Net Zero Power and Hydrogen: Capacity Requirements for Flexibility - Additional Sensitivities

Introduction

This note is an addendum to the AFRY report for the Climate Change Committee (CCC), 'Net Zero Power and Hydrogen: Capacity Requirements for Flexibility'. It presents an overview of the results of three additional modelling sensitivities, building on the reference Central scenario, as described in the main project report:

- a ban on unabated gas generation – this sensitivity explores the situation where no unabated gas is allowed to remain on the system after 2035, in contrast to the Central scenario where unabated gas was allowed to continue to provide a, significantly reduced, contribution to generation and security of supply;
- improved opportunities for grid storage – this sensitivity considers how the balance between various flexibility options may differ if further cost reductions were realised by a subset of grid storage solutions, longer duration services were feasible through some technologies and hydrogen retrofit was not available to unabated gas plant; and
- lower interconnection – this sensitivity considers how the system may adapt if there were lower levels of interconnection than assumed in the Central scenario. This sensitivity does not involve a re-running of the model, instead post-processing some of the existing Central scenario results.

1 Sensitivity 1: Ban on Unabated Gas

In the Central scenario, 12GW of unabated gas CCGT/GT capacity remains on the power system in 2035.[1] This capacity is utilised only infrequently (generation in 2035 is 11TWh which implies an average load factor of around 10%), providing valuable flexibility and contributing to ensuring security of supply. However, it also produces 4.2MtCO_2 which is almost 90% of total power system emissions.

At present, it is unclear how future policy decisions may impact on the ability to rely on unabated gas. Given this uncertainty over future treatment, and the role unabated gas continues to perform under the Central scenario, this sensitivity considers the impact of banning unabated gas generation during the period under investigation in the report.

Exhibit 1.1 – Input changes relative to the Central scenario

Technology	Changes relative to Central scenario
CCGT	All capacity is decommissioned by 2035 (2035 capacity was 11.8GW in Central)
GT	All capacity is decommissioned by 2035 (2035 capacity was 0.4GW in Central)
Gas and Diesel Engine	Half of the capacity is decommissioned by 2030, the remaining half by 2035 (2035 capacity was 4.8GW in Central)

In this sensitivity we impose a phased introduction of a ban on unabated gas capacity in the power sector. As summarised in Exhibit 1.1, all CCGTs, GTs, and engines are phased out by 2035, with half of engine capacity being phased out earlier, by 2030.

The main results of this sensitivity are:

- without access to unabated gas technologies, a secure power system can be maintained through greater reliance on alternative low-carbon technologies, primarily gas CCS, Hydrogen GT and grid storage; and
- overall emissions would fall by 4.4MtCO_2 in 2035.

However, this alternative would:

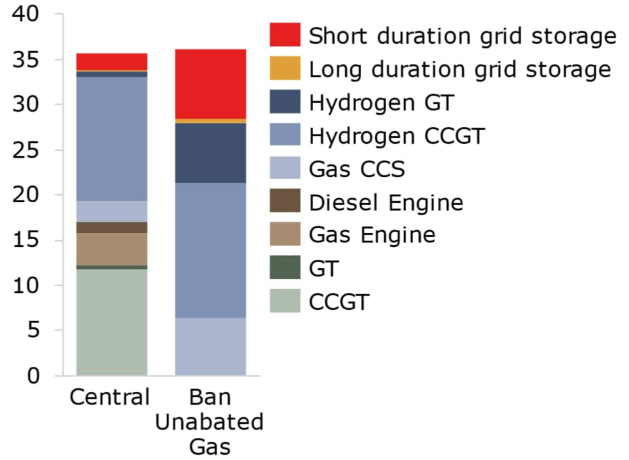
- increase overall system cost by 1.4£bn in 2035;

[1] In addition to CCGT and GT capacity, which we commonly refer to as unabated gas throughout this report, there is also 3.6GW of gas engines (grouped into the ‘Other’ technology type in the main project report), which run at very low load factor (2%) and the capacity of which is fixed.

- require an additional 18GW of low carbon capacity (generation and grid storage solutions) above that already envisaged in the Central scenario to be deployed by 2035; and
- augment the requirement for hydrogen storage by 4TWh by 2035, above the 5TWh already required in the Central scenario, exacerbating the potential delivery challenge.

The loss of the unabated gas capacity in 2035 is accounted for primarily by a combination of an increase in Gas CCS (4GW), Hydrogen GT (6GW), and grid storage (6GW) capacity on the system, as presented in Exhibit 1.2. The additional grid storage capacity includes both short duration (up to 4hr) and long duration (above 12hr) storage; overall, grid storage capacity more than doubles in 2035 relative to the Central scenario, as detailed in Exhibit 1.3.

Exhibit 1.2 – Generation and grid storage output capacity in 2035 (GW)



Notes: All the other generation and grid storage capacities remain unchanged. Grid storage is classified according to its duration: short duration storage has a duration of up to 4hr, medium duration storage ranges from over 4 to 12hr, and long duration storage has a duration of over 12hr.

This mix is explained by consideration of how the unabated gas generation was contributing to power system generation mix in 2035 in the Central scenario. Removing CCGTs and GTs increases the need for, and potential load factor of, dispatchable low-carbon generation, resulting in a situation where gas CCS is preferred to additional Hydrogen CCGT capacity because it can achieve higher load factors. CCS gas generation is presented in Exhibit 1.4.

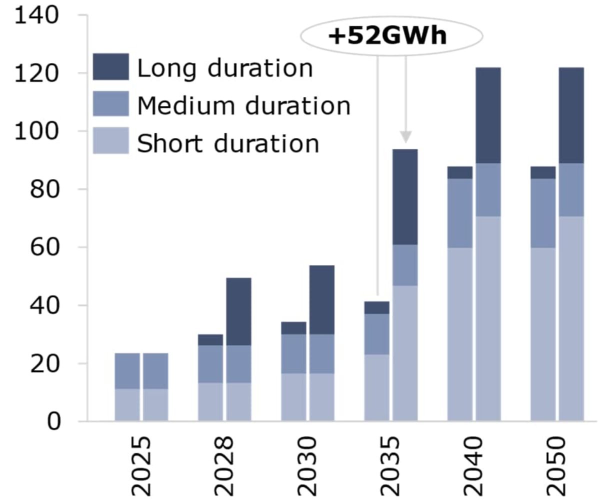
The loss of peak flexibility from unabated gas is compensated for through a combination of additional energy storage and hydrogen-fired generation. In relation to the latter, despite a slight reduction in total generation we observe an increased peak requirement for hydrogen-fired generation which has a knock-on requirement for additional hydrogen storage, as shown in Exhibit 1.5. Hydrogen storage capacity increases by over 50% in most years.

These changes have benefits to environmental performance of the system, reducing overall CO_2 emissions (see Exhibit 1.6) and, because of the greater grid storage capacity, leading to a reduction in RES curtailment (of 7TWh in 2035 relative to the Central scenario).

However, because they require more investment earlier in the period to replace existing unabated gas capacity, as well as supporting infrastructure such as H2 storage, there is an increase in the cost of achieving this solution, as shown in Exhibit 1.7.

Moreover, this potentially also increases the delivery challenge since there is an additional 11GW of low-carbon dispatchable generation capacity (above the 17GW already required in the Central scenario) by 2035, as well as an additional 4TWh of hydrogen storage capacity (on top of the 5TWh already required in the Central scenario).

Exhibit 1.3 – Grid storage capacity in the Central scenario (left bar) and Ban Unabated Gas sensitivity (right bar) (GWh)



Note: Grid storage is classified according to its duration: short duration storage has a duration of up to 4hr, medium duration storage ranges from over 4 to 12hr, and long duration storage has a duration of over 12hr.

Exhibit 1.4 – CCS gas generation (TWh)

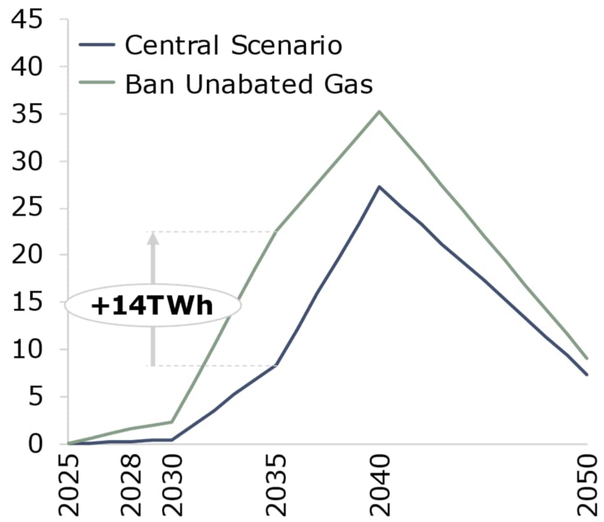


Exhibit 1.5 – Hydrogen storage capacity (TWh)

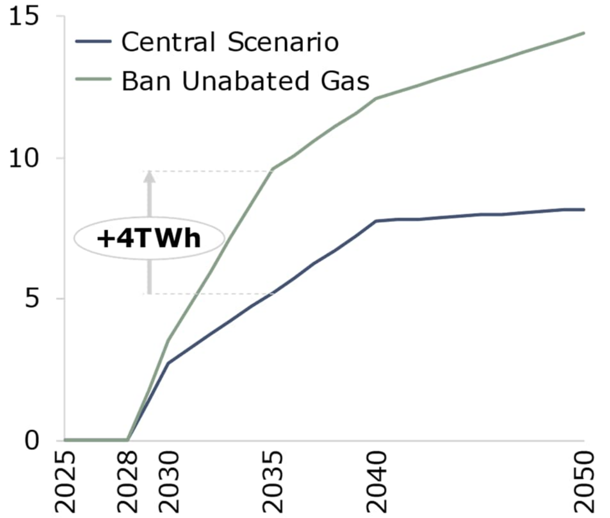


Exhibit 1.6 – CO_2 emissions ($MtCO_2$)

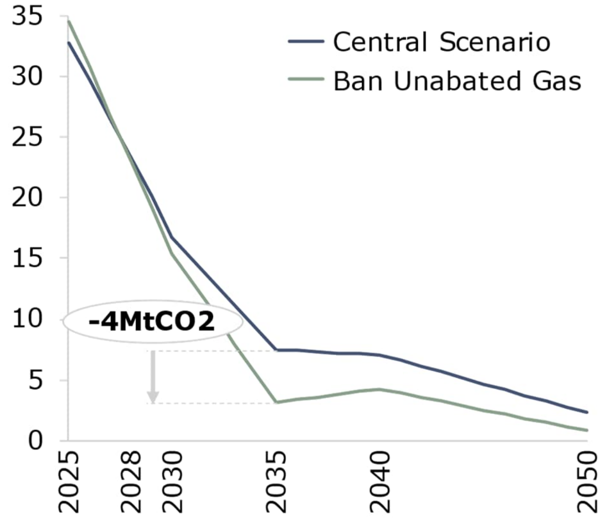
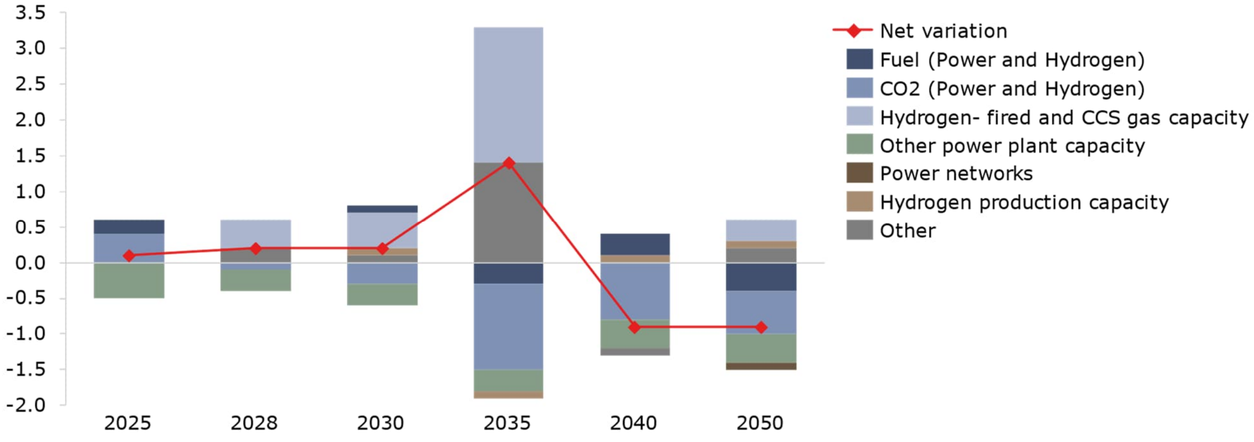


Exhibit 1.7 – Variation in GB's annual system costs (undiscounted) in Ban Unabated Gas sensitivity relative to Central scenario (£bn, real 2020)



'Other' costs include grid storage capacity, hydrogen networks and storage capacity, and C&I DSR costs.
Notes: Capital expenditures are calculated by dividing the total new capacity over a multi-year period and dividing by the number of years in that range (e.g., the 2025 capital expenditure for capacity deployed between 2023-2026 divided by 4). All investments made prior to 2025 are excluded from the system costs calculation. For simplicity, all RES capacity is expected to operate beyond 2050. Power import/export costs are disregarded. Finally, it is assumed that GB faces only 50% of the costs for new interconnectors, while the rest is covered by connected markets.

2 Sensitivity 2: Grid Storage

Throughout the main report, the increased need for flexibility to address the challenges of a net-zero system is well-established and a range of potential flexibility solutions are considered. In the Central scenario, the pattern of residual net demand and the relativities in cost and technical capabilities across solutions, resulted in a mix that relied (a) on hydrogen storage to address long duration flexibility requirements; (b) short and medium duration grid storage solutions and DSR to deliver real-time and within-day flexibility.

Since the out-turn solutions are dependent on the relative competitiveness and performance capabilities of the different technologies, we have used this sensitivity to consider whether improved cost performance and an ability to offer solutions over longer timeframes would alter the balance of flexibility solutions delivered. More favourable cost out-turns reflect the potential impact of government policies to support and de-risk longer duration grid storage solutions. In addition, we have expanded the range of technology options to capture evidence around emerging technology solutions with durations above the 72hr assumption for grid storage made in the Central scenario. Finally, we have removed the option of hydrogen retrofit for unabated gas CCGT.

The changes to cost, performance and availability of grid storage technologies are outlined in Exhibit 2.1.

Exhibit 2.1 – Input changes relative to the Central scenario

Technology	Locations	Hurdle rate	Efficiency	Costs	Financial lifetime
CCGT Hydrogen – Retrofit	Not allowed anywhere	-	-	-	-
CAES (up to 72hr)	North + Upper North	Lowered to 6.5%	Improved to 75%	-	Increased to 30 years
CAES (168hr)	North + Upper North + Scotland zones	6.5%	75%	Provided by AFRY	30 years
CAES (240hr)	Scotland zones	6.5%	65%	Provided by AFRY	30 years
Pumped Storage	-	6.5%	-	Capex decreased by 30%	-
Battery and LAES (>= 6hr)	-	6.5%	-	-	-

Note: Longer duration (240hr) CAES would have reduced efficiency due to different rock formation requirements.

The main results of this sensitivity are:

- significant increase in the use of long duration grid storage at the expense of hydrogen storage;
- reduction in the need for hydrogen capacity and infrastructure;
- no material changes in overall carbon emissions; and
- some increase in annual system costs, though this might be seen as a reasonable low regret impact given that it reduces the reliance of the system on technologies and infrastructure that have a high delivery risk.

Thanks to the more favourable grid storage cost out-turns and increased range of options, grid storage capacity jumps by 325GWh in 2035, above the already required 41GWh in the Central scenario. As detailed in Exhibit 2.2, this increase is primarily due to the larger deployment of long duration grid storage capacity, particularly 72hr CAES. In the longer term, however, a longer duration option enters the storage mix, namely the 240hr CAES, covering over 50% of the storage capacity from 2040 onward.

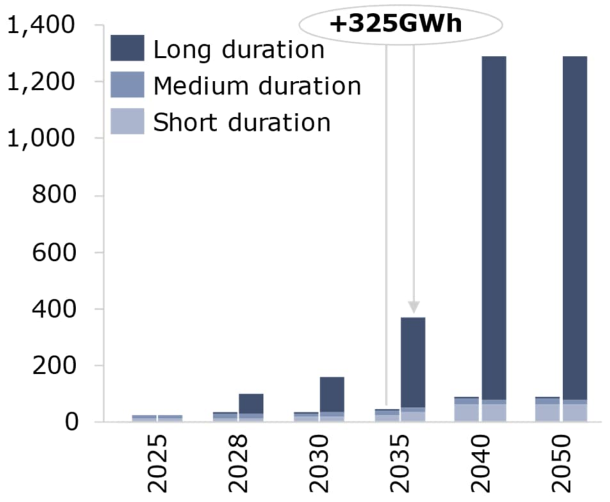
The enhanced power-sector flexibility diminishes the need for hydrogen-sector flexibility. Dispatchable low-carbon generation drops relative to the Central scenario, mostly due to decreased hydrogen-fired generation, as shown in Exhibit 2.3. Following a similar trend as generation, hydrogen-fired capacity declines too (it is 6GW lower in 2035).

As hydrogen usage lessens, the need for hydrogen production capacity decreases too (by 4GW in 2035), and so does hydrogen pipeline capacity (5GW decrease) and hydrogen storage capacity. As presented in Exhibit 2.4, hydrogen storage is only about 60% relative to the Central scenario (or, 2TWh lower) by 2035.

Carbon emissions are close to the Central scenario projections and don't vary significantly, as shown in Exhibit 2.5. Reduced blue hydrogen production and reduced RES curtailment (by 7TWh in 2035) determine downward pressure on emissions; that is however countered by increased CCS gas emissions (up to 2035) and by increased unabated gas emissions in some years.

Annual undiscounted system costs increase slightly in most years, driven by the material increase in grid storage capacity investment relative to the Central scenario. Only towards the end of the modelled period do costs start declining: by 2050, no additional grid storage capacity is required relative to 2040 and prior investment results in system cost savings. Despite costs being slightly higher than in the Central scenario, this outcome could be treated as a reasonable low regret impact, considering the reduced system reliance on technologies and infrastructure that have a high delivery risk.

Exhibit 2.2 – Grid storage capacity in the Central scenario (left bar) and Grid Storage sensitivity (right bar) (GWh)



Note: Grid storage is classified according to its duration: short duration storage has a duration of up to 4hr, medium duration storage ranges from over 4 to 12hr, and long duration storage has a duration of over 12hr.

Exhibit 2.3 –Dispatchable low carbon generation in the Central scenario (left bar) and Grid Storage sensitivity (right bar) (TWh)

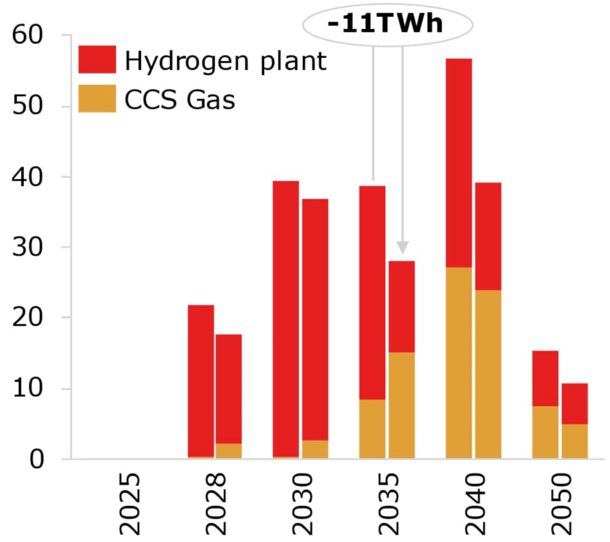


Exhibit 2.4 – Hydrogen storage capacity (TWh)

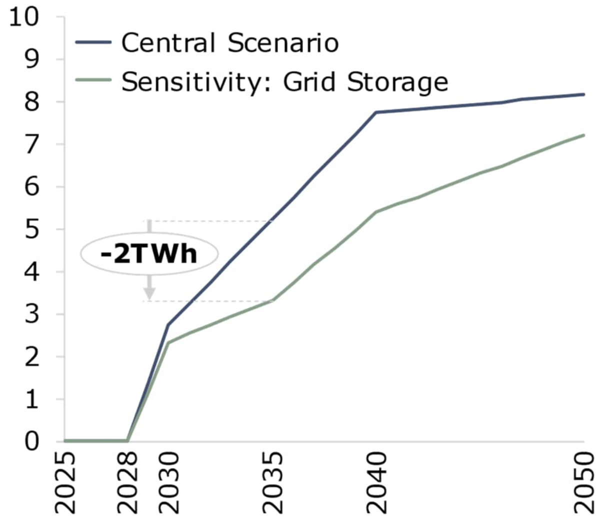


Exhibit 2.5 – CO2 emissions (MtCO2)

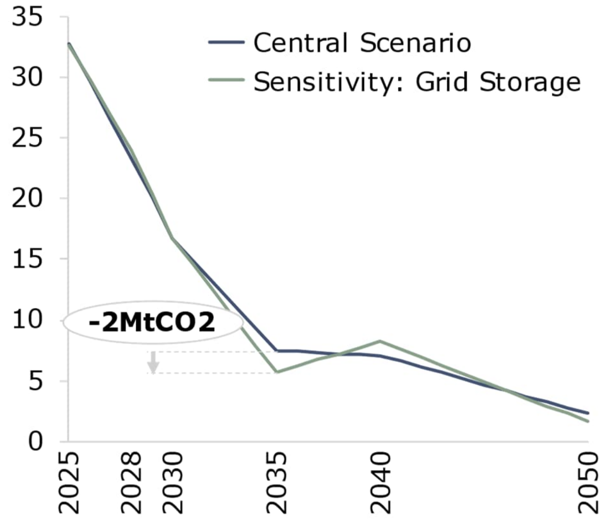
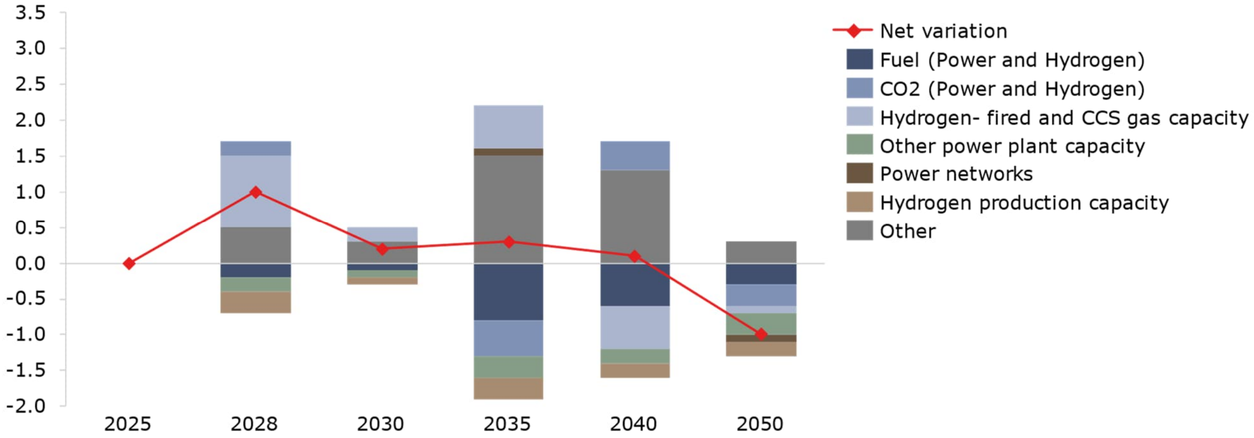


Exhibit 2.6 – Variation in GB's annual system costs (undiscounted) in Grid Storage sensitivity relative to Central scenario (£bn, real 2020)



'Other' costs include grid storage capacity, hydrogen networks and storage capacity, and C&I DSR costs.
Notes: Capital expenditures are calculated by dividing the total new capacity over a multi-year period and dividing by the number of years in that range (e.g., the 2025 capital expenditure for capacity deployed between 2023-2026 divided by 4). All investments made prior to 2025 are excluded from the system costs calculation. For simplicity, all RES capacity is expected to operate beyond 2050. Power import/export costs are disregarded. Finally, it is assumed that GB faces only 50% of the costs for new interconnectors, while the rest is covered by connected markets.

3 Sensitivity 3: Lower Interconnection

In the Central scenario, the level of interconnection is an exogenous assumption, with total interconnector capacity increasing to 21GW by 2035 and connecting to seven separate electricity markets. Over the period of analysis, while there are some variations in patterns of flows with particular markets, GB shifts from being a net importer of power in 2025 and 2028 to a net exporter over the following decade.

One of the main drivers behind this shift is the mismatch between the assumed rate of decarbonisation of the power system in GB and connected markets since we have incorporated the higher targets within the British Energy Security Strategy (BESS). In addition, since we have taken fixed growth in interconnector capacity, we do not comment on whether exports are the best way to manage some of the periods of negative residual net demand that emerge or if alternative solutions, such as additional green hydrogen production or grid storage, would have emerged.

In this sensitivity, we investigate how lower interconnection flows may impact on the results of the Central scenario. Within the scope of the project, we did not have the option to develop alternative decarbonisation pathways across Europe and/or to optimally determine levels of interconnection.

Therefore, we have undertaken a simpler analysis to proxy for the impact of lower interconnection. We have done this by assuming that if other European markets were decarbonising at the same rate as GB net power exports would be expected to decrease relative to the Central scenario and the net export volumes would therefore need to be accommodated by some other flexibility solution in the GB system that may offer opportunities to further reduce carbon emissions. Specifically, in agreement with the CCC, we have assumed that (a) net export flows in the years 2030, 2035 and 2040 would be zero; and (b) the generation would all be used to increase green hydrogen production (though it is recognised that, in reality, some of this excess may be used in grid storage applications, or hydrogen-fired or gas plants could be turned down).

The implied volume of green hydrogen production is shown in Exhibit 3.1.

Exhibit 3.1 – Key assumptions

	Unit	2025	2028	2030	2035	2040	2050
Net interconnector power exports from GB	TWh	-41.2	-8.5	47.0	35.2	55.9	-50.0
Power that could be electrolysed domestically	TWh	-	-	47.0	35.2	55.9	-
Potential increase in green hydrogen production	TWh (H_2)	-	-	35.4	27.0	43.7	-

Note: Electrolyser hydrogen-production efficiency is assumed to improve from 75% in 2030 to 78% in 2040.

The impact of reducing interconnector flows and increasing green hydrogen production depends on the use case for the additional green hydrogen volumes. As part of this analysis, we have considered two cases that have material differences in the additional emission reductions that may be realised:

- green hydrogen displaces blue hydrogen production; and
- green hydrogen fuels additional hydrogen-fired generation to displace unabated gas[2] generation with any excess then displacing blue hydrogen production.

The main insights from the analysis are:

- annual GB gas consumption can be reduced by between 32 and 55TWh over the period, representing 18% to 24% of total gas consumption in the Central scenario;
- the resulting emissions reduction can be between 0.5 and 6.6MtCO_2 per annum, with a greater impact if unabated gas generation is displaced since the majority of blue hydrogen emissions are captured; and
- there will need to be a corresponding increase in hydrogen production and storage investment. While we have not quantified the transport and storage infrastructure needs, additional electrolyser capacity of between 9 and 19GW can be anticipated by 2040 (which could reduce the need for ATR CCS capacity by between 4 and 7GW). In addition, up to 5GW of additional hydrogen-fired capacity may be required[3].

The results of the analysis for the blue hydrogen and unabated gas generation displacement options are provided in Exhibit 3.2 and Exhibit 3.3, respectively.

[2] In this sensitivity, unabated gas refers to CCGT and GT plant.
[3] As informed by the load factor range covered by all modelled scenarios and sensitivities in years 2030-2040, electrolyser capacity estimates reflect an out-turn load factor between 27 and 54%; ATR CCS capacity estimates reflect an out-turn load factor between 76 and 93%; and hydrogen-fired capacity estimates reflect an out-turn load factor between 14 and 55%.

Exhibit 3.2 – Key results for the case: green hydrogen displacing blue hydrogen production

	Unit	2025	2028	2030	2035	2040	2050
ATR CCS hydrogen production reduction	TWh (H_2)	-	-	35.4	27.0	43.7	-
ATR CCS gas usage reduction	TWh (gas)	-	-	44.2	33.8	54.6	-
Gas usage reduction from hydrogen sector	%	-	-	37%	25%	34%	-
CO_2 emissions reduction	$MtCO_2$	-	-	0.8	0.5	0.7	-
Reduction in annual CO_2 captured	$MtCO_2$	-	-	7.2	5.6	9.2	-
Reduction in CO_2 cumulatively captured	$MtCO_2$	-	-	10.2	41.5	80.2	100.0
Resulting CO_2 emissions from hydrogen sector	$MtCO_2$	-	-	1.7	2.1	2.2	-

Notes: ATR CCS is assumed to have an 80% efficiency, and CO_2 capture rate improving from 90% in 2030 to 93% in 2040. In order to calculate the reduction in CO_2 cumulatively captured, the CO_2 captured in non-modelled years was estimated through interpolation based on results from modelled years, and on the trend observed in net IC power exports – so that only years in which interpolated net exports are positive are considered (years 2029-2045).

Exhibit 3.3 – Key results for the case: green hydrogen displacing dispatchable unabated gas generation, with any excess then displacing blue hydrogen production

	Unit	2025	2028	2030	2035	2040	2050
ATR CCS hydrogen production reduction	TWh (H_2)	-	-	3.2	7.1	31.8	-
Gas usage reduction from power sector	TWh (gas)	-	-	35.7	23.0	13.4	-
Gas usage reduction from hydrogen sector	TWh (gas)	-	-	4.0	8.8	39.7	-
Gas usage reduction from power sector	%	-	-	45%	55%	19%	-
Gas usage reduction from hydrogen sector	%	-	-	3%	7%	25%	-
CO_2 emissions reduction from power sector	$MtCO_2$	-	-	6.5	4.2	2.4	-
CO_2 emissions reduction from hydrogen sector	$MtCO_2$	-	-	0.1	0.1	0.5	-
Reduction in annual CO_2 captured	$MtCO_2$	-	-	0.7	1.5	6.7	-
Reduction in CO_2 cumulatively captured	$MtCO_2$	-	-	0.9	6.6	29.6	44.0
Resulting CO_2 emissions from power sector	$MtCO_2$	-	-	7.8	0.6	1.6	-
Resulting CO_2 emissions from hydrogen sector	$MtCO_2$	-	-	2.4	2.5	2.5	-

Notes: Hydrogen CCGT are assumed to have efficiency improving from 54% in 2030 to 55% in 2040. ATR CCS is assumed to have an 80% efficiency, and CO_2 capture rate improving from 90% in 2030 to 93% in 2040. In order to calculate the reduction in CO_2 cumulatively captured, the CO_2 captured in non-modelled years was estimated through interpolation based on results from modelled years, and on the trend observed in net IC power exports – so that only years in which interpolated net exports are positive are considered (years 2029-2045).

Next, Exhibit 3.4, Exhibit 3.5, Exhibit 3.6, and Exhibit 3.7 present the key results of this sensitivity, highlighting how the Central scenario results compare with the range obtained in this analysis.

We recognise that this analysis involves some major simplifications regarding implications of lower interconnection flows and/or capacity. In particular, it ignores the cost-effectiveness of green hydrogen production at times when GB is exporting in the Central scenario – it may be more efficient to charge storage, or turn down hydrogen-fired or gas plants. However, the results demonstrate that there may be wider benefits from addressing excess renewables through other means than exporting and these considerations may affect future interconnection decisions.

Exhibit 3.4 – Gas usage (TWh of gas)

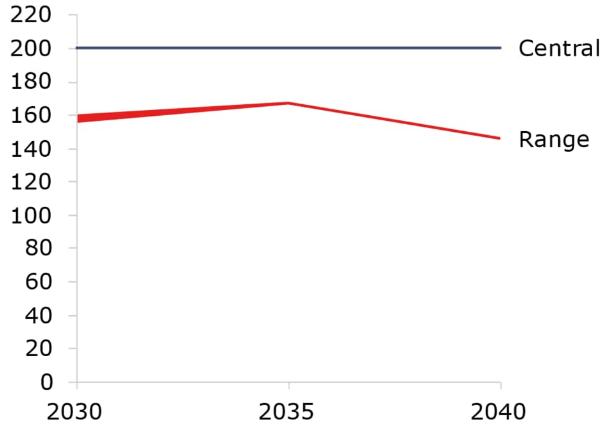


Exhibit 3.5 – CO_2 emissions ($MtCO_2$)

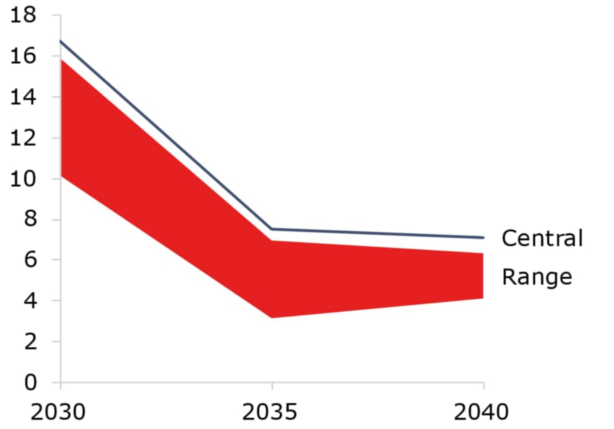


Exhibit 3.6 – CO_2 captured annually ($MtCO_2$)

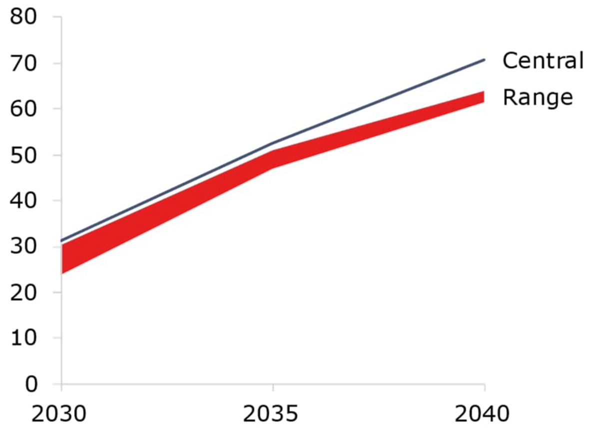
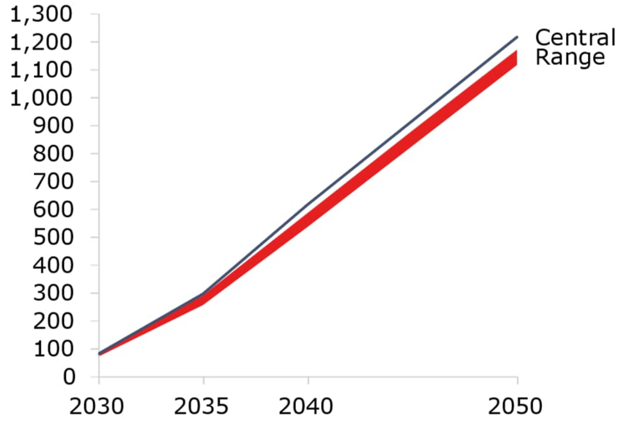


Exhibit 3.7 – CO_2 captured cumulatively ($MtCO_2$)



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