Department for
Business, Energy
& Industrial Strategy

MODELLING 2050: ELECTRICITY SYSTEM ANALYSIS

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Contents

Summary

The UK government is committed to a target of net zero greenhouse gas emissions by 2050. This will require extensive decarbonisation of all sectors of the economy and the deployment of greenhouse gas removal technologies to remove any residual emissions.

Electricity will be increasingly important in supporting delivery of net zero, potentially providing around half of final energy demand as its use for heat and in transport increases. Understanding the ways in which the system can deliver more electricity whilst producing fewer carbon emissions, and the relative cost of doing so, is central to developing our energy strategy to support delivery of net zero.

This paper sets out the modelling assumptions, methodology and outputs of our analysis of the electricity system in 2050. This analysis helps us to understand the potential impact on system costs of reducing carbon emissions at different levels of demand, using different combinations of generating and storage technologies.

A key challenge when determining how to decarbonise is the inherent uncertainty involved in modelling over such a long period. Our approach allows us to consider a wide range of different sources of uncertainty for the electricity system. As new issues emerge, we will continue to refine our analysis to understand their potential impacts.

Our electricity system modelling does not attempt to determine the precise level of demand or extent of decarbonisation required in 2050, and does not examine the risks or deliverability of the different combinations of generating and storage technologies, or the wider benefits they may bring.

Our main findings from this analysis are:

- There is no single optimal technology mix; many capacity mixes can meet different carbon emissions levels at low cost. This is true for all levels of demand modelled (see section 4).
- Electricity system costs are lowest when carbon intensity[1] is between 5-25gCO_2/kWh (see section 2).
- All low-cost[2] solutions include significant levels of wind and solar. Wind and solar generation could more than quadruple by 2050 (see section 2).

[1] Carbon intensity is the amount of carbon dioxide emitted per unit of electricity generated, measured in grams of CO_2 (gCO_2) per kilowatt hour (kWh) of generation

[2] Low-cost solutions are those which fall at or below the 10th percentile (i.e. the lowest 10%) of total system costs for deployment mixes at any given emissions level. See Section 3 for further detail.

- System flexibility reduces system costs (see section 2.1). It does this by reducing curtailment of wind and solar and flattening demand for electricity, and therefore the overall capacity required. Our modelled options include batteries, demand side response and interconnectors.
- All low-cost solutions also require other forms of low-carbon generation to provide resilience during extended periods of low wind and solar irradiation. Our modelled options to provide this are nuclear, gas generation with Carbon Capture, Usage and Storage (CCUS), and short-term dispatchable generation from unabated gas and/or low-carbon hydrogen (see sections 2 and 4).
- Moderate levels of low-carbon hydrogen could replace unabated gas fired generation and reduce the requirement for other low-carbon generation. The extent of the impact is dependent on the quantity and cost of hydrogen available for generating electricity. We have only modelled the impact of low-carbon hydrogen-fired generation, but technologies that can offer longer-term storage than current technologies (i.e. batteries) could have similar impacts (see section 4.1).

The rest of this report is structured as follows:

1. **Modelling Methodology:** where we outline our main assumptions and methodological approach.
2. **Cost and decarbonisation trends:** high level results from our modelling, examining the impact of different levels of decarbonisation on system cost.
3. **Methods to identify low-cost technology mixes:** an overview of the analytical techniques employed, including the use of threshold maps to help identify optimal capacity mixes.
4. **Identifying low-cost technology mixes:** the results of our analysis, which outline how different technology mixes can meet different levels of demand at different levels of carbon intensity.
5. **Conclusion/ Next steps:** the main findings of our analysis, the key limitations, a comparison with other similar studies, a consideration of cross-sector integration and an overview of additional workstreams that we will look to include in the future.
6. **Annexes:** expanded methodology and additional results including information on security of supply, curtailment, and flexibility.

1 Modelling methodology

We used BEIS' model of the electricity sector, the Dynamic Dispatch Model (DDM)[3] to explore the cost of the electricity system in a single future year (2050) for a wide range of different scenarios, deployment mixes and cost assumptions.

Dynamic Dispatch Model (DDM)

The DDM is an electricity supply model, currently modelling the GB power sector out to 2050. It allows analysis of the impact of different policy decisions on capacity, costs, prices, security of supply and carbon emissions. The DDM employs two key algorithms:

- Dispatch algorithm, which models electricity supply and demand
- Investment algorithm, which forecasts revenues and costs based on the Dispatch algorithm for new plants and retirements

The DDM relies on many exogenous assumptions and inputs, and results can be sensitive to changes in these assumptions. Key ones include:

- Generation and financing costs
- Build limits
- Security of Supply requirement
- Electricity Demand
- System operability requirements
- Carbon and fuel costs
- Load Factors
- Interconnector capacity

The DDM has a number of limitations, the most important of which are:

- It is deterministic, in that a given set of inputs will always produce the same outputs.
- Plants are assumed to be profit maximising, and act according to economic rationality.
- The DDM does not tell us the optimal mix of technologies to ensure security of supply or decarbonise. The mix is defined by user inputs.

The DDM reports total system costs which can also be used to examine the relative costs of two or more different systems in a particular year.

[3] For further background information on the DDM please see: https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm

To generate different deployment mixes, we identified plausible 2050 capacity ranges for those low-carbon technologies[4] that are deployable at scale[5] (Gas CCUS 2-30GW, Offshore Wind 40-120 GW, Onshore Wind 15-60GW, Solar 15-120GW, Nuclear 5-40GW) and divided them into several discrete levels. We modelled each possible combination of technologies, with the DDM calculating a mix of additional capacity (i.e. gas, batteries) needed to meet security of supply requirements. This resulted in a total of 3360 unique low-carbon deployment mixes.

We also considered the potential role of hydrogen-fired generation, and in particular the extent to which it could replace unabated gas-fired peaking generation. There is a high degree of uncertainty around the volume of hydrogen that might be available for the power sector in 2050, and its price. We considered a range of scenarios – in the main part of the paper we consider a scenario where the total amount of hydrogen-fired generation is constrained to 20 TWh or less, and hydrogen is twice as expensive as natural gas[6]. We assume that this hydrogen is made by steam methane reformation with Carbon Capture and Storage (sometimes labelled as "blue" hydrogen) and include the residual carbon emissions in our overall power sector carbon emissions[7]. We also assumed that hydrogen-fired generation would be incentivised to dispatch ahead of unabated gas-fired generation. Additional scenarios are presented in the annex.

We used the department's UK TIMES Model[8] (UKTM) to identify two different scenarios for the UK. These each support reaching net zero emissions across the whole economy by 2050 (Table 1). There are a number of factors which will determine electricity demand in

[4] Biomass with Carbon Capture and Storage (BECCS), which can provide negative emissions, is not considered in this analysis. This is because the amount of biomass that will be available, and the sector in which it is most efficiently used to meet net zero are both uncertain and under review as part of the work to develop a biomass strategy. Other renewable generation technologies such as hydro, wave and tidal may have a role to play in reaching net zero but are outside the scope of the current modelling.

[5] Other technologies that can produce low carbon electricity may have a future role to play in the UK. We have focused on those technologies that are currently cost competitive and have significant growth potential in the UK. This does not mean other technologies will not be needed but we expect these technologies to make up the bulk of our future generation

[6] We replace natural gas generation up to 20TWh. The volume of hydrogen that could be produced by electrolysis is not the focus of this analysis; however 20TWh is consistent with what could be produced from electrolysers powered by electricity generation that would otherwise be curtailed in some low-cost, low-carbon generation mixes. We have not explicitly included the costs of electrolysers or any other necessary infrastructure in our analysis, however overall costs of the necessary hydrogen infrastructure are included in our assessment of the hydrogen price. Our central gas price assumption in 2050 is 19.5£/MWh (2012 prices). In our core hydrogen scenario (hydrogen price = 2x gas price) this equates to a hydrogen price of approximately 39 £/MWh [c. 1.2 £/Kg in 2020 prices]. Where hydrogen is used to replace natural gas generation, we applied a 10% increase in the gas plant capital costs.

[7] We assume that the emissions associated with generation from hydrogen produced by steam methane reformation with carbon capture would be 15% of the equivalent natural gas generation.

[8] UKTIMES is a UK whole energy system optimisation model developed by University College London and BEIS The model allows us to explore different possible decarbonisation scenarios by considering the availability, performance, feasible build rates, and costs of existing and new technologies. More information can be found at https://www.ucl.ac.uk/energy-models/models/uk-times

2050. Greater deployment and use of electric vehicles, more heat pumps or favourable economic growth could mean that demand grows to a significantly higher level. Conversely, greater energy efficiency or use of alternative technologies like hydrogen for industrial processes or heating could limit the growth in electricity demand. To create the scenarios used in this analysis, we varied assumptions about the abatement potential in sectors other than the power sector. We ran several other UKTM scenarios, varying technical assumptions to ensure the range was consistent with a range of possible decarbonisation pathways e.g. with greater or lesser use of hydrogen and electricity for both transport and heat. The electricity demand scenarios reflect approximate illustrations of the range of possible demand levels in GB – they are neither forecasts nor bounds on what electricity demand might be in 2050 but are used to demonstrate the directional impact of differing levels of demand on different aspects of the electricity system.

Scenario	2050 power sector demand (TWh)	Narrative
Net Zero Lower demand	575	More abatement potential outside the power sector. Road transport mostly electrified with some hydrogen used for LGVs and HGVs. Substantial electrification of heat but with hydrogen also playing an important role particularly for industry.
Net Zero Higher demand	672	Less abatement potential outside the power sector. Road transport nearly all electrified with minor use of hydrogen HGVs. Hydrogen use is restricted leading to higher levels of electrification across homes and businesses though it still has an important role in decarbonisation of industry.

Table 1*: Power sector demand levels consistent with meeting net zero across the whole economy.*

We tested each deployment mix (with and without hydrogen) against these two levels of electricity demand. The model provides system flexibility through demand side response[9] and batteries[10] as well as 18GW of interconnector capacity[11]. We also tested the impact of removing the demand side response and storage and reducing the level of interconnection.

[9] Demand side response minimises the difference between demand and supply (net of intermittent generation). It is provided by residential electric vehicles and heat pumps (using a combination of water storage and preheating).
[10] 4h duration lithium ion batteries are deployed by the model, typically a total of 20-30GW.
[11] Our modelling simplifies the roles for demand shifting, interconnection and storage. We recognise that may not reflect all business models or technologies that could exist in the future, including where a single provider may offer multiple services such as balancing and frequency response, or vehicle to grid.

For each modelled scenario we captured a range of key metrics. Among these were the carbon intensity (in gCO_2/kWh) and the total system costs (the annualised costs of building and operating the system for 2050 only, including generation, transmission and distribution, balancing and carbon costs valued at the Green Book appraisal value, all in 2012 prices). We also tested the robustness of our results to different technology cost assumptions using the low, central and high construction cost projections as set out in BEIS generation cost report[12], assuming plants operating in 2050 are constructed through the 2030s and 2040s to take account of changes over time to costs, load factors and efficiencies.

[12] https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

2 System cost and decarbonisation trends

Figure 1 shows the annual system costs and carbon intensity of the 3,360 deployment mixes at the two illustrative levels of demand and at central technology cost assumptions. This scatter plots also show the impact of different deployment restrictions. Several key conclusions can be drawn from this figure.

In both scenarios, demand is a key driver of system costs; higher demand requires more capacity.

Without hydrogen (Figure 1A)

- For each level of demand, the minimum electricity system cost is found at carbon intensities between approximately 10-25gCO2/kWh. System costs increase significantly at both very low emissions (below 5g CO2/kWh) and higher emissions[13].
- With neither additional new nuclear (beyond the ~5GW provided by Sizewell B[14] and Hinkley Point C) or gas CCUS the system is dependent on renewables to provide low-carbon generation. This significantly limits the amount of decarbonisation that can be achieved and increases the system costs of decarbonisation (see black squares).
- This is because the additional renewable capacity required to replace unabated gas generation during periods of low renewable output either increases systems costs more than using additional nuclear and/or gas CCUS to do the same thing, or is not achievable within the build limits[15] used in this modelling.
- For example, in the higher demand scenario the lowest carbon intensity that can be achieved without gas CCUS or additional nuclear is 16gCO2/kWh, with system costs significantly higher than with gas CCUS or nuclear.
- Introducing either new nuclear (red circles) or gas CCUS (blue diamonds) greatly increases the range of decarbonisation options; however, low-cost solutions at low emissions (at 5gCO2/kWh or below) can only be achieved with a combination of new nuclear and gas CCUS (yellow circles).
- Notably, all low-cost solutions still include significant levels of renewables.

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[13] Note that a more expensive electricity system may deliver net zero at lower cost overall, depending on the relative cost and/or difficulty of decarbonisation in other sectors or through Greenhouse Gas Removal (GGR) technologies.

[14] Sizewell B's current stated lifetime is to 2035, but EDF has expressed its aim to extend its life for 20 years beyond that to 2055, subject to regulatory approval.

[15] For capacity assumptions, see p.3

With hydrogen[16] (Figure 1B)

- For each level of demand, the minimum electricity system cost is found at carbon intensities between approximately 5-15gCO2/kWh. System costs increase at both very low emissions (below 5g CO2/kWh) and higher emissions.
- System costs with hydrogen are lower than system costs without hydrogen.
- As in the scenario without hydrogen, generation mixes without nuclear and CCUS limit the amount of decarbonisation that can be achieved and/or increase the system costs at low emissions (see black squares). However, lower emissions are achievable at lower cost than without hydrogen.
- Low-cost solutions down to around 5gCO2/kWh are possible without nuclear, but this is dependent on the quantity and cost of hydrogen available for generating electricity.

[16] This is the hydrogen scenario referred to on page 4 where the total amount of hydrogen-fired generation is constrained to 20 TWh or less, and hydrogen is twice as expensive as natural gas. See Annex A1 & A4 for further hydrogen price/availability scenarios.

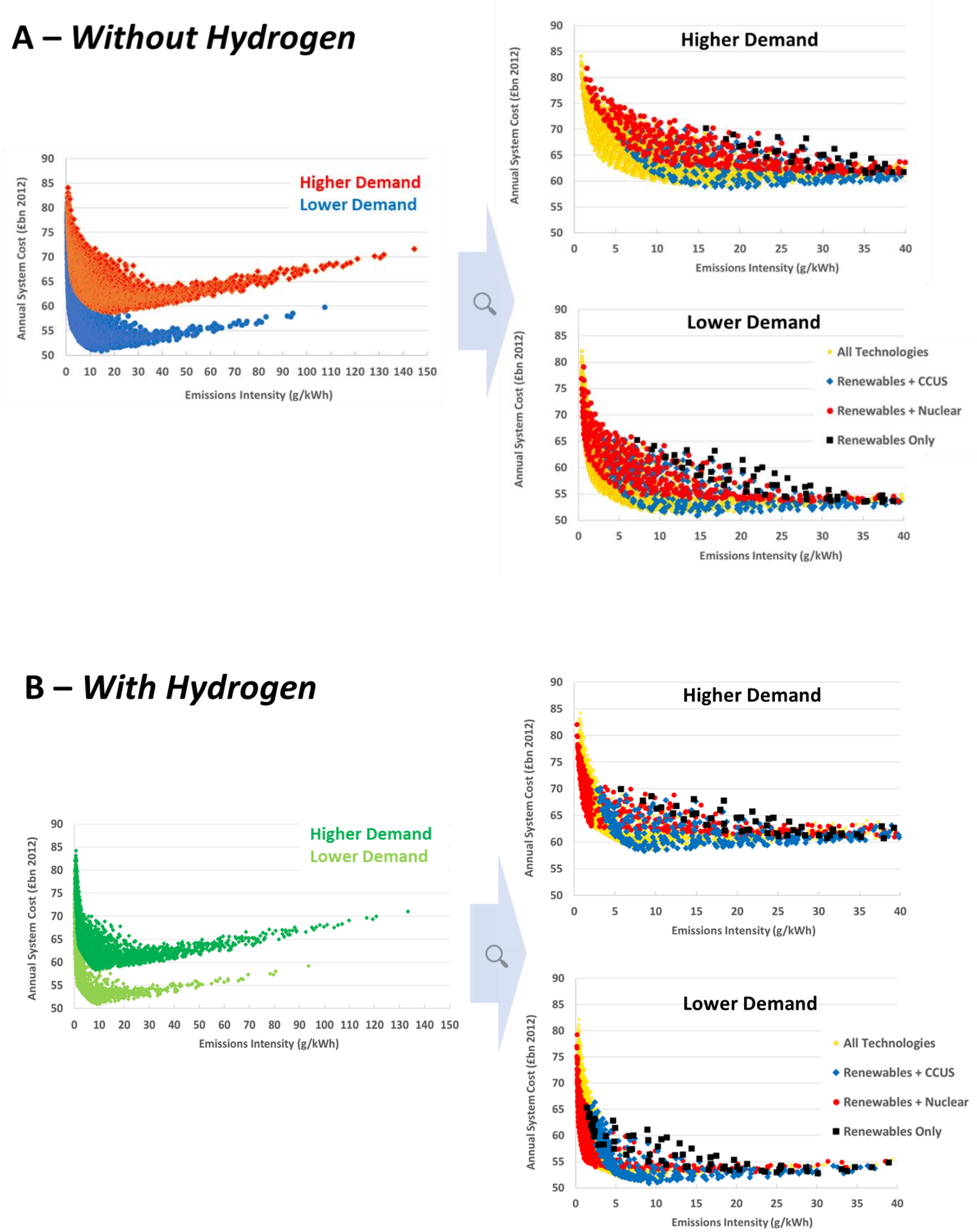

Figure 1: *Cost vs carbon emissions scatter plots at central technology cost assumptions, without hydrogen (A), and with hydrogen (B). The plot on the left shows results from all model runs at both demand levels. The plots on the right show the impact of different technology restrictions at each demand level (with the emissions axes restricted to ≤40gCO_2/kWh). Yellow circles show data from all model runs (with no technology restrictions). The blue diamonds are restricted to systems with renewables and gas CCUS only (no new nuclear), red circles show systems with renewables and new nuclear only (no CCUS) and black*

squares have neither new nuclear or gas CCUS (with high levels of renewables providing low-carbon generation).

2.1 The importance of system flexibility

Figure 2 shows the potential scale of the impact of system flexibility in 2050. In this illustrative set of model runs the flexibility provided by a combination of demand side response, battery storage and interconnection significantly reduce the system costs compared to scenarios with extremely low levels of flexibility. For example, in the high demand scenario without hydrogen, there is a reduction of up to £12bn per year at a carbon intensity of 5gCO_2/kWh. Scenarios with hydrogen show a moderate reduction in the relative impact of very low flexibility.

We can conclude that system flexibility is essential in bringing down system costs in a low-carbon system. From here on in this paper we assume that higher levels of flexibility will be provided on the system as described in section 1. In this analysis we have not explicitly included any longer-term storage (in our modelling demand side response and batteries are limited to intraday transactions) but we have modelled the impact of using low-carbon hydrogen for electricity generation, and longer-term storage would have similar impacts.

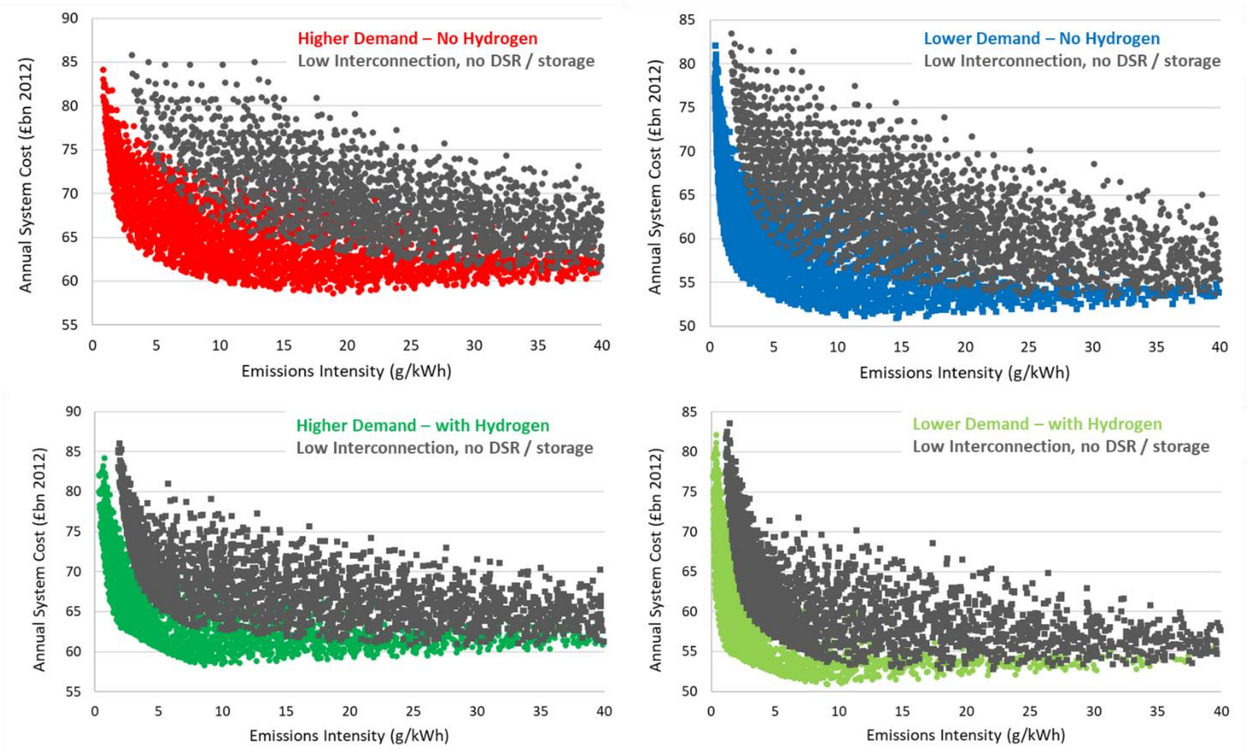

Figure 2: *The impact of flexibility in different scenarios. The scatter plots show the outcomes under extremely low flexibility scenarios (grey), where we have removed all demand side response (DSR) and storage provided by batteries and reduced the total capacity of interconnectors (from 17.9GW to 9.8GW). These are contrasted with results using our standard assumptions with high interconnection, DSR and battery build limits (in colour).*

3 Method for identifying low-cost deployment mixes

This analysis also enables us to identify specific capacity combinations of the different generating technologies that underlie low-cost, low-carbon systems, with or without hydrogen. To make full use of the data, we developed a **threshold** method, designed specifically to accommodate the inherent uncertainty in our data, and to ensure that we focussed on generation mixes robust to this uncertainty. The method has several steps:

1. For a particular level of demand and technology costs we identify which deployment mixes can meet a specified carbon intensity (e.g. 10gCO_2/kWh). We rank the deployment mixes that meet this emissions level by their total system cost and define the lowest 10th percentile as the “low-cost threshold”. All mixes with system costs below this threshold are deemed “low-cost” solutions (fig 3).

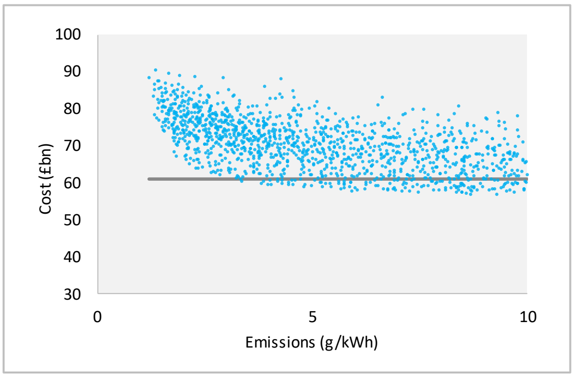

Figure 3: *Identifying low-cost deployment mixes. The scatter plot shows all “solutions” falling within 10gCO_2/kWh in an illustrative scenario. The horizontal grey line represents the low-cost threshold which contains the cheapest 10% of all the solutions.*

Using this approach, we can populate maps showing, for a given demand and technology cost scenario, the combinations of nuclear and CCUS that are within the low-cost threshold at or below different carbon intensities (fig 4).

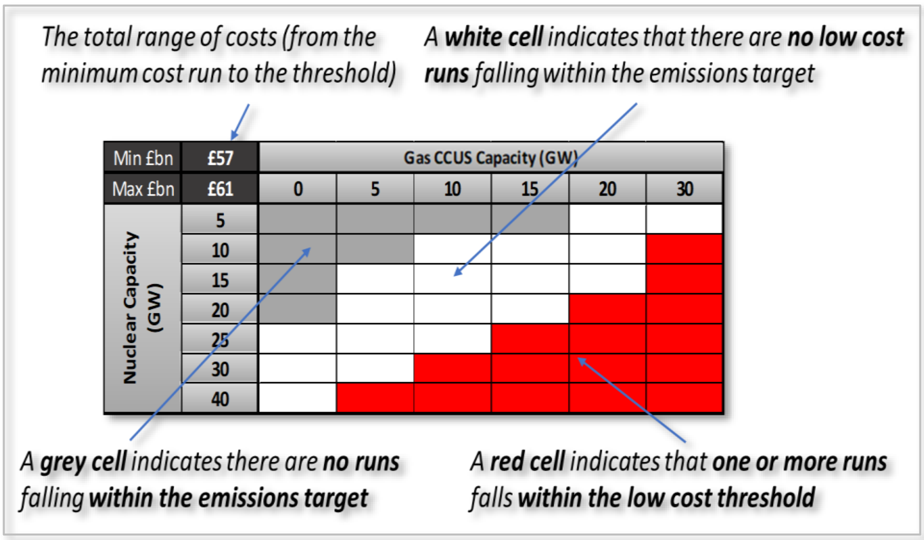

Figure 4: *Identifying which technology ranges can deliver low-cost solutions. The maps shown here are for central demand, low flexibility. The map identifies low-cost solutions at a specific level of nuclear and gas CCUS capacity.*

We can also illustrate the total volume of renewable capacity for the same demand and technology cost scenarios using a new metric, the **renewables generating potential** (measured in TWh). This is the theoretical amount of generation that would result if there was zero curtailment (due to the oversupply) of wind and solar. Figure 5 illustrates how we present this additional dimension within a threshold map.

		Gas CCUS Capacity (GW)					
		2	5	10	15	20	30
Nuclear Capacity (GW)	5						670
	10						580
	15					580	510
	20				540	510	430
	25			510	450	430	360
	30			430	370	350	290
	40	350	300	270	270	270	270

Figure 5: *Identifying the amount of renewables needed to provide low-cost solutions at each level of nuclear and CCUS. Shown here is a threshold map for central demand, low flexibility and central cost assumptions. At any given level of nuclear and CCUS, there are a number of different renewable mixes that lead to low cost solutions, giving rise to a range in the overall renewable generation. The number in each coloured cell represents the minimum level of renewables providing a low cost solution (expressed as total renewable generation potential, measured in uncurtailed TWh).*

2. To take account of uncertainty over technology costs, we constructed cost scenarios based on different combinations of low/central/high capex assumptions for each of the low-carbon technologies. We assumed that wind and solar costs were correlated (all other costs were uncorrelated). This resulted in 27 scenarios, which we assumed to be

equally likely[17]. These were averaged to produce a combined density heat map for different combinations of nuclear and CCUS across all technology costs, at a given carbon intensity and level of demand (fig 6).

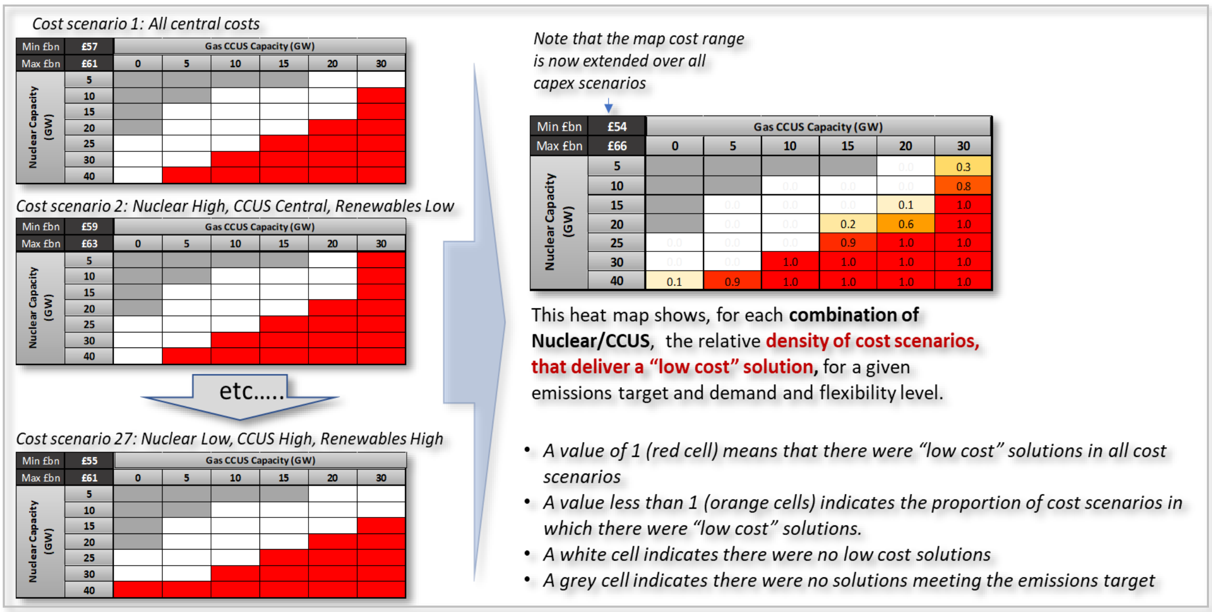

Figure 6: *By combining individual threshold maps into a density heat map we can visualise the relative density of low-cost solutions, over all 27 cost scenarios.*

[17] The results of this analysis were found to be insensitive to the precise distribution of technology costs (data not shown). A uniform distribution was used for simplicity.

4 Identifying low cost mixes

4.1 Nuclear and gas CCUS deployment

In the following set of results, we identify which deployment mixes can provide low-cost solutions across different scenarios; with and without hydrogen, at higher and lower demand and at 3 different levels of carbon intensity (5, 10 and 25 gCO_2/kWh)[18].

Figure 7A summarises the levels of nuclear and gas CCUS for which we obtain low-cost solutions over all technology cost scenarios, without hydrogen. It demonstrates that a wide range of combinations can provide low-cost solutions that are robust to different technology cost assumptions (red cells). This figure also supports the key conclusion from figure 1, that low-cost solutions at low carbon intensities (5gCO_2/kWh or below) can only be achieved with a combination of new nuclear *and* gas CCUS. For example, to deliver an carbon intensity at or below 5gCO_2/kWh at higher demand, combinations comprising 20GW-40GW of nuclear and 15-30GW of gas CCUS (at least 50GW in total) are needed to provide low cost solutions over all technology cost scenarios.

Figure 7B summarises the levels of nuclear and gas CCUS for which we obtain low-cost solutions over all technology cost scenarios, with hydrogen. Including a relatively small amount of hydrogen-fired generation – in this case 20TWh[19] - reduces the requirement for both nuclear and gas CCUS at all levels of demand and carbon. For example, to deliver an carbon intensity at or below 5gCO_2/kWh at higher demand, combinations comprising 15GW-30GW of nuclear and 15-30GW of gas CCUS (at least 35GW in total) are needed to provide low-cost solutions over all technology cost scenarios.

This is because, in our modelling, hydrogen-fired generation operates with the same flexibility as unabated gas today and can be delivered for relatively low capital costs compared to other low-carbon generation. By only generating when required it can provide additional low-carbon electricity to meet demand during periods of low wind or solar irradiance more efficiently than nuclear, CCUS or increased renewable capacity. In other words, without hydrogen more low-carbon capacity is required to ensure the same proportion of low-carbon generation. This leads to higher levels of renewable curtailment and higher overall costs

[18] The levels of emissions intensity are upper limits, so scenarios are included if they achieve 5gCO_2/kWh or less, 10gCO_2/kWh or less and 25gCO_2/kWh or less.

[19] We have not used the model to determine the optimal amount of hydrogen generation capacity. Instead we allocated a proportion of the total gas plant capacity, equivalent to the relative amount of hydrogen to gas generation. We estimate that approximately 10-20GW would be sufficient to provide up to 20TWh of generation in a typical low-cost system.

Longer term storage technologies would have a similar impact on the generation mix as generating electricity from low carbon hydrogen regardless of how that hydrogen has been produced. However, longer term storage, including using excess renewable generation to produce hydrogen, which is stored and then used to generate electricity, will further reduce systems costs by using excess renewable generation in one period to help meet demand in another.

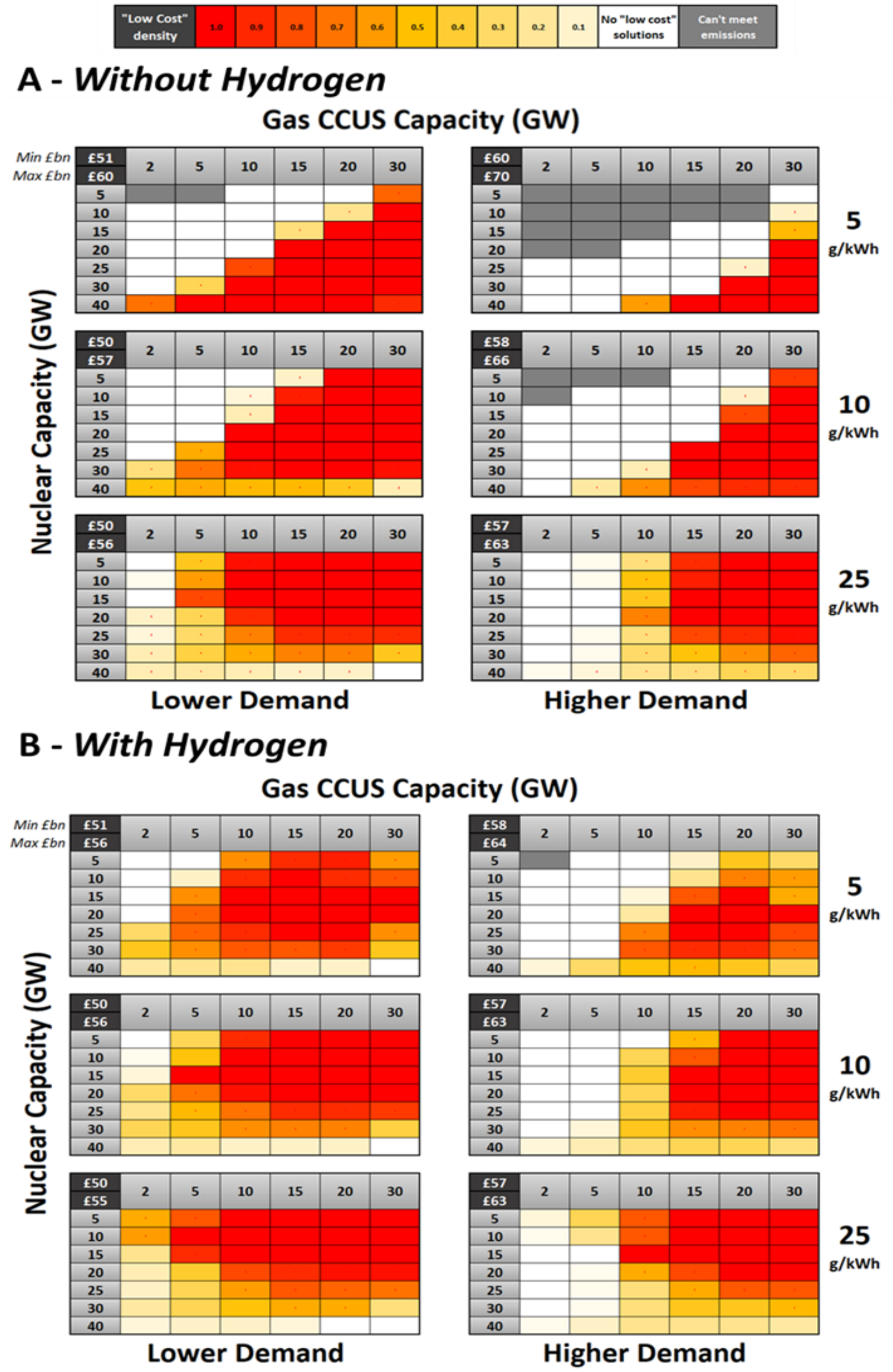

Figure 7: *Identifying low-cost combinations of nuclear and gas CCUS. Each heat map reveals where there are low-cost solutions under different levels of demand and emissions target, without (A) and with (B) hydrogen. Grey cells indicate that there are no solutions that meet emissions targets. White cells indicate there are no low-cost solutions. The orange/red shading indicates the relative density of low-cost solutions (a colour key is shown at the top of the figure). The prices shown in the top left corner of each map represent the min/max annual system costs associated with low-cost solutions over <u>all</u> technology cost scenarios. Note that for each single technology cost scenario, low-cost solutions (in the lowest 10th percentile of all solutions) are all within a range of approximately £3-4bn. The minimum system costs associated with central technology cost assumptions only are also shown in figure A3.*

4.2 Renewable generation

Figure 8 shows the minimum requirement for the total renewable generating potential at each low-cost combination of nuclear and gas CCUS. This figure shows how the total demand for renewables increases with higher demand and lower carbon intensities. Renewable demand correlates inversely with the deployment of nuclear and gas CCUS. Scenarios with low amounts of nuclear and/or gas CCUS require a higher volume of renewables than those with higher amounts. Note that the actual renewable generation in these scenarios will be somewhat less than the potential expressed in figure 8 because of curtailment at times of excess generation.

Figure 8B shows that with hydrogen, the demand for renewables is significantly lower at a given nuclear and CCUS capacity than it was without hydrogen (Figure 8A). This is for the same reasons set out at the end of section 4.1.

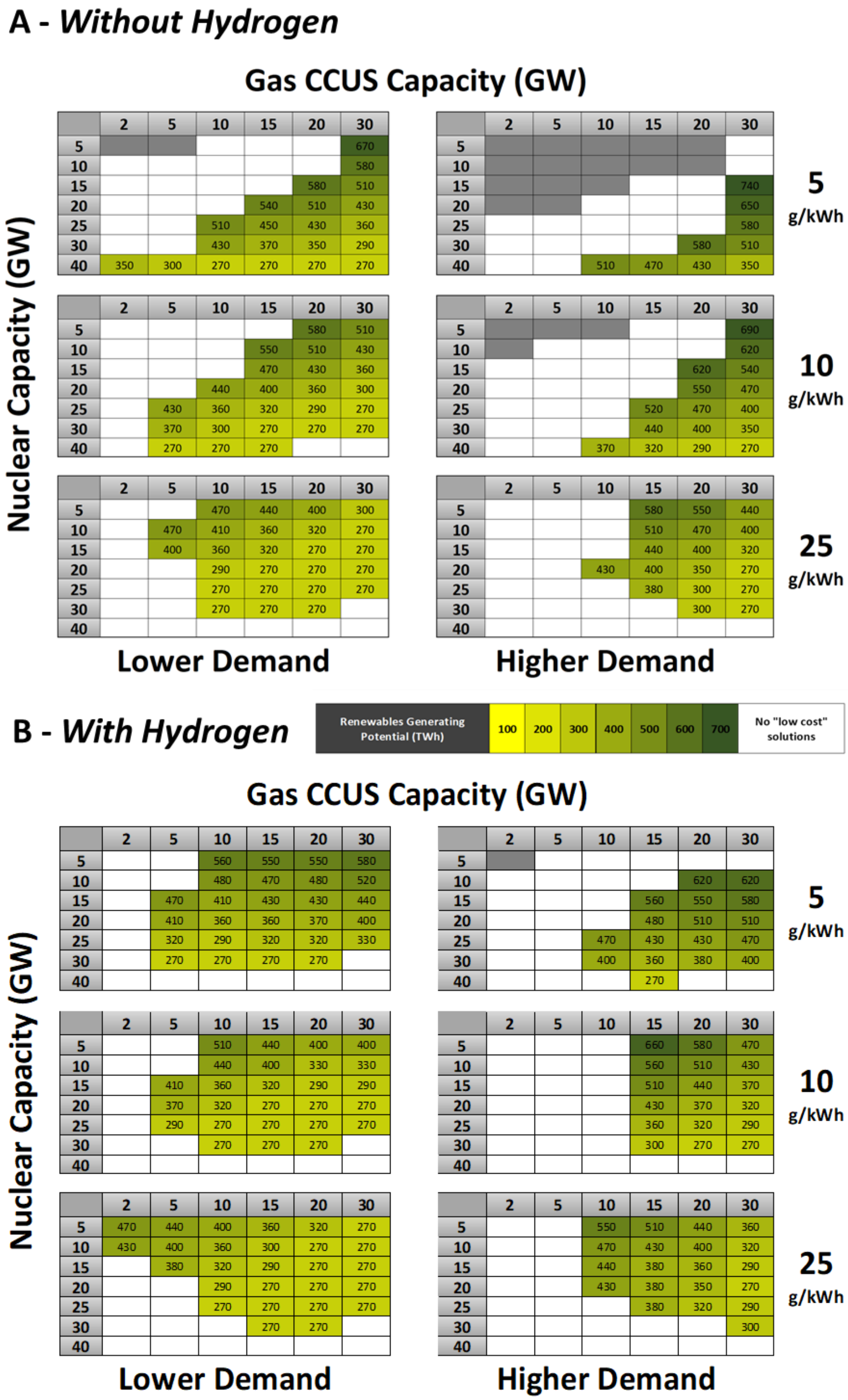

Figure 8: *Identifying the amount of renewables deployed in low-cost scenarios. The maps show the minimum amount of renewables (expressed as the uncurtailed generation potential) required for low-cost solutions at each combination of nuclear and gas CCUS capacity, in each demand/ emissions scenario. The maps are based on central cost assumptions only. The demand for renewables increases with higher demand, lower emissions targets, or lower levels of nuclear and/or gas CCUS.*

4.3 Renewable deployment

Different combinations of offshore wind, onshore wind and solar could provide similar levels of total renewable generation. Figure 9 identifies low cost renewable capacity mixes that could provide the different ranges of (uncurtailed) renewable generation that were identified for different scenarios in figure 8.

Solar Capacity (GW)	20	40	80	120

Min TWh	200	Onshore Wind Capacity (GW)			
Max TWh	300	15	25	40	60
Offshore Wind Capacity (GW)	40	15	15	0	0
	60	0	0	0	0
	80	0	0	0	0
	100	0	0	0	0
	120	0	0	0	0

Min TWh	500	Onshore Wind Capacity (GW)			
Max TWh	600	15	25	40	60
Offshore Wind Capacity (GW)	40	0	0	0	120
	60	0	120	80	15
	80	40	15	15	0
	100	15	0	0	0
	120	0	0	0	0

Min TWh	300	Onshore Wind Capacity (GW)			
Max TWh	400	15	25	40	60
Offshore Wind Capacity (GW)	40	80	40	15	0
	60	15	0	0	0
	80	0	0	0	0
	100	0	0	0	0
	120	0	0	0	0

Min TWh	600	Onshore Wind Capacity (GW)			
Max TWh	700	15	25	40	60
Offshore Wind Capacity (GW)	40	0	0	0	0
	60	0	0	0	120
	80	0	120	80	15
	100	40	15	15	0
	120	0	0	0	0

Min TWh	400	Onshore Wind Capacity (GW)			
Max TWh	500	15	25	40	60
Offshore Wind Capacity (GW)	40	0	120	80	15
	60	40	15	15	0
	80	15	0	0	0
	100	0	0	0	0
	120	0	0	0	0

Min TWh	700	Onshore Wind Capacity (GW)			
Max TWh	800	15	25	40	60
Offshore Wind Capacity (GW)	40	0	0	0	0
	60	0	0	0	0
	80	0	0	0	0
	100	120	120	80	0
	120	0	0	0	0

Figure 9: *Identifying low-cost renewable capacity mixes that could make up the total renewable (uncurtailed) generation required in different scenarios (as identified in figure 8). The maps summarise the range of renewable capacity mixes that make up all low-cost solutions (over all core demand and emissions scenarios, with and without hydrogen, using central cost assumptions). The minimum solar requirement is shown at each level of offshore/onshore. The total (uncurtailed) renewable range provided by each set of technology mixes, in each map, is indicated in the blue cells in the top left corner.*

4.4 Renewable curtailment

Figure 10 shows the level of renewables curtailment. For all scenarios, curtailment increases as the proportion of renewables in the generation mix increases. With hydrogen, because of the generally lower volumes of renewable generation required (at a given level of nuclear and CCUS capacity), curtailment is lower. This is particularly evident at lower carbon emission levels.

The inclusion of within day storage, and demand side response help to reduce curtailment. Curtailment could be further reduced by the deployment of longer-term storage technologies, which maximise the utilisation of renewables and can help to reduce system costs and carbon intensity. In figure A6 we consider the potential impact of utilising curtailed electricity.

A - *Without Hydrogen*

Gas CCUS Capacity (GW)

Nuclear Capacity (GW)

	2	5	10	15	20	30
5			369	314	243	130
10	398	343	299	202	177	96
15	327	298	230	152	117	74
20	257	203	176	118	92	49
25	203	164	113	81	64	38
30	139	104	80	50	40	22
40	70	45	30	30	30	30

	2	5	10	15	20	30
5						297
10						231
15				355	301	178
20			356	284	233	144
25	384	358	285	219	169	110
30	359	290	218	169	142	86
40	218	181	129	106	76	39

5 g/kWh

	2	5	10	15	20	30
5	314	245	177	127	78	46
10	244	177	119	75	58	29
15	177	117	94	52	38	20
20	115	94	50	35	29	10
25	82	63	37	19	13	8
30	62	51	22	12	12	12
40	30	30	30	30	30	30

	2	5	10	15	20	30
5				243	181	102
10		326	272	181	145	81
15	355	256	205	144	94	59
20	261	193	145	121	73	40
25	193	168	109	74	58	26
30	133	111	86	50	35	20
40	81	66	50	28	21	14

10 g/kWh

	2	5	10	15	20	30
5	79	60	30	19	12	12
10	62	40	29	18	12	12
15	38	26	26	20	26	9
20	28	35	28	12	12	10
25	19	19	13	8	13	8
30	17	12	12	12	12	12
40	30	30	30	30	30	30

	2	5	10	15	20	30
5	158	103	83	49	37	26
10	103	78	60	47	34	13
15	77	58	44	19	19	13
20	60	39	27	18	18	13
25	38	37	26	26	19	19
30	34	28	34	28	28	10
40	27	21	21	14	21	14

25 g/kWh

Lower Demand **Higher Demand**

B - *With Hydrogen*

Renewables Curtailment (TWh)	10	20	50	100	150	200	300

Gas CCUS Capacity (GW)

Nuclear Capacity (GW)

	2	5	10	15	20	30
5	151	129	65	60	61	78
10	96	80	43	40	42	63
15	77	52	38	38	38	39
20	49	49	28	28	29	35
25	37	19	13	19	19	29
30	17	12	12	12	12	22
40	30	30	30	30	30	30

	2	5	10	15	20	30
5		297	206	124	102	103
10	272	207	145	99	78	84
15	205	144	95	74	59	82
20	145	113	73	56	56	56
25	109	89	51	37	37	58
30	86	65	34	28	28	35
40	50	27	21	14	21	21

5 g/kWh

	2	5	10	15	20	30
5	97	65	49	19	20	12
10	75	62	28	18	12	12
15	52	38	26	20	9	9
20	35	35	28	10	7	10
25	19	12	8	8	13	8
30	17	12	12	12	12	12
40	30	30	30	30	30	30

	2	5	10	15	20	30
5	243	181	124	83	49	26
10	181	123	79	60	46	13
15	122	93	59	44	19	13
20	90	73	39	28	18	13
25	75	58	37	26	19	19
30	48	34	34	28	28	10
40	27	21	21	14	21	14

10 g/kWh

	2	5	10	15	20	30
5	30	30	12	12	12	12
10	29	18	18	18	12	12
15	26	26	26	20	9	9
20	28	12	28	10	7	10
25	19	12	8	8	13	8
30	17	12	12	12	12	12
40	30	30	30	30	30	30

	2	5	10	15	20	30
5	67	50	37	26	26	26
10	60	46	34	14	13	13
15	44	44	20	19	19	13
20	40	28	27	18	18	13
25	38	37	26	26	19	19
30	34	28	34	28	28	10
40	27	21	21	14	21	14

25 g/kWh

Lower Demand **Higher Demand**

Figure 10: *Identifying the amount of renewable curtailment in all (not just low cost) scenarios. This map is based on the lowest cost solution for a given level of nuclear and CCUS capacity. Curtailment increases as the proportion of renewables in the generation mix increases. Curtailment is generally lower with hydrogen.*

4.5 Low-cost, low-carbon generation mixes

Figure 11 shows a number of illustrative mixes with carbon intensities of 5gCO_2/kWh or less. These are all at low-cost except for the high renewables mix without hydrogen, which can deliver the same carbon intensity but not at low-cost. The inclusion of hydrogen[20] leads to a lower overall system cost (see also Annex figure A1) and also enables a low-cost solution with a greater proportion of renewables. This demonstrates a range of different possible balances between CCUS, nuclear and renewables. There is also optionality in the precise mix of renewable technologies that can make up the total generation

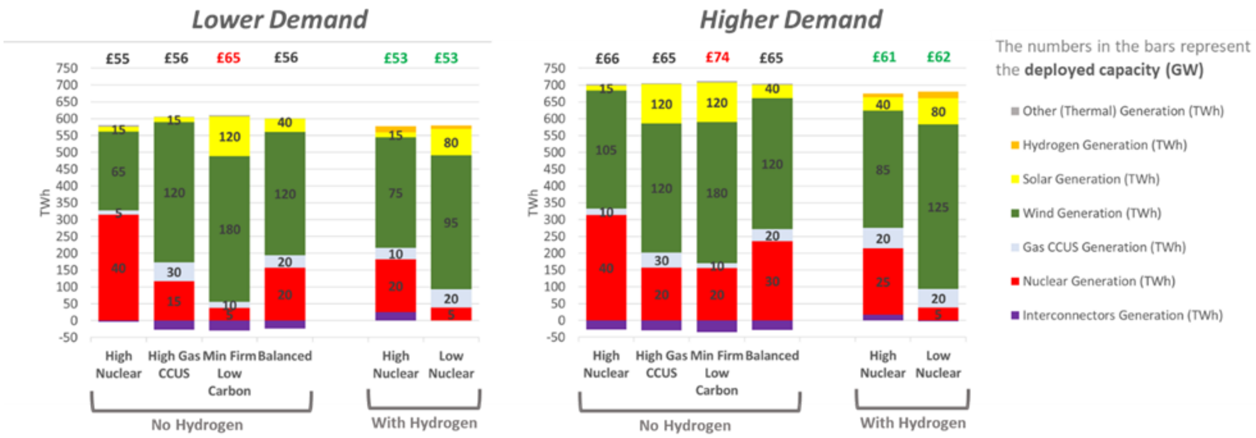

Figure 11: *An illustration of how very different mixes can make up low-cost systems in both demand scenarios. The bar charts show different generation mixes with or without hydrogen. These are all at equivalently low-cost except for the high renewable mixes without hydrogen. The bars indicate the annual generation provided by each technology; in the case of interconnectors this is the net generation, i.e. imports minus exports. The numbers in the bars represent the deployed capacity in GW. The annual systems cost (in £bn 2012) are shown above each bar.*

[20] In these illustrative 5gCO_2/kWh systems the range of hydrogen generation shown by the orange bars is 10-18TWh.

5 Conclusions/Next steps

Our analysis has shown that:

- There is no single optimal technology mix; many capacity mixes can meet different carbon emissions levels at low cost. This is true for all levels of demand modelled (see section 4).
- Electricity system costs are lowest when carbon intensity is between 5-25gCO_2/kWh (see section 2).
- All low-cost solutions include significant levels of wind and solar. Wind and solar generation could more than quadruple by 2050 (see section 2).
- System flexibility reduces system costs and the amount of low carbon generation required by reducing curtailment of wind and solar and flattening demand for electricity (see section 2.1 and 4.1). Our modelled options include batteries, demand side response, interconnectors and short-term dispatchable generation from unabated gas and/or low-carbon hydrogen
- Without hydrogen-fired generation or long-term storage, all low-cost solutions require other forms of low-carbon generation to provide resilience during extended periods of low wind and solar irradiation. Our modelled options to provide this are nuclear and gas generation with Carbon Capture, Usage and Storage (CCUS) (see sections 2 and 4.1).
- Moderate levels of low-carbon hydrogen could replace unabated gas-fired generation and reduce the requirement for new nuclear and gas CCUS in low carbon systems. It is technically possible for higher levels of hydrogen-fired generation to also replace nuclear and gas CCUS but this is dependent on the quantity and cost of hydrogen available for generating electricity. We have only modelled the impact of low-carbon hydrogen fired generation, but long-term storage would have similar impacts (see section 3.1).

There are some limitations to our analysis which should be noted:

- It is based on two illustrative net zero scenarios – other scenarios, with potentially materially different power sector demands and carbon emissions are possible
- We have considered only 2050 system costs, and not the transition costs of getting from today's system to 2050
- We calculated the impact of deploying hydrogen "off model", making the simplifying assumption that it would only displace natural gas generation, with no other impact on the generation mix. In reality, there will be a complex interaction between the price of hydrogen and its place in the merit order. It is possible that policies, not considered here, would need to be in place to optimise the use of hydrogen.
- We have not presented any analysis on the production of hydrogen by electrolysis. The amount of hydrogen in our core scenario (up to 20TWh power output) is broadly consistent with an amount that could be derived from electrolysis of curtailed renewables

in low-cost, low-carbon systems. However, if the economics of hydrogen production more generally favoured electrolysis then higher volumes could be demanded from the power sector, which could in turn impact the relative cost of different generation mixes (see figure A6).

- We have not included long-term storage

Future work will further consider these limitations.

Annexes

A1. Minimum system costs with different hydrogen scenarios

Figure A1 compares the system costs under different hydrogen scenarios; blue hydrogen (with 15% of gas equivalent carbon emissions) limited to 20TWh of output generation (as in our core scenario), green hydrogen (with zero carbon) and unlimited blue hydrogen. We tested each with a hydrogen price ranging from 1-6 times the natural gas price. In all

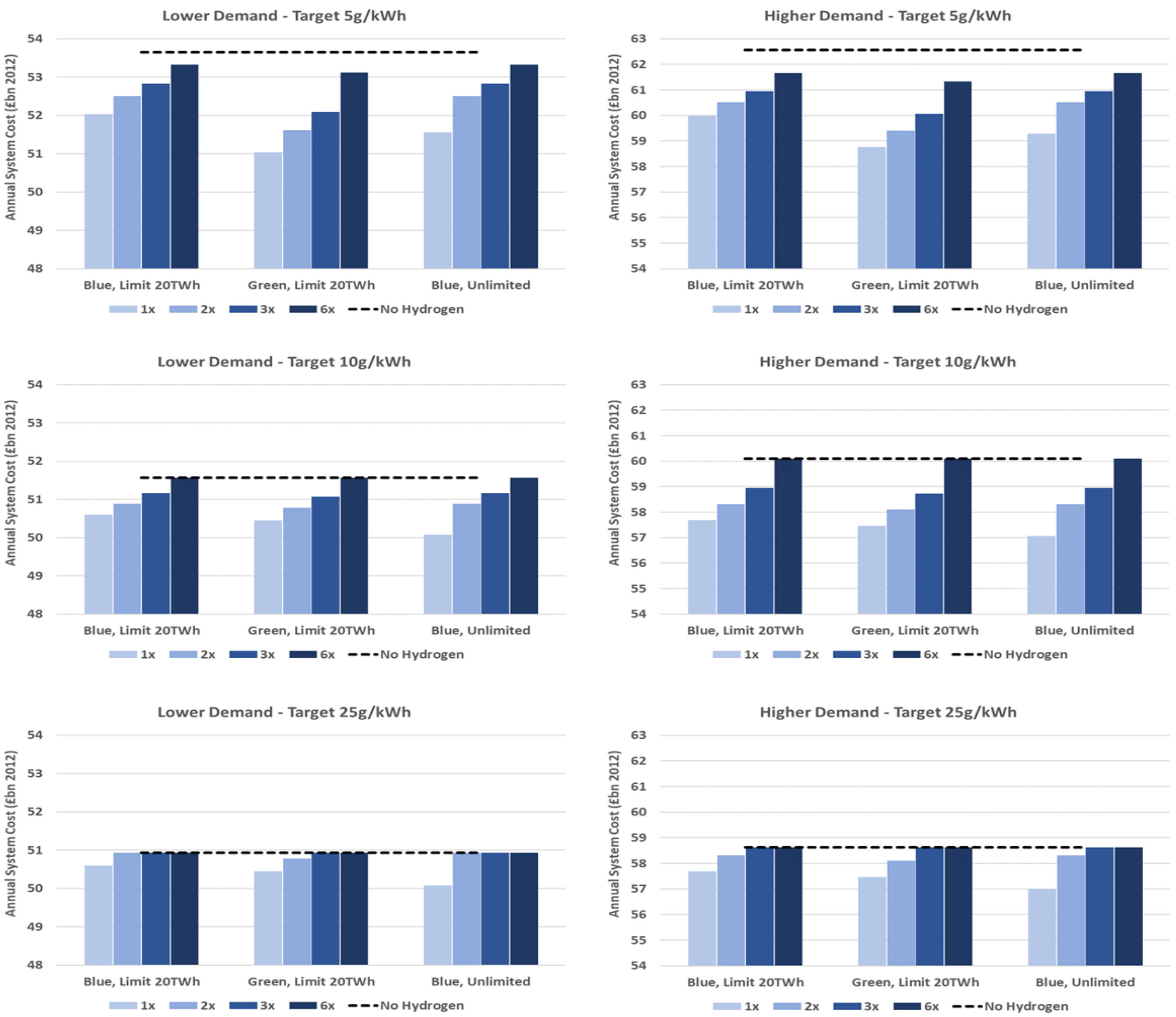

Figure A1: *The bar charts show the minimum system cost for different demand levels at different emissions targets for 3 distinct hydrogen scenarios (blue hydrogen limited to 20TWh, green hydrogen limited to 20TWh and unlimited use of blue hydrogen) and cost assumptions, defined relative to the natural gas price (19.5£2012/MWh) over a 1-6 fold range. These are compared to the minimum system costs without hydrogen (black dashed line). Note that 20TWh blue hydrogen is equivalent to our core scenario in the main body text. Blue hydrogen has 15% of equivalent gas generation emissions. We assume that "green" hydrogen has zero emissions.*

cases systems with hydrogen are cheaper than those without at 5gCO_2/kWh. There are still savings at higher emissions targets for the lower priced hydrogen scenarios

A2. Comparing carbon abatement costs

Figure A2 shows that systems with hydrogen can have lower costs of abatement.

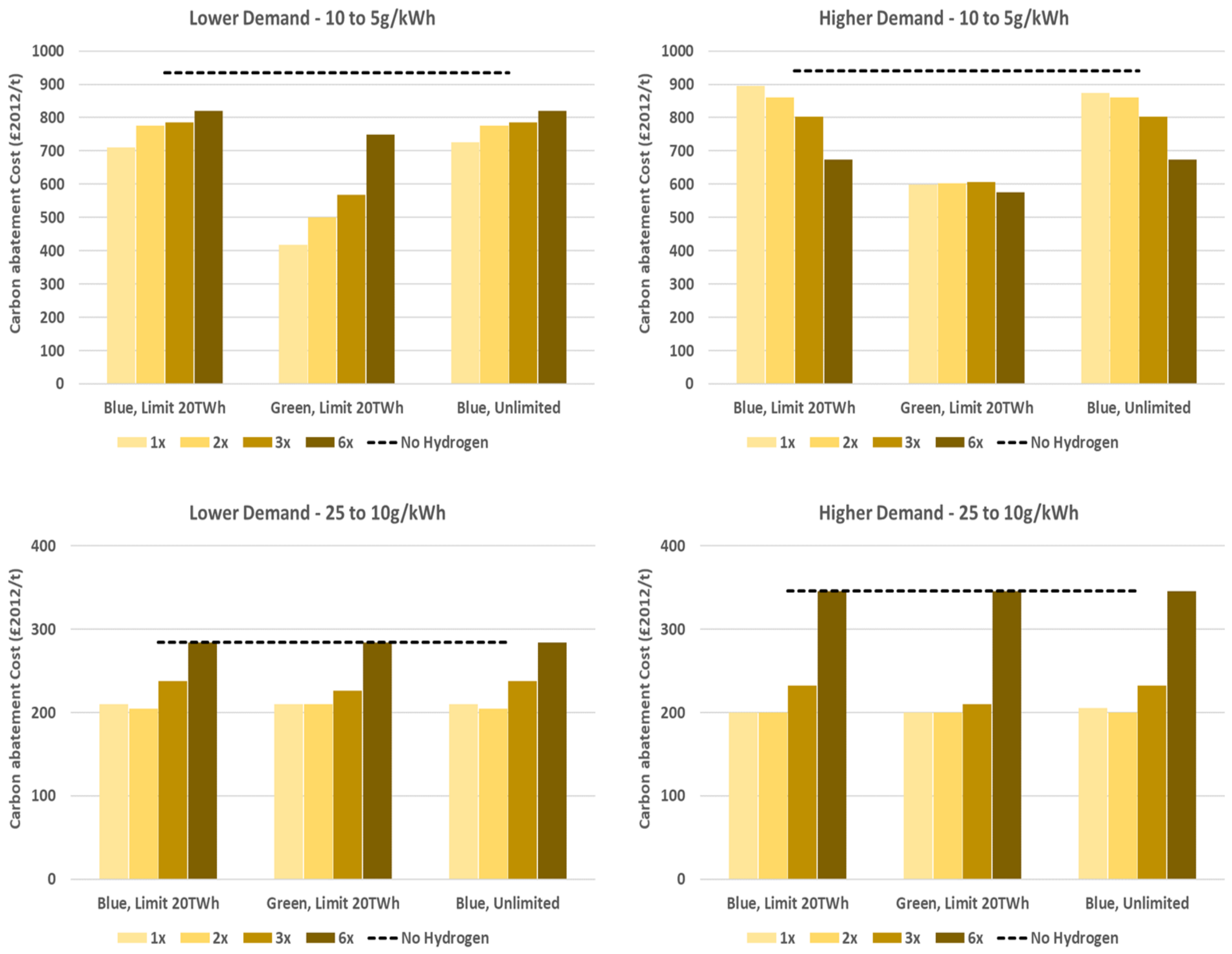

Figure A2: *The bars show the average abatement cost moving between different emission targets under the different scenarios evaluated in figure A1 above. The average abatement cost is equal to the difference in the minimum system costs excluding carbon costs, divided by the difference in carbon emissions associated with each emissions target. The abatement costs with hydrogen are compared to those without hydrogen in each case (black dashed line).*

A3. Minimum system costs under central technology cost assumptions

A - *Without Hydrogen*

Gas CCUS Capacity (GW)

Nuclear Capacity (GW)

5 g/kWh

	Lower Demand						Higher Demand					
	2	5	10	15	20	30	2	5	10	15	20	30
5			£65.1	£63.3	£60.3	£56.3						£70.0
10	£66.6	£64.6	£63.0	£59.4	£58.0	£54.9						£67.7
15	£64.6	£63.2	£61.0	£57.5	£56.0	£54.3				£72.5	£70.7	£66.1
20	£62.6	£60.7	£59.0	£56.3	£55.3	£53.7			£72.7	£70.6	£68.5	£64.5
25	£60.6	£59.1	£56.9	£55.1	£54.5	£53.7	£74.4	£73.8	£70.7	£68.5	£66.8	£64.1
30	£58.8	£57.2	£55.8	£54.3	£53.9	£53.7	£73.8	£71.5	£68.7	£66.6	£65.4	£63.5
40	£56.5	£55.1	£54.8	£54.8	£54.9	£55.8	£69.9	£68.2	£66.1	£65.1	£63.9	£62.6

10 g/kWh

	Lower Demand						Higher Demand					
	2	5	10	15	20	30	2	5	10	15	20	30
5	£63.5	£61.1	£57.9	£55.9	£53.5	£51.9				£67.7	£64.9	£61.7
10	£61.2	£58.9	£56.1	£53.9	£53.3	£51.6		£71.1	£69.1	£65.5	£64.0	£60.9
15	£59.0	£56.8	£55.2	£53.3	£52.7	£51.7	£72.5	£69.0	£67.0	£64.7	£62.3	£60.3
20	£57.0	£55.8	£53.9	£53.0	£52.6	£52.0	£69.9	£66.9	£65.3	£63.6	£61.6	£60.3
25	£55.8	£54.8	£53.6	£52.9	£52.6	£52.5	£67.9	£66.4	£64.0	£62.1	£61.3	£60.1
30	£55.2	£54.5	£53.7	£53.1	£52.9	£53.5	£65.9	£65.0	£63.2	£61.9	£61.0	£60.6
40	£54.9	£54.6	£54.8	£54.8	£54.9	£55.8	£64.2	£63.6	£62.6	£62.0	£61.6	£61.6

25 g/kWh

	Lower Demand						Higher Demand					
	2	5	10	15	20	30	2	5	10	15	20	30
5	£54.9	£53.6	£52.6	£52.2	£51.7	£50.9	£64.7	£62.6	£61.5	£60.2	£59.6	£58.6
10	£54.1	£53.4	£52.6	£52.1	£51.6	£51.2	£63.2	£62.2	£61.0	£60.4	£59.8	£58.9
15	£53.9	£53.2	£52.8	£52.3	£52.1	£51.7	£62.8	£61.8	£61.0	£60.2	£59.9	£59.1
20	£53.9	£53.6	£53.0	£52.7	£52.3	£52.0	£62.3	£61.7	£60.9	£60.6	£59.9	£59.4
25	£54.2	£53.8	£53.3	£52.7	£52.6	£52.5	£62.0	£61.6	£61.3	£60.6	£60.4	£60.0
30	£54.2	£53.9	£53.3	£53.1	£52.9	£53.5	£62.2	£62.0	£61.4	£61.1	£60.7	£60.5
40	£54.9	£54.6	£54.8	£54.8	£54.9	£55.8	£62.7	£62.4	£61.9	£61.7	£61.6	£61.6

Lower Demand | Higher Demand

B - *With Hydrogen*

Gas CCUS Capacity (GW)

Nuclear Capacity (GW)

5 g/kWh

	Lower Demand						Higher Demand					
	2	5	10	15	20	30	2	5	10	15	20	30
5	£57.5	£56.2	£53.5	£52.8	£52.7	£53.5		£69.8	£65.8	£62.7	£61.6	£62.0
10	£55.4	£54.6	£53.2	£52.5	£53.1	£53.4	£69.1	£66.7	£64.1	£62.2	£61.2	£61.4
15	£54.7	£53.6	£52.8	£52.6	£52.7	£53.0	£67.1	£64.9	£62.5	£61.2	£60.5	£61.5
20	£54.2	£53.7	£52.7	£52.7	£52.6	£53.2	£65.2	£63.8	£61.7	£60.8	£60.7	£60.7
25	£54.0	£53.4	£53.0	£52.9	£52.8	£53.7	£64.0	£62.9	£61.5	£60.6	£60.5	£61.4
30	£53.8	£53.5	£53.1	£53.1	£53.0	£53.9	£63.4	£62.5	£61.1	£60.8	£60.6	£61.1
40	£54.8	£54.6	£54.8	£54.9	£55.0	£55.9	£62.8	£62.2	£61.6	£61.5	£61.6	£62.0

10 g/kWh

	Lower Demand						Higher Demand					
	2	5	10	15	20	30	2	5	10	15	20	30
5	£55.0	£53.8	£52.7	£51.8	£51.5	£50.9	£67.8	£65.4	£62.8	£60.9	£59.5	£58.3
10	£54.2	£53.5	£52.5	£51.8	£51.3	£51.2	£65.6	£63.5	£61.3	£60.5	£59.6	£58.6
15	£53.7	£53.0	£52.5	£52.0	£52.0	£51.7	£63.9	£62.5	£61.0	£60.3	£59.5	£58.9
20	£53.6	£53.3	£52.7	£52.5	£52.2	£52.1	£62.8	£62.1	£61.0	£60.3	£59.6	£59.3
25	£53.8	£53.4	£52.9	£52.6	£52.6	£52.6	£62.4	£61.8	£61.1	£60.3	£60.1	£60.0
30	£53.8	£53.5	£53.1	£53.1	£53.0	£53.7	£62.3	£61.7	£61.1	£60.8	£60.6	£60.5
40	£54.8	£54.6	£54.8	£54.9	£55.0	£55.9	£62.3	£62.1	£61.6	£61.5	£61.6	£61.7

25 g/kWh

	Lower Demand						Higher Demand					
	2	5	10	15	20	30	2	5	10	15	20	30
5	£53.0	£52.7	£52.1	£51.6	£51.3	£50.9	£61.6	£60.8	£60.0	£59.5	£59.1	£58.3
10	£53.1	£52.6	£52.1	£51.8	£51.3	£51.2	£61.1	£60.8	£60.2	£59.7	£59.2	£58.6
15	£53.2	£52.8	£52.5	£52.0	£52.0	£51.7	£61.3	£61.1	£60.2	£59.8	£59.5	£58.9
20	£53.5	£53.2	£52.7	£52.5	£52.2	£52.1	£61.3	£60.9	£60.5	£60.2	£59.6	£59.3
25	£53.8	£53.4	£52.9	£52.6	£52.6	£52.6	£61.6	£61.2	£60.9	£60.3	£60.1	£60.0
30	£53.8	£53.5	£53.1	£53.1	£53.0	£53.7	£61.9	£61.6	£61.1	£60.8	£60.6	£60.5
40	£54.8	£54.6	£54.8	£54.9	£55.0	£55.9	£62.3	£62.1	£61.6	£61.5	£61.6	£61.7

Lower Demand | Higher Demand

Figure A3: *The minimum system costs associated with central technology cost assumption only; one of the 27 cost scenarios used to construct the heat maps shown in figure 7. Here the red-blue colour scale is illustrative only – it does not identify the lowest 10*[th] *percentile of system costs. All other assumptions are equivalent to those used in figure 7.*

A4. Low-cost generation mixes in alternative hydrogen scenarios

4.1 Low-cost "green" hydrogen with limited availability

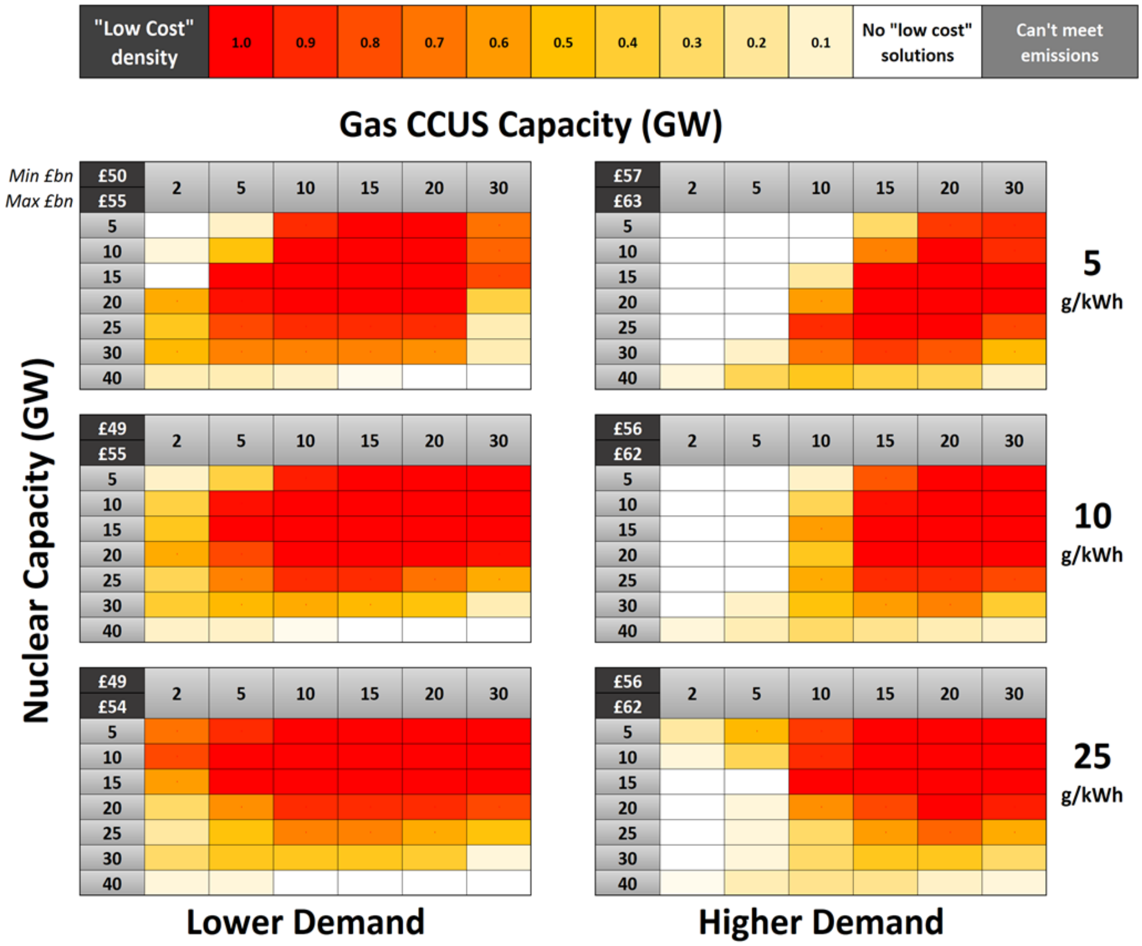

Figure A4: Identifying low cost generation mixes assuming a scenario with green hydrogen, limited to 20TWh, with hydrogen priced at 1x gas price. This scenario is intended to represent the case where a limited amount of hydrogen is produced from the electrolysis of curtailed renewables. The heat maps are produced by the same method as for figure 7.

Figure A4: *Identifying low cost generation mixes assuming a scenario with green hydrogen, limited to 20TWh, with hydrogen priced at 1x gas price. This scenario is intended to represent the case where a limited amount of hydrogen is produced from the electrolysis of curtailed renewables. The heat maps are produced by the same method as for figure 7.*

4.2 Unlimited "blue" hydrogen (2x gas price)

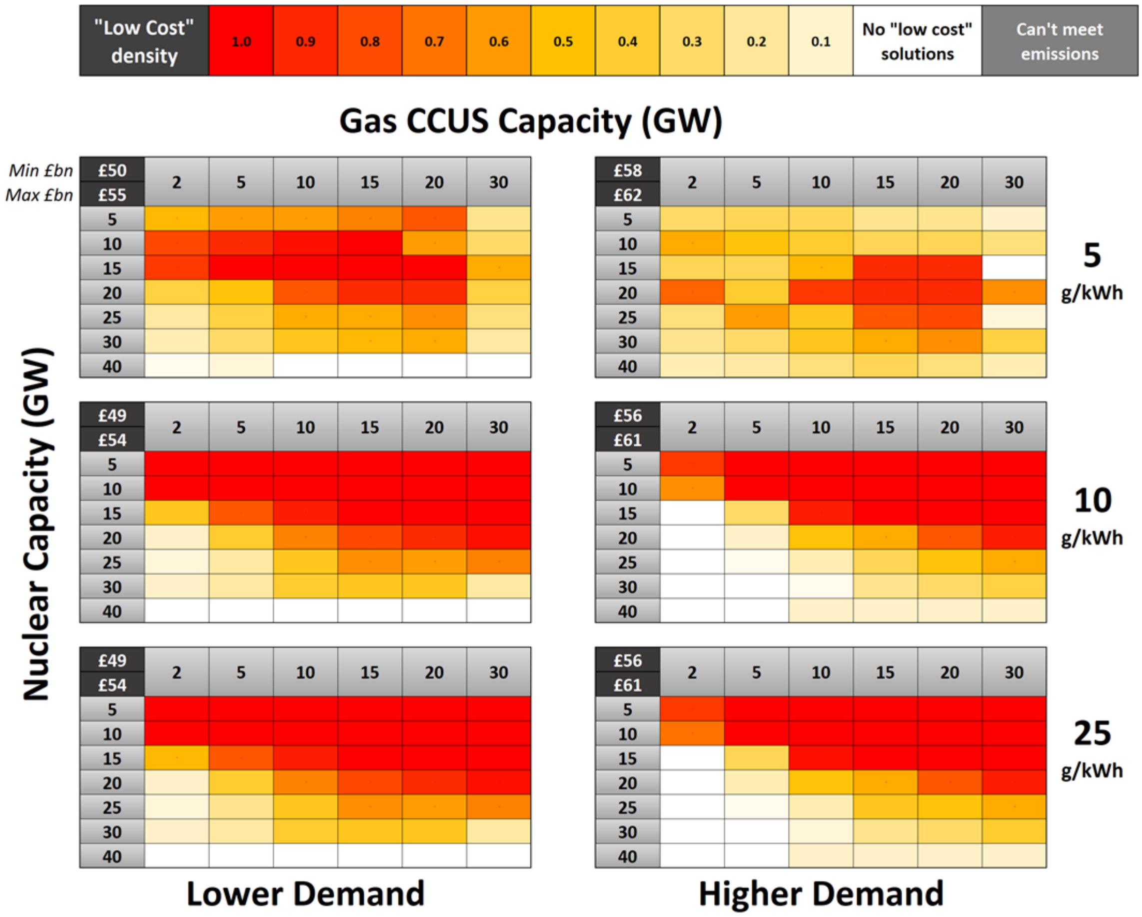

Figure A5: *Identifying low cost generation mixes assuming a scenario with blue hydrogen, with no limit, with hydrogen priced at 2x gas price. This scenario is intended to represent the case where there is plentiful supply of hydrogen in a market predominantly sourced from methane reformation. The heat maps are produced by the same method as for figure 7.*

A5. Utilising curtailed power

Figure A6 shows how system costs could change if there is a use for curtailed electricity. This could be hydrogen production by electrolysis but could also represent alternative forms of flexible demand. Using curtailed power will ultimately lower the cost of systems with high levels of curtailment. The scale of the impact will depend on the value of curtailed power. In the case specific to hydrogen production this value will represent the costs of electrolysis relative to the market value of “green” hydrogen.

Gas CCUS Capacity (GW)

Nuclear Capacity (GW)

No use of curtailment

	2	5	10	15	20	30
5		£69.8	£65.8	£62.7	£61.6	£62.0
10	£69.1	£66.7	£64.1	£62.2	£61.2	£61.4
15	£67.1	£64.9	£62.5	£61.2	£60.5	£61.5
20	£65.2	£63.8	£61.7	£60.8	£60.7	£60.7
25	£64.0	£62.9	£61.5	£60.6	£60.5	£61.4
30	£63.4	£62.5	£61.1	£60.8	£60.6	£61.1
40	£62.8	£62.2	£61.6	£61.5	£61.6	£62.0

15 £/MWh

	2	5	10	15	20	30
5		£65.3	£62.8	£60.8	£60.1	£60.5
10	£65.1	£63.6	£61.9	£60.7	£60.0	£60.1
15	£64.0	£62.7	£61.1	£60.1	£59.7	£60.3
20	£63.1	£62.1	£60.6	£59.9	£59.9	£59.9
25	£62.4	£61.5	£60.7	£60.1	£59.9	£60.5
30	£62.2	£61.5	£60.6	£60.4	£60.2	£60.6
40	£62.0	£61.8	£61.3	£61.3	£61.3	£61.7

30 £/MWh

	2	5	10	15	20	30
5		£60.8	£59.7	£59.0	£58.6	£58.9
10	£61.0	£60.5	£59.7	£59.2	£58.8	£58.9
15	£60.9	£60.6	£59.7	£59.0	£58.8	£59.0
20	£60.9	£60.4	£59.5	£59.1	£59.1	£59.1
25	£60.8	£60.2	£59.9	£59.5	£59.4	£59.6
30	£60.9	£60.5	£60.1	£59.9	£59.8	£60.1
40	£61.3	£61.4	£61.0	£61.1	£61.0	£61.4

Figure A6: *The impact on system costs from utilising curtailed power output. All maps are for higher demand, targeting 5gCO_2/kWh under the core hydrogen scenario (blue H2 limited to 20TWh of power output at 2x gas price). The costs shown are for central technology costs only. The top figure shows the original system costs (as in A3). The next two rows show the changing system costs under the assumption that the curtailed electricity (as identified in figure 9) provides a net income per unit of power, as per the different values indicated (15 or 30 £/MWh). Note that here the red-blue colour scale is illustrative only.*