EnergyREV

Analysis of net-zero pathways for a hospital and a university campus

Alexandre Canet, Muditha Abeysekera and Jianzhong Wu

March 2022

INDUSTRIAL STRATEGY

UK Research and Innovation

Authors

- **Alexandre Canet** | Cardiff University
- **Muditha Abeysekera** | Cardiff University
- **Jianzhong Wu** | Cardiff University

This report should be referenced as:

Canet, A., Abeysekera, M. and Wu, J. 2022. Analysis of net-zero pathways for a hospital and a university campus. Energy Revolution Research Centre, Strathclyde, UK. University of Strathclyde Publishing. ISBN: 978-1-909522-98-5

Acronyms

CHP	Combined Heat and Power
DER	Distributed energy resources, this includes small scale generation units such as photovoltaic panels, wind turbines and solar thermal panels.
GHG	Greenhouse gas emissions (measured in the amount of carbon dioxide equivalent)
Li	Lithium-ion
MES	Multi-energy systems
PV	Photovoltaics
QEH	Queen Elizabeth Hospital in Kings Lynn, UK
UW	University of Warwick campus, UK
SLES	Smart Local Energy Systems

Contents

Summary 4

Background 5

2. Net-zero pathways for a hospital and a university campus 7

3. Simulation results 9
   - 3.1 GHG emissions 9
   - 3.2 Energy usage and grid connection capacity 12
   - 3.3 Cost analysis 14
     - 3.3.1 Cumulative cost 14
     - 3.3.2 Impacts of electricity prices on cost 15

4. Key findings 20

5. Limitations and further work 22

6. References 23

Appendix 24
   - A. Methods 24
     - A.1 Simulation model for Multi-Energy System sites 24
     - A.2 Metrics 25
   - B. Input data and assumptions 25
     - B.1 Case studies data 25
     - B.2 Installed capacity 26
     - B.3 Merit order 27
     - B.4 Technical-economic parameters of technologies 28
     - B.5 Carbon intensity of energy 28
     - B.6 Energy Prices 29

Summary

The 2050 net-zero target set by the UK government will require changes at different levels of the energy system including single dwellings, commercial buildings and campuses, cities and the national energy supply infrastructure. The public sector has committed to a 75% reduction in greenhouse gas emissions (GHG) by 2037 compared to 1990 levels and net-zero by 2050. In this research, different pathways to decarbonise energy provision at a hospital and a university campus in the UK by 2050 were analysed considering the technical, economic and GHG emission implications.

The insights gained from this work will be useful to policy makers and facility managers who are considering how best to meet GHG reduction targets. From a net-zero perspective, this briefing paper shows that decarbonising heat with heat pumps in the short/medium term and decarbonising electricity with on-site distributed energy resources (DER) in the long-term is more expensive but emits significantly less GHG.

It shows that GHG reductions of 98% can be achieved by 2050. But electrifying heat and moving to DER will increase both costs and pressure on the electricity grid. For these changes to be effective the electricity grid must be decarbonised. It also shows that for sites to access electricity with a low carbon intensity at a reasonable price – which they must do to meet net-zero targets – they will need to be able to shift their demand to times when cheaper and lower carbon electricity is available.

The dilemma faced by sites with natural gas-fired CHP generators was also highlighted. Their replacement by electricity-based technologies such as heat pumps can increase peak electricity imports by more than 100%, creating constraints for the public electricity grid. It also increases the exposure of the sites to increase in electricity prices. Further cost-benefit analysis would need to be conducted which will consider aspects such as grid reinforcement costs, GHG emissions and resilience to uncertain energy prices to determine the future of on-site natural gas-fired CHP generators.

Further work is required to generalise the results to similar sites and conduct additional sensitivity analysis to assess the impact of uncertainties of technology costs and energy prices on decarbonisation pathways.

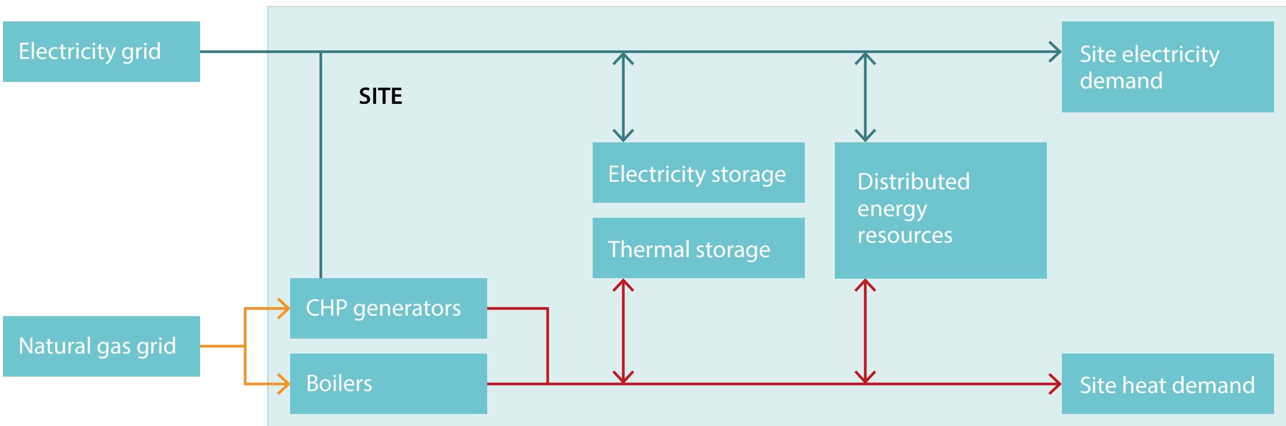
Background

In October 2021, the UK government released its Net-zero strategy report which describes a long term plan to reduce carbon emissions by 2050. The report states an intermediate target of 75% reduction in greenhouse gas emissions (GHG) by 2037 for public sector buildings compared to 1990 levels and net-zero by 2050.

Figure 1 shows the general arrangement for energy supply at a large building or building complex in the UK (described as multi-energy site, MES). It is typically connected to the public electricity and natural gas grids and may include on-site generation of electricity, heat and energy storage technologies. The heat requirements of the site are supplied solely by natural gas-fired boilers and in some instances, jointly with combined heat and power generation units (CHP). DER such as wind turbines and photovoltaics (PV) panels can also be installed.

In 2019, there was more than 6 GW of CHP generators installed in the UK, with almost 70% of them using natural gas (BEIS, 2021). Investment in CHP generators at an MES was expected to reduce site energy costs and carbon emissions compared to using grid electricity. However, the net-zero transition may impact their long term economic and environmental benefits as gas prices are to increase due to carbon taxes and the carbon intensity of grid-supplied electricity in the UK is rapidly decreasing. Modelling work undertaken in (BEIS, 2020) suggested that by 2032 the electricity produced by CHP generators will have higher carbon intensity than grid electricity. Their potential role in providing upward and downward flexibility to the wider system was also highlighted in (Abeysekera et al, 2022).

Figure 1: General arrangement for energy supply at a multi-energy system site.



Reducing the GHG emissions of MES sites to reach emission reduction targets requires investments in switching to low-carbon energy technologies. This action may include installing fluctuating electricity, such as PV panels, and solar thermal panels for heat generation, installing electricity and thermal energy storage and replacing natural gas boilers with heat pumps or with hydrogen boilers. Some challenges need to be considered for investments in decarbonisation pathways including,

- The risk of not achieving the GHG emission reductions by the target date
- The high capital cost of new equipment and the increase in operational costs
- Public electricity grid connection constraints affecting the design of on-site energy system
- Uncertainties in future energy prices and grid carbon emissions intensity

This paper presents a study of net-zero pathways for energy provision at two MES sites, a hospital and a university campus. The study uses a case study-based approach and presents a methodology of analysing decarbonisation pathways and deriving insights for similar sites. The aim is to address the following questions,

- What is the roadmap and investment required to achieve emission reduction commitments in MES sites?
- How does prioritising low carbon heat before low carbon electricity impact the GHG emissions of an MES site?
- What are the technical impacts of the energy transition of MES sites on the local energy grid?

This work is carried out as part of the EnergyRev research consortium WP5-3 Next Wave of Local Energy Systems in a Whole Systems Context funded by the UKRI.

2. Net-zero pathways for a hospital and a university campus

Net-zero pathways were developed for models based on the energy system of the Queen Elizabeth Hospital (QEH) and the University of Warwick (UW) campus site.

The QEH is a regional hospital in Kings Lynn, Norfolk, UK. The QEH NHS Trust owns and operates a multi-vector energy system on-site, including two natural gas CHP generators units, four natural gas boilers and an 800 kW wind turbine (owned by a third party). The UW is based on 720 acres between West Midland and Warwickshire counties on the outskirts of Coventry, UK. The UW owns and operates an integrated energy supply system to meet on-site energy demand, including five natural gas CHP generators, three natural gas boilers and two thermal storage tanks, and a heat network with 19 km of hot-water-carrying pipes. The site also has 593 kW of PV panels installed in different rooftops across the campus.

A comparison of the characteristics of the energy demand and the installed capacity of natural gas boilers and CHP generators of the two case studies is provided in Table 1.

This information was used to create four cases based on two initial arrangements. In the initial arrangement number 1, heat requirements were met by natural gas boilers, and in the initial arrangement number 2 by natural gas boilers and CHP generators, such as:

1. Case 1 QEH: Half-hourly electricity and heat demand from QEH and initial arrangement 1
2. Case 1 UW: Half-hourly electricity and heat demand from UW and initial arrangement 1
3. Case 2 QEH: Half-hourly electricity and heat demand from QEH and initial arrangement 2
4. Case 2 UW: Half-hourly electricity and heat demand from UW and initial arrangement 2

Table 1: **Characteristics of the energy system of QEH and UW. The half-hourly energy demand data from 2020 was used to calculate these values for QEH and from 2019 for UW.**

Characteristics	QEH	UW
Peak electricity demand (MW)	1.9	10.2
Annual electricity demand (GWh)	10.0	60.7
Peak Heat demand (MW)	5.2	17.5
Annual heat demand (GWh)	22.5	62.4
Natural gas boilers installed capacity (kW_{th})	10,548	14,764
Natural gas CHP generators installed capacity (kW_e/kW_{th})	1,274/1,699	8,200/9,200

Figure 2 shows the two initial arrangements and the three pathways that were modelled for each of the case studies. The three pathways were:

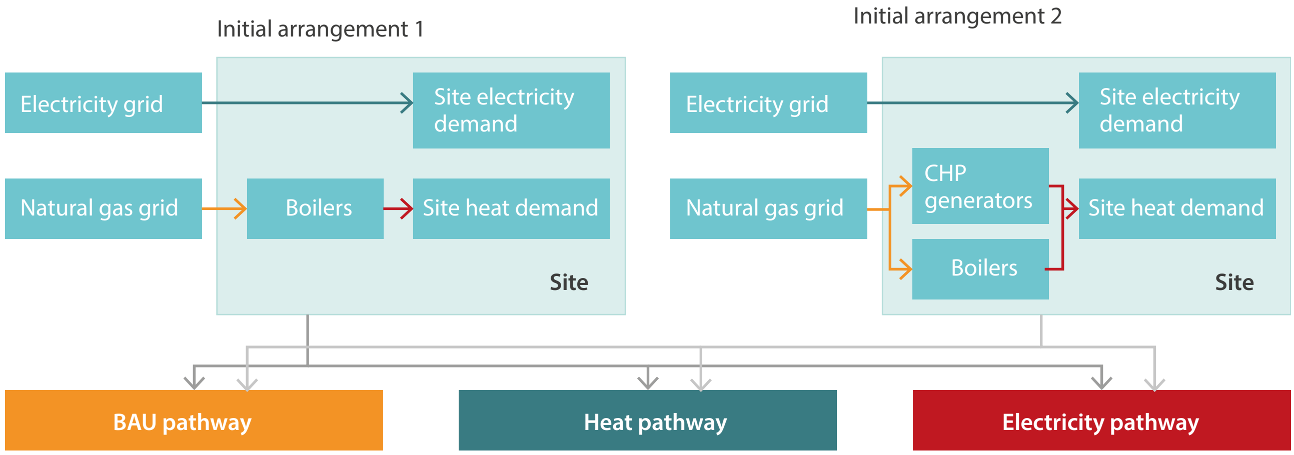
1. A business-as-usual pathway (BAU). This is the counterfactual pathway where the initial arrangement is maintained from 2020 to 2050.
2. A Heat pathway (HEAT). This is a pathway where the heat demand is decarbonised before electricity. The fossil fuel-based heating technologies of the initial arrangement are replaced by a combination of heat pumps and thermal storage in 2026, and by adding PV panels to the system in 2036.
3. An Electricity pathway (ELEC). This is a pathway where electricity demand is decarbonised before the heat demand. PV panels and Lithium-ion (Li) batteries are added to the initial arrangement in 2026 and, the fossil fuel-based heating technologies are replaced by heat pump systems in 2036.

The 12 sets of results were produced by simulating each of the case studies' initial arrangement and pathways. The results were combined to cover the period 2020 to 2050 and used to calculate the following metrics:

- GHG emissions by year
- Cumulative GHG emissions for the period 2020 to 2050
- Capital expenditure (CAPEX) by year
- Operating expenses (OPEX) by year
- Cumulative cost for the period 2020 to 2050
- Amount of electricity and heat consumption by year
- Peak electricity import by year

A detailed description of the methodology is available in Section A. The input data and assumptions used for modelling and calculating the metrics is available in Section B.

Figure 2: Initial arrangements and pathways for a MES site.



INDUSTRIAL STRATEGY
UK Research and Innovation

3. Simulation results

3.1 GHG emissions

The installation of low carbon heating technologies first provides the largest reduction in cumulative GHG emissions at both sites. The analysis of cumulative GHG emissions is more important than annual GHG emissions metrics when focusing on climate change. To mitigate climate change the goal is to decrease the concentration of GHG emissions in the atmosphere. Figure 3 shows the cumulative GHG emissions of transition pathways for QEH and UW. The ELEC and HEAT pathways provide significant GHG emissions savings compared to the BAU pathways. For QEH and UW and the two initial arrangements, the HEAT pathway decreases the GHG emissions by 71% to 78% compared to the BAU pathways. For the ELEC pathways, the decrease of the GHG emissions is between 43% to 48% compared to the BAU pathways.

Details about the input data used to calculate the GHG emissions can be found in the Appendix B.5.

The comparison of the GHG emissions shows that QEH and UW can have their GHG emissions increase by 40% to 125% if they use CHP generators in addition to gas boilers. This is produced by the lower carbon intensity of the electricity grid compared to the electricity produced using a natural gas CHP generator.

Figure 3: Cumulative GHG emissions for the pathways based on the initial arrangements for the two case studies.

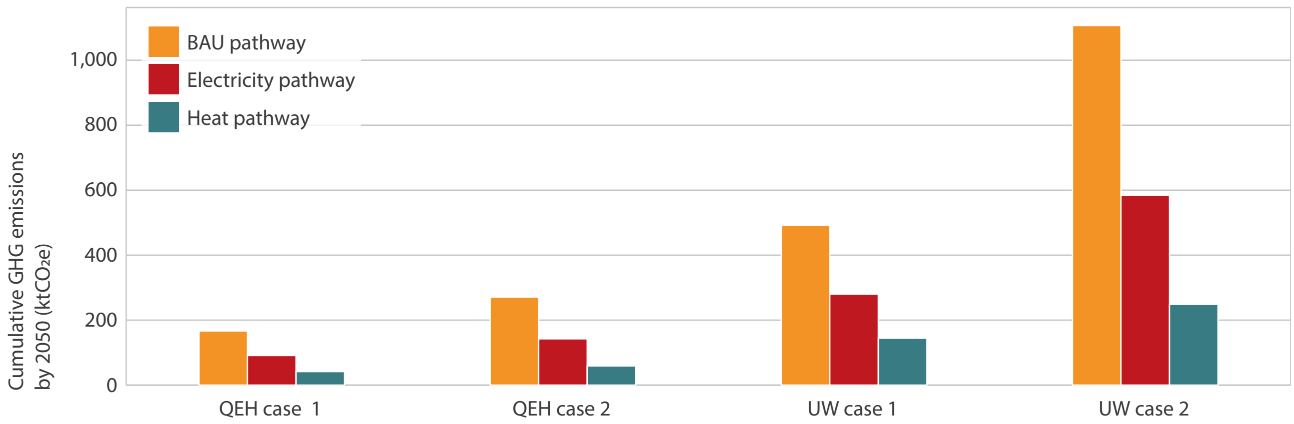


Figure 4: GHG emissions of QEH and UW in 2050 in the different pathways.

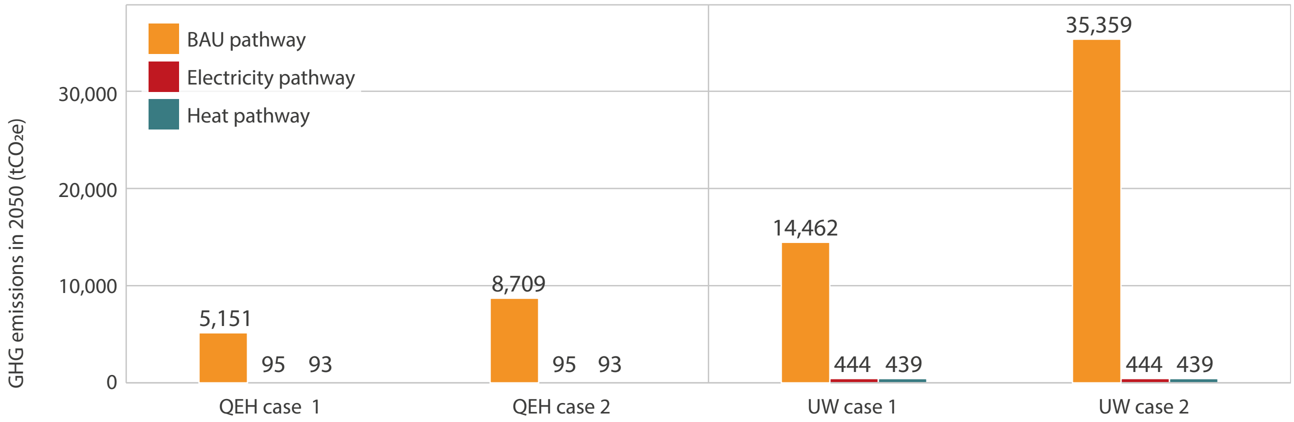


Figure 4 shows the GHG emissions of the different pathways for the two case studies in 2050. A ~98% reduction in GHG emissions of the ELEC and HEAT pathways compared to the BAU pathways is seen. The slight difference between the ELEC and HEAT pathways is due to the use of Li-batteries instead of thermal storage.

This highlights the reliance on grid carbon intensity reduction to achieve net-zero targets at the two sites.

The Current scenario used to produce the previous figures assumes a significant decrease in the carbon intensity of the grid from 2020 and 2050. It is based on the Leading the Way scenario from the National Grid Future Energy Scenarios 2011 (National Grid ESO, 2021b) (see Appendix B.5 for more details). The sensitivity of GHG emission performance to the carbon intensity of the grid was carried out by assuming a conservative scenario, named No Change scenario, which assumes the electricity grid carbon intensity level to remain at the 2020 average level of 152 gCO_2/kWh. It is used to represent a scenario where MES sites do not have access to electricity with low carbon intensity all the time.

Figure 5 and Figure 6 show the cumulative GHG emissions of the pathways using the carbon intensity of the grid from the Current scenario and the No Change scenarios for QEH and UW.

The most significant increase in cumulative GHG emissions is seen for the HEAT pathways, with an increase of 86% to 131% for QEH and 100% to 186% for UW.

The increase in the cumulative GHG emissions in the No Change scenario compared to the Current scenario is more significant in Case 1 pathways than Case 2 pathways. This is explained by the use of CHP generators in Case 2 pathways which produce electricity with a similar carbon intensity to the grid in the No Change scenario, negating some of the emissions savings that could occur when the grid is decarbonising.

Figure 7 shows the emissions of the pathways for the QEH and UW in 2050 under the No Change scenario. The GHG emissions from the sites in the HEAT end ELEC pathways in 2050 are ~23 times higher in the No Change scenario than in the Current scenario (see Figure 4). This highlights the reliance on grid carbon intensity reduction to achieve net-zero targets at the two sites.

Figure 5: Cumulative GHG emissions of the QEH pathways based on the Current and No Change scenarios.

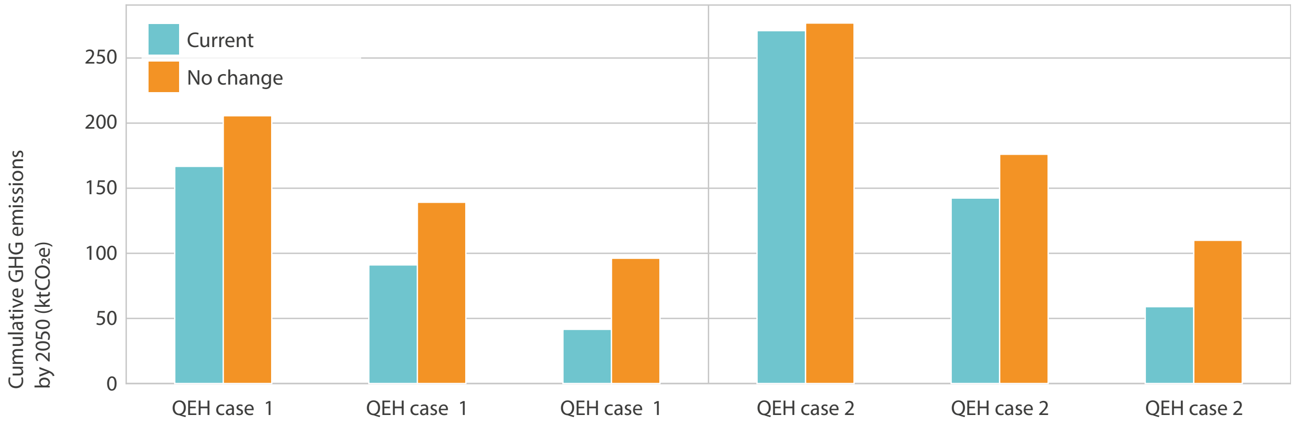


Figure 6: Cumulative GHG emissions of the UW pathways based on the Current and No Change scenarios.

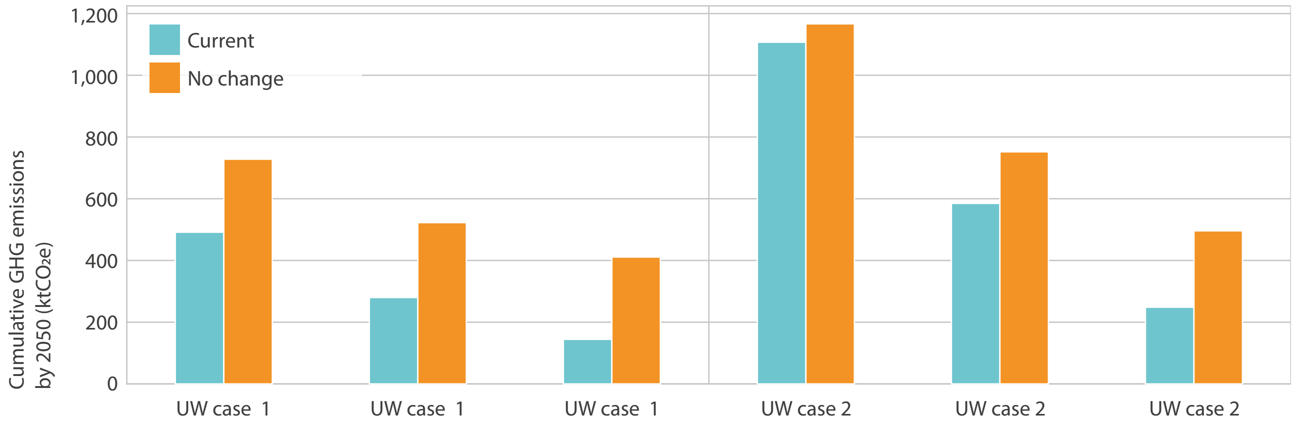
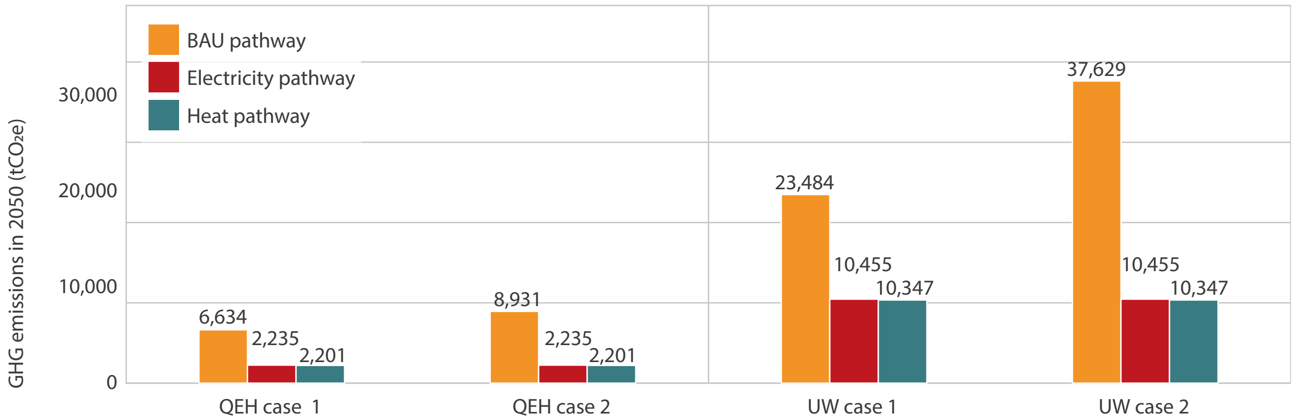


Figure 7: GHG emissions in 2050 based on the carbon intensity of the grid from the No Change scenario.



3.2 Energy usage and grid connection capacity

The electrification of heat to decarbonise sites can have significant impacts on the electricity use of sites and must be considered carefully.

Figure 8 shows the electricity consumption of QEH and UW at different periods for the different pathways. The electrification of heat increases the electricity consumption of QEH by 50% from 2026 for the HEAT pathway and from 2036 for the ELEC pathway. For UW, the increase happens at the same periods, but it is only 13%.

A slight increase in electricity consumption is also seen in the electricity pathway in 2026 to 2035. This is due to the charging of the Li-batteries during periods of low on-site electricity generation. No difference between case 1 and 2 are seen.

Figure 9 shows the peak electricity import of QEH and UW at different periods for the different pathways. The electrification of heat increases the peak electricity import of the QEH by 56% for case 1 and 105% for case 2. For UW, the increase is of 28% for case 1 and 61% for case 2.

Figure 10 shows the heat supplied by QEH and UW at different periods for the different pathways. Due to the thermal storage and the associated losses, a slight increase of the heat supplied is observed for the HEAT pathways.

Figure 8: Electricity consumption for different time periods for the different pathways and initial arrangements. The electricity consumption was calculated as the sum of the electricity grid import and the on-site electricity generated.

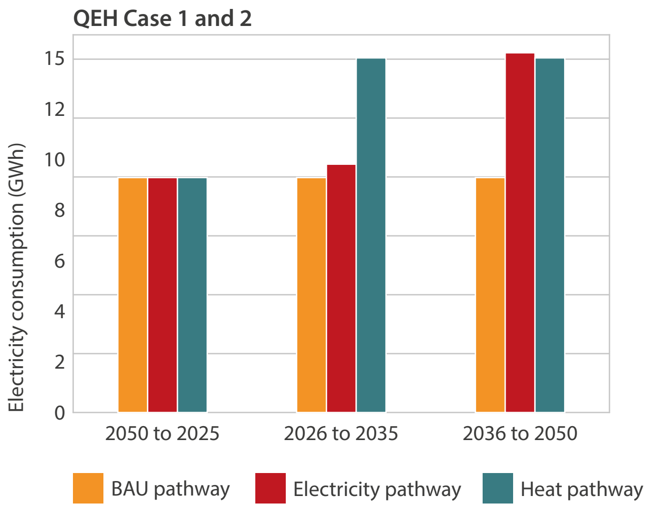


Figure 9: Peak electricity import for different periods for the different pathways and initial arrangements.

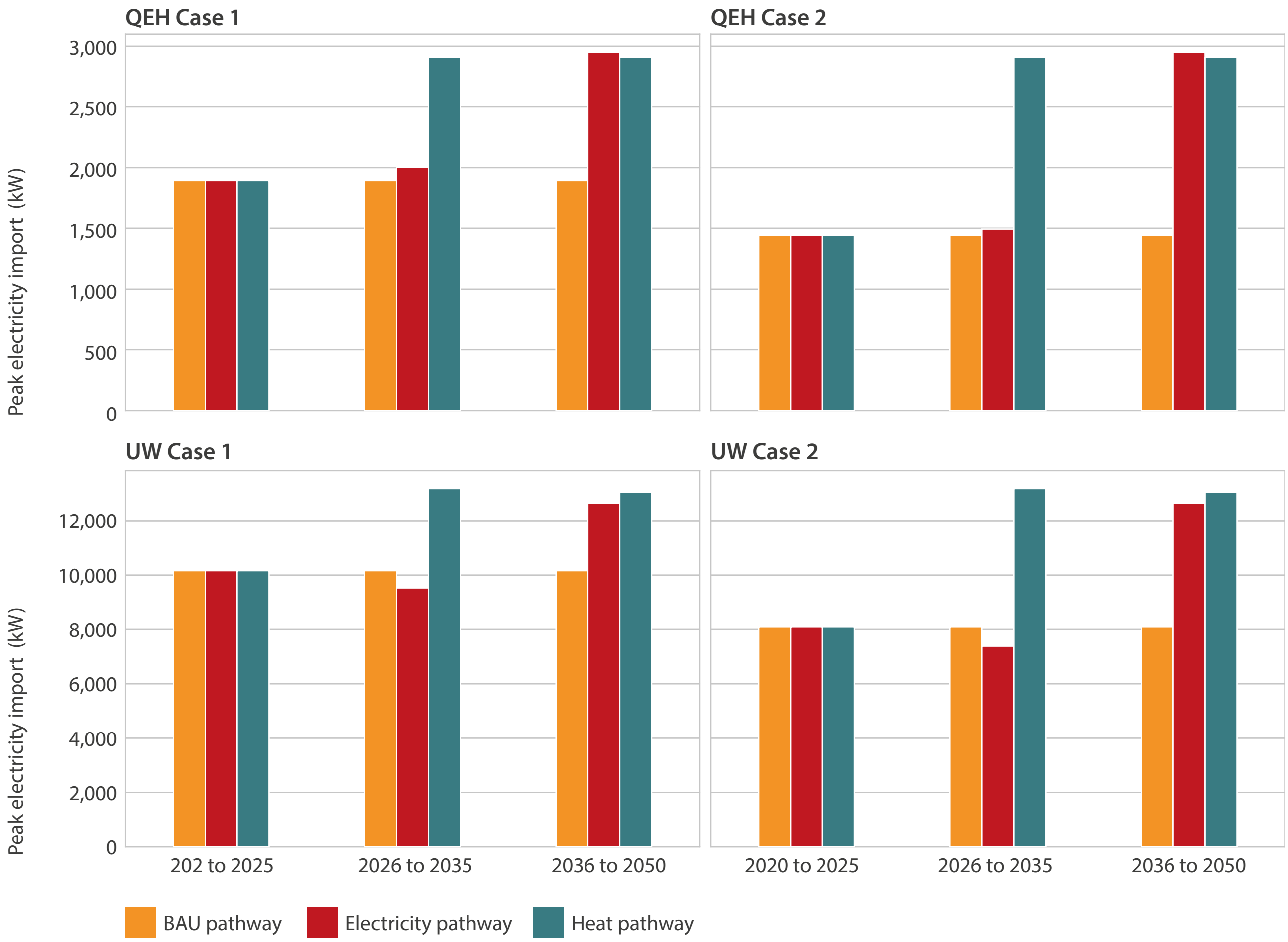
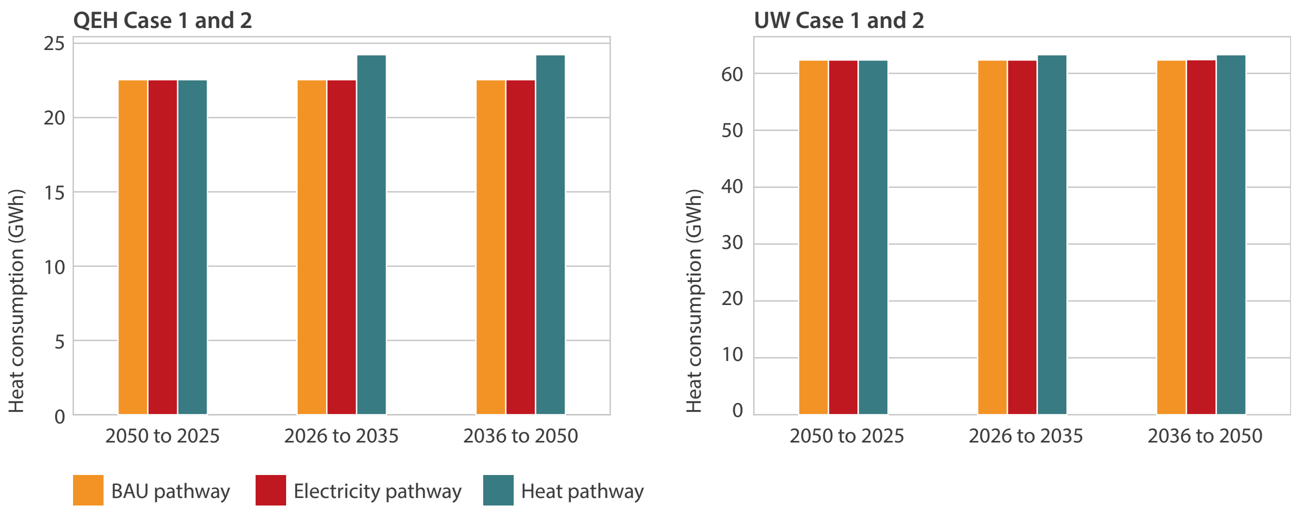


Figure 10: Heat supplied for different time periods for the different pathways and initial arrangements.



3.3 Cost analysis

3.3.1 Cumulative cost

The HEAT pathway is the most expensive of the pathways for QEH and UW when it comes to cumulative cost in 2050. It is followed by the ELEC pathway and the BAU pathway across all pathways and regardless of the initial arrangement. The initial arrangement 2 which includes CHP generators is always cheaper than its counterparts that start with initial arrangement 1.

Figure 11 shows that for QEH, the cumulative costs of the ELEC pathway are 19% higher than for the BAU pathway for case 1 and 2. On the other hand, the cumulative costs of the HEAT pathway are 29% to 33% higher than of the BAU pathways for case 1 and 2.

Figure 12 shows that for UW, the cumulative costs of the ELEC pathway are 4% to 7% higher than for the BAU pathway for case 1 and 2. The cumulative costs of the HEAT pathway are 16% higher than for the BAU pathway for case 1 and 2.

The gap between the ELEC and HEAT pathways with the BAU pathway are less significant with UW than with QEH due to:

1. Higher load factors of the units minimising the impact of the increase in CAPEX of the newly installed units
2. Higher electricity consumption to heat consumption ratio for UW than for QEH led to higher electricity import from the grid and decreased the amount of savings that can be achieved by choosing a different pathway.

Figure 11: Cumulative cost in 2050 of the three pathways and the initial arrangements of QEH.

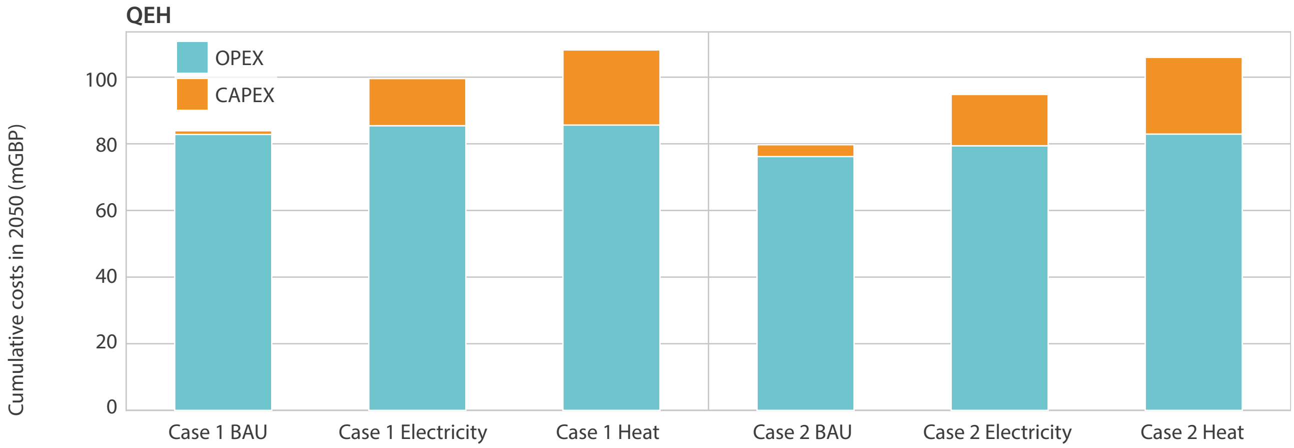
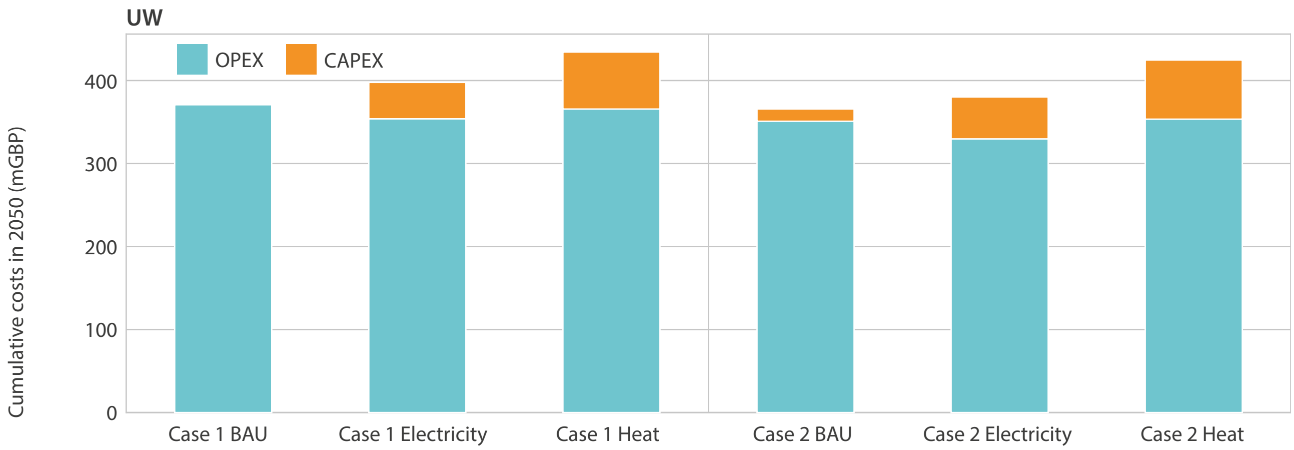


Figure 12: Cumulative cost in 2050 of the three pathways and the initial arrangements of UW.



3.3.2 Impacts of electricity prices on cost

The sensitivity of the cumulative cost of the system to the electricity prices increases with the increase in electricity demand due to the electrification of heat.

Figure 13 shows the five electricity prices scenarios used to produce the results of this sensitivity analysis. For the Electricity price 0% scenario, the electricity price is unchanged from 2020 and 2050 and is set to the value of the electricity price in 2020 shown in Figure 25 (14.4 p/kWh). For the other scenarios, an increase from 0% to 100% of the 2020 electricity price was used between 2020 and 2050 with a 25% increment. No change to the gas prices was considered.

Figure 14 and Figure 15 show the increase of the cumulative cost of the different pathways for QEH and UW if the electricity prices rise (e.g., the results of the ELEC pathway for case 1 QEH based on a 25% increase of the electricity prices are compared to the results of the ELEC pathway for case 1 QEH based on a 0% increase of the electricity prices).

For case 1 QEH, this is shown by an increase of 26% to the cumulative cost for the BAU pathway compared to the base case (BAU with 0% increase in electricity price) whereas for the ELEC pathway and the HEAT pathway the increase is of more than 35%. For case 2 QEH ELEC and HEAT pathways similar results are observed. However, the increase of the BAU pathway is less than 5%. This is due to the CHP generators which allow the site to be less sensitive to changes in electricity prices by producing its own electricity.

Similar observations can be made for UW, but one of the main differences is the higher sensitivity of UW to electricity prices even for the BAU pathway. This is explained by a higher electricity demand to heat demand ratio than QEH and the requirements to import more electricity as the CHP generators do not produce as much electricity when heat demand is lower.

Figure 13: Electricity prices scenarios used in the sensitivity analysis.

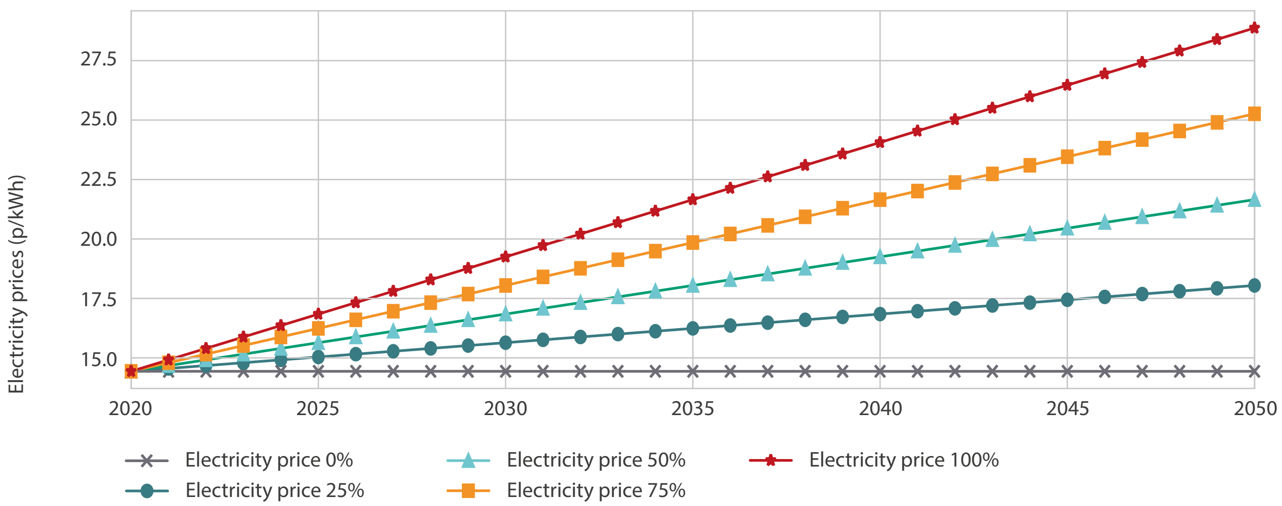


Figure 14: Increase in the cumulative costs in 2050 for QEH pathways.

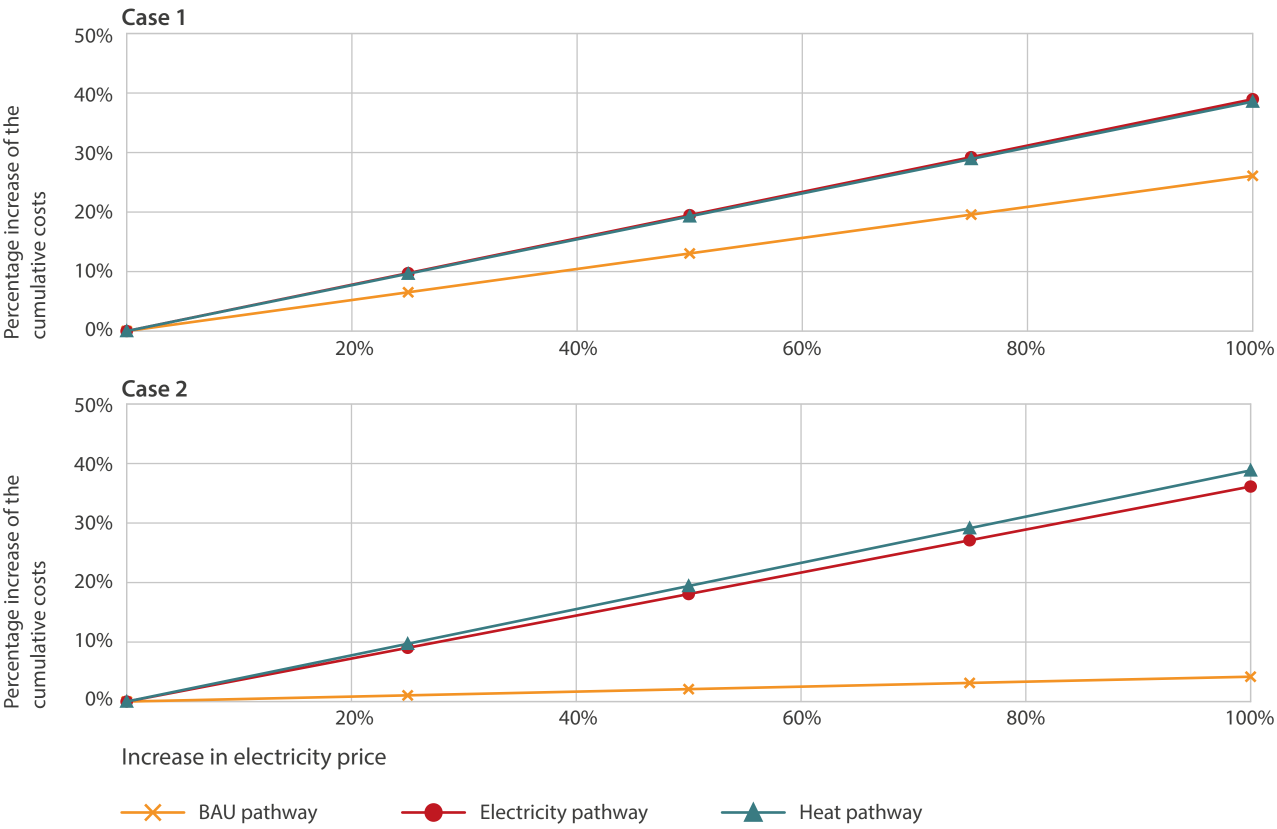
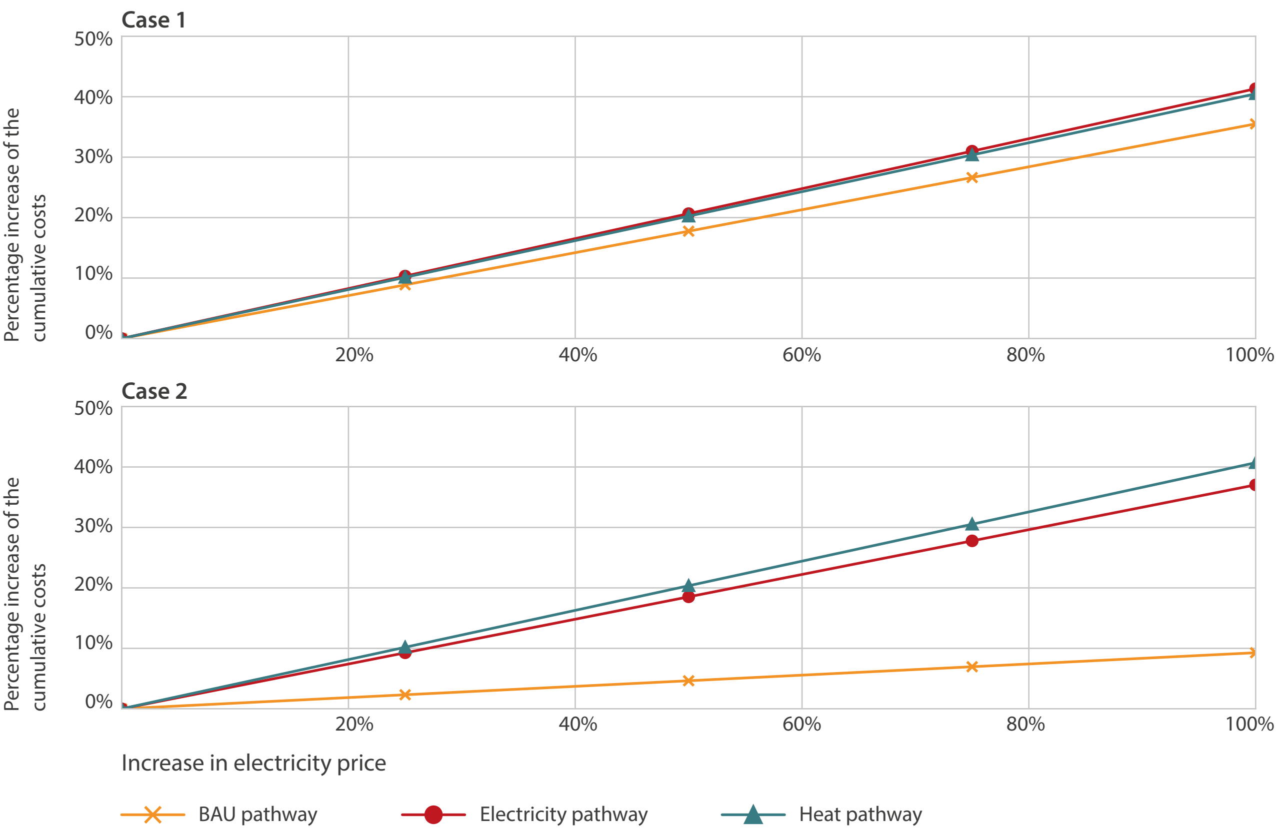


Figure 15: Increase in the cumulative costs in 2050 for UW pathways.



3.3.3 Impact of time-of-use-tariff on cost

The ability to shift demand to time with cheaper and lower carbon electricity will be necessary to make the transition possible.

For this section, an annual half-hourly time-of-use-tariff profile was used to calculate the cost of electricity imports for the two sites between 2020 and 2050. The half-hourly day ahead electricity price for GB in 2020 from the Nordpool historical market data (Nord Pool, 2022) was scaled based on the annual average electricity price shown for each year from 2020 to 2050 (see Appendix B.6) and used to mimic the half-hourly time-of-use-tariff profile.

Table 2 shows the impact of switching from an average electricity price to a time-of-use tariff on the cumulative costs in 2050 of the different pathways. The charging/discharging schedule was unchanged. Overall, the tariff change increases the overall cost of the pathways by 1% to 1.7%.

Figure 16 and Figure 17 show the half-hourly average electricity demand in QEH and UW for cases 1 and 2 in 2020 and 2050 for the HEAT pathways. Similar figures are seen for the ELEC pathways. It shows the higher average electricity demand during high electricity prices in 2020 and 2050 which explains the increase in cost seen in Table 2.

A large amount of the electricity demand of QEH in 2020 happens during above average electricity prices. It changes as electrification of heat is happening and in 2050, a large amount of the demand is happening during periods with lower-than-average electricity prices. For UW, this shift in demand does not occur when comparing electricity demand in 2020 and 2050 because the heat and electricity demand happens during above than average electricity prices. To replicate the results seen for QEH to UW, larger energy storage may be required and/or more capacity for on-site electricity generation during periods above average electricity prices.

Table 2: Difference in the cumulative cost by 2050 of the pathways for the two sites by using time of use tariff compared to the same pathways using annual average electricity prices

Charging/discharging schedule	Pathways	QEH	UW
Electricity Demand	Case1_ELEC	1.2%	1.6%
	Case2_ELEC	1.0%	1.1%
	Case1_HEAT	1.3%	1.7%
	Case2_HEAT	1.3%	1.6%

Figure 16: Half-hourly average electricity imports of QEH in 2020 for Case 1 and 2 and in 2050. The shaded areas represent the periods with above average electricity prices derived from the DA electricity prices.

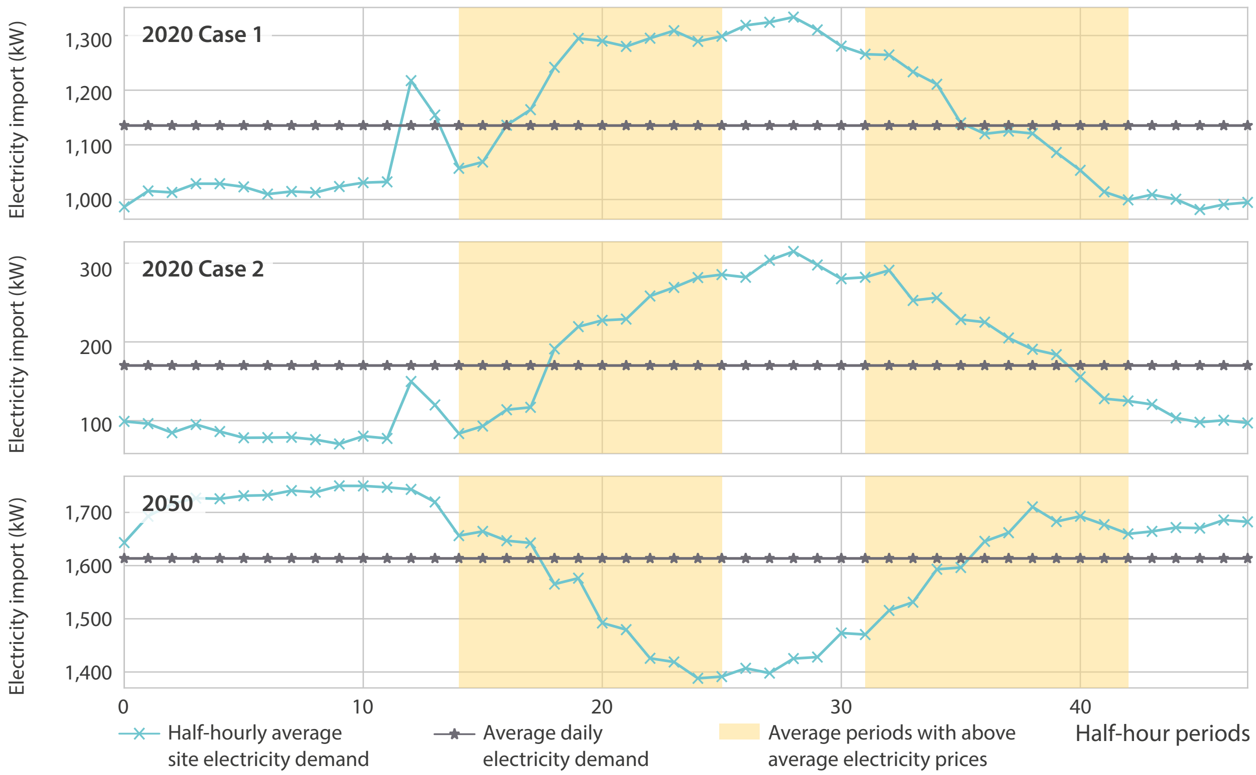
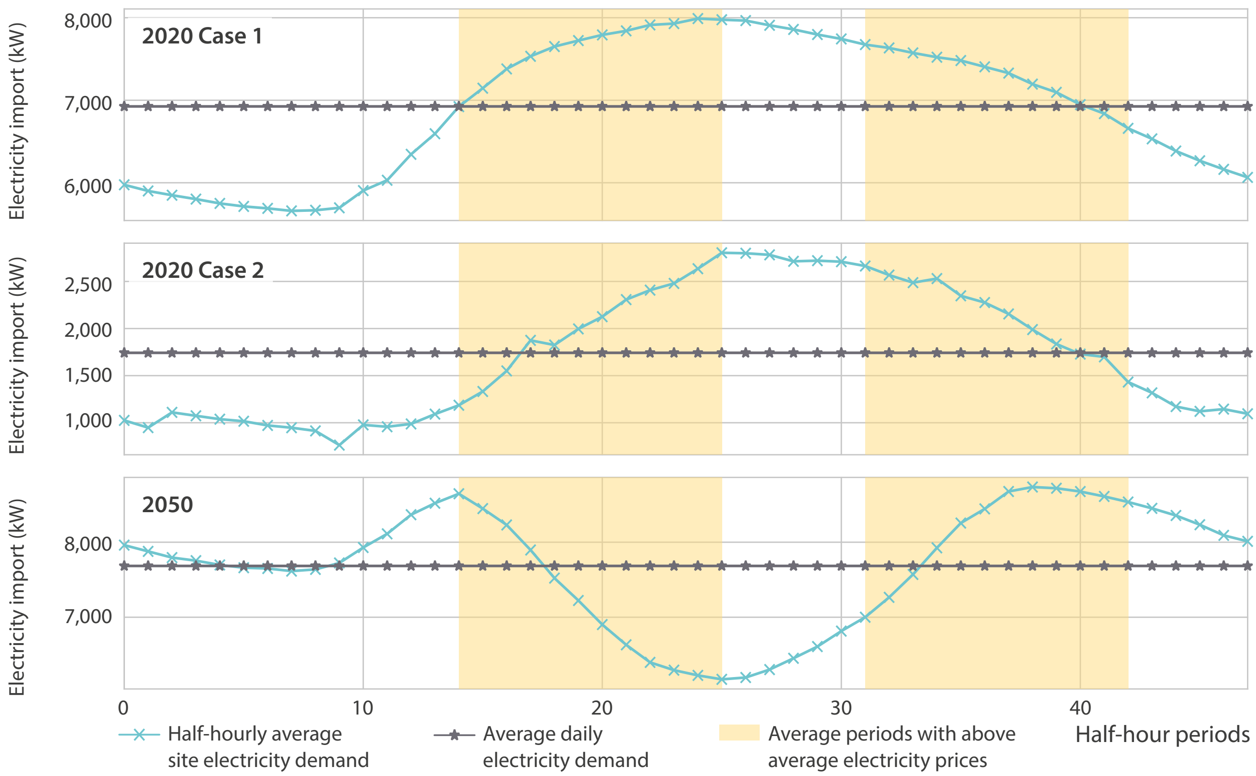


Figure 17: Half-hourly average electricity imports of UW in 2020 for Case 1 and 2 and in 2050. The shaded areas represent the periods with above average electricity prices derived from the DA electricity prices.



The impacts on costs of using an alternative charging/discharging schedule was studied. This alternative schedule was based on the DA electricity price profile and used Equation 1, with the threshold being the value of the percentile of the electricity price to identify charging and discharging periods. Perfect foresight of the DA electricity price was assumed.

Table 3 shows that for QEH, switching the charging/discharging schedule based on the electricity demand to the electricity prices results in savings in the cumulative costs of 0.5% to 1.1%. For UW, the costs increase from 0.5% to 1.6%. This is explained by the time of use of imported electricity. The difference in costs savings between HEAT and ELEC pathways is because Li-batteries can displace more electricity at equivalent capacity than thermal storages. For instance, a 5 MWh thermal storage can only displace 1 MWh of electricity if heat is produced with a heat pump with a COP of 5.

Table 3: Difference in the cumulative cost by 2050 of the pathways for the two sites by using time-of- use tariff compared to the same pathways using annual average electricity prices. The charging/discharging schedule of the energy storages was updated to be based on the day ahead electricity prices profile seen in ?

Charging/discharging schedule	Pathways	QEH	UW
Electricity Price	Case1_ELEC	-1.1%	1.0%
	Case2_ELEC	-0.6%	0.5%
	Case1_HEAT	-0.5%	1.6%
	Case2_HEAT	-0.5%	1.4%

4. Key findings

From a net-zero perspective, this briefing paper shows that decarbonising heat with heat pumps in the short/medium term and decarbonising electricity with on-site DER in the long-term (HEAT pathways) is more expensive but emits significantly less GHG over the period. For the two sites, the carbon intensity of the expenditures over the period 2020 to 2050 was calculated at 385 585 gCO_2e/GBP for the HEAT pathways, 700–1,500 gCO_2e/GBP for the ELEC pathways and 1,300–3,400 gCO_2e/GBP for the BAU pathways. However, it was also shown that regardless of the pathways, residual emissions equivalent to ~2% of the current emissions remained that would need to be offset. Their amount is directly linked to the level of decarbonisation of the main electricity grid.

Another key finding was the dilemma around using on-site natural gas CHP generators. The two sites were shown to decrease the overall cost by 2%–5% but increase the GHG emissions over time by 40%–125% compared to the same sites without CHP generators. Decommissioning those CHP generators and installing heat pumps for decarbonising heat increased the peak grid electricity import by 40% to 100% for the two sites and across the ELEC and HEAT pathways. This option will not be accommodated easily by the distribution network operators. The business case for on-site natural gas CHP generators is becoming complex as multiple factors such as cost, GHG emissions and grid capacity need to be considered.

The sensitivity analysis showed that a crucial aspect of achieving the net-zero target was for the sites to access electricity with a low carbon intensity and affordable price. Therefore, the capability to shift the demand to time with cheaper and lower carbon electricity will be necessary to make the transition possible.

When part of a SLES, MES sites adopting a HEAT or ELEC pathway could increase the dependency on the electricity grid as their on-site electricity generation capacity is decreasing. Further research would need to be conducted to estimate if this loss in capacity is more beneficial to be replaced at SLES or at national level.

The insights gained from this work will be useful to policy makers and facility managers who are considering how best to meet GHG reduction targets. Table 4 summarises those findings.

Table 4: Summary table of the challenges and actions/changes on stakeholders	
Challenges	**What does it mean for stakeholders?**
Electrification of heat may require increasing the grid electricity import capacity of MES sites	**DNOs**: Must provide information about areas which are constrained and reinforce the network where it is economically viable, as well as provide new revenue streams to helping customers (e.g., creation of a distribution network flexibility market). **Facility managers**: Liaise with their DNOs and energy supplier to assess their grid electricity import capacity and the impact of their net-zero strategy on it. The capability to shift energy demand for constrained sites may become a requirement. **Policy**: Helping MES sites to retain an equivalent level of on-site generation in constrained areas.
The future of natural gas combined heat and power generators	**Policy**: Removing subsidies/incentives for the installation of new gas CHP generators in unconstrained areas or soon to be reinforced areas. **Facility managers**: Planning for their phase-out in areas where the grid electricity import is not constrained.
Decarbonising heat first is more beneficial for mitigating climate change but it is more expensive.	**Facility managers**: Planning for the replacement of the fossil-fuel based heating of their facility. **Policy**: Making it economically viable to replace fossil-fuel based heating with low carbon heating in the short-medium term. Not allowing new sites to have fossil-fuel based heating installed.
Supply chain to support the electrification of heat	**Policy**: visibility and consistency in the subsidies/incentives provided to the sector to develop. **Installers**: training of the workforce.

5. Limitations and further work

We set boundaries that limit the scope of the investigation. The results are focused on two specific sites, and despite them having different sizes and energy demand profiles, it is not possible to generalise the findings to all MES sites. Some sites may have very different energy usage and thus some of the findings of this paper may not apply to them.

Furthermore, there are parameters and input data that carry uncertainties but have not been included in the sensitivity analysis such as:

- The sizing of the energy storage
- The cost of carbon dioxide
- The impact of additional revenue from providing services to the power grid
- The type of low carbon technologies considered could be extended to include solar thermal storage, fuel cells and biogas CHP generators
- The change in the capital cost of units
- The impact of energy savings on the choice of the net-zero pathway
- The change in the controls when switching from fossil-fuel based heating to heat pump systems which could impact the way heat is dispatched
- The impact of including scope three emissions on the choice of heat and electricity supply options

Further work would generalise the results and deal with the uncertainties listed in this section.

6. References

Abeysekera, M., Xu, X., Canet, A. and Wu, J. 2022. Characterising the operation and flexibility of campus energy systems. Energy Revolution Research Centre, Strathclyde, UK. University of Strathclyde Publishing. ISBN: 978-1-909522-95-4

BEIS (Department for Business, Energy & Industrial Strategy), 2019. Updated energy and emissions projections: 2019. London: Crown Copyright.

BEIS, 2020. Combined Heat and Power (CHP): the route to 2050 – call for evidence. London: Crown Copyright

BEIS, 2021. Combined heat and power: pathway to decarbonisation call for evidence. London: Crown Copyright.

BEIS, 2021b. Greenhouse gas reporting: conversion factors 2021. London: Crown Copyright.

Energinet and Danish Energy Agency, 2016. Technology data for energy plants for electricity and district heating generation. Copenhagen: Danish Energy Agency.

National Grid ESO, 2020. Future Energy scenarios 2020 costing data workbook. Warwick: National Grid ESO.

National Grid ESO, 2021. FES 2021 data workbook. Warwick: National Grid ESO.

National Grid ESO, 2021b. Data workbook of future energy scenarios 2021. Warwick: National Grid ESO.

Nord Pool, 2022. Historical Market Data. Lysaker, Norway: Nord Pool AS.

Pfenninger, S. and Staffell, I. 2016. Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data. *Energy*, **114**: 1251–1265. doi: 10.1016/j.energy.2016.08.060

Staffell, I. and Pfenninger, S. 2016. Using bias-corrected reanalysis to simulate current and future wind power output. *Energy*, **114**: 1224–1239. doi: 10.1016/j.energy.2016.08.068

Appendix

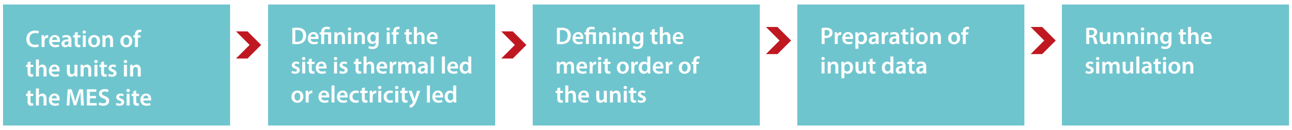


Figure 18: Steps to simulate the behaviour of a MES site using the simulation model.

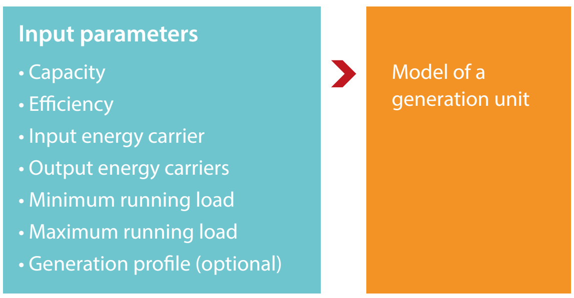
A. Methods

A.1 Simulation model for Multi-Energy System sites

A simulation model was created to imitate an MES site. The objective of the simulation model is to dispatch the units of the MES site to meet the heat and electricity demand of the site at every timestep. This model was built in Python.

Figure 18 shows the steps required to simulate an MES site using the simulation model. The first step is to create a MES site by creating models of the on-site generation, energy storage units and the size of the connection with the electricity grid. The user then defined whether the site is thermal or electricity led and how the units should be dispatched by defining a merit order. The half-hourly electricity and heat demand data of the site are prepared and used when running the simulation.

Figure 19: Creation of a model of a generation unit.



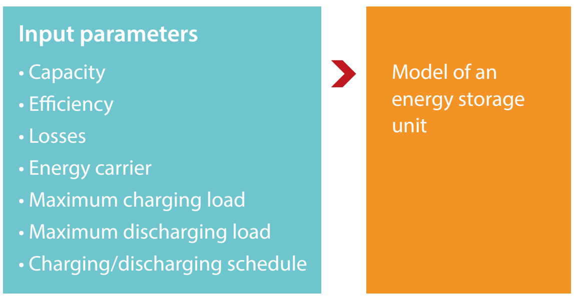
A.1.1 Modelling generation units

Figure 19 shows the input parameters used to create a model of a generation unit such as the capacity and efficiency of the unit, and some of its constraints such as the minimum running load and minimum starting load. A generation profile is defined for fluctuating energy sources units such as PV panels, wind turbines and solar thermal panels.

A.1.2 Modelling energy storage

Figure 20 shows the input parameters used to create an energy storage model. In addition to some parameters such as losses, maximum charging load and maximum discharging load, the energy storage model requires a charging/discharging schedule for the simulation model to decide how much required energy is dispatched at each time step. For instance, if the MES site has a Lithium-Ion (Li) battery installed that requires to be charged, the site's electricity demand will be the electricity demand of the site plus the electricity demand to charge the battery.

Figure 20: Creation of a model of an energy storage unit.



The charging/discharging schedule was derived from the half-hourly electricity demand of the site in 2020. Equation 1 shows that the energy storage is charging when the electricity demand of the site at time i, defined as P_i, is below the threshold. The value of the threshold was defined as the value of the 60th percentile of the day d and i the half-hour period of the day. A perfect foresight was assumed to derive this schedule.

$$\begin{cases} \text{charging when } P_i \leq threshold_d \\ \text{discharging otherwise} \end{cases} \quad \forall i \in [0, \ldots, 47] \quad (1)$$

A.1.3 Energy dispatch

In this research, the MES sites were modelled as thermal-led so heat is dispatched before electricity. The merit order for each energy carrier was also defined.

The system was not controlled to maximise electricity export but to supply the sites' electricity demand.

A.2 Metrics

The equations to calculate the metrics used in this research are listed below.

The cumulative cost for an MES site in the period 2020 to 2050 was calculated using Equation 2. $CAPEX_y$ is the sum of the equivalent annual cost of all the technologies installed at year y. It is calculated using $CAPEX_{tech,t}$ (GBP), the capital cost of the technology at the time of installation t; IR the internal rate and n the lifespan of the technology, as shown in Equation 3.

OPEXy is the sum of the variable OPEX and the fixed OPEX of the technologies installed at year y with $Q_{tech,carrier}$ (kWh), the annual energy consumed by a specific technology; $O_{tech,carrier}$ (GBP/kWh), the variable operating cost which includes the fuel costs and some maintenance cost and some fixed operation cost $Fixed\ OPEX_{tech}$ (GBP) as shown in Equation 4. The electricity grid was considered as a technology with no CAPEX and no fixed operating cost.

$$Cumulative\ cost = \sum_{y=2020}^{2050} CAPEX_y + OPEX_y \quad (2)$$

$$CAPEX_y = \sum_{tech} \frac{CAPEX_{tech,t} \times IR}{(1-(1+IR)^{-n})} \quad (3)$$

$$OPEX_y = \sum_{tech} \sum_{carrier} Q_{tech,carrier} \times O_{tech,carrier} + \sum_{tech} Fixed\ OPEX_{tech} \quad (4)$$

The cumulative GHG emissions for an MES site in the period 2020to 2050 was calculated using Equation 5. GHG_y is the GHG emissions of the site at year y. It is calculated using Equation 6 where $Q_{tech,carrier}$ is the amount of energy used by the technology tech over a year and $GHG\ factor_{carrier}$ the GHG emission factor of the energy carrier.

$$Cumulative\ GHG\ emissions = \sum_{y=2020}^{2050} GHG_y \quad (5)$$

$$GHG_y = \sum_{tech} \sum_{carrier} Q_{tech,carrier} \times GHG\ factor_{carrier} \quad (6)$$

The peak electricity import was calculated using Equation 7 where P_t (kW) is the average electricity import of the site at the half-hourly time step t for year y.

$$Peak\ electricity\ import_y = \max(P_1, \ldots, P_{17520}) \quad (7)$$

B. Input data and assumptions

This section describes the input data used for the simulation models and the metrics calculation.

B.1 Case studies data

The half-hourly heat demand and electricity demand data from QEH and UW for an entire year was used as input to the simulation model. The year 2020 was used for QEH and the year 2019 for UW. The data was cleaned from outliers by replacing values falling into the 1st or 99th quantile with linearly interpolated values.

Solar irradiation data for the location of the sites and the year of the data was also added to the input data to derive the electricity output of solar PV panels. This data was collected directly from the Met Office for QEH and the website renewables.ninja (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016) for UW.

Figure 21 shows the energy demand for heating and electricity on the two sites. For QEH, the heating demand is 2.3 times higher than its electricity demand. For UW, it is a 1:1 ratio between heating and electricity demand.

Figure 21: Annual electricity and heat demand in QEH and UW. The year used for QEH was 2020, and 2019 for UW.

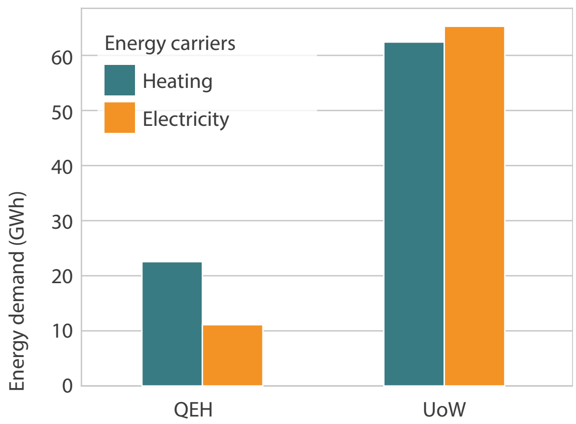


Figure 22 shows the daily average half-hourly electricity and heat demand for QEH. Most of the electricity demand happens during working hours ~8am to 5pm, whereas most of the heat demand is early morning, from midnight to ~8am.

Figure 23 shows the daily average half-hourly electricity and heat demand for UW. The electricity pattern is similar to QEH, but most heat demand happens later in the morning, from ~5 to 11am.

B.2 Installed capacity

Table 5 shows the installed capacity of the CHP generators and gas boilers in the four initial arrangements. The real systems have the same installed capacity as the Case 2.

Figure 22: Average half-hourly electricity and heat demand of QEH in 2020.

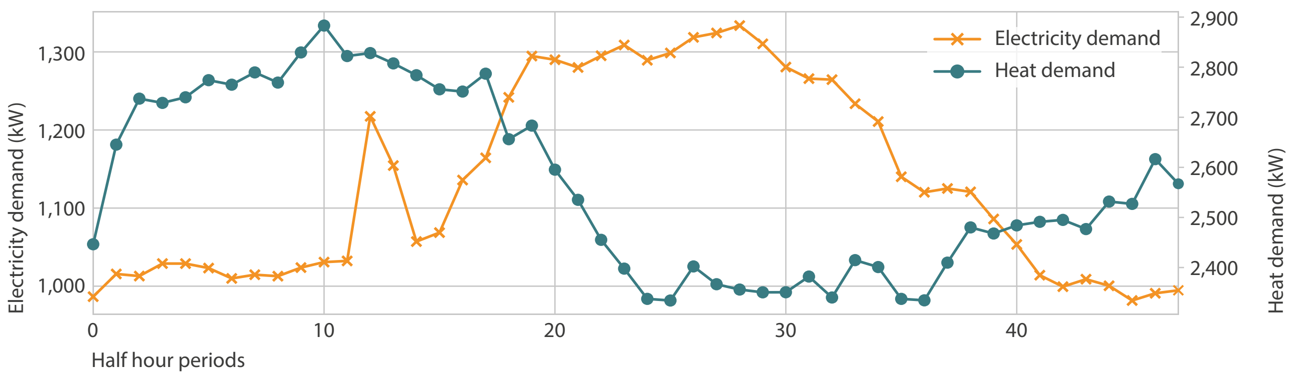


Figure 23: Average half-hourly electricity and heat demand of UW in 2019.

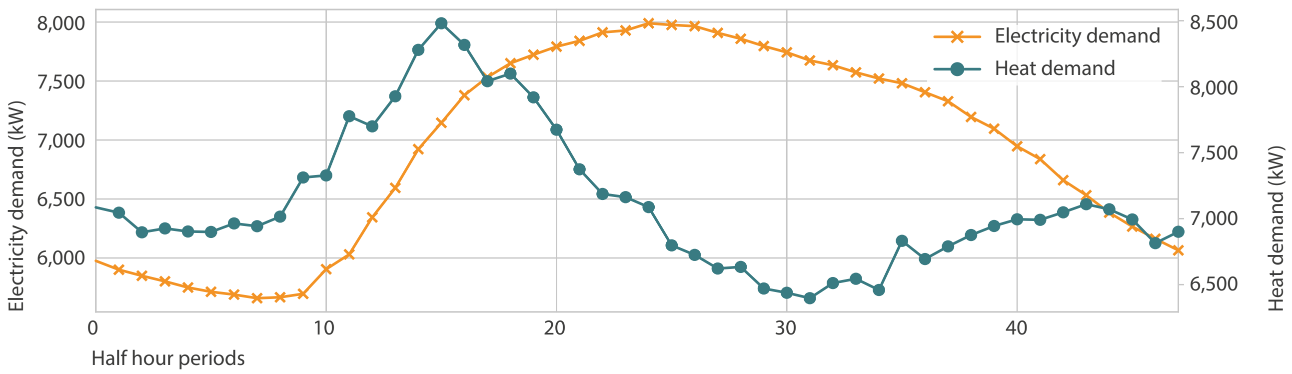


Table 5: Installed capacity of the CHP generators and gas boilers for the different initial arrangements for QEH and UW

Initial Arrangements	CHP generators (kW_e/kW_{th})	Gas boilers (kW_{th})
Case 1 QEH	NA	10,548
Case 1 UW	NA	14,764
Case 2 QEH	1,274/1,699	10,548
Case 2 UW	8,200/9,200	14,764

Table 6: Installed capacity of the technologies in the future configurations

MES sites	Heat pumps (kW_{th})	PV panels (kW)	Li batteries (kWhe)	Thermal storage (kWh_{th})
QEH	5,720	705	3,874	11,735
UW	19,206	5,260	5,000	8,710

Table 6 shows the installed capacity of the technologies as part of the ELEC and HEAT pathways. For QEH and UW, the capacity installed of the heat pumps is equal to the maximum half-hourly heat demand plus 10%. The thermal storage capacity is set to cover 10% of the daily peak heat demand. The capacity of the Li batteries is set to cover 10% of the daily peak electricity demand. For the thermal storage and Li battery systems, the charging/discharging load was set to fully charge or discharge the systems in half a day. The capacity of the PV panels was set to the electricity demand up to the value of the 1st quantile of the site.

B.3 Merit order

Table 7 shows the merit order defined for the ELEC and HEAT pathways. The merit order in the BAU pathway is unchanged from 2020 to 2050.

Table 7: Merit orders of the units for each pathway and configuration. The numbering indicates the dispatch order, unit 1 is dispatched first, unit 2 second, etc.				
Energy carrier	**Pathways**	**Initial arrangement**	**Configuration 1 (2026 to 2035)**	**Configuration 2 (2036 to 2050)**
Heat	ELECP	1. CHP units* 2. Gas boilers	1. CHP units* 2. Gas boilers	1. Heat pumps
	HEATP		1. Thermal storages 2. Heat pumps	1. Thermal storages 2. HP
	BAUP		1. CHP units* 2. Gas boilers	1. CHP units* 2. Gas boilers
Electricity	ELECP	1. CHP units* 2. Electricity from the grid	1. Li Batteries 2. PV panels 3. CHP units* 4. Electricity from the grid	1. Li Batteries 2. PV panels 3. CHP units* 4. Electricity from the grid
	HEATP		1. Electricity from the grid	1. PV panels 2. Electricity from the grid
	BAUP		1. CHP units* 2. Electricity from the grid	1. CHP units* 2. Electricity from the grid
*CHP units are only included in the pathways using Case 2 QEH or Case 2 UW.				

B.4 Technical-economic parameters of technologies

Technical-economic parameters used to calculate the capital investment and operational costs were compiled from two sources: the FES 2020 costing data workbook (National Grid ESO, 2020) and a dataset of technical and economic parameters produced by the Danish TSO Energinet (Energinet and Danish Energy Agency, 2016).

The Microsoft Excel workbook file is available as a supplementary file to this report.

B.5 Carbon intensity of energy

Figure 24 shows the carbon intensity of electricity and natural gas between 2020 and 2050. The carbon intensity of the electricity from the grid was from the FES 2021 Leading The Way scenario (National Grid ESO, 2021b). The carbon intensity of natural gas from the grid was from Defra (BEIS, 2021b). No change in the carbon intensity of natural gas was assumed in this research.

B.6 Energy Prices

Figure 25 shows the electricity and gas prices projected between 2020 and 2050. These prices were calculated by adding the cost of carbon to the electricity and gas prices, which were fixed at 13.7 p/kWh for electricity and 2.8 p/kWh for natural gas (energy prices for services in 2020 in the reference scenario from BEIS, 2019). The carbon cost between 2020 and 2050 was from the FES 2021 Leading the Way scenario (National Grid ESO, 2021b) and was combined with the carbon intensity of electricity and gas between 2020 and 2050 shown in Section B.5.

Figure 24: Carbon intensity of electricity and natural gas between 2020 and 2050.

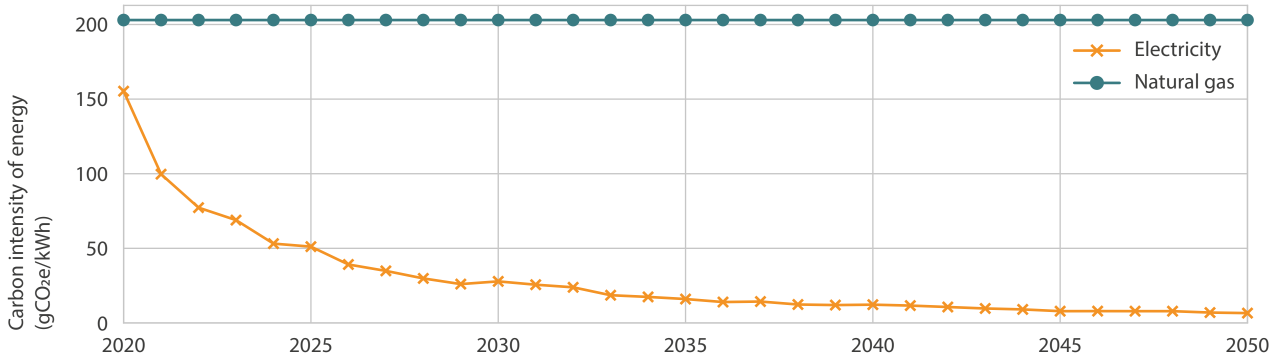
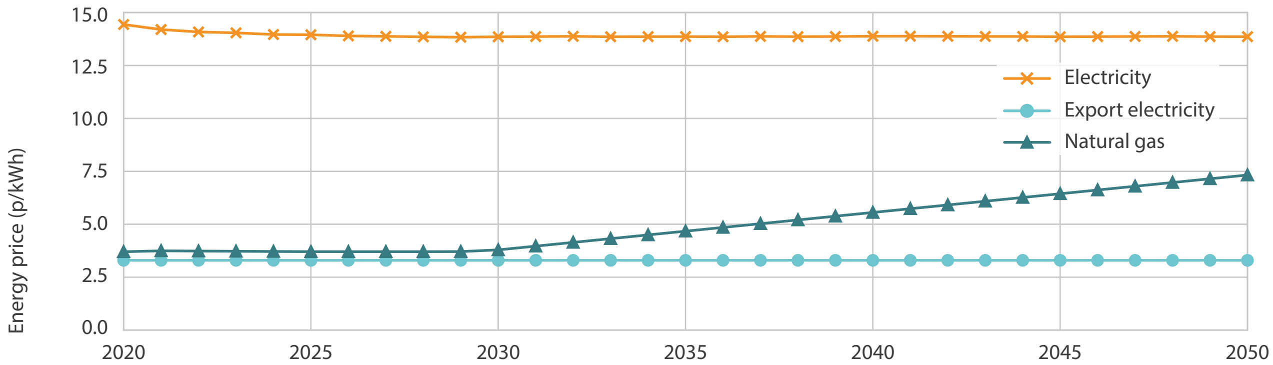


Figure 25: Energy prices between 2020 and 2050 using the cost of carbon from the FES 2021 Leading the Way scenario and the carbon intensity of the electricity grid and gas grid shown in Figure 24.



Want to know more?

www.energyrev.org.uk

@EnergyREV_UK

EnergyREV

info@energyrev.org.uk

Sign up to receive our newsletter and keep up to date with our research, or get in touch directly by emailing info@energyrev.org.uk

About EnergyREV

EnergyREV was established in 2018 (December) under the UK's Industrial Strategy Challenge Fund Prospering from the Energy Revolution programme. It brings together a team of over 50 people across 22 UK universities to help drive forward research and innovation in Smart Local Energy Systems.

ISBN 978-1-909522-98-5

EnergyREV is funded by UK Research and Innovation, grant number EP/S031863/1