Onshore & Offshore Projects
- Impact of Risk Mitigation Measures on Bid Price – Onshore & Offshore Projects
- Impact of Risk Mitigation Measures on Cost to Consumer per MW – Onshore & Offshore Projects

The figures in each section show the impact of applying the risk mitigation measures by presenting:

- the impact of mitigating each identified risk from Section 5 individually
- the impact of mitigating each identified risk from Section 5 simultaneously creating a combination effect
- comparison between the two scenarios: ‘Pragmatic Bidder’ and ‘Pragmatic Bidder with Risk Mitigation’.

The combination effect exists because the risk mitigation measures will interact with each other. As an example, constraints and TLAFs are multipliers to the volume. If you apply the measures individually, they both apply to the full volume. When you apply them together, the TLAF multiplier is applied to the volume that has already been reduced by the constraint multiplier. The difference between this and the sum of the individual changes is the combination effect.

It should be noted, the reason the combination effect is so high is because when the risk mitigation measures are applied individually, except for merchant tail, they are based on a 15-year timeframe, but the combination effect is based on a 20-year timeframe to allow for merchant tail risk mitigation measures to be considered at the same time. The results of the CBA show the per MW impact in order to allow like-to-like comparison.

Generally, it could be expected that required WACC, bid price, and consumer impact will all move similarly, however, this is not always the case. For example, WACC is more affected at the time costs are incurred and when the revenues from the subsidy are received across the lifetime of the asset, whilst bid price is more affected by the level and timing of the costs incurred and any wholesale revenues received. This means that mitigations may affect the required WACC, bid price, and consumer cost differently. In particular, the merchant tail risk mitigation measure of extending the contract duration means that it is not always a like for like comparison between this risk mitigation measure and others.

6.2 Impact of Risk Mitigation Measures on required WACC

In this section, the risk mitigation measures proposed in section 5 have been analysed and the sensitivity of the **required WACC** to these changes is understood. The impact of each individual risk being mitigated and the combination effect of all the risks being mitigated together has also been analysed. Finally, a comparison is shown between the original WACC required by the pragmatic bidder and the new WACC required by the pragmatic bidder when certain risks are mitigated. This analysis is carried out for both onshore and offshore wind projects.

As can be seen in both Figure 17 and Figure 18 below, increasing certainty around risks outside of a bidder’s control lowers the risk perception and in turn lowers the required WACC.

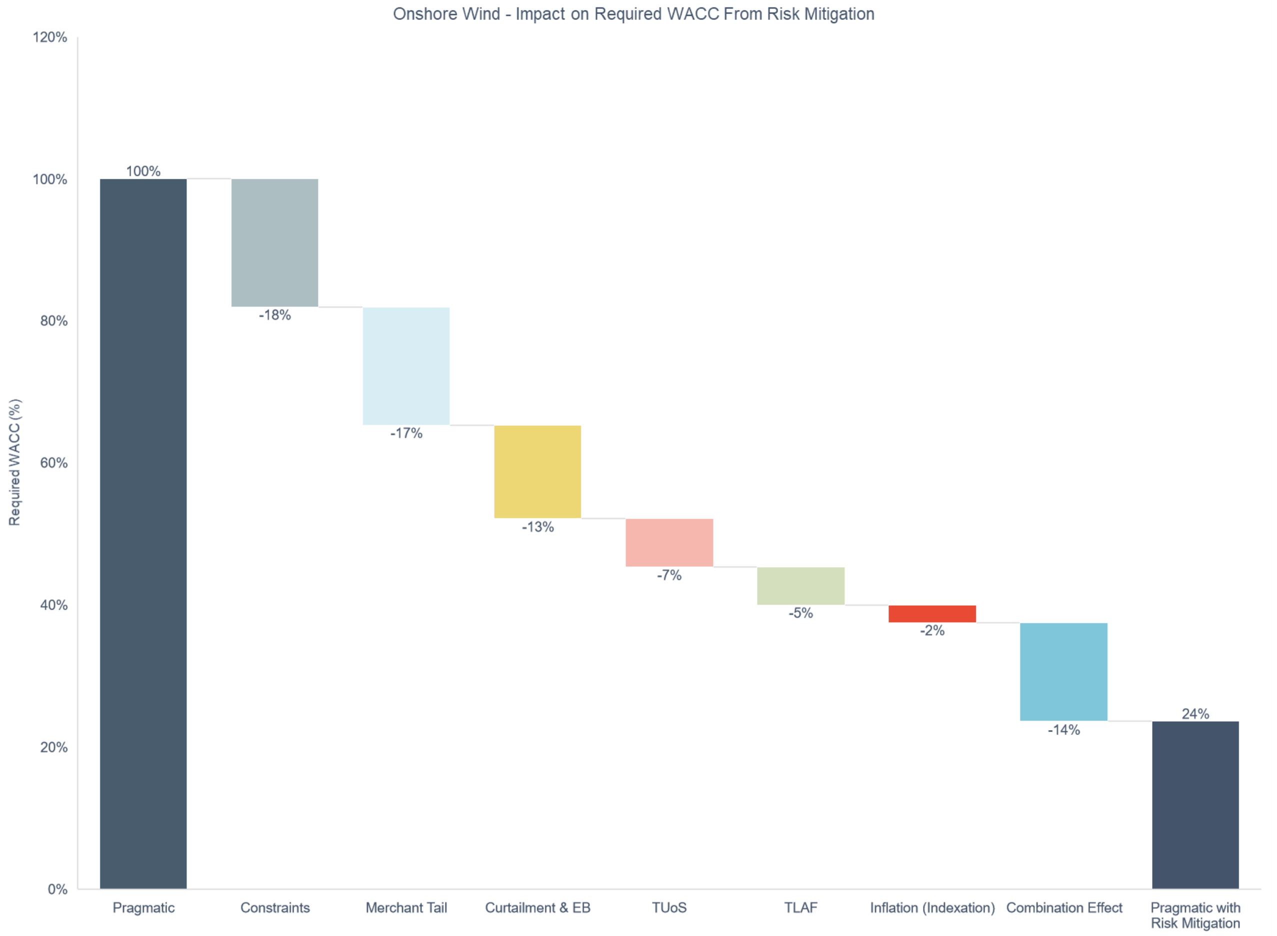
6.2.1 WACC impact for onshore wind projects

The mitigation measure applied to the constraints risk has the greatest impact on the required WACC for an onshore project. Constraints are very difficult to model accurately for most pragmatic bidders. The current RESS T&Cs do not compensate developers for constraints at any level, therefore the mitigation proposed here of compensation for constraint levels over 2% was expected to have a significant impact on required WACC reduction.

The mitigation measure applied to the merchant tail risk has the next greatest impact on the required WACC. This is to be expected, as increasing the RESS contract duration by 5 years makes a significant impact in the modelling.

The cumulative impact of all risk mitigation measures, including the combination effect, results in a 76% reduction in required WACC. As discussed in Section 6.1.3, this is mainly because extending the contract duration by 5 years amplifies the benefits seen, and as a result there is a high combination effect of 14%.

Figure 17: Onshore Wind Project - Impact of Risk Mitigation Measures on Required WACC



Source: Cornwall Insight analysis

6.2.2 WACC impact for offshore wind projects

Again, the mitigation measure applied to the constraints risk has the greatest impact on the required WACC for an offshore wind project. Similarly, for offshore wind projects constraints are very difficult to model accurately for most pragmatic bidders. The current RESS T&Cs do not compensate developers for constraints at any level, therefore the mitigation proposed here of compensation for constraint levels over 2% was expected to have a significant impact on required WACC reduction.

The mitigation measure applied to curtailment and EB has the next greatest impact on the required WACC for an offshore wind project. Unlike for onshore wind projects, the mitigation measure applied to merchant tail risk has less impact for an offshore wind project. This is due to differences in capture prices in the merchant tail period for onshore and offshore wind and higher required WACC for offshore projects, meaning that changes affecting later years of the horizon have less impact.

The cumulative impact of all risk mitigation measures, including the combination effect, is a 65% reduction in required WACC. Combining all impacts results in a lower required WACC compared to the sum of the individual risk mitigation impacts. Again, this is due to the merchant tail risk mitigation measure combining with the other risk mitigations, and extending the contract duration amplifies the benefits seen giving an additional combination effect of 11% in this case. This value is lower than the onshore wind project value due to the required WACC reduction from the merchant tail risk mitigation being less, as discussed in the previous paragraph.

Figure 18: Offshore Wind Project - Impact of Risk Mitigation Measures on Required WACC

Source: Cornwall Insight analysis

6.3 Impact of Risk Mitigation Measures on Bid Price

In this section, the risk mitigation measures proposed in Section 5 have been analysed and the sensitivity of **bid prices** to these changes and the reduced required WACC is understood. The impact of each individual risk being mitigated and the combination effect of all the risks being mitigated together has also been analysed. Finally, a comparison is shown between the original bid price used by the pragmatic bidder and the new bid price used by the pragmatic bidder when certain risks are mitigated and a reduction in required WACC is seen. This analysis is carried out for both onshore and offshore wind projects.

As can be seen in both Figure 19 and Figure 20, the reduction in WACC has a significant impact on reducing the bid prices seen for both onshore and offshore wind projects.

6.3.1 Bid price impact for onshore wind projects

The reduction in required WACC from the implementation of the risk mitigation measures reduces bid price by 42% for onshore projects.

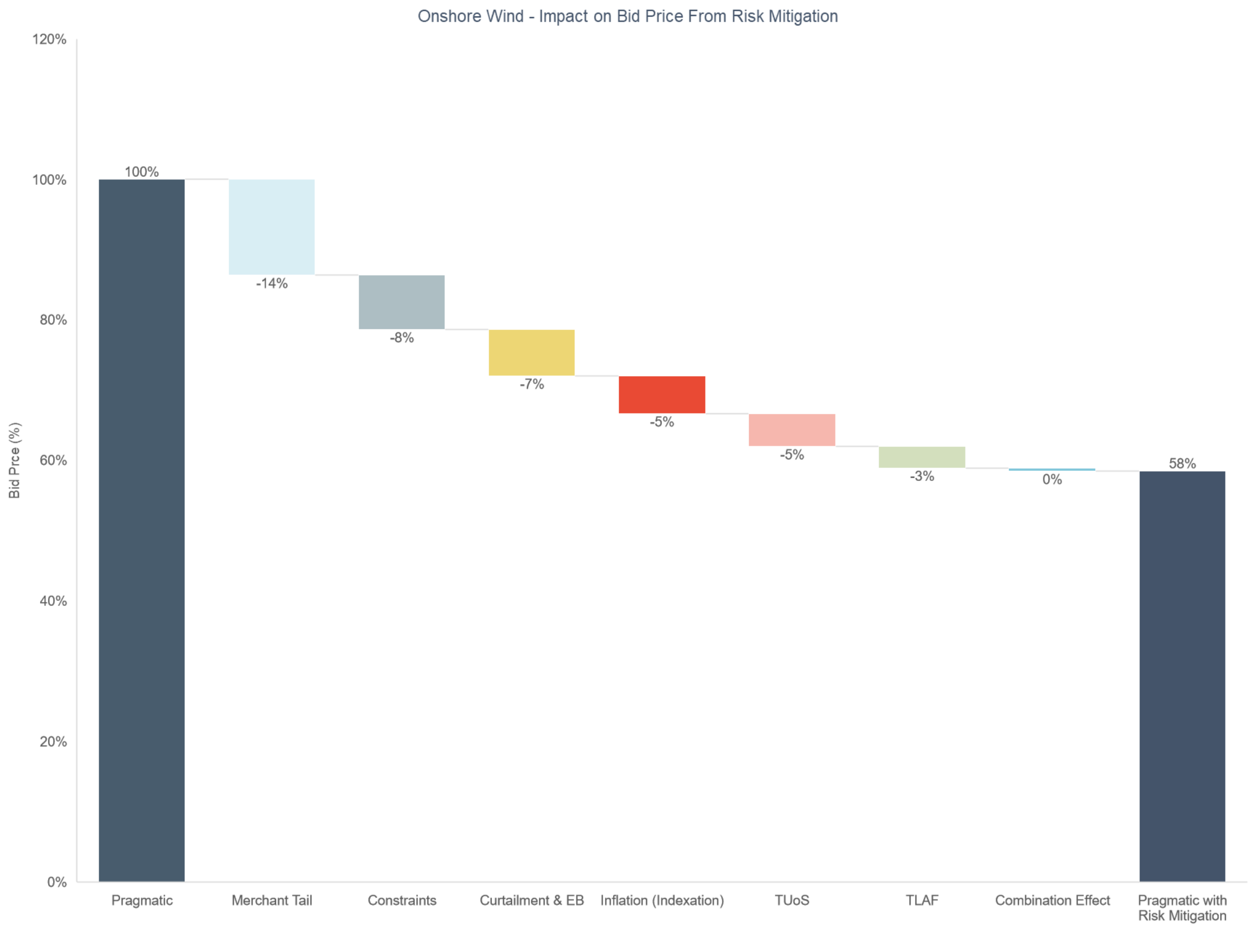
The mitigation measure applied to the merchant tail risk has the greatest impact on the bid price. However, the merchant tail risk mitigation measure increases the bid subsidy period by 5 years.

This means that the bid price is repaid over a longer period than the other risk mitigation measures shown. This is different to the results seen for the required WACC as the mitigation measure applied to the merchant tail risk is to extend the subsidy period for five years to a twenty-year horizon, meaning the costs are spread over an additional 5 years. Therefore, the relative impact of this risk mitigation on bid price is greater than other measures, for example, constraints, which considers a 15-year horizon.

Interestingly, the inflation risk mitigation has more impact on the level of subsidy required rather than the timing of costs and revenues, so a greater impact to the bid price is observed than to the required WACC.

The combination effect here is slightly lower than for the required WACC. This can be attributed to, for example, the constraints risk mitigation measures which applied as a percentage to the full volume when considered in isolation, but when combined with other volume related factors, such as TLAF risk mitigation, they are applied as a percentage to a lower volume resulting in a lower impact on bid price overall. There is also the fact that the effect of the mitigation measure applied to the merchant tail risk mainly affects the volume over which the costs are recovered. The other mitigation measures however, have an impact on the cost of the project as well as the volume over which it is recovered.

Figure 19: Onshore Wind Project - Impact of Risk Mitigation Measures on Auction Bid Price



Source: Cornwall Insight analysis

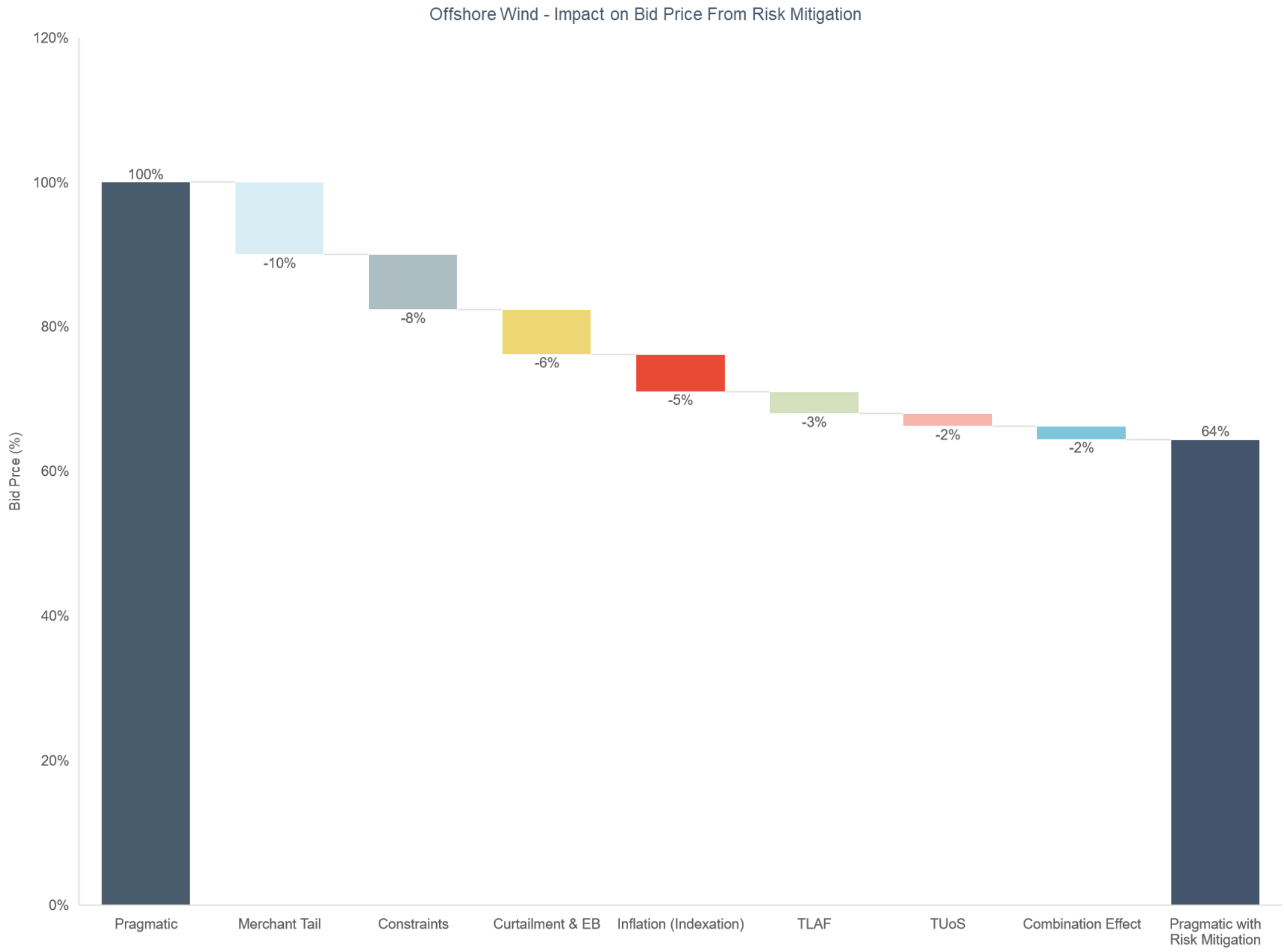
6.3.2 Bid price impact for offshore wind projects

The reduction in required WACC from the implementation of the risk mitigation measures reduces bid price by 36%.

Whilst it still has the greatest impact to the bid price for an offshore wind project, the mitigation measure applied to merchant tail risk has less impact for an offshore wind project than an onshore wind project due to differences in capture prices in the merchant tail period for onshore and offshore wind. Additionally, higher WACC for offshore means that changes particularly affecting later years of the horizon have less impact.

As with an onshore wind project, the combination effect here is slightly lower, as, for example, constraint risk mitigation measures are applied as a percentage to the full volume when considered in isolation, but when combined with other volume related factors, like TLAF risk mitigation, the constraint risk mitigation measures are applied as a percentage to a lower volume, which results in a lower impact on bid price when all mitigation measures are combined. There is also the fact that the effect of the mitigation measure applied to the merchant tail risk mainly affects the volume over which the costs are recovered. The other mitigation measures however, have an impact on the cost of the project as well as the volume over which it is recovered.

Figure 20: Offshore Wind Project - Impact of Risk Mitigation Measures on Auction Bid Price



Source: Cornwall Insight analysis

6.4 Impact of Risk Mitigation Measures on Consumer Costs

The key objective of this study was to understand the extent to which the cost to the consumer is impacted by mitigating the risks identified in Section 5. Figure 21 and Figure 22, show that if certain risks are mitigated for a pragmatic bidder then the cost to consumer could potentially be reduced by up to 48% for onshore wind projects and 63% for offshore wind projects. This is based on the reduced required WACC for the pragmatic bidder. The reduced WACC reduces their bid price which in turn lowers the cost to the consumer over the lifetime of the RESS contract. As discussed in Section 6.1, the cost to consumers of the implementation of the risk mitigation measure is considered in the modelling. Therefore, consumer cost savings reflect both the reduction in costs associated with the contracted auction price reductions but also the increase in costs for the mitigation of risks where required.

The results are presented on a per MW basis as the capacity for onshore wind projects assumed in the modelling is less than the capacity for offshore wind projects modelled. This ensures that the reduction in consumer costs is presented on a like for like basis for both onshore and offshore wind projects.

6.4.1 Consumer cost impact for onshore wind projects

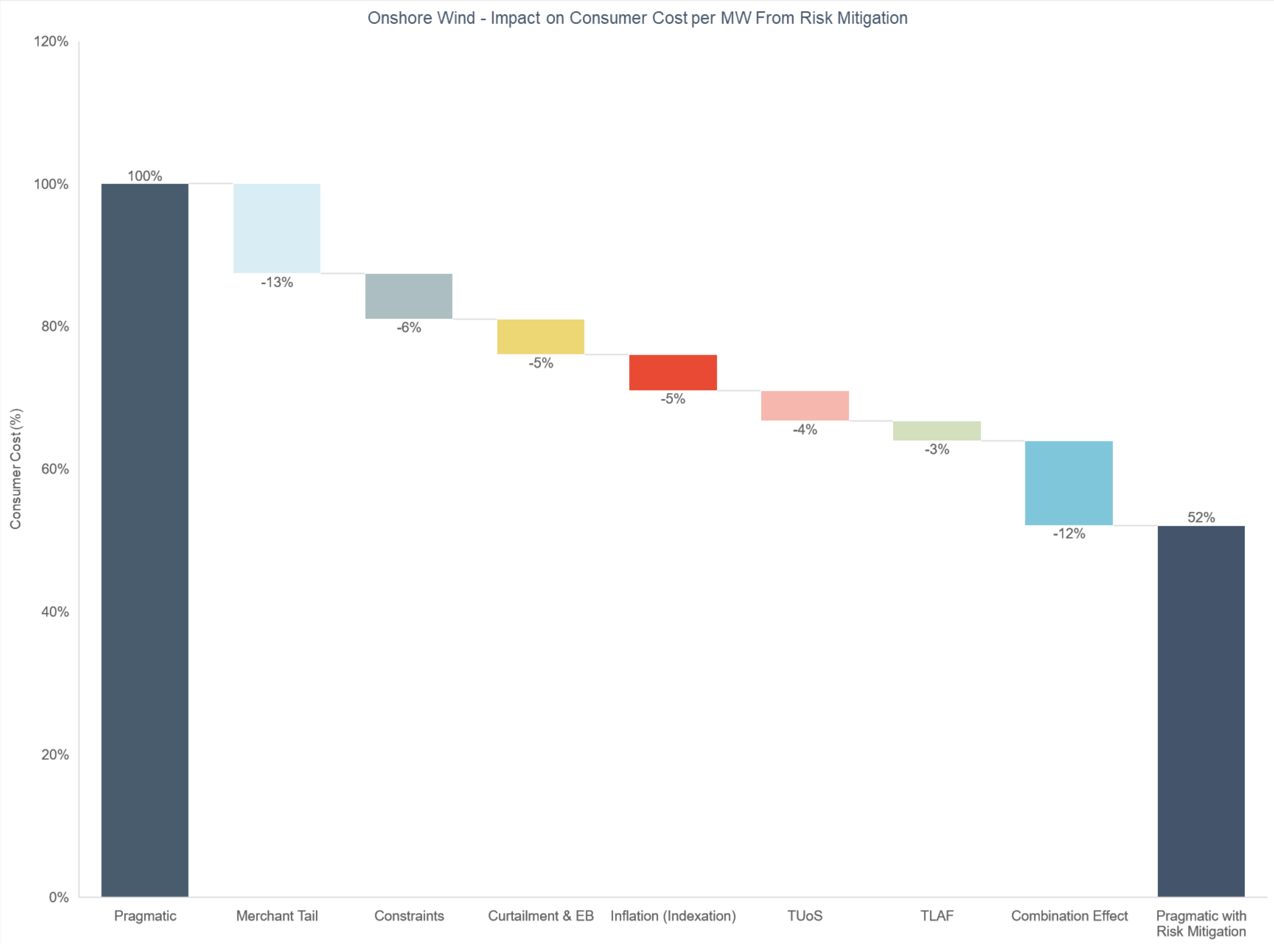
As stated above, a reduction of 48% in consumer cost across the lifetime of the RESS contract can potentially be achieved by utilising the risk mitigation measures proposed in this report.

Across all risk mitigation measures the impact on consumer cost is lower than for the required WACC. This is because the capacity for onshore wind projects is low and thus has less of an impact on the consumer costs experienced.

The combination effect is high in this case as it is driven by the impact of the risk mitigation measure applied to merchant tail risk which drives an additional five years of subsidy to be paid by the consumer. Combining all impacts results in a lower cost to consumer, similar to the reduction in required WACC seen in the earlier section, compared to the sum of the individual risk mitigation impacts. Again, this is mainly because when the merchant tail risk mitigation is combined with the other risk mitigations, extending the contract duration amplifies the benefits seen and there is an additional combination effect to be considered.

These results show that even if the subsidy contract duration is increased, significant benefits to consumers can be seen if these risk mitigation measures are applied.

Figure 21: Onshore Wind Project - Impact of Risk Mitigation Measures on Consumer Costs



Source: Cornwall Insight analysis

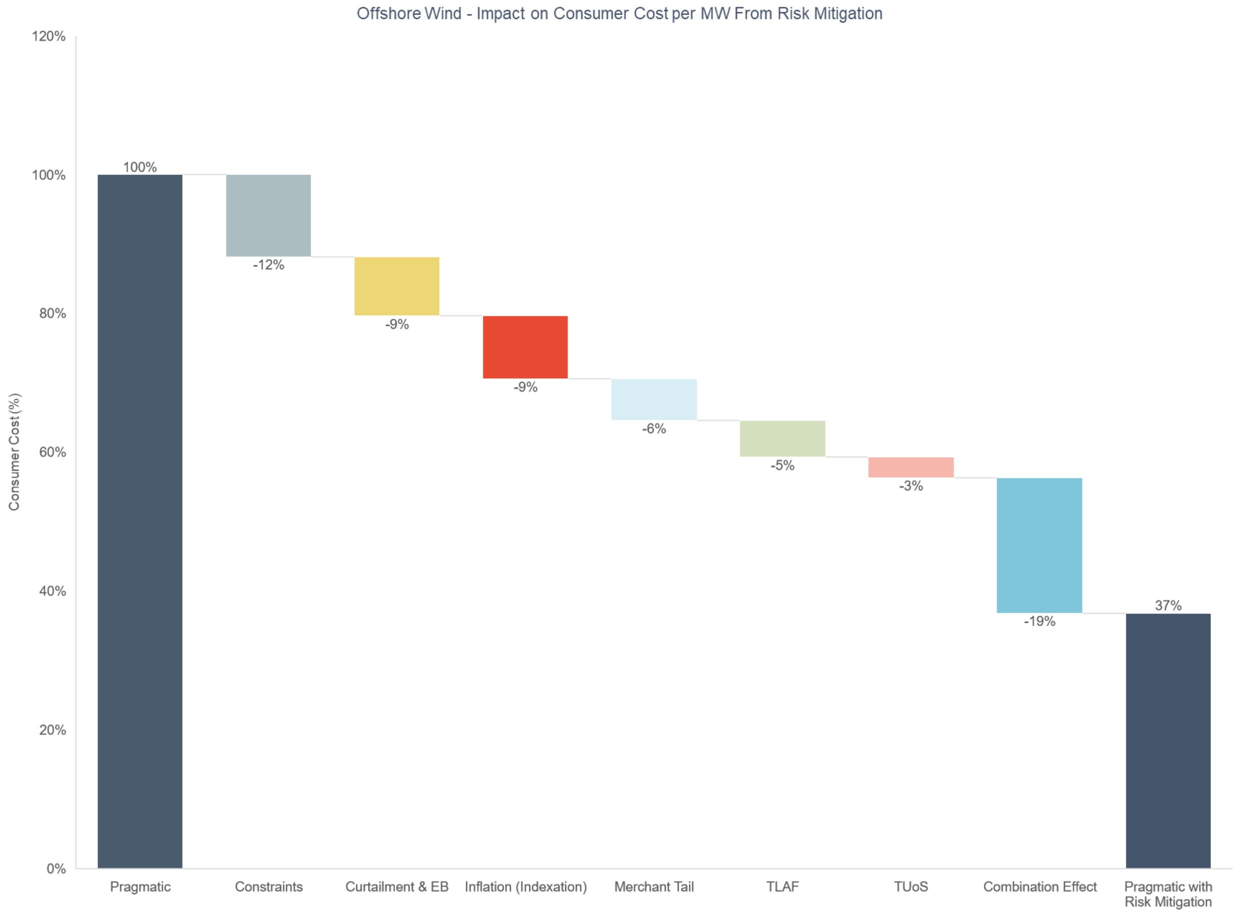
6.4.2 Consumer cost impact for offshore wind projects

As stated above, a reduction of 63% in consumer cost across the lifetime of the RESS contract can potentially be achieved by utilising the risk mitigation measures proposed in this report.

The impact of the risk mitigation measures is higher for offshore wind projects than onshore wind projects as the capacity of offshore wind projects modelled in this analysis is much greater than the capacity modelled for onshore wind projects and thus can have more impact on the consumer cost experienced. However, we have presented the results on a per MW basis to ensure a like for like comparison between onshore and offshore wind projects. The combination effect is also higher and assists in the higher cost to consumer reduction than for onshore wind projects.

As before for required WACC and bid price, the mitigation measures applied to merchant tail risk have less impact for an offshore wind project. This is due to differences in capture prices in the merchant tail period for onshore and offshore wind projects. Additionally, higher WACC for offshore wind projects mean that changes particularly affecting later years of the horizon have less impact. However, the results do show that even if the subsidy contract duration is increased, significant benefits to consumers can be seen if these risk mitigation measures are applied.

Figure 22: Offshore Wind Project - Impact of Risk Mitigation Measures on Consumer Costs



Source: Cornwall Insight analysis

7. Key Findings

We observe that there is a definite reduction in costs to the consumer when the identified risks are mitigated. While certain risk mitigation measures have a higher impact than others, there is an additional combination effect causing increased savings when all the identified risks are mitigated together.

Overall, the impact of the risk mitigation measures is greater for offshore wind projects than onshore wind projects. Notwithstanding the higher capacity factor, the larger overall magnitude of offshore wind versus onshore wind projects modelled in this analysis gives rise to the greater impact on the consumer cost experienced. As such, in Table 14 we have presented the results on a per MW basis to ensure a like for like comparison between onshore and offshore wind projects. The combination effect is also higher and assists in the higher cost to consumer reduction than for onshore wind projects. This can also be attributed to the different distributive weighting of, or exposure to, different risks to each technology.

Table 14: Summary of per MW savings for consumers as per CBA

Risk	Reduction in Cost to Consumer- Onshore wind	Reduction in Cost to Consumer- Offshore wind
Constraint	6%	12%
Curtailment and Energy Balancing	5%	9%
Inflation risk (Indexation)	5%	9%
Merchant Tail Risk	13%	6%
TLAF	3%	5%
TUoS	4%	3%
Combination effect	12%	20%
Total savings for consumers	~48%	~63%

Each risk identified in Section 4, the treatment of those risks in Ireland and internationally, the risk mitigation measure applied, and the results of the CBA analysis are summarised now.

Dispatch Down Risk due to Curtailment and Energy Balancing

Under the current RESS T&Cs, curtailment of renewable generation is compensated once curtailment levels reach 10%, however dispatch down driven by energy balancing is not compensated. The Clean Energy Package will require the SEM Committee to look at the market design and ensure that non-market redispatch is compensated appropriately, this work has commenced with a decision paper published in March 2022 but further clarity is still needed. Assessment of EirGrid's constraint reports highlight that whilst the curtailment levels were not as high as forecasted between 2014 - 2021, there is a direct correlation between increasing renewable generation and increased curtailment levels. It is vitally important that EirGrid continue to work to increase SNSP levels so that curtailment levels can reduce. Energy Balancing (EB) is not something that renewable generators have had to consider in any great detail up to now given the levels of renewable generation connected to the system and the priority order for redispatch for energy balancing. As renewable generation increases in Ireland this will become more of an issue and RESS developers are having to consider this in their bids.

Internationally, we saw that Denmark, GB, Belgium, Spain, and Germany compensate their renewable energy generators, either partially or fully, for curtailment. We can take lessons from Germany who compensate for 95% of curtailment & EB and recommended that not only curtailment but also EB is compensated when levels go above 10%.

The CBA assumed a risk mitigation measure where curtailment & EB are compensated when levels exceed 10% during a given year over the duration of the RESS contract. For onshore wind, this resulted in a consumer cost saving of ~5% / MW, while for offshore wind it resulted in a consumer cost saving of ~9% / MW.

Dispatch Down Risk due to Constraints

Under the current RESS T&Cs, dispatch down due to constraints on the network is not compensated and the developer must bear the full risk over the lifetime of the project. Constraints are very difficult to accurately model and there are no publicly available forecasts that cover the duration of a RESS contract (15 years) and beyond. Assessment of EirGrid constraint reports highlight that the previously provided forecasts were overly optimistic and outturn constraint levels were much higher in reality. Constraint levels have steadily risen over the past 4 years ranging between 3.3% to 8.9% depending on location. The Clean Energy Package will require the SEM Committee to look at the market design and ensure that non-market redispatch is compensated appropriately, this work has commenced with a decision paper published in March 2022 but clarity is still needed. Until such time as compensation methods are known, developers are considering constraint risk in their bid price discovery.

Internationally, we saw that in Denmark, GB, Belgium, Spain, Germany, and Italy there is some method of compensation adopted for dispatch down due to constraints and it is the system operator’s responsibility to minimise constraints. We can learn from Belgium, who use a locational specific compensation for constraints and recommended that Ireland incorporates a locational nodal cap for constraints.

In the CBA, to illustrate a locational nodal cap, we assumed that constraints are compensated when constraint levels exceed 2% during a given year over the duration of the RESS contract. For onshore wind, this resulted in a consumer cost saving of ~6% / MW, while for offshore wind it resulted in a consumer cost saving of ~12% / MW.

This saving has been calculated while accounting for the indirect cost the consumer will have to bear for compensating constraints. There can be additional savings to the consumer if there are upgrades made to the network and constraint levels drop quite low.

TLAF Risk

Under the current RESS T&Cs there is no fixed TLAF assigned to projects. They change annually depending on new generation, demand connections, or network changes in the location. It is difficult for a developer to predict how their TLAF will change, especially as there is low visibility of new generation connections at specific nodes. Further to this, EirGrid does not provide TLAF forecasts for specific nodes. Therefore, developers are considering TLAF risk in their bid price discovery.

Internationally, we saw that in Belgium transmission losses are considered while calculating support payments for offshore wind. In GB, developers must bear 45% of transmission losses, whilst in France, the TSO bears the cost of transmission losses attached to grid connection delays. We recommended that the TLAF for a project is fixed at the level of TLAF assigned to the generator post commissioning for the duration of the RESS contract.

In this CBA, to illustrate a fixed TLAF assigned to a generator post commissioning, we assumed a fixed value for TLAF of 0.99 for the duration of the RESS contract. For onshore wind, this resulted in a consumer cost saving of ~3% / MW while for offshore wind it resulted in a consumer cost saving of ~5% / MW.

TUoS Risk

Under the current RESS T&Cs there are no fixed TUoS charges assigned to projects. They are reviewed annually and we saw in our research swings of 1-15% around the country between 2020 and 2021. EirGrid does not provide TUoS forecasts and the extreme volatility and unpredictability of these charges means that developers are considering TUoS risk in their bid price discovery.

Internationally, we saw that GB has a specific tariff for every generator and a cap on transmission charges. We recommended that the TUoS charge for a project is fixed at each individual node and indexed to inflation.

In the CBA, to illustrate a fixed TUoS charge at each individual node indexed to inflation, we assumed that the TUoS charge was based on an average of the TUoS charge at all nodes in 2020/21 and indexed it to the Irish CPI. For onshore wind, this resulted in a consumer cost saving of ~4% / MW, while for offshore wind it resulted in a consumer cost saving of ~3% / MW.

Merchant Tail Risk

Under the current RESS T&Cs, the period of support for RESS projects extends to 15 years which leaves a large revenue gap towards the typical 25-year end of the lifetime of the plant. Developers use market model forecasts to predict the revenue they could earn in the wholesale market. Developers are considering merchant tail risk in their bid price discovery. Depending on their comfort level with a market model forecast, the merchant tail risk results in further impact to bid price.

Internationally, we saw that in Denmark, France, Belgium, and Germany there are instances of renewable support extending to 20 years. We recommended that a support period of 20 years is also considered for RESS projects.

In the CBA, we assumed 20 years of support. For onshore wind this resulted in a consumer cost saving of ~13% / MW, while for offshore wind it resulted in a consumer cost saving of ~6% / MW.

Inflation Risk

Under the current RESS T&Cs, there is no indexation that addresses the risk of inflation on the contracted auction price[73] for a developer. It is very difficult for a developer to forecast inflation levels, especially in the long-term. Therefore, inflation risk is considered in their bid price discovery.

Internationally, we saw that GB fully indexes their renewable energy bids against their consumer price index (CPI). The Dunkirk model in France partially indexes certain costs against inflation using multiple indices. This model is more complex and could require individual assessment of projects to determine indexation levels. We therefore recommended that the contracted auction price is fully indexed against the Irish CPI.

In the CBA, we assumed full indexation against the Irish CPI of the contracted auction price for the duration of the RESS contract. For onshore wind this resulted in a consumer cost saving of ~5% / MW, while for offshore wind it resulted in a consumer cost saving of ~9% / MW. As these savings are made over a long period of time, there is a lower chance that the consumer will pay high costs due to the implementation of this risk mitigation measure. Furthermore, indexed projects are more likely to be funded by institutional pension funds, with lower required WACCs possibly reducing consumer costs further.

Combination Effect

It is interesting to note that, for both onshore and offshore wind, when all the risk mitigation methods are incorporated in the model simultaneously it leads to an additional saving to the consumer. We have termed this as the combination effect. For onshore wind projects this resulted in an additional consumer cost saving of ~12% / MW, while for offshore wind projects it resulted in an additional consumer cost saving of ~20% / MW.

Key Recommendations

Based on the CBA results and our understanding of the current RESS T&Cs and the Irish electricity market, the key recommendations around the various risk mitigation methods that have been

[73] *RESS uses a pay as bid model.*

discussed in this report are presented in Table 15.

Table 15: Key recommendations

Risk	Risk Mitigation method	Recommendation	Action element(s)	Timeline	Action owner(s)
Dispatch Down Risk – Curtailment & EB	10% cap on Curtailment & EB.	Current RESS T&Cs already include a 10% cap for curtailment related dispatch down. We recommend that this is extended to energy balancing related actions, especially as there is still lack of clarity around the implementation of Article 12 and Article 13 of the EU Electricity Regulation, despite the SEMC decision paper published.	Changes made to RESS T&Cs to include compensation for energy balancing related actions	Quick win	• DECC • CRU
Dispatch Down Risk – Constraints	A nodal cap for constraints.	Further assessments need to be carried out before this risk mitigation method can be put into place.	First, design methodology to assign nodal caps. Second, nodal caps to be assigned to every node after node wise assessment is carried out	Medium term	• EirGrid • DECC • CRU
TLAF Risk	Fixed TLAF at the level assigned post commissioning.	Further assessments need to be carried out before this risk mitigation method can be put into place. Other countries, except Belgium, did not mitigate this risk through auction design. The long-term impact if this is implemented in the RESS T&Cs need to be assessed.	Assessment of long-term impact of fixing TLAF	Long term	• CRU

Risk	Risk Mitigation method	Recommendation	Action element(s)	Timeline	Action owner(s)
TUoS Risk	Fixed TUoS charges at each individual node at the year of auction and indexed to inflation.	Further assessments need to be carried out before this risk mitigation method can be put into place. Other countries studied did not mitigate this risk within their auction design and therefore lessons cannot be learnt from them regarding the long-term impact of fixing TUoS charges.	Assessment of long-term impact of fixing TUoS charges	Long term	• CRU
Merchant Tail Risk	Extending the length of the subsidy to 20 years.	No restrictions within the EU state aid documents, on the basis of which RESS was approved, that would prevent a 20-year subsidy period. However, However, approvals for changes will have to be taken from the European Commission as currently a maximum support period of 16 years has been approved.	Application to extend state aid for a period of 20 years for future RESS rounds	Medium Term	• DECC • CRU • European Commission
Inflation Risk	Contracted auction price fully indexed against the Irish CPI.	Reducing the risk of inflation through indexation has a dual benefit: first, to reduce the bid price by lowering interest rates; second, to bring in additional sources of investment, such as institutional investors and pension funds, who otherwise may not bear the risks of investing under the current RESS T&Cs. This will contribute considerably to expanding the investor base, which is key considering Ireland's RE targets.	Include 100% indexation against the CPI in RESS T&Cs	Quick win	• DECC • CRU

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