



UR consultation: Assessment on the need for a regulated operating revenue regime for future interconnection

Mutal Energy Response

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A Northern Ireland company

working for consumers



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1. Background to Mutual Energy

Mutual Energy Limited (**MEL**) owns and operates large-scale, strategic energy assets in the long-term interest of Northern Ireland (**NI**) energy consumers, including critical energy infrastructure linking the NI energy system to Great Britain (**GB**). Our assets are critical in maintaining security of energy supplies to NI.

Since 2003 we have owned and maintained the Moyle electricity interconnector between Scotland and Northern Ireland¹. The interconnector is funded on a fully mutualised basis on behalf of NI energy consumers. To date MIL has delivered savings in excess of £100m through its low cost of capital, generates significant profit and cash that stand to benefit Northern Irish consumers, and maintains class leading levels of availability, helping to maintain a secure supply of electricity in Northern Ireland.

2. Executive Summary

In Q4 2024, Mutual Energy engaged Frontier Economics and LCP Delta to complete an assessment of the economic impacts of investment in further interconnection between the SEM and GB electricity markets under a range of plausible scenarios of the expected evolution of demand/supply dynamics in the GB/Irish electricity markets. Some key conclusions Mutual Energy has taken from their assessment are summarised below:

- **Additional interconnection to GB is likely to reduce wholesale prices in the SEM if there is a more rapid build out of renewables in GB and, on a marginal cost basis, GB has cheaper decarbonised dispatchable power generation.** This is because expensive SEM dispatchable generation would be offset by imports of subsidised (and therefore marginally cheap) surplus renewable generation from GB. As the penetration of renewable generation in the SEM however catches up with GB, and SEM pricing reduces, this dynamic would change, with more benefits coming from imports of subsidised, lower cost, decarbonised, dispatchable generation from GB, when renewable output across both markets is low.
- **Additional interconnection could help reduce the level of dispatch down due to oversupply but this may be limited by network constraints in GB, requires effective market arrangements, and its impact reduces as both markets decarbonise.** This is due to the coincidence in renewable generation between SEM and GB.
- **Utilising interconnection to reduce dispatch down however is a ‘blunt instrument’ compared to using electricity storage.** Storage allows an increased proportion of the benefits from subsidised renewables to be retained by the source market reducing the overall renewable generation capacity required to decarbonise the market, as well as the level of investment in dispatchable thermal peaking generation required. In contrast, exporting renewables will tend to result in the importing market benefitting more from the renewable subsidy being paid by SEM consumers – i.e. the opposite of SEM importing renewable power subsidised by GB energy consumers.
- **If the demand (and therefore price signal) driving higher imports to SEM emanates from Ireland, then the ability of additional interconnection to meet that demand**

¹ Via subsidiary company Moyle Interconnector Ltd (“MIL”)

depends upon the capability of the transmission system to physically deliver imported electricity to the relevant locations. In the specific case of additional interconnection between GB and Northern Ireland it will therefore depend upon the timing of the delivery of the new North South Interconnector (NSI).

- **Developing the LirIC interconnector ahead of the commissioning of the new North South Interconnector (NSI) could increase network congestion and exacerbate the dispatch down of renewable generation in Northern Ireland.** It would be prudent to model the sensitivity of the needs case for LirIC to the development of the new NSI.
- Given the GB market is substantially larger than the SEM it is possible that GB could sustain a level of subsidised exports to SEM, rather than vice versa. **If the level of benefit accruing to external markets from GB subsidies however is extensive it is possible that it could trigger a review of interconnector trading arrangements more generally.** Again, it would seem prudent to model the sensitivity of the needs case for LirIC to potential changes in interconnector trading arrangements – e.g. subsidised power not being made available available to export or the importing market having to make a contribution towards the cost of the subsidy being provided by the exporting market.

As a general conclusion, based on the assumptions that were employed by Frontier Economics and LCP Delta, including in relation to the rate of renewable build out and the relative cost of low-carbon dispatchable generation across the two market, **development of the LirIC interconnector is likely to deliver both system and consumer benefits to the SEM, particularly if developed in the 2030s, and after the commissioning of the new NSI.**

While we believe, if appropriately timed, and subject to commissioning of the NSI, development of LirIC could deliver benefits to the SEM and to Northern Irish energy consumers, we have a number of potential concerns relating to some of the proposals set out in the consultation.

These are summarised below:

- The level of benefits that accrue to Northern Irish energy consumers will be significantly impacted by the form of regulatory support provided to LirIC. We therefore recommend that if the needs case demonstrates that regulatory support should be provided, that very careful consideration is given to the appropriate form of regulated support that is introduced. While not explicitly stated as such in the consultation, the impression given by the process currently being proposed, including the parallel work being considered and discussed in appendix A, is that there is a working assumption that a ‘cap and floor’ regime is likely to be the best regulatory support mechanism for Northern Ireland. We do not believe this assumption however is warranted. As set out in our answer to question 3, **Northern Ireland has benefited significantly from mutualised ownership of the Moyle interconnector, where consumers have taken on all of the risk associated with the investment, but in return receive all of the benefits. Under a ‘cap and floor’ regime this risk reward balance would be expected to significantly change – i.e. consumers would still bear a substantial portion of the investment risk but could end up receiving only a fraction of the benefit. Such a substantial change in the risk reward balance would need to be clearly demonstrated to be in the long-term interests of NI energy consumers.** Mutualisation however is not the only potential alternative approach to a cap and floor regime, and other jurisdictions, including continental Europe and Ireland, in relation to the Celtic and EWIC interconnectors, have

used a RAB based approach. **We think it is critically important therefore that the decision on regulatory support is not prejudged, and that other proven approaches to regulatory support are properly considered, not just a ‘cap and floor’ regime.**

- We are concerned that the regulatory process relating to the development of the needs case for LirIC, and the decisions regarding whether to provide regulatory support, as well as the specific form of that support, is being overly compressed and rushed to meet Ofgem timelines. In the context of the potentially significant and long-term implications of these decisions on NI energy consumers, we believe the proposed approach outlined in the consultation imposes unjustifiable risk. **Sufficient time must be allocated to carefully analyse, consider, and consult upon the myriad of complex issues associated with the development of further electricity interconnection in Northern Ireland.** This will help ensure an optimal outcome is achieved for NI energy consumers.

As a final observation, **consideration should be given to whether NI energy consumers should take the risk of providing regulatory support to LirIC ahead of the commissioning of the NSI.** Unfortunately, there is a long history of legal challenges and extensive delay to the development of the NSI, and while it is currently anticipated that it will be operational by 2032, there is no guarantee that this will be the case. **Subject to the outcomes of the needs case assessment, including formal quantification of the potential impacts of the NSI, careful consideration should be given to whether any decision to grant regulatory support is made conditional upon the successful commissioning of the NSI.**

3. Introduction

Mutual Energy welcomes the opportunity to respond to UR's consultation on the assessment on the need for a regulated operating revenue regime for future interconnection. Our views are informed by our experience as owner of the Moyle electricity interconnector, our knowledge of the NI electricity system, our experience of operating under the SEM market arrangements, as well as by analysis that we commissioned in Q4 2024 and that was carried out by Frontier Economics and LCP Delta.

4. Consultation Questions

Our answers to the questions posed in the consultation paper are set out below.

Question 1: Do respondents have any views regarding additional interconnection in Northern Ireland that you would like to highlight? If so, please provide details.

In Q4 2024, Mutual Energy engaged Frontier Economics and LCP Delta to complete an assessment of the economic impacts of investment in further interconnection between the SEM and GB under a range of plausible scenarios of the expected evolution of demand/supply dynamics in the GB/Irish electricity markets. Frontier Economics advised on modelling assumptions and market arrangements and LCP Delta carried out the modelling.

Assumptions for the SEM market were based upon the Gas Evolution and Constrained Growth scenarios from EirGrid/SONI's 2023 Tomorrow's Energy Scenarios. GB market assumptions were based upon the Hydrogen Evolution scenario from NESO's 2024 Future Energy Scenarios. Other EU markets were modelled at a higher granularity.²

The analysis assessed the impact of additional SEM-GB interconnection alongside existing SEM electricity interconnection plus the Celtic interconnector. The modelling was completed over a fifteen year horizon from 2035 to 2050.

The extent of uncertainty regarding decarbonisation pathways combined with the increasing reliance on 'out of market' support mechanisms – e.g. for renewables, hydrogen, and carbon capture and storage, makes it a challenge to conduct this type of analysis. The economic impacts of adding new interconnection were shown to vary significantly depending upon the underlying assumptions employed for each market. The main objective in conducting the analysis was therefore to identify the dynamics that drive the market impacts of adding further interconnection to the SEM.

Some key observations Mutual Energy has taken from the assessment are provided below:

- Interconnection provides significant benefits where there is a substantial price differential between markets. However if the price differential tends to be in one direction, benefits accrue asymmetrically, favouring the market that tends to have higher wholesale prices. In the context of the GB and SEM markets modelling indicated that there are two main factors that drive price spreads: the relative level of renewable penetration in each market, and the relative cost of dispatchable generation.

² For an overview of these general modelling assumptions please see appendix 1, section A

- On review of market fundamentals and recent trends, it appears likely that in the mid-term there will be a faster deployment of renewable generation in GB compared to the SEM. In particular, investment in offshore wind is viewed as a key driver in delivering rapid decarbonisation of electricity production, and the GB offshore wind sector is significantly more advanced than that of either Northern Ireland or Ireland.³ This gap however will have to close for Ireland and Northern Ireland to deliver upon their respective net zero emissions targets.
- Because renewable generation is subsidised via ‘out of market’ support contracts, its marginal cost to the electricity market tends towards zero. Increasing decarbonisation via renewables therefore reduces market pricing, although not necessarily consumer costs (due to the impact of subsidies). In the case of electricity interconnection between GB and SEM, a faster pace of renewable investment in GB tends to result in lower GB market prices, which drives increasing GB exports to SEM.
- The cost of low-carbon dispatchable generation in GB is likely to be cheaper than in the SEM, even if there was broad alignment in the relative capacity margins within each market. This is because GB will have nuclear generation capacity and is able to more easily utilise gas-fired generation with carbon capture and storage (gas CCS), both of which are expected to be cheaper on a marginal cost basis than using hydrogen for dispatchable generation; blue hydrogen is assumed to be the marginal source of hydrogen production in the modelling.
- Given the lack of potential sites for carbon storage on the island of Ireland, under a net zero scenario SEM is arguably more likely to rely on hydrogen fired dispatchable generation to maintain security of electricity supply. Even if SEM does adopt gas CCS, on a marginal cost basis, it is expected to be more expensive than in GB because of higher carbon shipping costs (to transport the captured carbon back to GB for long-term storage) and the much smaller achievable economies of scale.
- The actual marginal costs of gas CCS and hydrogen within each jurisdiction (as well as nuclear generation in GB) however will be influenced by the policy decisions made within each jurisdiction. In particular, the relevant ‘out of market’ financial support mechanisms in place, as well as the timings of when those mechanisms are withdrawn, once the relevant technologies become fully established.
- Assuming the marginal cost of dispatchable generation (i.e. the production cost after subsidy) is cheaper in GB than the SEM, whenever renewable energy production across both markets is limited, it will tend to result in lower market prices in GB and therefore increased exports to SEM.
- **One high-level conclusion from the analysis is therefore that additional interconnection to GB is likely to reduce wholesale prices in the SEM.**⁴ This is because a more rapid build out of renewables in GB means expensive SEM dispatchable generation will be offset by imports of subsidised (and therefore marginally cheap) surplus GB renewable generation. As the penetration of renewable

³ See appendix 1, section B

⁴ See appendix 1, section C

generation in the SEM catches up with GB however, this dynamic will change over time. More benefits are forecast to come from imports of subsidised, lower cost, decarbonised, dispatchable generation from GB (gas CCS) whenever the renewable output in both jurisdictions is low.

- To the extent that decarbonisation of the SEM market accelerates relative to the GB market, the forecast reduction in the SEM wholesale price resulting from additional interconnection lessens (or, in the extreme, price spreads could reverse, significantly increasing exports to GB, leading to price increases in the SEM). For example, it is worth noting the growing political scepticism from the Conservatives and Reform regarding the UK net zero target that could result in a slower pace of GB renewable investment in future.
- Similarly there is uncertainty in relation to the relative pricing of GB and SEM low-carbon dispatchable generation, including regarding the potential impacts of financial support mechanisms for CCS and hydrogen, and the timings of when ‘out of market’ support for these new technologies might be reduced, or removed. **In general, however, assuming an appropriate approach to regulatory support is established, it seems reasonably likely that increasing levels of interconnection to GB, via projects such as LirIC, will deliver benefits, particularly in the 2030s.**
- Given the renewable investment expected under the Renewable Electricity Price Guarantee scheme in Northern Ireland to deliver the 2030 80% RES-E target, a significant increase in the oversupply of renewable generation in Northern Ireland (and the SEM more generally) is expected. **Additional interconnection can help reduce the level of dispatch down due to oversupply, but this could be limited by network constraints in GB, requires effective market arrangements, and its impact reduces as both markets decarbonise.** This is due to the coincidence in renewable generation between SEM and GB.⁵
- **Utilising interconnectors to reduce dispatch down however is a ‘blunt instrument’ compared to using electricity storage, which via the SEM market price is incentivised to maximise benefits to SEM consumers.** This was demonstrated by a modelling sensitivity ran by LCP in which an ‘additional’ GB interconnector was replaced with an 8-hour storage system with the same power rating. Despite the energy limit of the store (it can overall ‘move’ substantially less renewable electricity, due to its restricted storage capacity) there was only a relatively small c10% reduction in the achieved consumer benefits.
- **This is because storage allows an increased proportion of the benefits from subsidised renewables to be retained by the source market,** facilitating otherwise surplus renewable generation to be used to displace higher priced dispatchable generation when output from renewables is low. **This reduces the overall renewable generation capacity required to decarbonise the market, as well as contributing to the installed capacity of dispatchable generation necessary to maintain system adequacy, reducing the level of investment in dispatchable thermal peaking**

⁵ See appendix 1, section D

generation required.⁶ In contrast, exporting renewables results in the importing market benefitting from the renewable subsidy being paid by SEM consumers (albeit the SEM also receives some benefit from those exports, such as reduced ‘dispatch down’, but with diminishing returns relative to the cost of subsidy support provided); the opposite outcome to the SEM importing marginally low-priced subsidised renewables and other types of low-carbon dispatchable generation, from GB.

- When looked at objectively, and considering the substantial difference in size between the GB and SEM markets, it seems much more likely that GB could sustain a more significant level of subsidisation of renewable exports to the SEM than vice versa.⁷
- Nevertheless, there is a risk that **if excessive benefits accrue in the importing market due to the subsidies being paid for by consumers in the exporting market, it could trigger a review of cross border trading arrangements at some point in the future - i.e. the effective subsidisation of SEM electricity prices by GB consumers indicated in the modelling may prove unsustainable.**
- The level of imports, and therefore the benefits to SEM, are impacted by assumptions on the demand growth in SEM, as well as its location. Currently demand is growing at a much faster rate in Ireland than Northern Ireland, predominantly due to the ongoing investment in data centres in Ireland, and this dynamic could be further exacerbated if the pace of electrification in Ireland is greater than in Northern Ireland. **If the demand driving higher imports (by pushing the SEM clearing price further up the generation cost curve) emanates from Ireland, then the ability of additional interconnection to meet those demand requirements depends upon the capability of the transmission system to physically deliver imported electricity to relevant locations.** In the specific case of additional interconnection between GB and Northern Ireland this therefore depends upon the timing of the delivery of the new North South Interconnector (NSI).
- **Developing the LirIC interconnector ahead of the commissioning of the new NSI could therefore lead to significantly increased network congestion in Northern Ireland, with imports driving extensive redispatch actions by the TSO via the balancing market.** While there may still be a net benefit to consumers from lower wholesale pricing in SEM, it is expected that the overall benefit would be considerably less than if the same level of interconnection was built between GB and a suitable location in Ireland. In the latter case the imports would likely result in significantly less redispatch by SEM TSOs, reducing market imperfection costs and improving consumer benefits.
- Imports of electricity from GB contribute to the dispatch down of renewable generation in Northern Ireland. This again currently is linked to the north south constraint on the island, which prevents electricity scheduled to be generated in (or imported to)

⁶ The latter is also true in relation to interconnection, the relative benefits of installing storage relative to interconnection in improving capacity adequacy being determined by the de-rating factors applied to the technologies via the SEM capacity market.

⁷ The increase in the GB wholesale price is significantly less than the price reduction it causes in SEM due to the difference in the relative sizing of the two markets - see appendix 1, section C.

Northern Ireland from being able to flow to ROI to meet the demand responsible for causing the price signal in SEM. This forces SONI to take redispatch actions to maintain system security. **It is anticipated that adding LirIC ahead of the delivery of the new NSI would further increase the frequency and volume of dispatch down in Northern Ireland.** The needs case for the LirIC interconnector is therefore expected to be stronger after commissioning of the new NSI.

In summary, the key conclusions that we have drawn from the Frontier Economics / LCP Delta assessment are:

- Additional interconnection between GB and the SEM is likely to be beneficial, particularly in the 2030s.
- The main benefit is likely to be a decrease in SEM wholesale pricing due to GB consumers subsidising exports to SEM. This is predicated on the GB market decarbonising more quickly than the SEM and the marginal cost of low-carbon dispatchable generation in GB being cheaper than SEM.
- If the level of benefit accruing to external markets from GB subsidies is extensive it could trigger a review of interconnector trading arrangements. This could substantially change the outcome of the analysis.
- The forecast benefits of the LirIC interconnector decrease substantially if the new NSI is not delivered, or is subject to further significant delay.
- In this scenario LirIC imports are likely to drive a substantial increase in redispatch actions by SONI to manage increasing transmission constraints. The resulting increase in imperfection charges would reduce consumer benefits. It is also expected that there would be an increase in the level of dispatch down experienced by renewable generation located in Northern Ireland.
- In general, in relation to managing dispatch down, interconnection is a reasonably blunt tool. It is limited by the price spread between markets and the willingness/ability of the neighbouring market to receive exports. As export levels increase, it also risks substantially more of the benefits of the renewable subsidies paid by SEM consumers accruing to the importing market.
- Investing in storage may therefore provide a better long-term solution to renewable dispatch down than interconnection because it will respond to price signals in the local market and results in more of the benefits from investment in renewable generation accruing to consumers in their source market, who pay the cost of the renewable subsidy.
- Given the GB market is substantially larger than the SEM market it seems significantly more likely that GB could sustain a level of subsidised exports to SEM, rather than vice versa.⁸

⁸ The Norwegian government has effectively put a moratorium on developing new interconnectors until 2029 due to high domestic energy prices and security of supply concerns – please see <https://www.hvdcworld.com/news/norway-blocks-all-new-interconnectors?>

Based on the above observations, recommendations regarding the approach to the assessment of the needs case for LirIC are provided in our answer to question 4.

Q2. Do respondents have any additional considerations they believe should be included within the step two workstream? If so, please provide details.

As indicated in our response to UR’s consultation on whether to grant a licence to the promoters of the LirIC interconnector, the sequencing of the two step approach imposes unnecessary risk on Northern Irish energy consumers.

While the development of the LirIC interconnector is less likely to progress in the absence of some form of support being provided by the Utility Regulator (i.e. step two of the current two step licensing process), this is not certain. It is possible that the project could proceed on a purely merchant basis on the NI side. It is therefore a possible outcome that the Utility Regulator could refuse to provide a form of regulatory support to LirIC, because the needs case assessment concludes that developing LirIC is not in the interests of NI consumers, but the project nevertheless proceeds - this could be a poor outcome for Northern Irish consumers.⁹

In light of the scale of the potential impacts development of the LirIC interconnector could have (positive or negative), it is therefore essential that the ‘needs case’ assessment conducted by the Utility Regulator is transparent and robust, and is not rushed. The timelines set out to conduct the ‘needs case’ in the consultation are extremely tight, especially if consultancy support has not already been appointed. For context, the work Mutual Energy conducted with Frontier Economics and LCP Delta took over six months to complete, largely due to the challenges outlined in our answer to question 1, specifically in relation to the uncertainty around assumptions, and the scale of the impact of ‘out of market’ support mechanisms. We expect that the ‘needs case’ assessment being conducted by the Utility Regulator will require a wider scope of works.

As a general comment, in relation to the proposed approach outlined in the consultation for the step two workstream, the main objective seems to be to try to ‘dovetail’ the decision making process of the Utility Regulator into the timelines set out for GB cap and floor decisions being taken by Ofgem, rather than ensuring sufficient time is taken to ensure the correct decision is taken on behalf of Northern Irish energy consumers. Whilst we can appreciate the LirIC promoter’s imperative for an expedited process, given that they have made more progress with Ofgem, it is nevertheless essential that the interests of Northern Irish energy consumers are properly considered in this matter.

Taking sufficient time to carry out a transparent and comprehensive ‘needs case’ assessment will protect the interests of consumers, as well as ensure there is a high degree of confidence in the final decision (whatever that proves to be) regarding whether to grant a form of regulatory support to LirIC.

⁹ Mutual Energy acknowledges that a detailed ‘needs case’ assessment would not normally be carried out by the Utility Regulator prior to the grant of a license. However, there is the potential for investment in new electricity interconnection to have a significant negative impact on wholesale pricing. The small scale of the SEM market (and the NI electricity system, from the perspective of impacts on network constraints / dispatch down) relative to the size of the LirIC interconnector exacerbates the scale of the risks.

At a high level we recommend that appropriate timeframes are set out to properly complete the following steps under the ‘step two’ workstream:

- 1) Complete a thorough ‘needs case’ assessment to determine whether further investment in GB to NI interconnection is in the interest of SEM, and specifically, NI energy consumers
- 2) Subject to the outcome of 1), decide if a regulatory support regime should be provided by NI consumers for the LirlC interconnector
- 3) If the outcome of 2) is a decision to provide a regulatory support regime, carry out a detailed assessment of feasible potential mechanisms to determine their relative benefits within the context of Northern Ireland and the SEM
- 4) Consult upon the optimal regulatory support regime, including the detailed design of the mechanism

Q3. Are respondents aware of any other interconnector revenue models outside of those listed above? If so, please provide details for any other models considered to be available.

Yes. We recommend that the mutual model is carefully considered as an alternative approach to supporting interconnector development in Northern Ireland. Mutualisation of the Moyle Interconnector has saved NI energy consumers well over £100m to date, with surplus cash generated being used to benefit Northern Irish energy consumers, rather than paid to shareholders.

Mutual Energy commissioned Centrus, a corporate finance advisory firm, to objectively assess the benefits and drawbacks of the mutual model. Some of the main observations noted within the report are set out below:

- Mutualisation works particularly well for large-scale, strategic infrastructure investments. This is because it is difficult to successfully transfer risk associated with these types of assets to a corporate investor. Their critical importance means, in practice, government and regulators would not realistically allow them to fail.
- A corporate investor however will charge a substantial premium for the perceived transferal of such risks, resulting in a poor outcome for consumers, increasing investment costs, without actually delivering a substantial reduction in the risk profile faced by consumers.
- Explicitly acknowledging that the consumer will underwrite the risk on such investments however can deliver a better outcome, reducing investment costs, without, in practice, substantially increasing consumer risk.
- Within the context of Northern Ireland, Mutual Energy Limited is an example of an effective business structure within which the risks associated with the ownership and operation of strategic energy infrastructure can be effectively and efficiently managed on behalf of consumers.
- The mutual approach works particularly well for investments with high upfront capital costs and long investment horizons. This is because the benefits of a significantly lower cost of capital are maximised.

- As well as lowering funding costs the model ensures that all profits generated by the mutualised assets are utilised to the benefit of current and future Northern Irish energy consumers and the wider NI economy, rather than paid as dividends to shareholders.
- The model also ensures that all residual value associated with a mutualised asset, that would otherwise be transferred to investors post the revenue support period, remains with the consumer, including land rights, grid connection, cable routes, etc.

The approach employed to mutualise the Moyle interconnector (the **mutual model**) is comparable to a cap and floor regime, except there is no requirement for a cap – or the cap can be considered to equal the floor. Typically under a corporate financing structure a spread between the cap and floor is necessary to provide a return to equity investors, whereas the mutual model is 100% debt financed and therefore all upside accrues to consumers. The mutual model can also accommodate a longer debt term than a typical cap and floor regime, with a lower cost of capital than a capital structure that includes equity.

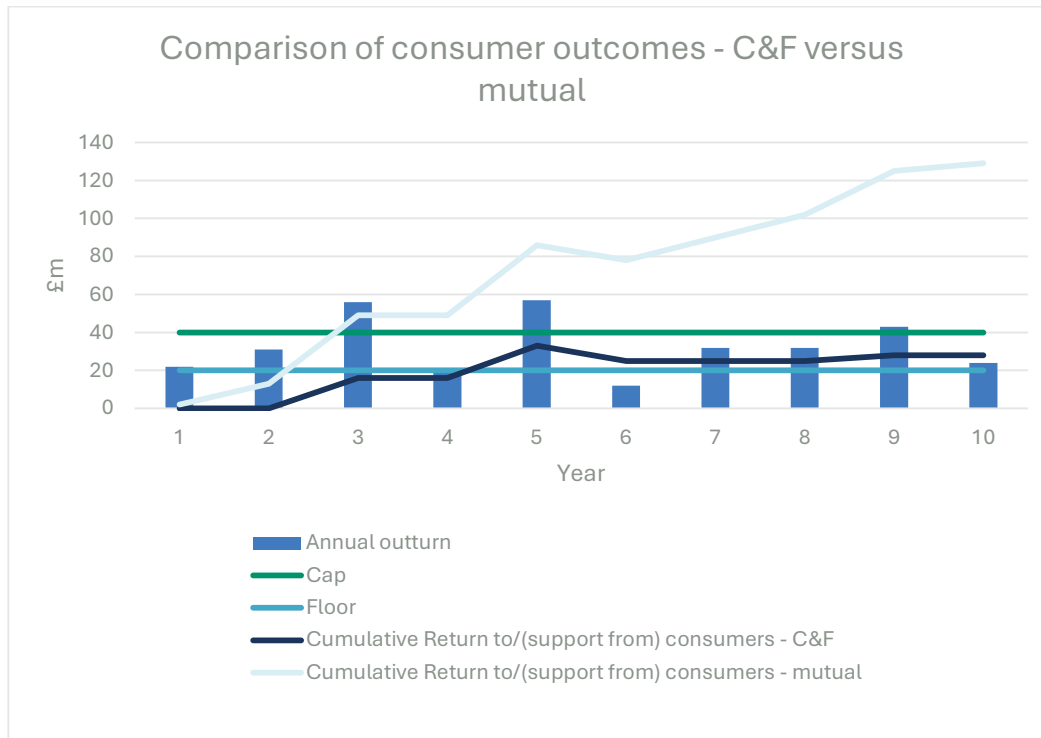
Interconnector revenues can be very volatile. The chart(s) below illustrate how substantial the potential benefits of a mutualised delivery could be, compared to a cap and floor regime. In this simplified illustration we assume an annual cap of £40m (cap and floor only) and a floor of £20m for both a mutual and cap and floor model. These are broadly based on those stated in the CRU’s consultation on the post construction review of the Greenlink Interconnector. In this simplified example, we assume that performance against the cap and floor are assessed on an annual basis without any smoothing adjustments. We then apply a random number generator to determine the revenue outturn each year (a number between zero and 60). The table below describes the logic applied as to where surpluses go, and where shortfalls are funded under each model, given the 3 different potential outturns.

	Mutual	C&F
Outturn<Floor	Difference between outturn and floor is a cost to consumers	Difference between outturn and floor is a cost to consumers.
Cap>Outturn<Floor	Difference between outturn and floor is a return to consumers	Difference between outturn and floor is a return to investors
Outturn>Cap	Difference between outturn and floor is a return to consumers	Difference between cap and floor is a return to investors Difference between outturn and cap is a return to consumers

The chart below then illustrates the cumulative effect on consumers of applying this logic under a cap and floor regime (black line) compared to a mutual (light green line) over ten years¹⁰. Whilst this is a simple illustrative example, it demonstrates that the difference in consumer outcomes can be stark even under reasonably benign assumptions. Under a cap and floor regime consumers will only receive returns when the cap is breached, otherwise they are either providing support, or the investor is profiting. With a mutual model consumers carry all of the risk associated with the investment but see returns as long as the business generates revenues in excess of its running costs / floor. **The key consideration is therefore whether the potential**

¹⁰ Chosen simply for readability of the chart

benefits NI consumers forgo under a ‘cap and floor’ regime are appropriately offset by the additional quantum of risk being taken on by the investor. This criteria would equally apply to assessment of the relative benefits of a RAB regime, which is likely to sit somewhere between a ‘cap and floor’ regime and a mutualised regime.



Above we used randomly generated outturns. Our point is amplified if a consistent outturn above the cap was assumed. Subject to the level the cap is set at, under this scenario the returns to consumers under a mutualised approach would significantly exceed those payable under a ‘cap and floor’. We expect a RAB regime would fall somewhere in between, depending on how the allowable costs and rate of return were set.

The point also holds if we look at a consistent outturn between the cap and floor levels. In this scenario (outturn between the cap and floor) the cap and floor regime does not return any surpluses, whereas the returns to consumers under the mutualised regime could still be significant. Again, we would expect that a RAB regime would fall somewhere in between.

In this simple analysis the only scenarios where consumers would not be better off would be where revenues are consistently at or below the floor (see Appendix 2 for illustration of this and preceding examples). Such an outcome however is likely to be unsustainable for investors (as it precludes a return for equity investors) who would likely seek an uplift in their floor payments to keep the asset in operation.

This links to a key consideration as to whether the merchant, cap and floor, regulated or mutual model is the optimal choice for consumers – **allocation of risk**. Under the merchant model the developer accepts all of the risk and retains all of the reward. An example of this is the Eleclink interconnector which was developed at risk but has already generated revenues well in excess of

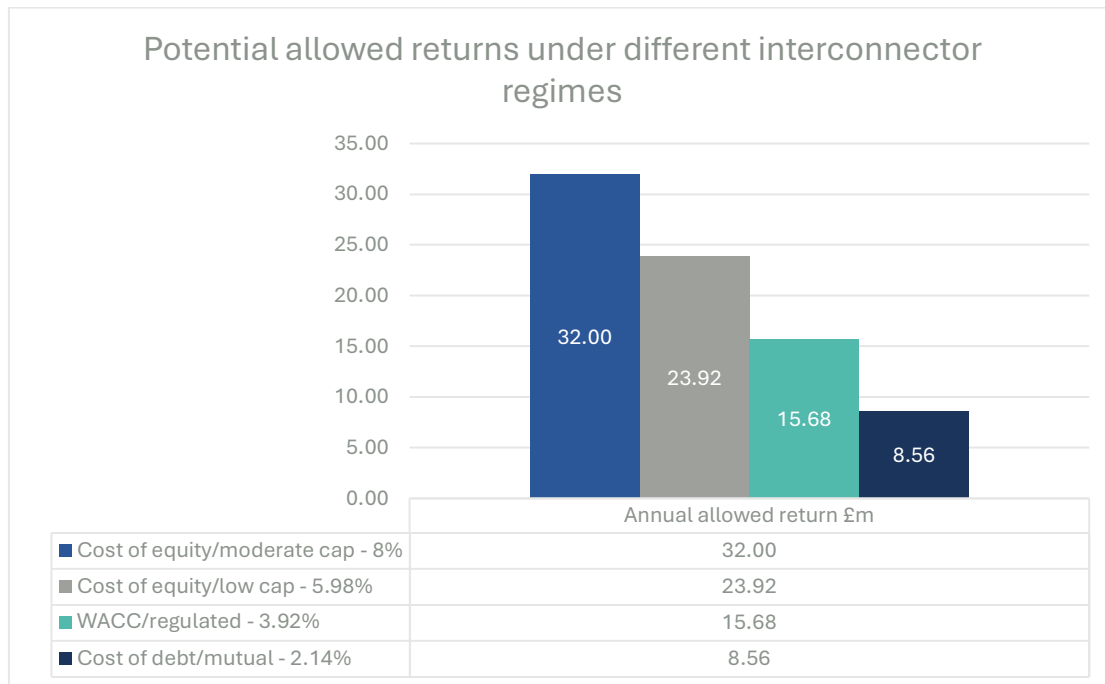
its construction cost after 4 years of operation. Under the cap and floor model, our observation is that the developer generally accepts limited risk in comparison to the returns available up to the cap. The key cost categories will be development, capital and operating. The risk associated with all but the latter is largely essentially transferred to consumers when setting allowances at the post construction review stage of the cap and floor regulatory process i.e. whilst the development costs are initially at risk and the developer entitled to a return, as long as they are not demonstrably inefficient the scale of risk associated with development and capital costs is limited and largely regulatory. Efficient operating costs are also recoverable, so again there is limited risk left with the developer other than some availability risk and the market risk that market spreads consistently do not generate revenues in excess of the floor. From review of cap and floor levels for interconnectors between GB and Europe¹¹, the spread between cap and floor rates of return is in the range of 7-9% real. In comparison to a regulated or mutual model this appears relatively generous and careful consideration should be given to the level of potential returns that are warranted for the actual level of risk accepted by the developer. We note that the EWIC¹² and Celtic¹³ interconnectors have been developed under the regulated model with, as expected, allowed WACCs well below the cap rates of return allowed on other GB interconnectors.

Referring to the most recent example of Celtic's proposed real WACC of 3.92% can be illustrative of the different potential developer returns and costs to consumers under the different models. The real cost of debt feeding into the Celtic WACC is 2.14% (which we could use as a proxy for a floor return or required returns under a mutual regime) and the real cost of equity in the Celtic WACC is 5.98% (we could use this as a proxy for a cap although we note that this cost of equity is based on an equity beta of 0.75 whereas a beta of 1.25 is typical in Ofgem and CRU cap and floor decisions i.e. we would expect a cap calculation based on these numbers to come up with a materially higher value). The chart below illustrates the extent of potential costs to consumers under each of these rates of return if we apply them to a regulated asset value of £400m. We also include an 8% cap in this illustration as this is in line with historic floor decisions.

¹¹ Includes Ofgem decisions on NEMO Link, North Sea Link, IFA2 and Greenlink and CRU decision on Greenlink.

¹²<https://cruie-live-96ca64acab2247eca8a850a7e54b-5b34f62.divio-media.com/documents/cer12149.pdf>

¹³https://consult.cru.ie/ga/system/files/materials/492/CRU202594%20-%20Price%20Review%20Six%20-%20Onshore%20Cost%20of%20Capital_428299_2.PDF



As is evident, there is a very large range of potential consumer costs (or returns to interconnector owners) under different models and UR should carefully consider whether the risk taken (or not taken) by consumers and developers under each option is commensurate with the cost. The Moyle Interconnector clearly demonstrates the feasibility and potential significant benefits of the mutualised regime. We therefore recommend that both this and a RAB regime are considered in Northern Ireland as an alternative regulatory support mechanism to a ‘cap and floor’ regime .

Q4. Do respondents agree with the criteria and principles to be applied during this assessment? If not, please provide details of other criteria/principles that may also warrant consideration.

The areas outlined in Table 6.1 in the consultation paper constitute a high-level framework for the needs case assessment. As a general observation, we would not consider these to be assessment criteria. They are more akin to a broad scope of works required to conduct the analysis. Formal criteria and their relative weightings will need to be clearly defined in advance of conducting the ‘needs case’ assessment. Setting appropriate weightings in advance is important, as it is possible that the assessment criteria being used could compete against each other – e.g. imports from GB may reduce wholesale pricing in SEM but could result in higher levels of dispatch down. We provide some initial thoughts below regarding potentially important areas assessment criteria should consider:

- To what extent would development of LirIC improve energy security in Northern Ireland?
- Will developing LirIC reduce overall system costs in the SEM?
- If so, will those system benefits result in cost savings for NI customers?
- Does LirIC help support and accelerate the decarbonisation of electricity production in NI?
- Does LirIC reduce the cost of decarbonising the NI electricity system?

- Does LirIC reduce the need for future network investment?
- Will LirIC help reduce the level of dispatch down of NI renewables?
- Will LirIC proceed in the absence of a regulatory support mechanism?
- To what extent will provision of regulatory support to LirIC reduce costs for NI consumers?
- What is the cost to customers of underwriting the financial risks faced by LIRIC under various regulatory support models?
- Does the cost to consumers of underwriting this risk represent a fair deal for consumers – i.e. considering all proven regulatory support regimes?
- What specific form of regulatory support delivers the best balance of risk and reward between investors and NI consumers?
- Does providing a form of regulatory support for LirIC provide better value for consumers than other potential technologies – e.g. long duration energy storage?

Our comments on the specific areas outlined in Table 6.1 are provided below.

Modelling Assessment and System Impacts Assessment

As set out in our answer to question 1 there is a high degree of uncertainty around how electricity markets in relevant jurisdictions will evolve out to 2050. There are therefore a myriad of assumptions that need to be carefully considered, not least the decarbonisation pathways markets will follow, the pace at which emission reductions are likely to be delivered, and the potential impacts various forms of ‘out of market’ support mechanisms might have on future market scheduling and pricing – e.g. renewables, hydrogen, CCS, storage, etc. There are also key assumptions regarding the timing of network upgrades – e.g. the delivery of the NSI in Northern Ireland - as well as the possibility of more fundamental changes to market arrangements, such as locational pricing, or a change to the rules governing the cross border trade of electricity.¹⁴

Based on the dynamics outlined in our answer to question 1, we suggest particular attention is given to the following areas:

- System security requirements, including consideration of any potential changes to capacity market de-rating factors that may result from increased reliance on interconnector imports to ensure SEM capacity adequacy¹⁵
- The legislated emission reduction targets in each jurisdiction and a considered view on whether targets will be delivered, and over what timeframe
- The potential impact on outcomes if legislated targets are revised – e.g. if political sentiment were to change in relation to the rate of decarbonisation
- The desired amount of renewable generation capacity installed locally in NI
- The rate of renewable build out in each relevant jurisdictions
- The rate of decarbonisation of dispatchable generation in relevant jurisdictions
- The approach to decarbonising dispatchable generation in relevant jurisdictions

¹⁴ Please refer back to footnote 1 above.

¹⁵ Would the requirement for SEM dispatchable generation in practice be proportionately reduced in response to further investment in GB interconnection? To what extent are SONI/EirGrid content to further increase reliance on interconnector imports to ensure system security, or will capacity de-rating factors need to be revised to maintain an adequate level of security?

- The marginal cost of dispatchable generation in relevant jurisdictions
- The rate of electricity demand growth in relevant jurisdictions
- The level of flexible demand in relevant jurisdictions
- Anticipated future investment in interconnection in relevant jurisdictions
- Anticipated future investment in energy storage in relevant jurisdictions
- Anticipated future investment in electrolysis in relevant jurisdictions
- The availability of blue hydrogen in relevant jurisdictions
- The marginal price of hydrogen in relevant jurisdictions
- The feasibility and cost of gas CCS on the island of Ireland
- The extent of network investment expected in Northern Ireland
- The timing of the deployment of network upgrades, including the NSI
- The ‘out of market’ support mechanisms employed in relevant jurisdictions
- The impact of ‘out of market’ support mechanisms in relevant jurisdictions on electricity market dynamics
- Potential impacts of material changes to market arrangements in relevant jurisdictions that may impact LirIC revenues – e.g. for capacity and system services
- The impact of zonal pricing in relevant jurisdictions – e.g. in SEM if the NSI is not delivered

As set out in our answer to question 1, we believe assumptions in these areas could have a significant impact upon the outcome of the ‘needs case’. We recommend that appropriate modelling sensitivities are therefore devised to quantify and qualitatively assess the potential level of upside and downside risk associated with the base case.

A specific area that should be assessed is the scale of the impact of the NSI on the needs case for the LirIC interconnector. There is a long history of the NSI being subject to legal challenge, and extensive ongoing delays. It would therefore seem prudent to run a sensitivity to quantify the scale of this risk, which in turn will facilitate an informed and balanced assessment of whether it is appropriate that NI energy consumers take on this risk – see our answer to question 5 below.

Another area that should be carefully considered is the future trading arrangements for interconnectors. Modelling indicates that significant benefits can accrue in markets from importing electricity that has a low marginal price because its production is being subsidised by consumers in the exporting market – e.g. under a regulatory support scheme. This dynamic can apply to both renewable and dispatchable generation, such as hydrogen and gas CCS, but may not be politically sustainable in the long term, particularly if benefits are asymmetrical, and persist over a prolonged period of time. As the general level of ‘out of market’ subsidisation is increasing, we believe it is worth at least running a sensitivity to understand the impact a change to interconnector trading rules could have – e.g. if subsidised power was not available for export or if it were assumed that a proportion of the subsidy had to be repaid to the exporting market.

It is also important that the market modelling does not just assess the impacts of developing LirIC for the SEM as a whole, but supports specific analysis of its impacts on the Northern Irish electricity system, and consumers.

Cost and Technical Assessment

We agree with the type of information being requested from LirIC to inform the ‘needs case’. However we are concerned that the time set out to complete the assessment is not sufficient. The regulatory process is being compressed to dovetail with Ofgem timelines, which significantly increases risk for NI consumers. Effectively the equivalent of Ofgem’s Initial Project Appraisal (IPA) and Final Project Appraisal (FPA) are being combined into a single process with a Draft Determination in Q3 26 (the IPA) ahead of a Final Determination in Q4 26 (the FPA). We believe this is problematic.

Substantial changes to modelling assumptions were implemented following consultation by Ofgem in March 2024 on their ‘minded-to’ IPA decision. This required further modelling work to be completed ahead of Ofgem’s final decision, taken in November 2024. We therefore are concerned that the timeframes proposed by the Utility Regulator will not provide sufficient time for meaningful consultation – i.e. for respondents feedback on the Draft Determination to be properly considered and, where appropriate, incorporated into the Final Determination. For example, current timelines are unlikely to be sufficient to facilitate the completion of further modelling work ahead of the Final Determination, which means there will not be an opportunity for industry stakeholders to meaningfully contribute to the assumptions used for the assessment. We are concerned that the proposed approach and aggressive timelines (to dovetail with Ofgem’s cap and floor process), while beneficial to LirIC, undermine the efficacy of the consultation process, inappropriately increasing risks for NI energy consumers.

We would also highlight the need to consider the extent to which, in practice, government, regulators and SONI will be willing to rely on electricity imports from GB to maintain security of electricity supply in Northern Ireland. This will determine the actual level of investment in dispatchable generation in Northern Ireland that will be offset by LirIC. In particular, it is worth considering whether there is likely to be any potential change to capacity market de-rating factors as a result of the development of the LirIC interconnector, which would have a negative impact on the benefits that accrue to the system (result in less dispatchable capacity being offset), as well as reduce the capacity market revenues paid to LirIC (which could then have an impact on regulatory support).

Other areas that warrant consideration include revenue expectations for interconnectors under any future arrangements for system services in SEM, as well as the expected future status of SEM-GB market coupling, and therefore whether forward capacity rights for SEM-GB interconnectors are sold forward. We would observe that, in general, all other things being equal, forward sales of capacity are likely to result in lower revenues for interconnector owners than out-turn market spreads. This is because a portion of the perceived value of the capacity product will tend to end up being shared with the capacity holder and, in the case of physical transmission rights, the mechanics of their use make it difficult to fully capture market spreads.

Deliverability Assessment

We recommend that the deliverability assessment conducted should consider more than just the decision between a ‘cap and floor’ regime and a merchant model, and we therefore welcome the drafting that has been employed in the consultation, which clearly recognises the possibility of other support mechanisms - e.g. “a regulated revenue regime, including a cap and floor model”.

As set out in our answer to question 3, there are proven alternative forms of regulatory support that could be considered for the NI side of the LirIC interconnector other than a cap and floor mechanism, including mutualisation and a RAB based model. If the needs assessment demonstrates there are benefits to the development of LirIC for Northern Irish energy consumers, and determines a regulated support mechanism is required to bring forward the investment, a thorough review of these potential mechanisms should be carried out by UR to determine the optimal mechanism, which appropriately balances risks and rewards between NI consumers and the developer.

The benefits of a mutualised approach to interconnector ownership are clearly evidenced by the Moyle interconnector in Northern Ireland. Northern Irish consumers have historically taken all the risk on interconnector investment (there is no regulatory support for the Moyle interconnector provided by GB and its 100% debt finance is underpinned by NI consumers) and in return receive all of the benefits. This has, on the whole, proved beneficial. Moyle Interconnector Ltd typically delivers availability in excess of availability incentive levels set by Ofgem for cap and floor interconnectors, has achieved savings to date of over £100m (as of March 2025) due to the low cost of capital enabled by the mutualised regime, and generates significant profit and cash to the benefit of NI energy consumers. In the case of LirIC, Ofgem have already agreed to provide a cap and floor for the GB side, but a move away from the mutual model on the NI side would need to be demonstrated to be in the long-term interests of NI energy consumers. The concern is that under a cap and floor NI consumers could end up taking on the majority of the risk (on the NI side) but receiving only a very limited proportion of the benefits.

While the mutual model for interconnection has delivered benefits for NI consumers, we also recommend that a RAB based support model is also considered, as well as the myriad of potential design options for a cap and floor regime, including: the approach to the floor calculation, whether there should be profit sharing between the floor and any cap introduced, the level of any cap, and the appropriate approach to profit sharing above the cap.

The decision regarding whether to provide LirIC with regulatory support, and the subsequent decision regarding the most appropriate form of regulatory support, will have major long-term impacts on the SEM, the NI electricity system, and NI energy consumers. **Given the scale and complexity of the work that needs to be undertaken to properly consider these issues, Mutual Energy is concerned that the proposed process and timelines outlined in the consultation, conflating the needs assessment with the decision on regulatory support, are not sufficient, and impose a substantial, and unjustified risk, on NI energy consumers.**

Q5. Do respondents support the proposed parallel work to be commenced in Q3 2026 regarding the development of a regulated operating revenue regime framework? If not, please provide supporting details.

Our primary concerns with the parallel work being proposed are set out below:

- 1) The proposed nature of the parallel work seems to presuppose that, if the needs case for LirIC is positive, and a regulatory support mechanism is deemed necessary to bring forward investment, development of a cap and floor regime is the next 'logical' step – see annex A of the consultation. In the absence of any detailed analysis or evidence, and in the context of a mutualised regime successfully operating in Northern Ireland, as

well as RAB models being used in other jurisdictions, including for the Celtic interconnector in Ireland, we would contend that this presumption is unwarranted.

- 2) The compressed timeframes being suggested, and the resulting substantial contraction of the regulatory process necessary to deliver them (again evidenced by the ‘two-step’ licensing process and parallel work proposal within the consultation), results in unjustified risks being imposed on NI energy consumers. **Given the potential significant long-term implications of the regulatory decisions being taken it is essential that sufficient time is taken to carefully analyse, and to properly consider and consult upon the complex issues associated with the development of further electricity interconnection in Northern Ireland.** This will help to ensure an optimal outcome is achieved for energy consumers. We therefore recommend that UR engage with Ofgem to request they grant an extension to LirIC under their cap and floor process to facilitate the necessary work in Northern Ireland to be carried out, in a thorough and measured manner.

As a final observation, **consideration should be given to whether NI energy consumers should take the risk of providing regulatory support to LirIC ahead of the commissioning of the NSI.** Unfortunately, there is a long history of legal challenges and extensive delay to the development of the NSI, and while it is currently anticipated that it will be operational by 2032, there is no guarantee that this will be the case. **Subject to the outcomes of the needs case assessment, including formal quantification of the potential impacts of the NSI, careful consideration should be given to whether any decision to grant regulatory support is made conditional upon the successful commissioning of the NSI.**



Appendix 1: Modelling Assumptions

Section A: General Modelling Assumptions

I-SEM Modelling Assumptions

Given the policy landscape, relative to the progress made on their delivery assumptions were made on what the I-SEM market will look like in future


- For this project, modelling is undertaken from 2035 to 2050 to understand the impact of additional interconnection in I-SEM.
- This requires assumptions on what the future system across Ireland will look like, including future demand, capacity mix and commodity prices
- The counterfactual for demand and generation capacity based on the Eirgrid and SONI 2024 Tomorrow's Energy System scenarios. A combination of the Gas Evolution and Constrained Growth scenarios were used, with key assumptions as outlined in the table.

Data item	Counterfactual	All-Island values in selected years
Demand	2035-2050: TES GE scenario.	2035: 70.7 TWh, 2050: 94.1 TWh
Peak Demand	2035-2050: TES GE scenario.	2035: 12.1 GW, 2050: 15.5 GW
Onshore wind capacity	2035-2050: TES CG scenario.	2035: 11.9 GW, 2050: 14.9 GW
Offshore wind capacity	2035-2050: TES CG scenario.	2035: 2.5 GW, 2050: 17.5 GW
Solar capacity	2035-2050: TES CG scenario.	2035: 7.8 GW, 2050: 15.2 GW
Hydrogen generation capacity	2035-2050: Adjusted TES GE scenario (conversion of CCGTs takes place with a delay, from 2040-2050)	N/A
Pumped hydro storage capacity	2035-2050: TES CG scenario.	2035: 0.65 GW, 2050: 0.65 GW
Interconnection capacity	Greenlink commissioned in 2025 and Celtic IC in 2027.	2035: 2.2 GW, 2050: 2.2 GW




Connected Market Assumptions

Assumptions for GB and France are taken from published scenarios by NESO and ENTSO-E respectively

Energy market in GB 

- For the GB market, we use the **Hydrogen Evolution (HE) scenario** from NESO's Future Energy Scenarios (2024).
 - One adjustment is made, delaying the rollout of offshore wind by five years because the rate assumed in FES is unlikely to be realistic.
- We have chosen HE to use given this appears to be the **most consistent GB scenario** to the Irish market assumptions.
- The HE scenario involves:
 - System driven change
 - Power sector becoming net negative by 2035
 - Wider (though still reasonable) use of hydrogen for home heating, industry and fuel – excess hydrogen production enables an export market
 - Hydrogen is produced largely through methane reformation and electrolysis

Energy market in France 

- Assumptions for France are taken from ENTSO-E's TYNDP publication and align with the Global Ambition scenario.
- This scenario achieves Net Zero by 2050 across Europe driven by a fast and global move towards the Paris Agreement targets.
- It is considered more realistic than the distributed energy scenario as it assumes a wider range of power sector technologies are used in the transition to Net Zero.



Interconnector assumptions

Various assumptions are made on the current and future interconnectors connecting into I-SEM

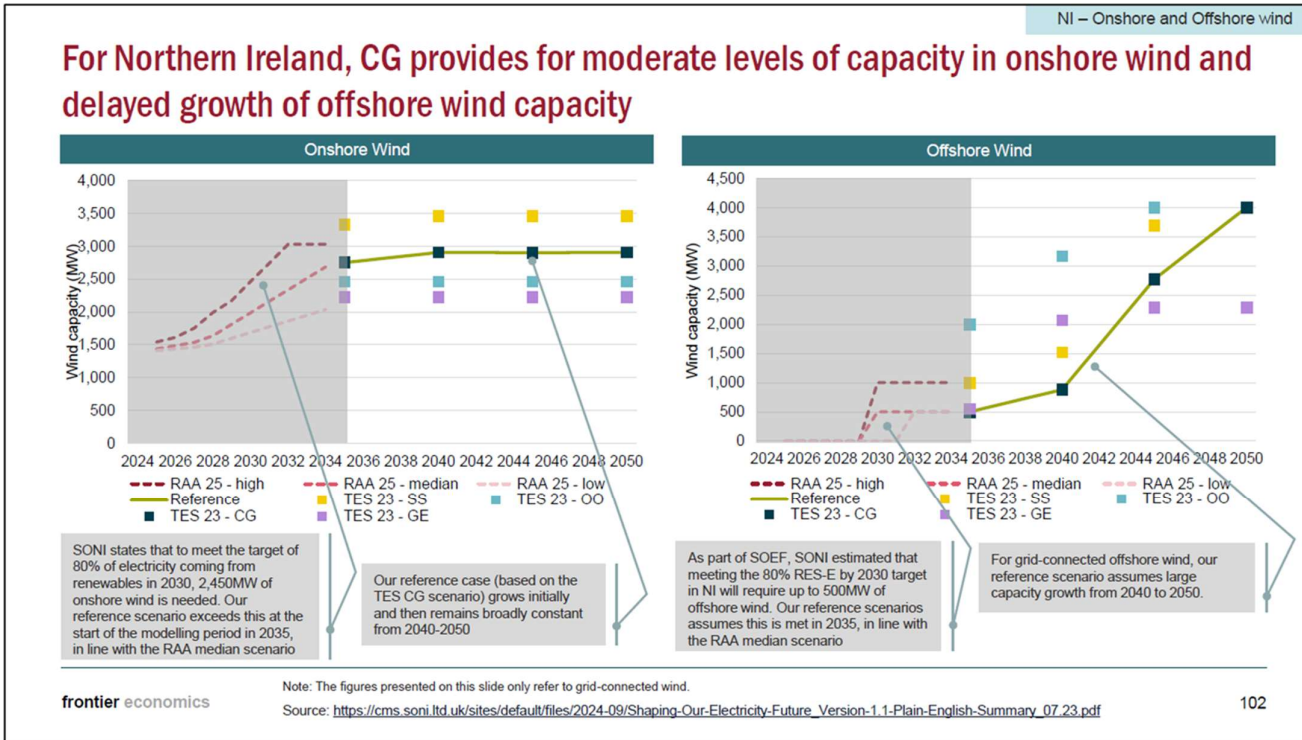
- Assumptions on interconnection capacity growth are guided by an assessment of the pipeline of specific interconnection projects. This is because the construction of interconnection involves cooperation with other countries, which takes a considerable amount of time (e.g., cap and floor approval processes in UK/Ireland; just obtaining PCI status can take up to 3 years), and there is evidence that there will be a shortage of supply for cables over the coming decade given competition from other transmission and interconnection projects.
- Interconnection to GB:** LiriC and Mares have both recently passed Ofgem's Initial Project Assessment for receiving support under the cap-and-floor scheme. While NESO modelling assumes the year of commission is 2030, we are providing for a 5-6 year delay to their build, in light of experience of other interconnector projects previously built under the cap-and-floor scheme.
- Interconnection to Europe:** Celtic Link to France is already under development expected to come online by 2027. We provide for an additional interconnector to France in 2040, which is guided by the DECC Interconnector Policy Statement in RoI but modelled with a five-year delay.*
- The assumptions for each of the interconnectors, including the current interconnectors between GB and I-SEM (Moyle, EWIC and Greenlink) are outlined in the table opposite. This includes the connected country, the size of the interconnector, the assumed commissioning year, electrical losses and ownership (for the system cost calculation).

Interconnector	Connected Country	Size, MW	Commissioning Year	Losses	Ownership
Moyle	GB	500	Already online	2.36%	100% I-SEM
EWIC	GB	505	Already online	4.68%	100% I-SEM
Greenlink	GB	504	Already online	2.32%	50:50
Mares	GB	750	2035	3.00%	50:50
LiriC	GB	700	2036	2.80%	50:50
Celtic	France	700	2027	6.00%	50:50
Future Europe IC	France	700	2040	6.00%	50:50

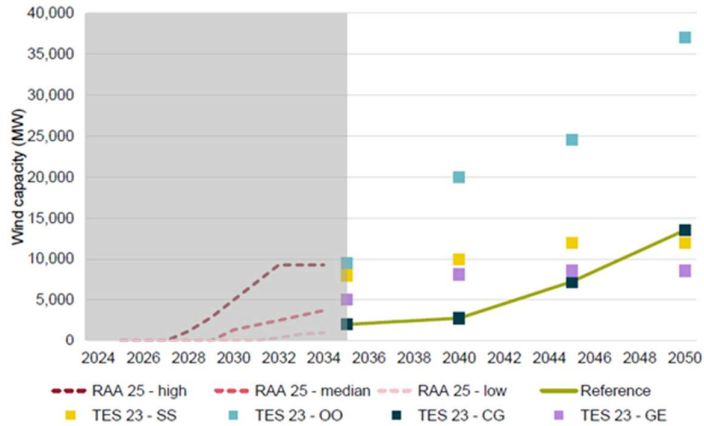
* *We will establish our anticipated interconnection needs to be tested against technical feasibility, financial viability and benefits to the State and people ... A second connection to France by the middle of the next decade. This will build upon the collaborative relationship between EirGrid and the French TSO in progressing the Celtic Interconnector.* <https://assets.gov.ie/static/documents/national-policy-statement-on-electricity-interconnection-2023.pdf>



Section B: SEM Offshore Wind Assumptions



We follow CG for offshore wind which provides for delayed deployment as compared to targets, reflecting ongoing challenges to the development of this sector in Ireland



- Compared to other more ambitious TES scenarios, CG assumes that there is delayed deployment of grid-connected offshore wind relative to CAP targets and the RAA – median forecasts.
 - The ambitious CAP 2024 offshore wind target for 2030 (5GW) is achieved with a 13-year delay by 2043.
- Using the more conservative CG scenario, which is more in line with the low RAA scenario, factors in the risk that Ireland does not have the necessary capability (notably the offshore transmission system) to achieve the levels of grid-connected offshore wind envisioned in the CAP targets over the coming decade (see next slide).

Note: The figures presented on this slide only refer to grid-connected offshore wind.

Current indications suggest that a significant scaling up of offshore wind in Ireland will be challenging due to several factors

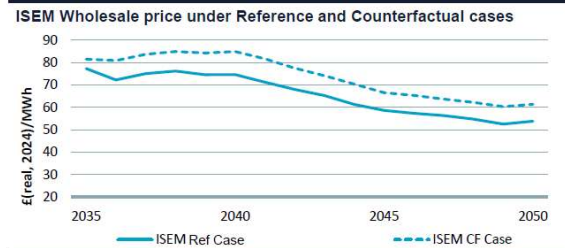
Grid connection	<ul style="list-style-type: none"> ■ The IWEA¹ previously estimated in 2020 that in a BAU scenario Ireland will only deliver 670 MW of offshore wind by 2030 . ■ The main bottleneck identified was grid capacity. According to Eirgrid, there is currently only 1.5-2 GW of capacity available on the east coast for offshore wind, which means that without major upgrades it will not be possible to meet the 5 GW ambition.
Industrial strategy	<ul style="list-style-type: none"> ■ Since then, Ireland has completed an offshore wind auction (with another to follow in Q4 2025) and set out a comprehensive strategy (<i>Offshore Wind Industrial Strategy - 2024</i>) for growing their offshore wind industry. This strategy covers the short-term actions required to meet the 2030 targets and the long-term actions required to grow the industry and meet long-term targets. ■ However, the strategy has only been recently published and, according to Wind Energy Ireland, there are insufficient resources in place to resource the planning of infrastructure required, which suggests that grid connection may remain an ongoing issue.² Wind Energy Ireland have previously suggested the required actions to meet 2030 targets were mostly being met, but behind the schedule required.³
Economics of buildout	<ul style="list-style-type: none"> ■ The 37GW assumed in the offshore opportunity TES scenario is high as a proportion of peak demand (15-17GW by 2050, according to TES) in comparison to other countries. For example, GB is aiming towards 80-100GW of offshore wind by 2050, with peak demand between 100-120GW (according to NESO FES)⁴. ■ This level of rollout would have the Irish system highly geared towards offshore wind, greatly surpassing peak demand levels. Qualitatively, the system would likely require high levels of flexibility (e.g. interconnection, electrolyser capacity) to make this economic for developers. It is not clear whether this level of flexibility to accommodate wind would be economical.
Required scale up in comparison to GB	<ul style="list-style-type: none"> ■ GB has developed around 13GW of offshore wind capacity since its <i>Offshore Wind Industrial Strategy 2013</i>, with over 10GW from auctions in development.⁵ The TEC register for all proposed and unbuilt capacity is over 100GW.⁶ Therefore, while GB has an ambitious plan, it also has a pipeline of projects ready to deliver. It has taken the UK 15 years to reach that industry maturity. ■ However, Ireland is still in the early stages of developing its industry and while there are several projects in development, there is not yet a track record for delivering the required projects at scale. ■ It may be possible for Ireland to scale up its offshore wind capacity in future, but there is limited evidence of delivery and it is unclear how the energy system would manage the capacity assumed in <i>Offshore Opportunity</i>.



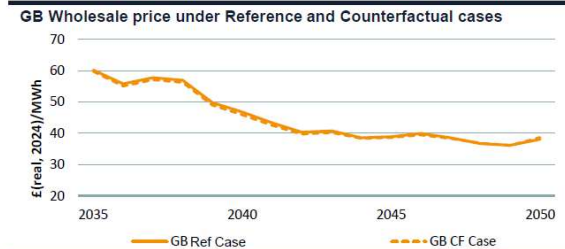
Section C: Potential impacts on wholesale market pricing

Wholesale price change

The addition of LirIC and Mares leads to a decrease in the I-SEM wholesale price



- The addition of LirIC and Mares results in increased imports to that displace more expensive gas and hydrogen generation in ISEM and thus reduces wholesale prices.
- Under the reference case, wholesale prices drop by an average of 11% or £8.4/MWh compared to the counterfactual.
- This is an important driver of the decrease in congestion rents for interconnectors.
- In comparison, there is very little change in the GB wholesale prices with the addition of LirIC and Mares because the export volumes relative to the overall size of the GB market are small.



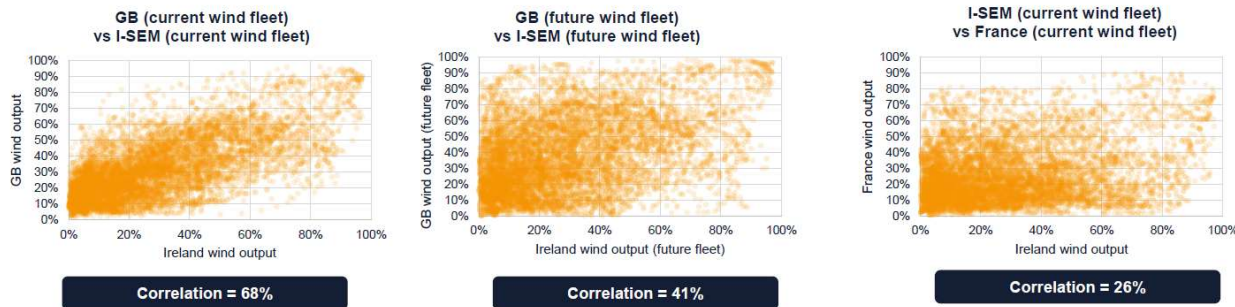


Section D: Coincidence in GB/SEM wind generation

Capturing interconnector fundamentals

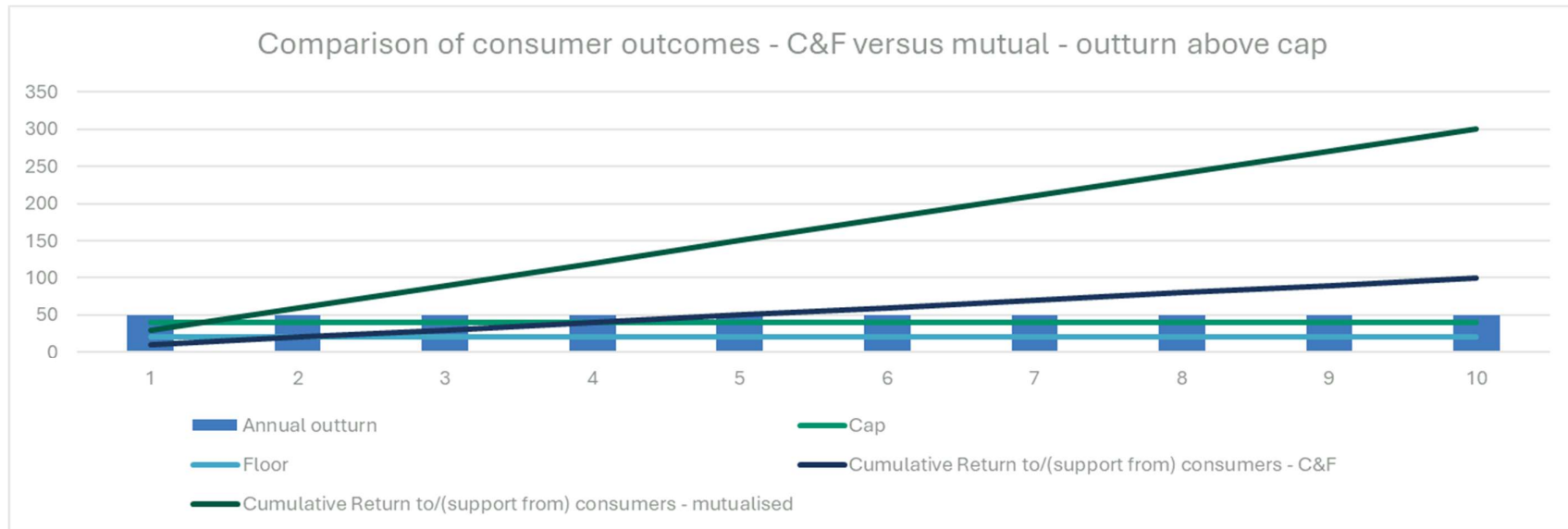
Our modelling captures the underlying fundamental drivers of interconnector value

- As the I-SEM and GB power systems decarbonise and become increasingly dominated by wind, electricity prices will be increasingly driven by renewable generation patterns in addition to demand.
- This presents an opportunity for interconnection. Wind output is typically much less correlated between markets than demand, leading to price differentials and arbitrage opportunities. The location of this wind is also important. As shown below, the output of the current GB and I-SEM wind fleets are relatively correlated (~68%), but as new wind is added in more geographically remote offshore locations, the future wind fleets' correlation (in 2030s) will decrease (~41%). However, competing interconnectors between more geographically separated markets could have even larger opportunities, with the current Irish and France wind fleets' correlation only 26%.
- Our modelling reflects these correlations, with detailed geospatial modelling capturing the changes in the location of the wind fleets over time.

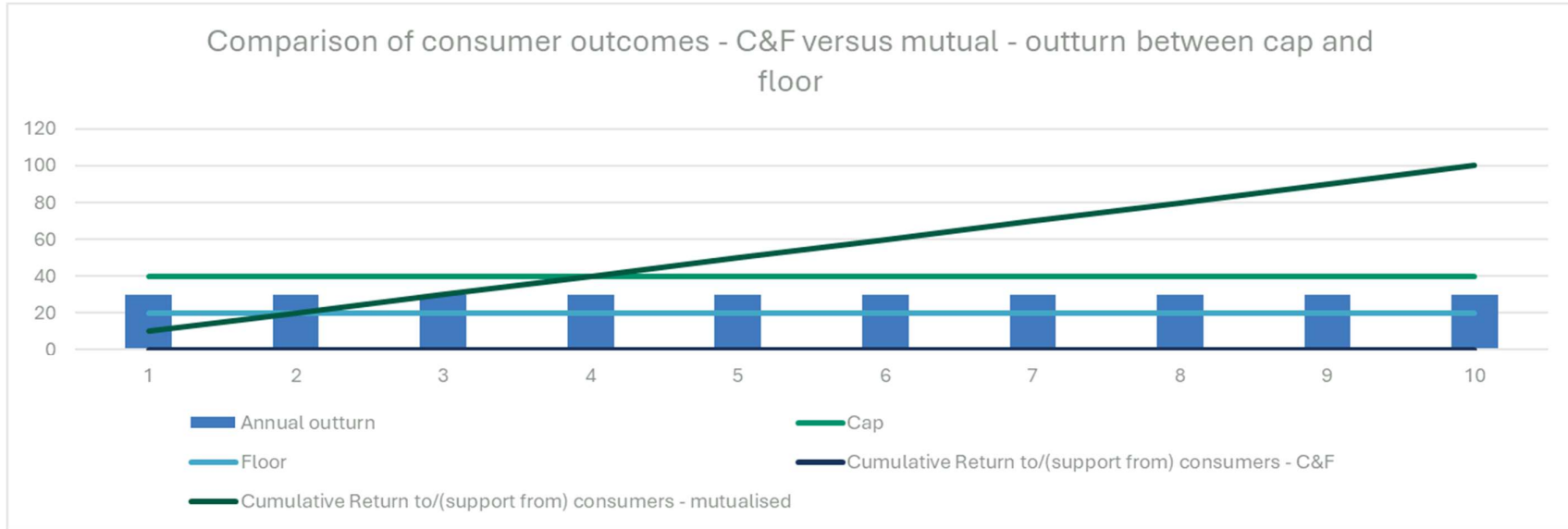




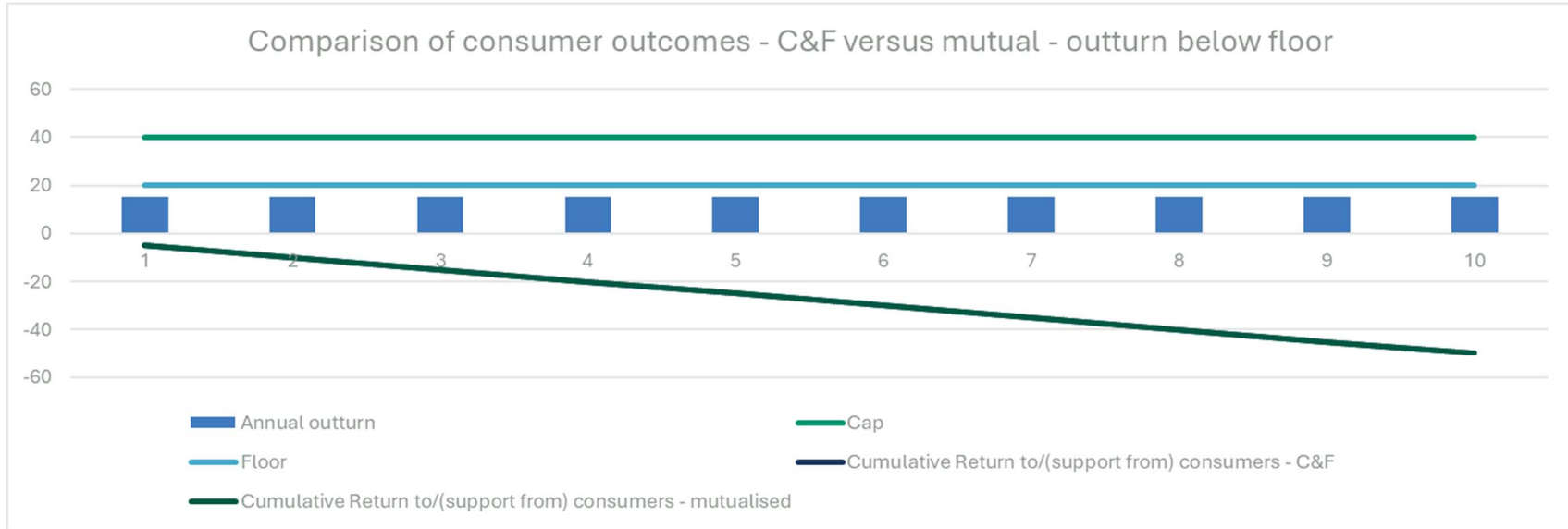
Appendix 2: Supplementary charts



In this example an outturn of £10m above the cap returns a cumulative £100m to consumers under a cap and floor. With a mutualised model revenues above the *floor* accrue for the benefit of consumers, with a cumulative benefit of £300m.



In this example an outturn of £10m above the floor does not return anything to consumers under a cap and floor. With a mutualised model revenues above the floor accrue for the benefit of consumers, with a cumulative benefit of £100m.



In this example an outturn of £5m below the floor results in the same outcome under a cap and floor or mutualised regime, with consumers providing cumulative support of £50m in both cases.