IMPACT OF EMR ON INTERCONNECTION

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A report to Department of Energy and Climate Change

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TABLE OF CONTENTS

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SUMMARY

Objective of work

DECC has commissioned Pöyry to analyse the impact on the GB market and interconnection to surrounding countries as a result of some of the current proposed policy measures from the Electricity Market Reform and Cash-out Reform. To do this, we have run a series of different scenarios and sensitivities in the GB electricity market using our pan-European electricity model (Zephyr). These scenarios have been specified by DECC, with the aim of flexing three main input assumptions, which differ from scenario to scenario:

- the implementation of a Balancing Mechanism cash-out reform, simulated by ***removing*** an assumed existing implicit price cap of £500/MWh on the wholesale electricity price;
- the Capacity Payment Mechanism (CM); and
- the Interconnector Capacity (IC).

We have assessed these by undertaking scenarios plus sensitivities as agreed with DECC. Many key input and assumptions for our modelling have been provided or specified by DECC. Thus none of the scenarios or sensitivities represent a formal Pöyry view based entirely on Pöyry assumptions.

Approach to work

To develop the scenarios and sensitivities, we have used Zephyr, Pöyry's proprietary electricity dispatch model. The Zephyr power model is a economic dispatch model based on optimisation of all power stations and renewables in Europe, allowing detailed investigation of the impact of wind and intermittent renewables, plant generation and profitability, wholesale market prices, emissions and interconnector usage and revenues.

Scenarios investigated

The six main scenarios that have been run are:

- **Baseline** – DECC central assumptions on fuel prices, demand, policy targets of meeting renewable targets by 2020 and achieving 100gCO_2/kWh[1] by 2030 with agreed capacities of NNB and CCS; BM cash-out reform leading to no cap on the wholesale price; no capacity market; expected interconnection capacity of 4 GW in 2030.
- **Scenario 1** – as Baseline but with wholesale price cap at £500/MWh to represent an unreformed cash-out mechanism.
- **Scenario 2** – as Baseline but with capacity market as proposed and defined by DECC.
- **Scenario 3** – as Scenario 1 but with capacity market as proposed and defined by DECC.
- **Scenario 4** – as Scenario 2 but with increased interconnection to c.10 GW in 2030.

[1] The emission intensity considered in this work, as defined by DECC, is calculated as the total power CO_2 emissions in GB divided by the demand in GB, both netted of the small scale gas Combined Heat and Power (CHP).

- **Scenario 5 –** as the Baseline but with increased interconnection to c.10 GW in 2030.

In addition, we have also run two sensitivities respectively on the Baseline and on Scenario 5. These sensitivities, as specified by DECC, are:

- **Sensitivity A** – sensitivity on Baseline with capacities of NNB and Carbon Capture and Storage (CCS) replaced by equivalent Combined Cycle Gas Turbine (CCGT). Sensitivity does not meet $100gCO_2/kWh$ by 2030.
- **Sensitivity B** – sensitivity on Scenario 5 with capacities of NNB and Carbon Capture and Storage (CCS) replaced by equivalent CCGT. Sensitivity does not meet $100gCO_2/kWh$ by 2030.

Conclusions from scenarios

Impact of nuclear new build and CCS Contract for Difference

By assumption, a CfD for NNB and CCS leads to more build of these technologies. As a result, the CfD for NNB and CCS leads to a reduction in the GB annual average wholesale price by around 2.2% (£1.7/MWh), due both to wider system margins and more low-priced periods when nuclear or wind sets prices.

The CfD has no significant impact on interconnector flows – causing a reduction in imports of the order of 0.4TWh or 1% of maximum. The CfD has a very small impact on Continental prices, causing a small drop of £0.2/MWh.

The CfD leads to lower GB prices and hence lower interconnector revenues – by around 9%. Throughout this analysis, we have assumed that interconnectors do not get paid capacity payments.

The impact of a BM cash-out reform (without CM)

In this work, we have assumed that the current market design in GB has an implicit price cap of around £500/MWh, as a result of the current design of the Balancing Mechanism and STOR contracts. Thus we have also assumed that cash-out reform would lead to this implicit price cap being removed.

In a market with no CM, removing the implicit price cap of £500/MWh leads to higher build of CCGTs and hence a less tight system and less load loss. In total there is about 2GW more plant on the system without a price cap by 2030. However, there is limited impact of prices as the increase in high priced periods (>£500/MWh) is compensated by a reduction in medium-priced periods (£100-500/MWh).

There is practically no impact on Continental or Irish prices, and interconnector flows are barely affected. There is a very limited impact on interconnector revenues, as both flows and prices are largely equal.

The impact of a BM cash-out reform (with CM)

The impact of capacity of removing the implicit price cap from of £500/MWh where a CM exists is the **reverse** of the situation without a CM. Removing the implicit price cap means that GB can rely more on imports at key periods as prices can spike, and so to fulfil the 10% capacity margin, less plant is required to be built and supported under the CM.

The removal of the implicit price cap causes GB prices rise by around £1/MWh as a result of the lower capacity on the system, with a negligible impact on Continental prices. However, the rise in wholesale prices is offset by a decrease in the CM – with the CM price decreasing about £9/kW. There is an almost-zero impact on interconnector revenues and flows.

The impact of a CM (with cash-out reform)

Implementing a CM leads to 4GW of additional gas turbines compared to a scenario without, with annual average wholesale prices in GB falling by £6/MWh as capacity margins are looser. There is a small decrease on Continental prices (<1%) with no significant impact on interconnector flows.

The large drop in GB prices causes interconnector revenues to fall by about 15% on average. As part of this analysis, we have assumed that interconnectors do not get paid capacity payments – the impact on revenues would probably be less if capacity market revenues were available to interconnectors.

The impact of a CM (without cash-out reform)

Assuming that cash-out reform does not take place and thus there remains an implicit wholesale price cap of £500/MWh, the impact of a CM is much greater than with cash-out reform. The CM causes 9GW of additional plant to be built as interconnectors cannot be relied upon due to the implicit price cap. The increase in capacity causes annual average wholesale prices to fall by £7/MWh. There is no significant impact on interconnector flows, which remain almost-baseloading. Interconnector revenues fall by almost 20% on average as a result of falling GB prices reducing price differentials.

The impact of increased interconnection (with CM)

By increasing interconnection by 6GW by 2030, about 3GW less firm capacity is required in GB. It also causes annual average wholesale prices to fall by up to 3% (£2/MWh) as high-cost British generation (due to the carbon price floor) is replaced by cheaper imports. Greater interconnection also increases annual average wholesale prices on the Continent, with Norwegian and Danish prices increasing by up to £4.5/MWh, and other countries by around £1/MWh.

Irrespective of the level of interconnection tested, the interconnectors operate close to baseload imports – the carbon price floor leads to such a large differential in wholesale prices that even a significant increase in interconnection is not sufficient to alleviate it. Interconnector revenues per kW are heavily affected by increasing the interconnection – France and Dutch interconnector revenues drop by as much as around 21%.

The overall capacity credit of the 10GW of interconnection is around 60%, varying from a low with SEM (23%) and France (44%) to a high with Norway (96%).

Key metrics

The following table gives key metrics of installed capacity, derated capacity margin, interconnector revenues, capacity credit, capacity payments and wholesale prices

Figure 1 – Key metrics for Baseline and scenarios 1-3

	No capacity market	Capacity market	No capacity market	Capacity market
No cash out reform (Implicit price cap)	Scenario 1	Scenario 3		
Cash out reform (No price cap)	Baseline	Scenario 2		
	Capacity installed in 2030 (GW)		Derated cap. in 2030, excl IC (%)	
No cash out reform (Implicit price cap)	108	117	-1.6%	8.8%
Cash out reform (No price cap)	110	114	0.5%	5.8%
	IC revenues 2022-2030 (£/kW/yr)		Capacity credit IC in 2030 (GW)	
No cash out reform (Implicit price cap)	180	137	2.1	0.3
Cash out reform (No price cap)	177	144	3.2	2.5
	Cap. payment 2022-2030 (£/kW/yr)		WP 2022-2030 (£/MWh)	
No cash out reform (Implicit price cap)	n.a.	50	75	71
Cash out reform (No price cap)	n.a.	42	75	72

Concluding comments

One of the more notable aspects of this interconnector analysis carried out for DECC is that the interconnectors are importing electricity to GB at almost-baseload levels. This results directly from the large differential in prices between GB and surrounding countries as a result of the carbon price floor being much higher in GB than the ETS price in other countries. This means that interconnector flows are barely affected by any policy or market changes – the difference in wholesale prices is so large that it becomes the dominant factor driving interconnector flows. In particular this affects interconnectors to Ireland, France, Belgium and Netherlands, as interconnectors to Iceland (and to a lesser extent Norway) would probably operate at near-baseload flows to GB, irrespective of the carbon price floor.

Baseloading interconnectors combined with high price differentials means that all interconnector new build considered in all scenarios is profitable – in some cases extremely profitable.

A future where GB and Continental carbon prices were much more closely aligned or equal would potentially lead to different results.

1. BACKGROUND TO PROJECT

1.1 Introduction

Pöyry Management Consulting has been commissioned by the Department of Energy and Climate Change (DECC) to determine the impact on the GB market, Continental prices, and interconnector flows from:

- a Capacity Market (CM);
- balancing mechanism (BM) cash out reform; and
- the Contract for Difference (CfD) for New Nuclear Build (NNB) in GB.

We have assessed these by undertaking scenarios plus sensitivities as agreed with DECC. Furthermore many key input and assumptions for our modelling have been provided or specified by DECC. Thus none of the scenarios plus sensitivities represent a formal Pöyry view based entirely on Pöyry assumptions.

1.2 Conventions

All monetary items in this report are expressed in pounds in real 2012 terms, unless otherwise stated. Annual data relates to the calendar year running from 1 January to 31 December of the indicated year, unless otherwise stated.

Where tables, figures, and charts are not specifically sourced they should be attributed to Pöyry Management Consulting.

1.2.1 Sources

The input data are based on:

- DECC input where specified in this report; and
- Pöyry data where specified in this report.

Where data is not specifically sourced it should be attributed to Pöyry Management Consulting.

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2. OVERVIEW OF METHODOLOGY

2.1 Introduction

To analyse the impact on the GB market of a CM and of the CfD for NNB we have run a series of different scenarios and sensitivities[2] in the GB electricity market using our pan-European electricity model Zephyr (see Section 2.2.1). These scenarios have been specified by DECC, with the aim of flexing three main input assumptions, which differ from scenario to scenario:

- the wholesale electricity price cap, to simulate a Balancing Mechanism cash-out reform;
- the Capacity Payment Mechanism (CM); and
- the Interconnector Capacity (IC).

The six main scenarios that have been run are:

- **Baseline** – DECC central assumptions on fuel prices, demand, policy targets of meeting renewable targets by 2020 and achieving 100gCO_2/kWh[3] by 2030 with agreed capacities of NNB and CCS; no cap on the wholesale price; no capacity market; expected interconnection capacity of 4 GW in 2030.
- **Scenario 1** – as Baseline but with wholesale price cap at £500/MWh to represent the current market set-up with an implicit price cap due to an unreformed cash-out mechanism.
- **Scenario 2** – as Baseline but with capacity market as proposed and defined by DECC.
- **Scenario 3** – as Scenario 1 but with capacity market as proposed and defined by DECC.
- **Scenario 4** – as Scenario 2 but with increased interconnection at 10 GW in 2030.
- **Scenario 5 –** as the Baseline but with increased interconnection at 10 GW in 2030.

Through the comparison of the outputs of the Baseline and the four scenarios, focusing in particular on the interconnection flows and the wholesale price in the UK as well as in the other European countries, we have drawn conclusions regarding the magnitude of the impact of a CM on the GB electricity market and the incentives to build the interconnections.

In addition, we have also run two sensitivities respectively on the Baseline and on Scenario 5. These sensitivities, as specified by DECC, are:

- **Sensitivity A** – sensitivity on Baseline with capacities of NNB and Carbon Capture and Storage (CCS) replaced by equivalent CCGT. Sensitivity does not meet 100gCO_2/kWh by 2030.

[2] The difference between a Scenario and a Sensitivity is that in the Scenario we make sure that the new plant build in the future can recover their fixed and variable costs, while in a Sensitivity we change some of the assumptions used in a Scenario and we look directly at the final results without eventually adjusting the location and the amount of the new capacity build in the future.

[3] The emission intensity considered in this work, as defined by DECC, is calculated as the total power CO_2 emissions in GB divided by the total power generation in GB, both netted of the small scale gas Combined Heat and Power (CHP).

- **Sensitivity B** – sensitivity on Scenario 5 with capacities of NNB and Carbon Capture and Storage (CCS) replaced by equivalent CCGT. Sensitivity does not meet 100gCO_2/kWh by 2030.

By comparing the Sensitivity A with the Baseline and Sensitivity B with Scenario 5, we have analysed the effect of the CfD for NNB on the internal market.

The scenarios and sensitivities are summarised in Figure 2.

Figure 2 – Summary of scenarios and sensitivities

	Emissions target gCO_2/kWh	**Cash-out reform/ implicit price cap**	**CM**	**IC by 2030**	**NNB and CCS CfD**
Baseline	100	Cash-out reform/ no cap	None	Low (4GW)	Yes
Sensitivity A	**None**	*As Baseline*			**None**
Scenario 1	100	**No reform/ implicit cap at £500/MWh**	None	Low (4GW)	Yes
Scenario 2	100	Cash-out reform/ no cap	**Yes**	Low (4GW)	Yes
Scenario 3	100	**No reform/ implicit cap at £500/MWh**	**Yes**	Low (4GW)	Yes
Scenario 4	100	Cash-out reform/ no cap	**Yes**	**High (10GW)**	Yes
Scenario 5	100	Cash-out reform/ no cap	None	**High (10GW)**	Yes
Sensitivity B	**None**	*As Scenario 5*			**None**

2.2 Approach to the work

To develop the scenarios and sensitivities, we have used Zephyr, Pöyry's proprietary electricity dispatch model. Our Zephyr model uses a linear program (continuous variables), is unique to Pöyry and enables us to model the wholesale electricity market across the all Europe.

2.2.1 The Zephyr model

Zephyr excels at quantifying and simulating markets with high levels of intermittent generation and flexibility: increasingly a prerequisite to accurately model contemporary European energy markets.

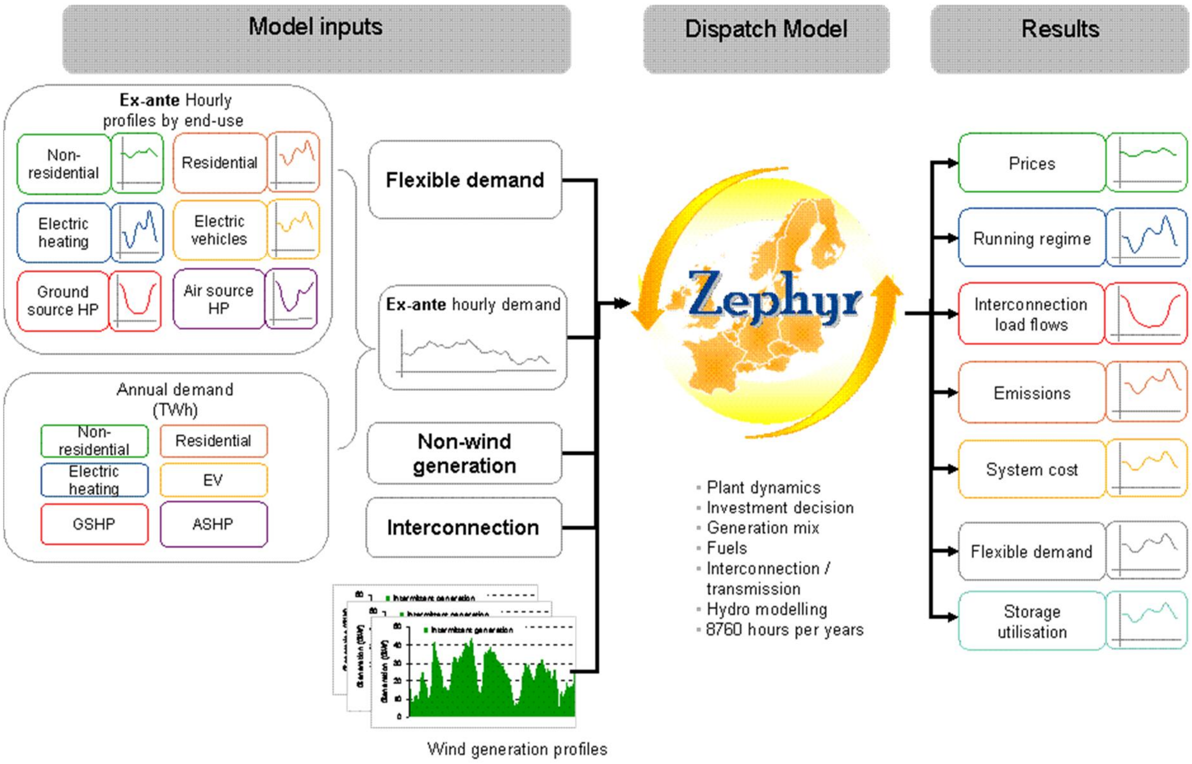
The Zephyr model also produces detailed output of power plant operation, from which we can calculate and compare the total variable costs of all the plant on the system in each model run of the work.

Benefits of Zephyr include:

- Modelling of every hour in the year – a total of 8,760 hours per year, across a range of historical weather years.
- Pan-European approach – this allows us to model the interaction of markets across Europe including interconnector behaviour simultaneously with GB market modelling.
- Historical weather year approach – the relationships between weather (determining e.g. wind, solar and hydro generation) and demand for electricity are complex and critical to accurate analysis. Zephyr uses consistent sets of (very detailed) historical data patterns for wind, solar irradiation, hydro inflows and demand.
- Historical data – to representatively model each single future year, we use historical weather patterns to capture a range of potential outcomes and better capture the capacity value of the interconnectors.
- Improved hydro modelling – a hydro module calculates the water values of hydro generation which are used in the Zephyr dispatch, based on weekly inflow profiles.

Figure 1 below provides an illustrated overview of Zephyr.

Figure 3 – Overview of Pöyry's Zephyr model



2.2.2 Model variables and settings

For the modelling of the scenarios and sensitivities, we agreed with DECC to run five historical years and six historical years. The historical years are 2006, 2007, 2008, 2009, 2010. The future years are 2018, 2020, 2022, 2024, 2027, 2030.

The variables used in the model can be categorized as "endogenous", "exogenous" or "mixed".

The "exogenous" variables are the inputs of the model; the main ones consist in:

- Fuel and carbon price projections;
- Electricity demand projections;
- Renewable technologies development (to 2020);
- Interconnector development projections; and
- Historical intermittent profiles for solar and wind and demand profiles.

The "endogenous" variables are the outputs of the model and are defined for each hour of the future year and each historical year. The main ones are:

- Wholesale price for each of the modelled market zone;
- Flows between the modelled zones through the interconnections; and
- Plants dispatch following a merit order criteria and complying with the constraint that the electricity demand must be met;

The "mixed" variable is the amount of new thermal capacity (and to a certain extent renewables post 2030) built in the future years and needed to meet the increase of the demand and to replace the retirement of the plants, as well as to achieve the emissions requirements by 2030. The process of running the model and dispatching the new thermal capacity is reiterated several times until we reach a self-consistent solution. In the Baseline (and high interconnection) we have allowed up to a couple of hours of load loss per year (averaged across historical years), though if plants are profitable at a lower level of load loss they are of course built. In the other scenarios the security standard is largely an output.

More details about the input assumptions are given in Section 3.

2.2.3 De-rated capacity margin

For the calculation of the de-rated capacity margin, used in the Scenarios with a Capacity Market (CM) in GB, we have applied a de-rating factor, by technology type, to the installed capacity. These de-rating factors, provided by DECC and by Pöyry, are shown in Figure 4.

The de-rated capacity margin has been calculated as (de-rated capacity minus peak demand) / de-rated capacity. In the de-rated capacity we have also considered a partial contribution from the interconnectors.

Figure 4 – De-rated factors for capacity margin calculation

Technologies	Derating factor	Provided by
BiomassConversion	87%	DECC
CCGT	87%	DECC
CCSCoal	87%	DECC
CCSGas	86%	DECC
CHP_Gas	59%	Pöyry
Coal	87%	DECC
GT	77%	DECC
Oil_steam	90%	DECC
Solar	0%	DECC
Onshore	22%	DECC
Offshore	22%	DECC
PumpedStorage	95%	Pöyry
RoR	42%	Pöyry
Biomass	87%	DECC
Geothermal	89%	Pöyry
Tidal	22%	DECC
Wave	22%	DECC
Nuclear	90%	DECC
Nuclear AGR newer	81%	DECC
Nuclear AGR older	67%	DECC
Demand side management	100%	Pöyry

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3. ASSUMPTIONS FOR MODELLING

3.1 Common assumptions

Annual commodity prices have been provided by DECC and are shown in Figure 5 for modelled years.

Figure 5 – Fuels price assumptions

	2018	2020	2022	2024	2027	2030
Coal (£/tonne)	74.0	74.8	74.8	74.8	74.8	74.8
Gas (p/therm)	71.9	71.9	71.9	71.9	71.9	71.9
Oil (£/tonne)	567.0	577.3	587.6	598.4	614.3	631.1
Biofuel (£/MWh)	24.3	24.3	24.3	24.3	24.3	24.3
Carbon (£/tonne)	7.6	8.6	9.2	9.9	11.0	12.3

The electricity demand projection is provided by DECC and is shown in Figure 6 for the modelled years.

Figure 6 – Demand projections[4]

	2018	2020	2022	2024	2027	2030
Demand (TWh)	311.6	309.8	317.4	324.4	343.7	363.9

The annual demand figures have been converted to hourly demand profiles using Pöyry data on historical demand in GB for the historical years 2006-2010. The Pöyry profiles are based on historical data published by National Grid, with adjustments for GDP growth and embedded generation.

Intermittent generation (onshore wind, offshore wind and solar) are modelled on an hourly basis using Pöyry wind and solar capacity factors. These are based on consistent weather patterns to the demand profiles, calculated using data on hourly wind speeds across GB and the Continent, converted to capacity factors using power curves.

DECC also provides the Carbon Price Support (CPS) floor which feeds in our modelling as a variable cost component to thermal plants in UK. The values used are shown in Figure 7 for the modelled years.

Figure 7 – CPS floor in GB

	2018	2020	2022	2024	2027	2030
CO2 price floor (£/tonne)	28.0	32.4	41.1	49.7	62.7	75.7

[4] There is a small difference between the starting point for the demand forecasts, with a discrepancy between the DECC and Pöyry numbers. It was not possible to confirm the source of this small difference, so within the modelling, we have used DECC demand growth rates rather than absolute demand forecasts.

Figure 8 – EU ETS price for the modelled years

	2018	2020	2022	2024	2027	2030
ETS CO2 price (£/tonne of CO2)	7.6	8.6	9.2	9.9	11.0	12.3

We also agreed with DECC to consider the following constraints in the modelling:

- The 2020 renewables target are met in 2020.
- An emission intensity[5] of 100gCO_2/kWh must be achieved by 2030. To achieve this target we have eventually increased the renewable installed capacity above the renewable target. Generation and emissions from small scale CHP will be excluded from the calculations.
- The Value of Loss Load (VoLL[6]) is set to £10,000/MWh.

We also model a CM in France, assuming a mechanism similar to that in GB, with a target of 10% capacity margin, including a partial contribution from interconnection. Any shortfalls in revenues for new entrants will be made up as a capacity payment. French plant will be assumed to bid in the same manner as German plant (i.e. despite an additional revenue stream from the capacity mechanism, they do not use this to reduce their bid prices).

In the Irish market, we assume that the SEM continues with some form of capacity payment. However, we will assume this does not feed into interconnector flows with GB (i.e. interconnector flows are driven by the SMP only in Ireland, but the SMP plus Scarcity Rent in GB). We assume short-run marginal cost bidding in the SEM with no bidding above SRMC to recover fixed costs, and thus the capacity payment will be broadly sufficient to ensure new entry is profitable and to cover the annual fixed costs of existing assets[7].

We have assumed that there are no capacity payments for interconnectors, or plant in Netherlands, Belgium, Germany or Nordpool.

Installed capacities in Figure 9 have been provided by DECC and are not changed in any scenario. Values are the same even for the sensitivities, apart from CCS and nuclear which are replaced by equivalent CCGT, as explained more in details in Section 4.1.1.

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[5] The emission intensity, as defined by DECC, is the overall emission of CO_2 divided by the total demand, both netted of small scale CHP.

[6] The VoLL is the price we apply to each unit of electricity demand which is not met by the electricity generation. A slightly higher figure than the £10,000/MWh has been used in the modelling to partially account for the fact that there will be slightly fewer hours of load loss with two hourly resolution as opposed to one (or indeed half hourly)

[7] As a result of an ongoing consultation, it is possible there will be much higher ancillary service payments in the SEM than currently, which may be very technology specific and hence affect new-build decisions. However we have not accounted for this as details are yet to be finalised.

Figure 9 – Installed capacity assumptions (fixed in all scenarios)

Installed capacity (GW)	2018	2020	2022	2024	2027	2030
Coal unabated	0.4	0.4	0.4	0.4	0.4	0.4
Gas CCS	0.4	0.4	0.4	0.4	0.4	0.4
Coal ASC CCS	0.0	0.0	0.0	0.0	0.0	0.0
Coal IGCC CCS	0.4	0.4	0.4	0.4	0.4	0.4
Nuclear	0.0	0.0	0.0	0.0	1.7	6.6
Large Biomass	0.0	0.0	0.0	0.0	0.0	0.0
Small Biomass	0.5	0.5	0.5	0.5	0.5	0.5
Tidal	0.1	0.2	0.2	0.2	0.2	0.2
Wave	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired	0.0	0.0	0.0	0.0	0.0	0.0
Biomass CHP	0.0	0.0	0.0	0.0	0.0	0.0
GT	0.0	0.0	0.0	0.0	0.0	0.0
BiomassConversion	1.5	1.5	1.5	1.5	1.5	1.5
Nuclear AGR newer	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear AGR older	0.0	0.0	0.0	0.0	0.0	0.0
Coal unabated - Drax	0.0	0.0	0.0	0.0	0.0	0.0
Biomass - Enhanced cofiring	3.2	3.2	3.2	3.2	3.2	3.2
Nuclear FOAK	0.0	1.7	1.7	3.3	3.3	3.3
Gas CCS FOAK	0.0	0.0	0.0	0.0	0.8	2.4
Coal ASC CCS FOAK	0.0	0.0	0.0	0.0	0.0	0.0
Coal IGCC CCS FOAK	0.0	0.0	0.0	0.0	0.0	0.0
Interconnectors	2.5	2.5	2.5	2.5	2.5	2.5
AutoGeneration	1.8	2.5	2.5	2.5	2.5	2.5
PumpedStorageAndHydro	0.1	0.2	0.2	0.2	0.2	0.2
Gas CCS (converted CCGT)	0.0	0.0	0.0	0.0	0.0	0.0

3.2 Specific assumptions by scenario and sensitivity

In this project we have run a Baseline case, five Scenarios and two Sensitivities. The assumptions, defined by DECC for each of them, are summarized in Figure 10.

Figure 10 – Assumptions used to model the different scenarios and sensitivities

	WP cap	CM	IC with GB in 2030
Baseline	No	No	~ 4 GW
Scenario 1	£500/MWh	No	~ 4 GW
Scenario 2	No	Yes	~ 4 GW
Scenario 3	£500/MWh	Yes	~ 4 GW
Scenario 4	No	Yes	~ 10 GW
Scenario 5	No	No	~ 10 GW
Sensitivity A	As Baseline but with capacities of NNB and CCS replaced by CCGT		
Sensitivity B	As Scenario 5 but with capacities of NNB and CCS replaced by CCGT		

3.2.1 Interconnector capacity

Figure 11 shows the values (for both directions) of the interconnector capacities in 2030 between GB and the surrounding market zones.

Figure 11 – Interconnector capacity in 2030 in Baseline, Scenario 1-3

Interconnector capacity in 2030 (MW)	Import in GBR	Export from GBR
Belgium	0	0
France	1988	1988
Netherlands	1000	1000
Northern Ireland	290	410
Norway	0	0
Republic of Ireland	450	450

Figure 12 summarizes the increase of 6 GW in the interconnector capacity in 2030 between Great Britain and the surrounding countries, as well as the commissioning year of the interconnector upgrade. Values have been proposed by Pöyry and agreed by DECC. For the interconnection between Great Britain and Iceland, we have modelled the interconnection as a fixed flow from Iceland to Great Britain, due to the lower electricity prices in Iceland.

Figure 12 – Interconnection capacity increase in 2030 in Scenario 4 and 5

Interconnection increase (MW)	Import in GBR	Export from GBR	Year of upgrade
Belgium	1000	1000	2018
Norway	1400	1400	2020
France	1000	1000	2020
Denmark	1000	1000	2021
France	1000	1000	2025
Iceland	600	0	2025

3.2.2 Capacity Payment Mechanism

The CM for GB is modelled in Scenario 2, Scenario 3 and Scenario 4.

The features of this CM, as defined by DECC, are:

- pay as clear auction;
- ten year contracts for new plant, one year for existing;
- auctions are four years ahead of delivery year;
- £300/kW price cap in auction;
- no reliability option: generators keep energy market revenue;
- CfD and Renewable Obligation (RO) plants excluded from CM; and
- reliability standard of 10% de rated capacity margin.

In the case of the CM modelling in GB, capacity will be built so as to enforce the 10% margin. In the wholesale energy market, we assume that plant do not bid only their short-run marginal costs – they bid up in the same way as in the Baseline scenario. Thus the mark up on short-run marginal cost (Scarcity Rent) is the same function of capacity margin as the Baseline. Within the capacity auction, we assume that plant bid their shortfall from the energy market – i.e. the difference between the annual required revenues and the annual fixed cost (for existing plant), or their new entry costs for new plant.

The resulting capacity payments are shown in Figure 13 below.

Figure 13 – Levels of Capacity Payment in the three capacity payment scenarios

£/kW/yr	Scenario 2 (CM)	Scenario 3 CM+PriceCap	Scenario 4 (HighIC+CM)
2022	41	45	41
2024	42	51	40
2027	44	52	42
2030	40	50	41

3.2.3 Installed capacity

The installed capacity of the technologies listed in Figure 14 have been provided by DECC as starting values in our modelling. These values have been amended by us during the modelling of the different scenarios. In particular:

- CCGT and Gas Turbine (GT) installed capacity have been amended so to make sure that the hours of Lost Load (LL) do not exceed two hours/year in the scenarios without CM or to ensure a capacity margin of 10% in the scenarios with CM.
- Installed capacity for wind and solar have been amended so to meet the renewable target in 2020 and achieve an emission intensity of 100gCO_2/kWh in 2030

Figure 14 – Installed capacity development, values amended in modelling

Installed capacity (GW)	2018	2020	2022	2024	2027	2030
CCGT	6.6	6.6	6.6	10.2	21.0	27.3
GT	0.0	0.0	0.0	0.0	0.0	1.5
Onshore	7.0	8.2	9.0	9.6	10.4	10.4
Offshore	7.5	10.2	12.4	13.6	13.8	13.8
Solar	8.7	11.4	11.4	11.4	11.4	11.4

The installed capacity of NNB and CCS is replaced by equivalent CCGT in both Sensitivity A and Sensitivity B. It will however only be added when it is required on capacity grounds – in effect t the 2018-20 nuclear and CCS will be replaced by CCGT in 2022 in Sensitivity A and 2023 in Sensitivity B, as will be explained more in detail in Section 4.1.1.

4. RESULTS

4.1 The impact of a nuclear new build and CCS CfD

The impact of a CfD for NNB and CCS has been examined by comparing the Baseline with the related Sensitivity A – examining a low interconnected world with CfDs (Baseline) with a world without the CfDs (Sensitivity A). We have also compared Scenario 5 (high interconnected world with a CfD) with the related Sensitivity B (no CfD).

In both the Baseline and Scenario 5 we have modelled a CfD mechanism which supports NNB and CCS technologies leading to greater build of these technologies, while in the two sensitivities we have modelled a market situation without CfD, by replacing the NNB and CCS with equivalent CCGT in terms of available capacity.

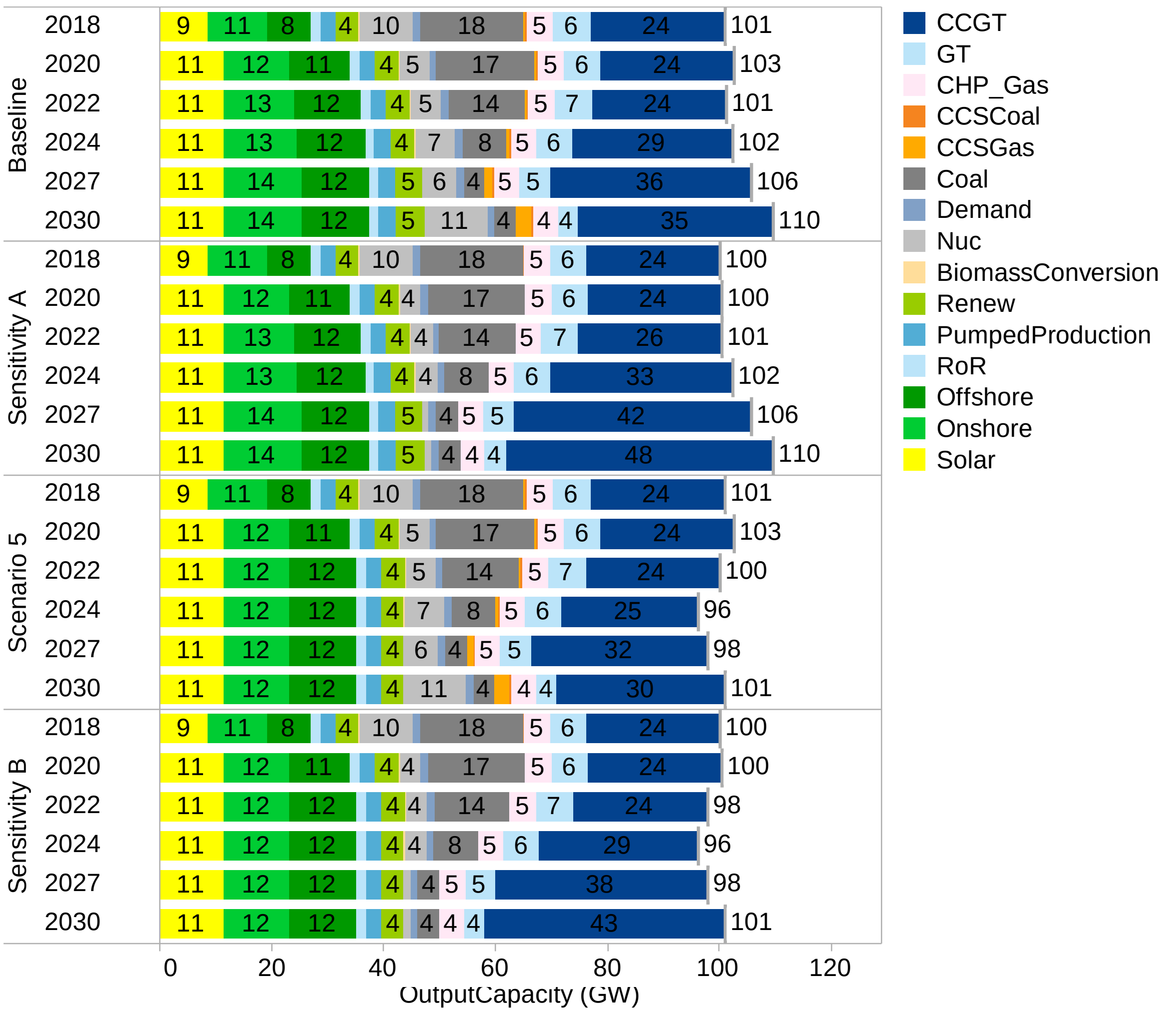
Summary 1 – Impact of a nuclear new build and CCS CfD

- Installed capacity
  - By assumption, a CfD for NNB and CCS leads to more build of these technologies.
- GB wholesale prices
  - The CfD for NNB and CCS leads to a reduction in the GB wholesale price by around 2.2% (£1.7/MWh), due both to wider system margins and more low-priced periods when nuclear or wind sets prices.
- Continental and Irish prices
  - GB prices are significantly higher than Continental prices by 2030 in all scenarios due to the carbon price floor.
  - The CfD causes a small drop of less than £0.2/MWh in Continental prices, although Irish prices slightly more affected with the CfD causing a drop of up to £0.44/MWh in 2020.
- Interconnector flows
  - Due to the carbon price floor, GB imports very heavily – practically baseload – across interconnectors, and this increases over time as the carbon price differential increases. Comparing the scenarios, the CfD has no significant impact on interconnector flows – causing a reduction in imports of the order of 0.4TWh in the low IC cases or 1TWh in the high interconnector cases (c.1% of maximum imports).
- Interconnector revenues
  - Interconnector revenues are driven largely by the differential in carbon prices between GB and the Continent. The CfD leads to lower GB prices and hence lower interconnector revenues – by as much as around 9%.
- Emissions intensity
  - Without a CfD for NNB and CCS, emissions intensity is higher, as a result of the replacement of zero-carbon nuclear and CCS with CCGTs.

4.1.1 Installed capacity

Figure 15 shows the installed capacity by technology type for the modelled years and for the Baseline, Sensitivity A, Scenario 5 and Sensitivity B.

Figure 15 – Installed capacity in Baseline, Scenario 5, Sensitivity A and B



The installed renewable capacity in the Baseline and Scenario 5 is such that the renewable targets are met in 2020 and the CO_2 emissions in 2030 are below 100gCO_2/kWh. In the Baseline larger capacity of wind is required to meet the emission target in 2030, compared to Scenario 5. This is because Scenario 5 has increased generation coming from the border countries, as explained more in detail in Section 4.1.5.

We have added new entrant CCGT such that the number of hours of lost load in each modelled year (see Figure 16) does not exceed two hours, and the new entrant plants are profitable.

Figure 16 – Hours of Lost Load, Baseline and Scenario 5

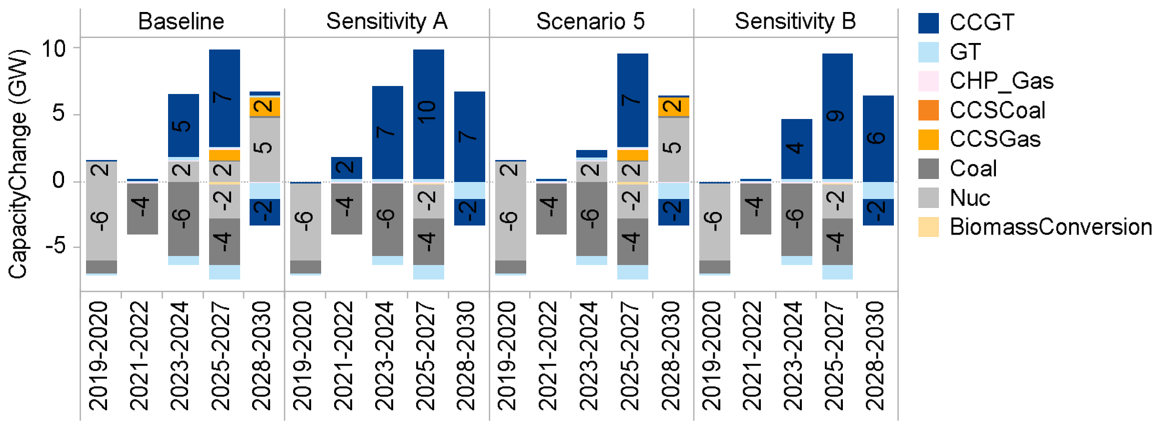
Hours of lost load	2018	2020	2022	2024	2027	2030
Baseline	0	0	1	2	2	1
Scenario 5	0	0	0	2	2	2

Figure 17 – Energy unserved, Baseline and Scenario 5

Energy unserved (MW)	2018	2020	2022	2024	2027	2030
Baseline	0	0	425	1133	1343	643
Scenario 5	0	0	0	1885	1082	1653

Figure 18 shows the new plants build (positive values) and the retirals (negative values) for the Baseline, Sensitivity A, Scenario 5 and Sensitivity B. In both Sensitivity A and sensitivity B the NNB and CCS have been replaced by equivalent CCGT, whose profitability has not been checked since they are sensitivities on the Baseline and Scenario 5. We have replaced the first unit of nuclear build in 2020 with equivalent CCGT later: in 2022 in Sensitivity A and in 2023 in Sensitivity B because, before these years, the market is not tight enough (i.e. the capacity margin is looser).

Figure 18 – New build and retiral for Baseline, Scenario 5, Sensitivity A and B



In Figure 19 and Figure 20 are shown the values of the de-rated capacity margins in the Baseline and Scenario 5. The values including interconnectors are not available (n.a) as we have not calculated the capacity credit of interconnection.

Figure 19 – De-rated capacity margin, Baseline

Derated capacity margin (%)	2018	2020	2022	2024	2027	2030
With interconnectors	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Without interconnectors	13.4%	10.0%	2.8%	1.6%	0.3%	0.5%

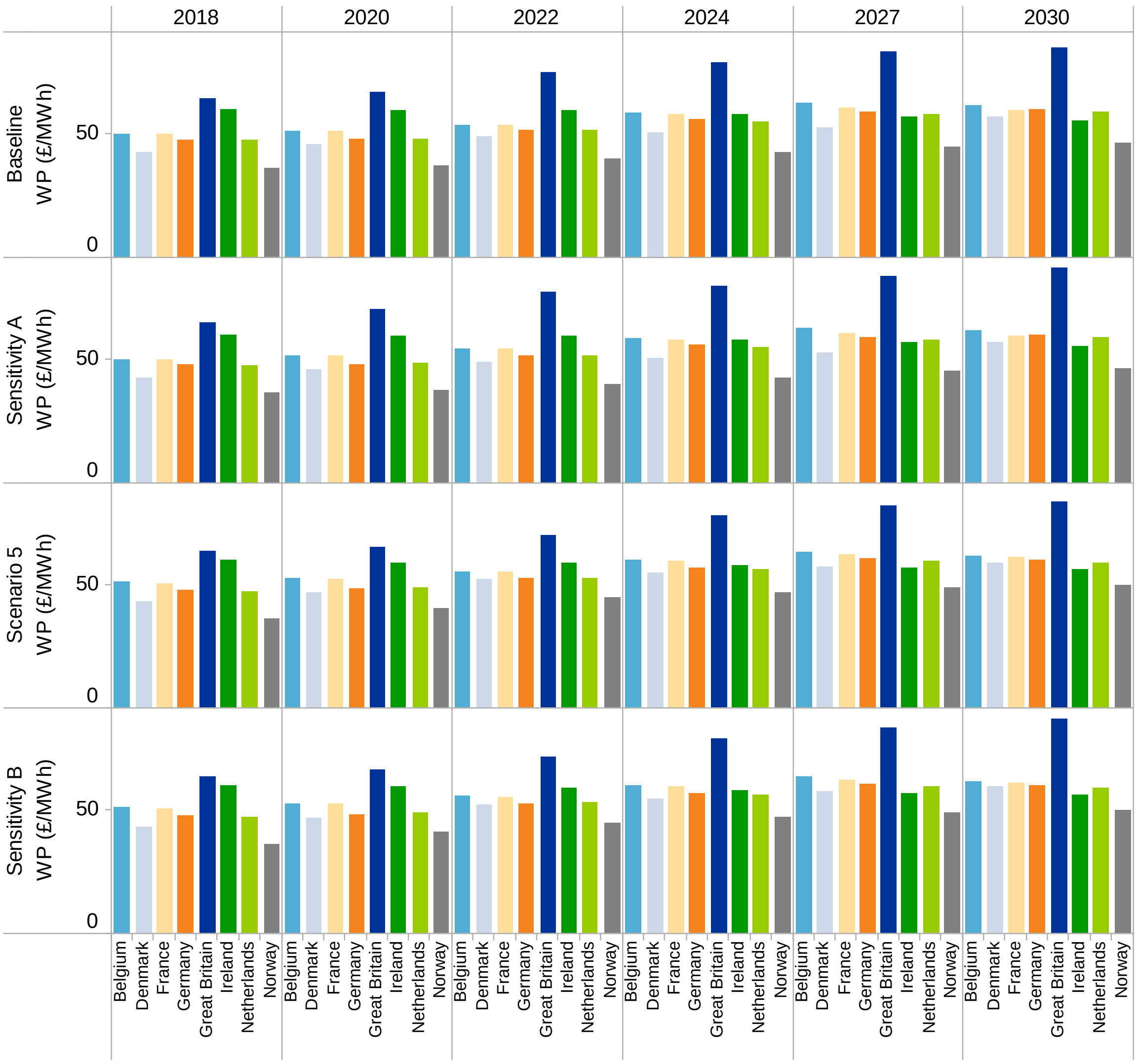
Figure 20 – De-rated capacity margin, Scenario 5

Derated capacity margin (%)	2018	2020	2022	2024	2027	2030
With interconnectors	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Without interconnectors	13.4%	10.0%	2.2%	-5.6%	-8.1%	-8.5%

4.1.2 Prices

Figure 21 shows the wholesale price projections for the Baseline, Sensitivity A, Scenario 5 and Sensitivity B across Europe and for all the modelled years. The higher price in GB compared to the other connected countries is due mainly to the higher CO_2 carbon price support: in 2030 the effective CO_2 price in GB is £75.5/tonne (see Figure 7) versus £12.3/tonne (Figure 8) in the other European countries. The price in the Irish SEM starts nearer the level in GB but as more CCGT capacity is commissioned in the Republic of Ireland the effect of the CPS on prices in the Irish market reduces. Moreover, the penetration of gas relative to coal is high in the Irish market in the first years of the modelled period.

Figure 21 – Wholesale price projections for Baseline, Scenario 5, Sens. A and B



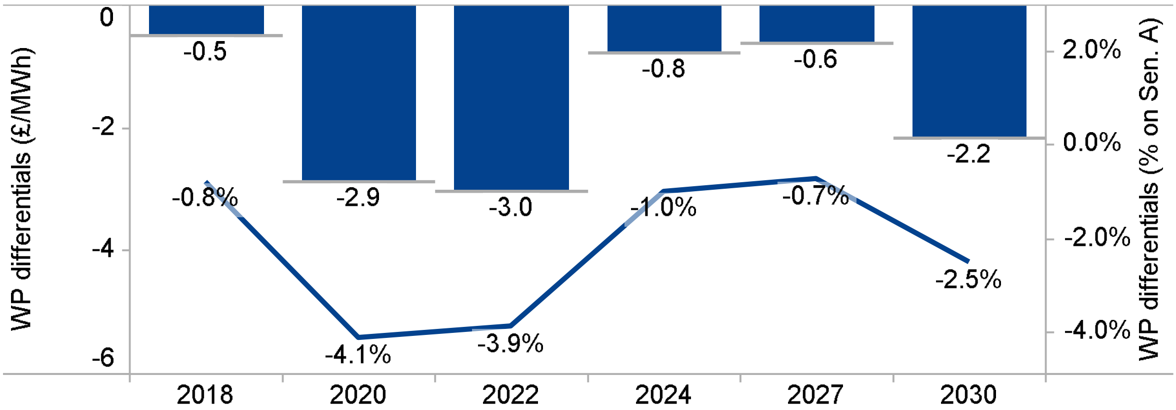
The GB price differentials between the Baseline and Sensitivity A and between Scenario 5 and Sensitivity B are shown respectively in Figure 22 and Figure 23 for all the modelled years. Values are reported both in £/MWh and in percentage terms on Sensitivity A and Sensitivity B.

The CfD for NNB and CCS leads to a reduction in the GB wholesale price in both the Baseline and Scenario 5 compared to the related sensitivities. This reduction is mainly due to two factors:

- In the period 2018-2022 the GB system is looser in the Baseline compared to Sensitivity A because the first nuclear unit and early CCS increase the overall capacity earlier (see Section 4.1.1).
- From 2024 onwards the difference is due to an increase in the number of periods where low variable costs technologies (nuclear/renewables) are setting the price.

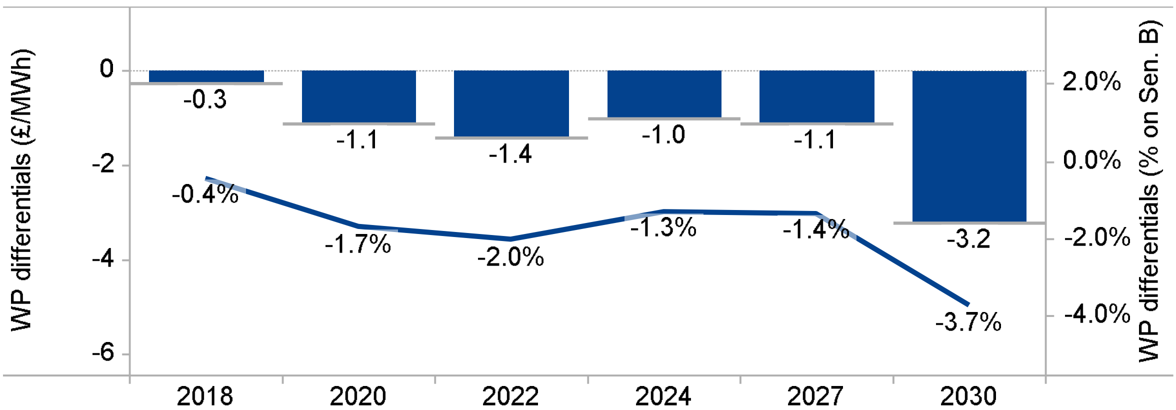
If we analyse the price differentials from 2024 onwards, it is possible to notice a bit of a lull in 2027 from the increasing differential over the time, mainly in Figure 22. This is in part due to the end of subsidies for enhanced cofiring and in part due to a falling number of low prices in France (due to nuclear closures) feeding into GB.

Figure 22 – GB price differentials – Baseline *less* Sensitivity A



Note: Negative values means the CfD has reduced prices.

Figure 23 – GB price differentials – Scenario 5 *less* Sensitivity B



Note: Negative values means the CfD has reduced prices

By comparing Figure 22 with Figure 23 we can notice that:

- In the period 2018-2022 the price differentials between Scenario 5 and Sensitivity B are lower than the price differentials between the Baseline and Sensitivity A. This is due to increased interconnections between GB and the border countries which partly 'offset' the difference in the installed capacity between the scenarios and the sensitivities. Hence the GB system, in Scenario 5 and Sensitivity B, does not get as tight as in the Baseline and Sensitivity A.
- From 2024 onwards, the price differentials between Scenario 5 and Sensitivity B is higher than the price differentials between the Baseline and Sensitivity A because in Scenario 5 and Sensitivity B the increased interconnection results in more lower prices being 'imported' from the Continent.

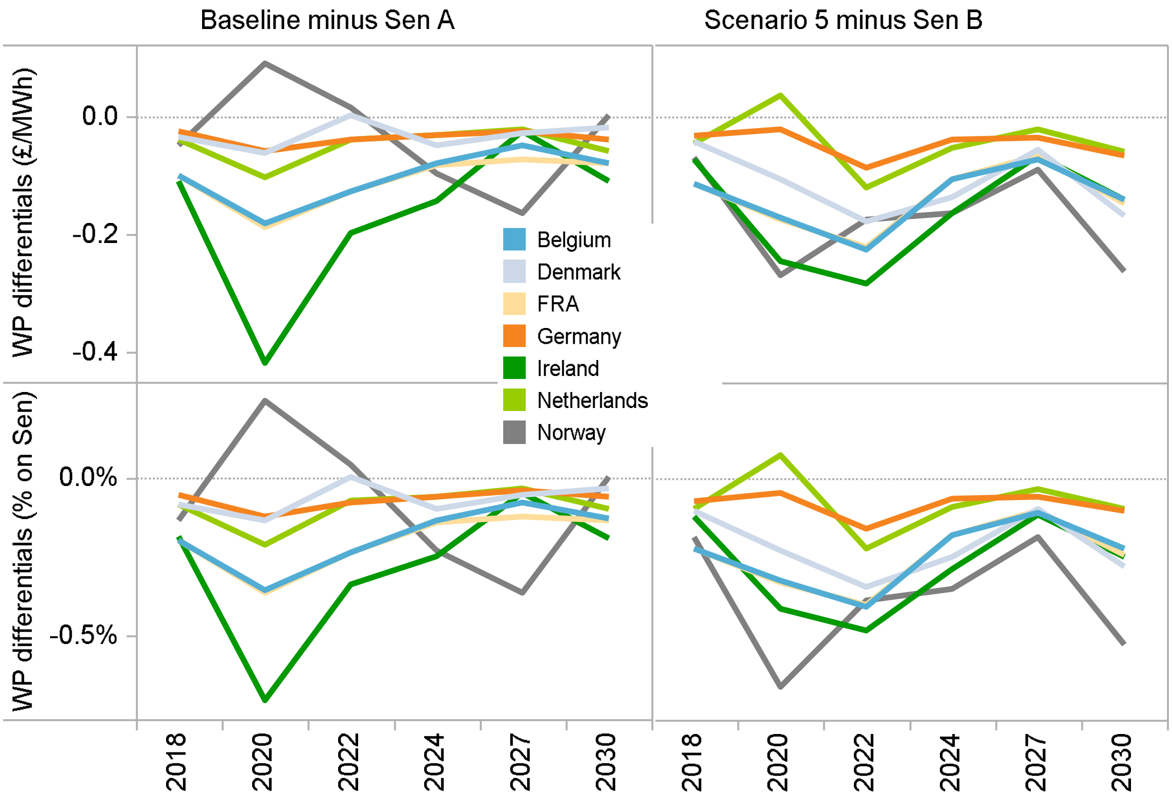
The maximum price reduction in the Baseline is of 4.1% in 2020 compared to Sensitivity A, while in the Scenario 5 the maximum reduction on sensitivity B is of 3.7% in 2030.

Figure 24 shows the differentials of the prices across Europe between the Baseline and Sensitivity A and between Scenario 5 and Sensitivity B, for all the modelled years. Values are reported both in £/MWh and in percentage on Sensitivity A and Sensitivity B.

Price differentials are now much lower than in GB (the price differential doesn't exceed the 0.8% on the related sensitivity) and can be considered negligible compared to the effects of other uncertainties over the timeframe. The tiny impact on Europe is due to the fact that GB is a net importer (see Figure 25) and interconnections represent only a small fraction of the market, in particular for France and Netherlands.

The differentials between Scenario 5 and Sensitivity B are slightly higher than the differences between the Baseline and Sensitivity A. This effect can be explained by the higher interconnector capacity which means that GB interconnection is a greater share in the European markets and hence changes in GB have a greater influence.

Figure 24 – EU price differentials between Baseline, Scenario 5 and sensitivities



Note: Negative prices mean that the CfD has caused a drop in prices.

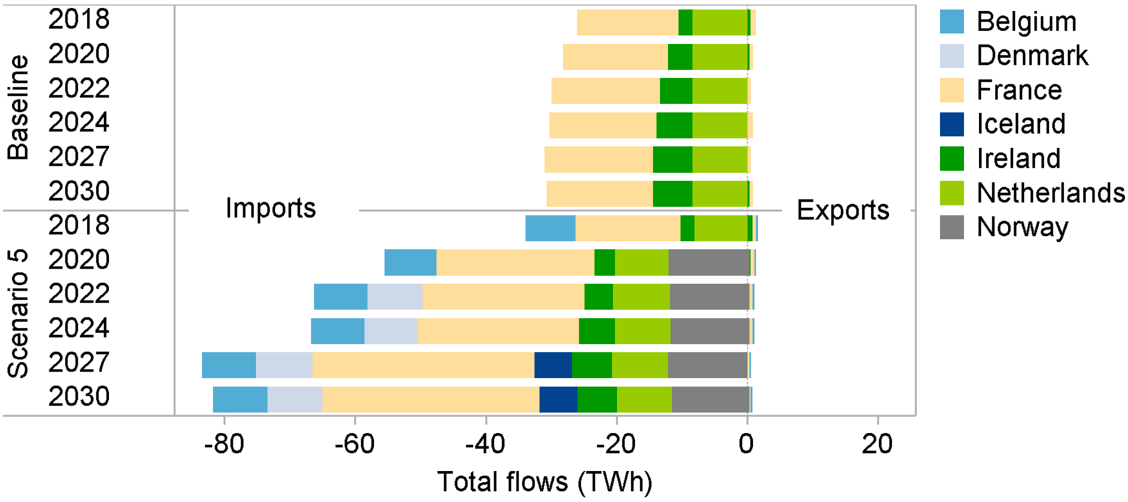
4.1.3 Flows

Figure 25 shows the total GB flows across the modelled period for the Baseline and Scenario 5. The positive values represent the exports from GB towards the connected countries, the negative values represent the imports in GB. As expected, given the higher GB wholesale price compared to the border countries and given the increasing gap in the wholesale price over the modelled timeframe (see Figure 21), GB is a net importer, particularly in the later years.

On the import side, the interconnector is very highly utilized: in the Baseline the maximum import is around 31TWh in 2027, while in Scenario 5 the maximum import is around 83.5 TWh in 2027.

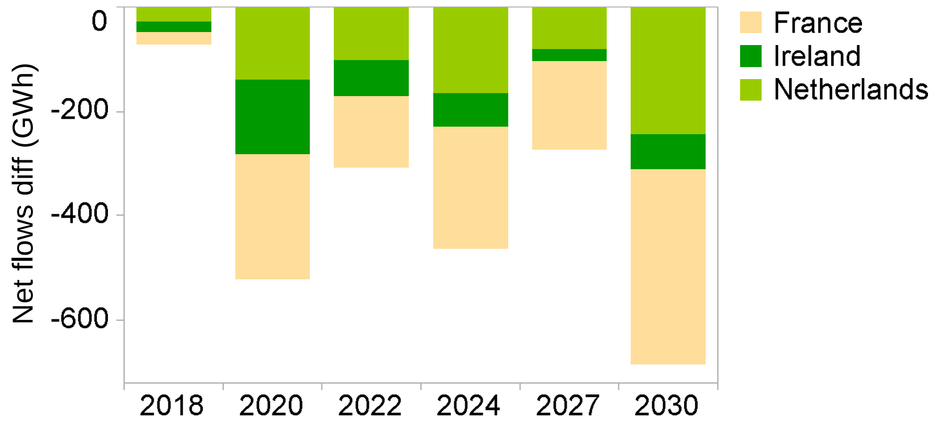
On the other hand, exports can be considered as negligible.

Figure 25 – Total GB flows in Baseline and Scenario 5



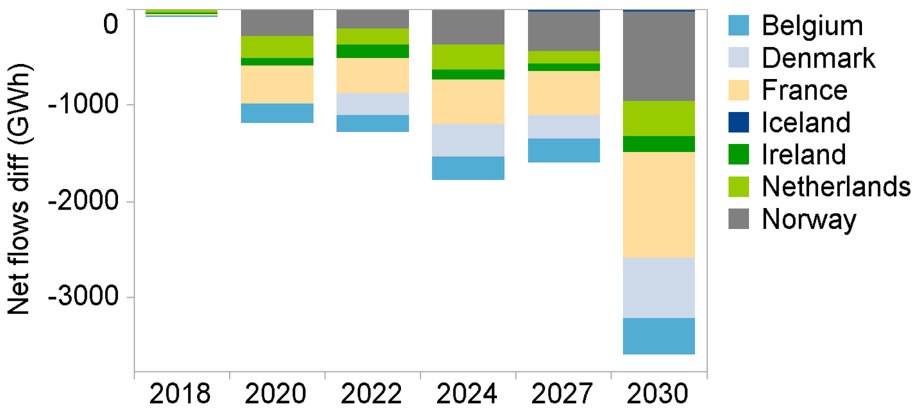
The change in net flows is shown in Figure 26 and Figure 27. Given that the effect of the CfD for NNB and CCS in the Baseline and Scenario 5 is to reduce prices compared to the sensitivities it leads to GB slightly lower net imports than in the sensitivities – however in all scenarios, GB remains a significant net importer.

Figure 26 – Net flow differentials – Baseline (with CfD) *less* Sensitivity A (no CfD)



Note: negative values mean that the CfD reduces net imports

Figure 27 – Net flow differentials – Scenario 5 (with CfD) *less* Sensitivity B (no CfD)



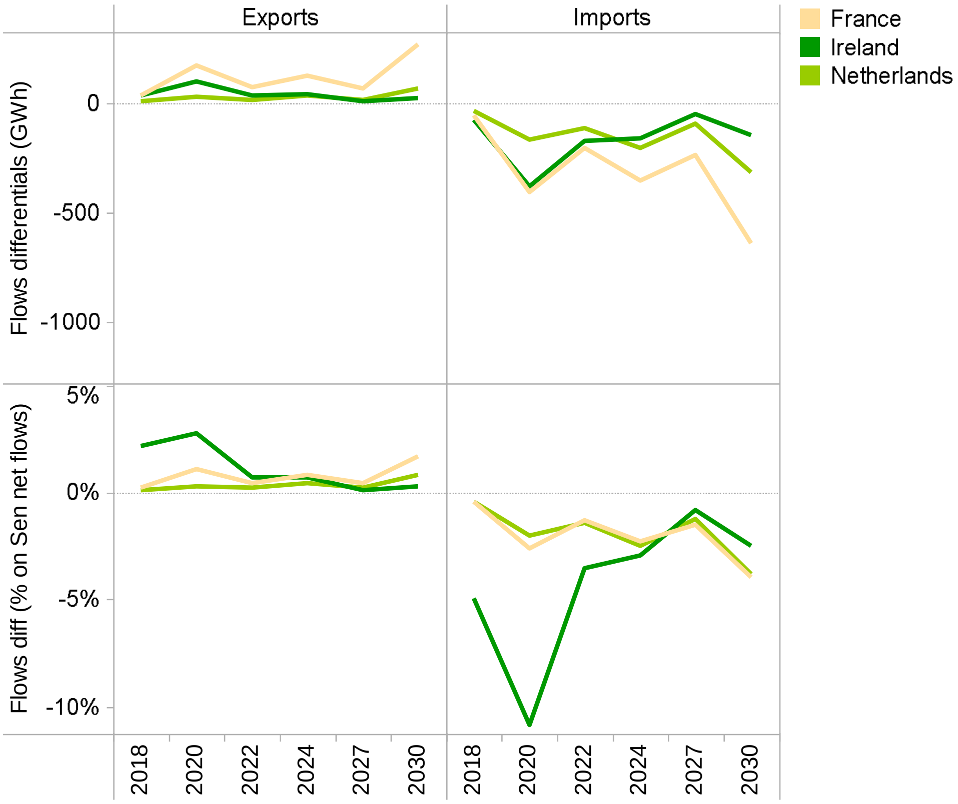
Note: negative values mean that the CfD reduces net imports

The flow differentials between the Baseline and Sensitivity A and between Scenario 5 and Sensitivity B are shown in Figure 28 and Figure 29 for all the modelled years. Values are reported both in GWh and in percentage on the net flows of the sensitivities.

Exports increase in the Baseline and Scenario 5 compared to Sensitivity A and Sensitivity B. This effect mirrors the lower wholesale price in the Baseline and Scenario 5 compared to related sensitivities (see Figure 24). The flow differentials are quite tiny: the maximum difference is of 355GWh in 2030 between the Baseline and Sensitivity A and of 411GWh in 2020 between Scenario 5 and Sensitivity B. The bigger differences in terms of percentage are towards Ireland because of the lower volumes exchanged compared to France and Netherlands. The difference is particularly evident in 2018 and 2020, when wholesale price in Ireland are quite similar to prices in GB and hence this smaller wholesale price difference makes the flows between GB and Ireland more sensitive compared to the flows between GB and the continent.

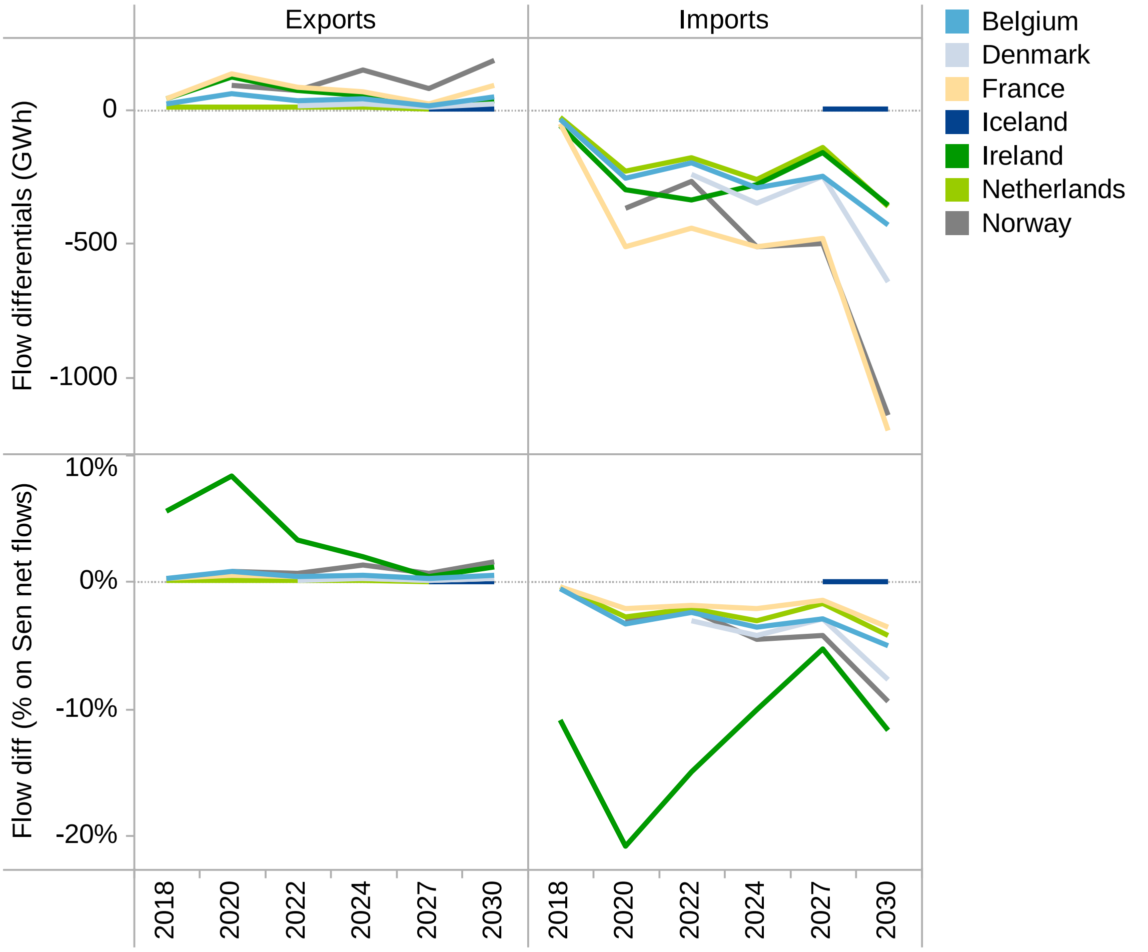
The lower wholesale price in the Baseline compared to Sensitivity A and in Scenario 5 compared to Sensitivity B, on the other hand, reduces **imports** in the Baseline and Scenario 5 compared to the related sensitivities. The flow differentials are now bigger than the exports: the maximum difference is of 1104GWh in 2030 between the Baseline and Sensitivity A and of 4134GWh in 2030 between Scenario 5 and Sensitivity B. Again, the bigger flow differences in terms of percentage between GB and Ireland, mainly in 2018 and 2020, are due to the lower volumes exchanged and the smaller differences in the wholesale price.

Figure 28 – GB flow differentials – Baseline *less* Sensitivity A



It is noticeable in Figure 29, that the flow differentials between GB and Iceland are zero. This is because flows with Iceland has not been optimized and has been modelled as fixed flows of around 5.3TWh in 2027 and 2030, corresponding to an installed interconnector capacity of 600 MW operating at full load for the all year.

Figure 29 – GB flow differentials – Scenario 5 *less* Sensitivity B



4.1.4 Revenues for interconnectors

Figure 30 shows the interconnector revenues for each modelled year and for the Baseline, Sensitivity A, Scenario 5 and Sensitivity B. These revenues are based on market (price differentials) only and assume that interconnector do not get paid capacity payments. The revenues of the interconnector with Ireland are quite low compared with the other interconnectors, in particular before 2027, because of smaller price differences and hence smaller flows (see Figure 25).

The interconnector revenues increase over the years because of increased flows lead by increased price differentials between GB and the border countries.

Interconnector revenues are slightly smaller in the Baseline compared to Sensitivity A (see Figure 31), because of smaller price differences between GB and the border countries. The differences are in any case quite tiny: the maximum interconnector revenue in the Baseline is £234.8/kW/year in 2030 with Netherlands, versus £219.3/kW/year always in 2030 with Netherlands.

In Scenario 5 and Sensitivity B we have the same trends as in the Baseline and Sensitivity A. Again, the interconnector revenues in Scenario 5 are slightly smaller than in Sensitivity B (see Figure 32): the maximum interconnector revenue in Scenario 5 is £280.5/kW/Year in 2030 with Norway, versus £259.5/kW/Year always in 2030 with Norway.

The revenues of the interconnection with Norway in Scenario 5 and Sensitivity B are particularly notable, because of the high utilization of this interconnection due to very low wholesale price in Norway compared to those in GB.

Figure 30 – Interconnector revenues for Baseline, Scenario 5, Sensitivity A and B

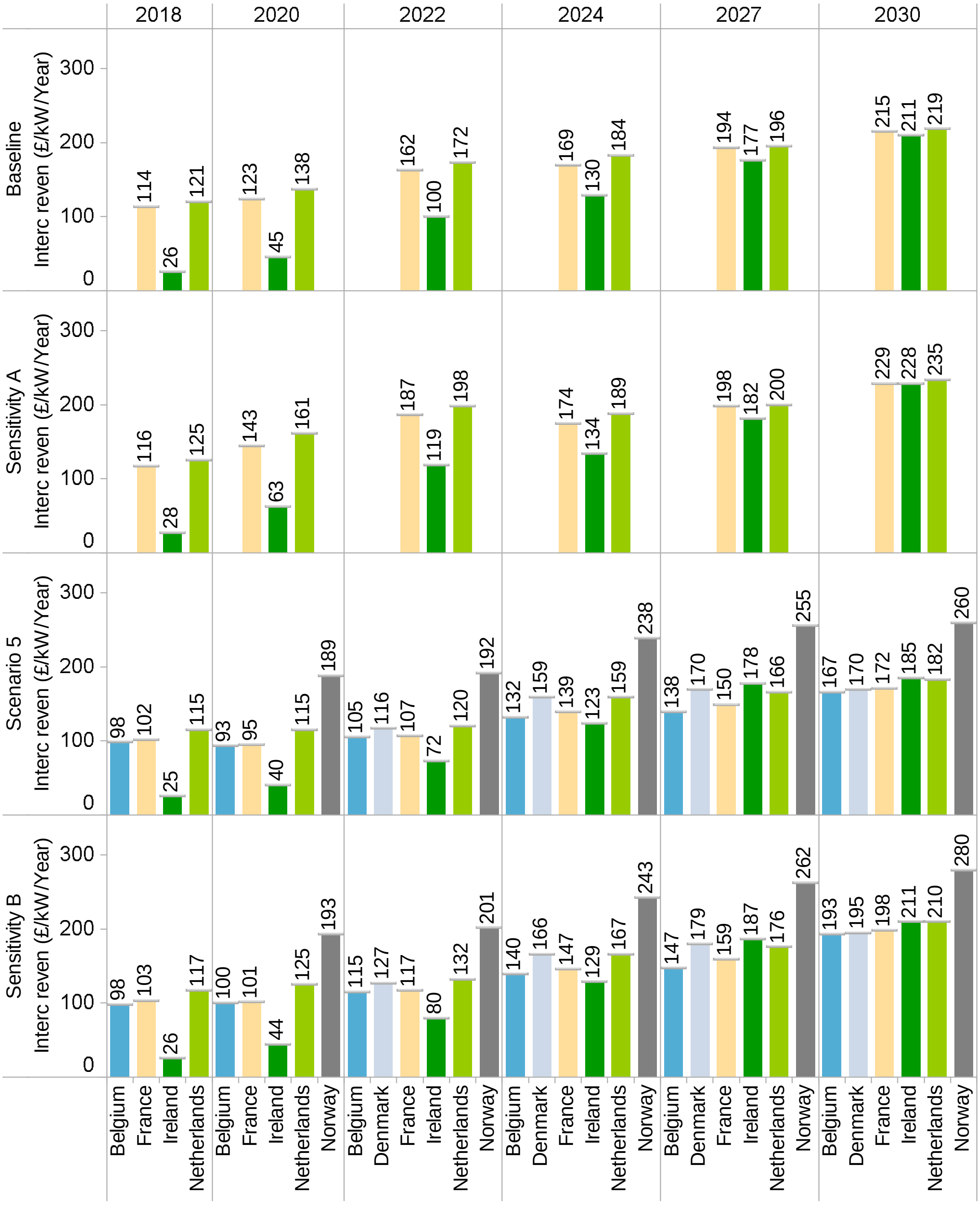
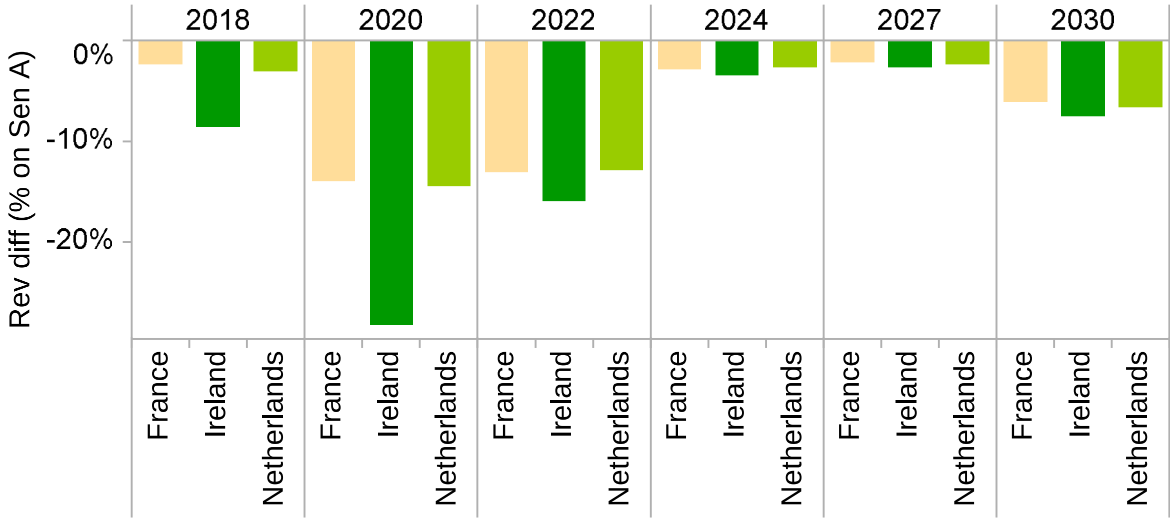
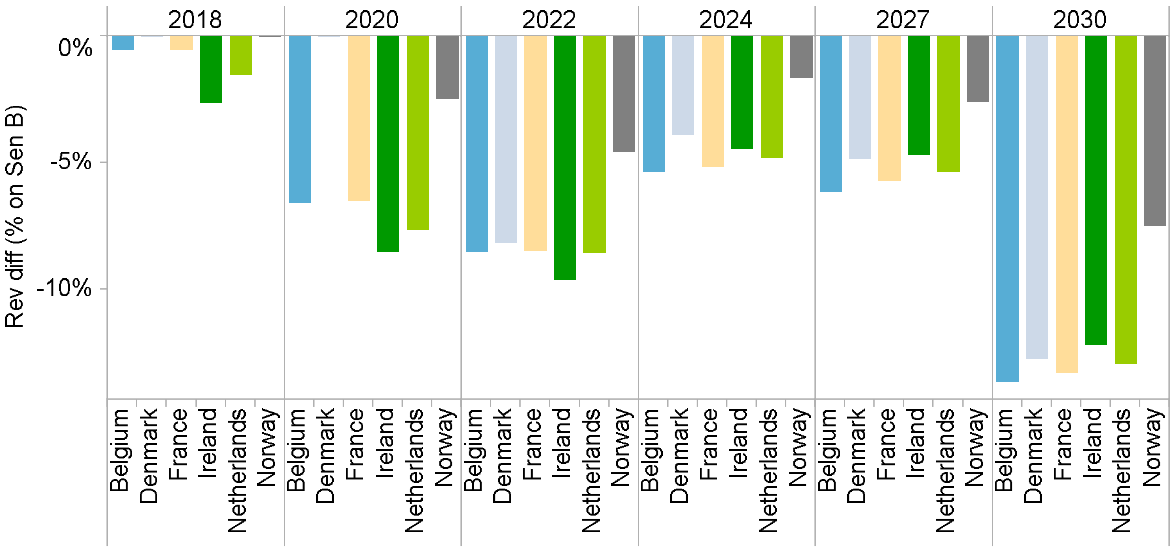


Figure 31 – Interconnector revenue differentials – Baseline *less* Sensitivity A



Note: Negative revenue differentials means CfD has reduced revenues.

Figure 32 – Interconnector revenue differentials – Scenario 5 *less* Sensitivity B



Note: Negative revenue differentials means CfD has reduced revenues.

Figure 33 – Average interconnector revenues differentials – Baseline *less* Sensitivity A

	Ireland	Netherlands	France
Revenue differentials (% on Sensitivity A)	-7.0%	-8.7%	-6.7%

Note: average across all modelled years: (avg(Baseline) less avg(Sensitivity A)) / avg(Sensitivity A)

Figure 34 – Average interconnector revenues differentials – scenario 5 *less* Sensitivity B

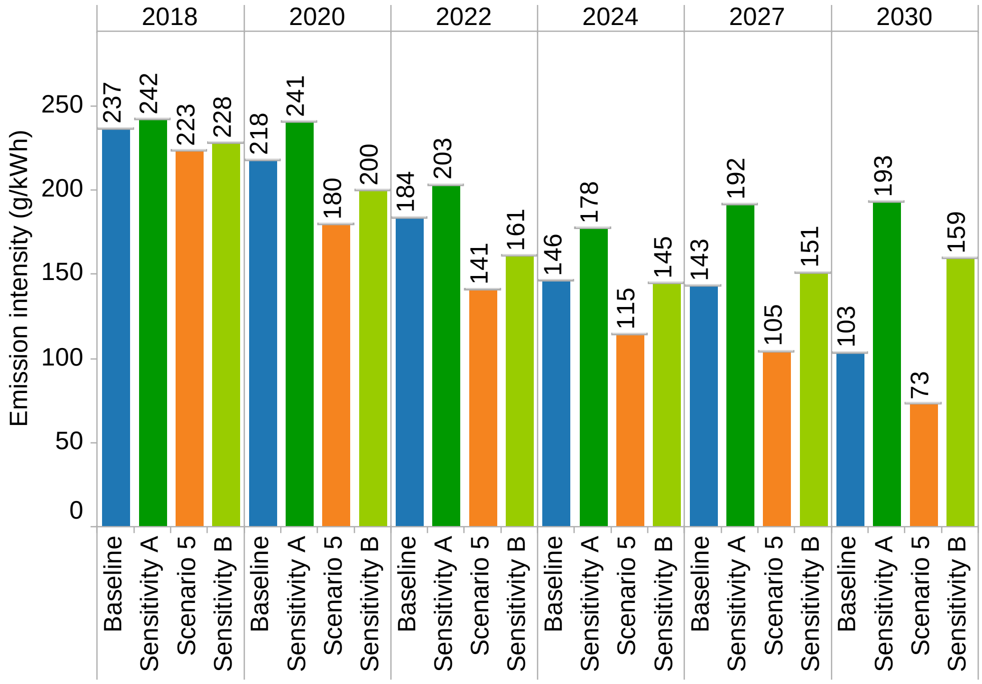
	Norway	Netherlands	Denmark	Ireland	France	Belgium
Rev diff (% on Sen B)	-3.9%	-7.3%	-7.6%	-7.7%	-7.3%	-7.6%

Note: average across all modelled years: (avg(Scenario 5) less avg(Sensitivity B)) / avg(Sensitivity B)

4.1.5 Emission intensity

The emission intensity, following DECC definition, has been calculated as the overall emission of CO_2 from GB generation divided by the total demand, both netted of small scale CHP. Values of the emission intensity achieved in the modelled years for the Baseline, Sensitivity A, Scenario 5 and Sensitivity B are shown in Figure 35.

Figure 35 – Emission intensity in the Baseline, Scenario 5, Sensitivity A and B



The emission target of around 100gCO_2/kWh in 2030 has been achieved, in the Baseline, by increasing the renewable penetration beyond 2020. In Scenario 5 the emission intensity is well below the target without any need to increase the renewable installed capacity after 2020. In fact, a lower thermal generation in Scenario 5 compared to the Baseline is offset by larger imports from the surrounding countries through the increased interconnection.

In both Sensitivity A and Sensitivity B the emission intensity is higher than the target because the NNB and CCS have been replaced by CCGT.

4.2 The impact of a BM cash-out reform (without CM)

In this work, we have assumed that the current market design in GB has an implicit price cap of around £500/MWh, as a result of the current design of the Balancing Mechanism and STOR contracts. The current BM and STOR system is represented by Scenario 1.

We have also assumed that cash-out reform would lead to this implicit price cap being removed – this is the assumption in the Baseline.

Hence to assess the impact of a cash-out reform in GB and the the removal of the implicit cap on the wholesale price of £500/MWh, we have compared the Baseline (no cap) with Scenario 1 (£500/MWh cap, see Figure 10). The only difference between Scenario 1 and the Baseline is the cap on the wholesale price on Scenario 1: all other input and assumptions are the same between the two scenarios. The price cap also implies that, in Scenario 1, there could be loss of load in GB with GB exporting at the same time.

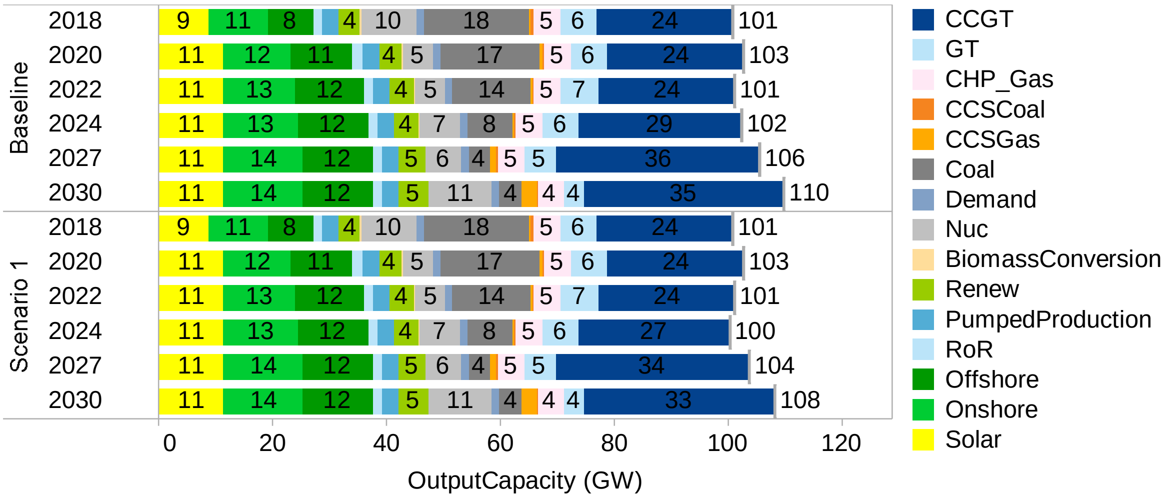
Summary 2 – Impact of a BM cash-out reform (without CM)

- Installed capacity – The removal of the implicit cap on prices leads to higher build of CCGTs and hence looser system margins and less load loss. In total there is about 2GW more plant on the system by 2030 when the implicit price cap is removed.
- GB wholesale prices – GB prices are largely unaffected on average. Removing the implicit price cap by definition leads to some high priced periods (>£500/MWh), but a corresponding decrease in medium-price periods (£100-£500/MWh) due to a wider system margin. 2022 is the exception – as this is the first year that the price cap bites there is the same new build in both scenarios.
- Continental and Irish prices – The removal of the implicit price cap has negligible impact on Continental and Irish prices (<0.01%)
- Interconnector flows – The removal of the implicit price cap has negligible impact on Continental interconnector flows (<1%) – they remain almost baseload importing irrespective of the price cap.
- Interconnector revenues – Continental interconnector revenues are not affected by the removal of the implicit price cap, apart from in 2022 with no capped prices increasing interconnector revenues compared to the capped scenario.

4.2.1 Installed capacity

Figure 36 shows the installed capacity by technology type for the modelled years and for Scenario 1 and the Baseline.

Figure 36 – Installed capacity in Baseline (no price cap) and Scen. 1 (price cap)



We have added new entrant CCGT such that the number of hours of lost load in the Baseline does not exceed two hours and the new entrant plants are profitable. In Scenario 1, the cap on the wholesale price drives downwards the profitability of plants, so a tighter system (more load loss, as shown in Figure 37) is required for profitability of new entrant plants to be similar to the Baseline. This explains the higher installed capacity in the Baseline compared to Scenario 1.

Figure 37 – Hours of lost load, Scenario 1 (price cap)

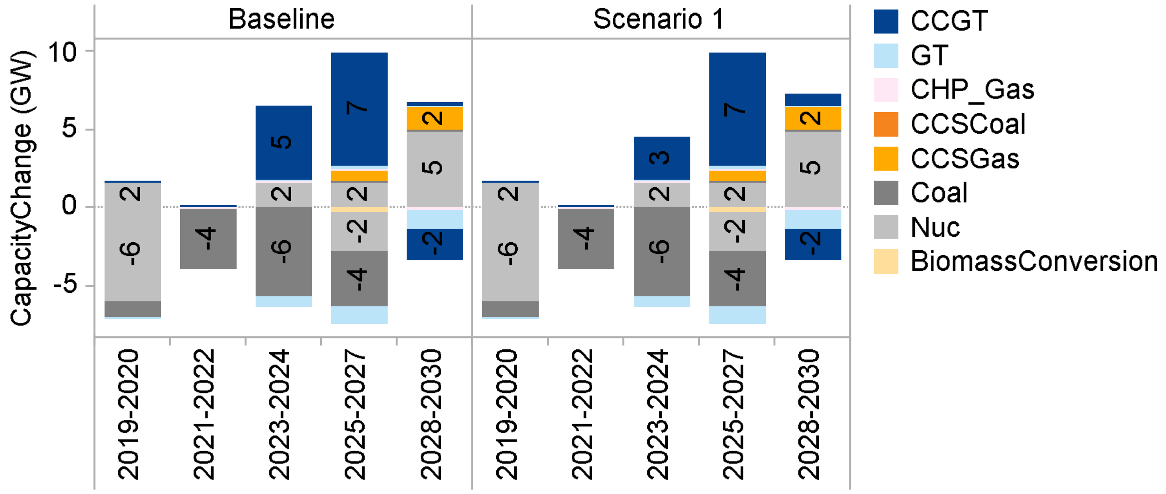
Hours of lost load	2018	2020	2022	2024	2027	2030
Scenario 1	0	0	1	4	5	3

Figure 38 – Energy unserved, Scenario 1 (price cap)

Energy unserved (MW)	2018	2020	2022	2024	2027	2030
Scenario 1	0	0	425	6768	7699	4372

Figure 39 shows the new plants build (positive values) and the retirals (negative values) for Scenario 1 and for the Baseline.

Figure 39 – New build/retiral in Baseline (no price cap) and Scenario 1 (price cap)



In Figure 40 are shown the de-rated capacity margins in Scenario 1. The values including interconnectors are not available (n.a) as we have not calculated the capacity credit of interconnection.

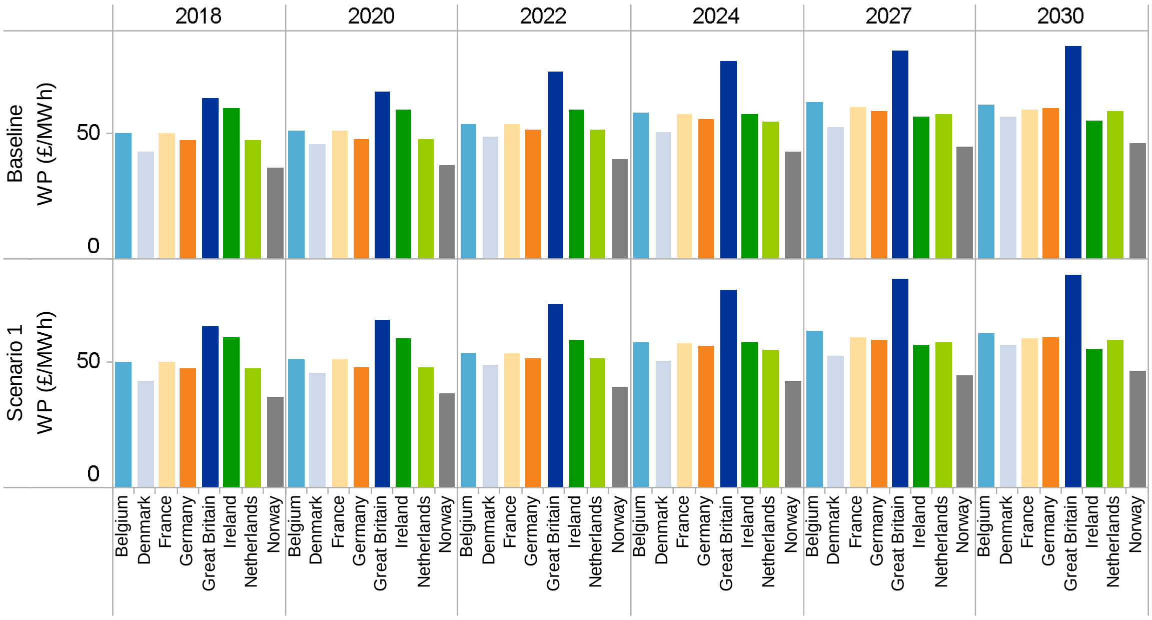
Figure 40 – De-rated capacity margin, Scenario 1

Derated capacity margin (%)	2018	2020	2022	2024	2027	2030
With interconnectors	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Without interconnectors	13.4%	10.0%	2.8%	-1.3%	-2.6%	-1.6%

4.2.2 Prices

Figure 41 shows the wholesale price projections for Scenario 1 and the Baseline across Europe and for all the modelled years. Wholesale prices in the Baseline are very similar to Scenario 1.

Figure 41 – Wholesale projections for Baseline (no price cap) and Scenario 1 (price cap)

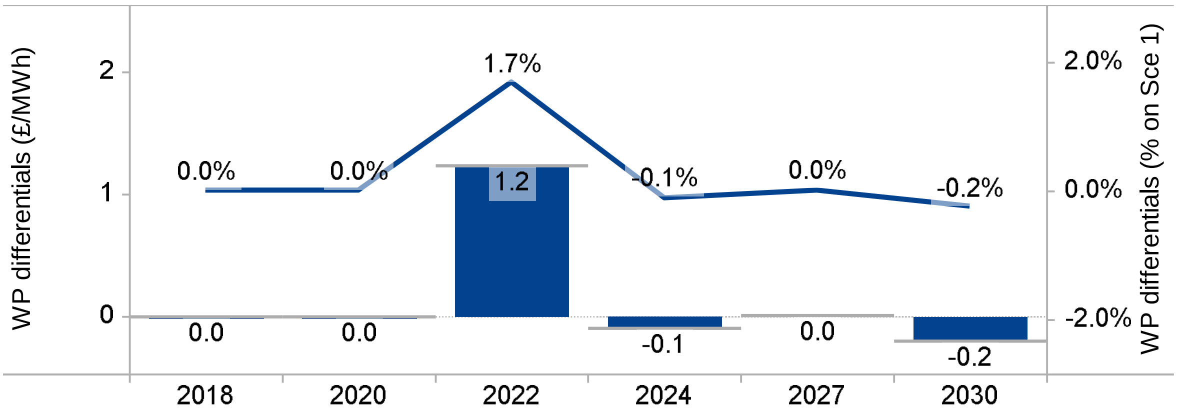


The GB price differentials between the Baseline and Scenario 1 are shown in Figure 42 for all the modelled years. Values are reported both in £/MWh and in percentage on Scenario 1.

Before 2022 the price differences between the Baseline and Scenario 1 are negligible because there are not many periods with a wholesale price greater than £500/MWh due to the situation of overcapacity.

Prices are higher in the Baseline compared to Scenario 1 in 2022, when the market becomes tighter and hence wholesale price increase above the threshold of £500/MWh.

Figure 42 – GB price differentials – Baseline (no price cap) *less* Scenario 1 (price cap)



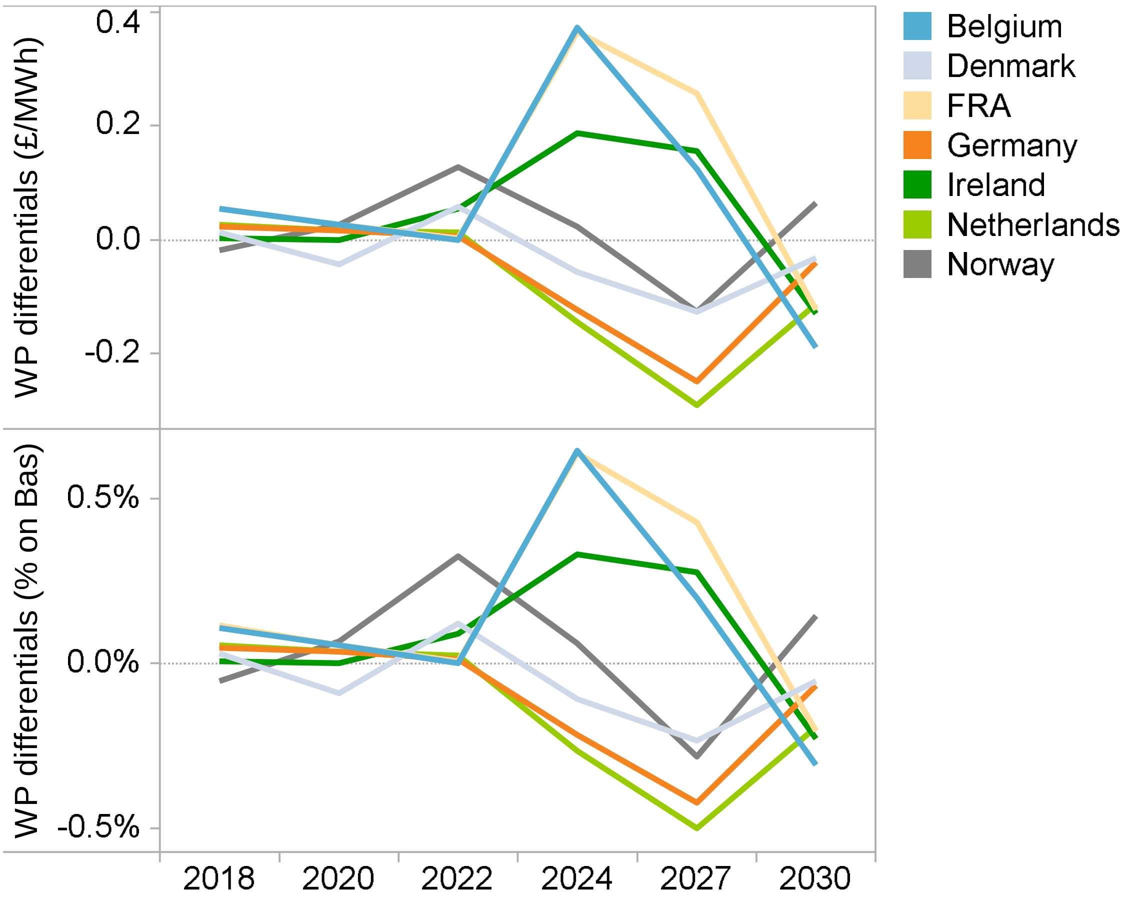
Note: Positive price differentials means that removal of the implicit price cap has raised prices

From 2024 onwards the effect of no price cap is offset by a higher installed capacity in the Baseline compared to Scenario 1. Price differentials from 2024 can be considered negligible.

Figure 43 shows the price differences across Europe between the Baseline and Scenario 1, for all the modelled years. Values are reported both in £/MWh and in percentage on the Baseline.

Price differentials in the border countries between Scenario 1 and the Baseline are very low (below 0.6% in all cases) and can be considered almost negligible compared to the effects of other uncertainties over the timeframe. Price differentials are higher in 2024 due to the limited requirement for new entry on the Continent meaning the changes in GB can feed through. As we move towards 2030 the requirement for new entrant plants to be profitable reduces the wholesale price differentials.

Figure 43 – EU price differentials – Baseline (no price cap) *less* Scenario 1 (price cap)



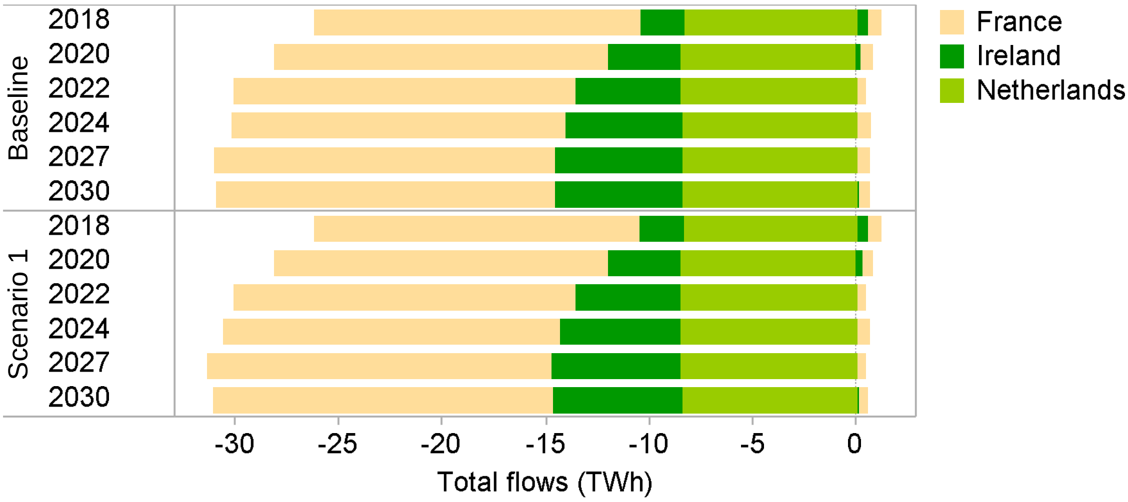
Note: Positive price differentials mean the removal of the price cap has raised prices

4.2.3 Flows

Figure 44 shows the total GB flows across the modelled period for the Baseline and Scenario 1. The positive values represent the exports from GB towards the connected countries, the negative values represent the imports in GB.

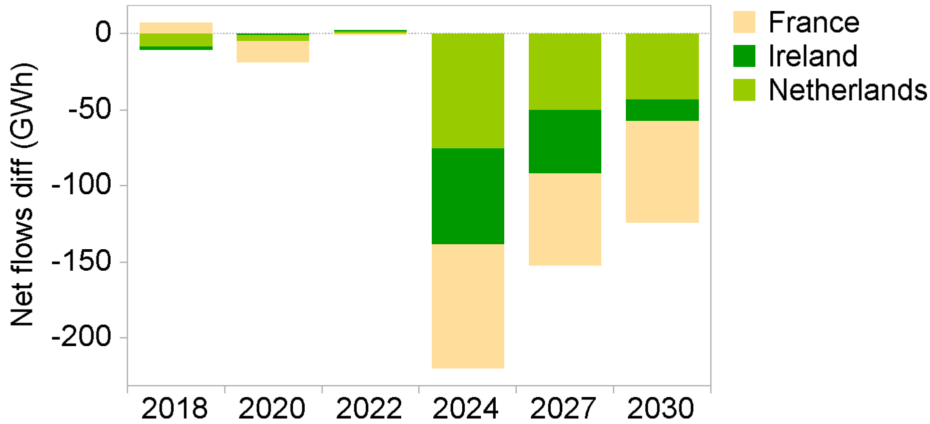
In both scenarios GB is importing most of the time, particularly in later years, while exports are almost negligible.

Figure 44 – Total GB flows in Baseline (no price cap) and Scenario 1 (price cap)



Positive values represent the exports, negative values the imports

Figure 45 – Net flow differentials – Baseline (no price cap) *less* Scen 1 (price cap)



Note: negative values mean that removing the price cap decreases net imports

Figure 46 – GB flow differentials – Baseline (no price cap) *less* Scen 1 (price cap)

Note: For exports, positive values mean a price cap reduces exports. For imports, positive values means a price cap reduces imports.

The flow differences between the Baseline and Scenario 1 are shown in Figure 46 for all the modelled years. Values are reported both in GWh and in percentage on the net flows of Scenario 1.

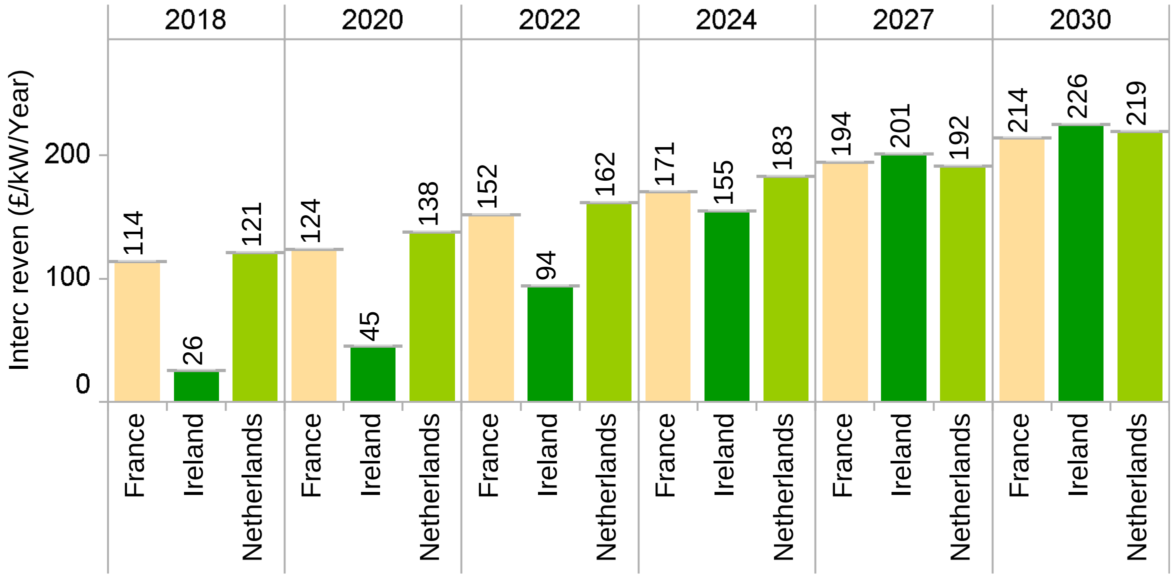
Export differentials are negligible before 2024 because wholesale price differences are quite low due to the market being loose, hence the wholesale price cap rarely binds in Scenario 1. From 2024 onwards the exports increase in the Baseline because the GB market is looser than in Scenario 1 (more new entrant CCGT due to higher profitability).

Import differences are negligible before 2024 because of zero number of periods with wholesale price greater than £500/MWh. From 2024 onwards, the looser market in GB in the Baseline (due to a higher installed capacity compared to Scenario 1) reduces the imports .

4.2.4 Revenues for interconnectors

Figure 47 shows the interconnector revenues in Scenario 1 for each modelled year. These revenues are based on market (price differentials) only and assume that interconnector do not get paid capacity payments.

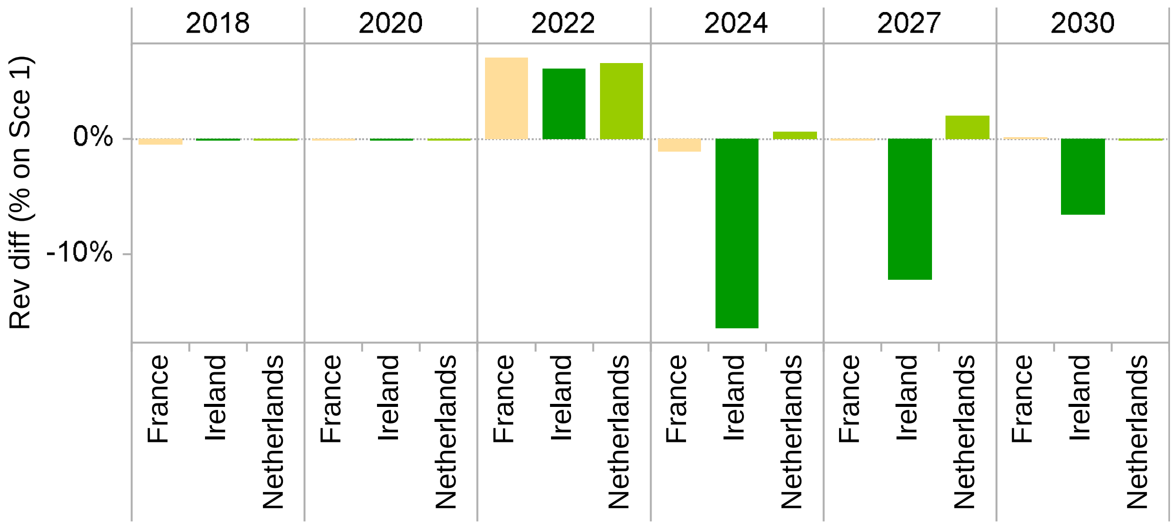
Figure 47 – Interconnector revenues for Scenario 1 (price cap)



The interconnector revenues between the Baseline and Scenario 1 are shown in Figure 48 for all the modelled years.

The differences in revenues are relatively small, particularly for France and Netherlands (with the exception of 2022). Larger differences in revenues occur in the GB-Ireland interconnector, but still very small.

Figure 48 – Interconnector revenue differentials – Baseline (no price cap) *less* Scenario 1 (price cap)



Note: Positive values mean that a price cap causes a fall in revenues.

Figure 49 – Average Interconnector revenue differentials – Baseline (no price cap) *less* Scenario 1 (price cap)

	Ireland	Netherlands	France
Revenue differentials (% on Scenario 1)	-7.9%	1.6%	0.9%

Note: average across all modelled years: (avg(Baseline) less avg(Scenario 1)) / avg(Scenario 1)

4.3 The impact of a BM cash-out reform (with CM)

As stated in Section 4.2, we have assumed that the current market design in GB has an implicit price cap of around £500/MWh, as a result of the current design of the Balancing Mechanism and STOR contracts. The current BM and STOR system represented by Scenario 3, whilst a cash-out reform that removes this implicit price cap is modelled as Scenario 2.

The impact of cash-out reform could be different in a market with a CM than in one without. Hence to assess the impact of a cash-out reform and removal of the implicit price cap, we have also modelled Scenario 3 (described in Figure 10) with a CM in GB and a wholesale price cap of £500/MWh. The features of this CM, as defined by DECC, are listed in Section 3.2.2. We have then compared Scenario 2 (with CM, without wholesale price cap) with Scenario 3, in order to assess the effect of removing the implicit wholesale price cap in a market with CM in GB.

Summary 3 – The impact of a BM cash-out reform (with CM)

- Installed capacity – In a market with a CM, removing the implicit price cap via BM cash-out reform leads to less capacity being built in GB than with a wholesale price cap – in particular less OCGTs. This is because removing the implicit price caps mean GB can rely more on imports at key periods, and so to fulfil the 10% capacity margin less plant is required.
- GB wholesale prices – The removal of the implicit price cap leads to prices that are around £1/MWh higher, as a result of the lower capacity that is built to meet system margins. As a result of higher wholesale prices, capacity payments fall.
- Continental and Irish prices – Price cap leads to a tiny increase of up to £0.3/MWh in Continental prices – this is a negligible change in price given other uncertainties.
- Interconnector flows – The BM cash-out reform has an almost-zero impact on interconnector flows.
- Interconnector revenues – The BM cash-out reform has an almost-zero impact on interconnector revenues.

4.3.1 Installed capacity

Figure 50 shows the installed capacity by technology type for the modelled years and for Scenario 2 and Scenario 3.

Figure 50 – Installed capacity in Scenario 2 (CM, no price cap) and Scenario 3 (CM, price cap)

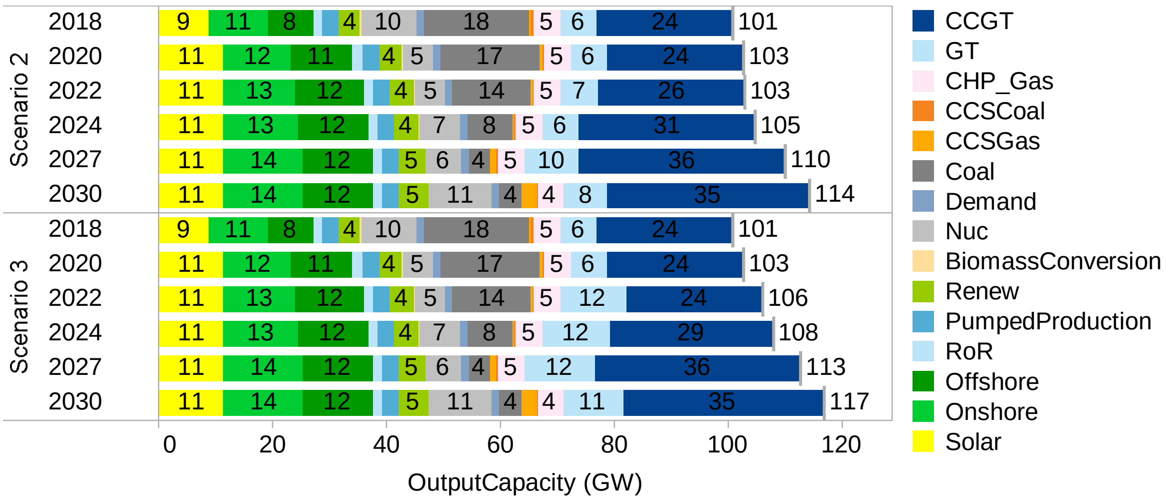
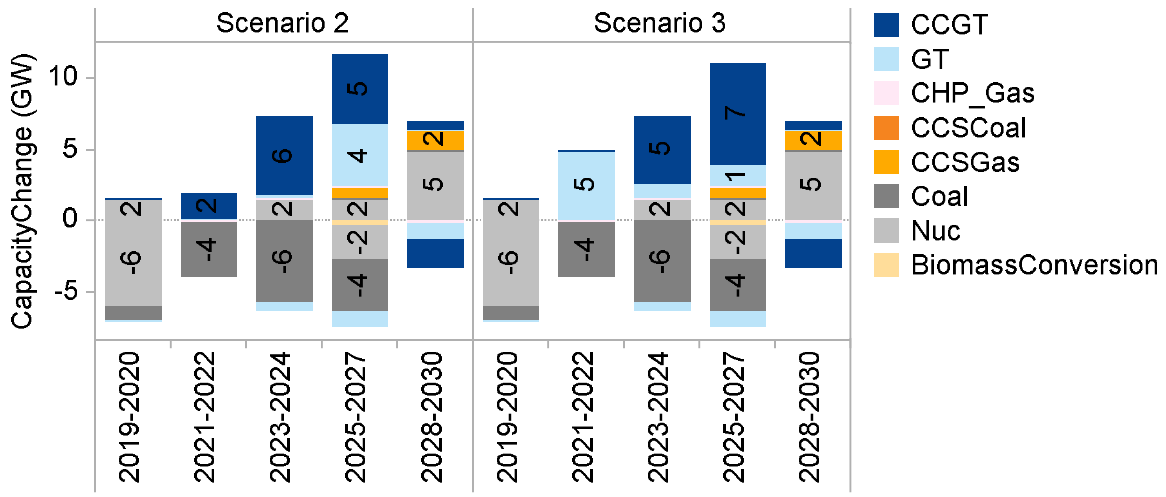


Figure 51 shows the new plants build (positive values) and the retirals (negative values) for Scenario 2 and for Scenario 3.

Figure 51 – New build and retiral for Scenario 2 (CM, no price cap) and Scenario 3 (CM, price cap)



By comparing Scenario 2 with Scenario 3 the decrease in the overall installed capacity is due to higher wholesale price, hence GB is more able to rely on Continental interconnectors to be available at peak times. As a result, to fulfil the 10% system margin, less capacity is required.

In Figure 52 and Figure 53 are shown the de-rated capacity margins in Scenario 2 and Scenario 3.

Figure 52 – De-rated capacity margin, Scenario 2

Derated capacity margin (%)	2018	2020	2022	2024	2027	2030
With interconnectors	17.7%	14.4%	9.8%	9.6%	9.5%	9.5%
Without interconnectors	13.4%	10.0%	5.4%	5.4%	5.5%	5.8%

Figure 53 – De-rated capacity margin, Scenario 3

Derated capacity margin (%)	2018	2020	2022	2024	2027	2030
With interconnectors	17.7%	14.4%	13.5%	13.4%	12.7%	12.5%
Without interconnectors	13.4%	10.0%	9.2%	9.1%	8.7%	8.8%

4.3.2 Prices

Figure 54 shows the wholesale price projections for Scenario 2 and Scenario 3 across Europe and for all the modelled years. Wholesale prices in Scenario 2 are very similar to prices in Scenario 3.

Figure 54 – Wholesale price projections for Scenario 2 (CM, no price cap) and Scenario 3 (CM, price cap)

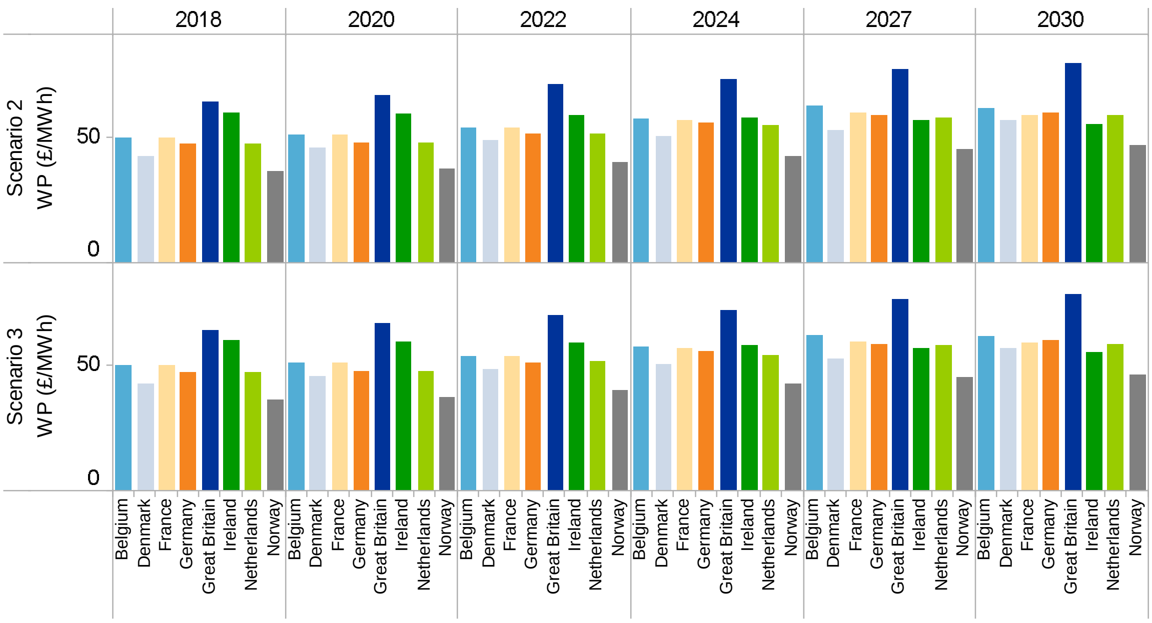
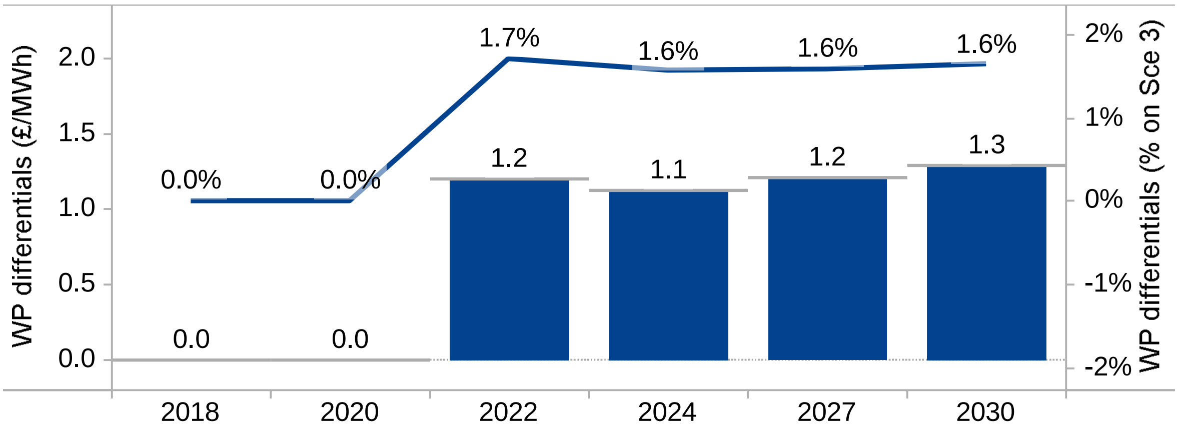


Figure 55 shows the differentials of the prices across Europe between Scenario 2 and Scenario 3 for all the modelled years.

Before 2022 the price differences between Scenario 2 and Scenario 3 are negligible because there are not many periods with a wholesale price greater than £500/MWh due to an overcapacity. Prices are higher in Scenario 2 compared to Scenario 3 from 2022 onwards because of the combined effect of no wholesale price cap and lower installed capacity in Scenario 2 compared to Scenario 3.

Figure 55 – GB price differentials – Scenario 2 (CM, no price cap) *less* Scenario 3 (CM, price cap)



Note: Positive price differentials mean removal of implicit price cap has raised price.

Capacity payments are shown in Figure 56. The removal of the implicit price cap leads to higher wholesale prices but a decrease in capacity payments of £9/kW on average.

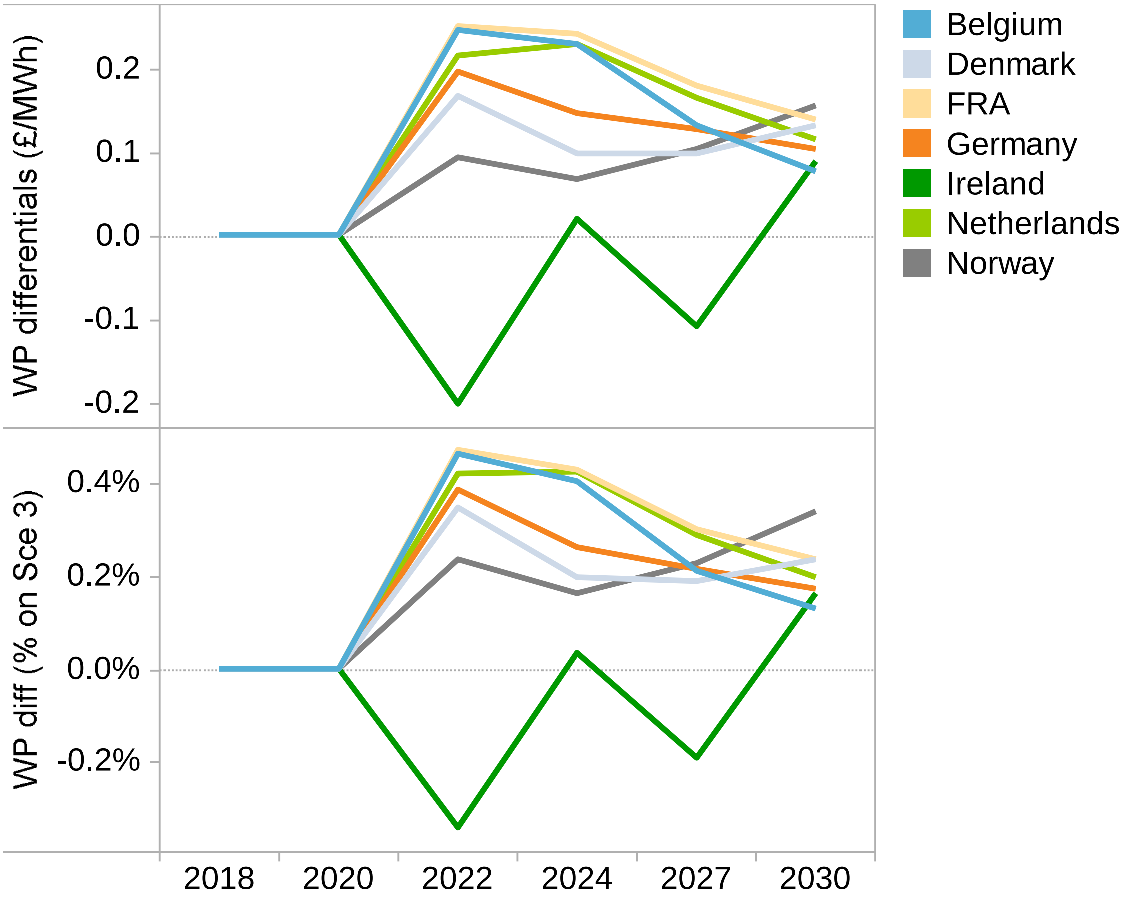
Figure 56 – Capacity Payment in Scen 2 (CM, no price cap) and Scen 3 (CM, price cap)

£/kW/yr	Scenario 2 (CM)	Scenario 3 CM+PriceCap
2022	41	45
2024	42	51
2027	44	52
2030	40	50

Figure 57 shows the differentials of the prices across Europe between Scenario 2 and Scenario 3, for all the modelled years. Values are reported both in £/MWh and in percentage on Scenario 3.

Price differentials in the border countries between Scenario 2 and the Scenario 3 are very low (below 0.5% in all cases). All modelled differentials are almost negligible compared to the effects of other uncertainties over the timeframe

Figure 57 – EU price differentials – Scenario 2 (CM, no price cap) *less* Scenario 3 (CM, price cap)

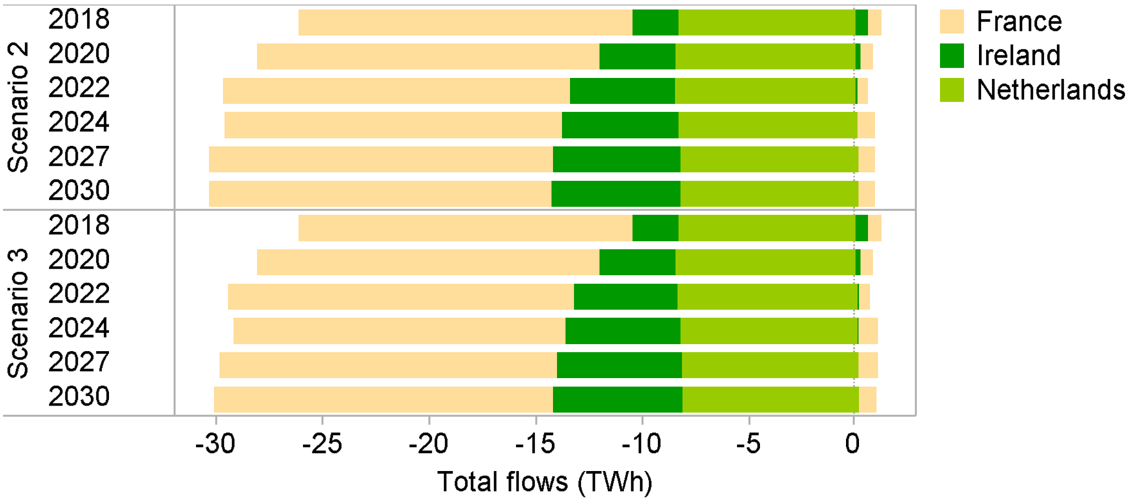


Note: Positive price differentials mean a price cap has lowered price.

4.3.3 Flows

Figure 58 shows the total GB flows across the modelled period for Scenario 2 and scenario 3. The positive values represent the exports from GB towards the connected countries, the negative values represent the imports in GB.

Figure 58 – Total GB flows in Scenario 2 (CM, no price cap) and Scenario 3 (CM, price cap)



Positive values represent the exports, negative values the imports

Figure 59 - Net flow differentials – Scenario 2 (CM, no price cap) *less* Scenario 3 (CM, price cap)

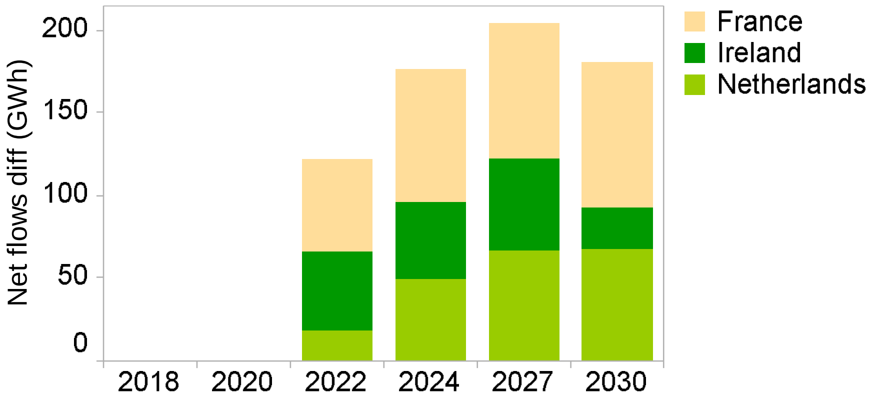
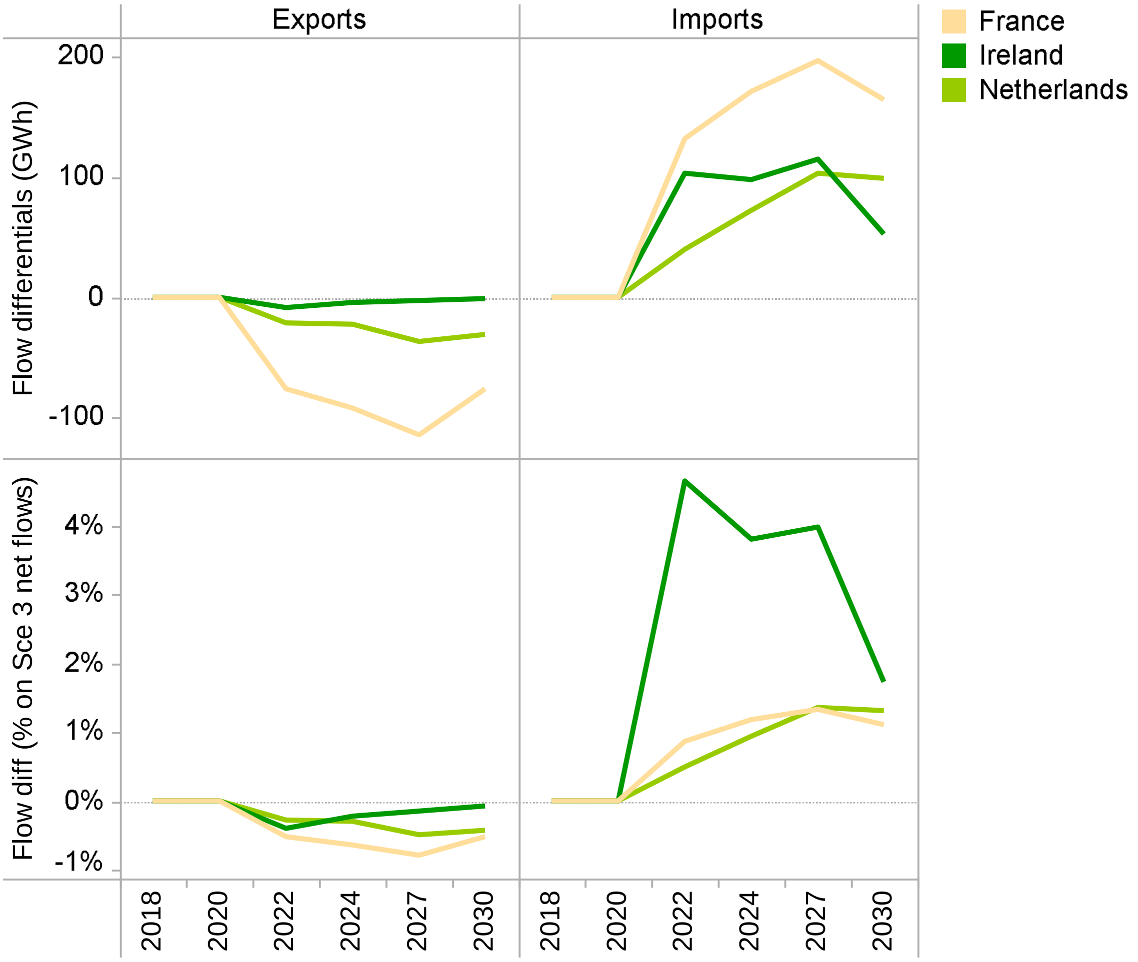


Figure 60 – GB flow differentials – Scenario 2 (CM, no price cap) *less* Scenario 3 (CM, price cap)



Note: Positive numbers mean an increase as a result of removing the price cap.

The flow differentials between Scenario 2 and Scenario 3 are shown in Figure 60 for all the modelled years. Values are reported both in GWh and in percentage on the net flows of Scenario 3.

Export differentials are negligible before 2024 because the market is loose, hence the wholesale price cap rarely binds in Scenario 3. From 2022 onwards the exports decrease in Scenario 2 because of higher wholesale price differentials with the border countries and the GB market being tighter due to lower installed capacity compared to Scenario 3 (effect driven by the combination of the CM and the wholesale price cap).

Import differences are negligible before 2024 because there are no periods with wholesale price greater than £500/MWh. From 2022 onwards, the tighter market in GB in Scenario 2 (lower installed capacity compared to Scenario 3 because of the CM effect) drives the imports upward.

Import differentials are slightly bigger than the exports, hence the overall effect is an increase in the flows between GB and the border countries – however, the scale of this change is negligible.

4.3.4 Revenues for interconnectors

Figure 61 shows the interconnector revenues for each modelled year and for Scenario 3. These revenues are based on market (price differentials) only and assume that interconnector do not get paid capacity payments.

The interconnector revenue differentials between Scenario 2 and Scenario 3 are shown in Figure 62.

From 2022 onwards, the higher wholesale price differentials between UK and the border countries in Scenario 2 mean interconnector revenues are higher in Scenario 2 compared to Scenario 3.

Figure 61 – Interconnector revenues for Scenario 3 (CM, wholesale price cap)

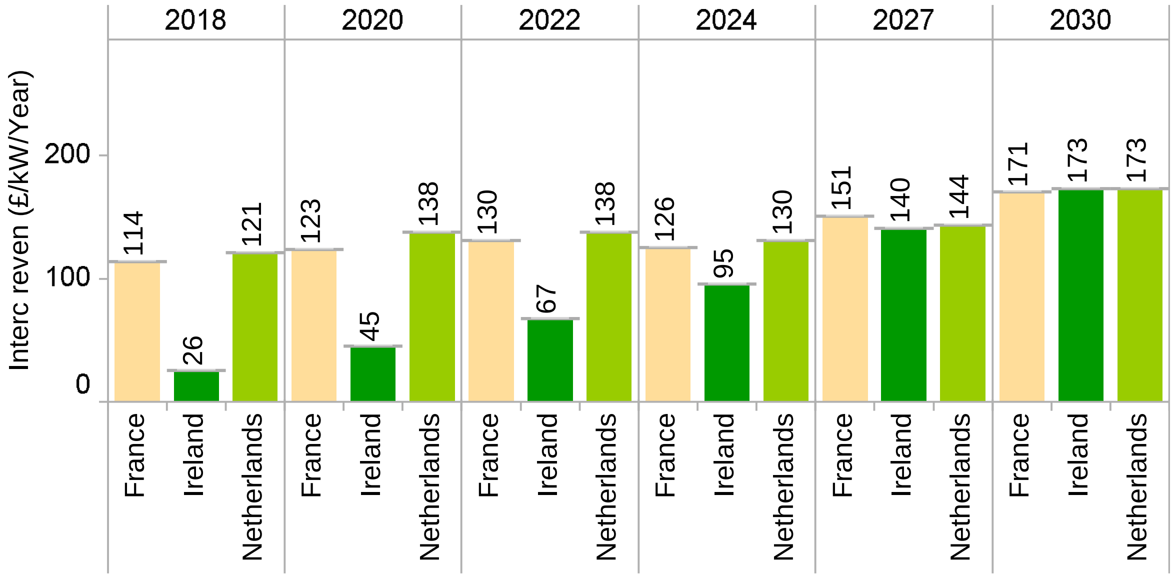


Figure 62 – Interconnector revenues differentials – Scenario 2 (CM, no price cap) *less* Scenario 3 (CM, price cap)

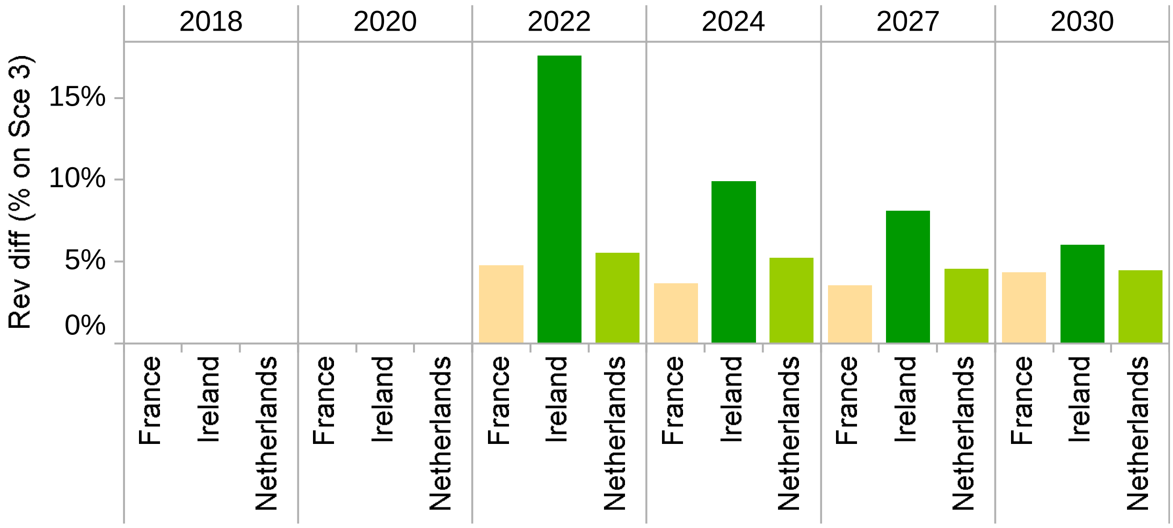


Figure 63 – Average interconnector revenues differentials – Scenario 2 (CM, no price cap) *less* Scenario 3 (CM, price cap)

	Ireland	Netherlands	France
Revenue differentials (% on Scenario 3)	7.8%	3.4%	2.9%

Note: average across all modelled years: (avg(Scenario 2) less avg(Scenario 3)) / avg(Scenario 3)

4.4 The impact of a CM (with cash-out reform and removal of implicit price cap)

To assess the impact of a CM in GB, with cash-out reform, we have modelled Scenario 2 (described in Figure 10) and compared it with the Baseline. The only difference between Scenario 2 and the Baseline is that in Scenario 2 we model a CM by enforcing a 10% capacity margin in each modelled year. The features of this CM, as defined by DECC, are listed in Section 3.2.2. All other input assumptions in Scenario 2 are the same as in the Baseline.

The CM modelled in Scenario 2 starts only from 2022 onwards, hence differences between Scenario 2 and the Baseline will be null before 2022.

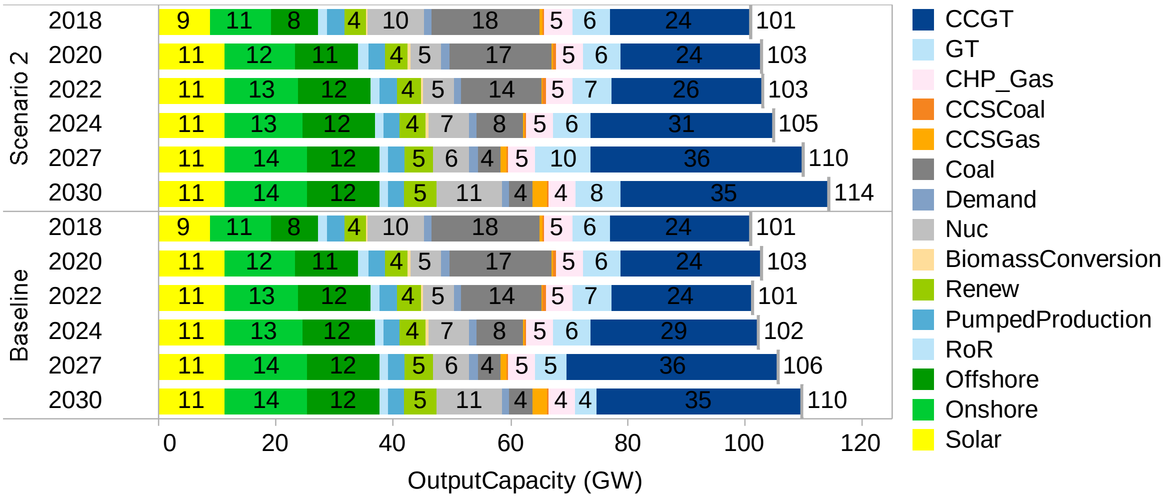
Summary 4 – The impact of a CM (with cash-out reform)

- Installed capacity – The CM leads to 4GW more gas turbines built.
- GB wholesale prices – The CM causes GB prices to fall by up to £6/MWh as capacity margins are looser.
- Continental and Irish prices – The CM has a small effect (<1%) on Continental and Irish prices, with the impact varying by country. These changes are not significant given other uncertainties.
- Interconnector flows – The carbon price floor renders the impact of the CM negligible.
- Interconnector revenues – Revenues decrease as a result of a CM as GB wholesale prices are lower – reducing the price differential with the Continent.

4.4.1 Installed capacity

Figure 64 shows the installed capacity by technology type for the modelled years and for Scenario 2 and the Baseline.

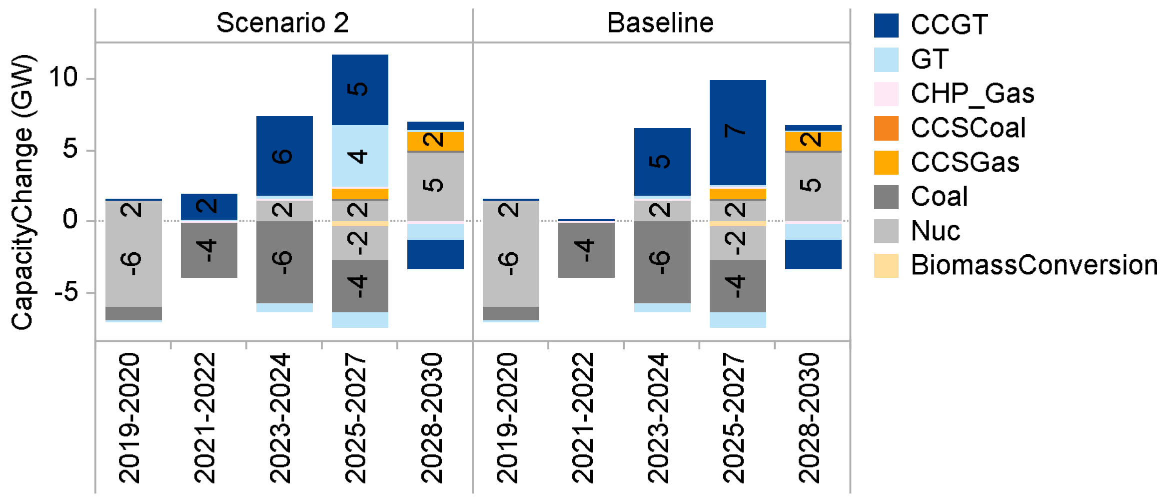
Figure 64 – Installed capacity in Scenario 2 (CM) and the Baseline (no CM)



To achieve a capacity margin of 10% in all modelled years we build more OCGT compared to the Baseline and we anticipate the building of the first new CCGT from 2023 to 2022. The profitability of the new entrant CCGT and OCGT is ensured by the CM.

Figure 65 shows the new plants build (positive values) and the retirals (negative values) for Scenario 2 and for the Baseline.

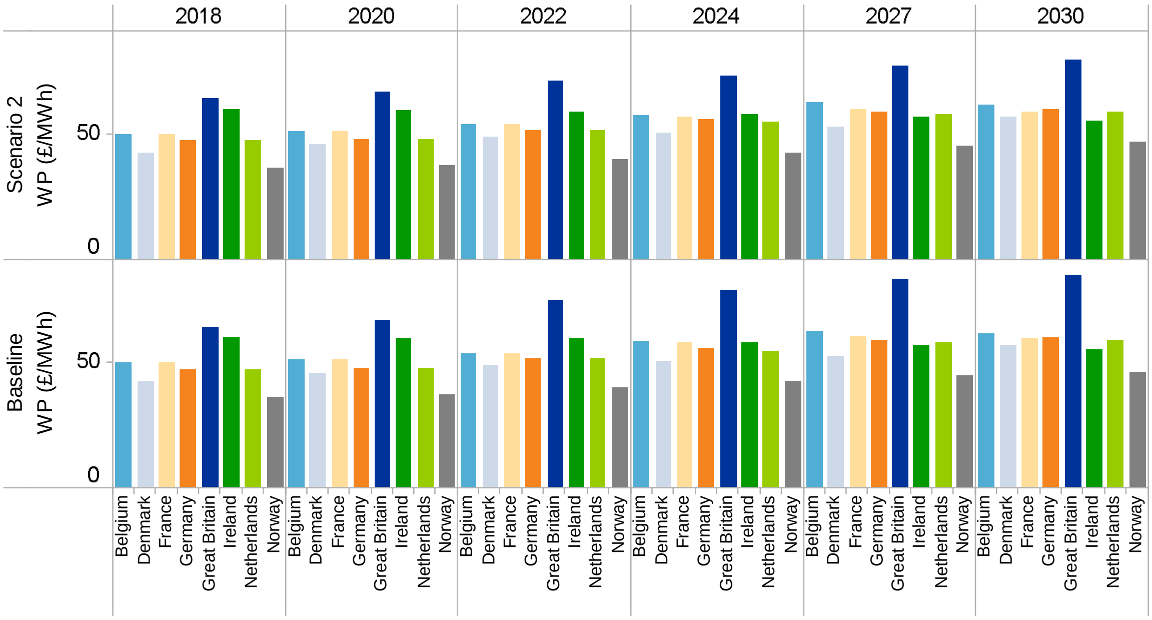
Figure 65 – New build and retiral for Scenario 2 (CM) and the Baseline (no CM)



4.4.2 Prices

Figure 66 shows the wholesale price projections for Scenario 2 and the Baseline across Europe and for all the modelled years. Prices before 2022 are the same as in the Baseline because the CM starts in 2022. From 2022 onwards, wholesale price in the Continent are very similar in Scenario 2 compared to the Baseline. GB prices decrease significantly compared to the Baseline from 2022 onwards because the CM leads to a higher installed capacity.

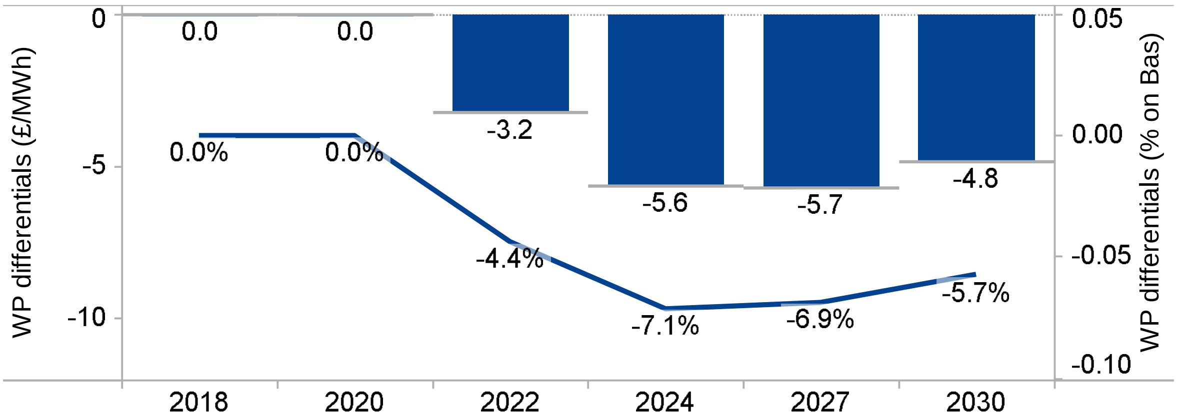
Figure 66 – Wholesale price projections for Scen. 2 (CM) and Baseline (no CM)



The GB price differences between Scenario 2 and the Baseline are shown in Figure 67 for all the modelled years. Values are reported both in £/MWh and in percentage on the Baseline.

The CM only starts in 2022, hence price differentials are zero in the previous years. From 2022 onwards the increased installed capacity in Scenario 2, compared to the Baseline, economically supported by the CM, drives downwards the wholesale price. The drop in 2030 is due to a combination of a slight difference in the amount of load loss in the Baseline in the two years, and the effect of the merit order curve in GB.

Figure 67 – GB price differentials – Scenario 2 (CM) *less* the Baseline (no CM)

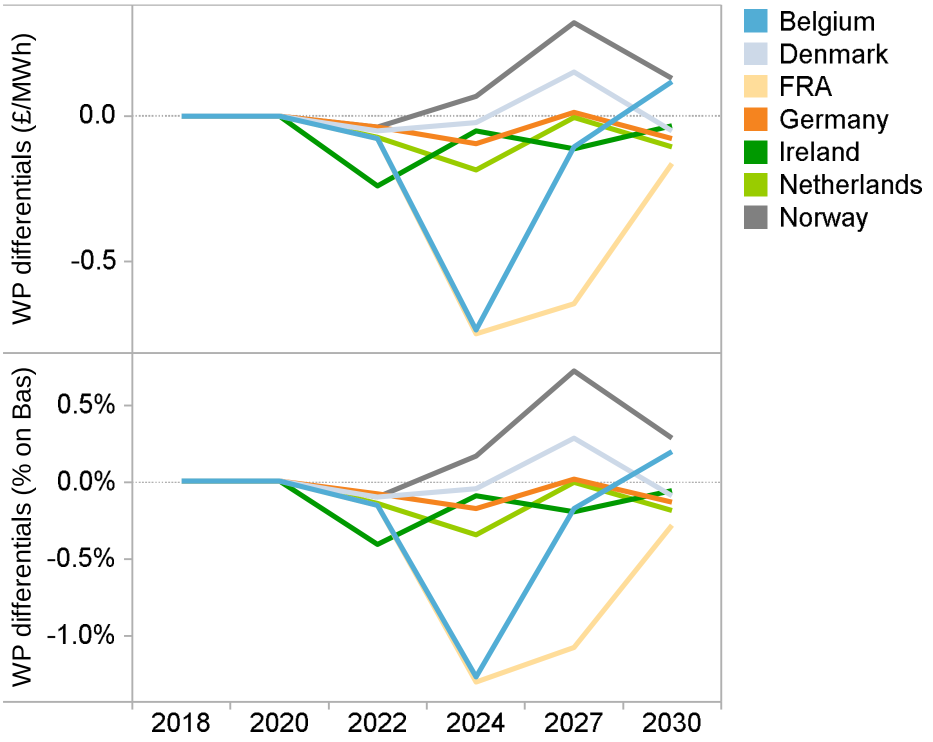


Note: Negative price differentials mean the CM has caused a decrease in prices.

Figure 68 shows the differentials of the prices across Europe between Scenario 2 and the Baseline, for all the modelled years. Values are reported both in £/MWh and in percentage on the Baseline.

Price differentials in the border countries between Scenario 2 and the Baseline are very low (below 1.3% in all cases). All modelled differentials are almost negligible compared to the effects of other uncertainties over the timeframe. Price differentials are higher in 2024 due to the limited requirement for new entry on the continent meaning the changes in GB can feed through. As we move towards 2030 the requirement for new entry to be profitable reduces the range of wholesale price changes.

Figure 68 – EU price differentials – Scenario 2 (CM) *less* Baseline (no CM)



Note: Positive differentials mean that the CM has increased prices.

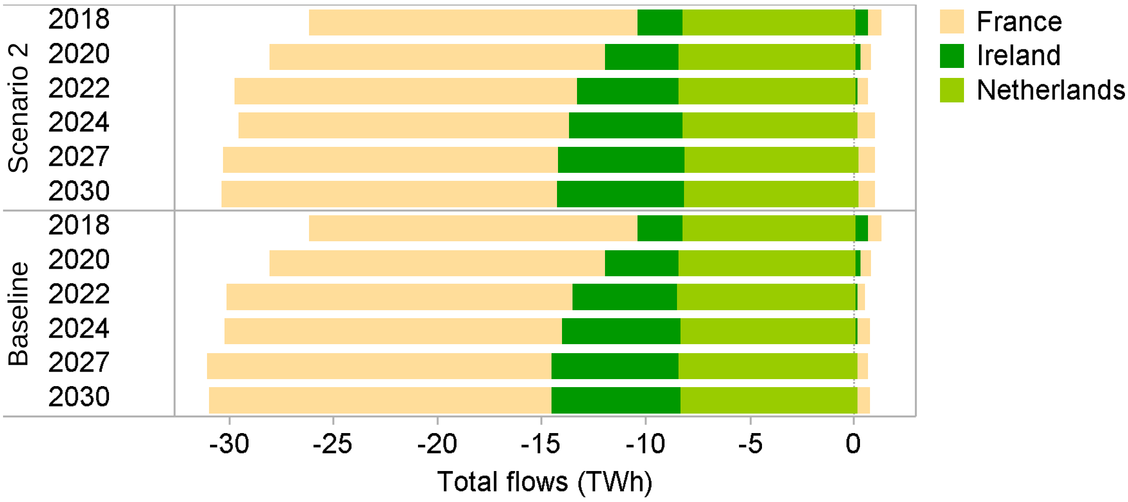
4.4.3 Flows

Figure 69 shows the total GB flows across the modelled period for Scenario 2 and the Baseline. The positive values represent the exports from GB towards the connected countries, the negative values represent the imports in GB.

Despite the increase in the installed capacity in Scenario 2 compared to the Baseline, which drives the wholesale price downwards, GB is still a net importer given the higher wholesale price compared to the border countries. The trend in Scenario 2 is very similar to the Baseline and exports are almost negligible in both scenarios. In effect, the impact of the carbon price floor is to render the impact of the CM negligible.

The flow differentials between Scenario 2 and the Baseline are shown in Figure 71 for all the modelled years. Values are reported both in GWh and in percentage on the net flows of the Baseline.

Figure 69 – Total GB flows in Scenario 2 (CM) and the Baseline (no CM)



Positive values represent the exports, negative values the imports.

Figure 70 – Net flow differentials – Scenario 2 (CM) *less* Baseline (no CM)

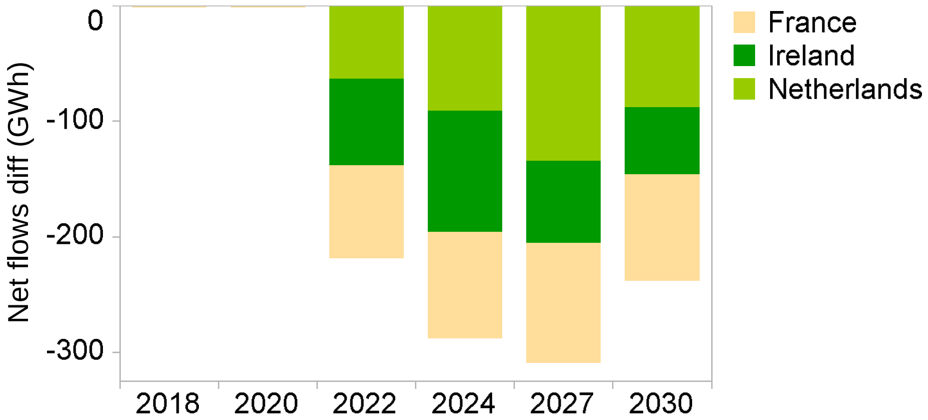
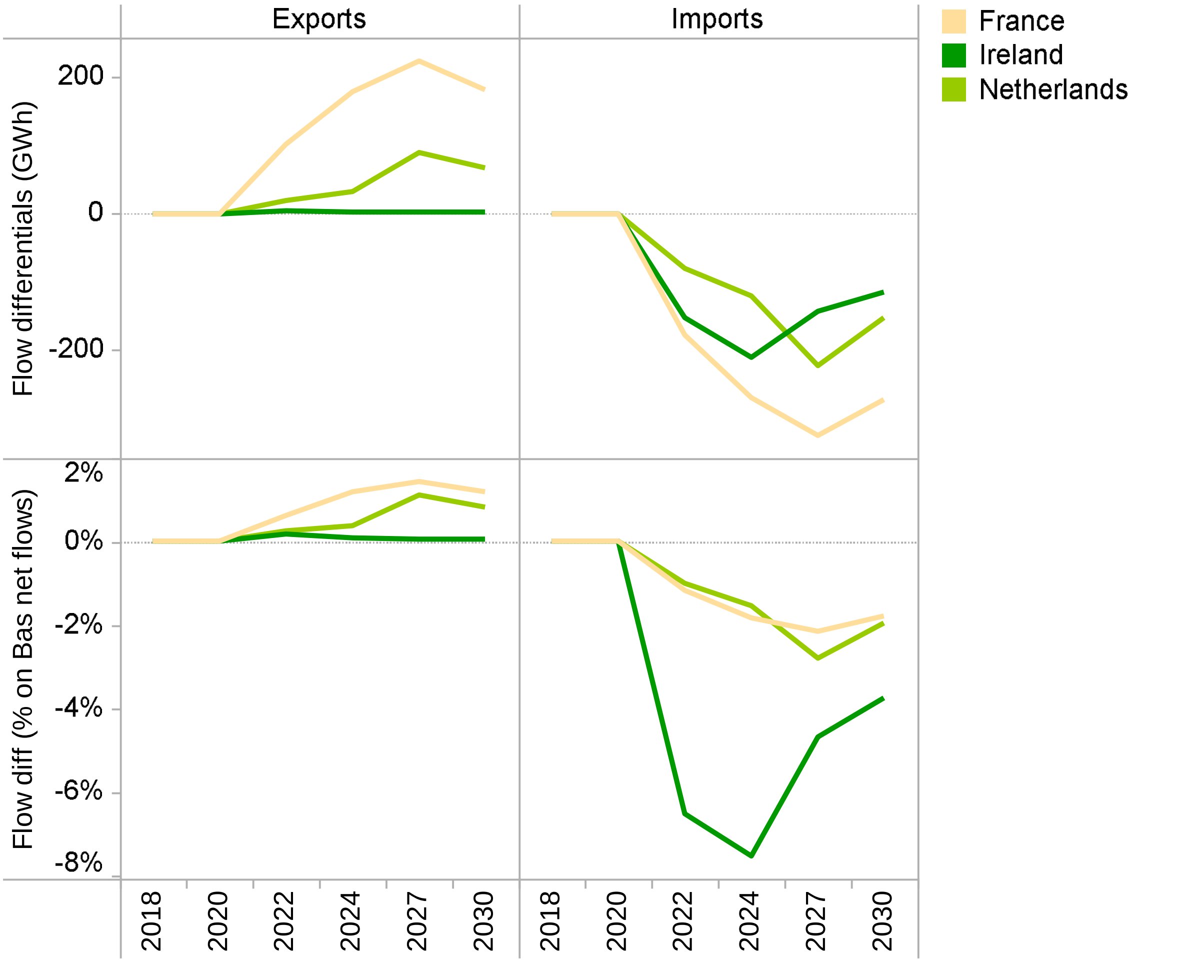


Figure 71 – GB flow differentials – Scenario 2 (CM) *less* Baseline (no CM)



Note: Positive values for exports means that the CM has increased exports. Positive values for imports means that the CM has increased imports.

Both imports and export differentials between Scenario 2 and the Baseline are zero before 2022 because the CM only starts in 2022.

Because of the lower price differentials between GB and the border countries in Scenario 2 compared to the Baseline, exports increase in Scenario 2 while imports decrease.

Import differentials are greater than the export differentials, hence the overall effect is a reduction in the flows between GB and the border countries.

4.4.4 Revenues for interconnectors

Figure 72 shows the interconnector revenues for each modelled year and for Scenario 2 and the Baseline. These revenues are calculated based on wholesale price differentials multiplied by the flows on the interconnector – they do not take account of any other revenues streams (such as capacity payments).

The interconnector revenues differentials between Scenario 2 and the Baseline are reported in Figure 73.

Revenues for interconnector are the same as the Baseline before 2022. From 2022 onwards the lower prices in Scenario 2 in GB reduce the interconnector revenues compared to the Baseline.

Figure 72 – Interconnector revenues for Scenario 2 (CM)

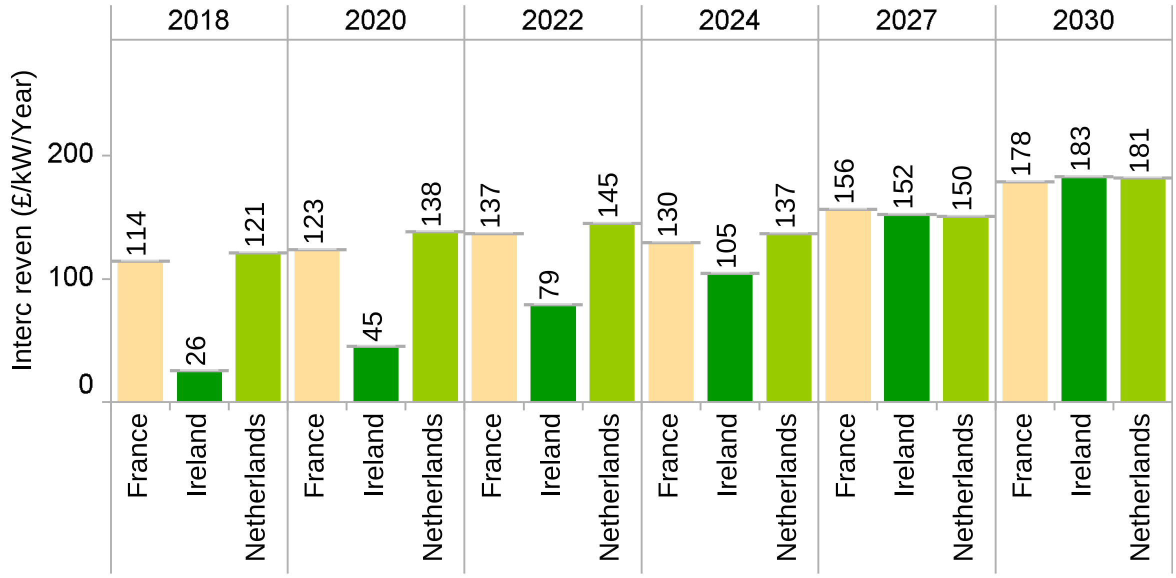
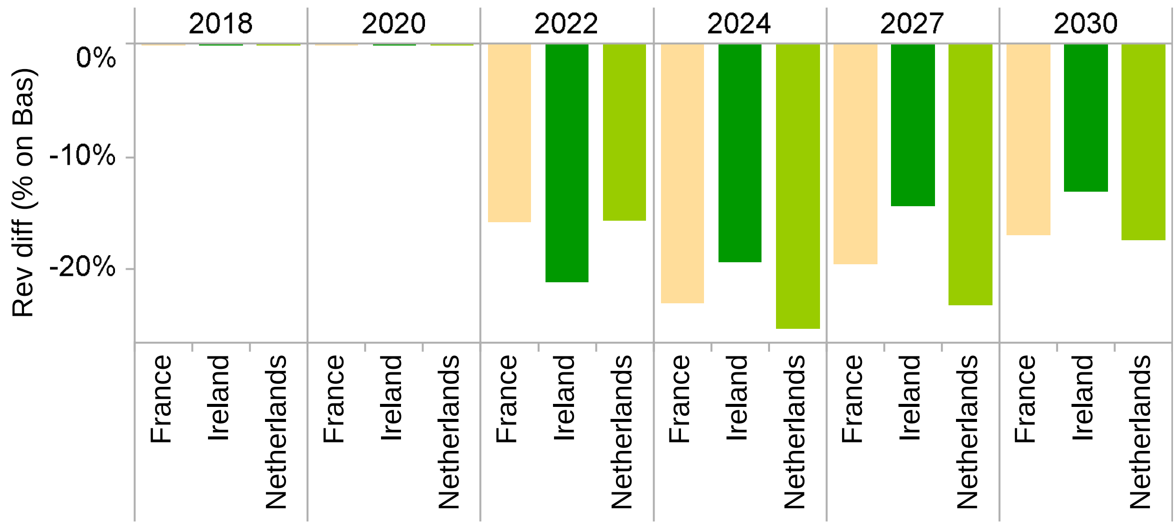


Figure 73 – Interconnector revenue differentials – Scenario 2 (CM) *less* Baseline (no CM)



Note: Negative values mean the CM has decreased interconnector revenues

Figure 74 – Interconnector revenue differentials – Scenario 2 (CM) *less* Baseline (no CM)

	Ireland	Netherlands	France
Revenue differentials (% on Baseline)	-14.2%	-15.2%	-14.4%

Note: average across all modelled years: (avg(Scenario 2) less avg(Baseline)) / avg(Baseline)

4.5 The impact of a CM (without cash-out reform and hence continuance of existing implicit price caps)

To assess the impact of a CM in GB, further to the analysis explained in Section 4.3, we have also modelled Scenario 3 (described in Figure 10) with a CM in GB and compared it with Scenario 1 (without CM), in order to assess the effect of a CM in GB when the wholesale price is capped at £500/MWh as a result of an unreformed cash-out mechanism. The features of this CM, as defined by DECC, are listed in Section 3.2.2.

Summary 5 – The impact of a CM (without cash-out reform)

- Installed capacity
  – The CM leads to an increase in capacity of around 9GW compared to a market without a CM, as a result of the requirement to achieve a 10% capacity margin.
- GB wholesale prices
  – Wholesale prices are roughly £7/MWh lower with a CM than without.
- Continental and Irish prices
  – The capacity payment leads to a very small (max 1.2%) drop in Continental prices, with France, Netherlands and Belgium most affected.
- Interconnector flows
  – There is no significant impact on interconnector flows (max change of 0.15%).
- Interconnector revenues
  – Compared to no CM, a CM causes a drop in revenues of around 15% on interconnectors to France, Ireland and Netherlands, as GB prices fall owing to more capacity.

4.5.1 Installed capacity

Figure 75 shows the installed capacity by technology type for the modelled years and for Scenario 3 and Scenario 1.

Figure 75 – Installed capacity in Scenario 3 (CM, price cap) and Scenario 1 (no CM, price cap)

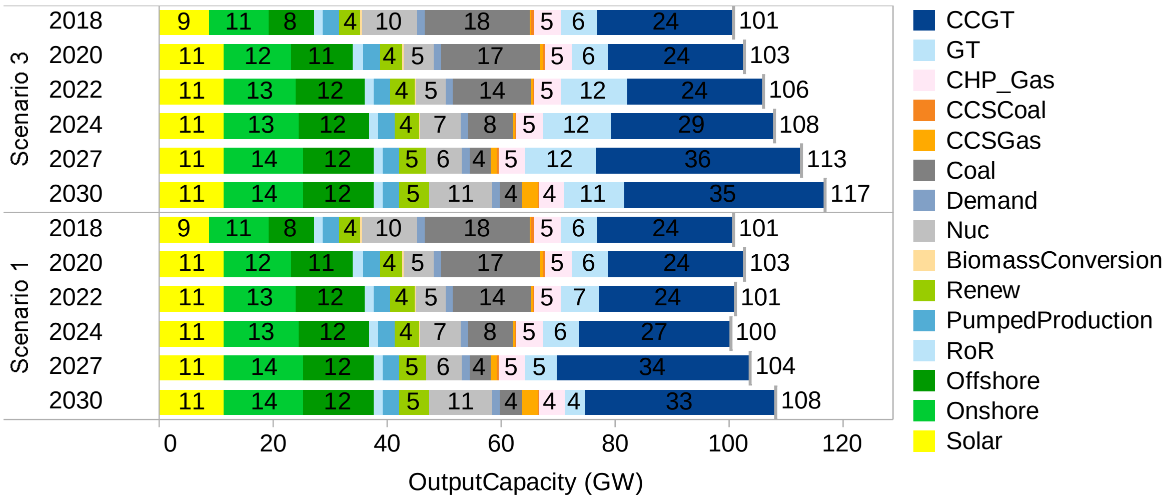
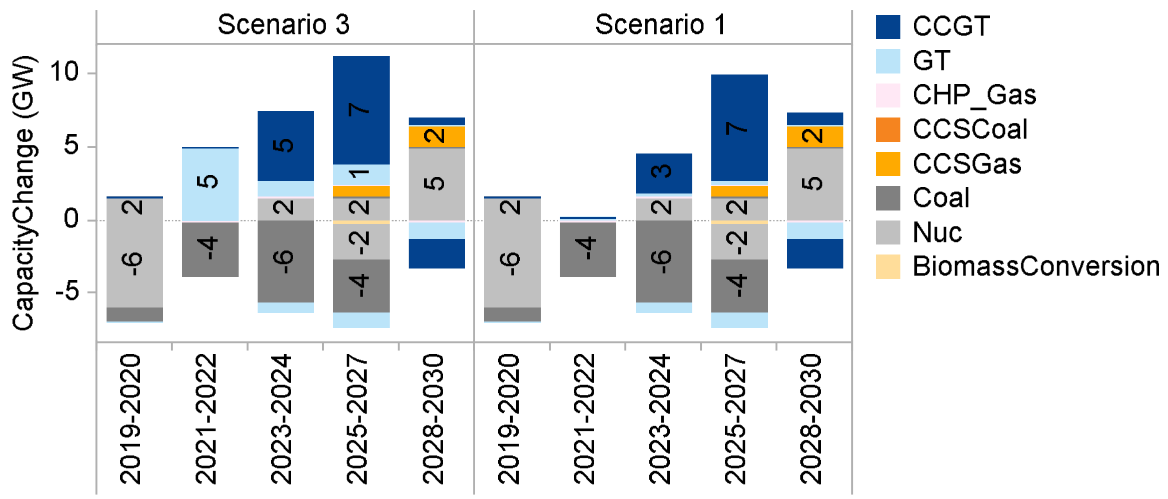


Figure 76 shows the new plants build (positive values) and the retirals (negative values) for Scenario 3 and scenario 1.

A CM in GB (comparison of Scenario 3 with Scenario 1) leads to a big increase in the installed capacity (around 9GW more in Scenario 3 compared to Scenario 1 from 2027 onwards) necessary to achieve a capacity margin of 10%, bearing in mind that Scenario 1 itself had significantly less capacity than the baseline (more load loss due to the wholesale price cap).

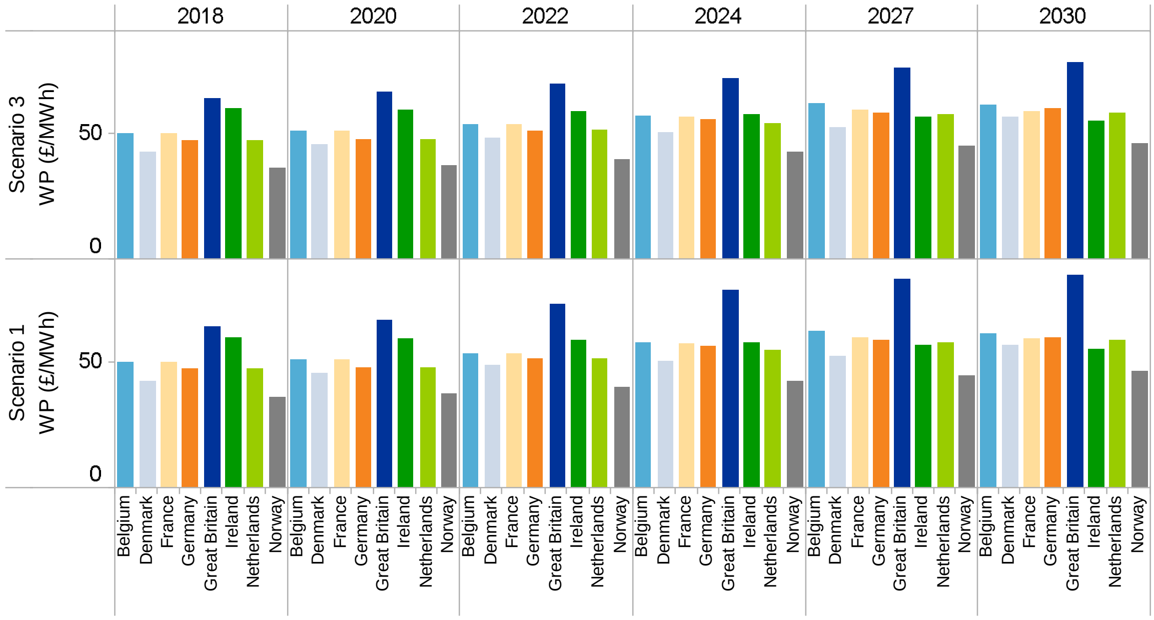
Figure 76 – New build and retiral for scenario 3 (CM, price cap) and Scenario 1 (no CM, price cap)



4.5.2 Prices

Figure 77 shows the wholesale price projections for Scenario 3 and Scenario 1 across Europe and for all the modelled years.

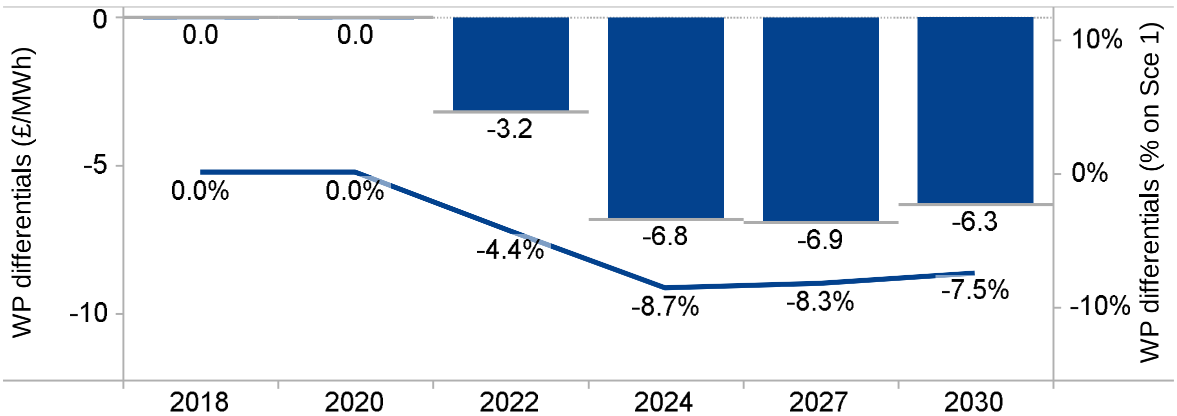
Figure 77 – Wholesale price projections for Scenario 3 (CM, price cap) and Scenario 1 (no CM, price cap)



The GB price differentials between Scenario 3 and Scenario 1 are shown in Figure 78 for all the modelled years. Values are reported both in £/MWh and in percentage on Scenario 1.

The CM only starts in 2022, hence price differentials are zero in the previous years. From 2022 onwards the increased installed capacity compared to Scenario 1, economically supported by the CM, drives downwards the wholesale price.

Figure 78 – GB price differentials – Scenario 3 (CM, price cap) *less* Scenario 1 (no CM, price cap)

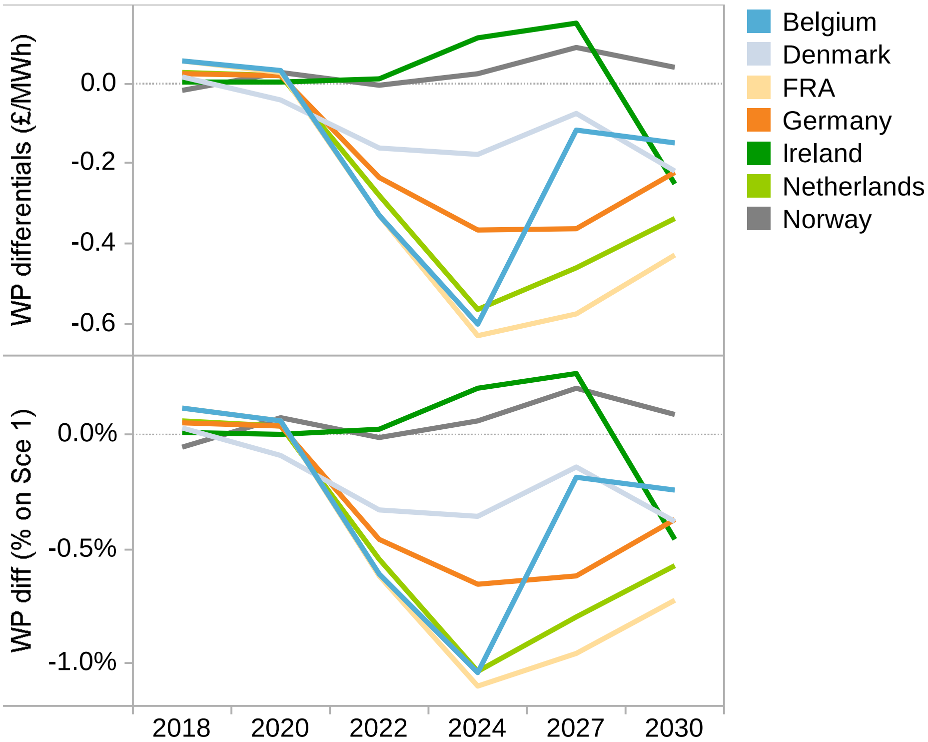


Note: Negative price differentials mean a CM reduces prices

Figure 79 shows the price differentials across Europe between Scenario 3 and Scenario 1, for all the modelled years. Values are reported both in £/MWh and in percentage on Scenario 1.

Price differentials in the border countries between Scenario 3 and Scenario 1 are very low (below 1.2% in all cases). The differences fall on the Continent as the need for new entry increases; it is smallest in the countries with the most need to thermal new entry (Belgium and Germany). France has a capacity payment, so can absorb a drop in the wholesale price.

Figure 79 – EU price differentials – Scenario 3 (CM, price cap) *less* Scenario 1 (no CM, price cap)



Note: Negative price differentials mean that a CM reduces prices

4.5.3 Flows

Figure 80 shows the total GB flows across the modelled period for Scenario 3 and Scenario 1. The positive values represent the exports from GB toward the connected countries, the negative values represent the imports in GB.

The flow differentials between Scenario 3 and Scenario 1 are shown in Figure 82 for all the modelled years. Values are reported both in GWh and in percentage on the net flows of Scenario 1.

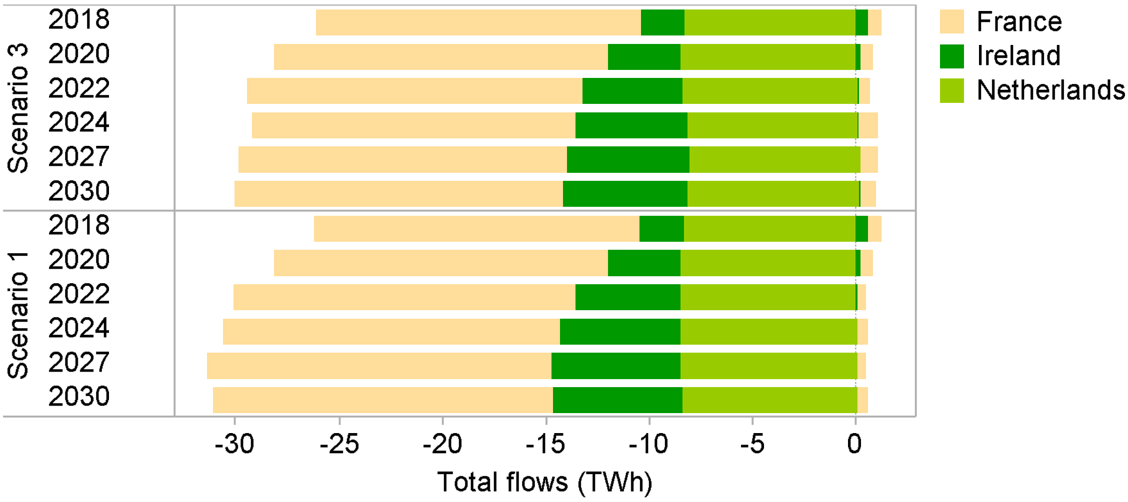
Flow differentials are zero before 2022 since the CM starts only in 2022.

Exports increase from 2022 onwards driven by the lower price differentials between GB and the border countries.

From 2022 onwards the flow **imports** decrease compared to Scenario 1 given the lower price differentials between GB and the border countries

Import differentials are greater than the export differentials, hence the overall effect is a reduction in the flows between GB and the border countries. However, overall the impact is negligible.

Figure 80 – Total GB flows in Scenario 3 (CM, price cap) and Scenario 1 (no CM, price cap)



Positive values represent the exports, negative values the imports

Figure 81 – Net flow differentials – Scenario 3 (CM, price cap) *less* Scenario 1 (no CM, price cap)

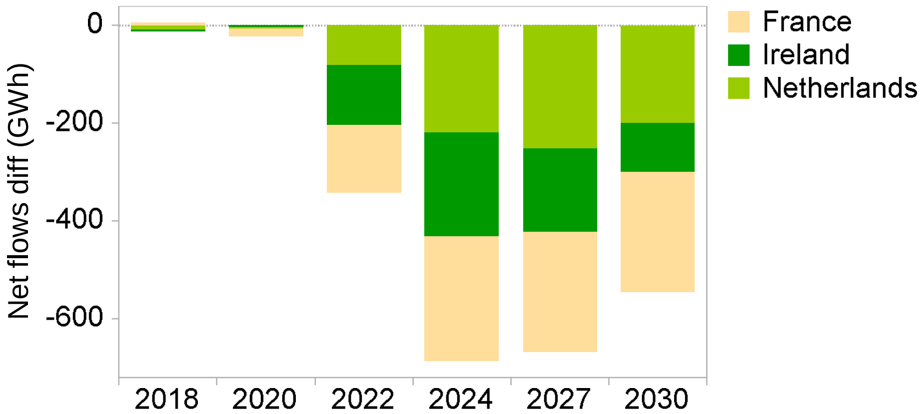


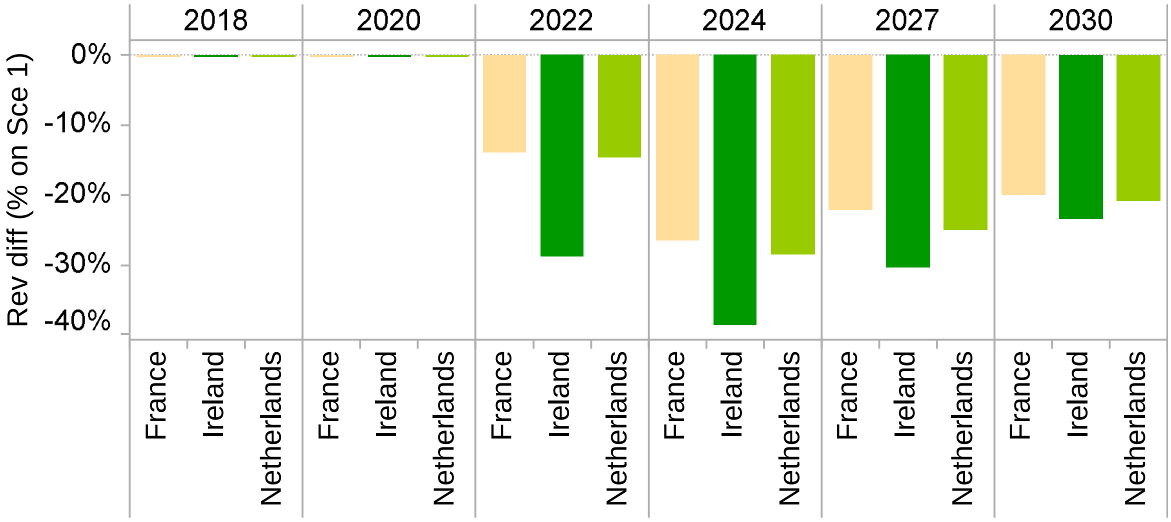
Figure 82 – GB flow differentials – Scenario 3 (CM, price cap) *less* Scenario 1 (no CM, price cap)

Note: Positive values for exports mean a CM increases exports, positive values for imports means the CM increases imports.

4.5.4 Revenues for interconnectors

Figure 83 shows the interconnector revenue differentials between Scenario 3 and Scenario 1. Interconnector revenues are lower in Scenario 3 as a result of the CM depressing wholesale prices in GB leading to lower price differentials between GB and the Continent.

Figure 83 – Interconnector revenue differentials – Scenario 3 (CM, price cap) *less* Scenario 1 (no CM, price cap)



Note: Negative values means a CM reduces revenues

Figure 84 – Interconnector revenue differentials – Scenario 3 (CM, price cap) *less* Scenario 1 (no CM, price cap)

	Ireland	Netherlands	France
Revenue differentials (% on Scenario 1)	-26.9%	-16.8%	-15.8%

Note: average across all modelled years: (avg(Scenario 3) less avg(Scenario 1)) / avg(Scenario 1)

4.6 The impact of increased interconnection (with CM)

To assess the impact of an increased interconnection between GB and the border countries, with a CM in GB, we have modelled Scenario 4 (described in Figure 10) and compared it with Scenario 2. The details of the increased interconnections have been provided by DECC and are reported Figure 12. The features of the CM, as defined by DECC, are listed in Section 3.2.2.

Summary 6 – The impact of increased interconnection (with CM)

- Installed capacity – Increased interconnection leads to higher flows into GB, and hence lower requirement for new capacity to be built – 6GW of additional interconnection leads to about 3GW less firm capacity built.
- GB wholesale prices – Increasing the amount of interconnection causes prices to fall to 2-3%– the very high prices in GB driven by the carbon price floor are reduced slightly by cheaper imports.
- Continental and – Increasing interconnection to other countries causes

	Irish prices	their prices to rise – in particular Norwegian and Danish prices rise up to £5/MWh, although other prices rise by around £1/MWh
▪	Interconnector flows	– Irrespective of the level of interconnection tested, the interconnectors operate close to baseload imports – the carbon price floor leads to such a large differential in wholesale prices that even a significant increase in interconnection is not sufficient to alleviate it.
▪	Interconnector revenues	– Interconnector revenues per kW are heavily affected by increasing the interconnection – France and Dutch interconnector revenues drop by around 21%.
▪	Capacity credit	– The overall capacity credit of the 10GW of interconnection is around 60%, varying from a low with SEM (23%) and France (44%) to a high with Norway (96%).

4.6.1 Installed capacity

Figure 85 shows the installed capacity by technology type for the modelled years and for Scenario 4 and Scenario 2.

The increased interconnection in Scenario 4 compared to Scenario 2 leads to higher flows into GB, hence a lower installed capacity will be required to achieve a supply margin of 10%. Comparing the two scenarios, there is a difference of 5GW generation capacity, of which 2GW is wind, thus the addition of 6GW of interconnection capacity leads to 3GW less firm capacity.

Figure 86 shows the new plants build (positive values) and retirals (negative values) for Scenario 4 and Scenario 2.

Figure 85 – Installed capacity in Scenario 4 (High IC, CM) and Scenario 2 (low IC, CM)

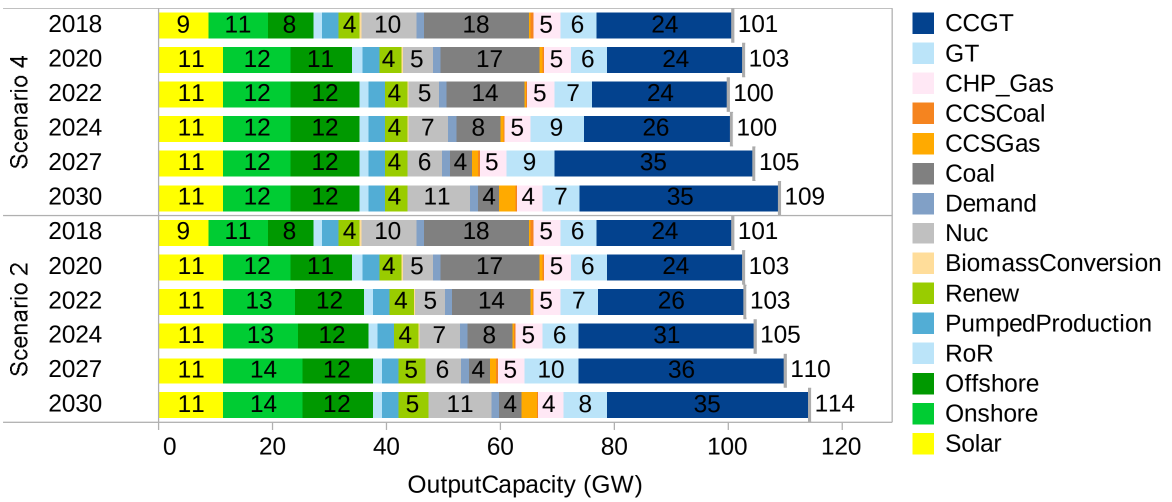
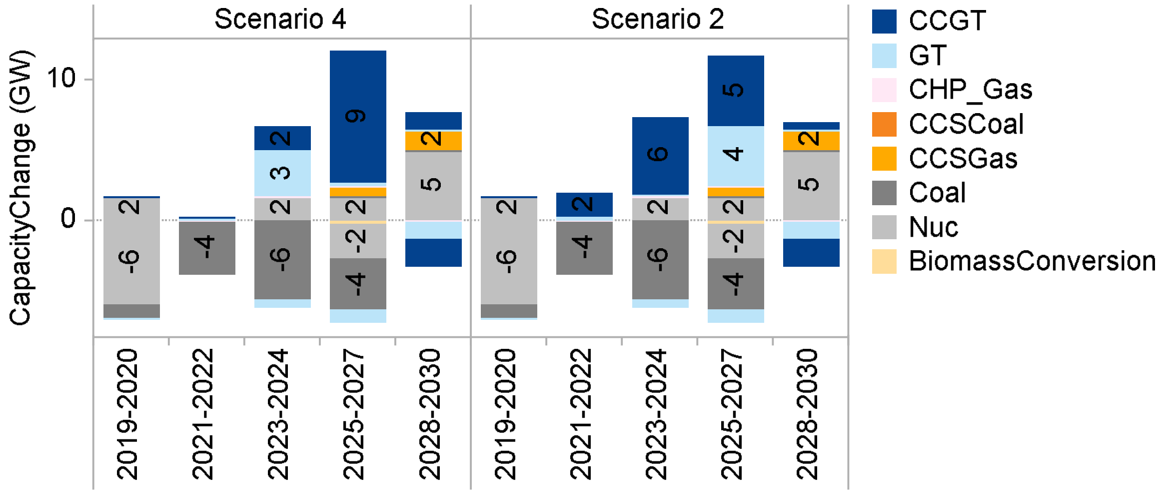


Figure 86 – New build and retiral for Scenario 4 (high IC, CM) and Scenario 2 (low IC, CM)



In Figure 87 are shown the de-rated capacity margins in Scenario 4.

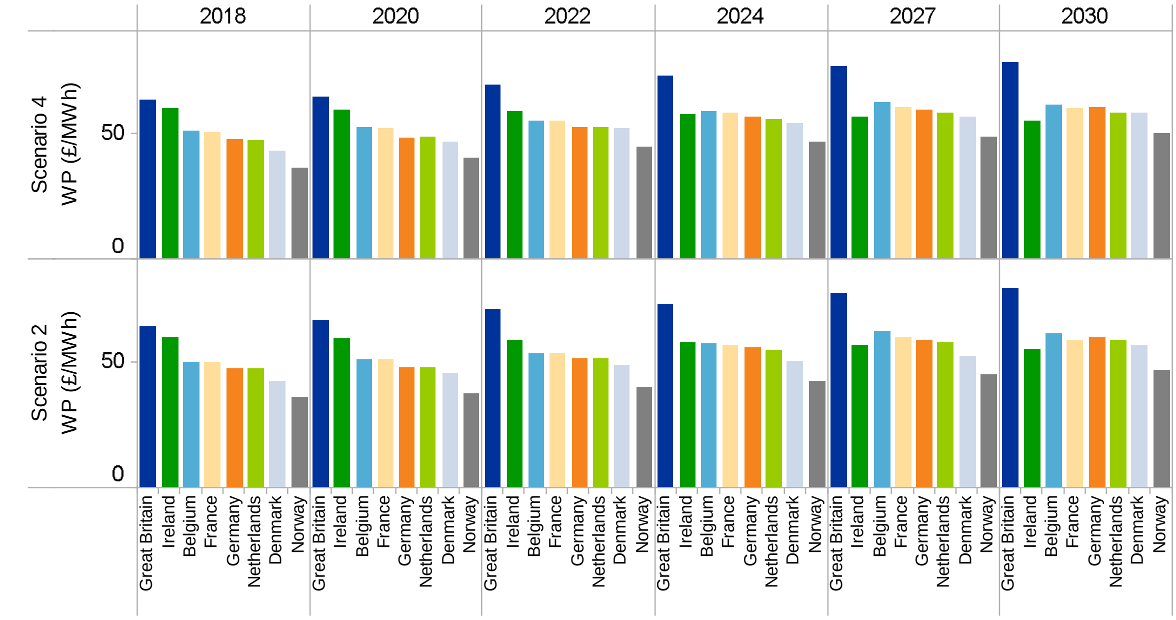
Figure 87 – De-rated capacity margin, Scenario 4

Derated capacity margin (%)	2018	2020	2022	2024	2027	2030
With interconnectors	17.7%	14.4%	10.8%	10.1%	10.1%	10.3%
Without interconnectors	13.4%	10.0%	2.2%	0.2%	0.7%	1.4%

4.6.2 Prices

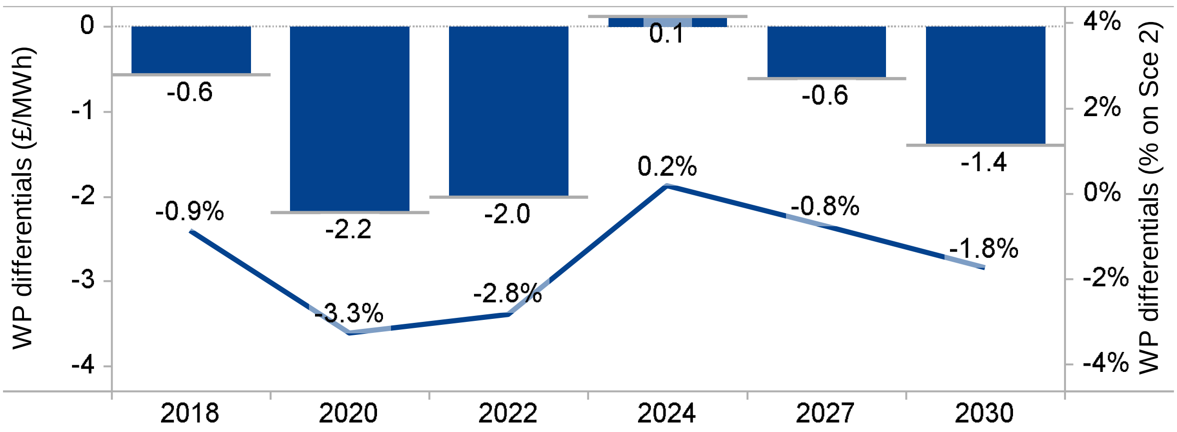
Figure 88 shows the wholesale price projections for Scenario 4 and Scenario 2 across Europe and for all the modelled years.

Figure 88 – WP projections for Scenario 4 (High IC, CM) and Scenario 2 (Low IC, CM)



The GB price differentials between Scenario 4 and Scenario 2 are shown in Figure 78 for all the modelled years. Values are reported both in £/MWh and in percentage on Scenario 2. Overall, increasing the amount of interconnection causes prices to fall – the very high prices in GB driven by the carbon price floor are reduced slightly by cheaper imports.

Figure 89 – GB price differentials – Scenario 4 (High IC, CM) *less* Scenario 2 (Low IC, CM)

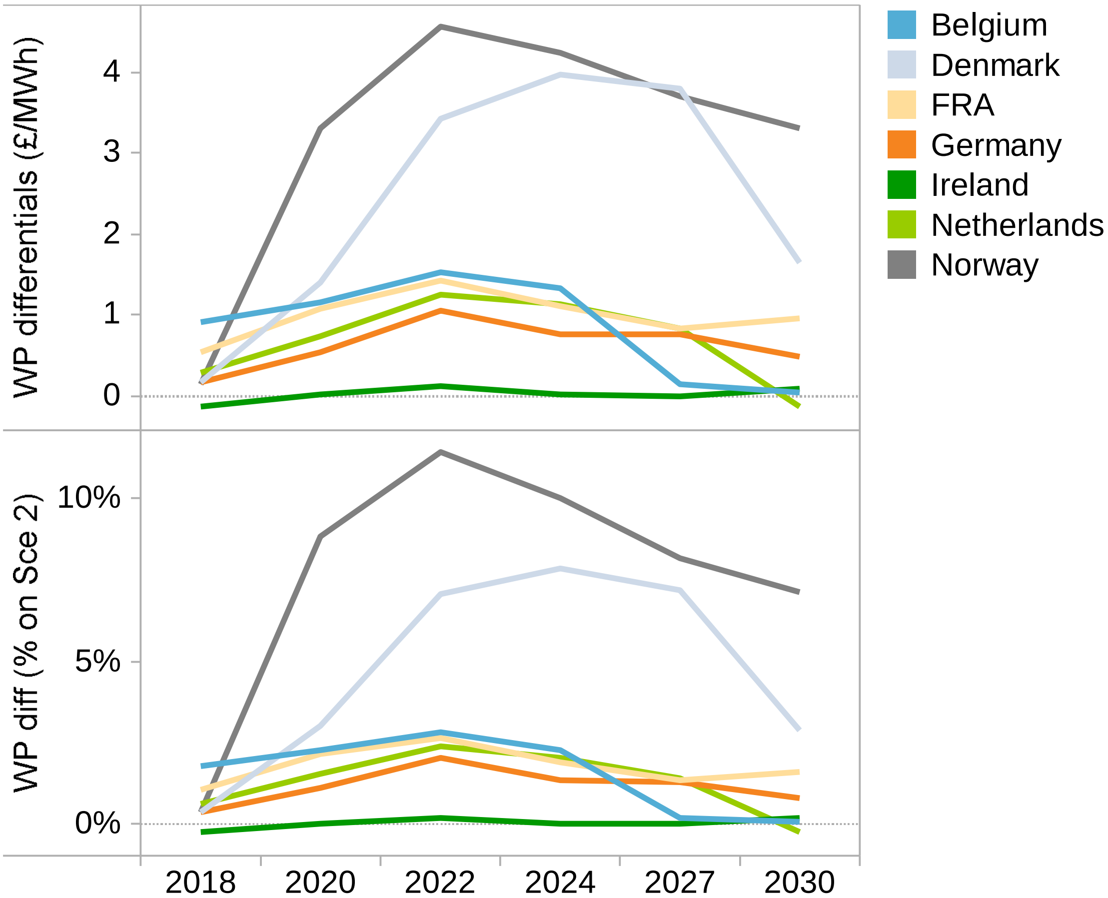


Note: Negative numbers mean that increasing IC causes prices to fall.

Figure 90 shows the price differentials across Europe between Scenario 4 and Scenario 2, for all the modelled years. Values are reported both in £/MWh and in percentage on Scenario 2.

Increasing the amount of interconnection causes a significant impact on the Norwegian and Danish markets – causing prices to rise by up to £4.5/MWh. The interconnection to Norway and Denmark allows them to exports very heavily to GB which causes their own prices to rise in response. The impact on the other Continental European countries is lower – prices rise by around £1/MWh as a result of the increased interconnection.

Figure 90 – EU price differentials – Scenario 4 (High IC, CM) *less* Scenario 2 (Low IC, CM)



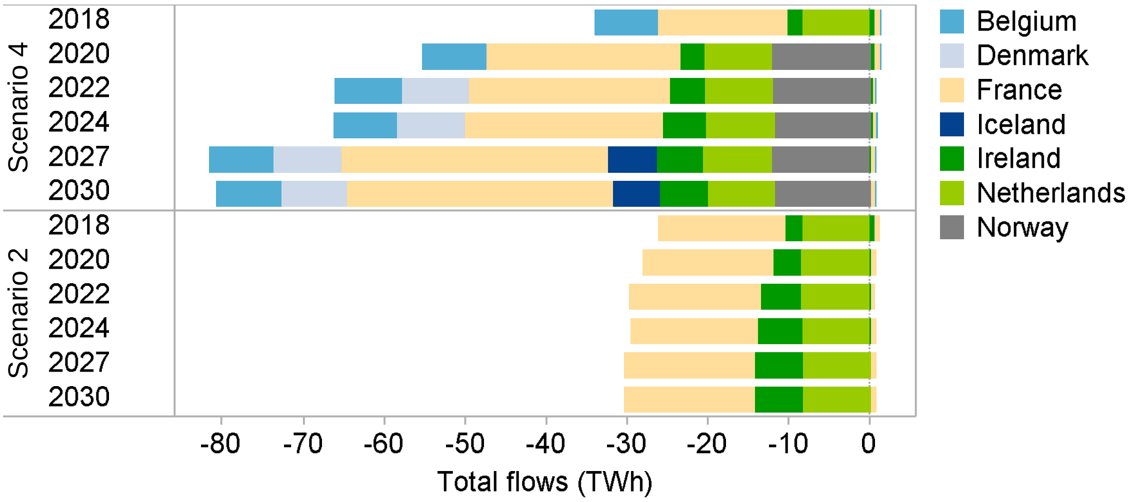
Note: Positive values mean higher IC causes prices to rise.

4.6.3 Flows

Figure 91 shows the total GB flows across the modelled period for Scenario 4 and Scenario 5. The positive values represent the exports from GB toward the connected countries, the negative values represent the imports to GB.

In both scenarios, the interconnector operate close to baseload imports – the carbon price floor leads to such a large differential in wholesale prices that even a significant increase in interconnection is not sufficient to alleviate it.

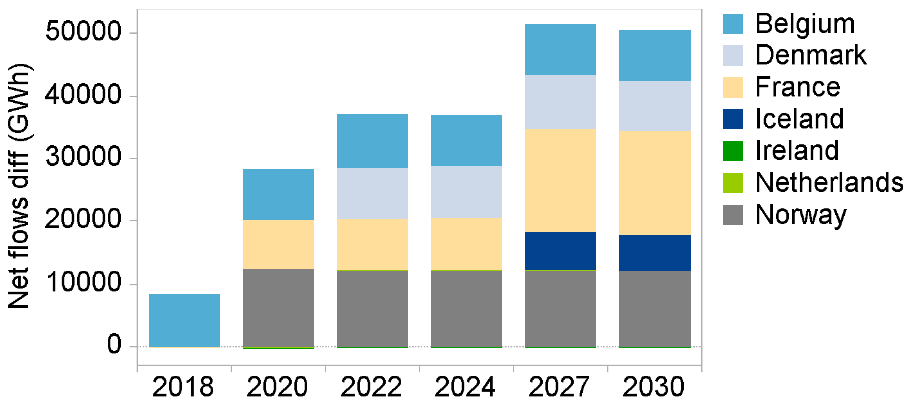
Figure 91 – Total GB flows in Scenario 4 (High IC, CM) and Scenario 2 (How IC, CM)



Positive values represent the exports, negative values the imports

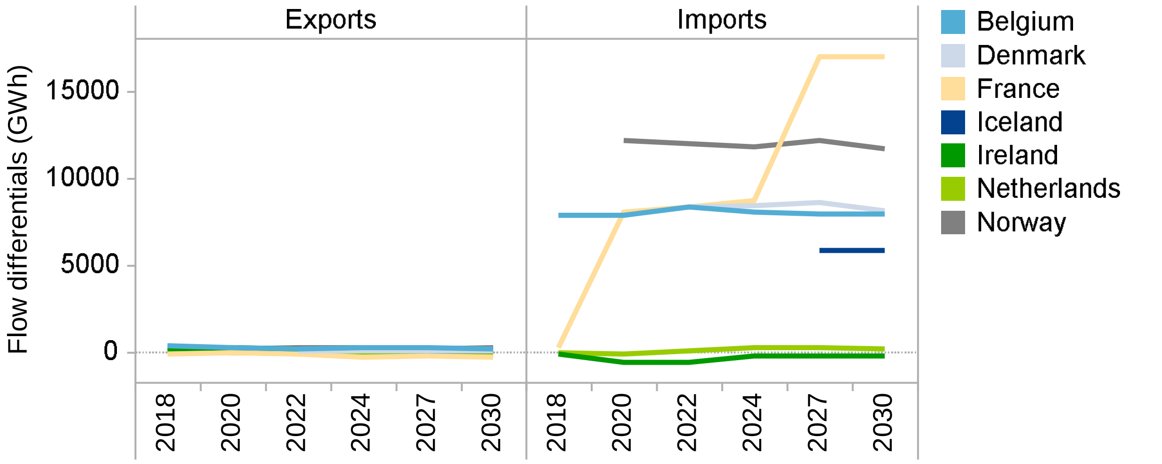
As a result of the significant increase in interconnection and the sustained differential in carbon prices, interconnection flows increase substantially, by 100TWh by 2030.

Figure 92 – Net flow differentials – Scenario 4 (Low IC, CM) *less* Scenario 2 (High IC, CM)



Note: negative flows means increasing interconnection increases imports

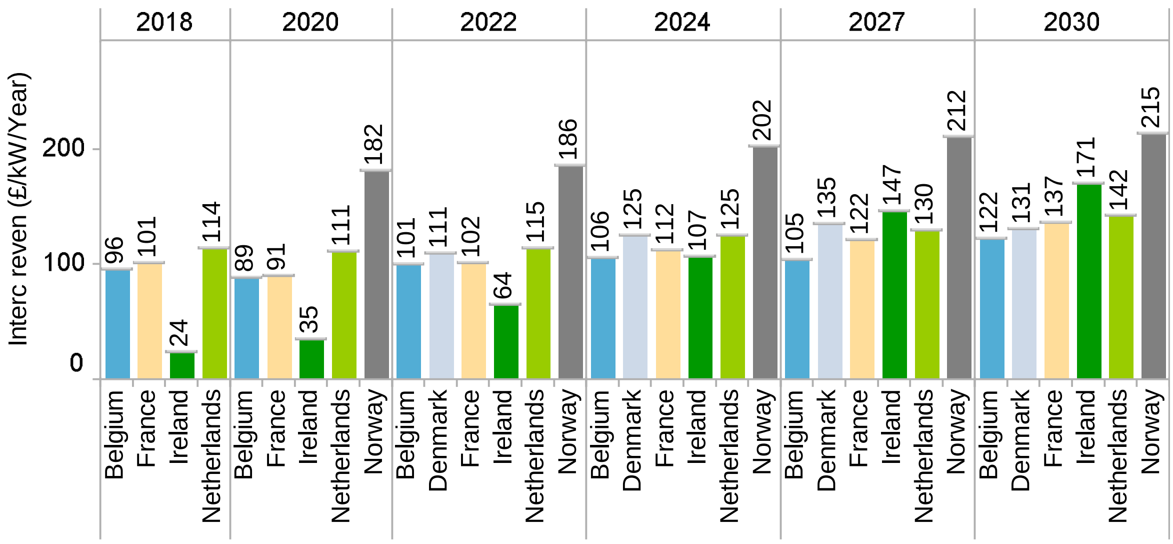
Figure 93 – GB flow differentials – Scenario 4 (high IC, CM) *less* Scenario 2 (low IC, CM)



4.6.4 Revenues for interconnectors

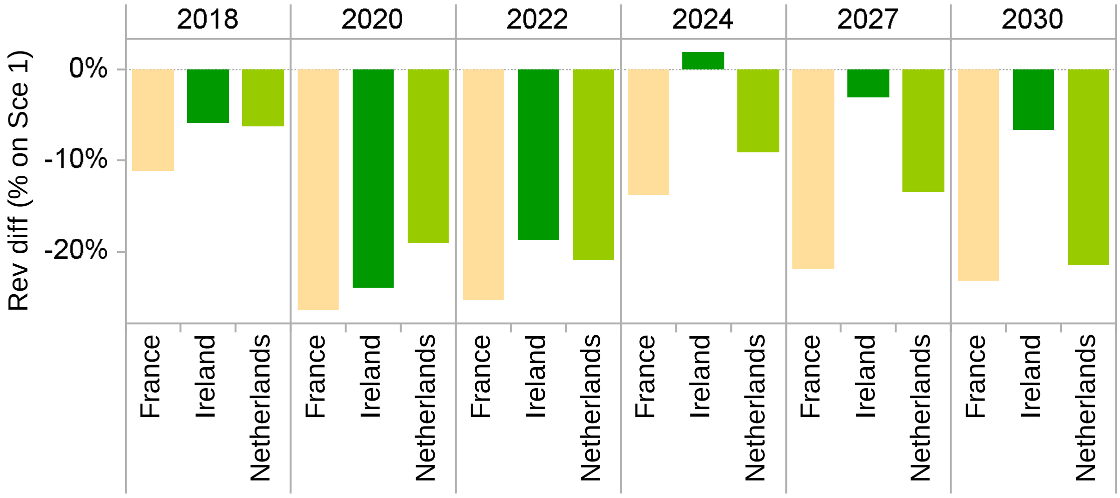
Figure 94 shows the interconnector revenues for Scenario 4. These revenues are based on market (price differentials) only and assume that interconnector do not get paid capacity payments. It is notable that interconnector revenues to Norway are the greatest – this interconnector makes almost twice the revenues of the other interconnectors.

Figure 94 – Interconnector revenues for Scenario 4 (High IC, CM)



Interconnector revenues on a per kW basis reduce with increasing interconnection. For example, the increase in the interconnector to France by 1GW 1GW or 50% and Belgium by causes revenues per kW for France drop by 20-30%, and to Netherlands to drop by 20% in 2020 and 2022.

Figure 95 – Interconnector revenues differentials - Scenario 4 (high IC, CM) *less* Scenario 2 (low IC, CM)



Note: Negative revenue differentials means increasing interconnection lowers profitability

Figure 96 – Average interconnector revenues differentials - Scenario 4 (high IC, CM) *less* Scenario 2 (low IC, CM)

	Ireland	Netherlands	France
Revenue differentials (% on Scenario 2)	-7.2%	-15.6%	-20.8%

Note: average across all modelled years: (avg(Scenario 4) less avg(Scenario 2)) / avg(Scenario 2)

4.7 Interconnection capacity credit

The calculation of interconnection capacity credit is not a simple exercise, and there is no one single methodology. The calculation involves looking at the lost load that GB has with the interconnectors. Then the interconnectors are ‘removed’, and the additional capacity that would need to be added if GB to bring the lost load back down to two hours is calculated.

It should be noted that calculation of interconnection capacity credit was not a key deliverable from this work, and thus although we are comfortable with the figures quoted, a more in-depth analysis may give slightly different numbers. Thus we have marked all the capacity credit numbers as approximate.

For this study, a particular issue concerns the current overcapacity situation on the Continent – if this is assumed to continue into the future, the capacity credit of interconnectors will be much higher than if we assume a more balanced outcome. Going forward, margins still tend to be a little higher on the Continent than GB, since a flatter demand net wind/solar duration curve means a smaller price markup is required at a given capacity margin. In addition, the assumption of a Capacity Mechanism in France means that there is a persistent ‘overcapacity’ situation in France.

In the Irish SEM there is currently a very large overcapacity. Going forward, things may be expected to tighten. However, in this analysis the presence of the CPS in GB and no CPS in the Republic of Ireland encourages CCGT build in the SEM so keeps margins larger than they would otherwise have been.

4.7.1 Baseline

For the Baseline scenario, we carried out three calculations of the system margin. The first was the Baseline with wide system margins in Continental Europe, with few hours of lost load. This leads to a much higher capacity credit, as there is always spare capacity on the Continent to supply GB at times of system stress. As a result, the average interconnection capacity credit was 86%, with over 90% for France and Netherlands.

In the second calculation, we examined the capacity credit of interconnection assuming that the Continent had roughly two hours of lost load: Norway/Finland/Sweden was tightened up, but to a lesser extent, given that there was no new thermal build there in any case. Netherlands was also tightened up a lot, but has a very large overcapacity so we still had less than two hours of load loss per year. The SEM was tightened a little more, consistent with the current market rules. Overall, the capacity credit of interconnection with a tighter Continental (and Irish) system is 62% on average.

Finally we looked at a situation where the Continent was even tighter and had an average of three hours of lost load – this gave an average credit of 54%.

The split by interconnection is given in Figure 97 below.

Figure 97 – Approximate IC capacity credit – Baseline scenario

	Baseline – Continental overcapacity	Continent tightened to 2 hours lost load	Continent tightened to 3 hours lost load
Ireland	53%	11%	0%
France	92%	65%	53%
Netherlands	97%	97%	92%
Total (GW)	**3.2**	**2.3**	**2.0**
Installed capacity (GW)	**3.7**	**3.7**	**3.7**
Average credit	**86%**	**62%**	**54%**

4.7.2 Scenario 4 (High IC)

For the High Interconnection scenario, in assessing the capacity contribution we used the same methodology as for the Baseline (2 hours) scenario, tightening the system until there was roughly two hours per load loss per year in the thermal countries.

The overall credit was 5.9GW in total in 2027 (first modelled year after all the interconnection is commissioned). Splitting this between interconnectors is difficult, since the incremental contribution of the continental interconnectors (i.e. contribution of the last MW) is significantly lower (in percentage terms) than the overall contribution. However, we have attempted a very rough split below.

Figure 98 – Approximate implied capacity credits for Scenario 4 (high IC, CPM)

County	Contribution (MW)	Capacity (MW)	Contribution(%)
SEM	170	740	23%
Iceland	580	600	97%
Norway	1,350	1,400	96%
Denmark	820	1,000	82%
Netherlands	700	1,000	70%
Belgium	550	1,000	55%
France	1,740	4,000	44%
Total	5,910	9,740	61%

4.7.3 Other scenarios

We have examined two scenarios where there is a Capacity Mechanism – Scenario 2 (with no GB price cap) and Scenario 3 (with an implicit price cap). Scenario 3 with an implicit £500/MWh price cap in GB creates some specific issues. Here GB would be forced to export if prices in the interconnected markets went above £500/MWh. The key input to understand the capacity credit of interconnection is at what capacity margin Continental prices go above £500/MWh. We have rerun the 2 hours of load loss case, but assumed Continental prices go above £500/MWh when the capacity margin on the Continent is 2%. We feel this is better than simply taking the price results of the model, as the exact point at which prices go above £500/MWh on the Continent is highly uncertain. For Ireland, instead of looking at a 2% tightness, but have assumed load loss in GB in preference to the SEM. Since load loss in the SEM and GB often coincide (or to put it another way the SEM has load loss when Britain is unable to supply it with power), the capacity credit of interconnection with Ireland is negative.

All the results are shown in Figure 99. These figures are marginally lower than those previously presented to DECC since we have applied a maximum 97% availability to interconnection to represent maintenance and outages.

Figure 99 – Approx capacity credit for Baseline and Scenarios 1-3

	Baseline	Scenario 1	Scenario 2	Scenario 3
Ireland	53%	50%	19%	-62%
France	92%	53%	70%	9%
Netherlands	97%	64%	97%	51%
Total (GW)	3.2	2.1	2.5	0.3
Total capacity (GW)	3.7	3.7	3.7	3.7
Average capacity credit	86%	56%	67%	8%

4.8 Installed capacity differentials in 2030

Figure 100 shows the differences in the installed capacities among the scenarios. Values are reported in GW and refer to the difference between scenario *m* and scenario *n*.

Figure 100 – Installed capacity differentials (GW) – Scenario *m* less Scenario *n*

Scenario *m* / ***less* Scenario *n***	Baseline	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Baseline	0.0	1.6	-4.5	-7.1	-4.7	3.2
Scenario 1	-1.6	0.0	-6.1	-8.7	-6.3	1.6
Scenario 2	4.5	6.1	0.0	-2.6	-0.2	7.7
Scenario 3	7.1	8.7	2.6	0.0	2.4	10.3
Scenario 4	4.7	6.3	0.2	-2.4	0.0	7.9
Scenario 5	-3.2	-1.6	-7.7	-10.3	-7.9	0.0

5. CONCLUSIONS

5.1 Impact of nuclear new build and CCS Contract for Difference

By assumption, a CfD for NNB and CCS leads to more build of these technologies. As a result, the CfD for NNB and CCS leads to a reduction in the GB annual average wholesale price by around 2.2% (£1.7/MWh), due both to wider system margins and more low-priced periods when nuclear or wind sets prices.

The CfD has no significant impact on interconnector flows – causing a reduction in imports of the order of 0.4TWh or 1% of maximum. The CfD has a very small impact on Continental prices, causing a small drop of £0.2/MWh.

The CfD leads to lower GB prices and hence lower interconnector revenues – by around 9%. Throughout this analysis, we have assumed that interconnectors do not get paid capacity payments.

5.2 The impact of a BM cash-out reform (without CM)

In this work, we have assumed that the current market design in GB has an implicit price cap of around £500/MWh, as a result of the current design of the Balancing Mechanism and STOR contracts. Thus we have also assumed that cash-out reform would lead to this implicit price cap being removed.

In a market with no CM, removing the implicit price cap of £500/MWh leads to higher build of CCGTs and hence a less tight system and less load loss. In total there is about 2GW more plant on the system without a price cap by 2030. However, there is limited impact of prices as the increase in high priced periods (>£500/MWh) is compensated by a reduction in medium-priced periods (£100-500/MWh).

There is practically no impact on Continental or Irish prices, and interconnector flows are barely affected. There is a very limited impact on interconnector revenues, as both flows and prices are largely equal.

5.3 The impact of a BM cash-out reform (with CM)

The impact of capacity of removing the implicit price cap from of £500/MWh where a CM exists is the **reverse** of the situation without a CM. Removing the implicit price cap means that GB can rely more on imports at key periods as prices can spike, and so to fulfil the 10% capacity margin, less plant is required to be built and supported under the CM.

The removal of the implicit price cap causes GB prices rise by around £1/MWh as a result of the lower capacity on the system, with a negligible impact on Continental prices. However, the rise in wholesale prices is offset by a decrease in the CM – with the CM price decreasing about £9/kW. There is an almost-zero impact on interconnector revenues and flows.

5.4 The impact of a CM (with cash-out reform)

Implementing a CM leads to 4GW of additional gas turbines compared to a scenario without, with annual average wholesale prices in GB falling by £6/MWh as capacity margins are looser. There is a small decrease on Continental prices (<1%) with no significant impact on interconnector flows.

The large drop in GB prices causes interconnector revenues to fall by about 15%. As part of this analysis, we have assumed that interconnectors do not get paid capacity payments – the impact on revenues would probably be less if capacity market revenues were available to interconnectors.

5.5 The impact of a CM (without cash-out reform)

Assuming that cash-out reform does not take place and thus there remains an implicit wholesale price cap of £500/MWh, the impact of a CM is much greater than with cash-out reform. The CM causes 9GW of additional plant to be built as interconnectors cannot be relied upon due to the implicit price cap. The increase in capacity causes annual average wholesale prices to fall by £7/MWh. There is no significant impact on interconnector flows, which remain almost-baseloading. Interconnector revenues fall by around 15% as a result of falling GB prices reducing price differentials.

5.6 The impact of increased interconnection (with CM)

By increasing interconnection by 6GW by 2030, about 3GW less generating capacity (firm capacity) is required in GB. It also causes annual average wholesale prices to fall by up to 3% (£2/MWh) as high-cost British generation (due to the carbon price floor) is replaced by cheaper imports. Greater interconnection also increases annual average wholesale prices on the Continent, with Norwegian and Danish prices increasing by up to £4.5/MWh, and other countries by around £1/MWh.

Irrespective of the level of interconnection tested, the interconnectors operate close to baseload imports – the carbon price floor leads to such a large differential in wholesale prices that even a significant increase in interconnection is not sufficient to alleviate it. Interconnector revenues per kW are heavily affected by increasing the interconnection – France and Dutch interconnector revenues drop by as much as around 21%.

The overall capacity credit of the 10GW of interconnection is around 60%, varying from a low with SEM (23%) and France (44%) to a high with Norway (96%).

5.7 Concluding comments

One of the more notable aspects of this interconnector analysis carried out for DECC is that the interconnectors are importing electricity to GB at almost-baseload levels. This results directly from the large differential in prices between GB and surrounding countries as a result of the carbon price floor being much higher in GB than the ETS price in other countries. This means that interconnector flows are barely affected by any policy or market changes – the difference in wholesale prices is so large that it becomes the dominant factor driving interconnector flows. In particular this affects interconnectors to Ireland, France, Belgium and Netherlands, as interconnectors to Iceland (and to a lesser extent Norway) would probably operate at near-baseload imports to GB, irrespective of the carbon price floor.

Baseloading interconnectors combined with high price differentials means that all interconnector new build considered in all scenarios is profitable – in some cases extremely profitable.

A future where GB and Continental carbon prices were much more closely aligned or equal would potentially lead to different results.

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