Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines Follow On

Title: Scenario 10 Results Pack

Abstract:

Various scenarios for the UK's power fleet composition in 2030 and 2040 were developed. Dispatch modelling in Plexos was carried out by Baringa on these fleets to investigate the role gas fed plants might have in future. This includes the ability to study load factors, stop/starts etc, and together with concomitant pricing, provide a picture of investment remuneration. The effect of key drivers is studied e.g. gas price.

Context:

Increasing amounts of subsidised renewable power is reducing load factors of gas fired power generation. This work set out to get a view on whether new gas GT looked investible, and if GTs with CCS could expect reasonable load factors. The work concludes with a comparison of gas usage in three scenarios , the first being a continuation of current trends in fleet composition, the second where renewable lead the decarbonisation , and a third where baseload plants lead decarbonisation. Slidepack and excel formats are provided.

Cost-optimal pathways to decarbonising the GB power sector

Final Report

Client: Energy Technologies Institute (ETI)
Date: 4/8/2017
Version: v3_0

Executive Summary (1)

Detailed analysis of cost-optimal annual decarbonisation pathways to 2050 considering capacity and operational dispatch requirements, and current policy momentum effects

- ETI commissioned Baringa to undertake detailed analysis of what the cost optimal power sector capacity mix could look like around the 2030 point on the pathway to 2050, which allows for feasible operation (in line with GB's reliability standard for a loss of load expectation of 3 hours per year) and which is consistent with a trajectory that enables the UK to meet its longer term, economy-wide emissions target.

- The analysis was undertaken in PLEXOS using the LT Plan (Long-Term) functionality that is available. A model was developed that minimises the total costs (capital, fixed operating and variable operating costs) of generation while ensuring the security of supply and meeting the carbon targets. For existing capacity we have used our detailed in-house generation database that includes all power plants that participate in the wholesale markets along with their operational characteristics. The plant retirement decisions are an exogenous input to the model.

- The costs of new entry capacity were mainly advised from the ESME database while the operating characteristics were a combination of ETI data supplemented by additional Baringa information where relevant (e.g. ramp rates or start costs for more detailed operational analysis which are not present in the ESME database). Fossil fuel prices were based on near term forward prices and International Energy Agency's (IEA) long-term projections as the most recent available set of assumptions. A carbon intensity target was set at 90gCO2/kWh for 2030 and to net zero carbon emissions for 2050 (linear interpolation in between)

- We simulated the GB power market for the horizon of 2022 to 2050 using the inputs described above. The simulation was run on annual basis with a reduced chronology (6 sample days per year with hourly dispatch and representation of interconnected market prices from Baringa's pan-European power model). In the period 2022-2030, all coal and some older gas plants are decommissioned. The carbon intensity target remains high during that period and many technologies such as CCS and Nuclear remain expensive. As a result most of new capacity deployment comes from CCGT.

- Most of the peaking capacity requirements for that period are met by OCGTs. In the period 2030-2050, carbon intensity target drops significantly and therefore there is need for more low carbon capacity. In this period, Nuclear is the dominant baseload capacity build and required new peaking additions are met by compressed air electricity storage and pumped heat electricity storage, on top of the existing pumped hydro capacity (from a set of battery and flow battery options).

Executive Summary (2)

Detailed analysis of cost-optimal annual decarbonisation pathways to 2050 considering capacity and operational dispatch requirements, and current policy momentum effects

- Using the optimised pathway capacity mix, we also simulated the 2030 spot year in a detailed way (full hourly dispatch), generating projections of dispatch and prices for that year. Whilst the pathway analysis applied direct CO2 intensity constraint as part of the optimisation, using outputs from this analysis it is possible to infer what level the carbon price would have to reach to meet the 2030 intensity target. This requires ~58 GBP per ton of CO2 to achieve the equivalent 90gCO2/kWh target given the Base Case capacity mix in 2030. In terms of the broader system operation in 2030 most of the flexibility is provided by CCGTs while OCGT only generates at periods of very high net load (demand net of wind and solar generation). Gas CCS and Nuclear are used for baseload generation.

- In addition, we ran several sensitivities and compared these to the base case (alongside a range of other National Grid, CCC, ETI and Baringa scenarios):
  - In Low Demand, significantly less baseload capacity is built over the entire horizon especially nuclear and CCS
  - In Low Fuel Prices, Gas CCS is favoured as the main baseload unit at the expense of nuclear
  - In Low Interconnection, there is need for more capacity - especially baseload because GB is expected to be a net importer in the medium term
  - In High Renewables, the need for baseload capacity decreases but additional OCGTs and storage units are required to provide peak / flexible capability
  - In Flexible EVs, the flexibility of the electric vehicles reduces the requirement for dedicated storage units
  - In Constrained CCS, the restrictions of CCS in the 20s/early 30s, causes a permanent change to the system favouring renewables and storage
  - In Constrained Nuclear, the restrictions of nuclear in the 20s favour the deployment of CCS technologies and renewables

Executive Summary (3)

Policy makers need to recognise evolving roles of existing/new technologies and adapt accordingly

- **Pathway for power sector CO2 targets**
  - The analysis shows that the pathway for any implied power sector CO2 intensity target is an important driver of consumer costs. Targeting a <100gCO2/kWh (90 in this study) target in 2030 appears expensive given the high CO2 price needed to achieve this. A 'marginally' more relaxed target (e.g. pushing this back to 2035) would likely help bring down costs as it allows existing gas assets - which are due to retire around this point - to be run harder until the end of their technical lives, and for new baseload low carbon technology costs to come down further before significant expansion. Testing this against the Base Case led to a reduction in electricity system costs of ~£6bn over the pathway to 2050 on an undiscounted basis (or ~£3bn at the Treasury Social Discount Rate of 3.5%).
  - In general there are only relatively small differences in the generation mixes across scenarios (both within this study and other published) that achieve a ~90-100gCO2/kWh intensity by 2030, however, the differences are more significant post-2030 given the challenges associated with meeting a near zero intensity target. Towards the end of pathway the push to reduce CO2 intensity below ~20-30gCO2/kWh to zero starts to drive up costs significantly, given the need for biomass-CCS or nuclear over fossil CCS and the need to remove remaining sources of fossil-based flexible plant from the system. However, comparison with ESME model scenarios indicate that a net negative CO2 intensity in the power sector is likely to be a cost-effective way of helping to directly and indirectly decarbonise the wider energy system.

- **Low carbon baseload technology support**
  - This study, along with other published scenarios, highlights the need for a significant low carbon baseload capacity by 2050 (accounting for well over half of all generation) to achieve near zero carbon intensity, as well as the costs associated with trying to achieve this predominantly via a wind/solar focused route (noting that significant deployment of intermittent renewables is still seen across all scenarios).
  - Under base case assumptions nuclear is the preferred baseload technology, but the range of sensitivities shows that the economics can still swing in favour of CCS. Given long term uncertainties over the cost of these technologies and fossil fuel prices it is important to consider how policy incentives (such as the Contracts for Difference (CfD) mechanism) can be recast to directly support *technology-neutral* procurement of low carbon baseload. Over the technology-neutrality can be extended in a broader sense – via mechanisms such as carbon price - to a wider range of abatement options across the energy system.

Executive Summary (4)

Policy makers need to recognise evolving roles of existing/new technologies and adapt accordingly

- **Peaking / flexible plant and the role of gas**
  - At a high-level we distinguish been plant providing purely peaking backup capacity – i.e. plant that is expected to only run for a few hours a year to meet high demand periods. For these periods high carbon plant such as OCGT may still be a viable option as their limited running hours provides negligible contribution to emissions. By contrast, plant providing broader system flexibility are expected to run for more hours across the year, in particular helping to accommodate swings in intermittent wind and solar, but the emissions implications of these plant are more significant.
  - Significant new CCGT build (4-8GW+) comes online in the early/mid 2020s across the range of our scenarios, but with limited additional build from the late 2020s. The new CCGT functions as mid-merit plant providing both flexibility and peaking capacity, but their load factors decline significantly through the 2030s as the CO2 constraint tightens. Some OCGT is built into the 2030s as a cheap form of peaking backup capacity rather than a more general source of flexibility, but there is a broader shift to lower carbon forms of flexibility such as storage to help manage the system across the year. As the system develops it is important that the Capacity Market / CfD mechanisms evolve accordingly; recognising the declining role of CCGTs and sufficiently incentivising storage (dedicated or 'behind the meter'), which becomes implicitly low carbon as the electricity system decarbonises, or low carbon mid-merit plants such as hydrogen turbines which can provide both peaking capacity and flexibility, but are not covered adequately by policy. Hydrogen turbines are able to provide these services due to fast ramp rates and effectively no restriction on running hours from an emissions perspective, assuming the hydrogen is itself produced via a low carbon process.
  - It should also be noted that the significant anticipated expansion of electric vehicles and electric heating (coupled with hot water storage) over the longer term will provide a substantial pool of flexibility that could be used to manage the electricity system (and without necessarily requiring the use of vehicle-to-grid). This can be achieved by making small changes to charging patterns across a very large diversified pool of consumers, providing flexibility without materially impacting the consumers underlying travel patterns or heating requirements. Where a 3rd party (e.g. aggregator, system operator, etc) can directly control this flexibility in response to real-time changes on the wider system this may prove to be significantly cheaper than building dedicated flexibility options such as large scale batteries. Policy makers should work to ensure that remaining technical, commercial and regulatory barriers to exploiting this 'consumer-led' flexibility are removed.
- **Managing uncertainty in the future costs of the electricity system**
  - The sensitivity analysis has shown that delaying expansion of new nuclear/CCS and interconnection by ~5-10 years, around the late 2020s, leads to modest increases in electricity costs of <1% on average per year, whilst accelerating the deployment of renewables raises costs by ~7-8% (assuming that learning rates are not impacted materially in the near term e.g. due to supply chain constraints). Given the rapid evolution of technology costs at the global level it is important to review this evidence base systematically, particularly while support schemes are differentiated by technology, to appropriately target future rounds of support and reduce the cost of decarbonising the system.
  - Future changes in fuel prices and demand (particularly peak) can lead to significant changes in electricity system costs; reductions of over 20% in annual costs in the 'low' sensitivities explored. Demand and supply side policy need to better coordinated to ensure that where demand-side measures (such as efficiency) are more cost-effective they are prioritised over expanded supply e.g. through adjusted targets in the Capacity Market. For fuel prices, as mentioned previously, mechanisms such as CfDs need to evolve to consider how future commodity price risk can be built into a technology neutral support mechanism for plant such as CCS, rather than being fully transferred to the consumer by default via fuel price indexation.

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Purpose of the study

Explore detailed cost-optimal pathways to decarbonisation and compare to other scenarios

- The energy sector will need to be transformed in the next few decades from fossil-fuelled based to a low carbon system. The three objectives of the transformation of our energy sector are to ensure security of supply, provide affordable energy and mitigate the environmental pollution caused by its consumption. Even though all three energy sub-sectors (power, heat, transport) have been through change in the last decade, the power sector has seen the most disruption from new technologies. In contrast, the main change in the other two sectors has been efficiency gains. In the long-term, the transport and heat sectors are likely to be further electrified. Therefore, the power sector is expected to play an even greater role in the transformation and decarbonisation of the energy sector. The electricity system is complex and there is need to balance supply and demand in real time. In addition, some renewable resources such as wind and solar are intermittent. For that reason, finding the cheapest and cleanest source is not enough. There is also need to provide flexibility to the grid and to ensure continuous supply. A combination of several technologies will deliver the transformation that the power sector needs such as nuclear, wind, solar, tidal, biomass, CCS and battery storage
- The purpose of this study is to find the lowest cost optimal capacity mix of GB taking into account cost parameters, emission targets and reliability of supply *specifically for the GB electricity system.* This explores decarbonisation of the power sector under assumptions which are consistent with the progress required from the electricity sector to meet the UK's overarching emissions target. Whilst many whole energy system studies have been undertaken (e.g. the ETI's Energy System Modelling Environment (ESME) own model or the UK Times Model) to explore cost optimal pathways for the energy system as whole these generally contain a much simpler representation of the electricity system, whilst trading off emissions reduction from this sector versus the wider energy system. The purpose of this study is to undertake a 'deep dive' into the power sector looking at cost-optimal pathways whilst considering a detailed view of both
  - Capacity expansion (annual across the pathway); the view of capacity expansion takes into account 'momentum effects' from current policy before moving to a cost optimised – policy neutral - pathway
  - Operational issues by simulating detailed hourly dispatch of the system and constraints such as ramp rates across a number of characteristic days.
- By focusing on the power sector in more detail it is then necessary to carefully consider the evolution of exogenous boundary conditions that feed into the power sector, such as electricity demand, commodity prices (including scarce resources such as bioenergy or production of hydrogen) cost of imports, etc. These have been informed by the ETI ESME model along with other analysis such as Baringa's Pan-European Electricity model. To undertake the analysis we have:
  - Developed a GB model in PLEXOS (a commercial power systems modelling tool) to optimise the capacity mix for the period 2022-2050
  - Carefully constructed a base case and a number of sensitivities around this. The base case has been constructed to be deliverable from today's starting point, taking into account current committed investments as well as trends that are likely to drive retirement decisions for existing plant, and best available evidence on future commodity prices and technology costs.
  - Compared these pathways with other scenarios from National Grid, the Committee on Climate Change (CCC) and Baringa's in-house view
- This slidepack is accompanied by separate Excel assumptions and results workbooks.

Methodology

Use of PLEXOS tool to simulate annual capacity expansion and hourly operational dispatch

- For the optimisation of the capacity mix we have used the Long-Term (LT) planning functionality within PLEXOS (a commercial power sector modelling tool https://energyexemplar.com/software/plexos-desktop-edition/)
- The focus year of the study is 2030, but the simulation has been run with longer optimisation horizon of 29 years: 2022-2050. An ambitious carbon target has been set for the 2050 point (net zero emissions for the power sector – consistent with the likely requirements to meet statutory emissions targets). In order for this target to be met, there has to be significant effort several years before which can affect capacity build decisions at the 2030 point
- The model uses exogenous inputs such as:
  - Hourly electricity demand for the horizon
  - Renewable hourly generation profiles for each technology and region
  - Fuel prices
  - Carbon emission targets
  - Existing capacity mix including their operational parameters
  - Build and operating costs and parameters for new plants

  The sources of inputs are a combination of Baringa, ETI and CCC assumptions

  We have assumed no a 'policy neutral' approach to meeting demand and carbon constraints (i.e. no direct subsidies/support post 2022)
- The model optimises the capacity build decisions by minimising the total system costs while respecting reserve requirements and environmental targets. Note that this model is not co-optimising transmission capacity expansion alongside generation and storage, but it does have a simple geographical representation to reflect differences in assumed transmission costs and/or load factors of new plant with geographical siting restrictions such as wind or nuclear
- The total costs compromise from:
  - Build and fixed costs dependent on capacity built
  - Operational costs dependent on the hourly generation dispatch. The hourly dispatch were simulated for 6 sample days per year of the horizon
- Thereafter, the optimised capacity mix was fed into the full hourly Short-Term (ST) optimisation model (full-year simulation without sampling of days) to provide detailed dispatch projections. The ST model was run for 2030 and provides detail outputs such as prices and generation dispatch.
- The study is focused on GB and adjustments have been made to remove Northern Ireland from the analysis (as this region is effectively integrated within the Irish Single Electricity Market)
- *Further details of the modelling approach are provided in Annex A*

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Summary of key inputs for Base Case

The sources of inputs are primarily a combination of Baringa's in-house assumptions, ETI data and the Committee on Climate Change (see noted slides and supporting workbook for further details)

GB-wide inputs

Demand profiles *(Slide 11)*	▶ Demand is based on the CCC's 5th carbon budget assumptions ▶ Intraday shape changes post 2030 based on ETI ESME model outputs
Interconn-ection *(Slide 18)*	▶ Neighbouring prices provided as exogenous input from Baringa Pan-EU electricity market model ▶ Price uplift modelled because it influences imports/exports
Commodity prices *(Slide 15)*	▶ Gas and coal prices increase in the period 2017-2050 based on IEA ▶ Hydrogen and Biomass are based on ETI ESME model outputs
Carbon intensity *(Slide 16)*	▶ Carbon intensity target of 90 gCO2/kWh in the power sector by 2030 and zero by 2050, broadly reflecting CCC power sector ambitions
Capacity adequacy *(Slide 17)*	▶ Minimum de-rated capacity reserve margin set at 3.4% post 2021 consistent with National Grid assumptions

Plant-level inputs

Existing capacity *(Slide 12)*	▶ Existing plant parameters, capacity and retirement dates from the Baringa Decarbonisation scenario
New capacity committed *(Slides 12-13)*	▶ Capacity that is projected to come online by 2022 and/or is driven by ancillary service/heat revenues from Baringa Decarbonisation scenario assumptions
New capacity costs *(Slide 14)*	▶ Capital, fixed costs and discount rate based on ESME ▶ Missing costs/rates by Baringa ▶ No subsidy for new build
New capacity limits *(Slide 14)*	▶ Capacity build rates are be constrained by limits ▶ Limits based on region and type from ESME
Renewables profiles	▶ Wind, tidal and wave hourly load factor profiles from ETI data

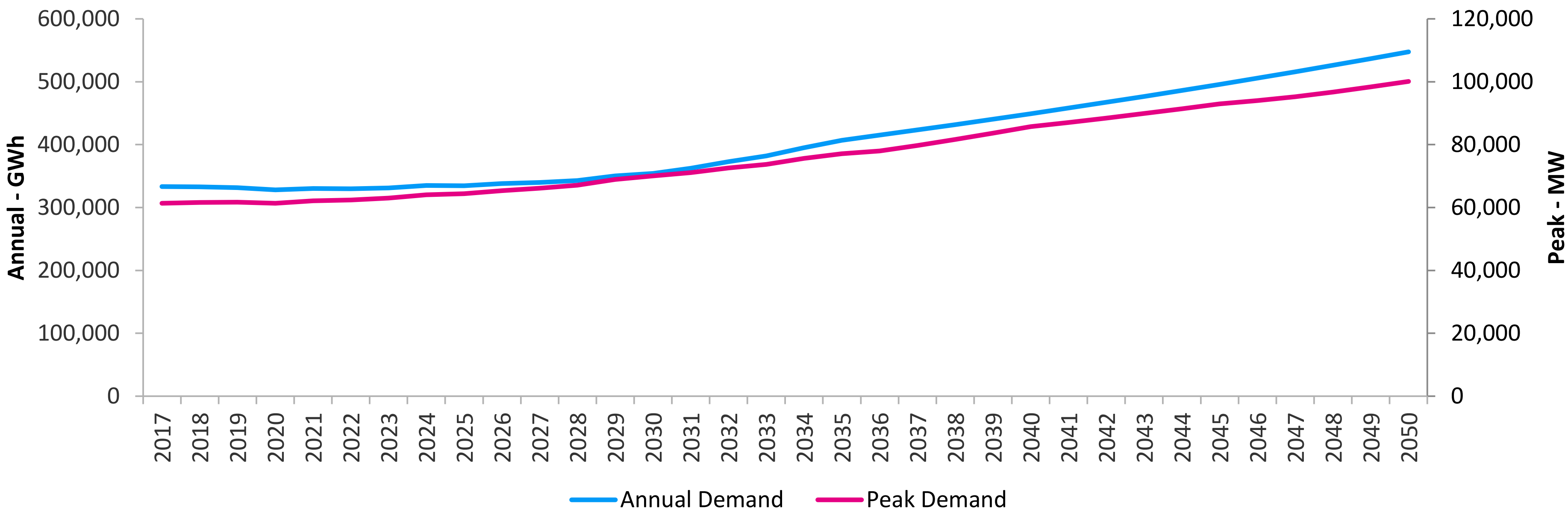
LT settings*

Planning horizon *(Section 6A)*	▶ 2017-2021 capacity as exogenous input ▶ LT Planning horizon: 2022-2050 ▶ Single step optimisation
Chronology *(Section 6A)*	▶ Sampled Chronology with 6 Sample days per year ▶ Linear solution

Demand profiles

Steady increase in annual/peak demand due to assumed electrification of heat and transport

- For the period 2017-2035, the annual demand used for the model is based on the figures from the central scenario of the CCC's report "Sectoral scenarios for the Fifth Carbon Budget". The Northern Ireland component has been removed from these figures because this model only simulates the GB market
- For the period of 2036-2050, we have assumed a steady growth rate of 2% per annum for the annual demand and a slightly lower growth rate for the peak demand, assuming that a large part of the increased demand will come from electrification of heat and transport which can be flexibly managed
- In the Base Case, annual demand* is assumed to increase from all-time low of 329 TWh in 2020 to 354 TWh by 2030 and further to 548 TWh by 2050. The intraday shape of the demand in GB is based on a combination of the historic profile and input from ESME taking into account future flexibility from heat storage (i.e. ESME can choose how to use this storage to help minimise peak electricity demands associated with electrified heating)
- These demand figures do not include electricity demand from auto-producers, which are assumed to be covered within the industry sector. Thus, the capacity of auto-producer CHPs (Combined Heat and Power) has been removed from the model



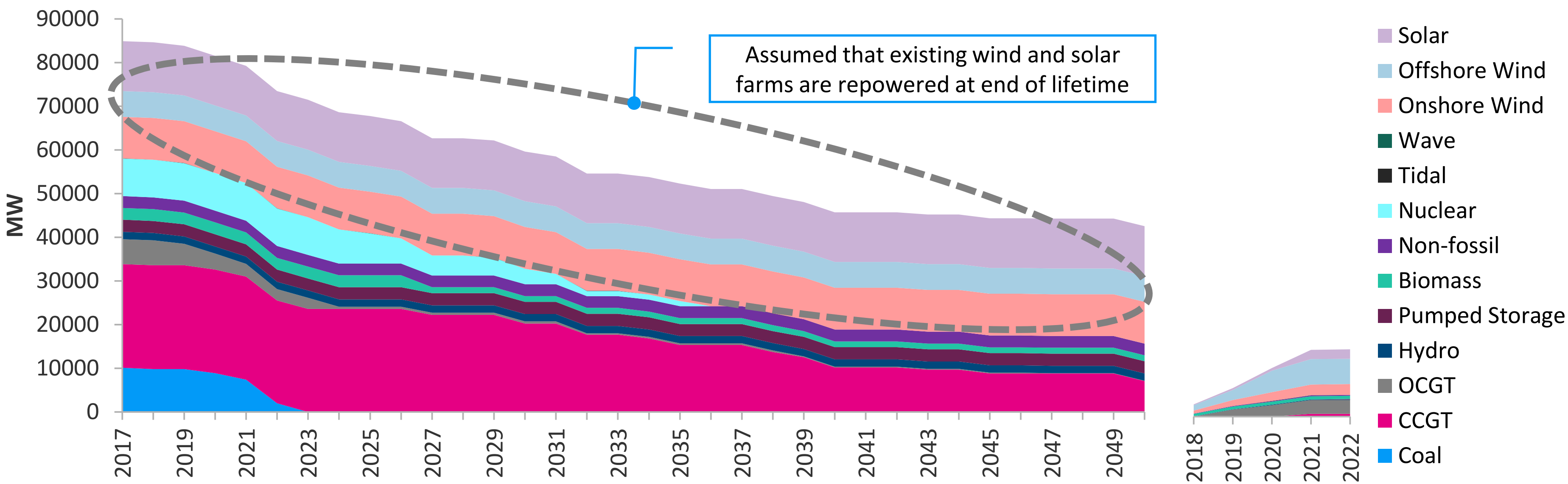
* The annual demand is the station-gate transmission-level demand. This demand includes transmission and distribution losses

Capacity assumptions

Exogenous assumptions around existing plant retirement and ‘committed’ new build

- Existing Plants: The retirements of existing plants are an exogenous input to the model and follow the Baringa Decarbonisation scenario (consistent with meeting ~100gCO2/kWh in 2030 and 50gCO2/kWh by 2040 – see Annex B for further details)with some further delays in the retirement of nuclear and coal. As we can see from the chart in the left, there are three types of plants affected by retirements:
  - Coal, which is completely decommissioned by the end of 2024
  - CCGT, as well as OCGT* units, from which some older plants are decommissioned
  - Nuclear plants which are nearly all decommissioned by 2035
- New plants: Some of the new plants are already committed through the Capacity Market auctions, expected through the known low carbon support schemes (Contracts for Difference or Feed in Tariffs) or by being at an advanced development/construction stage. Therefore, those capacity additions should also be fed into the model as exogenous inputs. We assume that the committed capacity additions are all the additions that come online in the Baringa Decarbonisation scenario in the period 2017-2021. Hinkley Point C (3.2 GW) is assumed to be committed but the model selects the optimal time for commissioning between 2026 and 2030. Detailed assumptions are provided in a supporting Excel workbook.

Existing Capacity **Committed Capacity**

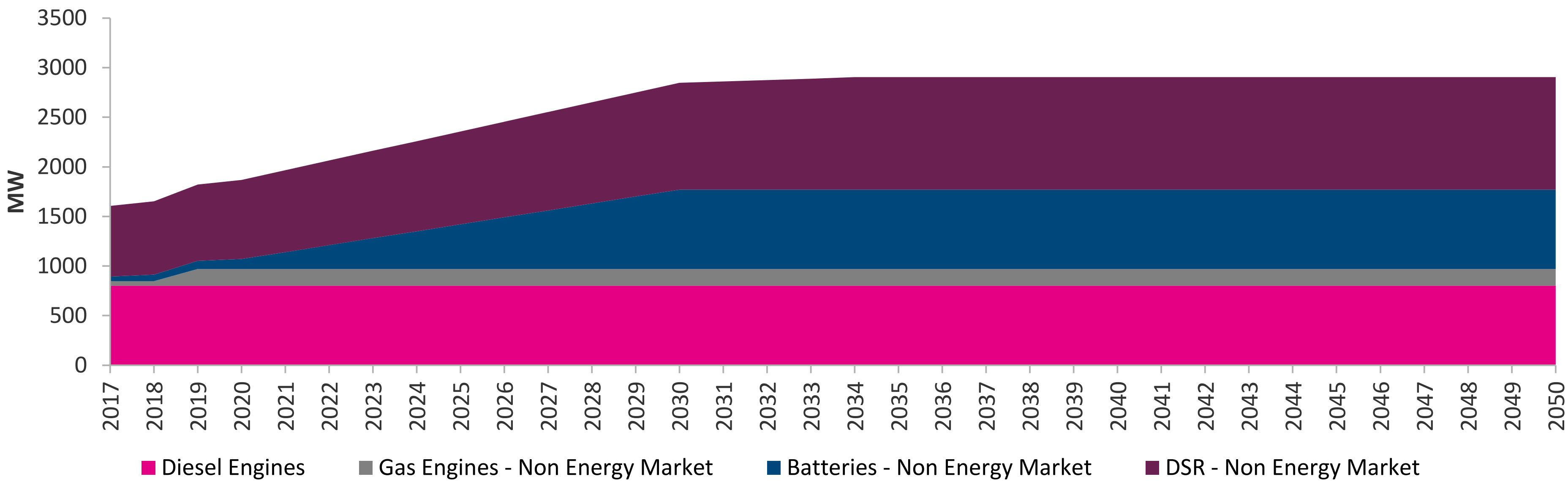


* OCGT: Also includes engines which are fuelled by gas or oil and participating in the wholesale market

Capacity assumptions

Combined Heat and Power (CHP) and ancillary services plants

- The PLEXOS Long-Term Plan phase can optimise the new capacity assumptions based on their participation in the wholesale market and their contribution to meeting system security of supply constraints (i.e. a representation of the capacity market reserve margin)
- However, there are units for which a large part of their revenues come from other sectors or streams such as CHPs that co-produce heat; or gas/diesel engines, DSR and batteries that participate heavily in the ancillary services market or balancing mechanism. These types of units cannot easily be optimised by the LT functionality and therefore are be provided as an exogenous input, based on Baringa's Decarbonisation Scenario. Distribution connected CHP's have been excluded from the study by netting them from demand as discussed in the previous slides.
- The units in the graph below are not allowed to generate in the model because they do not participate in the wholesale market and make minimal net contribution to energy supply given the balancing services they primarily contribute to. However they still contribute towards the overall peak capacity reserve of the system. Note that it is still possible for the model to deploy additional storage capacity that is primarily motivated by wholesale market or capacity market revenues.



New capacity

Key exogenous inputs required

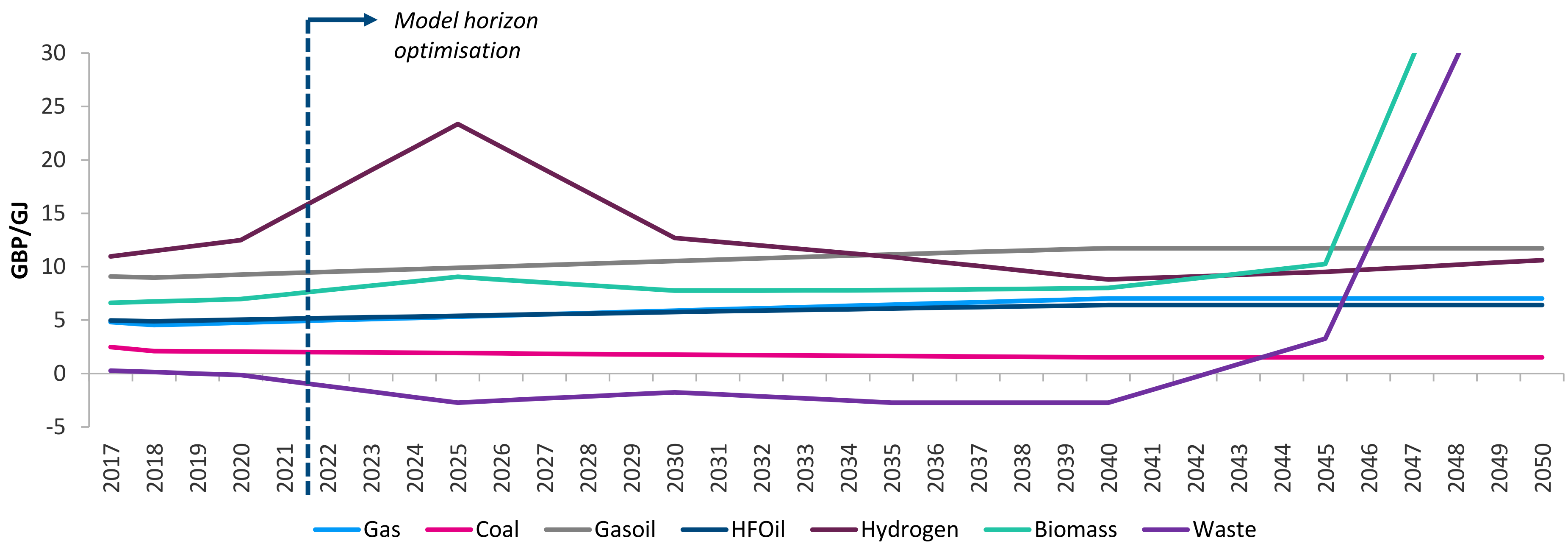
- All units that come online post 2022 , which are not driven by ancillary services revenues or heat, are the output of the model. The model optimises the capacity mix in a cost-effective way while respecting capacity margin and carbon emissions constraints.
- Endogenous transmission capacity expansion is not considered due to the additional complexity it adds to the optimisation. At a system level the impact is not expected to be a material driver of the system (given insights from the whole system ESME model), but to proxy some of the second order impacts on technology choice we have included region-specific TNUoS costs (Transmission Network Use of System) in the costs of new Onshore Wind, Offshore Wind and Nuclear. This is a proxy to reflect the likely differences in transmission reinforcement costs if these technologies are deployed in particular locations across GB, whereas other technologies - such as CCGT or OCGT – do not have the same restrictions on siting.
- In addition, we have added an estimate of total transmission systems costs for the results (based on Baringa's internal TNUoS forecasts) to provide an illustration of the relative importance of this component (for both non- and region-specific technologies) with overarching electricity system costs.
- For all units where the build is decided/optimised, the following characteristics have been provided:

Value	Source
Capex	ESME with changes in the Onshore Wind and Solar assumptions based on recent Baringa data. These reflect a faster decline in costs as observed in studies of recent global auctions and our work with a range of project developers. For example, see Baringa's study for Scottish Renewables on expected near term costs for future Contract for Difference auctions in GB.
FOM	ESME
WACC	ETI assumption of flat 8% rate
Economic lifetime	ESME
Technical lifetime	ESME
Max Annual Build Rates	ESME
VOM	ESME
Efficiency	ESME
Max Build	ESME
Firm Capacity	Baringa: Same as the de-rating factors used in the GB Capacity Market (CM)
Discount Rate	Treasury: 3.5% discount rate that is used to discount all future cash flows to a NPV (Net Present Value) basis

Commodity prices

Use of IEA forecasts for fossil fuel prices and ETI ESME model outputs for energy carriers such as hydrogen

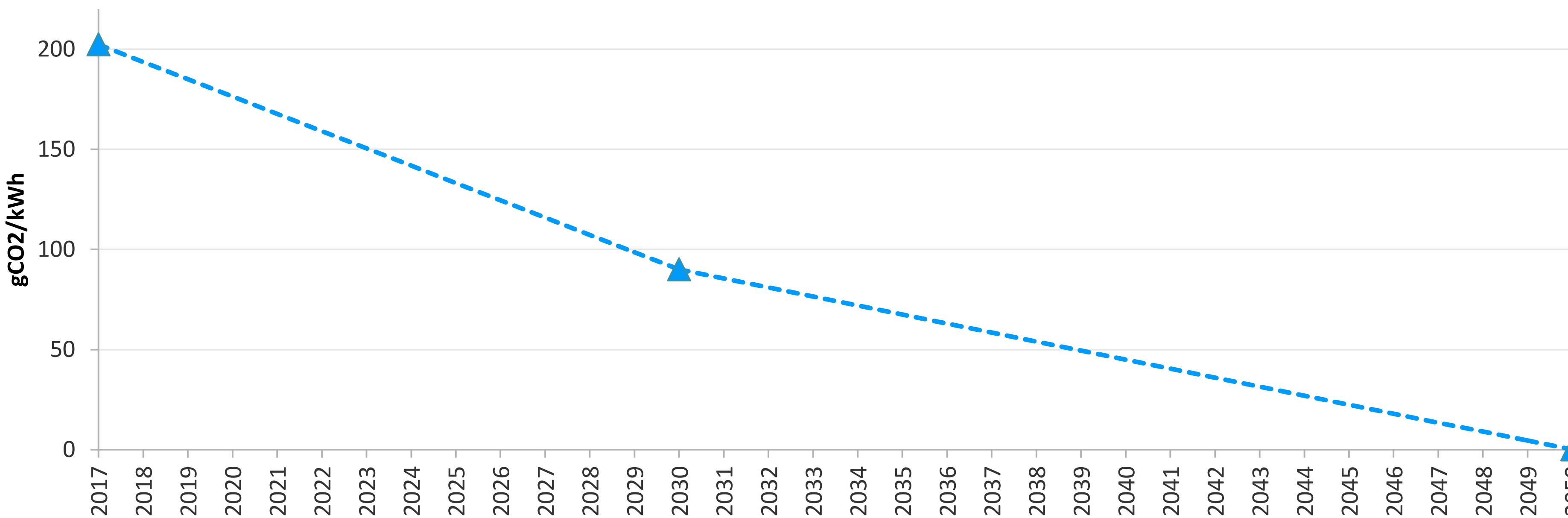
- The commodity prices are an exogenous input in the model. Fossil fuel prices are taken from the Baringa Decarbonisation Case. Baringa Decarbonisation Case follows the forward curves in the short-term and interpolates to the long-term price point of IEA's WEO "450" scenario
- The ETI's whole energy system model ESME (v4.1 Reference Case) is used to generate prices for energy carriers that are either produced by the wider system or whose cost depends significantly on how they are used across different energy sectors (based on marginal or 'shadow price' outputs).
  - Hydrogen price given production largely through CCS routes
  - Biomass and waste prices; both of these are scarce low carbon resources and the significant price rises in the late 2040s represent competition for use to achieve decarbonisation in different parts of the energy system
  - Costs of CCS transport and storage are also included in the model based on the deployment across the wider energy system in ESME: These costs are assumed to be about 12 GBP/tCO2 in 2022 and they gradually increase to 19 GBP/tCO2 by 2050



Carbon emissions target

Rapid decarbonisation required by 2030 trending to zero carbon emissions by 2050

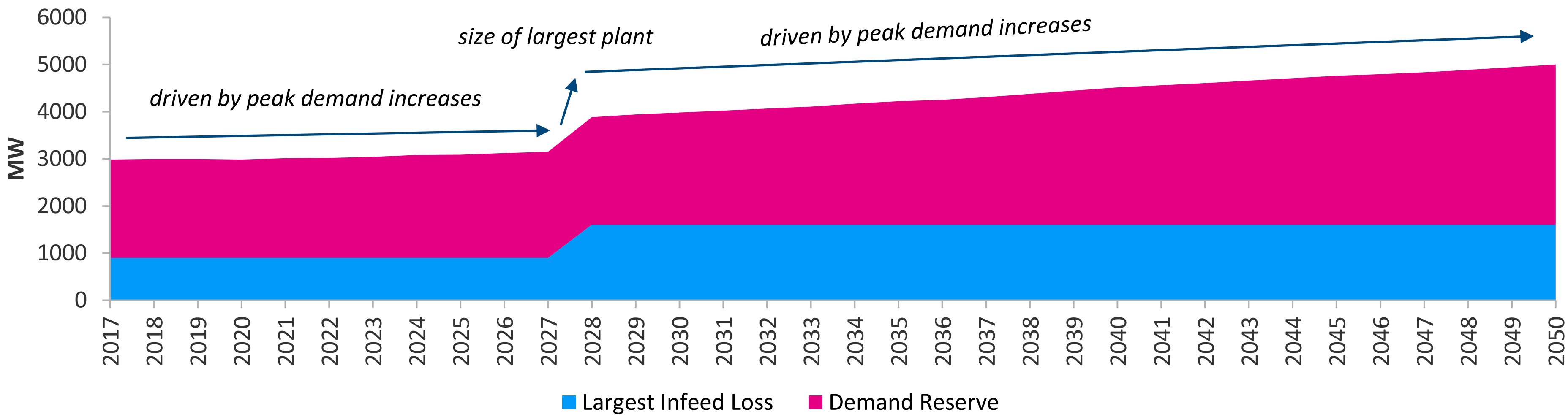
- Carbon emissions are restricted via an explicit Carbon Intensity Constraint
  - An exogenous input of carbon intensity limit: $\frac{\sum_i CarbonEmissions}{\sum_i Generation} \leq CarbonIntensityLimit$
  - Imports are not included in the carbon intensity calculation and hence the carbon intensity impacts on domestic GB generation only
- The CCC's fifth carbon budget concludes that the carbon intensity should be below 100g/kWh by 2030 and close to zero by 2050 in order to achieve the UK's overarching carbon targets.
- This model targets a carbon intensity of 90 gCO2/kWh by 2030 and 0 gCO2/kWh by 2050. We have used a carbon intensity of 200gCO2/kWh for the year 2017 based on Baringa Decarbonisation case. In order to avoid a rush to build low-carbon capacity just before these spot years, we have used linear interpolation for the years in between:



Capacity adequacy

Reflects of core requirements of the GB Capacity Market (CM) via a security of supply constraint

- As discussed in further detail in Annex A, capacity adequacy can implemented in a number of ways but for the purposed of this study we have used a Minimum De-rated Capacity Reserve constraint:
  - $MinCapacityReserve = PeakDemand * (1 + DeratedCapacityMargin) + LargestInfeedLoss$
  - *Largest infeed loss is currently 900 MW due to the risk of the largest unit going offline unexpectedly (Sizewell B).*
  - *If a larger unit enters the system (such as Hinkley Point C) then the largest infeed loss should change (e.g. 1600 MW). This is likely to happen in the late 2020s*
- The sum of the Firm Capacity (de-rated capacity based on their expectation of availability at peak) of all generators and interconnectors have to be at least at the same level as the MinCapacityReserve. The Firm Capacity is calculated using the same derating factors as the CM auctions
- The Derated Capacity Margin over the peak has been set as 3.4%. This is the margin required to meet National Grid's capacity targets. National Grid sets the capacity target in order to ensure that the risk of security of supply is within the government's reliability standard of 3 hours LOLE (Loss Of Load Expectation)*

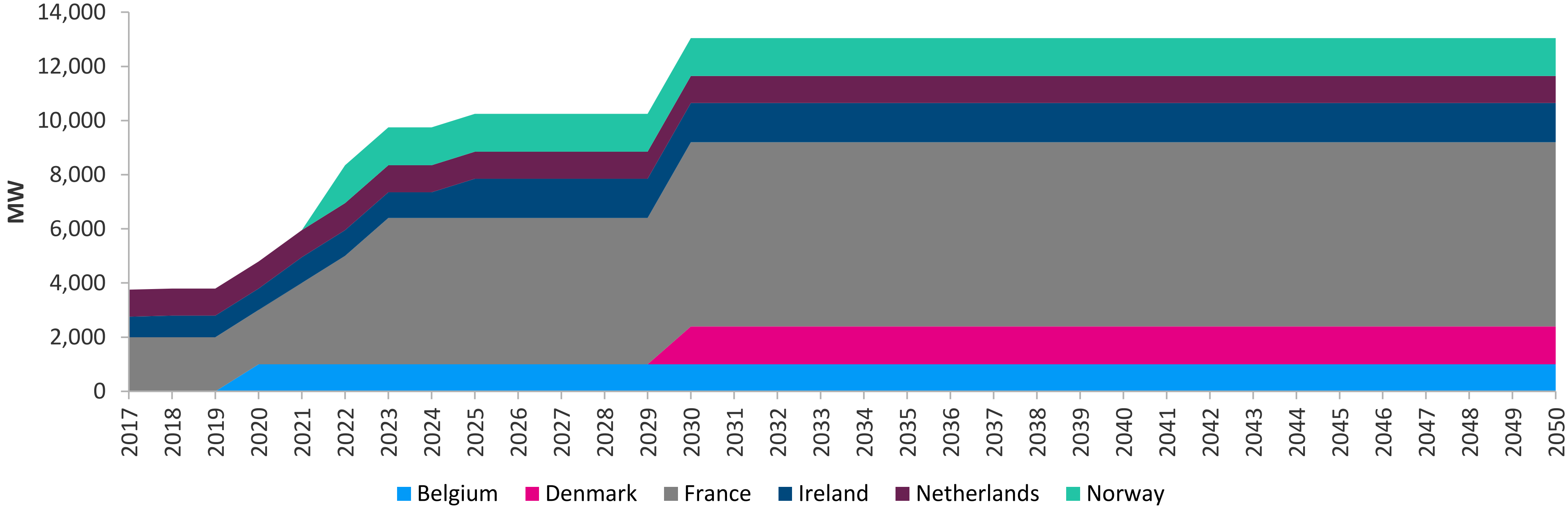


*LOLE is defined as the number of hours in which the demand exceeds the supply

Interconnection

A significant increase in interconnection capacity is expected by the 2030s

- In 2017, GB has a relative low interconnector capacity (2GW with France and another 2 GW across the SEM and Netherlands). However, GB is projected to increase levels of interconnection with France to 6 GW by 2030 and add interconnectors with Norway and Belgium in the early 2020s, based on Baringa's Decarbonisation scenario (assessing the likelihood of each new interconnector on a project-by-project basis). Therefore, the impact of neighbouring markets into the GB wholesale market will increase in the future and total imports are likely to increase
- The model does not include the full system of these markets but allows electricity exchange between them and GB based on the maximum transfer capacity and the price projection of these markets. The transfer interconnection capacity and price projections are exogenous inputs to the model. The prices of the interconnected markets have been projected through Baringa's pan-European power market model
- In the short-term average prices in those markets are higher in GB than all interconnected markets but the interconnector capacity is low and therefore the imports are restricted. One of the main causes for price differences is the carbon price which is higher in GB than other markets. The prices spreads for GB are about 8GBP/MWh and 4GBP/MWh for France and Ireland respectively. Norway which is projected to be interconnected in the future with GB has some of the lowest power prices in Europe due to the higher hydro generation



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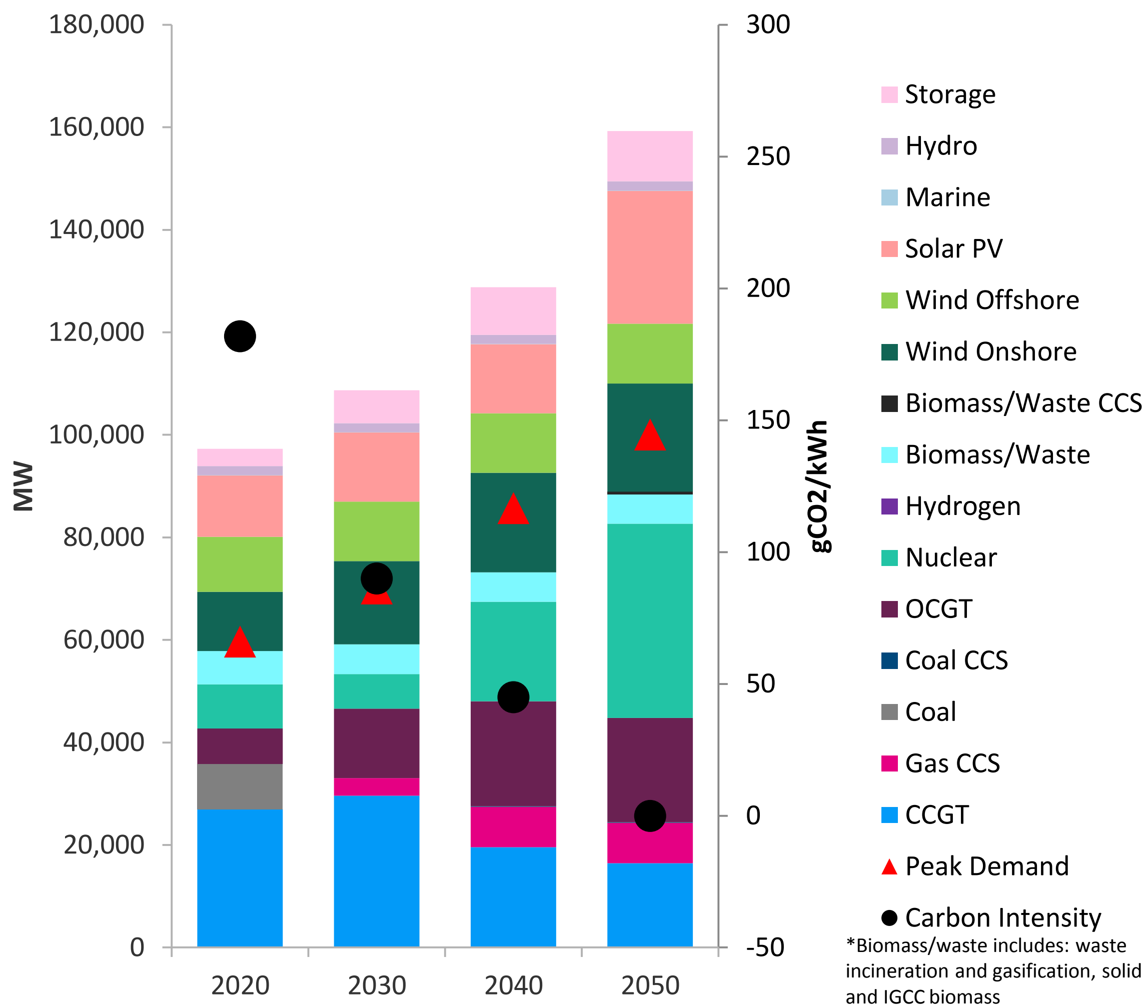
Base Case outputs

Baringa

To meet the UK's long-term CO2 targets a significant increase in low carbon baseload plant and intermittent renewables supported by flexible storage and fossil peaking plant is needed

- The overall Base Case capacity expansion shows both a significant increase in low carbon baseload plant (nuclear and CCS) and intermittent renewables (solar and wind) supported by flexible storage and fossil peaking plant. However, the significant expansion in baseload plant does not occur until the latter half of the pathway
- The Base Case model builds approximately 9 GW of OCGT in the 2020s and another 6 GW in early 2030s in order to provide cheap capacity reserve for the system
- Post 2035, the Base Case model chooses storage units to provide capacity reserve rather than OCGT due to the reduction in capex costs of storage and the broader benefits of balancing supply/demand
- The main baseload capacity built is nuclear and specifically Nuclear Gen III of which over 20 GW are built during the 2030s and 2040s
- Approximately 10 GW of onshore wind and 20 GW of solar PV are build over the horizon
- The retirement of heavy carbon emitters such as coal plants and older CCGT as well as the new low carbon plants such as wind and CCS helps to meet the 90gCO2/kWh target in 2030
- In 2050, emissions are net zero: The small amount of emissions that are produced from the Gas CCS capacity are offset by the negative* emissions from Biomass and Waste CCS

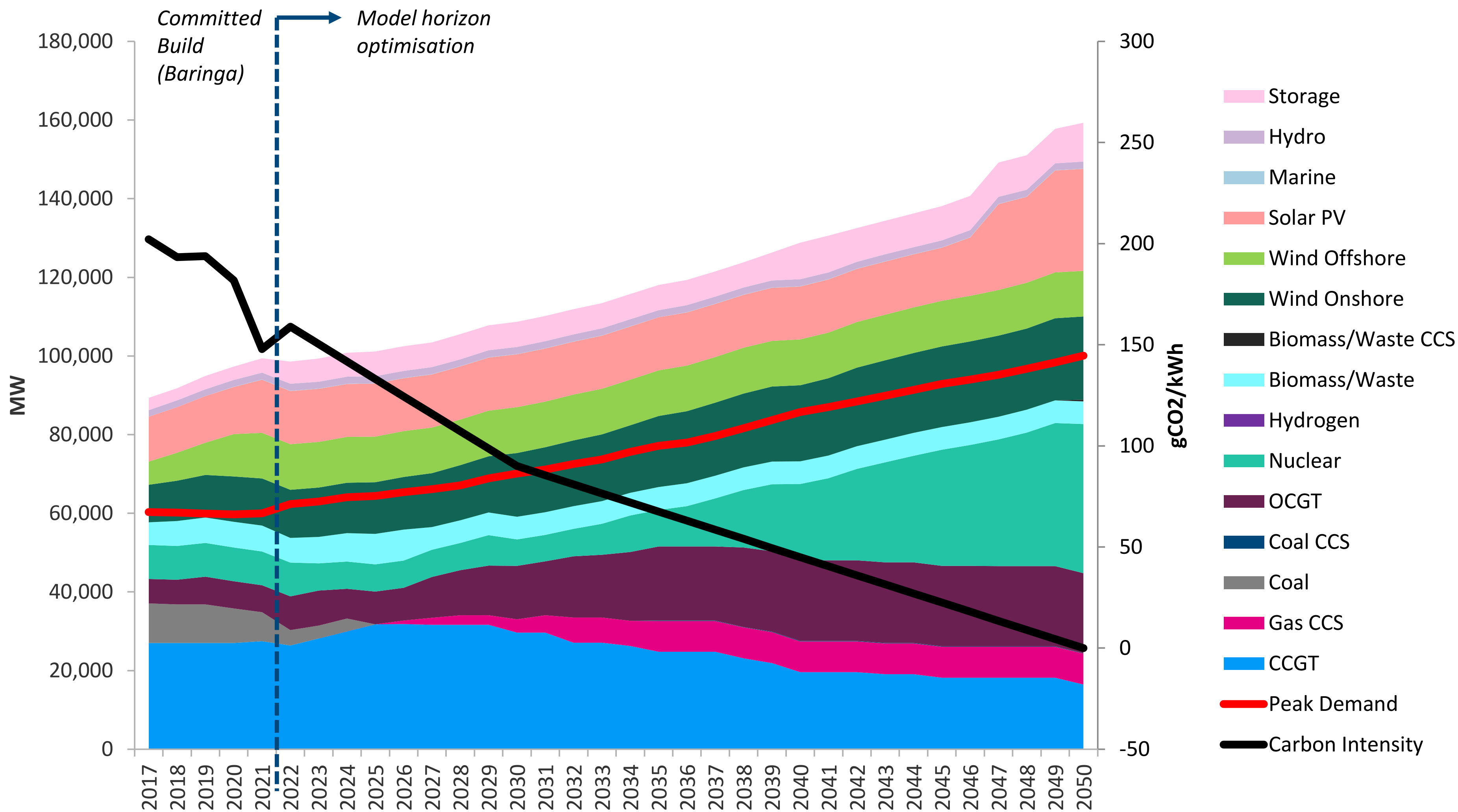


*Biomass/waste includes: waste incineration and gasification, solid and IGCC biomass

* Biomass lifecycle emissions are nearly zero as emissions in combustion/production are broadly offset by emissions captured during growth. Biomass CCS effectively prevents the re-release of CO2 during combustion

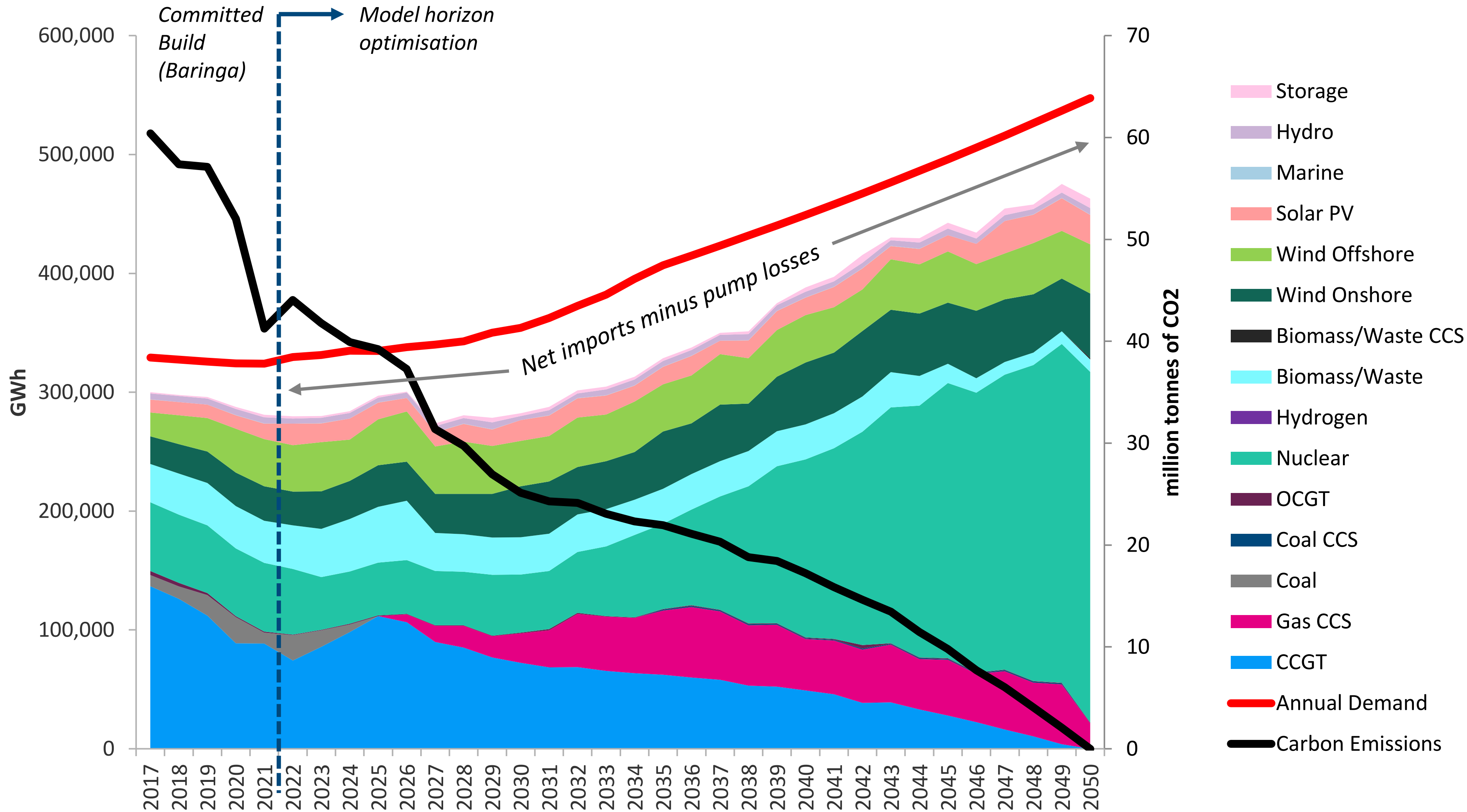
Base Case outputs

Annual capacity mix evolution in the full horizon



Base Case outputs

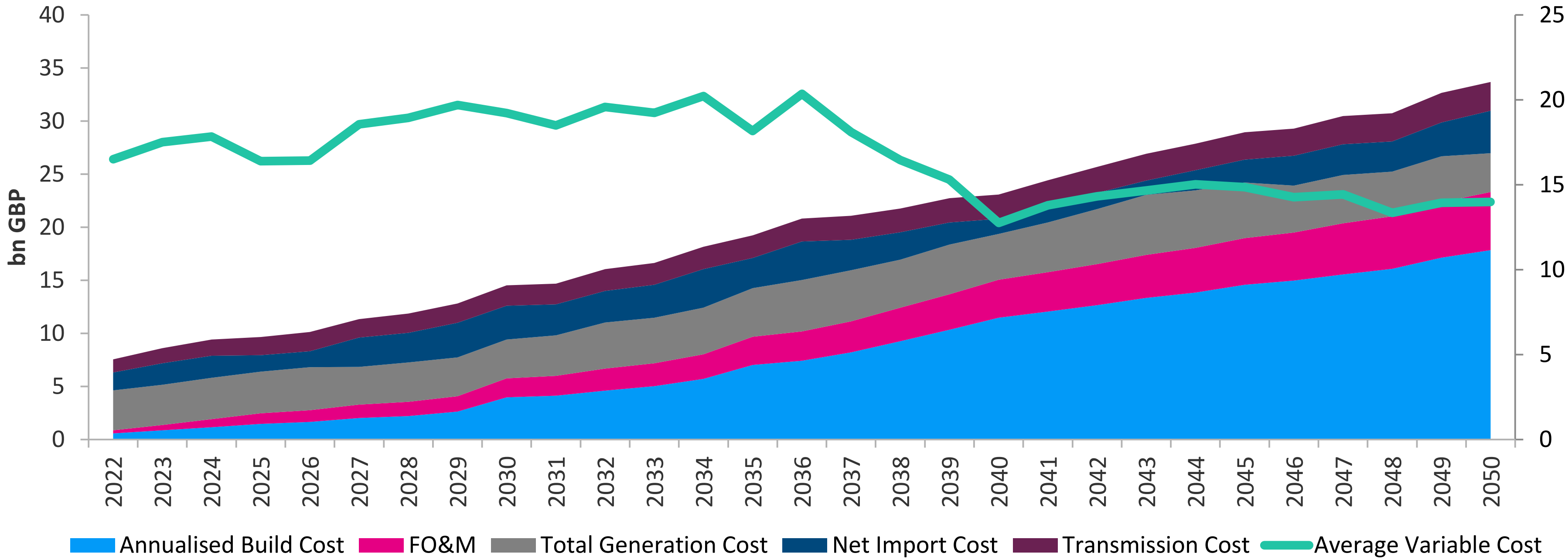
Indicative generation mix evolution for the full horizon, shows significant decline in fossil plant post 2030 to provide a peaking role coupled with significant use of imported electricity



Base Case outputs

The development of new low marginal cost plant increase the capital investments but reduce the average variable cost of generation

- In the first years of the horizon, most system costs come from generation costs (fuel, variable operating & maintenance costs (VOM), start/shutdown costs)
- In 2030, generation costs (i.e. fuel and operating costs) make up ~25% of the total system costs, whilst total GB supply based costs (excluding transmission and imports) account for 65% of total system costs. Import costs are significant as a portion of total system costs compared to the level of supply they provide because imports are needed mostly in times of high system stress with corresponding high power prices
- The investment in new capacity, especially low carbon, increases the fixed costs such as build costs but reduces the variable generation costs relative to demand supplied due to the higher low marginal cost generation
- The fixed costs (annualised build costs and fixed operating & maintenance (FO&M) costs) of the existing capacity are not included in this estimate of systems costs (and have no impact on the decisions for the forward looking pathway)

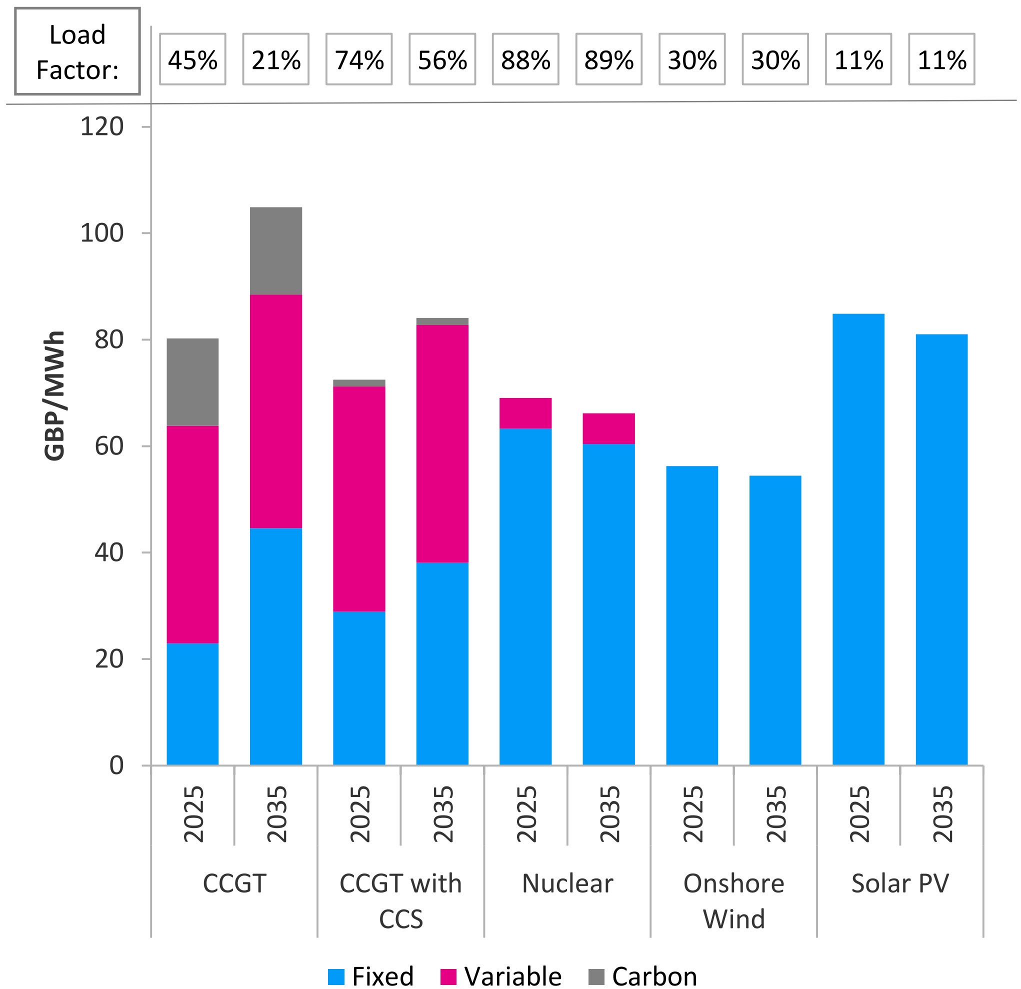


Generation and Net Import costs are currently LT outputs – the variation in wind and solar load factors is in part the cause of variation of net imports

Levelised Cost of Electricity (LCOE)

Levelised fixed costs of conventional gas increase as the load factor reduces over the horizon

- The objective function is to minimise operational and build costs taking into account constraints. Some technologies offer low operational costs for high build costs (e.g. Nuclear, Wind) while other technologies offer cheap firm capacity due to low build costs (e.g. OCGT)
- CCGTs are able to generate electricity at a reasonable cost in the 20s but as the carbon targets become stricter, CCGTs are pushed out of the merit and their load factor halves. The CCGTs continue to be operational in the 30s and early 40s as mid-merit plants but they become peaking plants in mid-late 40s. Therefore, unlike many studies, the LCOEs presented here factor in the changing operation of the plant over the pathway from the modelling results, rather than using a presupposed load factor. The levelised fixed costs of CCGT increase substantially over the period 2025-2035 because the load factor is much lower and the same amount of cost has to be spread to reduced generation. The load factor of CCGT CCS also reduces but the impact is lower than in CCGT and the CCS are able to continue operating at baseload up to late 40s
- Note that the carbon constraint has been applied directly as a CO_2 intensity target. The levelised costs take the shadow (or marginal) price of carbon from the model which is necessary to achieve the desired CO_2 target, to provide an overall illustration of the levelised cost for each generator type.
- The levelised cost of electricity is not the only cost taken into account. The capacity mix needs to also provide for flexibility and system security. For example, Onshore Wind is the cheapest option to provide energy but it is intermittent and provides very little firm capacity. Build decisions are made taking onto account also the value of capacity offered by new plants. Please refer to the next slide for the value of (firm) capacity into the power system



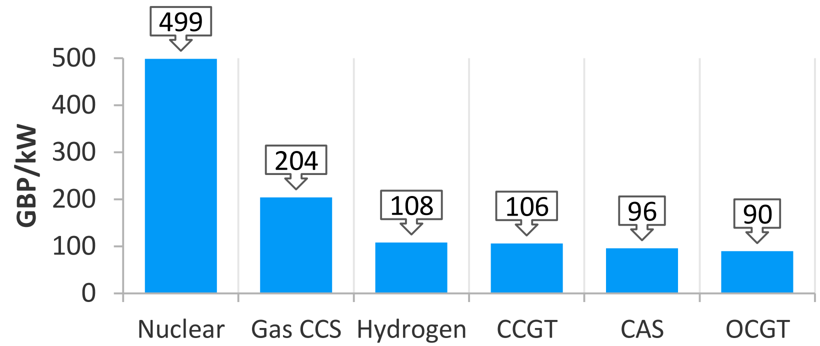
* Levelised Cost of Electricity

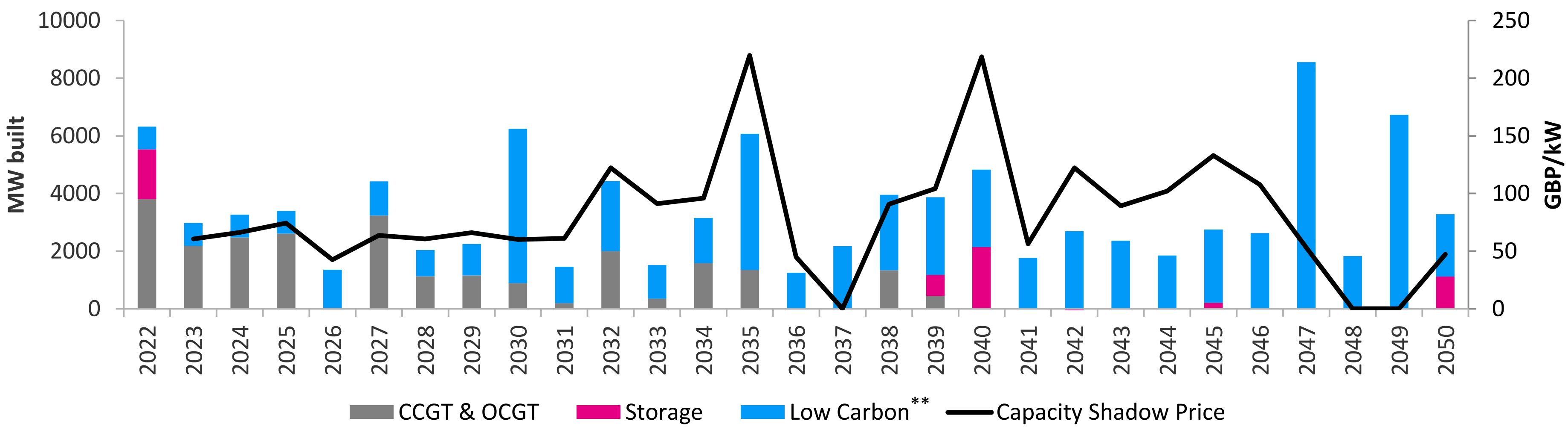
Value of capacity

Broad shift over the pathway from OCGT towards electricity storage as the marginal cost unit providing peaking capacity

- Power system economics are not only affecting by costs of providing energy but also by costs of providing flexibility and reliability to the system. There are units such as OCGT that even though they have high variable generation costs, they have low capital and fixed operating costs. These types of units run only for a few hours per year but they ensure security of supply
- In this model, we have applied a minimum de-rated capacity reserve constraint which has to be met every year. The capacity shadow price reveals the marginal value of capacity for the system (i.e. the decrease in total system costs resulting from an extra unit of peaking capacity to meet the reserve constraint). Even though it fluctuates throughout the horizon, it is on average slightly below the OCGT annualised fixed cost as OCGT has some limited energy market operation that reduces the effective cost of providing peaking capacity. Compressed Air Storage (CAS) has higher annualised fixed cost but also provides (zero carbon) energy benefits and thus is preferred towards the end of the horizon as a peaking unit

Annualised CAPEX and Fixed Costs in 2025*





* Includes build costs and fixed operating and maintenance costs over the plant's economic lifetime

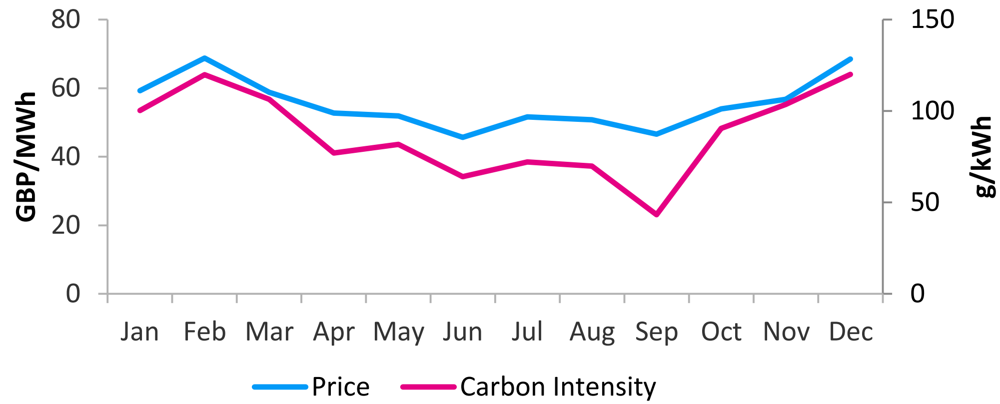
** All new build outside of CCGT/OCGT and storage

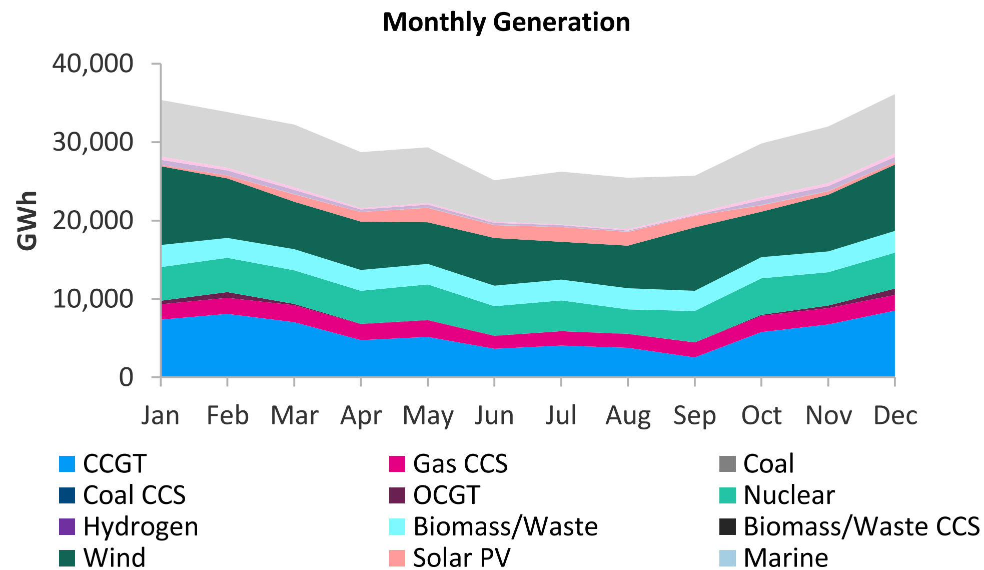
Base Case dispatch results in 2030

Monthly/Seasonal results for 2030 show typical seasonal swing with lower summer demand and associated prices and carbon intensity

- The average day-ahead wholesale price in 2030 is projected to be 55.5 GBP/MWh compared to the projected 46 GBP/MWh for 2017. Carbon intensity has been set to be 90g/kWh in 2030. The carbon price required to achieve this level of carbon intensity in 2030 is approximately 58 GBP/tCO2 which is considerably higher than current 22 GBP/tCO2
- From the monthly charts, we can observe that the system is tighter during the winter months which is attributed to the higher demand. Prices and carbon intensity are higher during those months
- Imports are projected to supply approximately the 23% of the electricity demand compared to 9% in 2017. The increase of imports is caused by increase in interconnection capacity and also to stricter CO2 emissions limit in GB compared to neighbouring markets as evident by the lower EUA prices (current and projected). Import prices are taken from Baringa's Pan European electricity model. The LT model compares these with the marginal cost of generation in GB and (accounting for losses on the interconnector) decides whether to import/export or remain at float (i.e. no flow).

Output	Units	Value
Price	GBP/MWh	55.5
Carbon Intensity	g/kWh	90
Net Generation	GWh	273,908
Pump Load	GWh	4,452
Net Imports	GWh	81,649
Generation Costs	bn GBP	3.8
Net Imports Costs	bn GBP	3.5

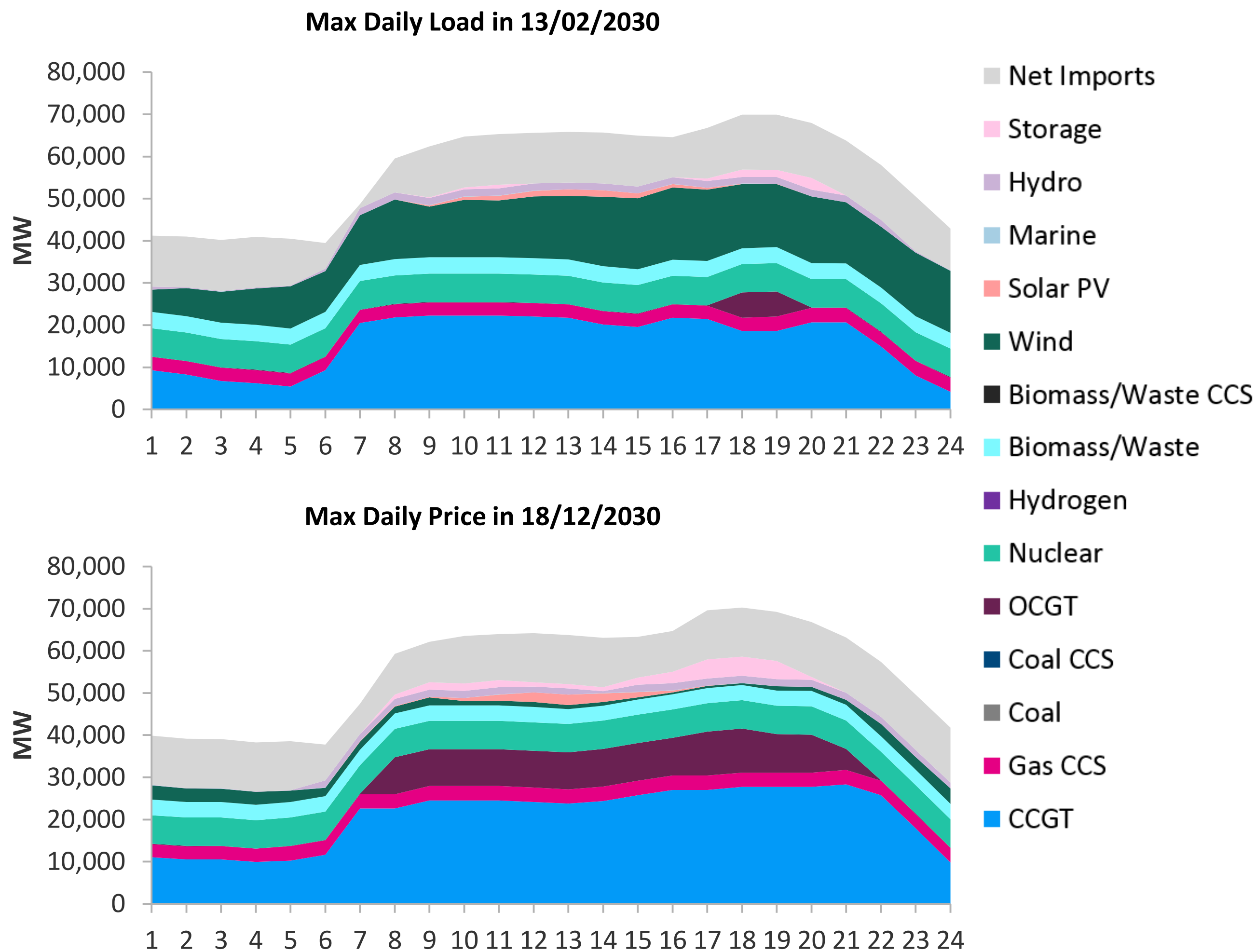




Base Case dispatch results in 2030

OCGT’s and storage need to operate when the system is stressed which raises the wholesale prices

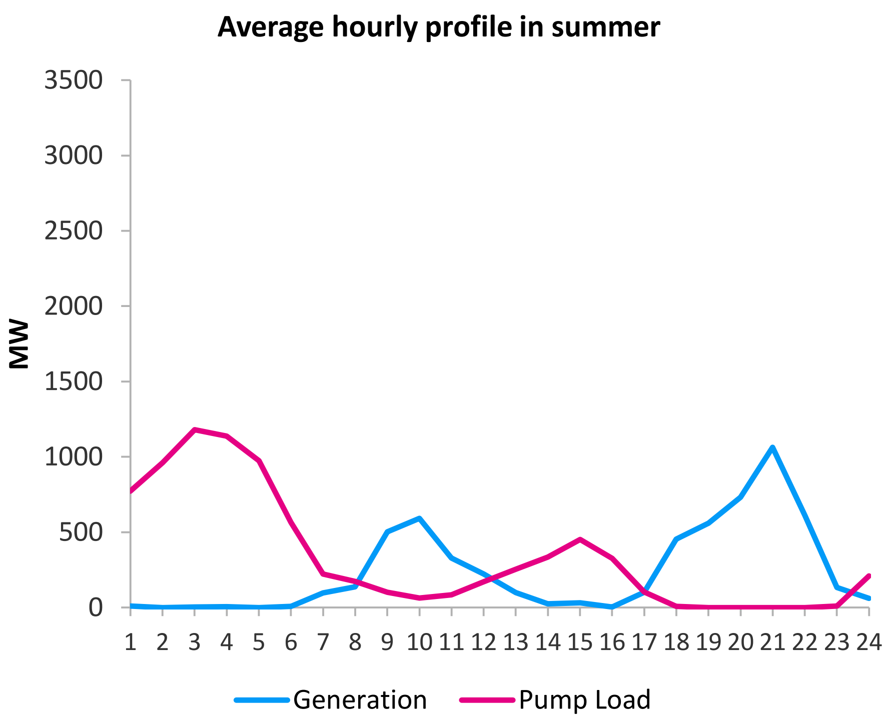
- The maximum daily load day is not necessarily the day with the highest system stress as we can see on the charts
- The maximum daily average price occurs in a day with nearly no wind generation
- OCGT and gas engine units generate during peak hours in that day in order to supply demand and that leads to very high prices
- CCGT typically run at high load factors during the high demand hours and at lower load factors during the night
- Nuclear, Gas CCS and biomass units run at baseload in both days
- Storage units generate power during the peak times in both days (see next slide for further details)

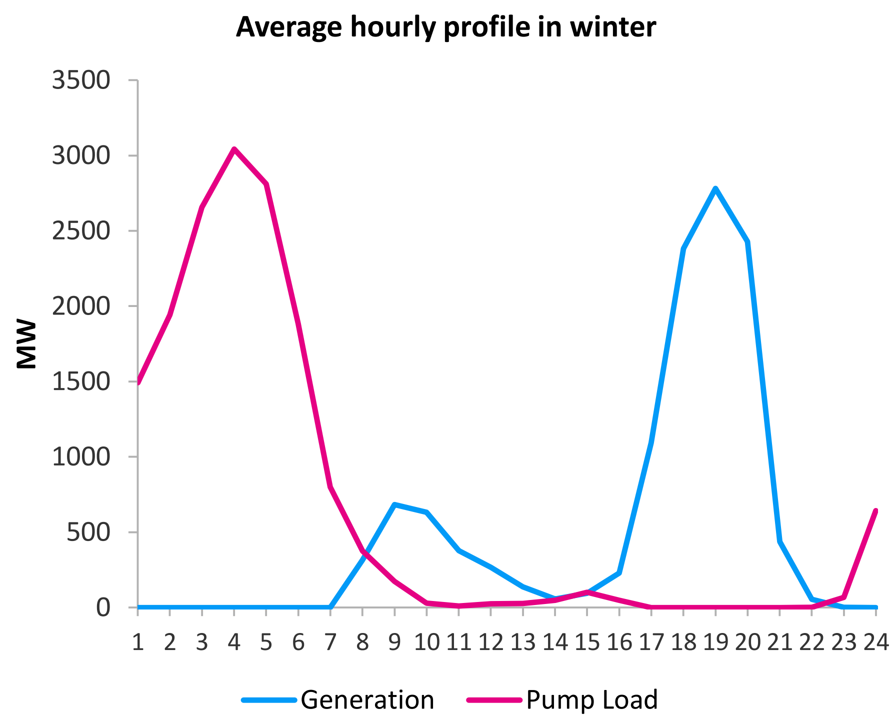


Base Case dispatch results in 2030

Storage units store surplus electricity typically during the night and generate for the grid during the morning and evening peaks

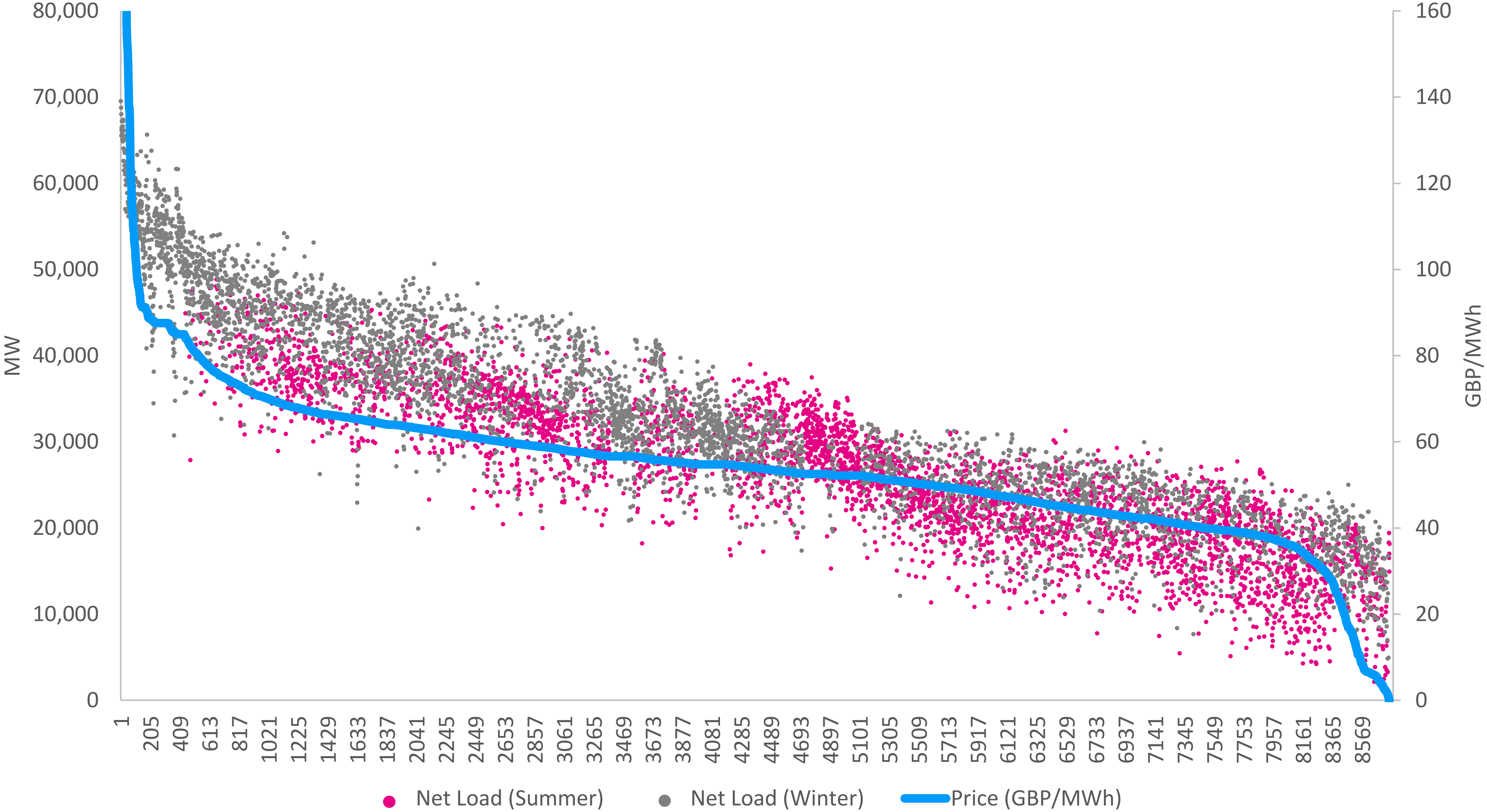
- In winter, the capacity margin is tighter and price differentials are higher in both relative and absolute terms and therefore, storage units have greater economic incentive to operate more. In winter months, storage units store electricity during night time and generate during the morning and evening peaks.
- In summer months, storage units operate much less. The hourly shape of operation is similar, however, storage units store electricity not only during night but also during early afternoon when demand is low but solar generation is high.
- The charts below show the injection (or pumping load) or withdrawal (generation) from the storage units on an average daily basis across the summer and winter.





Base Case price duration curve in 2030

Net load (demand net of wind and solar generation) has to be met by thermal generation and thus there is strong correlation between net load and prices. Net load is higher during winter



Base Case summary

- In the first half of the horizon there is significant OCGT and CCGT build. OCGT's annualised fixed costs of only 90GBP/kW allow the OCGT to provide cheap firm capacity. New entry CCGT operate as a baseload plant for the period mid-late 20s but they are gradually transform to mid-merit plant in the 30s as the carbon intensity targets lower and more low marginal cost capacity comes online. There is no role for additional new entry CCGT in the 30s due to the load factors being very low to justify the higher capital costs compared to OCGT

- The model recognises the net zero carbon emissions target for 2050 and plans ahead the capacity in the 30s to achieve that target. Post 2030, most capacity coming online is low carbon and mainly nuclear. Nuclear capacity supplies nearly two-thirds of the demand in 2050 with wind, solar and imports supplying the rest. On the other hand, Gas CCS is assumed to have only a 95% carbon emission removal rate and therefore its long-term role is limited due to the net zero carbon emissions target for 2050.

- Even though Gas CCS and CCGT provide flexibility to the system, there are units that provide flexibility at a lower capital cost such as OCGTs and storage. The model builds over 6 GW of storage units to accommodate renewable intermittency and demand fluctuations. Storage units store electricity during the night and generate during the morning and evening peaks. They tend to operate more during the winter when prices are higher. The average shadow price/value of capacity fluctuates but on average is slightly below the annualised fixed cost of new OCGT.

- The average wholesale price of the GB market in 2030 is projected to be 55.5 GBP/MWh under this capacity mix. The prices fluctuate throughout the year with prices being generally higher in the winter (by approximately 10 GBP/MWh). Prices are between 40-65 GBP/MWh for 80% of the year which corresponds to the marginal cost of CCGTs (varying depending on class). Wind and solar generation have a significant impact on prices as they reduce the load that needs to be met by thermal generators. For a few hours of the year when the capacity margin is very tight, prices increase substantially due to the scarcity premia that some generators can capture.

- *The results from the Base Case are contrasted against various additional sensitivities undertaken for this project in section 5, alongside a range of other external scenarios.*

Table of contents

Sensitivities

Explore the impact of discrete issues on the Base Case as opposed to composite scenarios

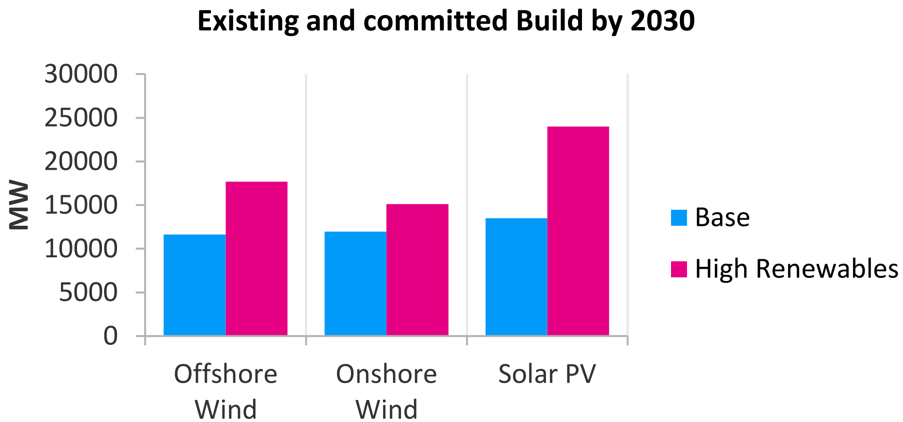
- 7 sensitivities have been run in order to test the change of the final capacity mix and its trajectory during the 2030s

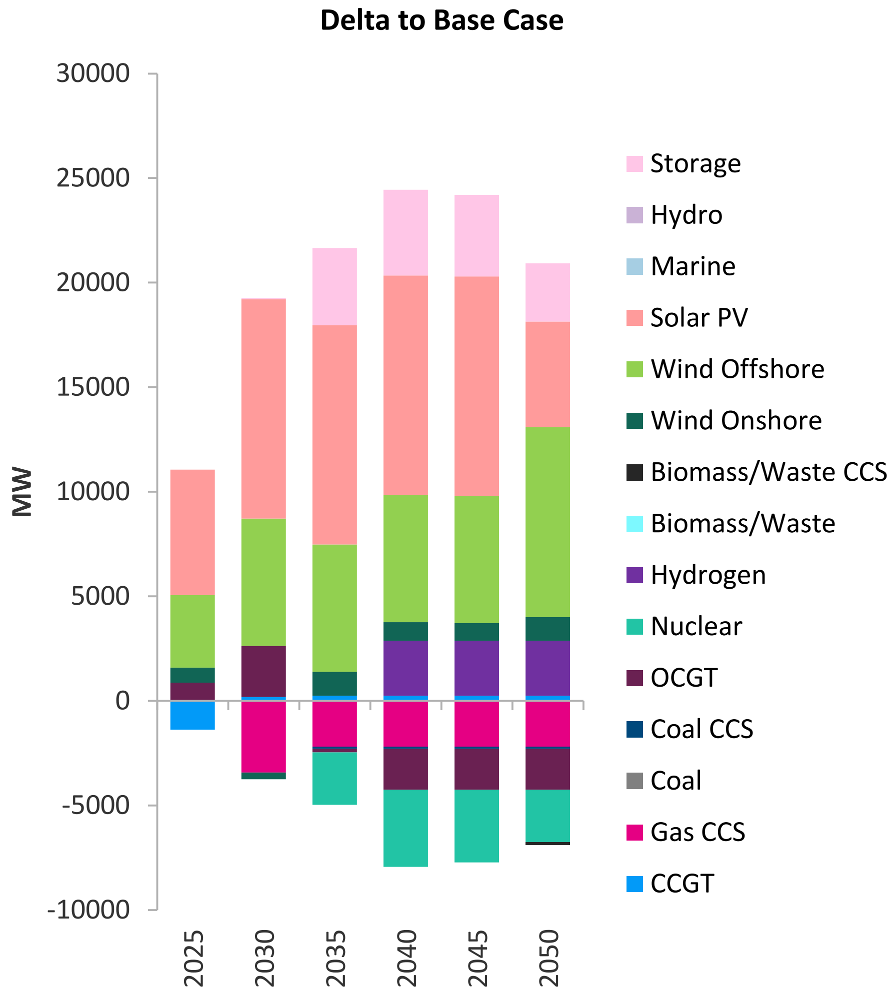
Sensitivity	Description
High Renewables	Government continues to support renewables up to 2028. Significant wind (onshore and offshore) and solar capacity comes online in the next decade in line with National Grid Gone Green scenario’s long-term projections
Flexible EVs	Electric Vehicles' demand is more flexible. Within the Base Case the load profile reflects broad load shifting overnight base on Time of Use (ToU) Tariffs. In the sensitivity half of the electric vehicles' demand if assumed to be managed flexibly by the System Operator during the 8pm to 6am window in order to smoothen the demand profile and facilitate integration of wind
Constrained CCS	CCS technology (including hydrogen which requires CCS to become carbon neutral) build rates and future cost reductions have been delayed by ten years. Long-term costs by 2050 remain the same.
Constrained Nuclear	Nuclear build rates and future cost reductions have been delayed by five years. Long-term costs remain the same
Low Fuel Prices	Fuel prices reflect a low GDP growth scenario where global prices remain low as a result
Low Interconnection	Interconnection is lower: Interconnection with Denmark does not go forward, interconnection with Norway is delayed, new interconnection with France is reduced
Low Demand	Demand is lower. Demand stays flat up to 2030 and then increases in line with National Grid Slow Progression scenario. In 2030 demand is 70 and 62 GW in Base Case and Low Demand respectively. In 2050, the difference is higher with 100 GW in Base Case and 73 in the Low Demand

High Renewables

Higher renewable penetration due to increased investments in the 20s lowers incentives for baseload capacity throughout the period and increases incentive for storage and hydrogen

- The High Renewables' scenario assumes continued support for renewables (including onshore wind) up to 2028. Wind and solar capacity follows the trajectory of Baringa Decarbonisation up to 2028. Baringa Decarbonisation has the same long-term target as National Grid Gone Green
- One impact of the higher renewable penetration is that there is less need for baseload capacity such as Gas CCS and Nuclear
- On the other hand there is additional need for peaking capacity due to the higher intermittency of renewables and the lower derating margin that results from the lower nuclear and CCS build. In the 20s we can observe that all additional peaking capacity comes from OCGTs but in the 30s and 40s it comes from storage and hydrogen due to the higher number of operating hours of the flexible plant and the need for this to be low carbon to allow the system to meet the CO2 constraint
- Below we can see the comparison of the renewable committed and existing build (exogenous input to the model) of the sensitivity compared to Base Case



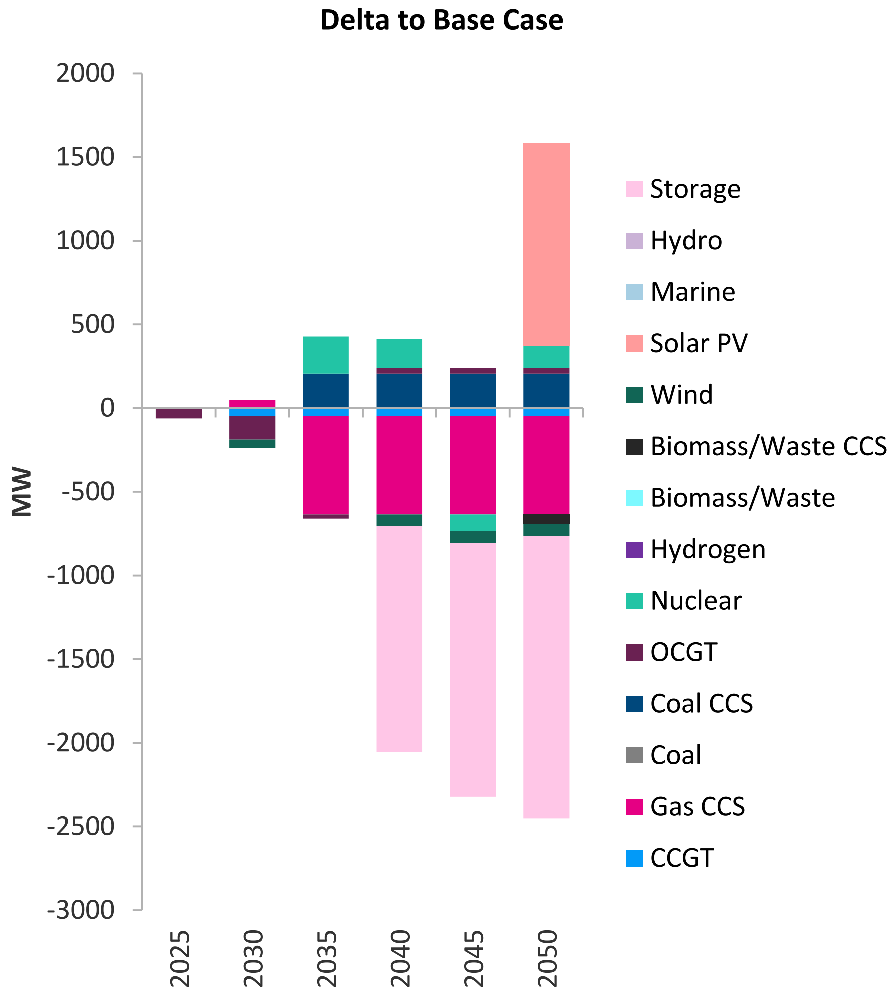


Flexible EVs

Baringa

Enabling EV's flexibility in charging reduces the requirement for grid batteries which reduces overall costs of electricity

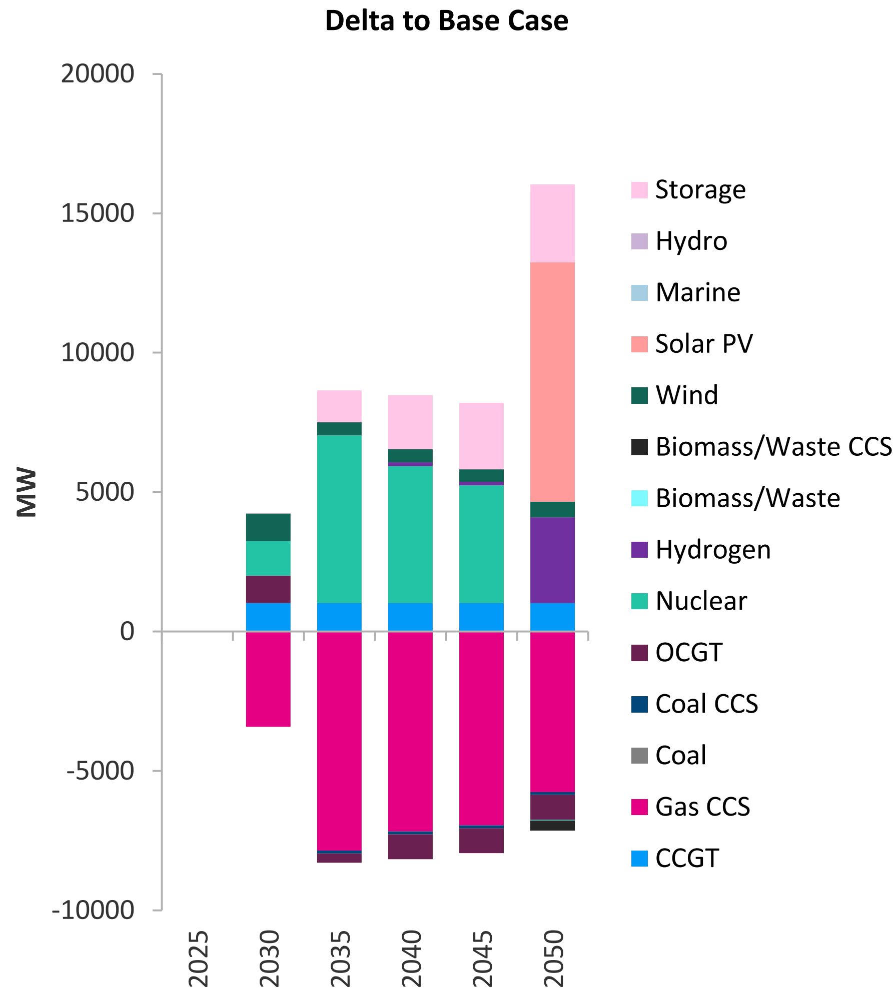
- A part of the future electricity demand will come from Electric Vehicles. The demand from electric vehicles can be flexible, which means that the consumer (or a demand-side aggregator on the behalf of the consumer) can choose when to charge the electric vehicle. In this study, we have used National Grid's Gone Green assumptions for EVs: In Gone Green, there are 12 million vehicles by 2040 (27% of the total number of cars). On average, these vehicles consume 2 MWh/year demand. Hence the total EV annual demand is projected to be 24 TWh by 2040
- In the Base Case we assume that there are ToU tariff schemes in place that make the EV load profile broadly flat, by helping to shift load away from evening peak into the overnight period.
  - In this sensitivity, we assume that 50% of the EV demand is truly flexible and load aggregators / the System Operator can shift demand in off-peak times (8PM-6AM). PLEXOS optimises the interval at which this load will be consumed in order to minimise the system costs. The optimisation is subject to constraints around ensuring the vehicles are sufficiently charged by 6am and that peak charging does not exceed the typical home charging rating
- The EV load flexibility has an impact to both peaking and baseload capacity:
  - Peaking: In the short-term OCGTs are affected negatively. However EV penetration is relatively low and therefore the reduction in OCGT capacity is moderate. In the long-term storage capacity is affected very negatively due to the EV penetration increasing substantially
  - Baseload/intermittent generation: low opex capacity such as nuclear and coal ccs is favoured more compared to gas ccs which is lower capex. This is due to the flexibility of EVs which can accommodate baseload generators better



Constrained CCS

If CCS is delayed, it never converges to the Base Case long-term figure but it is replaced by other technologies

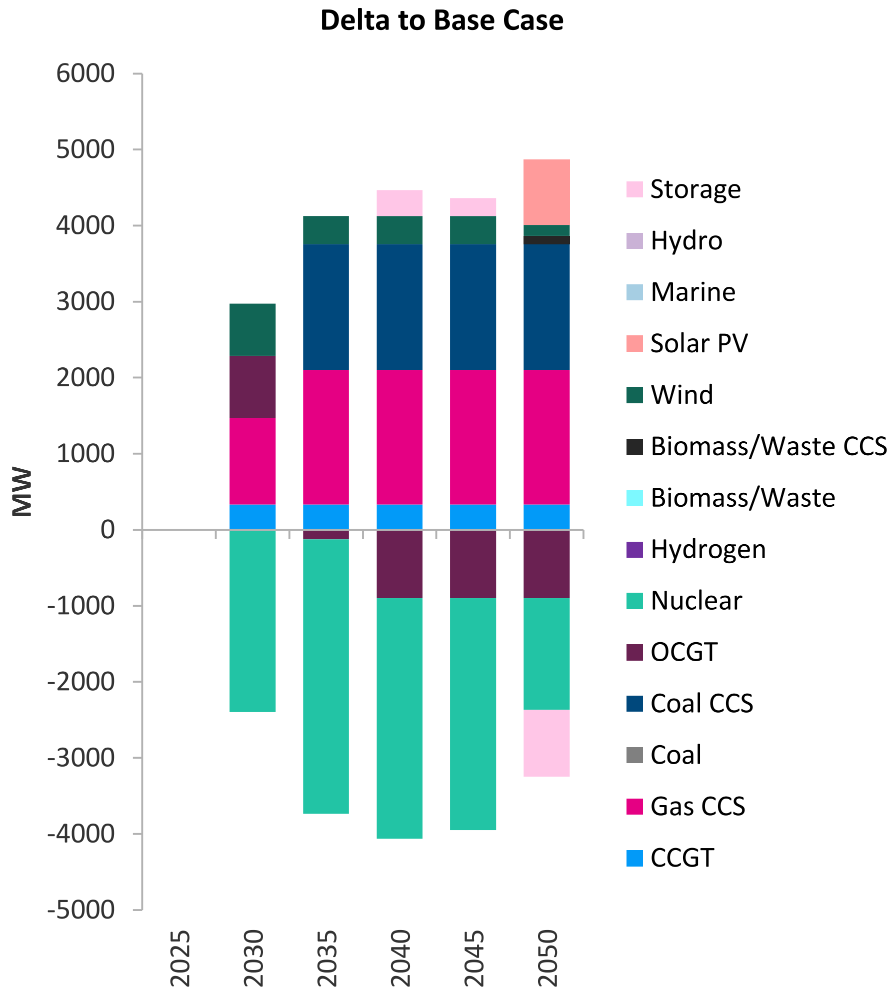
- The direct impact of CCS constraint is that during the 2020s and 2030s there is much less Gas CCS capacity built
- In response to the lack of low carbon capacity built, nuclear projects come forward and nuclear replaces most of the CCS capacity in the period 2030-2045. However in the last few years, Nuclear converges to the same point as in the Base Case
- We can observe that much more hydrogen capacity is built in the last few years compared to Base Case. This is due to two reasons:
  - Hydrogen becomes cheaper than Gas CCS during in those years. In the Base Case, Gas CCS is built mainly in the 30s when hydrogen technologies are very expensive. Hydrogen was not being built because of the legacy CCS units remaining in the system. When CCS is delayed, PLEXOS chooses to never built it but replace it with other units
  - Hydrogen provides cheap capacity and can also generate clean electricity at a reasonable cost which is very valuable in 2050 when carbon costs are very high and gas generation becomes very expensive



Constrained Nuclear

If Nuclear is delayed, CCS fills the gap in low carbon baseload generation in the 30s but nuclear is still favoured as the long-term solution

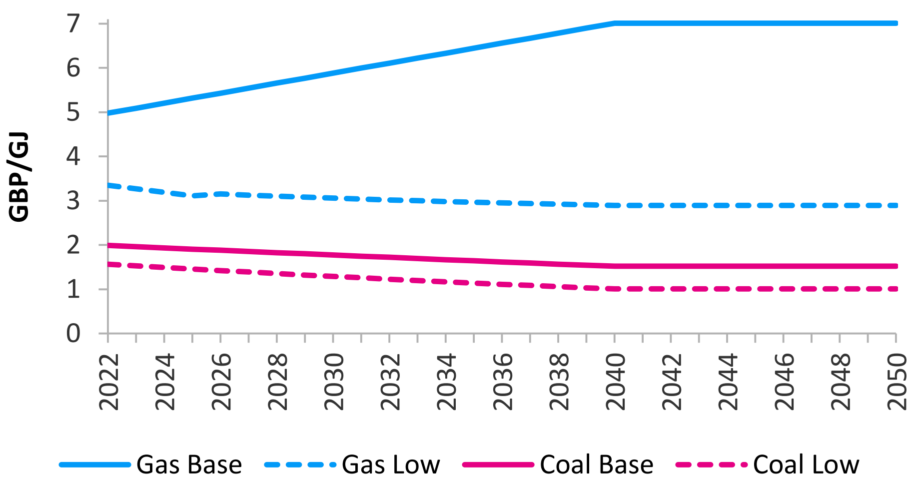
- The direct impact of constrained Nuclear is of course a reduction in the nuclear capacity built over the horizon
- This creates a greater need for baseload capacity which mostly comes from gas and coal CCS
- We can observe that even though in the 2020s and 2030s there is much less nuclear capacity built than in the Base Case, the difference reduces in the late 2040s as under the base case assumptions Nuclear is still a preferred route for providing low carbon baseload supply



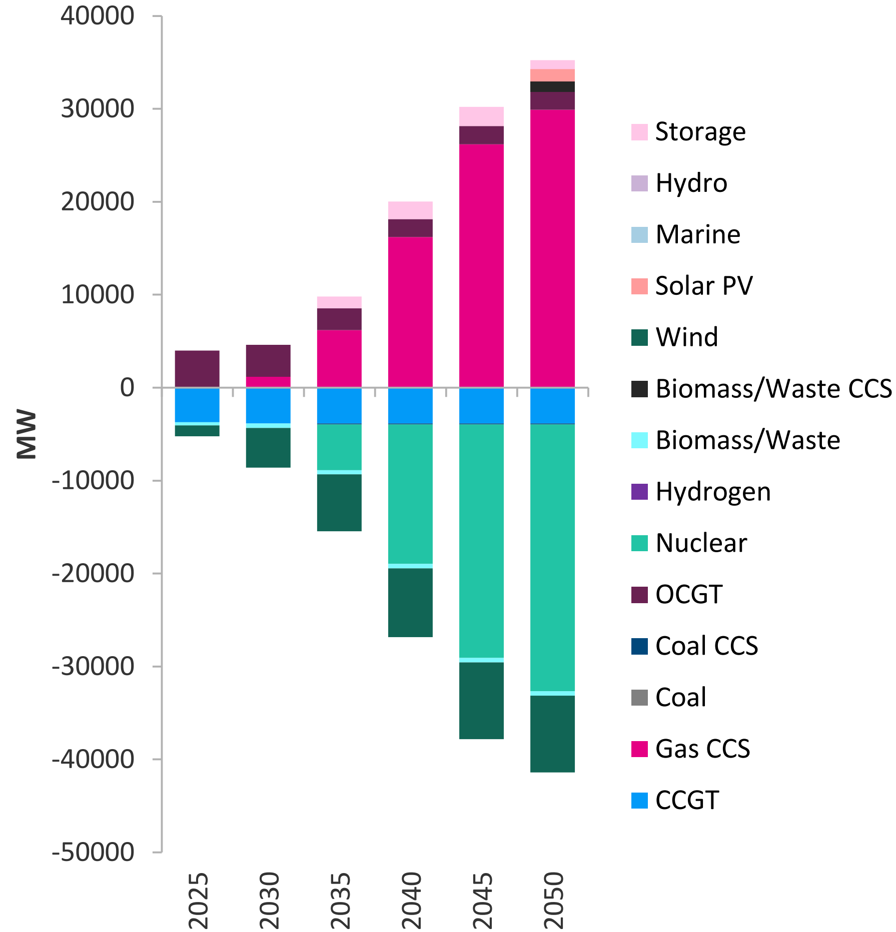
Low Fuel Prices

Lower gas prices allow for Gas CCS to become more competitive than nuclear and become the main low carbon baseload unit in GB

- The Low Fuel Prices sensitivity reflects a low GDP growth world where the fuel prices remain low over the horizon
- A large part of the costs of Gas CCS is the fuel cost component. That component is significantly reduced in this sensitivity and Gas CCS becomes much more competitive compared to nuclear and wind. Therefore Gas CCS replaces partially nuclear and wind for the entire horizon
- In addition, is more biomass and waste CCS capacity built towards the 2050 point compared to the Base Case. The reason is a need to neutralise the carbon emissions from the Gas CCS generation and meet the target of net zero emissions
- In the Low Fuel Prices, coal prices reductions are much lower than gas in both absolute and relative terms and therefore Coal CCS deployment remains zero



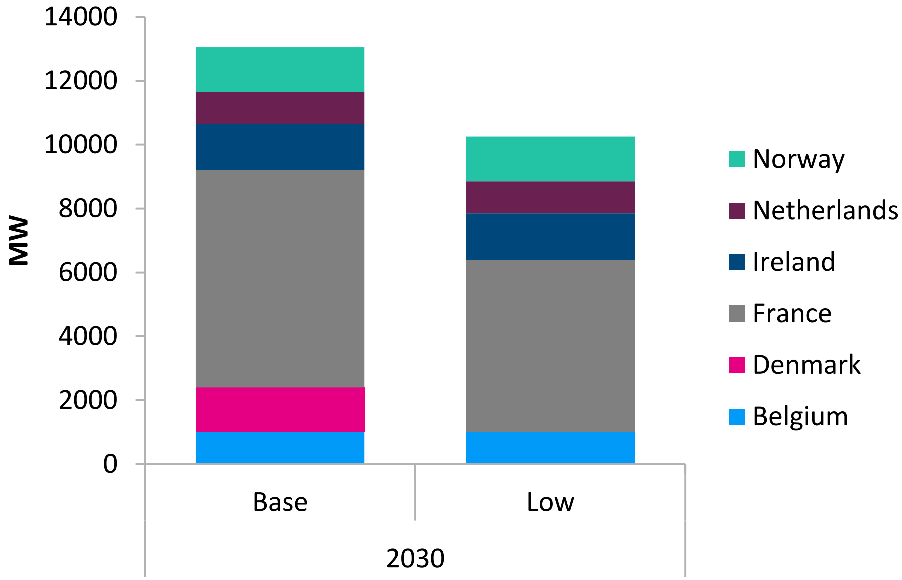
Delta to Base Case

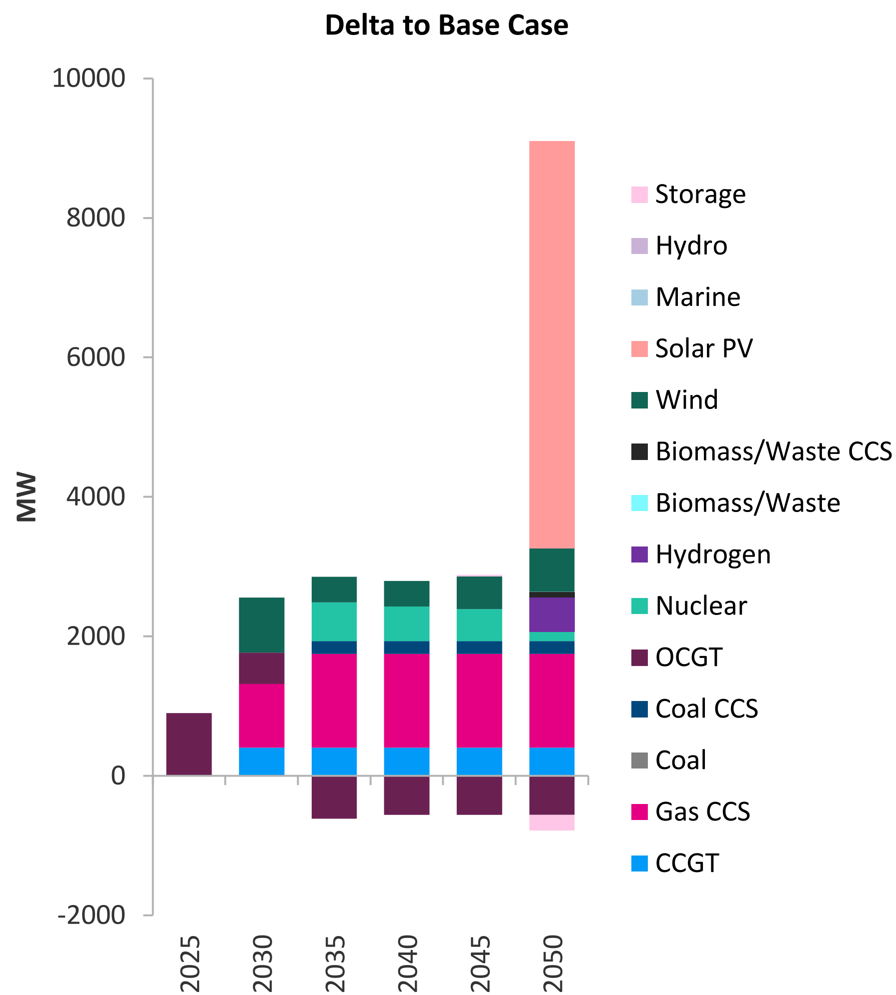


Low Interconnection

The lack of interconnection incentivises more capacity build in GB especially gas-based

- Lower interconnection leads to lower capacity margin. As a consequence there is need for more firm capacity to be added such as gas. In the 2020s there is some OCGT built to make up for the lower interconnection de-rated capacity.
- However in the 2030s and 2040s Gas CCS is built to greater extend which provides both energy but also capacity to the GB system. Therefore there is less need for low capex peaker capacity post 2030. This reveals that most benefits of interconnection come from energy rather than capacity
- In addition, lower interconnection leads to an increase in required energy supply in GB (from energy that was previously being imported). As this must be provided at net zero carbon intensity this leads to more low carbon capacity being deployed, in particular a ~20% increase in solar in 2050

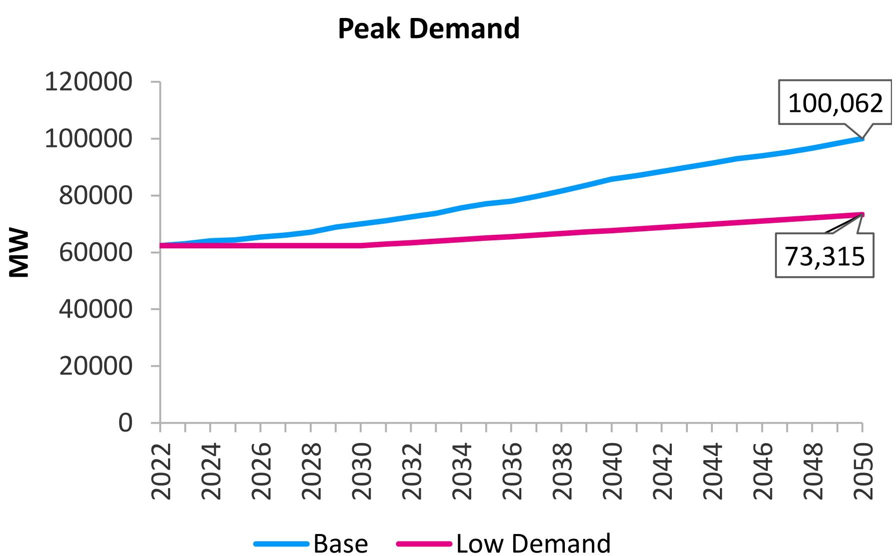


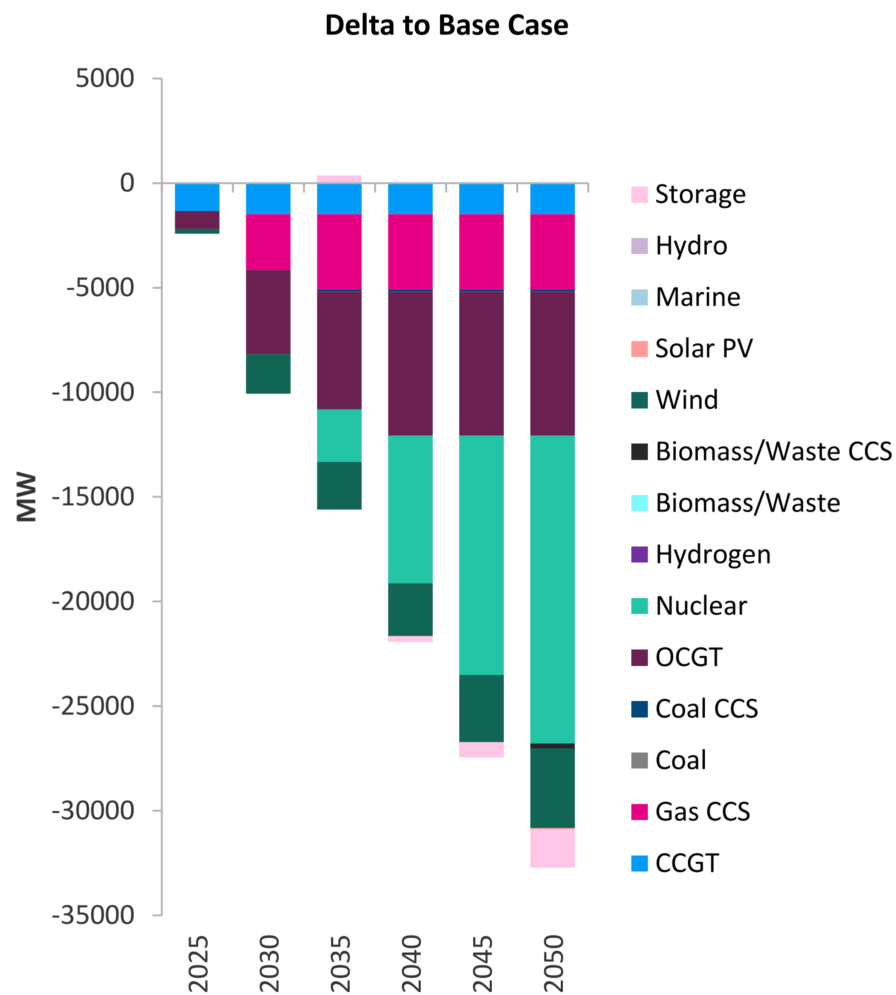


Low Demand

Reduces the requirement for new capacity which poses significant risk to investors

- In the Low Demand sensitivity, demand remains flat in the period 2022-2030 and then interpolates to the 2040 NG Consumer Power assumption. Post 2040, the growth rate remains flat as in the previous ten years
- In this sensitivity, there is less capacity constructed in nearly all types
- The capacity mix cannot be easily compared with the Base Case because the peak demand is different
- The capacity build decisions are less affected in the 20s because the differential between the two scenarios is not high. CCGT deployment is similar to Base Case with only 9% reduction by 2050. In contrast CCS and nuclear deployment is just above 50% of the Base Case

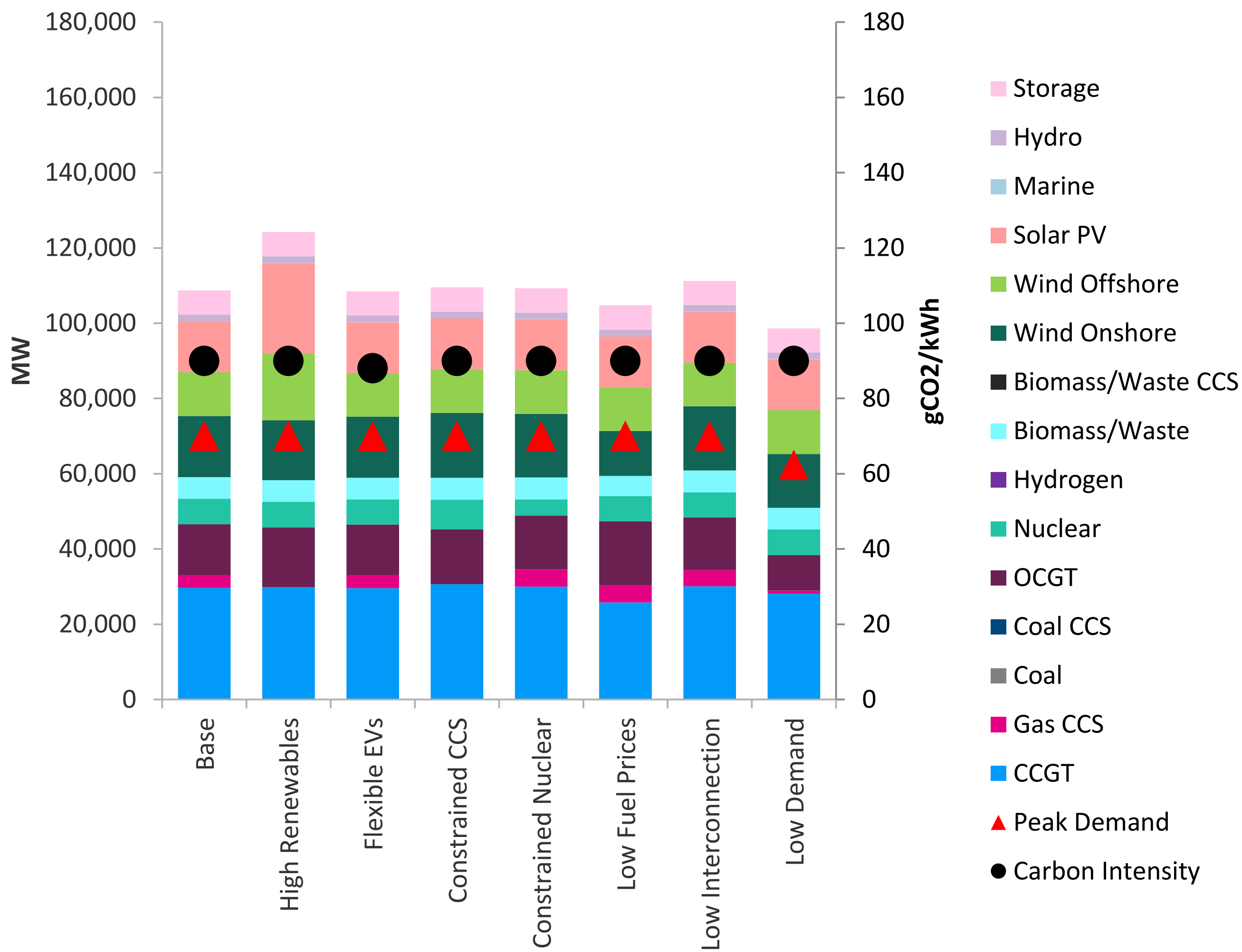




Sensitivities – capacity comparison in 2030

Capacity mix in 2030 is similar across most scenarios and not drastically different than the current

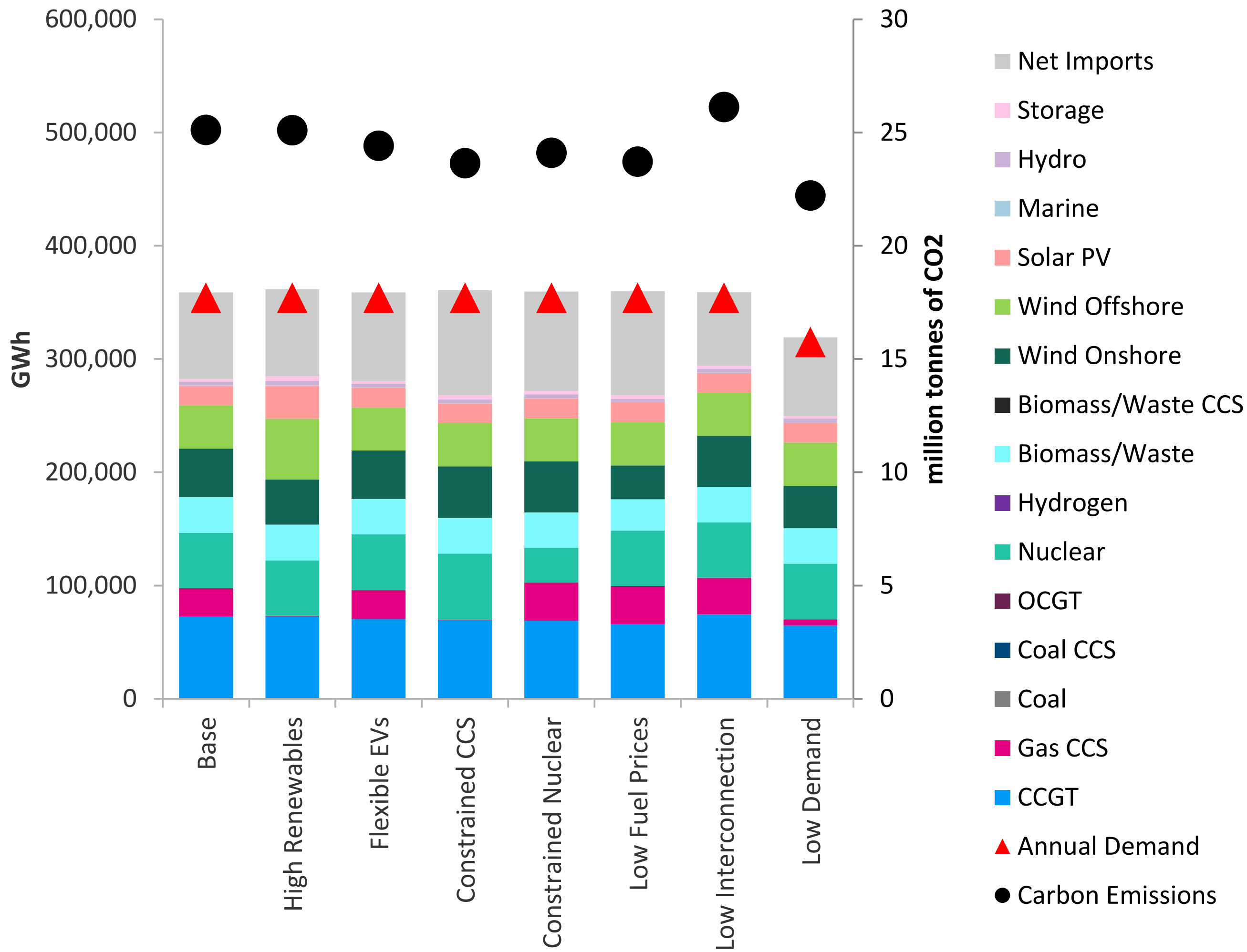
- The majority of the capacity in 2030 has already be commissioned. For that reason, all scenarios have similar capacity mix in 2030
- High Renewables has the largest difference with the Base Case in 2030 because the sensitivity affects the support of renewables over the period 2022-2028. It is also the scenario with the highest renewables penetration across all scenarios with higher storage capacity to balance them
- There is no CCS deployment in High Renewables due to the low variable cost generation surplus and in the Constraint CCS due to the delays in technology development
- There is no solar development in any scenario except the High Renewables



Sensitivities – generation comparison in 2030

Nuclear remains at similar levels in most scenarios while a combination of imports and CCS supplies most of the demand increase

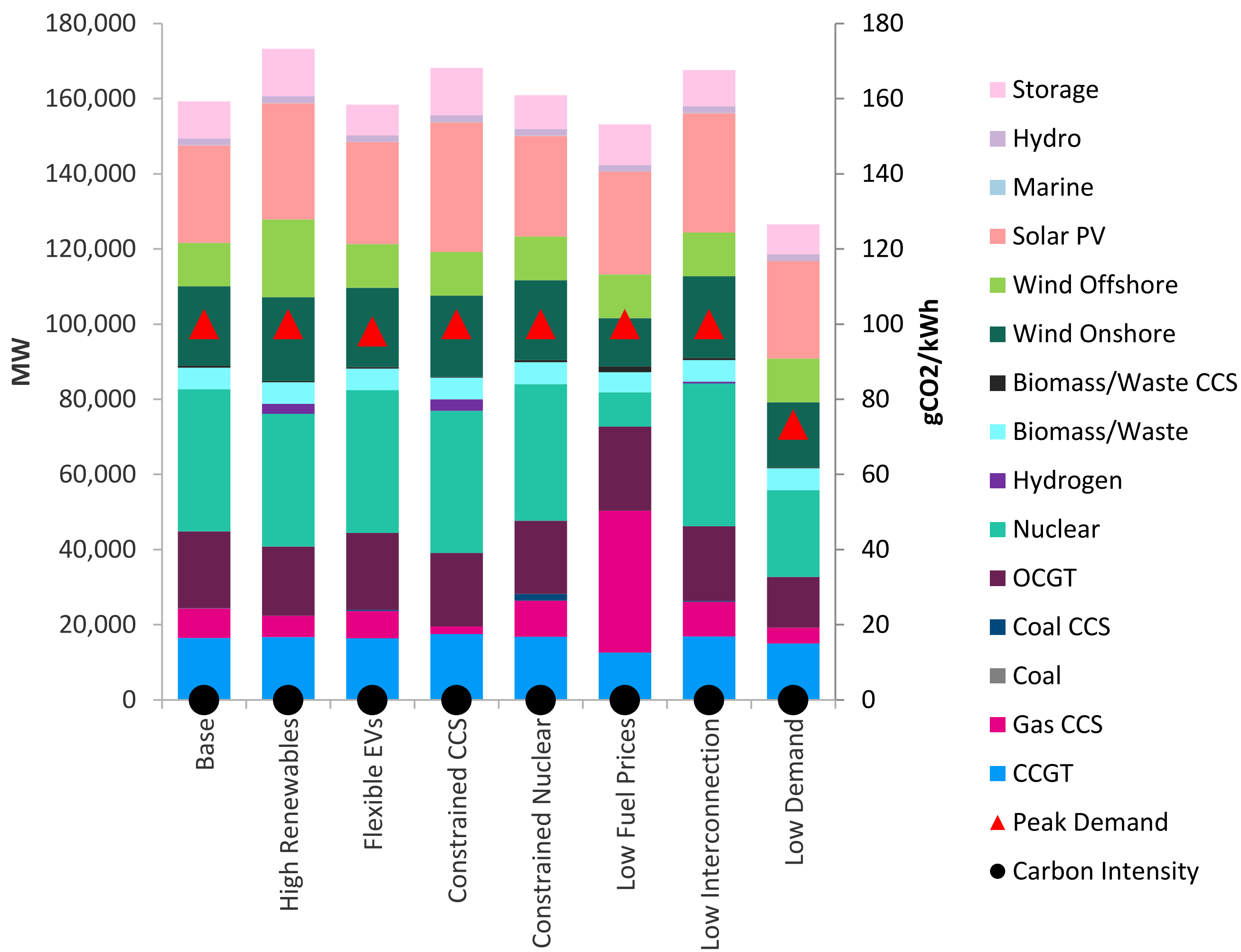
- CCGT generation is very similar in all scenarios. The main difference between scenarios is observed in low carbon generation: In Base, Flexible EVs, Constrained Nuclear, Low Fuel Prices and Low Interconnection there is about 20 TWh of CCS power generation. In other scenarios that generation is provided by renewables (High Renewables) or Nuclear (Constrained CCS)
- Low Interconnection has the highest carbon emissions in absolute terms due to the reduced imports from the interconnectors



Sensitivities – capacity comparison in 2050

There is need for about 45 GW low carbon baseload capacity to meet the 2050 carbon emissions targets

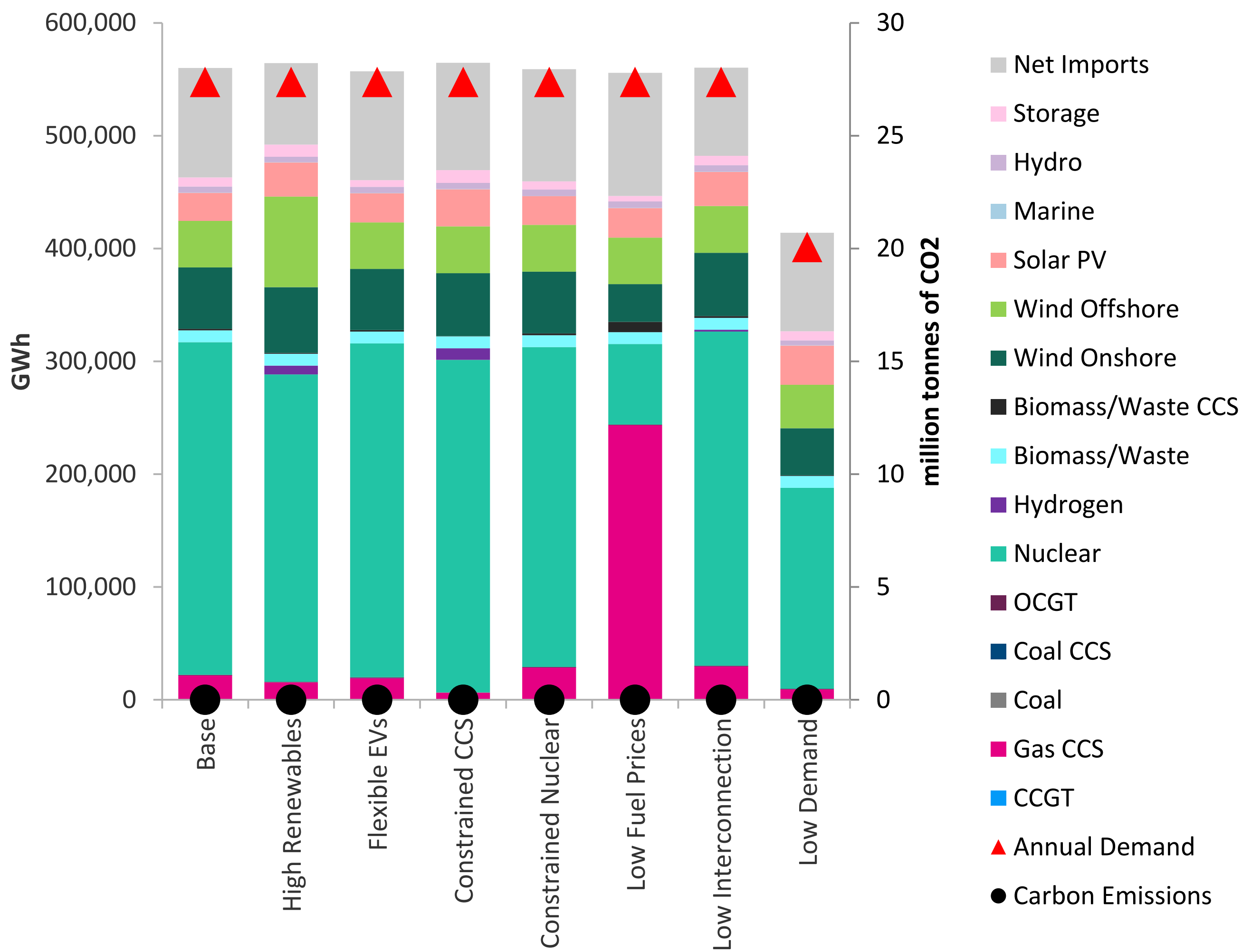
- In all scenarios except Low Demand, there is about 45 GW of new CCS and nuclear capacity coming online to supply the load without increasing the carbon emissions
- The storage capacity is higher in the scenarios where the renewable penetration is higher due to the higher energy benefits provided by storage when intermittent generation is high
- Hydrogen capacity is built in the High Renewables and Constrained CCS scenarios



Sensitivities – generation comparison in 2050

In all scenarios except Low Fuel Prices, Nuclear is favored by the model as the main baseload unit that can reduce carbon emissions

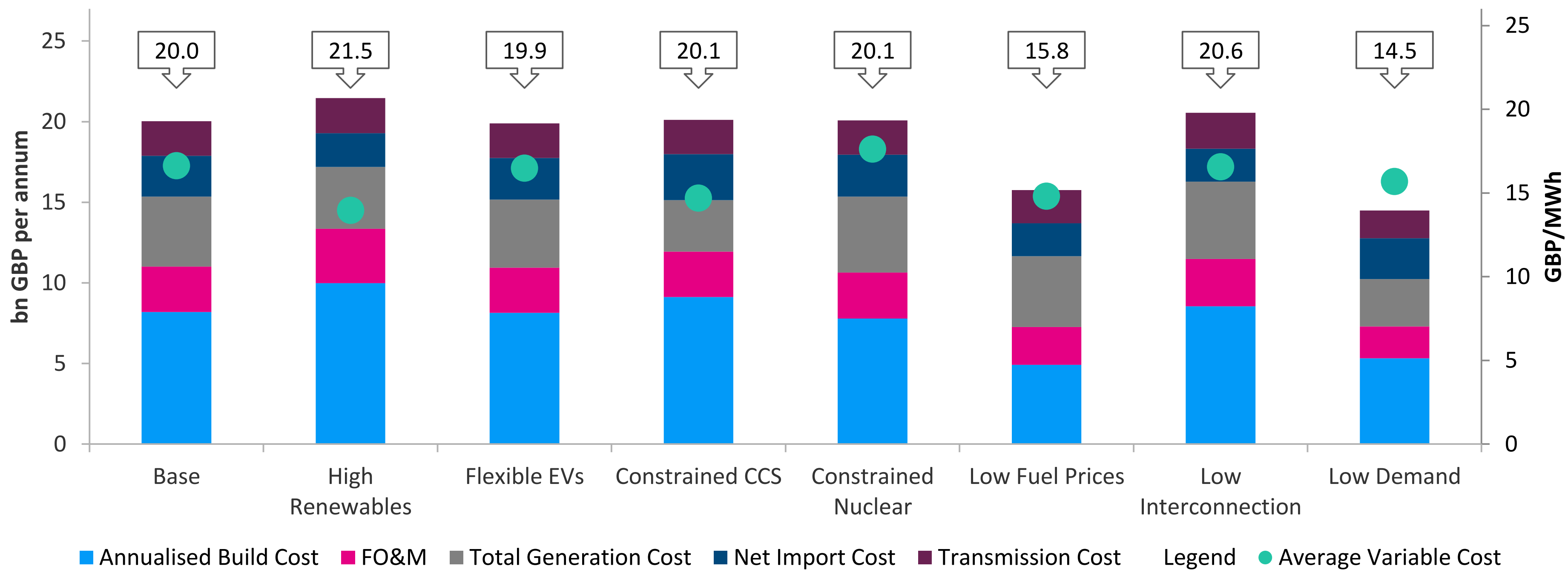
- Most scenarios have similar generation mix in the 2050 points. There are two sensitivities that stand out as being very different:
  - Low Demand in which Nuclear generation is much lower
  - Low Fuel Prices in which CCS generation is substantially higher (over 200TWh per annum). The carbon emissions from these units are balanced from the Biomass/Waste CCS that are attributed with negative lifecycle emissions
- High Renewables projects the lowest net imports (even than Low Interconnection) due to the excess zero variable cost generation in many hours of the year
- In scenarios with high renewables or constraints on CCS, hydrogen turbine capacity is introduced to provide additional, flexible low carbon supply



Sensitivities – cost differences

Average annual costs over the horizon

- The average annual cost of the GB system in the Base Case across the horizon is about 20 billion GBP (excluding existing capacity fixed costs)
- Flexible EVs have slightly lower costs because there is less storage capacity built. We have not assumed any extra cost associated with utilising the potential for flexibility of EVs. Low Fuel Prices have lower cost because the variable cost of CCGT and Gas CCS is much lower during the entire horizon. Low Demand has naturally lower costs compared to Base Case since there is less need for new capacity and fuel consumption
- Constrained Nuclear and CCS scenarios have slightly higher costs than Base Case due to the delays in those technologies that force the model to choose higher cost solutions. High Renewables have lower generation and import costs because the extra renewable capacity is nearly zero variable cost but it occurs high capitals costs upfront, most of them coming from the offshore wind farms. Low Interconnection has the second highest annualised costs from all sensitivities because of the lack of cheap imports from Norway and other European markets and the flexibility that they provide.



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Summary of other scenarios

Range of National Grid, CCC, ETI and Baringa in-house scenarios contrasted with new base case and sensitivity results

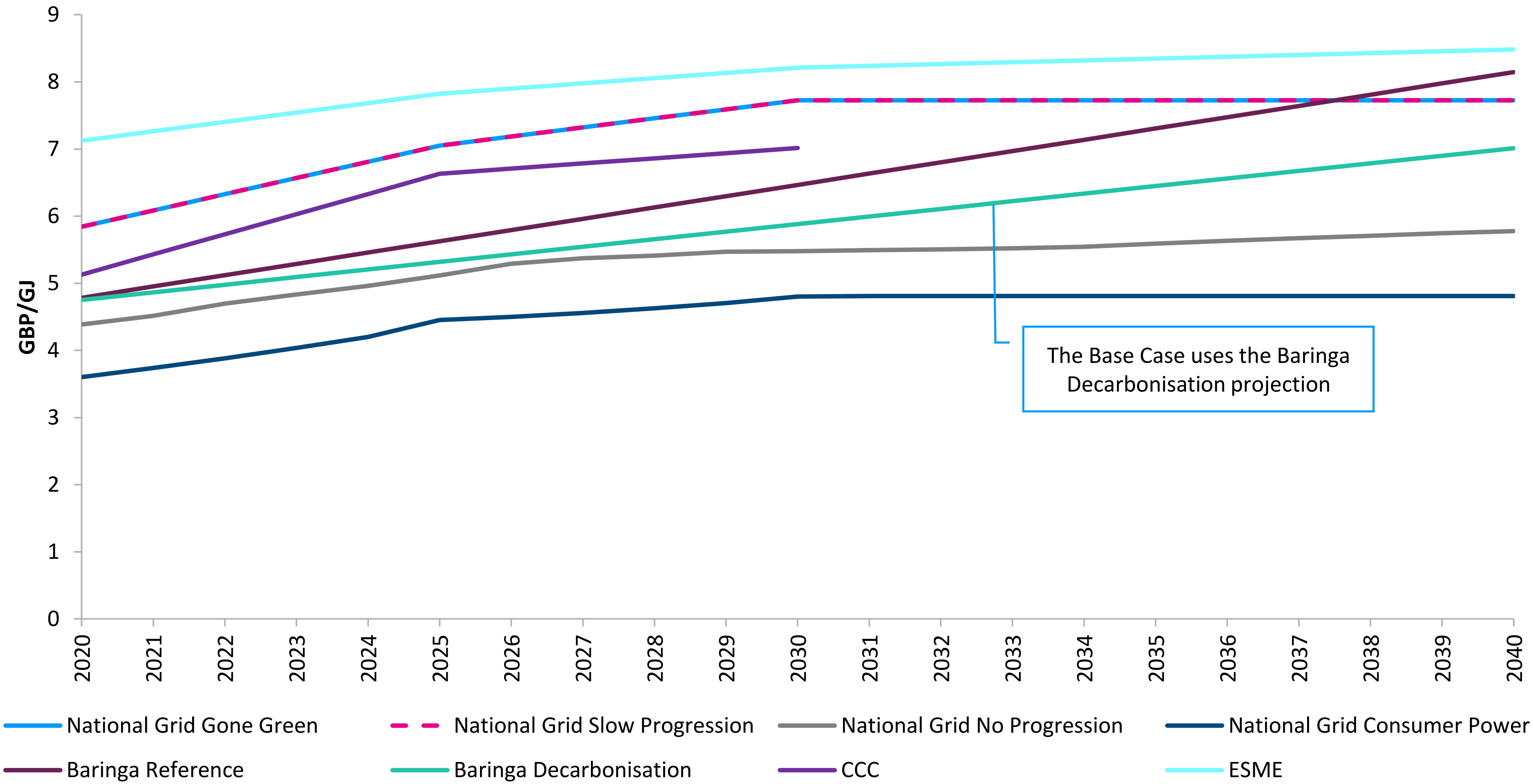
- We have researched and included several other scenarios from various sources (National Grid, Baringa, CCC, ETI ESME), in order to compare them with the output of the modelling from this project capacity mix
  - *A brief summary of the scenarios is provided below, please see the annex for a more detailed overview of these scenarios (their capacity mix, their main assumptions and a short description of the methodology used to deduce them)*
- **National Grid Future Energy Scenarios** provides four scenarios that differ in respect to the economic prosperity assumed and the ambition to decarbonise the power system. These scenarios are finalised after cycles of scenario modelling and feedback from stakeholders. The most progressive scenario is the Gone Green scenario which assumes 18 GW of nuclear, 11 GW of CCS, 48 GW of wind and 36GW of solar by 2040 which results in very low carbon emissions
- **Baringa** models four GB scenarios of which two are of interest for this study:
  - Reference Case which is our main view of how the GB power system will develop given our current central view of likely policy/market arrangements
  - Decarbonisation Case in which we assume that the government will provide as much economic support as necessary in order to deliver more significant reduction in power sector carbon emissions targets (<100 gCO2/kWh by 2030)

  Baringa's approach follows modelling cycles where:
  - Commodity prices are an exogenous input projected using a combination of forward prices and IEA long-term projections
  - Demand is an exogenous input projected based on National Grid projections
  - An initial input of sensible capacity assumptions is tested in the model
  - The power plant economic viability is checked
  - The capacity assumptions are changed and checked again for several cycles
- **CCC** follows a simpler methodology than National Grid and Baringa: It only provides capacity figures for 2030 which are manually adjusted in order to meet the carbon intensity target of 90g/kWh
- **ESME** is a whole energy system least cost optimisation model with carbon emissions target that includes not only the electricity sector but also heat, transport and other sectors, but with the electricity sector modelled in less detail compared to this study and the Baringa / National Grid scenarios. The results are based on 100 pathway simulations from ESME v4.1 with an additional maximum 100gCO2/kWh electricity intensity target in 2030.

- *In presenting the key metrics peak demand is reflects an ACS (average cold spell), the CO2 intensity target applies to UK based generation (import prices have a carbon price embedded within them) and NI is excluded from the results unless otherwise stated*

Scenario comparisons and conclusions: Gas price

Gas price increases in all scenarios from current levels as result of global trends in the commodity markets

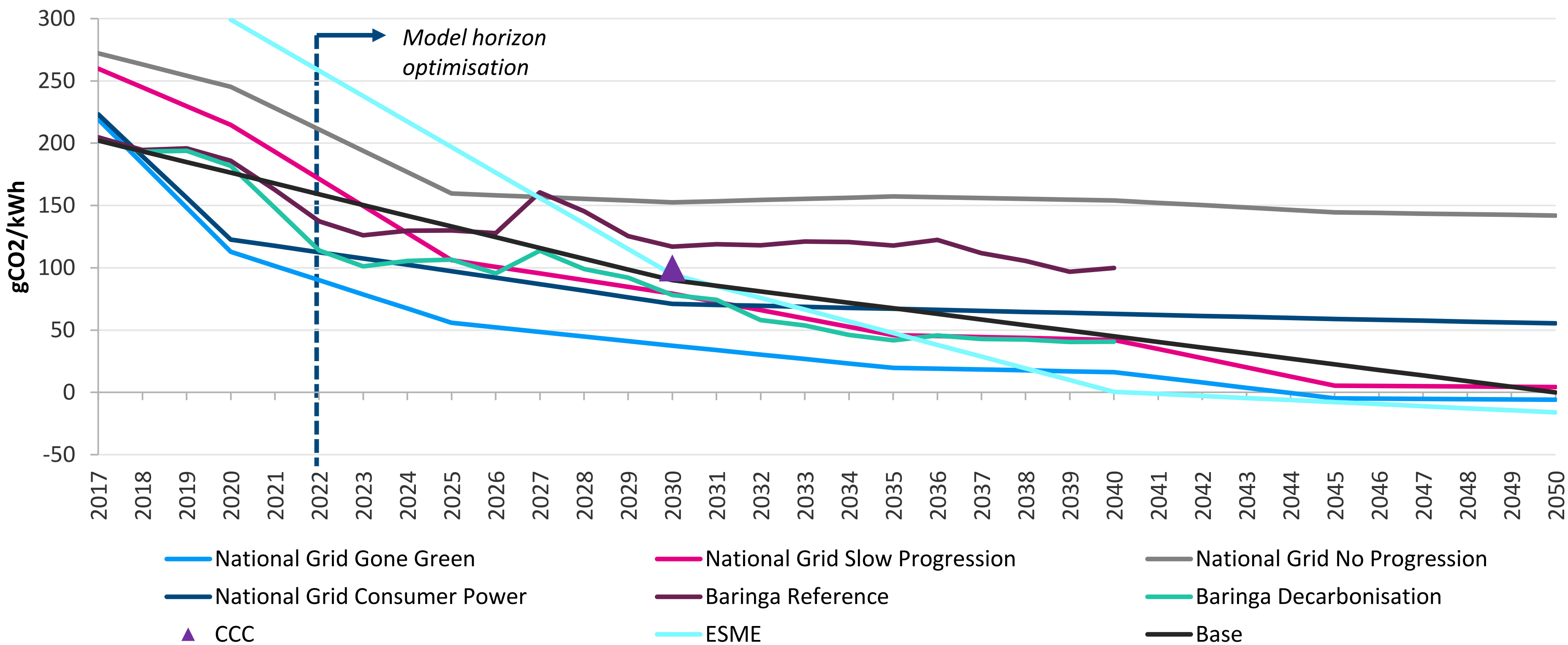


National Grid's Gone Green and Slow Progression have the same price

Scenario comparisons and conclusions: Carbon intensity

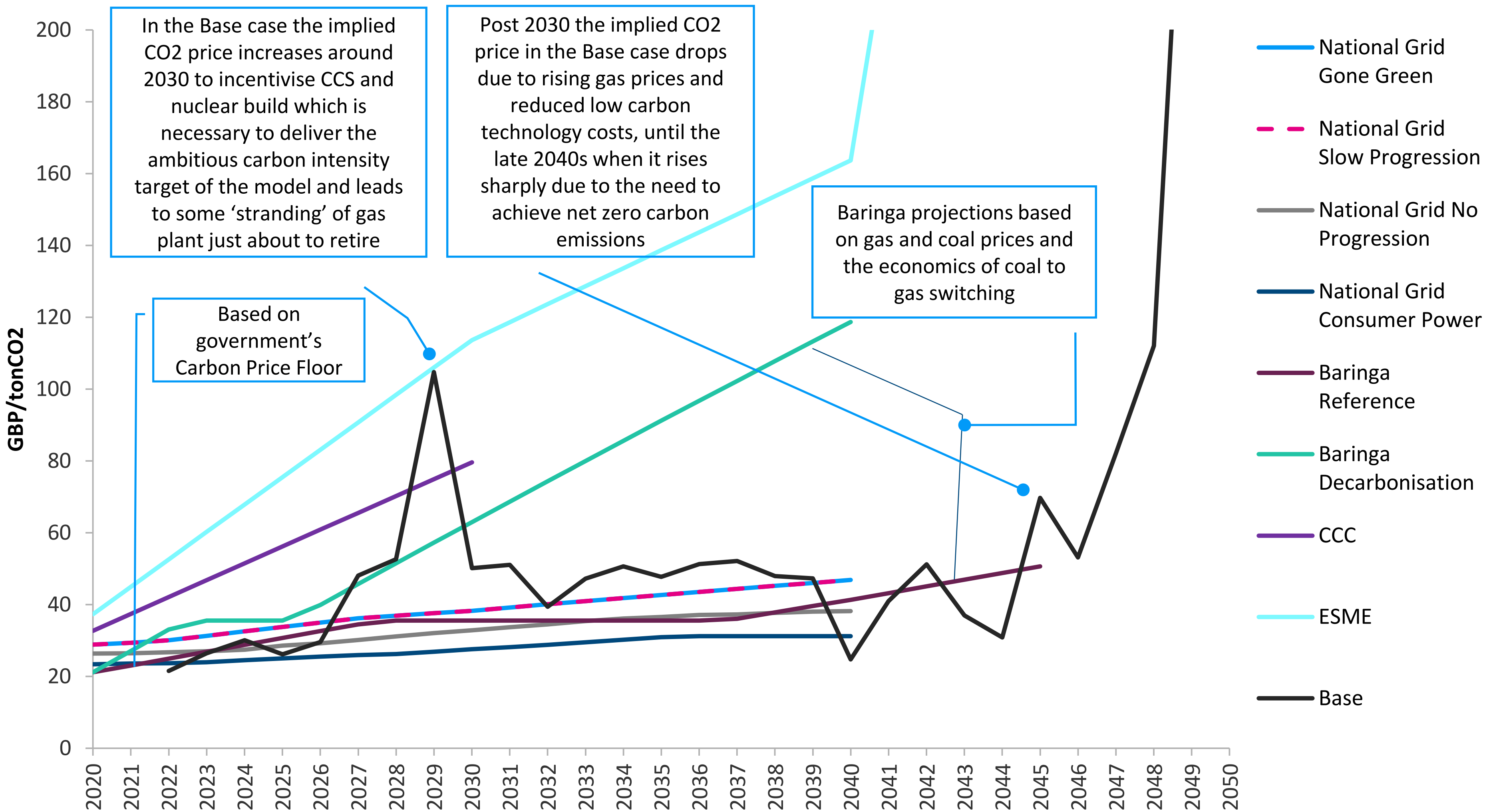
Carbon intensity drops in all scenarios significantly compared to current values

- A major difference between the Baringa and National Grid's scenarios on the one hand and ESME scenario on the other is that the latter assumes no interconnector flows. Therefore, they start from a higher point of carbon intensity (about 300 g/kWh) due to lack of imports
- All scenarios except the Baringa Reference and National Grid No Progression achieve lower carbon intensity than 100g/kWh by 2030. Both National Grid Gone Green scenarios and the ESME scenario achieve negative emissions by 2050.
- From 2022-2040 the carbon intensity of this project's Base Case scenario follows closely the Baringa Decarbonisation and National Grid Slow Progression



Scenario comparisons and conclusions: Carbon

Carbon Price increases in order to meet carbon targets in all scenarios. These are implied outputs (shadow prices) for the Base/ESME scenarios and assumed inputs for all others.



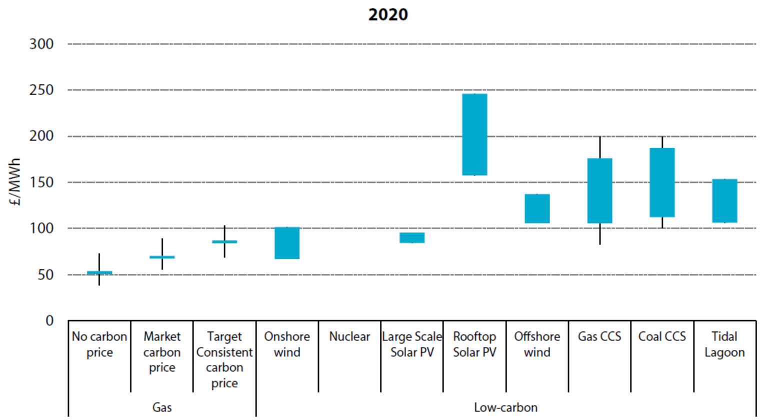
National Grid's Gone Green and Slow Progression have the same price

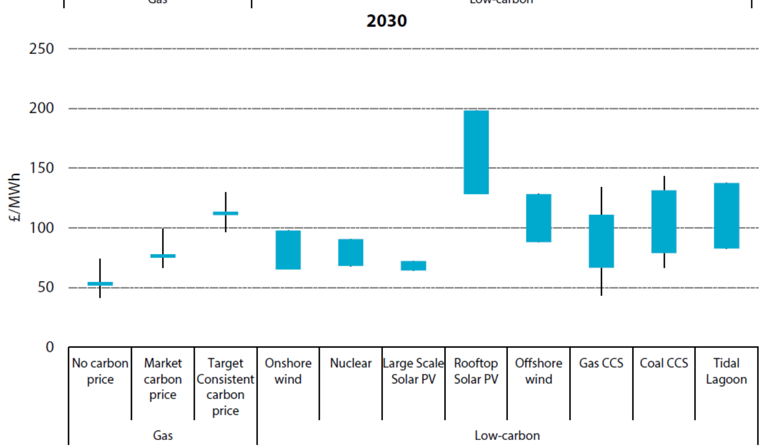
Scenario comparisons and conclusions: Levelised costs

Technology costs are not published in NG scenarios and CCC scenarios (left) provided levelised costs with assumed load factors

CCC Scenario implied levelised Costs

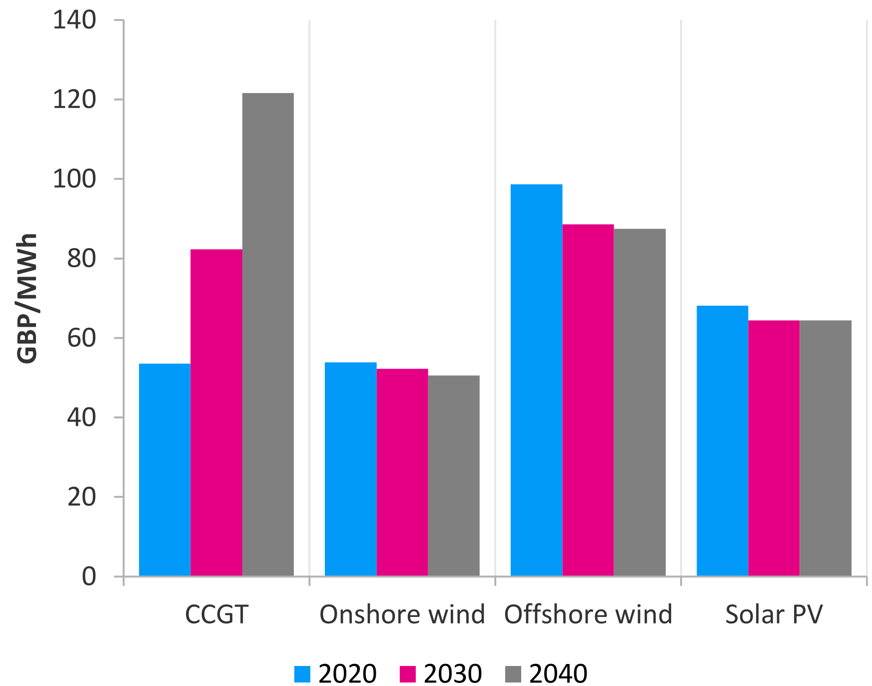
- CCC assumes higher costs for the gas plants compared to ESME or Baringa, but does not appear to recognise the expected decline in load factor over the lifetime of a new plant built in 2020 vs 2030





Baringa Decarbonisation Scenario assumed costs

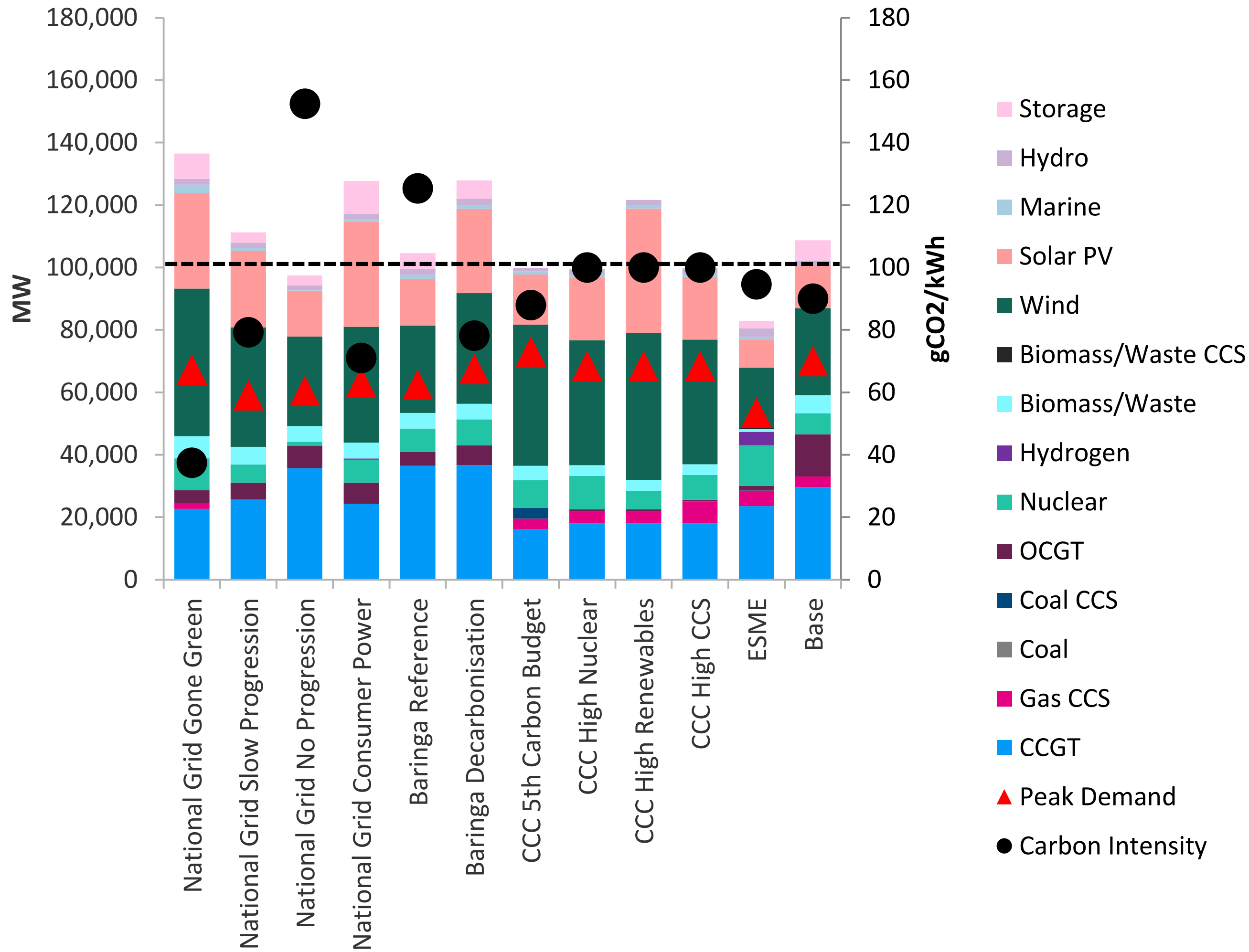
- CCGT is the main baseload unit in the Baringa Decarbonisation scenarios for the most of the horizon. Rising gas and carbon costs increase LCOE in the 2030's which result in lower load factors for existing build and very limited new build. This is consistent with the analysis in the cost-optimised Base Case from this study shown previously in slide 24.



Scenario comparisons and conclusions: 2030

Compared to other scenarios that 'broadly' achieve 100gCO2/kWh by 2030 the Base Case pathway has lower renewables (no new offshore post 2022) and more OCGT peaking plant

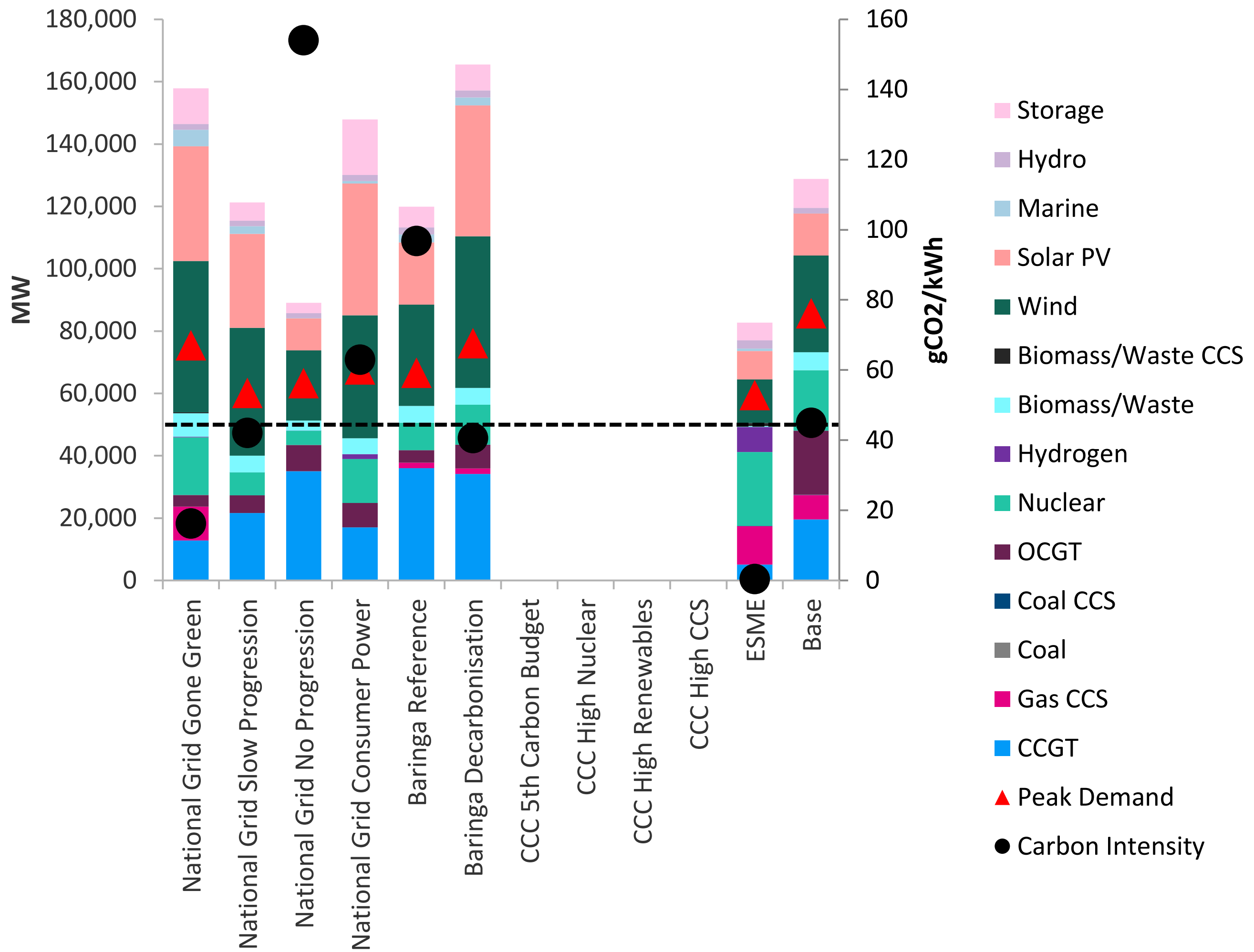
- National Grid and Baringa are more conservative with regards to future deployment of immature technologies. There is no CCS deployment in those scenarios except in NG's Gone Green
- CCC and ESME scenarios assume that significant CCS capacity coming come online in the 20s
- In the 2030, in nearly all scenarios CCGT is the main baseload unit. CCC has the lowest CCGT operational capacity because assumes very high low carbon capacity nuclear and CCS that along with wind displaces CCGT generation
- In most scenarios, carbon intensity is around 100gCO2/kWh in 2030. NG's Gone Green targets a quicker decarbonisation than in other scenarios such as ESME and Base Case but the long-term target is similar. However, it is not clear how this scenario achieves substantially lower carbon intensity (~40gCO2/kWh) when compared to others such as the CCC 5th Carbon budget or Baringa Decarbonisation case



Scenario comparisons and conclusions: 2040

Base Case in 2040 features more low carbon baseload (nuclear and gas CCS) and OCGT peaking backup compared to other scenarios which achieve broadly similar carbon intensities

- The large penetration of wind and solar in some scenarios such as NG Gone Green and Consumer Power is balanced by increased storage and OCGT
- All scenarios with low carbon intensity targets have high nuclear capacity that functions as low carbon baseload capacity
- Gone Green, ESME and Base Case scenarios are the only ones that include substantial Gas CCS capacity
- NG's No Progression and the Baringa Reference carbon intensity remain above 100g/kWh in 2040 but all other scenarios project lower than 50g/kWh for that year
- Base Case assumes the highest peak demand compared to all other scenarios, which - with the exception of ESME - do not go to 2050 and have a more limited view of the challenges associated with decarbonisation in the last decade. Both the Base Case and ESME assume significant ongoing electrification to meet the 2050 targets, but this materialises closer to 2050 for ESME (see next slide)



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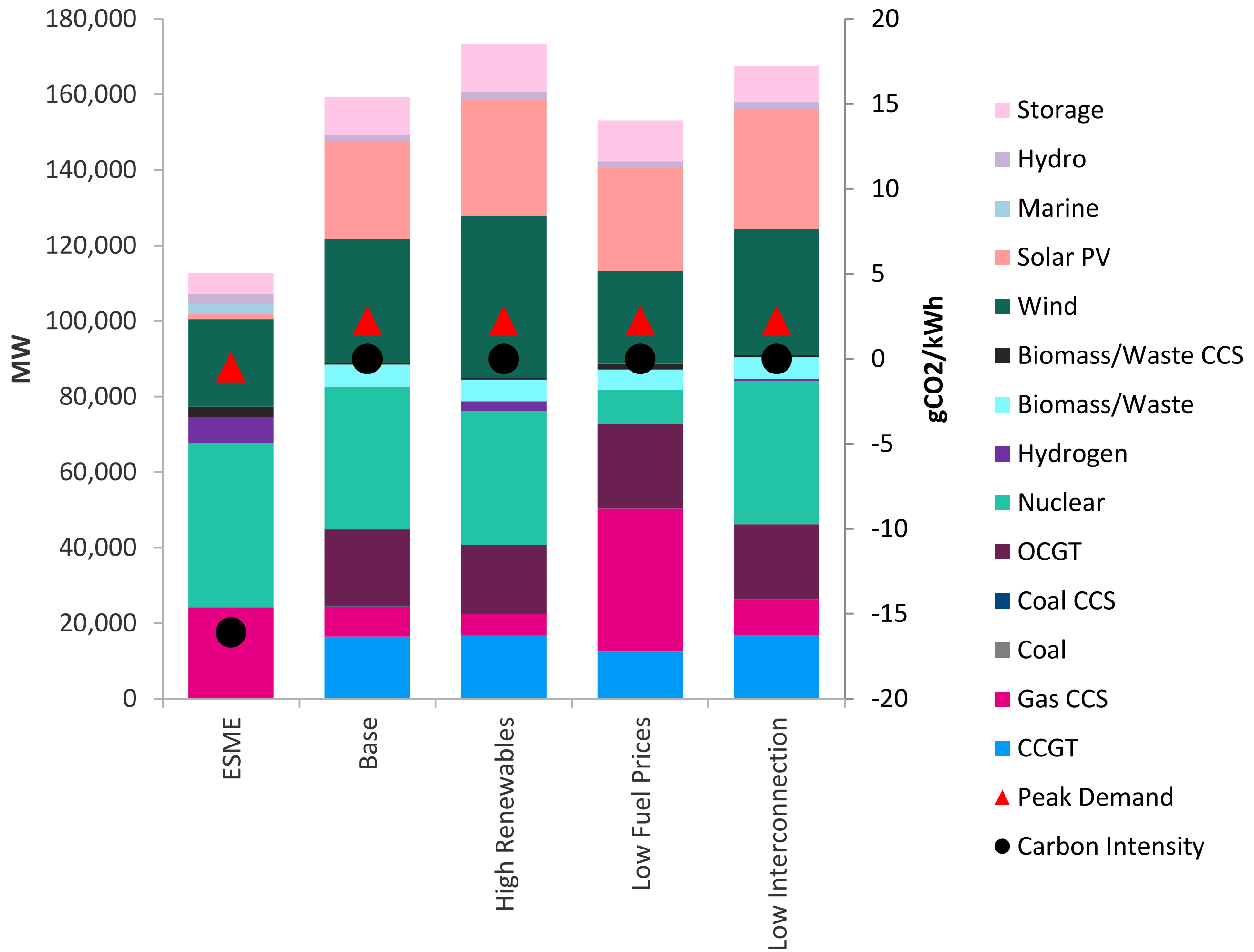
Scenario comparisons and conclusions: 2050

Capacity mix in 2050: Nearly all capacity in 2050 will be built post 2017. Legacy thermal assets such as CCGTs will only have role as peaking plants

- The Base Case scenario projects much higher capacity build due to the higher demand assumption and capacity margin requirement
- The carbon intensity of the Base Case was targeted at net zero while the ESME achieves negative emissions by 2050 (-16g/kWh)
- ESME mix is based largely on nuclear, CCS and wind generation to supply the demand: It projects capacity of 46 GW, 13 GW and 50 GW for nuclear, CCS and wind respectively
- The Base Case mix has visible differences to the ESME mix, in particular baseload Nuclear and Gas CCS capacity is lower, while solar is significantly larger. Also the Base capacity mix has large OCGT and CCGT capacity in 2050 which provide reserve but do not generate electricity due to carbon emissions limits. Those units remain operational in order to provide reserve to the grid. Storage capacity is much higher in the Base Case.

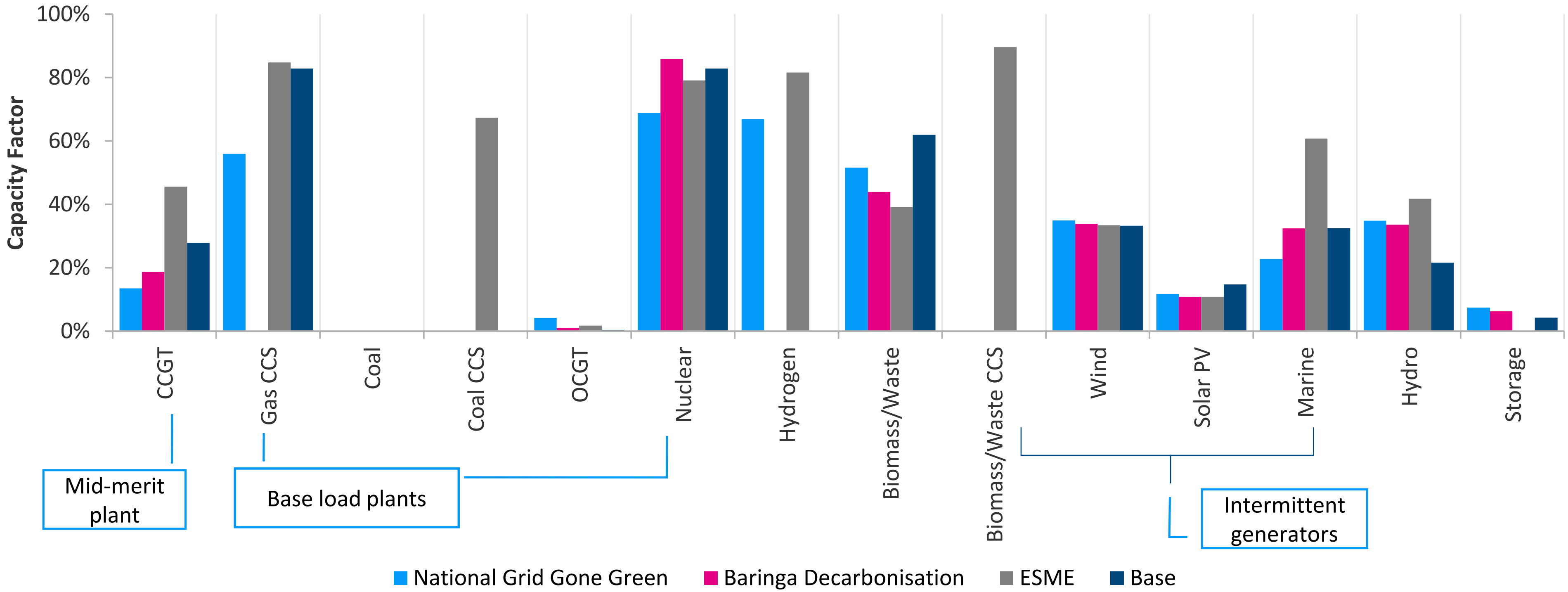


N.b. only the ESME and the PLEXOS Base model provide capacity figures for 2050

Scenario comparisons and conclusions: Generation in 2030

The role of gas plant (both abated and unabated) varies significantly in 2030 across the scenarios for which there is data available

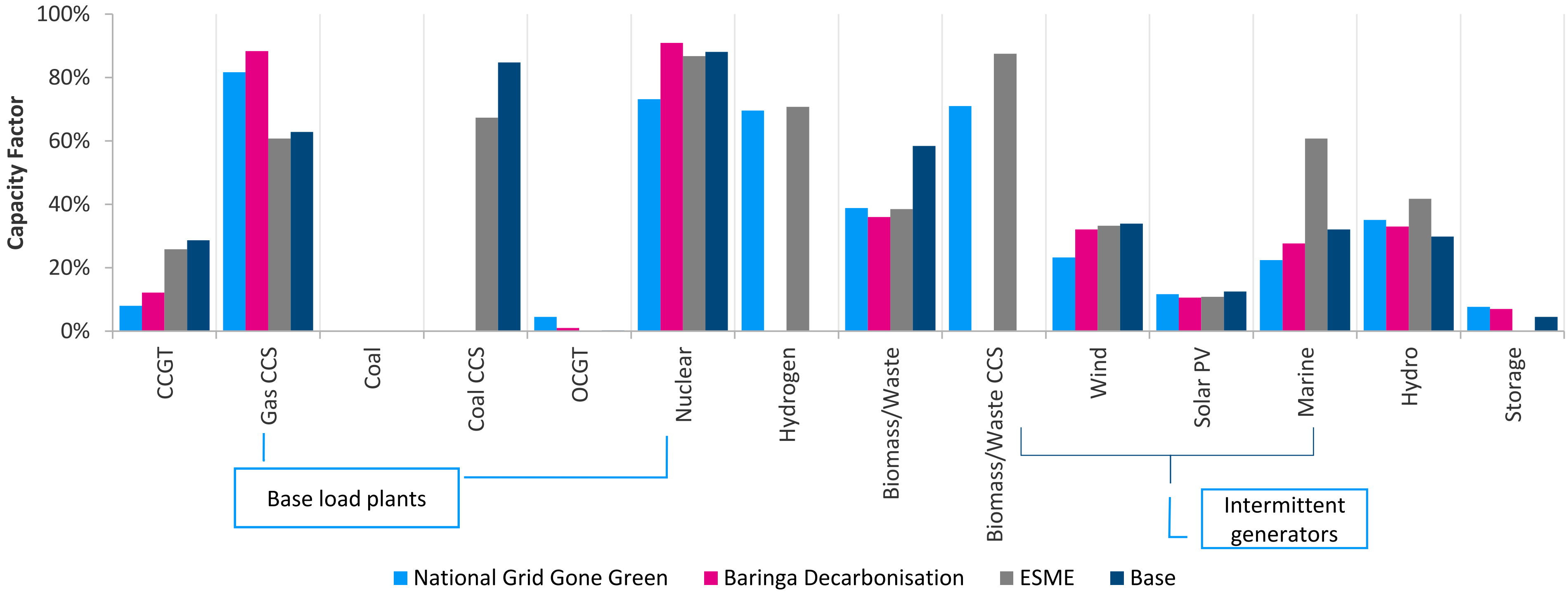
- In all scenarios, Nuclear and Gas CCS operate as baseload units with load factors over 60%
- CCGT operate as mid-merit plants with load factors in the range of 15%-45%. In ESME CCGT load factors are the highest because the carbon intensity target for 2030 is the highest of the four scenarios and there is lower carbon costs. By contrast National Grid's Gone Green scenario has a reduced role for gas (CCGT and CCS) given that this scenario has already achieved an emissions intensity well below the others by 2030 (~40gCO2/kWh versus 90-100gCO2/kWh)
- In all scenarios, OCGTs and storage units operate at low load factors as peaking units



Scenario comparisons and conclusions: Generation in 2040

Generation capacity factors in 2040

- Lower carbon intensity target increases carbon costs for generators and impacts negatively CCGT load factors. CCGTs are gradually pushed out of merit to become peaking plants. In the Base Case, CCGT load factors increase but it has to be stressed out that total CCGT generation decreases substantially due to several old CCGT retirements
- CCS and nuclear remain the main baseload units in all scenarios, the slightly lower nuclear load factor in Gone Green is assumed to be due to the focus on SMR (Small Modular Reactors) with lower availability factors than larger units. OCGT's and storage units continue to operate during times of high system stress and prices. Wind load factors reflect the majority of capacity coming from onshore wind, with lower availability than offshore wind.



Understanding differences between other scenarios

Challenging in some cases due to limited data availability of underlying assumptions

Baringa and National Grid

- Baringa and National Grid's scenarios are fairly similar to each other. The greatest similarities can be found between Baringa Decarbonisation and National Grid Gone Green on the one hand and Baringa Reference and National Grid Slow Progression on the other. However, as mentioned in an earlier slide National Grid's Gone Green scenario achieves a significantly lower carbon intensity in 2030 compared to other, apparently similar, scenarios.
- Baringa focuses on private plant economic viability while National Grid checks the capacity assumptions by having feedback sessions with a range of stakeholders from across the energy industry, Government, academia
- Both Baringa and National Grid scenarios focus on GB and take into account imports/exports in contrast to CCC and ESME that do not model import/export flows

ESME compared to other scenarios

- ESME capacity mix has nearly no new CCGT build. One reason for that is that gas prices are higher in ESME than any other scenario. However, the deployment of Gas CCS in the ESME model shows the lack of new CCGT may be due to carbon emissions targets and more limited representation of within day/year operational requirements due to its more limited timeslicing (i.e. 5 diurnal timeslices rather than hourly dispatch as ESME represents the whole energy system rather than just electricity)
- ESME projects a much higher nuclear build than the other scenarios, which is likely driven by two main reasons:
  - Carbon emission targets
  - No construction risk factored in the capex which in a market-driven scenario would be included by a higher (technology specific) WACC (Weighted Average Cost of Capital)assumption. Within ESME all technologies have a technology neutral 8% WACC.
- ESME has much lower renewables build in the first 20 years, as it does not represent existing subsidies explicitly and the high availability of nuclear. However, we observe very large wind deployment towards the last 10 years due to the nuclear max quantity achieved which only allows CCS and renewables as key power decarbonisation technologies.

Differences between the Base Case and other scenarios

More limited differences in the 2030 timeframe, but more significant differences by 2050

Base Case comparison with other scenarios

- In the nearer term to 2030 the Base Case model and sensitivities are fairly similar to the range of other published scenarios targeting a ~90-100gCO2/kWh intensity target around this point, which is broadly to be expected given the limited time window to undertake substantial change and momentum effects from existing policy and already committed new build.
- Baringa Reference Case is our main view of where the GB power market is headed. The major differences between this study's Base Case and the Reference Case are:
  - The Reference Case has more conservative assumptions for heat and transport electrification and thus demand is lower
  - The Reference Case has assumed that government will continue with renewable subsidies in the 20s while in Base Case there are no subsidies post 2022 and therefore has lower wind and solar deployment in a cost-optimised world
  - The Base Case model favours high risk immature technologies such as nuclear, hydrogen and batteries for generation and satisfying flexibility requirements, given the assumption of a technology neutral WACC. However, for those technologies to achieve lower costs there will be need for policy support in the early stages of their development.

ESME and Base Case

- ESME and the Base Case both provide a least-cost optimal view of how CO2 targets should be met to 2050. The former provides a whole system view with a more limited representation of the power sector within this, whilst this study has focused on a detailed power sector view at the expense of the wider system (but uses boundary conditions informed by ESME in many cases)
- The Base Case model projects higher CCGT and other flexible capacity compared to the ESME (and CCC) scenarios because PLEXOS's sampled chronology (with hourly dispatch across sampled days) provides a better representation of operational constraints such as ramp rates. The Base Case model has a higher storage capacity build than ESME which also facilitates renewables penetration. There are two reasons for this:
  - Storage provides energy market benefits which may not be modelled in other scenarios
  - WACC for this study is 8% (based on the ESME technology neutral assumption) compared to 15% in Baringa scenarios which strongly impacts merchant energy market battery
- By 2050, ESME also tends to build more nuclear and CCS (including biomass CCS) along with hydrogen turbines to generate net negative emissions from the power sector as a choice (as its CO2 target is economy wide) whereas the base case is targeting a net zero intensity. I.e. this implies it is highly cost-effective to use the power sector as a means to directly and indirectly decarbonise the wider system.

Key messages for policy makers

Policy needs to adapt to recognise evolving roles of existing and new technologies

Pathway for power sector CO2 targets

- The analysis shows that the pathway for any implied power sector CO2 intensity target is an important driver of consumer costs. Targeting a <100gCO2/kWh (90 in this study) target in 2030 appears expensive given the high CO2 price needed to achieve this. A 'marginally' more relaxed target (e.g. pushing this back to 2035) would likely help bring down costs as it allows existing gas assets - which are due to retire around this point - to be run harder until the end of their technical lives, and for new baseload low carbon technology costs to come down further before significant expansion. Testing this against the Base Case led to a reduction in electricity system costs of ~£6bn over the pathway to 2050 on an undiscounted basis (or ~£3bn at the Treasury Social Discount Rate of 3.5%).
- In general there are only relatively small differences in the generation mixes across scenarios (both within this study and other published) that achieve a ~90-100gCO2/kWh intensity by 2030, however, the differences are more significant post-2030 given the challenges associated with meeting a near zero intensity target. Towards the end of pathway the push to reduce CO2 intensity below ~20-30gCO2/kWh to zero starts to drive up costs significantly, given the need for biomass-CCS or nuclear over fossil CCS and the need to remove remaining sources of fossil-based flexible plant from the system. However, comparison with ESME model scenarios indicate that a net negative CO2 intensity in the power sector is likely to be a cost-effective way of helping to directly and indirectly decarbonise the wider energy system.

Low carbon baseload technology support

- This study, along with other published scenarios, highlights the need for a significant low carbon baseload capacity by 2050 (accounting for well over half of all generation) to achieve near zero carbon intensity, as well as the costs associated with trying to achieve this predominantly via a wind/solar focused route (noting that significant deployment of intermittent renewables is still seen across all scenarios).
- Under base case assumptions nuclear is the preferred baseload technology, but the range of sensitivities shows that the economics can still swing in favour of CCS. Given long term uncertainties over the cost of these technologies and fossil fuel prices it is important to consider how policy incentives (such as the Contracts for Difference (CfD) mechanism) can be recast to directly support *technology-neutral* procurement of low carbon baseload. Over the technology-neutrality can be extended in a broader sense – via mechanisms such as carbon price - to a wider range of abatement options across the energy system.

Key messages for policy makers (2)

Policy needs to adapt to recognise evolving roles of existing and new technologies

Peaking / flexible plant and the role of gas

- At a high-level we distinguish been plant providing purely peaking backup capacity – i.e. plant that is expected to only run for a few hours a year to meet high demand periods. For these periods high carbon plant such as OCGT may still be a viable option as their limited running hours provides negligible contribution to emissions. By contrast, plant providing broader system flexibility are expected to run for more hours across the year, in particular helping to accommodate swings in intermittent wind and solar, but the emissions implications of these plant are more significant.
- Significant new CCGT build (4-8GW+) comes online in the early/mid 2020s across the range of our scenarios, but with limited additional build from the late 2020s onwards. The new CCGT functions as mid-merit plant providing both flexibility and peaking capacity, but their load factors decline significantly through the 2030s as the CO2 constraint tightens. Some OCGT continues to be built into the 2030s as a cheap form of peaking backup capacity rather than a more general source of flexibility, but there is a broader shift to lower carbon forms of flexibility such as storage to help manage the system across the year. As the system develops it is important that the Capacity Market / CfD mechanisms evolve accordingly; recognising the declining role of CCGTs and sufficiently incentivising storage (dedicated or 'behind the meter'), which becomes implicitly low carbon as the electricity system decarbonises, or low carbon mid-merit plants such as hydrogen turbines which can provide both peaking capacity and broader flexibility, but are not covered adequately by current policy. OCGT provide the majority of new peaking units in the first 2/3 of the pathway, with limited energy market operation. However, as the CO2 constraint tightens and more intermittent renewables are deployed electricity storage becomes the preferred option as it helps balance the wider system as well as provide peaking capacity.
- It should also be noted that the significant anticipated expansion of electric vehicles and electric heating (coupled with hot water storage) over the longer term will provide a substantial pool of flexibility that could be used to manage the electricity system (and without necessarily requiring the use of vehicle-to-grid). This can be achieved by making small changes to charging patterns across a very large diversified pool of consumers, providing flexibility without materially impacting the consumers underlying travel patterns or heating requirements. Where a 3rd party (e.g. aggregator, system operator, etc) can directly control this flexibility in response to real-time changes on the wider system this may prove to be significantly cheaper than building dedicated flexibility options such as large scale batteries. Policy makers should work to ensure that remaining technical, commercial and regulatory barriers to exploiting this 'consumer-led' flexibility are removed.

Managing uncertainty in the future costs of the electricity system

- The sensitivity analysis has shown that delaying expansion of new nuclear/CCS and interconnection by ~5-10 years, around the late 2020s, leads to modest increases in electricity costs of <1% on average per year, whilst accelerating the deployment of renewables raises costs by ~7-8% (assuming that learning rates are not impacted materially in the near term e.g. due to supply chain constraints). Given the rapid evolution of costs at the global level it is important to review this evidence base systematically, while support schemes are differentiated by technology, to appropriately target future rounds of support.
- Future changes in fuel prices and demand (particularly peak) can lead to significant changes in electricity system costs; reductions of over 20% in annual costs in the 'low' sensitivities explored. Demand and supply side policy need to better coordinated to ensure that where demand-side measures (such as efficiency) are more cost-effective they are prioritised over expanded supply e.g. through adjusted targets in the Capacity Market. For fuel prices, as mentioned previously, mechanisms such as CfDs need to evolve to consider how future commodity price risk can be built into a technology neutral support mechanism for plant such as CCS, rather than being fully transferred to the consumer by default via fuel price indexation.

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PLEXOS Engine

Baringa

A commercial tool that optimises the power sector in the long-term (capacity mix) and short-term (generation dispatch)

- We run our models on commercially available power market modelling software (Plexos). It is used globally by power market participants, regulators, and analysts for modelling power systems of all characteristics
- PLEXOS allows the detailed modelling of electrical systems: It receives inputs such as existing and future generators with their characteristics, fuel prices and hourly demand. It optimises the generator dispatch in a way that the total costs are minimised. Typical outputs are generation dispatch and hourly power prices
- The engine can optimise several electrical nodes with different supply and demand balance that can be connected with lines providing different prices for each. It also allows complex constraints to be modelled
- PLEXOS can also optimise capacity, transmission line and storage deployment decisions (we have not included transmission build decisions in this study)

Baringa scenario inputs

Assumptions

- Fuel & carbon prices
- Demand (growth & shape)
- Plant build
- Plant retirement

Baringa generator dataset

Detailed plant-level database

- Installed capacity
- Efficiencies
- Operating costs
- Operational constraints

PLEXOS

Detailed generation dispatch model

- Hourly generation dispatch
- Model interconnected markets
- Optimisation of operational constraints such as start costs, ramp rates and heat rate curves
- Hourly wind and solar profiles based on historic data
- Hydro and pumped storage
- Scheduling of maintenance and unplanned outages

Outputs

- Power prices
- Generation schedules
- Emissions
- Dispatch costs
- Wholesale revenues and gross margins
- Imports & exports

PLEXOS Integrated Simulation Phases

Provide a tractable way to analyse the power sector from the near term (e.g. hourly) to the long-term (e.g. decadal). The four phases can be run in sequence with one phase informing the next

PLEXOS Integrated Simulation Phases

Baringa

Each of the phases optimises a different property of the power system and feeds to the next

Planning and optimisation stages

LT Plan (Long-Term)	•The LT stage optimises the system in the long-term (across several years) •It requires inputs related to the capital and fixed costs of assets as well as fuel prices and demand •It provides a solution for capacity, line and storage build and retirement decisions by minimising the investment and production cost for the horizon while respecting constraints	What is the optimal capacity mix?
PASA (Projected Assessment of System Adequacy)	•The PASA stage focuses on the balance of supply and demand in the medium term •It requires inputs related to the maintenance and forced outage rates of the available plants •It can model planned and random outages of generation plants and transmission lines, and its severity	What is the optimal dispatch of a given capacity mix?
MT Schedule (Medium-Term)	•The MT Schedule is used to give fast results for medium to long-term studies •It handles all user-defined constraints including those that span several weeks, months, or years •Each constraint is optimised over its original timeframe and the MT Schedule to ST Schedule Bridge algorithm converts the solution obtained, e.g. a storage trajectory, to targets or allocations for use in the shorter step of ST Schedule	
ST Schedule (Short-Term)	•ST modelling provides the full chronology, tracking the status of individual generator units from one period to the next •It receives as inputs fuel prices, half-hourly/hourly demand, detailed plant/line characteristics and the maintenance/storage schedules from MT •The ST solution provides half-hourly/hourly dispatch figures, prices, unserved energy, revenues of plants etc.	

PLEXOS Long-Term Plan

Baringa

Inputs and settings in the LT Plan

Inputs used in both ST and LT
- Hourly demand profile
- Existing plants
- New plants (committed)
- Fuel and carbon prices
- Import/export prices

Inputs used only in LT
- New plants costs
- New plants characteristics
- New plants build constraints
- Minimum capacity reserve or maximum LOLP
- Carbon target

LT settings
- Planning horizon
- Chronology

LT outputs
- Units build/retired by type and year
- Build, retirement and fixed costs
- Indicative variable costs
- Capacity reserve by region and year
- Indicative capacity factors

PLEXOS Long-Term Plan Stage

Minimisation of the long-term costs of electricity production

- The LT Plan stage takes decisions to minimise the NPV of the total costs in the system across the planning horizon
- There are four long-term cost components and each of these costs have trade-offs:
  - An increase of the build costs by building an additional high efficient plant will lead to a decrease of the energy costs due to less fuel spent
  - An increase of the build costs by building a peaking plant can lead to a decrease of the energy costs due to lower unmet energy
  - An increase of retirement costs (e.g. retiring an old and expensive to maintain plant) will decrease the fixed operating costs

	one-off		annual	interval
Total Costs =	**Build Costs** +	**Retirement Costs** +	**Fixed Operating Costs** +	**Energy Costs**
LT minimises the total costs of the system of the horizon taking into account the constraints and trade-offs	One-off cost to build new • Capacity • Lines* • Storage	One-off cost to retire existing or new • Capacity • Lines* • Storage	Annual fixed costs for existing and new assets that are paid since the asset is built until it is retired	These are the short-term costs of the system: • Fuel • Carbon • Variable operating • Start/stops • Unmet Energy

*Not included in this analysis

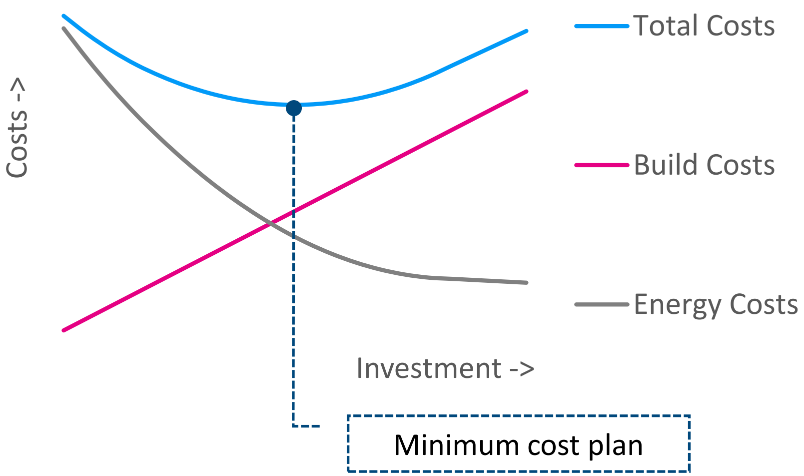
PLEXOS Long-Term Plan Stage

Trade-offs between the cost components

- There are four long-term cost components and each of these costs have trade-offs, for example:
  - An increase of the build costs by building a new high-efficiency plant can lead to a decrease of the energy costs due to less fuel spent
  - Also an increase of the build costs for a peaking plant can lead to a decrease of the energy costs due to lower unserved energy
  - An increase of retirement costs (e.g. retiring an old and expensive to maintain plant) will decrease the fixed operating costs and may increase the energy costs slightly if the old plant had positive load factor

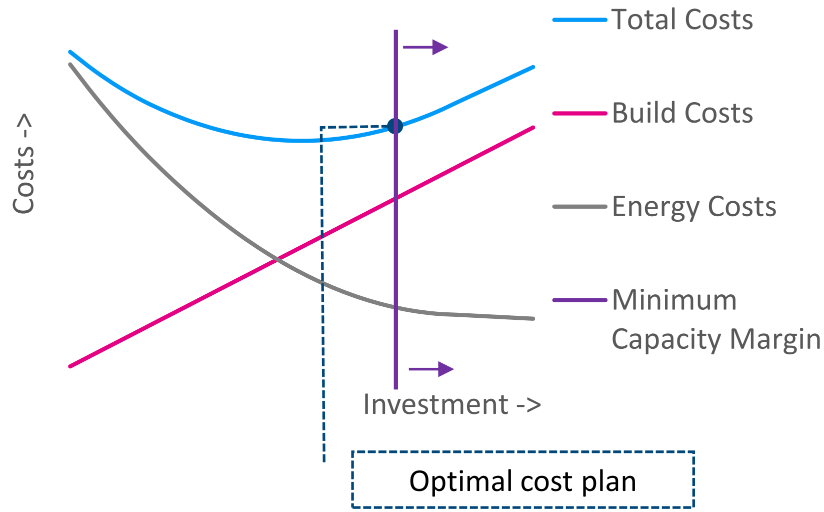
Impact of new asset build - unconstrained

- Retirement option is neglected and fixed costs of new plants are included in the build costs
- Energy costs decrease as more new assets are build. However, the gains are diminishing due to cannibalisation effect



Impact of new asset build - constrained

- If we suppose that the regulator requires a minimum capacity margin, the optimal solution may change: More capacity may be added in the system in order to satisfy the margin requirement
- The increase of build may come from cheaper peaking plants with high energy costs thus resulting in lower gains in energy costs



PLEXOS Long-Term Plan stage

LT Plan decisions

Capacity/battery build

- The capital costs of the new unit are annualised:

$$AnnualisedCapex = BuildCost \cdot Capacity \cdot \left(\frac{WACC}{1-(1+WACC)^{EconomicLife}}\right)$$

- The annualised build costs added to the annual fixed costs affects LT Plan's minimisation formula:

$$AnnualisedCost = AnnualisedCapex + FO\&M\ Charge$$

- Constraints can be applied to the specific unit such as maximum number of units built (over full period) and max number of units built per year
- These inputs can be dynamic and change through the planning horizon

Property	Value	Units
Max Capacity	200	MW
FO&M Charge	20	GBP/kW/year
Firm Capacity	190	MW
Build Cost	2000	GBP/kW
Technical Life	40	years
WACC	10	%
Economic Life	25	years
Max Units Built	10	-
Max Units Built in Year	2	-

- These units require all the other property inputs such as heat rates, ramp rates, start/stop costs etc.

Retirement*

- The retirement costs of a unit are not annualised
- A unit automatically retires after the end of its technical lifetime. Alternatively, a unit may retire earlier if this option is set on and If the fixed costs are higher than the sum of
  - the extra costs of early retirement (in NPV terms)
  - the contribution of the old plant into reducing energy costs
  - The avoided costs of building more firm capacity for ensuring security of supply
- Constraints can be applied to the specific unit and the inputs below can be dynamic and change through the planning horizon:

Property	Value	Units
Max Capacity	200	MW
FO&M Charge	20	GBP/kW/year
Firm Capacity	190	MW
Retirement Cost	80000000	GBP
Technical Life	40	years
Economic Life	25	years
Max Units Retired	10	-
Max Units Retired in Year	2	-

* Retirement decisions are an exogenous input for this model

PLEXOS Long-Term Plan stage

There are a number of approaches to represent capacity adequacy and system security in PLEXOS, for this study we have focused on use of a minimum capacity reserve

Cost-driven

- The system security can be achieved by including a cost of unserved energy: If part of the load is not met, then the energy costs increase
- Therefore, investment in new capacity can be incentivised because the energy costs can reduce due to the increased available capacity. If the NPV of the reduction in unserved energy costs is higher than the increase in production costs and capital costs then the new asset is being built
- The higher the cost of unserved energy, the higher the incentive to build more capacity

Disadvantages of cost-driven

- However, investment in new capacity may not be justified economically if the unserved energy occurs only in few hours within the year.
- In addition, the LT Plan uses reduced chronology and is usually run in deterministic mode. Therefore, the full risk of unserved energy may not be revealed by the simulation

Reliability driven

- The LT Plan allows for constraints on minimum reliability or capacity requirements to ensure the system security
- Firm Capacity is the capacity that is assumed to be the capacity available in the peak time or times of high system stress. Firm can be set during the LT Plan set-up
- Min Capacity Reserve: It can be used to set an absolute level of minimum capacity reserve:

$$\sum_G FirmCapacity + \sum_I FirmCapacity \geq MinCapacityReserve \ *$$

- Min Capacity Reserve Margin: It can be used to set a relative level of minimum capacity reserve:

$$\frac{\sum_{G\,\&\,I} FirmCapacity - PeakDemand}{PeakDemand} \geq MinCapResMargin$$

- Max LOLP (Loss of load probability): It can be used to set a maximum level of loss of load probability
- Max EDNS (Expected demand not served): It can be used to set a maximum level of expected unserved demand
- These capacity or reliability requirements can be changed throughout the planning horizon

- ***In this model, we have used reliability driven approach and specifically Minimum Capacity Reserve because it best reflect the requirements that determine the current Capacity Market auctions***

*G: Generators, I: Interconnectors

PLEXOS Long-Term Plan Stage

LT Plan Chronology – for this study we have used the sampled option as this reflects the hourly dispatch conditions (and e.g. associated flexibility requirements) across the sampled periods

- The LT Plan takes into account all four cost components to derive an optimal solution. The build/retirement costs are one-off costs and the fixed operating costs are paid on annual basis. The energy costs however are more complicated because they are paid every interval
- The ST Schedule receives the capacity mix as input and optimises the energy costs on an interval basis (Full chronology)
- On the other hand, LT Plan (like MT) uses reduced chronology due to the increased complexity of the problem
- There are three available chronologies for the LT Plan which differ in methodology, running times and accuracy
- The LT solution can be integer (2 units built) or linear (e.g. 1.85 units built)
- The horizon can be further broken down in steps to produce a less accurate solution if there is lack of computational resource

Partial chronology

- A load duration curve is formed for every day/week/month/year
- Every curve has a number of blocks per period to represent the variability of generation and demand within the period (e.g. 6 or 12 blocks)
- Partial chronology is the only one that is not chronological (loss of shape)
- Unit commitment is not modelled
- Storage units are not balanced within the duration curves but only between different duration curves
- It is the least accurate but faster to run
- Particularly inaccurate with systems with high renewables penetration

Fitted chronology

- One curve is formed for every day/week/month/year
- Every curve has a number of blocks per period to represent the variability of generation and demand within the period (e.g. 6 or 12 blocks)
- Fitted chronology retains the original ordering of intervals but reduces their number by combining them
- Accuracy is lost in modelling ramp rates and starts/stops

Sampled chronology

- The Sampled chronology preserves full periods of time (e.g. day/week/month)
- The number of sample days/weeks/months modelled is lower than the in the full chronology (365/52/12 respectively)
- More accurate but slower than the other two chronologies
- The choice of samples by PLEXOS may distort the average load factors for wind units if their profiles are provided in an hourly basis

- ***For this model, we have used Sampled methodology because it best simulates the flexibility requirements in electricity markets***

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Other scenarios

National Grid Future Energy Scenarios (FES)

- National Grid has four main "Future Energy Scenarios" (FES) for GB
- These scenarios are result of cycles of scenario modelling and stakeholder feedback throughout the year
- National Grid offers no probability for these four scenarios and does not state one of these as the reference scenario
- These scenarios were last updated in July 2016
- National Grid scenarios are limited geographically to GB and they do not include Northern Ireland
- Interconnector flows are modelled
- Source: http://fes.nationalgrid.com/fes-document/

Prosperity: + More money available / – Less money available

Consumer Power

Consumer Power is a market-driven world, with limited government intervention. High levels of prosperity allow for high investment and innovation. New technologies are prevalent and focus on the desires of consumers over and above reducing greenhouse gas emissions.

Gone Green

Gone Green is a world where policy interventions and innovation are both ambitious and effective in reducing greenhouse gas emissions. The focus on long-term environmental goals, high levels of prosperity and advanced European harmonisation ensure that the 2050 carbon reduction target is achieved.

No Progression

No Progression is a world where business as usual activities prevail. Society is focused on the short term, concentrating on affordability above green ambition. Traditional sources of gas and electricity continue to dominate, with little innovation altering how energy is used.

Slow Progression

Slow Progression is a world where economic conditions limit society's ability to transition as quickly as desired to a renewable, low carbon world. Choices for residential consumers and businesses are restricted, yet a range of new technologies and policies develop. This results in some progress towards decarbonisation but at a slower pace than society would like.

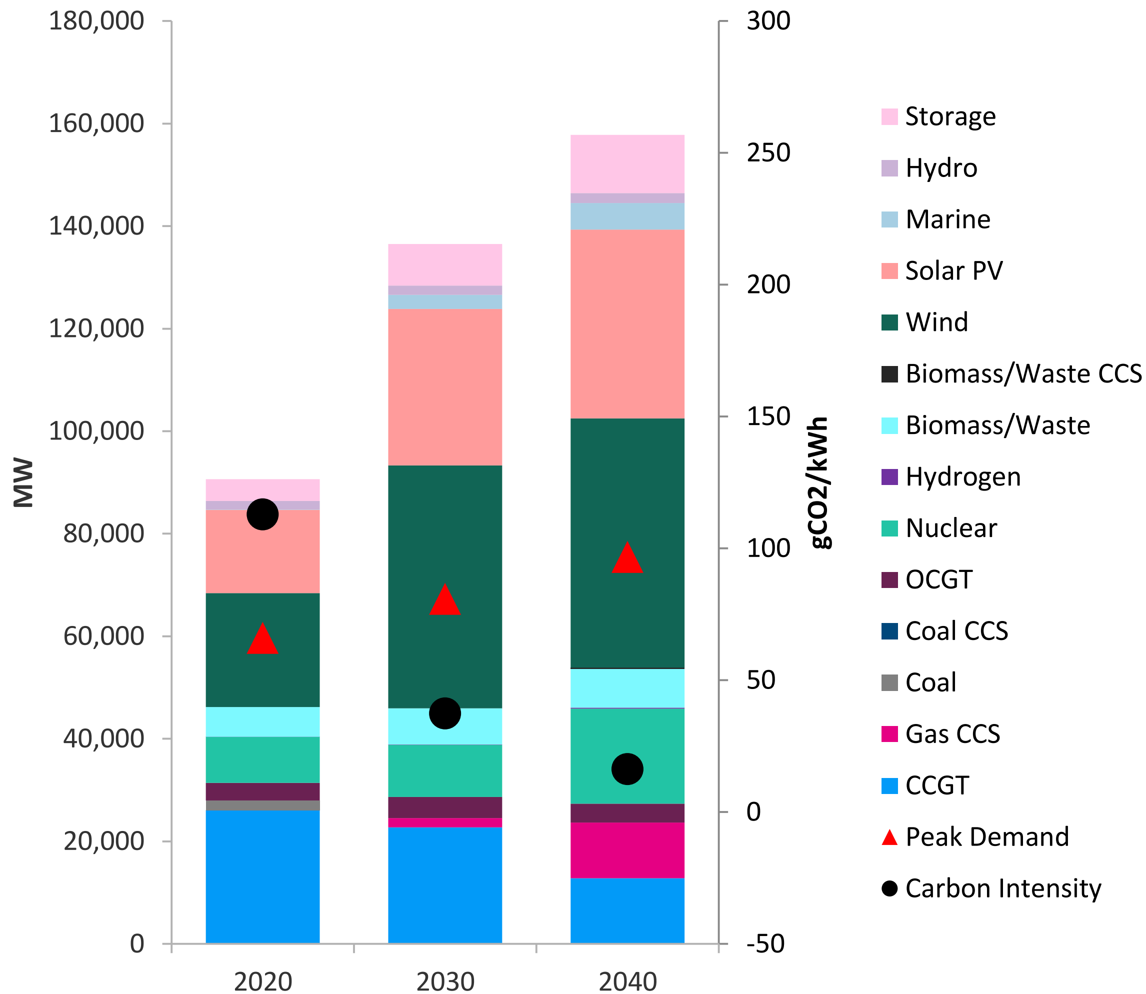
Green ambition: – Less focus / + More focus

Source of table: National Grid Future Energy Scenarios (FES)

Other scenarios

National Grid Gone Green Scenario

- National Grid has four scenarios for the GB energy sector
- “Gone Green” is the scenario the government energy policy delivers a very large reduction in carbon emissions and targets nearly net zero carbon emissions from the power sector for 2050
- “Gone Green” and “Consumer Power” are the National Grid scenarios with the highest interconnection capacity assumption (23GW by 2040). Also Gone Green is the only scenario that assumes positive net exports in the long-term
- Peak demand increases from 60 GW today to 75 GW by 2040
- The demand is driven by economic growth rates and trends in electrification and energy efficiency by 2040:
  - 4.8 million air-source heat pumps
  - 20 TWh reduction in residential heat demand
  - Increase of electrification of heat to over 25%
  - 27% of vehicles are electric
- Regarding the capacity mix, Gone Green assumes high penetration of renewables (over 35 GW of solar and nearly 50 GW of wind by 2040). CCS and nuclear provide 11 and 19 GW of firm capacity while CCGT capacity drops to 12 GW by 2040
- The carbon intensity in the National Grid Gone Green scenario drops to 37g/kWh by 2030 and further to -6g/kWh by 2050* due to biomass and waste CCS technologies deployed post 2040

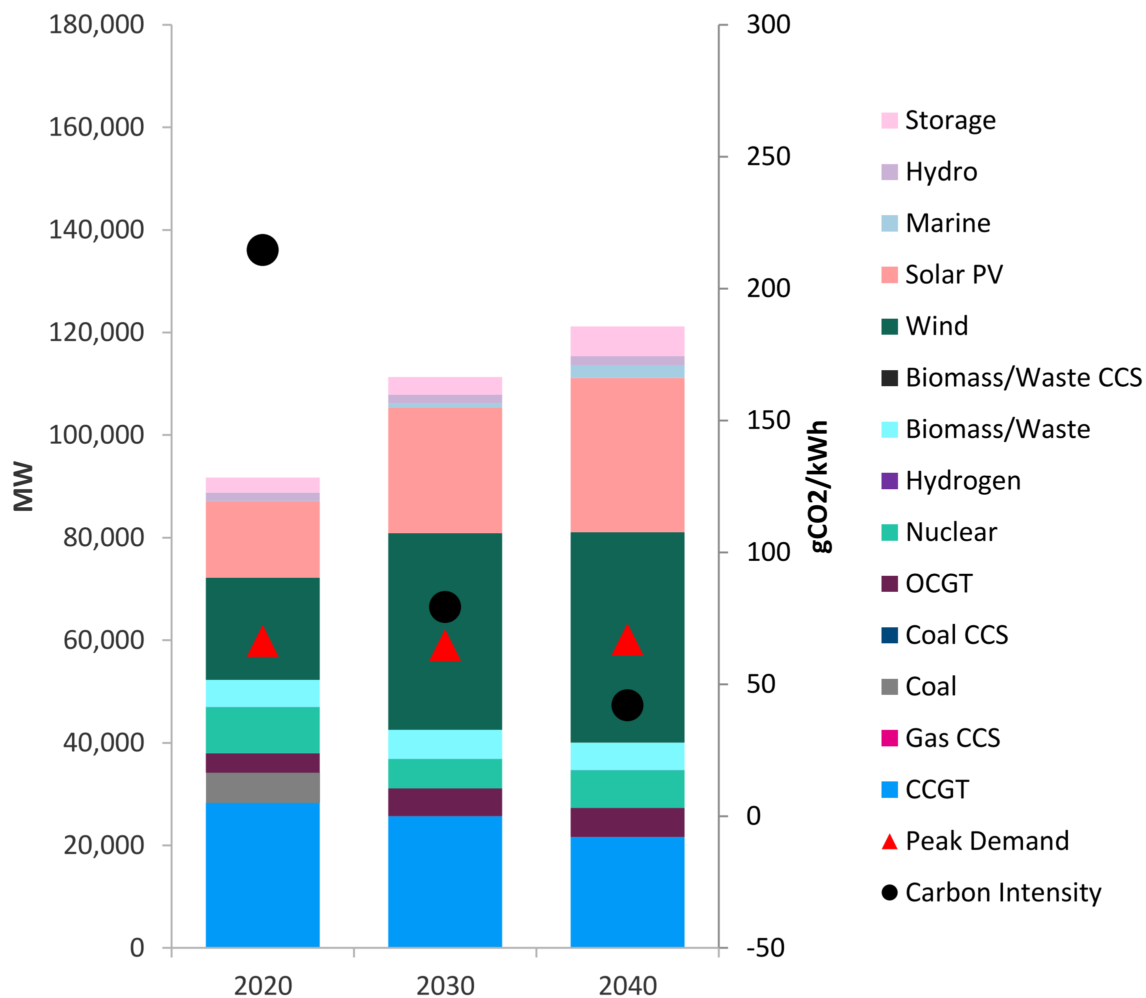


*National Grid provides capacity data only until 2040 but emissions projections until 2050

Other scenarios

National Grid Slow Progression Scenario

- "Slow Progression" has similar long-term carbon targets with "Gone Green" but is much slower in meeting those targets due to economic difficulties
- Slow Progression assumes 16 GW of interconnector capacity by 2040
- This scenario assumes peak demand to stay at current level for the entire horizon
- The annual demand is driven by:
  - 1.1 million air-source heat pumps
  - 22% of cars become electric
- The carbon intensity in the National Grid Slow Progression scenario drops to 79g/kWh by 2030 and further to 4g/kWh by 2050* due to biomass and waste CCS technologies deployed post 2040

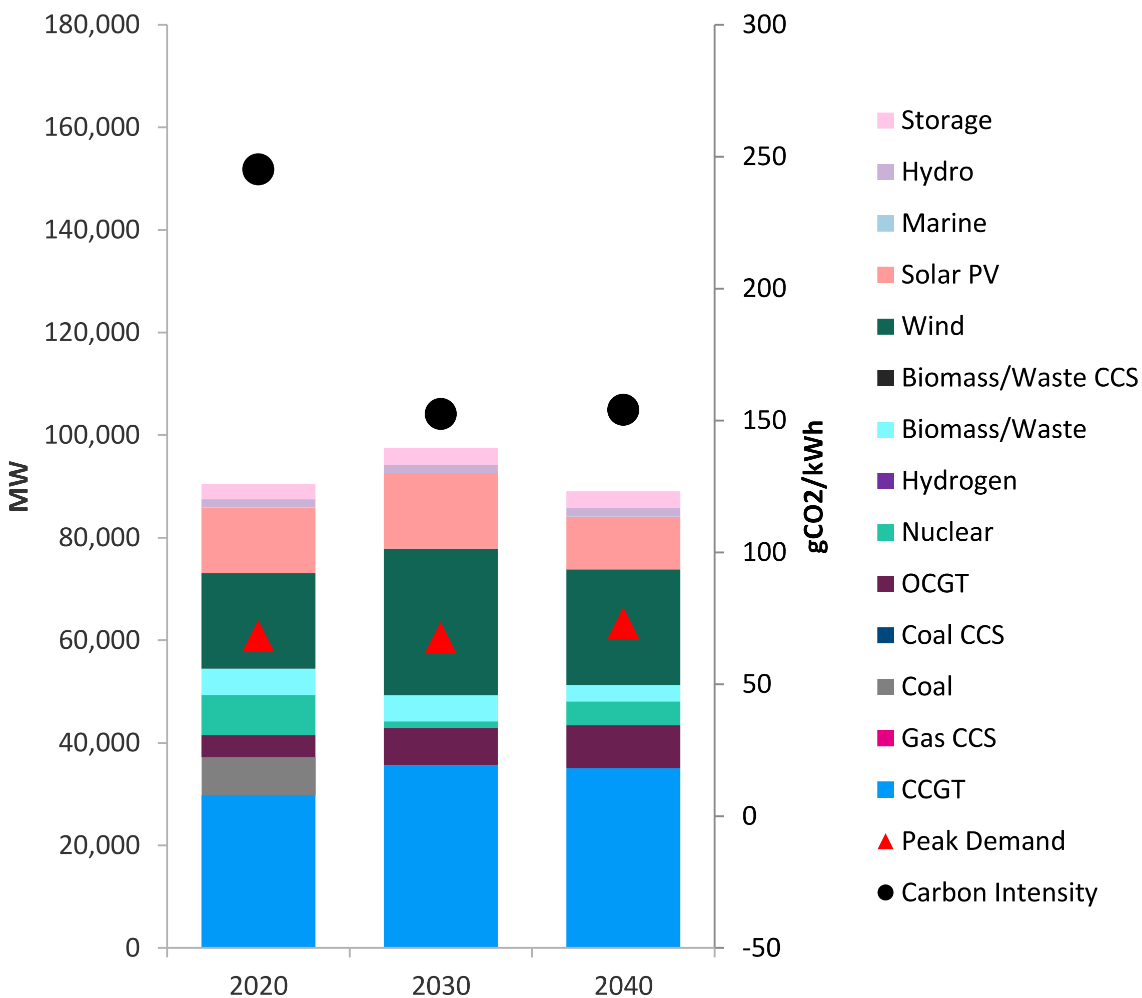


*National Grid provides capacity data only until 2040 but emissions projections until 2050

Other scenarios

National Grid No Progression Scenario

- No Progression is a market-driven scenario with limited government intervention in which economic difficulties result in very low uptake in new technologies
- No progression assumes 13.5 GW interconnection assumption by 2040 which is the lowest assumption from all National Grid scenarios
- This scenario assumes by 2040:
  - 0.9 million air-source heat pumps
  - 11% of vehicles are electric
- In the 20s there is some new wind and CCGT capacity coming online. New nuclear is developed post 2030 (much slower than other scenarios)
- The carbon intensity in the National Grid No Progression scenario drops to 150g/kWh by 203. Post 2030, the carbon intensity stays nearly flat (140g/kWh by 2050)

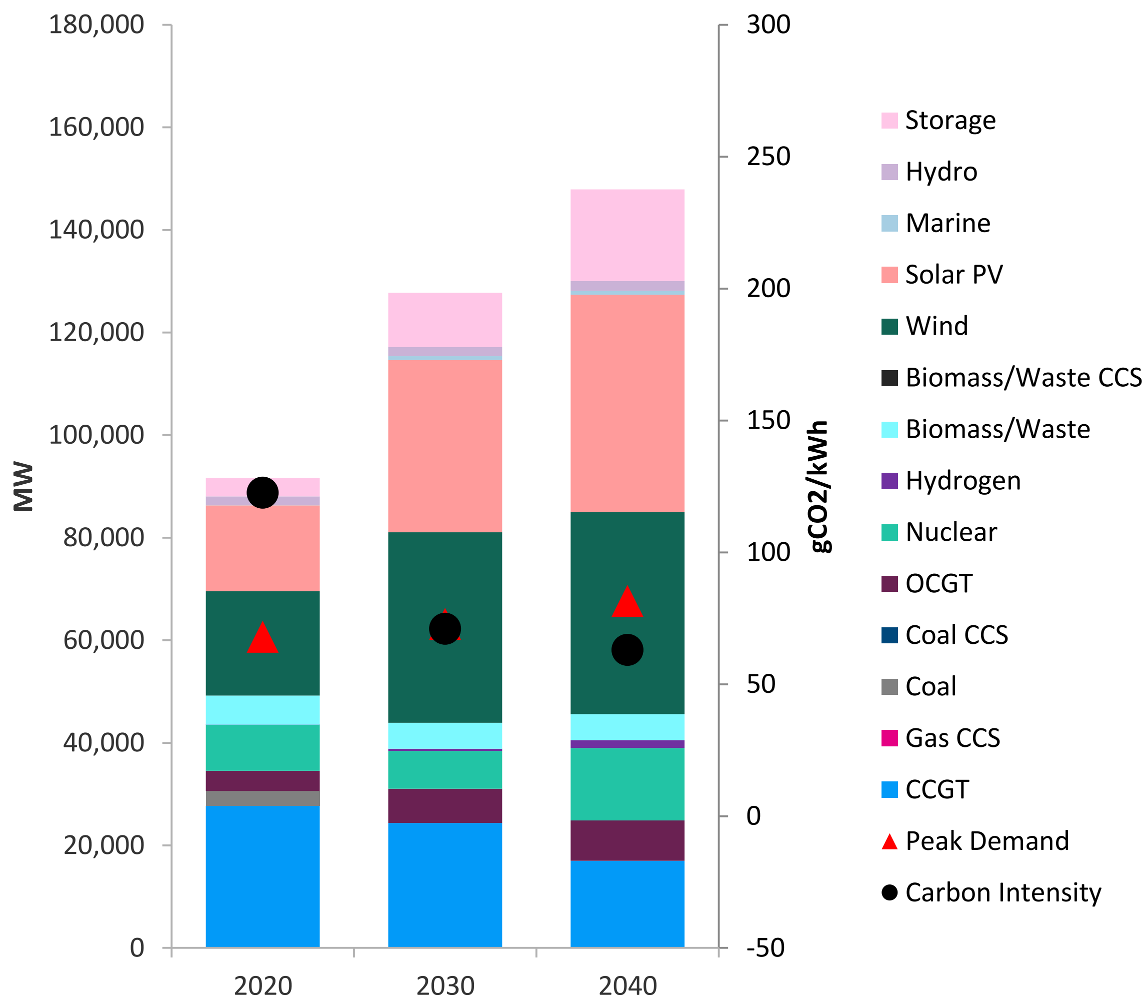


*National Grid provides capacity data only until 2040 but emissions projections until 2050

Other scenarios

National Grid Consumer Power Scenario

- "Consumer Power" is the market-driven scenario from National Grid. There is limited government intervention and as a result the uptake of new low carbon technologies is slow
- "Gone Green" and "Consumer Power" are the National Grid scenarios with the highest interconnection capacity assumption (23GW by 2040)
- This scenario assumes by 2040:
  - 1.1 million air-source heat pumps
  - 22% of vehicles are electric
- In the consumer Power scenario, we can observe that no new CCGT replaces the retired ones. New capacity comes online mainly from wind and solar while. Storage and OCGT are added to the system to balance the higher renewable penetration. In the 30's considerable nuclear capacity is added in the system
- The carbon intensity in the National Grid Consumer Power scenario drops to 71g/kWh by 2030 and further to 55g/kWh by 2050* due to biomass and waste CCS technologies deployed post 2040

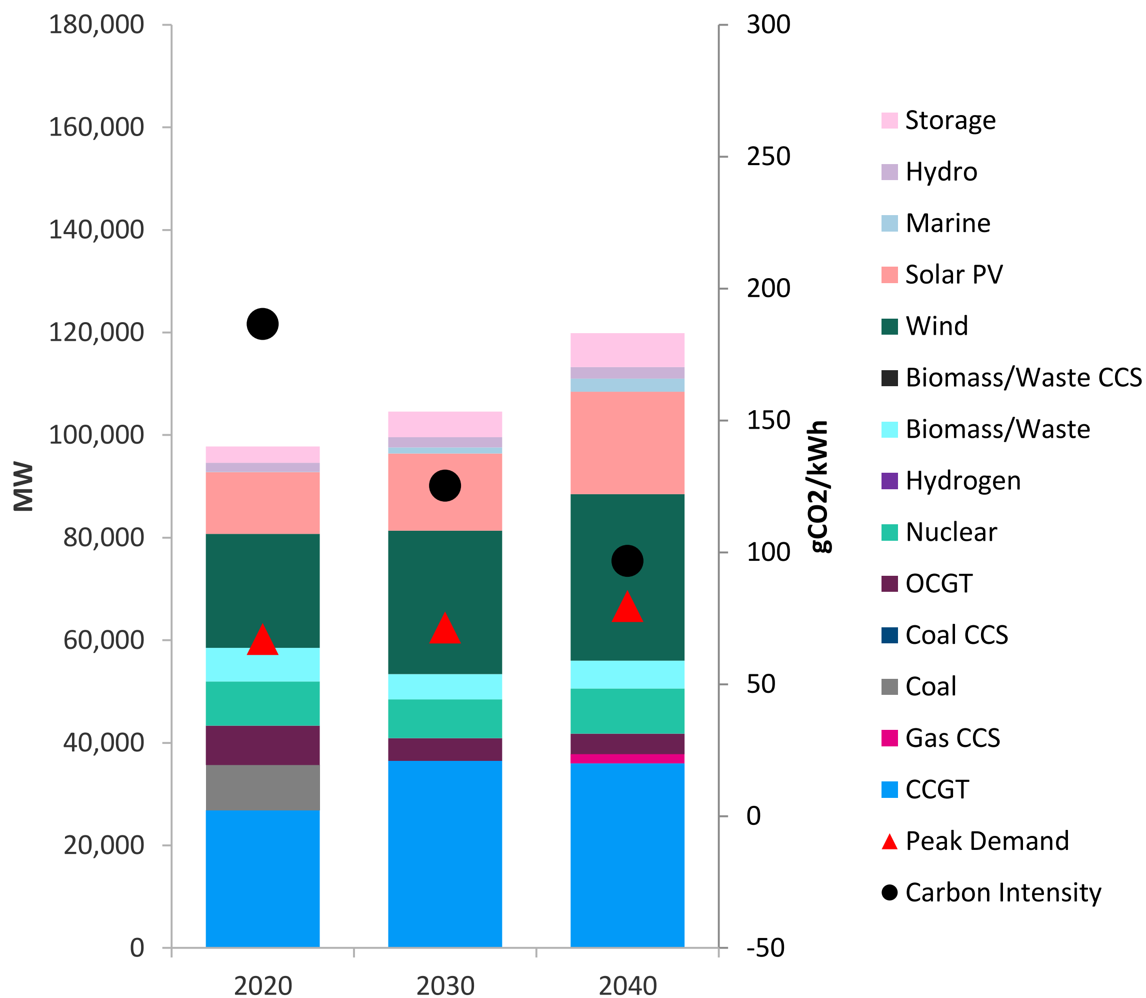


*National Grid provides capacity data only until 2040 but emissions projections until 2050

Other scenarios

Baringa Reference Case

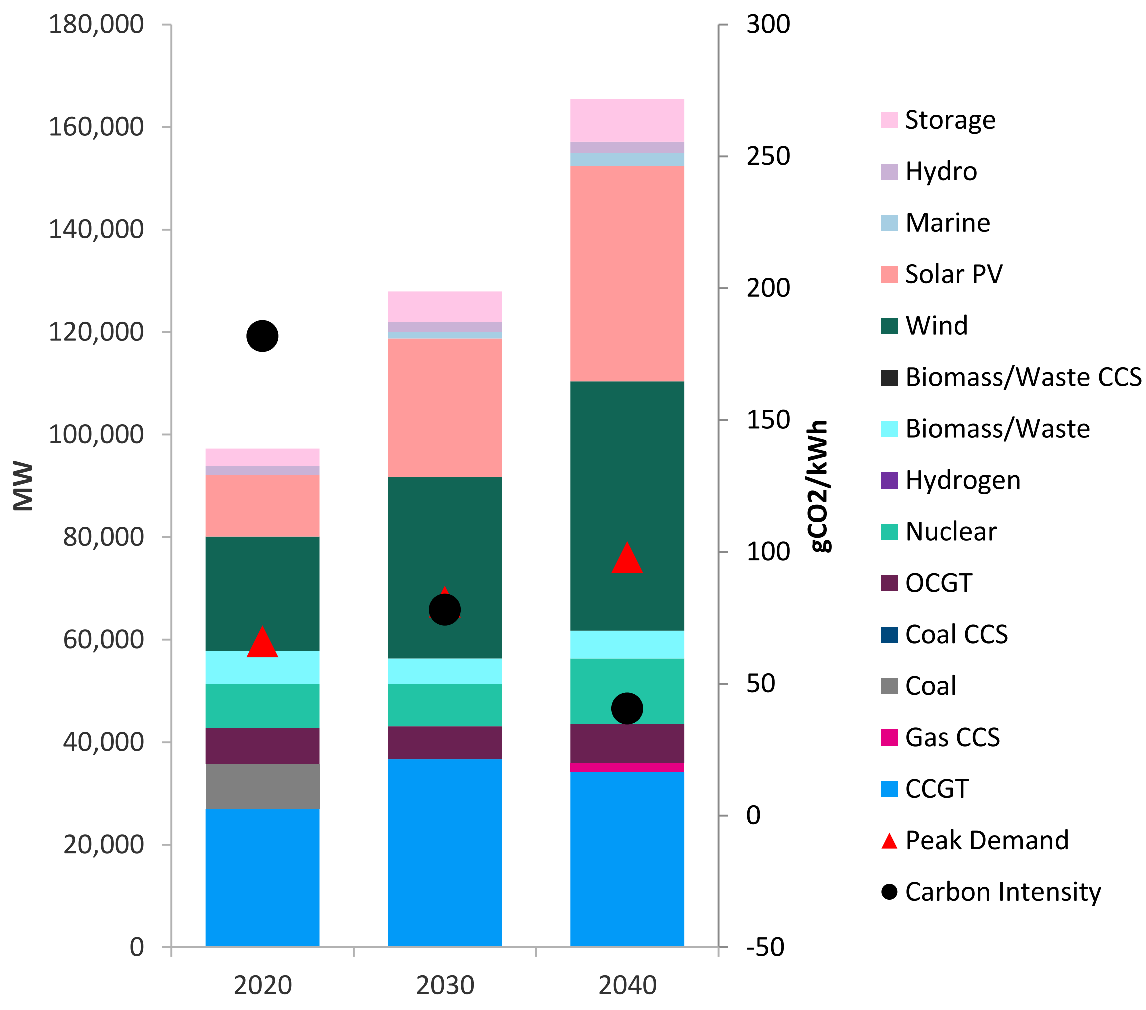
- Baringa simulates the GB power market and makes projections under four scenarios: Reference Case, Downside, High Oil and Decarbonisation
- The Reference Case is Baringa's base case scenario and represents a private sector view of the market: Baringa performs checks on the economic viability of the plants by comparing the projected revenues from the wholesale market, the capacity market and the ancillary services market with the projected plant costs
- All commodity prices are projected to increase in line with the IEA's "New Policies" scenario
- The demand is assumed to increase slightly (0.5% on average) post 2020
- Regarding the capacity mix, CCGT capacity is expected to increase in the 20s to replace the retired coal capacity. The penetration of renewables such as wind and solar are projected to continue their increase as well. In the 30's, we assume some significant nuclear capacity additions and some CCS projects
- The carbon intensity in the Baringa Reference Case drops to 116g/kWh by 2030 and just below 100g/kWh by 2040



Other scenarios

Baringa Decarbonisation Case

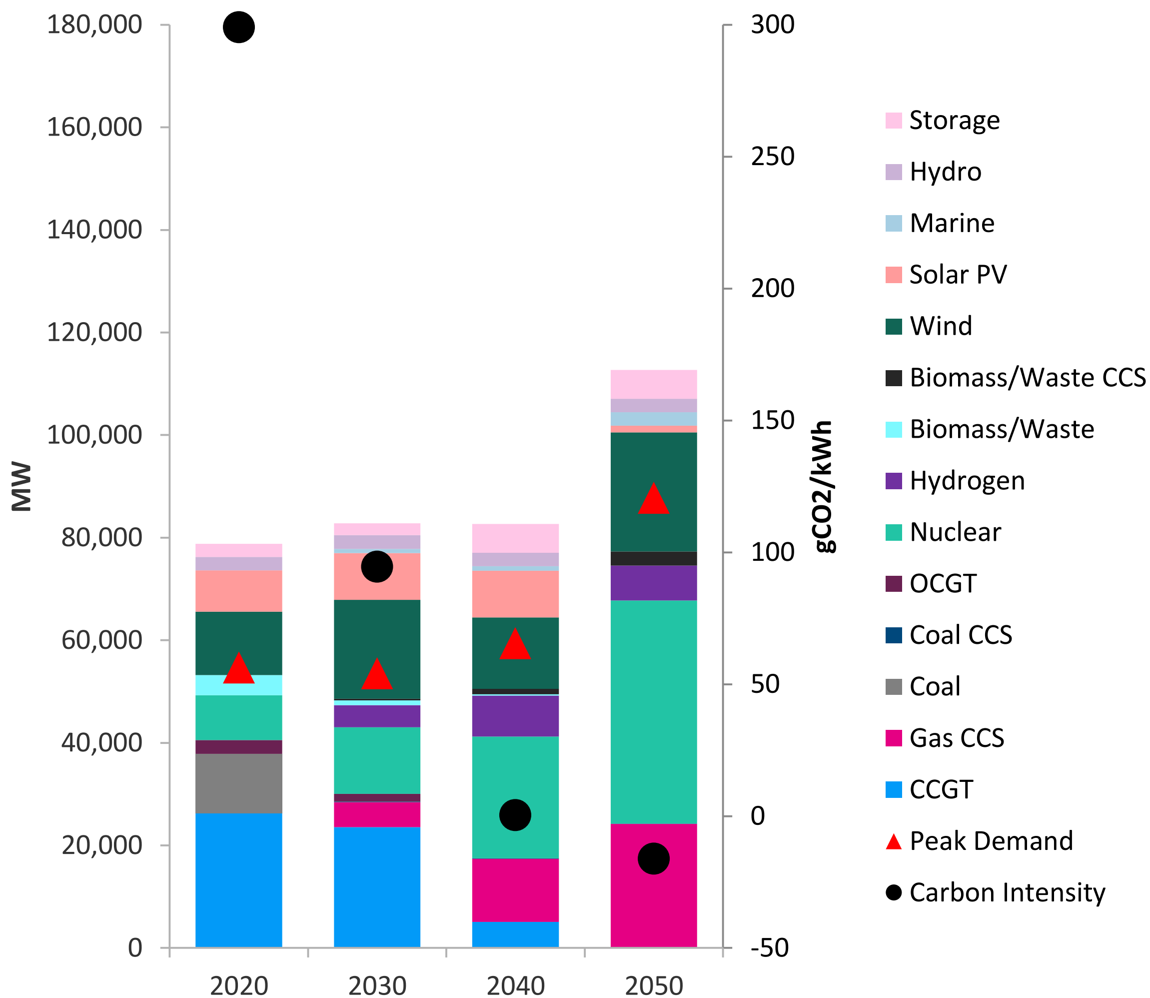
- In the Decarbonisation case, we explore a scenario in which Government is successful in implementing policies which bring forward further investment in low carbon generation (renewables, nuclear and CCS), and hence these targets are met. It explores the impact of deep decarbonisation in the GB power market and in particular the impact on power prices. In this scenario, we target a carbon intensity below 100g/kWh in 2030 and below 50 g/kWh in 2040
- For thermal plant, the commercial viability of existing and new plant is checked as per the Reference Case scenario, for new low carbon plant it is assumed that the Government expands the Levy Control Framework accordingly
- For commodity prices, the Decarbonisation Scenario follows the Reference Case forward curve and then trends to the IEA "450" scenario price
- Interconnection capacity reaches 13 GW by 2040
- The demand is assumed to increase with 1.2% per year post 2020 due to assumptions of high heat & transport electrification
- The Decarbonisation Scenario assumes that nuclear build comes earlier, higher renewables penetration and more OCGT build to meet peak demand when the intermittent capacity has low generation, the trajectory broadly aligns to National Grid's Gone Green scenario
- The carbon intensity in the Baringa Decarbonisation drops to 78g/kWh by 2030 and to about 40g/kWh by 2040



Other scenarios

ETI - Energy System Modelling Environment (ESME) v4.1 Reference Case Pathway Simulation

- ESME was developed by the ETI
- It is a techno-economic, least cost-optimisation model (minimising all capital, operating and resource costs) of the whole UK energy system (including power, buildings, transport, industry, etc.) over the pathway from now to 2050
- It ensures all energy service demands are met (heat, transport km, etc.) whilst balancing supply/demand and meeting overarching user defined constrains on carbon emissions (economy wide carbon budgets and 2050 target) and technology build/resource limits, etc.
- Current results are based on ESME v4.1 from average of 100 pathway simulations (with an additional custom power sector constraint targeting ≤100gCO2/kWh in 2030.) Results presented exclude Northern Ireland
- Import and export flows are assumed zero
- ACS peak demand is projected to slightly decrease from 54.7 GW in 2020 to 53.6 GW in 2030. Post 2030, peak demand is projected to increase to reach 59.5 GW by 2040 and 87.8 by 2050
- ESME capacity has much higher nuclear and CCS buildout (44 GW and 25 GW installed capacity respectively in 2050). In addition, it assumes that wind and solar capacity will decrease over time due to the farms not being repowered at the end of their lifetimes
- The carbon intensity reduces to just below 100 g/kWh in 2030 and then drops to negative intensity by 2050 (-16g/kWh)

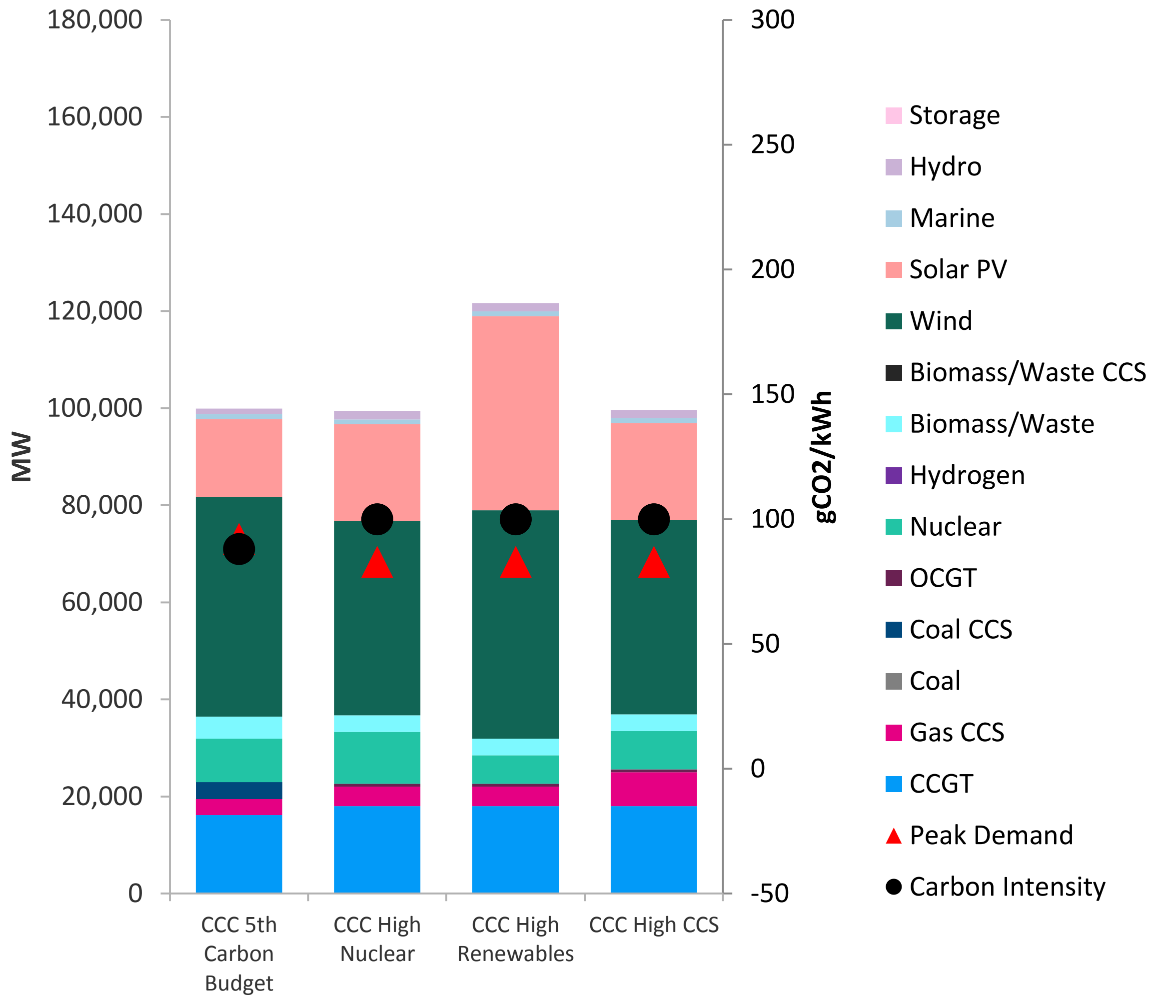


Other scenarios

Committee on Climate Change (CCC)

- The Committee on Climate Change is an independent body tasked with advising the UK government on how to deliver reduction of carbon emissions in a cost effective way
- We have used two different datasets from CCC:
  - The most recent was published in July 2016 and can be found here: https://www.theccc.org.uk/publication/fifth-carbon-budget-dataset/

  (*generation figures are provided and were converted to capacity using standard load factors*)
  - The other one is older but more detailed and can be found here: https://www.theccc.org.uk/publication/power-sector-scenarios-for-the-fifth-carbon-budget/ In the annex, CCC references (for technology costs and commodity prices) are based on this report rather than the most recent (which does not provide the relevant underlying data)
- The CCC modelling assumes flows are zero but takes into account interconnectors as reserve that allows the system to meet peak requirements
- All CCC scenarios are optimistic in terms of low carbon technology development
- The de-rated capacity in CCC scenarios (excluding interconnection) appears lower than peak demand, but CCC does not provide storage capacity figures apart from the existing pumped storage capacity



This chart provides the capacity mix in 2030. CCC focuses on 2030 as the spot year of study

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Abbreviations/Glossary

Term	Explanation
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture & Storage
CHP	Combined Heat & Power
CM	Capacity Market
CO2	Carbon Dioxide
DSR	Demand-Side Response
Economic Life	The number of years of plant operation over which the capital costs are spread
EDNS	Expected Demand Not Served [PLEXOS]
ESME	Energy System Modelling Environment (Model developed by ETI)
EV(s)	Electric Vehicle(s)
FO&M	Fixed Operating & Maintenance (costs)
GBP	Great-Britain Pound (assume real 2017 when not stated otherwise)
IEA	International Energy Agency
IEA's WEO	IEA World Energy Outlook
LCOE	Levelised Cost Of Electricity
LOLE	Loss Of Load Expectation [PLEXOS]
LOLP	Loss Of Load Probability [PLEXOS]
LT	Long-Term (plan) [PLEXOS]
MT	Medium-Term (schedule) [PLEXOS]
NG FES	National Grid Future Energy Scenarios
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
PASA	Projected Assessment of System Adequacy [PLEXOS]
PV	PhotoVoltaics
SEM	Single Electricity Market (Common electricity market of Republic of Ireland & Northern Ireland)
ST	Short-Term (schedule) [PLEXOS]
Technical Life	The total number of years of operation (from commissioning to decommissioning)
TNUoS	Transmission Network Use of System (charges)
ToU	Time of Use (charge)
VOM	Variable Operating & Maintenance (costs)
WACC	Weighted Average Cost of Capital

Baringa