Clean Power 2030

Annex 4: Costs and benefit analysis

NESO
National Energy
System Operator

1. Introduction

Our advice on pathways to clean power for Great Britain by 2030 concludes that clean power by 2030 would support the wider push towards net zero by 2050. It will involve an investment programme averaging over £40 billion annually, which, with the right policy mix, can be delivered without increasing costs for consumers, without compromising security of supply and while bringing local economic and job opportunities.

This technical paper sets out further detail on the analysis and methodology behind our findings on the costs and benefits attached to a clean power system for 2030.

The remaining sections of this paper cover:

- Approach and assumptions.
- Climate, carbon and environment.
- Additional detail on cost analysis.

2. Approach and Assumptions

In considering the cost of a future clean power system, we have sought to include as many system costs as possible, whilst also being careful not to double count any components of system cost.

A full view of our methodology and assumptions (including data sources for costs) can be found in this technical annex, with key points as follows:

- Generation CAPEX, as outlined in our analysis, represents new generation investment compared to today.
- All costs have been rebased to 2024 prices for clear comparison. Where appropriate, we have applied technology-specific price adjustments to CfD eligible technologies, to reflect cost changes observed in these technologies in recent years.
- Demand in our clean power pathways is higher than in the Counterfactual, representing faster electrification. We have focused our results on unit system costs to allow for clear comparison.
- The Counterfactual is the same as in the Future Energy Scenarios 2024 but with aligned gas and carbon prices to allow for more direct comparison between the clean power pathways. It has much lower deployment of low carbon technologies than the clean power pathways, but there is still some (for example 29 GW offshore wind and 20 GW onshore by 2030). Full details are published in the FES data workbook (data table ES1).
- Gas prices are consistent across the Counterfactual and clean power pathways, using the 2023 value (around 100 p/therm), which is also where prices lay in mid-October 2024 and which lies between the Department for Energy Security and Net Zero's (DESNZ) central and high gas price cases.
- A high carbon price including modelling based on a raised price for the UK (forecast European carbon price plus £25 GBP/t) is applied for both pathways and the Counterfactual.

2.1 Technical documentation of methodology to quantify system investment

NESO commissioned Baringa to provide support to the economic impact assessment of the Clean Power 2030 pathways. This involved identifying and quantifying the necessary infrastructure and investments between today and 2030 in the Counterfactual and the pathways, including sensitivities.

Additionally, the analysis aims to provide insights and indications regarding potential impacts on electricity bills and the wider economy. How investments and costs translate into bills and the economy will depend on policy design and market dynamics that we do not attempt to predict as part of the clean power report.

To deliver this report's objectives, a suite of quantitative work has been undertaken, based on data and analysis from multiple parts of NESO as well as Baringa's expertise and market insights. NESO uses PLEXOS, a comprehensive energy modelling software used for analysing and optimising power systems and energy markets and to produce projections of generation mix for the future.

The rest of part 2.1 is organised as follows:

- In this section, we describe input data and assumptions, including the sources of the input data and additional assumptions made to complement the data. We also discuss their differences across the pathways.
- In the subsequent section, we set out our methodology for calculating total system costs, including capital and operating expenditure by each cost element and the steps to translate them into annualised costs.

2.1.1 Inputs and Assumptions

Input data to complete the calculations were drawn from a wide range of teams within the NESO and public domain. Table 1 sets out the key input data and their sources, with more details followed in the subsections.

Table 1: **List of input data**

Data	Unit	Source	Pathway variable	Sensitivities	Section
Generation capacity	MW	NESO (PLEXOS model) & FES data workbook	Yes	No	Generation capacity
Generation technology CAPEX	£/kW	DESNZ, complemented by Baringa analysis based on public sources	No	Yes (low case, base case and high case for CfD technologies)	Generation technology cots
Generation technology FOM	£/kW/year	DESNZ	No	No	
Generation technology variable operations and maintenance costs (VOM) (excl. fuel costs, emission costs)	£/MWh	DESNZ	No	No	
Generation technology lifetime	Years	DESNZ	No	No	
Generation technology WACC	%	DESNZ	No	No	
Generation fuel costs & emission costs	£m/year	NESO (PLEXOS model)	Yes	Yes for gas price (base case, low case and high case)	

Data	Unit	Source	Pathway variable	Sensitivities	Section
Transmission network CAPEX	£m	NESO received data from TOs – highly confidential	Yes	No	Networks
Transmission network OPEX	£m/year	NESO, Ofgem, Baringa analysis	Yes	No	
Offshore network cost	£m/year	NESO, Baringa analysis – highly confidential	Yes	No	
Distribution network CAPEX	£m	Baringa analysis based on public sources	No	No	
Distribution network OPEX	£m/year	Baringa analysis based on public sources	No	No	
Constraint costs (thermal)	£m/year	NESO	Yes	No	Constraint costs
Constraint costs (voltage and stability)	£m/year	NESO	No	No	
Electricity demand	GWh	NESO (PLEXOS model)	Yes	No	Electricity demand
Flexibility load	GWh	NESO (PLEXOS model)	Yes	No	
CO_2 transportation and storage unit costs	£/tCO_2	NESO and Baringa analysis based on public sources	No[1]	Yes, base case and high case	CO_2 and hydrogen infrastructure
CO_2 captured	tCO_2	NESO (PLEXOS model)	Yes	No	
Hydrogen infrastructure	£m	NESO	Yes	No	

1 Each pathway has different requirements and thus different total costs.

Data	Unit	Source	Pathway variable	Sensitivities	Section
Wholesale price (baseload and technology specified capture price)	£/ MWh	NESO (PLEXOS model)	Yes	No	Import and export
Import costs	£m	NESO (PLEXOS model)	Yes	No	
Export credits	£m	NESO (PLEXOS model)	Yes	No	

2.1.2 Generation capacity

Generation capacity is taken from NESO modelling for the two Clean Power 2030 pathways and the Counterfactual.[3] This gives the total installed generation capacity and new capacity additions by category between 2023 and 2030, together with the differences between each of our pathways and the Counterfactual. The capacity additions were used to calculate the amount of new investment required, while total installed capacity was used for calculating fixed operating costs. The capacity addition is calculated based on the differences of capacity between 2023 and 2030 at technology category level, except for nuclear and interconnectors, which is done at project level.

As older renewable support schemes, such as the Renewables Obligation and the earliest Contracts for Difference (CfD) reach the end of their contractual periods, we assume that capture prices are high enough to keep these renewable generators open as support mechanisms expire, so we are not assuming that any new capacity is displacing existing capacity.

2.1.3 Generation technology costs

Generation cost assumptions, such as CAPEX, fixed OPEX and variable OPEX (excluding fuel and emissions costs) are sourced from the latest publicly available data from DESNZ publications:

- Electricity generation costs 2023 - GOV.UK (www.gov.uk)
- BEIS Electricity Generation Costs (2020) - GOV.UK (www.gov.uk)
- BEIS Electricity Generation Costs (November 2016) - GOV.UK (www.gov.uk)
- Hydrogen production costs 2021 - GOV.UK (www.gov.uk)
- Storage cost and technical assumptions for electricity storage technologies - GOV.UK (www.gov.uk)
- Methodology used to set Administrative Strike Prices for CfD Allocation Round 6 (publishing.service.gov.uk)

Fuel costs[2] and emission costs[3] were extracted directly from the PLEXOS model, as total costs are output in the unit of £m/year. The VOM were calculated based on the unit cost from DESNZ sources, in the unit of £/MWh, multiplied by the dispatched volume in MWh from the PLEXOS model.[4]

2 Fuel cost: gas prices are the average of the forecast data from third party suppliers based on their highest projections in line with the Holistic Transition pathway (FES 2024) narrative.

3 Emissions costs: Carbon prices are the differential between British and European carbon forecast prices to 2030 from third party suppliers. This is aligned to the European carbon price plus a price offset of 25 GBP/tonne.

4 Solar and wind generation are set up with negative variable VOM in PLEXOS model to represent subsidies. To avoid the total system cost being distorted by negative variable OPEX costs supplied by PLEXOS runs, the negative values were overwritten by the unit VOM costs as supplied by DESNZ.

The main fuel assumption affecting our analysis is the gas price. A gas price of around 100p/therm has been assumed for the economic impact analysis, as used in the Future Energy Scenarios and implying a continuation of the current (October 2024) price. This is towards the higher end of DESNZ's gas price projections and in line with the 2023 gas prices. This assumption provides comparability against today, while it could also represent elevated prices due to geopolitical events and supply chain issues continuing into the future.

We kept the same gas price for both pathways for the economic analysis to isolate the impact of other factors, such as the higher deployment of renewable energy sources, on the overall cost analysis.

Two gas price sensitivity analyses have been conducted as well, as seen in Figure 1: for our raised gas sensitivity we use the higher gas price in the Hydrogen Evolution pathway FES 2024, which in 2030 is comparable to the peak prices seen during the higher months of 2022, and a reduced price sensitivity using DESNZ's central projection.

The different sensitivities against the DESNZ scenarios can be seen below.

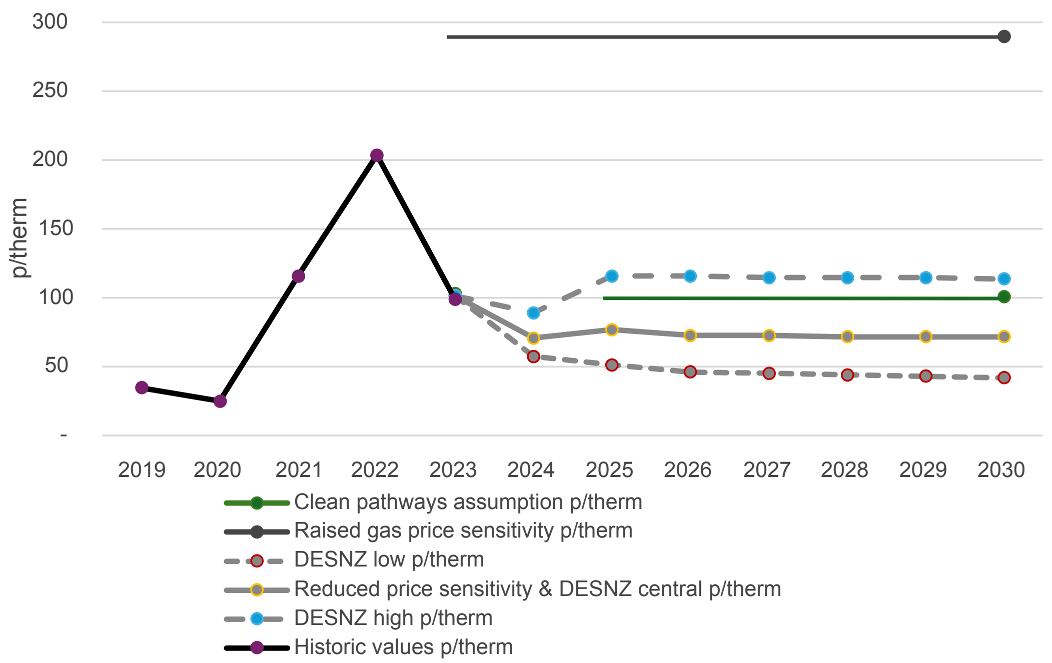

Figure 1: **Gas price assumptions**

We also take our carbon price projection, which is based on an average of independent forecasts, from the Future Energy Scenarios Holistic Transition assumptions. As set out in the main report, for the clean power analysis we modelled a UK carbon price that is £25/tCO_2 above this price, at £147/tCO_2 in 2030, given the need to limit gas generation running for export in a clean power system. This is a modelling assumption, not a policy recommendation, noting that the UK has had a Carbon Price Support scheme for the last decade, currently set at £18/tCO_2, raising the UK carbon price above the level implied by the price of traded emissions allowances.

We have used consistent single unit-level CAPEX, fixed OPEX and variable OPEX figures per technology from the present to 2030. The analysis focuses on calculating the system cost in 2030 under our clean power pathways and does not aim to determine precise annual capacity deployment or year-specific costs. Therefore, we have assumed single cost figures per technology for the entire modelling period.

Two key adjustments to DESNZ-sourced baseline cost figures were applied:

1. CPI-inflation adjustment

- Given DESNZ cost assumptions are reported across multiple publications and in different price bases, we have rebased raw costs from their original price bases to real 2024 terms using the Consumer Price Index (CPI).
- This adjustment is applied to all technologies in scope.

2. Technology-specific adjustment:

- Costs of CfD-eligible technologies considered in the analysis (onshore wind, offshore wind, and solar PV) were further adjusted to reflect observed cost increases in recent years. The adjustment was based on DESNZ's methodology used to set Administrative Strike Prices for CfD Allocation Round 6, where uplifts are applied to the construction and infrastructure costs while pre-development costs remain unchanged.
- DESNZ technology cost assumptions for CfD-eligible technologies with a commissioning year in 2025 (expressed in 2024 real terms) served as the baseline for this relative adjustment.
- This technology-specific adjustment ensures that recent market developments are incorporated into the cost assumptions for technologies crucial to achieving clean power.

To address the high uncertainty surrounding the CAPEX of the CfD technologies, two sensitivities were examined. These sensitivities involved applying DESNZ's cost scenario of high and low on generation CAPEX, adjusted for inflation and based around a central case aligned to the latest auction as described above. This allowed for testing the high and low cases in terms of cost variability.

The hurdle rate is a critical assumption in our calculation. It reflects the required rate of return on capital expenditure for each technology and therefore the size of annual payments required to pay off this capital expenditure and achieve this required rate of return. To inform our analysis, we have utilised DESNZ's published hurdle rates for relevant technologies.

The operational lifetime of technologies is another important assumption as it impacts the repayment period for capital expenditure. Longer operational lifetimes result in smaller annual repayments, which are a key component of our 2030 system cost calculation. To ensure consistency, we have used DESNZ's published operational lifetime assumptions for the relevant technologies in our analysis.

Decommissioning costs were only accounted for nuclear technology, and they were inferred from the most recent publicly available data published by the Government. They are accounted in the fixed OPEX cost assumptions in the BEIS 2016 Generation Costs[5] report. In practice, this represents the quarterly levy reactors pay into the Nuclear Liabilities Fund, out of which decommissioning costs are paid. This levy is around £3 /MWh and does not vary by pathway. For all other generation technologies, decommissioning costs have not been included in the analysis. This is because the model does not make assumptions on repowering and it is assumed that renewable plants will continue to operate until 2030 without additional support after their Renewable Obligation (RO) or Contract for Difference (CfD) expires. Additionally, the decommissioning costs of these technologies are very low compared to nuclear and they are unlikely to significantly impact system costs or alter overall conclusions.

2.1.4 Networks

Alongside generation CAPEX, 2030 system cost will be driven by expenditure on Great Britain's transmission and distribution networks. Given the short timeframe between 2024 and 2030, in the context of major network reinforcement projects, it is unlikely that transmission and distribution CAPEX can meaningfully differ between Clean Power 2030 pathways.

5 BEIS Electricity Generation Costs (November 2016) - GOV.UK (www.gov.uk)

Operational expenditure for transmission and distribution networks is based on allowed annual OPEX under the relevant price control round, projected forward by assuming it grows in line with total network capacity using peak demand as the indicator. Peak demand data were taken from the Clean Power 2030 modelling for the Clean Power pathways and from FES 24 published data for the Counterfactual.

Transmission network expenditure is based on forecasted network reinforcement spend gathered by NESO from Transmission Operators, aggregated to the system level to avoid inclusion of commercially sensitive information.[6] Transmission CAPEX is annuitised based on Ofgem RIIO-3 methodology,[7] with a WACC of 4.06%, gearing of 60%, cost of equity of 5.46%, cost of debt of 3.13% and an assumed asset lifetime of 45 years. To estimate transmission OPEX, the analysis is based on the RIIO-ET2 price control round, which allows for £999.3 million of OPEX across three Transmission Operators (TOs) from April 2021-April 2026. The annual average of £200m is assumed to grow in line with total network capacity. The relative growth of peak demand between 2023 and 2030, serving as an indicator of total network capacity expansion, is then multiplied by the average annual OPEX from 2021-26 to determine the OPEX in 2030.

For offshore network costs, NESO has gathered commercially sensitive cost data for all offshore projects. From this data, 80% has been allocated to CAPEX, while the remaining 20% has been allocated to OPEX. The unit cost in £/MW is calculated by dividing the total cost by the total capacity. To determine the total cumulative CAPEX in £m, 80% of the unit cost is multiplied by the new capacity additions of offshore wind projects. Similarly, for OPEX, the remaining 20% of the unit cost is multiplied by the total installed capacity. The cumulative CAPEX and OPEX are then annuitised. Offshore network costs were annuitised using the same WACC and lifetime assumptions as above for other transmission network.

The distribution network expenditure used in this analysis is based on forecast expenditure made by Distribution Network Operators (DNOs) as part of the current RIIO-ED2 price control period, covering 2023-2028. To extrapolate the forecast spend for 2028-2030, a methodology that indexes relevant portions of the forecast spend to NESO's modelled capacity deployment and peak demand figures was developed by Baringa. The methodology is as follows:

- The RIIO-ED2 Final Determinations for each DNO, which cover total investment by each DNO over the 5-year period from 1 April 2023 to 31 March 2028, are taken and broken out by type of spend.
- This spend is then categorised into three groups: a) spend driven by new distribution capacity, b) spend driven by total size of distribution network, c) overhead spends not affected by network size.
- The RIIO-ED2 determinations are based on projected demand under the Counterfactual in FES 2024. Great Britain's annual peak customer demand is used as a proxy for the size of the network, with increases in Peak Demand as a proxy for new capacity on the system.
- The total RIIO-ED2 costs over the 5-year period are allocated to the years 2023-2027, splitting the costs for each spend category based on: a) total system size, b) new capacity in each year, and c) even split over the 5 years.
- FES 2024 pathway projections are then used to estimate costs for the period 2028-2030.

Specifically, the costs are categorised as follows:

- Costs not scaling with capacity: non-operating CAPEX, closely associated indirects (CAI), business support costs.
- Costs scaling with total capacity: non-load related CAPEX, network operating costs.
- Costs scaling with new capacity: load related CAPEX.

6 Our economic costing analysis was carried out alongside finalisation of model runs for network analysis, meaning that there are some minor differences in the assumptions made for network analysis and economic costing. Both involve acceleration of three key projects to deliver one year earlier, by 2030, given their criticality for clean power (as described in the main clean power report). The clean power pathways in the economics modelling also see two other projects deliver a year earlier and two deliver a year later compared to the Counterfactual. This does not significantly change the network costs between pathways.

7 RIIO-3 Sector Specific Methodology Decision – Finance Annex

2.1.5 Constraint costs

Network constraint costs, including thermal constraint costs and voltage and stability balancing costs, were provided as an annual OPEX, from analysis conducted in NESO. These costs were incorporated into the total cost calculation. Thermal constraint costs were calculated for each pathway separately as they make up the majority of constraint costs and they can differ significantly based on the generation mix. The voltage and stability balancing costs are provided with a single projection over all pathways, based on NESO's balancing cost annual report 2024[8] as they make a minor contribution to the total constraint costs values.

2.1.6 Electricity Demand

Electricity demand, including flexibility load, is pulled from the PLEXOS model covering both pathways. Electricity demand varies between the different pathways and is used to translate the system cost into cost per useful energy (£/MWh), where useful energy is the consumer load plus electrolysis.

2.1.7 CO_2 and hydrogen infrastructure

The CO_2 transportation and storage costs are determined by multiplying the unit cost of £/tCO_2, obtained from publicly available sources, by the total amount of CO_2 captured from power plants based on PLEXOS outputs. Specifically for the unit cost, a widely cited source, the Strategic UK CCS Appraisal study[9] was used, giving a unit cost ranging from £14.1-£23.5 /tCO_2 (real 2024). For our central case, we use the central value of £18.8 /tCO_2. However, considering the age of this source and the uncertainty surrounding the technology and business model, we also conducted a sensitivity analysis using an alternative value from an academic study which estimated the cost at £78 /tCO_2.[10] This higher value takes into account the potential higher costs that early projects may face initially due to under-utilised pipelines, as business models for CO_2 transportation and storage are still being developed.

The estimation of capital and operational costs for new hydrogen infrastructure (pipeline transport) at British level has been conducted by NESO. For the Counterfactual, no transmission infrastructure is assumed to be necessary due to localised hydrogen production and as such, there is less of a requirement for large scale transportation. Similarly, for the two clean power pathways, the requirements were assumed to be the same due to the similarity in hydrogen needs, with large-scale storage not assumed to be possible by 2030.

8 neso.energy/document/318661/download
9 Strategic UK CCS Storage Appraisal | The ETI
10 Industrial carbon capture utilisation and storage in the UK — University of Strathclyde. Higher sensitivity value calculated from total investment required and carbon emissions sequestrated across Track 1 and Track 2.

2.1.8 Import and export

Import and export volume can be obtained from PLEXOS solution at hourly level. To calculate the cost of imports, the import volume is multiplied by the British wholesale price, while for exports, the export volume is multiplied by the British wholesale price to obtain a credit (negative cost).

Wholesale electricity price is available as an output from PLEXOS model at hourly level. The hourly profile will be used to calculate the annual and monthly profiles, including baseload price by calculating the time-weighted average as well as technology-specific capture price by calculating the generation weighted-average.

For the CAPEX of interconnectors, there are four new projects in our Clean Power 2030 pathways commissioning between 2024 and 2030, Mares (750 MW), NeuConnect (1400 MW), GreenLink (500 MW), and VikingLink (1400 MW). Three of these projects, excluding Mares, are also present in the Counterfactual. We calculate the cost of the additional capacity, relative to 2024, based on project benchmarks available for Mares and Neuconnect as below.

According to the Mares website,[11] its CAPEX is €860 million (£733 million). As per Ofgem's Final Project Allowance decision, NeuConnect will be permitted £989.0 million (real 2022) in CAPEX, which is rebased to 2024 terms and used as an input. In the analysis, 100% of the capital cost is included as generation CAPEX. This cost represents the expense of accessing import/export prices and serves as a proxy for the generation used or displaced in the interconnected countries. The fixed operational expenditure (OPEX) of interconnectors is also accounted for within the generation OPEX. It is assumed that the variable OPEX, (which reflects the cost of electricity transportation across the interconnector) is covered by the price differential that the interconnector benefits from. Therefore, it has been disregarded in the system cost calculation to avoid double counting.

11 Subsea electricity interconnector between Ireland and the UK

2.2. System Cost Calculation

2.2.1 Overview of approach

The analysis aims to comprehensively capture all the costs associated with the power sector, specifically pertaining to the building, operation and maintenance of power generation and network assets in the British energy system in 2030. This includes considering network costs, generation costs and constraint costs. The primary focus is on calculating the relative system costs for each of our pathways and the FES 2024 Counterfactual. As set out above, all costs in this document are presented in real 2024 terms, unless explicitly stated otherwise.

Step 1: Disaggregate system costs

The first step involves breaking down the system into specific cost components: generation costs, network costs, and constraint costs.

- **Generation costs.** They include the capital expenditure (CAPEX) and operational expenditure (OPEX) (fixed and variable including fuel cost and carbon costs) of each generation technology considered in the pathways.
- **Network costs.** They encompass the CAPEX and OPEX of Great Britain's transmission network, distribution network, offshore network, hydrogen infrastructure and CO_2 transport and storage for power generation, which are utilised by the power generation technologies under consideration. Onshore enablers were not included in the analysis due to challenges in obtaining relevant data.
- **Constraint costs.** Thermal and voltage/stability costs were also considered per pathway.

Step 2: Source cost data

The second step involves sourcing cost data for each cost component per technology. Further details on the cost source material and inflation adjustment approach can be found in Section 2.1 above.

Step 3: Calculate system costs in 2030

This step involves calculating system costs specific to the year 2030 for each pathway. The calculation includes annuitised generation and network CAPEX (A), generation and network OPEX (B), constraint costs (C) incurred in 2030. Table 1 summarises the build-up of our 2030 system cost calculation.

Component A - Annuitised CAPEX is divided into annuitised CAPEX for generation assets (A1) and network assets (A2) and it accounts for the additional investment needed in 2030 compared to 2023.

- **A1:** The assumed generation CAPEX in £/kW for each technology is multiplied by the respective targeted capacity for each technology per each pathway. These total CAPEX figures per technology are then annuitised using technology-specific WACC and operational lifetime assumptions.
- **A2:** The annuitised network CAPEX is calculated by annuitising the £m figures calculated by NESO (for transmission network, offshore, CO_2 transport and storage and hydrogen infrastructure) and calculated by Baringa (for distribution network) using WACC rates and operational lifetime assumptions.

Component B – OPEX comprises the £m figures for 2030 OPEX, covering fixed and variable payments for both generation and network assets. Fuel and emissions costs of generation are included reflecting the gas price and CO_2 price assumptions.

Component C – Constraint costs comprise the £m thermal and voltage/stability costs incurred in 2030.

The sum-total of components A, B, and C yields the total system costs in £m for 2030 for each pathway to clean power as demonstrated in Table 2. The difference in 2030 system costs is then calculated between:

- Each pathway.
- Each pathway relative to NESO's Counterfactual.

Table 2: 2030 System cost methodology

2030 System Cost	A: Annuitised CAPEX	A1. Annuitised generation CAPEX
		A2. Annuitised network* CAPEX
	B: 2030 OPEX (fixed and variable)	B1: 2030 generation OPEX (fixed and variable)
		B2: 2030 network* OPEX
	C: 2030 constraint costs	C1: Thermal constraint costs
		C2: Voltage and stability constraint costs

* The term 'network' includes transmission, offshore, distribution, CO_2 transport and storage and hydrogen infrastructure.

Step 4: Calculate unit system costs

In the final step, the system cost per unit (£/MWh) is calculated to enable the comparability of cost components between different pathways. This ensures comparability across pathways, regardless of the varying demands. The calculation involves dividing the cost component calculated in step 3 by the total generation, adjusted for round trip efficiency losses from batteries.

The difference in 2030 system cost per unit is then calculated between:

- Each Clean Power 2030 pathway.
- Each Clean Power 2030 pathway relative to NESO's Counterfactual pathway.

These pathway costs can be compared against each other for 2030, but are not directly comparable to cost estimates for the current system (for example, as only CAPEX for new build capacity is included).

We also set out comparisons to today's system in the main report. Those comparisons begin by calculating the per unit average generation costs for the 2023 system and the 2030 system based on prices projected for 2030. For those calculations, we assume a cost for gas generation based on the mid-October gas price (around 100 pence/therm) and a carbon price of £147/tCO_2. We compare the costs of renewables based on the strike prices from the latest renewables auction (Allocation Round 6).

As set out in the main report, we further adjust for the extra generation that needs to be produced to cover curtailment and storage losses and for exports based on the wholesale electricity price expected from our 2030 modelling. Network costs are calculated on a £/MWh basis for 2023 and 2030 then compared, for both the network investment costs and constraint costs.

Our values in the main report comparing costs to today's system are based on central values for our assumptions as outlined above. Simple testing of assumptions illustrates the impact of the assumptions – under our Reduced Gas price assumption (the DESNZ central assumption) the relative cost of the clean power system would be around £5-10/MWh higher, although the system cost as a whole would of course fall compared to a world with higher gas prices. Using DESNZ's central case for traded carbon values would also shift relative costs by around £5-10/MWh.

3. Climate, carbon and electrification

A clean power system is a critical milestone in the wider push to net zero. It enables the decarbonisation of other sectors such as transportation and heating through the adoption of electric vehicles and heat pumps. A decarbonised power sector is also vital for other critical elements of net zero, such as low carbon hydrogen produced by electrolysis and carbon removals.

3.1 Carbon budgets

Delivering clean power by 2030 supports the UK's commitment to reduce greenhouse gas emissions by 68% in 2030 compared to 1990 levels (excluding emissions from international aviation and shipping), as outlined in its Nationally Determined Contribution (NDC) under the Paris Agreement. The 2030 NDC, recommended by the Climate Change Committee (CCC), is a step towards the legally-binding Sixth Carbon Budget for 2033-2037.

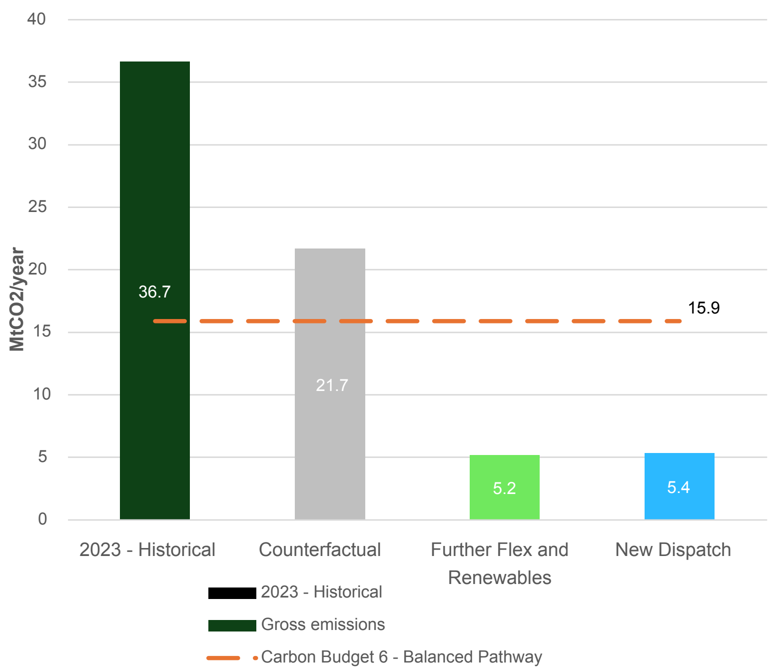

Figure 2: **Emissions from unabated gas and residual emissions from CCS (excluding ACT, EfW and CHP)**

Clean power in 2030 will significantly reduce carbon emissions in the power sector as seen in Figure 2. Net electricity emissions in our pathways are less than a quarter of those in the Counterfactual (i.e. in a world with the slowest credible decarbonisation). This is also well below the CCC's pathways to net zero that were the basis for the NDC under the Paris Agreement and the Sixth Carbon Budget.

3.2 Wider greenhouse gas emissions

In line with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, we also show the transfer of CO_2 to storage for power as reported within the energy sector. Where this relates to bioenergy with CCS, it results in negative emissions reported against the power sector. These 'removals' of CO_2 are separately accounted by the CCC and not part of the dotted line on the chart above.

Similarly, emissions in the above chart only consider emissions directly associated with power generation, such as emissions from unabated gas fired generation and residual emissions from gas plants with CCS. In line with emissions accounting conventions, biomass is considered to have zero emissions (on the basis that the emissions released were previously removed from the atmosphere during the biomass growth phase and with the wider lifecycle emissions reported in other sectors). Emissions from ACT, combined heat and power generation and energy from waste are accounted for by CCC in industry and waste sectors, rather than power generation. A full breakdown of emissions by all power-generating technologies in the Counterfactual and the pathways is provided below in Figure 3.

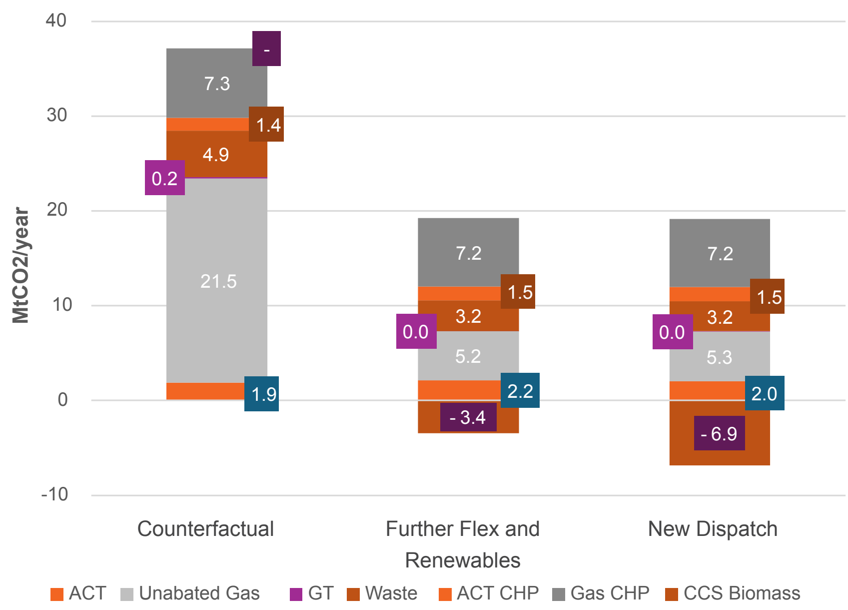

Figure 3: 2030 Carbon emissions by technology

There is a corresponding drop in the carbon intensity of power generation, from over 140 gCO_2/kWh in 2023 to around 15 gCO_2/kWh in 2030 in our pathways, as seen in Table 3 below. With carbon dioxide removal from biomass with carbon capture and storage (BECCS) accounted for, net carbon intensity in 2030 would be around 5 gCO_2/kWh in the Further Flex and Renewables pathway (with one unit converted to BECCS) and below zero in the New Dispatch pathway (with two BECCS units).

Table 3: Grid carbon intensity

Grid carbon intensity (CO_2/kWh)	2030 CF	2030 Further Flex and Renewables	2030 New Dispatch
Carbon intensity inc. ACT, EfW and CHPs (w/o BECCS)	120.0	51.1	52.5
Carbon intensity exc. ACT, EfW and CHPs (w/o BECCS)	78.1	15.0	15.9
Carbon intensity exc. ACT, EfW and CHPs (w BECCS)	-	5.0	<0

Should there be no biomass CCS conversions by 2030, a clean power system can still be reached as the unconverted biomass plants would have slightly higher capacity and use slightly less fuel for each MWh of output. These plants could still provide the required clean power when needed. However, there would be less removal of carbon from the atmosphere, which could make wider carbon targets harder to meet.

Although BECCS contributes to CO_2 removal and biomass contributes to clean power, the biomass supply chain still produces other emissions, with sustainability vital if it is to be an attractive option in terms of lifecycle emissions. More information on this issue and the UK's sustainability criteria are available in DESNZ's Biomass Strategy 2023.

There are also lifecycle emissions attached to other generation types, for example those involved in producing the steel used in wind turbines. We have not undertaken new analysis on these emissions for this report but note that previous studies have shown that these emissions can fall with wider economy decarbonisation and are relatively low (typically lower than the equivalent lifecycle emissions attached to extraction and transportation of fossil gas for use in gas-fired generation). Within the technologies that are expanded in our clean power pathways, gas with CCS would be expected to have significantly higher lifecycle emissions than other options like wind and solar.

4. Additional detail on costs estimates

Section 2 set out the methodology and sources used in our cost analysis. The main clean power report sets out the results from that analysis. In this section we set out more detail behind the cost analysis.

4.1 Auction prices and costs of generation

Figure 4 below shows the Allocation Round (AR6) strike prices and the costs of gas assets. We report just the running costs of unabated gas (the 'short-run marginal cost' or SRMC), since the required plants have already been built and would still need to remain on the system in the clean power pathways. We report the full costs ('long-run marginal cost', LRMC), including the build costs for CCS gas, since these plants would need to be built as well as facing costs to run.

Under today's gas price assumptions, and the projected carbon price, the running costs of unabated gas assets are significantly higher than recently contracted strike prices awarded to developers in the recent AR6 CfD auction. This outcome is highly sensitive to the gas price assumption, as shown by the raised- and reduced-gas sensitivities, although even in the reduced-gas sensitivity the CCGT SRMCs are still higher than the AR6 strike prices.

Carbon price is also a key driver of gas SRMC, which is the reason CCS gas SRMCs appear to be lower than unabated plants. CCS gas also includes cost of CO_2 transport and storage (T&S), where we apply our central estimate of £18.8 /tCO_2. Our high case estimate of £78 /tCO_2 (not shown here) would add over £30 /MWh to the cost shown on the chart.

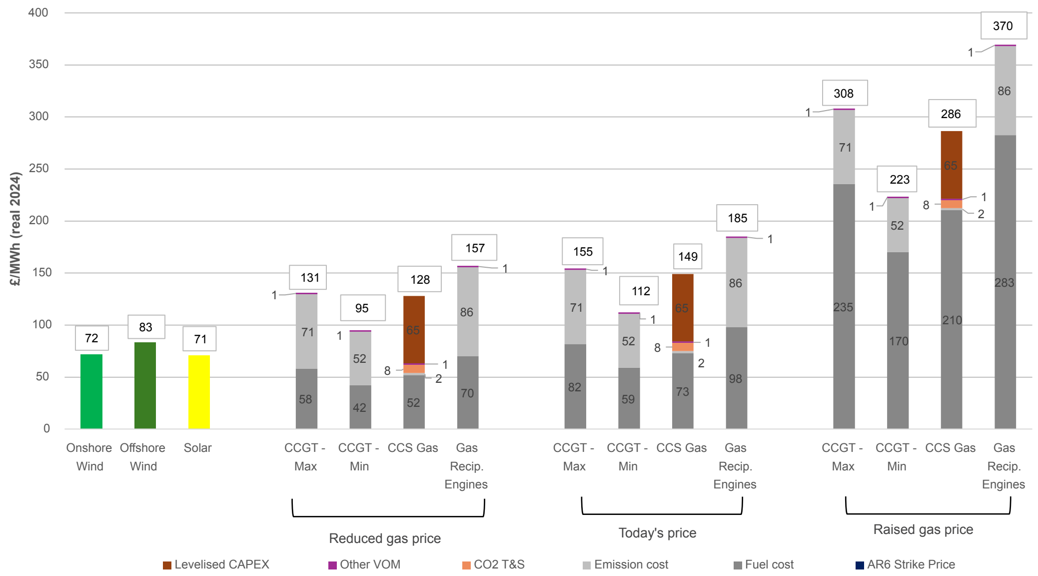

Figure 4: AR6 Strike Price vs SRMC/LRMC of gas assets in 2030

We also worked with Baringa to consider the risk of prices escalating as pace is increased in line with the clean power pathways. This informed a cost sensitivity looking at the risk of higher costs than implied by recent auction results. The analysis shows that, compared to our base assumption of similar approach and prices to those in AR6, an approach that avoided any infra-marginal rents could reduce costs to consumers by £2 /MWh, while one with the highest infra-marginal rents could see costs increase by £8 /MWh. If tightened supply chains further push up capital spend by 25%, costs to consumers would go up a further £7 /MWh.

4.2 Sensitivity on offshore wind CfD strike price given different procurement strategies

Considering the potential impact of CfD costs as its portfolio expands in the future, we conducted an investigation into different procurement strategies and their effects on offshore wind strike prices. In order to assess the impact of different procurement strategies on offshore wind strike prices, we conducted a sensitivity analysis within the context of the Further Flex and Renewables pathway. The analysis was carried out using Baringa's proprietary offshore wind CfD auction modelling.

The approach involved creating a supply stack of all pipeline projects and ranking them based on bid prices. Bid prices were determined by considering asset-specific capital expenditure (CAPEX), offshore transmission owner (OFTO) costs, load factors, a merchant tail and constraints. These factors were based on Baringa's Q2 2024 Reference Case wholesale price projection, along with assumptions on the weighted average cost of capital (WACC).

The following procurement strategies were investigated, and the results are presented in Figure 5 as follows:

- BAU: Allocation Round-weighted Price. This strategy assumes the continuation of allocation rounds in the existing format, with approximately 5 GW of offshore wind capacity procured per round. To meet the capacity requirements of the Further Flex and Renewables pathway, an additional 5 Allocation Rounds (AR7-AR11, with a smaller volume in AR11) were assumed to take place between the present and the final date for achieving the Clean Power 2030 target. Strike prices were determined as the capacity-weighted average of all allocation rounds.
- Individual Bid Prices. This approach assumed that each offshore wind asset has its own required levelised cost of energy (LCOE), and the overall strike price was calculated as the capacity-weighted average of all assets giving the lowest strike price among the different strategies.
- Buy all-in-one at max bid. This strategy involved a single pay-as-clear auction to procure all offshore wind capacity, where all projects were paid the highest bid price to meet the required capacity.
- Buy all-in-one at max bid + 25% CAPEX. Similar to strategy 3, this approach inflated the CAPEX (excluding OFTO costs) by 25% to account for potential supply chain pressures resulting from the rapid deployment of capacity. This procurement strategy forecasts the highest strike prices and thus the highest cost for the consumer.

By examining these procurement strategies, we gained insights into their impact on offshore wind strike prices and their implications for the Further Flex and Renewables pathway.

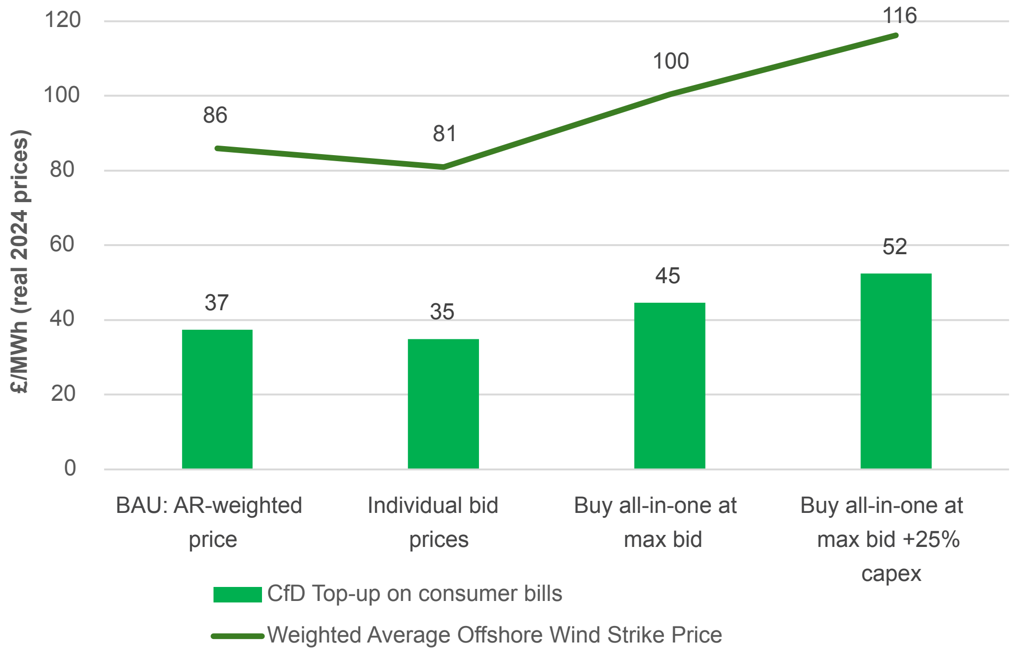

Figure 5: **Offshore wind CfD strike price sensitivity - 2030**

4.3 Investment

There is already a significant level of investment underway in the British power sector, including contracts and commitments for new generation and storage assets, as well as network expansion.

In our pathways for a clean power system in 2030, we anticipate even higher levels of investment. Specifically, investment in renewable technologies stands out as the largest category, with an annual average investment of at least £20 billion in the clean power pathways. Among the renewable technologies, offshore wind is expected to be the largest component, with annual average investment of at least £12 billion, as depicted in Figure 6 below. Investment in gas-fired generation remains relatively consistent across pathways, as a substantial fleet is still required to ensure the security of supply, even in the clean power pathways.

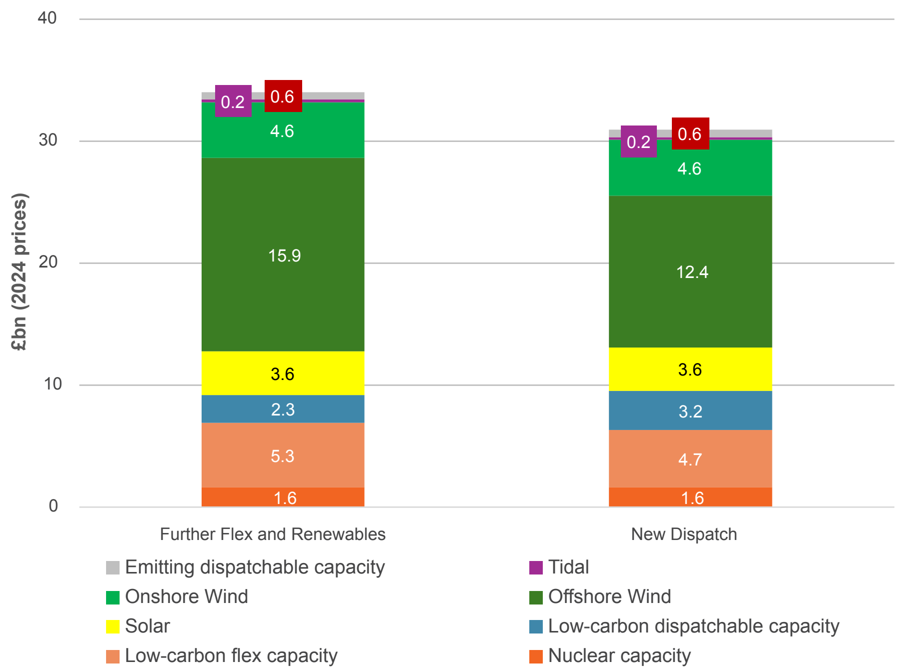

Figure 6: **Average technology investment cost 2025-2030**

Emitting dispatchable capacity: biomass, gas CHP, GT, GT CHP, steam oil. Low-carbon dispatchable capacity: waste, waste CHP, hydrogen CHP, biomass, biomass CHP, CCGT H2, CCS gas.

4.4 Generation levels and exports

One factor contributing to higher system costs in our pathways is the increased available energy within the system, not all of which is utilised by local consumers. In both Further Flex and Renewables and New Dispatch pathways, the customer load is approximately 2% higher compared to the Counterfactual. Additionally, there is an additional 4-5% of energy allocated for electrolysis as illustrated in Figure 7. Due to the higher offshore wind capacity, a greater portion of the available energy is exported, curtailed or lost due to storage round-trip inefficiency. These factors collectively contribute to the higher system costs observed in our pathways.

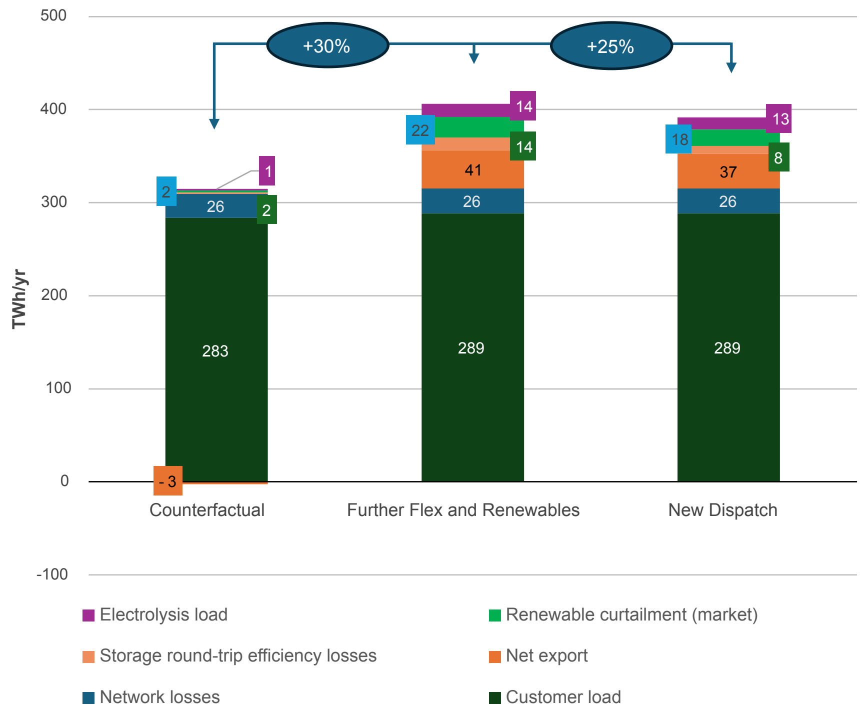

Figure 7: Energy flow 2030

Note we do not include grid curtailment here, which will further widen the gap between the pathways and the Counterfactual. These figures are calculated for the economic modelling on a simplified Plexos run using three-hour rather than one-hour intervals, so will not exactly match curtailment levels in the dispatch modelling, as reported in the data workbook.

In 2023, Great Britain was a net exporter importer of electricity, spending approximately £2.5 billion[12] on net electricity imports. As Great Britain transitions to a clean power system, it is anticipated to become a net exporter of electricity (Figure 9). However, exports will be highest during periods of high renewable energy output, which typically coincide with relatively lower prices under current arrangements (Figure 8). While exporting can help recover some costs compared to curtailing excess generation, significant net exports at low prices still incur some overall costs to the British system.

12 Based on DUKES data, excluding Northern Ireland.

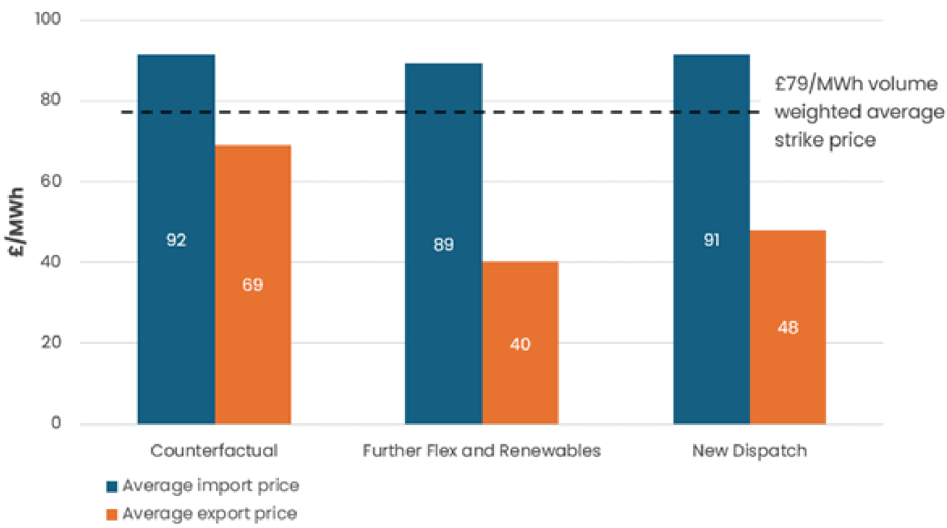

Figure 8: Import and export prices in 2030

Volume weighted average wind/solar strike price is calculated based on the estimated generation in 2030.

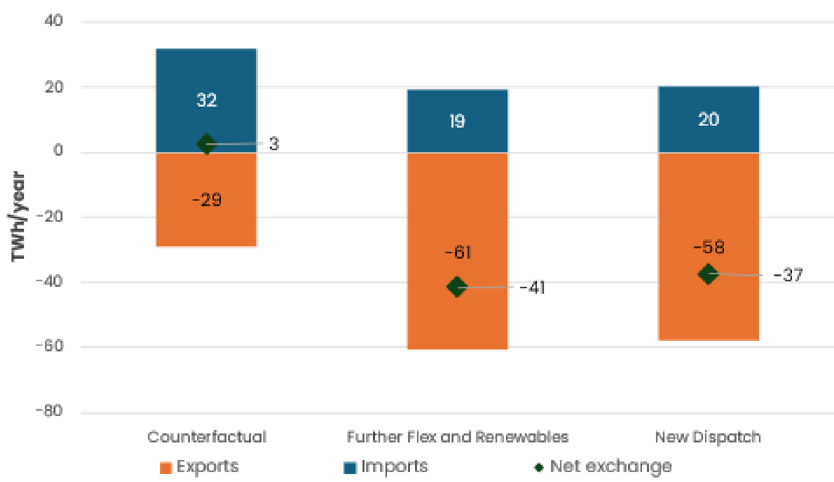

Figure 9: Net Interconnector import against export in 2030

4.5 Networks

In the pathways, the network requirements differ from the Counterfactual. Figure 10 demonstrates higher constraint costs[13] due to increased levels of renewables in the system. While there are minor differences in transmission network investment, no variations are assumed for distribution network investment. However, there is an expected increase in offshore network infrastructure, particularly in Further Flex and Renewables, driven by the higher growth of offshore wind.

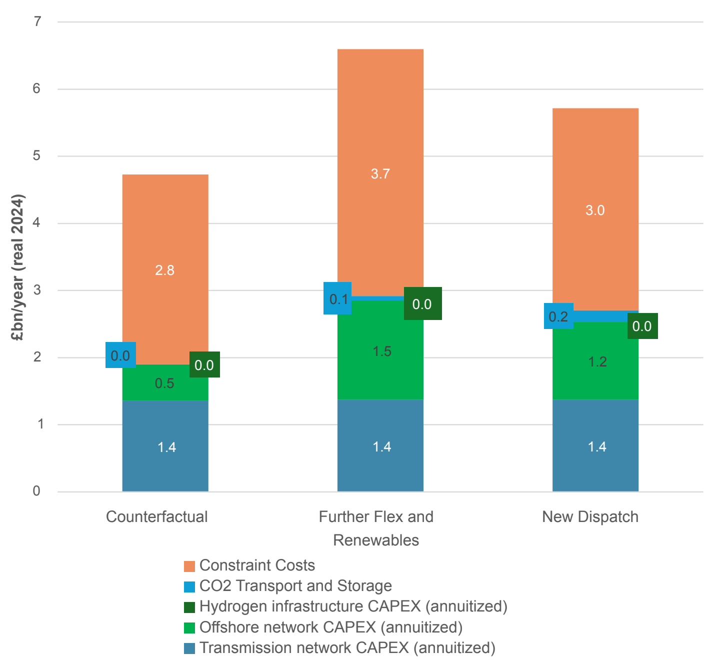

Figure 10: **2030 annuitised network and constraint costs**

4.6 Aggregate system costs and gas price exposure

The clean power mission presents both opportunities and risks. Removing barriers to delivery may reduce costs, improve access to affordable capital and increase competition. However, there are also risks associated with the accelerated pace, such as reduced competitive pressure or increased supply chain constraints, which could lead to increased costs. Managing these challenges will be a key task for the Clean Power Unit.

Protection from gas price volatility is an important consideration, taking into account the impact of the very high gas price increase in 2022 following the Russian invasion of Ukraine. Our pathways demonstrate varying levels of resilience to potential gas price spikes.

If gas usage for power generation remained at 2023 levels, an increase of the gas price at the 2022 levels would add approximately £70 /MWh to annual British system costs, while in the clean power pathways, it would only add around £10 /MWh. The reason for this difference is that gas would be utilised less frequently in our pathways compared to the Counterfactual and today, as demonstrated in the price duration curve provided in Figure 11.

The price duration curve illustrates the distribution of prices over a year for both pathways, the Counterfactual and 2023. The range of Short Run Marginal Costs (SRMCs) is labelled by technology types, indicating the potential for a technology to be the marginal price setter. Interconnectors also play a role across the entire price range.

13 Constraint costs here include thermal constraints plus costs such as voltage and stability, and, owing to the compressed report timescales, were based on earlier model runs, hence there is a small difference compared to the thermal constraint costs discussed in the main report.

In our pathways to clean power, with higher levels of renewable penetration, the percentage of hours with zero or negative prices significantly increases from less than 10% in the Counterfactual to 25% in the pathways.[14] Clearly, the spike in wholesale market prices is much less in the pathways compared to historical 2023 prices.

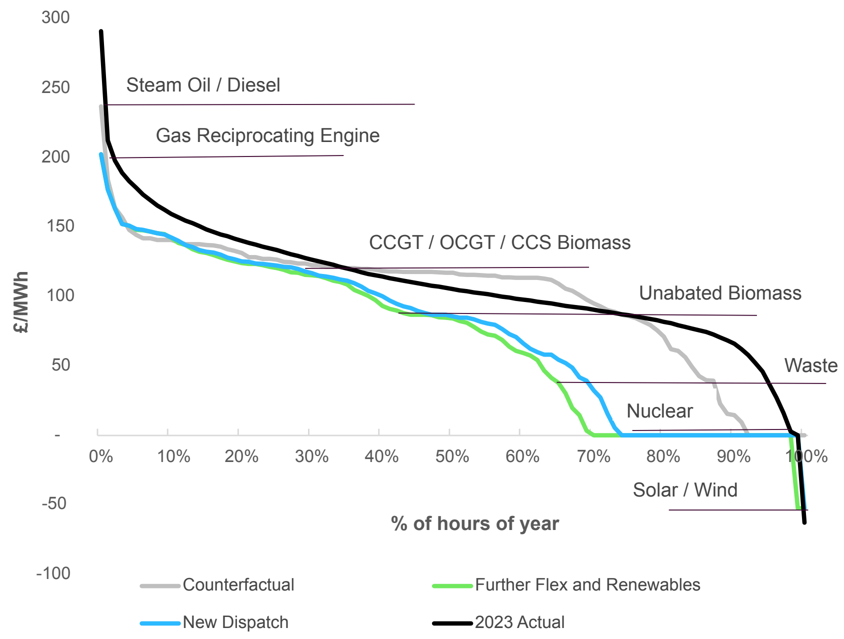

Figure 11: **Price duration curve 2030**

In a gas-dominated power system, where gas sets the dominant price, wholesale prices can often exceed the short-term marginal cost of other power plants. This results in generators, especially those not contracted under CfDs, receiving higher prices and greater infra-marginal rents. However, the clean power pathways reduce the frequency of gas price dominance, leading to a decrease in payments and infra-marginal rents for generation in 2030 with low marginal costs that are not contracted under CfDs. This includes existing nuclear plants and those receiving Renewable Obligation Certificates. As a result, our clean power pathways contribute to driving down system unit costs, as set out in our main clean power report.

14 The negative prices are mainly due to the dispatch model being set up with renewable subsidies including CfD as negative costs. In reality, the CfD contracts are designed to avoid negative prices, so these periods may well also see zero prices.

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