Department of Mechanical and Aerospace Engineering

Modelling of a hydrogen fuel cell CHP system

For community scale in Scotland

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Signed: Merlin Carnegie   Date: 24/08/2018

Abstract

Hydrogen and fuel cell technology is a potential solution to renewable energy storage and low emission heating. This thesis sets out to model and analyse the components, fuel consumption, carbon emission and operating costs of a hydrogen fuel cell CHP system for a community in Scotland. A base case scenario model of a current typical Scottish household, which is grid connected and is using a condensation boiler for water and space heating, was compared with that of a fuel cell CHP system in island operation and of a fuel cell CHP system which is grid connected. The results were matched with the demands of the community to find a best fit. The results suggested that hydrogen fuel cell CHP system can provide full electrical and heat demand matches for an average Scottish household. This is dependent on future technological advances.

Acknowledgements

I would like to say thank to Dr Paul Tuohy, who helped guide me through this thesis and the RESE course in general. To Andrew Lyden, who was a great help, getting me set up with EnergyPRO. Also, to Chris Dunham, who provided A temporary subscription to EnergyPRO.

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1. Introduction

The UK has pledged to reduce its CO_2 Emissions by 80% by the year 2050, and the Scottish government has also set the target of producing100% renewable electricity by the year 2020. As of February 2018, renewable electricity production in Scotland sits at 54%. Figure 1 shows the total energy consumption in Scotland; heating accounts for over half the energy consumption and yet, in 2016, the proportion of renewable heat production was only at 4.8-5.0% (Scottish Government, 2018).

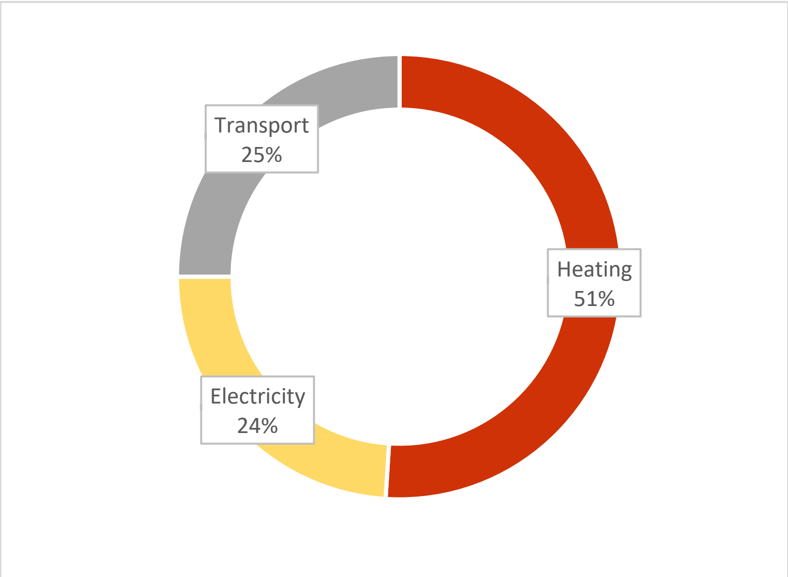


Figure 1: Scottish energy consumption mix. (data: (Scot Gov, 2018))

80% of Scottish homes rely on natural gas to heat their homes, which generally require 3% more energy to heat on average than homes in the rest of the UK. Biomass CHP is already a mature technology in the UK, and the UK government see it as the path for reducing emissions in the residential heat sector (Ren and Gao, 2010). Biomass CHP systems produced 555 GWh of heat in 2016 (Scottish Government, 2018). However, the combustion of biomass still produces large amounts of CO_2. Therefore, its 'green' credentials can be questioned. Hydrogen has already been explored as a potential storage medium for the renewable electricity industry. This technology uses excess energy produced by renewable means to convert water into hydrogen that can then be used by a fuel cell for a later demand. Hydrogen fuel cells also produce a lot of heat, so they could be used in a CHP system to further improve their efficiency. If hydrogen fuel cell technology could be combined with CHP technology, it would help provide 0% emission heat (providing the hydrogen is also produced without emissions). District heating is currently a popular technology in Scotland, with both the University of Strathclyde and the University of Glasgow installing district heating schemes in the past 5 years. From that, the term, 'district energy' could be applied to the envisaged scheme for this project: a community which produces and consumes its own carbon-free energy. This would help decentralise the energy market and would also add energy security.

1.1. Aims

The aims of this thesis are to model and analyse a hydrogen fuel cell fuelled CHP system for a typical Scottish community of 200 households. The model encompasses the following three scenarios:

- Scenario 1: Base Model - current typical set up, grid connected and using a natural gas condensation boiler, with no renewable energy production unit.

- Scenario 2: Hydrogen fuel cell CHP system in island operation with thermal store.

    - Scenario 2a: Add an electrical store

    - Scenario 2b: Add an electrical store and an electric boiler

    - Scenario 2c: Electric boiler without electrical store

- Scenario 3: Hydrogen fuel cell CHP system with grid connection and thermal store.

The scenarios 2 and 3 will be modelled with and without partial load of the CHP system, for all iterations.

1.2. Scope

This thesis looks to a future where certain hurdles and issues surrounding the relevant technologies have been overcome. In this scope section, these assumptions have been set out. These assumptions include the following:

- A hydrogen fuel production and supply chain has been fully developed and is commercially competitive with natural gas.

- The cost of hydrogen is competitive with natural gas.

- The cost of fuel cells is competitive with other forms of CHP compatible technologies.

The electrical and thermal demands based on the average requirements of a Scottish community of 200 households were taken into consideration. Each household was assumed to be of average size and occupancy with no extra renewable production units or passive house qualities.

Scenario 2 works in island operation. It assumes a constant supply of hydrogen, but no possibility of national grid connection. This is similar to the network in Stornoway, which has its own Liquid Petroleum Gas (LPG) network (William Morrison, 2011).

Hydrogen would be imported from the mainland replacing the 3000 tonnes of LPG imported every year.

Scenario 3 would be applicable to any community that has either created its own hydrogen network or that has upgraded its local national gas network to accommodate pure hydrogen.

This paper will focus on the modelling and working of the hydrogen fuel cell CHP system, not the electrical/thermal storage, housing improvements or other renewables.

The costs of the systems were based on operating costs and did not consider the capital costs of installing the system and payback period.

This paper assumes that the supplied hydrogen is 100% pure, and therefore, the fuel cell did not feature a fuel processor. The option of using a hydrogen boiler or gas turbine was not considered.

1.3. Methodology

The first step was to conduct thorough research into literature and modelling software packages. Once an initial scope was set, a literature review was completed, and software was trialled and tested. The software was required to model hydrogen and CHP or heat recovery systems, as well as strong electrical and thermal modelling capabilities. Since the system would be based in Scotland, it was important to model for the whole year to account for the disparity between winter and summer demands. The time increments would be hourly to create a manageable data package. It was decided to model the system for a community of 200 as this would smooth the demand profile, making it more realistic, because with a single dwelling, it is possible that an electric shower (very high demand) could be used for 10 minutes making it hard to model over the hour. Each scenario was simulated with varying configurations, which were laid out in the next two sub sections. For each scenario, a configuration was selected via the yearly energy match; the selected configuration (best combined electrical and heat match) was explored further through selected weeks' electrical and heating graphs generated from the software package.

1.3.1. Scenario 1

The methodology for scenario 1 required the efficiencies for a condensation boiler and the prices for the fixed rate electricity market and natural gas.

1.3.2. Scenario 2

Figure 2 depicts the modelling process for scenario 2.

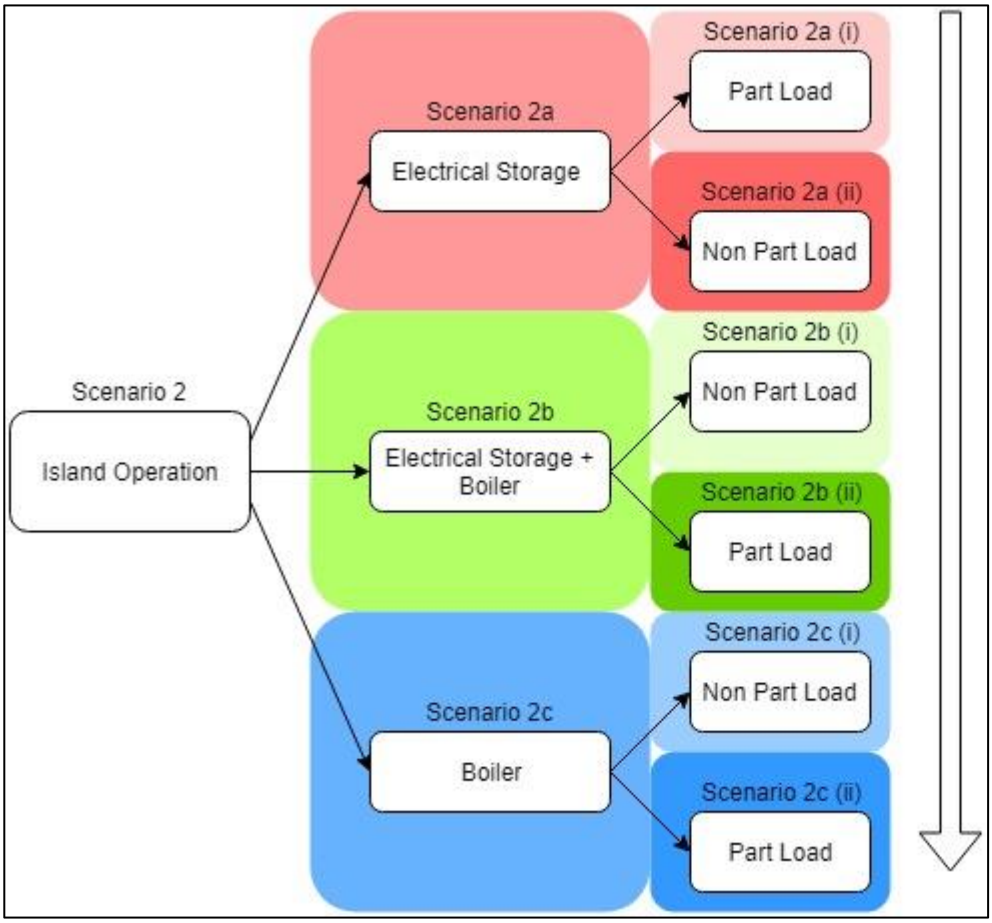


Figure 2: Scenario 2 methodology

There were three configurations: first, adding electrical storage (scenario 2a); second, adding an electric boiler to combine with the electrical storage (scenario 2b); and third, removing the electrical storage to model system with only the electric boiler as auxiliary power (scenario 2c). Each of these sub scenarios was modelled with the partial load option for the CHP system on and off, resulting in a total of seven configurations (including the original scenario 2, without any auxiliary power). The deciding values were energy match followed by operating cost

1.3.3. Scenario 3

Figure 3 shows the iterations simulated for scenario 3.

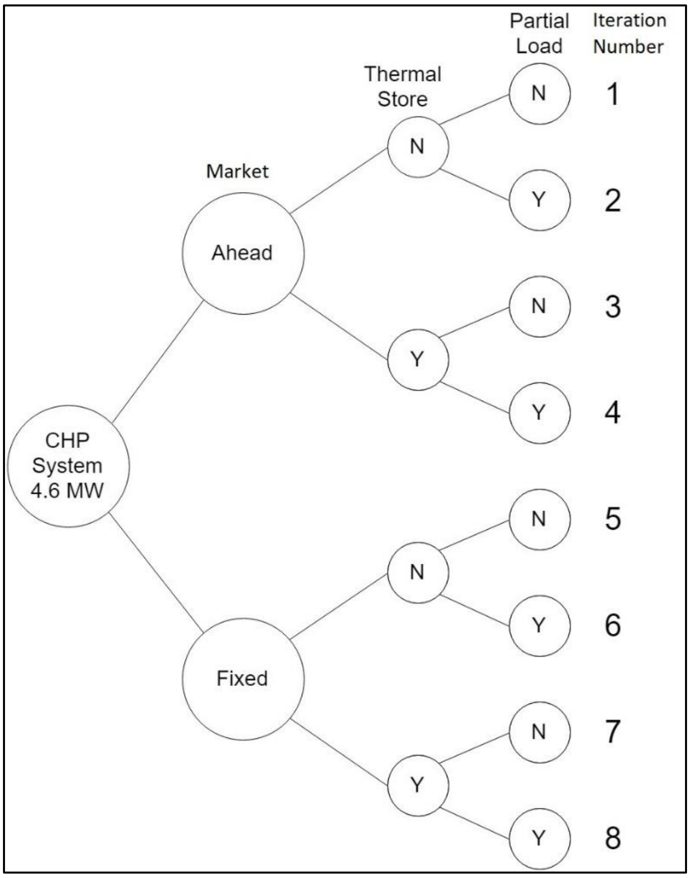


Figure 3: Scenario 3 methodology

In scenario 3 a combination of configurations was used. This included: changing the market with which the system trades electricity (ahead or fixed); whether there was a thermal store; and whether the partial load was activated or not. The deciding value was operating income.

Two extra simulations were run, which added a heat rejection for both day ahead and fixed tariff markets.

1.4. Thesis Structure

The first section of this paper consists of a literature review on hydrogen, fuel cells and CHP systems. The second section explains and lays out the modelling process. The third section lists the results. The fourth section discusses the results whilst also highlighting the study’s limitations and the scope for future work. The fifth section draws conclusions from the results and discussion and relates these to the field.

2. Literature Review

2.1. Hydrogen

Hydrogen is the most abundant element in the known universe. It has the highest energy density per gravitational mass of any fuel. Storing the energy produced from renewable sources is a key issue that needs to be solved for renewables to be integrated into community scale projects (Lyden, Pepper and Tuohy, 2018). It could also aid in the decentralisation of the energy network, which could improve all-round efficiencies, as displayed in Figure 4.

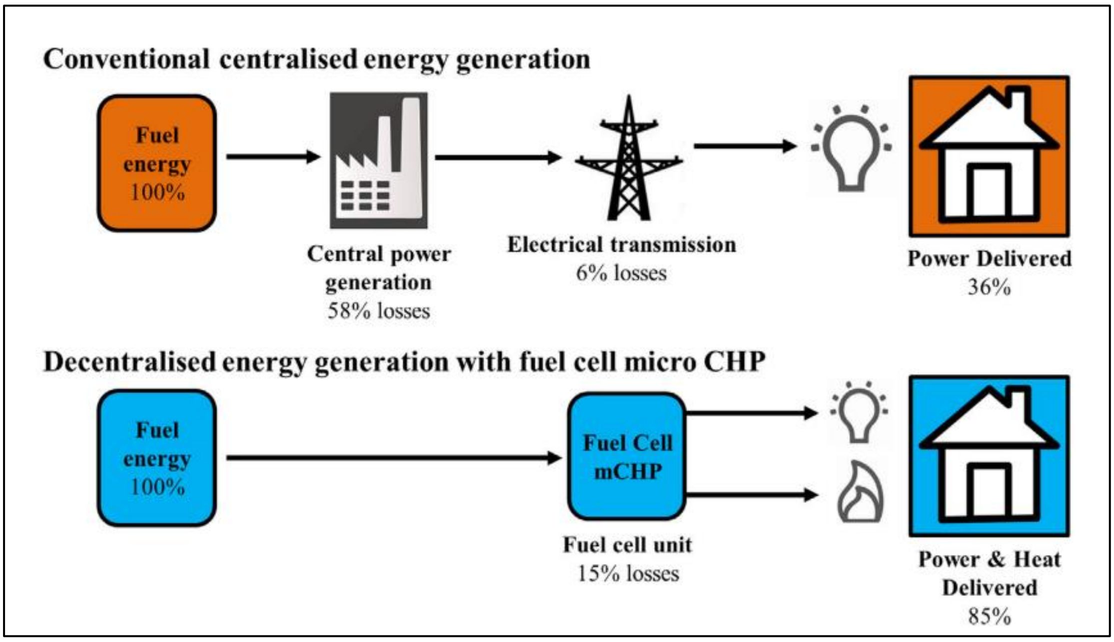


Figure 4: Potential energy efficiency savings through decentralisation (Elmer et al., 2015)

There has been increasing interest in researching the conversion of surplus renewable energy into hydrogen through electrolysis for storage. Numerous studies have concluded this to be a technically viable solution (see for example: Mathiesen and Lund, 2005; Carton and Olabi, 2010; Shabani and Andrews, 2011; Pedrazzi, Zini and Tartarini, 2012).

In 2014, the global hydrogen production was 40 billion kg per year (Stockford *et al.*, 2015). This is equivalent to 1332 TWh, which is 80% of the UK's current annual energy consumption (BEIS, 2018c). The most widespread hydrogen production process in the UK is Steam Methane Reforming (SMR), which can still produce significant emissions (Stockford *et al.*, 2015). As the research, technology and costs develop, hydrogen production through electrolysis will become more commercially viable.

2.2. Fuel Cells

Hydrogen fuel cells (FC) were invented in 1839. They use the electrochemical reaction between hydrogen and oxygen to produce electricity, heat and water (Elmer *et al.*, 2015). The electricity is produced on the anode side by the electrochemical reaction, whilst oxidising the cathode side. With the flows of free ions going through the electrolyte, a current is created in an external circuit (Murugan and Horák, 2016). Even though they have been around for a long time, hydrogen fuel cells haven't gained marketability (mostly due to costs), but as the technology is remerging as a potential solution for the stochasticity and for a storage solution, the costs are beginning to fall (Staffell and Green, 2013).

According to Elmer *et al.*, 2015, there are six main types of fuel cell:

1. Proton Exchange Membrane Fuel Cell (PEMFC)
2. Alkaline Fuel Cell (AFC)
3. Direct Methanol Fuel Cell (DMFC)
4. Phosphoric Acid Fuel Cell (PAFC)

5. Molten Carbonate Fuel Cell (MCFC)

6. Solid Oxide Fuel Cell (SOFC)

Currently, these fuel cells work on the principle that the system uses a fuel processor to convert the directly supplied hydrocarbon fuel, which in most cases is natural gas, but can also be other fuels such as LPG or biogas (Dodds *et al.*, 2015; Elmer *et al.*, 2015). PEMFC and SOFC are the most widely used fuel cells, and have attracted the most investment in the past few decades (Gencoglu and Ural, 2009; Dodds *et al.*, 2015). Figure 5 shows the current capacities and efficiencies of PEMFC and SOFC technologies.

Application		PEMFC	SOFC
		Residential	Residential/commercial
Electrical capacity	(kW)	0.75–2	0.75–250
Thermal capacity	(kW)	0.75–2	0.75–250
Electrical efficiency[a]	(LHV)	35–39%	45–60%
Thermal efficiency[a]	(LHV)	55%	30–45%
Current maximum lifetime	'000 h	60–80	20–90
	years	10	3–10
Degradation rate[b]	Per year	1%	1–2.5%

[a] Rated specifications when new, which are slightly higher than the averages experienced in practice.
[b] Loss of peak power and electrical efficiency; thermal efficiency increases to compensate.
[c] Requires an overhaul of the fuel cell stack half-way through the operating lifetime.

Figure 5: PEM and SO Fuel Cell Performance (source: Dodds et al., 2015)

PEMFCs are considered low temperature fuel cells, operating between 80°C and 250°C, whereas SOFCs operate at high temperatures between 250°C and 1000°C. As shown in Figure 5, PEMFCs have higher overall efficiencies over SOFCs, but SOFCs have a higher electrical efficiency (Murugan and Horák, 2016).

Table 1 lists the main advantages and disadvantages of both fuel cells.

Table 1:Advantages and disadvantages of PEMFC's and SOFC's (Elmer et al., 2015)

	PEMFC	SOFC
Advantages	Quick Start up time, compact, can vary output quickly, no corrosive fluids used	Useful high temperature heat output can be used in another cycle, no liquid electrolyte used
Disadvantages	Expensive Platinum catalysts required, high purity of H_2 required	Long start up time, expensive heat resistant materials needed

The present model used a PEMFC due to their quick start up time and ability to vary output easily, as well as their higher share of the market (90%) and their longer life span (Dodds *et al.*, 2015). Recently, there has been more research into using graphene instead of platinum to aid in reducing production costs of PEMFCs which could increase their commerciality prospects dramatically (Zhou *et al.*, 2014; Sahoo *et al.*, 2018).

2.3. CHP Systems

Combined Heat and Power (CHP) or cogeneration systems are identified using a single fuel source to produce electricity and heat, so that both can be used locally and simultaneously. CHP systems have been regarded as one of the major alternatives to traditional heating, increasing efficiencies and reducing emissions (Dong, Liu and Riffat, 2009).

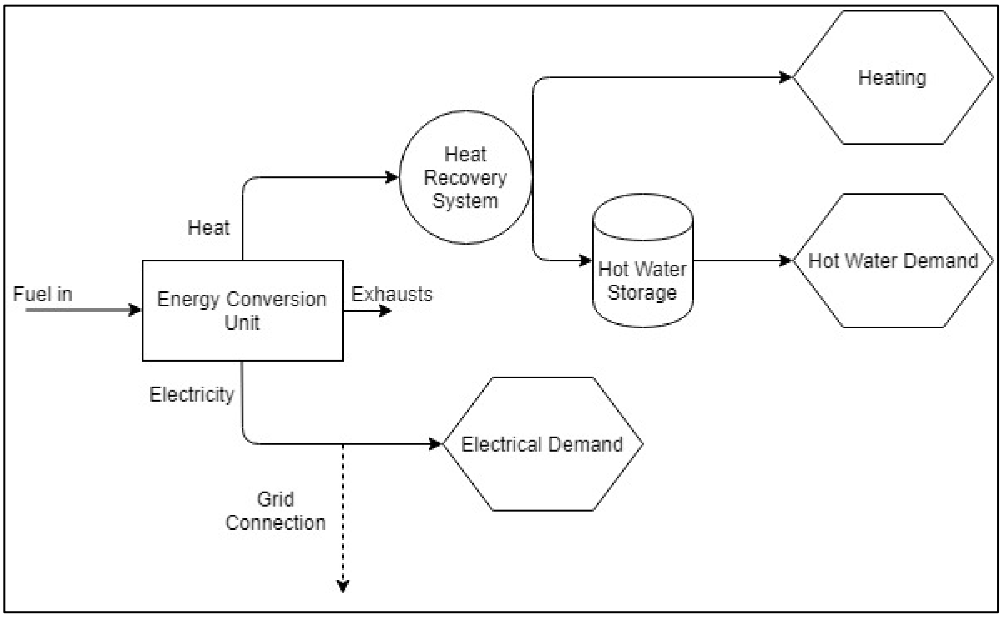


Figure 6: CHP System

Figure 6 shows a concept diagram of a CHP system. The fuel is combusted or reacted, depending on what energy unit is being used, which creates electricity and heat plus any exhausts. The electricity then supplies the load and any residual electricity is either sold to the grid (if grid connected) or stored. A heat recovery system heats a water system, either storing the heat for hot water use or for supplying space heating. Most systems in UK also have a backup boiler to supply hot water during peak demands. The excess heat could also be used for cooling through an absorption chiller; this is referred to as combined cooling heating and power (CCHP) or trigeneration (Mago, Fumo and

Chamra, 2009; Gu *et al.*, 2014). CCHP will not be covered in this paper since the site is in Scotland, where there is rarely any cooling demand.

2.4. Fuel Cell CHP systems

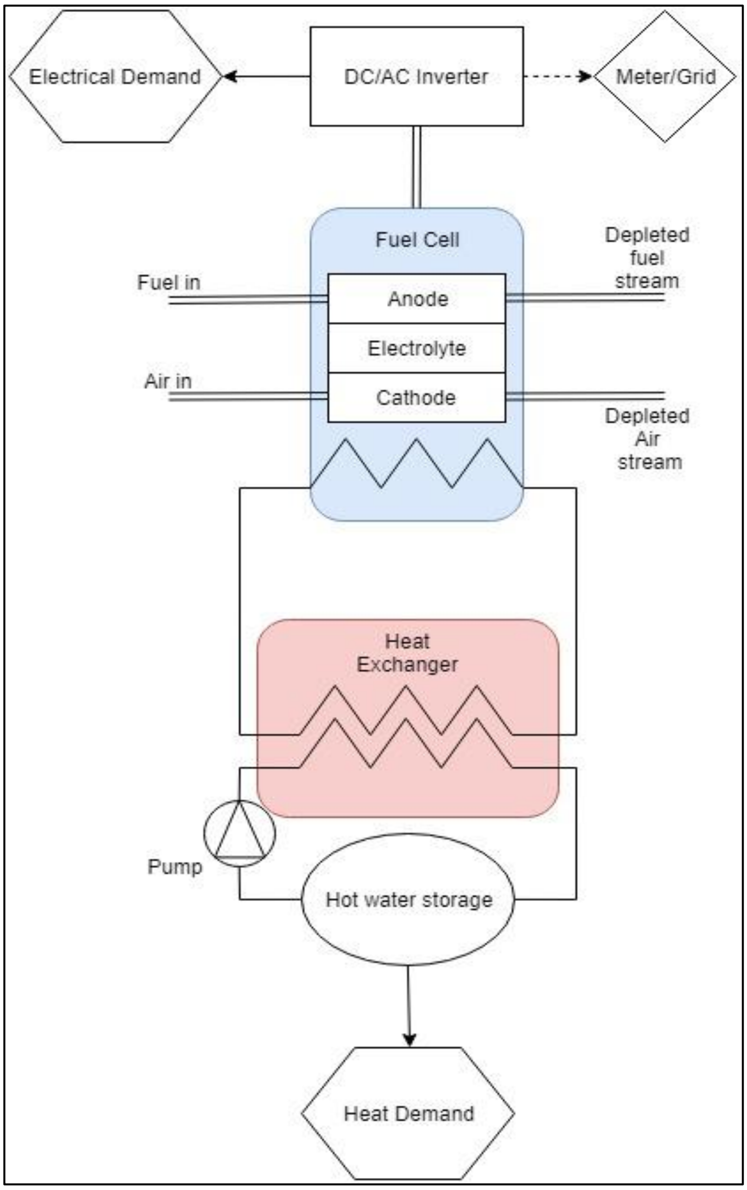


Figure 7: Fuel Cell CHP system

Figure 7 shows the fuel cell CHP scheme. The main components are as follows (Gigliucci *et al.*, 2004):

- The fuel cell stack, where the hydrogen and oxygen combine in an electrochemical reaction to produce DC electricity, heat and water

- DC/AC inverter, which converts the DC current into AC to be used or sold to the grid
- Heat recovery system, which recovers the heat generated by the stack to an external water circuit through a heat exchanger
- Hot water tank, which stores the thermal energy for when it is needed
- Plant, essential fans, pumps, piping, valves and control systems

3. Modelling

This section sets out the information gathered to build the model for each scenario. All data collected was for 2017.

3.1. Software selection

The initial investigation into software consisted of a trial and error method. A publication by (Lyden, Pepper and Tuohy, 2018)(see Appendix A) was used to aid in the selection process. The software needed to be able to do the following:

1) Allow a Fuel Cell/Hydrogen network to be modelled or imitated
2) Accommodate both electrical and thermal systems
3) Model to the community scale
4) Work in hourly time steps
5) Work in island operation
6) Allow both thermal and electrical storage

After trialling HOMERpro, it was deemed that the thermal side of the modelling tool was insufficient and that the lack of modularity did not allow the modelling of this type of system.

Second, MERIT was trialled. This Strathclyde built piece of software would mean extensive software support. However, it was deemed too hard to manage in terms of user friendliness. Additionally, its CHP function made it hard to modulate the different configurations required for this project.

EnergyPRO is a software package made by EMD, a Danish software company, it was originally created to model CHP systems and has since developed further (EMD, 2018). It allows for the CHP system to be fuelled by any fuel defined by the user and allows the efficiencies of energy conversion unit to be imitated by user defined inputs and output.

3.2. Climate Data and Site Selection

Site selection for this project was not a critical point of the project because theoretically, it could be applied to any community. Due to the example of a district gas network which imports fuel in Stornoway, it was decided to limit the site selection to the Isle of Lewis. This selection was based on the availability of climate data through EnergyPRO. Figure 8 shows where the Isle of Lewis is compared to the mainland of Scotland.

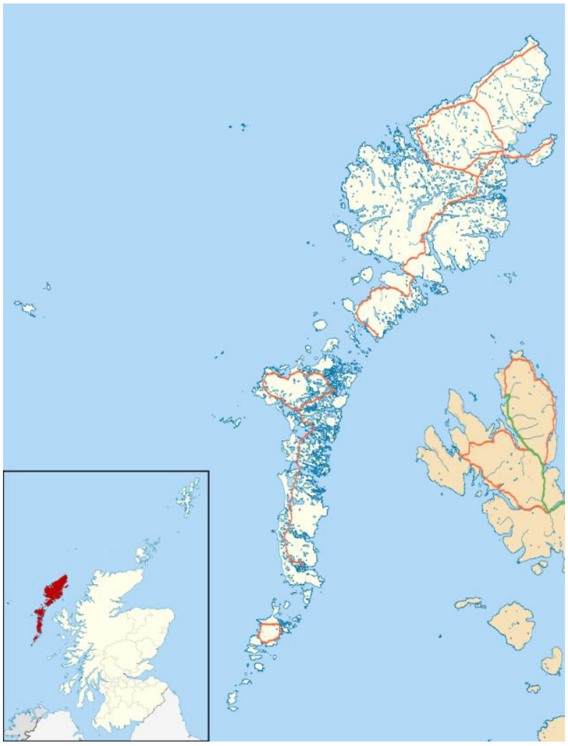


Figure 8: Map of the Isle of Lewis

(Contains OS data © Crown copyright and database right (2018))

EnergyPRO has an integrated database of climate data available to any user. Figure 9 shows the interface and exact location of where the climate data was recorded (yellow triangle).

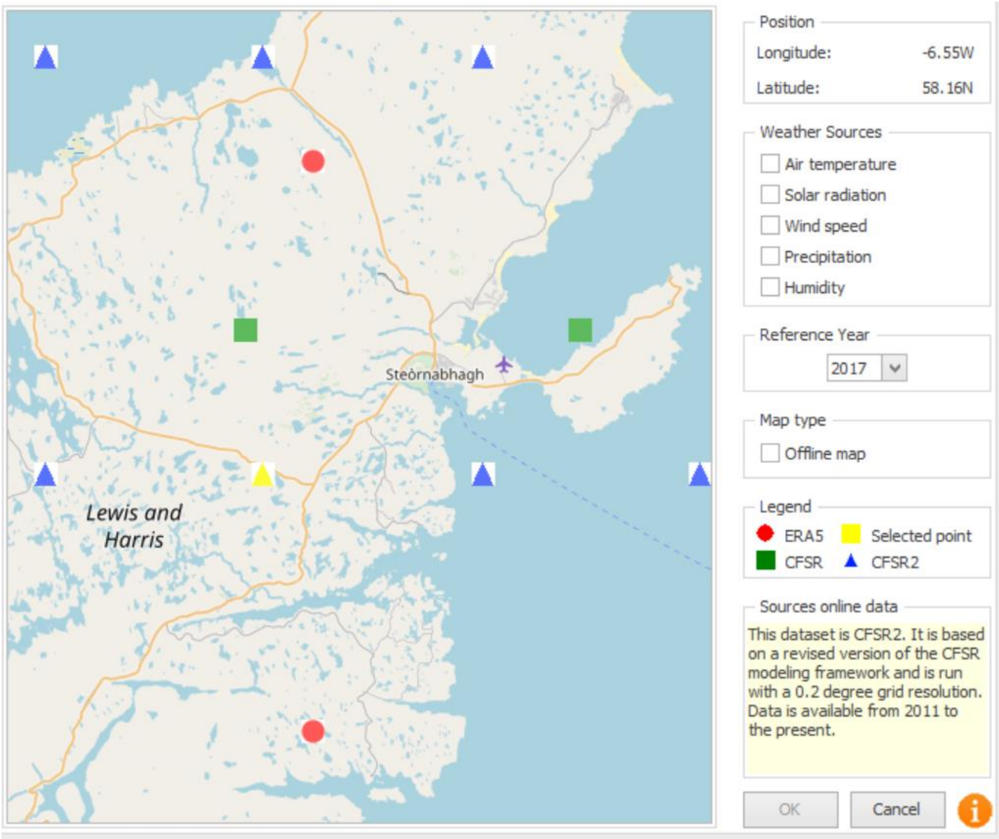


Figure 9: Climate data and site location (EMD, 2018).

The climate data shown is for the village of Achmore, but as stated earlier, this is arbitrary because it could be applied to any community. The climate data did not affect the modelling software unless any renewables were integrated into the modelling tool.

3.3. Electrical Demand

The electrical demand was created using a typical daily household demand and then multiplied by 200 to reflect the community demand. The daily household demand profile was created with the HomerPro demand creator; Figure 10 shows this demand profile.

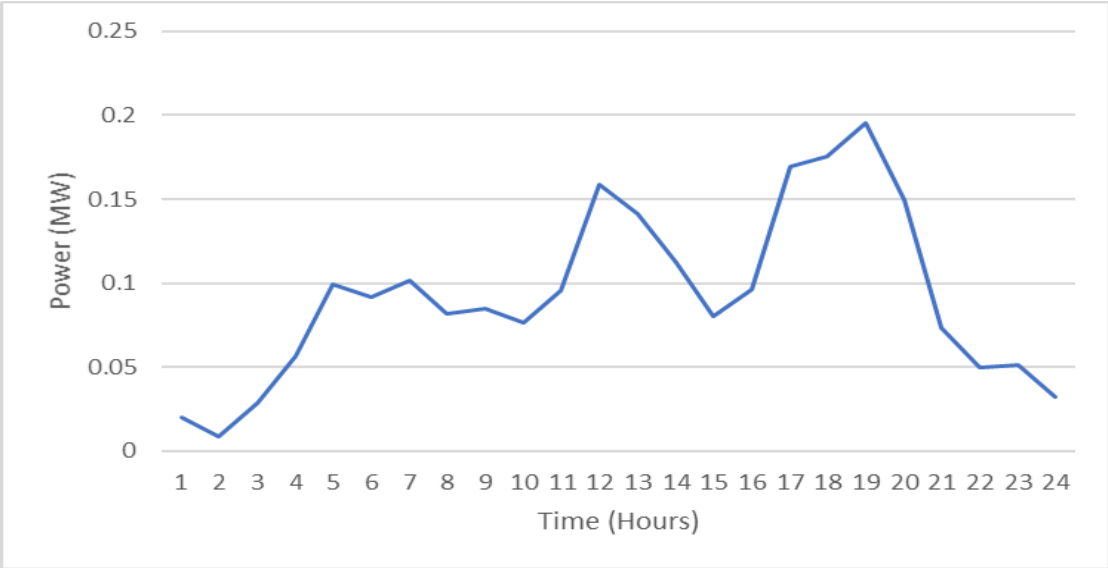


Figure 10: Typical daily electrical demand for 200 households

The average yearly electricity consumption per household in Scotland in 2017 was 4122 kWh (Scottish Government, 2018). The total electricity consumption per household from the demand profile was 4105 kWh; therefore, it was determined to be accurate.

Figure 11 shows the yearly electricity demand profile for the 200 households.

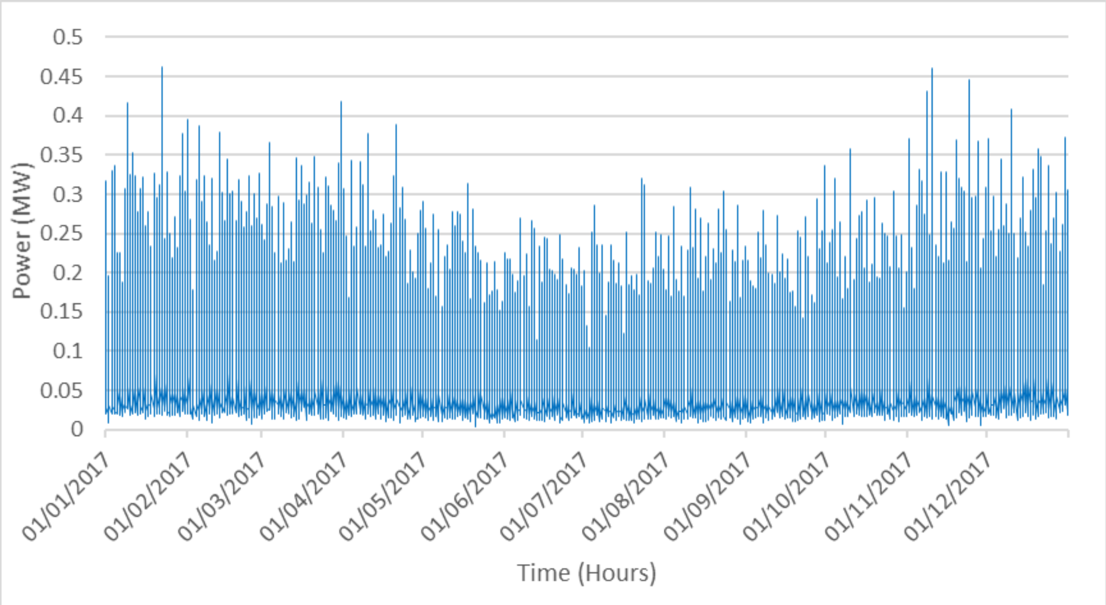


Figure 11: Yearly electrical demand for 200 households (MW)

The peak demand for the demand profile in Figure 9 is 463 kW (0.463 MW).

3.4. Thermal Demand

The thermal demand was created manually, similarly to the electrical demand. The first step was to create a typical daily demand profile for a single household. This was created based on published information (Nuytten *et al.*, 2013). Figure 12 shows the demand profile created.

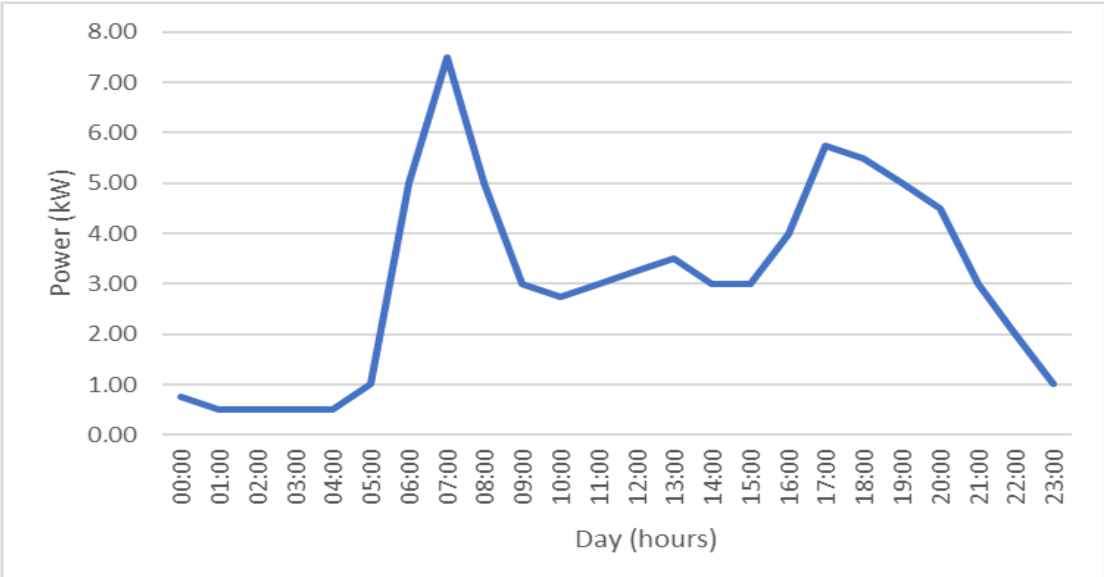


Figure 12: Typical daily thermal demand profile for a single Scottish household in January

The demand profile in Figure 12 shows that there is a peak in demand in the morning as this is when most people will wake up and start their day. Figure 12 depicts a typical day in January, but the general profile of the demand will not change throughout the year, only the total amount of daily energy.

Figure 13 displays the disparity between winter and summer heating demands in the UK.

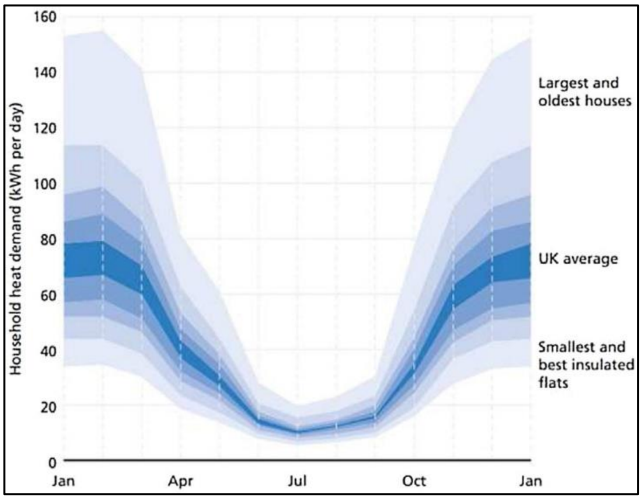


Figure 13: Average daily heating demand disparity between summer and winter for a single household in the UK (Dodds et al., 2015).

An average daily demand profile was then created for each month, which can be seen in Appendix B. These totals coincide with the Scottish Statistics for 2017 (Scottish Government, 2018). The profiles were then put into HOMERpro's demand profile builder, which scrambled the monthly profiles to creates a year's profile in hourly increments. This profile was for a single household, so it was multiplied by 200. The full year's demand profile for 200 households is shown in Figure 14.

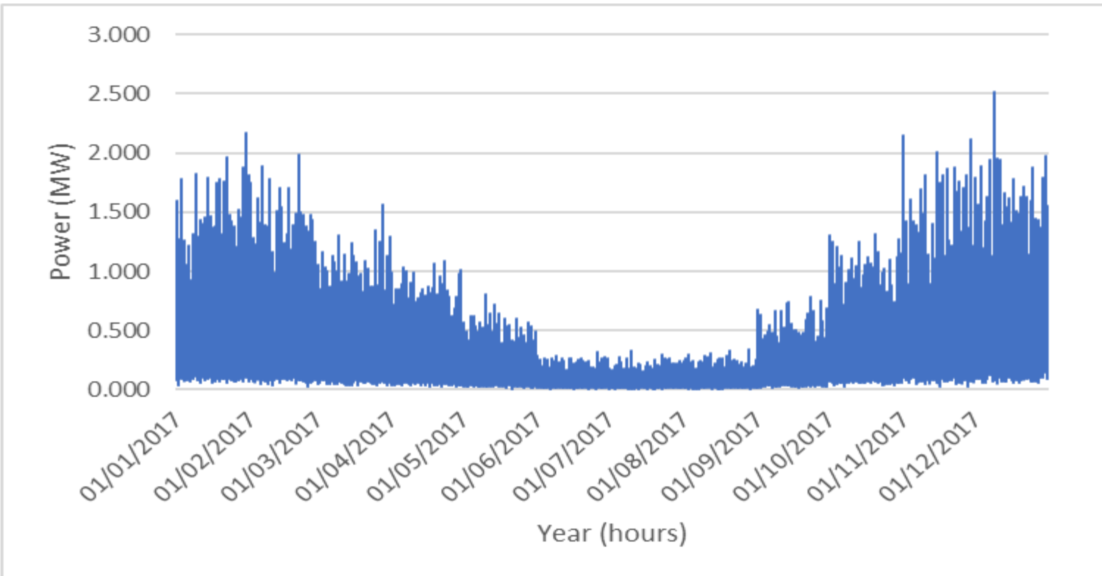


Figure 14: Yearly Heating demand for 200 households (MW)

3.5. Fuel

All heating units either relied on a 100% hydrogen gas network or a natural gas network. The heating values, emissions and costs for hydrogen and natural gas (mainly methane) were determined accordingly.

3.5.1. Heating Values

Table 2 shows the calorific values for both hydrogen and natural gas in kWh/kg at 1 bar of pressure and 0°C.

Table 2: Heating values of hydrogen and natural gas

	Higher Heating Value (HHV)	Lower Heating Value (LHV)
Hydrogen	39.4	33.3
Natural Gas (US)	14.5	13.1

All values were obtained from the engineering toolbox (*Fuels - Higher and Lower Calorific Values*, 2003). The LHV was used for modelling purposes.

3.5.2. Emissions

The supplied hydrogen was presumed to be clear of any impurities, and therefore, would not release any emissions other than water. Current fuel cells have reformers built in to convert natural gas to hydrogen. However, hydrogen produced from renewables or biogas could be used in the future (Dodds *et al.*, 2015).

The main emissions from natural gas are carbon dioxide (CO_2) and nitrogen oxides (NO_x). These emissions are summarised in kilogram of pollutant per kilogram of fuel combusted (kg/kg) in Table 3.

Table 3: Emissions from natural gas (BEIS, 2018b)

	Natural Gas
Carbon dioxide (kg_{CO2}/kg_{fuel})	2.75
Nitrogen Oxides (kg_{NOx}/kg_{fuel})	0.001

Carbon dioxide is considered to be one of the main causes of global warming, and is one of the main targets for emissions reductions (Solomon *et al.*, 2008; Shakun *et al.*, 2012).

Nitrogen oxides are the main pollutants, which contain nitrogen and oxygen, the most prevalent being nitric oxide (NO) and nitrogen dioxide (NO_2). These nitrogen oxides are known to degrade local air quality (Seinfeld and Pandis, 2006).

Gas leakages are not considered, though they too can be harmful to the environment (Howarth, Santoro and Ingraffea, 2011; Saunois *et al.*, 2016).

3.5.3. Costs

According to the Department for Business, Energy and Industrial Strategy's "Quarterly Energy Prices", the average standard gas bill was £631 based on a consumption of 15000 kWh, giving a price of 42.10 £/MWh (BEIS, 2017). In agreement with these figures, EnergyPRO calculated gas price to be 0.55 £/kg (0.0421 £/kWh x 13.1 kWh/kg = 0.55 £/kg).

3.6. Electricity markets

Two types of electricity markets were compared: the fixed market and the day ahead market. Both these markets produce a carbon footprint for the production of energy; this is measured in g_{CO2}/kWh. These markets are defined in subsequent sections.

3.6.1. Fixed Tariff Market

The fixed electricity market is used by most households in the UK; the client and energy provider agree to a fixed energy price for a certain period. The average standard electrical bill for 2017 was £619 based on a consumption of 3800 kWh, yielding a standard rate of 162.90 £/MWh (619/3800 = 16.29 p/kWh)(BEIS, 2017). This value is for the import of electricity and correlates with the electricity supplier's rates. If a household or community generates its own electricity, then it can then be sold back to the grid. The tariff for the export of electricity is based on a standard feed-in tariff plus a generation tariff, which depends on the generation method. The current standard feed-in tariff is 5.24 p/kWh (Ofgem, 2017). Table 4 shows a selection of the different rates for generation types with similar capacities or relevance.

Table 4: Generation tariffs for different technologies (Ofgem, 2017)

Generation Type	Installed Capacity (kW)	Generation Tariff (p/kWh)
Large Solar PV	1000-5000	0.45
Anaerobic digestion	500-5000	2.07
CHP	0-2	14.52
Hydro	2000-5000	4.73
Wind	1500-5000	0.84

As can be seen in Table 4, there is currently no tariff for CHP larger than 2kW; this is because it is considered that the only qualifying renewable fuel for CHP technology is biogas from anaerobic digestion. For the sake of this paper, it is assumed that the generation tariff for a hydro fuel cell CHP system would be the same.

Table 5 summarises the fixed tariff prices.

Table 5: Import/Export of electricity fixed tariffs

	Tariff (£/MWh)
Import of electricity	162.90
Export of electricity	197.60

3.6.2. Day Ahead (Spot) Market

The day ahead electricity market is based on an auction between buyers (demand) and sellers (supply) bidding for multiple areas and hours for the next day. The European Power Exchange (EPEX) market operates the energy markets for the United Kingdom Germany, Austria, Luxembourg, France, Switzerland, Belgium and the Netherlands. It fixes the prices by matching the supply and demand curves and calculates the Market Index Price (MIP), which is the intersection between both curves, for each hour of the next day (Cornélusse, 2014). Figure 15 shows a typical days pricing.

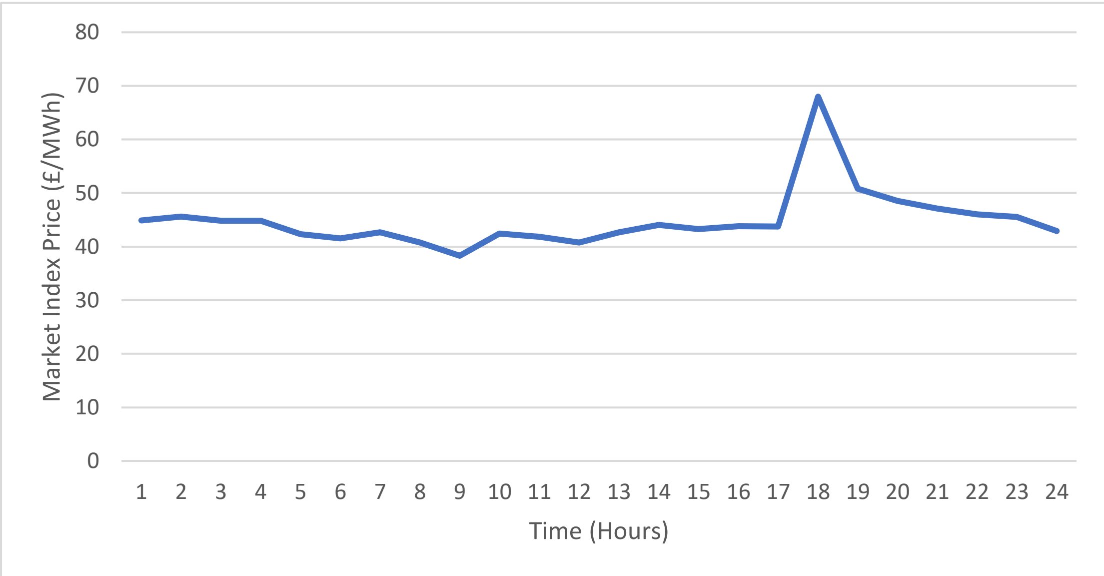


Figure 15: Day ahead Market Index Price for 01/01/2017

The day ahead market MIP data for 2017 were obtained from Elexon Portal (https://www.elexonportal.co.uk) and can be found in the attached excel sheet "Merlin Carnegie thesis data references.xlsx" under EPEX 2017 tab.

3.6.3. Emissions

The amount of CO_2 per kWh of electricity produced by each market was the same, as it can be presumed that the energy mix was similar whether the grid supply was fixed or day ahead.

The value for the UK's electrical energy mix was calculated using the total amount of carbon dioxide emitted by power stations in 2017. The total carbon dioxide, 72 million tonnes (Mt) (BEIS, 2018a) was divided by the total amount of energy produced, 336 TWh (BEIS, 2018b), which equals 0.214 Mt/TWh equating to 214g/kWh. This value corresponds to the valued released by the mobile application GridCarbon, which calculates the carbon intensity of the UK electrical grid in real time. Figure 16 shows an example of the interface and the variation in a selected 24-hour period (21:10 16/08/18).

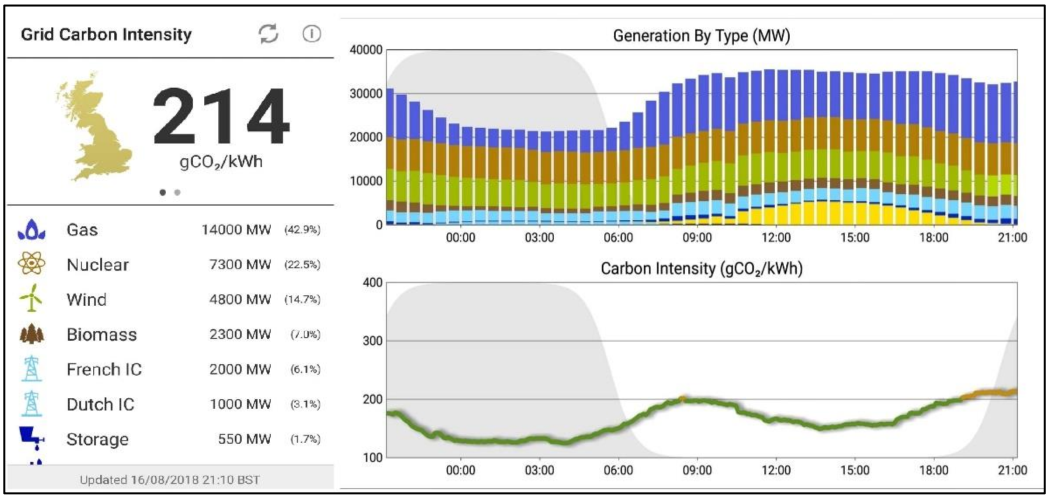


Figure 16: Grid Carbon Intensity displaying the UK energy mix.

Figure 16 shows a strong validation for the calculated value; it also shows that natural gas is currently the biggest provider of electrical supply.

3.7. Model Components

3.7.1. Fuel Cell CHP

There is no specific fuel cell energy unit in EnergyPRO. However, the CHP option allows for the energy efficiency ratios and the suppling fuel to be set. This forms the basis of the fuel cell CHP system model. The electrical efficiency was be set at 40% and the heat efficiency 55%, giving an overall efficiency of 95%. The “warmup” inefficiencies were not considered.

3.7.2. Thermal Store

The thermal store assumed that the top of the tank was at 90°C and the bottom was at 50°C, which were the pre-set values given. EnergyPRO calculates the amount of heat capacity in MWh based on these temperatures and the size of the tank. The tank was sized to accommodate enough capacity to supply the daily average heat demand which is 8.55 MWh/day, this was found to be 185m^3 giving a heat storage capacity of 8.58 MWh.

3.7.3. Electrical Storage

The electrical storage was not specified but could have been a flow battery or Li-on depending on what was available. It was sized to accommodate the daily maximum, which is 3.66 MWh/day. The electrical store was therefore 4MWh with a discharge and charge rate of 0.5 MW which was enough to supply at peak demand.

3.7.4. Electric boiler

The electric boiler used was 99% efficient (Fan, 2018).

4. Results

This section displays the results from the modelling. The results for each of the scenarios results are broken down into 3 subsections: energy, emissions and running costs.

4.1. Scenario 1: Base Case

The diagram of scenario 1 is shown in Figure 17. The electricity demand is supplied by a fixed tariff market, whilst the heat demand is supplied by a natural gas condensation boiler with an efficiency of 90% (Chen *et al.*, 2012).

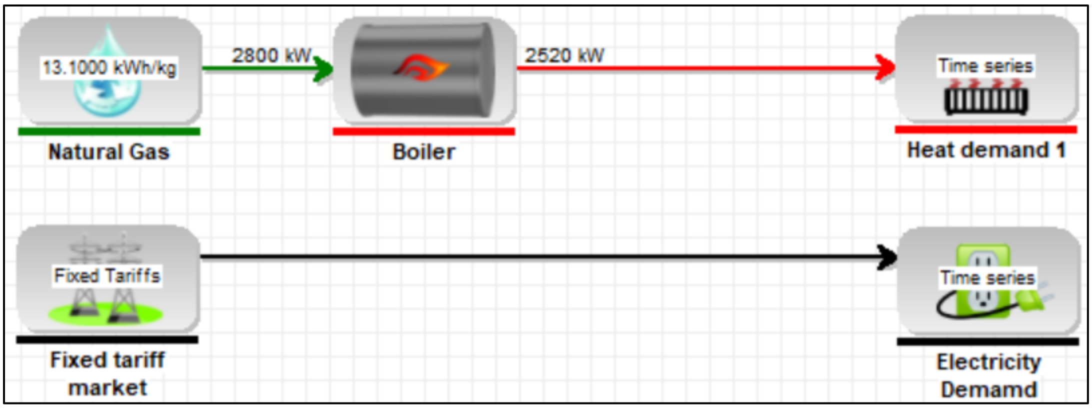


Figure 17: Scenario 1 schematic

For the boiler to supply a 100% match, it must be sized to the peak demand, 2.516 MW. Therefore, the boiler rated capacity must be above 2.795 MW (2.516/90%), which can be rounded to 2.8 MW. Appendix C shows the annual energy conversion figures, which determine the yearly match and whether the size of the system is sufficient. A sanity check was conducted by reducing the heat output of the boiler to 2500kW, which would result in the peak load not being met. When it was changed, the heat production went from 3123 MWh (100% match) to 3122.9MWh (99.997% match). This was the expected result, confirming that the model was working correctly. Table 6 summarises the annual energy results.

Table 6: Scenario 1 annual energy results

Total Heat Demand	3,123 MWh
Total Heat Production	3,123 MWh
Peak Demand	2.5 MW
Heat Match	100%
Total Electricity Demand	821.1 MWh
Total Electricity Demand	821.1 MWh
Peak Demand	0.5 MW
Electricity Match	100%
Fuel Consumption (NG)	264,882 kg

Figure 18 shows a winter week, Monday 04/12/17 to Sun 10/12/17, which was the week with the peak demand of the year, 2.516 MW, on Saturday 09/12/17.

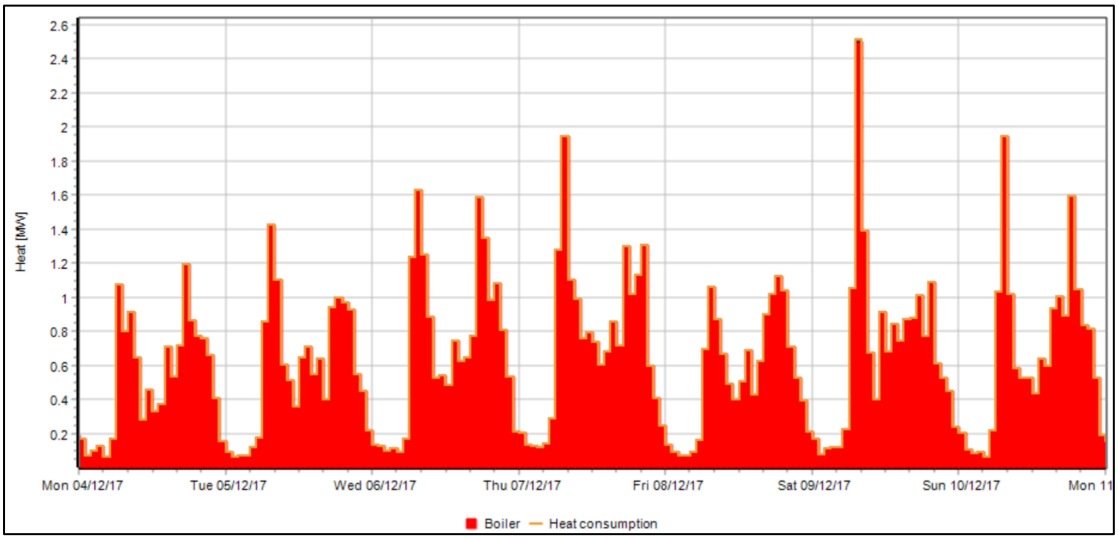


Figure 18: Scenario 1 winter week heating graph

As can been seen in Figure 18, the boiler met the demand at all times by varying its output for any demand.

4.1.1. Emissions

Emissions	2017
CO2	[tonne]
Natural Gas	726
Importedelectricity	176
CO2 Total	**902**
NOx	**[kg]**
Natural Gas	264
NOx Total	**264**

Figure 19: Scenario 1 emissions (EMD, 2018)

The model calculated the related emissions associated with each energy supply. This only applies to scenario 3 as electricity can be imported from the grid and there are emissions when generating said energy. Figure 19 shows that in the base case a community of 200 household would emit 902 tonnes of CO2 per year, including 726 tonnes locally and 264 kg of NO_x, which is potential damaging to local air quality.

4.1.2. Running Cost

The full monthly running costs results are presented in Appendix D; Table 7 summarises the annual results below.

Table 7: Scenario 1 annual running cost

Cost	System Running Cost
Imported fuel (NG)	£145,685
Imported electricity	£133,837
Total Cost	£279,522

A sanity check was carried out on the running costs. According to the model, the prices per household were £728 for gas and £669 for electricity; these costs correspond to the quoted prices found in the literature (£631heat; £619 electricity) (BEIS, 2017). This confirmed that the model's pricing of fuel was in the same order, and therefore, working correctly.

4.2. Scenario 2: Island Operation

Stornoway on the Isle of Lewis currently supplies it's 6200 residents with a district LPG network (William Morrison, 2011; Highlands and Islands Entreprise, 2014). The plant imports 3000 tonnes of LPG every year, which is the primary source of heating on the island. The island is also grid connected by a 33 kV subsea connector, but there are potential plans by the Scottish Government and SSE to upgrade this to accommodate the large amount of wind projects that have been approved in the area (SSE, 2015). From a logistics point of view, converting a local gas network such as Stornoway's would be relatively easy compared to converting the mainland's. Whether it is technically possible is yet to be detemined, but there is some research that suggests it could be possible.

Figure 20 shows a schematic of scenario 2. The initial approach was to run simulations for different sizes of fuel cell, 1500 – 250 in six steps of 250 kW.

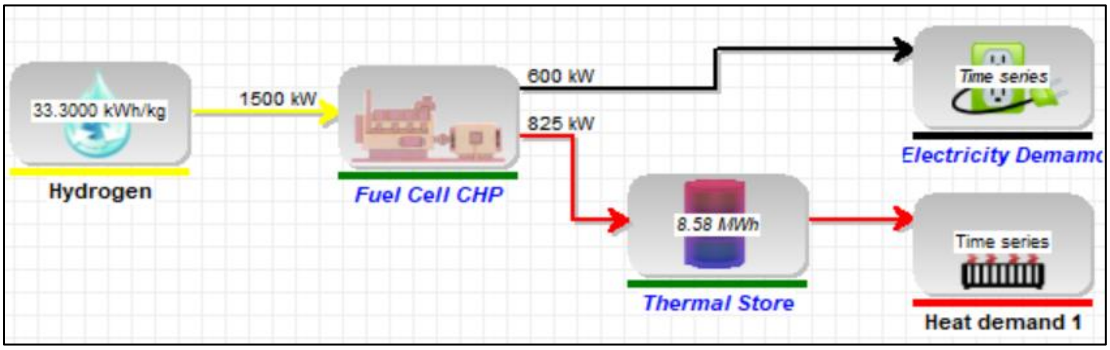


Figure 20: Scenario 2 Schematic

In table 8, if the match is considered: insufficient (<70%) the cell is red; moderate (70% - 85%) the cell is orange; and good (>85%) the cell is green.

Table 8: Scenario 2 annual energy match

CHP (kW)	Heating Capacity (kW)	Electrical Capacity (kW)	Heat Production (MWh)	Electrical Production (MWh)	Heat Match	Electrical Match	Total Match
1500	825	600	1102.2	801.6	35%	98%	34%
1250	687.5	500	1102.2	801.6	35%	98%	34%
1000	550	400	1101.8	801.3	35%	98%	34%
750	412.5	300	1097.4	798.1	35%	97%	34%
500	275	200	1066.7	775.8	34%	94%	32%
250	137.5	100	892.2	649.1	29%	79%	23%

Table 8 shows the results of the simulations run. When the electrical capacity was above that of the electrical peak demand (500 kW), as in the first two iterations, the CHP was running to follow the electrical demand, which also caps the heat production. This was to be expected, as there is a large discrepancy between the two demands during the winter weeks.

This is shown in the graphs in Figure 21 for the winter week (04/12/17-10/12/17). These graphs were produced with data from the first iteration.

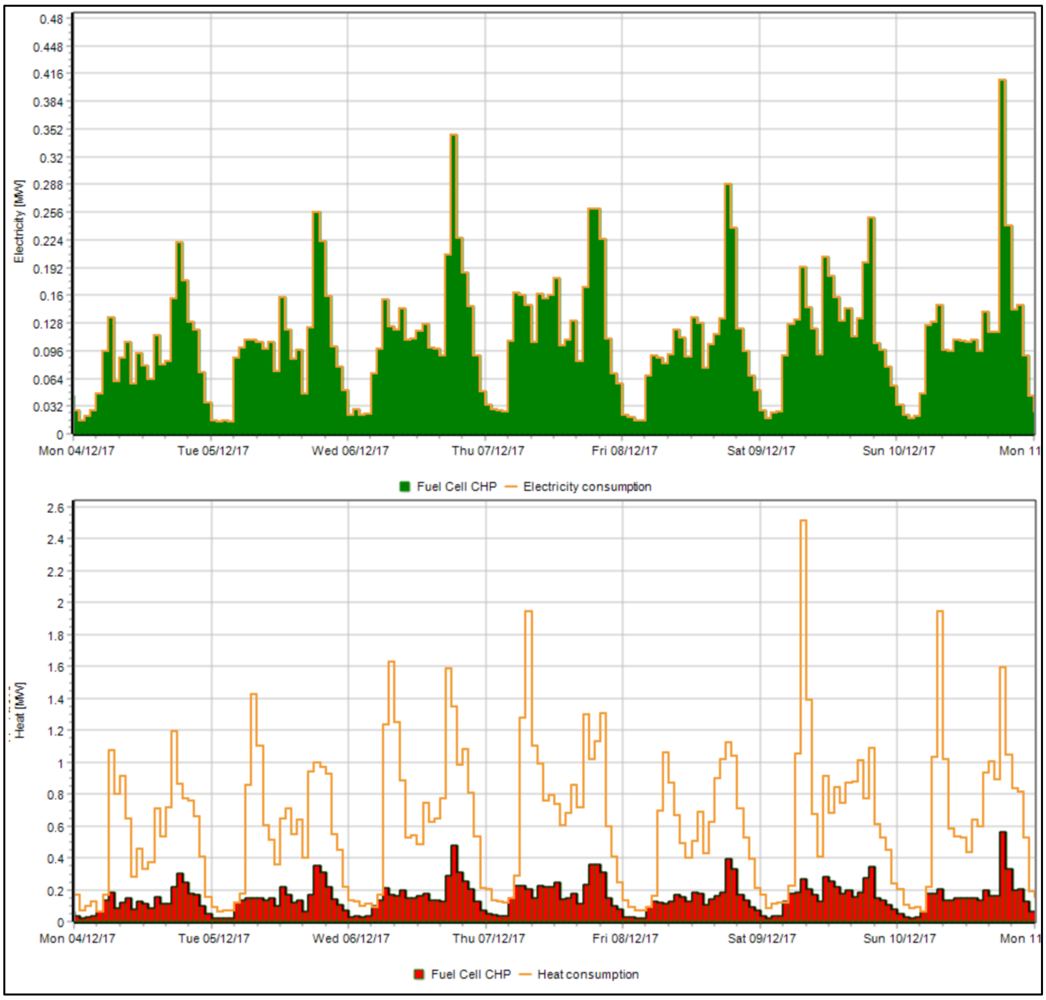


Figure 21: Scenario 2 electrical and heat graphs

In the electrical graph, shown in green (Figure 21), the electrical supply from the CHP can clearly be seen to be following and covering the electrical demand. This dictates the heat output, which also follows the same pattern; however, it only covers approximately one third of the demand, so there is no surplus going to the thermal store.

During the summer, the heating and electrical demands were not too dissimilar in terms of magnitude. Figure 22 shows a summer week's (Monday 26/06/17- Sunday 02/07/17) electrical, heat and thermal store.

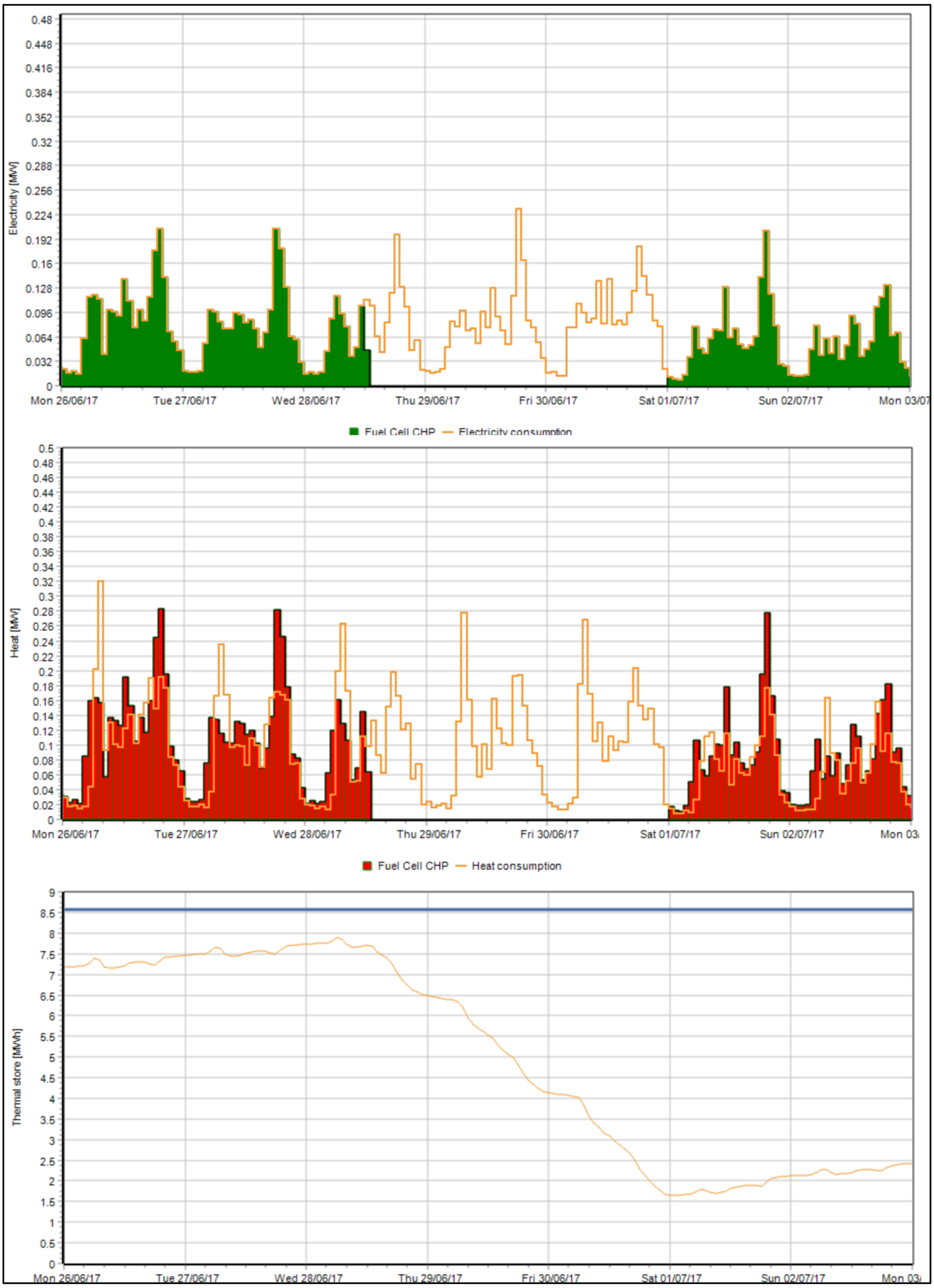


Figure 22: Scenario 2 summer week electrical, heating and thermal storage graph

From figure 22, there is an error in the model because the CHP system cuts out. The reason for this has not been determined, but the phenomenon occurred on multiple occasions and will be discussed further in the discussion section.

The CHP system was always running on ‘high’ priority, so the CHP would always preferentially supply a particular demand over any other energy conversion unit.

4.2.1. Running costs

The only cost associated with scenario 2 model was the import of hydrogen. The best size options would either be 750 kW or 500 kW as determined by comparing costs in table 9.

Table 9: Scenario 2 running costs between two highest matches

CHP size	Heat match	Electrical Match	Total match	Running Cost
750	35%	97%	34%	£32,956
500	34%	94%	32%	£32,032

4.3. Scenario 2a: Island Operation with an Electrical Store.

An electrical store was added to the model to examine its effect. An electrical store could help alleviate the discrepancies between the two demands. Figure 23 shows a schematic of scenario 2a.

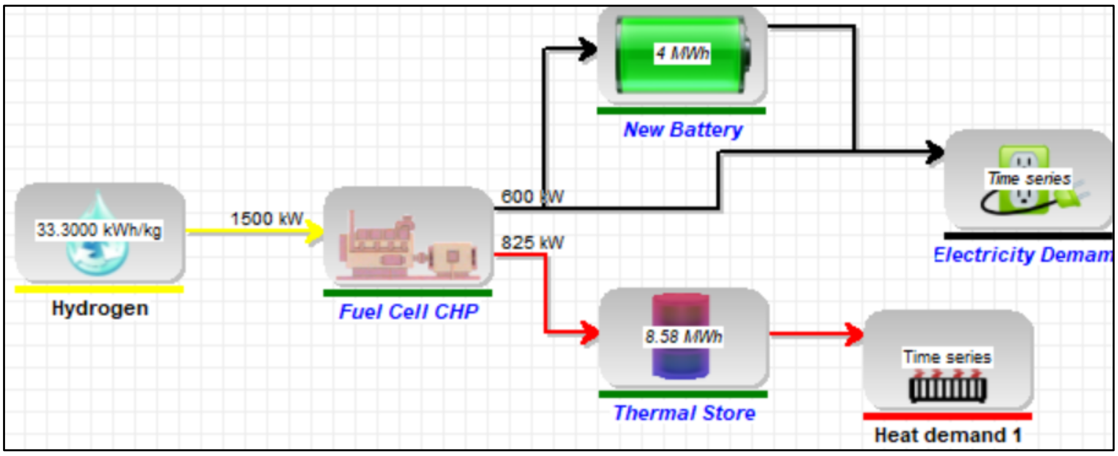


Figure 23: Scenario 2a schematic

The system was simulated for the given sizes of fuel cell running at partial load (scenario 2a (i)) and non-partial load (full load) (scenario 2a (ii)). This was allowed by the battery because otherwise, the fuel cell could only run at times when both demands were higher than the max capacity of the fuel cell.

Appendix E shows the full results for the CHP running at partial load and full load. Table 10 summaries the best fitting configuration for both.

Table 10: Scenario 2a summary of best matches

	CHP	Heat Capacity	Electrical Capacity	Partial Load (Y/N)	Heat Production (CHP)	Electrical Production	Heat Match	Electrical Match	Combined	Hours of Operation	kg of Fuel Imported	Running Cost
Partial Load	500	275	200	Y	1115.8	811.5	36%	99%	35%	8603	60923	£33,508
Full load	500	275	200	N	1215.6	884.1	39%	108%	42%	4597	66374	£36,506

From table 10, it can be seen that the initial match improvement due to the addition of a battery was only 1%, with a slightly higher running cost. However, by limiting the CHP system to only run at full load, the match was increased to 39% (adjusted for the surplus electricity), which is a 5% rise. By running the system at full load only, this also reduced that number of hours in operation, which could prolong the lifespan of the

Figure 24: Scenario 2a (i) electrical, discharge/charge and state of storage graphs

system.

Figure 24 shows electrical graph in green (top), the charge and discharge graph (middle), and the battery state of charge (bottom); the graphs were constructed using data from a winter week and 500kW CHP system. It can clearly be seen that when the system reaches capacity (200kW), the battery makes up the supply (this happens most often in the evenings). The battery is quickly recharged overnight. However, the state of charge graph shows that very little of the 4MWh capacity was used; in fact, the battery never went above 0.5 MWh depth of discharge over the whole year. This indicates that the battery could be much smaller. Figure 25 shows the same graphs for scenario 2a (ii), when the CHP was only allowed to run at full load.

Figure 25: Scenario 2a (ii) electrical, discharge/charge and state of storage graphs

In Figure 25, it is evident that the battery was used much more, as it discharged to below 2MWh; the full electrical store was used several times over the year in this scenario. It can also be noted that the discharge/charge graph is the inverse of the electrical consumption.

Figure 26 shows the thermal graphs from both Scenario 2a (i) and 2a (ii).

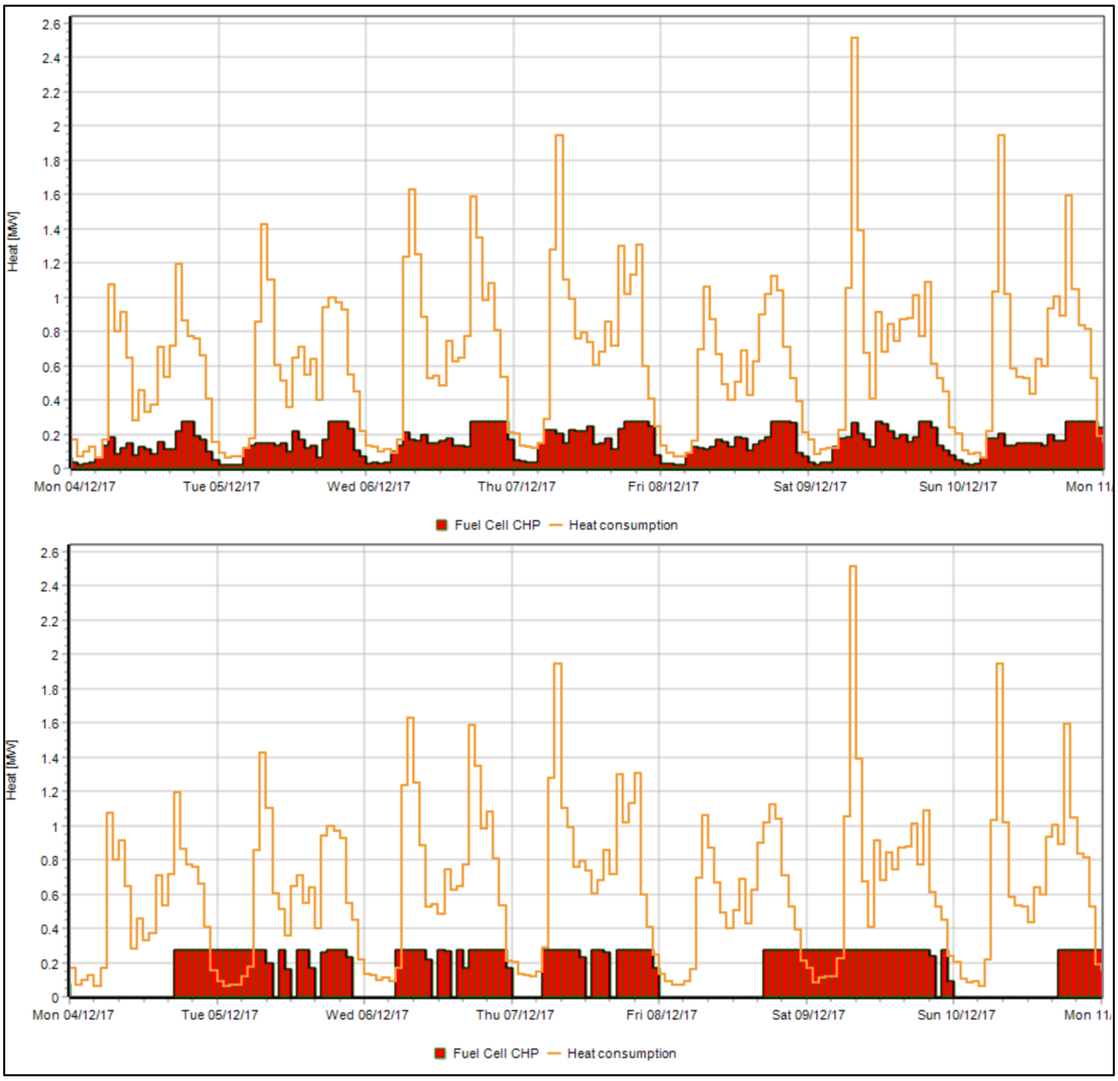


Figure 26: Scenario 2a (i) and 2a (ii) thermal graphs

It can be seen from both graphs in Figure 26 that the thermal capacity was far too low.

4.4. Scenario 2b: Island Operation with an Electrical Store and Electric Boiler

Due to the discrepancies between the electrical and heating demands, the model was able to account for most of the electrical demand, but there was still a big shortfall for the thermal demand. Modelling was used to determine whether this could be alleviated by adding an electrical boiler, which would supply more heat and increase the electrical internal demand. Figure 27 shows the schematic for scenario 2b.

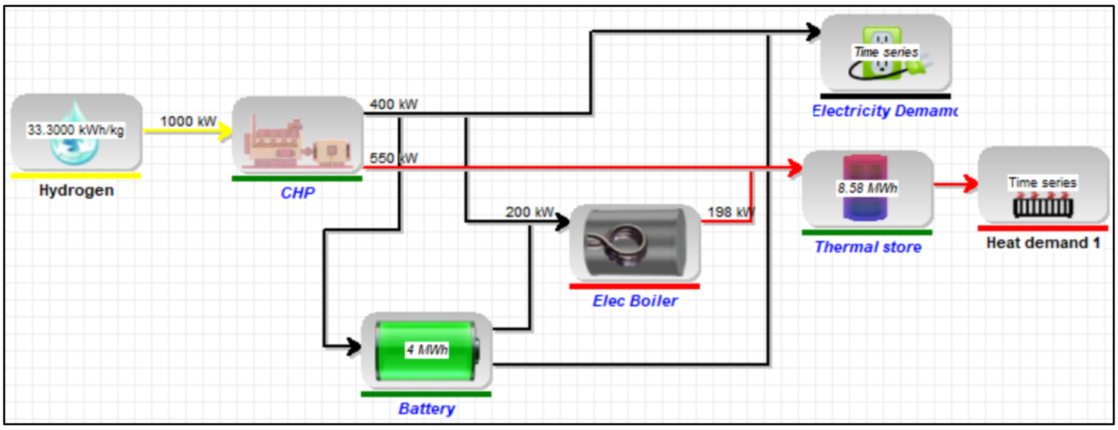


Figure 27: Scenario 2b schematic

Following the methodology, the scenario was again modelled with and without partial load (scenario 2b (i) and scenario 2b (ii) respectively). The simulations modelled compared different combinations of fuel cell and electric boiler – a table of all iterations can be seen in Appendix F. Table 11 summarises the best options for both scenario 2b (i) and 2b (ii).

Table 11: Scenario 2b summary of best matches

	CHP	Heat Capacity	Electrical Capacity	Electric Boiler	Partial Load (Y/N)	Heat Production (CHP)	Heat Production (Boiler)	Heat Production (Total)	Electrical Production	Electrical consumed	Electrical Total	Heat Match	Electrical Match	Combined
Full Load	1250	687.5	500	300	N/Y	2236.1	820.8	3056.9	1626.2	829.2	797	98%	97.1%	95%
Partial Load	1000	550	400	200	Y/Y	2266.6	854.7	3121.3	1648.4	863.4	785	100%	95.6%	96%
	750	412.5	300	200	Y/Y	2248.2	835.2	3083.4	1635	843.7	791.3	99%	96.4%	95%

From Table 11, the matches have vastly improved in both scenarios 2b (i) and 2b (ii); adequate electricity and heating are provided. There are two possible configurations for

2b (ii): a 1000kW fuel with a 200 kW electric boiler, or a 750 kW fuel cell with a 200 kW electric boiler. The following graphs will be based on the 750 kW setup, because it would be marginally cheaper to run (£68,064 for the 1000 kW and £67,513 for the 750 kW). It would also be cheaper in capital costs.

4.4.1. Scenario 2b (i)

Figure 28 shows the electrical graphs for scenario 2b (i)

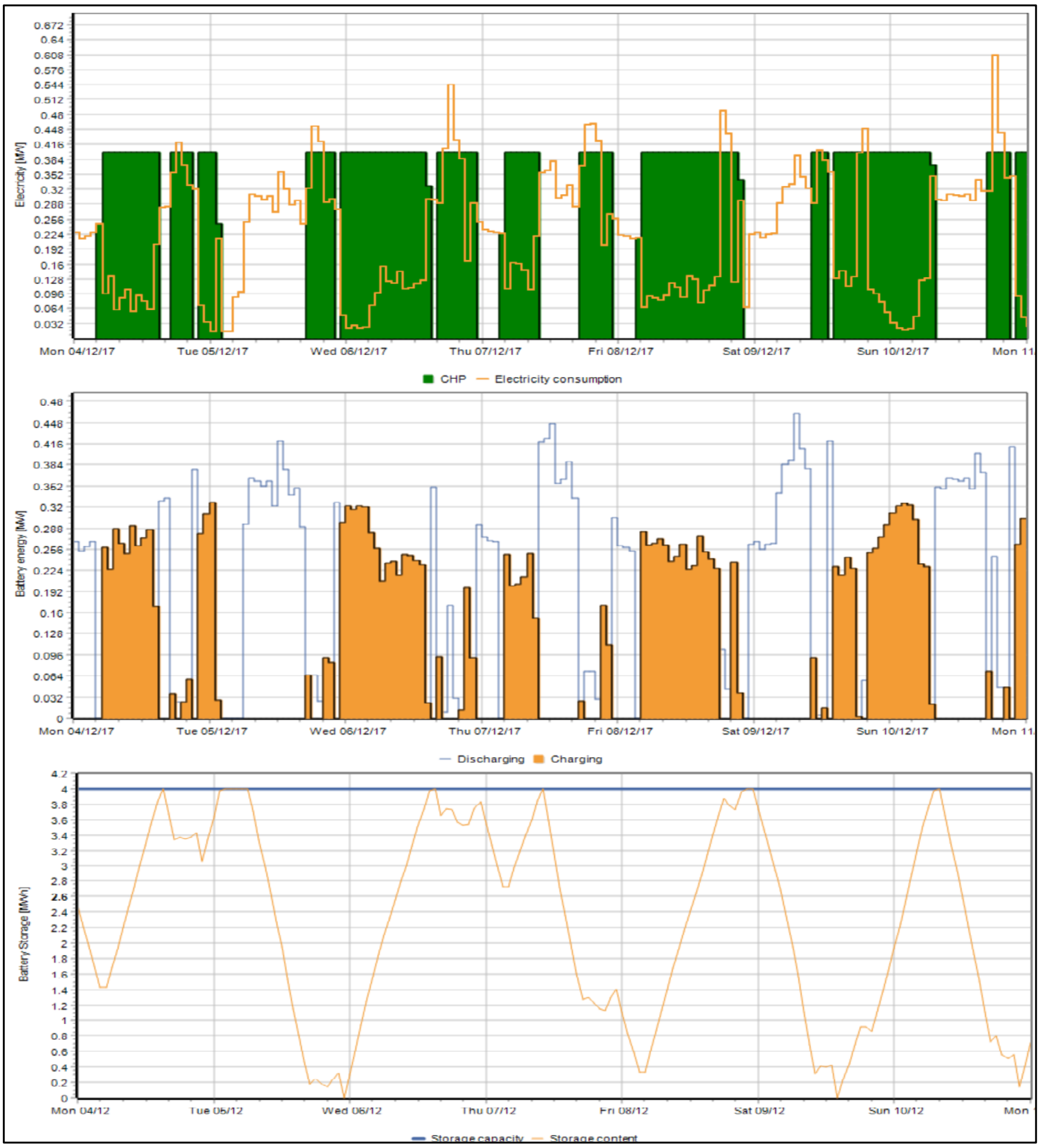


Figure 28: Scenario 2b (i) electrical, discharge/charge and state of storage graphs

Similarly, to Scenario 2a (ii) the electrical consumption graph and discharge graph follow each other, whereas the charging graph is the difference between the CHP production and consumption. In this scenario, the full depth of discharge is used.

Figure 29 shows the thermal graphs for scenario 2b (i).

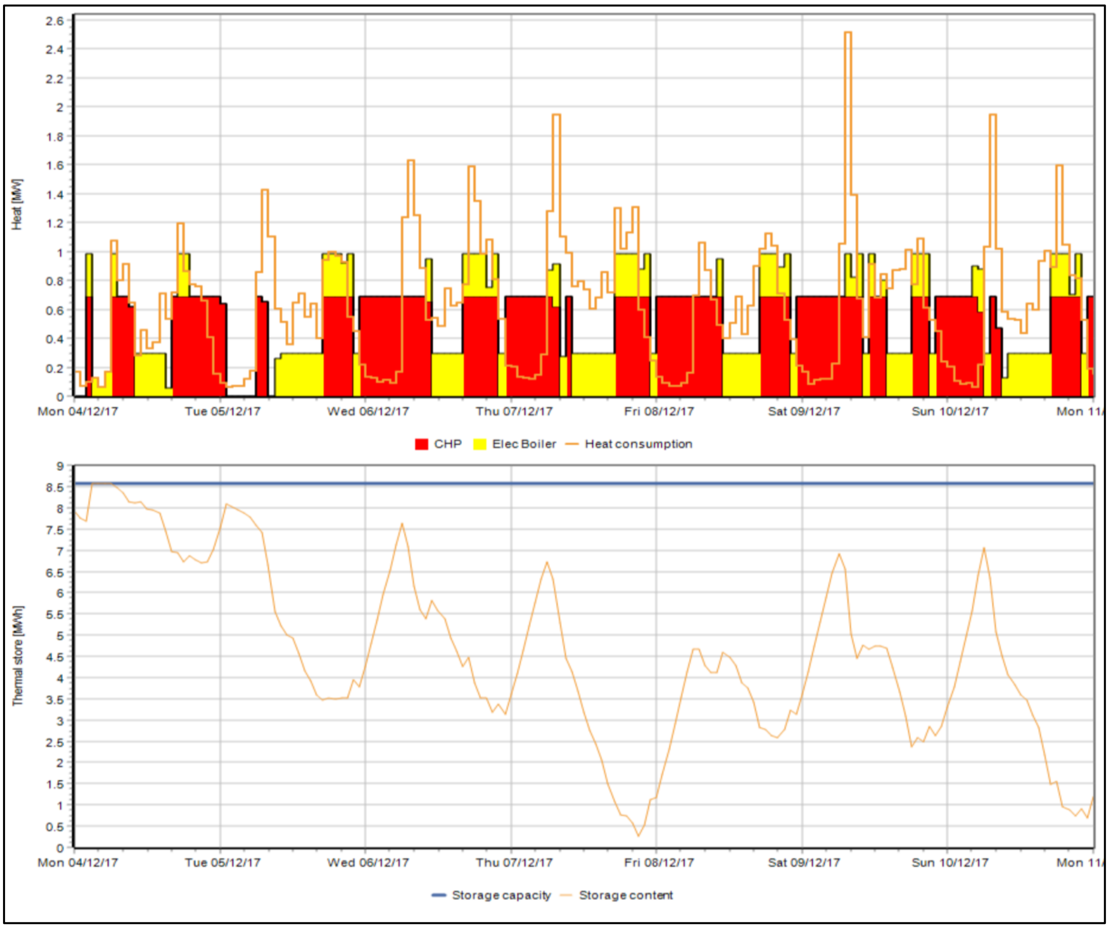
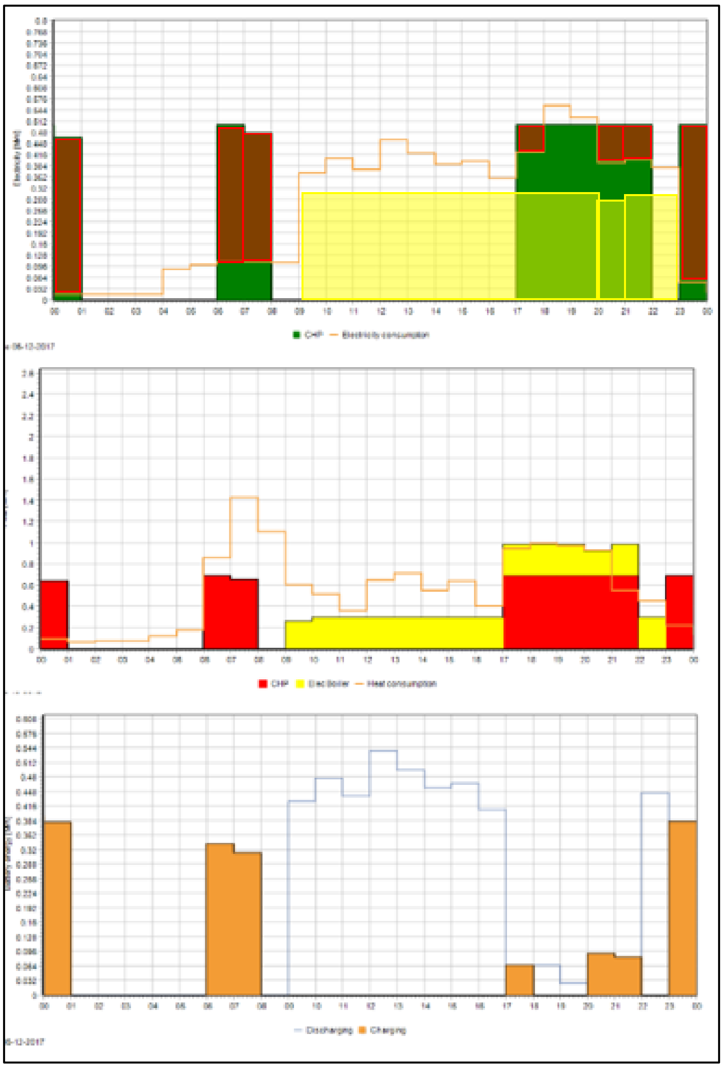


Figure 29: Scenario 2b (i) thermal and thermal storage graphs

In figure 29, it can be seen that the majority of the heating load was supplied by the CHP system. The electric boiler supplied a secondary boost and base during times when the CHP was not on. Finally, the thermal store supplied at peak times.

Figure 30 highlights the effect of the electric boiler on the electrical demand over one day (Tuesday 05/12/17).



= Proportion of electrical demand used by electric boiler.

= Excess electricity goes to battery.

Figure 30: Scenario 2b(i) effect of the electric boiler on electrical demand

When the electric boiler was switched on, the electrical demand increased, which transitioned to the discharge of the battery.

4.4.2. Scenario 2b (ii)

Figure 31 shows the electrical graphs for Scenario 2b (ii).

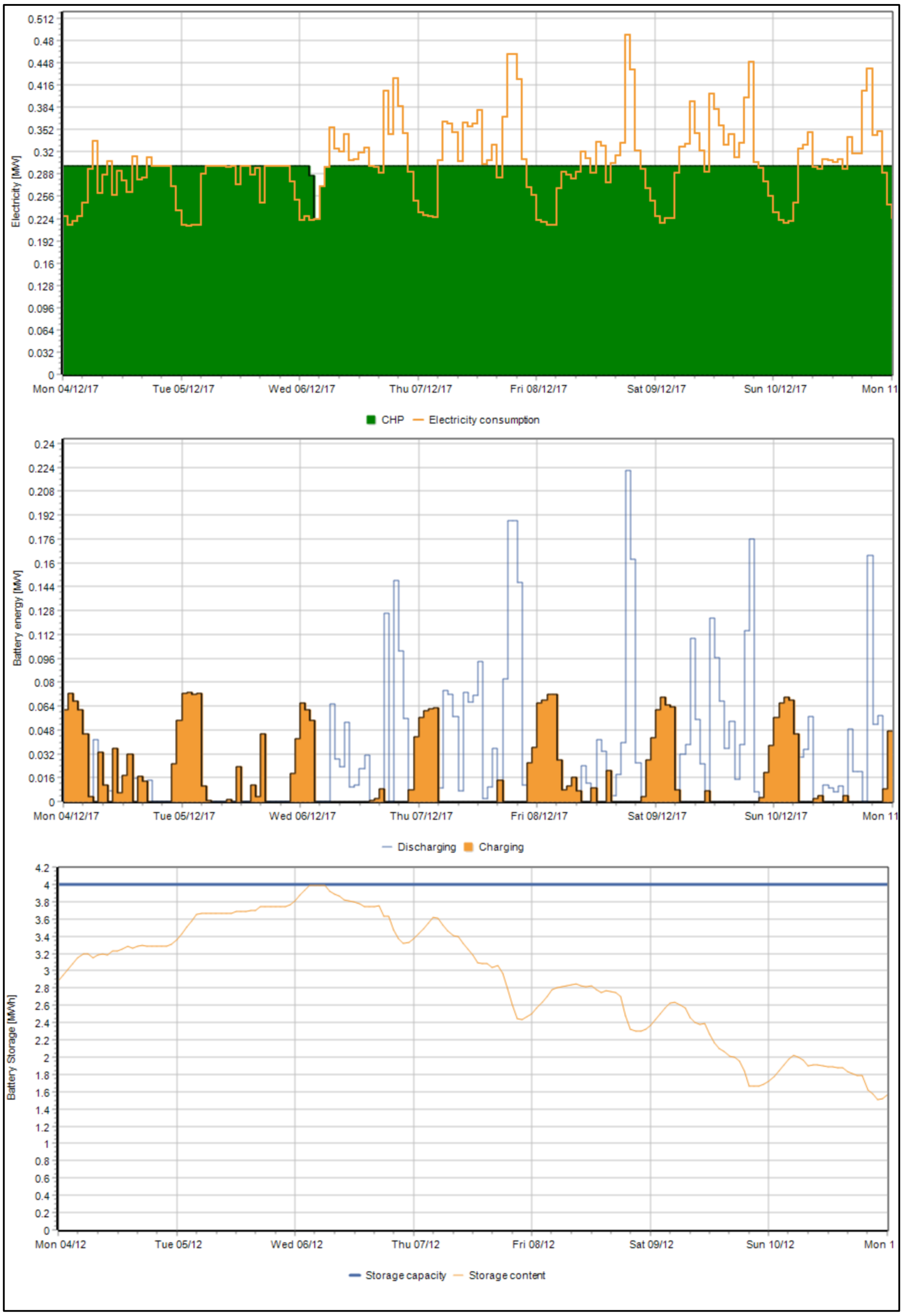


Figure 31: Scenario 2b (ii) electrical, discharge/charge and state of storage

From Figure 31, the electrical demand was mostly covered by the CHP with the battery alleviating any peaks and troughs. However, Figure 32 shows that the battery was only used during the winter months.

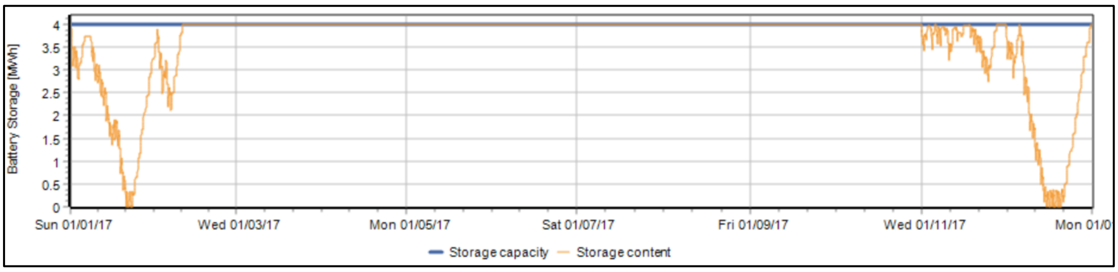


Figure 32: Scenario 2b (ii) yearly battery storage

Figure 33 shows the heat production and thermal store graphs.

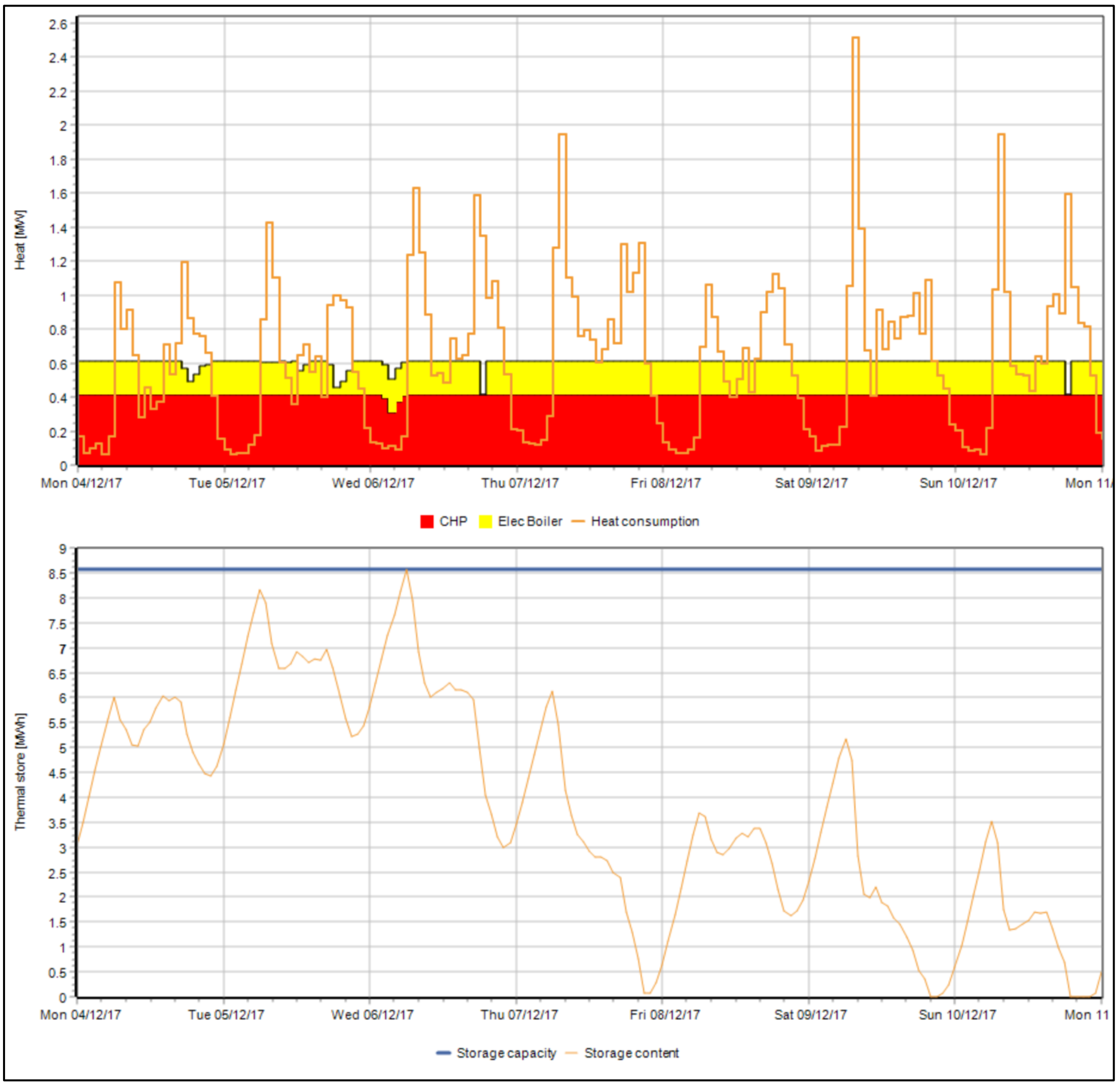


Figure 33: Scenario 2b (ii) thermal and thermal storage graphs

From Figure 33, the heat demand was similarly covered by the CHP, providing a base load and the storage alleviated the peaks and troughs.

4.5. Scenario 2c: Island Operation with an Electric Boiler

For most of the year, in scenario 2b (ii) the battery was not used. Batteries are expensive and the less components there are, the cheaper the system would be to set up. Figure 34 shows the schematic of scenario 2c.

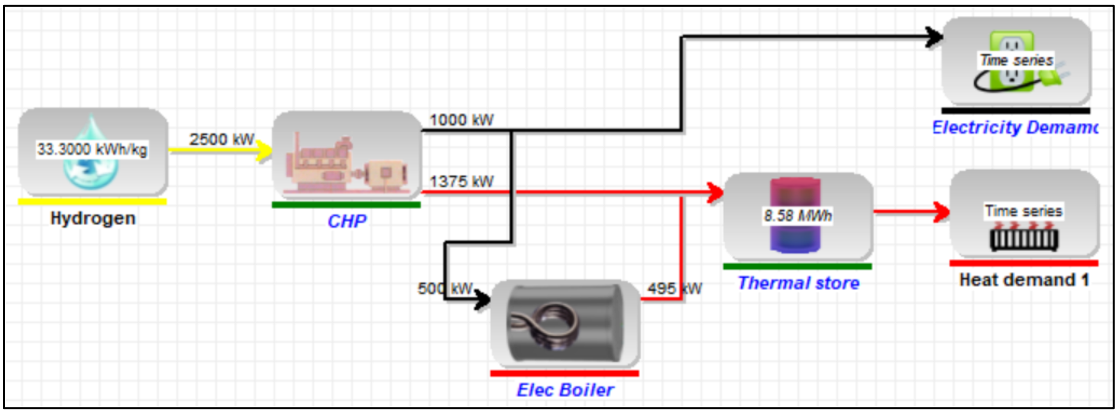


Figure 34: Scenario 2c schematic

The full results for scenario 2c are in Appendix G. Table 12 summarises the best matches for both scenarios 2c CHP at full load (scenario 2c (i)) and CHP at partial load (scenario 2c (ii))

Table 12: Scenario 2c summary of best matches

	CHP	Heat Capacity	Electrical Capacity	Electric Boiler	Heat Production (CHP)	Heat Production (Boiler)	Heat Production (Total)	Electrical Production	Electrical consumed	Electrical Total	Heat Match	Electrical Match	Combined
Full Load	750	412.5	300	300	2124.7	961	3085.7	1545.2	970.7	574.5	99%	70.0%	69%
Patial load	1000	550	400	400	2264.5	858.5	3123	1649.9	865	784.9	100%	95.6%	96%

By removing the battery, the system could only store energy in the form of heat. Therefore, in scenario 2c (i), the electricity relied on the heat demand. The maximum electrical match achieved was 79%, but this had a detrimental effect of the heating (77%) and brought the overall match down to 61% (see Appendix G).

Figure 35 shows the electrical, heating, and thermal store graphs for scenario 2c (i).

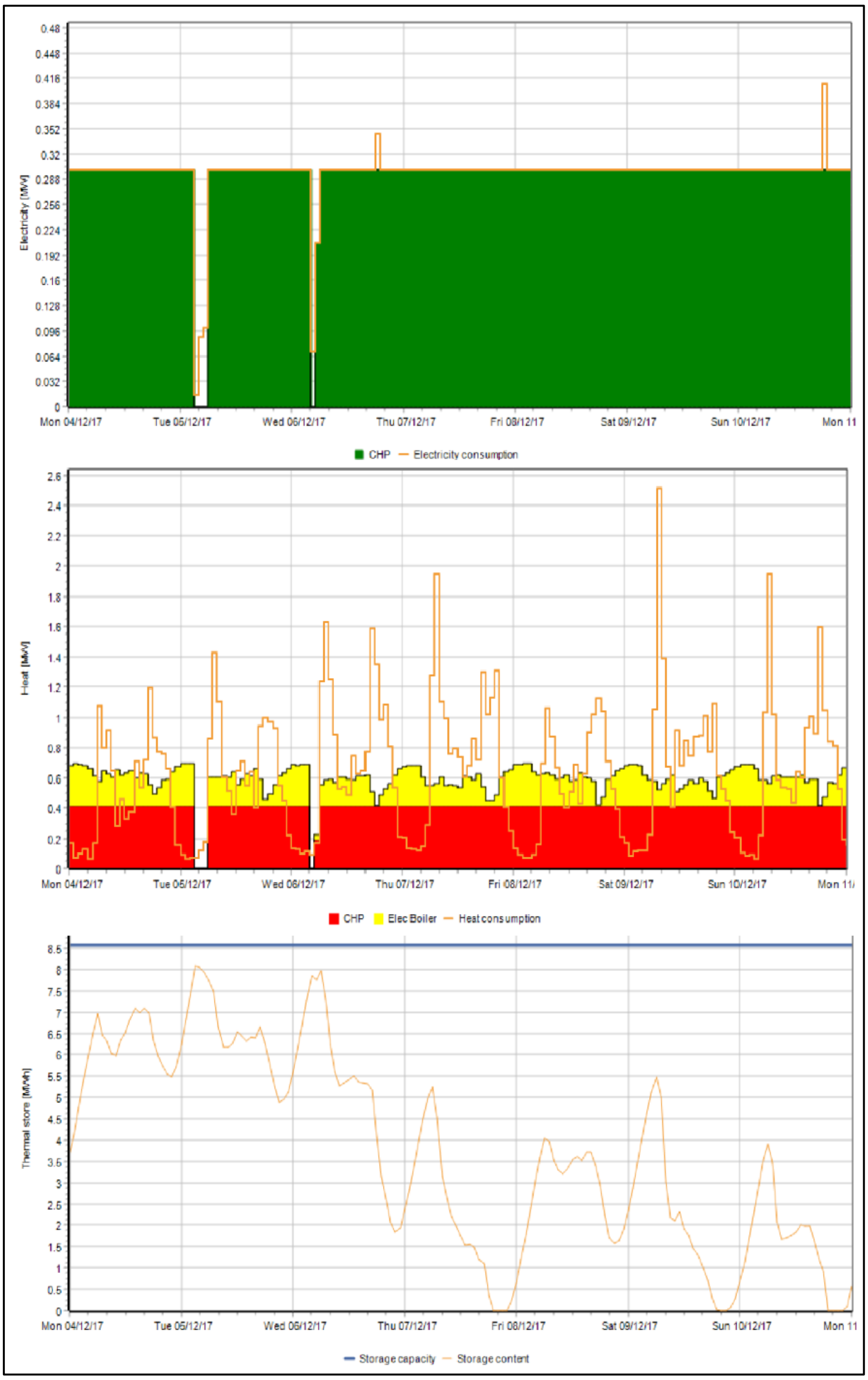


Figure 35: Scenario 2c (i) electrical, heating and thermal store graphs

In figure 35, it can be seen that the CHP ran at full capacity for almost the whole week. The electric boiler could only run when the CHP system was running. It produces the inverse of the electrical demand, storing any surplus heat. The CHP system stopped twice during this week, because there was be enough space in the thermal to accommodate what would be produced at full load.

The graphs for Scenario 2c (ii) are represented in Figure 36.

Figure 36: Scenario 2c (ii) electrical, heating and thermal store graphs

Figure 36 shows that the CHP system and electric boiler worked with the thermal storage to provide a full match of the heating demand. This resulted in the CHP working at full capacity. Any electricity that was not being used by the demand was diverted to be stored as heat.

4.6. Scenario 3: Grid Connected

Scenario 3 explored the possibility of connecting to the mainland grid and looked at some the different configurations. The biggest indicator of viability was operating income. Figure 37 shows the schematic of scenario 3.

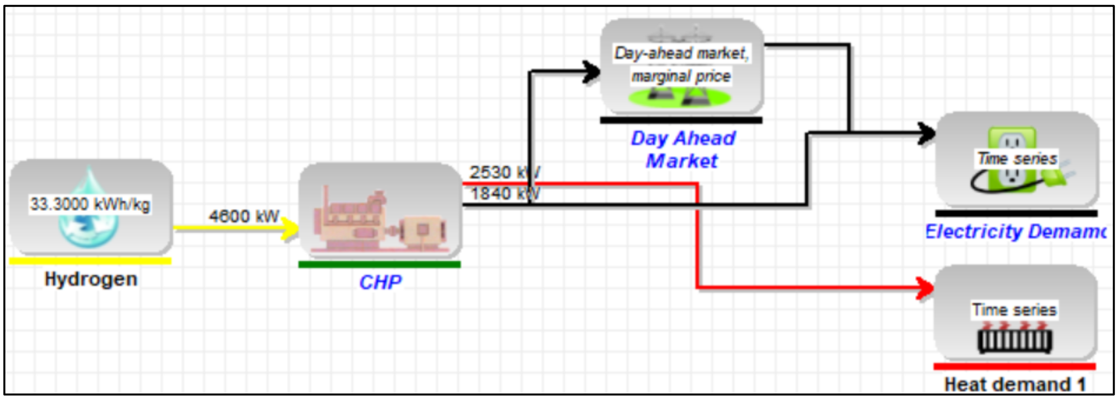


Figure 37: Scenario 3 schematic

For this scenario, only one size of fuel cell CHP was investigated, to ensure that the maximum heat demand would always be met; therefore, the size was determined to be 4.6 MW (2.5/055= 4.5454 ≈ 4.6). As per the methodology, 8 simulations were run, which varied the following parameters: fixed/ahead markets; thermal store yes/no; partial load yes/no. The full results are displayed in Appendix H.

Table 13: Scenario 3 summary of simulations

Iteration Number	Market	Hot Water Storage	Partial load (Y/N)	Heat Production	Electrical Production	Electrical Exported	Electrical imported	Electrical Total	Running Cost (£)	CO2 Emissions (tonne)	Hours of Operation	Fuel Imported (kg)
1	Ahead	N/a	N	0	0	0	821.1	821.1	-£39,606	176	0	-
2	Ahead	N/a	Y	3123	2271	1497.4	47.2	820.8	-£19,214	10	8760	170,514
3	Ahead	8.58	N	3038.5	2209.8	2024.5	635.7	821	£10,692	136	1201	165,904
4	Ahead	8.58	Y	3123	2271.2	2045.1	594.9	821	£12,547	127	8760	170,514
5	Fixed	N/a	N	0	0	0	821.1	821.1	-£133,837	176	0	-
6	Fixed	N/a	Y	3123	2271.2	1497.4	47.2	821	£194,402	10	8760	170,514
7	Fixed	8.58	N	3056.2	2222.7	2152.1	750.5	821.1	£211,149	161	1208	166,871
8	Fixed	8.58	Y	3123	2271.2	2152.3	702.2	821.1	£217,063	150	8760	170,514

Table 13 shows a summary of these results. It can be seen that the system ran similarly no matter which market it was on, and the only significant difference was income. The system could not run at full load without a thermal store, which was to be expected.

However, the electrical demand was still met by the grid, and therefore the discrepancy in price between the two markets is shown. In iterations 2 and 6 (no thermal store and partial load) the system followed the heat demand and sells any excess electricity it had left to the grid. In iterations 3, 4, 7 and 8, the system turned on under two conditions: firstly, the priority was low (based on high price for electricity) and there was enough thermal store, or secondly, the thermal storage was low. Figure 38 shows an example from iteration 7 over two days.

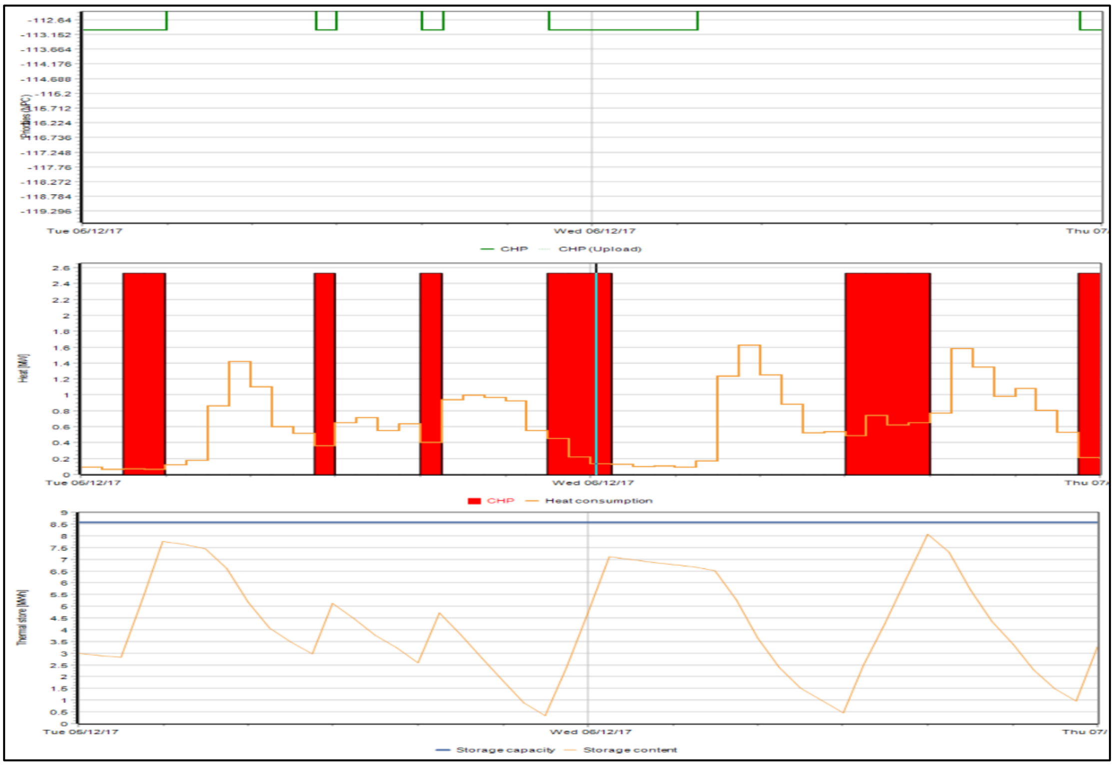


Figure 38: Scenario 3 iteration 7 priorities, heating and thermal store graphs

4.6.1. Scenario 3 with Heat Rejection

Both models for scenario 3 had the option of rejecting heat added. Table 14 shows the results, and the full results are shown in Appendix H.

Table 14: Scenario 3 with heat rejection summary.

CHP	Market	Heat Production	Heat Rejection	Heat Total	Electrical Production	Electrical Exported	Electrical imported	Electrical Total	Running Cost (£)	Fuel Imported (kg)
4600	Ahead	22162.8	19039.8	3123	16188.4	15297.3	0	891.1	£17,081	1,210,090
4600	Fixed	22162.8	19039.8	3123	16188.4	15297.3	0	891.1	£2,357,199	1,210,090

Again, the market had no effect on the system or outputs, just the income, because with the heat rejection, the system was able to run at full capacity 24 hours per day 365 days per year. Figure 39 shows the heat graph for the day ahead market for the whole year.

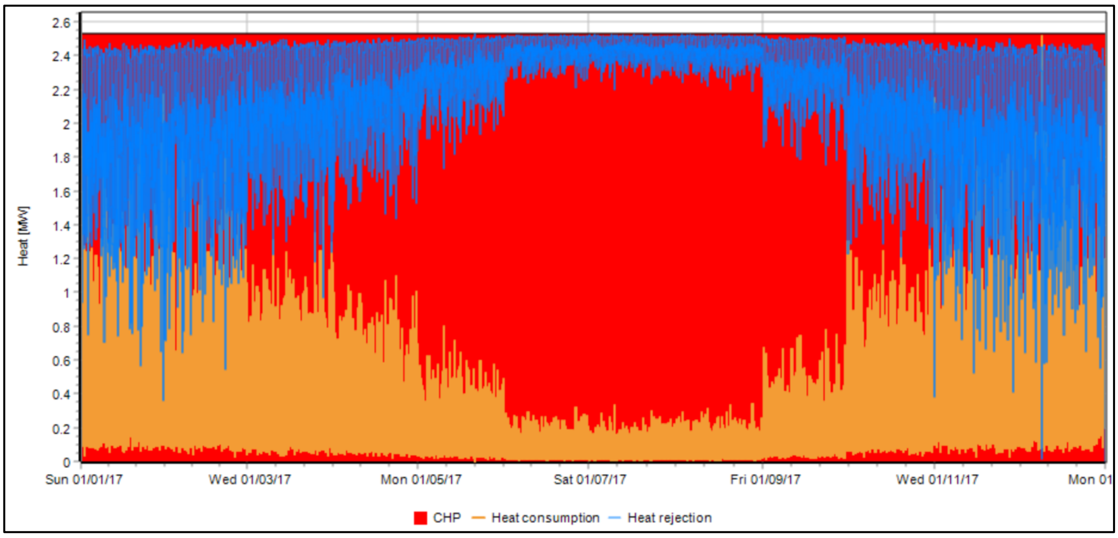


Figure 39: Scenario 3 with heat and rejection heat graphs over 2017

From figure 39, the heat rejection (blue) is the inverse of the consumption (orange) due to the constant production from the CHP system (red).

5. Discussion

In this section, the results, limitations and future work are discussed. The results from scenario 1's base case corresponded well with the relevant current energy consumption. This gave a good foundation to explore different options for the island and grid connected scenarios.

5.1. Scenario 2

The initial results from the modelling of scenario 2 provided a good electrical match, which was encouraging. This was due to the disparity between the two demands. In scenario 2, the system was electrically led; it could not have been thermally led without either a grid connection or an electrical dump. The system was modelled with grid connection in scenario 3, but the software package did not allow for an electrical dump. Initially, attempts were made to correct this disparity by changing the efficiency ratios of the fuel cell, for example, by imitating an electrical dump. In this case, the outputs of the fuel cell would be 825 kW of heat capacity and 215 kW capacity for electricity. To provide that much heat capacity from a PEM fuel cell, it would need to have a capacity of 1500 kW (825/55%), meaning the electrical output would actually be 600 kW (1500*40%). The model would be imitating an electrical dump of 385 kW (600-215), but there was no way to record such a dump, as there is with heat rejection. The results from these initial tests can be found in the attached MS excel spreadsheet.

In this scenario and all scenarios in island operation, there was an error in the model. In every iteration, the system shut down three times over the summer for a couple of days at a time, the first coming towards the end of June in each configuration. This was most likely a software error, as no discernible reason could be determined.

In scenario 2a, an electrical store was added to increase the manageability of the electrical supply, which would then improve the thermal supply. At partial load (scenario 2a (i)), this improved by 1%, but the electrical store also allowed the CHP system to only run at full capacity, which improved the overall match by 7%. There was limited literature discussing whether it is more efficient to run a CHP system at full or partial load. By running only at full load, the fuel cell was running for fewer hours over the course of a year, which could mean it would last longer. However, this would no doubt affect the efficiency of the fuel cell itself and could also lead to faster deterioration.

By adding an electric boiler into the system in scenario 2b, the electrical demand was increased, thus increasing the overall heat output as well as the heat output from the boiler itself. This levelled out the demands and provided very good matches in both partial and full load operation. However, this meant there would be many parts to the system, meaning more potential redundancies. It would also negatively affect the capital cost.

Scenario 2c addressed these issues by removing the battery while keeping the electric boiler. In this scenario, when the CHP system was on full load only (scenario 2c (i)), the electrical match worsened, which was to be expected. However, when the CHP system was allowed partial load, the match improved marginally, making it the highest match out of any configurations from the scenario 2 simulations. If this scenario was compared to the current situation on Stornoway, where 3000 tonnes of LPG is imported to supply heat to 6800 people (around 2840 ($6800/2.4= 2833 \approx 2840$) households), the configuration in table 15 would provide both electricity and heat, whereas the current situation only supplies heat.

Table 15: Island operation best match

CHP	Heat Capacity	Electrical Capacity	Electric Boiler	Heat Production (Total)	Electrical Total	Heat Match	Electrical Match	Combined	kg of Fuel Imported
1000	550	400	400	3123	784.9	100%	95.6%	95.59%	123,638

From Table 15, 123.65 tonnes of hydrogen needed to be imported to supply a community of 200 households. If the system could be scaled up to supply for 2840 households, the amount of hydrogen needed to be imported would be 1756 tonnes ((2840/200)*123.65) per year. However, the hydrogen supply chain is currently very expensive, and there would also be storage and transport issues, due to hydrogen's very low density.

5.2. Scenario 3

The major conclusion drawn from the scenario 3 results was that the disparity between the two prices for exporting electricity indicated that the fixed sell rate is too high or the day ahead market function is not functioning properly within the software. With the potential of a high voltage subsea cable being connected to the main land, it is not farfetched to imagine a CHP system functioning in the same manner as in scenario 3. By operating at full capacity, the operating income would be maximised. This can be determined from the results as that was the case for both the fixed and day ahead markets.

5.3. Limitations

The limitations of the project were mostly outlined by the assumptions which were defined before beginning the modelling process. For example, the assumption that the hydrogen production and supply chain was commercially developed could be quite far in the future; though technically deemed to be possible, it is unclear what the timeframe might be (Garland, Papageorgopoulos and Stanford, 2012). Additionally, fuel cells are not currently economically competitive with other CHP compatible technologies, but again, additional developments and technologies could attenuate this limitation (Garland, Papageorgopoulos and Stanford, 2012). The assumption that all 200 houses in the community are homogenous with no energy saving retrofits is vastly simplified. Only 5.4% of heat produced in Scotland is renewable, but the Scottish government has put in place numerous incentives to decrease demand, such as loft insulation incentives (Scottish Government, 2018). It has already been established that hydrogen can be produced sustainably (Dodds *et al.*, 2015). PEM fuel cells are not currently produced at a relevant scale, but thanks to their modularity, as the technology matures, large PEM fuel cells should be a possibility (Lacko *et al.*, 2014). Network losses were not considered, but again, due to the modularity of fuel cells, it could be considered that the modelled capacity was made up of 200 individual fuel cell micro CHP systems similar to those in the Enefarm project in Japan (Ren and Gao, 2010).

5.4. Future Work

In the future, this work could be expanded in many directions.

For example, tri-generation would help balance the heating demand by add a cooling demand for the summer that uses excess heat by the means of an absorption chiller.

The inclusion of electric vehicles (EVs) in the modelling scenarios would add another interesting dynamic. EVs would add an extra store and demand side management plan. They would be particularly useful in the community-based schemes. EVs do not exclude hydrogen fuel cell cars.

Instead of relying on imported, pure hydrogen, hydrogen could be made on site through renewable means. The issues with a hydrogen economy and importing hydrogen gas could be alleviated through onsite generation using renewables and an electrolyser.

Some parts of this study relied on existing gas networks for the transport of pure hydrogen. It should be studied whether and how the current gas network could be upgraded to accommodate pure hydrogen. An island like Lewis would be the perfect setting to test the theory of a hydrogen gas network for residential purposes.

Models could be iterated using other stationary hydrogen energy units, such as hydrogen gas turbines or hydrogen boilers, which could be used in combination with or in place of other components.

This study did not take into account capital costs for the installation of such schemes or a payback period; therefore, it would be imperative for future studies to investigate the economic viability of this technology as it matures.

6. Conclusions

In conclusion, a hydrogen fuel cell CHP system could deliver a full match for both heating and electrical demand of a 200 household community with the aid of an electric boiler. Further research and much more investment is necessary to determine the viability of this technology as many components need further development. Hydrogen has the potential to be a big player in the energy sector, helping to reduce emissions and to provide more energy security.

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8. Appendices

8.1. Appendix A

Tools	Criteria Met?	Community scale	Case study	Planning-level design	LZCT	Storage/ DSM	Time step	Electrical	Thermal	References used
AEOLIUS	No	National/regional	No	Yes	Yes	Yes	Minutes	Yes	No	(Connolly et al., 2010)
Balmorel	No	No	No	Yes	Yes	Yes	Hourly	Yes	Yes	(The Balmorel Open Source Project, 2017)
BCHP Screening Tool	No	No	No	Yes	No	Yes	Hourly	Yes	Yes	(Connolly et al., 2010; U.S Department of Energy, 2016)
Biomass decision support tool	Yes	Yes	-	Yes	Yes	Yes	Hourly	No	Yes	(The Carbon Trust, 2017)
CitySim	No	Yes	-	No	Yes	Yes	Hourly	Yes	Yes	(Allegrini et al., 2015; Robinson et al., 2009; Ruan, Cao, Feng, & Li, 2017)
COMPOSE	Yes	Yes	-	Yes	Yes	Yes	Hourly	Yes	Yes	(Connolly et al., 2010; van Beuzekom et al., 2015)
DECC 2050 Calculator	No	No	No	Yes	Yes	Yes	Yearly	Yes	Yes	(Department of Energy & Climate Change (DECC), 2017)
DER-CAM	Yes	Yes	-	Yes	Yes	Yes	5 mins	Yes	Yes	(Marnay et al., 2013; Mendes et al., 2011)
E4Cast	No	No	No	Yes	Yes	Yes	Yearly	Yes	Yes	(Connolly et al., 2010)
EMPS	No	No	No	Yes	Yes	Yes	Weekly	Yes	No	(Connolly et al., 2010; Vogstad, 2000)
EnergyPlan	Yes	National/regional	Yes	Yes	Yes	Yes	Hourly	Yes	Yes	(Lund et al., 2007; University of Aalborg, 2017a)
EnergyPRO	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	Yes	(EMD, 2017b; Kiss, 2015)
ENPEP-BALANCE	No	National/regional	No	Yes	Yes	No	Yearly	Yes	Yes	(Connolly et al., 2010; Mirakyan & De Guio, 2013; van Beuzekom et al., 2015)
ESP-r	No	Yes	-	No	Yes	Yes	Seconds	Yes	Yes	(Beausoleil-Morrison et al., 2012; University of Strathclyde, 2017)
ETEM/Markal-lite	No	Yes	-	Yes	Yes	Yes	Yearly	Yes	Yes	(Drouet & Thénié, 2009; Mirakyan & De Guio, 2013; ORDECSYS, 2017)
eTransport	Yes	Yes	-	Yes	Yes	Yes	Hourly	Yes	Yes	(Bakken & Skjelbred, 2007; Bakken, Skjelbred, & Wolfgang, 2007)
GTMax	No	No	No	Yes	Yes	Yes	Hourly	Yes	Yes	(Connolly et al., 2010; U.S Department of Energy Office of Science & Argonne National Laboratory, 2017)
H2RES	Yes	Yes	-	Yes	Yes	Yes	Hourly	Yes	Yes	(Duić & da Graca Carvalho, 2004; Lund et al., 2007; Neves, Silva, & Connors, 2014)
HOMER	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	Yes	(Chmiel & Bhattacharyya, 2015; HOMER Energy, 2017c; Sinha & Chandel, 2015)
Hybrid2	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	No	(Baring-gould, 1996; Mills & Al-Hallaj, 2004)
HYDROGEMS	No	Yes	-	No	Yes	Yes	Minutes	Yes	No	(Connolly et al., 2010; Ulleberg & Moerkved, 2008)
IDA-ICE	No	No	No	No	Yes	Yes	Minutes	No	Yes	(Allegrini et al., 2015)
iHOGA	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	No	(Phrakonkham, Le Chenadec, Diallo, & Marchand, 2009; Sinha & Chandel, 2014; University of Zaragoza, 2017)
IKARUS	No	No	No	Yes	Yes	Yes	5 years	Yes	Yes	(Connolly et al., 2010; Mirakyan & De Guio, 2013)
INFORSE	No	No	No	Yes	Yes	Yes	Yearly	Yes	Yes	(Connolly et al., 2010)
Invert	No	National/regional	Yes	Yes	Yes	No	Yearly	Yes	Yes	(Connolly et al., 2010; Ragwitz et al., 2005)
KULeuven OpenIDEAS framework	No	Yes	-	No	Yes	Yes	Minutes	Yes	Yes	(R. Baetens et al., 2012; Ruben Baetens et al., 2015; Connolly et al., 2010)
LEAP	No	No	No	Yes	Yes	Yes	Yearly	Yes	Yes	(Mirakyan & De Guio, 2013; Swan & Ugursal, 2009; Wirth et al., 2015)
MARKAL/TIMES	Yes	Yes	-	Yes	Yes	Yes	Hourly	Yes	Yes	(Comodi, Cioccolanti, & Gargiulo, 2012; Faraji-Zonooz, Nopiah, Yusof, & Sopian, 2009)
MERIT	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	Yes	(Born, 2001)
Mesap/PlaNet	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	Yes	(Connolly et al., 2010; Mirakyan & De Guio, 2013; Prasad, Bansal, & Raturi, 2014)
MESSAGE	No	No	No	Yes	Yes	Yes	5 Years	Yes	Yes	(Bakken & Skjelbred, 2007; Cai, Huang, Lin, Nie, & Tan, 2009; Connolly et al., 2010; Mirakyan & De Guio, 2013)
MiniCAM	No	National/regional	No	Yes	Yes	Yes	15 years	Yes	Yes	(Connolly et al., 2010)
MODEST	Yes	Yes	Yes	Yes	Yes	Yes	Hourly	Yes	Yes	(Connolly et al., 2010; Henning, 1997, 1998)
NEMS	No	No	No	Yes	No	Yes	Yearly	Yes	Yes	(Connolly et al., 2010)
Neplan	No	Yes	-	No	Yes	Yes	Minutes	Yes	Yes	(NEPLAN, 2017)
NetSim	No	Yes	-	No	Yes	No	Hourly	No	Yes	(Carpaneto, Lazzeroni, & Repetto, 2015; Olsthoorn, Haghighat, & Mirzaei, 2016)
ORCED	No	No	No	Yes	Yes	Yes	Hourly	Yes	No	(Hadley & Hirst, 2008; Prasad et al., 2014)
PERSEUS	No	No	No	Yes	Yes	Yes	36-72/year	Yes	Yes	(Connolly et al., 2010)
Polysun	No	No	No	Yes	Yes	Yes	15 minutes	Yes	Yes	(Bava & Furbo, 2017; Vela Solaris AG, 2017)
PRIMES	No	No	No	Yes	Yes	Yes	Yearly	Yes	Yes	(Blok, Jager, & Hendriks, 2001; Olsthoorn et al., 2016)
ProdRisk	No	Yes	-	Yes	Yes	Yes	Hourly	Yes	No	(Connolly et al., 2010; SINTEF, 2017)
RAMSES	No	No	No	Yes	Yes	Yes	Hourly	Yes	Yes	(Connolly et al., 2010; Lambert et al., 2006)
RETScreen	No	Yes	-	Yes	Yes	Yes	Monthly	Yes	Yes	(Choi & Yun, 2015; Connolly et al., 2010; Mancarella, 2014; Mirakyan & De Guio, 2013)
SimREN	Yes	Yes	-	Yes	Yes	Yes	Minutes	Yes	Yes	(Connolly et al., 2010; Herbergs, Lehmann, & Peter, 2017; Wirth et al., 2015)
STREAM	No	National/regional	No	Yes	Yes	Yes	Hourly	Yes	Yes	(Technical University of Denmark, 2017)
Termis	No	Yes	-	No	Yes	No	Minutes	No	Yes	(Ancona, Bianchi, Branchini, & Melino, 2014; Schneider Electric Software LLC, 2017)
TRNSYS	No	Yes	-	No	Yes	Yes	Seconds	Yes	Yes	(Allegrini et al., 2015; Connolly et al., 2010; Kalogirou, 2001; Sinha & Chandel, 2014; TRNSYS, 2017; van Beuzekom et al., 2015)
UniSyD3.0	No	No	No	Yes	Yes	Yes	Bi-weekly	Yes	Yes	(Connolly et al., 2010)
WASP	No	Yes	-	Yes	Yes	Yes	12/year	Yes	Yes	(Connolly et al., 2010)
WILMAR Planning Tool	No	No	No	Yes	Yes	Yes	Hourly	Yes	Yes	(Connolly et al., 2010)

Appendix A: Software selection table (Lyden et al., 2018)

8.2. Appendix B

	January	February	March	April	May	June	July	August	September	October	November	December
00:00	0.75	0.7125	0.5175	0.4125	0.2625	0.11625	0.105	0.1125	0.2625	0.5175	0.72375	0.765
01:00	0.5	0.475	0.345	0.275	0.175	0.0775	0.07	0.075	0.175	0.345	0.4825	0.51
02:00	0.5	0.475	0.345	0.275	0.175	0.0775	0.07	0.075	0.175	0.345	0.4825	0.51
03:00	0.5	0.475	0.345	0.275	0.175	0.0775	0.07	0.075	0.175	0.345	0.4825	0.51
04:00	0.5	0.475	0.345	0.275	0.175	0.0775	0.07	0.075	0.175	0.345	0.4825	0.51
05:00	1	0.95	0.69	0.55	0.35	0.155	0.14	0.15	0.35	0.69	0.965	1.02
06:00	5	4.75	3.45	2.75	1.75	0.775	0.7	0.75	1.75	3.45	4.825	5.1
07:00	7.5	7.125	5.175	4.125	2.625	1.1625	1.05	1.125	2.625	5.175	7.2375	7.65
08:00	5	4.75	3.45	2.75	1.75	0.775	0.7	0.75	1.75	3.45	4.825	5.1
09:00	3	2.85	2.07	1.65	1.05	0.465	0.42	0.45	1.05	2.07	2.895	3.06
10:00	2.75	2.6125	1.8975	1.5125	0.9625	0.42625	0.385	0.4125	0.9625	1.8975	2.65375	2.805
11:00	3	2.85	2.07	1.65	1.05	0.465	0.42	0.45	1.05	2.07	2.895	3.06
12:00	3.25	3.0875	2.2425	1.7875	1.1375	0.50375	0.455	0.4875	1.1375	2.2425	3.13625	3.315
13:00	3.5	3.325	2.415	1.925	1.225	0.5425	0.49	0.525	1.225	2.415	3.3775	3.57
14:00	3	2.85	2.07	1.65	1.05	0.465	0.42	0.45	1.05	2.07	2.895	3.06
15:00	3	2.85	2.07	1.65	1.05	0.465	0.42	0.45	1.05	2.07	2.895	3.06
16:00	4	3.8	2.76	2.2	1.4	0.62	0.56	0.6	1.4	2.76	3.86	4.08
17:00	5.75	5.4625	3.9675	3.1625	2.0125	0.89125	0.805	0.8625	2.0125	3.9675	5.54875	5.865
18:00	5.5	5.225	3.795	3.025	1.925	0.8525	0.77	0.825	1.925	3.795	5.3075	5.61
19:00	5	4.75	3.45	2.75	1.75	0.775	0.7	0.75	1.75	3.45	4.825	5.1
20:00	4.5	4.275	3.105	2.475	1.575	0.6975	0.63	0.675	1.575	3.105	4.3425	4.59
21:00	3	2.85	2.07	1.65	1.05	0.465	0.42	0.45	1.05	2.07	2.895	3.06
22:00	2	1.9	1.38	1.1	0.7	0.31	0.28	0.3	0.7	1.38	1.93	2.04
23:00	1	0.95	0.69	0.55	0.35	0.155	0.14	0.15	0.35	0.69	0.965	1.02
Total	**73.5**	**69.825**	**50.715**	**40.425**	**25.725**	**11.3925**	**10.29**	**11.025**	**25.725**	**50.715**	**70.9275**	**74.97**

Appendix B: Daily heat demand profiles for each month

8.3. Appendix C

Heat demands:

Heat demand 1	3,123.0 MWh	
Max heat demand	2.5 MW	

Heat productions:

Boiler	3,123.0 MWh/year	100.0%

Electricity demands (not including electricity consumed by energy units):

Electricity Demamd	821.1 MWh
Max electricity demand	0.5 MW

Electricity exchange:
Fixed tariff market:

	Night [MWh/year]	Total [MWh/year]
Exported electricity, Fixed tariff market	0.0	0.0
Imported electricity, Fixed tariff market	821.1	821.1

Hours of operation:
Fixed tariff market:

	Night [h/Year]	Total [h/Year]	Of annual hours
Out of total in period	8,760.0	8,760.0	

Turn ons:

Boiler	0

Fuels:

By fuel

	Fuel consumption
Hydrogen	0.0 kg
Natural Gas	264,881.8 kg

By energy unit

Boiler	3,470.0 MWh	=264,881.8 kg
Total	3,470.0 MWh	

Appendix C: Annual energy conversions results from EnergyPRO

8.4. Appendix D

Calculated Period: 01/2017 - 12/2017 (All amounts in £)	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Revenues													
Sale of electricity													
Day ahead	0	0	0	0	0	0	0	0	0	0	0	0	0
Fixed	0	0	0	0	0	0	0	0	0	0	0	0	0
Sale of electricity Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total Revenues	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Operating Expenditures													
Imported fuel													
Natural Gas	145,685	21,137	17,866	15,072	11,423	7,342	3,234	2,972	3,329	7,332	14,461	19,736	21,781
Hydrogen	0	0	0	0	0	0	0	0	0	0	0	0	0
Imported fuel Total	**145,685**	**21,137**	**17,866**	**15,072**	**11,423**	**7,342**	**3,234**	**2,972**	**3,329**	**7,332**	**14,461**	**19,736**	**21,781**
Imported electricity													
Fixed	133,837	13,513	11,737	12,834	11,125	10,018	9,219	9,039	9,776	10,067	11,173	12,021	13,315
Day ahead	0	0	0	0	0	0	0	0	0	0	0	0	0
Imported electricity Total	**133,837**	**13,513**	**11,737**	**12,834**	**11,125**	**10,018**	**9,219**	**9,039**	**9,776**	**10,067**	**11,173**	**12,021**	**13,315**
Total Operating Expenditures	**279,522**	**34,650**	**29,604**	**27,906**	**22,548**	**17,360**	**12,453**	**12,011**	**13,105**	**17,399**	**25,634**	**31,757**	**35,096**
Net Cash from Operation	**-279,522**	**-34,650**	**-29,604**	**-27,906**	**-22,548**	**-17,360**	**-12,453**	**-12,011**	**-13,105**	**-17,399**	**-25,634**	**-31,757**	**-35,096**
Cash Account	**-279,522**	**-34,650**	**-64,254**	**-92,160**	**-114,707**	**-132,067**	**-144,520**	**-156,531**	**-169,636**	**-187,035**	**-212,669**	**-244,427**	**-279,522**

Appendix D: Monthly operation income from EnergyPRO

8.5. Appendix E

	CHP	Heat Capacity	Electrical Capacity	Battery	Hot Water Storage	Partial Load (Y/N)	Priority (High/Low)	Operation Mode	Heat Production (CHP)	Electrical Production	Heat Match	Electrical Match	Combined	Hours of Operation	kg of Fuel Imported	Running Cost
Partial Load Scenario 2a (i)	1500	825	600	4	8.58	Y	High	NPC	1102.2	801.6	35%	98%	34%	8597	60179	£33,098
	1250	687.5	500	4	8.58	Y	High	NPC	1102.2	801.6	35%	98%	34%	8597	60179	£33,098
	1000	550	400	4	8.58	Y	High	NPC	1102.3	801.7	35%	98%	34%	8597	60186	£33,102
	750	412.5	300	4	8.58	Y	High	NPC	1104	802.9	35%	98%	35%	8597	60278	£33,153
	500	**275**	**200**	**4**	**8.58**	**Y**	**High**	**NPC**	**1115.8**	**811.5**	**36%**	**99%**	**35%**	**8603**	**60923**	**£33,508**
	250	137.5	100	4	8.58	Y	High	NPC	1084.4	788.6	35%	96%	33%	8748	59207	£32,564
Non Partial load Scenario 2a (ii)	1500	825	600	4	8.58	N	High	NPC	0	0	0%	0%	0%	0	0	£0
	1250	687.5	500	4	8.58	N	High	NPC	26.9	19.6	1%	2%	0%	40	1471	£809
	1000	550	400	4	8.58	N	High	NPC	252.6	183.7	8%	22%	2%	475	3790	£2,085
	750	412.5	300	4	8.58	N	High	NPC	950.8	691.5	30%	84%	26%	2394	51914	£28,553
	500	**275**	**200**	**4**	**8.58**	**N**	**High**	**NPC**	**1215.6**	**884.1**	**39%**	**108%**	**42%**	**4597**	**66374**	**£36,506**
	250	137.5	100	4	8.58	N	High	NPC	1088.3	791.5	35%	96%	34%	7983	59420	£32,681

Appendix E: Full results for scenario 2a

8.6. Appendix F

	CHP	Heat Capacity	Electrical Capacity	Electric Boiler	Battery	Hot Water Storage	Partial Load (Y/N)	Priority (High/Low)	Operation Mode	Heat Production (CHP)	Heat Production (Boiler)	Heat Production (Total)	Electrical Production	Electrical consumed	Electrical Total	Heat Match	Electrical Match	Combined	Hours of Operation	kg of Fuel Imported	Running Cost
CHP No Battery Partial load Scenario 2b (i)	1500	825	600	100	4	8.58	N/Y	High/Low	NPC	672.2	119.3	791.5	407.4	120.5	286.9	25%	35%	9%	888/1235	36,705	£20,188
	1500	825	600	200	4	8.58	N/Y	High/Low	NPC	1673.5	430.2	2103.7	1014.2	434.5	579.7	67%	71%	48%	2159/2270	91,373	£50,255
	1500	825	600	300	4	8.58	N/Y	High/Low	NPC	2350.4	705.7	3056.1	1424.5	712.8	711.7	98%	87%	85%	3014/2588	128,333	£70,583
	1500	825	600	400	4	8.58	N/Y	High/Low	NPC	2205.4	917.1	3122.5	1336.6	926.3	410.3	100%	50%	50%	2701/2655	120,413	£66,227
	1250	687.5	500	100	4	8.58	N/Y	High/Low	NPC	563	120.1	683.1	409.4	121.3	288.1	22%	35%	8%	893/1244	30,737	£16,905
	1250	687.5	500	200	4	8.58	N/Y	High/Low	NPC	1560	490.4	2050.4	1134.5	495.3	639.2	66%	78%	51%	2411/2586	85,176	£46,847
	1250	**687.5**	**500**	**300**	**4**	**8.58**	**N/Y**	**High/Low**	**NPC**	**2236.1**	**820.8**	**3056.9**	**1626.2**	**829.2**	**797**	**98%**	**97%**	**95%**	**3398/2985**	**122,087**	**£67,148**
	1250	687.5	500	400	4	8.58	N/Y	High/Low	NPC	2093.8	1028.8	3122.6	1522.8	1039.2	483.6	100%	59%	59%	3215/2850	114,322	£62,877
	1000	550	400	100	4	8.58	N/Y	High/Low	NPC	1432.5	316.7	1749.2	1041.8	319.9	721.9	56%	88%	49%	2780/3283	78,213	£43,017
	1000	550	400	200	4	8.58	N/Y	High/Low	NPC	2071	650.6	2721.6	1506.2	657.2	849	87%	103%	90%	3897/3445	113,076	£62,192
	1000	550	400	250	4	8.58	N/Y	High/Low	NPC	2192.2	781	2973.2	1594	788.9	805.1	95%	98%	93%	4121/3325	119,691	£65,830
	1000	550	400	300	4	8.58	N/Y	High/Low	NPC	2170.1	952.6	3122.7	1578.2	962.2	616	100%	75%	75%	4108/3465	118,486	£65,167
	750	412.5	300	100	4	8.58	N/Y	High/Low	NPC	1725.2	371.8	2097	1255	375.6	879.4	67%	107%	72%	4303/3909	94,220	£51,821
	750	412.5	300	200	4	8.58	N/Y	High/Low	NPC	2108.6	795	2903.6	1333.9	803	530.9	93%	65%	60%	5280/4256	115,157	£63,336
	750	412.5	300	300	4	8.58	N/Y	High/Low	NPC	2124.6	961.9	3086.5	1545.5	971.6	573.9	99%	70%	69%	5157/5059	116,031	£63,817
	500	275	200	100	4	8.58	N/Y	High/Low	NPC	1709.3	435.3	2144.6	1243.1	439.7	803.4	69%	98%	67%	6319/4641	93,327	£51,330
	500	275	200	200	4	8.58	N/Y	High/Low	NPC	1768.8	636.4	2405.2	1286.4	639.6	646.8	77%	79%	61%	6432/5950	96,576	£53,117
CHP Battery Partial load Scenario 2b (ii)	1500	825	600	100	4	8.58	Y/Y	High/Low	NPC	1866.7	566.4	2433.1	1357.6	572.1	785.5	78%	95.7%	75%	8561/5919	101,921	£56,057
	1500	825	600	150	4	8.58	Y/Y	High/Low	NPC	2109.8	741.9	2851.7	1534.4	749.5	784.9	91%	95.6%	87%	8560/5496	115,193	£63,356
	1500	825	600	200	4	9.58	Y/Y	High/Low	NPC	2266.3	854.9	3121.2	1648.3	863.5	784.8	100%	95.6%	96%	8560/5146	123,733	£68,053
	1250	687.5	500	100	4	14.58	Y/Y	High/Low	NPC	1866.6	566.6	2433.2	1357.5	572.4	785.1	78%	95.6%	74%	8559/5925	101,917	£56,054
	1250	687.5	500	150	4	15.58	Y/Y	High/Low	NPC	2509.7	742.2	2851.9	1534.4	749.7	784.7	91%	95.6%	87%	8559/5502	115,191	£63,355
	1250	687.5	500	200	4	16.58	Y/Y	High/Low	NPC	2266.2	855	3121.2	1648.1	863.7	784.4	100%	95.5%	95%	8558/5178	123,733	£68,053
	1000	550	400	100	4	20.58	Y/Y	High/Low	NPC	1867.8	566.9	2434.7	1358.4	572.6	785.8	78%	95.7%	75%	8559/5947	101,979	£56,088
	1000	**550**	**400**	**200**	4	21.58	Y/Y	High/Low	NPC	**2266.6**	**854.7**	**3121.3**	**1648.4**	**863.4**	785	**100%**	**95.6%**	**96%**	**8557/5224**	**123,752**	£68,064
	750	412.5	300	100	4	8.58	Y/Y	High/Low	NPC	1876.4	567.2	2443.6	1364.6	572.9	791.7	78%	96.4%	75%	8558/5962	102,450	£56,348
	750	**412.5**	**300**	**200**	**4**	**8.58**	**Y/Y**	**High/Low**	**NPC**	**2248.2**	**835.2**	**3083.4**	**1635**	**843.7**	**791.3**	**99%**	**96.4%**	**95%**	8557/5264	122,750	£67,513
	750	412.5	300	300	4	8.58	Y/Y	High/Low	NPC	2244.9	844.4	3089.3	1632.7	853	779.7	99%	95.0%	94%	8556/5124	122,572	£67,415
	500	275	200	100	4	8.58	Y/Y	High/Low	NPC	1831.3	540.6	2371.9	1331.8	546.1	546.1	76%	66.5%	51%	8560/5845	99,987	£54,993
	500	275	200	200	4	8.58	Y/Y	High/Low	NPC	1831.1	572.5	2403.6	1331.7	578.3	753.4	77%	91.8%	71%	8556/5622	99,979	£54,988

Appendix F: Full results for scenario 2b

8.7. Appendix G

	CHP	Heat Capacity	Electrical Capacity	Electric Boiler	Hot Water Storage	Partial Load (Y/N)	Priority (High/Low)	Operation Mode	Heat Production (CHP)	Heat Production (Boiler)	Heat Production (Total)	Electrical Production	Electrical consumed	Electrical Total	Heat Match	Electrical Match	Combined	Hours of Operation	kg of Fuel Imported	Running Cost
CHP Non Partial load Boiler Partial load Scenario 2b (i)	1500	825	600	400	8.58	Y/Y	High/Low	NPC	871.2	413.3	1284.6	633.6	417.5	216.1	41%	26.3%	11%	1116/1116	47,565	£26,161
	1500	825	600	500	8.58	Y/Y	High/Low	NPC	2032.7	1089.9	3122.6	1478.4	1100.9	377.5	100%	46.0%	46%	2468/2468	110,988	£61,044
	1500	825	600	600	8.58	Y/Y	High/Low	NPC	2003.4	1118.6	3122	1457.4	1129.9	327.5	100%	39.9%	40%	2429/2429	109,414	£60,178
	1250	687.5	500	300	8.58	Y/Y	High/Low	NPC	725.7	307	1032.7	527.8	310.1	217.7	33%	26.5%	9%	1128/1128	39,623	£21,793
	1250	687.5	500	400	8.58	Y/Y	High/Low	NPC	2075.7	1046.7	3122.4	1509.6	1057.3	452.3	100%	55.1%	55%	3089/3089	113,335	£62,334
	1250	687.5	500	500	8.58	Y/Y	High/Low	NPC	2039.8	1083	3122.8	1483.5	1093.9	389.6	100%	47.4%	47%	2967/2967	111,374	£61,256
	1000	550	400	200	8.58	Y/Y	High/Low	NPC	572.7	196.6	769.3	416.5	198.6	217.9	25%	26.5%	7%	1133/1126	31,271	£17,199
	1000	550	400	300	8.58	Y/Y	High/Low	NPC	2072.9	972	3044.9	1507.6	981.9	525.7	97%	64.0%	62%	3838/3831	113,182	£62,250
	1000	550	400	400	8.58	Y/Y	High/Low	NPC	2088	1034.7	3122.7	1518.6	1045.2	473.4	100%	57.7%	58%	3797/3790		£0
	750	412.5	300	100	8.58	Y/Y	High/Low	NPC	416.9	87.7	504.6	303.2	88.5	214.7	16%	26.1%	4%	1133/1041	22,765	£12,521
	750	412.5	300	200	9.58	Y/Y	High/Low	NPC	1785.7	711.3	2497	1298.7	718.5	580.2	80%	70.7%	56%	4435/4343	97,500	£53,625
	750	**412.5**	**300**	**300**	**10.58**	**Y/Y**	**High/Low**	**NPC**	**2124.7**	**961**	**3085.7**	**1545.2**	**970.7**	**574.5**	**99%**	**70.0%**	**69%**	**5151/5061**	**116,006**	**£63,803**
	500	275	200	100	11.58	Y/Y	High/Low	NPC	1303.2	343	1646.2	947.8	346.5	601.3	53%	73.2%	39%	4900/4403	71,155	£39,135
	500	275	200	200	12.58	Y/Y	High/Low	NPC	1769.6	633.2	2402.8	1287	639.6	647.4	77%	78.8%	61%	6435/5956	96,622	£53,142
CHP Partial load Boiler Partial load Scenario 2b (ii)	1500	825	600	100	8.58	Y/Y	High/Low	NPC	1866.6	566.3	2432.9	1357.6	572.1	785.5	78%	95.7%	75%	8561/5919	101,919	£56,055
	1500	825	600	150	8.58	Y/Y	High/Low	NPC	2109.5	741.8	2851.3	1534.2	749.3	784.9	91%	95.6%	87%	8560/5496	115,178	£63,348
	1500	825	600	200	8.58	Y/Y	High/Low	NPC	2266.1	854.7	3120.8	1648.1	863.4	784.7	100%	95.6%	95%	8560/5151	123,727	£68,050
	1500	825	600	300	8.58	Y/Y	High/Low	NPC	2266.4	856.6	3123	1648.3	865.2	783.1	100%	95.4%	95%	8552/4476	123,743	£68,059
	1500	825	600	400	8.58	Y/Y	High/Low	NPC	2266.1	856.9	3123	1648	865.6	782.4	100%	95.3%	95%	8549/4162	123,728	£68,050
	1500	825	600	500	8.58	Y/Y	High/Low	NPC	2266.1	856.9	3123	1648.1	865.4	782.7	100%	95.3%	95%	8549/4163	123,729	£68,051
	1500	825	600	600	8.58	Y/Y	High/Low	NPC	2266.1	856.9	3123	1648.1	865.4	782.7	100%	95.3%	95%	8549/4164	123,730	£68,052
	1250	687.5	500	100	8.58	Y/Y	High/Low	NPC	1866	566.3	2432.3	1357.1	572.1	785	78%	95.6%	74%	8559/5925	101,885	£56,037
	1250	687.5	500	150	8.58	Y/Y	High/Low	NPC	2018.2	741.4	2759.6	1533.3	748.9	784.4	88%	95.5%	84%	8559/5502	115,109	£63,310
	1250	687.5	500	200	8.58	Y/Y	High/Low	NPC	2265.3	854.5	3119.8	1647.5	863.2	784.3	100%	95.5%	95%	8558/5144	123,683	£68,026
	1250	687.5	500	300	8.58	Y/Y	High/Low	NPC	2266.1	856.9	3123	1648.1	865.5	782.6	100%	95.3%	95%	8550/4543	123,728	£68,050
	1250	687.5	500	400	8.58	Y/Y	High/Low	NPC	2266	857	3123	1648	865.6	782.4	100%	95.3%	95%	8548/4224	123,722	£68,047
	1250	687.5	500	500	8.58	Y/Y	High/Low	NPC	2266	857	3123	1648	865.7	782.3	100%	95.3%	95%	8549/4203	123,722	£68,047
	1000	550	400	100	8.58	Y/Y	High/Low	NPC	1861.8	564	2425.8	1354	569.7	784.3	78%	95.5%	74%	8559/5930	101,654	£55,910
	1000	550	400	200	8.58	Y/Y	High/Low	NPC	2259.8	851.4	3111.2	1643.5	860	783.5	100%	95.4%	95%	8557/5230	123,387	£67,863
	1000	550	400	300	8.58	Y/Y	High/Low	NPC	2264.1	858.9	3123	1646.6	864.6	782	100%	95.2%	95%	8550/4619	123,680	£68,024
	1000	**550**	**400**	**400**	**8.58**	**Y/Y**	**High/Low**	**NPC**	**2264.5**	**858.5**	**3123**	**1649.9**	**865**	**784.9**	**100%**	**95.6%**	**96%**	8548/4540	123,638	£68,001
	750	412.5	300	100	8.58	Y/Y	High/Low	NPC	1836.6	549.4	2386	1335.7	555	780.7	76%	95.1%	73%	8558/5890	100,275	£55,151
	750	412.5	300	200	8.58	Y/Y	High/Low	NPC	2191.6	805.8	2997.4	1593.9	814	779.9	96%	95.0%	91%	8557/5265	199,663	£109,815
	750	412.5	300	300	8.58	Y/Y	High/Low	NPC	2244.1	844	3088.1	1632.1	852.6	779.5	99%	94.9%	94%	8556/5124	122,528	£67,390
	500	275	200	100	8.58	Y/Y	High/Low	NPC	1694.5	473.4	2167.9	1232.3	478.2	754.1	69%	91.8%	64%	8560/5778	92,518	£50,885
	500	275	200	200	8.58	Y/Y	High/Low	NPC	1830.9	572.4	2403.3	1331.6	578.2	753.4	77%	91.8%	71%	8556/5620	99,967	£54,982

Appendix G: Full results for scenario 2c

8.8. Appendix H

Iteration Number	CHP	Heat Capacity	Electrical Capacity	Market	Hot Water Storage	Partial load (Y/N)	Heat Production	Heat Rejection	Heat Total	Electrical Production	Electrical Exported	Electrical imported	Electrical Total	Heat Match	Electrical Match	Combined	Running Cost (£)	CO2 Emissions (tonne)	Hours of Operation	Fuel Imported (kg)
1	4600	2530	1840	Ahead	N/a	N	0	N/a	0	0	0	821.1	821.1	0%	100%	0%	-£39,606	176	0	-
2	4600	2530	1840	Ahead	N/a	Y	3123	N/a	3123	2271	1497.4	47.2	820.8	100%	100%	100%	-£19,214	10	8760	170,514
3	4600	2530	1840	Ahead	8.58	N	3038.5	N/a	3038.5	2209.8	2024.5	635.7	821	97%	100%	97%	£10,692	136	1201	165,904
4	4600	2530	1840	Ahead	8.58	Y	3123	N/a	3123	2271.2	2045.1	594.9	821	100%	100%	100%	£12,547	127	8760	170,514
5	4600	2530	1840	Fixed	N/a	N	0	N/a	0	0	0	821.1	821.1	0%	100%	0%	-£133,837	176	0	-
6	4600	2530	1840	Fixed	N/a	Y	3123	N/a	3123	2271.2	1497.4	47.2	821	100%	100%	100%	£194,402	10	8760	170,514
7	4600	2530	1840	Fixed	8.58	N	3056.2	N/a	3056.2	2222.7	2152.1	750.5	821.1	98%	100%	98%	£211,149	161	1208	166,871
8	4600	2530	1840	Fixed	8.58	Y	3123	N/a	3123	2271.2	2152.3	702.2	821.1	100%	100%	100%	£217,063	150	8760	170,514
	4600	2530	1840	Ahead	N/a	N/a	22162.8	19039.8	3123	16188.4	15297.3	0	891.1	100%	109%	109%	£17,081	0	8760	#######
	4600	2530	1840	Fixed	N/a	N/a	22162.8	19039.8	3123	16188.4	15297.3	0	891.1	100%	109%	109%	£2,357,199	0	8760	#######

Appendix H: Full results for scenario 3