New electricity interconnection to GB – operation and revenues

CLIENT: Department of Energy and Climate Change

DATE: February 2014

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Version History

Version	Date	Description	Prepared by	Approved by
1.0	19/12/2013	Draft	Pavlos Trichakis Luke Humphry	Ilesh Patel Andrew Nind
2.0	13/02/2014	Final	Pavlos Trichakis Luke Humphry	Ilesh Patel Andrew Nind

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Introduction

Redpoint, a business of Baringa Partners, has undertaken analysis for DECC over the last 12 months in order to improve Government's evidence base on the impact of additional electricity interconnection to GB[1]. As a follow up to the original analysis, DECC has asked for advice and analysis in two further areas of interest:

- What are the prospective revenues and operating profiles for new electricity interconnectors that link GB with neighbouring countries (without being project specific)?
- What difference would it make to revenues if foreign generators or interconnector owners were not eligible for GB Capacity Mechanism (CM) payments?

We have addressed these questions by assessing the performance of a number of hypothetical links to France, Belgium, Norway and Ireland. Given the uncertain application of the cap and floor regulatory model at the date of modelling, we have assumed merchant operation for all of these links. We have focussed on arbitrage revenues, with CM payments treated as a potential extra source of income.

Scenarios modelled

Our analysis has been undertaken under a range of plausible scenarios and covers the period 2016 to 2035. The scenario framework was developed jointly with DECC and was designed to be consistent with the UK keeping within its carbon budgets. The scenarios employed here are broadly consistent with the 4 scenarios developed during the original analysis, however some key assumptions (including fossil fuel and carbon prices, electricity demand and generation capacity mix) were updated to reflect more recent DECC views.

These scenarios can be summarised as follows:

1. <u>GB importing</u> – this is a scenario where interconnectors are utilised mostly to transfer lower cost electricity from Continental Europe to GB[2]. This is likely to materialise in a world with moderate-to-high gas prices, in which generators face significantly higher carbon prices in GB compared to Europe, and in which it is possible to import[3] surplus low carbon electricity (particularly from renewable energy sources) from the Continent. In this scenario, the current government trajectory for the Carbon Price Floor in GB (rising above 70 £/tCO_2 in 2030) is combined with a continuation of low EUA prices in the Emissions Trading Scheme.
2. <u>Flexible operation</u> – this is a scenario where significant output from flexible sources of energy is required, and this requirement increases the extrinsic value of interconnectors[4].

[1] Impacts of further electricity interconnection on Great Britain – A report by Redpoint Energy, a business of Baringa Partners, for the Department of Energy and Climate Change (November 2013).

[2] Note that this does not imply that interconnectors would be importing power to GB 100% of the time, but there would be a strong tendency for imports into GB to dominate export from GB.

[3] Throughout this report, "import" and "export" are from the perspective of GB.

[4] An electricity interconnector is said to have high intrinsic value when a large differential in average prices exists between the two connected markets. Conversely, an electricity interconnector is said to have high extrinsic value when, even though the difference in average prices may be small, significant random hourly price variation exists between the two connected markets.

This is likely to materialise in a world in which very significant amounts of intermittent renewable technologies (particularly wind) are deployed across Europe, partly due to high fossil fuel prices incentivising their deployment. This scenario also assumes that in the long term generators in GB face broadly similar carbon prices to those in Continental Europe.

3. Low utilisation – this presents a more challenging scenario for developing electricity interconnectors since price differences across European markets remain relatively low due to persistently low and stable fossil fuel prices (which result in relatively small differences in the costs of generation between markets, compared with other scenarios). This scenario also assumes that in the long term generators in GB face similar carbon prices as in Continental Europe and that, whilst unabated gas plant dominate in the short- to medium-term, there is an increased role for gas Carbon Capture and Storage (CCS) and coal CCS in the longer term due to low fossil fuel prices and relatively slow progress in offshore wind.

4. Carbon price convergence – this scenario uses the same fundamental assumptions as Scenario 1 (i.e. moderate fossil fuel prices coupled with a relatively balanced, albeit renewables favouring, generation mix in the UK and Continental Europe), however it is now assumed that EUA carbon prices rise very strongly in the 2020s and gradually converge with carbon prices in GB (which are driven by the Carbon Price Support (CPS) policy as in Scenario 1).

Note that the levels of CPS in Scenarios 2 and 3 would be consistent with a government decision to freeze the CPS level at £18/tCO2 nominal from 2015/16 for a period of four years. However Scenario 4 and particularly Scenario 1 (which reflects policy at the time of writing) imply significantly higher levels of CPS.

Overview of approach

The original analysis undertaken for DECC focused on the net welfare impact of multiple combinations of hypothetical electricity interconnectors across a number of different fundamental scenarios. The analysis described here builds on this work and extends it by considering the commercial implications (in terms of projected revenues under the four scenarios) for six potential further GB interconnection links: three to France (which we call FRA1, FRA2 and FRA3) and one to each of Belgium (BEL),Norway (NOR) and the Republic of Ireland (IRL).

Three key extensions to the original work have been undertaken:

1. Adding uplift in our pan-European market model in order to produce projected wholesale electricity market prices, on the basis of which the energy revenues of projects can be assessed;
2. Using a Redpoint model of the proposed Capacity Mechanism (CM) in GB to derive annual CM clearing prices;
3. Combining the outputs from our fundamental market modelling (i.e. wholesale electricity market modelling and capacity market modelling) to produce initial estimates of the potential revenues of the six interconnector projects with the aid of an interconnector dispatch tool (the Interconnector Revenue and Analysis Tool – IRAT).

IRAT may be used to analyse the energy flows and revenues for electricity interconnectors, individually and in aggregate, for different portfolios of cable capacity and different scenarios for wholesale markets. Interaction between different interconnectors within a given portfolio takes place through the feedback of interconnector dispatch into prices in the connected markets. This interaction is important as developing additional interconnection will have an impact on the economics of existing projects (commonly referred to as “revenue cannibalisation”) and also on the

economics of other potential new-build projects. The extent of revenue cannibalisation will mainly depend on the timing and size of new interconnectors and the markets to which they are connected.

In addition to feedback parameters of interconnector flows into prices, IRAT contains a number of other relevant assumptions for each potential interconnector such as ramp rates, electrical capacity, date of commissioning and whether the interconnector is assumed to earn revenues from the capacity market. It has an embedded interconnector dispatch engine that determines interconnector dispatch (i.e. flows across the interconnector as determined by price differences) and hence all interconnector and portfolio results on the basis of input parameters.

Electricity market revenues

Based on the assumptions in this report, our wholesale electricity market modelling shows that under all scenarios there is a considerable difference between GB prices and Continental European prices until at least the mid-to-late 2020s. This difference is determined largely by CPS policy resulting in increased generation costs for fossil fuel based GB generators during this period[5], coupled with the relatively high running costs of the GB generation fleet compared to the main markets in Continental Europe. The results summarised below assume that capacity markets exist in GB and the connected markets (except Norway), and influence wholesale prices, but capacity revenues for interconnectors are not included in these results.

Analysis of electricity market revenues for Scenario 1 shows little differentiation between the (hypothetical) interconnectors on average, with typical annual earnings of £150-160/kW over the modelling horizon. These earnings are relatively stable for all links except IRL, which has earnings below £100/kW initially but close to £200/kW by the end of the timeframe. Import revenues (i.e. import to GB) account for approximately 80-90% of total revenues, with the exception of IRL for which exports account for 20-40%.

For Scenario 2, a greater variation is observed, but annual revenues are still above £100/kW for all interconnectors considered here. High revenues arise because high wind penetration across Europe increases system intermittency, thus also increasing price arbitrage opportunities between the connected markets. In this scenario, high price volatility in the GB and Irish markets results in IRL earning the highest average revenues, which range from £150-315/kW per year, with the top end of the range being achieved towards the end of the modelling horizon. Annual revenues for NOR range between £80-230/kW, owing to strong imports to GB in the early years when Norwegian prices are low, and then to high price volatility in the later years. Market revenues for the links to France and Belgium are slightly lower, spanning the range £60-200/kW.

For Scenario 3, low gas and coal prices lead to relatively low and stable generation costs, with small absolute differences between markets. As a result, price arbitrage opportunities remain subdued, with no significant variations in the simulated electricity revenues of the interconnectors considered. Electricity revenues lie in the range £50-75/kW per year for the most part, although FRA1 in particular is able to take advantage of the premium in GB prices during the early years of its operation (2017-2019) when annual revenues range between £95-110/kW. Despite its high utilisation of around 70-90%, NOR has the lowest revenues per kW in this scenario. This is because Norwegian prices are slightly higher than French/Belgian prices due to the fact that unabated coal is relatively expensive vis-à-vis unabated gas[6] and as a result NOR import revenues

[5] For a typical unabated CCGT plant in GB, an increase in carbon costs of £1/tCO_2 would increase its generation costs by approximately £0.35-0.40/MWh. For a typical unabated coal plant in GB this figure would be in the range £0.85-0.90/MWh.

[6] For Scenario 3, using the assumptions employed in this report, clean spark spreads (i.e. the theoretical gross margins of a gas-fired generator, obtained by subtracting the estimated fuel and carbon costs per unit of electricity from the corresponding market electricity prices) are higher than clean dark spreads (the equivalent gross margins for a coal-fired generator). Equivalently, coal generation is

are negatively affected. Furthermore, the higher transmission losses of NOR (due to its greater length) compared to the French and Belgian links further hinder its revenues, particularly in a world with low average price differentials.

Finally, for Scenario 4 IRL again achieves the highest average annual revenues on a £/kW basis, ranging from £90-235/kW, with the high end of the range reached towards the end of the modelling horizon. Over time, high wind penetration in GB and Ireland creates significant price arbitrage opportunities. NOR has the second highest revenues, which typically range between £80-140/kW per year, with the exception of years 2026-2029 when annual revenues are around £50-60/kW. During these years, there is lower import utilisation as GB prices gradually converge with Norwegian prices. From 2030 onwards, however, NOR revenues recover as GB prices become progressively more volatile with the continuing increase in wind generation. A similar story is observed with the French and Belgian links, with revenues declining until 2030 despite high utilisation (typically around 70-80%), and then increasing towards the end of the modelling horizon as a result of high average spreads when GB is exporting.

Capacity market revenues

It has not been possible to find a way for interconnected capacity to participate in the first GB capacity auction for delivery in October 2018. Work is ongoing to find a means of participation for interconnected capacity in subsequent auctions. The analysis here has attempted to quantify potential future interconnector income from participation in GB capacity auctions, under the assumption that a means is successfully found for interconnected capacity to participate.

We have not attempted to quantify possible income from capacity auctions in other countries. Implicitly, we have assumed in our wholesale market modelling that capacity mechanisms are developed in France, Belgium and Ireland – the assumed capacity margins in these countries are similar to GB and the relationship between capacity margins and the scarcity premia in wholesale prices is quantified in the same manner as for GB. However, we have modelled the capacity auctions themselves, and resultant capacity prices, for GB only.

For the purposes of this analysis, capacity payments are assumed to be paid to interconnector owners, rather than foreign generators. However, there are other participation options in which foreign generators would receive capacity payments. In some of these options, an interconnector 'agent' could act on their behalf and distribute the income according to a pre-agreed sharing arrangement. The values calculated in this report may be interpreted as the amounts that the interconnector agents have to distribute from GB auction payments. No assumptions in this report on the means of participation for interconnected capacity represent government policy.

Based on the simulated GB CM clearing prices, we have divided the modelling timeframe into 4 blocks:

- For the first 5 years of operation (2019-2023 inclusive[7]), annual auction clearing prices under the developed scenarios average between £32-36/kW. This is because in general there is sufficient generating capacity to meet peak electricity demand, which is assumed to grow modestly (approximately 1% per annum) during this period;

more expensive than CCGT generation, and hence power prices are higher in Germany, where the coal market share is significant, than in France and Benelux where gas and nuclear have more influence. Germany in turn has a strong influence on Scandinavian prices via (existing) interconnection with Denmark (particularly West Denmark) and Sweden, as well as future interconnection with Norway.

[7] We recognise that the first delivery in the CM is scheduled for October 2018; however given that we are modelling calendar years we have assumed that the CM starts in January 2019 (i.e. three months later than currently planned).

- During the next 4 years (2024-2027 inclusive), with significant retirements of Large Combustion Plant Directive coal plant and strong peak demand growth of around 2% per year, new generating capacity is required. As a result, annual auction clearing prices under the developed scenarios average between £41-45/kW during this period as both new OCGT as well as more expensive new CCGT capacity is required to ensure that security of supply is maintained;
- During 2028-2031, strong peak demand growth is assumed to continue (roughly 2.5% per annum); however during this period there is significant investment in new nuclear and new CCS capacity, alongside additional new wind plant. This low-carbon plant reduces the capacity requirement in the CM and hence puts downward pressure on CM clearing prices. These average £26-27/kW under all developed scenarios;
- Finally, during the last years of the modelling horizon (2032-2035), peak demand growth is assumed to be even stronger (approximately 3% per annum) and as a result, despite further investments in low carbon generation technologies, additional OCGT capacity is required to meet the desired de-rated capacity margin. During this period auction clearing prices average approximately £37/kW under all developed scenarios, reflecting the costs of developing new OCGTs.

Capacity payments to interconnector owners would also depend on the annual interconnection capacity that is declared available for the GB CM. Available supply is likely to differ for each interconnector depending on installed capacity and projected operation during periods of system stress in GB. Based on individual interconnector de-rating factors[8] developed from the market projections in the original analysis, we have calculated the potential payments. For most interconnectors - and under most scenarios - these payments are relatively modest, with the following key conclusions being drawn:

- For Scenario 1, FRA1, BEL and NOR benefit from consistently high de-rating factors and potential capacity payments are circa £30/kW per year. In the case of IRL, the de-rating factor is much lower (since system stress conditions in SEM are well correlated with system stress conditions in GB), and consequently capacity payments average £20/kW.
- For Scenario 2, it is less certain that capacity will be available at times of system stress in GB and average CM revenues are typically lower: approximately £24-26/kW for the French and Belgian links and only £16/kW for IRL. For NOR average CM revenues remain above £30/kW since correlation between the Norwegian and GB electricity markets is relatively weak and hence a higher de-rating factor is used.
- Similarly for Scenario 3, NOR is again receiving the highest capacity payments on average (just below £30/kW), followed by the French and Belgian links (averaging around £22-24/kW) and finally IRL (only around £10/kW). Low price differentials in this scenario lead to reduced arbitrage revenues. Hence, if such a world were to materialise, capacity payments could provide a significant proportion of overall revenues compared to the other scenarios modelled.
- Finally, for Scenario 4, as for Scenarios 2 and 3, NOR earns the highest average capacity payments (just below £30/kW). It is followed by the French and Belgian links (averaging around £22-24/kW) and finally IRL (averaging around £15/kW).

[8] By “de-rating factor” we mean the availability factor assumed in the capacity auctions. A high de-rating factor corresponds to a high level of availability.

Revenue cannibalisation

The analysis has considered the mutual impact of electricity revenues for new interconnectors: as each new one is added, the revenues of existing interconnectors may be reduced, a process known as revenue cannibalisation. The extent to which cannibalisation occurs depends on how the market responds, in particular on the market counterfactual if interconnection is not built. In this study, we have assumed in agreement with DECC that the market would respond such that the overall system security as measured by the de-rated capacity margin in GB is held constant. Based on our earlier report[9], we have estimated the equivalent volume of CCGT capacity, in de-rated capacity terms, for each of the hypothetical links considered in this study; and in the counterfactual we have 'built' that volume of CCGT capacity in lieu of the relevant link.

The broad conclusion of this analysis is that, with the assumption of market response (building CCGT capacity in place of interconnector capacity), the mutual cannibalisation of further interconnectors is relatively modest and in some cases even negative. We have assumed that further interconnection beyond 1GW to each of France, Belgium, Norway and Ireland would be to France, and for this reason FRA experiences some cannibalisation in all scenarios. The greatest level of cannibalisation is approximately 10% of revenues for FRA in Scenario 1, arising from an extra 2GW of interconnection to France.

Interpretation of results

It is worth stressing that the range of projected wholesale electricity prices and interconnection revenues in the four scenarios described in this report does not reflect the full range of potential uncertainty in the market. Rather, projections in this study are intended to be representative of the long term trends in the GB market according to current DECC and/or Redpoint views with regards to fossil fuel and carbon prices, electricity demand projections and views on the GB generation capacity mix. The results should not be attributed to any particular project, as they are based on a generic 1GW size and generic assumptions with respect to link technical parameters. Nevertheless they represent interconnector revenues that are realistic in each of the scenario 'worlds' that we have considered.

[9] Impacts of further electricity interconnection on Great Britain – A report by Redpoint Energy, a business of Baringa Partners, for the Department of Energy and Climate Change (November 2013).

1. Introduction

1.1 Introduction

The EU has legislated to promote greater levels of electricity interconnection between member states through various directives including, most recently, the Third Package[10]. The UK is strongly committed to the single European energy market as the Prime Minister emphasised in a speech at Bloomberg in January 2012. In parallel, Ofgem has published its proposals for a cap and a floor on revenues for a project to Belgium (Project Nemo) and pushed ahead with the Integrated Transmission Planning and Regulation (ITPR) project to assess whether any changes to the existing GB electricity transmission arrangements are required to facilitate a future integrated system. DECC has also published its *'Electricity System: Assessment of Future Challenges'*,[11] in which it presented findings from its analysis into the value of flexibility.

To this end, DECC recently published Government's views on further interconnection[12], in particular on objectives and the network planning and project assessment of interconnection. Similarly, Redpoint/Baringa have undertaken extensive analysis for DECC over the last 12 months in order to improve Government's evidence base on the impact of additional electricity interconnection on GB[13]. Hence significant work has been undertaken to promote interconnection and understand the value of discrete projects. However, just 2 GW of interconnector capacity has been built to connect to GB since IFA came online in 1986.

Today, there are a number of credible new interconnector projects seeking to connect GB to other markets. If all of these projects came to fruition, this would represent a very significant increase in the connectivity of the GB electricity market to other electricity markets in Europe. However, it is not certain that all of these projects being brought to completion would represent a beneficial outcome for GB, or for GB consumers (who would be taking on some risk with them should the project be regulated through a cap and floor approach). The marginal private and social returns to new interconnection capacity are diminishing as prices in the connected markets converge with more interconnection capacity and the efficiency benefits of dispatching the most efficient forms of generation across the connected markets are realised.

Therefore, the magnitude and diversity of proposed interconnector projects and the changing regulatory landscape at EU and GB level imply a need for government to consider its overall policy in respect of future interconnectors. The purpose of this report is to assess the commercial revenues that interconnectors might be able to achieve, based on electricity price arbitrage, and how those revenues vary by connected market and by the overall volume of new interconnection. Also the report assesses the potential impact on interconnector economics of revenues from GB Capacity Mechanism (CM) payments.

[10] Described in the Preamble Clauses 59 and 60, Article 3(10), Article 21(8b), Article 38(2a) and Article 46 (4).

[11] DECC, August 2012. *Electricity System: Assessment of Future Challenges.*

[12] DECC, December 2013. *More Interconnection: improving energy security and lowering bills*.

[13] Impacts of further electricity interconnection on Great Britain – A report by Redpoint Energy, a business of Baringa Partners, for the Department of Energy and Climate Change (November 2013).

1.2 Objectives and approach

Redpoint/Baringa have undertaken extensive analysis for DECC over the last 12 months in order to improve Government's evidence base on the impact of additional electricity interconnection on GB[14]. As a follow up to the original analysis, DECC have asked for advice in two further areas of interest:

- What are the prospective revenues and operating profiles for new electricity interconnectors that link GB with neighbouring countries (without being project specific)?
- What difference would it make to revenues if foreign generators or interconnector owners were not eligible for GB Capacity Mechanism (CM) payments?

The original analysis undertaken for DECC focused on the net welfare impact of multiple combinations of electricity interconnectors across a number of different fundamental scenarios. The analysis described here builds on this work and extends it by considering the commercial implications for six potential new cables, comprising three to France, and one each to Belgium, Norway and Ireland. These cables are referred to by the following acronyms: FRA1, FRA2, FRA3, BEL, NOR and IRL. These cables are hypothetical – they do not refer to any real projects – and we have used generic assumptions for their technical characteristics.

This additional analysis has entailed the following extensions to the original study:

1. Adding uplift in our pan-European market model in order to produce wholesale electricity market prices, on the basis of which the commercial revenues of projects can be assessed;
2. Using a Redpoint model of the proposed Capacity Mechanism in GB to derive annual CM clearing prices;
3. Utilising the outputs from our fundamental market modelling (i.e. wholesale electricity market modelling and capacity market modelling) in order to quantify the revenues available to the six generic interconnector projects using an interconnector dispatch tool and financial model (the Interconnector Revenue and Analysis Tool – IRAT).

The report is structured as follows:

- Chapter 2 describes the modelling approach used to project market prices in GB and interconnected markets, as well as the approach used for modelling interconnector flows and associated wholesale electricity market revenues;
- Chapter 3 presents wholesale electricity market revenues based on electricity arbitrage opportunities between the interconnected markets. This analysis has been undertaken for years 2016-2035 across the four scenarios that have been developed for the purposes of this study;
- Chapter 4 presents potential capacity market revenues based on simulated CM auction clearing prices for each of the four scenarios, and an associated set of interconnection de-rating factors; and
- Chapter 5 presents our conclusions.

All figures presented here are in 2012 real £ monetary terms unless otherwise stated.

[14] Impacts of further electricity interconnection on Great Britain – A report by Redpoint Energy, a business of Baringa Partners, for the Department of Energy and Climate Change (November 2013).

2. Overview Approach

In this section we start by describing the modelling approach that we employed in order to project wholesale electricity prices in GB and interconnected markets. A key differentiation between the modelling described here compared to the original analysis is that our pan-European market model now also includes an uplift function which recognises that prices sometimes rise above short run marginal costs as plant seek to cover their fixed and investment costs, particularly during periods when supply margins are tight.

We then describe the modelling approach undertaken in order to simulate the proposed capacity market in GB. It has not been possible to find a way for interconnected capacity to participate in the first capacity auction for delivery in October 2018. Work is ongoing to try to find a solution to this. However, the introduction of capacity payments in GB could be expected to influence capacity margins in GB, potentially leading to a lower level of uplift in GB prices, which would in turn affect GB interconnector revenues.

Finally we describe the Interconnector Revenue and Analysis Tool (IRAT) that we have used for this study[15]. IRAT will allow DECC to carry out analysis of interconnector investments, with suitable assumptions for costs, technical parameters and required returns. For the purposes of this report, IRAT uses the results of our fundamental market modelling (wholesale electricity market as well as capacity market) to inform estimates of portfolio revenues for different combinations of the hypothetical links described above. We do not, in this report, assess the returns for specific projects.

2.1 Redpoint pan-European market model

The Redpoint pan-European market model covers all of the electricity markets to which Britain may in future be directly connected via an interconnector. Thus, among others, we model in detail the markets of Great Britain, Ireland (the Single Electricity Market – SEM), Norway, the Netherlands, Belgium, and France. We also model neighbouring countries such as Germany that have a significant influence on these markets. These markets are all modelled using a detailed bottom-up methodology, in which power stations are modelled individually and dispatch is determined on a least-cost basis, i.e. to minimise the costs of generation in north-west Europe.

For detailed simulation of the dispatch of power markets at an hourly level we use a third party product, PLEXOS for Power Systems. PLEXOS is highly regarded power market simulation software used globally by system operators, utilities and commodity traders and we have used it extensively over the last seven years to model European power markets in detail.

At its heart lies a dispatch 'engine' based on a detailed representation of market supply and demand fundamentals at an hourly granularity. The supply mix is represented with the operating parameters of generating plant including costs and operational constraints. For wind, we model a detailed generation profile based on recent history for wind speeds, and projected future wind capacity: the results for wind generation vary hour by hour and year by year. The demand side is

[15] We have developed IRAT from a similar model that has been used extensively on a previous client assignment. The core functionality (arbitrage modelling) has been developed and tested on several previous interconnector projects undertaken by Redpoint in recent years. The main inputs to IRAT include the wholesale price projections, which are developed within our well-established PLEXOS modelling framework.

represented as a projected hourly profile (derived from historic calibration). Market dispatch is then simulated with system-level constraints (e.g. emission limits) optimised to deliver the least cost solution. The marginal cost for each plant is calculated from heat rate curves, fuel costs, transportation costs, non-fuel variable operating costs and carbon costs. Start-up and no-load costs are used in the 'unit commitment' decisions that are taken within PLEXOS.

The outputs from this simulation include – at an hourly level of granularity:

- System short run marginal cost,
- Generation levels,
- Emissions levels (CO_2 in particular),
- Fuel use, and
- Interconnector flows.

2.2 Uplift and price modelling

In order to derive wholesale electricity prices from system short run marginal costs (SRMC) we have developed an 'uplift' function in our modelling which recognises that prices sometimes rise above short run marginal costs as plant seek to cover their fixed and investment costs – which may not be fully covered by SRMC. We model uplift as a function of the hourly capacity margin: the tighter the capacity margin (during periods of low system availability and / or high demand), the higher the uplift[16]. Conversely, in periods of high system availability (e.g. summer nights) the uplift can be negative as plant effectively compete to remain on the system, despite low prices that may be lower than SRMC. This pricing mechanism reflects the scarcity value of power on an hourly basis.

We estimate uplift from historic data and calibrate our uplift function on a regular basis to ensure that it reflects the most up-to-date market data. Uplift is applied on an hourly basis to the SRMC in the PLEXOS modelling. On an annual average basis, uplift is a relatively small component (probably less than 10% of the average price), but can be significant in periods when the capacity margin is especially tight, or conversely especially slack.

We estimate uplift from historic data and calibrate our uplift function on a regular basis to ensure that it reflects the most up-to-date market data. This calibration is also reflected in our modelling of the capacity mechanism, where generator bids into the capacity mechanism are assumed to be driven by an expectation of uplift levels consistent with our calibration.

A key assumption in our analysis is that the advent of a capacity mechanism either in GB or elsewhere does not alter the historic relationship between the capacity margin and uplift. This assumption is underpinned by the conjecture that bids into the capacity mechanism will be based on the expectation that uplift levels will carry on into the future, i.e. that generators will continue to price up at times of scarcity of available generation capacity in the wholesale market.

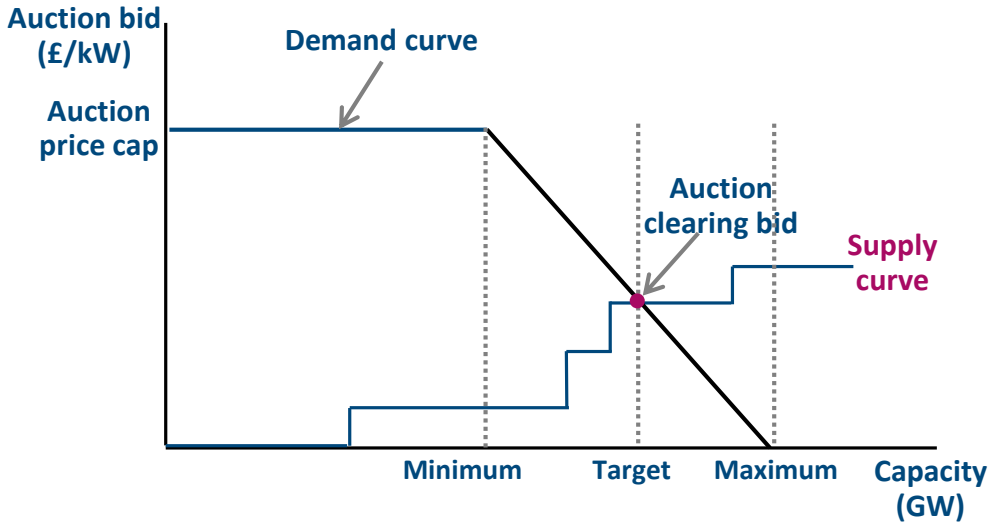
[16] The uplift function is fitted on the basis of historical evidence, comparing model backcasts (using observed fuel prices, carbon prices, demand levels and plant availability levels as inputs) with observed market prices (from power exchanges in the relevant market).

2.3 Capacity market modelling

Plans for capacity auctions in GB are at an advanced stage of development, with the first auction planned for November 2014, leading to delivery of capacity by October 2018. It has not been possible to find a way for interconnected capacity to participate in the first capacity auction for delivery in October 2018. Work is ongoing to try to find a solution to this. However, even if direct participation is ruled out, interconnectors will be affected by the CM. Its introduction will influence capacity margins in GB, leading to a lower level of uplift in GB prices, which would in turn affect GB interconnector revenues.

Redpoint/Baringa has developed a model of the proposed GB Capacity Mechanism (CM), which is continuously updated in order to take account of DECC's most recent publications, to account for, among other factors, the influence of net Cost Of New Entry (CONE), generation de-rating factors, and the associated penalty regime. The mechanism by which the capacity price is derived is illustrated in Figure 1, targeting a de-rated capacity margin of 5% with DECC's de-rating factors. This is approximately consistent with the security target of 3 hours loss of load expectation.

Figure 1 Capacity mechanism illustration



The auction is based on a stack of all the offer prices, where the stack volume in GW (x-axis) is the de-rated capacity of the generators participating in the mechanism, summed in ascending price order. Offer prices in the CM are a function of annual fixed costs, capital costs for new build, the profits (infra-marginal rents) that generators earn in the wholesale market, and risk premia (determined by the likelihood of penalty payments for unavailability at times of system stress). We find the point in the stack at which the de-rated capacity intersects with the demand curve (the level of demand is itself a function of the auction price). The offer price of this marginal generator then sets the capacity price for that year.

The mechanism will clear either on older existing plant, or on potential new build, in either case determined on the basis of the 'missing money' required to cover annual fixed and, for new-build plant, annuitised capital costs as well. If the mechanism clears on a new build project, the model assumes that this plant will subsequently be built. The results of the capacity mechanism model are fed into the PLEXOS model of the wholesale market through an impact on the capacity mix,

and this in turn indirectly influences wholesale power prices. Within the market model, wholesale market prices are a function of two factors (as discussed above):

- The short run marginal cost of the marginal generating plant in each period; and
- A calibrated 'uplift' function, which adds a margin to the system short run marginal cost depending on the tightness (capacity margin) in each period.

The capacity mechanism (CM) will tend to stabilise the annual margin of capacity over peak demand, and therefore reduce the impact of uplift on power prices. Thus, it is likely that the existence of the CM would result in lower GB wholesale prices than in a world without a CM. This would in turn result in lower net power imports into GB (and, equivalently, higher net power exports from GB), unless other interconnected markets adopt similar mechanisms.

In summary, our Capacity Market modelling assumes the current policy position that only GB generators and demand side response have access to the GB Capacity Market. The GB Capacity Market is modelled in full as per the methodology set out above which utilises the "missing money" approach which is consistent with DECC's internal modelling as a baseline. This approach results in reduced energy prices to the extent that additional capacity remains on the system as a result of the CM. Furthermore, these reduced electricity prices affect interconnector flows and revenues.

In Continental Europe, capacity mechanisms may be introduced in certain countries, but here also the impact on interconnector revenues is likely to be indirect (i.e. via the influence that capacity mechanisms could have on the capacity mix and capacity margin). In Germany, for example, a strategic reserve is favoured, in which a relatively small quantity of back-up capacity is held back in reserve. Meanwhile, in France a supplier obligation is favoured, which will lead to de-centralised capacity auctions. Our modelling has assumed these capacity mechanisms are in place in Continental Europe[17] and considered the implications for the plant on the system in each year in each scenario: in broad terms, the long run effect is to stabilise the capacity margin across all modelled markets to similar levels as GB (with little year-to-year variation) and to prevent high levels of uplift in wholesale prices. We have not modelled the income that interconnectors might receive from direct participation in these capacity mechanisms.

2.4 Interconnector Revenue and Analysis Tool (IRAT)

We have developed an Excel-based tool that uses the results of our fundamental market modelling (wholesale electricity market modelling and capacity market modelling) to inform estimates of portfolio revenues. Analysis of the level of additional interconnection (and to which markets) that is likely to be commercially attractive can be undertaken using this tool.

IRAT itself contains assumptions and inputs for each potential interconnector such as feedback parameters of interconnector flows into market prices, interconnector ramp rates, interconnector capacity, interconnector date of commissioning and whether the interconnector is assumed to earn revenues from the capacity market. IRAT has an embedded interconnector dispatch engine that determines interconnector dispatch, prices in connected markets and hence all interconnector and portfolio results on the basis of input parameters.

[17] It is unlikely that capacity payments will be introduced in NordPool. Here, however, the situation is different insofar as the system is potentially energy constrained rather than capacity constrained. Over the next 10-20 years, we expect an energy surplus to persist, which will only dissipate with the retirement of nuclear stations in Sweden and increased interconnection to mainland Europe.

New interconnectors will have an impact on the economics of both existing and other potential new interconnectors (this is commonly described as "revenue cannibalisation" – see Appendix F for more details). Therefore, it will be important to analyse combinations of interconnectors accounting for existing ones in determining which interconnector projects (and combination of projects) are likely to be commercially attractive.

Our modelling has been undertaken against a 'central' background of additional GB interconnection[18], with the price effects (or 'elasticity') of each potential interconnector thus determined for each time period and market. These price effects do not change depending on the make-up of the portfolio[19].

Key outputs of IRAT for each combination and each additional GB interconnector project[20] include:

- Interconnector dispatch and flow duration curves;
- Price duration curves in GB and connected markets;
- Interconnector wholesale market revenue after losses;
- Interconnector revenues from the capacity market.

2.5 Market response to additional interconnection

The development of additional interconnection plays an important role both for power system dispatch purposes (and thus price formation), and for system security of supply. It is therefore necessary to consider the likely market response when additional interconnection is developed, taking into consideration whether a capacity mechanism is also assumed to be operational in one or both of the connected markets. In general, market response will heavily depend on the assessment by market participants of the operation of the interconnector, i.e. whether the interconnector is mostly used to import or export electricity, particularly during periods of system stress.

For the purposes of the modelling described here, the following methodology was employed in order to take the GB market response – in terms of generation capacity build - into account when additional interconnectors are developed in our model:

1. Firstly we looked at hypothetical interconnector flows – based on the market prices –

[18] For the purposes of this study, the 'central' background of additional GB interconnection assumed that only FRA1, BEL and NOR are developed. All price elasticities were then calculated based on this 'central' background of additional interconnection capacity by adding or removing each interconnector separately as relevant (i.e. adding it if it is not already included in this central background or removing it if it is already included). Our modelling has also shown that even if a different 'central' background was chosen, the results and conclusions stemming from this study would not have been materially different.

[19] Given our past experience of modelling electricity interconnectors, we consider the second order feedback of individual interconnectors into the price effect on other interconnectors as relatively minor on the scale of the overall GB electricity system. As a result, for the purposes of this study we assume that the price effect on GB and the connected market of developing an additional interconnector is independent of whether additional interconnectors are or are not developed. While we consider this approximation to be appropriate for the purposes of the interconnector revenue and analysis tool (especially taking into account the large range of combinations that the tool is intended to analyse), it would not be appropriate for a Final Investment Decision on any individual interconnector investment decision. Such a case would require dedicated modelling of the relevant interconnector.

[20] By 'additional GB interconnectors' we mean additional to existing GB interconnectors in the base configuration (i.e. all 6 interconnectors considered here).

across the four modelled scenarios from the original analysis during the 100 hourly periods (roughly 1%) with highest prices in GB. We completed this analysis for years 2015, 2020, 2025, 2030 and 2035, and for Configuration A3 which by 2035 was assumed to contain 2 GW of additional interconnection capacity to France, 1 GW to Belgium, 1 GW to Norway and 1 GW to Ireland (i.e. moderate levels of additional interconnection, similar to the levels considered in this report).

2. Based on the level and direction of interconnector flows during these periods, we derived average de-rating capacity factors for the six interconnectors considered in this study across the 5 spot years under consideration. These average de-rating capacity factors also take interconnector availability into account, which is assumed to be 97% for all interconnectors considered here with the exception of NOR and FRA3 (for which availability factors of 95% were used, reflecting the longer distances of these projects).
3. Finally, using the derived average de-rating factor and the 1 GW capacity of each hypothetical interconnector we assumed that an equivalent CCGT de-rated capacity[21] would be displaced in GB due to the development of that interconnector. If the de-rating factor was calculated to be negative then the interconnector would lead to additional CCGTs being developed in GB.

Average expected interconnector flows during GB system stress conditions and across the four scenarios considered here are shown in the Tables below (Table 1 for Scenario 1, Table 2 for Scenario 2, Table 3 for Scenario 3, and Table 4 for Scenario 4). These tables also contain the average de-rating factors that were derived for each interconnector based on these expected flows and multiplied by an interconnector's assumed availability factor.

Table 1 Interconnector flows, Original Analysis – Scenario 1 ("GB Importing")

Border	Importing (%)	Exporting (%)	No Flow (%)	Average de-rating factor (%)
GB – Belgium	97%	0%	2%	94%
GB – France	98%	1%	1%	94%
GB – Ireland	58%	0%	42%	56%
GB – Norway	99%	1%	0%	93%

Table 2 Interconnector flows, Original Analysis – Scenario 2 ("Flexible Operation")

Border	Importing (%)	Exporting (%)	No Flow (%)	Average de-rating factor (%)
GB – Belgium	70%	2%	29%	66%
GB – France	76%	3%	21%	71%
GB – Ireland	47%	3%	50%	43%

[21] The de-rating factor for CCGTs was assumed to be 85% and this assessment was carried out in 400 MW intervals of CCGT capacity.

Border	Importing (%)	Exporting (%)	No Flow (%)	Average de-rating factor (%)
GB – Norway	92%	1%	8%	86%

Table 3 Interconnector flows, Original Analysis – Scenario 3 ("Low Utilisation")

Border	Importing (%)	Exporting (%)	No Flow (%)	Average de-rating factor (%)
GB – Belgium	66%	0%	34%	64%
GB – France	73%	0%	26%	71%
GB – Ireland	27%	0%	73%	26%
GB – Norway	86%	0%	14%	82%

Table 4 Interconnector flows, Original Analysis – Scenario 4 ("Carbon Price Convergence")

Border	Importing (%)	Exporting (%)	No Flow (%)	Average de-rating factor (%)
GB – Belgium	72%	0%	28%	70%
GB – France	67%	2%	31%	63%
GB – Ireland	45%	1%	53%	43%
GB – Norway	89%	0%	11%	85%

In summary, results presented in this study do not simply compare two system outcomes which only differ with respect to whether or not an additional GB interconnector is developed, all other capacity being the same. They compare an outcome in which an additional GB interconnection project is developed with a counterfactual in which an equivalent amount of new-build CCGT capacity is developed instead of the interconnector, where equivalence is based on the expected de-rating factors of both the interconnector in question and the CCGT. As a result, the impact of the interconnector on GB power prices (as well as on revenues of already operational GB interconnectors) will be less than we would see if there is no market response.

As an example, suppose 1 GW of interconnector capacity is built, and this is equivalent to 0.7 GW of CCGT (by the above definition of equivalence). We assume that new CCGT build is reduced by 0.7 GW, because prospective developers 'see' the interconnector being built and therefore reduce their own construction plans. The new interconnector causes prices in GB to fall, because it is mainly used for importing electricity, but prices fall less than they would if developers were to build the extra 0.7 GW as well. A similar argument applies if GB mainly exports, in which case the amount of equivalent CCGT capacity would be negative.

3. Electricity Market Revenues

This section presents results coming directly out of IRAT with regards to estimated electricity market revenues of the six hypothetical interconnectors considered in this study. The revenues described here assume efficient hourly interconnector dispatch based on price arbitrage opportunities between the connected markets and always flow from the market with the lowest price to the market with the highest price. They are therefore based on the assumption that interconnectors are accurately dispatched based on prevailing hourly wholesale market conditions, and that their capacity has not been reserved to provide ancillary services or security of supply. Similarly, the possibility that interconnectors may be inefficiently dispatched in order to meet prior contracted obligations has not been taken into account when calculating electricity market revenues.

Interconnector dispatch in IRAT takes the individual technical characteristics of interconnectors into account, with the main ones being import and export capacity, total losses attributed to the interconnector, ramp rates, and availability. Furthermore, IRAT allows the user to assess different configurations for each of the scenarios described here, however results presented in this section are based on the following assumptions for the commissioning of new interconnectors (hereby referred to as the "All In" interconnection configuration[22]):

1. FRA1 is assumed to be operational from the 1st January 2017;
2. BEL is assumed to be operational from the 1st January 2019;
3. NOR and FRA2 are assumed to be operational from the 1st January 2020;
4. FRA3 and IRL are assumed to be operational from the 1st January 2022.

Within this configuration, the mutual cannibalisation of revenues by the interconnectors on each other is fully taken into consideration. We have isolated the cannibalisation effects in a self-contained annex at the back of this report, Appendix F.

[22] This is a conservative assumption as interconnector revenues are reduced to some extent as additional interconnectors are developed, a process known as 'cannibalisation' – see Appendix F for more details.

3.1 Scenario 1 ("GB Importing")

In Scenario 1 the annual average price in GB is consistently higher than in surrounding markets (France, Belgium, Ireland, Norway) due to the significantly higher carbon prices that generators in GB are facing as a result of the CPS policy coupled with low EUA carbon prices throughout. It is interesting to note, however, that towards the end of the timeframe prices start to decline as a result of the amount of low carbon generation on the system. This also leads to a decline in the price differentials between GB and the other European markets: for example, whilst the average price difference between GB and France during 2017-2028 is £16-23/MWh, by 2035 this has been reduced down to £11/MWh.

On average, Norwegian prices are the lowest over the timeframe considered here, although they rise faster than other prices as high carbon prices affect German coal prices which in turn affect Norwegian prices via interconnection. On the other hand Irish prices, whilst starting from a significant premium compared to Continental Europe (due to the relative inefficiency of the Irish generation capacity mix, along with high GB prices pushing up prices in SEM), decline to a similar level by the end of the modelling horizon due to very high wind penetration[23] along with assumed investments in more efficient new CCGT plant.

Figure 2 Annual average price summary – Scenario 1 ("All In" Configuration)

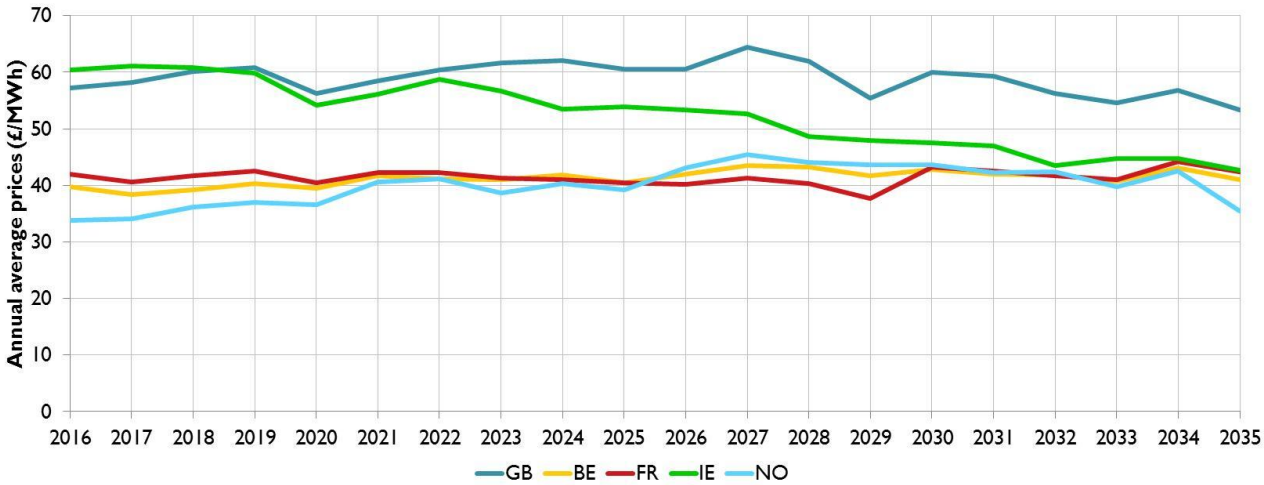


Figure 3 shows the overall portfolio revenue and flows for Scenario 1 assuming all six of these projects are built. It can be seen that the developed interconnectors are very profitable, with average annual portfolio revenues remaining between £130-165/kW for the duration of the modelling horizon and with relatively little year-to-year variation. In this world, the developed interconnectors are mainly used to import significantly cheaper electricity into GB. Overall utilisation remains very high (between 85-95%), with imports largely dominating (import utilisation ranges between 61-93%), although progressive decarbonisation of the GB power sector leads to considerably more exports towards the end of the modelling horizon. By 2035, for example, export utilisation reaches 24% compared to less than 5% before 2020.

[23] By 2035 our modelling shows that wind is at the margin approximately 11% of the time in SEM – see Appendix E.

Figure 3 Portfolio revenue and portfolio flows – Scenario 1 ("All In" Configuration)

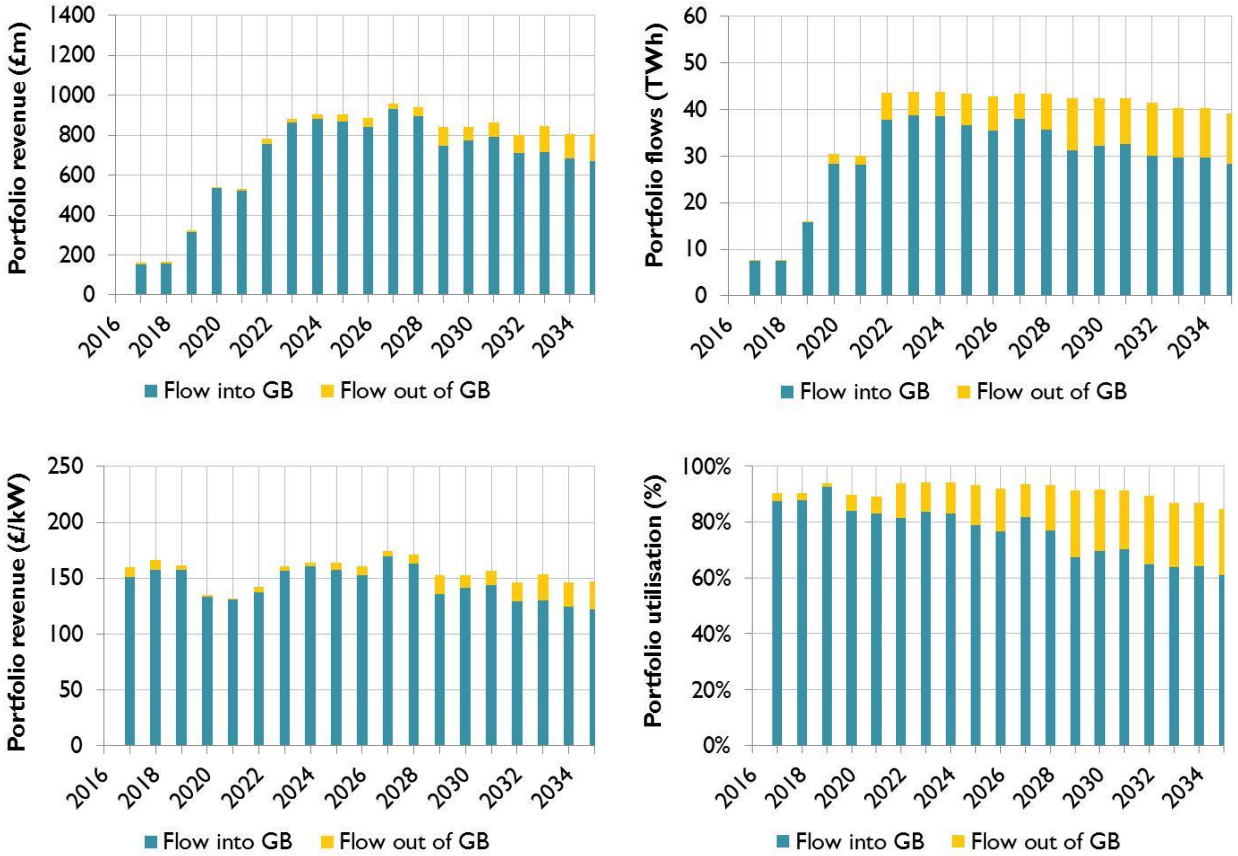
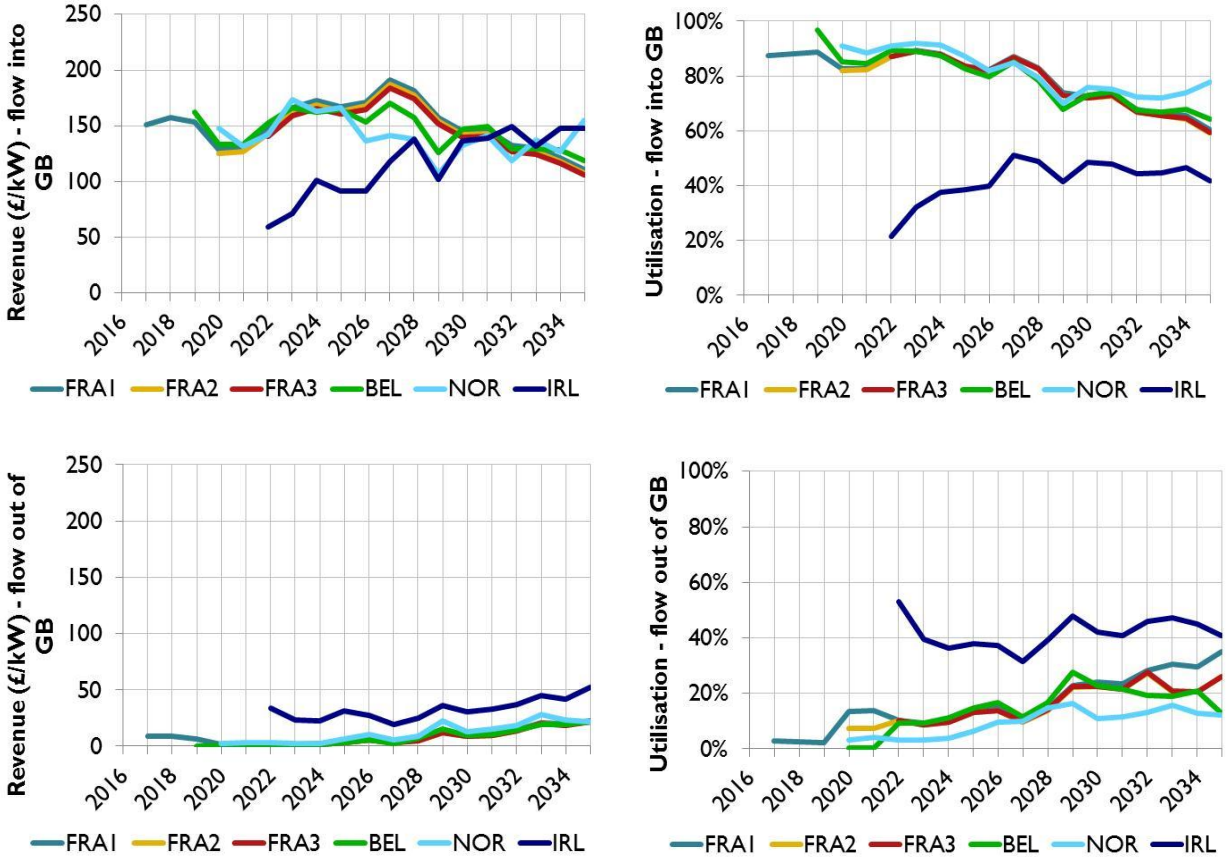


Figure 4 shows detailed revenue and portfolio flows for each of the six interconnectors considered in this study. Again it is interesting to note that there is little differentiation between individual interconnector revenues, which are typically (with the exception of IRL) in the range of £130-165/kW per year for the duration of the modelling horizon. This is because GB maintains a significant premium over the other markets considered here due to higher GB carbon prices and as such import revenues typically account for approximately 80-90% of total revenues. The exception to this is IRL for which export revenues make up a considerable part (between 14-36%) of overall revenues.

Figure 4 Interconnector revenue and portfolio flows – Scenario 1 ("All In" Configuration)



3.2 Scenario 2 ("Flexible Operation")

In Scenario 2 high fossil fuel prices are reflected in higher electricity prices than we have seen in Scenario 1. However, in the long term the strong growth in renewables (particularly wind) and nuclear, both of which have low short run marginal costs, puts significant downward pressure on prices.

Ireland remains the most expensive market throughout the modelling horizon due to its high dependence on (relatively inefficient) gas-fired generators. With increasing Irish wind penetration, annual average prices in SEM are progressively reduced towards the end of 2020s, although they still remain slightly above the other countries under investigation. Until the late 2020s GB also remains expensive relative to NW Continental Europe (compared to France, for example, annual average GB prices are higher by around £17-19/MWh during 2017-2019 and then by around £5-10/MWh during 2020-2029). In part this is due to moderately higher carbon prices in GB: GB and EUA carbon prices only converge from 2027 onwards (Table 11). Towards the end of the modelling horizon, very high wind penetration in GB (total installed GB wind capacity is assumed to be 43 GW by 2030) causes the differential to fall, with GB being cheaper from 2033 onwards.

Since the Norwegian electricity market is hydro-dominated, it is more insulated from high fossil fuel prices than the other countries considered here. As a result, Norwegian power prices are

consistently lower, although the gap narrows from 2020 onwards, particularly as more interconnectors are developed that connect Norway with GB and Germany/Netherlands.

Figure 5 Annual average price summary – Scenario 2 ("All In" Configuration)

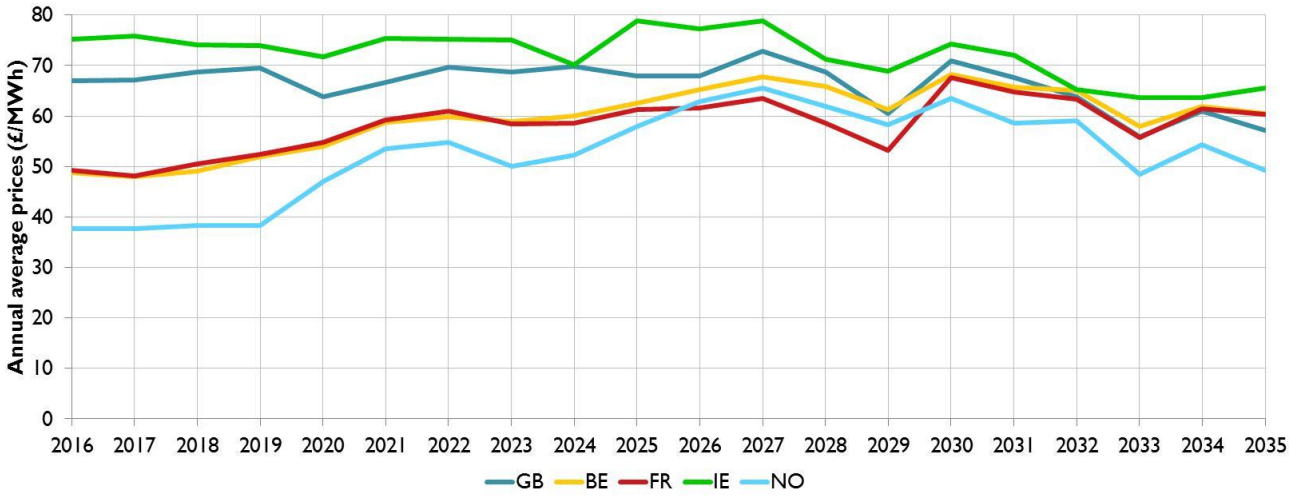


Figure 6 shows the overall portfolio revenue and flows for Scenario 2. Unlike Scenario 1, it can now be seen that there is significant year-to-year variation in portfolio revenues on a £/kW basis:

- New interconnectors that are able to operate in the early years (2017-2019) are very profitable (annual portfolio revenues are around £140-160/kW) as they are able to take advantage of the significant premium of GB prices relative to NW Continental European prices.
- In the later years, from 2020 to 2027, portfolio revenues decline and range between £75-110/kW per year. The interconnectors considered in this study are still mostly used to import electricity to GB, however the average spread when GB is importing is now considerably lower as GB prices gradually converge with European prices.
- Finally, from 2028 onwards interconnector revenues rise substantially (annual portfolio revenues now range between £110-210/kW per year) with the majority of additional revenues coming from GB exports due to very high GB wind penetration. Interestingly most flows are still the other way round (i.e. GB is mostly importing) however significant interconnection value is now driven by periods of negative prices in GB. This suggests that the average spread of GB exporting is considerably higher than the average spread of GB importing.

Figure 6 Portfolio revenue and portfolio flows – Scenario 2 ("All In" Configuration)

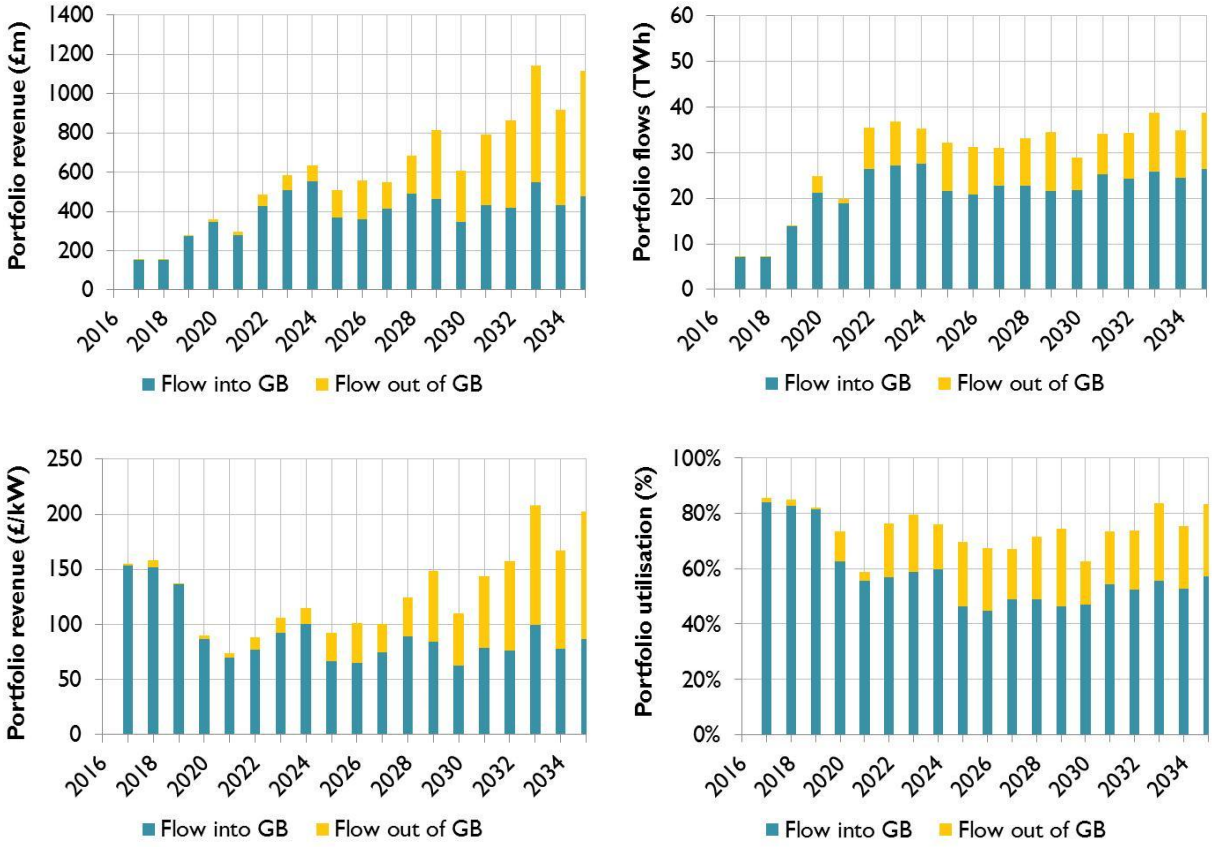


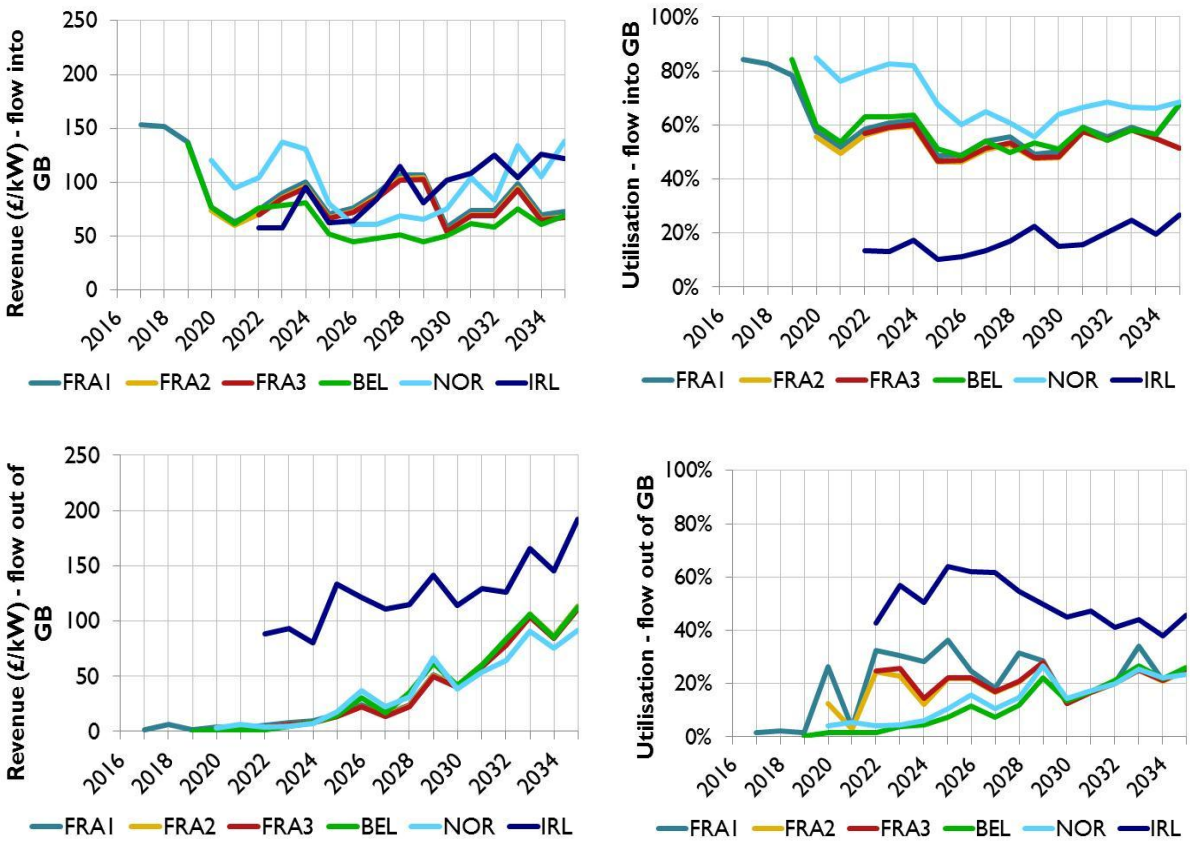
Figure 7 shows detailed revenue and portfolio flows for each of the six interconnectors considered here. It is interesting to note that in this scenario, despite IRL being the new interconnector with the lowest utilisation (annual utilisation ranges between 55-80%), it is also the interconnector with the highest average annual revenues which range between £150/kW to as high as 315/kW towards the end of the modelling horizon. As previously explained, this is due to the very high wind penetration in GB and Ireland in this scenario which create significant price arbitrage opportunities (due to price volatility) between the two markets, despite the relatively high correlation of their respective wind outputs and despite the fact that average price differences between the two markets are not significant (see Figure 5). Furthermore, even though the interconnector is flowing mostly from GB to Ireland, revenues for GB imports and GB exports are broadly similar reflecting the fact that wind generation is more often at the margin in SEM.

Revenues for NOR are also high, ranging approximately between £80-220/kW per year, owing to strong imports to GB in the early years as Norwegian prices remain at lower levels and then to both import revenues and export revenues as GB prices become progressively more volatile with the continuous increase in wind generation.

A similar story is observed with the French and Belgian links with high utilisation throughout (typically around 70-80%) and increased revenues towards the end of the modelling horizon as a result of high average spreads when GB is exporting. These high average spreads are observed due to the face that in the later years low carbon plant (particularly wind) are more often at the margin in GB compared to France/Belgium and thus during those periods respective price differences are high, thus resulting in high revenues for these interconnectors. In the earlier years

revenues are mostly driven by GB imports, which however are somewhat moderated as GB prices gradually converge with NW Continental European prices in the 2020s.

Figure 7 Interconnector revenue and portfolio flows – Scenario 2 ("All In" Configuration)



3.3 Scenario 3 ("Low Utilisation")

In Scenario 3 low fossil fuel prices are reflected in noticeably lower electricity prices compared to Scenarios 1 and 2. Wholesale electricity prices converge throughout Europe although GB and Irish levels remain slightly higher on average during the earlier years due to higher carbon prices in GB and utilisation of relatively inefficient gas plant in Ireland respectively. In Continental Europe prices rise gradually throughout the modelled timeframe in line with the assumed increase in carbon prices (from approximately £7/t in 2016 up to £39/t in 2030).

Using the assumptions employed here, average clean spark spreads in this scenario are higher than average clean dark spreads[24]. As a result, with unabated gas remaining cheap vis-à-vis unabated coal, Norwegian prices are slightly higher than French and Belgian prices. This is due to the influence of the German market, where coal market share is very significant, on Scandinavian prices via existing interconnection with Denmark (particularly West Denmark) and Sweden, as well

[24]The term clean spark spread refers to the theoretical gross margin of a gas-fired generator from selling a unit of electricity, taking its fuel and carbon costs into account. The term clean dark spread refers to the equivalent gross margin for a coal-fired generator.

as future interconnection with Norway. In the French and Belgian markets, however, gas and nuclear have more influence and thus power prices remain slightly lower in this scenario for the majority of the modelling horizon.

As in Scenarios 1 and 2, progressive decarbonisation of the Irish and GB power generation sectors leads to wholesale electricity prices gradually declining in the long term across these markets. In Ireland, decarbonisation is achieved mostly through investments in wind, whereas in GB there is substantial investment in wind, nuclear and CCS technologies.

Figure 8 Annual average price summary – Scenario 3 ("All In" Configuration)

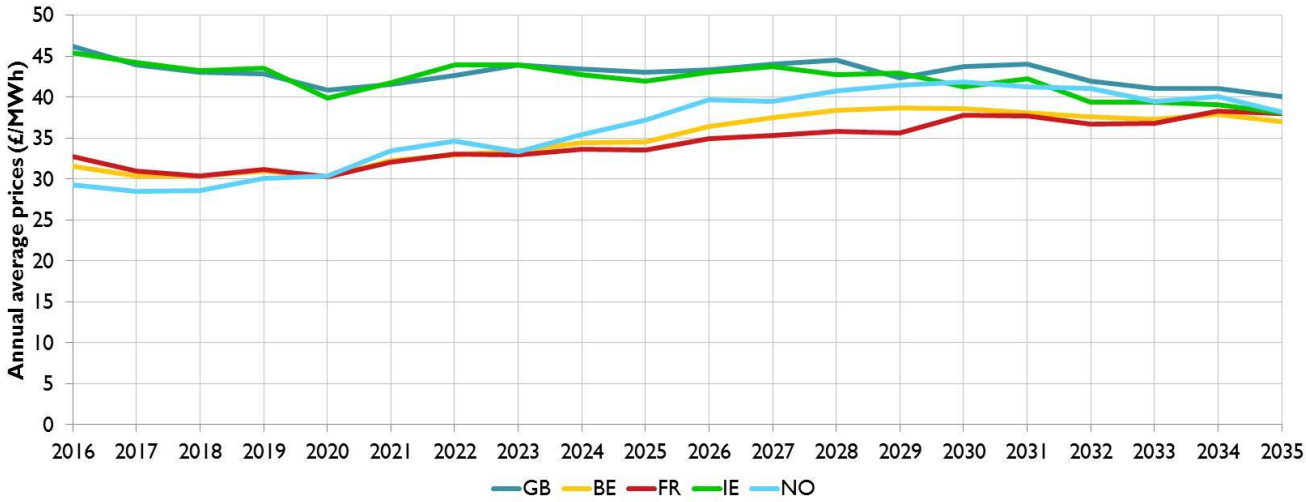


Figure 9 shows the overall portfolio revenue and flows for Scenario 3. It is interesting to note that interconnector utilisation in this scenario remains relatively high in spite of the small differences between average price levels (as shown in Figure 8). This is due to the fact that transit costs (link losses and system losses attributed to the links) amount typically to only around £2-3/MWh as wholesale electricity prices remain at low levels throughout the modelling horizon. Export volumes are low (close to zero in the early years but rising to around 20% by 2035) as GB prices retain a premium over Continental and NordPool levels.

Despite high utilisation, portfolio revenues on a £/kW basis are relatively low owing to small average price differentials especially from mid-2020s onwards as shown in Figure 8. As a result, the intrinsic value of interconnectors is reduced, with portfolio revenues appearing particularly low when compared against equivalent results from Scenarios 1 and 2. It should be stressed, however, that for earlier years (2017-2023) portfolio revenues are relatively robust, albeit gradually declining, and average approximately £80/kW per year (in the range of £60-105/kW). This is because revenues during these early years are driven mostly by GB imports as a result of the CPS policy pushing up GB prices. In the following years (2024-2035) portfolio revenues remain relatively stable averaging approximately £54/kW (between £49-65/kW), with export revenues increasing moderately over time due to above-mentioned investments in low carbon generation technologies in the GB market. In this scenario, however, some new-build inflexible low carbon generation capacity (nuclear and intermittent renewables) is replaced by gas CCS and coal CCS thus also reducing the extrinsic value of GB interconnectors due to the increased flexibility provided by the latter technologies. As a result, prices in GB remain relatively flat even in the later years when the GB power generation sector is largely decarbonised, thus also leading to low average spreads when GB is exporting (and hence low export revenues).

Figure 9 Portfolio revenue and portfolio flows – Scenario 3 ("All In" Configuration)

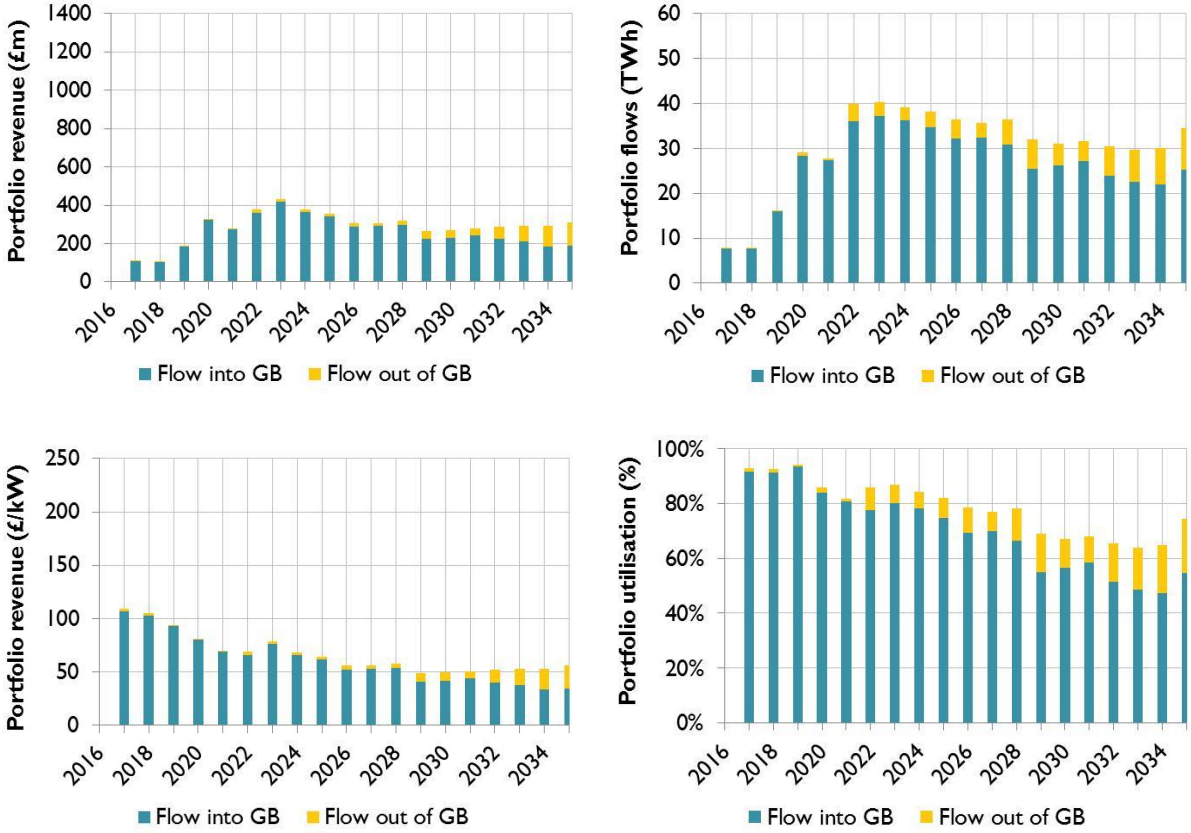
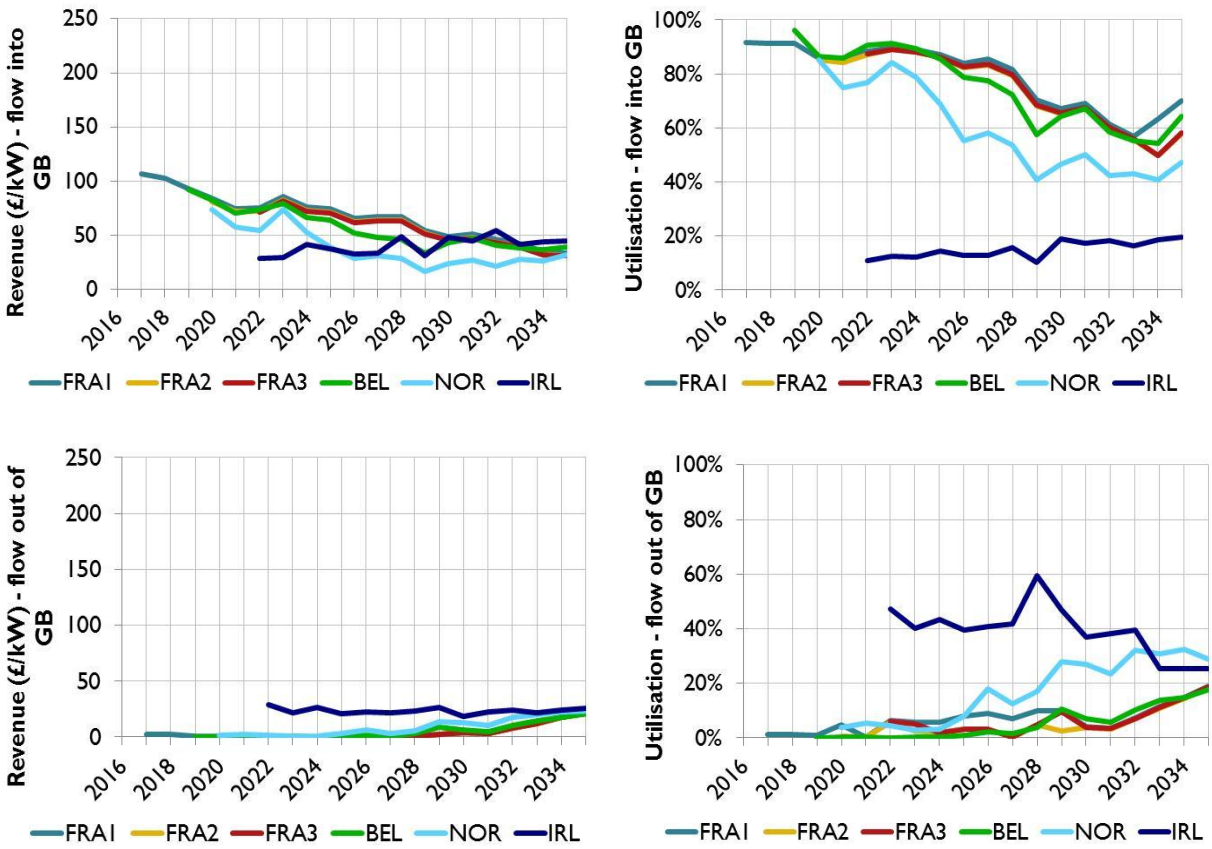


Figure 10 shows detailed revenue and portfolio flows for each of the six interconnectors considered in this study. It can be seen that there are no significant variations between the different interconnectors, with total annual revenues typically averaging between £50-75/kW per year. Due to its assumed early commissioning date, FRA1 is able to take advantage of the premium in GB prices during the early years of its operation, particularly during 2017-2019 when its annual revenues range between £95-110/kW.

Despite its relatively high utilisation of around 70-90%, NOR has the lowest electricity revenues in this scenario. This is because Norwegian prices are slightly higher than French/Belgian prices in this scenario (for reasons previously explained) and as a result import revenues for NOR are negatively affected. Furthermore, the higher losses of NOR compared to the French and Belgian links further hinder its revenues, particularly in a world with low average price differentials.

Figure 10 Interconnector revenue and portfolio flows – Scenario 3 ("All In" Configuration)



3.4 Scenario 4 ("Carbon Price Convergence")

Figure 11 shows annual average prices for Scenario 4 for the countries under consideration in this report. It can be seen that GB and Ireland retain a considerable price premium compared to Continental Europe until well into the 2020s (GB due to higher carbon prices as a result of the CPS policy and Ireland due to a relatively inefficient generation mix) but gradually converge towards the end of the modelling horizon. This convergence is both due to carbon prices in GB and Europe converging from 2030 onwards, and to significant investments in low carbon generation technologies (mainly wind in Ireland and wind and nuclear in Britain) putting downward pressure on wholesale power prices in these two countries.

In Continental Europe prices rise gradually throughout the modelled timeframe in line with the assumed significant increase in carbon prices (from approximately £7/t in 2016 up to £76/t in 2030). Norwegian prices tend to converge with prices in France and Belgium as more interconnectors between Norway and NW Continental Europe (Netherlands and Germany) are developed; at the very end of the timeframe, replacement plant in the Nordic region leads to a price fall.

Figure 11 Annual average price summary – Scenario 4 ("All In" Configuration)

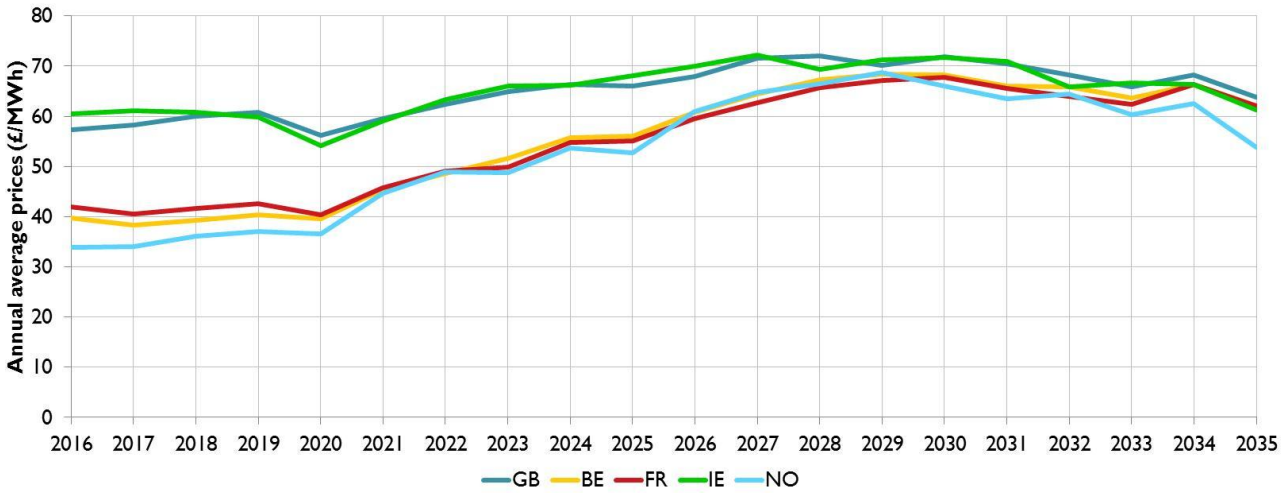


Figure 12 shows the overall portfolio revenue and flows for Scenario 4. On a £/kW basis, the results may be crudely characterised by three timeframes as follows:

- Until 2023, interconnectors are performing well (annual portfolio revenues are around £100-165/kW per year, albeit gradually decreasing) as they are able to take advantage of the considerable premium of GB prices relative to Continental European prices due to the CPS policy.
- From 2024-2029, annual portfolio revenues continue to decline and range between £60-90/kW. The main reason for this decline in revenues is gradually decreasing import utilisation as GB prices converge with Continental European prices.
- Finally, from 2030 onwards interconnector revenues recover (with annual portfolio revenues rising back to £100/kW) with the majority of additional revenues coming from GB exports due to high GB wind penetration. Interestingly most flows are still the other way round (i.e. GB is mostly importing) however considerable interconnection value is now driven by periods of negative prices in GB. This is because by the end of the modelling horizon the average spread of GB exporting is approximately 50% higher than the average spread of GB importing.

Figure 12 Portfolio revenue and portfolio flows – Scenario 4 ("All In" Configuration)

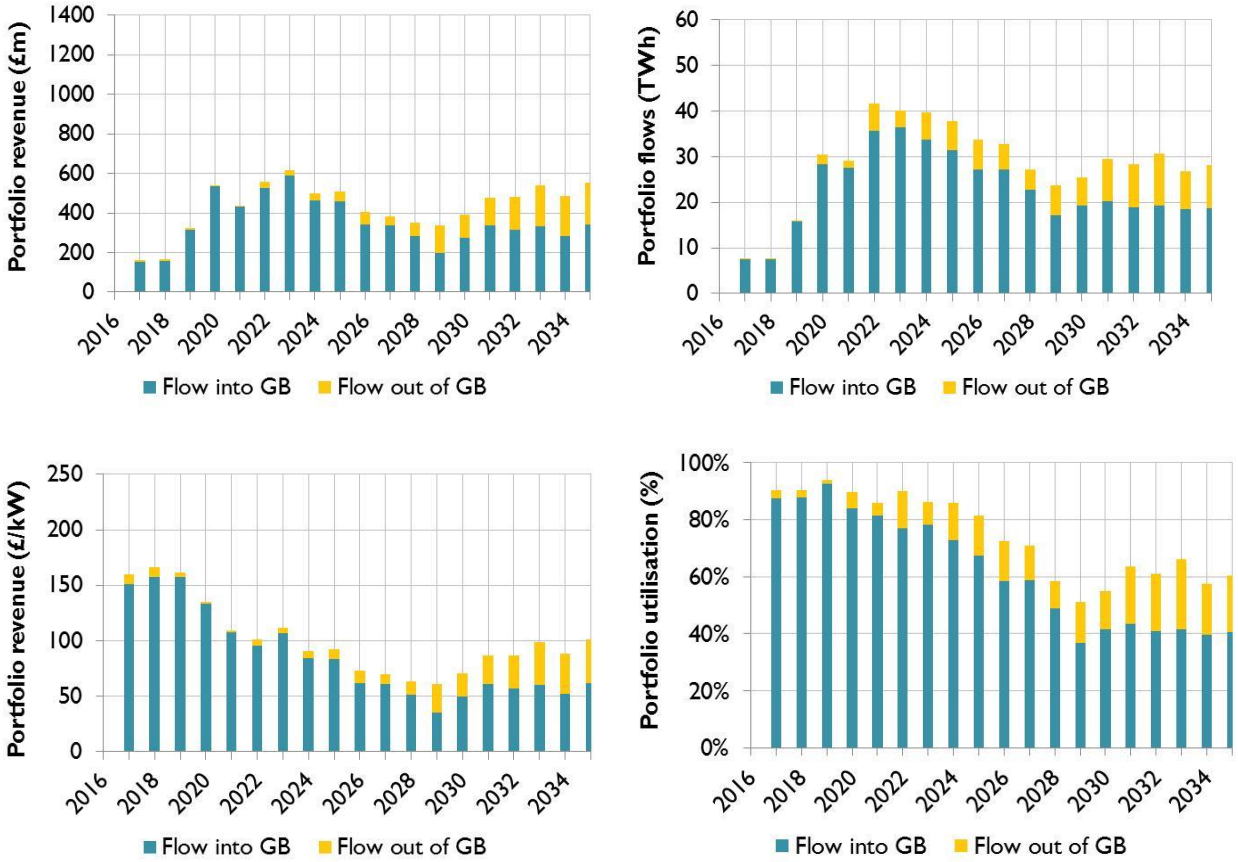
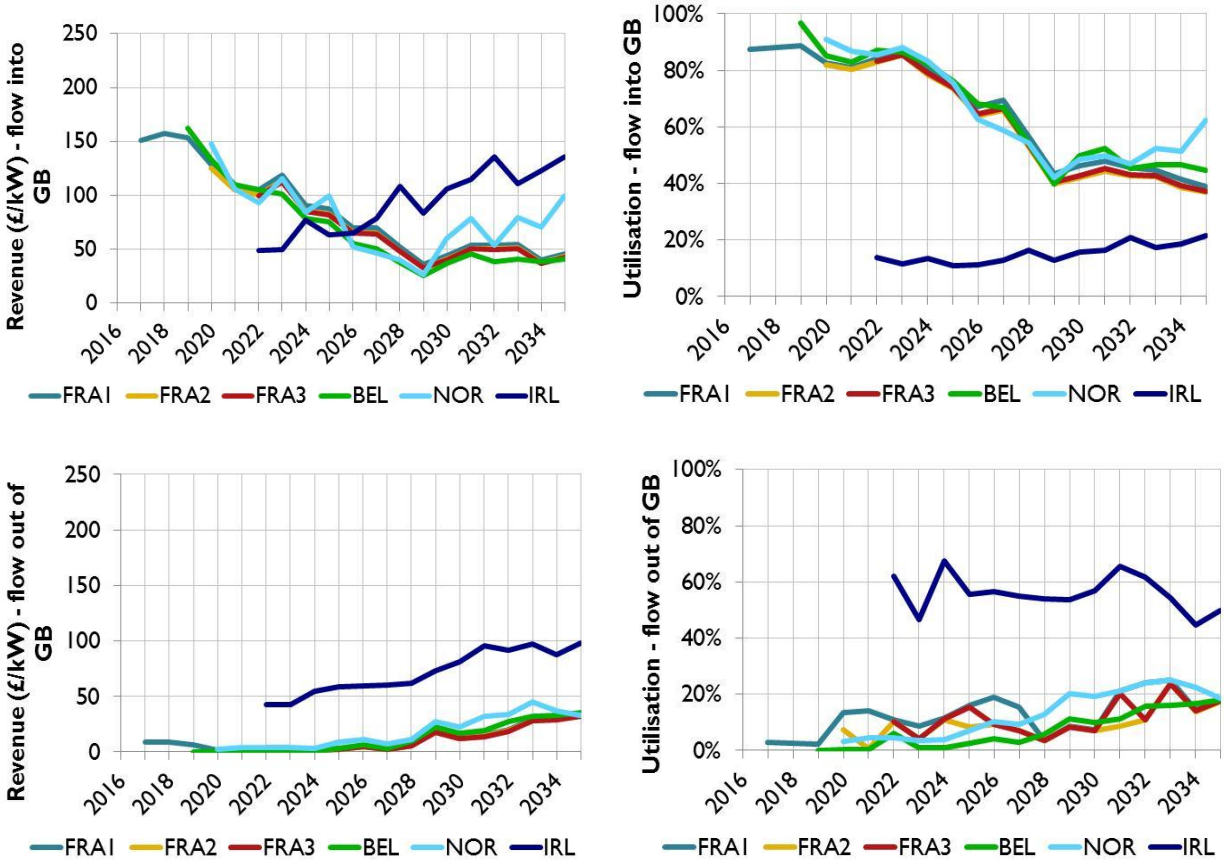


Figure 13 shows detailed revenue and portfolio flows for each of the six interconnectors considered here. Despite relatively low utilisation levels (between 58-83%) compared to the other interconnectors, IRL results in the highest average annual revenues on a £/kW basis which range between £90/kW to as high as £235/kW towards the end of the modelling horizon. This is a similar conclusion to Scenario 2, and comes as a direct result of the high wind penetration in GB and Ireland creating significant price arbitrage opportunities between the two markets despite the relatively strong correlation between their wind outputs. Furthermore, even though the interconnector is flowing mostly from GB to Ireland, revenues for GB imports and GB exports are broadly similar reflecting the fact that wind generation is more often at the margin in SEM.

NOR has the second highest unit revenues which typically range between £80-140/kW per year, with the exception of years 2026-2029 when revenues are around £50-60/kW per year. Until 2029, NOR revenues follow a declining trend due to reduced import utilisation as GB prices gradually converge with Norwegian prices. From 2030 onwards, however, NOR revenues recover as GB prices become progressively more volatile with the continuous increase in wind generation, thus creating price arbitrage opportunities.

A similar story is observed with the French and Belgian links with revenues declining until 2030 despite relatively high utilisation throughout (typically around 70-80%, although it can be as low as 50% for some years) and increased revenues towards the end of the modelling horizon as a result of high average spreads when GB is exporting. In the earlier years revenues are mostly driven by GB imports, which however are somewhat moderated as GB prices gradually converge with NW Continental European prices in the 2020s.

Figure 13 Interconnector revenue and portfolio flows – Scenario 4 ("All In" Configuration)



4. Capacity Market Revenues

The methodology we employed for modelling GB capacity market revenues has been described in detail in Section 2.3. Plans for capacity auctions in GB are at an advanced stage of development, with the first auction planned for November 2014, leading to delivery of capacity by October 2018. It has not been possible to find a way for interconnected capacity to participate in the first capacity auction for delivery in October 2018. Work is ongoing to try to find a solution to this.

For the purposes of this study we have considered what difference it would make to the economics of specific projects if foreign generators or interconnector owners were eligible for GB Capacity Mechanism (CM) payments. Potential GB capacity payments for interconnectors would mainly depend on two key factors:

1. The annual CM auction clearing price, as determined by the annual stack of supply and demand bid-offer prices in the GB CM auction;
2. The annual interconnection capacity that is declared to be available for the CM. This is likely to differ for each interconnector depending on installed capacity and projected operation during periods of system stress in GB.

Under current proposals, plant supported by a CfD or the RO will be ineligible to participate in the CM ("excluded plant"). Since the capacity of generation plant that are not supported by either low carbon support mechanism remains largely unchanged by scenario (i.e. CCGT, OCGT and unabated coal plant capacity is broadly similar under the four scenarios modelled here[25]), our modelling shows that the type of generation technology that will set the annual CM auction clearing price for a specific year also does not change by scenario. There are, however, some small differences in CM auction clearing prices due to differences in wholesale electricity market revenues by scenario (and hence the "missing money" required from the CM may also differ).

As there is currently uncertainty with regards to the price caps that may be imposed in the CM, and in order to smooth out the significant year-to-year variations in CM clearing prices that we observed in our CM modelling[26], we divided the modelling timeframe into 4 periods:

- For the first 5 years that the CM is assumed to be operational (2019-2023[27]) auction clearing prices under the developed scenarios average between £32-36/kW. This is because in general there is sufficient generating capacity to meet peak electricity demand which is assumed to grow modestly (approximately 1% per annum) during this period. Wholesale electricity revenues for low-merit gas and coal plant, however, are close to zero and as a result these plant need to recover their annual fixed costs almost fully from the CM;
- For the next 4 years (2024-2027), and due to significant retirements of LCPD coal plant coupled with stronger peak demand growth of around 2% per year, new generating capacity is required. As a result, auction clearing prices under the developed scenarios

[25] See Appendix C for the GB capacity mix under each of the four modelled scenarios.

[26] We averaged out CM clearing prices during these four periods in order to minimise the potential variation in capacity payment revenues when calculating projected IRRs. Whilst timing is clearly very important for the economics of developing an interconnector, we felt that we were already taking this sufficiently into account through our wholesale market modelling and did not wish to convolute this further by introducing additional significant year-to-year variation with CM revenues.

[27] We recognise that the first delivery in the CM is scheduled for October 2018 however given that we are modelling calendar years we have assumed that the CM starts in January 2019 (i.e. three months later than currently planned).

average between £41-45/kW during this period as both new OCGT as well as more expensive new CCGT capacity is necessary to ensure that security of supply is maintained.

- During 2028-2031 strong peak demand growth continues (roughly 2.5% per annum) however during this period there is significant investment in new nuclear and new CCS capacity which (along with a minor contribution from additional new-build wind plant) puts downward pressure on CM clearing prices. These have been found to average between £26-27/kW under all developed scenarios;
- Finally, during the last years of the modelling horizon (2032-2035) peak demand growth is assumed to be even stronger (approximately 3% per annum) and as a result, despite further investments in low carbon generation technologies (mainly nuclear and CCS, along with wind which however has a considerably lower de-rating factor), additional OCGT capacity is required to meet the desired de-rated capacity margin. During this period auction clearing prices were found to average approximately £37/kW under all developed scenarios reflecting the costs of developing new OCGTs.

Table 5 CM auction clearing prices

CM auction clearing price (£/kW)	2019-2023	2024-2027	2028-2031	2032-2035
Scenario 1	32.8	42.3	26.2	37.2
Scenario 2	35.6	45.2	26.7	37.3
Scenario 3	31.6	40.9	26.2	37.3
Scenario 4	32.6	41.7	26.0	37.2

Figure 14 shows potential revenues from capacity payments relative to revenues from the wholesale electricity market for Scenario 1 and for four interconnector projects: an additional GB-France link (FRA1), BEL, NOR and IRL[28]. In order to calculate CM revenues the de-rating factors from Table 1 were used: these show strong imports to GB during peak GB conditions, particularly for the Scandinavian and NW Continental European links.

- A broadly consistent story is observed for FRA1, BEL and NOR with high capacity payments due to the assumed high de-rating factors for these interconnectors in this scenario. Electricity revenues are relatively stable and average around £150/kW for the years considered here, whilst capacity payments (eligible from 2019 onwards) for these interconnectors are just over £30/kW. This suggests that potential capacity payments for these links are approximately a fifth of wholesale electricity revenues.
- Due to increasing intermittency as more wind is deployed in Ireland and GB, electricity revenues for IRL display a rising trend over time, increasing from £100/kW in 2022 up to £200/kW in 2035. On average, electricity revenues for the years that IRL is operational until 2035 are also around £150/kW. Due to the relatively low de-rating factor for IRL, however, (since system stress conditions in SEM are relatively well correlated with system stress conditions in GB) capacity payments average only approximately £20/kW. Hence for this link CM revenues are less than 15% of wholesale electricity market revenues.

[28] The graphs presented in this section do not include the other two additional GB-France links (FRA2 and FRA3) since on a £/kW basis their revenues are similar to the revenues shown for FRA1 (albeit with slightly lower wholesale electricity revenues due to the fact that FRA1 is assumed to have the lowest losses and as such has a slightly higher utilisation).

Figure 14 CM revenues relative to electricity revenues – Scenario 1 ("All In" Configuration)

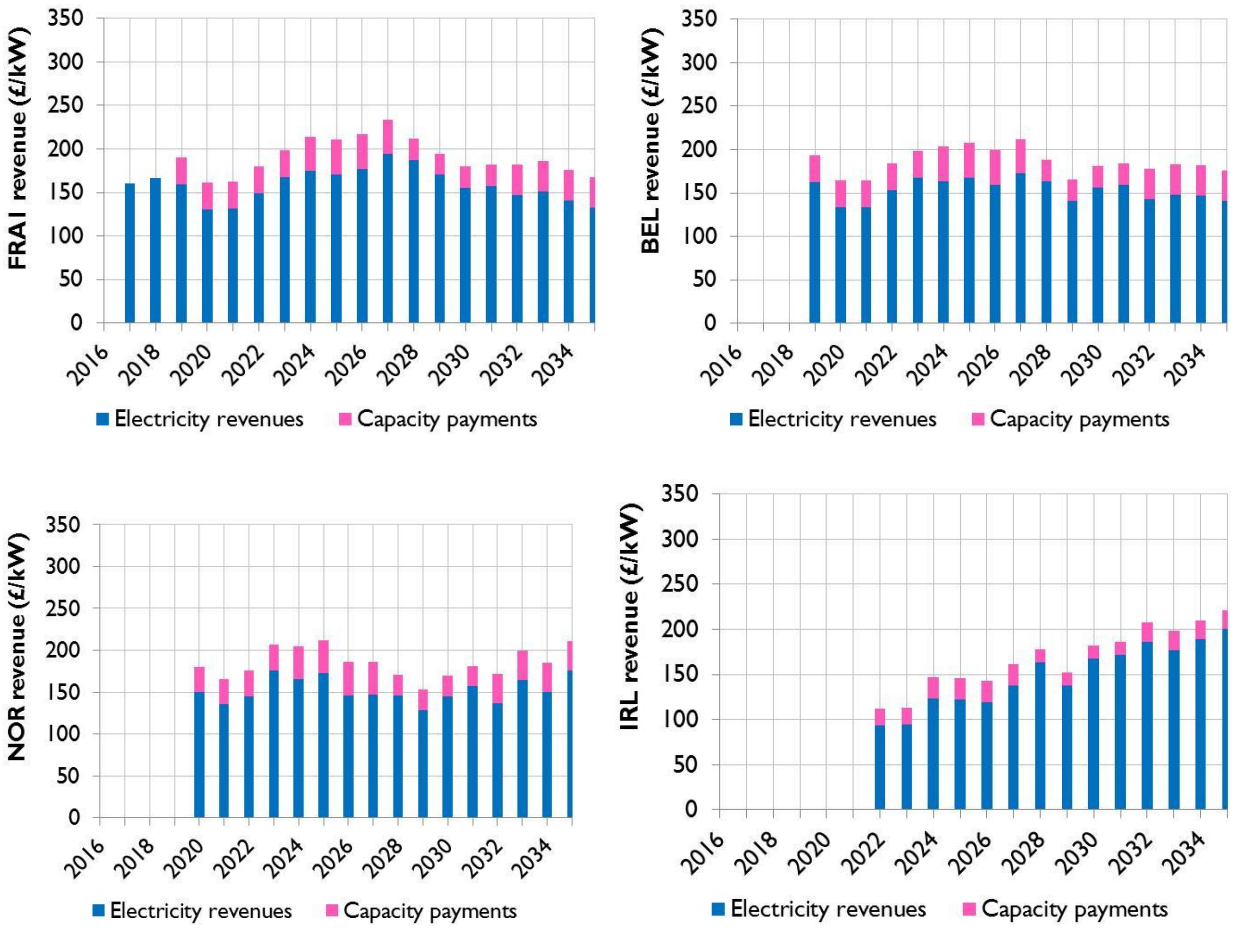


Figure 15 shows potential revenues from capacity payments relative to revenues from the wholesale electricity market for the same four links for Scenario 2 and using the de-rating factors from Table 2.

- With the exception of NOR, average CM revenues are now lower compared to Scenario 1 – approximately £24-26/kW for the French and Belgian links from 2019 onwards and only £16/kW for IRL.
- For NOR average CM revenues are just over £30/kW since correlation between the Norwegian and GB electricity markets is relatively weak and hence a higher de-rating factor is used.
- This suggests that for the years considered here, capacity payments for FRA1 and BEL are around 20-25% of wholesale electricity revenues (which average approximately £105-125/kW), and a similar proportion for NOR (with electricity revenues of around £130/kW).
- For IRL a combination of high wholesale electricity revenues (especially towards the end of the modelling horizon) coupled with a low assumed de-rating factor means that capacity payments are only 7% of wholesale electricity revenues (which average approximately £220/kW).

Figure 15 CM revenues relative to electricity revenues – Scenario 2 ("All In" Configuration)

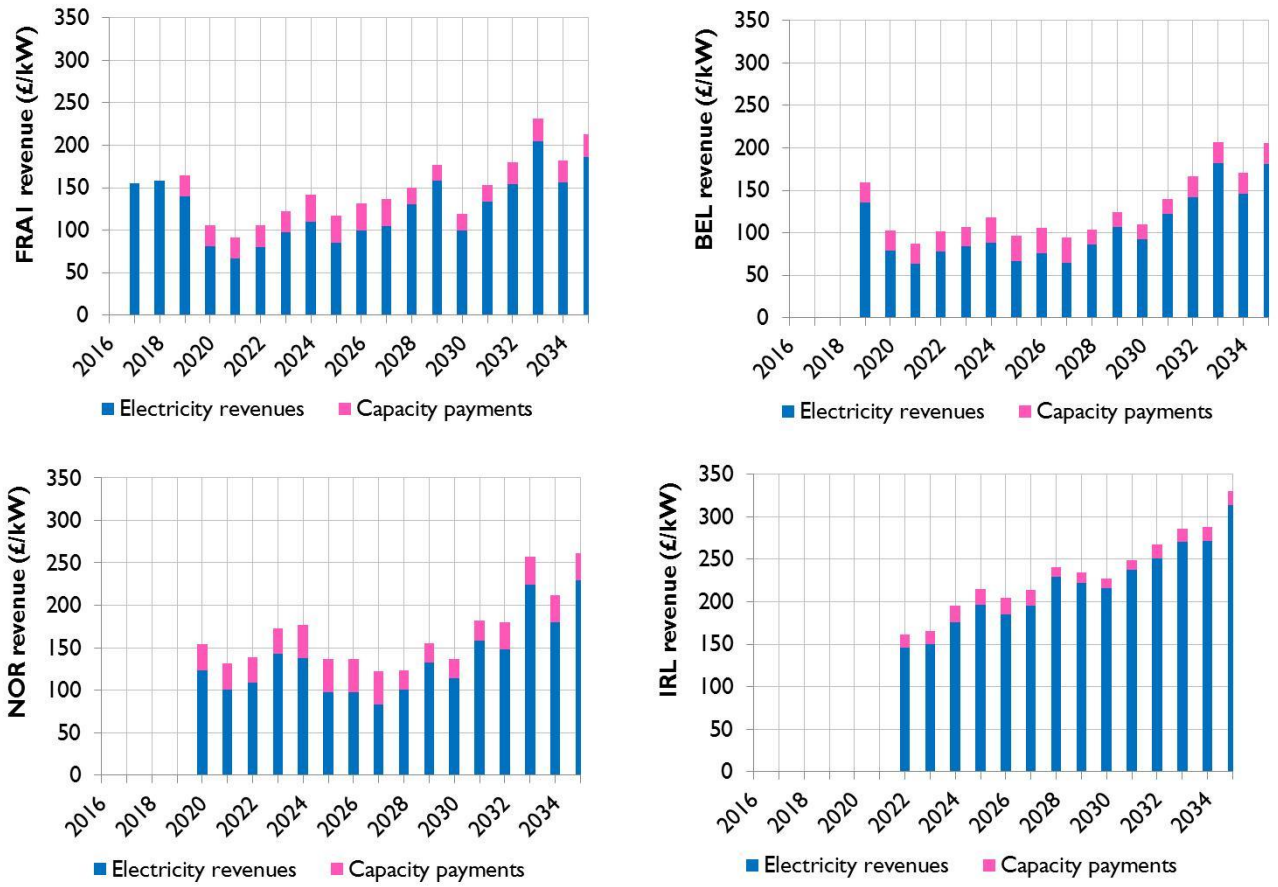
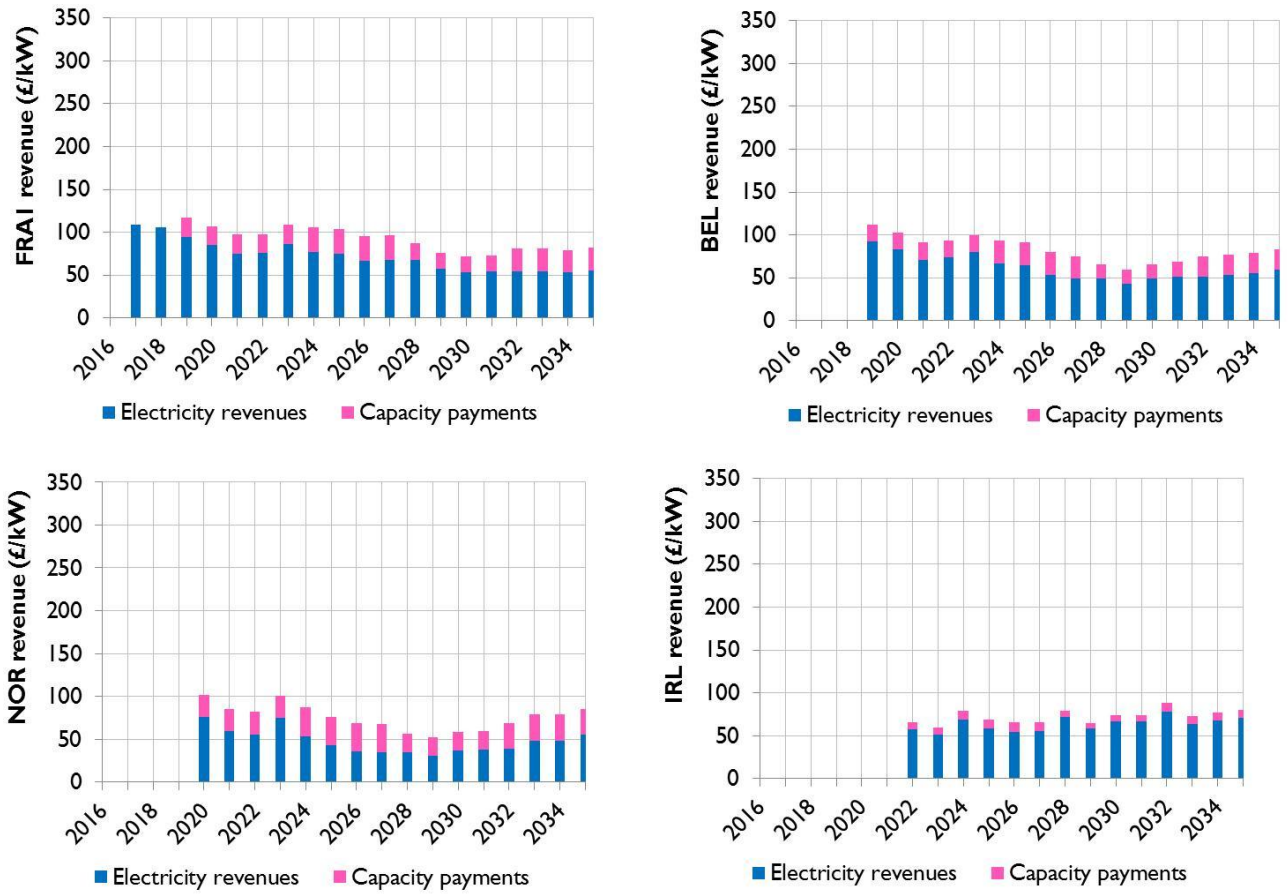


Figure 16 shows potential revenues from capacity payments for Scenario 3 and using the de-rating factors from Table 3.

- CM revenues are broadly similar to those observed under Scenario 2, with NOR receiving the highest capacity payments (just below £30/kW), followed by the French and Belgian links (around £22-24/kW). Capacity payments for IRL are low (averaging less than £10/kW) due to its very low de-rating factor in this scenario (26%).
- As explained in Section 3.3, low price differentials in this scenario lead to reduced price arbitrage opportunities and thus electricity market revenues for the links considered here are subdued. Hence, if such a world were to materialise, capacity payments could provide a significant portion of overall revenues.
- For the years considered here, for example, capacity payments for FRA1 and BEL are between 33-35% of wholesale electricity revenues (which average only £60-70/kW) whilst for NOR this is close to 60% (with average electricity revenues of only £48/kW).
- IRL is again the link with the lowest potential capacity payments relative to electricity market revenues. Capacity payments are roughly 10% of wholesale electricity revenues (which show little year-to-year variation and average approximately £65/kW).

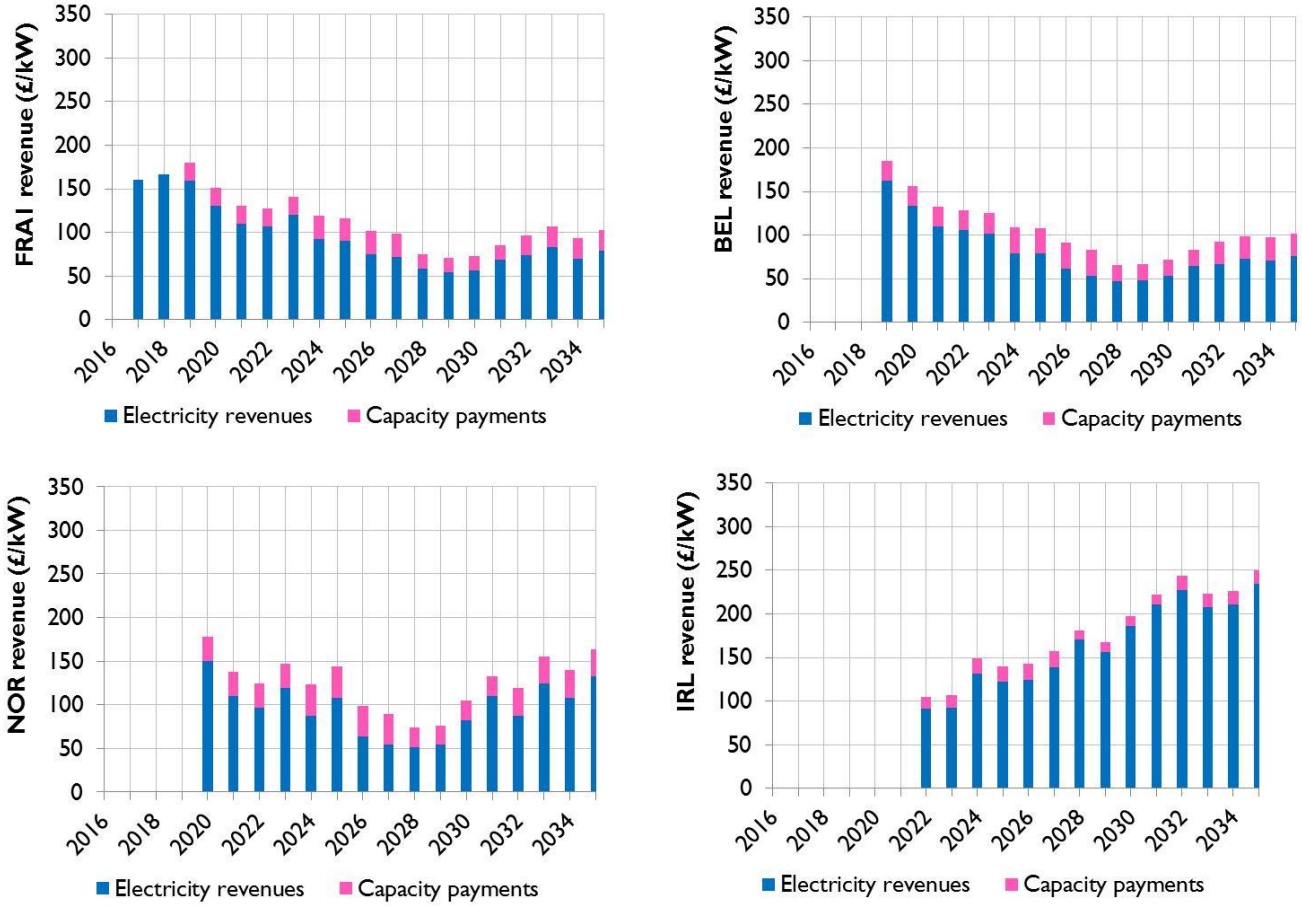
Figure 16 CM revenues relative to electricity revenues – Scenario 3 ("All In" Configuration)



Finally, Figure 17 shows potential revenues from capacity payments for Scenario 4 and using the de-rating factors from Table 4.

- Again NOR is receiving the highest capacity payments on average (just below £30/kW), followed by the French and Belgian links (averaging around £22-24/kW) and finally EWC1 (averaging around £15/kW).
- NOR and BEL are the two links where potential capacity payments are highest relative to electricity market revenues. For NOR this averages around 30% (with average electricity revenues of £96/kW) whilst for BEL the equivalent figure is 29% (with average electricity revenues of £82/kW).
- Due to its early commissioning date, FRA1 is able to take advantage of early years (particularly 2017-2019) when price differentials between France and GB are significant, and hence its average electricity market revenues are relatively high (averaging £96/kW). As a result, capacity payments relative to electricity revenues are relatively low, approximately 22%.
- For IRL a combination of high wholesale electricity revenues (especially towards the end of the modelling horizon) coupled with a low assumed de-rating factor means that capacity payments are only 9% of wholesale electricity revenues (which average approximately £165/kW).

Figure 17 CM revenues relative to electricity revenues – Scenario 4 ("All In" Configuration)



5. Conclusions

This study has presented revenue projections (wholesale electricity market revenues and potential capacity payment revenues) for six hypothetical GB interconnector projects considered in this study: FRA1, FRA2, FRA3, BEL, NOR and IRL. These projections have been derived in IRAT using fundamental power market modelling in PLEXOS, along with the dedicated tool that Redpoint/Baringa has developed to simulate the forthcoming GB capacity market. IRAT is an Excel-based interconnection portfolio assessment tool that has been enhanced for the purposes of this study.

In general, the interconnectors considered here appear commercially attractive on the basis of price arbitrage under most scenarios and for most interconnectors. This is mainly due to the premium that exists between GB prices and Continental prices in the early years of their operation (until mid-to-late 2020s). In the later years, when average price differentials between GB and Continental Europe have been reduced under all scenarios, an increasing proportion of interconnector value is driven by price volatility due to significant wind penetration in the GB market. This has been observed under all scenarios with the exception of Scenario 3 where GB wind penetration is assumed to be low as decarbonisation in the longer term is achieved mainly through CCS technologies.

Under the range of scenarios considered in this study, interconnectors to France and Belgium are projected to earn annual revenues in the range from £60/kW to £160/kW excluding capacity payments. If capacity payments are accessible to interconnector owners, the corresponding range is from £80/kW to £190/kW. The lower end of the range corresponds to Scenario 3, in which commodity prices are generally low and flat across Europe. The upper end of the range corresponds to Scenario 1, in which fossil fuel prices are at central levels and crucially the GB carbon floor price follows the current proposed trajectory to 2030.

The 1GW interconnector to Norway exhibits a revenue range of around £50/kW to £150/kW per annum in the absence of capacity payments, and £75/kW to £185/kW with capacity payments. Thus overall revenue is broadly similar but with a slightly higher dependence on the GB CM. The revenues for this interconnector are high relative to French interconnectors in Scenario 2, which has high fossil fuel prices and a high degree of intermittency, but low relative to French interconnectors in Scenario 3, which has low fuel and power prices.

The 500MW interconnector to Ireland exhibits the greatest upside potential: the bottom of the range of revenues is again around £60/kW but the top of the range (in Scenario 2) is as high as £220/kW per annum. There appears to be considerable upside for this link if prices in GB and Ireland are high and volatile, with significant levels of income in both directions of flow. Note that this finding is dependent on significant wind penetration in the two countries over the next decade.

A further finding is that the level of income for FRA1, FRA2 and FRA3 is similar. The revenue cannibalisation that would be incurred from the development of 3GW rather than 1GW to France is smaller than the variation in revenues from year to year. A more significant issue is therefore one of timing: later developments would be adversely affected by convergence of power prices that might occur from carbon price convergence between GB and the EU, as analysed in Scenario 4.

It is worth stressing that the range of projected wholesale electricity prices and interconnection revenues in the four scenarios described in this report does not reflect the full range of potential uncertainty in the market. Rather, projections in this study are intended to be representative of the long term trends in the GB market according to current DECC/Redpoint views with regards to fossil

fuel and carbon prices, electricity demand projections and views on the GB generation capacity mix.

A Appendix - Scenario Framework

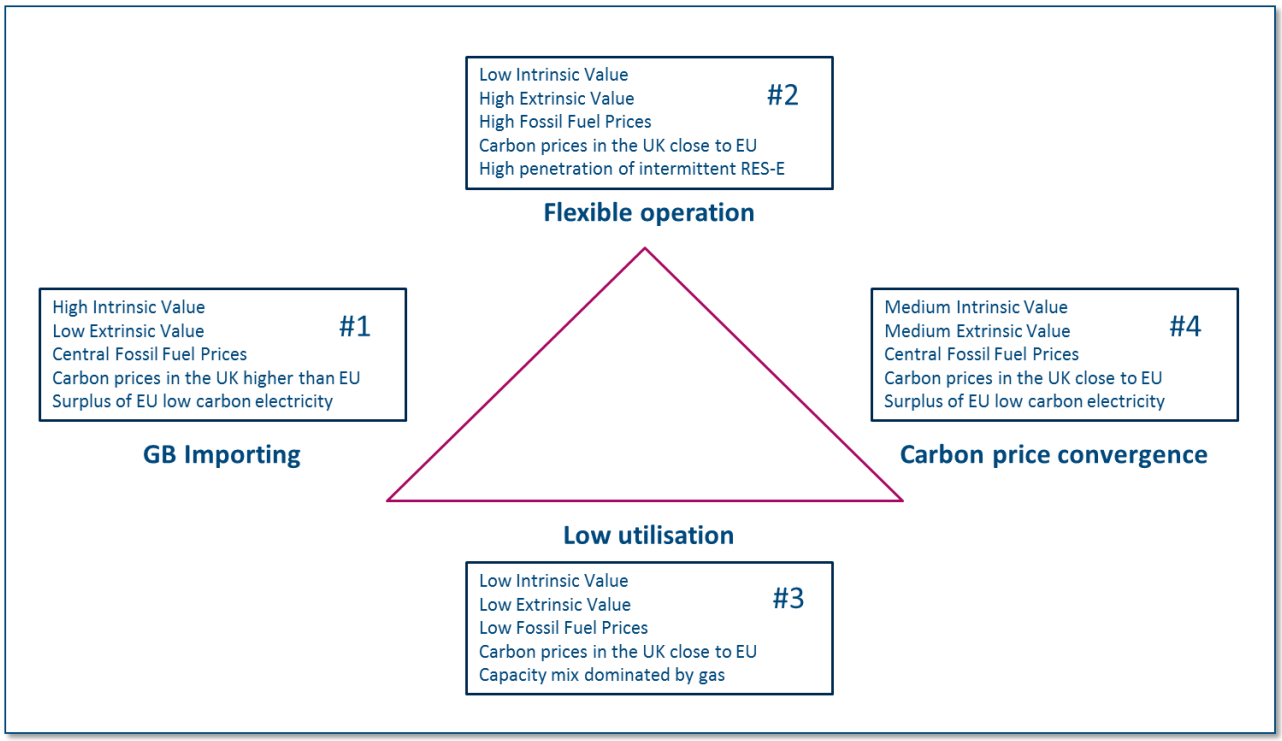
In the original analysis we carried out for DECC we considered the main drivers that are likely to have the most significant impact on the timing, location and volume of interconnection between GB and neighbouring markets. These were identified as:

1. Gas prices;
2. Carbon prices (and in particular the difference between carbon prices in GB versus Continental Europe, for example due to the Carbon Price Floor policy);
3. HVDC (High Voltage Direct Current) cable cost;
4. Renewable technology costs; and
5. EU commitment to renewables targets by 2020 and beyond.

In addition to those factors, other important drivers must also be taken into account such as overall electricity demand levels and the shape of demand (particularly as demand side response is deployed), developments in electricity storage technologies, internal grid and network reinforcements and balancing arrangements across Europe (and the possibility of sharing reserve for example), among others.

Figure 18 shows the four scenarios modelled for the purposes of this study.

Figure 18 Scenario framework



1. GB importing – this is a scenario where interconnectors are utilised mostly to transfer lower cost electricity from Continental Europe to GB[29]. This is likely to materialise in a world with moderate gas prices, where generators face significantly higher carbon prices in GB compared to Europe, and where it is possible to import through interconnection surplus low carbon electricity (particularly from renewable energy sources) from the Continent.
2. Flexible operation – this is a scenario where significant amounts of flexibility are required, with higher intermittency across European power markets than that seen under the GB importing scenario increasing the extrinsic value of interconnectors[30]. This is likely to materialise in a world where very significant amounts of intermittent renewable technologies (particularly onshore and offshore wind) are deployed across Europe, partly due to high fossil fuel prices incentivising their advanced deployment. This scenario also assumes that in the longer term generators in GB face broadly similar carbon prices as in Continental Europe.
3. Low utilisation – this is a more challenging scenario for developing interconnectors since electricity price differences across European markets remain low due to persistently low fossil fuel prices. This scenario also assumes that in the longer term generators in GB face broadly similar carbon prices as in Continental Europe and that, whilst unabated gas plant dominate in the short- to medium- term, there is an increased role for gas CCS (Carbon Capture and Storage) and coal CCS in the longer term due to low fossil fuel prices and relatively slow progress in offshore wind.
4. Carbon price convergence – this scenario uses the same fundamental assumptions as Scenario 1 (i.e. moderate fossil fuel prices coupled with a relatively balanced, albeit renewables favouring, generation mix in the UK and Continental Europe), however it is now assumed that EUA carbon prices rise very strongly in the 2020s and gradually converge with carbon prices in GB (which are dictated by the CPS policy).

[29] Note that this does not imply that interconnectors would be importing power to GB 100% of the time, merely that there would be a strong tendency for imports into GB to dominate export from GB.

[30] An electricity interconnector is said to have high intrinsic value when a large differential in average prices exists between the two connected markets. Conversely, an electricity interconnector is said to have high extrinsic value when, even though the difference in average prices may be small, significant random hourly price variation exists between the two connected markets.

The key assumptions that were used to model these scenarios are described in more detail below.

1. GB Importing

Overview
A scenario where GB becomes a net importer of electricity over the modelling horizon. This is likely to materialise in a world with moderate gas prices, where generators in GB face significantly higher carbon prices compared to Europe (for example due to the Carbon Price Support policy), and where it is possible to import surplus low carbon electricity (or renewable electricity more specifically) from the Continent. This scenario assumes that decarbonisation of GB power sector is achieved, but the Government does not consider domestic action to be of paramount importance. There is central electricity demand growth, coupled with central electrification of the heat and transport sector and central progress on DSR.

Gas prices	Commodity prices	Carbon prices	GB capacity mix	EU capacity mix	Electricity demand
DECC Central	DECC Central	DECC Central	Balanced	Renewables-favouring	Central (with Central DSR)

Likely overall level of interconnection	Central to High
GB capacity mix	Significant contribution by nuclear (19 GW by 2035) and renewables (and wind more specifically - 37 GW by 2035), the remainder largely based on unabated gas and some gas CCS (8.5 GW) towards the later years of the modelling horizon.
EU capacity mix	Decarbonisation is achieved in line with each country's specific targets. Nuclear and CCS (towards the later years) both play an important role towards decarbonisation for some countries, however new build investments are largely dominated by renewables, particularly onshore wind and solar PV.
Electricity demand	Central demand growth with central GDP growth and central progress in the electrification of the heat and transport sector. There is also some impetus for the Government to encourage DSR uptake which is also assumed to occur according to central projections.

2. Flexible operation

Overview
A scenario where significant amounts of flexibility are required, with high intermittency across Europe increasing the extrinsic value of interconnectors. This is likely to materialise in a world with high gas prices and where significant amounts of intermittent renewable technologies (particularly wind) are deployed across Europe. This is also compatible with a world where significant renewable technology cost reductions are realised, particularly for offshore wind. The Carbon Price Floor policy is maintained in GB. Similarly, other European countries are equally ambitious in pursuing renewable new build, although they achieve their goals without the use of a carbon price floor. There is central view electricity demand growth with central view progress in the electrification of the heat and transport sector. DSR uptake, however, is high in order to provide some of the required flexibility associated with high wind penetration.

Gas prices	Commodity prices	Carbon prices	GB capacity mix	EU capacity mix	Electricity demand
DECC High	DECC High	Redpoint Central	Wind-favouring	Wind-favouring	Central (with High DSR)

Likely overall level of interconnection	Central to High
GB capacity mix	Very strong contribution by onshore and offshore wind (52 GW by 2035) at the expense of gas CCS whose development is limited due to persistently high gas prices. There is also considerable contribution by nuclear (19 GW by 2035), with the remaining capacity largely provided by unabated gas, other renewables and some gas CCS (1.4 GW) towards the later years of the modelling horizon.
EU capacity mix	Power sector decarbonisation in other European countries is achieved in line with each country's specific targets. Compared to Scenario 1, there is now an even greater penetration of wind (particularly offshore) at the expense mainly of CCS. The contribution of nuclear remains unaffected due to high gas prices, with nuclear playing an important role to the path towards decarbonisation for some EU countries.
Electricity demand	Central demand growth due to central GDP growth and central progress in the electrification of the heat and transport sector. There is now a high uptake of DSR in the residential and commercial sectors in order to provide some of the flexibility required by the introduction of such large quantities of wind power.

3. Low Utilisation

Overview
A challenging scenario for developing interconnectors since electricity price differences across European markets remain low (thereby reducing interconnector intrinsic value) due to persistently low fossil fuel prices. This scenario also assumes that generators in GB face broadly similar carbon prices as in Continental Europe, with the UK Government committed to meet its 2020 targets. In the longer term, the Government's renewable ambitions are somewhat curtailed as renewable technologies are not proven as cost-competitive as unabated gas and CCS. This scenario assumes central view demand growth and central view progress in the electrification of the heat and transport sector, coupled with central DSR uptake.

Gas prices	Commodity prices	Carbon prices	GB capacity mix	EU capacity mix	Electricity demand
DECC Low	DECC Low	Redpoint Central	Gas-favouring	Gas-favouring	Central (with Central DSR)

Likely overall level of interconnection	Low
GB capacity mix	In the medium term (up to 2025), new build investments are similar to Scenario 1 and are largely dominated by unabated CCGT, onshore and offshore wind and solar PV. In the longer term, however, persistently low gas prices mean that decarbonisation is now achieved largely through gas CCS (12.7 GW by 2035) and coal CCS (4.5 GW) at the expense of wind (25 GW by 2035) and nuclear (16 GW by 2035). Lower wind penetration also means that less OCGT capacity is required as back-up capacity in order to ensure that security of supply is maintained at desired levels.
EU capacity mix	A similar story can be drawn for the capacity mix of the other European countries we have modelled. Low gas prices result in considerably higher deployment of unabated gas in the short-to-medium term, while decarbonisation in the long term is achieved through greater CCS deployment at the expense of nuclear, wind (particularly offshore) and solar PV.
Electricity demand	Central demand growth due to central GDP growth coupled with central progress in the electrification of the heat and transport sector. DSR uptake in the residential and commercial sector is also assumed to take place according to central projections.

4. Carbon price convergence

This scenario uses the same fundamental assumptions as Scenario 1 (i.e. moderate fossil fuel prices coupled with a relatively balanced, albeit renewables favouring, generation mix in the UK and Continental Europe) however it is now assumed that in the longer term generators in GB face broadly similar carbon prices as in Continental Europe due to strong growth in EUA carbon prices in the 2020s. Assumptions on carbon prices are set out in detail in the following Section.

B Appendix – Fossil Fuel and Carbon Prices

Table 6 Brent crude assumptions

Calendar year	Brent crude prices ($/bbl, real 2013)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2013	110.0	125.0	95.0	110.0
2014	111.3	128.3	93.7	111.3
2015	112.7	131.7	92.4	112.7
2016	114.0	135.2	91.1	114.0
2017	115.4	138.8	89.9	115.4
2018	116.8	142.5	88.6	116.8
2019	118.2	146.2	87.4	118.2
2020	119.7	150.1	86.2	119.7
2021	121.1	154.1	85.0	121.1
2022	122.6	158.2	83.8	122.6
2023	124.1	162.4	82.7	124.1
2024	125.6	166.7	81.5	125.6
2025	127.1	171.1	80.4	127.1
2026	128.6	175.6	79.3	128.6
2027	130.2	180.3	78.2	130.2
2028	131.8	185.1	77.1	131.8
2029	133.4	190.0	76.1	133.4
2030	135.0	195.0	75.0	135.0
2031	135.0	195.0	75.0	135.0
2032	135.0	195.0	75.0	135.0
2033	135.0	195.0	75.0	135.0
2034	135.0	195.0	75.0	135.0
2035	135.0	195.0	75.0	135.0

Table 7 ARA coal assumptions

Calendar year	ARA coal prices ($/t, real 2013)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2013	91.4	96.0	86.8	91.4
2014	97.6	107.4	87.7	97.6
2015	103.9	112.7	88.5	103.9
2016	107.7	118.0	89.4	107.7
2017	111.5	123.3	90.2	111.5
2018	115.3	128.6	91.1	115.3
2019	119.1	133.9	91.9	119.1
2020	122.9	139.2	92.8	122.9
2021	122.9	144.6	92.8	122.9
2022	122.9	149.9	92.8	122.9
2023	122.9	155.2	92.8	122.9
2024	122.9	160.5	92.8	122.9
2025	122.9	165.8	92.8	122.9
2026	122.9	165.8	92.8	122.9
2027	122.9	165.8	92.8	122.9
2028	122.9	165.8	92.8	122.9
2029	122.9	165.8	92.8	122.9
2030	122.9	165.8	92.8	122.9
2031	122.9	165.8	92.8	122.9
2032	122.9	165.8	92.8	122.9
2033	122.9	165.8	92.8	122.9
2034	122.9	165.8	92.8	122.9
2035	122.9	165.8	92.8	122.9

Table 8 NBP gas assumptions

Calendar year	NBP gas prices (p/th, real 2013)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2013	63.6	73.2	54.1	63.6
2014	66.7	88.2	51.7	66.7
2015	69.7	90.6	49.3	69.7
2016	70.6	93.0	46.9	70.6
2017	72.2	95.4	44.6	72.2
2018	73.8	97.9	42.2	73.8
2019	73.8	100.5	42.2	73.8
2020	73.8	103.2	42.2	73.8
2021	73.8	105.4	42.2	73.8
2022	73.8	105.4	42.2	73.8
2023	73.8	105.4	42.2	73.8
2024	73.8	105.4	42.2	73.8
2025	73.8	105.4	42.2	73.8
2026	73.8	105.4	42.2	73.8
2027	73.8	105.4	42.2	73.8
2028	73.8	105.4	42.2	73.8
2029	73.8	105.4	42.2	73.8
2030	73.8	105.4	42.2	73.8
2031	73.8	105.4	42.2	73.8
2032	73.8	105.4	42.2	73.8
2033	73.8	105.4	42.2	73.8
2034	73.8	105.4	42.2	73.8
2035	73.8	105.4	42.2	73.8

Table 9 EUA carbon assumptions

Calendar year	EUA carbon prices (£/t, real 2013)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2013	3.5	3.5	3.5	3.5
2014	3.6	4.1	4.1	3.6
2015	3.7	4.5	4.5	3.7
2016	3.8	6.9	6.9	3.8
2017	3.9	9.2	9.2	3.9
2018	4.2	11.6	11.6	4.2
2019	4.5	14.0	14.0	4.5
2020	4.9	16.3	16.3	4.9
2021	5.0	18.7	18.7	12.0
2022	5.1	21.0	21.0	19.1
2023	5.2	23.4	23.4	26.3
2024	5.4	25.8	25.8	33.4
2025	5.5	28.1	28.1	40.5
2026	5.7	30.5	30.5	47.7
2027	5.8	32.8	32.8	54.8
2028	5.9	35.2	35.2	62.0
2029	6.1	37.6	37.6	69.1
2030	6.3	39.0	39.0	76.2
2031	6.4	39.0	39.0	76.2
2032	6.6	39.0	39.0	76.2
2033	6.7	39.0	39.0	76.2
2034	6.8	39.0	39.0	76.2
2035	7.0	39.0	39.0	76.2

Table 10 Carbon Price Floor assumptions

Calendar year	Carbon Price Floor assumptions (£/t, real 2013)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2013	7.2	7.2	7.2	7.2
2014	11.8	11.8	11.8	11.8
2015	19.0	19.0	19.0	19.0
2016	23.1	23.1	23.1	23.1
2017	26.0	26.0	26.0	26.0
2018	28.2	28.2	28.2	28.2
2019	30.5	30.5	30.5	30.5
2020	32.7	32.7	32.7	32.7
2021	37.0	32.7	32.7	37.0
2022	41.4	32.7	32.7	41.4
2023	45.7	32.7	32.7	45.7
2024	50.1	32.7	32.7	50.1
2025	54.4	32.7	32.7	54.4
2026	58.8	32.7	32.7	58.8
2027	63.2	32.7	32.7	63.2
2028	67.5	32.7	32.7	67.5
2029	71.9	32.7	32.7	71.9
2030	76.2	32.7	32.7	76.2
2031	76.2	32.7	32.7	76.2
2032	76.2	32.7	32.7	76.2
2033	76.2	32.7	32.7	76.2
2034	76.2	32.7	32.7	76.2
2035	76.2	32.7	32.7	76.2

Table 11 Carbon Price Support assumptions

Calendar year	Carbon Price Support assumptions (£/t, real 2013)			
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
2013	3.7	3.7	3.7	3.7
2014	8.2	7.7	7.7	8.2
2015	15.4	14.5	14.5	15.4
2016	19.3	16.2	16.2	19.3
2017	22.1	16.8	16.8	22.1
2018	24.0	16.6	16.6	24.0
2019	25.9	16.5	16.5	25.9
2020	27.8	16.3	16.3	27.8
2021	32.0	14.0	14.0	25.0
2022	36.3	11.6	11.6	22.2
2023	40.5	9.3	9.3	19.5
2024	44.7	6.9	6.9	16.7
2025	48.9	4.5	4.5	13.9
2026	53.2	2.2	2.2	11.1
2027	57.4	0.0	0.0	8.3
2028	61.6	0.0	0.0	5.6
2029	65.8	0.0	0.0	2.8
2030	70.0	0.0	0.0	0.0
2031	69.8	0.0	0.0	0.0
2032	69.7	0.0	0.0	0.0
2033	69.5	0.0	0.0	0.0
2034	69.4	0.0	0.0	0.0
2035	69.2	0.0	0.0	0.0

C Appendix – GB Capacity Mix

The GB installed generation capacity mix for Scenario 1 is taken from the "Draft Delivery Plan - 32% Renewables Core Scenario" (as of June 2013). Our view is that the OCGT capacity in the Draft Delivery Plan is excessive (33.4 GW by 2035) relative to the CCGT capacity (18.1 GW by 2035) and thus for the modelling described in this report we replaced some of the OCGT capacity with CCGTs: 2 GW by 2025, 5 GW by 2030 and 6 GW by 2035. This ensures that throughout the modelling horizon CCGT capacity remains roughly comparable to current levels. The resultant GB installed generation capacity mix for Scenario 1 is shown in Table 12 below.

Table 12 GB installed generation capacity – Scenario 1

GW	2015	2020	2025	2030	2035
CCGT	28.0	27.2	31.3	27.3	24.1
Coal unabated	15.8	12.7	5.4	-	-
Gas CCS	-	0.3	1.1	5.0	8.5
Coal CCS	-	0.3	0.3	0.3	0.3
Nuclear	9.1	10.7	8.1	13.6	19.4
Onshore Wind	7.9	10.4	12.2	13.5	14.7
Offshore Wind	4.2	8.0	13.6	18.1	22.7
Biomass	3.3	3.1	3.0	2.4	0.3
Marine	0.0	0.1	0.4	0.9	1.1
Hydro	1.7	1.9	1.9	2.0	2.0
Pumped Storage	2.8	2.8	2.8	2.8	2.8
OCGT	0.9	0.7	9.8	17.8	27.4
Oil Fired	1.2	-	-	-	-
AutoGeneration	5.0	6.7	6.7	6.7	3.4
Large Solar	0.8	2.4	3.2	3.2	3.2
Other RES (large)	2.4	3.1	3.8	4.5	5.2
Other RES (small)	5.2	8.0	9.9	10.6	10.6

In Scenario 2 (and compared to the capacity mix for Scenario 1) we have replaced roughly 7 GW of gas CCS with an additional 15 GW of offshore wind by 2035. Since peak demand in Scenario 2 is assumed to be lower compared to the other two scenarios on account of additional DSR uptake (peak demand in 2035 for example is assumed to be 71.7 GW compared to 79.7 GW under Scenarios 1 and 3), there is also reduced OCGT capacity (4.8 GW less by 2035). The other generation technologies are assumed to have the same values as under Scenario 1. The resultant GB installed generation capacity mix for Scenario 2 is shown in Table 13 below.

Table 13 GB installed generation capacity – Scenario 2

GW	2015	2020	2025	2030	2035
CCGT	28.0	27.2	31.3	27.3	24.1
Coal unabated	15.8	12.7	5.4	-	-
Gas CCS	-	0.3	0.8	1.4	1.4
Coal CCS	-	0.3	0.3	0.3	0.3
Nuclear	9.1	10.7	8.1	13.6	19.4
Onshore Wind	7.9	10.4	12.2	13.5	14.7
Offshore Wind	4.2	10.7	21.1	29.4	37.7
Biomass	3.3	3.1	3.0	2.4	0.3
Marine	0.0	0.1	0.4	0.9	1.1
Hydro	1.7	1.9	1.9	2.0	2.0
Pumped Storage	2.8	2.8	2.8	2.8	2.8
OCGT	0.9	0.7	8.2	14.6	22.6
Oil Fired	1.2	-	-	-	-
AutoGeneration	5.0	6.7	6.7	6.7	3.4
Large Solar	0.8	2.4	3.2	3.2	3.2
Other RES (large)	2.4	3.1	3.8	4.5	5.2
Other RES (small)	5.2	8.0	9.9	10.6	10.6

Finally, in Scenario 3 low fossil fuel prices mean that some nuclear and renewable capacity is now replaced by gas CCS and coal CCS. By 2035 (and compared to the capacity mix for Scenario 1) we have replaced 3.2 GW of nuclear, 8 GW of small-scale solar PV, 12 GW of offshore wind and 2 GW of peaking OCGT capacity with 4.2 GW of coal CCS and 4.2 GW of gas CCS. The other generation technologies are assumed to have the same values as under Scenario 1. The resultant GB installed generation capacity mix for Scenario 2 is shown in Table 14 below.

Table 14 GB installed generation capacity – Scenario 3

GW	2015	2020	2025	2030	2035
CCGT	28.0	27.2	31.3	27.3	24.1
Coal unabated	15.8	12.7	5.4	-	-
Gas CCS	-	0.3	1.1	6.2	12.7
Coal CCS	-	0.3	0.3	1.5	4.5
Nuclear	9.1	10.7	8.1	13.6	16.2
Onshore Wind	7.9	10.4	12.2	13.5	14.7
Offshore Wind	4.2	8.0	9.5	9.9	10.3
Biomass	3.3	3.1	3.0	2.4	0.3
Marine	0.0	0.1	0.4	0.9	1.1
Hydro	1.7	1.9	1.9	2.0	2.0
Pumped Storage	2.8	2.8	2.8	2.8	2.8
OCGT	0.9	0.7	9.8	16.8	25.4
Oil Fired	1.2	-	-	-	-
AutoGeneration	5.0	6.7	6.7	6.7	3.4
Large Solar	0.8	2.4	3.2	3.2	3.2
Other RES (large)	2.4	3.1	3.8	4.5	5.2
Other RES (small)	3.0	3.0	3.0	3.0	2.6

D Appendix – Capacity Market Assumptions

The cost and revenue assumptions for the key generation technologies participating in the CM are shown in the following two Tables.

Table 15 Cost assumptions for the key generation technologies participating in the CM

Cost assumptions (£/kW)	Existing Coal	Existing CCGT	New CCGT	New OCGT
Risk premium for participating in the CM	£5/kW	£5/kW	£5/kW	£5/kW
TNUoS costs	Depending on plant location	Depending on plant location	£5/kW	£3.5/kW
Annual Operations and Maintenance (O&M) costs	£37.5/kW	£23.2/kW	£23.2/kW	£10.8/kW
Annuitised capital costs	-	-	£65.0/kW	£32.7/kW

Table 16 Revenue assumptions for the key generation technologies participating in the CM

Revenue assumptions (£/kW)	Existing Coal	Existing CCGT	New CCGT	New OCGT
Ancillary services revenues	£5/kW	£10/kW	£10/kW	£15/kW
Electricity market revenues (including revenues from operating during VoLL periods)	As informed by PLEXOS	As informed by PLEXOS	As informed by PLEXOS	As informed by PLEXOS

Furthermore, we have also assumed a maximum annual build rate of 2.26 GW for new OCGTs in line with the “Draft Delivery Plan - 32% Renewables Core Scenario” (as of June 2013).

E Appendix – Negative Pricing Periods

A topic currently attracting interest amongst energy policy makers are periods of negative prices during intervals when curtailment of renewable generators (mainly wind and solar) or other inflexible generation technologies occurs. The European Commission recently reported that "*on a Sunday afternoon in mid-June wind and solar assured more than 60% of power generation in Germany, resulting in negative hourly prices in the whole CWE region*" [31]. With the anticipated increase in intermittent renewable technologies across European markets this phenomenon is expected to be more pronounced in the future unless system flexibility also increases[32].

In our analysis we have assumed that negative prices are observed in European markets during periods when supported low carbon generation technologies are "at the margin" (i.e. setting the clearing price in a country's respective wholesale electricity market). This is based on recent observations as explained in the paragraph above and we have therefore implicitly assumed that there is no shift in policy to prevent negative pricing periods from occurring.

Table 17 shows the frequency of negative pricing periods observed in our model for year 2035 under the "All In" interconnection configuration. For the GB market negative pricing periods are infrequent for all scenarios with the exception of Scenario 2 which assumes very high wind penetration (particularly offshore). Belgium and France are both well interconnected markets whilst Norway, in addition to relatively high interconnection also contains very significant energy storage capacity (in the form of large hydropower plant). As a result, these markets rarely experience negative pricing periods, even under Scenario 2. Finally, for Ireland, very high wind penetration coupled with low overall interconnection and hydro levels lead to frequent negative pricing periods for all scenarios with the exception of Scenario 3.

Table 17 Frequency of negative prices (2035) – "All In" Configuration

Frequency of negative prices (%)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Great Britain	2.1%	11.9%	0.0%	2.1%
Belgium	0.4%	2.5%	0.0%	0.4%
France	0.5%	2.5%	0.0%	0.5%
Norway	0.0%	0.5%	0.0%	0.0%
Single Electricity Market	10.9%	14.4%	3.5%	10.9%

As previously mentioned, electricity interconnectors are an important source of system flexibility. Table 18 shows the frequency of negative pricing periods observed in our model for year 2035 under the Base interconnection configuration (which does not include FRA2, FRA3 and IRL). It is

[31] European Commission: Quarterly report on European electricity markets – Volume 6, Issue 2, Second Quarter 2013. Available at: http://ec.europa.eu/energy/observatory/electricity/doc/20130814_q2_quarterly_report_on_european_electricity_markets.pdf

[32] In addition to electricity interconnection, other flexible technologies could include hydro pumped storage and other energy storage technologies, demand side response technologies, and flexible power generation technologies such as OCGTs.

interesting to note that the frequency of negative pricing periods in GB has now increased as less interconnection capacity (3.3 GW less) is available for exporting wind generation during high GB wind periods. Similarly, the frequency of negative pricing periods in SEM has also increased.

As shown in Table 19, the "All Out" interconnection configuration results in the most frequent negative pricing periods in the GB market. Compared to the "All In" interconnection configuration, for example, which contains a total of 6 GW of additional interconnection capacity, our modelling shows that the frequency of negative pricing periods in GB increases by almost 5% under Scenarios 1 and 4, and almost 10% under Scenario 2.

Table 18 Frequency of negative prices (2035) – "Base" configuration

Frequency of negative prices (%)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Great Britain	3.9%	15.8%	0.0%	3.8%
Belgium	0.4%	2.4%	0.0%	0.4%
France	0.4%	2.2%	0.0%	0.4%
Norway	0.0%	0.4%	0.0%	0.0%
Single Electricity Market	15.2%	16.9%	5.7%	15.0%

Table 19 Frequency of negative prices (2035) – "All Out" configuration

Frequency of negative prices (%)	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Great Britain	6.9%	21.7%	0.1%	6.9%
Belgium	0.2%	2.1%	0.0%	0.3%
France	0.3%	2.0%	0.0%	0.3%
Norway	0.0%	0.3%	0.0%	0.0%
Single Electricity Market	15.9%	17.7%	5.6%	15.8%

In summary, negative pricing periods can be a significant income source for electricity interconnectors provided that these periods are not well correlated between the connected markets. Additional interconnection has been shown here to reduce the frequency of negative prices, however for relatively inflexible markets proliferation of renewable technologies (particularly wind and solar) will still likely lead to periods when these technologies are "at the margin".

Furthermore, the modelling described in this report is based on the assumption that there is no shift in policy to prevent negative pricing periods from occurring. If this were to materialise (for example by introducing a common floor price of zero across European energy exchanges), interconnection electricity market revenues would be negatively affected.

F Appendix – Cannibalisation of Interconnector Revenues

As explained in Section 2.5, results presented in this study compare an outcome in which an additional GB interconnection project is developed with a counterfactual in which an equivalent CCGT capacity is developed instead of the interconnector, where equivalence is based on the expected de-rating factors of both the interconnector in question and the CCGT. As a result, the impact of the interconnector on GB power prices (as well as on revenues of already operational GB interconnectors) will be somewhat subdued compared to a situation where no market response is assumed.

Table 20 shows the change in the annual average revenues for the three Base interconnectors (FRA1, BEL and NOR) in the Base interconnection configuration (i.e. assuming that only these three interconnectors are developed) compared to the "All In" interconnection configuration where all 6 potential interconnectors considered here are assumed to be operational by 2022. The following conclusions can be drawn from this analysis:

1. For Scenario 1, where GB electricity interconnectors are used to import cheaper electricity from abroad, developing additional electricity interconnectors has been found to noticeably reduce revenues for interconnectors that are already assumed to be operational. The reduction is particularly noticeable in France (circa 10% of revenues), as the two additional links are both to France, but also the Belgian link revenues are reduced. There is a smaller impact on NOR.
2. A similar story is observed for Scenario 4, although interconnector revenue cannibalisation is now lower compared to Scenario 1 because by 2030 carbon prices in GB and Europe have converged and thus the cost-effectiveness of importing electricity from abroad compared to producing from CCGTs in GB is now reduced in the longer term. Building a CCGT has a similar impact on market prices. Revenue cannibalisation is greatest for FRA1 due to the fact that an additional two links to France are assumed to be developed in the "All In" configuration with a combined capacity of 2 GW, thus further converging prices between these two markets. For NOR, the impact of the extra links is actually less than the impact of the counterfactual CCGT capacity on NOR revenues.
3. For Scenarios 2 and 3 it is not clear cut whether developing additional electricity interconnectors will lead to greater interconnector revenue cannibalisation compared to developing an equivalent CCGT capacity. Whilst the FRA1 revenues fall slightly, the BEL revenues are static and the NOR revenues actually rise. This lack of pattern is because during the later years of the modelling horizon, when carbon prices between GB and Europe have converged, it is more cost-effective to generate electricity from CCGTs in GB compared to deploying interconnectors to import electricity from abroad.

Table 20 Average annual revenues based on electricity revenues only – "Base" versus "All In" Configuration

£/kW (pre-tax real)		Scenario 1	Scenario 2	Scenario 3	Scenario 4
FRA1 – Base		177	128	76	103
FRA1 – All In		159	126	72	96
BEL – Base		167	103	62	83
BEL – All In		154	106	61	82
NOR – Base		158	127	45	93
NOR – All In		153	136	48	96

Similar conclusions can be drawn when looking at results (Table 21) which include both wholesale electricity revenues as well as potential capacity market revenues. Note that we do not model the impact of interconnectors on CM clearing prices.

Table 21 Average annual revenues based on electricity revenues and GB CM revenues – "Base" versus "All In" Configuration

£/kW (pre-tax real)		Scenario 1	Scenario 2	Scenario 3	Scenario 4
FRA1 – Base		206	151	97	122
FRA1 – All In		188	149	93	116
BEL – Base		199	127	84	107
BEL – All In		186	130	83	106
NOR – Base		191	158	73	122
NOR – All In		185	167	75	125

The broad conclusion of this analysis is that, with the assumption of market response (building CCGT capacity in place of interconnector capacity), the mutual cannibalisation of further interconnectors is relatively modest and in some cases even negative. We have assumed that further interconnection would be to France, and for this reason FRA experiences some cannibalisation in all scenarios. The greatest level of cannibalisation is approximately 10% of revenues for FRA in Scenario 1, arising from an extra 2GW of interconnection to France.