WIND ENERGY IRELAND

Baringa



Lower Bills, Cleaner Power

Making Irish wind cheaper

November 2026

Contact







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WIND ENERGY IRELAND

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Foreword from Wind Energy Ireland

Wind farms are the first line of defence for Irish electricity consumers. Every day, they help to push down wholesale electricity prices and protect us from volatile international gas markets.

Between 2000 and 2023 our wind farms delivered a net saving of nearly €840 million to Irish consumers. More recently, new wind and solar farms built with the support of the Government's Renewable Electricity Support Scheme have paid hundreds of millions of euro back to consumers.

But it's not enough. It's not nearly enough.

Ireland has some of the highest electricity prices in Europe and behind those statistics are families struggling to pay their bills, farmers fighting to keep their heads above water and businesses doing everything they can to stay competitive.

High electricity prices also discourage the electrification of our energy system, slowing our transition to an electrostate and prolonging our dependence on imported fossil fuels when we should be firmly on the path to energy independence.

Within the next four to five years, wind farms will be Ireland's number one source of electricity. This will be a landmark achievement for our industry and for the country's energy revolution, but consumers must see and feel the benefit.

To do that, we must make building wind farms in Ireland more affordable.

No Government ever consciously decided that Ireland should be an expensive place to build a wind farm. But, over time, layers of policy, risk, regulation and a lack of coordination have produced exactly that result.

Grid connection requirements add unnecessary costs while grid charges can change after investment decisions have been made. Wind farms with batteries face unnecessary restrictions on how those batteries can operate. And every year growing volumes of clean electricity are wasted because our electricity system cannot use them.

The State's renewable energy support contracts are shorter than in other countries and do not provide developers with full protection against inflation. Each of these problems increases risk. And greater risk means more expensive finance, more expensive wind farms and, ultimately, more expensive electricity.

Wind farms save money for Irish consumers but the more expensive we make it to build a wind farm in Ireland, the more consumers need to pay for the electricity it produces, and the smaller the final benefit for Irish families and businesses.

But we can fix this.

In *Lower Bills, Cleaner Power* the team at Baringa identify seven policy changes, all within the power of Government or State agencies, that could reduce the cost of developing a typical Irish wind farm by almost 23 per cent.

And these are not theoretical savings. Baringa estimates that, had these changes been in place for last year’s auction, wind farms could have cleared at €69 per megawatt-hour instead of €97, saving Irish electricity consumers €120 million from that auction alone.

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That is the opportunity in front of us.

Wind energy is already one of Ireland's greatest economic and energy assets. We have the wind. We have the projects. We have the expertise. And now we have a clear roadmap for making the electricity they produce cheaper.

If Government, regulators and industry act together, we can build the wind farms Ireland needs at lower cost, cut electricity prices for homes and businesses and accelerate our journey towards genuine energy independence – transforming Ireland into an electrostate powered by clean, affordable renewable power.

Noel Cunniffe

CEO, Wind Energy Ireland

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Policy recommendations from Wind Energy Ireland

Policy	Recommendation	Stakeholders
Grid connection costs	Streamline grid connection requirements to ensure technical specifications are proportionate to the fundamental physical needs of the system, while maintaining system security and reliability.	CRU, EirGrid, ESB Networks
Fixed grid charges	Provide long-term certainty on TUoS charges and TLAFs by locking in the applicable charges from the project's final investment decision.	CRU, EirGrid
Contract tenor of RESS	Extend RESS contract tenor from 15 to 20 years, increasing revenue certainty, reducing financing costs and providing greater long-term value for consumers. This is already in place for offshore wind through ORESS.	DCEE, DPER
Contract indexation in RESS	Move to full indexation of RESS contracts to remove the majority of project exposure to inflation and reduce the cost of financing.	DCEE, DPER
Hybrid connections	Remove barriers to hybrid connections, allowing co-located storage to charge directly from wind generation and optimise the site to reduce dispatch down.	DCEE, CRU, EirGrid, ESB Networks
Adoption of LDES	Establish policy support for sustained deployment of long-duration energy storage (LDES) in line with the capacities identified in *Shaping Our Electricity Future* and *Tomorrow's Energy Scenarios*.	DCEE, CRU, EirGrid, ESB Networks
Further mitigation of dispatch down	Deliver a coordinated *Dispatch Down Action Plan*, combining grid investment and operational measures with demand-side flexibility, interconnection, dynamic line rating, hybrid connections and LDES.	DCEE, CRU, EirGrid, ESB Networks

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Executive summary

Our analysis suggests that the cost of developing a wind farm in Ireland could be reduced by almost 23% with the delivery of seven enabling policies.

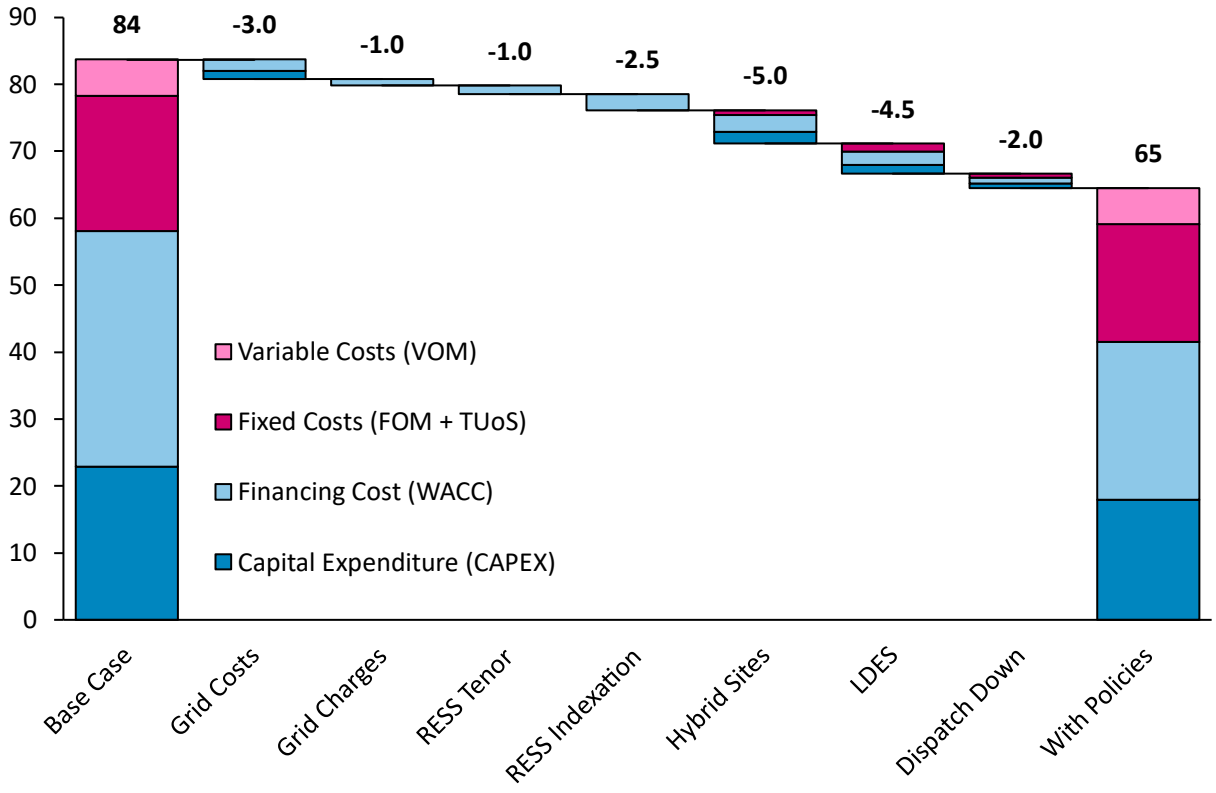
This finding, calculated for a typical 100 MW onshore wind farm connecting in 2030 with support from a Renewable Electricity Support Scheme (RESS) contract, could be realised by successful implementation of policy levers addressing planning and grid, RESS design, and dispatch down.

As presented in Figure 1 below, a €19 per megawatt-hour (MWh) saving on development costs could be unlocked with the streamlining of grid requirements (3 €/MWh), the fixing of grid charges for the project lifetime (1 €/MWh), an extended tenor and full indexation for RESS contracts (4 €/MWh), a less restrictive hybrid sites policy (5 €/MWh), the adoption of long-duration energy storage, or 'LDES', (4 €/MWh), and a range of further solutions to address dispatch down (2 €/MWh).

Wind projects that 'repower' existing sites with the latest technology could benefit from a 27% overall reduction in development costs.

With the terms of RESS 6 removing the barrier to repowered projects qualifying for support, prospective projects across Ireland are now enabled to make use of existing site infrastructure; cutting costs, lowering risk, and accelerating delivery. Our analysis suggests that repowering alone could reduce development costs by more than 11% in the absence of other policies.

Figure 1: Impact of explored policies on the LCOE of an Irish wind project, €/MWh (real 2026)



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Our findings suggest that, if these policies had been successfully implemented ahead of RESS 5, wind farms could have cleared as low as 69 €/MWh.

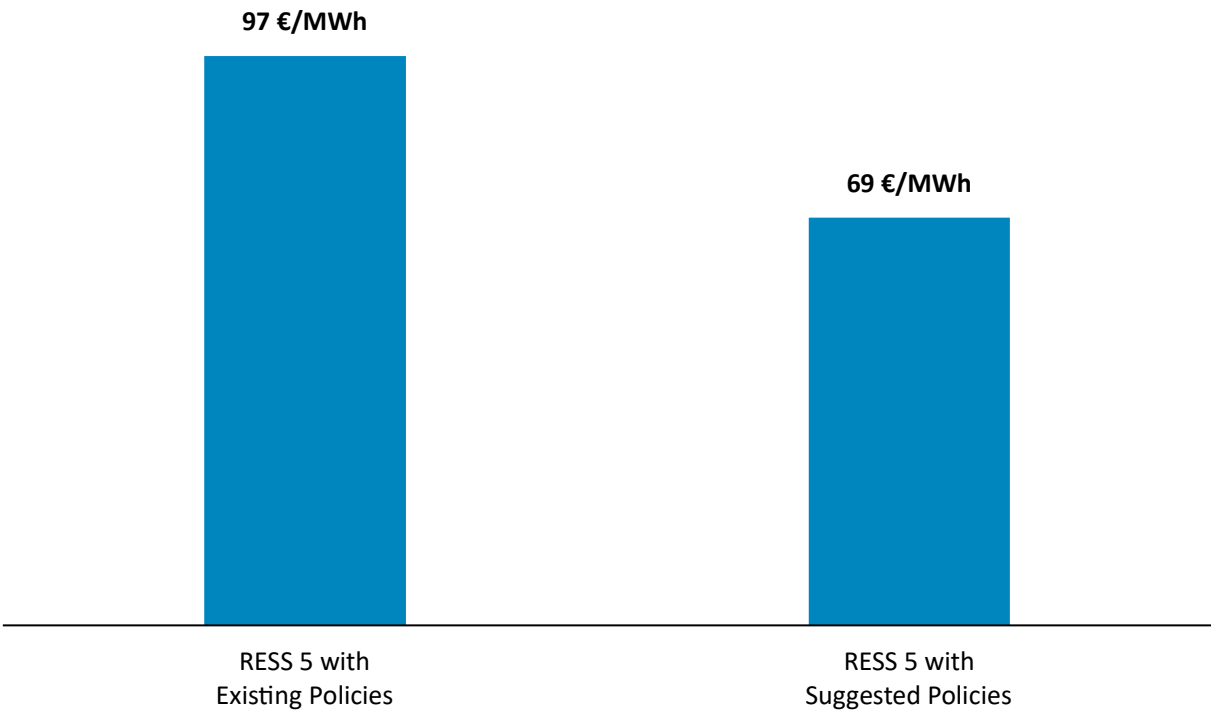
This reduction in contract prices, down from the 97 €/MWh seen in the auction, would have resulted from a roughly equal split of lower upfront capital costs (streamlining of grid costs and implementation of hybrid sites), reduced project risk (fixing of grid charges and increased revenue certainty from the adjustments to RESS design), and the direct result of changes to the design of the contracts themselves (a longer tenor and full indexation).

This finding, presented in Figure 2 below, does not consider any savings that could have been realised if the repowering terms of RESS 6 had been implemented in the earlier auction, which could have further reduced the bids of specific projects.

Policies that directly adjust the design of RESS would have made an outsized impact on contract prices relative to development costs. Extending the tenor of contracts from 15 to 20 years could have reduced contract prices by 2 €/MWh, though the true value of this policy lies in the protection offered to consumers against long-term price volatility. Providing full indexation of contracts, up from the 30% offered today, would have contributed half of the decrease in clearing price, a total of 15 €/MWh including a lower cost of financing.

Each of the policies explored, in particular the full indexation of contracts, would then offer corresponding savings on the power bills of Irish consumers.

Figure 2: Impact of policies on the average strike price of wind successful in RESS 5, €/MWh



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This reduction in average contract price would have manifested on consumer bills as a saving of €120 million for RESS 5 alone.

Extending support contracts from 15 to 20 years could have contributed €20 million of this saving, in part because long-term revenue certainty would lower project risk, but also because the two-way contracts would result in net payments to consumers over the final five years of support.

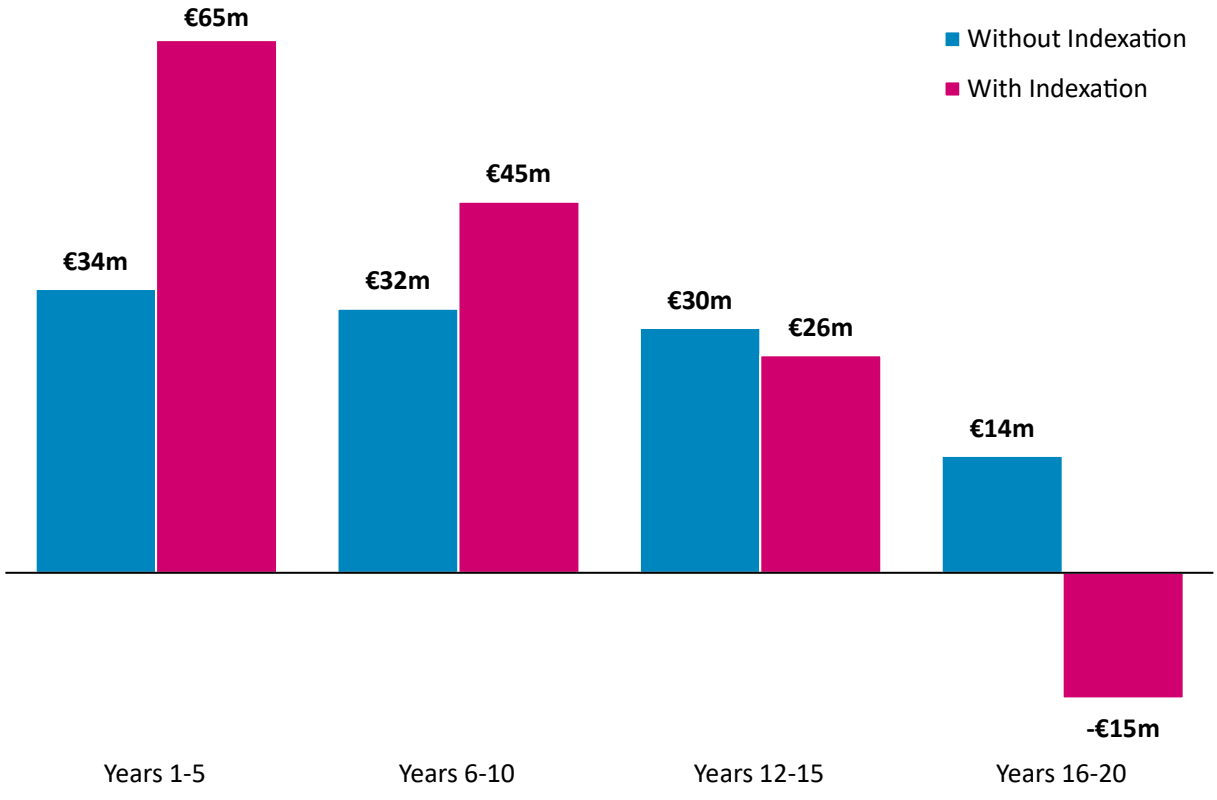
Complementing longer contracts with full indexation to address inflationary risk could have increased savings by a further €10 million, and, as presented in Figure 3 below, moved the savings forward in time towards the start of the contracts, when they are of most value to consumers.

Our analysis has focused on onshore wind, but the policies explored would also unlock lower development costs for offshore wind and solar projects.

With the exception of adjusting the design of RESS, each of the policies we have analysed in this study would offer equivalent benefits for onshore wind farms progressing through other 'routes-to-market', whether independently or with the backing of a corporate.

Development costs would also be lowered for offshore wind and solar projects, a consideration that we have conservatively excluded from the presented savings on offer to Irish consumers from the seven policies explored in our study.

Figure 3: Consumer savings unlocked by explored policies for RESS 5, million euros (real 2026)



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1 Introduction

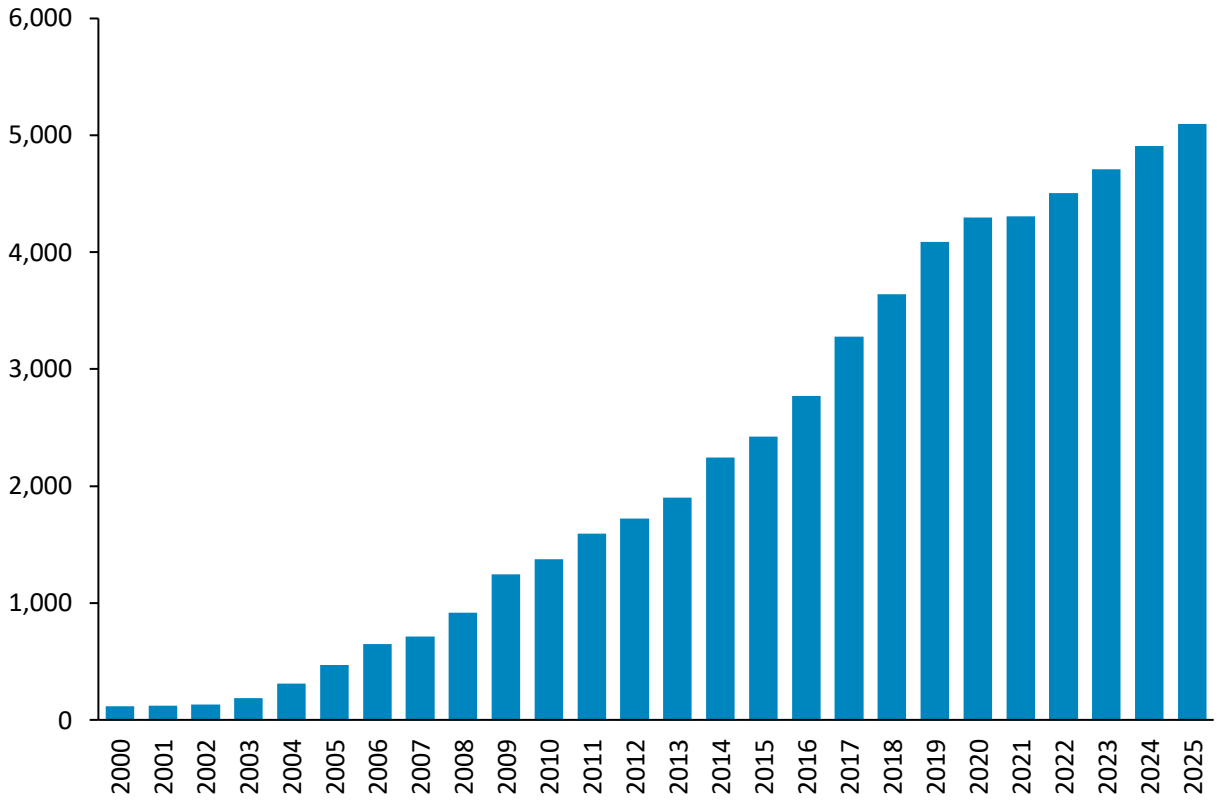
1.1 Wind power in Ireland

1.1.1 The growth to date

Since the turn of the millennium, wind power in Ireland has grown from a near-zero starting point to supply a third of domestic electricity consumption.[1] Around 5,100 megawatts (MW) of onshore wind capacity is now installed across Ireland.[2] A single offshore wind site, the 25 MW Arklow Bank Phase 1 project, has been in operation since 2004, though lodged an application in 2025 for permission to decommission.[3]

Figure 4 below presents the growth in installed onshore wind capacity across Ireland.[4]

Figure 4: Installed capacity of onshore wind farms in Ireland, MW



[1] **New record for wind energy in Ireland**, EirGrid

[2] **System and Renewable Data Reports**, EirGrid

[3] **Proposed Decommissioning of Arklow Bank Wind Park Phase 1**, An Coimisiún Pleanála

[4] The values presented are end-of-year.

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1.1.2 Available routes-to-market

This growth in onshore wind has been enabled through a series of Government-backed support mechanisms, as well as a thriving corporate power purchase agreement (PPA) market,[5] fuelled predominantly by the demand of global tech companies and other large energy users (LEUs) active in the market.

The first support scheme open to wind farms, the Alternative Energy Requirement (AER), provided payments to projects successful in any of six competition rounds between 1995 and 2003. A replacement programme, the Renewable Energy Feed-in Tariff (REFIT) scheme, issued contracts to renewable projects in three procurement rounds held between 2006 and 2015. The first two rounds, REFIT 1 and REFIT 2, were open to onshore wind projects, and provided support through 'one-way' contracts for difference (CfDs).[6]

Following the closure of REFIT 2 in 2015, seven auctions of its replacement initiative, the Renewable Electricity Support Scheme (RESS), have taken place since 2020, including five open to onshore wind, solar photovoltaics (PV) and other 'onshore' technologies. Two dedicated Offshore RESS (ORESS) auctions have also taken place, open exclusively to offshore wind farms. Projects successful in any of these rounds have received 'two-way' CfDs.[7] A sixth round open to onshore projects, RESS 6, is scheduled for November 2026.[8]

Each of these support schemes was designed to provide 'revenue certainty' to renewable projects by providing a guaranteed minimum price for each megawatt-hour (MWh) of electricity produced. In the case of the two-way CfDs of RESS, this arrangement also helps to insulate consumers during periods of elevated power price, as the wind and solar farms actively 'pay back' any market revenue above their contracted level. A net total of almost €500 million was conferred to consumers from contracted renewables between October 2022 and September 2023.[9]

[5] A PPA is a direct contract between a (typically renewable) generation asset, and a party that agrees to purchase the produced electricity (the 'offtaker').

[6] Under a one-way CfD, such as REFIT, a generator receives a set minimum value per megawatt-hour (MWh) produced, known as the 'strike price'. When the market price falls below the strike price, the generator receives a top-up payment to supplement their market revenue. When the market price exceeds the strike price, the generator does not have to pay back the difference, instead securing additional revenue.

[7] Under a two-way CfD, such as AER or RESS, a generator receives a set value, the strike price, for each MWh produced. When the market price falls below the strike price, the generator receives a top-up payment to supplement their market income. When the market price exceeds the strike price, the generator must pay back the difference.

[8] **RESS 6 Auction Timetable**, EirGrid

[9] **Public Service Obligation (PSO) Levy Decision Paper 2026/26**, Commission for Regulation of Utilities (CRU)

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1.1.3 The outlook for Irish wind

Looking forward, the penetration of wind and other renewables in the Irish generation mix is expected to increase significantly, driven by an ambition from Government to decarbonise the power sector and deliver energy security and sovereignty for Ireland. The *Climate Action Plan 2021*,[10] a flagship climate strategy document published by the Irish Department of Climate, Energy and the Environment (DCEE),[11] set an ambition for 80% of electricity consumption to be met by renewable sources by 2030.[12] An aligned target has since been adopted in Northern Ireland through the *Climate Change Act*,[13] which passed in 2022.

Corresponding targets for installed wind capacity for 2030 have been iterated on by DCEE since the announcement of the '80 by 30' ambition. As of the *Climate Action Plan 2025*,[14] these targets stand at 9,000 MW of onshore wind and 'at least' 5,000 MW of offshore wind capacity. A corresponding target of 8,000 MW stands for solar PV.

A stakeholder consultation commissioned by industry and published in 2023,[15] revealed a widespread industry sentiment that these ambitions cannot be realised by 2030 without structural change to policy, though may ultimately be achieved a few years later. The Irish Fiscal Advisory Council suggests that Ireland may fall short of its legally binding target to reduce economy-wide greenhouse gas emissions by 51% between 2018 and 2030, opening the door to fines imposed by European Union (EU) law.[16]

[10] **Climate Action Plan 2021**, DCEE

[11] Then known as the 'Department of the Environment, Climate and Communications (DECC)'.

[12] The impact of achieving 80% renewable electricity by 2030 in Ireland and Northern Ireland had first been explored in Baringa's ***Endgame*** and ***Achieving Zero*** studies respectively.

[13] **Climate Change Act (Northern Ireland) 2022**, Northern Ireland Assembly

[14] **Climate Action Plan 2025**, DCEE

[15] **Act Now**, KPMG

[16] **A colossal missed opportunity**, Irish Fiscal Advisory Council and the Climate Change Advisory Council

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1.2 The cost of Irish wind

1.2.1 The macroeconomic backdrop

Since the start of the decade, two key events have reshaped the costs associated with the development of wind farms.

Firstly, in 2020, the COVID-19 pandemic brought lockdowns that slowed global supply chains and prevented active projects from continuing to their planned timelines. This systemic slowing of supply chains created a scarcity of raw materials such as steel and concrete across markets, driving up prices. Support schemes across Europe had been issuing contracts at record low prices at this time, leaving developers exposed to the costs of drawn-out development and construction timeframes, and, if the price of supply had not been locked in beforehand, the rising cost of materials.

Secondly, in 2022, the Russian invasion of Ukraine delivered a shock to gas prices across Europe. Surging commodity prices meant higher costs for raw materials, due to the continued use of fossil fuels throughout global supply chains. The inflation brought by surging costs also delivered an increase to central bank interest rates, increasing the cost of financing for developers.

The compound effect of these macroeconomic factors has been seen in delays, revisions and cancellations of renewable projects across Europe.[17]

In the context of the conflict in Iran, the impact of rising commodity prices on the production and transport of materials and equipment is yet to be fully realised. A spike in the price of oil quickly led to a sharp increase in the cost of delivered fuels in Ireland, which will have a knock-on impact on the operation of machinery and transport of goods across the country.

1.2.2 The evolution of project costs

The cost of a wind farm can be represented as the levelised cost of electricity (LCOE). This metric is a measure of the overall cost per MWh of generation over a project's lifetime, and can be calculated by adding up all costs, from financing through construction, operation, and decommission, and dividing by the total electricity produced.[18]

The average LCOE of onshore wind farms globally has fallen by two thirds since 2010, and has been the lowest of any generation technology since 2020.[19] This fall, from 88 to 30 €/MWh in a decade and a half, has been driven by a continual progression of technology and expertise, decreasing perceived risk, and an adoption in emerging markets with lower development costs.

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[17] **Wind sector challenges are blowing over**, Ember

[18] The LCOE offers a metric with which to directly compare the development costs of renewable technologies. However, it is not always representative of the holistic 'system cost' of integrating projects into a power system, which can introduce additional costs, for example, from a need to reinforce the network. These can be accounted for in a metric known as the 'enhanced LCOE', or 'LCOE+'. However, if considering only costs, this augmented metric does not represent the actual impact on the cost to operate the system, as it does not account for savings offered through lower wholesale power prices, and on other tariff components. We have explored the overall costs and savings conferred to consumers by Irish renewables in ***Good for your Pocket***.

[19] **Renewable Power Generation Costs in 2025**, International Renewable Energy Agency (IRENA)

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A similar trend has been seen in Europe, with onshore wind LCOEs falling by 68% between 2010 and 2021,[20] though costs have since plateaued due to macroeconomic volatility and the rising cost of commodities. The cost of wind turbines across Europe has increased by around 10% since 2021, and the cost of financing increased by almost a third between 2023 and 2025.

The LCOE, as a representation of the cost per MWh of renewable power, has a direct impact on the costs (or savings) conferred to consumers to support wind farms, in markets where support schemes are available.[21] The average auction clearing price for onshore wind across Europe increased from 58 to 79 €/MWh between 2021 and 2024.

In Ireland, consumers have contributed to the development costs of wind farms through three iterations of national support schemes.

Wind farms supported by contracts issued through REFIT 1 and REFIT 2, which closed to applicants after 2009 and 2015 respectively, currently receive payments made at a minimum of 87 €/MWh.[22] REFIT contracts are one-way in nature, with the projects retaining any upside during periods of high prices, are fully indexed to the Irish Consumer Price Index (CPI), with their value increasing over time in line with inflation, and include measures to offset the cost of balancing their output when forecast errors arise.[23]

Five years later, in 2020, the RESS 1 auction cleared at an average nominal price of 75 €/MWh for wind,[24] despite the two-way nature of available contracts, and the lack of indexation or measures to address potential balancing costs.[25]

Since this first auction however, sustained macroeconomic volatility has contributed to a rise in the LCOE of onshore wind,[26] and the resulting contract prices of successful projects. The RESS 2 auction, held in 2022, cleared at an average nominal price of 98 €/MWh for wind, despite no major adjustments being made to the terms and conditions of the auction.[27]

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[20] **European Electricity Review 2025**, Ember

[21] Although LCOEs and support contract prices are strongly coupled, they are not directly comparable as the duration of support does not typically cover the full economic life of a wind farm, and the design of contracts can include specific terms that diverge from the definition of LCOE (such as the treatment of inflation).

[22] **Reference Prices for REFIT Schemes 2026**, DCEE

[23] Under a REFIT 1 contract, a project will receive a 'balancing payment', which is indexed to CPI, for every MWh of generation. These payments are additional to those received under the one-way CfD, with a strike price set by a technology-specific 'reference price', also indexed to CPI. The terms of REFIT 2 differ in that a nominal 9.9 €/MWh balancing payment is added to the technology-specific, and CPI-indexed, reference price to make up the strike price of each project. If the market payment exceeds the reference price, then some or all of the balancing payment is held back from the project. The market payment in each support round consists of the lower of the day-ahead market price, and an 80:20 blend (70:30 for wind farms under 5 MW) of the day-ahead price and the imbalance price in the balancing market (BM).

[24] **Renewable Electricity Support Scheme (RESS)**, EirGrid

[25] **RESS 1 Terms and Conditions**, DCEE

[26] Other factors, such as delays to infrastructure projects including the North South Interconnector, may have also contributed to rising development costs.

[27] **RESS 2 Terms and Conditions**, DCEE

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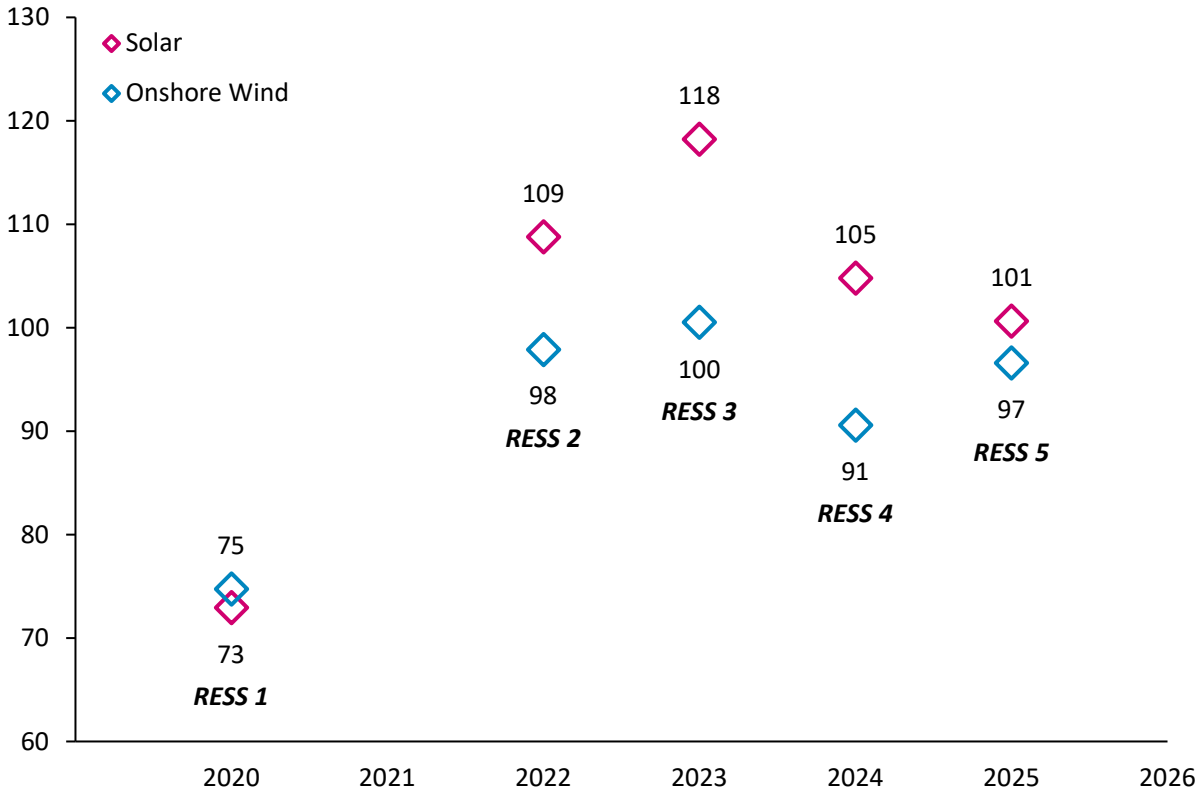
Government took steps to reduce clearing prices for onshore auctions from RESS 3 onwards, including partial indexation of contracts, and the implementation of the Unrealised Available Energy Compensation (UAEC) mechanism, which remunerates projects for energy lost to oversupply,[28] and curtailment.[29] Despite the introduction of these measures, contract prices for wind increased to an average of 100 €/MWh in 2023's RESS 3 auction.

Although such decisions are not typically made public, industry data suggests that a number of renewable projects contracted through RESS auctions, particularly RESS 1, have since terminated their contracts in favour of pursuing corporate PPAs.

Figure 5 below presents the average contract prices of successful projects by technology for each onshore RESS auction to date.[30]

Figure 5: Average contract price of projects successful in RESS auctions, €/MWh, nominal



[28] 'Oversupply' refers to dispatch down (the loss of potential generation) at the day-ahead stage, resulting from an excess of available renewable generation relative to demand.

[29] 'Curtailment' refers to dispatch down resulting from a need to maintain operational constraints at the system level, such as the system non-synchronous penetration (SNSP) limit.

[30] The values presented have been aligned with those published after each auction, and therefore may not reflect the average contracted prices of realised projects due to any subsequent terminations.

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1.2.3 The outlook for project costs

Despite the increasing volatility observed in development costs, the central view of our in-house projections considers the cost of wind farms to decrease over the remainder of the decade. This projection has been built up from analysis of a wide range of market intelligence and macroeconomic forecasts, though uncertainty remains as to how development costs, both in Ireland and across Europe, will play out over the coming years.

Table 1 below presents the key assumptions underpinning our 2030 outlook for levelised costs, including our view of:

- **Capital expenditure (CAPEX)**: The upfront funds used by a developer to design, build and commission a project. CAPEX includes a broad range of upfront costs, including: the manufacture, transport and assembly of turbines; the 'balance of plant', which includes site preparation, civil works, foundations and internal electrical infrastructure; the initial cost of the grid connection; and development expenditure (DEVEX), which comprises the cost of surveys and applications, legal spend, and the cost of running the development team itself.
- **Fixed costs:** The recurring costs of operating a wind farm that do not change with the volume of generation produced, typically measured on a 'per kilowatt (kW)' basis. These include the cost of servicing and maintaining the project, known as 'fixed operations and maintenance', or 'FOM', which includes land leases, insurance and 'commercial rates', taxes paid to local authorities. An ongoing charge to connect to and utilise the Irish power grid, the Transmission Use of System (TUoS) charge, is also typically considered under fixed costs.[31]
- **Variable costs:** The recurring costs of operation that are incurred for each MWh of power generated. These costs include 'variable operations and maintenance', or 'VOM', incurred due to wear, and the cost of balancing generation output when forecast errors arise. Variable and fixed costs are together known as 'operating expenditure (OPEX)'.
- **Weighted average cost of capital (WACC):** The overall cost of financing the project, including payments made to all sources of funding. The WACC itself is built up from the 'cost of debt', the interest rate paid on borrowed funds such as loans or bonds, and the 'cost of equity', the minimum return on investment expected by investors. The ratio of debt to equity raised to finance the project is known as the 'gearing'; a gearing of 60% means that 60% of the project has been financed through debt, and 40% through equity.

The costs in Table 1 correspond to a representative, or 'archetypal', 100 MW project, backed by a RESS contract and commissioned in 2030. Within our cost projection for this archetypal project, CAPEX makes up 27% of the LCOE, fixed costs 24%, variable costs 6%, and WACC 42%.

A more detailed breakdown is provided in Appendix B, including high-level sources for each line item.

[31] Some costs typically referred to as 'fixed', including TUoS and commercial rates, can be subject to change over time. They do, however, not vary with the generation output of the wind farm.

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Table 1: Key cost assumptions for an archetypal onshore wind project in Ireland

Levelised Cost of Onshore Wind	Units	2030
Costs & Charges		
CAPEX	*€/kW*	1,820
FOM	*€/kW per year*	44
TUoS	*€/kW per year*	9
VOM	*€/MWh*	5
Financing		
WACC (real, pre-tax)	*%*	7.5%
Economic life	*Years*	30
Generation Volumes		
Available energy	*%*	36%
Outturn generation	*%*	30%
Oversupply	*%*	6%
Curtailment	*%*	2%
Constraint[32]	*%*	9%
LCOE		
Levelised cost[33]	*€/MWh*	84

[32] 'Constraint' refers to dispatch down induced by congestion on the transmission and distribution networks.

[33] A wind farm with a levelised cost of 84 €/MWh may not necessarily need to bid into a RESS auction at 84 €/MWh to recover its costs, due to the specifics of RESS contract design that are not typically captured within the LCOE metric, such as contract indexation and tenor (including 'merchant tail revenues' received after contract expiry) and compensation for different forms of dispatch down.

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1.2.4 Policy solutions to lower costs

Despite Ireland's relative success in delivering wind power at scale, developers have typically had to tackle multiple hurdles throughout the realisation of their projects, particularly when it comes to securing planning permission and a grid connection.

However, the last few years have seen a series of positive developments made in these areas, through legislation at both national and EU levels.

The third iteration of the Renewable Energy Directive (RED III), passed by the EU in 2023,[34] and transposed into Irish law in 2025.[35] RED III brought with it broad provisions to accelerate planning and permitting for renewable energy projects, including mandatory decision timelines, though the ultimate impact of this directive is still to be seen. The decision to quash the refusal from An Coimisiún Pleanála, Ireland's national planning body, of planning permission for the Coolglass Wind Farm was upheld by the Irish Supreme Court in 2026. The ruling concluded that public bodies must take real consideration of national climate objectives in their decision making.[36]

Two batches of grid connection applications have now proceeded through 'Electricity Connection Policy – Generation and System Services (ECP-GSS)', a new grid offer process adopted following legislation in 2024.[37] The introduction of ECP-GSS brought timelines in line with the ruling of RED III, including bi-annual batch processing, twice the rate of the previous regime.

Although these developments, if successfully implemented, would actively reduce project risk and lower development costs for Irish wind, difficulties, inefficiencies and risks would remain. We have identified a series of policies, each within the control of the Irish Government or relevant State agencies, that could help to address remaining development challenges, and lower costs:

Policies in the fields of planning and grid:

- **Grid connection costs:** To qualify for a grid connection, an Irish wind farm must meet a series of minimum requirements set by EirGrid, the transmission system operator (TSO), and Electricity Supply Board (ESB) Networks, the transmission asset owner (TAO), distribution system operator (DSO) and distribution asset owner (DAO). These requirements have been noted by industry as being 'over-specified' in nature, or going beyond the fundamental, physical requirements of the system, as well as having steadily increased over the last decade.[38] A revised set of streamlined requirements, optimised to meet the physical requirements of the Irish power system, would reduce the capital cost of Irish wind without sacrificing safety or reliability.

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[34] **Directive (EU) 2023/2413**, EU

[35] **Statutory Instrument No. 426 of 2025**, Department of Housing, Local Government and Heritage

[36] **Coolglass Wind Farm Limited v An Bord Pleanála**, Irish Courts Service

[37] **ECP-GSS Decision Paper (CRU2024101)**, CRU

[38] Examples noted by industry contacts include a requirement for double busbars as a minimum, 'over-specified' circuit ratings and grid transformers (separate from 'future proofing'), increasingly constrained land rights requirements, late-stage delays and specification changes, and the avoidance of cables crossing public roads forcing routes to be redrawn and extended.

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- **Fixed grid charges:** The power generated by an Irish wind farm is transported across the country through the transmission network. The cost of operating, maintaining, and upgrading the network is recovered through TUoS charges, levied on both generators and consumers.[39] Although these charges are calculated and 'locked in' for a year at a time, generators remain exposed to changes in these tariffs over time, and the cost uncertainty that this brings. The same is true for the Transmission Loss Adjustment Factor (TLAF), which is applied to the revenues paid to generators to account for the loss of generated power as it flows through the network to areas of demand.[40] As with TUoS charges, TLAFs are subject to change each year. If these charges were to be locked in for each wind farm from the date of their final investment decision (even if the overall amount they pay is unchanged), then this increased visibility of lifetime costs could lower project risk and reduce the cost of financing.

Policies to adjust the terms and conditions of RESS:

- **Contract tenor of RESS:** Securing a support contract through RESS actively reduces the development cost of a wind farm. The revenue certainty offered by the guaranteed strike price reduces the perceived risk of investing in the project, which can lower both the cost of debt and the cost of equity, and can increase gearing. Offering longer support contracts through RESS, beyond the 15 years of support available today,[41] would provide greater revenue certainty to lenders and investors, further reducing the cost of financing. ORESS,[42] the latest rounds of the CfD scheme in Great Britain (GB),[43] and the 'EEG' scheme in Germany,[44] each provide successful projects with 20-year contracts. Analogous savings could also be realised by projects supported by corporate PPAs, if contract tenors were to increase.

- **Contract indexation in RESS:** Although the design of RESS offers more revenue certainty than an unsupported, or 'merchant', wind farm could expect from the power market, the value of each contract remains exposed to macroeconomic risk. Since RESS 3, contracts have included partial indexation, with 30% of their value increasing in line with inflation. Although this mechanism tempers inflationary risk for projects, 70% of the contracted value remains exposed to potential erosion over time. If the rapid inflation seen in recent years was to repeat, the value of RESS contracts in real terms could decrease by 7% over 12 months, even with the included partial indexation. Providing full indexation, 100% of the contract value, would abate this risk for the duration of support, lowering the cost of financing.

[39] **Statement of Charges 2025/26**, EirGrid

[40] **Approved TLAFs 2025/26**, EirGrid

[41] The support duration can increase up to 16.5 years if a project achieves commercial operation early, and can fall to a minimum of 14 years if delayed.

[42] **ORESS 2.1 Terms and Conditions**, DCEE

[43] **CfD Allocation Round 7 (AR7) Terms and Conditions**, Department for Energy Security and Net Zero (DESNZ)

[44] **Erneuerbare Energien Gesetz (EEG) 2021**, European Commission

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Policies to address dispatch down

- **Hybrid connections:** The Commission for Regulation of Utilities (CRU), the independent regulator for the Irish energy industry, published their decision paper on the sharing of grid connections by multiple generation or energy storage assets in April 2026.[45] Although the regulation introduces the option for 'co-location', or 'hybrid connections', multiple barriers remain to efficient and cost-optimal hybrid sites, which limit their value and discourage their adoption. Although a wind farm and energy storage asset can now share a grid connection, known as 'maximum export capacity (MEC) sharing', the current rules do not permit the storage asset to fill directly from the output of the wind farm, known as 'energy sharing' or 'cross-charging'. This caveat prevents effective optimisation of the site for avoidance of 'dispatch down', the loss of potential wind generation due to an overall excess relative to demand, or constraints on the system or network. Removing this caveat would allow for hybrid connections to become a viable tool for mitigating dispatch down, offering value beyond the sharing of grid connection costs.

- **Adoption of LDES:** The development of energy storage projects in Ireland can reduce dispatch down beyond their use in hybrid projects. Market signals naturally incentivise storage assets to charge when renewable output is high (and prices are low) and discharge when the renewable resource dies down (and prices rise). This dispatch behaviour actively reduces both oversupply and constraint, by shifting generation from hours of excess to hours of deficit. EirGrid and its Northern Irish counterpart, System Operator Northern Ireland (SONI), include the deployment of long-duration energy storage (LDES) projects in *Shaping our Electricity Future*,[46] which outlines a roadmap to achieving Ireland's 2030 targets, and *Tomorrow's Energy Scenarios*,[47] which provides a range of long-term outlooks for the Single Electricity Market (SEM), the combined set of power market arrangements across both jurisdictions. Supporting the development of LDES capacities as laid out in these documents would reduce the exposure of Irish wind farms to dispatch down, allowing more of their potential generation to reach consumers, and lowering the cost of each MWh delivered.

- **Further mitigation of dispatch down:** Dispatch down has been a fundamental issue for wind farms across Ireland, and EirGrid project the portion of curtailed power to increase sharply over the coming years.[48] As well as the effective implementation of hybrid sites and the adoption of LDES, there are multiple levers available to reduce dispatch down in Ireland, including dynamic line rating, demand-side flexibility, electrofuels, and interconnection. Although some of these options have begun to see success in Ireland,[49] continued investment in these technology and policy solutions could help to achieve a sustained reduction in dispatch down and moderate the loss of usable power from Ireland's wind fleet.

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[45] **Sharing of MEC (CRU202643)**, CRU

[46] **Shaping our Electricity Future v1.1**, EirGrid and SONI

[47] **Tomorrow's Energy Scenarios 2023**, EirGrid and SONI

[48] **Enduring Connection Policy (ECP) Constraint Forecast Reports**, EirGrid

[49] **ESB Networks deploys technology on 220 kV lines to unlock additional network capacity**, ESB Networks

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In addition to the seven prospective policy actions listed above, we have explored an eighth policy that has recently been actioned in the design of the upcoming RESS 6 auction.[50] This change in policy direction from prior auctions represents a material benefit to the development costs of specific projects across Ireland, which could in turn be conferred to consumers through lower contract prices for RESS 6 or future auctions:

- **Repowering of existing sites:** Once a wind farm reaches the end of its technical life, and its turbines are decommissioned, the site can be re-used for a new wind project, a process known as 'repowering'. In Ireland, older wind farms were typically built in areas with the best resource potential, i.e., sites were selected in part by how windy they were. Repowering of these older sites offers the opportunity to deploy newer, more efficient turbines in prime locations across Ireland. Beyond the available wind resource, repowering of an existing site typically brings lower costs across project financing and development than building on a new, 'greenfield' site, as the project can make use of existing infrastructure such as the grid connection. However, in the first five onshore auctions, a repowered project could only qualify for a RESS contract if its generation potential was at least 50% greater than the previous wind farm that stood on the site.[51] Developers are economically incentivised to maximise yields, but had been unable to repower projects for which this minimum was not achievable. The terms and conditions for RESS 6 have removed this requirement, superseding it with one for at least 300 €/kW of investment in the project, and a 20-year gap since the start of any prior support through AER or REFIT.

[50] **RESS 6 Terms and Conditions**, DCEE

[51] **RESS 5 Terms and Conditions**, DCEE

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1.3 Our study

In 2020, Everoze released *Saving Money*,[52] a report that explored a range of policy levers to reduce the cost of Irish wind. Their study, commissioned by Wind Energy Ireland, then the Irish Wind Energy Association (IWEA), showed that significant savings could be made if development hurdles in planning, grid and tax reform could be addressed, and that higher costs could result if restrictions in these areas were imposed.

Since the publication of this report, a subset of the policies investigated in the analysis have been implemented, and as highlighted above, the outlook for project costs has undergone fundamental change. Despite today's support scheme providing additional certainty for developers, the macroeconomic backdrop has resulted in a steady increase in the cost of Irish wind power. Capital costs are higher, and increasing uncertainty around inflation and dispatch down has compounded financing costs. With the 'cost-of-living crisis' remaining top of mind for many, and the inherent volatility in commodity prices beyond Ireland's control laid bare for the second time this decade, cutting the cost of Ireland's homegrown power sources is more important than ever.

In 2025, we published *Good for your Pocket*,[53] which showed the savings that wind and solar farms had unlocked on the power bills of Irish consumers since the start of the millennium, and the protection that these savings had offered during times of spiralling costs. We then turned our attention forward and assessed the continued dividends that the renewable transition could offer by 2030. Our finding, an annual saving of more than €600 million, was conservatively projected using the cost of developing a wind farm today. It would increase if these costs were to fall.

In this study, we have brought the analysis and approach of *Saving Money* up to date and explored a new suite of seven potential policies that could reduce development costs for Irish wind,[54] and ultimately, increase the net savings they could offer to consumers. An eighth policy, the removal of barriers to the participation of repowered projects in RESS, was addressed in the terms of RESS 6 during our analysis.

We first explored the impact of each of the policies described in Section 1.2.4 on the LCOEs of future wind projects, before translating these reductions into corresponding bid prices made into an indicative future RESS auction, and finally into savings received by consumers on their power bills.

We have assumed that recent policy decisions and regulations, such as the planning and grid permitting timelines mandated under RED III, are successfully implemented by the 2030 commission of our archetypal project, and that no major changes are made to other existing policies or contract terms, such as the removal of the UAEC mechanism from RESS.

Our analysis has centred on an archetypal, 100 MW onshore wind farm delivered in 2030 with the support of a RESS contract, though we highlight the value offered to onshore wind, offshore wind, and solar farms delivered through different routes-to-market.

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[52] **Saving Money**, Everoze

[53] **Good for your Pocket**, Baringa

[54] Throughout this report we refer to the overall 'per MWh' cost of an Irish wind farm interchangeably as 'LCOE' and 'development cost'.

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Throughout our study we have kept in contact with a panel of independent industry experts, giving them opportunity to provide feedback and challenge on our assumptions and methodology, and provide in-depth insight and data from the day-to-day processes of developing real-world projects.[55]

The remainder of our report is structured as follows:

- **Section 2** presents the impact of the eight policies, both individually and in aggregate.
- **Section 3** provides an overview of the methodology underpinning our results.
- **Section 4** summarises our key findings and their implications.
- **Appendix A** provides additional detail on the tooling used in our study.
- **Appendix B** presents our quantitative assumptions and results.
- **Appendix C** introduces Baringa, and some of our other publications.

In Section 2.1 we comment on the overall impact of the eight policy levers on the LCOE of a typical Irish wind farm, including consideration of the 'diminishing returns' of implementing multiple policies each designed to lower costs. In Section 2.2 we then explore the relative benefits attainable from each of the policies when implemented in isolation.

In the remainder of the section, we translate the combined LCOE impact into RESS contract prices (Section 2.3), and the savings realised on consumer bills (Section 2.4), and comment on the value to other renewable technologies (Section 2.5).

All monetary values are presented in real 1st of January 2026 euros (EUR) unless otherwise stated, with the exception of RESS contract prices, which are presented as published after each auction. We have assumed a long-term inflation rate of 2%, aligned with the European Central Bank.[56]

[55] Although we have drawn on real-world datapoints from our panel of industry experts, we have ultimately remained objective and independent in our methodology and interpretation of findings.

[56] **Two per cent inflation target**, European Central Bank

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2 Results and implications

2.1 The overall impact on project costs

2.1.1 A greenfield site

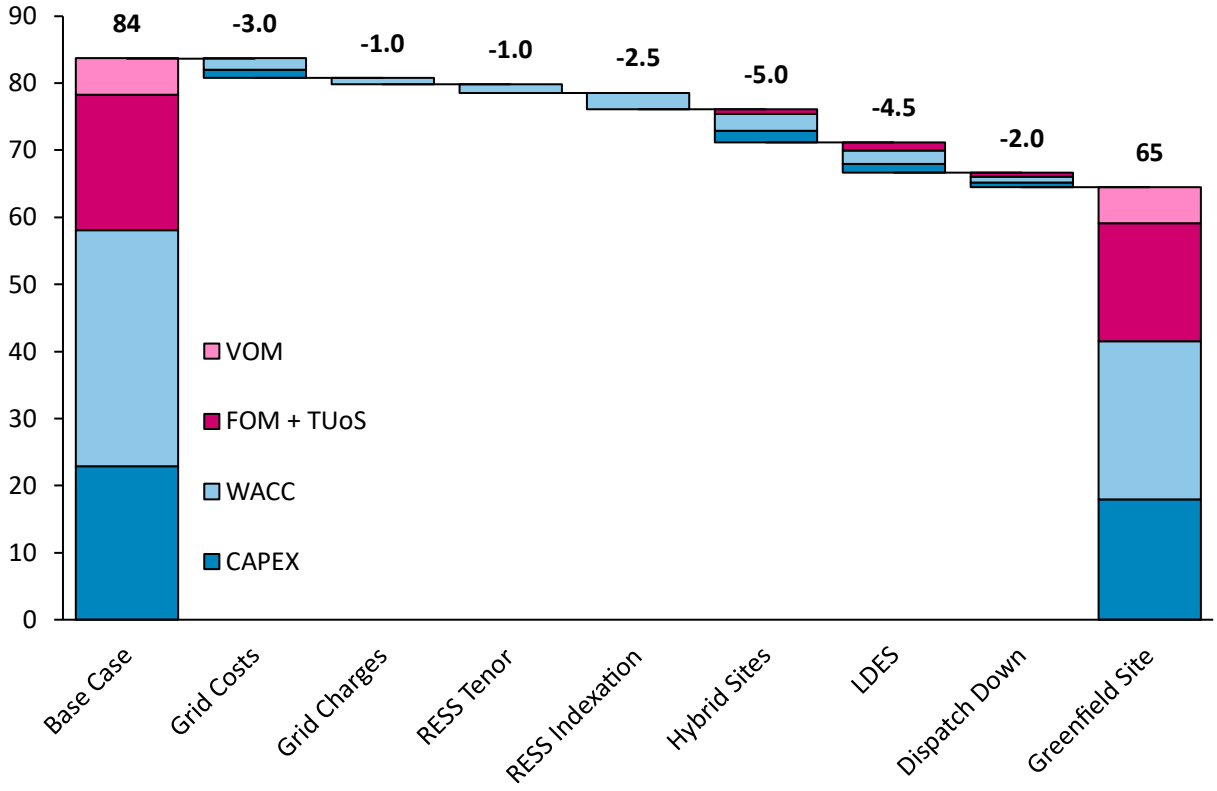
Our analysis suggests that the development cost of a typical Irish wind farm could be reduced by almost 23% if seven enabling policies were to be actioned by policymakers.

These savings would be realised across the capital, financing, and fixed costs of wind projects through the optimising and firming of grid costs, the derisking of RESS contracts, and measures to mitigate renewable power being lost to dispatch down.

The reduction in project LCOEs, presented below in Figure 6, represents the potential impact of seven policy levers applicable to a greenfield wind project, backed by RESS, and commissioned in Ireland in 2030.

Some of these policy levers, such as the adjustment to the terms and conditions of RESS, could be actioned with a signature at the bottom of a document. Others, such as the implementation of measures to support LDES, and otherwise moderate the risk of dispatch down, would require sustained effort in designing, consulting on, and implementing policy. The sooner these investments are made, the greater the dividends attainable from a lower-cost portfolio of wind farms.

Figure 6: Cumulative LCOE impact of explored policies on a greenfield Irish wind project, €/MWh



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The greatest savings could be realised by a combination of measures to address dispatch down, including hybrid sites, LDES, and other policy and technology solutions. Reducing the overall portion of lost wind power to 5% through a combination of policies, down from the 17% we project for the lifetime of a project commissioned in 2030, could lower the levelised cost of Irish wind by a cumulative 10 €/MWh, almost 12%.[57]

Our analysis suggests that the removal of barriers to hybrid sites could offer the largest potential saving of the policies explored; more than 5 €/MWh, or 6%, could be avoided by the flexibility to address dispatch down, and the sharing of grid costs. In this case, industry is enabled to invest further in renewable projects, without State support for the co-located energy storage assets.[58]

Beyond policies to address dispatch down, the streamlining of grid requirements for wind farms could reduce development costs by 3 €/MWh (almost 4%), the 'locking in' of grid charges through the life of the project could save around 1 €/MWh (just over 1%), and the adjustment of RESS terms and conditions could offer savings of a further 4 €/MWh (around 5%).

Although our findings suggest that the adjustment of terms for future RESS contracts would have a relatively small impact on the cost of developing Irish wind, around 5% across two policies, the use of LCOE as a metric obscures the impact on bid prices made into RESS auctions, and the ultimate costs and savings conferred to consumers. Our analysis of RESS prices and consumer costs is presented in Sections 2.3 and 2.4 respectively.

The overall saving presented above factors in the diminishing returns of implementing multiple policies aimed at reducing the cost of wind.

[57] The bars labelled 'Dispatch Down' in Figure 6 represent the residual savings possible under the assumption that both the 'Hybrid Sites' and 'LDES' policies have already been implemented. Savings to the LCOE unlocked by a reduction in dispatch down are presented as manifesting across 'CAPEX', 'WACC' and 'FOM + TUoS' as each decrease on a 'per MWh' basis if the generation output of the wind farm rises.

[58] The continued adoption of energy storage technologies also offers fundamental value for the Irish power system, and consumers, as we have quantified in our ***Store, Respond and Save*** and ***Game Changer*** studies, each published by Energy Storage Ireland.

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2.1.2 A repowered site

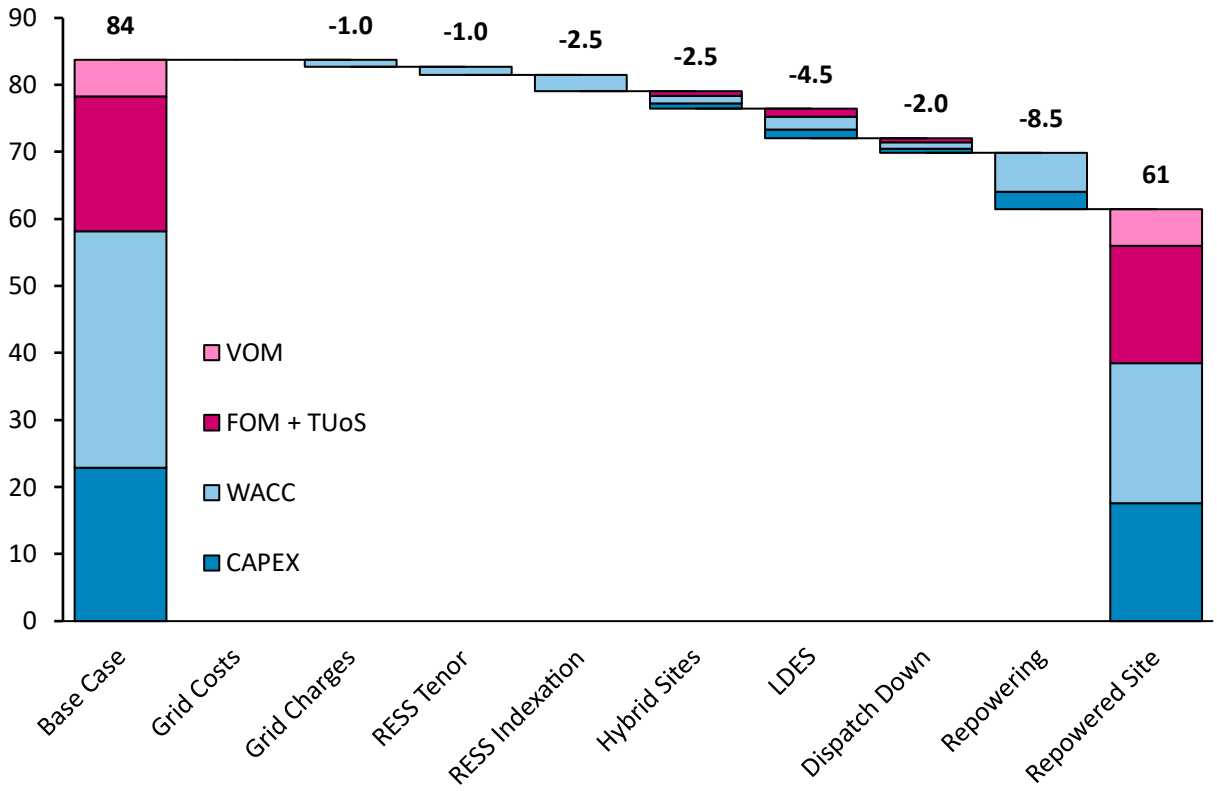
The removal of the barrier to repowered projects qualifying for RESS support could offer further savings for applicable sites – totalling 27% when combined with the seven suggested policies.

Our analysis suggests that, by making use of existing infrastructure, a repowered site could benefit from reduced costs across the upfront capital investment and the cost of financing, lowering the LCOE of a wind project by more than 11% when quantified in isolation.

This policy, actioned through a change of terms and conditions for the upcoming RESS 6 auction, represents the largest saving to project LCOEs offered by a single policy in our analysis, though its realisation will be project-specific, requiring access to viable existing sites to repower with the latest technology.

The overall reduction in LCOE in the case of a repowered site is presented below in Figure 7.[59]

Figure 7: Cumulative LCOE impact of explored policies on a repowered Irish wind project, €/MWh



[59] The results presented in Figure 7 assume that savings in grid CAPEX offered by 'Repowering' supersede those available through 'Grid Costs'.

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2.2 The relative impact of individual policies

2.2.1 Grid connection costs

Current situation: EirGrid and ESB Networks have set an 'over-specified' standard for grid connection requirements, beyond the physical requirement of the Irish system.

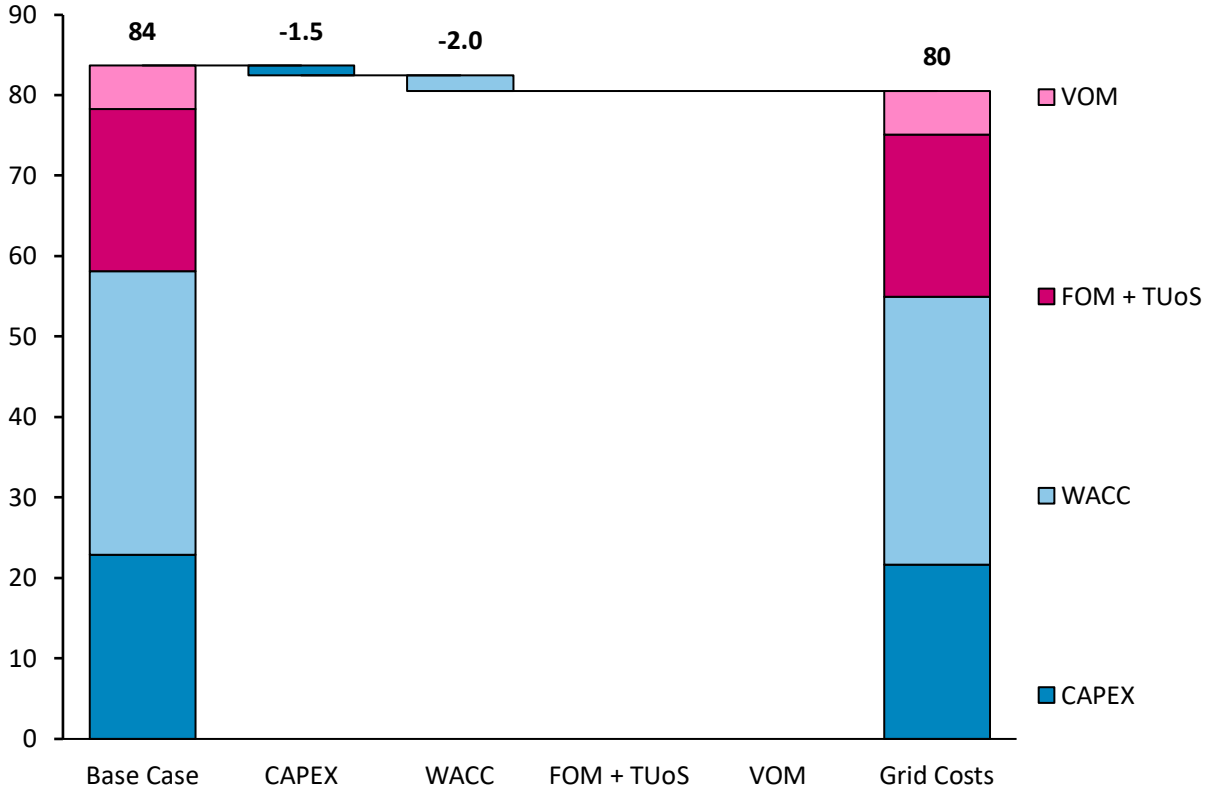
Policy solution: Streamline the requirements to match the fundamental needs of the system, reducing the capital cost of connection infrastructure.

Our analysis and findings: In collaboration with our panel of industry experts, we have estimated the portion of upfront grid CAPEX that could be saved by the streamlining of requirements, across both 'contestable' (privately procured by the project) and 'non-contestable' (paid directly to ESB Networks), as around 100 €/kW.

Our analysis suggests that this measure, a change of development rules for future projects, would lower the CAPEX of a typical wind farm by around 6%, reducing payments made to lenders and investors to cover this upfront cost.

We estimate that this policy could reduce the overall LCOE of Irish wind by just over 3 €/MWh, almost 4%, as presented in Figure 8 below. The presented savings include both the lower cost of infrastructure ('CAPEX'), and the corresponding reduction in the cost of financing it ('WACC').

Figure 8: Impact of optimised grid requirements on the LCOE of Irish wind, €/MWh



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2.2.2 Fixed grid charges

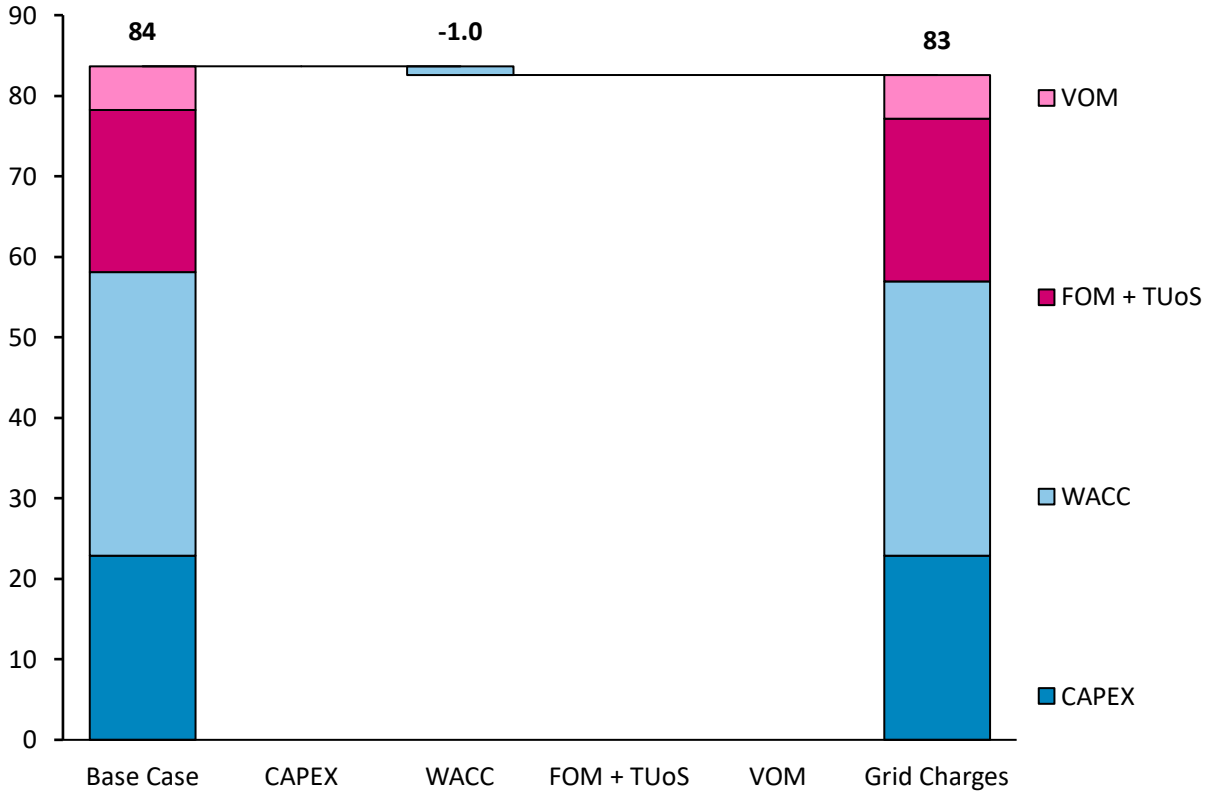
Current situation: Wind farms in Ireland are exposed to changes in TUoS and TLAF across their lifetime, each of which represent potential 'unforeseen' costs.

Policy solution: Lock in TUoS charges and TLAFs for Irish wind farms from the date of their final investment decision to increase cost certainty.

Our analysis and findings: We have estimated the impact of fixing grid charges as a 0.2% reduction in WACC for a typical wind project, based on analysis of the sensitivity of LCOEs to changes to TUoS and TLAF. Our assessment does not consider that wind farms ultimately pay lower TUoS charges, or receive higher TLAFs, instead that the removal of uncertainty in these costs lowers the perceived risk of the projects, and therefore the cost of financing.

This reduction offers savings of around 1 €/MWh on the overall LCOE of a wind farm, or just over 1%, as presented in Figure 9 below.

Figure 9: Impact of fixing grid charges on the LCOE of Irish wind, €/MWh



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2.2.3 Contract tenor of RESS

Current situation: Projects successful in RESS auctions are issued with support contracts covering their first 15 years, before they become exposed to merchant revenues.

Policy solution: Increase the tenor of RESS to 20 years, in line with contracts issued in GB, Germany, and other markets.

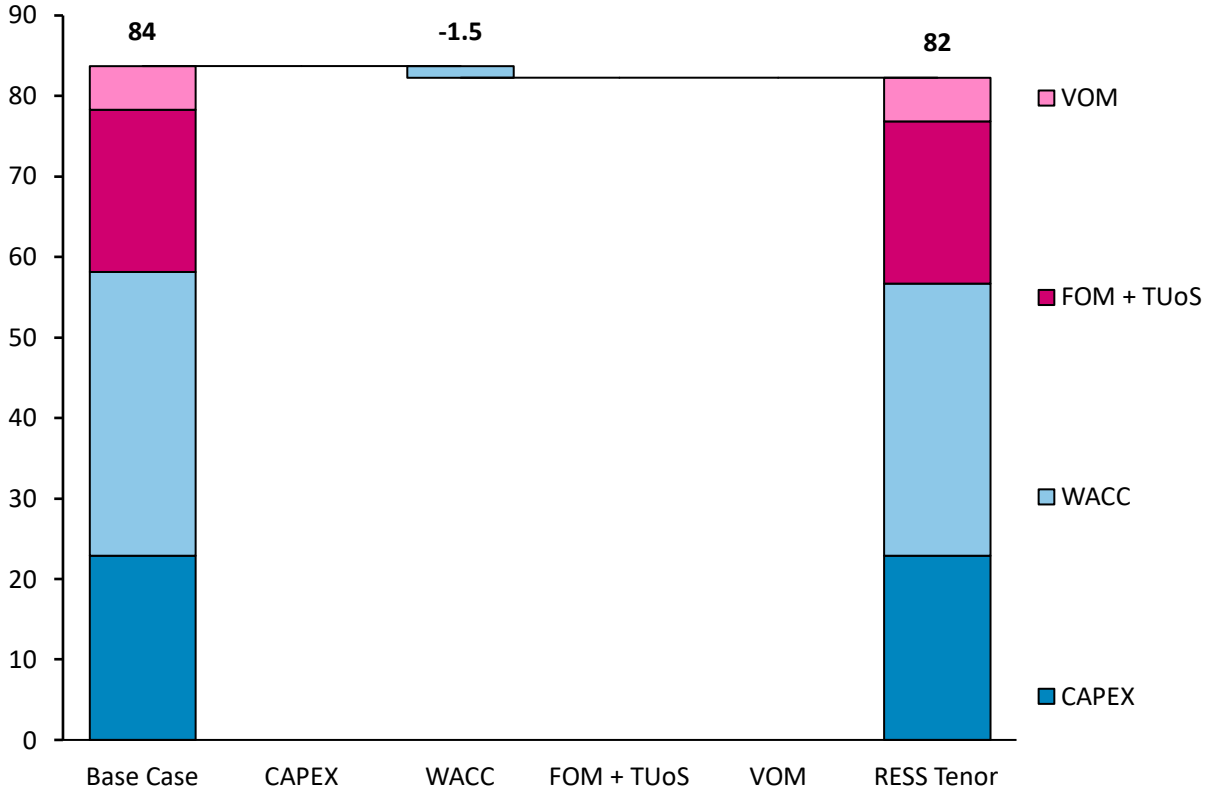
Note on RESS terms: As a policy that directly adjusts the terms of future RESS auctions, changes to contract tenor have an outsized impact on both RESS contract prices and consumer costs, as explored below in Sections 2.3 and 2.4 respectively.

Our analysis and findings: We have calculated the reduction in WACC associated with an extension of support contracts from 15 to 20 years, by considering the overall level of long-term risk for the project in each case. Our analysis suggests that the extended period of revenue certainty would lower project WACC by around 0.25%, and reduce LCOEs by 1.5 €/MWh, almost 2% of the total.

Our analysis also suggests that further extension of RESS contracts would lead to a roughly linear saving in WACC, i.e., a 25-year contract would result in a 0.5% overall reduction in WACC, and a 3.5% saving to the LCOE of a typical Irish wind farm.

Figure 10 below presents the results of our analysis for the 20-year contracts.

Figure 10: Impact of extending the contract tenor of RESS on the LCOE of Irish wind, €/MWh



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2.2.4 Contract indexation in RESS

Current situation: Support contracts issued since RESS 3 have included partial indexation covering 30% of their value, but the other 70% remains exposed to inflationary risk.

Policy solution: Issue fully indexed support contracts in future RESS auction rounds to address the exposure of projects to inflationary risk.

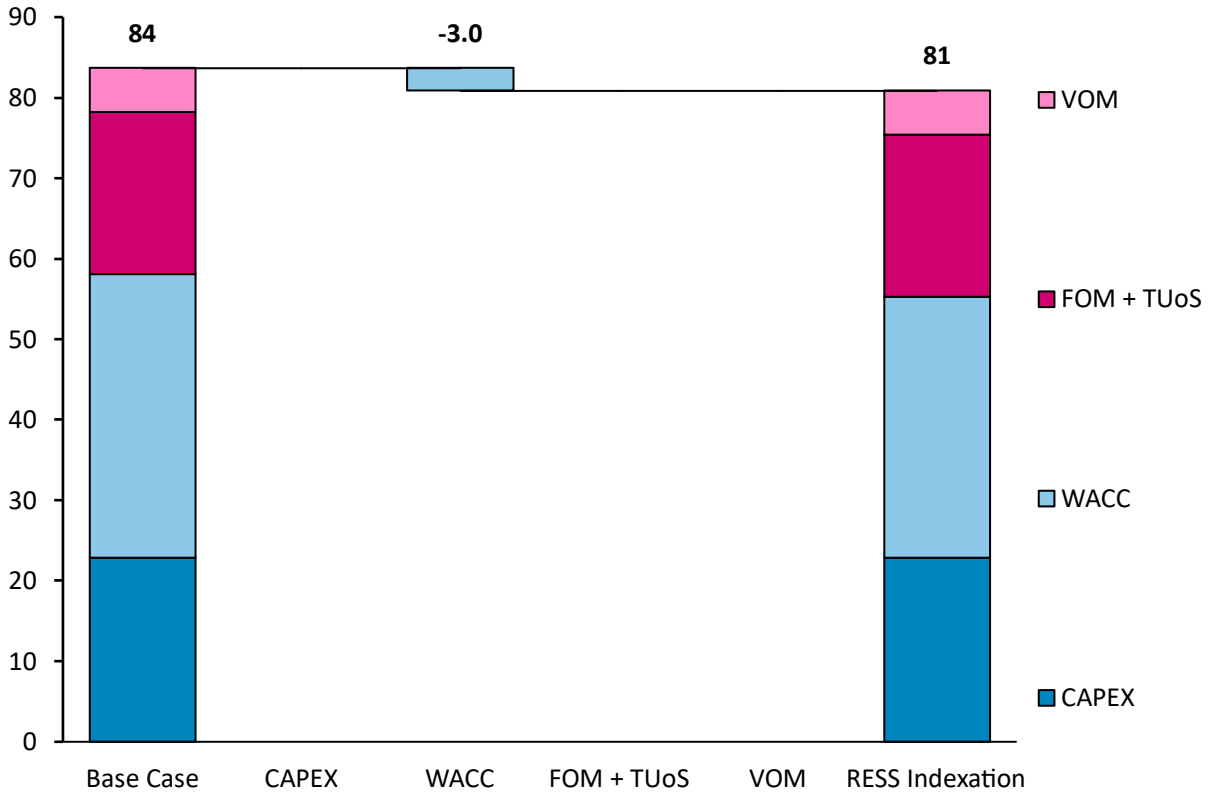
Note on RESS terms: As a policy that directly adjusts the terms of future RESS auctions, changes to contract indexation have an outsized impact on both RESS contract prices and consumer costs, as explored below in Sections 2.3 and 2.4 respectively.

Our analysis and findings: As with the previous policy lever, we have assessed the impact of this policy on the financing cost of projects supported by RESS by calculating the reduction in perceived risk relative to current policy.

We have calibrated the result of our financial analysis to datapoints provided by our panel of industry experts, resulting in a reduction of 0.5% to the WACC of a typical wind project. The inherent risk to short-term revenues, and the recent precedent of rapid inflation, each compound the perceived inflationary risk in the financing of wind projects, resulting in a greater WACC reduction than was calculated for an extended contract tenor.

As presented below in Figure 11, we have calculated the corresponding decrease in LCOE at 3 €/MWh, or around 3.5% of the total.

Figure 11: Impact of full indexation of RESS contracts on the LCOE of Irish wind, €/MWh



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2.2.5 Hybrid connections

Current situation: Although wind projects are permitted to share grid connections with co-located technologies, energy storage assets cannot charge directly from the output of the wind farm.

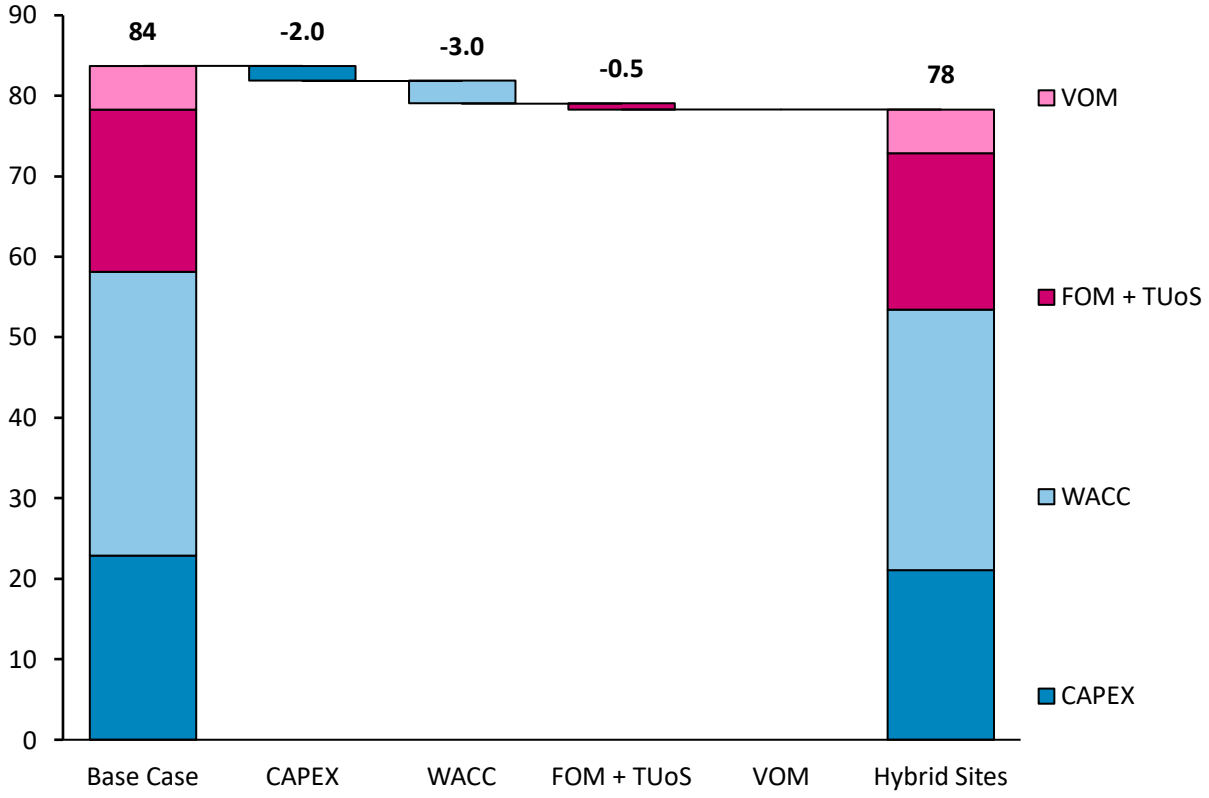
Policy solution: Allow storage assets to charge from co-located wind generation, enabling the overall site to be optimised to reduce dispatch down.

Our analysis and findings: We have quantified the overall savings that a hybrid connection with a battery storage asset could offer to a wind farm, including both reduced dispatch down exposure (from 'cross-charging'), and a sharing of grid connection CAPEX (from 'MEC sharing'). Our findings are presented below in Figure 12, which reflect the cost of the wind farm only.

We have modelled a cost-optimal hybrid arrangement for a 100 MW wind farm using our hourly projections of oversupply and curtailment for a market-average site, our technology cost assumptions for batteries of different sizes and storage durations, and the results of EirGrid's latest constraint analysis.[60] Our findings suggest that a 30 MW, 4-hour battery could reduce the exposure of the wind farm to all forms of dispatch down by around 20%, increasing the output of the project by around 3.5%, and reducing the 'per MWh' CAPEX and fixed costs in proportion.

We have assumed that the cost of the grid connection is split in line with the capacity of assets behind it, in MW, i.e., the battery 'pays for' around a quarter of the cost.

Figure 12: Impact of a hybrid connection with a battery asset on the LCOE of Irish wind, €/MWh



[60] **ECP-2.5 Constraint Reports for Solar and Wind**, EirGrid

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2.2.6 Adoption of LDES

Current situation: LDES is seen by Government, EirGrid and ESB Networks as a key tool in achieving a secure, affordable and decarbonised power sector, but little concrete policy has manifested to date.

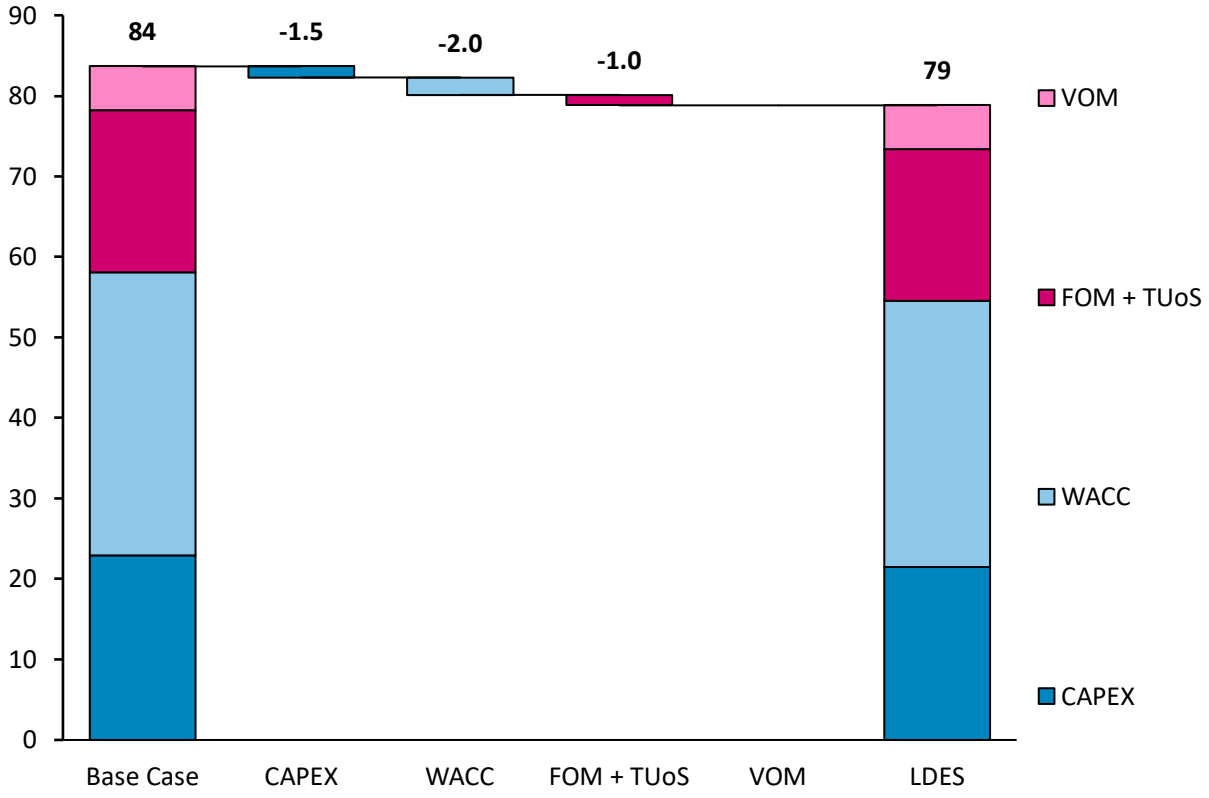
Policy solution: Support the sustained deployment of LDES in line with the capacities targeted in *Shaping our Electricity Future* and *Tomorrow's Energy Scenarios*.

Our analysis and findings: We have assessed the impact of long-duration energy storage (LDES) on the oversupply and constraint of a typical wind farm, and the corresponding decrease in the 'per MWh' cost of delivered renewable power. Our findings are presented in Figure 13 below.

We have used our model of the European power markets to simulate the oversupply of Irish wind farms, with and without the development of LDES projects across the SEM. We have aligned our capacity assumptions with the TSO's *Shaping our Electricity Future* for 6-hour (1,350 MW in Ireland) and 8-hour storage (700 MW in Ireland and 250 MW in Northern Ireland), and *Tomorrow's Energy Scenarios* for 100-hour storage (200 MW in Ireland by 2035, and 400 MW from 2040). Our model suggests that these capacities could reduce the oversupply of Irish wind by around 45%.

We have aligned our assumption for the impact of LDES on constraint with the lower estimate provided in TNEI's report published by Energy Storage Ireland in 2026, which suggested that strategic spatial deployment of LDES could reduce constraint volumes by 30% to 50% across Ireland.[61]

Figure 13: Impact of sustained build of LDES on the LCOE of Irish wind, €/MWh



[61] **Energy Storage Grid Benefits Report**, TNEI

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2.2.7 Further mitigation of dispatch down

Current situation: Dispatch down remains a pervasive risk to the commercial operation of wind farms, with significant uncertainty as to the outlook for oversupply, curtailment, and constraint.

Policy solution: Deliver sustained investment in a range of technology and policy solutions that can collectively address the risk of dispatch down.

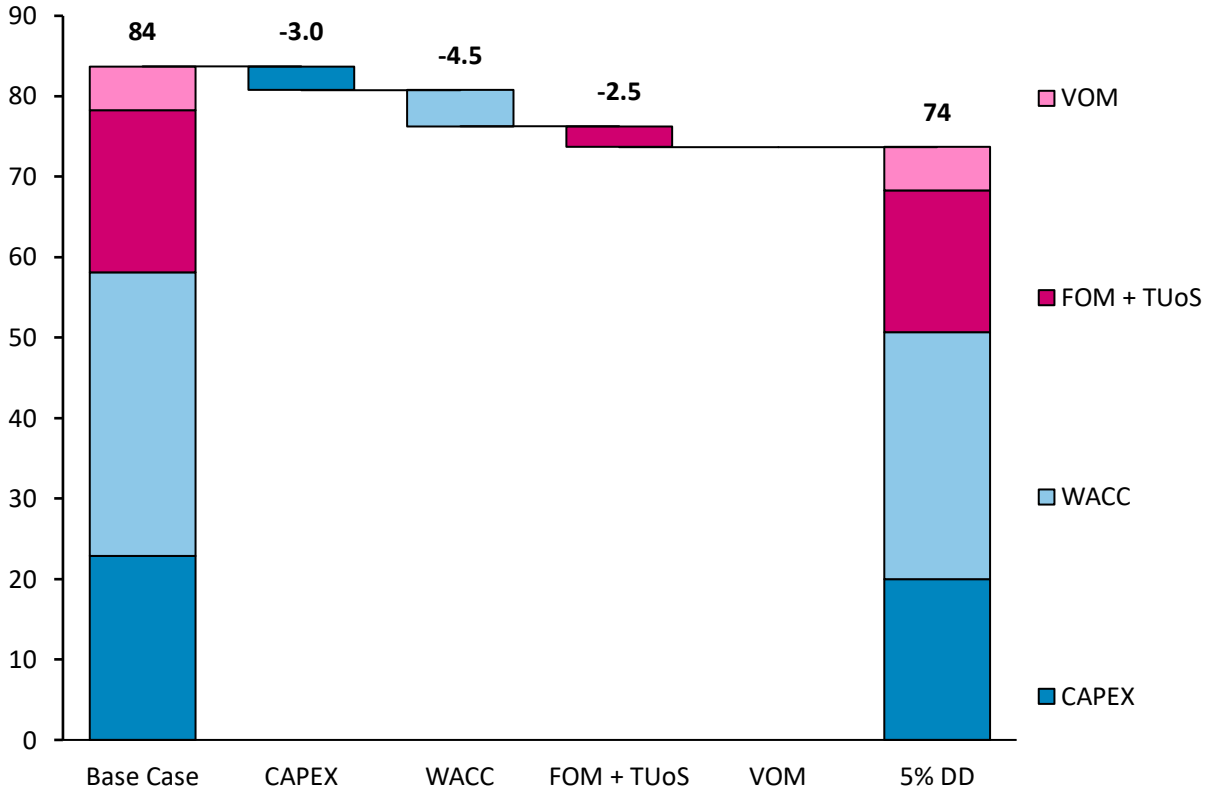
Our analysis and findings: We have calculated the impact of achieving 5% overall dispatch down across the lifetime of an archetypal wind farm, down from the 17% we project.

Our analysis suggests that a sustained mitigation could reduce the LCOE of a typical wind farm by around 10 €/MWh, almost 11% of the total 'per MWh' cost, as presented in Figure 14 below.

A combination of policies and interventions is likely to be required to achieve this outcome, including the use of unconstrained hybrid connections and an optimised deployment of LDES.

The results presented below have been calculated using our central projections for the evolution of oversupply and curtailment over time, with constraint figures from the latest iteration of EirGrid's reports, Enduring Connection Policy (ECP) 2.5.

Figure 14: Overall impact of reducing dispatch down to 5% on the LCOE of Irish wind, €/MWh



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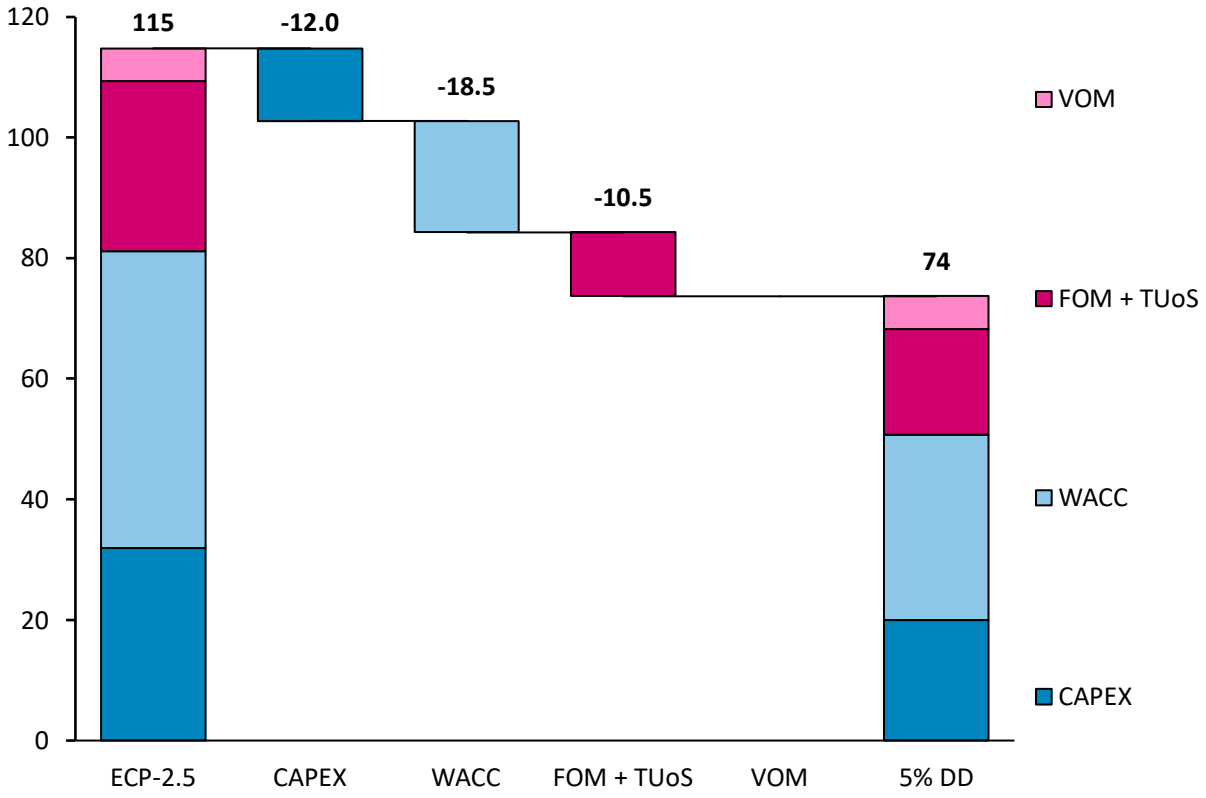
These projections for oversupply and curtailment, though reflective of our central 'Reference Case' view of the Irish market, are relatively modest compared to the TSO view. In addition to constraint, EirGrid also project oversupply and curtailment in their ECP reports, and the update for ECP-2.5 includes oversupply for new-build wind farms rising to almost 30% by 2030, with overall dispatch down as high as 45%.

We have quantified the impact of these projections on the LCOE of the archetypal wind farm, which would rise to 115 €/MWh, as well as the savings that would then be made if measures were taken to reduce the overall dispatch down to an average of 5% from this higher starting point.

The results of this analysis are shown below in Figure 15, and highlight both the scale of the risk that dispatch down could place on the development cost of Irish renewables, and the value of measures designed to address this risk. If this scenario was to manifest, then the mitigating measures highlighted below would become increasingly critical to moderate development costs.

Figure 15: Impact of reducing dispatch down from ECP levels to 5% on the LCOE of wind, €/MWh



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Oversupply can be fundamentally addressed by increasing the 'flexibility' of the system, i.e., shifting demand to, or creating it during, periods of excess renewable generation. Potential technology and policy solutions could include:

- Energy storage of all technologies and durations.
- Demand-side flexibility, i.e., consumers that can actively shift their load in response to price, including the demand of electric vehicles (EVs) and heat pumps.
- Vehicle-to-grid (V2G) technologies, which would allow for EVs to act as a form of energy storage for the system.
- Electrofuels, or 'power-to-X' (P2X), such as hydrogen and 'green ammonia', which can act as forms of long-term, or even seasonal, storage for the power market.
- Interconnection between markets, which can allow for exports of excess renewable power when traded efficiently.
- The continued uptake of price-responsive tariffs for consumers, enabled by smart meters.

Curtailment can be addressed by the deployment of technologies that can provide zero-carbon system services,[62] such as:

- Battery storage, which can provide fast-acting 'operating reserve' services.
- Synchronous condensers, which can provide 'inertia' and 'reactive power' services.
- LDES and decarbonised dispatchable generation, which can each provide 'replacement reserve' and 'ramping' services.

Constraint can be addressed by increasing the maximum transmission of power across the network or reducing the volumes flowing during periods of congestion. Potential technology and policy solutions could include:

- Strategic spatial deployment of energy storage of all technologies and durations, i.e., placing these assets in congested areas of the network to 'smooth out' the profile of wind generation crossing transmission constraints over time.
- Strategic deployment of demand-side flexibility.
- Dynamic line rating (DLR), a technology that adjusts the ratings of transmission and distribution lines to account for real-time weather conditions, allowing for more power to be transmitted during periods of cooler weather or precipitation.

Where fundamental, physical solutions can take time to be realised, policy measures, such as a cap on the dispatch down exposure of projects, could offer interim solutions to distribute the risk and lower development costs.

[62] 'System services' are a set of 'tools' used by EirGrid and SONI to keep the SEM power system stable. The current procurement framework, titled 'Delivering a Secure Sustainable Electricity System (DS3)', includes up to 14 services, though two, Dynamic Reactive Response (DRR) and Fast Post-Fault Active Power Recovery (FPFAPR) are not currently procured. These arrangements are expected to be superseded in 2027 by a new competitive regime, holistically referred to as the 'Future Arrangements for System Services (FASS)'.

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2.2.8 Repowering of existing sites

Current situation: A repowered project could previously only enter into a RESS auction if the new turbines could achieve an annual yield increase of at least 50% over the previous iteration.

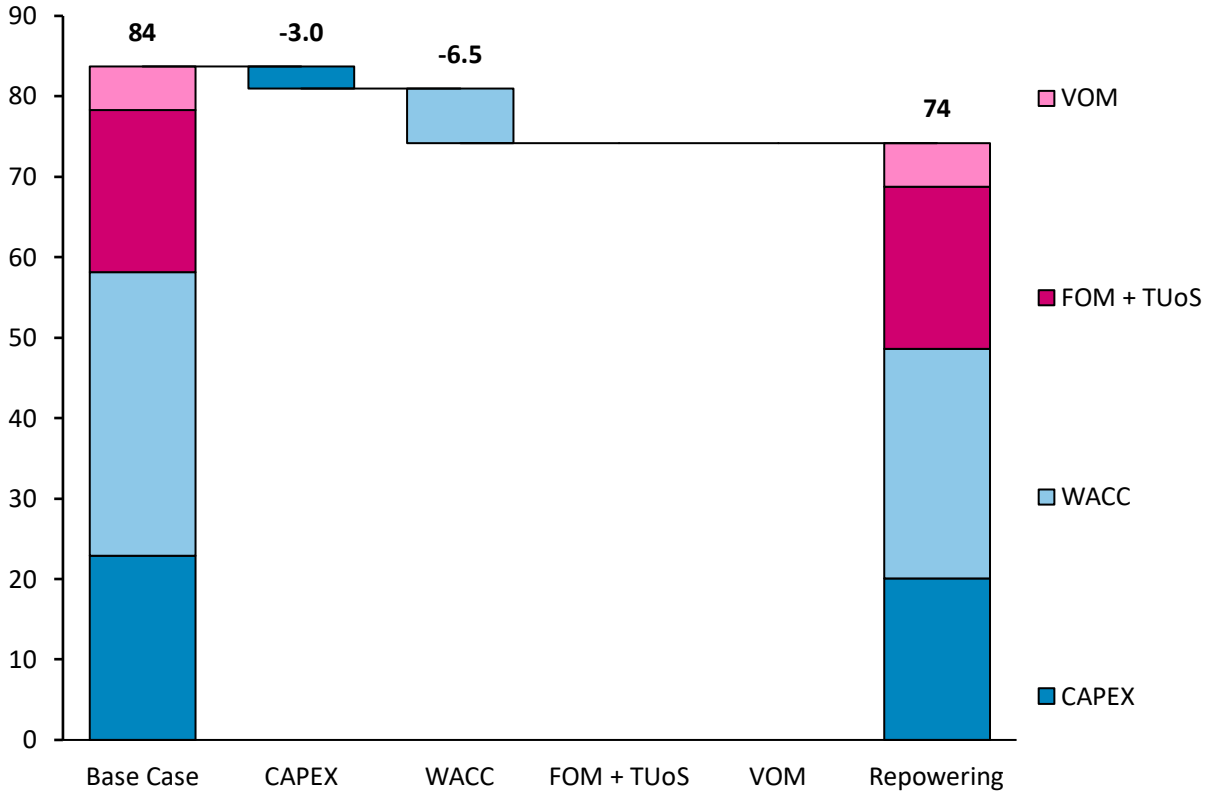
Policy solution: Replace this requirement with one for a minimum investment threshold, unlocking the potential savings for more sites across Ireland, as has now been actioned in the design of RESS 6.

Our analysis and findings: We have quantified the savings offered by repowering an Irish wind farm, across two areas of development costs; the upfront cost of a grid connection (CAPEX) and the cost of financing the project (WACC), with the result presented below in Figure 16.

Repowered projects can typically make use of grid infrastructure at existing sites, avoiding a portion of the upfront costs. We have estimated that a typical repowered site could benefit from a two-third reduction in grid CAPEX, a figure benchmarked with our panel of industry experts.

The use of existing infrastructure also reduces the potential for delays during permitting, derisking the project, and lowering the associated DEVEX. Similarly, the use of an existing site can bring access to historical yield data for the preceding project, and a 'smoother' planning process, given the previous project had received approval. Each of these aspects helps to reduce timeframes, costs and risks, which we have represented with a one-third reduction in DEVEX, and a 0.5% reduction in project WACC.

Figure 16: Impact of repowering on the LCOE of Irish wind, €/MWh



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2.3 The impact on RESS prices

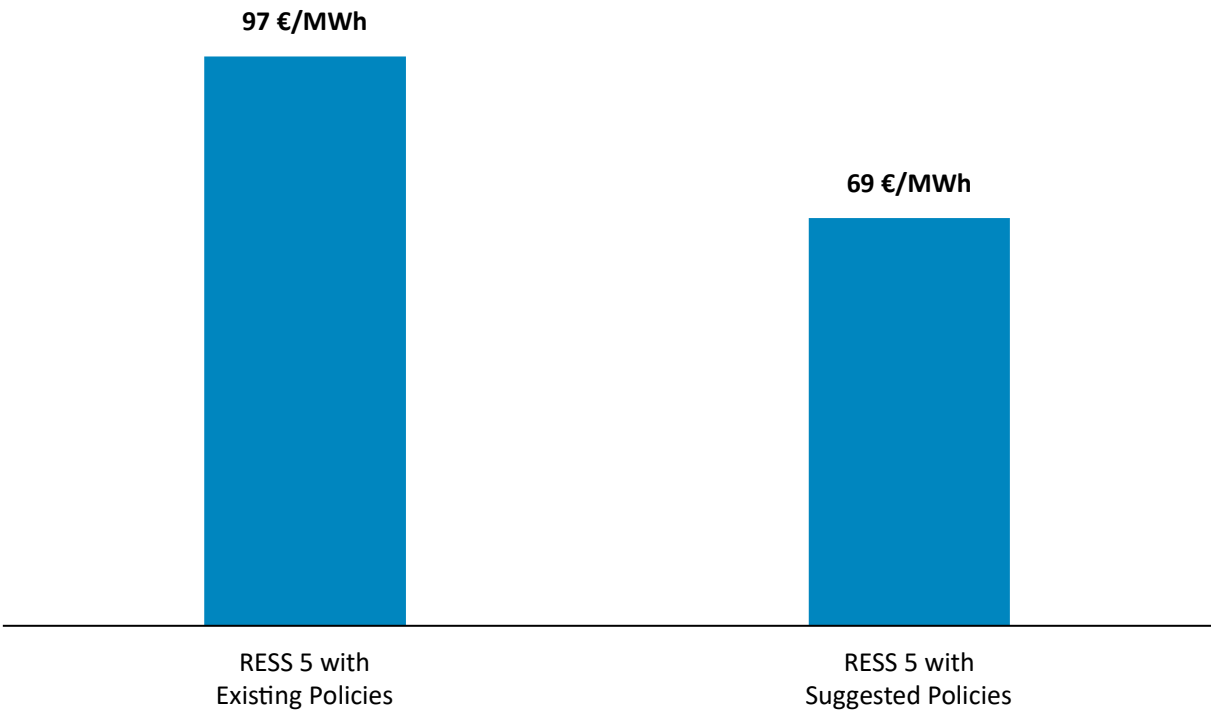
Our analysis suggests that the average contract price for wind projects successful in RESS 5 could have been as low as 69 €/MWh if these policies had been in place at the time of the auction.

This reduction in strike price of more than 27 €/MWh, or 28%, would have resulted from lower project CAPEX (8 €/MWh from the streamlining of grid costs and implementation of hybrid sites), reduced project risk (8 €/MWh from the fixing of grid charges, as well as increased revenue certainty from the adjustments to RESS design), and the direct result of changes to the design of the contracts (11 €/MWh from a longer tenor and full indexation).

The average strike price of contracts supported by RESS 5, with and without the explored policies, is presented in Figure 17 below. We have excluded any reduction in cost that could have been achieved if the change to repowering policy had been implemented ahead of this earlier auction.

Relative to our LCOE calculations, changing the terms of RESS offers outsized impact on contract prices. Full indexation could have reduced the average strike price of wind by 15 €/MWh, including the estimated reduction in WACC, more than half of our calculated saving. Issuing successful projects with 20-year contracts could have reduced prices by 2 €/MWh. This impact, though twice the size of the calculated LCOE saving, is relatively small compared to its indexation counterpart. However, the benefit of longer contracts lies in long-term price stability for consumers, as is explored below.

Figure 17: Impact of policies on the average strike price of wind successful in RESS 5, €/MWh



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2.4 The impact on consumer bills

The implementation of the explored policies could have increased the savings afforded to consumers by wind farms contracted through RESS 5 by more than €120 million.

In addition to this finding, calculated over the duration of the issued contracts, our analysis reveals that each of the individual policies analysed could offer savings to consumers by reducing payments made to contracted wind farms, and increasing payments made in the other direction. Policies that directly address the design of RESS could offer the greatest savings.

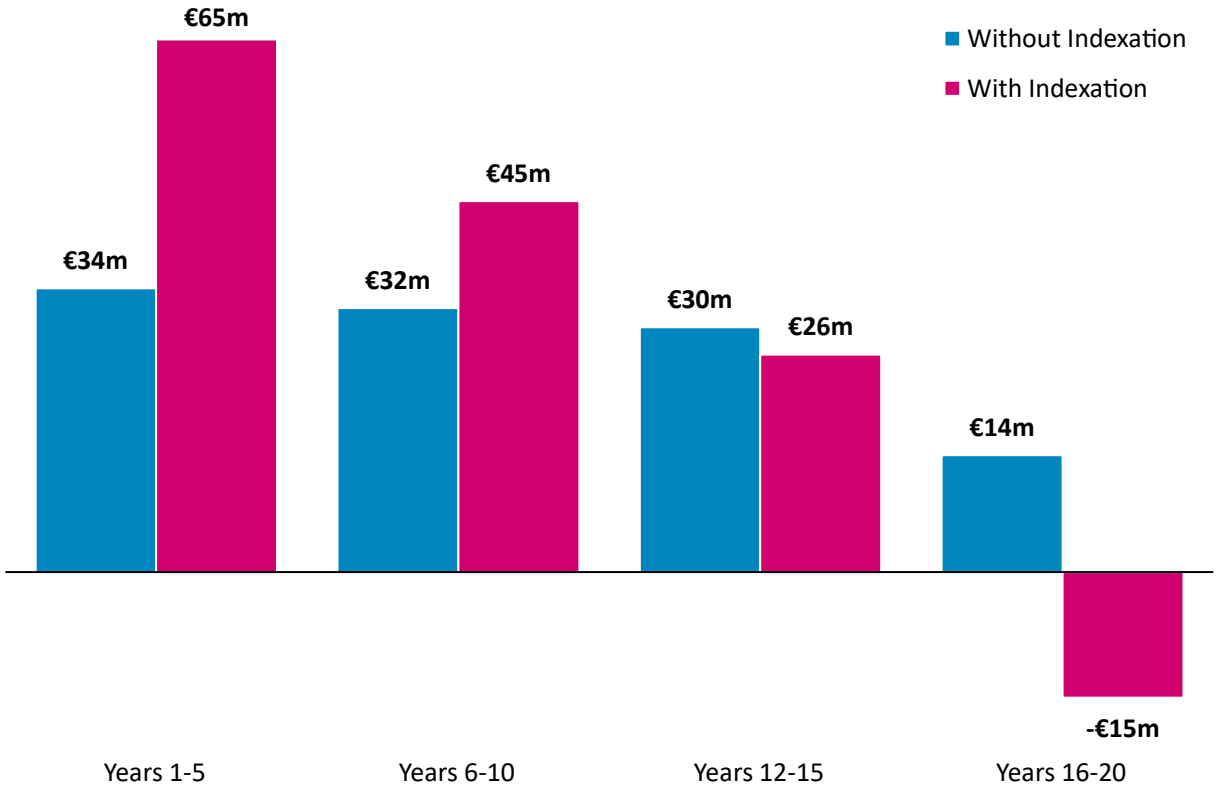
Extending support contracts from 15 to 20 years could have increased the consumer savings of wind farms supported by RESS 5 by almost €20 million.

This finding results from a combination of the lower cost of financing available for projects with greater long-term revenue certainty, and the net payments made to consumers over the final five years of the contracts.

Complementing longer contracts with full indexation to address inflationary risk could have increased savings by a further €10 million.

Although the introduction of full indexation would have reduced the average contract price by more than 15 €/MWh, the protection against inflation would have meant that strike prices would have been higher in real terms by the tail end of the support. The overall savings offered to consumers by the explored policies, with and without full indexation applied, are presented in Figure 18 below.

Figure 18: Consumer savings unlocked by explored policies for RESS 5, million euros



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The benefits of repowering have again been excluded from our calculations.

As Figure 18 highlights, the introduction of full indexation would offer dual benefits on consumer bills, both increasing the total savings from €110 million to €120 million, and realising these benefits earlier into the support contracts.

The impact of different timings for the realisation of savings can be assessed using an economic principle called the 'time value of money', which states that money received now is more valuable than money received later. This is because any money conferred today can be invested, for a consumer they may be put into savings or invested in a business, which can then yield interest or dividends over time.

Applying all seven policy levers, including full indexation, could have yielded €65 million over the first five years of RESS 5 contracts, up from the roughly €35 million delivered without this policy. The time value of money can be explicitly considered using a Net Present Value (NPV), which accounts for the decreasing value of money conferred over time. The NPV of consumer savings is increased by around 20% with the introduction of full indexation.[63]

Beyond these direct savings, inflationary uncertainty was highlighted during discussions with our panel of industry experts as a headline risk for new projects. Addressing this risk may help to incentivise the realisation of more wind farms, unlocking additional consumer savings and bringing Ireland closer to delivering on its national ambitions.

2.5 Value for other technologies

Our assessment of technology costs, and their impact on consumer bills, has focused exclusively on onshore wind projects backed by RESS. Each of the analysed policies, besides the two focusing on RESS contract design, would apply to merchant onshore wind projects, and those backed by PPAs. The delivery of these policies would also reduce the cost of realising other renewable technologies such as offshore wind and solar PV.

Optimising grid connection requirements could directly benefit both offshore wind and solar projects, as could the 'locking in' of TUoS charges and TLAFs for the lifetime of the projects. The latter could offer greater savings for offshore wind projects, which typically have a longer lead time from investment decision to construction and operation.

Extending the tenor of contracts offered through RESS could have an equivalent impact for solar projects, derisking them and lowering both LCOEs and contract prices. Offshore wind projects already benefit from 20-year contracts through ORESS, but an extension would unlock similar benefits in lower financing costs. The full indexation of RESS contracts would unlock value for contracted solar projects, as would the ORESS equivalent for offshore wind.

The mitigation of dispatch down, whether through effective hybrid sites, adoption of LDES, or other solutions, would similarly bring down the cost of offshore wind and solar projects.

Our above analysis of the savings offered to consumers excludes any benefits from a lower cost of solar that could have been realised for RESS 5 through implementation of the explored policies.

[63] Using a social discount rate of 4% as set by the Government's ***Expenditure Appraisal Framework***.

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3 Methodology overview

3.1 Our discounted cash flow model

We have developed a model, based in Excel, to systematically assess the impact of each policy on the development cost of Irish wind farms, as well as the combined impact of multiple policies.

Our model first calculates the LCOE of the archetypal, 100 MW wind farm using our internal, bottom-up assumptions for CAPEX, OPEX, WACC and VOM, as provided in Table 2 in Appendix B. The approach taken is equivalent to a 'discounted cash flow' calculation, which considers the return paid on debt and equity over the economic lifetime of the asset.

The model has functionality to adjust this calculation to reflect changes to individual inputs. We have calculated these adjustments using a series of other tools and processes, including:

- **Our power market model**: An in-house, bottom-up representation of power systems across Europe, which can simulate the hourly day-ahead power market arrangements of the SEM, and the deviations required to maintain system-level operational constraints. Further detail of our model is provided in Appendix A.
- **Our WACC tool:** An Excel-based tool that can estimate the impact on the cost of equity, cost of debt and gearing for a generation project due to changes in revenue stability, counterparty risk, exposure to fuel price volatility, regulatory risk, output stability, and technology risk. These risks are reflected in an 'asset beta', which quantifies how sensitive an asset's returns are to fluctuations in the market. Where a policy impacts the perceived risk of a wind project, the tool converts the avoided 'downside risk', such as increasing TUoS charges or delays to development timeframe, into adjustment to the asset beta, and ultimately to project WACC.
- **Our model of hybrid sites:** An Excel-based tool that optimises the dispatch of a battery storage asset to minimise the dispatch down exposure of a co-located wind farm based on the hourly generation and dispatch down profiles calculated by our power market model. Our tool can also cost-optimise the battery asset for capacity and storage duration, to deliver a targeted reduction in dispatch down for the least cost.

The output of these tools and models has then been benchmarked against, and complemented with, input from Baringa research and discussions with our panel of industry experts, who have been able to provide us with real-word data.

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3.2 Our renewable auction model

We have developed an Excel-based model capable of simulating RESS and ORESS auctions to project the volume, technology and average contract price of cleared projects. We have refined this model during each successive auction since RESS 1, building on the functionality to reflect the specific terms and conditions of each round.

The fundamental input to our model is a database reflective of the pipeline of eligible projects that could bid into a given auction. We have compiled this database for each auction in collaboration with Mullan Grid Consulting,[64] to capture key project characteristics including export capacity, firm access status, load factor, TLAF, estimated CAPEX, OPEX and VOM, and site-specific constraint volumes.

The databases for each auction reflect the credibility of projects to participate, depending on consenting and grid connection status, and their likelihood to choose an alternative route-to-market based on developer experience and available historical data.

A projected bid price is then drawn up for each project reflective of their respective technical, physical and delivery characteristics, as well as assumed bidding strategy, using a discounted cash flow calculation to achieve an assumed rate of return, considering any revenue attainable after the contract expires.

Finally, our model simulates the auction according to the terms and conditions of that round, constructing a merit order of project bids, and considering any design specifics such as evaluation correction factors (ECFs).

[64] **Advisory Services**, Mullan Grid Consulting

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4 Conclusion

Our analysis suggests that the cost of developing a wind farm in Ireland could be reduced by almost 23% with the delivery of seven enabling policies. This saving, calculated for a typical 100 MW onshore wind farm delivered in 2030 and backed by RESS, could be realised with a combination of levers to address project risks across planning and grid, RESS design, and dispatch down.

Wind projects that 'repower' existing sites with the latest technology could benefit from a 27% overall reduction in development costs. The removal of barriers to the participation of repowered projects in auctions, as addressed in RESS 6, could offer a route for developers to derisk projects, speed up development, and make use of existing infrastructure to lower costs further.

Our findings suggest that, if these policies had been successfully implemented ahead of RESS 5, wind farms could have cleared as low as 69 €/MWh. Half of this 28% reduction, down from an outturn average of almost 97 €/MWh, could have been realised though the mitigation of inflationary risk through full indexation of contracts.

This reduction in average contract price would have manifested on consumer bills as a saving of €120 million for RESS 5 alone. Extending RESS contracts from 15 to 20 years in duration would have realised €20 million of this saving, in addition to offering consumers increased protection from volatility in long-term power prices.

Our analysis has focused on onshore wind, but the policies explored would also unlock lower development costs for offshore wind and solar projects. Implementation of the policies for these other technologies could further increase the projected savings for consumers and make a material contribution to easing the pressure of rising power bills.

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Appendix A Further methodology detail

Our power market model

Baringa has developed an in-house pan-European wholesale power market model covering the Island of Ireland, GB, and mainland Europe for the purpose of power market studies. The model sits within PLEXOS,[65] a third-party commercial software that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, network analysis, and other purposes. Our 'Pan-EU' model is configured with key inputs and scenario assumptions such as commodity prices, generator build and retirement, and hourly demand, wind, and solar profiles, and has detailed representations of generator technical parameters and interconnection between markets.

The model engine carries out a least-cost optimisation across more than 40 interconnected European markets to project hourly generator dispatch and market prices.

The hourly demand shape and renewable resource profiles, both in the SEM and other European markets, are based on real-world meteorological data from a 'base weather year' of 2017, representative of a broadly 'average', or 'P50' year, with limited extreme weather or demand events throughout Europe.

Wind and solar assets are modelled as aggregated units in our PLEXOS model, with load factors and output profiles characteristic of averages over multiple site locations in each region. Where support schemes incentivise variation in bidding behaviour between assets, we model several 'objects' in PLEXOS per market that reflect this behaviour. A second distinction is made according to the vintage of wind assets, with newer projects assumed to have higher load factors. We consider repowering of legacy wind farms towards the end of their economic lifetimes.

The modelled representation of the all-island system closely replicates the way in which the market operates under the framework in place since the I-SEM process.[66] Generators are dispatched based on their short-run marginal costs, taking start fuel offtake, ramp rate, availability, minimum up and down times, heat rate profiles, and other technical attributes into account.

Two simulations take place in the model. In the first 'unconstrained' run, no system-level constraints are in place, and assets are dispatched on a merit-order basis, representative of the day-ahead schedule. In a second 'constrained' run, the system is re-optimised taking operational constraints, such as the SNSP and rate-of-change-of-frequency (RoCoF) limits, into account. Generators and interconnectors are re-dispatched from their day-ahead positions in accordance with these system-level constraints. A comprehensive set of reserve requirements is also modelled in this run.

The impact of transmission constraints, beyond the constrained capacity of the network between Ireland and Northern Ireland, is not considered in either market model run.

[65] **PLEXOS**, Energy Exemplar

[66] **Developing the I-SEM**, Single Electricity Market Operator (SEM-O)

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Appendix B Tabulated data

In this Appendix we present a selection of key data in tabulated format:

- Table 2 presents the assumed LCOE components in our Base Case.
- Table 3 provides a summary of our findings.

Table 2: Detailed cost assumptions for an archetypal onshore wind project in Ireland

Levelised Cost of Onshore Wind	Units	2030	Source
Costs & Charges			
CAPEX	*€/kW*	1,820	*Baringa market intelligence*
FOM	*€/kW per year*	44	*Baringa market intelligence*
TUoS	*€/kW per year*	9	*Fleet average value for 2025/26*
VOM	*€/MWh*	5	*Baringa market intelligence*
Financing			
WACC, real, pre-tax	*%*	7.5%	*Calculation*
WACC, nominal, pre-tax	*%*	9.5%	*Calculation*
Cost of debt, nominal, pre-tax	*%*	8.5%	*Baringa market intelligence*
Cost of equity, nominal, pre-tax	*%*	11.5%	*Baringa market intelligence*
Gearing	*%*	60%	*Baringa market intelligence*
Economic life	*Years*	30	*Baringa market intelligence*
Generation Volumes			
Available energy	*%*	36%	*Baringa market intelligence*
Outturn generation	*%*	30%	*Calculation*
Oversupply	*%*	6%	*Baringa modelled projection*
Curtailment	*%*	2%	*Baringa modelled projection*
Constraint	*%*	9%	*Fleet average value for ECP-2.5*
Oversupply - ECP sensitivity	*%*	30%	*Fleet average value for ECP-2.5*
Curtailment - ECP sensitivity	*%*	1%	*Fleet average value for ECP-2.5*
Constraint - ECP sensitivity	*%*	9%	*Fleet average value for ECP-2.5*
LCOE			
Levelised cost	*€/MWh*	84	*Calculation*

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Table 3: Summary of our quantitative findings

Our Findings	Units	2030
Base Case		
LCOE - base case	*€/MWh*	84
Planning & Grid		
LCOE - grid connection costs	*€/MWh*	80
LCOE - fixed grid charges	*€/MWh*	83
RESS Design		
LCOE - contract tenor of RESS	*€/MWh*	82
LCOE - contract indexation of RESS	*€/MWh*	81
Dispatch Down		
LCOE - hybrid connections	*€/MWh*	78
LCOE - adoption of LDES	*€/MWh*	79
LCOE - further mitigation of dispatch down	*€/MWh*	74
Actioned		
LCOE - repowering of existing sites	*€/MWh*	74
Combined Impact of Policies		
LCOE - greenfield site	*€/MWh*	65
LCOE - repowered site	*€/MWh*	61
RESS 5 Results		
Clearing price for wind	*€/MWh*	97
Clearing price for wind with greenfield policies	*€/MWh*	69
Procured annual volume of wind	*GWh*	671
Procured capacity of wind	*MW*	219
Consumer Savings		
Total - policies including indexation	*€m*	121
Total - policies excluding indexation	*€m*	110
NPV - policies including indexation	*€m*	100
NPV - policies excluding indexation	*€m*	79

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Appendix C About Baringa

We set out to build the world's most trusted consulting firm – creating lasting impact for clients and pioneering a positive, people-first way of working. We work with everyone from FTSE 100 names to bright new start-ups, in every sector.

You'll find us collaborating shoulder-to-shoulder with our clients, from the big picture right down to the detail: helping them define their strategy, deliver complex change, spot the right commercial opportunities, manage risk or bring their purpose and sustainability goals to life. Our clients love how we get to know what makes their organisations tick – slotting seamlessly into their teams and being proudly geeky about solving their challenges.

We have hubs in Europe, the US, Asia and Australia, and we work all around the world – from a wind farm in Wyoming to a boardroom in Berlin. Find us wherever there's a challenge to be tackled and an impact to be made.

Find out more at baringa.com or on LinkedIn and X.

More from Baringa

Good for your Pocket

In this study, commissioned by Wind Energy Ireland, we quantify the savings that renewables have conferred to the power bills of end consumers in Ireland since 2000. We then turn our attention forward to the potential for further savings if Ireland's renewable ambition for 2030 is achieved.

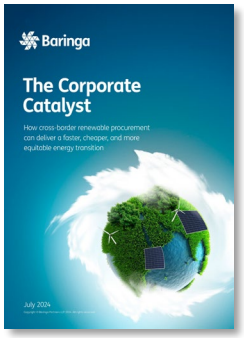
Read our report



The Corporate Catalyst

In this study, commissioned by Amazon, we explore the impact of enabling cross-border procurement of renewable electricity by corporates. Our analysis suggests that this single change to carbon accounting rules could unlock a faster, cheaper, and more equitable global energy transition.

Read our report



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