Report on the impact of additional interconnection and storage in Northern Ireland

Department for the Economy (DfE)

22 December 2025

FINAL REPORT

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Contents

Table of Defined Terms

AIRAA	All Island Resource Adequacy Assessment
BAU	Business As Usual
BM	Balancing Market
C&F	Cap & Floor
CBA	Cost Benefit Analysis
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
CHP	Combined Heat and Power
CM	Capacity Market
CO2	Carbon Dioxide
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
DASSA	Day Ahead System Services Auction
DfE	Department for the Economy
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators for Electricity
ESB	Electricity Supply Board
ETS	Emissions Trading Scheme
EU	European Union
EWIC	East West Interconnector
FES	Future Energy Scenarios
GB	Great Britain
H2P	Hydrogen to Power
HVDC	High Voltage Direct Current
IDM	Intraday market
LAES	Liquid Air Energy Storage
LDES	Long Duration Electricity Storage
LOLE	Loss of Load Expectation
OCGT	Open Cycle Gas Turbine
OTC	Over the counter
NESO	National Electricity System Operator
NI	Northern Ireland
NSI	North South Interconnector
PPA	Power Procurement Agreement
PSH	Pumped Storage Hydro
PSTRw	Strike Price
RA	Regulatory Authorities
REMA	Review of Electricity Market Arrangements
RES	Renewable Energy Sources
REPG	Renewable Electricity Price Guarantee
RO	Reliability Option
SEM	Single Electricity Market
SMR	Small Modular Reactor
SNSP	System Non-Synchronous Penetration
SONI	System Operator Northern Ireland
TES	Tomorrow's Energy Scenarios
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan

1. EXECUTIVE SUMMARY

Scope of work:

The Department for the Economy (DfE) of Northern Ireland (NI) commissioned CEPA to model and assess different future scenarios of interconnection and storage in NI. The overall goal of this research is to assess the costs and benefits to NI consumers of increasing interconnection or storage alternatives.

This report sets out the findings of CEPA's study, which conducts market modelling simulations, using our hourly pan-European electricity dispatch model.

We have calibrated a range of scenarios in agreement with DfE (a business-as-usual scenario and three alternative scenarios) reflecting different levels of interconnection and storage to support the analysis of the costs and benefits of increasing each within NI's energy system. In the Basecase we have modelled the effect of an increase in GB-NI interconnector capacity of 700 MW (reflecting the proposed LirIC interconnector project), and an additional 250 MW pumped-hydro storage facility and 1,775 MW of additional storage, both from short and medium duration.

Modelling has been carried out for the year 2034.

Findings:

Commercial case: The commercial case for Short-duration storage is modelled to be sufficient for a project to break even. However, medium and long-duration storage is modelled to not achieve a sufficient return, owing to the size of capital costs. The commercial case for interconnection is modelled to be sufficient to be positive, with an interconnector earning a return in excess of its revenue requirements.

Economic case: Additional GB-NI interconnection is modelled to have a *positive* net welfare impact to society of £22.7m per year, principally through achieving a reduction in wholesale prices. The additional storage capacity is modelled to have a *negative* net welfare impact of £34m per year, principally due to the operational benefits not matching the high cost of building the assets. However, it is noted that this result reflects the combination of adding a mix of short, medium and long-duration storage, whereas a focus on short-duration storage would be more likely to have a positive societal impact. It is also noted that longer-duration storage may be likely to have more material security of supply benefits which our modelling framework does not fully capture.

Wholesale price impact: Additional GB-NI interconnection is modelled to reduce SEM wholesale prices by £3.20/MWh in the Basecase (equivalent to a 5% reduction) by enabling additional imports from GB at times of renewable curtailment in GB when prices there are low or zero. By contrast additional storage is modelled to put upward pressure on SEM wholesale prices of £0.40/MWh (equivalent to a 0.5% increase) by increasing demand in periods when there would otherwise be curtailment of renewables.

Renewable generation and carbon impacts: Both increased storage and increased interconnection are found to reduce the degree of dispatch down of renewables in SEM – dispatch down of surplus NI renewables in the Basecase falls by 13% with the additional interconnector and by 4% when you add the additional storage. However, the extent to which increased interconnection reduces dispatch down may depend on how effectively the TSOs for SEM and connecting markets can take action to reverse the interconnector flows to help manage constraints. The combined effect of the increase in interconnector and storage capacity is to reduce modelled SEM-wide carbon emissions in the power sector by up to 4.5%, although the modelled reduction in NI emissions is smaller and in some cases has an upward effect where it leads to increased thermal generation in NI.

Interconnector flows: Across all scenarios, interconnector flows are fairly balanced between imports and exports, with NI exporting to GB slightly more than it imports. This is a change to existing market dynamics, where the lower cost of gas generation in GB leads to NI being a net importer from GB in many hours. The driver of this change is the decarbonization of both the SEM and GB markets, with interconnector flows in future increasingly determined by which market has excess renewables in a given hour – which is a function of changeable weather conditions and the degree of excess supply in each market.

Security of supply: Our analysis did not identify a reduction in lost load events from the additional interconnector or storage capacity. However, this may reflect the nature of the modelling approach – which assumed perfect foresight of demand and a single weather year. Further security of supply studies could demonstrate the value that the assets have in the event of an unexpected outage or a prolonged period of high demand and low renewable generation.

2. INTRODUCTION

As part of the identified actions from the Energy Strategy Action Plan for 2024 (March 2024), the Department for the Economy (DfE) of Northern Ireland (NI) commissioned CEPA to model and assess different future scenarios of interconnection and storage in NI. The overall goal of this research is to assess the costs and benefits to NI consumers of increasing interconnection or storage alternatives.

This report sets out the findings of CEPA's study, which conducts market modelling simulations, using our hourly pan-European electricity dispatch model.

We have calibrated a range of scenarios in agreement with DfE (a business-as-usual scenario and three alternative scenarios) reflecting different levels of interconnection and storage to support the analysis of the costs and benefits of increasing each within Northern Ireland's energy system. Modelling has been carried out for the year 2034, as this is the last year included in the most recent electricity forecast published by SONI and EirGrid (AIRAA 2025-2034).

This report is structured as follows:

- Section 2 provides an overview of the market in NI, GB and Ireland relating to interconnection and storage.
- Section 3 sets out the methodology applied in the market modelling, including consideration of the limitations to this approach.
- Section 4 sets out the modelling results in terms of the commercial assessment of the interconnector and storage assets assessed – i.e. whether these assets are likely to be commercially viable without public support.
- Section 5 sets out the modelling results in terms of the economic assessment of the interconnector and storage assets assessed – i.e. whether they are a net benefit to society, including assessment of impacts on NI consumers, producers, and environmental impacts.
- Section 6 summarises the conclusions from the modelling.
- Appendix A provides further detail on the key inputs and sources that have informed the modelling.

3. MARKET OVERVIEW

This section provides a general introduction to electricity markets, with a focus on arrangements in Northern Ireland, Ireland, and Great Britain (GB). Its purpose is to present the wider market and policy context surrounding the scenarios we have modelled as part of this work – which focus on the value of additional storage and interconnection in Northern Ireland. As such, this market overview focuses particularly on markets, regulatory models, trading arrangements and business models which are relevant to better understand the modelling work discussed in subsequent chapters.

The market overview is structured as follows:

- Section 3.1 provides a general introduction to electricity markets, focusing on markets and trading arrangements which are relevant to the Northern Irish context.
- Section 3.2 provides an overview of how the generation mix is expected to change within the time horizon considered in our modelling work, as the power sector in Northern Ireland and elsewhere decarbonises.
- Section 3.3 discusses interconnection, including an overview of existing and planned interconnector projects between the island of Ireland and GB, trading arrangements, and regulatory models for interconnectors.
- Section 3.4 discusses electricity storage, including an overview of the most relevant storage technologies, the business model underpinning electricity storage, and planned policy support schemes to incentivise investment into storage.

3.1. INTRODUCTION TO ELECTRICITY MARKETS

Electricity is a commodity, traded in competitive markets much like other commodities such as oil or gold. However, unlike physical commodities, electricity cannot be easily stored – at least not cheaply and at scale. At the same time, electricity is a basic necessity for domestic and commercial consumers, as well as a key input into most industrial processes. In order to avoid blackouts, which have vast societal costs, electricity markets therefore need to operate in such a way that supply exactly matches demand at all times, on a second-by-second basis.

For this reason, and because of the scale and technical complexity of modern electricity systems, electricity markets are articulated across different time horizons, with a variety of different actors, and covering a variety of different good and services – beyond the simple trading of electricity as a commodity. In this section, we provide an overall introduction to the most important of these markets and actors. We focus particularly on the Northern Irish context and the Single Electricity Market (SEM) on the island of Ireland, as well as arrangements in GB – which is currently the only other market that the SEM is physically connected to.

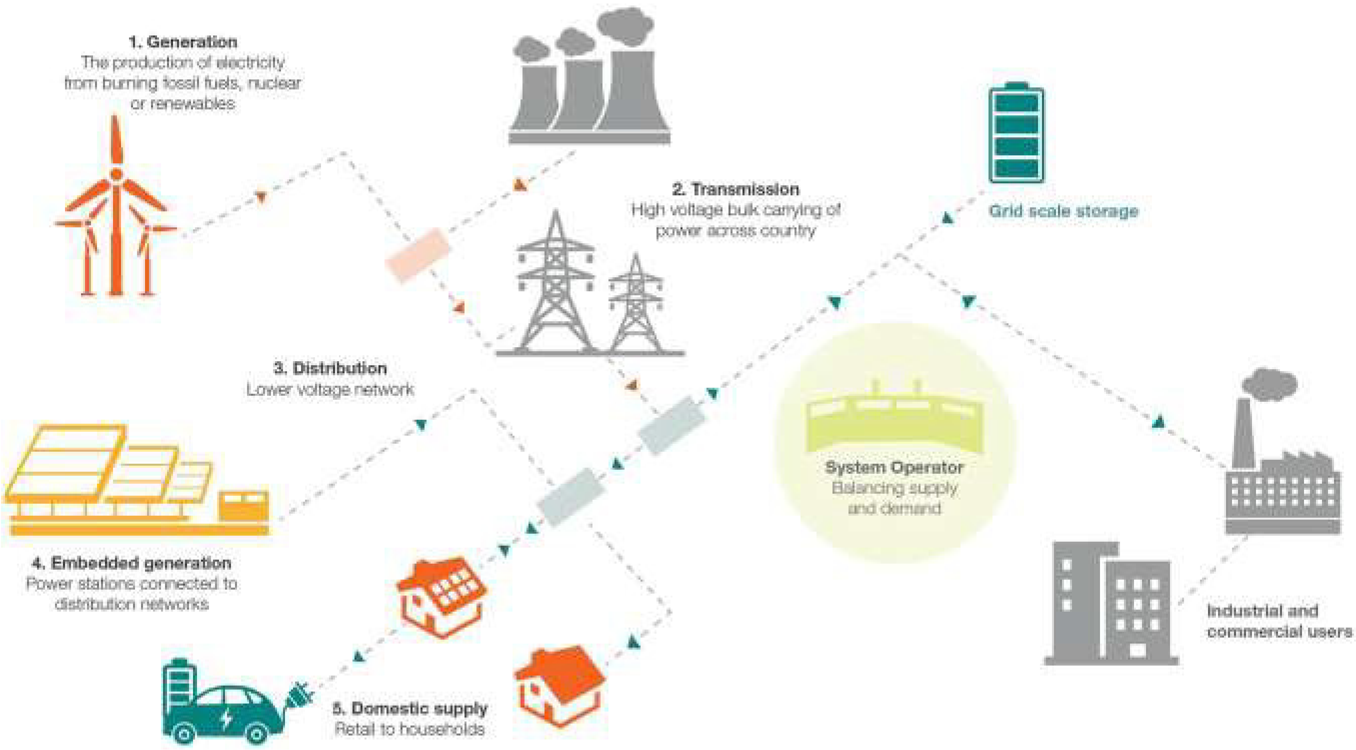
3.1.1. Key players and value chains

Ensuring that electricity demand from households and businesses is always met in real time relies on a large number of activities, including:

- **Production** by generators, including fossil fuel-based and renewable generation;
- **Transportation** through high-voltage transmission and lower-voltage distribution networks, which connect the generation with final demand;
- **Interconnection** between different electricity systems, enabling electricity produced in one system to be consumed in a different one and vice versa, up to a given technical capacity;
- **Electricity storage**, such as through grid-connected batteries which charge at times of excess supply and discharge during periods of excess demand; and

- **System operation**, i.e. the process of managing the flow of electricity across power grids, ensuring a stable supply by ensuring that electricity generation always matches demand in real time, and maintaining proper voltage and frequency levels across the system.

Figure 3.1: Overview of the energy system



Source: Energy UK

These activities are undertaken by a set of different actors, including:

- **Generators**, who own the generation assets.
- **Traders**, who buy and sell electricity in the relevant markets.
- **Network companies**, who own and operate the transmission or distribution network. In Northern Ireland, there is one network company owning both the transmission and the distribution network (Northern Ireland Electricity Networks). Typically, these companies are regulated regional monopolies, barred from also engaging in electricity generation or trading, and recover their costs via system charges on users of the electricity system.
- **System operators**, who are responsible for system operation as defined above. In Northern Ireland, this is undertaken by the System Operator for Northern Ireland (SONI), which is part of the same group as the operator for Ireland (EirGrid). In GB, it is undertaken by the National Energy System Operator (NESO).
- **Energy suppliers**, who buy electricity on behalf of their customers, and sell it back to them in the form of longer-term contracts. Suppliers compete for customers in the retail market, which is where domestic consumers and most businesses actually buy electricity for final consumption.

The trading of electricity primarily happens in the **wholesale market**, where electricity is sold by generators, traded, and ultimately bought by energy suppliers on behalf of their customers. The remainder of this section discusses the wholesale market in more detail, alongside other, related markets such as the balancing market and markets for ancillary services.

3.1.2. Sources of revenue for generators

At the wholesale level, electricity is bought and sold for specific time periods – typically, for every hour or half hour – based on forecasts of electricity demand for that given time period. Since demand forecasts become more accurate closer to delivery time, generators continue to re-assess their generation positions as time goes on. At the same time, for the system to work, a number of technical and physical constraints need to be met and accounted for at all times – including transmission constraints, voltage and frequency requirements.

In order meet all these constraints and allow generators to optimally schedule their dispatch in order to meet demand, electricity trading happens across several markets, spanning different time periods. Sections 0 and 3.1.4 describe how these markets are defined in terms of timing and geographic scope, respectively.

Selling electricity in the wholesale market is the primary way for generators to earn a revenue, but it is not the only one. In order to meet the various technical constraints referred to above, the system operator typically relies on a variety of "ancillary services" from generators (or storage operators), which it remunerates through separate contracts or auctions for each service. The principal ancillary services include:

- **Frequency response:** fast response by generators to adjust their output in order to stabilise system frequency when there are fluctuations in supply or demand. The flow of electricity through the network needs to be maintained at near-constant frequency in order to avoid damages to the network. These services are typically offered by generators with very fast response times, such as batteries or fast-ramping gas turbines.
- **Operating reserves:** services offered by generation assets which are kept on hold and ready to quickly increase their generation if called upon by the system operator, in order to meet sudden changes in supply or demand.
- **Voltage control:** generators adjusting their level of voltage to ensure that throughout the entire grid voltage levels are maintained constant, in order to avoid grid instability.
- **Black start capability:** offered by generators which have the capacity to restart part of the grid after a blackout, without the need to rely on external power.

In the SEM context, many of these ancillary services are currently remunerated through fixed tariffs set by the regulator, as part of the DS3 framework. As part of the Day Ahead System Service Auction (DASSA), SONI and Eirgrid are introducing volume-based competitive auctions for some of them in 2027, with the overall intention to procure more ancillary services through auction-based mechanisms in the future.[1] In GB, many ancillary services are already procured in competitive auctions.

In addition to being remunerated for ancillary services, generators can also receive other forms of revenue which are linked to policy support schemes, including the Capacity Market (CM) or Contracts-for-Difference (CfDs). Since these are effectively policy support schemes, they are described in detail in Section 3.2.2.

[1] Phased Implementation Roadmap

3.1.3. Trading arrangements

As discussed in the previous section, the need to balance supply and demand for electricity in real time means that forecasting electricity demand is of great importance to generators, who re-optimise their position based on increasingly accurate forecasts as time approaches delivery. In practice, the way this is achieved in the wholesale market is through a market structure which consists of several successive electricity markets. They are:

- Forward markets;
- The Day-Ahead Market (DAM);
- The Intra-Day Market (IDM); and
- The Balancing Market (BM).

Forward markets

Long before delivery time, generators, traders, and electricity suppliers begin to trade electricity with each other. These trades typically concern baseload electricity generation, i.e. the amount of electricity that can reasonably be expected to be consumed (and produced) regardless of specific forecasts. Forward trades – and trades of electricity more generally – can be either “physical” or “financial”.

Physical trades establish obligations for physical delivery of electricity generation at the agreed time. This means that if market participants commit to a certain buy or sell position in physical markets, they will face financial charges in the BM as part of the trading and settlement code if they are unable to adhere to these commitments. The reasoning for this is that the TSO will then need to take actions to ensure the physical balance of the system, and there are costs associated with moving another participant way from its physical position to ensure that supply and demand is balanced. By contrast, financial trades do not involve such an obligation.

SEM arrangements

In the SEM, all forward trading is financial, meaning that it does not involve commitments to physically generate electricity.

Instead, market participants in SEM can hedge their positions on generation and load served by purchasing financial contracts-for-difference (CfDs) at a strike price referenced to the price of one of these physical markets – most commonly the DAM. The structure of CfDs is explained in more detail in Section 3.2.2 (in the context of CfDs to support renewable generation), but essentially they involve agreeing a set value – called the “strike price” – for a given “reference price” ahead of time. Settlement is then based on the difference between the strike price and reference price rather than on the actual delivery of electricity.

As an example, a generator might sell a financial hedge contract at €100/MWh, referenced to the DAM price, for a certain day in March. If on that that day the DAM price is €110/MWh, the generator will pay the counterparty €10/MWh. However, if the market price is €90/MWh instead, the counterparty will pay the generator €10/MWh. This is a way for market participants to effectively agree electricity prices in advance, sometimes long before actually trading positions in physical markets.

However, the forward market in the SEM is not very liquid. A large proportion of volumes takes the form of “directed contracts” (a form of CfD) between electricity suppliers and the Electricity Supply Board (ESB), which faces obligations to act as market maker in the forward market owing to its dominant position in the SEM market. Directed Contracts are currently offered for up to four quarters ahead.

Corporate Power Purchase Agreements (PPAs) – whereby large commercial energy users commit to buying electricity at a fixed price typically over several years – are another form of forward trading through CfDs and provide a route to market for new merchant (i.e. unsubsidised) low carbon generation.

GB arrangements

Forward markets in GB allow both financial and physical trades, with large volumes of electricity traded physically well ahead of delivery time. Most trades are bilateral, direct trades between two parties – known as “over the counter” (OTC) trades – although there is also some electricity traded through exchange platforms similar to those used for day-ahead and intra-day trading.

In addition, in GB it is possible to physically trade electricity in forwards market through Power Purchase Agreements (PPAs), which are longer-term contracts – typically covering multiple years – between a generator and a customer interested in purchasing their electricity over prolonged periods of time. These types of agreements allow generators to reach final investment decisions on their projects by agreeing a fixed offtake price in advance for the electricity they will generate, whilst also providing customers with a fixed offtake price to shield them from volatile market prices.

Day-Ahead and Intra-Day markets

The DAM and IDM are ex-ante physical markets, meaning that trades in these markets establish obligations for physical delivery of electricity.

SEM arrangements

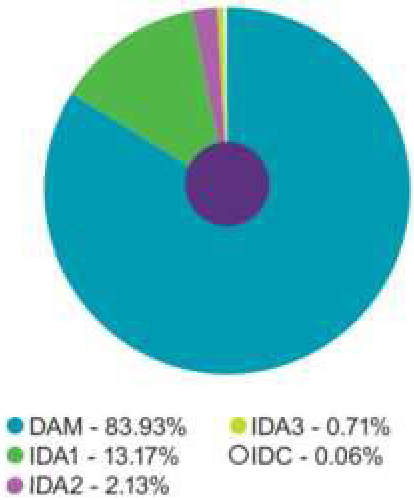
In the SEM, the DAM consists of one auction, with a bid submission deadline of 11:00 GMT, which produces a set of hourly prices (24 one-hour trading periods) for power that will be delivered the following day. All participants that clear in the auction receive the auction clearing price for each trading period. Participation is voluntary and open to demand-side and assetless traders (virtual bidders).

Market participants can then continue to adjust their positions by trading in the IDM, which consists of three auctions, as well as a continuous trading market running from the closing of the DAM up to one hour before real time. In the IDM, bids are made and positions are traded on a half-hourly basis.

All these auctions are pay-as-clear, meaning that all bidders who are successful in the auction receive the auction clearing price. The DAM, the continuous IDM trading market, and one of the three IDM auctions are local only, meaning that they only allow bids internal to the SEM. Two of the IDA auctions, however, referred to as IDA1 and IDA2, are coupled with GB, meaning that orders originating from both the SEM and GB are matched. The capacity of SEM interconnectors is therefore allocated in these two auctions, as discussed in more detail in Section 3.3.2.

As shown in Figure 3.2, over 80% of electricity volumes between October 2022 and September 2023 were traded in the DAM. This is for two main reasons: firstly, the day-ahead timeframe provides sufficient notice for generators to prepare for delivery, whilst also relying on reasonably reliable estimates of demand in most cases. The second reason is that many support schemes for renewable generation, such as renewable CfDs (discussed in Section 3.2.2), as well as financial CfDs traded in forward markets, are typically referenced to the DAM price. IDMs are typically used for generators and energy suppliers to refine their DAM positions as demand and supply forecasts are refined closer to delivery time.

Figure 3.2: Proportion of the total volume of traded electricity by volume, Oct 2022 to Sep 2023



Source: SEM Committee Report 2022-23

GB arrangements

In the GB market, there are also large volumes of physical trades occurring in the DAM, for the same reasons described above for SEM. The GB DAM consists of pay-as-clear auctions – however, unlike the SEM, in GB there are three different DAM auctions that generators and suppliers can participate in: two auctions of hourly granularity at 9:20 and 9:50 on the day ahead of delivery, and a third auction of half-hourly granularity at 15:30 on the day ahead of delivery.

The Balancing Market

The BM is the closest market to real-time delivery of electricity, which the system operator uses to take actions to address system imbalances and constraints. Unlike the previous markets we discussed, participation in the BM is mandatory for all generators in both the SEM and the GB market. Market participants are required to submit a set of incremental (offer to increase generation or decrease demand) and decremental (offer to decrease generation or increase demand) bids, relative to the wholesale markets positions they contracted in the DAM and IDMs.

Participants' deviations from their wholesale market positions are then settled based on the Imbalance Settlement Price. The Imbalance Settlement Price is determined by the marginal cost of providing balancing energy, based on the marginal energy action taken to meet the Net Imbalance Volume.

Participants who deviate from their wholesale market position based on imbalances, i.e. not in response to a dispatch instruction from the TSO, would be settled at this price. Participants who deviate from their wholesale market positions based on a dispatch instruction from the TSO in the Balancing Market would have this volume settled at the better of the Imbalance Settlement Price or their own Bid Offer Price. This generally has the effect that Balancing Market volumes for actions which were taken in-merit against the Imbalance Settlement Price would be paid-as-cleared at that price, and Balancing Market volumes for actions which were taken out-of-merit would be paid-as-bid at their own Bid Offer Price.

SEM arrangements

The SEM Imbalance Price is calculated for each five-minute period of the day and then averaged across the six periods constituting each half hour.

Since the SEM is a relatively small island market, with limited interconnection to other grids and significant transmission constraints, some of these technical constraints are particularly relevant in the Northern Irish and Irish context. For example, there are relatively strict "ramping" constraints in the SEM, requiring interconnectors to "ramp up" or "ramp down" – i.e. increase or decrease – their electricity flow at a pre-defined rate, rather than instantly, to avoid sudden frequency shocks to the system.

Maintaining adequate voltage levels in some areas is also more challenging than in other systems. These constraints lead to further restrictions on generators responding to market signals, e.g. minimum generation levels for certain generators. All of these constraints are ignored in the DAM and IDM, and addressed directly by the system operator through "non energy actions" in the BM.

GB arrangements

Unlike the SEM, the GB balancing mechanism involves a *pay-as-bid* auction for balancing actions. The GB imbalance price is then calculated for each half hour based on the cost of the most expensive energy balancing actions taken that are over 15 minutes long. This price is then applied to generators or suppliers whose physical positions diverge from their contracted positions.

A further difference between GB and SEM balancing arrangements is around dispatch, with the GB system operator involving "self-dispatch", where generators make autonomous decisions about when and how much to generated. If a generator dispatches in excess to its contracted position or any offers accepted in the BM, it will be remunerated for its excess generation at the BM imbalance price. By contrast the SEM system operators are responsible for central dispatch of generators, which is a more active role. The TSOs create the schedules based on participant technical and commercial data and then use dispatching tools to ensure that instructions are co-ordinated to each generator - thereby ensuring a real-time balance between supply and demand subject to relevant constraints. The participant bids and offers will determine when and how they operate within the various market and balancing arrangements.

3.1.4. Pricing Zones in the Wholesale Market

A key design question for electricity markets is the geographic scope of each wholesale market – i.e. the scope of the "pricing zone" where electricity is bought and sold, and supply and demand are balanced, resulting in one uniform electricity price within the zone. Since 2007, on the island of Ireland there is a Single Electricity Market (SEM), with the same wholesale price in Ireland and Northern Ireland. The SEM has undergone several reforms and updates, including a substantial one in 2018.

As mentioned in the previous section, transmission constraints between different parts of the system are not considered in DAM and IDM auctions. These auctions run as if the system were unconstrained, with actual constraints then addressed by the system operator in the BM. This ensures that the SEM can operate as one pricing zone, with the same wholesale electricity price everywhere on the island of Ireland.

Currently, the GB market also operates under one pricing zone, with a single national price. In 2022, the UK government began its Review of Electricity Market Arrangements (REMA) which noting the growing cost of constraint management in GB and initiated consideration of whether the GB system should move to locational pricing. In July 2025, the UK Government published an update to REMA which set out a decision to rule out locational pricing and to implement a model of "Reformed National Pricing".[2] Further work will be undertaken to develop the Reformed National Pricing, but DESNZ noted it may include strengthening locational signals within existing transmission network charges as well as a greater role for planning to determine where capacity should be situated in future and carrying out anticipatory investment in network capacity ahead of this.

3.2. The generation mix today and tomorrow

Both the UK and Ireland have put in place ambitious targets to transition away from fossil fuels towards a net zero energy system. Decarbonising the power sector is an integral part of any strategy to achieve net zero targets, not least because electrification of other sectors – such as heat or transport – will play a significant role in it. This

[2] https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-summer-update-2025/review-of-electricity-market-arrangements-rema-summer-update-2025-accessible-webpage

transition will have significant implications for how electricity is generated, and therefore also how it is traded, both within and between markets.

3.2.1. Targets and Scenarios

The UK and Irish governments, as well as the Northern Ireland Executive, have all put in place ambitious targets for decarbonising the power sector by 2030. In both Ireland and Northern Ireland, the target is for 80% of electricity to be generated from renewable sources by that year. In GB, the government has recently introduced an even more ambitious target of having an overall decarbonised electricity system by 2030, as part of the “Clean Power 2030” plan.[3]

These targets require significant investments into additional renewable generation capacity, particularly of wind generation, both offshore and onshore. Beyond 2030, the electricity system will continue to evolve and could follow different pathways to contribute to a net zero economy, with varying mixes of different low-carbon technologies. In order to compare alternative pathways and align assumptions on what these pathways might look like, the system operators for both the SEM and GB markets regularly publish a range of Net Zero-consistent scenarios, with detailed assumptions about the future generation mix.

For the SEM, EirGrid and SONI jointly issue the Tomorrow’s Energy Scenarios (TES), which cover both Ireland and Northern Ireland. The TES contain four scenarios with detailed pathways for how the generation mix could involve along the transition. The four scenarios are:

- **Self-sustaining**: A scenario in which generation is scaled in order to meet overall domestic demand in the SEM, with rapid decarbonisation and high demand-side flexibility.
- **Offshore opportunity**: In this scenario, interconnection with other markets is significantly increased in order to allow more scope for electricity exports at times of high wind generation. The power sector decarbonises rapidly, with a strong contribution from offshore wind.
- **Gas evolution**: This scenario relies more on the development of renewable gas opportunities, including hydrogen. The power sector decarbonises more steadily.
- **Constrained growth**: In this scenario supply chain difficulties lead to a slower decarbonisation of the power sector, with some targets not being met in time.

These projections of net-zero consistent pathways can be contrasted with the All-Island Resource Adequacy Assessment 2025-2035 (AIRAA), developed by SONI and EirGrid. The AIRAA provides a view of electricity demand and generation capacity in the short and medium term which is based on a bottom-up assessment of projects expected to get built rather than what would need to get built to be consistent with longer-term targets for carbon reduction.

As an example of varying assumptions between these scenarios, Table 3.1 shows how much different renewable generation technologies are expected grow between 2022 and 2050, with a mid-point in 2034 based on the AIRAA.

[3] In practice, the National Energy System Operator in GB is targeting a scenario where unabated gas generation makes up less than 5% of GB electricity demand in a typical year, and the system generates enough zero-carbon electricity overall (including electricity exported to other markets) to cover 100% of national demand. The UK government has accepted this definition of the target.

Table 3.1: Growth in renewable generation capacity (MW) between 2022 and 2030 in different TES scenarios.

Generation type	2025 MW, AIRAA	2034 MW, AIRAA	2050 MW range, TES
Northern Ireland			
			1,166 – 2,814
Onshore wind	1,440	2,690	2,225 – 3,458
Offshore wind	0	500	2,290 – 4,000
Ireland			
Solar PV	2,510	8,640	8,090 – 17,000
Onshore wind	5,420	8,770	7,375 – 12,000
Offshore wind	30	3,730	8,580 – 37,000

Source: AIRAA, Tomorrow's Energy Scenarios 2023

3.2.2. Policy Support

In order to achieve this rapid growth in renewable generation capacity, it is likely that a degree of policy support will be required to make the investments required sufficiently attractive to provide investor confidence, in line with policy objectives.

GB and Ireland have been providing direct financial support for renewables for a number of years now, whilst Northern Ireland has recently announced the intention to develop its own Renewable Energy Price Guarantee, with an aim to support meeting the target for 80% renewable share of electricity by 2030.[4]

Contracts for Difference

In both GB and Ireland, financial support for renewable generation is provided through Contracts-for-Difference (CfDs). When an investor enters into a CfD a "strike price" is agreed between them and the issuing party. This strike price effectively represents a guaranteed total price for their wholesale electricity generation (i.e. including market revenues and support payments) which the generator will receive over the duration of the contract for the electricity it produces.

Figure 3.3 illustrates how a CfD works in practice. The "reference price", in this case, is the wholesale price of electricity in the market that the generator operates in. Prices in the day-ahead market are used as reference prices in renewable CfD contracts in GB and SEM. Whenever the reference price is lower than the strike price, the generator receives the difference between the two as a subsidy.[5] Conversely, whenever the reference price exceeds the strike price, the generator pays back the difference to the issuing party. This ensures that the generator always effectively receives the strike price for the electricity it generates.

This form of support is intended to limit the wholesale price risk that developers face for a renewable project (which is capital intensive and has a long recovery period). Generators are guaranteed an overall fixed (inflation-linked) price for electricity generated regardless of the wholesale price for 15 years and can make a financial investment

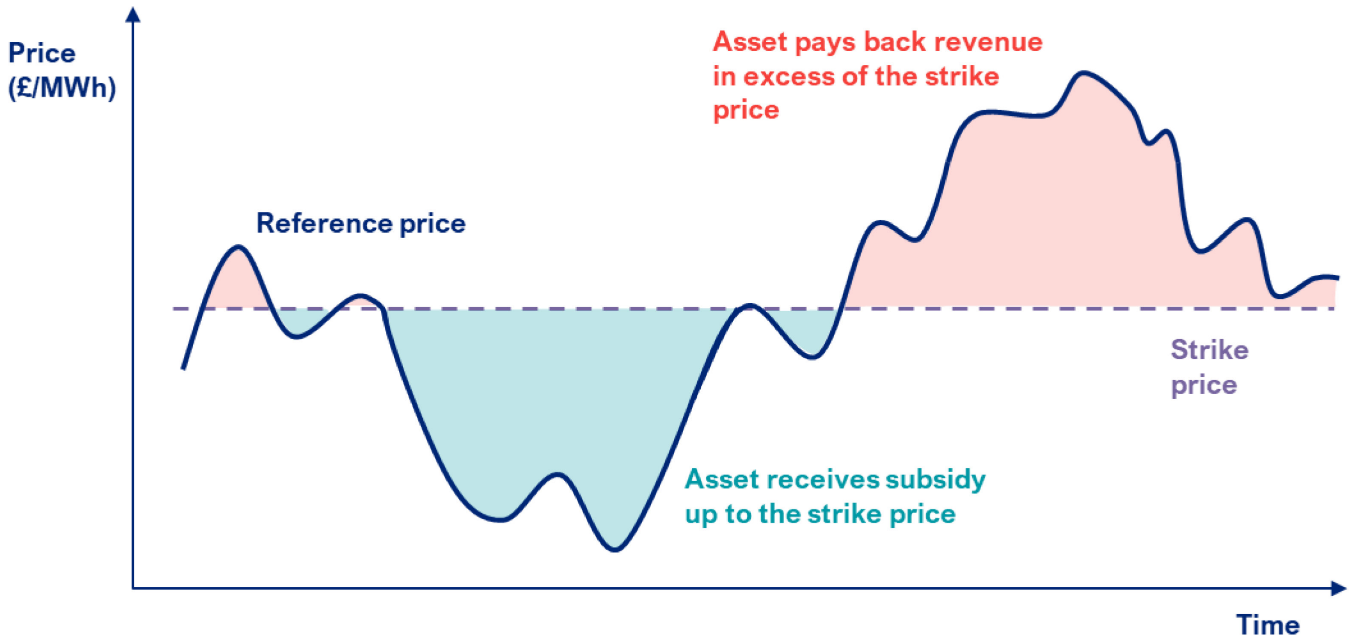
[4] https://www.economy-ni.gov.uk/articles/renewable-electricity-support-scheme

[5] An exception to this in current CfD contracts available is where the reference price is negative, in which case no CfD difference payment is made.

decision on this basis. This makes the proposition more attractive to investors - reducing the cost of capital and widening the pool of potential investors to include project finance.

The CfD also provides a long-term price hedge for consumers and avoids generators earning a windfall in the event of unexpectedly high wholesale prices arising.

Figure 3.3: Illustration of a Contract-for-Difference (CfD)



Source: CEPA illustration

In both Ireland and GB, strike prices for CfD allocation rounds are set through a competitive auction process. Renewable energy projects which meet certain qualification criteria – e.g. based on specific technological requirements, having secured a level of planning permission, etc. – can bid a strike price for which they would be willing to enter a CfD. The projects bidding the lowest strike prices which collectively deliver sufficient generation capacity to meet the auction's pre-determined target are selected and awarded a CfD. These auctions are typically pay-as-clear, meaning that the strike price for all successful projects in each auction is set based on the marginal project's bid.

As mentioned above, at present, Northern Ireland does not have a similar renewable CfD scheme. However, the Department for the Economy (DFE) announced its intention to establish a Renewable Electricity Price Guarantee (REPG), and recent advice commissioned by DFE recommended the adoption of a CfD scheme with similar arrangements to those in Ireland and GB.[6]

As part of its The UK government has consulted on potential reforms to the CfD scheme to pay generators on the basis of either capacity or "deemed generation" rather than actual generation. This is intended to mitigate distortions created by the CfD around how generators are dispatched.

Capacity Markets

Another form of market-based policy support is the capacity market. Unlike CfDs, which are primarily intended to provide financial support for renewable generation, capacity markets are aimed at ensuring power system reliability to a given standard typically expressed in a loss of load expectation (LOLE).

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[6] https://auroraer.com/wp-content/uploads/2024/06/Aurora_May24_NIR_Renewables_Scheme_Report.pdf

Capacity markets – or, more generally, Capacity Remuneration Mechanisms (CRMs) – are policy mechanisms whereby new or existing power plants (or equivalent capacity from demand side response, interconnectors or storage) receive a subsidy for each MW of additional generation capacity they provide to the system. As with renewable CfDs, the projects to be supported through this mechanism are selected based on a competitive bidding process, with pre-determined targets for capacity to be procured in each round and a pay-as-clear design.

In return for receiving these payments, the assets commit to being available and able to generate at times of system stress – e.g. when there are unusual surges in demand or shortages in renewable supply – such that the system operator could call on them to generate at these times. Capacity payments are issued to their recipients regardless of whether these stress events actually materialise: their purpose is simply to ensure that the assets are available, such that the system maintains a sufficient amount of generation capacity.

In addition to this arrangement, the CM can include a one-way CfD mechanism known as a “reliability option” (RO). The RO commits a generator to an obligation whereby if it is not available and dispatched in the BM and if a Strike Price is exceeded it will payback revenues. Units that are unavailable are not exposed to the payback unless the market price exceeds the Strike Price. SEM publish the strike price, determined in line with the Trading and Settlement code, on a weekly basis (PSTRw). There are secondary trading mechanisms for units unable discharge their obligations.

The RO is a “one-way” CfD in the sense that it works in the same way as the CfD illustrated in Figure 3.3 if the reference price exceeds the strike price, but does not involve any subsidy if the reference price is lower than the strike price (as the generator already receives support in the form of fixed capacity payments).

The strike price for ROs is typically set at high levels and well above the marginal cost of generation, such that generators receiving capacity payments make RO payments back to consumers when prices spike reflecting system stress condition. ROs are an important feature of the CM design in the SEM, but are not used in GB, where generators receiving capacity payments are required to be available when called upon by the system operator, but can keep the full revenue accrued during times of system stress if they are generating in those periods.

The capacity that each project is allowed to bid into the auction is “derated” based on a set of technology-specific derating factors. The aim of the derating factors is to reflect the likelihood of a generation asset being available, or able to provide capacity, at times of system stress. For example, a gas-fired plant and a battery may have the same power output. However, during a system stress event the gas-fired plant would normally be able to provide that level of generation capacity continuously for as long as is needed. A battery, on the other hand, may be limited to running for only an hour, depending on its capacity level. This risk is reflected in a derating factor for the battery that varies with its duration limitation, and which is typically much lower than the de-rating for a gas-fired plant. As a result of this de-rating, capacity payments typically account for only a small part of the revenue stream for a short-duration battery.

One challenge that is particularly relevant in the SEM context is how transmission constraints are dealt with. If specific locations within a market are transmission-constrained, procuring capacity on the other side of the constraint may not actually mitigate the risk of power outages if a stress event occurs. The additional capacity would be provided, but the transmission constraint may not allow for the electricity generated to be transported to the constrained area. In the SEM, this is particularly relevant in the context of transmission constraints between Northern Ireland and Ireland, and constraints around the Greater Dublin area.

In the SEM capacity market, locational capacity requirements of this kind are secured by setting minimum targets for capacity in given locations. Where this capacity is not successful in the overall pay-as-clear auction, projects can still be contracted on a pay-as-bid basis until sufficient locational capacity is procured.

The reliability standard for SEM is determined based on the relationship between the Value of Lost Load (VOLL) and the Net Cost of New Entry (Net CONE), which is currently set at 6.5 hours LOLE.[7] It informs the determination of the SEM-wide level of capacity to be procured that is published in the Initial Auction Information Pack (IAIP) ahead of each auction. Northern Ireland has a specific reliability standard of 4.9 hours LOLE, which informs the Final Auction Information Pack (FAIP) volume requirements as part of the Locational Capacity Constraint volumes determination for NI.

A further type of support mechanism is the Cap-and-Floor (C&F model) for interconnectors and for long duration electricity storage – which we describe in detail in Section 3.3.3.

3.3. INTERCONNECTION

Interconnection between different electricity markets is an important source of flexibility, particularly in the context of increased reliance on intermittent renewables. Interconnectors are usually high-voltage cables connecting different pricing zones. In the case of pricing zones coinciding with islands, as for the SEM and the GB market, these tend to be undersea high-voltage direct current (HVDC) cables.

This section provides an overview of existing and planned interconnectors which link the SEM to other markets, the trading arrangements for electricity to be traded through these interconnectors, and the regulatory models underpinning them.

3.3.1. Overview of existing and planned interconnectors

Three interconnectors are currently operational which link the SEM with the GB market. A fourth interconnector with France (Celtic) is currently under construction and will link the SEM directly with electricity markets in continental Europe. The proposed MaresConnect interconnector between Ireland and GB has been granted a cap and floor regime in principle by the GB regulator, Ofgem, while the Irish regulator, CRU, has consulted on its positive minded-to position on awarding MaresConnect a Cap and Floor regime in principle.[8] The proposed LirIC interconnector between Northern Ireland and GB has also been granted a cap and floor regime in principle by the GB regulator, Ofgem, and had a transmission licence granted by the NI regulator, UR.[9] LirIC has also applied to UR for a cap and floor arrangement. These six interconnectors are described in Table 3.2 and shown in Figure 3.4.

[7] https://www.semcommittee.com/files/semcommittee/media-files/Calculation%20of%20a%20single%20Value%20of%20Lost%20Load%20within%20the%20SEM%20Information%20Paper%20SEM-23-072.pdf

[8] https://maresconnect.ie/home-5/the-interconnector/tyndp/

[9] https://www.uregni.gov.uk/news-centre/grant-electricity-transmission-licence-ti-liric-limited

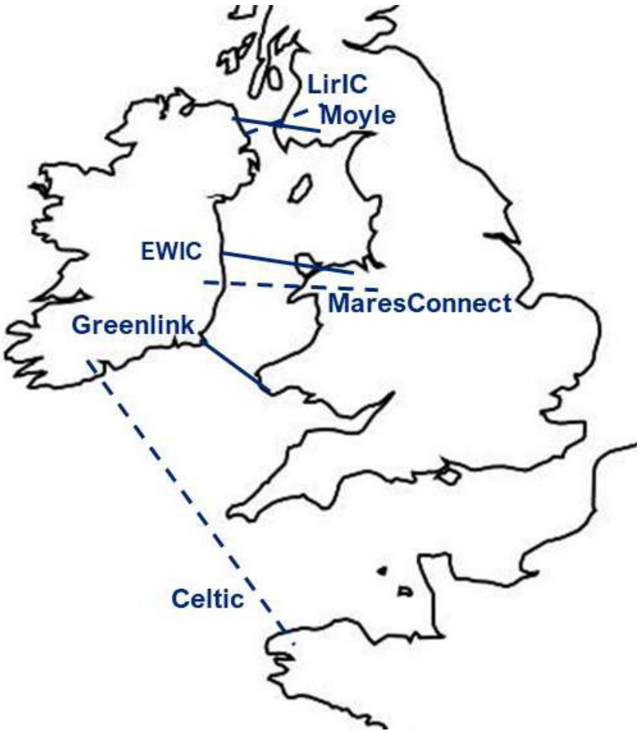
Table 3.2: Interconnectors between the SEM and other markets (operational or under construction)

Moyle	Northern Ireland (County Antrim) and Scotland (Ayrshire)	500 MW	2001
East-West Interconnector (EWIC)	Ireland (Dublin) and Wales (Flintshire)	500 MW	2012
Greenlink	Ireland (County Wexford) and Wales (Pembrokeshire)	500 MW	2025
Celtic Interconnector	Ireland (County Cork) and Finistère (France)	700 MW	2028 (targeted)
MaresConnect	Ireland (Greater Dublin Area) and Wales (Denbighshire)	750MW	2029 (targeted)
LirIC	Northern Ireland (County Antrim) and Scotland (Ayrshire)	700MW	2032 (targeted)

These interconnectors also differ in terms of their regulatory/business model: while Moyle and EWIC operate under a fully regulated model, and Celtic will operate under a similarly regulated model, Greenlink, MaresConnect and LirIC plan to operate under a Cap and Floor model. These regulatory models are explained in Section 3.3.3.

Another important interconnector that is currently being planned is the North-South Interconnector between Ireland and Northern Ireland. Since Ireland and Northern Ireland are part of the same electricity market (the SEM) the North-South Interconnector would not actually connect two different markets. Instead, it would significantly alleviate transmission constraints internal to the SEM. The project consists of a 400 kV overhead line from County Tyrone in Northern Ireland to County Meath in Ireland, increasing the internal network capacity from a max flow of +/-450 MW to +/-1.25 GW between NI and ROI. Its expected commissioning date is now expected in late 2031.

Figure 3.4: Operational and planned interconnectors to the SEM



Source: CEPA illustration based on approximate locations. Dotted lines indicate planned interconnectors which are not yet operational.

3.3.2. Interconnector Trading Arrangements

Interconnectors are able to partly recover their costs through what is known as "congestion revenues" in the DAM: when there is a price difference between the two markets linked by the interconnector, electricity should flow from the market with the lower price to that with the higher price. In this context, the revenue earned by the interconnector is the difference in electricity prices, multiplied by the volume of electricity transferred via the interconnector.[10]

When two previously separate markets are linked by an interconnector, their prices will tend to converge, with the extent of convergence dependent on the extent to which interconnector capacity is limiting. If prices are high in one market and low in the other, interconnection will have the impact of lowering prices in the higher-price market, but also of increasing them in the lower-price market. For this reason, regulators typically consider whether there will be systematic differences in prices between the two interconnected markets when assessing the impact of new interconnector projects.

Congestion revenues can be realised in two different ways depending on how the interconnector capacity is allocated between different market participants. Trading arrangements can either be based on **implicit capacity allocation**, achieved through market coupling algorithms which match supply and demand in different markets and simultaneously determine interconnector flow schedules, or **explicit capacity allocation**, through direct capacity auctions. This is particularly relevant in the context of the SEM and GB since Brexit, which resulted in a shift from an implicit to an explicit allocation model for interconnectors between GB and most European markets.

Implicit Allocation and Market Coupling

Within the EU, interconnector capacity is typically allocated implicitly through market coupling mechanisms such as Single Day-ahead Coupling (SDAC). SDAC relies on a market coupling algorithm (called PCR EUPHEMIA), which calculates day-ahead electricity prices across different European markets and implicitly allocates auction-based cross-border capacity between them.

With implicit allocation, interconnector capacity is assigned automatically based on supply and demand in the two connected markets and is traded together with electricity in a single market-based process. Before Brexit, SEM and GB were both part of SDAC and so were coupled at the DAM, allowing the capacity of SEM-GB interconnectors to be allocated implicitly.

However, since UK left the EU, SDAC no longer applies to flows between GB and the SEM, as discussed in more detail below.

Explicit Allocation through Capacity Auctions

Under explicit allocation, interconnector capacity is traded separately from electricity and allocated through explicit auctions. Market participants need to first buy interconnector capacity and then separately trade electricity in each of the two markets. These market participants can earn revenues by buying electricity in the market with the lower price and selling it in the one with the higher price, and interconnectors earn revenue by auctioning their capacity to these market participants.

This system is less efficient than implicit allocation and can more frequently result in situations where electricity is flowing through the interconnector in the "wrong" direction – i.e. from the market with the lower price to that with the higher price.

[10] In addition to congestion revenues, interconnectors in Northern Ireland, Ireland and GB are eligible to take part in the capacity market and receive capacity payments. In the SEM CM, new capacity units (including interconnectors) can apply to the Ras or the ability to bid for a Multi-year RO, for a period of up to 10 years. In the GB CM, interconnectors are only eligible for one-year contracts and have to participate in capacity auctions every year to obtain one.

SEM-GB Trading Arrangements

As mentioned above, when the UK was still a member state of the EU, both the SEM and the GB market were coupled with EU markets through SDAC, and interconnector capacity was allocated implicitly between GB and European markets as well as between the SEM and GB. When the UK left the EU, it also ceased to take part in SDAC, and interconnector capacity allocation between the GB and most European markets is now explicitly allocated as a result.

Since the UK left the EU, the SEM's operational interconnectors only linked the market to GB, effectively resulting in the SEM also being un-coupled from SDAC. Since explicit allocation is less efficient than implicit allocation, SEM-GB interim trading arrangements were established in order to still allow implicit allocation between the two markets. However, these post-Brexit arrangements only allow market coupling at the level of the intra-day market – as described above. Since lower volumes of electricity are traded in these markets, compared to the DAM, this can occasionally result in under-utilisation of the SEM-GB interconnector capacity.

Recognising the impact inefficient electricity trade has on the UK and EU, the Trade and Cooperation Agreement (TCA) signed post-Brexit instructs both sides to explore a technical solution known as 'multi-region loose volume coupling' (MRLVC). However, efforts to implement MRLVC have faced technical challenges, with UK and EU TSOs noting significant risks to implementation.[11]

In May 2025, the UK and European Commission set out plans to "explore in detail the necessary parameters for the United Kingdom's possible participation in the European Union's internal electricity market, including participation in the European Union's trading platforms in all timeframes."[12] This opens the door to the UK rejoining the SDAC and for GB-SEM interconnector capacity to resume being implicitly allocated through market coupling.

There is an impetus to find a solution to reintegrating the UK in the internal electricity market ahead of the Celtic interconnector between France and Ireland becoming operational, as at that point the SEM will be linked to another EU market and the SDAC will apply to the SEM again. The Celtic interconnector is expected to start operations in 2026.

It is worth noting that, although Northern Ireland has left the EU alongside the rest of the UK, the trading arrangements discussed in this section apply to any interconnectors between the SEM and GB, regardless of whether they are connecting GB to Ireland or Northern Ireland. This is to ensure that the SEM continues to operate as a single market for electricity, in line with the Windsor Framework and Northern Ireland Protocol. The UK and European Commissions plans for closer alignment of electricity markets including UK participation in the EU Emissions Trading Scheme (ETS).[13] This has potential to mitigate the risks to efficient cross-border trading that have been noted for when the EU Carbon Border Adjustment Mechanism (CBAM) comes into place.[14]

3.3.3. Regulatory Models for Interconnectors

There are three high-level regulatory models that may be applicable for interconnectors in the SEM and GB:

- Fully merchant model;
- Fully regulated model; and
- Cap-and-Floor (C&F) model.

[11] https://www.nemolink.co.uk/wp-content/uploads/2024/07/230710_MRLVC-report_redactions-for-publication-Feb2024_clean.pdf

[12] https://www.gov.uk/government/publications/ukeu-summit-key-documentation/uk-eu-summit-common-understanding-html

[13] https://www.gov.uk/government/news/pm-secures-new-agreement-with-eu-to-benefit-british-people

[14] https://www.energy-uk.org.uk/wp-content/uploads/2024/05/Energy-UK-Position-Paper-EU-CBAM-Concerns-and-Impacts.pdf

The merchant model consists simply in the interconnector being operated as a merchant asset, with no regulatory support or requirements. The initial investment needed to build the interconnector is recovered over the years through congestion revenues, allowing investors to make a return. The profitability of the investment is then a function of the average price spreads between the two interconnected markets. There are currently no interconnectors connecting to SEM which operate under a purely merchant model.

An alternative to the fully merchant model is the fully regulated model, in which interconnectors are treated as regulated assets, akin to standard onshore transmission lines. The owner of the interconnector is allowed to recover a pre-determined return on the original investment, set by the relevant regulator. This return is guaranteed through regular payments, the cost of which is recovered from system charges levied on all network users.

Under this model, revenues (including market arbitrage revenues, ancillary services and capacity payments), are netted off from the payments required for the interconnector to earn its allowed return. In cases where the revenues exceed what is needed to earn the return, they are used to lower overall system charges. Availability incentives are typically provided in order to ensure that any planned outages are limited to the minimum that is required for maintenance. This business model is typically used by state-owned transmission system operators in Europe. As mentioned above, the Moyle and EWIC interconnectors operate under a fully regulated model.[15]

Finally, many recently developed interconnectors connecting to GB operate under a C&F regime, which in many ways represents a hybrid model between fully merchant and fully regulated assets. Under the C&F regime, interconnectors are guaranteed to earn a minimum amount of revenue in any given period, called the floor. This floor is typically calculated to allow interconnectors to earn enough to repay their debt financing costs, fund ongoing costs, and earn a small return on their invested equity, although less than what they normally require, over the contract period. In turn, if the interconnector's revenue in any given period is capped at a higher level, which allows them to earn a higher return on their invested equity than what they would normally require. If the revenue lies in the corridor between the cap and the floor, the interconnector simply earns its merchant revenue. Figure 3.5 illustrates this model graphically. It is noted that a C&F regime has not been established in NI, although it is currently under consultation with regards to the LirIC interconnector.[16]

Cross-Border Regulatory Arrangements

We have so far described the regulatory model for interconnectors in general terms. However, since interconnectors are by definition relevant to two different electricity markets, interconnector projects typically engage with two different jurisdictions and system operators. Where they seek policy support, or a regulated business model, they typically make the case for this to system operators and regulators on both sides of the interconnection.

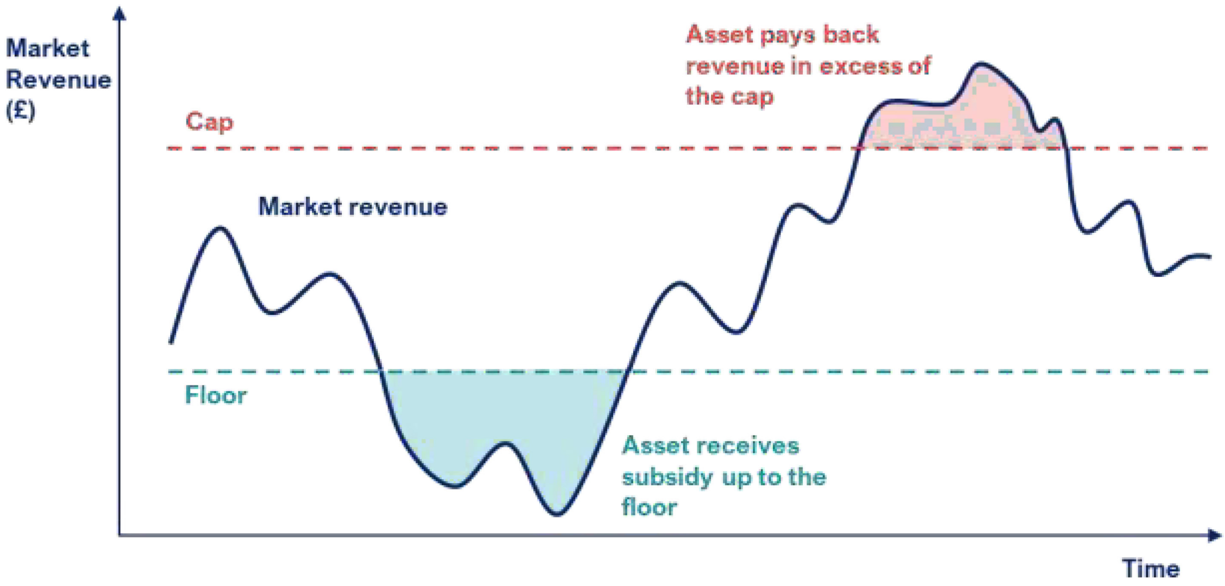
In most cases, the result is that any form of regulatory support on either side of the interconnection covers 50% of the interconnectors costs, revenues, or operations, with the other 50% determined by regulators on the other side. For example, we mentioned above that the Greenlink interconnector operates under a C&F model. It would be more accurate to say that it operates under two distinct C&F models, one awarded by the GB regulator (Ofgem) covering 50% of its costs, and the other awarded by the Irish regulator (the CRU) covering the other 50%.

[15] It is worth noting that Moyle, in particular, is operated by Mutual Energy as a mutualised business, meaning that it has no shareholders and is 100% debt financed. However, it still operates under a regulated model in the same way, in that its revenues are underwritten by Northern Irish consumers through system charges.

[16] https://www.uregni.gov.uk/consultations/consultation-assessment-need-regulated-operating-revenue-regime-future

There is currently no interconnector C&F regime in place in Northern Ireland. LirIC has been successful in securing a C&F agreement in principle from Ofgem on the GB side and is seeking an equivalent agreement from the Utility Regulator on the Northern Irish side.[17] [18]

Figure 3.5: Illustration of a Cap-and-Floor model



Source: CEPA illustration

3.4. Electricity storage

Grid-connected electricity storage has been identified as increasingly important in enabling the transition to renewables-based power systems. Similarly to interconnectors, electricity storage provides flexibility to the system, which can help manage the intermittency of renewable generation technologies such as wind and solar. However, unlike interconnectors, electricity storage allows to shift electricity supply across time periods rather than across geographic areas.

3.4.1. Overview of Electricity Storage Technologies

There are a variety of different electricity storage technologies – defined as technologies which are able to store electricity for the purpose of its future conversion back into electricity. These different technologies differ from each other across multiple dimensions, including:

- **Scale**: some electricity storage technologies - such as Pumped Storage Hydropower (PSH) - are typically very large in scale, e.g. in the hundreds of MW or more, and require specific geographical features for their constructions. Others (such as lithium-ion batteries) can be much smaller in scale and operate as distributed storage as well as larger projects.
- **Storage duration**: the "duration" of an electricity storage asset is defined as the amount of time it is able to discharge for at maximum power output capacity. For example, a one-hour duration battery would take one hour to fully discharge its stored energy at maximum output. On the other hand, longer-duration electricity

[17] https://www.uregni.gov.uk/files/uregni/documents/2024-05/consultation-for-electricity-transmission-licence-ti-liric-limited.pdf

[18] Ofgem had initially indicated that they were minded not to grant LirIC a C&F scheme, on the grounds that it would provide limited benefits to GB consumers. However, this decision has since been reversed following additional analysis of the predicted electricity flows between Northern Ireland and GB. Source: https://www.ofgem.gov.uk/sites/default/files/2024-11/Window_3_IPA_Decision.pdf

storage technologies can discharge continuously for several hours, sometimes entire days. There is no universally agreed minimum threshold for what constitutes Long Duration Electricity Storage (LDES), though it typically ranges between 4 and 8 hours.[19] CEPA's modelling of additional storage capacity includes three levels of duration – short duration (1-hour batteries), medium duration (6-hour batteries), and long duration storage (12-hour PSH).

- **Round-trip efficiency**: no technology is able to store electricity at 100% efficiency, meaning that the electricity which can be discharged is always lower in volume than the electricity required to charge the storage asset. However, efficiency can vary considerably between different technologies and is an important factor in quantifying their system benefits. Efficiency estimates for different storage technologies are shown in Table 3.3 below.
- **Technology maturity**: electricity storage has been a part of electricity systems for decades, particularly in the form of Pumped Storage Hydropower. More recently, lithium-ion batteries have also become increasingly integrated in many electricity systems around the world, including in the SEM. Other technologies, on the other hand, are novel and have not yet been tested at scale – but may represent a viable option in the future, particularly for LDES.

Table 3.3 provides an overview of some of the most important storage technologies which may play an important role in the energy transition in Northern Ireland, Ireland, and GB.

Table 3.3: Overview of selected electricity storage technologies

Name	Scale	Duration	Efficiency	Technology maturity	Examples/applications
Pumped Storage Hydropower (PSH)	Very large	4h to multiple days	75-85%	Mature	Turlough Hill Power Station in Ireland is the only PSH plant currently operating on the island of Ireland.
Lithium-ion (Li-ion) batteries	Small to medium	Typically 1-2h, but can be up to 8h	80-90%	Mature	In 2024, SSE acquired a 100MW 2-hour battery project in County Tyrone, Northern Ireland.[20]
Liquid Air Electricity Storage (LAES)	Medium to very large	12-16h	50-60%	Limited grid-scale demonstrations	In GB, Highview Energy aims to deliver four 200MW, 12.5-hour plants by 2030.[21]
Iron-air batteries	Medium to very large	Multiple days	40-50%	Limited grid-scale demonstrations	FuturEnergy has submitted a planning application in 2024 to build the first ever iron-air project in Europe. The initial phase involves a 10MW, 100-hour project.[22]

There are several other electricity storage technologies, but they are unlikely to play a significant role in the SEM or GB market over the next 10-15 years. Another technology which could be considered a form of electricity storage, even though it does not strictly fit the definition above, is Hydrogen-to-Power (H2P). Electrolytic hydrogen (also known as green hydrogen) can be produced using electricity from renewables, stored, and then burnt in a gas

[19] The UK Department for Energy Security and Net Zero considers the minimum duration for a storage asset to be considered a form of LDES to be 6 hours. Source: https://assets.publishing.service.gov.uk/media/670660eb366f494ab2e7b57a/LDES-consultation-government-response.pdf

[20] https://www.sserenewables.com/news-and-views/2024/05/sse-renewables-acquires-100mw-battery-storage-project-in-ni/

[21] https://highviewpower.com/projects/#uk-projects

[22] https://futurenergyireland.ie/battery-energy-storage-systems/

turbine to generate electricity. However, hydrogen can also be produced through steam methane reformation from natural gas (known as blue hydrogen where the carbon involved in captured and stored), and has other, non-power sector uses. H2P is often treated as a form of low-carbon dispatchable generation, rather than electricity storage, and a detailed assessment of its potential in Northern Ireland is outside the scope of this study.

It is possible that H2P will play a significant longer-term role in the future energy system, alongside other forms of dispatchable generation such as gas-fired generation – which can be made low-carbon by using biogas or adding carbon capture to it. Electricity storage, dispatchable generation, and interconnection are all different sources of supply-side flexibility, which will play an increasingly important role in supporting the transition to a renewables-based power system.

3.4.2. Commercial Model for Storage Operators

Typically, the business model for electricity storage relies on "revenue stacking", i.e. the ability of the asset to earn revenue from multiple different sources, including:

- Wholesale market trading;
- Ancillary services; and
- The Capacity Market (CM).

In the wholesale market, storage assets buy electricity when it is cheap, charge their assets, then sell it, and discharge the assets, when it is more expensive. Doing this optimally requires active trading capabilities, with optimisers typically looking at the evolution of price forecasts and re-optimising the asset's position as the forecasts are updated.

Alongside this, many storage assets earn revenue from ancillary services. For example, in GB the market for frequency response services is now effectively dominated by short-duration Li-ion batteries. Finally, storage assets also typically rely on CM payments as part of their business model. Shorter-duration assets tend to receive lower payments due to their low derating factors. Longer-duration assets, on the other hand, tend to have higher derating factors and are therefore likely to receive more revenue through the CM.

Some storage assets are traded in-house by the company that owns them, often as part of a wider portfolio, including generation assets. There is also a common alternative model, however, which consists in storage assets – particularly batteries – being handed over to third-party optimisers, who typically optimise a larger portfolio of similar assets. Third-party optimisers typically receive a fixed percentage of the margin achieved by the asset; although more recently we have also seen the emergence of medium-term tolling agreements in GB.[23]

3.4.3. Policy Support for Electricity Storage

Similarly to interconnectors, expected revenues for electricity storage technologies depend on the size of wholesale price spreads. However, instead of the spreads between different markets, storage revenues depend on the spreads within one market. These spreads are highly variable and very difficult to predict in advance – making electricity storage assets a relatively risky investment.

As a result, some investors in GB, Ireland, and Northern Ireland have been calling for policy support mechanisms for electricity storage technologies. These calls have so far been particularly strong with respect to support for LDES. In fact, in recent years there has been substantial investment into short-duration, grid-connected Li-ion batteries in both GB and Ireland, despite the lack of policy support (beyond the CM). Investment in LDES, on the other hand, has stalled despite its potential importance in delivering flexibility for the future energy system.

As a result, the UK government is currently in the process of establishing a new C&F scheme for LDES technologies, which will work in a similar way to the interconnector C&F scheme. Several technologies may be

23 https://modoenergy.com/research/battery-tolling-announced-gresham-house-octopus-energy-june-2024

eligible for the scheme, provided they can deliver a storage duration of 6 hours or more. This is likely to include new PSH plants, some first-of-a-kind LAES projects, and longer-duration, 6-8h Li-ion batteries. The first application window for LDES projects under the C&F scheme opened in April 2025, with the aim of the first projects being built and operational by 2030.[24]

Other than the planned C&F scheme for LDES in GB, there is currently no policy support scheme for electricity storage in Northern Ireland, Ireland, or GB. Additionally, in GB, as part of the ongoing REMA, the government is considering changes to the CM to provide additional support for storage technologies, for example by setting minimum targets for fast response or LDES as part of capacity auctions.[25]

24 https://www.ofgem.gov.uk/decision/long-duration-electricity-storage-cap-and-floor-application-window-1

25 https://assets.publishing.service.gov.uk/media/65e3a3193f69450263035fc1/4-alternative-capacity-market-auction-design.pdf

CEPA economics matters

4. METHODOLOGY

4.1. Model framework

For the purposes of this study, we have conducted market modelling simulations using our hourly pan-European electricity dispatch model framework. The model we licence was developed by Dr Chi Kong Chyong, a highly respected energy market modelling expert, with input from the experts on the CEPA team to ensure that it simulates dispatch in a manner that reflects real-world behaviour and to ensure that key nuances in the Great Britain (GB) and Europe policy landscape are captured.

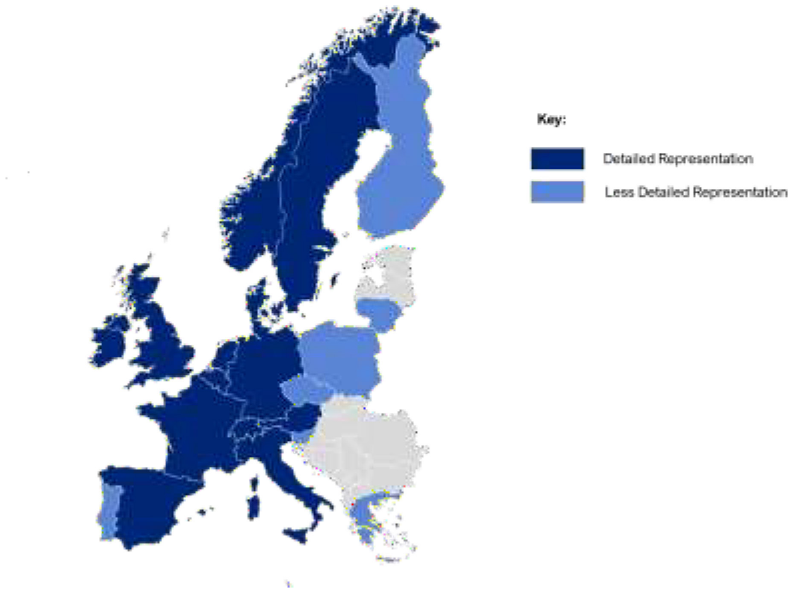
The model performs least cost optimisation of energy resources to determine the optimal means of meeting electricity requirements given assumptions around the capacity mix, demand growth, commodity prices, regulatory framework and network constraints. This enables the model to determine the expected market clearing prices and resource dispatch at an hourly level for the modelled period.

The model simulations and price determinations are based on a set of input assumptions, such as the generation capacity mix, generation supply costs, hourly renewable energy source (RES) generation availability profiles, interconnector capacities (and electricity prices in the connected markets), and hourly demand profiles.

4.1.1. Bidding zones and constraints

For our core set of simulations, we utilised our pan-European electricity model which covers the all-Island Single Electricity Market (SEM) in Ireland and Northern Ireland and has a detailed representation of the following countries in North Western Europe, including all markets/bidding zones directly connected to SEM: GB, France, Netherlands, Belgium, Germany, Italy, Norway, Sweden, Denmark, Spain, Switzerland, and Austria. This involves representation of the generation fleet by technology and with hourly representation of intermittent generation based on historic patterns. Power flows from other significant markets in Europe are considered in a less granular manner, i.e. with the price and volume of flows based on the expected marginal technology in each country.[26] This representation of European markets in the model is illustrated in Figure 4.1 below.

Figure 4.1: Markets included in CEPA's proprietary pan-European electricity model



Source: CEPA

[26] While Nordic countries as well as Italy have zonal markets, they have each been modelled at a national level as a modelling simplification, given the focus of this report is on the NI market, and there is no direct interconnection between SEM and these countries.

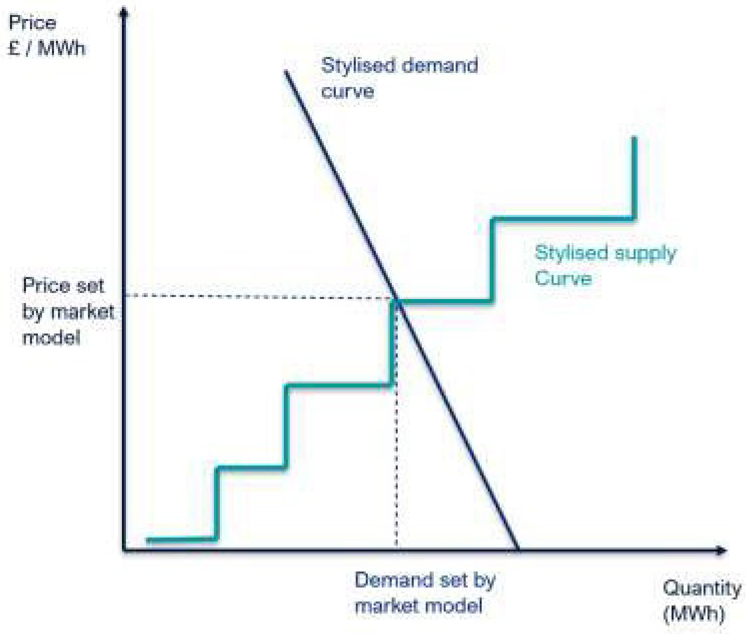
For the purposes of modelling the impacts of additional capacity in NI, we have also considered the impact of constraints between Northern Ireland and Ireland. Our modelling for each scenario has been carried out on two cases:

- **Unconstrained case**: In the unconstrained case, no network or system constraints are applied within SEM, reflecting how prices are set and generation dispatched in the wholesale market. This case is used to inform the assessment of the impact of the additional modelled interconnector and storage capacity on wholesale market outcomes.
- **Constrained case**: Three additional constraints have been applied in the constrained case to reflect limitations in network capacity and the need to preserve system stability – a boundary constraint between NI and Ireland, a System Non-Synchronous Penetration (SNSP) requirement that no more than 95% of generation in Northern Ireland comes from non-synchronous generation, and that at least two gas generation units in NI are operating at all times.[27] The constrained run is used to inform assessment of the impact of additional capacity on the cost of actions to manage network constraints as well as on the level of carbon emissions.

4.1.2. Wholesale price setting

Our market model calculates wholesale electricity prices by optimising economic dispatch (i.e., minimising the cost of production) to meet hourly demand. In practice, this means that our market model selects the least-cost portfolio of electricity supply (including dispatchable generation, storage, DSR, interconnection imports) to meet electricity demand (including DSR, and interconnector exports). This is illustrated in Figure 4.2 below, which provides an illustrative and simplified representation of the dispatch optimisation.

Figure 4.2: Stylised representation of the approach to price setting in CEPA's proprietary market model



Source: CEPA

CEPA's market model therefore sets the wholesale price equal to the marginal cost of production for the marginal supply source in each zone (i.e., the most expensive supply source of electricity that is consumed) subject to any

[27] It is noted that since the start of this project, Eirgrid and SONI have published an Operational Policy Roadmap which sets out potential changes to operational constraints applied – for instance delivering a system that can operate with 100% SNSP by 2035 and replacing the existing Minimum Number Of Units (MNOU) constraint.

constraints (i.e., interconnector losses or network limitations). For example, if a gas-fired CCGT is the marginal source of electricity supply in a given zone, then CEPA's market model would set the wholesale price equal to the short-run marginal cost of production for that gas-fired CCGT (e.g., fuel costs plus other variable costs of production).

How dispatch is determined within the model varies according to the following technology categories:

- **Thermal generation (e.g., gas, oil, coal):** Dispatch for these technologies is solved endogenously within our wholesale market model. These technologies can set the wholesale price based on their techno-economic characteristics – i.e., on the operational, fuel, and carbon cost of generation.
- **Exogenous generation (e.g., intermittent renewables and baseload generation):** Dispatch for these technologies is set based on an exogenous generation profile – i.e., historic wind and solar availability levels, with all plant having incentive to run in all periods with non-negative prices.
- **Flexibility (e.g., DSR, Pumped Storage, Batteries)**: These technologies can influence or set the wholesale price by shifting energy across time periods. For example, batteries 'buy' power at a certain wholesale price which it can then 'sell' at a price that recovers the cost of charging (including any losses) in a later period. The model optimises the charge and discharge patterns of storage technologies to minimise overall system costs and prices storage generation at the cost of charging (accounting for any losses).
- **Interconnectors**: Cross-border electricity flows act to reduce the degree of price differential between markets, with interconnectors modelled to flow from the higher-price market to the lower-price market in periods when the price difference is large enough to offset the efficiency losses across the interconnector.

4.2. Scenarios modelled

We have modelled the impact of additional interconnector and storage capacity against four scenarios for 2034 which we have calibrated in discussion with DfE – a Basecase and three sensitivities on the Basecase.

The Basecase scenario has been modelled under four variant cases reflecting differing levels of interconnector and storage capacity. We have used the AIRAA forecast for interconnection assumptions in low interconnection cases, whereas for the high interconnection scenarios we have included an NI-GB interconnector based on LIRIC, i.e. with a capacity of 700 MW. All other interconnector capacities remain the same. For storage, we have used DfE's inputs to build both the low and high scenarios. The low storage scenarios include the current storage capacity (c. 200 MW with approximately 1 hour of storage) and 765 MW of short-duration storage that are currently waiting for connection agreement. The high storage scenario includes an additional pumped-hydro storage facility that could produce 3GWh with an assumed duration of 12h (therefore 250 MW of storage capacity) and 1,775 MW of additional storage, both from short and medium duration. The additional 1,755 MW was split into short- and medium-duration storage using GB's FES 2034 forecasted proportions for Holistic Transition between batteries (short) and compressed air and liquid air alternatives (medium).

The assumptions for the Basecase are summarised in the table below. Modelling has been carried out of the Basecase against the four cases of differing levels of interconnector and storage capacity under a constrained and unconstrained run (to give an indication of the impact of additional interconnector and storage capacity on constraint costs).

Table 4.1: Basecase Modelling Scenario

	LILS: Low interconnection and low storage (Case 1 BAU)	**LIHS**: Low interconnection and high storage Case 2	**HILS**: High interconnection and low storage Case 3	**HIHS**: High interconnection and high storage Case 4
NI Interconnection	AIRAA forecast	AIRAA forecast	AIRAA forecast + LirIC (700MW)	AIRAA forecast + LirIC (700MW)
NI Storage capacities	Short (1h): 965MW Medium (6h): - Pumped hydro (12h): -	Short (1h): 2,514MW Medium (6h): 206MW Pumped hydro (12h): 250MW	Short (1h): 965MW Medium (6h): - Pumped hydro (12h): -	Short (1h): 2,514MW Medium (6h): 206MW Pumped hydro (12h): 250MW
Common assumptions	80% renewables 2030 target met with mix of onshore wind and solar; 1GW offshore wind operational by 2034; N-S interconnector operational by 2034; Greenlink and Celtic Interconnector are operational; and SONI low projected level of electricity demand.			

Source: CEPA & DfE

We have modelled three sensitivities on the Basecase scenario to test the sensitivity of the results to changes in individual assumptions:

- **Sensitivity 1 (S1) – Excludes PSH:** In this sensitivity the additional storage capacity modelled in Cases 2 and 4 excludes the 250MW pumped hydro storage facility, while retaining short- and medium-duration battery storage. This sensitivity is modelled for Cases 2 and 4 (i.e. those featuring high storage) under both constrained and unconstrained runs.
- **Sensitivity 2 (S2) – No Interconnector Redispatch**: In this sensitivity we assume that the allocation of flows on the SEM interconnectors is determined in the unconstrained run (i.e. reflecting the wholesale market) and cannot then be varied in the constrained run (i.e. reflecting the BM). This reflects an assumption that interconnectors cannot be redispatched in the BM to alleviate grid constraints.
- **Sensitivity 3 (S3) – No Interconnector Redispatch and Delay to NS Interconnector**: This sensitivity assumes SEM interconnector flows are fixed in the unconstrained run (as per Sensitivity 2), and also assumes that the NS Interconnector has not been completed by 2034 (i.e. the transmission constraint between Ireland and Northern Ireland is 450 MW).

4.3. Other markets considered

CEPA's market modelling framework quantifies impacts in the SEM day-ahead wholesale market. It is recognised that the additional interconnector and storage assets may provide services across a number of other markets. We have quantified the value of these services as follows:

Capacity markets

GB and SEM each maintain a capacity mechanism that pays providers for providing capacity that available.

We have assumed that the additional interconnector would be eligible for capacity payments in both SEM and GB. To derive the value of this, we have applied the de-rating factors used in each market for existing GB-NI interconnection in recent auctions (i.e. 47% in SEM and 54% in GB), and multiplied by the capacity price in each market (in SEM and in GB).

For the additional storage capacity, we have applied relevant SEM derating factors for the level of storage duration. This is 11.5% for 1-hour batteries, 37.4% for 6-hour storage capacity and 33.6% for pumped hydro storage with a presumed duration of 12 hours.[28]

For both interconnection and storage, we have applied a capacity price based on the estimated net cost of new entry (Net CONE) for providers (i.e. £95.9/kW year in SEM and £49/kW year in GB) used in determining capacity auction parameters.[29]

We have assumed that this payment is additional to the procurement of capacity that would take place in the counterfactual given the assumption that these assets are incremental and not displacing other capacity in GB or SEM.

Ancillary and Balancing Services:

We have modelled the additional revenues that interconnectors and storage may earn for ancillary and balancing services. These are services contracted by the System Operator for helping to manage the system.

We have applied ancillary services of £20/kW/year for interconnection based on CEPA analysis of revenue statements by Moyle.[30] It is noted however that the introduction of the Day Ahead System Services Auction could lead to competition for contracts driving down revenues below historical levels.

We have applied ancillary services of £25/kW/year for storage providers based on CEPA analysis of published revenue benchmarks for short duration battery storage in GB.[31] We have also considered the revenues that storage providers may earn for trading capacity at multiple time horizons, including in the balancing mechanisms, as market conditions change. We have applied an uplift of 17% of the modelled wholesale market revenues based on CEPA analysis of the breakdown of historic revenues for battery storage providers between wholesale market and balancing revenues.

We have not considered additional revenues that providers may earn for alleviating network constraints, noting that parties are expected to bid constraint services on a cost-reflective basis and are paid as bid. However, this may represent an understatement of potential revenues, given that providers may be able to recover some fixed costs within their bidding for constraint services.

We have assumed that this payment is displacing payments made to alternative providers, of which it is assumed that 16% are in NI and 84% are in Ireland, consistent with the split of demand between the markets.

4.4. KEY INPUTS AND ASSUMPTIONS

4.4.1. Demand

Annual demand for Northern Ireland and Ireland (SEM) was based on the low scenario forecast for 2034 of the EirGrid/SONI All-Island Resource Adequacy Assessment (AIRAA) 2025-2034. The low scenario was selected as it aligned more closely to DfE's expectations on heat pump adoption by 2034, while noting that this may imply a lower level of whole system decarbonisation.

The total annual demand for GB and other European countries was based on the NESO Future Energy Scenarios (FES) 2024 forecast, specifically the Holistic Transition scenario. This scenario was selected for GB as it aligns most closely—both in terms of demand and generation—with the Clean Power 2030 Action Plan, the latest government

[28] https://www.sem-o.com/sites/semo/files/documents/general-publications/IAIP2728T-4.pdf

[29] https://www.gov.uk/government/publications/capacity-market-auction-parameters-letter-from-desnz-to-neso-february-2025/final-auction-parameters-t-1-and-t-4-capacity-market-auctions (GB) and Capacity Remuneration Mechanism (CRM) (SEM)

[30] https://www.mutual-energy.com/wp-content/uploads/2024/09/MUTUAL-ENERGY-Annual-Report-2024-final.pdf

[31] https://www.cornwall-insight.com/thought-leadership/blog/riding-the-battery-storage-revenue-rollercoaster/

target for decarbonizing the GB power system, published after the FES 2024 report. To ensure consistency, the same scenario was used as the baseline for other European countries.

In all cases, we converted annual demand into an hourly demand assumption using country-specific exogenous hourly profiles based on historic demand patterns.

The level of annual demand assumed by market is shown in Table A0.3.

4.4.2. Demand Side Response (DSR)

We modelled two DSR technologies: load-shifting and peak-shaving. Load shifting refers to consumers changing the hours in which they consume electricity in response to market signals, while peak shaving refers to consumers curtailing demand in response to high prices.

We have used AIRAA DSR capacities for SEM and FES for both GB and the rest of European countries and allocated this 75% to peak-shaving and 25% to load-shifting.

For DSR peak-shaving, we have modelled the capacity in three equal tranches and assigned price thresholds of £500/MWh, £2500/MWh and £5000/MWh to the three tranches. It is recognised that there is uncertainty and limited data around the price threshold at which electricity demand may reduce – however the thresholds applied were selected to provide a wide range, consistent with the wide ranges observed in estimates of VOLL for non-domestic users.[32] For DSR load-shifting, the model optimises for when demand is met within a limited time window.

4.4.3. Generation

The model incorporates all generation technologies presented in Table 4.2 and whether their dispatch is endogenous (i.e. determined by the model in line with system requirements or market prices), exogenous baseload (i.e. a profile that is exogenously fixed and has capacity running in line with the overall level of system demand), and exogenous intermittent (i.e. based on historic generation profiles – though allowing for technologies to turn off in response to negative prices when subsidies are suspended).

[32] https://www.semcommittee.com/files/semcommittee/media-files/Calculation%20of%20a%20single%20Value%20of%20Lost%20Load%20within%20the%20SEM%20Information%20Paper%20SEM-23-072.pdf

Table 4.2: List of generation technologies modelled

Technology	Dispatch modelling
Gas CCGT high efficiency (only GB & SEM)	Endogenous
Gas CCGT mid efficiency (only GB & SEM)	Endogenous
Gas CCGT low efficiency (only GB & SEM)	Endogenous
Gas OCGT efficiency (only GB & SEM)	Endogenous
Gas CCS (only GB & SEM)	Endogenous
Gas (rest EU)	Endogenous
Fuel oil and diesel	Endogenous
Coal	Endogenous
Hydrogen	Endogenous
Battery (rest EU)	Endogenous
Battery Short (only GB & SEM)	Endogenous
Battery Medium (only GB & SEM)	Endogenous
Pumped storage	Endogenous
DSR (load shifting and peak shaving)	Endogenous
Biomass (inc. Biomass with CHP)	Exogenous - Baseload, based on country and technology-specific load factors
Biomass with CCS	Exogenous - Baseload, based on country and technology-specific load factors
Nuclear (SEM & rest EU)	Exogenous - Baseload, based on country and technology-specific load factors
Nuclear large (only GB)	Exogenous - Baseload
Nuclear SMR (only GB)	Exogenous - Baseload, based on load factor from FES
Waste & CHP	Exogenous - Baseload, based on load factor from FES
Other renewables (inc. geothermal and marine)	Exogenous - Baseload, based on load factor from FES
Hydroelectric (run-of-river and reservoir)	Exogenous - intermittent, based on historic generation profiles – but with some degree of endogeneity enabling refinement around the historical profile
Offshore wind	Exogenous - intermittent, based on market-specific availability profiles but endogenous curtailment when prices fall below zero
Onshore wind	Exogenous - intermittent, based on market-specific availability profiles but endogenous curtailment when prices fall below zero
Solar	Exogenous - intermittent, based on market-specific availability profiles but endogenous curtailment when prices fall below zero

Source: CEPA

We modelled the majority of fuelled and 'flexible' technologies endogenously – i.e., the model solves for the dispatch of these technologies based on their techno-economic characteristics (such as fuel efficiencies, variable operational costs, and emission intensities), fuel and carbon costs, and other market conditions, such as the demand profile and wind/solar resource availability profiles for intermittent renewable technologies.

Table 4.3 details the sources being used to estimate the techno-economic parameters.

Table 4.3: Techno-economic parameters

Variable	Source
Fuel costs	FES 2024 High Case (consistent with Holistic Transition)
Carbon price	FES 2024 High Case (consistent with Holistic Transition)
Average fuel efficiency	DESNZ Electricity Generation Costs 2023, with CEPA analysis of the relative proportion of the gas capacity within high, medium and low efficiency CCGT categories and OCGT / reciprocating engines.
Carbon intensity	TYNDP 2024 Implementation guidelines[33]
Variable cost	For renewables, technologies were assumed to have a variable cost of close to zero (with marginal differences modelled to enable the curtailment of renewables in line with the merit order suggested by the DESNZ Electricity Generation Cost. For thermal technologies we used DESNZ estimates.
Efficiency loss (for storage	CEPA assumptions: 15% for batteries of all duration, 25% for pumped hydro

For a subset of technologies, we modelled dispatch exogenously in line with historical generation profiles, based on the assumption that these technologies remain within merit and follow a similar generation pattern each year. This applies to some dispatchable generation which we consider to be 'must-run' baseload technologies (such as nuclear and biomass).

Generation capacities were mostly based on FES 2024 Holistic Transition (for GB and rest of EU) and AIRAA for SEM. The following are the exceptions or ad-hoc adjustments:

- Solar, onshore wind and offshore wind capacities in Northern Ireland were adjusted as per DfE's guidance. The adjustment relies on different assumptions about the timing of development of offshore wind capacities in Northern Ireland between AIRAA and DfE, and the underlying assumption of NI's meeting the 80% e-RES target by 2030 without offshore wind commissioning in time to support achieving this target. The capacities assumed for NI in 2034 for the purpose of this study were the following:
  - Solar: 1.0 GW
  - Onshore wind: 2.2 GW
  - Offshore wind: 1.0 GW
- Storage capacities for Northern Ireland were adjusted to the assumptions detailed in Section 4.2.
- We have modelled a minimum thermal generation requirement for NI in the constrained run. We have assumed that at least two thermal generation plants must be running for 50% of their plant's capacity, for system stability reasons.

4.4.4. Interconnection

For the modelling of interconnectors between markets, we used the following sources and assumptions:

- **Interconnection between SEM and other markets**: AIRAA forecast. See Section 4.2 for the details on the different assumptions per scenario.
- **Interconnection between GB and other markets (exc. SEM)**: FES 2024 Holistic Transition. Given that this data is not split by market, we have individually matched them using publicly available information about future interconnectors and assigned the remaining capacity using the proportions of existing interconnection.

[33] Implementation Guidelines for TYNDP 2024, March 2024, ENTSO-E

In order to be able to model the benefits of increased interconnection and storage in relieving network congestion between Ireland and Northern Ireland, we have additionally modelled the network constraint between these two jurisdictions.

There is currently 300 MW of net transfer capacity between Ireland and Northern Ireland. We have assumed an additional 900MW capacity from NI to Ireland, and 950MW additional capacity from Ireland to NI operational by 2034, consistent with TYNDP modelling assumptions. We run the model with and without this constraint (see more details in Section 4.1.1).

4.4.5. Policy

For the GB market, we have assumed national pricing is retained under the Core Scenarios.
For the NI market, we have assumed a CfD mechanism is introduced to procure the projected gap in renewables needed for NI to meet its 80% RES target by 2030, with the additional capacity met through a mixture of offshore wind, onshore wind and solar generation.

There is currently no support arrangement in place for either interconnection or storage in NI (aside from the SEM and GB capacity mechanisms which are technology-neutral and market-wide). However, it is recognised that if a project is assumed to be unable to recover its construction and financing costs from the range of market revenues, then policy support may be needed to ensure these projects are delivered.

We have estimated the potential missing money for the additional capacity based on estimates of the project costs and comparison with the modelled level of revenues. In the case of an NI-GB interconnector, we assumed that only 50% of any support costs are paid by NI consumers while 50% are paid by GB consumers.

In order to derive these policy costs, we align our assumptions of the costs and technical parameters of interconnector and storage assets with publicly available data on relevant comparator projects or industry surveys. A detailed list of our assumptions is available in Appendix A: Key Inputs and Sources.

4.5. Limitations to modelling approach

The following are some of the limitations that CEPA identifies from this modelling exercise:

- The modelling only covers one single snapshot year (2034). To the extent that decarbonisation and demand growth through electrification contribute to the economic case for storage and interconnection, modelling 2034 alone may understate the value of these assets.
- Modelling of demand and of renewable generation profiles is based on a single historic year (2019). Use of stochastic modelling based on a wider range of potential outcomes for demand and renewable generation levels could more accurately estimate the level of security of supply benefits. The impact of this on the estimation of benefits may also differ by technology – for instance with short duration batteries having a potentially more limited security of supply benefit against a prolonged period of cold weather and low wind than a pumped hydro storage asset.
- The model assumes perfect foresight of consumer demand and plant availability in the short-term. This is likely to understate the value of flexible assets as it cannot fully capture the incidence of system shocks near to real-time that flexible assets can respond to.
- The storage and interconnector capacity modelled is assumed to be incremental capacity to the BAU – i.e. it does not displace other existing or anticipated new capacity. This may understate the value of these assets in avoiding the need to building other infrastructure or in contributing to security of supply.
- The model assumes a decarbonisation pathway for GB and Europe (outside of NI) that is potentially consistent with Net Zero, depending on assumptions for how energy use is decarbonised outside of the electricity sector. There are significant challenges to a net-zero consistent pathway being achieved – for instance requiring delivery of a significant increase in infrastructure and changes to patterns of consumer

demand. The UK Committee for Climate Change (CCC) has noted a number of risks to UK decarbonisation continuing in line with the carbon budgets (i.e. interim targets), such as around barriers to uptake of electric vehicles and heat pumps. It is noted that there is also uncertainty around the extent to which additional demand can become price-responsive, providing system flexibility and avoiding the need for dispatch down of renewables.

- In the case of SEM, the demand and generation profiles generally follow the assumptions in the AIRAA, which sets out the forecast of the TSOs SONI and Eirgrid for NI and Ireland, and which may not necessarily be consistent with Net Zero policy objectives. In addition, NI electricity demand has been assumed to grow more slowly than forecast in AIRAA, reflecting DfE expectations of challenges to electrification. The slower pace of electrification until the 2034 modelled year means that an even higher pace of electrification may be needed from the late 2030s to be consistent with a Net Zero decarbonisation pathway.
- All renewable generation in SEM is assumed to be dispatchable – i.e. responsive to price signals – and bid into the wholesale market based on short run marginal cost. In reality, some small-scale capacity is non-dispatchable, including 70 MW of wind in NI. Assuming all renewable generation is dispatchable may slightly understate the cost of actions to manage constraints in the modelling. Moreover, renewable support schemes may incentivise some assets in SEM to run even when the power price is negative, such that the modelling may understate the potential arbitrage revenues for flexible assets such as interconnectors and storage in periods of negative power prices.
- The Basecase assumes that interconnectors are efficiently redispatched in the balancing mechanism to reflect constraints within SEM. In practice, there are typically barriers to the efficient redispatch of interconnectors that may lead to TSOs dispatching down domestic generation or turning up thermal generation ahead of redispatching interconnectors, which requires cooperation between TSOs. We have considered barriers to interconnector redispatch in Sensitivities 2 and 3.
- The transmission system is not modelled in detail – i.e. only reflecting constraints between Ireland and Northern Ireland. More detailed modelling of network constraints could further increase the volume of redispatch and dispatch down actions observed.

Policy support costs estimated are illustrative and reflect uncertainty around both the technical cost of the projects (which are based on international comparators which may have different characteristics), and the policy support arrangements put in place (which currently do not exist).

5. COMMERCIAL ASSESSMENT

This section sets out the commercial assessment of additional storage and interconnector capacity under the Basecase and sensitivities.

To carry out an assessment of the commercial case for the additional assets, we have modelled the annual revenue requirement for each asset. This revenue is set at the capital cost of the project (amortised over its economic life at a weighted average cost of capital) and its annual fixed costs. It represents the level of revenue which, if earned each year over the asset's economic life, would ensure the project just meets its required return. We have then estimated how much revenue the assets would earn from the different markets (wholesale market, capacity markets and ancillary services) in the modelled spot year.

The difference between the revenue requirement and the modelled revenues is noted as the residual revenue requirement. A positive residual indicates a potential need for a subsidy to be commercially viable, while a negative residual indicates the additional profit that the assets are expected to earn in that year over their revenue requirement.

This section presents the commercial case for additional interconnector and storage capacity in isolation from each other rather than in combination.[34]

5.1. Commercial Assessment of Additional Storage

The commercial assessment of storage assets considers the revenues modelled for the short, medium and long duration storage assets in the Basecase, and considers the short and medium duration storage assets in Sensitivity 1 (where no additional long duration storage is modelled).

Table 5.1: Commercial Assessment of Additional Storage Capacity in NI

Revenue (£/kW year)	Basecase			Sensitivity 1: Excludes PSH	
	Short Duration	Medium Duration	Long Duration	Short Duration	Medium Duration
Revenue Requirement	46	186	284	46	186
Modelled Revenue: Ancillary Services	27	38	45	27	39
Modelled Revenue: Capacity Market	11	36	32	11	36
Modelled Revenue: Wholesale Market	13	75	119	14	82
Residual revenue requirement[35]	**-4**	**38**	**87**	**-6**	**29**

[34] It is noted that the combination of the additional interconnector and storage capacity increases cannibalises the revenues of the other, such that the profitability of each is slightly reduced. This can be seen in Table 6.4, where the subsidy requirements for additional storage are greater in the case where additional interconnection is being developed at the same time.

[35] May differ from the shown revenue requirement net of modelled revenues due to rounding.

For the additional short-duration batteries modelled, the annual revenue requirement is just met in the Basecase, with ancillary and balancing services providing most of its revenues and the remainder coming from a mix of wholesale and capacity market revenues in the modelled year. The commercial assessment for the additional medium and long-duration storage indicates a significantly higher revenue requirement for medium and long-duration batteries reflecting the increased build costs. The higher build costs are only partially offset by increased revenues, particularly in the wholesale market. However, the assets do not achieve their required level of revenue to be commercially viable without further support.

The commercial assessment for medium batteries improves under Sensitivity 1, as wholesale market revenues are expected to be higher in the absence of the PSH facility. However, revenues would still be slightly short of the level required to fully offset the costs, and the assets could require policy support in order to be viable. It is noted that the missing money estimated for medium and long-duration storage may reflect a number of factors:

- The size of the additional NI storage capacity modelled (just over 2GW total) may lead to cannibalisation of storage revenues, whereas a smaller increase in storage capacity could lead to that storage being more commercially viable.
- We have assumed high levels of interconnection in the BAU, including the construction of the MARES connect between GB and IE, which may reduce the scale of arbitrage revenues for other forms of flexible capacity. This is supported by our modelling the scenario with both the additional interconnector and storage capacity, which shows lower revenues for the new storage assets than under the scenario with increased storage but no additional interconnection.
- We have assumed parties do not profit from services alleviating constraints. In practice, parties may be able to recover a degree of their fixed costs through their participation in the BM. However, actions to alleviate grid constraints over time, including through completion of the North South Interconnector (NSI), may mean that revenues from constraint management are uncertain and heavily discounted by developers.
- Some of the value of medium and long-duration batteries is in providing resilience - e.g. against low-likelihood high-impact risks. This is not fully captured in modelling – which considers a single weather year and does not stochastically model the potential for a lack of resource adequacy driven by incidents of high demand, low renewables and/or plant outages. The modelling may therefore be considered a conservative estimate of the revenue that LDES may be able to earn.
- While our estimates of wholesale revenues are an output from our model, the estimates of other market revenues are illustrative and based on benchmarks of existing revenues and so subject to greater uncertainty. Some medium and long-duration storage assets might reasonably expect to earn considerably more from ancillary and balancing services than reflected in our assumptions. For instance, it is noted that capacity market prices may increase over time once the cost of new entry is set by low-carbon technologies (such as gas with CCUS or hydrogen generation) rather than by existing unabated gas technologies.

5.2. Commercial Assessment of Additional Interconnector

The commercial assessment shown in Table 5.2 of the additional 700MW interconnector considers the revenues modelled for the LIRIC interconnector in the Basecase.[36] The annual revenue requirement is met principally through a mix of wholesale revenues (i.e. arbitrage between GB and SEM markets) and of SEM and GB capacity market revenues, with some additional revenues from ancillary services, with the interconnector earning revenues that are £90/kW year greater than required. It is noted that this surplus revenue may be partially recovered for customers if a Cap & Floor arrangement were in place.

Table 5.2: Commercial Case for 700 MW GB-NI interconnector

Revenue (£/kW year)	Basecase
Revenue Requirement	119
Modelled Revenue: Ancillary Services	20
Modelled Revenue: Capacity Market	72
Modelled Revenue: Wholesale Market	117
Residual revenue requirement	**-90**

We have assumed that the interconnector does not earn a profit from any redispatch actions taken in the BM, and so the commercial case for the interconnector does not differ for Sensitivities 2 or 3, which assumes interconnectors are not redispatched in the BM.

[36] It is noted that the modelling of Sensitivities 2 and 3 (reflecting restricted redispatch of the interconnector and a delay to completion of the North South interconnector) does not affect commercial assessment of the interconnector, as the Basecase assumes that actions taken to manage constraints by redispatching the interconnector are paid at cost and so do not provide an additional source of revenue.

6. ECONOMIC ASSESSMENT

In this section we set out the modelled socioeconomic impacts of the additional interconnector and storage assets. These impacts are identified for wholesale prices, renewable generation and carbon impacts, and security of supply. We then present a summary cost benefit analysis – bringing together the various monetised impacts and how they impact consumers and producers.

6.1. WHOLESALE COST OF ELECTRICITY

Modelling of wholesale market impacts of the additional interconnector and storage capacity draws from the Basecase scenario as well as Sensitivity 1 (which excludes the additional Pumped Hydro Storage from the High Storage cases).[37]

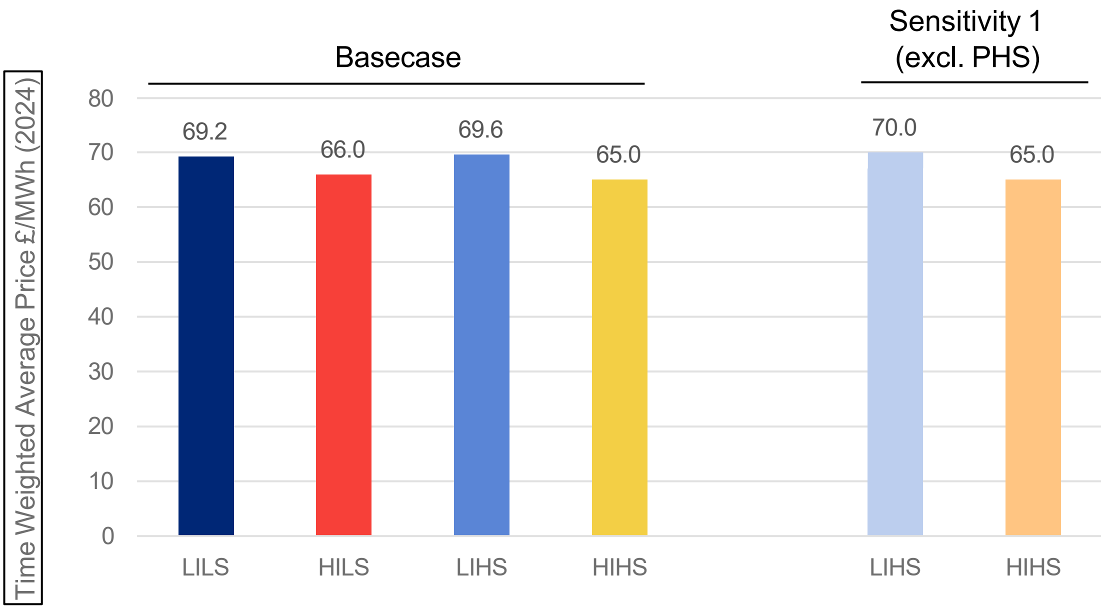
As shown in Figure 6.1, we have identified the following wholesale price impacts in our modelling:

- A £3.20/MWh reduction in wholesale prices as a result of the additional 700MW interconnector between NI and GB (equivalent to a 5% reduction).
- A £0.40/MWh increase in wholesale prices as a result of the additional 3GW storage capacity in NI (equivalent to a 0.5% increase). When excluding the PHS asset from the additional storage modelled (as in Sensitivity 1), there is a £0.80/MWh increase in wholesale prices (equivalent to a 1% increase).
- A £4.20/MWh reduction in wholesale prices as a result of the combination of the additional interconnector and storage capacity, both in the Basecase and under Sensitivity 1 (equivalent to a 6% reduction).

It is noted that while the additional interconnector and storage capacity are significant in size relative to electricity demand in NI, wholesale prices are set at the SEM level. This both mitigates the price impacts of new NI capacity on SEM pricing but also means that pricing impacts apply equivalently to consumers in Ireland as well as in NI.

[37] Sensitivities 2 and 3 involve assumptions affecting the extent and cost of managing constraints but which do not have an impact on wholesale market outcomes, which are based on modelling the SEM as an unconstrained market.

Figure 6.1: SEM Wholesale Price by Scenario



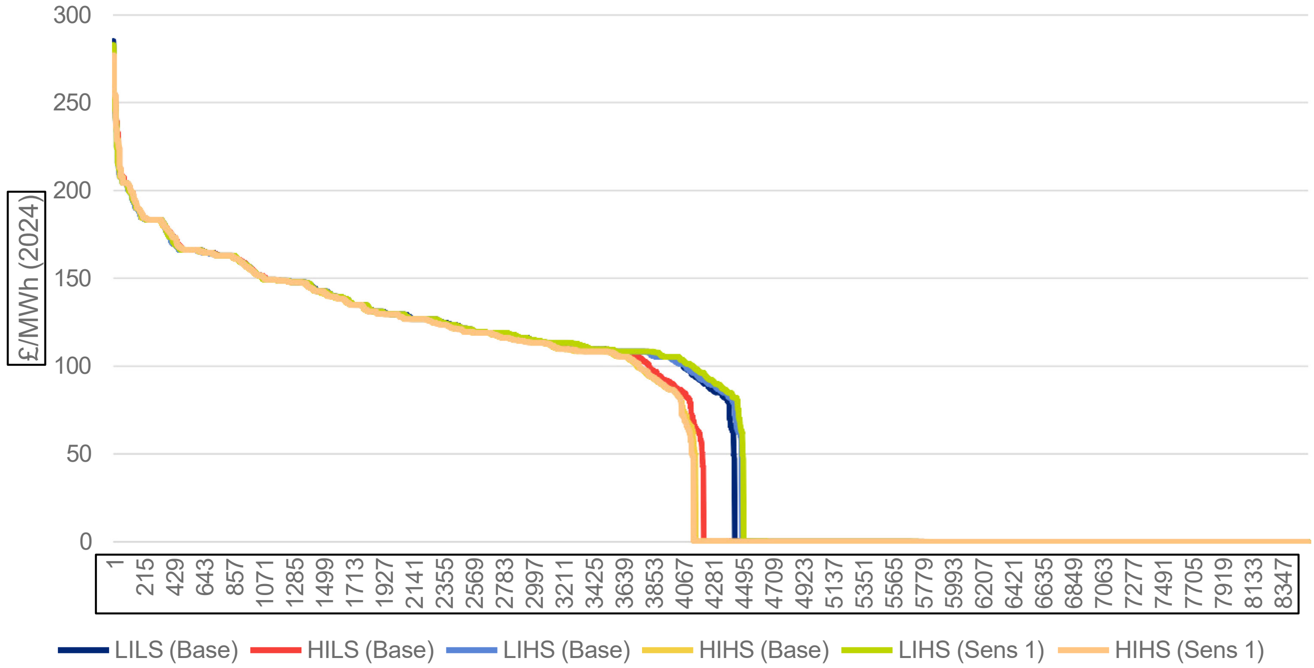
LILS*=Low Interconnection, Low storage (BAU against which other scenarios are measured)*
HILS*=High Interconnection, Low Storage*
LIHS*=Low Interconnection, High Storage (modelled for Basecase and Sensitivity 1)*
HIHS*=High Interconnection, High Storage (modelled for Basecase and Sensitivity 1)*

The additional GB-NI interconnection reduces SEM wholesale prices by enabling additional imports from GB at times of renewable curtailment in GB when prices there are low or zero. It should be noted that the benefit of this reduction in wholesale prices is shared across all SEM consumers, with NI consumers receiving a proportionate share of this reduction in wholesale market costs.

Additional storage puts some upward pressure on wholesale prices as a result of increasing demand for electricity in periods when there would otherwise be curtailment of renewables (raising prices in periods that would otherwise have a zero price), while discharging at times when gas generation is setting the market price. While increased wholesale prices is by itself a negative impact on consumers, it is noted that this may be partially offset by reduced subsidy payments needed for NI renewables with a CfD.

The impact of both interconnection and storage at different points in the year is illustrated in Figure 6.2 below, using price duration curves, which show hourly prices across the year in descending order of price. Whereas gas generation is currently the price setter in most periods today, by 2034 the SEM market is largely decarbonised. In about half of the hours in the year gas generation is the marginal plant and setting the price for the market, while in the other half of hours in the year, renewables are sufficient to meet demand and so prices collapse to around zero, reflecting the low marginal cost of renewables and the incentive to run to receive subsidies.

Figure 6.2: SEM Price Duration Curves



Storage makes wholesale prices smoother – raising prices when it charges and reducing prices when it discharges. The introduction of additional storage in NI serves to increase electricity demand in some hours and reduce electricity demand in others by shifting energy over time. For example, storage can shift renewable generation from periods where it would otherwise be curtailed to hours where it can meet domestic demand or be exported via interconnection to GB or France. The net effect could in theory be slightly positive or slightly negative depending on specific conditions and modelling assumptions.

In our modelling, we find that the introduction of additional storage leads to an average increase in wholesale prices across the 2034 spot year relative to the BAU case. Storage leads to prices rising from zero up to the cost of gas generation in some periods - as charging reduces periods of excess supply. However, most storage discharge is at periods when gas generation is still needed to meet demand, and so storage has more limited downward pressure on prices in these periods. The net effect of the additional storage is to increase prices in more periods than it decreases prices. This effect is observed in both the Basecase and Sensitivity 1 (where there is no PHS and all storage assets are short- or medium-duration batteries), with a greater impact in the latter. This finding is sensitive to assumptions made – for instance that the capacity mix in SEM is already adequately resourced to meet demand without the additional assets and therefore that there are few periods of system stress and high prices that can be mitigated by the additional storage.

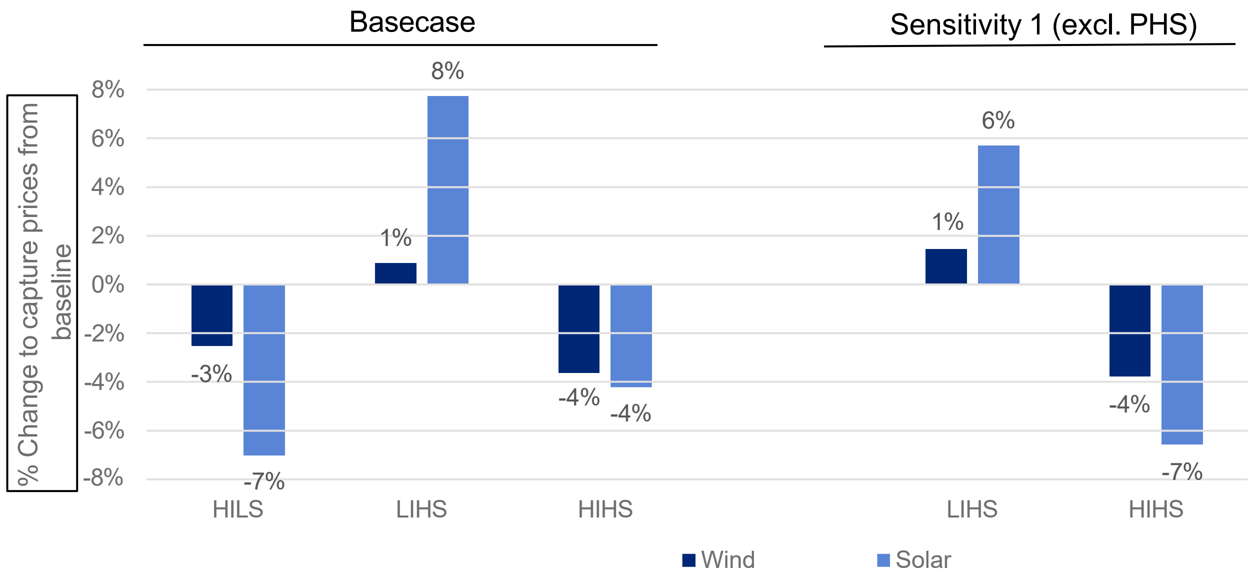
By contrast, the principal impact modelled of the additional interconnector is to increase the number of hours at zero prices – i.e. when there is excess renewables in GB and the additional imports are able to displace all gas generation in SEM.

We have also assessed the impact of the additional interconnector and storage capacity on capture prices. Capture prices are the prices achieved by particular technologies and represent the average price received for generation. Capture prices will typically differ from the average wholesale price because each renewable generator of a particular technology is correlated with the rest of the fleet (and with generation in interconnected markets) due to weather conditions. Capture prices have been calculated as the average price weighted by available generation for each technology.

As shown in Figure 6.3, increasing the level of storage has a positive impact on solar capture prices by reducing the scale of price variation across the day – in particular making periods of zero prices less common at times when solar generation levels are high. The impact of increased storage on wind capture prices is also positive but more limited.

Additional interconnection has a small negative impact on solar and wind capture prices. This is because interconnection increases the hours in which SEM imports power from GB at low or zero price more than it increases the number of hours in which SEM exports to GB at a higher price set by the cost of non-renewable generation in GB.

Figure 6.3: Impact of Additional Interconnector and Storage Capacity on SEM Capture Prices



6.2. Renewable Generation and Carbon Impacts

Renewables may be dispatched down (i.e. not dispatched when available) either due to curtailment of surplus renewables (i.e. SEM renewable generation exceeds demand in SEM net of imports such that some renewable generators are not dispatched on an unconstrained basis) or for grid reasons (for instance renewables in a particular region may be curtailed if there is insufficient network capacity to transport the output to areas of demand or to limit SNSP and ensure there is a minimum of must-run thermal units generating).

The level of curtailment of surplus renewables is calculated in our model by comparing dispatched renewable generation in our unconstrained cases with the level of available renewable generation. The level of curtailment for operational constraints is calculated by comparing the level of renewable generation that is dispatched in the constrained and unconstrained cases. The modelled impact of the interconnector and storage capacity is calculated based on the constrained cases and reflects the total level of dispatch down. [38]

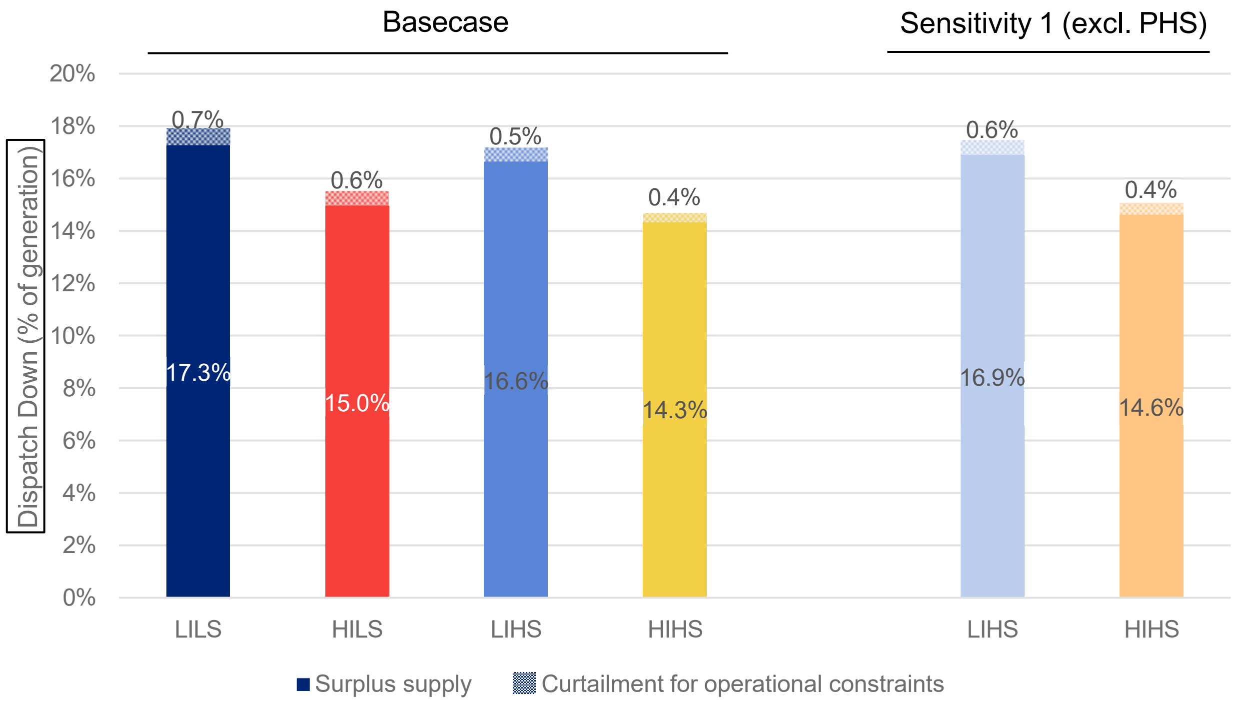
Both increased storage and increased interconnection are found to reduce the degree of dispatch down of renewables in SEM – principally the economic curtailment of surplus renewables.

As shown in Figure 6.4, dispatch down of surplus NI renewables in the Basecase falls by 13% when you add an interconnector, by 4% when you add additional storage, and by 17% when you add both additional interconnection and storage. If PSH is excluded (Sensitivity 1), additional storage capacity reduces dispatch down by 2%, or by

[38] CEPA's modelling of 17.9% renewable dispatch down in the Basecase LILS modelling for 2034 equates to 19.7% dispatch down of wind generation. By comparison, there was 18.6% wind dispatch down in NI in 2023, the most recent full year for which there is published data (https://cms.soni.ltd.uk/sites/default/files/publications/Appendix%205%20-%20Performance%20Measures.pdf). It is noted that CEPA's Basecase modelling for 2034 features a significantly increased level of renewables but also the completion of the North South Interconnector, which alleviates the need for curtailment of renewables for grid reasons.

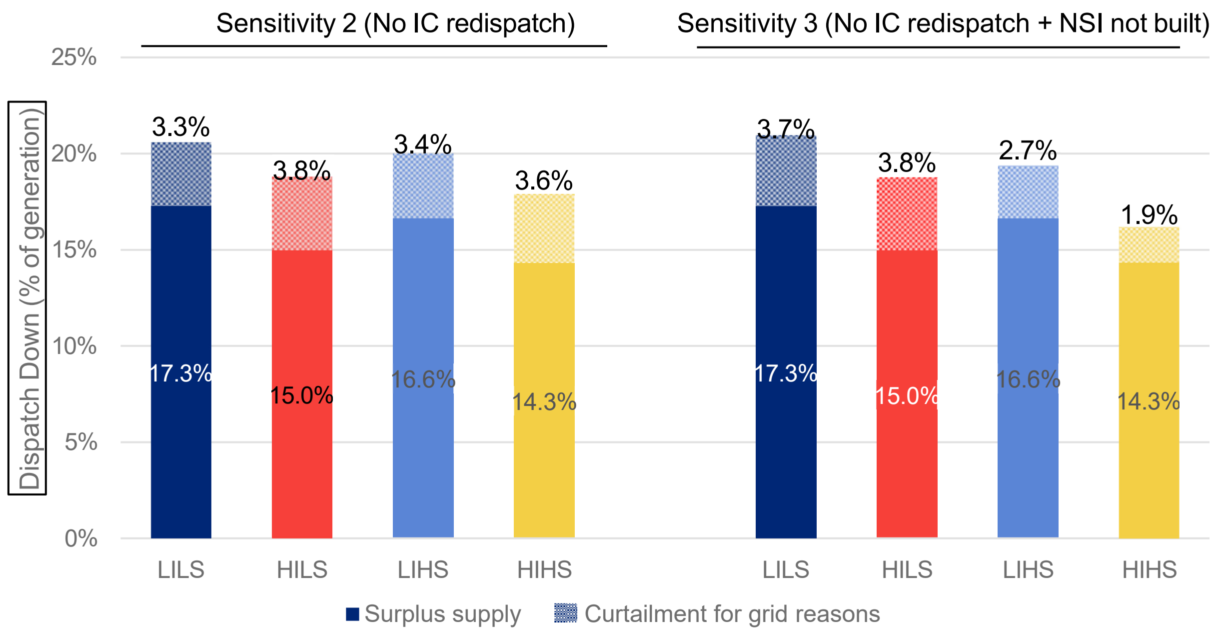
15% if in combination with additional interconnection. (It should be noted that a reduction in curtailment of surplus renewables is achieved across all renewables in SEM and not just NI generators).

Figure 6.4: Dispatch down of NI renewables as a share of generation in Basecase and Sensitivity 1



As shown in Figure 6.5, the dispatch down for grid reasons in the BAU scenario is significantly higher if interconnectors cannot be redispatched in BM timeframes – at 3.3% in Sensitivity 2, rising to 3.7% in Sensitivity 3 if the North South Interconnector is not completed for 2034. In this context, additional interconnection *increases* dispatch down for grid reasons to 3.8% in Sensitivity 2 and Sensitivity 3 due to exacerbating constraints within SEM (as interconnector flows are scheduled purely on the basis of unconstrained price differentials between SEM and connected markets). However, the overall effect of the additional interconnector is to reduce dispatch down – as the reduction in curtailment of surplus renewables is greater than the increase in curtailment for operational constraints.

Figure 6.5: Dispatch down of NI renewables as a share of generation in Sensitivities 2 and 3



The overall effect of both interconnection and storage is to increase renewables generation in NI across all scenarios, as shown in Figure 6.6 and Figure 6.7, with NI renewable generation providing a higher proportion of NI demand as a result of increased storage and interconnection.

Figure 6.6: NI renewable generation as a percentage of total electricity requirement in Basecase and Sensitivity 1

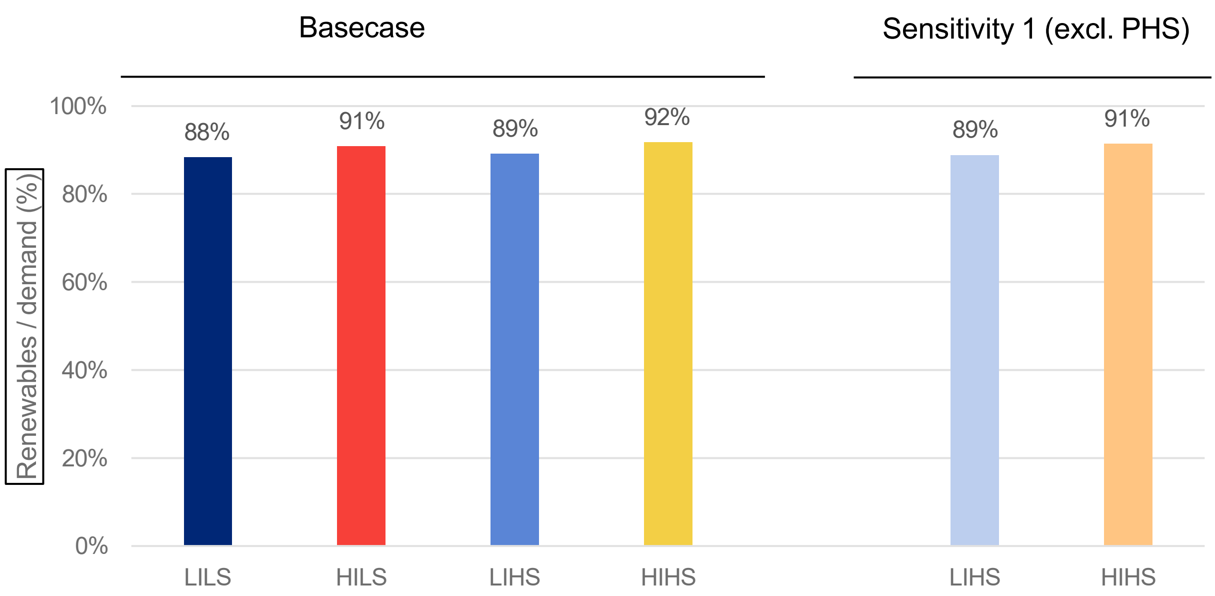
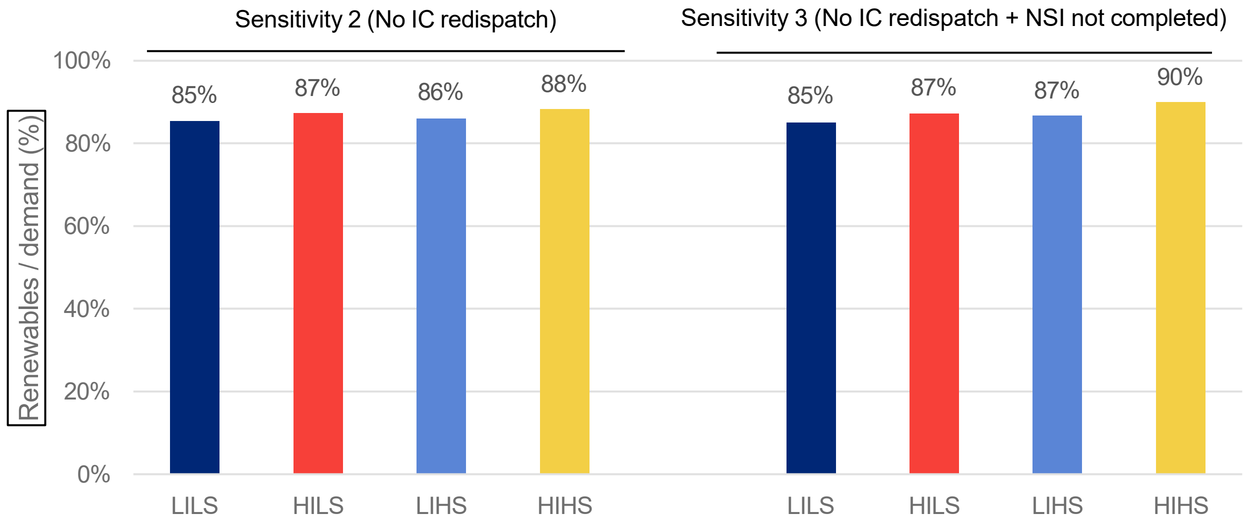


Figure 6.7: NI renewable generation as a percentage of total electricity requirement in Sensitivities 2 and 3



The levels of renewable generation and how they are affected by dispatch down for surplus supply or for grid reasons is set out in Table 6.1 and Table 6.2 below.

Table 6.1: NI Renewable Generation Levels (TWh) in Basecase and Sensitivity 1

TWh	Basecase				Sensitivity 1 (Exc PHS)	
	LILS	HILS	LIHS	HIHS	LIHS	HIHS
Available Renewable Generation	10.4	10.4	10.4	10.4	10.4	10.4
Surplus Supply	1.8	1.6	1.7	1.5	1.8	1.5
Curtailment for Operational Constraints	0.1	0.1	0.1	0.0	0.1	0.0
Dispatched Renewable Generation	8.5	8.8	8.6	8.6	8.9	8.8

Table 6.2: NI Renewable Generation Levels (TWh) in Sensitivities 2 and 3

TWh	Sensitivity 2 (No IC Redispatch)				Sensitivity 3 (No IC Redispatch + NSI Not Completed)			
	LILS	HILS	LIHS	HIHS	LILS	HILS	LIHS	HIHS
Available Renewable Generation	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Surplus Supply	1.8	1.6	1.7	1.5	1.8	1.6	1.7	1.5
Curtailment for Operational Constraints	0.3	0.4	0.3	0.4	0.4	0.4	0.3	0.2
Dispatched Renewable Generation	8.3	8.4	8.3	8.5	8.2	8.5	8.4	8.7

One effect of additional interconnector and storage capacity affecting volumes of renewable dispatch is on how renewables are remunerated through the CfD. If renewables run in more hours, they are able to recover their fixed costs over a wider number of hours and so may require a lower strike price if they are able to correctly anticipate their running hours when developing their CfD bids. Conversely, if renewables run in fewer hours, they would require a higher strike price to be able to recover their fixed costs. We have assumed that any change to the level of CfD payments driven by a change in the volume of renewable generation would be offset by a change in the strike price those generators would achieve.

CEPA's modelling finds NI power sector emissions of 0.9 MtCO2 in the BAU scenario in 2034, down from 2.1 MtCO2 in 2023.[39] Table 6.3 below shows the impacts of the additional interconnector and storage capacity on carbon emissions in NI and across SEM. Across all scenarios, increasing interconnection between NI and GB on its own (i.e. without also increasing storage) is modelled to slightly increase NI carbon emissions. However, the additional interconnection is modelled to reduce emissions at the SEM level in all scenarios except in Sensitivity 3 (where interconnectors cannot redispatch in the BM and the North South Interconnector is not completed by 2034. Increased storage on its own is modelled to reduce emissions at both a NI and SEM-wide level across all scenarios.

[39] NI Greenhouse Gas Statistics 1990-2023 Statistical Bulletin, AERA

Table 6.3: NI Carbon Impacts relative to LILS baseline

Scenario	Case	NI Carbon Impacts (tCO2) relative to LILS (BAU)	SEM Carbon Impacts (tCO2) relative to LILS (BAU)
Basecase	HILS	+6,417 (+0.7%)	-125,329 (-2.4%)
	LIHS	-10,848 (-1.2%)	-139,644 (-2.7%)
	HIHS	-1,710 (-0.2%)	-222,242 (-4.3%)
Sensitivity 1 (excludes PHS)	LIHS	-10,474 (-1.2%)	-87,797 (-1.7%)
	HIHS	+8,362 (+1.0%)	-160,624 (-3.1%)
Sensitivity 2 (no interconnector redispatch)	HILS	+10,190 (+1.2%)	-120,340 (-2.4%)
	LIHS	-13,618 (-1.6%)	-142,045 (-2.8%)
	HIHS	-3,669 (-0.4%)	-229,511 (-4.5%)
Sensitivity 3 (no interconnector redispatch + NSI not completed)	HILS	+77,737 (+8.7%)	15,522 (+0.3%)
	LIHS	-28,257 (-3.2%)	-103,741 (-2.0%)
	HIHS	+19,916 (+2.2%)	-43,727 (-0.9%)

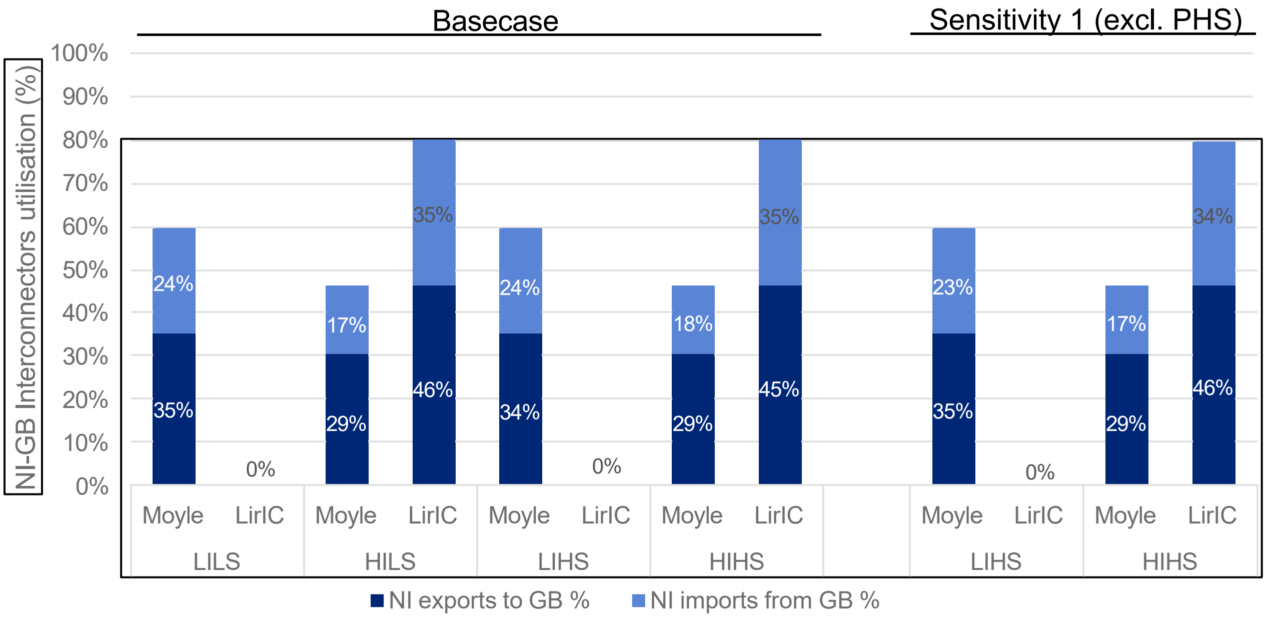
The addition of LirIC increases NI carbon emissions due to its effect on interconnector flows. In some periods, the addition of LirIC prompts imports of power from GB when demand is higher relative to renewable generation – with gas-fired generation in GB displacing some of the gas-fired generation in Ireland. In a smaller number of periods, the addition of LirIC prompts exports of power to GB – with gas-fired generation in NI displacing some of the gas-fired generation either in GB (or in another market GB would otherwise be importing from). The result is that the addition of LirIC significantly reduces Irish emissions while slightly increasing NI emissions. The increase in CO2 emissions when adding interconnection is higher in the scenarios where no interconnector redispatch is assumed (Sensitivities 2 and 3) as there are hours on which NI need to turn up gas-fired generation to meet the IC commitments from the day-ahead market (reflected in our unconstrained simulations). This impact is sensitive to the assumptions around the efficiency factors of different gas plants in Ireland and NI.

By contrast the additional storage capacity leads to a clear reduction in NI carbon emissions across the scenarios by reducing renewable curtailment and shifting renewable production from periods of excess renewables supply to periods when it is displacing gas generation. It should be noted that the benefit of NI storage on reducing economic curtailment goes to all renewable generators in SEM (as wholesale prices are set across the SEM), limiting the scale of the impact on NI renewable generators in particular.

6.3. Interconnector Flows

The effect of the additional NI-GB interconnector (modelled on LirIC) is shown in Figure 6.8 below. Utilisation of the new interconnector (LirIC) is 81%, which is higher than the utilisation of the existing Moyle interconnector without new interconnection. This is because LirIC is assumed to be the most efficient SEM interconnector once built – such that it is used first where there is a GB-SEM price differential. The existing GB-NI interconnector (Moyle) as well as other Ireland to GB interconnectors see a reduction in their utilisation as the new interconnector cannibalizes the revenues of less efficient interconnectors.

Figure 6.8: Utilisation of NI-GB interconnectors in Basecase and Sensitivity 1



Interconnector flows across all scenarios are fairly balanced between imports and exports, with NI exporting to GB slightly more than it imports. This is a change to existing market dynamics, where the lower cost of gas generation in GB in many hours leads to NI being a net importer from GB. The driver of this change is the decarbonization of both the SEM and GB markets, with interconnector flows in future increasingly determined by which market has excess renewables in a given hour – which is a function of changeable weather conditions and the degree of excess supply in each market.

6.4. Security of Supply

No security of supply impacts were noted in the modelling carried out, with zero periods of lost load captured across all the scenarios.

It should be noted that this finding may be sensitive to a number of assumptions:

- The additional interconnector and storage capacity are modelled in addition to (rather than displacing) the capacity assumed in the AIRAA and so provide additional capacity over what is required to meet the reliability standard.
- A low level of demand growth was assumed in NI reflecting slow uptake of electric heat pumps and vehicles, further reducing pressures on capacity margins.
- The modelling reflects demand and renewable generation patterns from a single historic year (2019) and is deterministic – i.e. it does not account for volatility in the level of plants facing unplanned outages. As such it may not capture the impact of additional storage or interconnection on events where security of supply margins are tight and prices may spike in absence of additional flexible capacity. Monte Carlo simulation (i.e. use of repeated runs to reflect potential variation in demand or renewable supply over the year) is out of scope for this assessment but would provide a more robust quantification of security of supply benefits.
- The potential additional security of supply benefits from the additional interconnector and storage capacity against wider weather patterns may differ by technology – for instance with short duration batteries having a potentially more limited security of supply benefit against a prolonged period of cold weather and low wind than a pumped hydro storage asset.

6.5. Cost Benefit Analysis

The implications of the different impacts of the additional interconnector and storage capacity on NI are considered in this section in terms of implications for NI consumers, producers (including interconnectors and storage) and for carbon emissions. In doing so we have made assumptions around the allocation of impacts between consumers / producers of NI, Ireland and GB, which are set out in more detail in this section. The impact assessment follows UK Green Book guidance[40].

Consumer Surplus

Consumer surplus represents the benefit to NI consumers from the additional interconnector and storage capacity (i.e. lowering electricity costs for consumers in NI). It is made up of a number of components:

- Wholesale market: This is the impact of the assets on wholesale market costs paid by NI consumers. (Given NI is part of the wider SEM market, it is noted that most of the wholesale market impact of the assets is actually borne by Irish consumers, who are not accounted for in this analysis.)
- Capacity market: This represents the impact on NI consumers of the capacity contracts for the additional assets.
- Constraint management: This is the impact on NI consumers of a change in network constraint payments in NI.
- CfD difference payments: This is the impact on NI consumers of a change in NI CfD difference payments to supported renewable generation, partially offsetting the impact of the assets on wholesale market costs.
- Asset build costs borne by NI consumers: Where the additional assets are commercially loss making we have assumed a support payment is made to make them viable, with the cost of this borne by NI consumers in the case of storage, and split equally between NI and GB consumers in the case of the interconnector.

We have not included the impact on consumers from ancillary and balancing services, as it is assumed that any such revenues earned by the interconnector and storage capacity are displacing contracted services from equivalent providers in SEM. This may slightly understate the consumer benefit of the additional capacity in increasing competition for ancillary and balancing services and therefore driving down prices in these markets.

As shown in Table 6.4 the additional interconnector has a benefit to NI consumers of £29.7m in reducing wholesale costs in the Basecase. This is mostly offset by additional costs to consumers of capacity market contracts, increased constraint management costs, CfD difference payments (i.e. mitigating the impact of reduced wholesale prices on consumers). The residual impact on consumers is an increase in consumer welfare of £20.2m in the modelled year.

For the additional storage assets, NI consumer impacts are negative as a result of the combined assets increasing wholesale costs (though partially offset by reduced CfD difference payments), constraint costs, and capacity payments. NI consumers are also paying support payments to cover the residual revenue requirement to make the assets commercially viable. The net effect is to reduce consumer welfare by £29.4m in the modelled year in the Basecase.

The overall consumer impacts of the storage assets may differ significantly between the short, medium and long-duration storage assets – with the latter requiring the most support from consumers. Under Sensitivity 1 (excluding PHS), we see the impact of increased storage on consumer surplus is £20m higher than under the Basecase, reflecting the fact that the PHS asset is modelled to require the largest additional subsidy from consumers.

[40] https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-government/the-green-book-2020

Table 6.4: NI Consumer Surplus Impacts in Basecase and Sensitivity 1

NI Consumer Surplus	Unit	Basecase			Sensitivity 1 (excludes PHS)	
		HILS vs LILS	LIHS vs LILS	HIHS vs LILS	LIHS exc PHS vs LILS	HIHS exc PHS vs LILS
Wholesale Market	£m	29.7	-3.3	39.1	-7.6	39.6
Capacity Market	£m	-5.2	-5.1	-10.4	-3.8	-9
Constraint Management	£m	-1.3	-0.4	-3.3	0	-2.7
CfD Difference Payments	£m	-2.9	6.9	-3.8	6.9	-5.9
Asset build cost borne by NI consumers	£m	0	-27.6	-32.1	-4.5	-5.9
Value of lost load	£m	0	0	0	0	0
Total Consumer Surplus	**£m**	**20.2**	**-29.4**	**-10.5**	**-9**	**16**
Annual domestic household bill impact	£	-5.7	8.3	3.0	2.5	-4.5

The consumer benefit of the additional interconnector falls significantly in Sensitivity 3, i.e. if interconnectors are not redispatched in the BM and if the North South Interconnector is not completed by 2034. In this case, the additional interconnector leads to a significant increase in constraint costs, offsetting most of the consumer benefits of the additional interconnector modelled in the Basecase.

Table 6.5: NI Consumer Surplus Impacts in Sensitivities 2 and 3

NI Consumer Surplus	Unit	Sensitivity 2: No Interconnector Red spatch			Sensitivity 3: No Interconnector Redispatch and NSI not co pleted by 2034		
		HILS vs LILS	LIHS vs LILS	HIHS vs LILS	HILS vs LILS	LIHS vs LILS	HIHS vs LILS
Wholesale Market	£m	29.7	-3.3	39.1	29.7	-3.3	39.1
Capacity Market	£m	-5.2	-5.1	-10.4	-5.2	-5.1	-10.4
Constraint Management	£m	-1.5	-0.4	-3.6	-13.5	-7.9	-25.4
CfD Difference Payments	£m	-3.4	6.2	-4.4	-3.0	6.3	-4.0
Asset build cost borne by NI consumers	£m	0	-27.6	-32.1	0	-27.6	-32.1
Value of lost load	£m	0	0	0	0	0	0
Total Consumer Surplus	**£m**	**19.5**	**-30.2**	**-11.4**	**8.0**	**-37.6**	**-32.8**
Annual domestic household bill impact	£	-5.5	8.5	3.2	-2.2	10.6	9.2

Producer Surplus

Producer surplus represents the *benefit* to NI producers from the additional interconnector and storage capacity (i.e. increasing revenues for producers in NI).[41] It is made up of a number of components:

- Wholesale market: This is the impact of the additional assets on revenues (net of production costs) for NI producers and interconnectors in the wholesale market.
- Capacity market: This represents the value of the capacity contracts for additional NI interconnector and storage capacity.
- CfD difference payments: This is the impact on supported NI producers of a change in CfD difference payments (offsetting the wholesale market impact for those producers).
- Ancillary and Balancing Services: This represents the value of the revenues earnt by the additional NI interconnector and storage capacity, net of the equivalent value to displaced NI producers.
- Asset build cost borne by NI producers: This represents the annualised costs of financing, building and operating the additional interconnector and storage capacity net of any policy support received.

We have not included the impact on producers from constraint management services, as we have assumed that parties bid their cost price for these services and so do not earn a net revenue. However, it is recognised that in practice storage assets may be able to price a proportion of their fixed costs into these services to earn additional revenue. This would reduce the degree of policy support required by the medium and long duration assets.

As shown in Table 6.6, the additional interconnector has a benefit to NI producers of £3.9m. This is principally driven by the additional revenues earned by LirIC across the capacity, wholesale and ancillary service markets, which more than offsets the £41.5m annualised cost of the asset.

The NI producer impact from the additional storage capacity is negative (-£7m). This result reflects the more significant build costs for the storage assets (particularly the medium and long duration assets) and the relatively lower additional revenues for those assets.

Table 6.6: NI Producer Surplus Impacts

NI Producer Surplus (£m)	Basecase			Sensitivity 1 (excludes PHS)	
	HILS vs LILS	LIHS vs LILS	HILS vs LILS	LIHS vs LILS	HILS vs LILS
Wholesale Market	10.4	64.6	54.8	42.4	28.0
Capacity Market	25.0	31.3	56.3	23.2	48.2
CfD Difference Payments	2.9	-6.9	3.8	-6.9	5.9
Ancillary and Balancing Services	7.0	50.6	56.9	41.6	48.2
Asset build cost borne by NI producers	-41.5	-146.5	-183.4	-98.6	-138.6
Total Producer Surplus	**3.9**	**-7.0**	**-11.5**	**1.7**	**-8.2**

[41] We have assumed for this analysis that the Moyle interconnector is counted as an NI producer (it is owned by Mutual Energy, which reinvests earning for the benefit of energy users in Northern Ireland). LirIC is assumed to be 50% NI, 50% GB interconnector – with 50% of both revenues and build costs attributed to NI in this CBA.

Table 6.7: NI Producer Surplus Impacts in Sensitivities 2 and 3

NI Producer Surplus (£m)	Sensitivity 2: No Interconnector Redispatch			Sensitivity 3: No Interconnector Redispatch and NSI not completed by 2034		
	HILS vs LILS	LIHS vs LILS	HILS vs LILS	LIHS vs LILS	HILS vs LILS	LIHS vs LILS
Wholesale Market	10.4	64.6	54.8	10.4	64.6	54.8
Capacity Market	25.0	31.3	56.3	25.0	31.3	56.3
CfD Difference Payments	3.4	-6.2	4.4	3.0	-6.3	4.0
Ancillary and Balancing Services	7.0	50.6	56.9	7.0	50.6	56.9
Asset build cost borne by NI producers	-41.5	-146.5	-183.4	-41.5	-146.5	-183.4
Total Producer Surplus	**4.4**	**-6.3**	**-11.0**	**4.0**	**-6.3**	**-11.4**

Carbon Emissions

Carbon emission impacts from the additional modelled interconnector and storage capacity are illustrated in Table 6.8. We have initially modelled the value of the impact on carbon emissions set out in Table 6.3 on the social cost of carbon consistent with UK government appraisal guidance (which is £363/t for 2034).[42] We have netted off from this the value of the traded EU emissions allowances (which is assumed to be £139/t in 2034 based on FES projections) to calculate the externality value of the change in carbon emissions. This reflects the value of the carbon emission impact that is not already accounted for in the wholesale market impacts. As per Table 6.9, this shows a negative societal impact from reduced carbon emissions associated with the additional interconnector and a positive societal impact associated with the additional storage capacity.

[42] https://www.gov.uk/government/publications/traded-carbon-values-used-for-modelling-purposes-2024

Table 6.8: Carbon Impacts relative to baseline

Scenario	Case	Total value of CO2 Emissions (£m) relative to LILS baseline	Carbon externality not reflected in wholesale market impacts (£m) relative to baseline
Basecase	HILS	-2.3	-1.4
	LIHS	3.9	2.4
	HIHS	0.6	0.4
Sensitivity 1 (excludes PHS)	LIHS	3.8	2.4
	HIHS	-3.0	-1.9
Sensitivity 2 (no interconnector redispatch)	HILS	-3.7	-2.3
	LIHS	5.0	3.1
	HIHS	1.3	0.8
Sensitivity 3 (no interconnector redispatch + NSI not completed by 2034)	HILS	-28.3	-17.5
	LIHS	10.3	6.4
	HIHS	-7.2	-4.5

It should be noted that the value of emissions is only calculated for the change in emissions associated with NI producers. However, as shown in Table 6.8, the overall modelled impact of the additional interconnector is to reduce emissions in Ireland by significantly more than NI emissions are increased.

Net Welfare Impact

The net welfare impacts shown in Table 6.9, bringing together the identified impacts on NI consumers and producers, as well as the value of carbon externalities. These results show that the introduction of an additional GB-NI interconnector has a positive net welfare impact in the Basecase, principally through the additional revenue that the interconnector can earn, though these are partially offset by an increase in consumer costs and an increase in carbon emissions. However, in a scenario where there is limited redispatch of interconnectors and where the North South Interconnector is not completed (i.e. Sensitivity 3), the additional interconnector exacerbates the constraints in the BAU and has a negative societal impact.

Increased storage capacity has a negative impact on net welfare in the Basecase as a result of reduced revenues for storage (particularly medium and long-duration assets) and the need for subsidy payments from consumers to make these assets viable. The combination of increased interconnection and storage capacity has a negative impact that reflects the shortfall in revenues accruing to the medium and long-duration storage assets necessitating subsidy, although this is partly offset by the positive net welfare impacts associated with the additional interconnector. This result is principally driven by the high cost of the modelled Pumped Hydro Storage asset. With this asset excluded (i.e. Sensitivity 1), increased storage capacity is modelled to have a positive impact on society.

Table 6.9: NI Net Welfare Impacts

NI Net Welfare (£m)	Basecase		Sensitivity 1 (excludes PHS)		
	HILS vs LILS	LIHS vs LILS	HILS vs LILS	LIHS vs LILS	HILS vs LILS
Total Consumer Surplus	20.2	-29.4	-10.5	-9.0	16.0
Total Producer Surplus	3.9	-7.0	-11.5	1.7	-8.2
Carbon Externality	-1.4	2.4	0.4	2.4	1.9
Net Welfare Impact	**22.7**	**-34.0**	**-21.7**	**-4.9**	**5.9**

Table 6.10: NI Net Welfare Impacts in Sensitivities 2 and 3

NI Net Welfare (£m)	Sensitivity 2: No Interconnector Redispatch			Sensitivity 3: No Interconnector Redispatch and NSI not completed by 2034		
	HILS vs LILS	LIHS vs LILS	HILS vs LILS	LIHS vs LILS	HILS vs LILS	LIHS vs LILS
Total Consumer Surplus	19.5	-30.2	-11.4	8.0	-37.6	-32.8
Total Producer Surplus	4.4	-6.3	-11.0	4.0	-6.3	-11.4
Carbon Externality	-2.3	3.1	0.8	-17.5	6.4	-4.5
Net Welfare Impact	**21.7**	**-33.4**	**-21.5**	**-5.5**	**-37.5**	**-48.6**

The findings of a positive net welfare impact from an additional interconnector and a negative net welfare impact from additional storage in the Basecase are sensitive to a number of assumptions and limitations in the model framework:

- The scenarios modelled assumed the additional interconnector and storage capacity are provided on top of a capacity mix that is already adequate to meet demand. A BAU scenario with tighter capacity margins could see higher revenues and greater security of supply benefits from additional interconnection and storage capacity (particularly medium and long duration storage).
- The non-wholesale market revenue projections for storage and interconnection are based on benchmarks from the market today and are subject to uncertainty about how they may differ by 2034 in the context of a significantly decarbonised power system.
- Similarly, estimates of the cost of the additional assets is based on analysis of publicly available benchmarks around the capital cost and cost of capital – there is significant uncertainty around the cost of actual projects that might come forward.

Appendix A: Key Inputs and Sources

Table A0.1: Cost assumptions for interconnectors and storage assets

Cost input	Value	Source
Interconnector capex	£0.9m/MW	Greenlink Final Project Assessment (Ofgem)
Interconnector opex	£26k/MW/year	Greenlink Final Project Assessment (Ofgem)
Short-duration storage capex	£0.4m/MW	Modo benchmark from Q3 2024
Short-duration storage opex	£5k/MW/year	LCP Delta Report for DESNZ, Archetype 1
Medium-duration storage capex	£1.8m/MW	Modo benchmark from Q3 2024 for a short-duration battery, assuming a proportion of costs are rescaled with a longer duration asset.
Medium-duration storage opex	£10k/MW/year	LCP Delta Report for DESNZ, Archetype 2
Long-duration storage capex	£2.3m/MW	LCP Delta Report for DESNZ, Archetype 4 (high end of the range, uplifted 20% to account for longer and riskier construction)
Long-duration storage opex	£15k/MW/year	LCP Delta Report for DESNZ, Archetype 4

Table A0.2: Technical parameters for interconnectors and storage

Technology	Technical parameter	Value	Source
Interconnectors	Asset life	25 years	C&F duration
	Hurdle rate	5.5%	Based on average between allowed return at the cap and floor for Window 3
	Construction time	6 years	Based on information on the LirIC website
Short-duration storage	Asset life	20	LCP Delta Report for DESNZ, Archetype 1
	Hurdle rate	7.3%	LCP Delta Report for DESNZ, Archetype 1
	Construction time	1 year	LCP Delta Report for DESNZ, Archetype 1
Medium-duration storage	Asset life	30 years	LCP Delta Report for DESNZ, Archetype 2
	Hurdle rate	7.3%	LCP Delta Report for DESNZ, Archetype 2
	Construction time	1.5 years	LCP Delta Report for DESNZ, Archetype 2
Long-duration storage	Asset life	50 years	LCP Delta Report for DESNZ, Archetype 4
	Hurdle rate	7.3%	LCP Delta Report for DESNZ, Archetype 4 (high end of range)
	Construction time	4 years	LCP Delta Report for DESNZ, Archetype 4

Table A0.3: Demand Assumptions by Market

Market	Source Scenario	Demand in 2024	Demand in 2034
Northern Ireland	AIRAA-Low	8.0	9.8
Ireland	AIRAA-Median	35.8	49.5
GB	FES-Holistic Transition	282.5	370.2
Austria	FES-Holistic Transition	76.8	98.5
Belgium	FES-Holistic Transition	89.0	114.2
Denmark	FES-Holistic Transition	42.7	64.2
Germany	FES-Holistic Transition	581.6	877.1
France	FES-Holistic Transition	477.6	605.6
Italy	FES-Holistic Transition	344.1	418.8
Netherlands	FES-Holistic Transition	126.2	211.8
Switzerland	FES-Holistic Transition	65.2	79.9
Sweden	FES-Holistic Transition	147.1	187.0
Spain	FES-Holistic Transition	258.2	332.3
Norway	FES-Holistic Transition	144.8	181.1

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