Department for Energy Security & Net Zero

Cabinet Office

Government Property Function

Catapult Energy Systems

Public Sector Combined Heat and Power (CHP)

The scale and cost-carbon challenge

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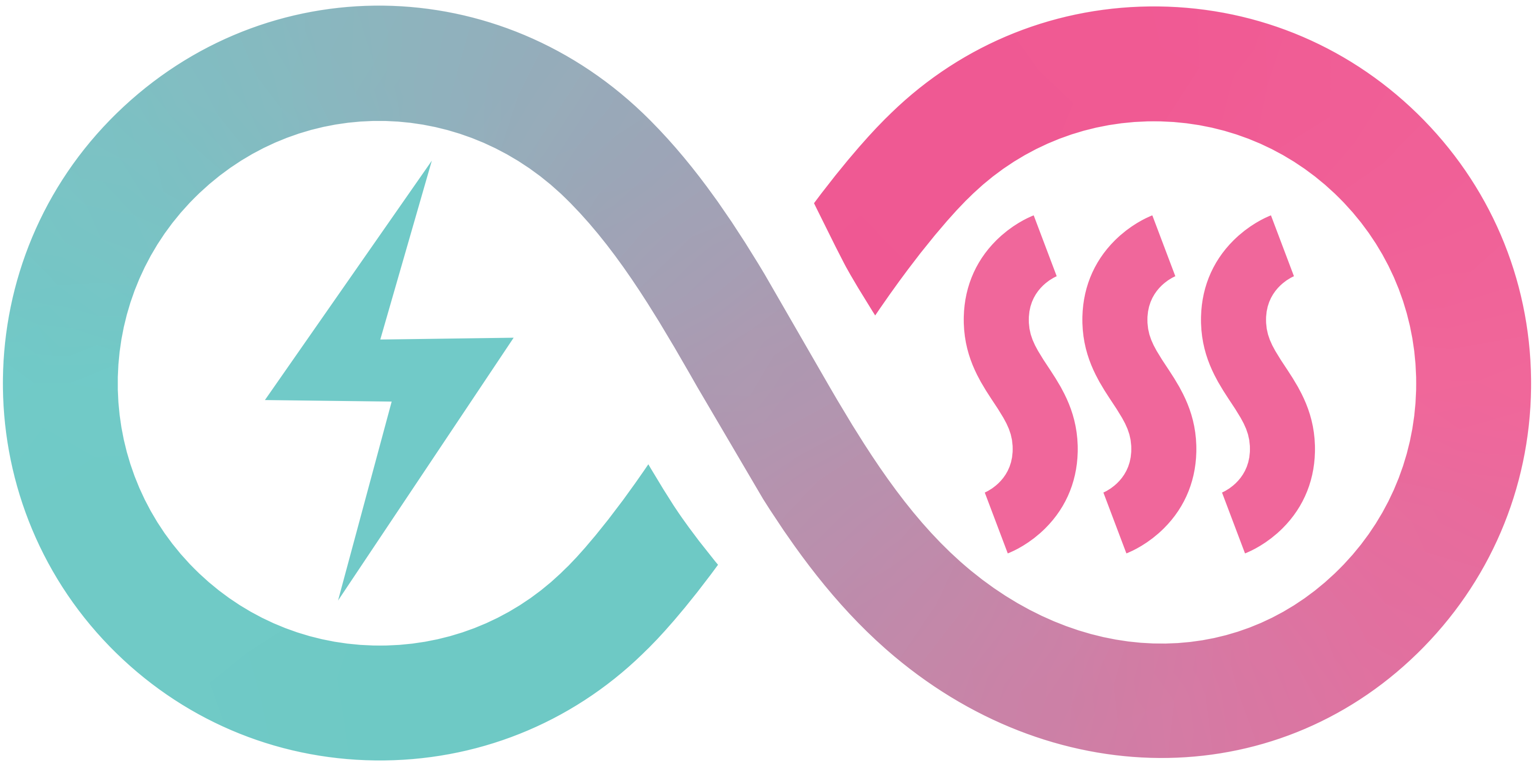

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Public Sector Decarbonisation Guidance

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Executive summary

For the past two decades Combined Heat and Power (CHP) has played a significant role in improving the efficiency of energy use across the UK in complex sites. Installed in both public sector estate and commercial sites it offered the opportunity for a site to receive cost-effective means of delivering both heat and electricity.

This report was produced by Energy Systems Catapult under the Benefits Maximisation programme, commissioned by the Department for Energy Security and Net Zero (DESNZ) Public Sector and Efficiency team; this report exposes the national energy risk associated with CHP end of life replacement. It has shown that the challenge is larger and more urgent than has previously been recognised.

It shows that:

1. **CHP installations** - Of the 2,059 CHP schemes registered with CHPQA, 309 or 15% are in the public sector, 70% of them are in healthcare settings.[1] A large proportion of these CHP installations will need replacement in the next 5-10 years.
2. **Unabated gas-fired CHP is no longer carbon-beneficial** - relative to an increasingly decarbonised electricity grid, and under the projections used in this analysis it is the highest-emitting option over the period to 2050.
3. **CHP economics** - CHP remains more economic than any low carbon technologies. This is predicated on current electricity and gas energy prices.
4. **Replacing CHP** - Transitioning away from CHP requires careful planning to manage grid capacity. Planning proactively for a low carbon replacement takes 3-5 years and potentially longer. If a like for like replacement is delivered reactively then it is unlikely low carbon steps will be taken until 2040.

[1] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

5. **Locational CHP opportunity** – CHP located in grid constrained areas offers an opportunity to provide flexibility to both the grid and the site.

In more detail CHP systems are embedded within the energy infrastructure of many of our most critical sites, particularly hospitals and university campuses, where they have provided a reliable and cost-effective means of delivering both heat and electricity.

For many years, this configuration offered genuine cost and carbon benefits compared to using a fossil fuel boiler alongside electricity imported from the grid. The context in which CHP operates has now changed. Many systems are approaching the end of their economic life at the same time as the UK energy system is undergoing rapid decarbonisation.

As the carbon intensity of grid electricity continues to fall, the greenhouse gas advantage that once justified gas-fired CHP has eroded significantly. Tightening air quality standards, particularly in urban areas, are placing additional pressure on combustion-based plant. And the financial case that made CHP attractive in the first place is now the very thing that makes its replacement so difficult.

The analysis in this report combines spatial data on CHP installations across Great Britain, a qualitative appraisal of replacement technology options, and quantitative modelling of the cost, carbon, and grid impact of the transition. The scale of the challenge is larger than previously recognised

Analysis of the Combined Heat and Power Quality Assurance (CHPQA) dataset identifies **309 public sector CHP installations in Great Britain that are registered with the scheme, representing approximately 15% of all CHPs that are registered**.[2]

Together, these installations account for around **414 MW of behind-the-meter electrical generation capacity**[2], roughly equivalent to 1% of Great Britain's winter peak electricity demand. The fleet is heavily concentrated in the **health sector, which accounts for around 70% of installations**, followed by universities at 15% and other education facilities at 9%.

This concentration is also geographic. Analysis of the Greater Manchester Combined Authority area alone identified around 33 MW of public sector CHP heat capacity sitting within the central Manchester heat network zone, illustrating the scale of anchor load potential that could support heat network development as these plants reach replacement.

[2] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

The age profile of this fleet is where the urgency becomes most apparent. Of the 309 public sector CHP installations identified[3], around 19 per cent (68 units) are already more than 15 years old and therefore beyond the typical economic lifespan of a gas engine CHP. A further 17 per cent sit in the 11 to 15 year bracket and will reach the same threshold within the next five years. The largest cohort, 42 per cent, falls in the 6 to 10 year bracket and has closer to a decade of useful life remaining before a replacement decision is required. Taken together, approximately three quarters of the public sector CHP fleet will reach a decision point about replacement, refurbishment, or decommissioning within the next decade.

The age profile also shows that CHP is not a technology of the past. Around 22 per cent of the fleet was installed within the last five years, representing 72 MWe of electrical capacity added since 2020.

There is no regulation preventing the installation of new gas-fired CHP in the public sector, and operators continue to consider it a viable option.

A recent review of NHS Green Plans found that 11 per cent of trusts (21 out of 190) reported intentions to install or upgrade CHP as part of their future decarbonisation approach.[4]

This illustrates the real risk that, without clearer signals and support, the default response to end-of-life CHP will be to install another one.

Because many of these installations were deployed during similar periods of policy support, the replacement wave is likely to concentrate within a relatively narrow window. This creates a timing challenge that goes beyond any individual site. If several hundred replacement decisions fall within the same few years, the pressure on supply chains, grant funding, and electricity network connection queues will be significant.

Whilst still cost effective, installations are no longer carbon positive against a decarbonised grid

Quantitative modelling of a representative 1.5 MW CHP replacement case reveals a fundamental tension that shapes every decision in this space. Under current market conditions, gas-fired CHP remains the lowest-cost option to operate by a significant margin. Every alternative assessed in this analysis is approximately 2.5 times more expensive to run on an annual basis when factoring in the dual-benefit of heat and electricity, with the dominant cost driver being the loss of cheap on-site electricity generation rather than the cost of the replacement heating technology itself.

[3] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

[4] Tabakov, P., Bhutta, M. et al. (2025). Decarbonizing the Healthcare Estate: Lessons Learned from NHS Trust Green Plans in England. Sustainability, 17(18), 8375. Available at: https://www.mdpi.com/2071-1050/17/18/8375

This structural cost advantage exists because the price of electricity in the UK is currently four to five times higher than the price of gas on a per-kilowatt-hour basis. Every kilowatt-hour of electricity a CHP generates on-site from relatively cheap gas avoids the purchase of a kilowatt-hour of significantly more expensive grid electricity. As long as this price gap remains wide, the financial logic at site level will continue to favour CHP, even as its carbon case weakens.

> **The financial case for CHP is not primarily about efficient heating. It is about the value of on-site electricity generation in a market where electricity costs approximately four to five times more per kilowatt-hour than gas.**

Historically with a carbon intensive electricity system CHP was seen as carbon beneficial, using energy efficiently (with reduced heat waste in electricity generation), but as the grid has decarbonised in the past decade this is no longer the case. In this report, we test six replacement options to demonstrate the impact of moving away from gas-fired CHP:

1. Replace with a like-for-like gas-fired CHP.
2. Replace with a gas boiler and electricity taken from the grid.
3. Replace with an air-source heat pump (ASHP) and electricity taken from the grid.
4. Replace with a ground-source heat pump (GSHP) and electricity taken from the grid.
5. Connect to an existing heat network and electricity taken from the grid.
6. Replace with hydrogen fuel-cell CHP.

Under the assumptions used in this analysis, gas-fired CHP is by a considerable margin the highest-emitting option over the period to 2050, and unlike every alternative its emissions do not reduce over time. Air source and ground source heat pumps deliver the strongest emissions reduction trajectory, benefiting automatically from the continued decarbonisation of the electricity grid. Yet these are also the technologies that carry the highest operating cost impact in the near term.

> **Public sector organisations with CHP systems face difficult investment decisions, caught between Net Zero obligations and the need to manage tight budgets.**

The grid constraints will slow the pace of change

Replacing a CHP with an electrically powered heating technology has a compounding effect on a site's electricity grid connection. The on-site generation that previously offset part of the site's demand disappears, and at the same time a substantial new heating load is added. For the representative case, the risk is that this can more than double peak grid import requirements. In many cases, this will exceed the site's existing contracted capacity and require physical infrastructure upgrades such as new substations or reinforced cabling, with high capital costs and long lead times.

The potential cumulative impact on the distribution network, when large numbers of sites transition from CHP will be significant. This is likely to be more acute in the urban areas where most CHP is concentrated and where the grid is already under the greatest pressure.

Where sites do transition, they risk delays with ageing equipment driven by the UK connection queue. The UK connection queue, operated by the National Energy System Operator, has grown to over 700 GW of projects, and commercial connection timelines of 18 months to over a decade are now common in some regions.

Transitioning from CHP is not as simple as a new heat source project as it simultaneously requires additional network capacity, which can lead to grid reinforcement and delays

For public sector sites planning CHP replacement, early engagement with their distribution network operator will be critical. But engagement alone cannot create capacity that does not exist, and the pace of the transition across the sector will in many cases be set by the pace at which local networks can accommodate the change.

Proactive replacement planning takes longer than expected

Replacement projects typically take three to five years from initial planning, feasibility, design, installation through to operational handover. It takes longer if grid reinforcement or additional connections are required, leading to delays.

A site that begins planning in 2026 is therefore looking at an operational replacement date no earlier than 2029.

A site that waits until its CHP is failing loses most of its options and typically defaults to like-for-like replacement, locking in a further 15 to 20 years of fossil fuel dependency.

The decisions made at public sector sites over the next two to three years will shape the carbon trajectory of the estate well into the 2040s.

A site that installs a like-for-like CHP in 2027 will still be operating that plant in 2045, well beyond the dates by which most public sector organisations have committed to reach Net Zero. A site that invests in a low carbon alternative will face higher upfront and operational costs, but will benefit from the progressive decarbonisation of the grid and will avoid the risk of stranded assets as carbon pricing and air quality regulation continue to tighten.

The default trajectory, in which sites make individual decisions at the point of CHP failure under current market conditions, will produce an outcome that is materially worse for carbon emissions, energy security, and long-term value than a managed transition would deliver. Continued reliance on gas-fired CHP increases the public sector's exposure to international gas price volatility, a risk that has been sharply illustrated in recent years. At the same time, the evidence in this report suggests that existing CHP plants, if managed as transitional assets rather than replaced like-for-like, could play a valuable role in supporting local grid resilience during the transition period itself, providing flexible generation capacity and reducing peak demand on constrained networks. The gap between the default trajectory and a managed transition is where both the risk and the opportunity sit.

Managing the transition through a hybrid approach

A managed transition does not mean an immediate switch to a single low carbon heating technology at every site. For many public sector sites, particularly those with complex resilience requirements, constrained grid capacity, or extensive enabling works to deliver, a phased approach combining a primary low carbon heat source with a retained or smaller CHP in a transitional role could be the most practical route forward.

Repurposing existing CHP as a resilience and flexibility asset, rather than as the primary heat source, allows sites to deliver significant near-term carbon savings while the wider electrification of heat is planned and delivered. Managed carefully, with a clear and funded exit plan, this hybrid approach can bridge the gap between today's infrastructure and a fully decarbonised future without locking in another 15 to 20 years of fossil fuel dependency.

What the report concludes

The report draws several conclusions from the evidence it presents.

1. The challenge is larger and more urgent than has previously been recognised, and it is concentrated in a relatively small number of operator groups, most notably NHS trusts and higher education institutions. This concentration is both a risk and an opportunity, creating scope for coordinated action that would not be possible if the challenge were evenly distributed.

2. The cost-carbon tension is structural rather than incidental. It is driven by the price gap between electricity and gas and by the pace at which policy is narrowing that gap. Individual organisations cannot resolve it through better planning alone, and the transition cannot be left to site-by-site decisions under current market conditions without accepting a significant risk of collective carbon lock-in across the public sector estate.

3. The grid constraint will shape the pace of the transition regardless of what individual sites decide. Early and coordinated engagement between public sector estate holders and distribution network operators is essential, and there is a strong case for a deeper joint analysis of forward CHP replacement demand against network capacity and planned reinforcement.

4. A well-managed transition looks materially different from a standard boiler replacement. It requires long-term site energy master planning, early grid engagement, consideration of heat network opportunities, a realistic view of the role that transitional and hybrid CHP configurations can play, resilience designed in from the outset, and the integration of complementary measures such as solar, storage, and flexibility into the core business case rather than as afterthoughts.

5. The transition away from public sector CHP is coming, whether it is managed or not. The choice is not whether these assets will be replaced, but how. This report has tried to describe the shape of that choice honestly, and to provide the evidence base that those involved will need as the decisions are made.

Next steps

Based on the learnings from this report the following steps are recommended:

- Expand research to cover all CHP installations nationally.
- Further analysis of all CHP installations and consideration about their locations within areas of constraint and areas requiring flexibility.
- Research into potential scenarios for site-by-site adoption.
- Development of national guidance on how sites should assess their options for end-of-life CHP replacement.
- Incorporating impact of CHP scenarios into national carbon budgets modelling.
- Coordination with the bodies such as NHS England on future impact and decision making around CHP.

The risk of inaction is a public sector estate that remains structurally dependent on gas through the 2040s. Without coordinated planning and early action, the default outcome at site level is like-for-like CHP replacement. Repeated across 280 or more sites, this would lock in a further 15 to 20 years of fossil fuel dependency at many of the country's most critical sites, pulling the public sector estate out of alignment with Net Zero and leaving substantial stranded asset risk on the balance sheet.

The scale of the challenge

Combined Heat and Power generation has played a significant role in improving the efficiency of energy use across the UK public sector estate over the past two decades.

CHP systems are embedded within the energy infrastructure of many large and complex sites. Widely deployed across hospitals, universities, and large public buildings, they have provided a reliable and cost-effective means of delivering both heat and electricity, while historically offering carbon savings compared to using a fossil fuel boiler and electricity imports from the public grid.

This section draws on the Combined Heat and Power Quality Assurance (CHPQA) dataset to set out the scale, distribution, and age profile of public sector CHP in Great Britain, and to show why the coming decade will be a decisive one for a substantial portion of the estate.

The Combined Heat and Power Quality Assurance (CHPQA) programme

The CHPQA programme is a voluntary, UK-wide government scheme that has been in operation since 2000.

It assesses and certifies the energy efficiency of CHP installations, with successful certification providing eligibility for financial incentives such as Climate Change Levy exemptions.

It is open to any organisation operating CHP in the UK and has seen widespread uptake, with participation typically driven by operators seeking to access fiscal benefits through annual self-assessment of their scheme's energy performance. The CHPQA dataset used in this report was made available by DESNZ under a data sharing agreement.

Scale of CHP adoption in the public sector

There are over 2,059 CHP schemes registered[5] with the CHPQA programme in 2024, of which 309 installations (approximately 15 per cent) are located on public sector sites.[6]

The geographical dispersion of these installations throughout Great Britain is presented in Figure 1.

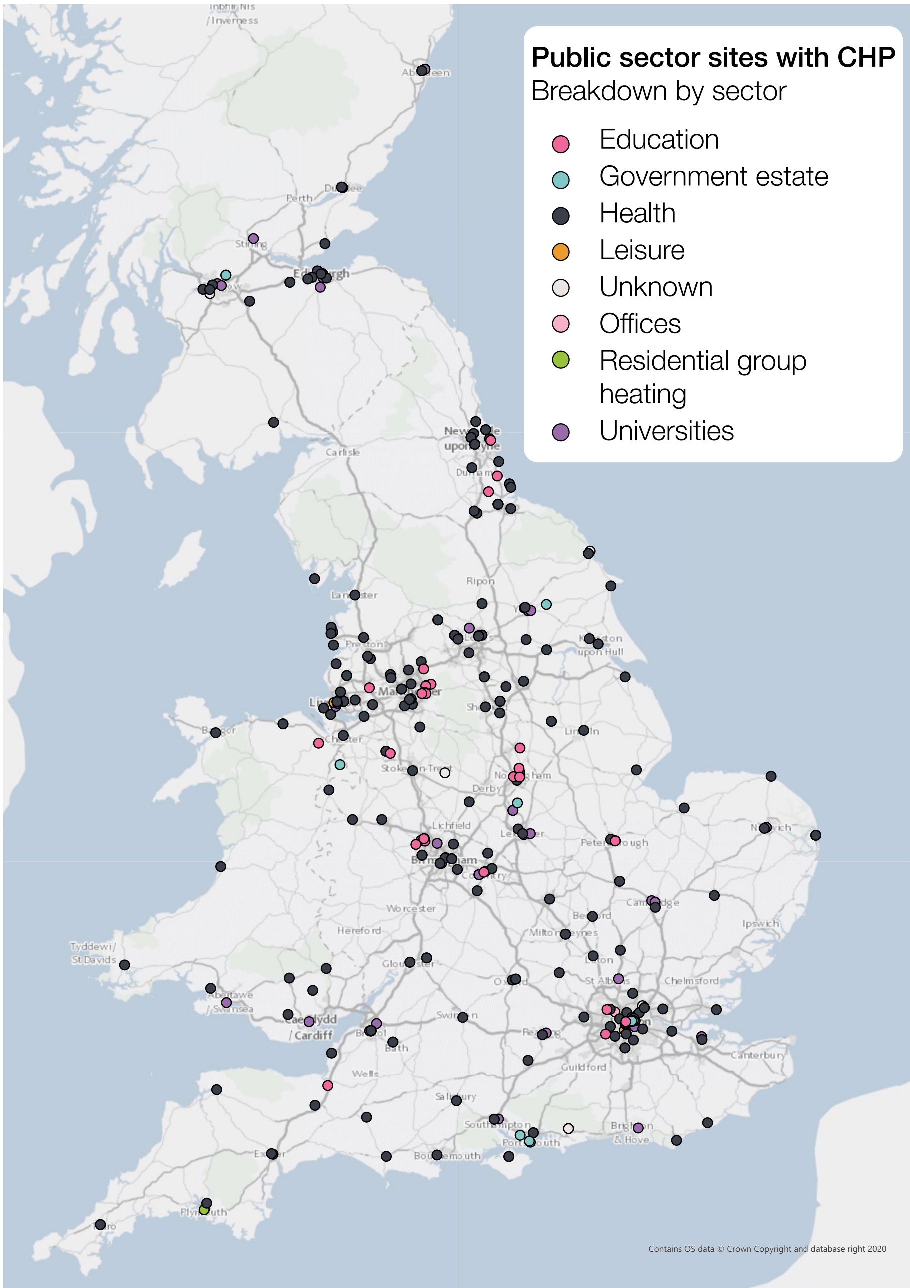


Figure 1: Geographic locations of CHP across the public sector estate[1]

[5] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

[6] Department for Energy Security and Net Zero (2026). Combined Heat and Power Quality Assurance (CHPQA) dataset.

The total CHP plant capacity in the public sector in 2024 was approximately 414 MWe[7], equivalent to around one per cent of Great Britain's winter peak electricity demand of approximately 45 GW.[8]

In absolute terms this is not a large share of national generation, but it represents a concentrated and strategically important portion of the public sector's energy infrastructure, sitting behind the meter at some of the country's most critical sites.

CHPQA data also shows that most installations within the public sector are concentrated in a small number of sectors.

Around 70 per cent of installations are in the health sector, 15 per cent in universities, and 9 per cent in other education facilities. The remainder is spread across government estate, leisure facilities, offices, and residential group heating schemes.[7]

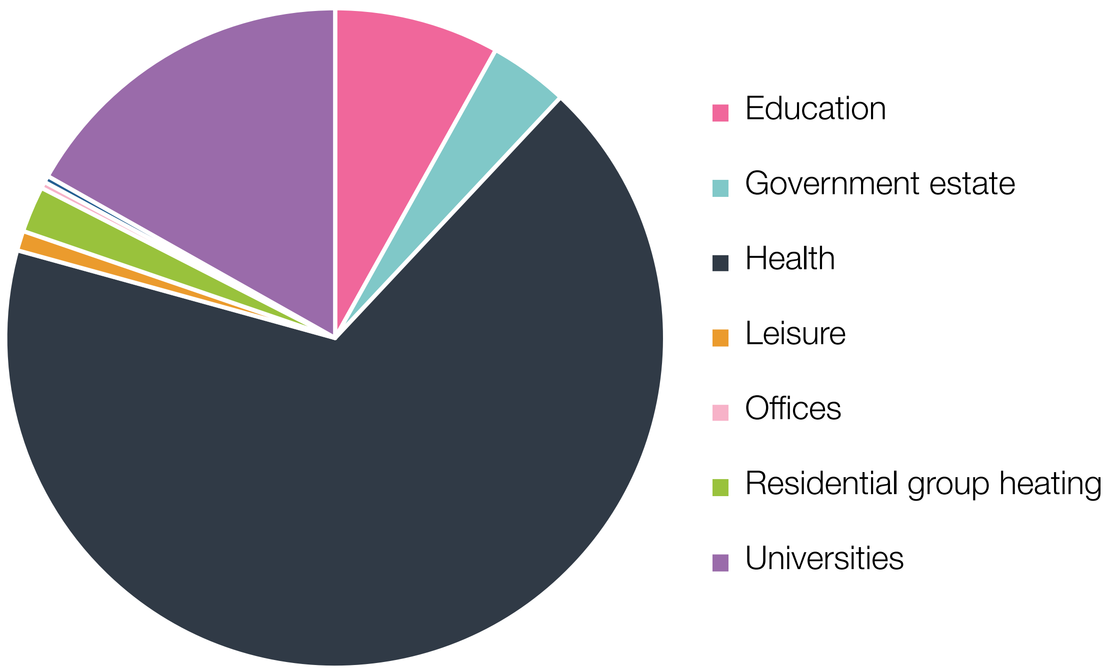


Figure 2: Breakdown of public sector categories with CHP schemes[1]

[7] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

[8] National Energy System Operator (2024). Winter Outlook 2024/25. Available at: https://www.neso.energy

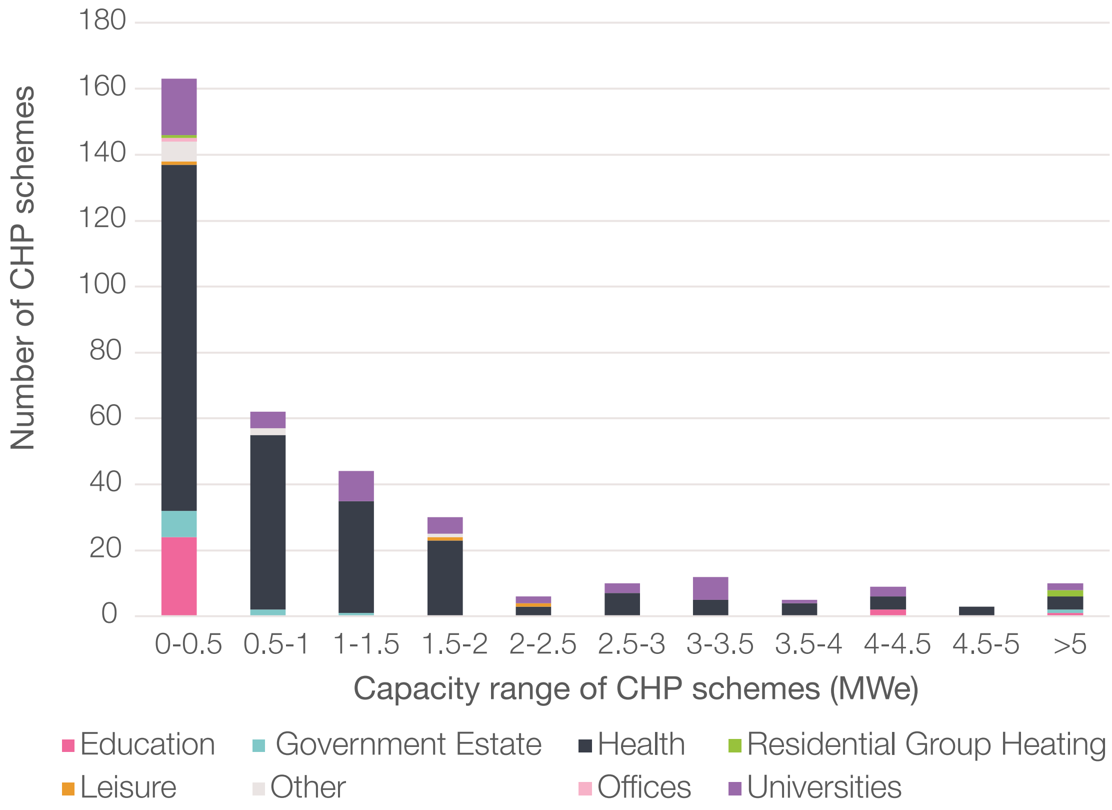


Figure 3: CHP plant size distribution in the public sector

This concentration matters because the transition challenge is not evenly distributed across the public sector. It falls disproportionately on a relatively narrow group of operators, most notably NHS trusts and higher education institutions, whose sites tend to be large, complex, and operationally sensitive.

The plant size distribution shows that most sites have relatively small CHP units, with over 80 per cent of schemes below 1.5 MW electrical capacity.[7]

A smaller number of larger installations, typically above 3 MW, account for a disproportionate share of total capacity and are concentrated in the largest hospital sites and university campuses. This has practical implications for the transition.

While there are many small sites where replacement decisions will be repeated across hundreds of operators, a relatively small number of large sites carry a significant proportion of the total capacity and associated carbon impact.

Most CHP plants will require replacement in the next decade

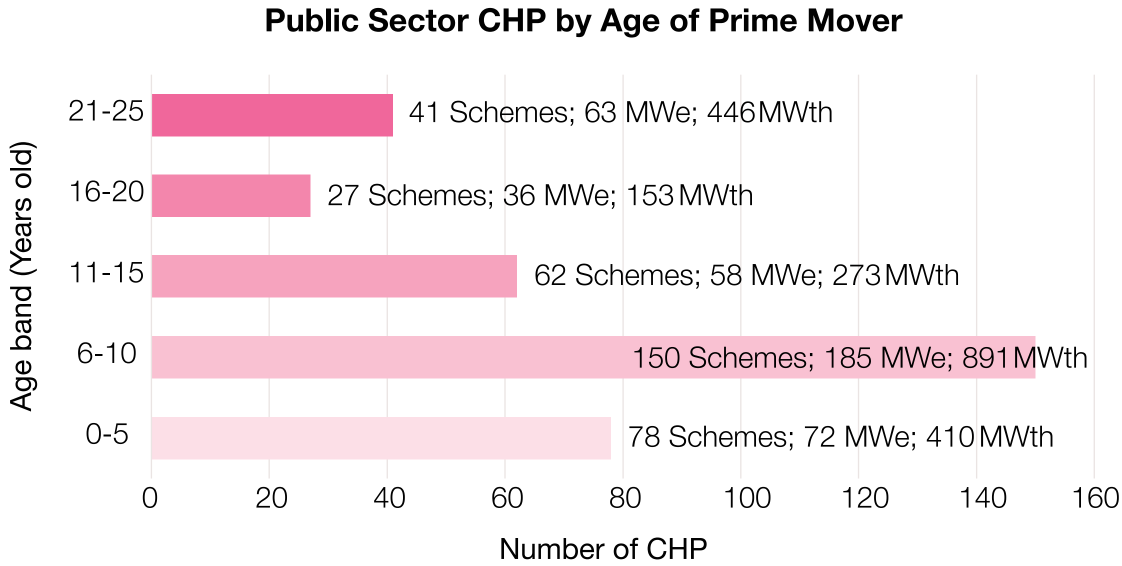


Figure 4: Public sector CHP by age of prime mover[1]

The typical economic lifespan of a gas engine CHP unit is generally considered to be 15 to 20 years[9,10], varying with prime mover type, operating hours, and maintenance regime. Beyond that point, units tend to experience declining efficiency, rising maintenance costs, and an increasing risk of unplanned outages, all of which erode the economic and carbon case that originally justified their installation.

Analysis of the CHPQA dataset shows that over 20 per cent of CHP units in the public sector (68 installations) are already more than 15 years old, with a further 60 per cent (212 units) in the 6 to 15 year age band and therefore approaching the typical replacement threshold.[7] Taken together, this means that approximately four fifths of the public sector CHP fleet will reach a decision point about replacement, refurbishment, or decommissioning before 2035.

It should be noted that these figures are derived from prime mover age data recorded in the CHPQA dataset, which has inherent limitations. In some cases, a prime mover may have been replaced on a site with multiple CHP units without this being reflected in the scheme record, and the CHPQA dataset only captures data from 2000 onwards, meaning that some installations may be older than their recorded age suggests. If anything, this means the analysis is likely to understate rather than overstate the age of the fleet, and the true replacement pressure may be greater than these figures indicate.

[9] Chartered Institution of Building Services Engineers (2023). Guide M: Maintenance Engineering and Management. 3rd edition. London: CIBSE. Available at: https://www.cibse.org/guidem

[10] Chartered Institution of Building Services Engineers (2013). AM12: Combined Heat and Power for Buildings. London: CIBSE.

The units in the older age bands are responsible for a large share of generation and heat output. The oldest band in the dataset, units between 21 and 25 years old, includes 41 installations responsible for approximately 63 MWh of annual electricity generation and 446 MWh of heat. The 16 to 20 year band includes 27 schemes generating around 36 MWh of electricity and 153 MWh of heat.

These are not small contributions to the energy supply of the sites they serve, and their loss or replacement will need to be managed carefully to maintain continuity of service.[11]

These ageing schemes are likely to be experiencing declining efficiency, rising maintenance costs, and increasing risk of unplanned outages, all of which erode the economic and carbon case that originally justified their installation. If a significant number of schemes are already at or beyond their economic life, there is a real risk that units will fail or become uneconomical to maintain before replacement solutions have been designed, funded, and delivered.

There is also a timing dimension to the challenge. Many CHP installations were deployed during similar periods of policy and funding support in the 2000s and 2010s, meaning that a large proportion of assets may reach end-of-life within a relatively narrow timeframe.

If replacement decisions across the sector cluster in the same few years, this could place additional pressure on supply chains, feasibility and design capacity, grant funding programmes, and electricity network connection queues.

[11] These generation and heat output figures are modelled estimates derived from the CHPQA dataset by combining registered capacity with typical operating assumptions for each age band.

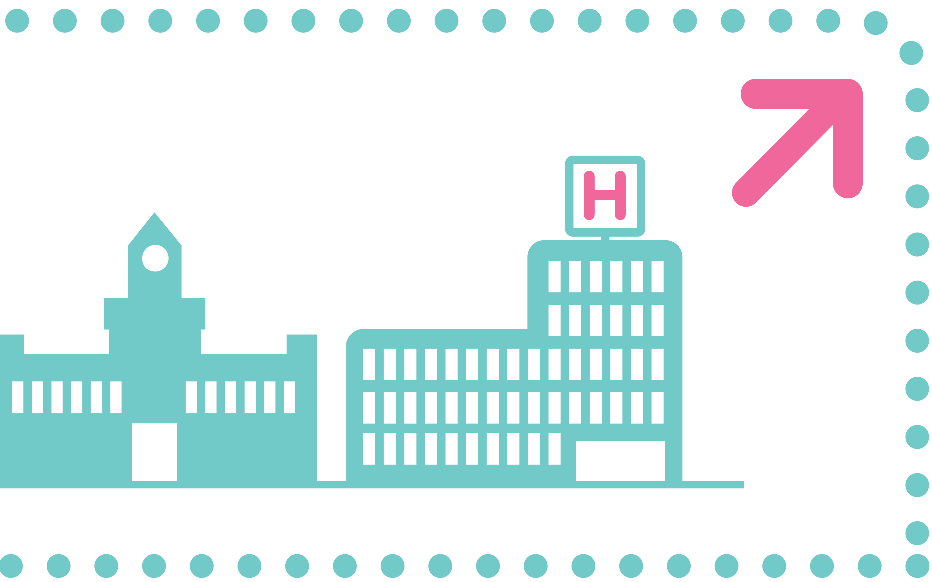
Overlaps with grid constraints and heat network zones

The replacement challenge does not sit in isolation. It interacts with two other features of the evolving energy system that will shape what is possible and affordable at any given site: the state of the local electricity network, and the development of heat network zones.

Mapping public sector CHP locations against areas of known electricity network congestion shows that a meaningful proportion of sites sit within regions where the distribution network is already under pressure. These are areas where new connections and connection upgrades face longer lead times and, in some cases, significant enabling costs.

For a public sector site planning to replace a CHP with an electrically powered heating solution, the local grid context will be a major determinant of both cost and timeline. The concentration of CHP in and around major urban areas, which are also the regions with the most constrained networks, means this is not a marginal concern.

The rollout of heat network zoning creates a different kind of opportunity. Public sector sites tend to have large and consistent heat demands, and many already operate campus heat networks fed by their CHP. As heat network zones are designated and developed, public sector sites with CHP become natural candidates for connection. They offer the kind of anchor load that can improve the commercial viability of a network, and their existing internal distribution infrastructure reduces the cost and complexity of connection compared to buildings without prior heat network experience.



Why this matters now

Given the scale of CHP infrastructure identified across the public sector estate, the case for acting now on decarbonisation planning is compelling.

The decisions made at each of these sites over the coming years will shape the carbon emissions of the public sector estate for another 15 to 20 years. A site that installs a like-for-like gas-fired CHP in 2027 will still be operating that plant in 2045, well beyond the dates by which most public sector organisations have committed to reach Net Zero.

A site that invests in a low carbon alternative will face higher upfront and operational costs, but will benefit from the progressive decarbonisation of the electricity grid and will avoid the risk of stranded assets as carbon pricing and air quality regulations continue to tighten.

The scale of the challenge, and the narrowness of the window in which it must be addressed, is the case for treating CHP transition as a strategic priority rather than a series of individual plant replacement decisions. The remainder of this report examines the financial, technical, and practical dimensions of that challenge, and sets out what a well-managed transition might look like.

The cost-carbon tension

The previous section set out the scale and urgency of the replacement challenge. This section turns to what that challenge looks like in financial and carbon terms for an individual site, and shows why the economics of moving away from CHP are fundamentally different from a standard boiler replacement.

The analysis that follows is built around a representative counterfactual CHP system rated at 1.5 MW electrical output, typical of systems found across the public sector estate.

The full specification of the representative case, along with the capital cost benchmarks, emission factors, and methodology used in the modelling, is provided in Appendix A.

A qualitative appraisal of each of the technology options, including aspects of whole system integration and Sankey diagrams showing how each changes the flow of energy at a site compared with the existing CHP, is provided in Appendix B.

The operational cost advantage of CHP

CHP generates both heat and electricity from a single fuel input, and much of its economic value comes from displacing electricity that would otherwise be purchased from the grid at a significantly higher unit cost than gas.

In the UK, the price of electricity is currently around four to five times the price of gas on a per-kilowatt-hour basis, with non-domestic electricity prices averaging around 24 p/kWh and gas prices around 5 p/kWh in 2025.[12] Every kilowatt-hour of electricity generated on-site from relatively low-cost gas avoids the purchase of a kilowatt-hour of significantly more expensive grid electricity. The wider this gap, the stronger the financial case for CHP.

[12] Department for Energy Security and Net Zero (2025). Prices of fuels purchased by non-domestic consumers in the United Kingdom. Quarterly statistical release. Available at: https://www.gov.uk/government/statistical-data-sets/prices-of-fuels-purchased-by-non-domestic-consumers-in-the-united-kingdom

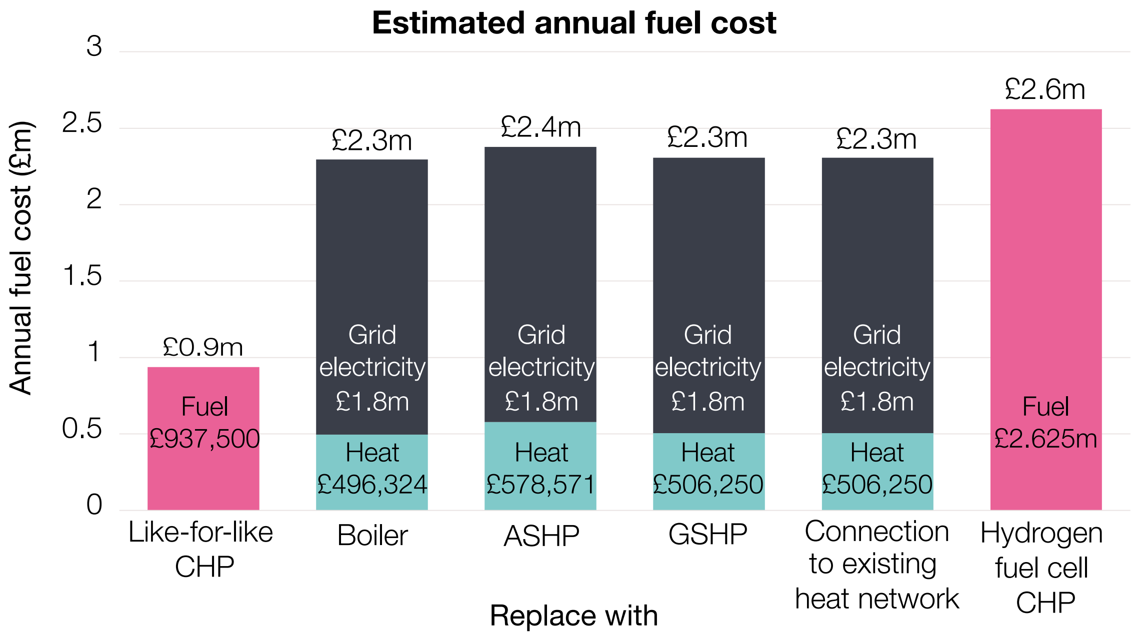


Figure 5: Estimated annual fuel cost of each transition technology option

When a CHP system is replaced with an alternative heating technology, this advantage is lost in two ways at once. The site must import all of the electricity previously generated on-site, and if the replacement is electrically powered, total electricity consumption rises further to meet the heating load. In most cases, the increase in electricity costs outweighs the saving from no longer purchasing gas for the CHP.

The scale of this impact is shown in Figure 5. The counterfactual CHP has an annual fuel cost of approximately £937,500. Every alternative option is significantly more expensive to operate, with annual energy costs ranging between £2.3 million and £2.6 million, approximately 2.5 times the CHP baseline. The dominant cost driver across all non-CHP options is the cost of importing the electricity previously produced on-site, and this is largely independent of the heating technology selected. Ground source heat pumps and heat network connection show the lowest heating-related costs among the alternatives. Hydrogen fuel cells carry the highest operating cost, driven by the current price of hydrogen as a fuel.

> **The financial case for CHP is not primarily about efficient heating. It is about the value of on-site electricity generation in a market where electricity costs approximately four to five times more per kilowatt-hour than gas.**

As long as the price gap between gas and electricity remains wide, this structural cost advantage will continue to make CHP the lowest-cost operating option, even as its carbon case weakens.

The capital picture

Capital costs for the six replacement options vary widely, reflecting both the maturity of the technology and the complexity of installation.

Figure 6 shows the estimated capital cost of replacing the representative 1.5 MW CHP with each alternative, using benchmark ranges derived from published sources (see Appendix A). It should be noted that these figures represent indicative plant and installation costs only, and do not include wider project costs such as feasibility, design, enabling works, and commissioning, which can add materially to total delivered cost.

A fossil fuel boiler is by far the lowest-cost option at approximately £170,000, reflecting the simplicity and maturity of the technology. At the other end of the range, hydrogen fuel cells carry the highest capital cost at an estimated £4.5 million, with ground source heat pumps close behind at £3.8 million.

Between these extremes, a notable finding emerges: a like-for-like CHP replacement and an air source heat pump installation are broadly comparable in capital cost terms, at £1.73 million and £1.77 million respectively. For a similar level of upfront investment, a site could install either a

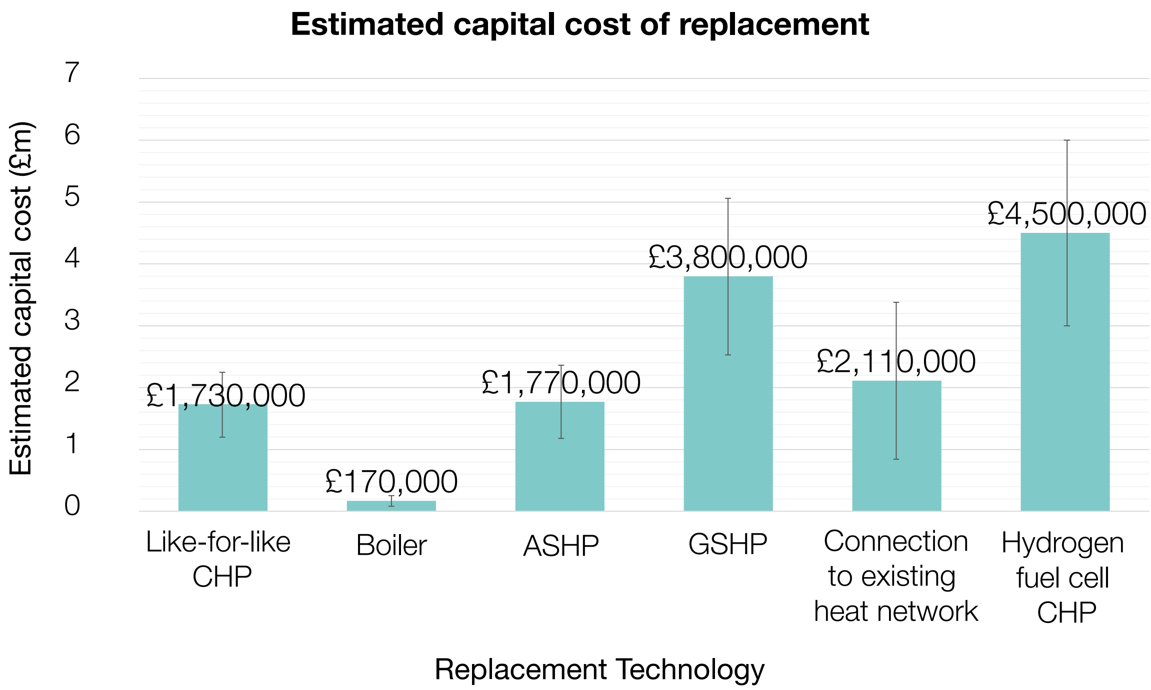


Figure 6: Estimated capital cost of replacing the representative CHP with each transition technology

new gas-fired CHP or an air source heat pump. Connection to an existing heat network sits slightly above this at £2.11 million, though with significant variation depending on distance to the network and the extent of internal modifications required.

The lowest capital cost options, boilers and like-for-like CHP, are those that do not support long-term decarbonisation. The technologies that deliver the greatest carbon reduction require significantly higher upfront investment.

Grid connection: the hidden cost

Replacing a CHP system with an electrically powered heating technology has a compounding effect on a site's grid connection.

The on-site generation that previously offset part of the site's load disappears, and if the replacement is electrically powered, a substantial new heating load is added at the same time. For the representative case, this can more than double peak grid import requirements (Figure 7).

In many cases, this will exceed the site's existing contracted capacity and require physical infrastructure upgrades such as new substations or reinforced cabling, with high capital costs and long lead times.

The implications of this when scaled across hundreds of public sector sites, many of them in areas where the grid is already constrained, are explored in Section 4.

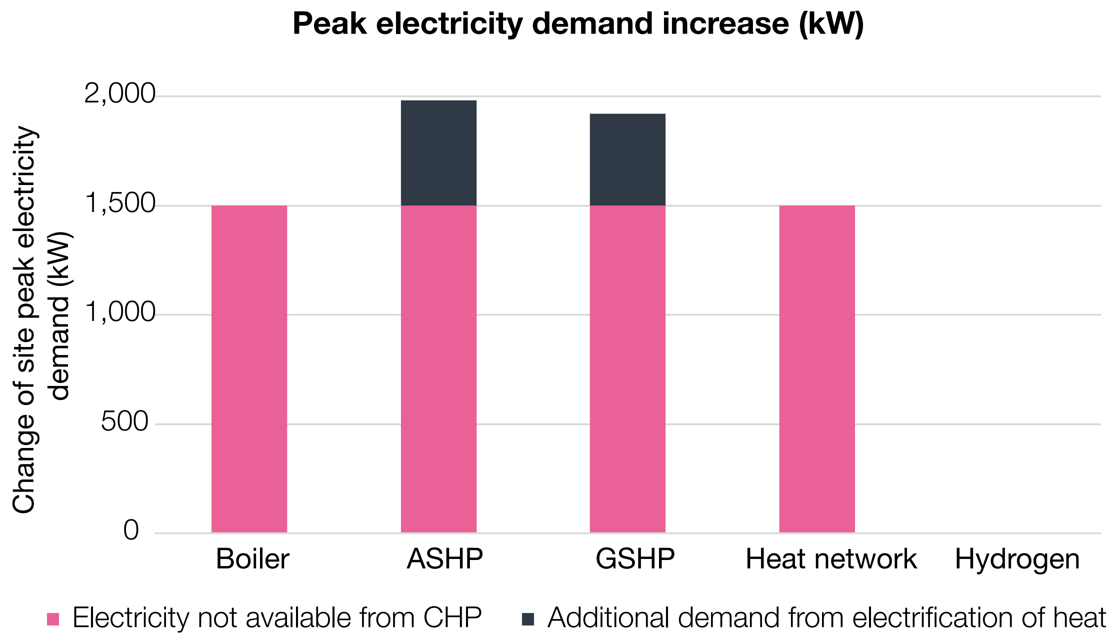


Figure 7: Peak grid electricity import increase for each replacement technology, showing the contribution from loss of CHP generation and from new electrical heating load

The carbon trajectory

While CHP has historically been recognised as a lower carbon option compared to separate generation of heat and electricity, this advantage has eroded as the carbon intensity of the GB electricity grid has fallen, and it is projected to continue falling towards the government's Clean Power 2030 target and beyond.[13] The emissions analysis presented here uses the HM Treasury Green Book supplementary guidance on the valuation of energy use and greenhouse gas emissions, which provides projected grid electricity emission factors out to 2050.[14]

Figure 8 presents estimated annual greenhouse gas emissions for each option from 2025 to 2050. Each alternative technology shows a declining emissions trajectory over time, driven by the progressive decarbonisation of the electricity grid. Technologies that are powered by or interact with grid electricity benefit automatically from the falling carbon intensity of that grid, without any change to the on-site plant or its operation.

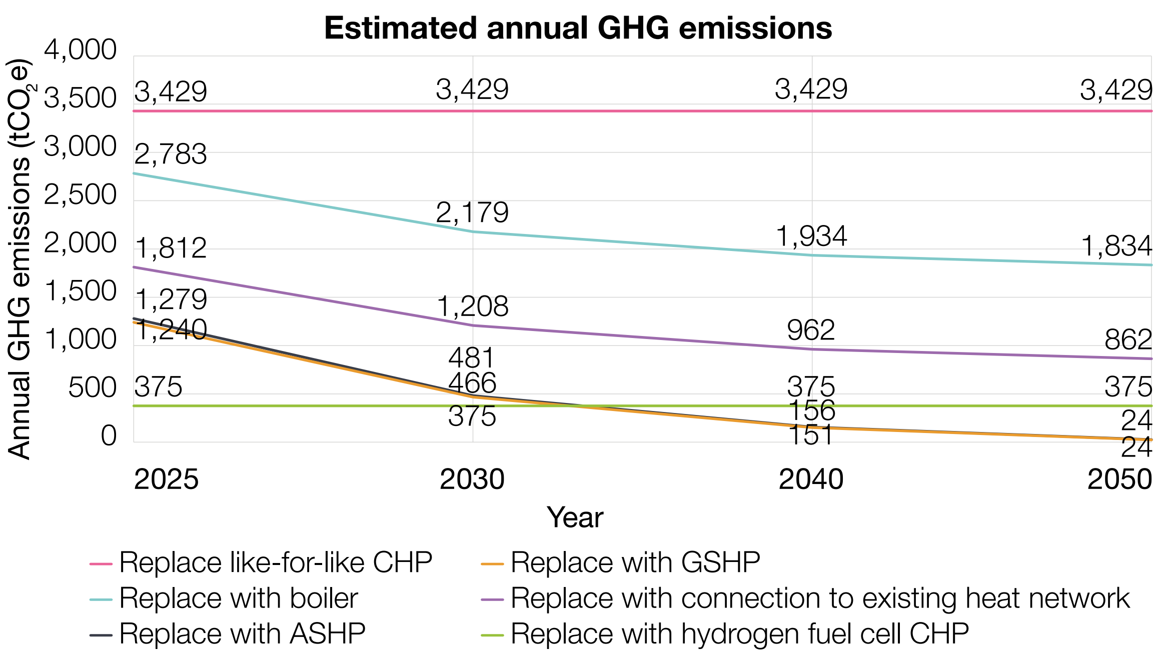


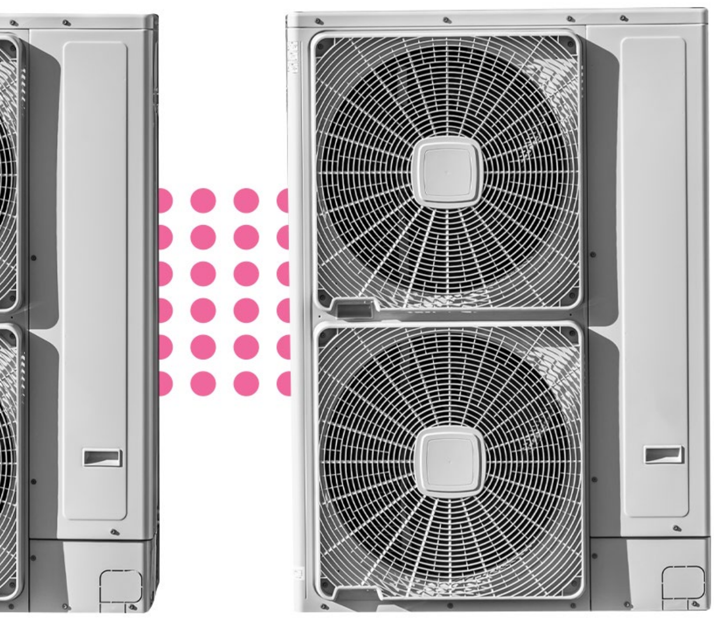
Figure 8: Estimated annual greenhouse gas emissions from 2025 to 2050 for each replacement technology

[13] Department for Energy Security and Net Zero (2024). Clean Power 2030 Action Plan. Available at: https://www.gov.uk/government/publications/clean-power-2030-action-plan

[14] HM Treasury and Department for Energy Security and Net Zero (2025). Valuation of energy use and greenhouse gas emissions: supplementary guidance to the HM Treasury Green Book. Available at: https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

The ground and air source heat pump options deliver the strongest emissions reduction trajectory of the established technologies, reflecting their high coefficient of performance and the compounding benefit of the decarbonisation of the grid. The fossil fuel boiler (using gas) starts lower than CHP because it consumes less gas overall, but it remains the highest-emitting alternative throughout the period. The hydrogen fuel cell, assuming supply of green hydrogen, shows a flat and low emissions profile but does not benefit from the same declining trajectory as the electrically powered options.

> **Under the assumptions used in this analysis, gas-fired CHP is by a considerable margin the highest-emitting option over the period to 2050, and unlike every alternative its emissions do not reduce over time.**



The dichotomy of cost and carbon

Taken together, the operational cost, capital cost, and carbon analyses reveal a fundamental tension at the heart of the CHP transition.

The options that deliver the greatest carbon savings are also those that impose the greatest financial impact. Conversely, the option that is cheapest to operate is the one that offers no carbon reduction at all.

This tension is not unique to CHP replacement, but it is particularly acute. In most building decarbonisation decisions, the counterfactual is a gas boiler, where the cost differential between fossil fuel and electric heating is the primary consideration. In the CHP case, the counterfactual also includes the loss of on-site electricity generation, which as the operational cost analysis has shown accounts for the majority of the cost impact.

Figure 9 brings together the capital, operational, and carbon analyses, comparing two timing scenarios: decarbonising heat in 2030, and deferring the transition by installing a like-for-like CHP in 2030 before replacing it with a low carbon alternative in 2045.

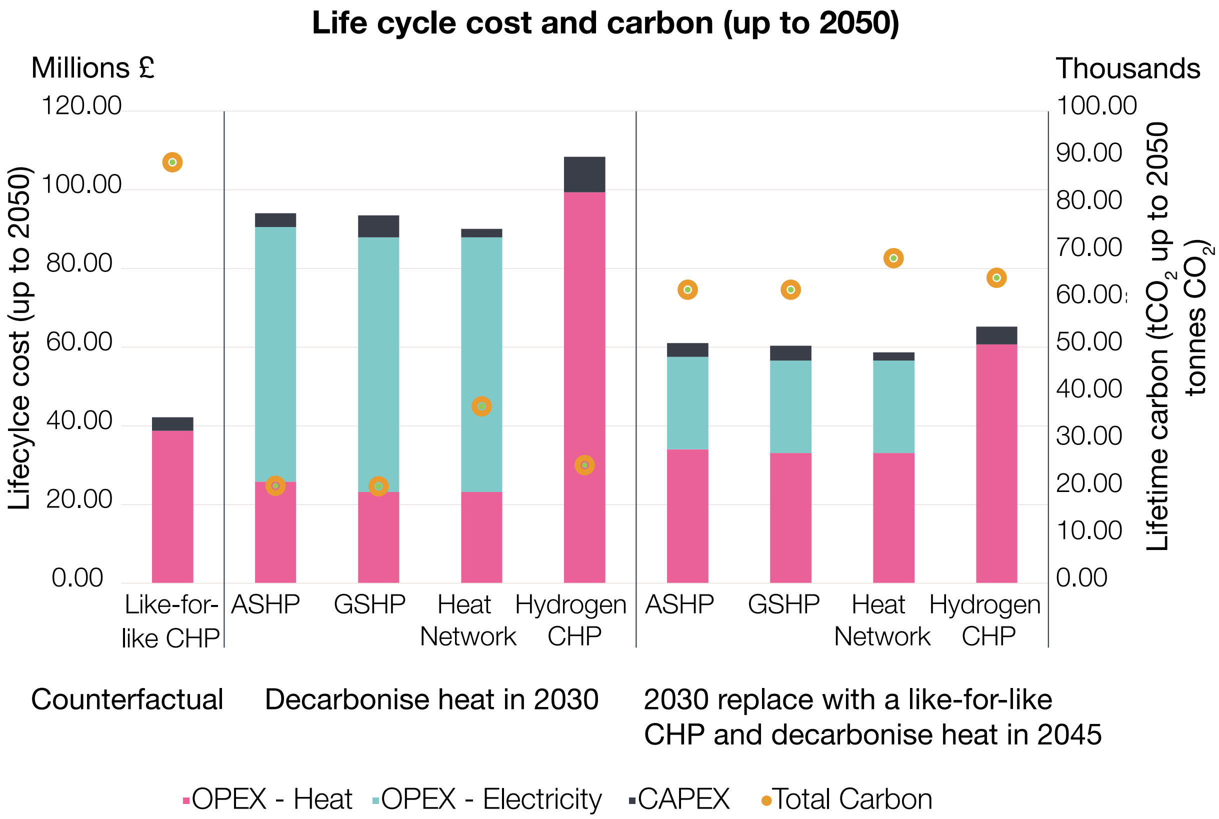


Figure 9: Lifetime cost and carbon emissions to 2050 for each replacement option under two timing scenarios

The analysis shows that delaying the transition carries a significant carbon cost.

Replacing CHP plants with low carbon alternatives at the next available replacement cycle, rather than installing another fossil fuel CHP in the interim, could roughly double the total carbon emissions reduction achieved by 2050. The financial picture is more mixed. Deferred scenarios reduce the near-term operational cost impact by retaining CHP for longer, but they also compress the period over which the low carbon alternative can deliver value and push significant capital costs into the 2040s.

The implications of this become much harder when viewed through the lens of the scale analysis in Section 2.

Approximately four fifths of the public sector CHP fleet will reach a decision point about replacement, refurbishment, or decommissioning before 2035. At each of these 280 or so sites, a decision-maker will be asked to weigh a low carbon option that costs roughly two and a half times more to operate, often more to install, and which in many cases requires a grid connection upgrade with its own timeline and cost, against a like-for-like CHP replacement that is cheaper on every financial metric in the near term.

Case study: Kingston Hospital NHS Trust

Kingston Hospital is a district general hospital serving around 350,000 people in southwest London. When its Heat Decarbonisation Plan was produced in 2021, the site's energy infrastructure was built around a gas-fired CHP system located in the main energy centre, generating electricity and heat for most of the campus, with around half the thermal output used to raise steam. The CHP contract was due to expire in 2024, creating a clear decision point.

The plan found that 85 per cent of the trust's carbon emissions came from natural gas, and that the site sat above the upper quartile of NHS hospitals for carbon intensity per square metre of floor area. Critically, modelling showed that if the trust continued with CHP, grid decarbonisation alone would reduce its emissions by only 5 per cent through to 2040, because the dominance of on-site gas consumption meant the site would see almost no benefit from a cleaner grid.

The recommended pathway was to disconnect the CHP at contract expiry, connect to a proposed district heat network for 80 per cent of main site demand, de-steam the site, expand the low temperature hot water network, and install heat pumps for outbuildings. Gas boilers would cover the residual 20 per cent, with a commitment to revisit this in 2032. Total capital expenditure was estimated at around £6.5 million.

While the plan set out a thorough technical pathway, it did not fully quantify the operational cost implications of losing on-site electricity generation. This is a common gap in heat decarbonisation plans from this period, and one that the framework described in this report is designed to address.

Source: Kingston Hospital NHS Foundation Trust (2022). Heat Decarbonisation Plan. Published by Salix Finance on behalf of the Department for Energy Security and Net Zero. Available at: https://www.salixfinance.co.uk/sites/default/files/2023-02/Kingston%20Hospital%20-%20HDP.pdf

Under current market conditions, the financially rational choice at site level is to install another CHP. Repeated 280 times over the next decade, that choice would lock in 15 to 20 years of further fossil fuel dependency across the majority of the public sector estate, carrying it well beyond 2040 and out of alignment with Net Zero commitments.

Public sector organisations with CHP systems face a difficult decision to invest in higher-cost solutions to meet Net Zero obligations while the market continues to reward the status quo.

This is not a problem that can be resolved at the level of an individual site. Individual organisations cannot control energy prices or the pace of grid decarbonisation, and the sheer number of replacement decisions falling within the same narrow window means that inconsistent site-by-site outcomes are almost inevitable under current conditions.

The business case for CHP replacement cannot be made on cost savings alone. It must instead be framed around the value of carbon reduction, compliance with tightening emissions policy, the avoidance of stranded asset risk as carbon pricing evolves, and the long-term alignment of the estate with national decarbonisation targets.

The grid bottleneck

Section 3 showed that replacing a single gas-fired CHP with an electrically powered alternative creates a substantial increase in peak grid electricity demand at site level, driven by the loss of on-site generation and the addition of new electrical heating load. Section 2 showed that approximately 280 public sector sites will reach a replacement decision point within the next decade. This section considers what happens when those two observations are combined.

A system-level consequence of many individual decisions

The grid impact of CHP replacement is not a problem that individual sites face in isolation. Each site that moves from CHP to electrified heat contributes both a reduction in behind-the-meter generation and an increase in peak import demand to its local distribution network. When a handful of sites do this, the impact is manageable. When hundreds of sites do it within the same decade, often in the same regions, the aggregate effect becomes significant.

The public sector CHP fleet identified in Section 2 represents approximately 414 MW of behind-the-meter electrical generation capacity[15]. If the majority of this capacity is replaced with grid-dependent heating solutions, the collective result is the loss of around 414 MW[15] of distributed generation and the addition of new electrical heating load in its place. The actual increase in peak grid demand will depend on the mix of technologies selected, the coincidence of peak demand across sites, and the extent to which complementary measures such as on-site solar and storage are deployed alongside. But the direction of travel is clear, and the scale is non-trivial.

[15] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

This matters because the public sector CHP estate is concentrated in the same regions that are already facing the most significant grid constraints. The clusters visible in the spatial analysis in Section 2, across London and the South East, the Midlands, Greater Manchester, and the Central Belt of Scotland, overlap closely with areas where the distribution network is under the greatest pressure from existing electrification and renewable connection demand.

A grid connection environment under pressure

The UK electricity grid connection process has been the subject of significant policy attention in recent years. By the end of 2024, the connection queue operated by the National Energy System Operator had grown to over 700 GW of projects, many times the capacity the country actually needs.[16]

NESO introduced a package of reforms in December 2025 aimed at reordering the queue and prioritising connections that align with strategic network needs, but the underlying reality remains that commercial connection projects continue to face delays of 18 months to over a decade in some regions.

[16] National Energy System Operator (2024). Connections Reform: Methodology and decisions. Available at: https://www.neso.energy/industry-information/connections/connections-reform

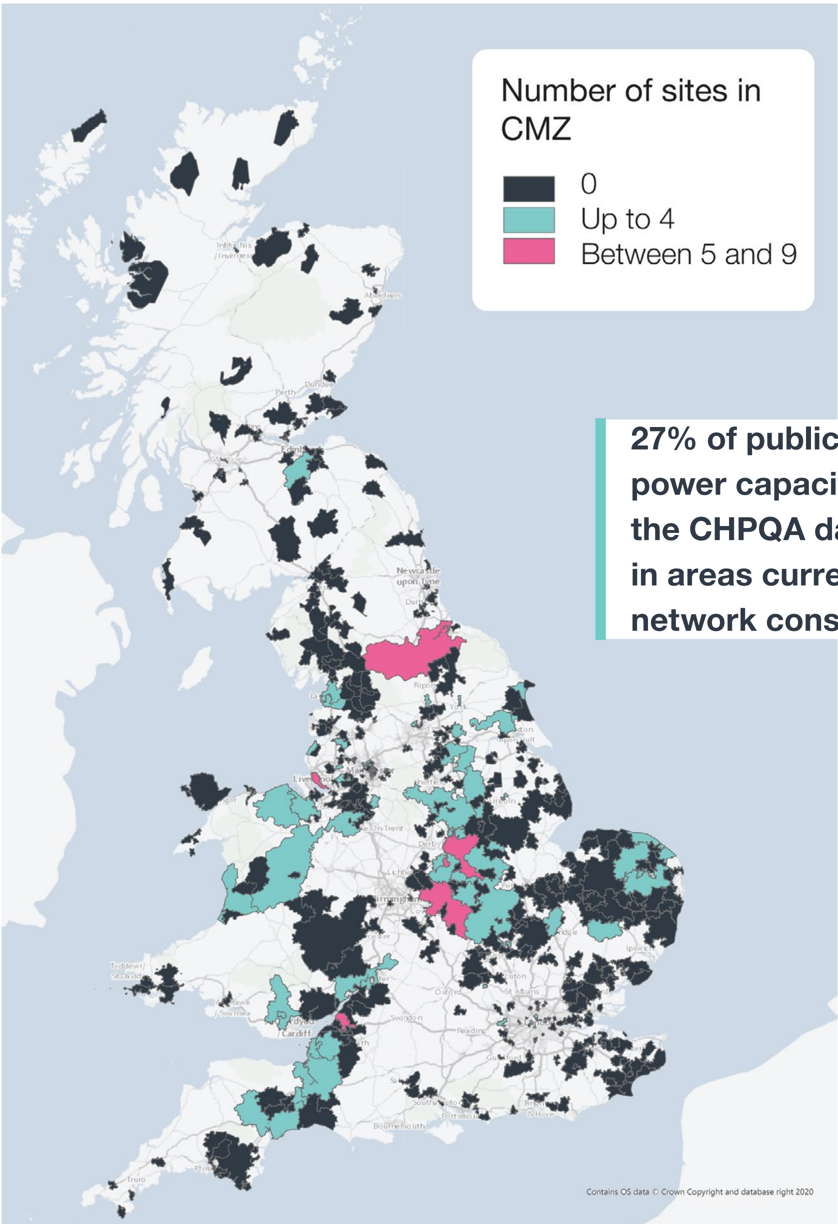
For a public sector site planning to replace a CHP, this is not an abstract concern. The site will need to secure additional import capacity from its distribution network operator at roughly the same time as it is selecting and procuring a replacement heating plant. If the local network has capacity available, the process can be relatively straightforward. If it does not, the site may face either a significant reinforcement cost, a long wait, or both. In the worst cases, the connection timeline can extend beyond the point at which the existing CHP can reliably continue to operate, forcing the site into reactive decisions that often default to like-for-like replacement.

> **Replacing a CHP is not simply a heating project. It is simultaneously a generation project and a grid connection project, and the lead times for the latter are often the longest and least controllable part of the transition.**

The situation is compounded by the lead times involved in CHP replacement projects themselves. Evidence from sites that have already begun the transition suggests that the period from initial feasibility study to operational handover is typically three to five years, and this is before accounting for grid connection delays. A site that begins planning for CHP replacement in 2026 is therefore looking at an operational replacement date somewhere between 2029 and 2031, assuming the grid connection process does not add further delay.

Concentration of demand in constrained regions

Figure 10 shows a map of public sector CHP locations overlaid with Congestion Managed Zones (CMZ). That map makes the point visually, but the underlying pattern deserves to be stated clearly. Public sector CHP is not evenly distributed across the country. It is concentrated in urban areas with large hospitals, universities, and government facilities, and those same urban areas are where distribution networks are already most heavily loaded. This means that the grid impact of CHP replacement will fall disproportionately on the regions least able to absorb it.



27% of public sector CHP total power capacity identified in the CHPQA data are located in areas currently identified as network constrained.[1]

Figure 10: Public sector CHP sites in network congestion managed zones

The implication is that the pace of the CHP transition will not be set by the pace at which individual sites make decisions, nor by the availability of replacement technology, nor by the availability of grant funding. In many cases it will be set by the pace at which local distribution networks can accommodate the new demand. This is a system-level constraint that sits largely outside the control of estate holders, and it will need to be planned for at a system level rather than resolved one site at a time.

Early and coordinated engagement

The evidence points clearly to the importance of early engagement between public sector estate holders and their distribution network operators, well ahead of the point at which the existing CHP plant reaches end-of-life. Where a site has a clear line of sight to its replacement date and can begin conversations with its DNO several years in advance, the chances of securing additional capacity within a workable timeframe are significantly better. Where a site leaves the conversation until it is already facing an end-of-life CHP, the available options narrow quickly and the default outcome often becomes a like-for-like replacement that locks in a further 15 to 20 years of fossil fuel dependency.

Coordinated engagement at a sector level could improve the picture further. If NHS England, the Department for Education, and the devolved equivalents were able to signal the collective scale and timing of expected CHP replacement activity to NESO and the DNOs, this information could feed into network planning assumptions and help ensure that reinforcement investment is directed where public sector decarbonisation will need it most. The CHPQA analysis presented in Section 2 provides much of the raw material for such a conversation, identifying not only the number and location of sites but also their likely replacement windows.

There is more work to be done on the grid capacity and electricity system impact of public sector CHP transition that DESNZ, NESO, and the distribution network operators may wish to take forward jointly. A deeper analysis of end-of-life CHP replacement across the public sector, set against the forward view of network capacity and planned reinforcement, would help quantify the scale of the system-level constraint and identify where early intervention is most needed. This report has set out the case that such work would be timely and valuable.

What this means for the transition

The grid bottleneck is not a reason to delay the transition away from CHP. If anything, it is the strongest reason to accelerate planning. Every site that begins its replacement conversation early gives itself more options. Every site that waits until its CHP is failing finds those options narrowing.

At a system level, the grid constraint reinforces the argument made in Section 3 that the CHP transition cannot be left to site-by-site decisions under current market conditions. The financial case at site level points towards like-for-like replacement. The carbon case points towards electrification. The grid reality means that neither outcome can be guaranteed at the pace or scale that either narrative implies. A managed transition, with early engagement, coordinated planning, and a realistic view of what the grid can absorb in each region, is the only route that avoids both the carbon lock-in of the default path and the delivery risk of an unmanaged scramble.

The next section turns to what such a managed transition looks like in practice, considering the elements of a well-planned approach to CHP replacement and the role that hybrid configurations, heat networks, and complementary measures can play in bridging the gap between where the fleet is now and where it needs to be.

Managing the transition

Given the scale of the challenge, the cost-carbon tension, and the grid constraints set out in the preceding sections, what does a well-managed transition look like?

Six themes emerge from the evidence:

1. long-term site energy planning,
2. early grid engagement,
3. heat network coordination,
4. the role of transitional and hybrid CHP,
5. resilience as an integral consideration,
6. complementary measures that can offset the financial and infrastructure impact.

Each is addressed in turn, though in practice they interact and need to be considered together.

Long-term site energy master planning

The analysis presented in this report has highlighted that the transition away from CHP is materially different from a standard boiler replacement. The loss of on-site electricity generation, the scale of the operational cost impact, the implications for electrical infrastructure, and the need for resilience planning all introduce a level of complexity that goes beyond what is typically addressed in a conventional heat decarbonisation plan.

Site energy master planning brings together the full range of demand reduction, generation, storage, flexibility, and decarbonisation opportunities into a coordinated strategy that considers how the site's energy system will evolve over time. Rather than treating CHP replacement as an isolated decision, a masterplan approach allows organisations to sequence investments, align enabling works with planned maintenance or refurbishment programmes, and identify where shared infrastructure such as heat networks or communal energy centres can serve multiple buildings. This approach is particularly valuable for large campus sites such as hospitals and universities, where the interactions between buildings, infrastructure constraints, and phasing of capital works are complex and where poor sequencing can lead to abortive costs or missed opportunities.

The Modern Energy Partners (MEP) programme, delivered between 2018 and 2022 as a collaboration between BEIS, the Cabinet Office, and Energy Systems Catapult, tested and refined an integrated approach to site energy master planning across 42 public sector sites. The programme developed detailed methodologies for whole-site energy assessment, infrastructure planning, and phased delivery of decarbonisation measures, and its findings remain directly relevant to the challenge of CHP replacement. Organisations considering how to approach an enhanced master planning exercise may find the MEP outputs a useful reference point, particularly the guidance developed on integrating electrical infrastructure planning, heat decarbonisation, and resilience requirements into a single coordinated strategy.[17]

An effective site energy master plan for a site with CHP should cover several elements beyond those typically found in a standard heat decarbonisation plan. It should include a full operational cost impact assessment comparing the current CHP operating cost against each replacement option on a like-for-like basis, modelled over the expected life of the replacement asset rather than at a single point in time. It should include an electrical infrastructure assessment that quantifies the increase in peak demand resulting from both the loss of on-site generation and the new electrical heating load, and that has been informed by early engagement with the distribution network operator.

[17] Modern Energy Partners programme: testing the practicalities of public sector decarbonisation. Energy Systems Catapult. Available at: https://www.gov.uk/government/publications/modern-energy-partners-project-public-sector-energy-efficiency

Case study: University Hospitals Bristol and Weston NHS Foundation Trust

University Hospitals Bristol and Weston NHS Foundation Trust (UHBW) set a target of carbon neutrality by 2030. With an average annual gas consumption of 55 GWh for heating across the Trust, and gas emissions accounting for the overwhelming majority of its operational carbon footprint, de-steaming the Bristol estate was identified as a critical early step on the Trust's decarbonisation pathway.

The Trust took a phased approach. In 2020, as a first phase, it installed a new heat network supplying four hospital buildings and replaced the ageing 1 MWe CHP engine with a more efficient 3.36 MWe unit, using the CHP replacement as a mechanism to fund the initial de-steaming works. In November 2020, UHBW secured £17 million from the Public Sector Decarbonisation Scheme Phase 1 to deliver the second phase. This replaced the remaining steam boilers with two 6.8 MW dual-fuel low temperature hot water boilers, extended the district heating network to a further six sites, and upgraded pumps, controls, and metering across the estate. In total, 4,939 metres of new pipework was installed at a capital cost of £14.4 million.

The results were substantial. De-steaming delivered a degree-day adjusted reduction in gas used for heating of 28.7 per cent against the three-year average, equivalent to an estimated annual saving of 7,881 MWh of gas. The project was completed within the PSDS delivery deadline of April 2022, despite significant challenges from equipment lead times and the need to maintain clinical services that relied on steam during the transition.

Bristol illustrates how a phased masterplanned approach can deliver material carbon savings in the near term while preparing the infrastructure for the eventual electrification of heating.

Source: Energy Managers Association (2023). Heat Decarbonisation at University Hospitals Bristol and Weston. Case study. Available at: https://www.theema.org.uk/heat-decarbonisation-at-university-hospitals-bristol-and-weston/

It should apply carbon valuation in line with HM Treasury Green Book guidance so that the carbon benefit of the transition can be expressed in financial terms alongside the capital and operational cost case. And it should include a clear phasing and sequencing plan that recognises the lead times involved in securing grid connections, procuring equipment, and delivering enabling works on operational sites.

> **The transition away from CHP cannot be approached as a single investment decision evaluated on simple payback. It requires a whole-life perspective that accounts for evolving energy prices, carbon values, and policy frameworks over the 15 to 25 year operating life of the replacement asset.**

Early engagement with distribution network operators

The grid bottleneck described in Section 4 makes early engagement with the distribution network operator one of the most important single actions in the transition. The evidence suggests that sites which begin conversations with their DNO several years before their CHP reaches end-of-life give themselves significantly more options than those which leave the conversation until the plant is failing. At the point where a CHP has failed or is about to fail, the realistic options narrow quickly, and the default outcome often becomes a like-for-like replacement that locks in a further 15 to 20 years of fossil fuel dependency.

The value of early engagement is not limited to understanding whether capacity is available. It also allows the site to understand the timeline and cost of any reinforcement that might be required, to factor this into procurement and project planning, and where appropriate to coordinate with other nearby sites or projects that might share the cost of reinforcement. In some cases, early engagement may reveal that the local network cannot accommodate the full electrical demand of a straightforward heat pump replacement, which in turn may point towards hybrid configurations or phased approaches that would not otherwise have been considered.

Heat network coordination

Public sector sites with CHP represent some of the largest and most consistent heat demands in any local area. Many already operate campus heat networks fed by their CHP and have the internal infrastructure that would make connection to a wider network relatively straightforward. As heat network zones are designated and developed under the Energy Act 2023[18], these sites become natural candidates for connection, offering the kind of anchor load that can improve the commercial viability of network development.

The overlap between public sector CHP locations and proposed or designated heat network zones was explored in Section 2. Where a site sits within or close to a designated zone, and where its CHP is approaching end-of-life, the coordinated timing of CHP decommissioning with heat network development can benefit both parties. The site gains access to a shared, low carbon heat source without having to fund the full capital cost of a standalone replacement. The network operator gains a large, reliable anchor load that underpins the commercial case for investment.

The Greater Manchester Combined Authority area provides a useful illustration of how significant this anchor load potential can be. Figure 11 shows the designated and proposed heat network zones across Greater Manchester, with each zone shaded according to the aggregate thermal capacity of public sector CHP located within it. The central Manchester zone contains approximately 33 MW of public sector CHP heat capacity, a substantial load that would make a material difference to the commercial viability of a network serving that area. The Bolton and Wythenshawe zones each contain over 10 MW of public sector CHP capacity, and several smaller zones contain further installations.

[18] Energy Act 2023, Part 8, Chapter 1. Available at: https://www.legislation.gov.uk/ukpga/2023/52/contents

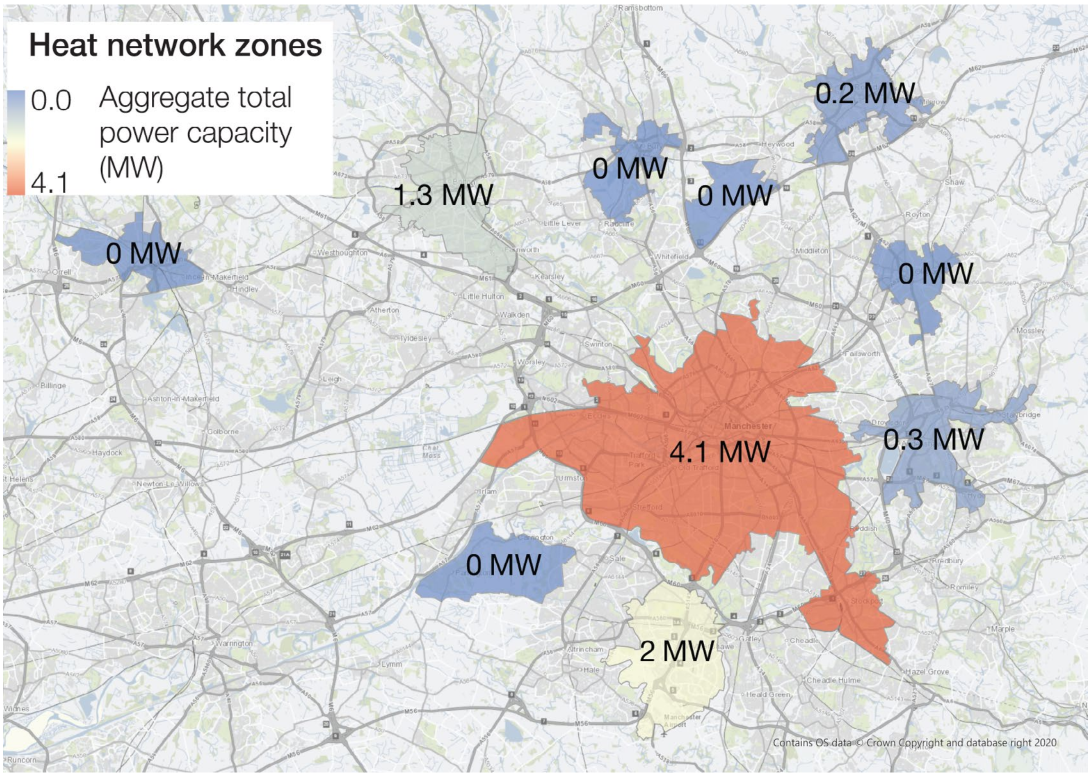


Figure 11: Public sector CHP heat capacity within designated heat network zones across the Greater Manchester Combined Authority area.[1]

These are not speculative loads. They are real, operational heat demands that are already being served by plants approaching the end of their economic life. As these CHP units reach replacement decisions over the next decade, the timing of those decisions will determine whether they are able to connect into emerging heat networks or whether they default to standalone replacement. Coordinated planning between the local authority, the prospective network operator, and the public sector estate holders in each zone could unlock significant value on both sides of the connection.

Realising this opportunity requires early and proactive engagement between public sector estate holders, local authorities, and heat network developers. It also requires the timing of decisions on either side to be compatible, which is not always the case under current arrangements. A site facing imminent CHP failure cannot wait three years for a heat network zone to be developed, and a network developer cannot underwrite investment on the promise of a connection that may or may not materialise. The evidence suggests that better information sharing between public sector estate holders and heat network developers, supported by the kind of spatial data presented in this report, would help to align these timelines and unlock connections that would otherwise be missed.

The role of transitional and hybrid CHP

While this report has set out the clear long-term case for moving away from gas-fired CHP, it also recognises that the transition cannot happen overnight, and that for some sites it may not be possible in a single step. Where grid capacity is constrained, where resilience requirements are particularly high, or where the scale of enabling works means a phased approach is the only practical option, a smaller or hybrid CHP configuration may have a legitimate transitional role. This is not the same as advocating for the continued installation of new fossil fuel CHP as a long-term solution.

A transitional CHP should be sized and operated as a bridging measure, with a clear and funded exit plan aligned to the site's Net Zero commitments. It should be accompanied by investment in the enabling works, such as de-steaming, conversion to low temperature hot water, and electrical infrastructure upgrades, that will allow the eventual transition to fully electrified or low carbon heating. The University of Warwick case study, presented in the next section, illustrates how a large and complex site can find a transitional role for its existing CHP plant while delivering significant carbon savings in the near term through the integration of heat pumps as the primary heat source.

Case study: The University of Warwick

The University of Warwick operates one of the largest and longest-established campus heat networks in the UK, serving over 25,000 residents across its Coventry site from three energy centres historically supplied by gas-fired CHP engines, gas boilers, and thermal storage.

Facing a Scope 1 and 2 Net Zero target of 2030, well ahead of the public sector norm, the university developed a long-term energy master plan to guide the phased transition of its campus energy infrastructure. An early step in August 2023 was to deprioritise the older CHP engines in the main energy centre, delivering immediate Scope 1 emissions reductions without requiring capital investment in replacement plant.

The university tested several alternatives including biomass and heat pumps. Two 350-metre test boreholes drilled in early 2024 established that local geology made open loop ground source heat pumps unfeasible, allowing the university to rule out that option with confidence. Large-scale air source heat pumps are now being designed as the primary heat supply, operating within the existing energy centres.

Rather than decommissioning the CHP plant, the university is retaining it in a transitional role, providing backup heat and power and providing the potential to deliver grid ancillary services. Solar PV panels are being deployed at scale with 1.8 MW peak output capacity already installed on roofs with plans in place to increase rooftop capacity to beyond 3 MW peak output in 2027, and an ambition to reach 6 MW of peak output generation by 2030.

The Warwick example illustrates how long-term master planning, phased delivery, transitional use of existing assets, and integrated complementary measures can work together to manage a complex CHP transition in practice.

Source: University of Warwick (2024). Decarbonising our energy. Warwick Sustainability case study. Available at: https://warwick.ac.uk/sustainability/case-studies/ourenergystrategy/decarbonise/

There is also a case for viewing existing gas-fired CHP plants as flexible energy assets that can provide value to the grid during the transition period itself. In congested areas, active CHP management can offer a cost-effective alternative to traditional network reinforcement, providing peak support and capacity services while the longer-term low carbon solution is being planned and delivered. This reframing of CHP from primary heat source to transitional flexibility asset is consistent with the longer-term decarbonisation trajectory, provided it is accompanied by a clear exit plan and does not become a justification for indefinite retention.

> **A hybrid approach accepts a continued, though significantly reduced, role for fossil fuel plant within a system that is predominantly low carbon in normal operation.**

The risk of failing to plan for this kind of transitional pathway is that sites install new CHP on a like-for-like basis and lock in a further 15 to 20 years of fossil fuel dependency, taking them well beyond 2040 and out of alignment with public sector carbon targets. The distinction between a transitional CHP with a clear exit plan and a like-for-like replacement without one is central to whether the transition is being managed or deferred.

Resilience as an integral consideration

For many public sector sites, particularly hospitals and other critical infrastructure, the transition away from CHP cannot be considered purely in terms of cost and carbon. Operational resilience is a non-negotiable requirement. Hospitals must always maintain heating and hot water supply, and any replacement strategy must demonstrate that it can meet this standard before it can be seriously considered.

Gas-fired CHP has historically provided a degree of built-in resilience that is easy to overlook. By generating electricity on-site from a fuel source independent of the electricity grid, CHP offers a measure of protection against grid outages and can, in some configurations, operate in island mode to maintain critical services during supply interruptions. It also provides simultaneous heat and power from a single asset, reducing the number of points of failure in the energy supply chain. When CHP is removed, this resilience benefit is removed with it and must be consciously designed back into the replacement system.

In practice, this means that most sites replacing CHP will not move to a single low carbon technology in isolation but will instead deploy a hybrid system that combines a primary low carbon heat source with backup capacity, thermal storage, and potentially retained or new on-site generation. Backup heating capacity, typically retained gas or oil boilers, may be required for sites with critical service requirements. Thermal storage can provide a reserve of stored heat that bridges short-duration interruptions. Battery storage and on-site solar PV can contribute to electrical resilience. For NHS sites in particular, Health Technical Memorandum 06-01 provides guidance on the resilience standards expected for electrical and heating systems, and any replacement strategy must demonstrate compliance with these requirements.[19]

The key message is that resilience is not an afterthought to be addressed once a heating technology has been selected. It should be integral to the system design from the outset, shaping the configuration, sizing, and control strategy of the replacement system. The cost of providing this resilience should be factored into the capital and operational cost comparisons from the beginning, as it can materially affect the total investment required and the realistic operating cost of the replacement system.

Alleviating the financial impact

Section 3 showed that replacing a CHP can increase annual energy costs by a factor of approximately 2.5 under current price conditions, driven primarily by the loss of on-site electricity generation. However, this cost impact is not inevitable. There are a range of complementary measures that, when deployed alongside a replacement heating technology, can substantially reduce the financial impact of the transition and in some cases improve upon the operational performance of the original CHP system.

The most direct way to offset the loss of CHP electricity generation is to replace it with on-site renewable generation, most commonly rooftop or ground-mounted solar PV. While solar PV does not replicate the dispatchable baseload profile of a CHP engine, it can displace a meaningful proportion of daytime grid electricity imports, reducing both cost and carbon. For large public sector sites with substantial roof areas, car parks, or adjacent land, solar PV can make a material contribution to closing the gap left by CHP removal.

Battery storage can enhance the value of on-site renewable generation by storing surplus electricity produced during periods of low demand and discharging it during peak periods when grid electricity is most expensive. It also provides short-duration supply resilience and can help to manage peak demand charges by reducing the site's maximum

[19] Department of Health and Social Care (2017). Health Technical Memorandum 06-01: Electrical services supply and distribution. Parts A and B. London: The Stationery Office

import capacity requirement. Where a site is replacing CHP and facing a significant increase in its peak electrical demand, battery storage can play an important role in reducing the size and cost of the electrical connection upgrade required.

Thermal storage, in the form of hot water buffer vessels or larger thermal stores, can decouple heat generation from heat demand. For heat pump systems in particular, thermal storage enables the heat pump to run during off-peak electricity tariff periods and store heat for use during peak periods, reducing operating costs without oversizing the heat pump itself.

Demand-side flexibility and participation in electricity markets offer a further route to reducing the net cost of the transition. Public sector sites with significant electrical loads, particularly those with heat pumps, battery storage, or electric vehicle charging infrastructure, are increasingly able to participate in flexibility services that reward the shifting of consumption away from peak periods or the provision of balancing services to the grid operator. Revenue from these services can help to offset the increased electricity costs associated with CHP replacement, and in some cases can form a meaningful component of the business case for electrification.

Longer-term commercial arrangements such as power purchase agreements with off-site renewable generators can provide a route to securing electricity at a known price over an extended period, reducing exposure to wholesale market volatility. Corporate power purchase agreements are becoming increasingly common in the public sector and can support both cost certainty and carbon reporting objectives.

> **The financial case for CHP replacement improves significantly when complementary measures are considered as part of the core business case, not as optional additions.**

These measures do not eliminate the underlying cost tension identified in Section 3, but they can materially reduce its impact and should be considered as integral to the replacement strategy from the outset rather than as afterthoughts once the heating technology has been selected.

Data, monitoring, and sector learning

Many of the assumptions used in this report and in site-level decarbonisation plans are based on modelled performance, benchmark costs, and projected energy prices. As early-mover sites begin to deliver CHP replacement projects, the real-world operational data from these installations will be invaluable in refining the evidence base for the sites that follow.

There is a strong case for public sector sites replacing CHP to commit to detailed post-installation monitoring and performance reporting, covering at a minimum the actual electricity consumption, heat output, system efficiency, and operating cost of the replacement system compared to the pre-existing CHP. This data would ideally be collected in a consistent format and shared across the sector through existing platforms such as the Estates Returns Information Collection for NHS sites, through continued CHPQA participation where the site retains any form of CHP, or through dedicated knowledge-sharing mechanisms developed for the purpose. Building this evidence base would allow future projects to be designed and costed with greater confidence, reduce the risk of underperformance, and support the continuous improvement of funding criteria and policy frameworks.

Conclusions and next steps

The evidence assembled in this report points to a clear and urgent picture. Around 309 public sector sites in Great Britain host gas-fired CHP plants, representing approximately 414 MW of behind-the-meter generation[20]. Four fifths of this fleet will reach a replacement decision point within the next decade, and the decisions taken at those sites over the next two to three years will shape the carbon trajectory of the public sector estate well into the 2040s.

Several findings from the analysis deserve to be highlighted as the report concludes.

The scale and concentration of the challenge is greater than has previously been recognised. CHP is embedded in some of the most critical and complex public sector sites, predominantly NHS hospitals and university campuses, and the replacement wave will fall disproportionately on a relatively small number of operator groups. This concentration is both a risk and an opportunity. It creates the potential for coordinated action across trusts and institutions that would not be possible if the challenge were evenly distributed.

The cost-carbon tension is structural, not incidental. Under current market conditions, gas-fired CHP remains the lowest-cost option to operate by a significant margin, with annual energy costs roughly 2.5 times lower than any low carbon alternative for the representative case assessed. At the same time, it is the highest-emitting option over the period to 2050, and unlike every alternative its emissions do not fall over time. Individual organisations cannot resolve this tension through better planning alone. It is driven by the price gap between electricity and gas, and by the pace at which that gap is being narrowed through policy.

[20] Department for Energy Security and Net Zero (2025). Digest of UK Energy Statistics (DUKES) 2025, Chapter 7: Combined Heat and Power. London: DESNZ. Available at: https://www.gov.uk/government/statistics/combined-heat-and-power-chapter-7-digest-of-united-kingdom-energy-statistics-dukes

The grid constraint will shape the pace of the transition regardless of what individual sites decide. Replacing CHP with electrified heating creates a compounding effect on site electrical demand, driven by the simultaneous loss of on-site generation and the addition of new heating load. When this is repeated across hundreds of sites in regions that are already facing network pressure, the cumulative impact on the distribution network will be significant. Early engagement with distribution network operators will be critical, but engagement alone cannot create capacity that does not exist.

The Public Sector Decarbonisation Scheme was the primary central funding mechanism for heat decarbonisation across the public sector, delivering over £2.5 billion across its first four phases and supporting hundreds of projects including heat pump installations, heat network connections, and enabling works such as de-steaming and electrical infrastructure upgrades.

The scheme has now closed, and its removal has had a material impact on the public sector's ability to plan and deliver decarbonisation projects at the scale and pace required. For CHP replacement projects in particular, which typically carry higher capital costs and longer lead times than standard heat decarbonisation works, the absence of a clear central funding route significantly increases the risk that sites will default to like-for-like replacement when their existing plant reaches end-of-life.

The timing dimension is unforgiving. Replacement projects typically take three to five years from feasibility to operational handover, before accounting for grid connection delays. A site that begins planning in 2026 is looking at an operational replacement date no earlier than 2029. A site that waits until its CHP is failing loses its options and typically defaults to like-for-like replacement, locking in a further 15 to 20 years of fossil fuel dependency.

Taken together, these findings point to a transition that is both more challenging and more time-critical than the current policy and funding framework appears to recognise. The default trajectory, in which sites make individual decisions at the point of CHP failure under current market conditions, will produce an outcome that is materially worse for carbon emissions, resilience, and long-term value than a managed transition would. The gap between these two trajectories is where the risk, and the opportunity, sits.

What next

This report represents the beginning of a broader conversation about how the public sector CHP transition should be managed. Several areas emerge from the analysis as warranting further work.

The first is a deeper evidence base on the grid system impact of public sector CHP replacement. A joint analysis of forward CHP replacement demand against distribution network capacity and planned reinforcement, drawing on the CHPQA dataset and network operator data, would help quantify the scale of the system-level constraint and identify where early intervention is most needed. This is work that would sit well with DESNZ, NESO, and the distribution network operators working together.

The second is the development of enhanced site energy planning guidance specific to CHP replacement. Standard heat decarbonisation plans do not adequately address the distinct challenges of CHP transition, including the loss of on-site generation, the scale of the operational cost impact, and the resilience implications. Guidance that reflects these specific requirements would support public sector organisations in commissioning feasibility work that captures what they actually need to know.

The third is continued monitoring of real-world performance from early-mover sites. As the first wave of CHP replacement projects completes over the coming years, the operational data from those installations will be invaluable in refining cost and performance assumptions for the sites that follow. A coordinated approach to capturing and sharing this data across the sector would accelerate learning and reduce the risk of repeated mistakes.

The fourth is attention to the commercial and regulatory framework that determines the financial case at site level. The structural cost tension described in this report cannot be resolved by individual sites or by funding alone. The pace of levy rebalancing, the evolution of carbon pricing, and the policy signals around on-site fossil fuel generation will all shape whether the transition can happen at the pace required.

The transition away from public sector CHP is coming, whether it is managed or not. The choice is not whether these assets will be replaced, but how. This report has tried to describe the shape of that choice honestly, and to provide the evidence base that those involved will need as the decisions are made.

Appendix A: Modelling methodology and assumptions

This appendix sets out the representative CHP case, cost benchmarks, emission factors, and modelling approach used in the quantitative analysis presented in Section 3. It is intended as a reference for readers who want to understand how the figures in the main text were derived, and to support anyone wishing to apply the accompanying spreadsheet tool to their own site.

The spreadsheet modelling tool

A spreadsheet tool was developed as part of this project to analyse the technical, economic, and carbon emissions impact of replacing a CHP plant with alternative technology options. The tool allows the user to specify the characteristics of an existing CHP plant, select a replacement technology, and apply assumptions about energy prices, carbon values, and grid intensity projections to generate estimates of capital costs, annual operating costs, peak electricity demand, and lifetime carbon emissions to 2050.

The analysis presented in Section 3 uses the tool with the default assumptions described in this appendix. Users applying the tool to their own site will need to adjust the inputs to reflect local conditions, particularly the size and operating profile of their CHP, the commercial terms available for each replacement option, and any site-specific factors affecting installation cost.

The representative CHP case

To provide a consistent basis for comparing the technology options, the analysis in Section 3 is built around a representative counterfactual CHP system. The system is rated at 1.5 MW electrical output, which is typical of the larger installations found across the public sector estate and which sits above the median plant size identified in the CHPQA analysis presented in Section 2. The operating profile assumes 5,000 hours per year of operation, reflecting a CHP that is used for a substantial portion of the year but not run continuously as pure baseload. Table 1 sets out the full specification.

Table 1: Representative CHP plant specifications

Input	Description	Values
Starting year	The first year used in the financial and carbon modelling	2025
Fuel type	The fuel used by the CHP engine	Natural gas
Electrical capacity	The nominal electrical capacity of the CHP engine	1,500 kWe
Thermal capacity	The recoverable thermal capacity of the CHP engine	1,688 kWth
Electrical efficiency	The proportion of fuel energy converted into electricity	40%
Thermal efficiency	The proportion of fuel energy recovered as useful heat	45%
Losses	The remaining proportion of fuel energy not recovered as useful heat or electricity	15%
Annual run hours	The assumed number of hours per year that the CHP operates	5,000

Applying these inputs produces the annual outputs shown in Table 2, which are used as the counterfactual baseline throughout the analysis in Section 3.

Table 2: Representative CHP annual outputs

Output	Description	Values
Fuel input	Total annual natural gas consumption	18,750 MWh
Electricity generated	On-site generation displacing grid imports	7,500 MWh
Heat recovered	Useful heat delivered to the site heating system	8,438 MWh
Losses	Fuel energy not recovered as useful output	2,813 MWh
Annual fuel cost	Based on non-domestic gas prices in 2025	£937,500
Annual emissions	Based on the natural gas emissions factor from HM Treasury Green Book guidance	3,429 tCO_2e

The replacement technologies considered in Section 3 are sized and operated to meet the same annual heat demand as the representative CHP. Where a replacement technology does not generate electricity on-site, the 7,500 MWh of electricity previously produced by the CHP is assumed to be imported from the national electricity grid.

It is worth noting that the analysis does not consider complementary on-site measures such as solar PV, battery storage, or demand-side flexibility, which in practice would be expected to offset a portion of the increased grid electricity consumption. These measures are explored qualitatively in Section 5 as part of the wider set of options for managing the transition.

Capital cost benchmarks

The capital cost estimates used in Section 3 are derived from published benchmarks for each technology in non-domestic buildings. Table 3 sets out the lower, central, and upper values used, together with the units in which they are expressed. A central value has been used for the headline figures in the main text, with the lower and upper bounds shown as error bars in Figure 6.

Table 3: Capital cost benchmarks

Option	Lower	Central	Upper	Unit
Replace with like-for-like CHP	£800	£1,150	£1,500	£/kWe
Replace with fossil fuel boiler	£50	£100	£150	£/kWth
Replace with air source heat pump	£700	£1,050	£1,400	£/kWth
Replace with ground source heat pump	£1,500	£2,250	£3,000	£/kWth
Heat network connection	£500	£1,250	£2,000	£/kWth
Replace with hydrogen fuel cell CHP	£2,000	£3,000	£4,000	£/kWe

The capital cost benchmarks in Table 3 are indicative ranges compiled from a combination of published sources and project experience, rather than drawn from a single authoritative dataset.

No single published reference provides comparable cost data across all six of the technologies assessed at the capacities typical of public sector sites, and publicly available figures are often drawn from domestic deployments, vendor marketing material, or individual project case studies rather than from standardised benchmarks.

The ranges used here draw on a number of sources including DESNZ Electricity Generation Costs publications for gas-fired CHP, Public Sector Decarbonisation Scheme data, the DESNZ Hydrogen Strategy for hydrogen fuel cell cost context, and CIBSE Guide M for life cycle and replacement cost considerations.

Where published data conflicted or was unavailable, the ranges have been broadened to reflect the genuine uncertainty in this market. The lower and upper bounds shown in Table 3 should therefore be understood as indicative rather than statistically derived confidence intervals.

Users of the analysis should treat the capital cost figures as order-of-magnitude estimates suitable for comparing the relative scale of investment across options, not as a basis for site-level procurement budgeting. Site-specific feasibility assessment will always be required to establish reliable capital cost estimates, and organisations should expect considerable variation from the benchmark ranges depending on local conditions, the state of existing infrastructure, and the commercial arrangements available at the time of procurement.

These figures also represent indicative core plant and installation costs only. They do not include the wider project costs that can make up a substantial proportion of total expenditure in practice, including feasibility studies, technical design, planning applications, project management, enabling works such as electrical infrastructure upgrades or conversion from steam to low temperature hot water, and commissioning. Organisations applying these benchmarks to their own sites should expect total delivered project costs to be materially higher than the plant cost figures alone.

A simple cost-per-kilowatt benchmark also does not capture the full range of factors that influence capital cost for some technologies. For heat network connections, the cost is heavily dependent on the distance between the site and the nearest connection point, the extent of civils and pipework required, and whether internal distribution systems need to be converted from steam to low temperature hot water. For hydrogen fuel cells, the cost of on-site hydrogen storage, safety systems, ventilation, and hazardous area classification can add significantly to the base plant cost. For ground source heat pumps, the number, depth, and spacing of boreholes, local geology, and access constraints all influence the final cost in ways that a simple benchmark cannot reflect. Site-specific feasibility assessment will always be required to establish a reliable cost estimate.

Energy price assumptions

The operational cost analysis in Section 3 uses non-domestic energy prices representative of 2025 conditions in Great Britain. Non-domestic electricity is assumed to cost approximately 24 p/kWh and non-domestic gas approximately 5 p/kWh, giving a price ratio of roughly four to five times on a per-kilowatt-hour basis. The hydrogen price used in the hydrogen fuel cell scenarios reflects current green hydrogen supply costs, which remain significantly higher than natural gas on an energy-equivalent basis.

These prices are applied consistently across all options to provide a fair basis for comparison. In practice, actual costs at any given site will vary depending on tariff structure, contractual arrangements, consumption volumes, and market conditions at the time of procurement.

Grid carbon intensity projection

The carbon analysis in Section 3 uses projected grid electricity emission factors from the HM Treasury Green Book supplementary guidance on the valuation of energy use8 and greenhouse gas emissions. This guidance provides central projections for the carbon intensity of GB grid electricity out to 2050 and is the standard reference used across government and the public sector for appraising the carbon impact of energy investments.

To illustrate the shape of that trajectory, Figure 12 reproduces the grid carbon intensity projection published by the Climate Change Committee in its Seventh Carbon Budget (February 2025). The chart shows two series. The historical pathway traces the actual carbon intensity of GB grid electricity from 2008 to the present, capturing the rapid decline driven primarily by the phase-out of coal generation and the expansion of renewable capacity over that period.[21]

The Balanced Pathway projection continues this trajectory forward, showing how the CCC expects grid carbon intensity to fall from current levels towards near-zero by the mid 2040s as the remaining unabated gas generation is displaced by wind, solar, nuclear, and firm low-carbon capacity. Unlike the Sixth Carbon Budget, which offered several alternative routes to net zero, the Seventh Carbon Budget is built around a single Balanced Pathway in which electrification and low-carbon electricity supply account for the largest share of emissions reductions.

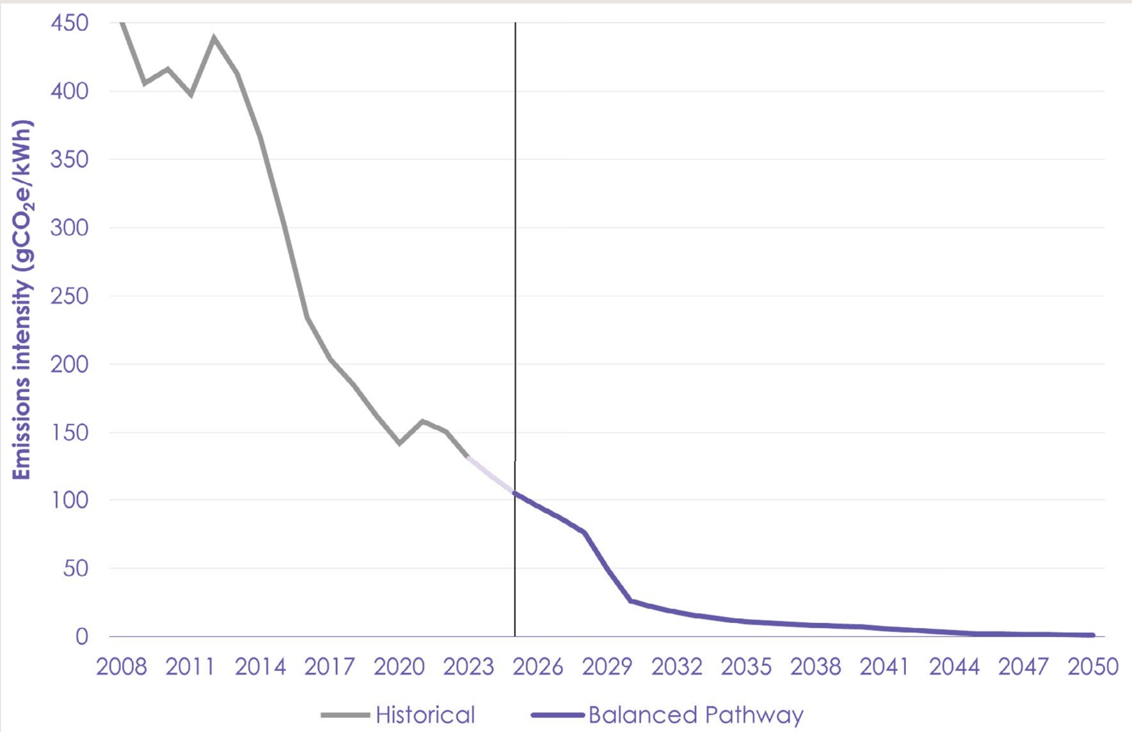


Figure 12: GB grid carbon emission intensity projection to 2050[14]

[21] Climate Change Committee (2025). The Seventh Carbon Budget: Advice to Government. February 2025. Available at: https://www.theccc.org.uk/publication/the-seventh-carbon-budget/

Applying the Green Book projection to the electrically powered replacement options in Section 3 means that their emissions fall automatically over time, without any change to the on-site plant or its operation. This is the mechanism by which the electrification options in Figure 9 deliver their strong emissions reduction trajectory. A site that installs an air source heat pump in 2030 will be benefiting from a much cleaner grid by 2040, and a near-zero-carbon grid by 2045, simply by virtue of the wider system decarbonising around it.

For the heat network option, the analysis assumes connection to a low carbon heat network with a carbon intensity declining in line with the grid. For the hydrogen fuel cell option, the analysis assumes supply of green hydrogen produced via renewable electrolysis, giving a low and effectively flat emissions profile. Both assumptions represent best-case configurations for these technologies. Actual carbon performance in practice would depend on the specific energy source of the heat network or the production method of the hydrogen supplied.

Lifetime cost and carbon modelling

The lifetime analysis presented in Figure 10 uses the full period from 2025 to 2050, applying annual electricity, gas, and hydrogen prices, annual grid carbon intensity values, and a single capital cost event at the point of installation. For the 2030 decarbonisation scenarios, the replacement technology is installed in 2030 and operates for 20 years. For the deferred scenarios, a like-for-like CHP is installed in 2030 and replaced with a low carbon alternative in 2045, with both the CHP capital cost and the subsequent replacement capital cost applied.

No discount rate has been applied to the cost figures in the main text, to keep the comparison straightforward and transparent. Users of the spreadsheet tool can apply a discount rate if they wish to express lifetime costs on a present-value basis, and this may be appropriate when comparing the analysis against internal investment appraisal requirements.

Limitations of the analysis

The quantitative analysis presented in Section 3 is designed to illustrate the scale and shape of the cost-carbon tension facing public sector organisations replacing CHP, using a single representative case. It is not intended as a substitute for site-specific feasibility work. The actual cost, carbon, and grid implications of a CHP replacement will vary with the size and operating profile of the existing plant, the characteristics of the site, the local grid context, the commercial terms available for each replacement option, and the timing of the decision relative to energy price and policy changes. Organisations considering a CHP replacement should use the figures in this report as a starting point for understanding the nature of the challenge, and commission a detailed feasibility assessment to establish the financial and technical case for their own site.

Appendix B: Alternative technology options appraisal

This appendix provides a qualitative appraisal of the six replacement technology options referenced in Section 3. Each option is considered across eight aspects of whole system integration (operation, people, information, infrastructure, interoperability, commercial, legislation, and resilience) and illustrated with a Sankey diagram showing how the flow of energy at the site changes compared with the representative 1.5 MW CHP counterfactual set out in Appendix A.

The six options assessed are:

1. A like-for-like CHP replacement (the counterfactual)
2. A gas boiler
3. A ground source heat pump
4. An air source heat pump
5. A connection to an existing heat network
6. A hydrogen fuel cell CHP

These options are assessed individually rather than in combination. In practice, many sites will deploy hybrid configurations that combine two or more of these technologies, and Section 5 of the main report discusses the role of hybrid and transitional approaches in more detail.

Replacement with a new gas-fired CHP

Gas-fired CHP is a commercially established solution that can deliver high overall efficiency and provide a reliable source of on-site heat and power. It is included here as the counterfactual against which all other options are assessed, representing the continuation of the current operating arrangement without a change in technology or fuel source.

In this scenario, a new gas-fired CHP unit is installed in place of the existing system. This maintains the same fundamental energy flows while offering the potential for improved performance due to advances in engine efficiency and heat recovery since the original installation. However, the underlying fuel remains natural gas, and the carbon performance of the system does not benefit from the progressive decarbonisation of the electricity grid.

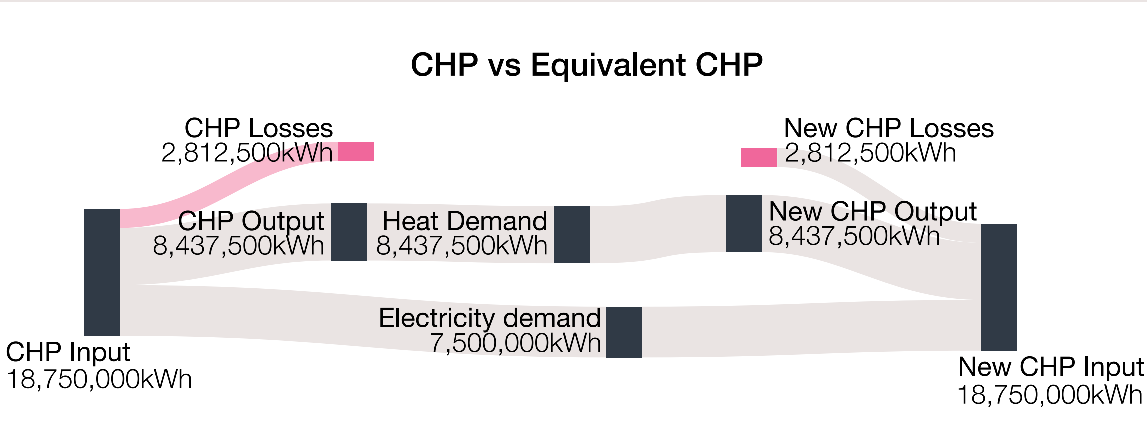


Figure 13: Sankey diagram comparing the energy flows of the existing CHP with a like-for-like replacement

Table 4: Aspects of a like-for-like CHP replacement

Aspect	Considerations
Operation	Maintenance approach and performance requirements need to be defined. The operating mode (baseload or load-following) should reflect the wider energy strategy of the site. A clear end-of-life strategy is needed to position CHP within the long-term decarbonisation pathway.
People	Affected stakeholders include estates teams, building users, and the surrounding community. Impacts such as noise, vibration, and local air quality need to be assessed and managed.
Information	Metering of heat, electricity, fuel use, and emissions is required to support performance verification. Integration with energy management systems allows ongoing optimisation.
Infrastructure	The condition, capacity, and remaining life of existing plant and networks need to be assessed. Compatibility with future low temperature and low carbon systems should be considered at the point of specification.
Interoperability	The new CHP should be designed to operate alongside technologies such as heat pumps, hydrogen, and heat networks in future. Avoiding system lock-in and maintaining flexibility for a staged transition are important design considerations.
Commercial	The business case should be tested against future energy prices, carbon costs, and policy direction. Whole-life costs should be compared with low carbon alternatives, including an assessment of stranded asset risk.
Legislation	Compliance is required with emissions limits, applicable schemes such as the UK Emissions Trading Scheme, and local air quality requirements. Alignment with public sector decarbonisation policy should be demonstrated.
Resilience	The role of the CHP in maintaining energy supply during grid outages should be defined, including its contribution to the resilience of critical loads and its integration with backup systems.

Replacement with a gas boiler

A gas boiler provides heat through the combustion of natural gas without generating electricity on-site. It is the simplest and lowest-cost replacement option, using a well-established technology that is familiar to estates teams across the public sector. However, it removes the on-site electricity generation that CHP provides and offers no meaningful pathway to decarbonisation in the long term.

In this scenario, the site's heating demand is met by a new gas boiler operating at a higher thermal efficiency than the CHP system it replaces, because the boiler is optimised solely for heat production. All electricity previously generated by the CHP must be imported from the grid, significantly increasing the site's electricity costs and its dependence on grid supply.

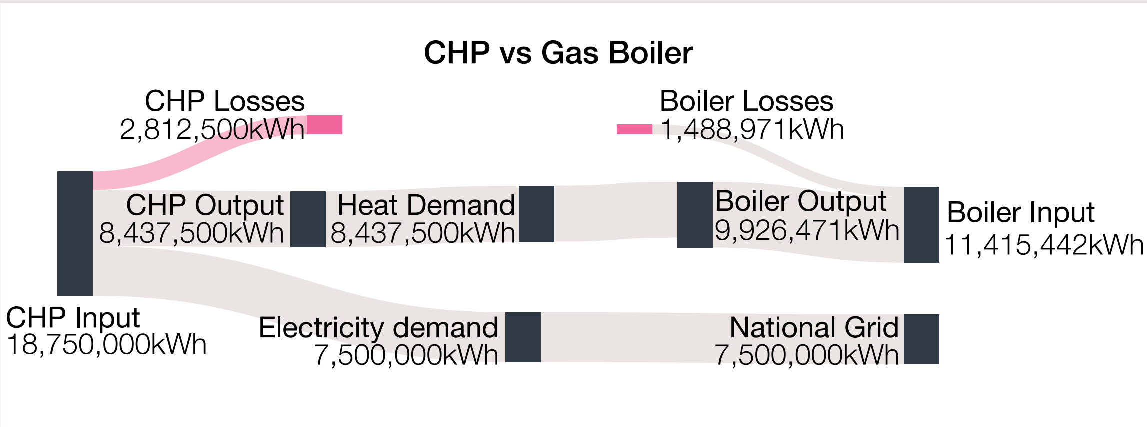


Figure 14: Sankey diagram comparing the energy flows of the existing CHP with a gas boiler replacement

Table 5: Aspects of a gas boiler replacement

Aspect	Considerations
Operation	Simple to operate with well-understood maintenance requirements and no on-site electricity generation to manage. A clear timeline for transition to a low carbon alternative should be established, as a gas boiler does not support long-term decarbonisation objectives.
People	Minimal disruption to building users during installation and low training requirements for estates teams. However, continued on-site combustion maintains existing concerns around flue emissions and local air quality.
Information	Metering requirements are straightforward, covering gas input and heat output. Integration with existing building management systems supports basic performance monitoring.
Infrastructure	A gas boiler can typically be accommodated within existing plant room footprints and can use established flue routes and gas supply. The electrical connection must be assessed to confirm it can handle the full site demand without on-site CHP generation.
Interoperability	Works well with conventional building services but does not support the wider system integration required by heat decarbonisation planning.
Commercial	Low capital cost, but ongoing exposure to gas price volatility and rising carbon costs over the asset lifetime. No pathway to reduced operating costs through decarbonisation.
Legislation	Does not align with the long-term policy direction to phase out fossil fuel primary heating across the public sector. Suitable only as short-term or backup plant within a broader transition plan.
Resilience	Provides reliable heat supply but no electrical resilience. The site becomes fully dependent on the grid for all electricity, removing the supply security that CHP previously provided.

Replacement with a ground source heat pump

A ground source heat pump extracts low grade heat from the ground through boreholes or buried pipework and upgrades it to a usable temperature using electrically driven compression. It typically delivers more stable and higher seasonal efficiencies than an air source heat pump because ground temperatures remain relatively constant throughout the year.

In this scenario, the site's heating demand is met entirely by a ground source heat pump, with all electricity sourced from the grid. The system requires a ground array of sufficient size to meet the heat demand without thermally depleting the ground source over time. Performance is influenced by local geology, borehole depth and spacing, and the design of the ground loop system.

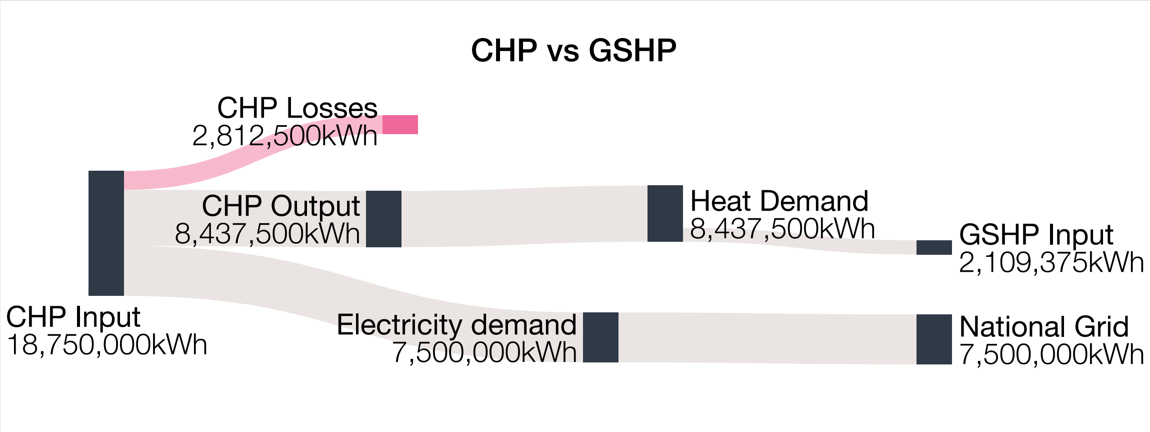


Figure 15: Sankey diagram comparing the energy flows of the existing CHP with a ground source heat pump replacement

Table 6: Aspects of a ground source heat pump replacement

Aspect	Considerations
Operation	Low mechanical complexity with fewer moving parts than CHP. Controls optimisation is critical to maintaining design efficiency. Long-term ground temperature monitoring should be planned for.
People	Installation involves significant disruption from drilling operations, including heavy plant access, noise, and temporary loss of external areas. Once installed, the system operates quietly. Skills development is needed for estates teams in heat pump operation and ground source management.
Information	Metering of electricity input, heat output, and ground loop performance is required. BMS integration supports optimisation and early identification of performance degradation.
Infrastructure	Significant external space is required for borehole drilling or horizontal ground collector installation. Existing heating distribution may need modification for lower flow temperatures. Electrical infrastructure upgrades are likely required.
Interoperability	The ground array is a long-life infrastructure asset, typically exceeding 50 years, that can serve multiple generations of above-ground heat pump plant. Compatible with future heat network connection and can provide cooling where designed for balanced operation.
Commercial	High capital cost, driven primarily by borehole drilling. The long asset life of the ground array and the higher, more stable coefficient of performance compared with air source heat pumps can deliver competitive whole-life costs.
Legislation	Well aligned with public sector decarbonisation policy. Planning and environmental permits may be required for borehole drilling depending on local authority and Environment Agency requirements.
Resilience	The site becomes fully dependent on the grid for heating electricity. Backup heating capacity is likely required for sites with critical service requirements. Thermal storage can enhance resilience by bridging short-duration supply interruptions.

Replacement with an air source heat pump

An air to water source heat pump extracts heat from the ambient air and upgrades it to a usable temperature using electrically driven compression. It is one of the most widely deployed low carbon heating technologies in the UK public sector, supported by an established supply chain and access to funding through the Public Sector Decarbonisation Scheme.

In this scenario, an air source heat pump meets the site's full heating demand, with all electricity sourced from the grid. The heat pump delivers heat at a lower flow temperature than conventional CHP or boiler systems, and its performance varies with ambient air temperature, with lower efficiencies during colder periods when heating demand is highest.

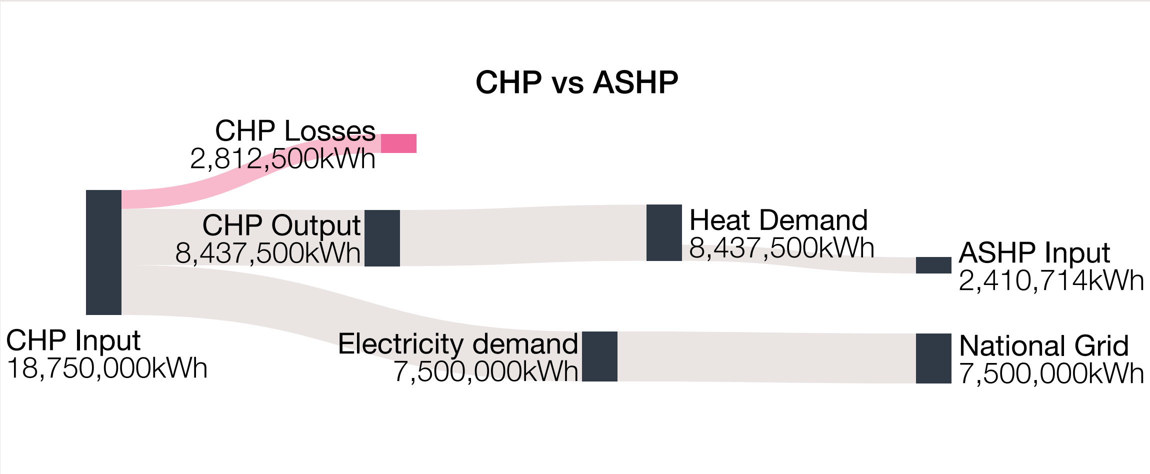


Figure 16: Sankey diagram comparing the energy flows of the existing CHP with an air source heat pump replacement

Table 7: Aspects of an air source heat pump replacement

Aspect	Considerations
Operation	Generally reliable and low maintenance once commissioned. Performance is sensitive to ambient temperature. Careful controls strategy, hydraulic design, and seasonal performance monitoring are needed to maintain efficiency.
People	External condenser units generate noise that must be assessed against the proximity of occupied spaces and neighbouring properties. Estates teams will require training in heat pump operation, controls, and fault diagnosis.
Information	Monitoring of coefficient of performance against design assumptions is essential to ensure the system is operating as intended. BMS integration supports demand-responsive control and tariff optimisation.
Infrastructure	Requires external space for condenser units, which can be substantial at the capacities needed for large public sector sites. Existing heating distribution may need modification to operate at lower flow temperatures, including larger emitters, buffer vessels, or conversion from steam to low temperature hot water. Electrical infrastructure upgrades are likely required.
Interoperability	Integrates well with wider electrification strategies and can operate alongside thermal storage, solar PV, and battery storage. Can provide cooling as well as heating from the same system in some configurations.
Commercial	Moderate to high capital cost. Operating cost is linked to electricity consumption and price, which is currently significantly higher per kilowatt hour than gas. The commercial case improves over time as the grid decarbonises and policy shifts narrow the electricity to gas price ratio.
Legislation	Strongly aligned with current policy, funding, and regulatory frameworks for public sector decarbonisation. Compatible with Building Regulations Part L and with long-term Net Zero commitments.
Resilience	The site becomes fully dependent on the grid for both heating and power. Backup heating capacity may be required for sites with critical service requirements. Thermal storage can help bridge short-duration supply gaps.

Connection to an existing heat network

A heat network distributes heat from a centralised energy source to multiple buildings via insulated pipework. In this scenario, a site connects to an existing or planned local heat network, removing the need for on-site heat generation and instead receiving heat from an external provider. All electricity is sourced from the grid.

The carbon performance of this option is determined by the heat source used by the network operator, which may include large-scale heat pumps, waste heat recovery, biomass, or in some cases residual gas-fired plants. The site has no direct control over the fuel mix but may secure carbon intensity commitments through the heat supply agreement.

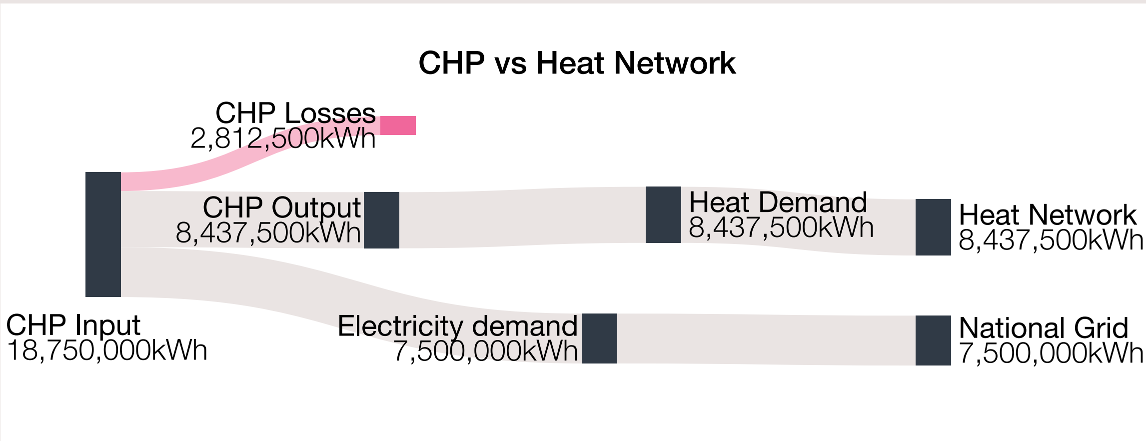


Figure 18: Sankey diagram comparing the energy flows of the existing CHP with a heat network connection

Table 8: Aspects of a heat network connection

Aspect	Considerations
Operation	The site is responsible for maintaining internal secondary distribution and heat interface units. Performance depends on the network operator's management of supply temperatures and efficiency. Service level agreements and response times should be clearly defined in the connection contract.
People	Connection works involve significant civils works for primary pipework routing. Once connected, the system is largely invisible to building users. Estates teams require new competencies in heat network contract management and heat interface unit maintenance.
Information	Metering at the point of connection is typically mandated by the network operator and may be subject to emerging consumer protection regulation. Internal secondary distribution should also be metered to manage energy costs and verify that contracted heat supply matches actual demand.
Infrastructure	Civils works are required for primary pipework from the network to the site, together with space for a heat interface unit or substation within the building. Internal distribution may need conversion from steam to low temperature hot water. The electrical connection must handle full site demand without CHP generation.
Interoperability	Compatible with future changes in the network's heat source as the operator transitions to lower carbon generation. Can operate alongside on-site solar PV and battery storage to manage the site's electricity position independently of the heat supply.
Commercial	High capital cost at system level, though typically shared across multiple connected buildings or organisations. Ongoing heat costs are subject to the tariff charged by the network operator and the terms of the heat supply agreement. Long-term cost certainty depends on the contractual framework.
Legislation	Aligned with government heat network policy, including heat network zoning under the Energy Act 2023 and emerging consumer protection regulation. Connection to a designated heat network zone may become a requirement for certain sites in future.
Resilience	The site becomes dependent on the network operator for heat supply continuity. Off-site outages affect all connected buildings. Backup heating capacity should be considered, and the heat supply agreement should include clear provisions for service continuity.

Replacement with a hydrogen fuel cell CHP

A hydrogen fuel cell generates both electricity and heat through an electrochemical reaction between hydrogen and oxygen, producing water as a by-product. It is the only alternative assessed in this report that retains on-site electricity generation alongside heat production. Carbon performance depends on the hydrogen source, with near-zero emissions at the point of use when supplied with green hydrogen from renewable electrolysis.

In this scenario, the fuel cell replaces gas-fired CHP on a like-for-like functional basis, providing both heat and power to the site. However, the technology remains at an early stage of commercial deployment for building-scale applications, and the business case is heavily dependent on hydrogen price, availability, and the development of supply infrastructure.

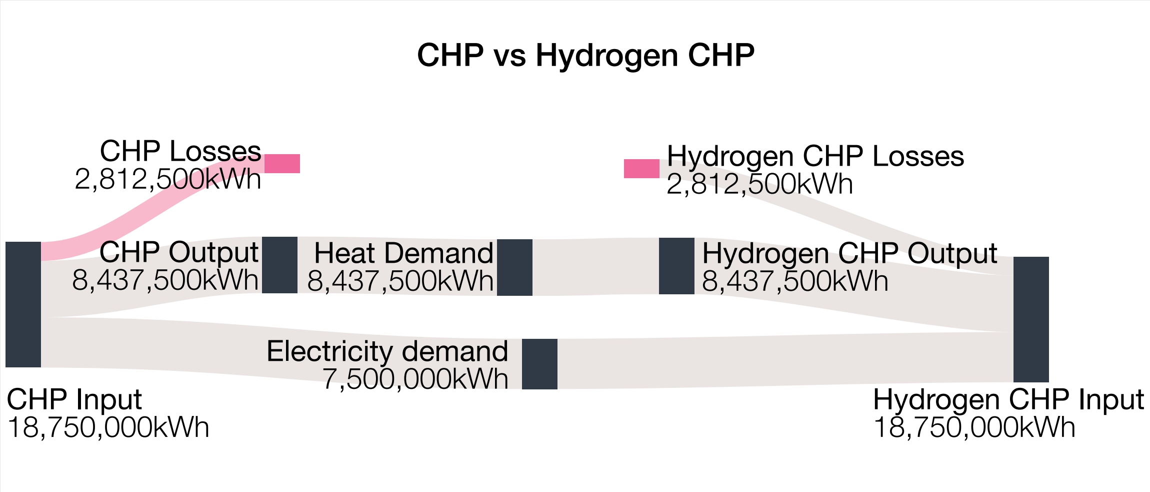


Figure 19: Sankey diagram comparing the energy flows of the existing CHP with a hydrogen fuel cell CHP

Table 9: Aspects of a hydrogen fuel cell CHP replacement

Aspect	Considerations
Operation	Fuel cell stacks have a finite operating life, typically 40,000 to 80,000 hours, after which stack replacement is required at significant cost. Specialist maintenance support is needed, and the supply chain for parts and servicing is less established than for conventional plant.
People	Hydrogen storage and handling on-site introduces safety considerations that must be communicated to staff and building users. Estates teams and safety officers will need to build new competencies in hydrogen safety, fuel cell operation, and risk management.
Information	Comprehensive metering of hydrogen input, electricity output, heat output, and system efficiency is required. Given the emerging nature of the technology, detailed operational data is critical for performance verification and for building the evidence base for future deployment decisions.
Infrastructure	Requires plant room space comparable to gas-fired CHP, plus additional space for hydrogen storage and safety systems, including ventilation, gas detection, and hazardous area zoning. A reliable hydrogen supply must be secured, whether via pipeline, delivered storage, or on-site electrolysis.
Interoperability	Retains the dual heat and power profile of gas-fired CHP but introduces a hydrogen supply chain dependency that does not exist to the same extent with grid electricity or natural gas.
Commercial	High to very high capital cost reflecting early-market status. Operating cost is heavily dependent on hydrogen price, currently significantly higher than natural gas per unit of energy. Stack replacement is a material future capital liability.
Legislation	Aligned in principle with public sector Net Zero ambitions if supplied with green hydrogen, but the regulatory framework for hydrogen in buildings is still developing. The technology lacks the established policy and funding frameworks available for heat pumps and heat networks.
Resilience	Retains on-site generation capability, providing some degree of independence from grid supply. However, overall resilience depends on hydrogen supply reliability, which is a newer and less proven supply chain. On-site storage provides a buffer but adds safety and spatial requirements.

Summary comparison

Table B7 brings together the key characteristics of each option at a glance, to support comparison across the six technologies. The full quantitative analysis of operational costs, capital costs, grid impact, and carbon emissions for each option is presented in Section 3 of the main report.

Table 10: Summary comparison of CHP replacement options

Option	Capital cost	Operating cost	Carbon performance	Key advantage	Key challenge
Like-for-like CHP	Moderate	Lowest	Highest emitting; flat to 2050	Retains on-site generation and lowest operating cost	Locks in fossil fuel dependency
Gas boiler	Lowest	High	Second highest; declines slowly	Simplest installation with lowest upfront cost	No long-term decarbonisation pathway
Air source heat pump	Moderate to high	High	Strong reduction trajectory	Widely deployed with established supply chain	Requires electrical infrastructure upgrades
Ground source heat pump	Highest of established technologies	High, partially offset by higher COP	Strongest reduction trajectory	Highest and most stable efficiency	High capital cost and significant site disruption during drilling
Heat network connection	Variable	High	Depends on network heat source	Removes on-site generation plant and shifts maintenance burden	Depends on availability of a local network
Hydrogen fuel cell CHP	Highest	Highest	Low and flat with green hydrogen	Retains on-site electricity generation	Early-market technology with limited commercial track record

Glossary

Term	Definition
Air source heat pump (ASHP)	A heating technology that extracts heat from ambient air and upgrades it using electrically driven compression. In this report, references to ASHPs mean air-to-water systems suitable for non-domestic heating.
Anchor load	A large, stable, and predictable heat or electricity demand that underpins the commercial viability of an energy infrastructure project such as a heat network. Public sector sites with CHP are often cited as strong anchor load candidates.
Balanced Pathway	The Climate Change Committee's recommended trajectory for UK emissions reductions from the present to Net Zero by 2050, set out in the Seventh Carbon Budget.
Baseload	A mode of operation in which a generating or heating asset runs continuously or near-continuously at a steady output, meeting the minimum demand on a system at all times.
Behind-the-meter	Describes energy generation or storage located on the customer side of the electricity meter, which supplies the site directly rather than being exported to the grid.
Building Management System (BMS)	Control system used to monitor and manage mechanical and electrical systems in a building.
Capacity charge	A fixed fee paid to the electricity network operator based on the maximum amount of power a site is contracted to draw from the grid, regardless of actual consumption.
Chartered Institution of Building Services Engineers (CIBSE)	The professional body for building services engineers in the UK, and the publisher of technical guidance including Guide M and the Applications Manual series.
Civils works	Construction works involving groundworks, excavation, foundations, and similar activities, typically required when installing new pipework, boreholes, or electrical infrastructure.

Term	Definition
Clean Power 2030	UK Government target to deliver a clean power electricity system by 2030.
Climate Change Committee (CCC)	Independent statutory body that advises the UK Government on emissions targets and reports on progress towards Net Zero.
Climate Change Levy	A tax on the non-domestic use of energy intended to encourage energy efficiency and reduce carbon emissions. CHP installations certified under CHPQA can qualify for exemptions.
Coefficient of Performance (COP)	The ratio of heat output to electricity input for a heat pump, used as a measure of efficiency. A COP of 3 means the heat pump delivers three units of heat for every unit of electricity consumed.
Combined Heat and Power (CHP)	A generation technology that produces both heat and electricity from a single fuel input, typically natural gas.
Combined Heat and Power Quality Assurance (CHPQA)	A voluntary UK government scheme that assesses and certifies the energy efficiency of CHP installations.
Connection queue	The backlog of projects waiting for new or increased electricity grid connections. Administered by the National Energy System Operator.
Counterfactual	The reference case against which alternative scenarios are compared. In this report, the counterfactual is a like-for-like gas-fired CHP replacement.
Department for Energy Security and Net Zero (DESNZ)	The UK government department responsible for energy policy, security of supply, and delivery of Net Zero.
De-steaming	The process of converting a site's heating distribution from a steam-based system to a low temperature hot water system, often a prerequisite for installing heat pumps.
Demand-side flexibility	The ability of an electricity consumer to shift or reduce their consumption in response to grid signals or price incentives, typically rewarded through participation in flexibility markets.
Dispatchable	Describes a generating asset that can be turned on or off or adjusted to meet changing electrical demand on short notice. Gas-fired CHP is dispatchable; solar PV is not.

Term	Definition
Distribution Network Operator (DNO)	The company responsible for operating the local electricity distribution network in a given region.
Emissions Trading Scheme (ETS)	A cap and trade system that sets a limit on greenhouse gas emissions from energy-intensive industries, the power sector, and aviation. The UK operates its own scheme known as the UK ETS.
Enabling works	Preparatory or supporting works required to allow the installation of a new energy system, such as electrical upgrades, pipework modifications, or plant room alterations.
End-of-life	The point at which an asset is no longer economical or practical to maintain and should be replaced or decommissioned.
Flexibility services	Services provided to the electricity grid operator that involve shifting, reducing, or providing electricity demand or generation on request, in return for payment.
Flue	A duct or pipe that carries combustion gases away from a boiler, CHP, or other fossil fuel plant.
Gigawatt (GW)	Unit of power equal to one billion watts.
Gigawatt hour (GWh)	Unit of energy equal to one billion watt hours.
Great Britain (GB)	England, Scotland, and Wales. The GB electricity grid does not include Northern Ireland, which operates as part of the Single Electricity Market with the Republic of Ireland.
Green Book	HM Treasury guidance on the appraisal of projects, programmes, and policies, including supplementary guidance on the valuation of energy use and greenhouse gas emissions.
Green hydrogen	Hydrogen produced through the electrolysis of water using renewable electricity, resulting in near-zero carbon emissions at the point of production.
Grid carbon intensity	A measure of the carbon dioxide emitted per unit of electricity generated, typically expressed in grams of carbon dioxide equivalent per kilowatt hour.
Ground source heat pump (GSHP)	A heating technology that extracts low grade heat from the ground and upgrades it using electrically driven compression.

Term	Definition
Health Technical Memorandum (HTM)	A series of guidance documents for the design and operation of NHS facilities. HTM 06-01 covers electrical services supply and distribution.
Heat interface unit	The equipment installed at the point where a building connects to a heat network, transferring heat from the network into the building's internal distribution system.
Heat network	A system that distributes heat from a central source to multiple buildings via insulated pipework, also known as district heating.
Heat network zoning	A designation framework under the Energy Act 2023 that identifies areas where heat networks are expected to be the lowest-cost route to decarbonising heat.
Hybrid system	An energy system that combines two or more technologies to deliver heat, power, or both, for example a heat pump used alongside a retained gas boiler or CHP.
Island mode	The ability of an on-site generation asset to continue operating and supplying the site during a grid outage, disconnected from the wider electricity network.
Kilowatt electrical (kWe)	Unit of electrical power output.
Kilowatt hour (kWh)	Unit of energy equal to one thousand watt hours.
Kilowatt thermal (kWth)	Unit of thermal power output.
Like-for-like replacement	The replacement of an asset with a new asset of the same type and similar specification, rather than with an alternative technology.
Load-following	A mode of operation in which a generating or heating asset adjusts its output to match changing demand on the site, rather than running at constant output.
Low Temperature Hot Water (LTHW)	A heating distribution system operating at lower flow temperatures than traditional steam or high temperature hot water systems.
Maximum Import Capacity (MIC)	The maximum amount of electrical power a site is contracted to draw from the grid at any one time.
Megavolt-ampere (MVA)	A unit of apparent power used to describe the capacity of electrical infrastructure such as substations and transformers.

Term	Definition
Megawatt (MW)	Unit of power equal to one million watts.
Megawatt electrical (MWe)	Unit of electrical power output at megawatt scale.
Megawatt hour (MWh)	Unit of energy equal to one million watt hours.
Megawatt thermal (MWth)	Unit of thermal power output at megawatt scale.
Modern Energy Partners (MEP)	A programme delivered by BEIS, the Cabinet Office, and Energy Systems Catapult that tested integrated approaches to public sector site energy masterplanning.
National Energy System Operator (NESO)	The independent body responsible for operating the electricity transmission system and planning the future of the GB energy system.
Net Zero	A state in which an organisation or jurisdiction's greenhouse gas emissions are balanced by equivalent removals, resulting in no net addition to the atmosphere. The UK has a legally binding commitment to reach Net Zero by 2050.
Non-domestic	Describes energy use or tariffs for commercial, industrial, and public sector consumers, as distinct from households.
Off-peak	Periods of the day when electricity demand is lower and prices are typically cheaper, most commonly overnight.
Office of Gas and Electricity Markets (Ofgem)	The UK energy regulator.
Part L	The section of the Building Regulations covering the conservation of fuel and power in new and existing buildings.
Payback	The length of time required for the financial savings from an investment to equal the initial capital cost.
Peak demand	The highest level of electricity or heat demand experienced at a site or on a network, typically occurring at particular times of day or year.
Photovoltaic (PV)	Technology that converts sunlight directly into electricity, typically deployed as solar panels.

Term	Definition
Plant room	The dedicated space within a building that houses mechanical and electrical equipment such as boilers, CHP units, pumps, and heat pumps.
Power Purchase Agreement (PPA)	A long-term contract between an electricity generator and a buyer, often used to secure a known price for renewable electricity.
Prime mover	The engine or turbine that drives a CHP unit, typically a reciprocating gas engine, gas turbine, or steam turbine.
Public Sector Decarbonisation Scheme (PSDS)	A UK Government grant funding scheme that supported heat decarbonisation and energy efficiency projects across the public sector.
Reinforcement	Upgrades to electricity network infrastructure such as substations, cables, and transformers to accommodate increased demand or generation.
Resilience	The ability of an energy system to maintain service during disruptions such as equipment failure, grid outages, or extreme weather.
Sankey diagram	A type of diagram that shows the flow of energy through a system, with the width of each flow arrow proportional to the quantity being represented.
Scope 1 and 2 emissions	A classification of greenhouse gas emissions. Scope 1 covers direct emissions from sources owned or controlled by an organisation. Scope 2 covers indirect emissions from purchased electricity, heat, or steam.
Self-consumption	The proportion of on-site generated electricity that is used by the site itself rather than exported to the grid.
Spark spread	The margin between the price of electricity and the fuel cost of generating that electricity from gas. Used as a measure of the economic case for gas-fired generation.
Stack (fuel cell)	The central component of a fuel cell in which hydrogen and oxygen react to produce electricity and heat. Fuel cell stacks have finite operating lives and periodic replacement is required.
Standby generator	A generating unit retained on-site to provide backup electricity supply during grid outages or equipment failures.

Term	Definition
Stranded asset	An investment in infrastructure or equipment that loses its value earlier than expected due to changes in policy, market conditions, or technology.
Substation	Electrical infrastructure that transforms voltage between different parts of the distribution network, typically required to supply large sites with electricity.
Thermal storage	A system that stores heat for later use, typically in the form of hot water in insulated tanks, allowing heat generation and heat demand to be decoupled in time.
Tonnes of carbon dioxide equivalent (tCO_2e)	Unit used to express the global warming potential of greenhouse gas emissions, including gases other than carbon dioxide converted to their equivalent climate impact.
Whole-life cost	The total cost of owning and operating an asset over its full life, including capital, operating, maintenance, and decommissioning costs.
Winter peak demand	The highest level of electricity demand experienced on the GB grid during the winter period, typically occurring on cold weekday evenings in December or January.

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