Annexes

Annex 1 – Low carbon heat technology options, pathways and supporting policies

	Technology	Pathways and Supporting Policy
Hydrogen	In theory, the existing gas grid could be retrofitted for the delivery of hydrogen to homes. However, this would require significant investment and upgrades to the gas network to ensure that it is safe, as well as 're-sleeving' of pipelines to prevent harmful methane leakages. The development of storage facilities for times of low demand would also be needed. Given these safety risks, illiquidity in production markets, and production challenges (see below), we suggest that Government pursue electrification as the primary source of home heating, using hydrogen where a viable alternative is not available. The two methods for producing hydrogen face significant challenges: 1. Blue hydrogen relies on carbon capture, which is currently unproven at scale, and involves residual CO_2 emissions as capture rates are <100%. It will also extend reliance on natural gas, leaving the UK exposed to volatile international gas markets and prices. 2. Utilising green hydrogen for heating is inefficient, requiring roughly five to six times the supply of electricity required from its main competitor, heat pumps, for the same heat output.[1] It also currently appears to not be cost competitive, estimated at two to three times more expensive than building decarbonisation via electrification.[2]	Government is currently reviewing the role of hydrogen in domestic heating, with a decision to come in 2026. To create greater certainty regarding the future of the sector, and thus accelerate the deployment of low carbon heating technologies, this decision should be addressed earlier (further info below). We recommend that Government state a preference for electrification in home heating, reserving valuable low carbon hydrogen supplies for other sectors that cannot electrify (such a heavy industry and transport. The Net Zero Strategy Delivery Pathway specifies the need for neighbourhood trials in 2023 and village trials in 2025.[3] The H100 trial, starting from mid-2024 will supply hydrogen to 300 homes. Government is committed to near term blending of hydrogen in the gas grid (up to 20% volume) and aims for 10GW low carbon hydrogen production capacity for use economy-wide by 2030.[4]

1: (IEA, 2021)

2: (Weidner and Guillén-Gosálbez, 2023)

3: (BEIS, 2021b)

4: (DESNZ, 2023b)

	Technology	Pathways and Supporting Policy
Heat Pumps	Renewables deployment trajectories mean heat pumps are projected to produce near-zero emissions by 2030. Air source heat pumps have an efficiency of over 300% and are around six times more efficient than green hydrogen[5] and are likely to offer the cheapest option for buildings decarbonisation.[6] Unlike hydrogen, heat pump technologies offer a route to low carbon cooling, demand for which is projected to increase due to climate change. Challenges include high capital cost; outdoor space requirements for fan components, the possible need for improved building insulation and/or larger radiators as they operate at lower temperatures than gas boilers. The electricity grid would need reinforcement to deliver sufficient power during periods of high demand. However, grid reinforcement will be required to accommodate automobile electrification and increasing demand for air conditioning in any case. Flexible, smart heat pumps could contribute to demand reductions during peak times.	Net Zero Strategy Delivery Pathway: between 7 and 11 million heat pumps are needed across the UK by the mid-2030s. Government committed to supporting 600,000 heat pump installations per year by 2028, expanding UK manufacturing, and targeting cost reduction by a minimum of 25-50% by 2025, to cost parity by 2030. £450 million Boiler Upgrade Scheme: provides £5,000 grants to support the switch to heat pumps in households, also providing a market-based incentive for manufacturers. The scheme is limited to 90,000 installations between 2022–2025. To promote innovation in heat pump technologies, the government committed £60 million.[7]
Heat Networks	Heat networks distribute heat generated or captured at a central local source via networks of underground hot water pipes, often capturing heat that would typically be wasted e.g., from factories, rivers, or the ground. They work particularly well to distribute heat in high density urban areas, scaling from networks catering for a cluster of buildings to entire cities. Currently, 14,000 heat networks provide lower-cost heating across the UK, but as of 2020, 93% of district heat networks in the UK were reliant on fossil fuels.[8] The networks mitigate the need to install boilers or electric heaters in each dwelling and may also be used for cooling.	Government pathways envisage that low carbon heat networks play a smaller role than either hydrogen or heat pumps, complementing whichever is chosen as the dominant technology. Government has committed £338 million through the Heat Network Transformation Programme, including a minimum contribution of £270m to the Green Heat Network Fund. Government aims to implement sector regulation and new heat network zones by 2025.[50]

5: (Cebon, 2022)

6: (Lowe and Oreszczyn, 2020)

7: (BEIS, 2021a)

8: (CCC, 2020b)

Annex 2 – Methodology: average v marginal cost pricing

For the "average cost" price scenario, we assumed that generators on CfD contracts will sell their energy at their contracted strike price, while existing nuclear and new renewable generators outside CfDs would be signing long term contracts at values that represent their generation costs. In addition, we assumed that ROC supported generators would be signing fixed long-term contracts at values that could be competitive with their expected merchant + ROC revenues. The final wholesale electricity price is calculated as the weighted average of these contracts and the realised or forecast market price for the remaining fossil fuel generation.

In the case of CfDs, the strike prices are already defined in the contracts, and we assume that they will only change based on inflation. For the volume estimation of CfDs output we used the LCCCs projections of CfD generation volumes for pre round 4 CfDs.[9] As round 4 generation is still not included in that database, we estimated the output volume by using the round 4 allocated capacity and expected delivery dates and standard capacity factors per technology.[10] We assumed that any round 5 generation would be entering operation after 2027, therefore it is not included in our estimation.

For future non-CfD nuclear generation, we used the 2022 generation and proportionally decreased it based on the expected decommissioning dates of the nuclear power plants. New non-CfD generation is calculated as the difference between renewable generation included in the FES 2023 System Transformation Scenario and all the existing and planned renewable generation (ROC and CfD renewables).[11] We assumed that existing nuclear generators and new renewables will be willing to contract their energy at 10% below the expected market price considering that this will eliminate their merchant risk.

Following the reasoning in the Pot-Zero proposal we assumed that existing ROC supported generators could be willing to move to fixed price contracts if these strike a good match between reducing their future merchant risk and not decreasing massively their expected return, calculated as the expected market price from the BAU scenario plus the expected ROC support, calculated as the average support per MWh from the last 5 years (71 £/MWh).[12] As the willingness to accept a lower price for a fixed contract is difficult to calculate and will depend on how much of the initial investment project has already recovered, we assumed the high price scenario considered in the Pot-Zero proposal (100 £/MWh).[13] Even though this price is lower than the expected revenues from market price electricity + ROCs, it decreases the risk, and covers the close to 5 years tail of the projects not covered by the RO scheme.

The remaining generation to reach the total electricity production from the FES 2023 System Transformation Scenario is assumed to be priced at the margin, meaning the same price the expected BAU wholesale price.

Once the wholesale price in this "average cost" price scenario is calculated, the final bill is obtained in the same way as for the BAU scenario. However, as ROC generators stop receiving the ROC support, and instead sell their energy directly at a contracted price, the policy portion of the bill corresponding to the ROC policy is eliminated. Furthermore, if CfD generators sell their energy at their contracted strike price, as assumed, then there would be no need for reconciliation of payments and the CfD allowance would be removed from the direct fuel component of the Default Tariff Cap.

9: (Low Carbon Contracts Company, 2022)

10: (BEIS, 2022a)

11: (National Grid ESO, 2023)

12: (Ofgem, 2021)

13: (Gross, MacIver and Blyth, 2022)