Department of Mechanical and Aerospace Engineering

An Analysis of Electricity and Hydrogen in Domestic Heating

Author: Innis Brawn

Supervisor: Dr Nick Kelly

A thesis submitted in partial fulfilment for the requirement of degree in

Master of Science in *Renewable Energy Systems and the Environment*

2022

Copyright Declaration

Signed: Innis Brawn   Date: 12-Aug-22

Abstract

This thesis looks at three separate routes of supplying heating to homes based around the premise of the H100 project (Leven, Fife, Scotland) which aims to generate hydrogen via wind power then supply that hydrogen directly to homes as natural gas is currently used, but applied to a theoretical site in Leuchars (Fife, Scotland). Each of the three routes starts with green energy generated from renewable wind power at the Leuchars site. The specifications for the wind turbine have been taken from that of the H100 project in Leven to allow for comparison to their results and calculations. The electricity is then used in one of three routes either 1) Directly in heat pumps, 2) Supplied to an electrolyser to produce hydrogen to be used as a gas directly in boilers to heat homes, or, 3) Supplied to an electrolyser to produce hydrogen which then feeds a Combined Cycle Gas Turbine (CCGT) to produce electricity which is supplied to heat pumps. These systems have then been analysed based on their end-to-end efficiency, ability to fill the capacity of the system requirements, total system cost and cost per kWh for heating.

Acknowledgements

This thesis is the result of the author's original research.

Table of Contents

1.0 Introduction 1
2.0 H100 Project Background 3
2.1.1 Turbine Methodology 5
2.1.2 Route Methodology 5
2.1.3 Electrolyser Methodology 6
2.1.4 Storage Methodology 6
2.1.5 Domestic Heating – End Use Methodology 8
2.1.6 System Cost Methodology 9
2.1.7 Cost per kWh Methodology 9
3.0 All Routes – Electrical Generation 11
3.1 H100 Data 11
3.2 Leuchars Site 12
3.3 Emissions 14
4.0 Route 1 – Electric End-to-End 15
4.1 Route 1 – Electrical Storage 15
4.1.1 Route 1 – Battery Storage 15
4.1.2 Route 1 – Alternative Storage 16
4.2 Route 1 – Electrical Infrastructure 17
4.3 Route 1 – Heat Pump Use 17
4.4 Route 1 – System Findings 19
4.5 Route 1 – System Costs 19
4.6 Route 1 – Fuel Costs 21
4.7 Route 1 – Miscellaneous Factors 22
5.0 Route 2 – Hydrogen Replacing Natural Gas 23
5.1 H100 Project Concept 23
5.2 Route 2 – Electrolysis – Hydrogen Production 24
5.3 Route 2 – Compression 26
5.4 Route 2 – Storage 26
5.4.1 Route 2 – Alternative Storage 27
5.5 Route 2 – Supply Network 28
5.5.1 Route 2 – The UK Network 30
5.6 Route 2 – Hydrogen Boilers 30
5.7 Route 2 – System Findings 31

5.8 Route 2 – System Cost 33
5.9 Route 2 – Fuel Cost 34
5.10 Route 2 – Miscellaneous Factors 34
6.0 Route 3 – Hydrogen in a CCGT 36
6.1 Route 3 – CCGT Layout 37
6.2 Route 3 – CCGT Equations 37
6.2.1 Route 3 – Gas Equations 37
6.2.2 Route 3 – Steam Properties 38
6.2.3 Route 3 – Overall System Equations 38
6.3 Route 3 – Emissions Control 40
6.4 Route 3 – Heat Pumps – End Use 42
6.5 Route 3 – System Findings 42
6.6 Route 3 – System Cost 43
6.7 Route 3 – Fuel Cost 44
6.8 Route 3 – Miscellaneous Factors 45
7.0 Results 46
8.0 Further Issues 48
8.1 Safety 48
8.1.1 Regulation 49
8.2 Training 50
8.3 Insulation of Homes 50
8.4 UK Wide Energy Use 50
8.5 Future Developments 51
9.0 Literature Review 52
9.1.1 Route 1 53
9.1.2 Route 2 55
9.1.3 Route 3 56
10.0 Conclusions 58
11.0 References 59
12.0 Appendices 68
12.1 Weather Data 68
12.1.1 2020 68
12.1.2 2019 70
12.1.3 2018 72
12.1.4 2017 74
12.2 Gas Calculations 76

12.2.1 Compressor 76
12.2.2 Combustion Chamber 77
12.2.3 Turbine... 77
12.2.4 HRSG... 77
12.2.5 Total Gas System 77
12.3 Steam Calculations... 78
12.3.1 HP-Steam Turbine 78
12.3.2 IP-Steam Turbine.. 79
12.3.3 LP-Steam Turbine.. 80

List of Figures

Figure 1 - Route 1 1
Figure 2 - Route 2 1
Figure 3 - Route 3 1
Figure 4 - NPV Summary Analysis - Network Innovation Competition H100 fife, SGN, 2020. 4
Figure 5 - H100 Project Partners 4
Figure 6 - Summary of Analysis for 1-900 Properties - Network Innovation Competition H100 fife, SGN, 2020. 6
Figure 7 - 2020 Hourly Data - Power Generated 13
Figure 8 - Electricity Prices - Ofgem 21
Figure 9 - H100 Project Flow 23
Figure 10 - CCGT Plant Layout 37
Figure 11 - Levelized Costs in £ per kWh 46
Figure 13 - 2020 Hourly Data - Wind Speed 68
Figure 14 - 2020 Hourly Data - % Power Generated 68
Figure 15 - 2020 Hourly Data - Power Generated 69
Figure 16 - 2020 Hourly Data - Degree Days <19C 69
Figure 17 - 2019 Hourly Data - Wind Speed 70
Figure 18 - 2019 Hourly Data - % Power Generated 70
Figure 19 - 2019 Hourly Data - Power Generated 71
Figure 20 - 2019 Hourly Data - Degree Days <19C 71
Figure 21 - 2018 Hourly Data - Wind Speed 72
Figure 22 - 2018 Hourly Data - % Power Generated 72
Figure 23 - 2018 Hourly Data - Power Generated 73
Figure 24 - 2018 Hourly Data - Degree Days <19C 73
Figure 25 - 2017 Hourly Data - Wind Speed 74
Figure 26 - 2017 Hourly Data - Power Generated 74
Figure 27 - 2017 Hourly Data - Degree Days <19C 75
Figure 28 - HP Steam Properties 78
Figure 29 - IP Steam Properties 79
Figure 30 - LP Steam Properties 80

List of Tables

Table 1 - Wind Turbine Performance 5
Table 2 - H100 Project Wind Generation Data.. 11
Table 3 - Leuchars Site Wind Generation Data... 12
Table 4 - Leuchars Site - Still Day Data 12
Table 5 - Route 1 System Costs 22
Table 6 - Electrolysis - Hydrogen Production 24
Table 7 - Hydrogen Production - Annual, 5-Day Gap and 7-Day Gap 25
Table 8 - H100 Proposed Network Design Parameters 29
Table 9 - Route 2 System Costs 33
Table 10 - Gas Plant Specifications 39
Table 11 - Steam Plant Specifications 40
Table 12 - Route 3 System Costs 43
Table 13 - Results.. 46

Nomenclature

Symbol	**Description**	**Units**
m/s	Speed in meters per second	-
T	Temperature	Degrees
°C	Degrees Celsius	-
K	Degrees Kelvin	-
P	Pressure	Pascal or bar
kPa	Kilo Pascal	-
bar	Pressure in bar	-
kg/s	Mass flow rate	-
ἠ	Efficiency	%
Cp	Specific Heat Constant Pressure	-
Cv	Heat Capacity	-
ȣ	Heat capacity ratio (Cp/Cv)	-
ε̨	Effectiveness	%

1.0 Introduction

The H100 project in Fife has been designed to produce hydrogen from green renewable wind energy, store it for a 5-day (rolling 120 hour) window, and supply it to up to 900 homes within the area for heating use as a replacement for natural gas. This thesis has looked at supplying the 900 homes using three separate routes to compare the end-to-end efficiency, capacity of each system, system capital cost and end-use energy cost. All three systems start with electricity generated from a green renewable source at a wind turbine and then go down their own routes of delivering heating:

Route 1) Renewable electric supply with battery storage powering heat pumps.

Route 2) Renewable electric supply powering electrolysis for hydrogen generation, storage and supply direct to homes as a gas to replace natural gas.

Route 3) Renewable electric supply powering electrolysis for hydrogen generation, storage and supply to a CCGT to power heat pumps.

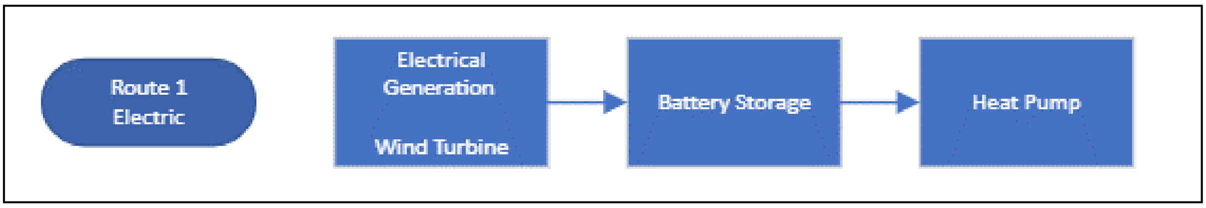

Figure 1 - Route 1

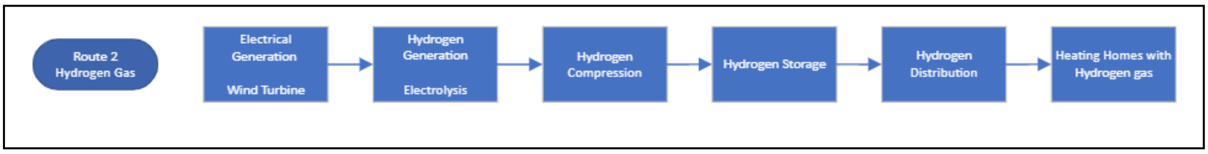

Figure 2 - Route 2

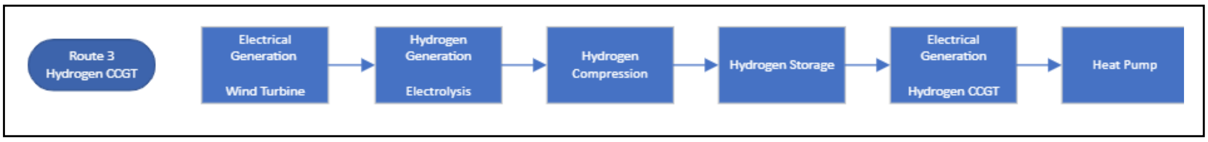

Figure 3 - Route 3

With domestic energy use being the second highest end user of energy in the UK coming second only to transport (Digest of United Kingdom Energy Statistics [DUKES], 2021), finding the most practical method for generation, storage and use of green energy will go a long way towards reducing emissions within the UK and helping achieve the target of Net Zero 2050 across the UK (HM Government, 2021, Net Zero Strategy: Build Back Greener).

2.0 H100 Project Background

The H100 project in Leven, Fife, Scotland, is a “first of a kind” system that aims to deliver hydrogen gas to homes as a replacement for natural gas. This project will replace natural gas in homes for heating and cooking purposes. This is being run as a test bed for replacing hydrogen in the wider gas network and will be used to establish the validity of “regulatory, technical, social and operational viability of transitioning to 100% hydrogen”.

With partners working on this project that are heavily gas oriented such as gas utility companies and consumer goods companies producing gas boilers and cookers, the information and findings may have some bias towards enabling the use of gas. This thesis has aimed to break down any information that may have a bias and analyse it further but in some cases has taken the information for comparison purposes with other systems.

Much of the information on the specifications of the system has been taken from the Network Innovation Competition (NIC) 2020 proposal (NIC H100 Fife, 2020, SGN) and the OfGem report (Company Secretary, 2020, NIC Decision Document, OfGem) on the H100 project. Other sources can be found online at SGN (www.SGN.co.uk), Fife Council (www.fife.gov.uk), H100 project (www.h100fife.co.uk), Kiwa (www.kiwa.com), OfGem (www.ofgem.gov.uk), Scottish Government (www.gov.scot) and many others who have parts to play in this large project. With government and industry backing there is a large push to check the viability of repurposing the existing gas network for 100% hydrogen use and many interested parties with vested interests in gas being used in the energy mix going forward.

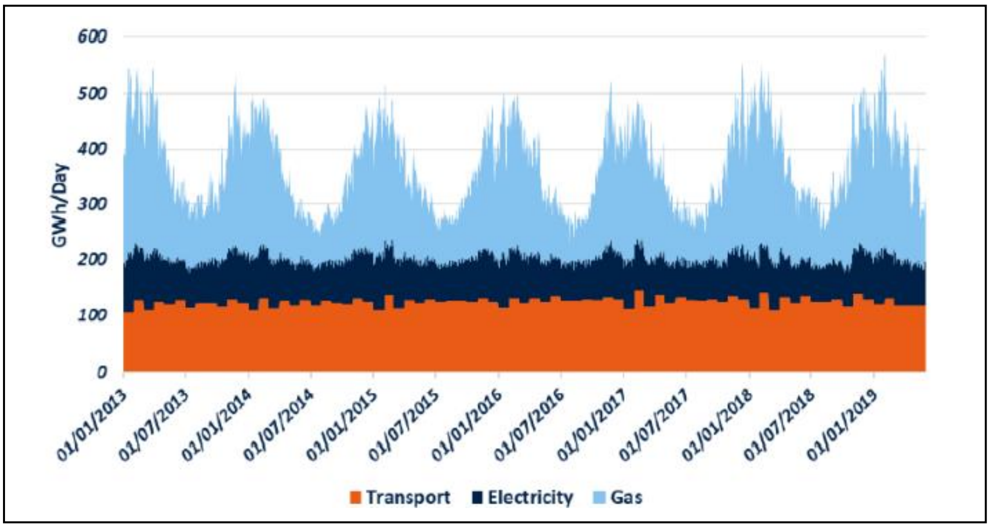

Figure 4 - NPV Summary Analysis - Network Innovation Competition H100 fife, SGN, 2020.

As can be seen from SGN's NPV Summary Analysis (Figure 4,) above which can be found in the Scottish Governments Statistics Hub (https://scotland.shinyapps.io/sg-scottish-energy-statistics), gas use as part of the energy mix makes up roughly a 1/3 to 3/5 of the total energy used in the UK by type.

Details that have been taken from the H100 project and used in this thesis have been included in the following sub-sections. Some of the main partners working on the H100 project are in the graphic below:

Figure 5 - H100 Project Partners

2.1.1 Turbine Methodology

The wind turbine used in the H100 project is a 7MW (6.5MW rated) turbine. Performance against wind speed for the wind turbine has been taken from the NIC report and is included in the table below:

Table 1 - Wind Turbine Performance

	No generation	Cut-in Speed	Power Curve Generation	Maximum Generation	Cut-out Speed
Wind Speed (m/s)	<3.5	3.5	3.5 - 12.5	12.5 - 25	25

The main assumptions made for wind generation have been stated below:

- It has been assumed that the turbine will have a linear power curve between 3.5 m/s and 12.5 m/s for ease of calculation.
- There will be 100% generation between 12.5 and 25 m/s and the wind turbine will automatically cut out over 25 m/s.
- It has been assumed that the turbine will be able to change its pitch and yaw to maximise the available wind at any given time.
- It has been assumed that there will be no downtime for maintenance or other activities. Whilst this is not realistic, it has been simplified for the modelling.

Further methodology and results from the wind turbine data and energy analysis have been included in section 3 for all routes as this is taken as the starting point regardless of the route taken.

2.1.2 Route Methodology

Each route has been analysed using the wind turbine results as a starting input in line with their main components. The main elements of which are detailed in the following sections but vary with each individual route. The overall system capacity to fill the required peak weekly heating load and the system efficiency are calculated for each route. The system cost based on each of the routes main components is calculated and presented along with the levelized costs in £/kWh based on the system output in order to determine a levelized cost for each route. This is then compared to a grid price for either electricity or gas depending on the output of the route.

2.1.3 Electrolyser Methodology

The electrolyser being used in the H100 project is sized at 4MW for the 900 homes. Although this is not all to be used in the initial phases of the project it has been sized for the maximum use required and will therefore be used in the analysis.

The type of electrolyser being used is a Polymer Electrolyte membrane (PEM) electrolyser as this has the best ability among its peers (Anion Exchange Membrane [AEM], Solid Oxide Electrolyser [SOE], etc.) to be able to ramp up and down quickly to respond to the changing input from a variable renewable source, as well as being a mature enough technology to be applied to this project.

A 24-hour operation cycle has been assumed and thus, if the electrolyser can be in operation, it is. Again, it has been assumed that there will be no downtime for maintenance or other activities.

2.1.4 Storage Methodology

Storage requirements of the H100 project have been sized for a 5-day window of storage in man-made tanks on the site. This is not in line with the maximum requirements given the peak gas use for a week as the table from the NIC report shows below, and as such will be discussed in later sections.

Number of Properties	1	300	900
Average annual gas consumption (kWh)	12,624	3,787,200	11,361,600
Peak year gas consumption (kWh)	13,712	4,113,721	12,341,164
Peak week consumption (kWh)	374	112,297	336,890

Figure 6 - Summary of Analysis for 1-900 Properties - Network Innovation Competition H100 fife, SGN, 2020.

All storage requirements will be based on the energy storage (kWh) alone to give a like-for-like storage solution in the rolling 7-day (168 hour) window and for peak usage for the 900 homes as in the table above. The type of storage used will be detailed in each relevant section.

Storage for the H100 project is to be in six man-made tanks holding 692 kg each for a total of 2850 kg at a pressure of 30 bar. (NIC report numbers are out with what would actually be held in those tanks 692 x 6 = 4152 kg)
The peak week energy usage from the NIC report (336,890 kWh) would require:

$$\frac{336{,}890}{33.6} = 10{,}026\ kg$$

of hydrogen to heat the 900 homes. If the meaning of "week" from the peak figure is taken to be 7-days then the 5-day window should require:

$$\frac{Peak\ kWh}{7}\ x\ 5 = \frac{336{,}890}{7}\ x\ 5 = \ 240{,}635\ kWh$$

Which equates to:

$$\frac{240{,}635}{33.6} = \ 7{,}162\ kg$$

This is still over the suggested 2850 kg in the NIC report. If this is translated into energy terms:

$$2{,}850\ x\ 33.6 = 95{,}760\ kWh$$

Of the 900 homes for the required period this can only fuel:

$$\frac{95{,}760}{336{,}890}\ x\ 100 = 28.42\ \%$$

Whilst this is enough to fuel the initial 100 homes that the H100 project is stating with, this system will require upgrading to be capable of sustaining heating in the 900 homes for the 5-day window. As such, the costs for the increased storage capable of sustaining the 900 homes for the 7-day window have been included in this thesis.

It is worth noting that SGN do not differentiate between gas uses within the home and that the number given in their NIC report may include gas used in cooking as well as heating. For the purposes of this thesis, the numbers given for annual and peak gas use will be taken as the number required for heat and nothing else. This assumes that all end uses in the house will be transferred to and supplied by an appropriate source and calculated out with the numbers in this study.

From *Sustainable Energy - Without The Hot Air* (D. MacKay, 2009, Sustainable Energy – Without The Hot Air, UIT, p. 51 - 53) gives figures on energy usage within the home in the UK, the main elements for heating are covered under hot water, heating and cooking with 12 kWh, 24 kWh and 1 kWh per day each. This gives a total of 37 kWh per day per household and 13,468 kWh annually per household, which is between the average and peak values stated in the NIC report (Figure 6). With a difference of only 1,088 kWh between the peak and average annual usage, the 13,468 kWh annually is reasonable. Taking cooking out of the equation, an assumption has been made that the hot water and heating systems are running together in all routes.

2.1.5 Domestic Heating – End Use Methodology

Housing use for the project has been left as a complex issue as all houses will have the option of switching to hydrogen or keeping natural gas. For this thesis however, the decision has been made to have all 900 homes modelled as though they have taken part in the project.

Heating requirements against the ambient air has been taken from the United Nations High Commission for Refugees (UNHCR) suggesting a temperature of 15–19°C which was used in the paper by C. Crawford, P. Manfield and A McRobie in 2005 (C. Crawford, P. Manfield, A McRobie, 2005, Energy and Buildings, Volume 37, p. 471-483). Degree days (https://www.energylens.com/articles/degree-days) under 19°C have been taken from the weather data used for the electrical generation. The same data set from the MIDAS website for the Leuchars site in Fife (https://catalogue.ceda.ac.uk/) has been used for both the wind and the ambient air temperature calculations.

It is assumed that all properties are of the same size, construction, and have the same thermal properties as well as the heating system having an assumed 92% conversion rate within the home to show system loses.

No cooling has been accounted for in these calculations. Whilst this is perhaps obvious for hydrogen boilers, air heat pumps have the ability to have a cooling cycle and so for a fair comparison in terms of the peak usage only the heating has been analysed.

With unrestricted and off-peak space heating both having increased since the 1960's (A.G. Ter-Gazarian, 2011, IET, Energy Storage for Power Systems, 2nd Edition, Power and Energy Series 63, p. 11, Figure 1.1) and global temperatures rising, the issue of heating and cooling homes globally will be one that has a large impact both locally and globally.

2.1.6 System Cost Methodology

System costs were taken for all major components of each route from relevant and up to date sources where possible. Any currency exchanges have been from dollars to pounds sterling and at the rate of $1:£0.82 (£0.82:$1, www.xe.com, 01-Jul-22).

2.1.7 Cost per kWh Methodology

Costs per kWh have been taken from the following place for comparison purposes for the levelized costs for each route:
"According to Ofgem40, as of the 1st April 2020, typical UK annual domestic energy consumption was 12,000 kWh for gas and 2,900 kWh for electricity. At present, the average unit price per kWh is 14.38p and 3.80p for electricity and gas respectively 41." (NIC Report, p. 65). Levelized costs were worked out from an alteration to the UK Governments paper outlining costs for hydrogen production (UK Government, BEIS, Hydrogen Production Costs, 2021) which uses a levelized cost formula to estimate the cost of production for a kg of hydrogen. Without knowing the true CAPEX or OPEX costs of a company and with this still being a growing sector this is an very much an estimate but does give a comparison. The equations given by the UK government have been altered to allow comparison of price per kWh of energy in each route given the output due to the energy delivered by each easier to compare.

In the following equations n = time period in years:

$$NPV\ of\ Total\ Costs = \sum_{n} \frac{Total\ CAPEX\ and\ OPEX_n}{(1 + discount\ rate)^n}$$

$$NPV\ of\ Energy\ Production = \sum_{n} \frac{Annual\ System\ Output_n}{(1 + discount\ rate)^n}$$

$$Levelised\ Cost\ of\ Energy = \frac{NPV\ of\ Total\ Costs}{NPV\ of\ Energy\ Production}$$

With the CAPEX and OPEX being two of the main factors in the first equation, and with a large expansion in the hydrogen economy planned globally (DOE Establishes Infrastructure Law's $9.5 Billion Clean Hydrogen Initiatives | American Public Power Association. Available at: https://www.publicpower.org/periodical/article/doe-establishes-infrastructure-laws-95-billion-clean-hydrogen-initiatives (Accessed: 17 May 2022)) (Department of Energy seeks to cut cost of hydrogen by 80% | American Public Power Association. Available at: https://www.publicpower.org/periodical/article/department-energy-seeks-cut-cost-hydrogen-80 (Accessed: 17 May 2022)) and even the US Department of Energy predicting that in 2025 hydrogen will cost $4.2 per kg through electrolysis (N.P. Brandon, Z. Kurban 2017, The Royal Society Publishing, Clean Energy and the Hydrogen Economy) it can be assumed that the cost for production as technology becomes more widespread will drop over the next 18 years as the UK heads towards Net Zero.

3.0 All Routes – Electrical Generation

3.1 H100 Data

Generation of green energy is done via a wind turbine detailed in section 1.1 for the starting point of all three routes. The sizing of the wind turbine specification has been taken from the H100 project at the Leven site (NIC Report and OfGem Report), and the wind data for the Leuchars site taken from the MIDAS website (Graphs in Appendix 12.1). The data analysis has been simplified with the assumptions and simplifications stated in section 1, as this is not the main focus of this thesis and so may not be as accurate as if modelled solely on its own.

The H100 project has the following electrical generation stated for the years 2010-2019:

Table 2 - H100 Project Wind Generation Data

H100 Project – Leven, Fife, Scotland	
Yearly Total Generation	15.1 - 17.1 GWh
Largest Gap in Generation	5 days

3.2 Leuchars Site

The Leuchars (Leven, Scotland) site data from the MIDAS website was analysed from 2017-2020 inclusive and the findings are in the tables below:

Table 3 - Leuchars Site Wind Generation Data

Year	Annual Energy (MWh)	Operational Hours (Hrs)	Still Hours (Hrs)
2020	20,602.46	5987	2797
2019	17,862.75	5478	3279
2018	19,221.78	5705	3054
2017	19,710.7	5998	2762
Average	**19,349.42**	**5792**	**2973**

Table 4 - Leuchars Site - Still Day Data

Year	Max Still Hours (Hrs)	Min Output (5 Days, MWh)	Min Output (7 days, MWh)
2020	49	40.12	90.68
2019	54	54.3	85.86
2018	22	68.48	126.52
2017	19.5	88.27	140.43
Average	**36.13**	**62.79**	**110.87**

The output of the turbine is around 17-20 GWh annually. This is slightly higher than the 16 GWh that the H100 project is using for annual generation but is due to the local wind conditions at the Leuchars site compared to the H100 (Leven) site, therefore the lower end of this has been taken making the average annual production 17 GWh for further calculations. As the annual output from the Leuchars site has been calculated at the higher end of the scale for the H100 site, the results should still be valid for comparison based on the rest of their figures.

The minimum output from the H100 project for both 5 and 7 days has been included to analyse the lowest levels of generation for comparison with the H100 projects 5-day gap and for a full week of production. A rolling 5-day and 7-day window was created in each year in order to gain the minimum total production. With the minimum 7-day production (85.86 MWh) being nearly double that of the 5-day minimum (40.12 MWh) and in different years (2019 and 2020 respectively), there is not a noticeable difference in the 5-day and 7-day gaps respectively. Due to the peak weekly kWh usage for gas being used in section 2 above, it will be assumed, since it is not stated otherwise, that this is for a standard 7-day week period. Therefore, all storage calculations have been based on this 7-day week.

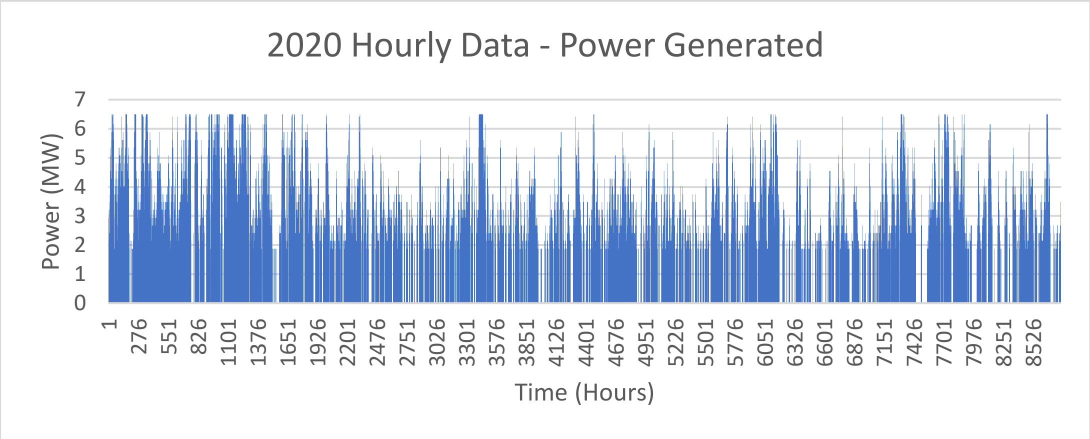

Figure 7 - 2020 Hourly Data - Power Generated

As can be seen in Figure 7, the wind at the Leuchars site is highly variable throughout the year with several points of no generation. There is always generation over a 5-day period and at least double that generation over a 7-day period so topping up storage should not be an issue.

Wind turbine availability for a 7MW (6.5MW rated) turbine is high with companies such as Siemens manufacturing models like the SG 6.6-170 onshore wind turbine that fit those specifications (www.siemensgamesa.com/).

The timing of electrical generation is not taken into account in the routes being analysed due to the fact that they all contain a 7-day window of storage and so any generation will be stored there until required. While wind power curtailment is an issue that is costing countries such as Germany millions of euros (N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing, p. 7) an attempt has been made in these routes to level the supply using storage. This is an area that would require in depth study in order to fully optimise any of the routes described.

3.3 Emissions

As this is a green renewable way to generate electricity, no emissions have been counted for at this stage. Depending on the construction of the turbine and the foundations (steel, concrete, etc.), the emissions included in the construction and maintenance of the turbine will be variable but are taken as “zero” in this thesis so that only the emissions generated by the route itself are considered.

4.0 Route 1 – Electric End-to-End

The first of the three routes (Route 1) models the use of renewable electricity generated by the wind turbine either used directly or stored in a chemical battery to power heat pumps in the 900 homes. Energy is stored for a 7-day (168 hour) gap in industrial scale batteries to allow for downtime in generation.

It should be noted that the electrical system outlined in this section does not make use of any optimisation or smart grid technology which would likely improve both the system performance, efficiency and provide load levelling.

The wind data and generation of 17 GWh has been taken from section 3 as the starting point.

4.1 Route 1 – Electrical Storage

4.1.1 Route 1 – Battery Storage

Based on utility management, there is an argument that a behind-the-meter (BTM) storage system would not be the best performing option for a utility back-up on a large geographical scale due to the low utilisation and difficulty in supplying grid requirements, and that Utility Scaled Shared Energy Storage (USSES) would be more appropriate (N, Bhusal, 2020, IEEE, Optimal Sizing and Siting of Multi-purpose Utility-scale Shared Energy Storage Systems). With this thesis only looking at a local scale the BTM storage is essentially what the USSES would provide in this scenario due to the small scale it is being applied, therefore the BTM storage will be utilised to provide primary electrical storage to the system.

The average cold spell (ACS) (A.G. Ter-Gazarian, 2011, IET, Energy Storage for Power Systems, 2nd Edition, Power and Energy Series 63, p. 15) for a severe winter peak demand has been taken from the SGN data and will be applied to the storage on all routes. With the ACS buffer for battery storage being around 9% higher than the usual winter peak demand this has been applied to the sizing of the storage.

With the base power load having to consider the longest duration that is required of it (A.G. Ter-Gazarian, 2011, IET, Energy Storage for Power Systems, 2nd Edition, Power and Energy Series 63, p. 17) the 5-day gap that is used in the SGN NIC report will be stretched to the 7-day gap and applied to the battery storage as well.

With the battery sized to be 109% of the peak weekly consumption so as to allow a buffer to not fully drain the battery in order to avoid causing any damage.

$$Battery\ Size = Peak\ Week\ Consumption * 1.09$$

$$\frac{336{,}890\ x1.09}{0.9} = 408{,}011\ \ kWh$$

From this, the storage required is 408,011 kWh and this has been rounded to a 408 MW / 9180 kWh to supply the 900 homes with the 10.2 kW heat pumps for 7 days. These calculations rely on the electricity being used purely for heating purposes.

Battery storage has been assumed to be 90% efficient as there will of course be losses during storage. Depending on the type of battery, this could range from 65 % for lead acid batteries to 90 % for lithium batteries (M. Reaudin et. al., 2010, Energy for Sustainable Development, Volume 14, 302-314) and with alternative storage available for heat purposes as discussed in 4.1.2 it is not unreasonable that this will be above 90 % efficient and at a lower cost for domestic heating. The 90 % efficiency that has been assumed may be high for large scale battery storage but this will ideally only be used for periods still days with no wind and so the efficiency should be relatively high.

4.1.2 Route 1 – Alternative Storage

Whilst battery storage has been sized for this route and allows the energy to be used in many forms, there are other forms of storage emerging that may prove more efficient purely for heat storage from an electrical source. These include storing heat energy in various salts (P.A.J. Donkers et. al., 2017, A Review of Salt Hydrates For Seasonal Heat Storage in Domestic Applications, Applied Energy, Volume 199, Pages 45-68) and other mediums. If one of these routes is chosen for storage of electrical energy as thermal energy then it may well prove an even more efficient route to take but would require further study.

4.2 Route 1 – Electrical Infrastructure

Upgrading the electrical infrastructure to take the load of the 900, 10.2 kW heat pumps (9180 kW total) will be a considerable undertaking. It should be noted however that with the increased use of electric vehicles for private owners the electrical network will likely require upgrading in the near future to allow for charging points at most homes.

The length of cabling required to upgrade the system has been taken from the NIC report estimates on gas pipe length for the system in Route 2 (8,495 m / 27,870 ft). This cabling does not include substation upgrade and/or installations which would be required for the 900, 10.2 kW heat pumps to be installed in the system.
Costs associated with this come in at around $42/ft (IEEE Insulated Conductors Committee, 2019)

Some form of smart grid and load balancing hardware and software would also be required to ensure the smooth supply of electricity at all times to the 900 homes. As this is not within the scope of this thesis it will not be dealt with but it should be mentioned that this would form a key part of the electrical system in both Route 1 and Route 3.
The electrical infrastructure is taken to be 100% efficient in its distribution due to the high efficiency of electrical distribution and the short routes being used in this study.

4.3 Route 1 – Heat Pump Use

The end use of the electricity in this route is to power heat pumps giving heating to the 900 homes. The heat pump chosen was an air source heat pump from the Governments now discontinued Renewable Heat Incentive (https://www.gov.uk/domestic-renewable-heat-incentive) scheme list of approved pumps. The data was taken from the RHI Monthly Official Statistics Tables from April 2022 (RHI Report, April 2022, UK Government, RHI).

Air Source Heat Pumps (ASHP) were chosen over ground or water source heat pumps as they are easier to retrofit to existing buildings and take up less space. As of April

2022, 68% of newly installed and accredited heat pumps were ASHPs under the Green Homes Grant voucher scheme (https://www.gov.uk/guidance/apply-for-the-green-homes-grant-scheme) which had an estimated capacity of 766.6 MW, and supplies 58% of the accredited capacity for the RHI scheme of new installations for the period (RHI Report, April 2022). For the scheme, a Seasonal Performance Factor (SPF) was calculated using the OfGem formula (www.ofgem.gov.uk/publications/heat-pump-seasonal-performance-factor-spf-calculation-template) and assigned to each heat pump and a minimum SPF score of 2.5 had to be achieved for the heat pump to be accredited by the scheme. The heat pump SPF has been taken as its Coefficient of Performance (COP) for the year and so a COP of 2.5 will be applied to the 900 homes to calculate the energy requirements. This is due to the large number of approved makes and models of heat pump as well as the variation between air, water and ground source heat pumps that are available. It is worth stating that the maximum SPF given to any of the ASHPs in the scheme was 4.2 and thus the efficiency of the system could be much higher if the maximum SPF of a high performing heat pump were to be used instead of the minimum of 2.5. From papers containing trials with field data on heat pumps, such as N.J. Kelly et al. (N.J. Kelly, J. Cockroft, 2010, Analysis of retrofit ASHP performance: Results from detailed simulations and comparison to field trial data, Elsevier, Energy and Buildings 43 (2011), 239-245), it can be shown that the actual performance of a heat pump does drop slightly given lower ambient temperatures but that the average annual COP of a heat pump was 2.7 compared with its nominal COP of 3. With the average annual temperature of 2020 being 9.3°C (with a maximum of 25.1°C and a minimum of -3.1°C) setting the COP to 2.5 is likely an underestimate of the performance of the system.

The efficiency for the heating system in each house was taken from N.J. Kelly et al. study on heat pumps which found it to be 92% efficient.

4.4 Route 1 – System Findings

System capacity and heating demand for Route 1 have been worked out as follows:

$$(Annual\ Wind\ Energy\ x\ COP\ Efficiency\ x\ Distribution\ Efficiency)$$
$$= Heating\ Delivered$$

$$17{,}000{,}000\ x\ 0.9\ x\ 2.5\ x\ 0.92 = 35{,}190{,}000\ kWh$$

$$System\ Capacity = \frac{Heating\ Delivered}{Peak\ Heating\ Required}$$

$$\frac{35{,}190{,}000}{12{,}341{,}164} = 2.85 = 285\ \%$$

With 285% of the system heating demand covered, the purely electric system easily covers the demand requirements for the heating load.

System efficiency is based on the following equations:

$$Systen\ Efficiency\ (ή) = \frac{Work\ out}{Work\ in}\ x\ 100$$

$$ή\ = \left(\frac{35{,}190{,}000}{17{,}000{,}000}\right) x\ 100 = 207\ \%$$

4.5 Route 1 – System Costs

Costs for the wind turbine will be included but taken as the same for all routes as they all have the same starting point. Costs for a wind turbine were taken from the International Renewable Energy Agency (IRENA) Power Generation Costs Report from 2021 (IRENA, Renewable Power Generation Costs, 2021, p. 63) from the range of \$780/kW to \$960/kW. The total installed costs however are higher, calculated as \$1,325/kW for 2021. As this is a stand-alone turbine and not part of a wind farm development the total cost of installation has been taken making the cost of purchasing and installing a 7MW (6.5MW rated) turbine cost \$9,275,000 which equates to

£7,605,500. This was compared with a second website for costs and found to be an accurate estimate (www.renewablesfirst.co.uk).

From an EIA report in 2021 and an IRENA report published in 2022 (IRENA, 2022, Renewable Power Generation Costs, p. 94), the cost of utility scale battery storage in the United States is as low as $589 / kWh. Putting battery costs for this scenario in the region of £240,318,479. This is higher than the National Renewable Energy Laboratory (NREL) (W. Cole, 2019, Cost Projections for Utility-Scale Battery Storage, National Renewable Energy Laboratory, www.nrel.gov/docs/fy19osti/73222.pdf) at $124 / kWh cost predictions for the low end of the market for 2030 which would lead to battery costs on this scale being around $50,593,364. With the uptake of battery usage there will of course be a supply and demand issue but along with this mass production comes economies of scale and so the lower figure is used in this study.

Costs for the raw materials for batteries has increased just last year with lithium being five times higher on the Chinese market (the largest battery producing country) than it was in January of 2021 and with other elements such as cobalt doubling in price and Nickel going up by 15% (https://www.ft.com/content/31870961-dee4-4b79-8dca-47e78d29b420). With demand forecast to outstrip supply it will be increasingly expensive to purchase batteries on the open market.

Electrical infrastructure upgrade costs are in the region of £$42/ft (https://www.powerandcables.com/21st-century-costs-of-underground-distribution/). Assuming the same distance of cabling will be required as pipe is being laid for Route 2 (8,495 m).

Electrical substation upgrades have been taken from a recent upgrade proposal in the Leven area by SP Energy (Scottish Power, Leven Primary Fault Level Mitigation, ED2 Engineering Justification Paper, M. Plecas, 2021) and estimated based on the minimal work required with a single substation upgrade for the entire network.

Heat Pump installation costs are in the region of £7k - £13k (energysavingtrust.org.uk) for purchase and installation. Since this project is on a large scale, buying power will be assumed and the lower price taken of £7k per heat pump for purchase and installation. This was checked against a trade website for comparative costs (tradesmencosts.co.uk/air-source-heat-pump) which stated between £6k - £16k and so the £7k is at the lower end of this and would still cover larger properties that are generally more expensive since a larger heat pump is required.

4.6 Route 1 – Fuel Costs

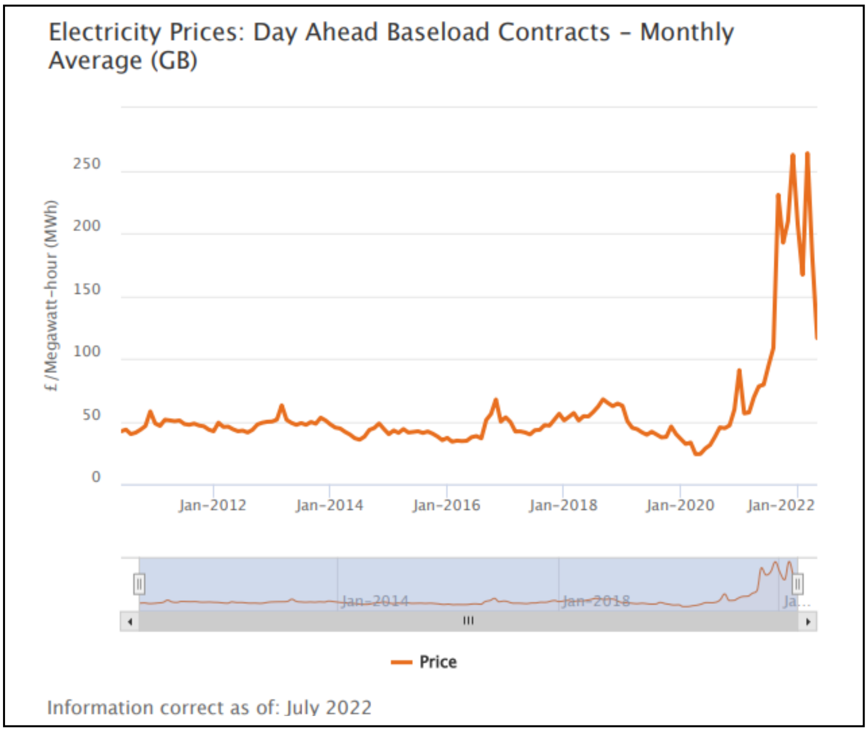

Figure 8 - Electricity Prices - Ofgem

As we can see from the OfGem website (https://www.ofgem.gov.uk/energy-data-and-research/data-portal/all-available-charts?sort=created), the cost of electricity has risen sharply in the last year (2021-2022). This is due to a number of contributing factors in the global economy but it is starting to fall again. The most recent price of £116.38/MWh (05-Jan-2022) breaks down to 0.11p/kWh for comparison, which is in line with those used for the NIC report calculations.

The levelized cost for Route 1 is £0.32/kWh (32p/kWh) based on the system costs and given a 5-year period to start with. This is over double the OfGem grid price for electricity at 14.38p/kWh but would possibly be lower considering the system capacity could support over twice the network of heat pumps, although the battery storage would also require to be increased possibly levelling the cost out again.

Table 5 - Route 1 System Costs

Element	**Cost**	**Cost (£)**	**Source**
Wind Turbine	$9,275,000	£7,605,500	IRENA, XE
Battery Storage	$124/kWh $50,593,364	£41,486,558	National Renewable Energy Laboratory (NREL)
Electrical Substation Upgrades	£332,000	£332,000	www.spenergynetworks.co.uk/userfiles/file/ED2-LRE-SPD-011-CV3-EJP%20-%20Leven%20Primary%20Fault%20Level%20Mitigation%20-%20Issue%202.pdf
Electrical Cabling	$42 / ft x 27,870 $1,170,540	£959,843	https://www.powerandcables.com/21st-century-costs-of-underground-distribution/
Heat Pump Installation	£7,000 x 900	£6,300,000	energysavingtrust.org.uk
Total Cost	N/A	£56,683,901	Calculation

4.7 Route 1 – Miscellaneous Factors

As can be seen from SGN's NPV Summary Analysis (Figure 4) total energy use in the UK is fairly steady for electricity but varies greatly for gas. With approximately 100 GWh/day going to electricity production (37.3 % of this generated by natural gas in CCGT) and, at peak times, around 400 GWh/day being used by gas, this leads to the question the costs of upgrading the electrical network to cope with the increase in demand if natural gas is to be dropped and not replaced by hydrogen.

For the end-use of heating the homes, no other factors have been taken into account other than the heating system itself. Therefore, no additional heating from bodies, solar energy or otherwise has contributed to the total. There is of course the opportunity to capitalise on these and include them in future studies to reduce the heating required by each household.

5.0 Route 2 – Hydrogen Replacing Natural Gas

5.1 H100 Project Concept

Replacing current natural gas with hydrogen is the real life aim of the H100 project. The project itself aims to supply a dual supply of both natural gas and hydrogen so that customers can select which they would prefer, but this thesis has assumed that all 900 homes will be taking part in all scenarios. An overview of the H100 project flow for the first 300 homes can be found below or on the Fife Local Government website (https://www.fife.gov.uk/kb/docs/articles/environment2/climate-change,-carbon-and-energy/h100-fife-hydrogen-heating-network) and below:

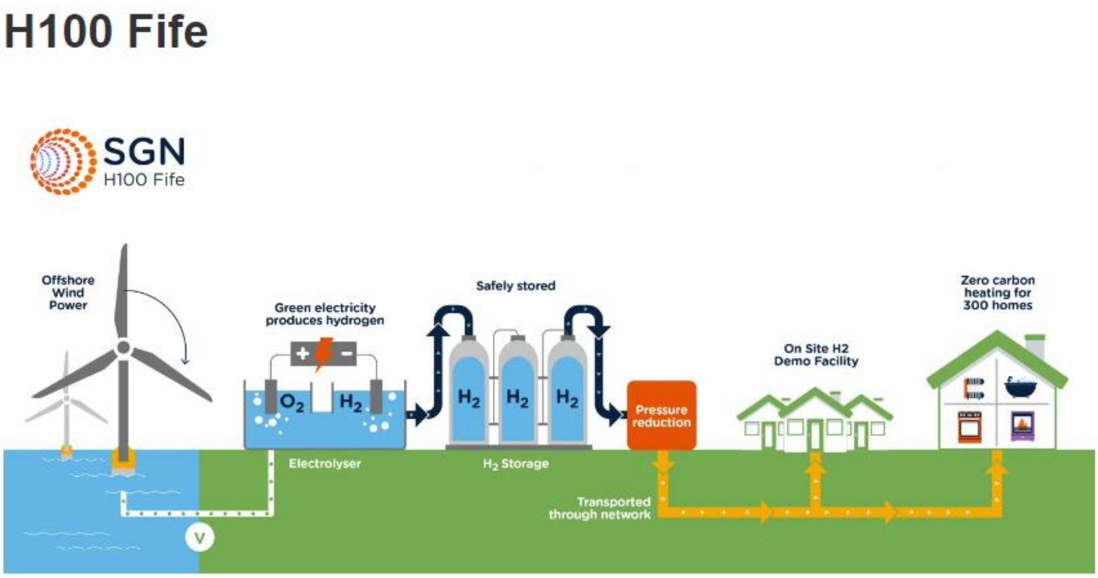

Figure 9 - H100 Project Flow

The water for the project is supplied by mains water and so there is no need for a desalination plant. It is assumed that this will be the case at the Leuchars site and so no desalination plant has been included in any of these scenarios. Should hydrogen be produced offshore a desalination plant would be required which would add to the costs and create a drop in efficiency for the system.

With water shortages being more commonplace and the supply of fresh water close to population centres on land being more useful for drinking water, it would be likely that a shift to offshore hydrogen generation with the use of desalination plants is a logical step.

As can be seen from SGN's NPV Summary Analysis (Figure 4), gas is used to ramp up and down the energy demand for heating during the winter months. Switching from natural gas to hydrogen gas will allow the use of the same infrastructure once fully upgraded. The SGN NIC report states that the plastic piping being used to upgrade the existing network is suitable for hydrogen, which therefore reduces the costs of any future developments for hydrogen distribution networks and also allows the current network to be utilised once it has been fully upgraded.

5.2 Route 2 – Electrolysis – Hydrogen Production

The electrolysis for creation of hydrogen relies on a 4 MW PEM electrolyser. The PEM electrolyser has been used as stated in 2.1.3 due to its ability to cope with the unreliable source of energy from renewable wind energy which can be seen in Figure 7. Table 6 has the system specifications that will be used going forward.

Table 6 - Electrolysis - Hydrogen Production

Energy (Wind)	17 GW
Electrolyser Capacity (E Cap)	4 MW
Electrolyser Efficiency (E Eff)	68 %
Lower Heating Value (Hydrogen)	33.6 kW/kg

With the 24-hour running of the electrolyser, the total annual hydrogen production and a rolling 7-day (168 hour) window for generation at the Leuchars site are in the Table 7:

Table 7 - Hydrogen Production - Annual, 5-Day Gap and 7-Day Gap

Year	Annual Generation (kg)	Annual Generation (kWh)	5-Day Minimum (kg)	7-Day Minimum (kg)
2020	416,954	14,009,654	812	2,698
2019	361,508	12,146,669	1,705	2,555
2018	389,012	13,070,803	1,385	3,765
2017	398,907	13,403,275	1,786	4,179
Average	391,595	13,157,600	1,422	3,299

With efficiency currently lying between 50-68% for an alkaline or PEM system (G. Barnes, L. Bennet, C. Maxwell, Development of early, clean hydrogen production in Scotland, 2021, p.95), any of electrolyser technologies could have been chosen but the PEM systems have a better capacity for ramping up and down with the variable renewable energy (VRE) sources (N.P. Brandon, Z. Kurban 2017, The Royal Society Publishing, Clean Energy and the Hydrogen Economy). As this system is planned for future implementation, the higher figure of 68% has been taken for the system. The cost for this system at the high end is around £1,400/kW_{el} and therefore the 4MW system required for the H100 project would be around £5.6 million. There are cheaper systems such as those in the US that come in at around $300/kW (~£254/kW) (US DOE - www.energy.gov) but it is unclear whether this was just for the unit itself or for all accompanying systems and installation.

The following equation has been used to work out the hydrogen generated in any required period:

$$Total\ Hydrogen\ Generation = \frac{Wind\ Energy\ x\ H2\ Electrolyser\ Efficiency}{Lower\ Heating\ Value}$$

For the 7-day storage window the minimum of 7-day production of 2,555 kg in 2019 has been taken.

5.3 Route 2 – Compression

Hydrogen production from a PEM electrolyser works at around 30 bar (Bessarabov, 2016, PEM Electrolysis for Hydrogen Production, p. 6) (I. Walker, B. Madden, F. Tahir, 2018, Hydrogen Supply Chain Evidence Base, UK Government) and therefore would not require compression for storage at 30 bar as specified in the H100 project. This also means that there would be no loss of efficiency in the system going from production to storage assuming that this pressure could be maintained in the transfer from production in the electrolyser to the storage tanks. Pressurised pipework that is continually filled with hydrogen could provide this link and ensure that there is no loss of pressure.

With both piston and centrifugal compressors being used in gas networks and the gas type not affecting piston compressors (P. E. Dodds, S. Demoullin,2013, Elsevier, Hydrogen Energy, Conversion of the UK gas system to transport hydrogen 2.2.3), these would be the obvious choice for the gas network upgrade if required and would reduce upgrade costs if they were already in place.

5.4 Route 2 – Storage

As with all routes, the 7-day window has been taken as the peak week for the 900 homes has been used.

"Chemical energy storage has a higher energy density and less energy loss than electrochemical storage, so it enables long-term storage" (Pyo Min-Jung, 2021)

The H100 project has specified in its NIC report, six tanks (4,000mm (id) x 25,000mm) at 30 bar for storage which they calculate as 692 kg (27,296 kWh) each and a 5-day storage of 2,850 kg (112,303 kWh). These tanks of 1,250 m3 at an average yearly temperature of 9.3°C and a pressure of 30 bar could potentially hold an H2 density of 2.516 kg/m^3 (https://cmb.tech/hydrogen-tools) giving 3,145 kg (105,672 kWh) each and a system total of 18,870 kg (634,032 kWh).

With a large bunded but non-pressurised tank costing over £70,000 (https://thetankshop.co.uk/) the additional engineering cost of putting this to a suitably pressurised container will double the cost to £140,000. This is to account for the added engineering, seals, pipework, pumps, gauges and sensors. Assuming a fairly fast uptake in the UK over the next 28 years as we head towards Net Zero, the tanks could cost around $117 / kWh (£95.94 / kWh) (B.D. James et. al., 2016, Final report: Hydrogen Storage System Cost Analysis, https://www.osti.gov/servlets/purl/1343975).

5.4.1 Route 2 – Alternative Storage

There are some estimates that put storage of renewable electricity by 2050 in hydrogen at 40% and the possibility of using depleted oil and gas fields an option for storage of hydrogen gas (N.P. Brandon, Z. Kurban 2017, The Royal Society Publishing, Clean Energy and the Hydrogen Economy). Hydrogen is currently stored in salt caverns within the UK (H21 Leeds City Gate Report, 2016, Northern gas Networks, Kiwa Gastec, Amec Foster Wheeler) which are a better option than depleted oil and gas reserves as "Salt caverns typically have lower gas capacities but enable higher delivery rates (power throughput) and thus can be used for balancing variations in energy supply from renewables. Depleted oil reservoirs have high capacity but lower power (and response times) and thus are considered more suitable for seasonal storage." (N.P. Brandon, Z. Kurban 2017, The Royal Society Publishing, Clean Energy and the Hydrogen Economy, p 12). With gas usage having a diurnal (morning and evening) and seasonal winter peak, having smaller, quick access stores, alongside large seasonal stores in these natural reservoirs to allow for the increased usage would make sense as opposed to creating vast quantities of man-made storage.

5.5 Route 2 – Supply Network

The pipe network that supplies all homes is operated at 75 mb which is a considerable drop from the 30 bar storage pressure. If this can be done through a series of decompression valves and stations then there would be no requirement for energy input to the system and therefore no, or a very limited, efficiency loss.

“Polyethylene 80 (PE80)”, currently used in the LP natural gas network for new construction and for the “Iron Mains Replacement Program” makes up “80 % of the 280,000 km” of pipework currently in the system (NIC report, p. 9). With much of the current pipework already suitable for hydrogen the upgrade costs would be far lower than if new installations were required.

The information in Table 2 in the NIC report has been transferred to Table 8 below for the information on pipe network sizing.

Table 8 - H100 Proposed Network Design Parameters

Pipe Diameter (mm)	**Length (m)**
250	150
180	673
125	2,609
90	3,321
63	1,742
Total	8,495

The size of the H100 supply network has been calculated to reach 1000 homes so should be within the parameters of the 900 homes within this study. The upgrades to the gas network cost around £58/m (https://cadentgas.com) and as this is one of the project partners this cost will be used.

Transporting the hydrogen gas via a contained pipework would not have a large efficiency drop (provided the network is small enough to allow this) and so this has been taken as 100% efficient due to the high starting pressure at the storage vessels and the low supply pressure. In reality, the distance from the supply would have an impact on the efficiency of delivery in a larger network and may include some pressure reduction stations which, depending on the type of station, may have an efficiency drop.

New meters would also require to be installed in the system at a cost of £230 a meter as hydrogen gas has a different flow rate and volumetric energy to natural gas (P. E.

Dodds, S. Demoullin,2013, Elsevier, Hydrogen Energy, Conversion of the UK gas system to transport hydrogen 2.2.4).

5.5.1 Route 2 – The UK Network

This local system does not take into account the requirement to shunt gas around the countrywide network that is currently in use for natural gas. Natural gas arriving at the St Fergus Terminal (St. Fergus, Aberdeenshire, Scotland) for instance is compressed and sent onwards down the system with the help of compressor stations such as that near Kirriemuir (Angus, Scotland) to ensure the gas continues south towards at the correct pressure and speed to the salt caverns in England which is currently the only natural storage used within the UK. This requires energy at each stage and would be another large drain on the efficiency on the system but has not been looked into for this thesis.

The total length of pipework within the UK is also a point of debate. With an estimate of 91,000 km in 2001 being changed to 101,800 km in 2004 (P. E. Dodds, S. Demoullin, 2013, Elsevier, Hydrogen Energy, Conversion of the UK gas system to transport hydrogen 2.7) and updated to 280,000 km of pipework as a system total (NIC report, p. 9), the exact requirements of the update leaves questions as to the total cost and disruption an upgrade to the entire system would cause.

5.6 Route 2 – Hydrogen Boilers

Hydrogen boilers do require to be retrofitted to all homes within the scheme as the current boilers for natural gas are not suitable for hydrogen. This is due to hydrogen requiring specific fittings and fixtures and those for natural gas not being compatible with hydrogen.

The hydrogen boiler efficiency has been taken as 90% (A. Chapman, et al, 2019, A review of four case studies assessing the potential for hydrogen penetration of the future energy system, Elsevier) which was comparable to gas boilers being installed in the UK in 2010 being used in field trials (N.J. Kelly, J. Cockroft, 2010, Analysis of retrofit ASHP performance: Results from detailed simulations and comparison to field trial data, Elsevier, Energy and Buildings 43 (2011), 239-245)) and does not take into account drops in system efficiency due to "parasitic losses from piping, control inefficiencies and on/off cycling" which have been taken to be 92 % efficiency (N.J. Kelly, J. Cockroft, 2010).

5.7 Route 2 – System Findings

Total hydrogen generated annual is worked out by the following:

$$Total\ Annual\ Hydrogen\ Generation$$
$$= \frac{Annual\ Wind\ Energy\ x\ H2\ Electrolyser\ Efficiency}{Lower\ Heating\ Value}$$

This gives a total annual production of hydrogen as:

$$Hydrogen\ Output\ (Mass) = \frac{Electrolyser\ Output(Energy)}{Lower\ Heating\ value}$$

$$\frac{17{,}000{,}000\ x\ 0.68}{33.6} = 344{,}047\ kg$$

The 344,047 kg of hydrogen equates to 11,560,000 kWh of energy to input into our heating system.

The system capacity has been calculated using the following formulas:

$$Heating\ Delivered$$
$$= (Annual\ Wind\ Energy\ x\ H2\ Production\ Efficiency)\ x\ H2\ Boiler\ Eff\ x\ System\ Eff$$

$$17{,}000{,}000\ x\ 0.68\ x\ 0.9\ x\ 0.92 = 9{,}571{,}680$$

$$System\ Capacity = \frac{Heating\ Delivered}{Peak\ Heating\ Required}$$

$$\frac{9{,}571{,}680}{12{,}341{,}164} = 0.775 = 78\ \%$$

This capacity is far below that of the purely electric system and does not hit our heating demand target. The extra 22% of capacity (2,769,484 kWh, 99,548 kg hydrogen) for the system would have to be supplied by road tanker, piped from the gas grid system, or by grid import of electricity to the electrolyser. The H100 project does allow for this but does not go into detail of what capacity is expected to be covered by grid imports or to be brought in by tanker. If brought in by tanker at £12/kg (between the £10-£15 figures most often quoted in current online publications such as RAC (www.rac.co.uk), AutoTrader (www.autotrader.co.uk), WhatCar (www.whatcar.com) and BBC News (www.bbc.co.uk/news) in 2022 then that would add a cost of £1,194576 for the extra 99,548 kg of hydrogen to make up the system capacity.

System efficiency is based on the following equations:

$$Systen\ Efficiency\ (ή) = \frac{Work\ out}{Work\ in}\ x\ 100$$

$$ή = \left(\frac{9{,}571{,}680}{17{,}000{,}000}\right) x\ 100 = 56.3\ \%$$

This is a large drop in efficiency of the system compared to the purely electric system and as a choice for heating on the basis of efficiency alone is far worse.

For the 7-day buffer as with the electrical storage, and to provide the 900 homes with the peak requirement (336,890 kWh) taken from the NIC report for the H100 Project, the network will have to supply 12,109 kg of hydrogen to the 900 homes given the efficiency drop in the system. This equates to roughly 128 tube trailers each carrying 95 kg (h2tools.org/bestpractices/storage-vessels) which would severely increase road traffic and lead to a further drop in efficiency for the system.

While there are few 100% ready hydrogen boilers on the market, many of the leading manufacturers such as Baxi, Ideal, Viessmann, Bosch/Worcester have put costs between £732 and £2,796 (https://www.boilerguide.co.uk).

5.8 Route 2 – System Cost

System costs for all major capital (CAPEX) elements have been put into Table 9:

Table 9 - Route 2 System Costs

Hydrogen Gas			
Element	**Cost**	**Cost (£)**	**Source**
Wind Turbine	$9,275,000	£7,605,500	IRENA, XE
Electrolyser	£1,400/kW_{el}	£5,600,000	N.P. Brandon, Z. Kurban 2017
Compressor	N/A	N/A	Bessarabov, 2016
Storage	£140,000 x 6	£840,000	thetankshop.co.uk/
Pipelines	£58/m x 8,495	£492,710	https://cadentgas.com
Boilers (New)	£2,796 x 900	£2,516,400	www.boilerguide.co.uk/
Boilers (Conversion)	£80 x 900	£72,000	P. E. Dodds, S. Demoullin, 2013
Cookers, Hobs (Conversion)	£180 x 900	N/A	P. E. Dodds, S. Demoullin, 2013
Meters, Detectors	£230 x 900	£207,000	P. E. Dodds, S. Demoullin, 2013
Total Cost (Retrofitted)	N/A	£14,817,210	Calculation
Total Cost (New)	N/A	£17,261,610	Calculation
H100 Estimated Total Project Costs (Comparison)	£26,396,905	26,396,905	H100 NIC Report

Costs for a PEM electrolyser include those for the expensive materials such as Palladium and platinum (cathode) as well as iridium or ruthenium oxides at the anode (Bessarabov, 2016, PEM Electrolysis for Hydrogen Production, p. 6).

Upgrading existing gas pipelines, boilers, cookers, etc. would be the first port of call in upgrading the system to hydrogen before the installation of new systems is performed. If the route of upgrading existing systems is followed, then the switch to hydrogen would be quicker and cheaper by a factor of 34.95 which is considerable saving of £2,444,400 in this Route for the 900 homes.

The H100 Project estimates that the cost saving to a customer is somewhere in the region of £8k-£17k and so has taken £12.5k to be the cost saving per customer of using hydrogen in the home as opposed to upgrading the electric and switching to a technology such as heat pumps.

5.9 Route 2 – Fuel Cost

The levelized cost for Route 2 is £0.4/kWh (40p/kWh) based on the system costs and given a 5-year period to start with. This is far more than the OfGem calculated cost of gas at 3.80p/kWh and shows the expense of using hydrogen as a gas when it is not being mass produced.

5.10 Route 2 – Miscellaneous Factors

There are however a couple of factors other than efficiency that should be thought of when picking a system to deliver heating.

Having a storage medium that can sit for long periods of time with no loss to energy is certainly a large boost to hydrogen as a fuel source for heating. Being able to produce hydrogen during summer months and supply the energy back in winter months when it is needed (as per NIC graph of fluctuating UK energy needs) is of valid interest when considering energy storage and supply.

Having a secondary supply network other than electric should also be considered. This provides the system with some redundancy should there be a failure of supply in either the electricity grid or the gas network. A mixed model with some built in redundancy would allow for failures or downtime whilst still ensuring a supply.

A drawback with using hydrogen in any system is the need for a water supply in order to produce the hydrogen. If this is done offshore with a desalination plant, then this will add a drop in efficiency and increase both the CAPEX and OPEX of the plant but it will have a ready supply of water for electrolysis. Producing hydrogen on shore however taps into the local water supply (in the case of the H100 project) and thus diverts a portion to hydrogen production.

It is worth noting that the UK government has estimated around 20 litres of potable water is required for each kg of hydrogen produced (I. Walker, B. Madden, F. Tahir, 2018, Hydrogen Supply Chain Evidence Base, UK Government). This means that, on average, 7,831,900 litres of water each year would be required for the electrolysis process. This could have a large drain on the local water supplies and makes offshore electrolysis a much better option with drinking water required for the ever-growing population. This has not been looked into in depth in this thesis but is an area of study worth pursuing, especially in landlocked countries that are looking to mass produce hydrogen as an alternative fuel source.

When looking at the UK network it is important to note that hydrogen has 20-30% less energy capacity than natural gas when working at the same pipe diameter and pressure as stated in multiple papers (P. E. Dodds, S. Demoullin,2013, Elsevier, Hydrogen Energy, Conversion of the UK gas system to transport hydrogen), (N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing, p. 6). With the UK using the "line pack" or "line packing" in the pipe network for short term storage during peak times this could very well impact the volume and areas in which storage is required in the future (A.G. Ter-Gazarian, 2011, IET, Energy Storage for Power Systems, 2nd Edition, Power and Energy Series 63, p. 4).

With hydrogen providing storage capacity that is "200 times the volumetric energy storage density of pumped hydro" (N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing, p. 7) and without the large impact on the landscape that comes along with large hydro projects, it does provide a green, compact and long-term store for VRE output.

6.0 Route 3 – Hydrogen in a CCGT

Using the hydrogen gas produced as it is in Route 2 above in a CCGT to provide electrical power to the heat pumps outlined in Route 1 is the third option that this thesis has taken into consideration.

Under section 4.3 (p.23) of the NIC report, it states that a mixed use of electricity from offshore wind and hydrogen as a gas to homes could be a solution to having a green solution to the fluctuations for heating in winter. There is no mention however of using this gas in a CCGT to produce electrical energy although they have already stated that this is how 37.36% of the electricity in the grid is generated (NIC Report, Project Business Case, p. 13).

Assumptions made are that the materials in use of construction of the CCGT plant are limited to current knowledge and so the maximum temperatures reached are limited to these constraints.
Output from Route 3 will be going to power electric heat pumps and so the thermal output from the station is not being analysed in depth.

Emissions from the gas turbine are NO_x emissions for the majority and with the efficiency of the system being the main focus of this thesis this is what the layout and equations are aimed at achieving. Further study could go into optimising the combustion temperatures and reducing the emissions accordingly with a lower combustion temperature giving lower NO_x emissions which has been discussed in the literature review.

With modern CCGT plants operating somewhere around 60% efficiency (D. Roddy, 2010, Advanced Power Plant Materials, Design and Technology, Wiley, p. 3) this sets the benchmark for what is expected from a hydrogen CCGT plant if they are to be competitive with current natural gas plants.

6.1 Route 3 – CCGT Layout

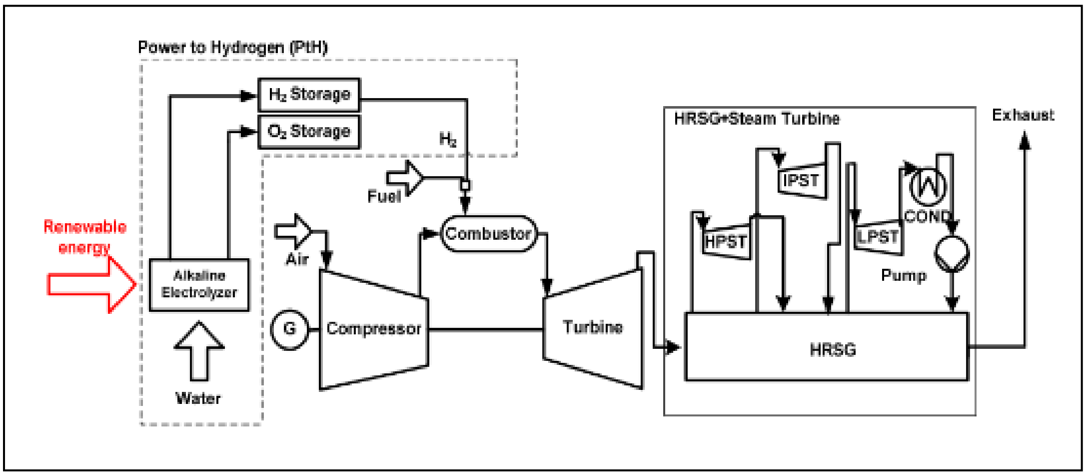

Figure 10 - CCGT Plant Layout

6.2 Route 3 – CCGT Equations

6.2.1 Route 3 – Gas Equations

The hydrogen created for the input to the CCGT is taken from the same layout and workings as it is in Route 2, therefore the 17 GWh of energy from the wind turbine is still transformed into 344,047 kg of hydrogen equating to 11,560,000 kWh of energy. This design takes into account the hydrogen rich gas that is used in the process. Pure hydrogen having an approximate heating value (LHV) of 120,000 KJ/kg (D. Roddy, 2010, Advanced Power Plant Materials, Design and Technology, Wiley, p. 21).

The NO_x emissions are the main emission caused by combustion of hydrogen, and the combustion flame temperature has a direct impact on the level of emissions. "The relative NO_x emissions are exponentially proportional to the flame temperature" (D. Roddy, 2010, Wiley, p. 25). With that in mind, this thesis is aiming for a high efficiency system and so the highest possible combustion flame temperature will be taken as 1500°C (1773.15 K) but it is possible to reach temperatures of up to 1700°C (1973.15 K) and with typical CCGT installations running at around an 18:1 to 20:1 pressure ratio this thesis uses a 20:1 ratio (D. Roddy, 2010, Wiley, p. 15 and 30). This is at the higher end of the combustion spectrum based on modern materials and construction but is feasible and is taken into account for these future power plants.

The characteristics for the steam cycle could reach pressures of 375 bar and temperatures of around 700°C (973.15 K) (D. Roddy, 2010, Wiley, p. 91). Going with a study that was carried out however (Pyo, M.-J., et el, 2021, A Comparative Feasibility Study of the Use of Hydrogen Produced from Surplus Wind Power for a Gas Turbine Combined Cycle Power Plant. Energies 2021, 14, 8342.) the pressures and temperatures used for the HP/IP/LP turbines will be 18,800/5000/500 kPA (188/50/5 bar) and 595/590/268°C (868.15/863.15/541.15 K) respectively. This is based on using advanced materials and construction methods for future hydrogen CCGT plants. "The GTCC system was based on a 283-MW-class commercial GT, and a triple-pressure heat recovery system was used for its bottoming steam turbine cycle." (Pyo, M.-J., et el, 2021).

6.2.2 Route 3 – Steam Properties

Steam properties were checked with the Spirax Sarco Steam Calculator (https://www.spiraxsarco.com/resources-and-design-tools/steam-tables/superheated-steam-region) and Steam Tables Online (www.steamtablesonline.com) to make sure that each starting point was correct. Any losses were assumed to be spread between the systems and taken as a whole between each turbine, with the associated works required from each pump between the turbines as stated in the paper (Pyo, M.-J., et el, 2021).

6.2.3 Route 3 – Overall System Equations

Overall System Efficiency equation:

$$ή = \frac{T_1 - T_2}{T_1}$$

$$ή\ (gas\ end\ to\ end) = \frac{1773.15 - 358.05}{1773.15} = 79.8\ \%$$

$$ή\ (gas\ exhaust\ to\ exhaust) = \frac{1338.55 - 358.05}{1338.55} = \frac{980.5}{1338.55} = 73\ \%$$

$$\acute{\eta}\ (steam) = 0.73\ x\ 0.9 = 65.7\ \%$$

With the gas turbine efficiency end-to-end being 79.8 % efficient, but the exhaust temperature from the gas turbine being 73 % efficient to the exhaust flue, the steam cycle being 90 % efficient takes the energy from the steam cycle to be 65.7 % efficient. Overall system efficiency from Pyo, M.-J., et el, 2021 has the system efficiency using 100% hydrogen as fuel at 61.4 % efficient which gives a 4.3 % error margin in calculation. This is most likely contributable to the efficiency drops at the various stages between each steam turbine.

Tables 10 and 11 are from a study on hydrogen powered CCGT (Pyo, M.-J., et el, 2021, Table 2 and Table 8). Each pressure level of the steam system contains an economizer, an evaporator, and a superheater, with the intermediate level also including a reheater:

Table 10 - Gas Plant Specifications

Gas		
Component	**Parameter**	**Rating**
Compressor	Pressure Ratio	20:1
	Inlet Temperature	15 °C 288.15 K
	Isentropic Efficiency	88%
Combustor	H2 Mass Flow	6.08 kg/s (Table 8)
	Pressure Loss	5.5 %
Turbine	Isentropic Efficiency	84.3%
	Inlet Temperature	1500 °C 1773.15 K
	Outlet Temperature	617 °C 890.15 K
	Exhaust Mass Flow	618 kg/s
Performance	Mechanical Efficiency	99.6 %
	Generator Efficiency	98.8 %
	Net Efficiency	40 %

Table 11 - Steam Plant Specifications

Steam		
Component	**Parameter**	**Rating**
Condenser	Pressure	5.08 kPA 0.05 bar
	Steam Flow Rate	199.13 kg/s
HP/IP/LP Steam Turbine	Inlet Pressure	18,800 / 5,000 / 500 kPA 188 / 50 / 5 bar
	Inlet Temperature	595 / 590 / 268 °C 868.15 / 863.15 / 541.15 K
	Isentropic Efficiency	90 %
HP/IP/LP Pump	Isentropic Efficiency	80 %
	Motor Efficiency	95 %
HRSG	Pinch Point Temperature	10 °C 283.15 K
	Exhaust Temperature	84.9 °C 358.05 K
Steam Turbine	Isentropic Efficiency	90 %

6.3 Route 3 – Emissions Control

Emissions control for a hydrogen CCGT plant focuses on reducing or abating NO_x as this is the main emission created from combustion of hydrogen gas. There is no CO_2 formed when 100 % hydrogen is combusted and so this is not of concern unless the fuel mix is altered away from 100 % hydrogen. The main controls for emissions are either pre-combustion or post-combustion. Pre-combustion technologies include:

- Dry low-NO_x combustors – These combustors pre-mix the hydrogen fuel with air and burn it under leaner conditions to lower the combustion flame temperature which lowers the NO_x formation. These types of combustor can lower NO_x emissions down to 9ppm (D. Roddy, 2010, Wiley, p. 41).

- Large amount of dilutants by volume such as nitrogen or steam can also be added for NO_x abatement during the combustion process but would rely on the injector nozzle of the plant being entirely redesigned to accommodate this. When tested however, the performance at 1800 K was just above 2 ppm (W. D. York, W. S. Ziminsky, E. Yilmaz, 2013, Development and testing of low NOx hydrogen combustion system for heavy-duty gas turbines, Journal of Engineering for Gas Turbines and Power, Volume. 135, 02201-4). With the temperature of the plant in Route 3 being 1500 K this should be an acceptable level of NO_x forming during combustion, but it could still be lowered further post-combustion.

Emissions reduction measures post-combustion include:

- Selective Catalytic Reduction (SCR) Unit – These units pump NH_3 upstream of the unit to react with the NO_x and form N_2 and H_2O. This can bring emissions down to as low as 2ppm but does cause a slight pressure drop and so gas turbine back pressure requires to be increased slightly to accommodate the overall effect on the system efficiency which is fairly small (D. Roddy, 2010, Wiley, p. 41).
- Exhaust gas recirculation back through the system via the intake depletes the intake air of O_2 by volume and therefore reduces the reactions with N in the air, this reduces the formation of NO, with the NO_x concentraations going down by 50% from an EGR (exhaust gas recirculation) of “30% and 40% in wet and dry EGR modes respectively” (M. Ditaranto, H. Li, T. Lovas, 2015, Concept of hydrogen fired gas turbine cycle with exhaust gas recirculation: Assessment of combustion and emissions performance, International Journal of Greenhouse Gas Control, 37, 377-383, p. 380). The “wet” and “dry” EGR modes refer to the saturation of steam being recirculated through the system. This study was later built on (M. Ditaranto, T. Heggset, D. Berstad, 2019, Concept of hydrogen fired gas turbine cycle with exhaust gas recirculation: Assessment of process performance, Energy, 192, 116646) with the performance of the turbines improving with the EGR instead of nitrogen dilution to the combustion mix and the NO_x formation not being affected if the EGR process is controlled properly.

There are several technologies and approaches available that will limit the NO_x formation from hydrogen combustion with limited effect on the overall efficiency of the plant. This should of course be taken into account when designing a hydrogen plant but should not be a major cause for concern while considering this technology in the energy mix due to the lack of carbon emissions with this technology.

6.4 Route 3 – Heat Pumps – End Use

The final stage of this Route is to supply the heat pumps used in Route 1 with the electrical energy created by the CCTG. The same specifications for the COP of 2.5 and the distribution system efficiency of 92 % have been used as in Route 1.

6.5 Route 3 – System Findings

The Net Efficiency for the CCGT is taken to be 61.4% (Pyo, M.-J., et el, 2021, Table 8) based on the hydrogen use in the turbine.

$$Heating\ Delivered = \ (Annual\ Wind\ Energy\ x\ H2\ Production\ Efficiency)\ x$$
$$CCGT\ Eff\ x\ Heat\ Pump\ COP\ x\ Distribution\ Efficiency$$

$$17{,}000{,}000\ x\ 0.68\ x\ 0.614\ x\ 2.5\ x\ 0.92 = 16{,}325{,}032$$

$$System\ Capacity = \ \frac{Heating\ Delivered}{Peak\ Heating\ Required}$$

$$\frac{16{,}325{,}032}{12{,}341{,}164} = 1.3 = 130\ \%$$

System efficiency is based on the following equations:

$$Systen\ Efficiency\ (ή) = \frac{Work\ out}{Work\ in}\ x\ 100$$

$$ή\ = \left(\frac{16{,}325{,}032}{17{,}000{,}000}\right) x\ 100 = 96.0 = 96\ \%$$

Even with the large drop in efficiency from both the electrolysis and the CCGT, the use of the heat pumps at the end of this route increases the efficiency enough that it proves to be an efficient use of renewable energy, if stored as hydrogen for later use in heating.

6.6 Route 3 – System Cost

Table 12 - Route 3 System Costs

Hydrogen CCGT			
Element	**Cost**	**Cost (£)**	**Source**
Wind Turbine	\$9,275,000	£7,605,500	IRENA, XE
Electrolyser	£1,400/kW_{el}	£5,600,000	N.P. Brandon, Z. Kurban 2017
Compressor	N/A	N/A	N/A
Storage	£140,000 x 6	£840,000	
CCGT Plant	\$769.97 / kW x 9180 (900 x 10.2) (\$1.18 billion for 283MW = \$4170kW) \$7,068,325	£5,796,027	Pyo, M.-J., et el, 2021
Electrical Substation Upgrades	£332,000	£332,000	www.spenergynetworks.co.uk/userfiles/file/ED2-LRE-SPD-011-CV3-EJP%20-%20Leven%20Primary%20Fault%20Level%20Mitigation%20-%20Issue%202.pdf
Electrical Cabling	\$42 / ft x 27,870 \$1,170,540	£959,843	www.powerandcables.com/21stcentury-costs-of-underground-distribution/
Heat Pump Installation	£7,000 x 900	£6,300,000	energysavingtrust.org.uk
Total Cost	N/A	£27,433,370	Calculation

For the use of a 283 MW Power to Gas (PtG) Hydrogen CCGT set-up the Pyo, M.-J., et el, 2021 (Table 10) study calculates that a cost of $1.18 billion is required with a OPEX saving of $0.19 billion / year and a payback of just 7.7 years so the low cost that is associated with it may prove to be correct.

Having said that, it is likely that this system will also require a battery storage device and smart grid set-up in order to function in the same manner as the electrical system in Route 1. This would add to the cost but would need to be modelled against the system requirements more precisely.

6.7 Route 3 – Fuel Cost

The modelled GT in the Pyo, M.-J., et el, 2021 study was based on a 283MW GT with an H2 mass flow through the combustor of 6.08 kg/s. Using this mass flow, the 7-day storage of 7,162 kg would be used up in:

$$\frac{7{,}162}{6.08} = 1177.96\ seconds = 19.63\ minutes$$

With the CCGT plant being 61.4 % efficient, for the peak week consumption, it would take:

$$\frac{336{,}890}{0.614} = 548{,}680\ kWh$$

This equates to:

$$\frac{548{,}680}{33.6} = 16{,}329\ kg$$

For the 7-day week and:

$$\frac{16{,}573}{7} = 2{,}332\ kg$$

Per day and 11,660 kg required for storage for the 7-day period.

The levelized cost for Route 3 is £0.37/kWh (37p/kWh) based on the system costs and given a 5-year period to start with. This is far more than the OfGem calculated cost of electricity at 14.38p/kWh and shows the expense of using hydrogen as a gas when it is not being mass produced as a source for electricity in a CCGT.

6.8 Route 3 – Miscellaneous Factors

With gas turbine plants having relatively quick start up times (2-3 minutes to full output) (A.G. Ter-Gazarian, 2011, IET, Energy Storage for Power Systems, 2nd Edition, Power and Energy Series 63, p. 20) to be able to meet gaps in production from the vast array of renewables that are being installed in and around the UK, they are well suited to form part of the energy mix in the future. With hydrogen being a clean burning fuel given the right abatement of NO_x emissions it is a clear sideways step in order to maintain the UK's mix of energy generation.

7.0 Results

Comparing the results from the MIDAS data at the Leuchars site to those of the H100 project proposal the data does line up with the inputs used for the project which validates the findings in this thesis.

The capacity of the system to supply the required heating to the 900 homes and the efficiency of each system for the three routes as well as the total system cost and fuel cost have been compared in Table 13 below:

Table 13 - Results

Route	Capacity (%)	Efficiency (%)	System Cost (£)	Energy Cost (£ / kWh)
1 – Electric	285	207	56,683,901	0.32
2 – Hydrogen Gas	78	56.3	17,261,610	0.4
3 – Hydrogen CCGT	130	96	27,433,370	0.37

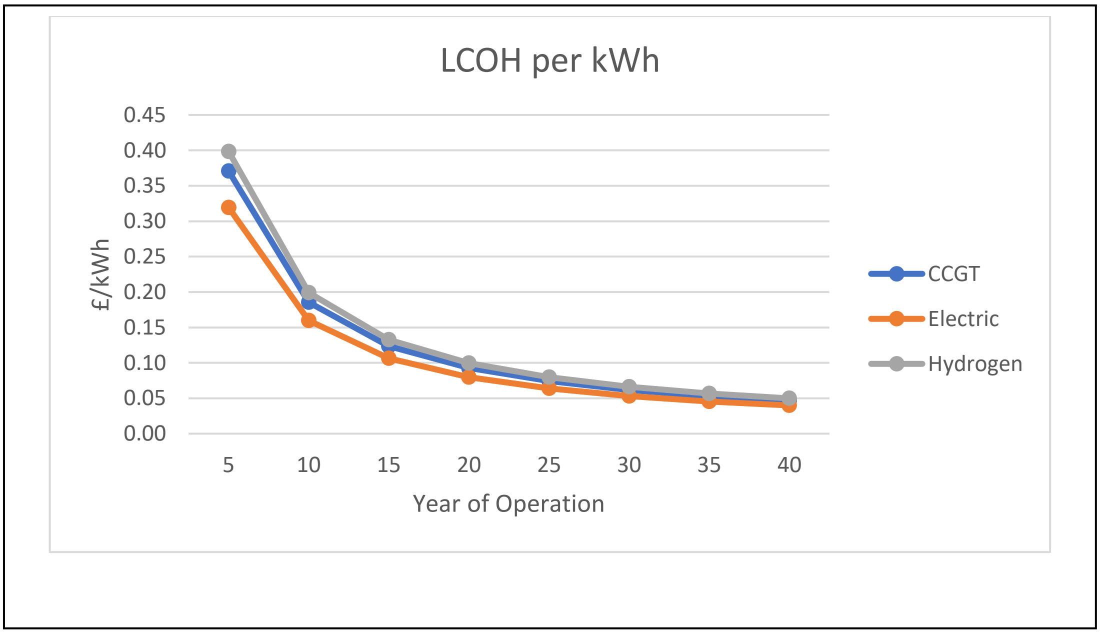

Figure 11 - Levelized Costs in £ per kWh

Route 1 and Route 3 both supply the capacity for the system as well as a surplus and are both far more efficient than the hydrogen gas to boiler system in Route 2. As such they both look like better options over the pure hydrogen system.

The efficiency of the electric systems is far higher than that of the pure gas system and the capacity of the system is only reached by Routes 1 and 3 using the heat pumps. If using hydrogen gas straight to domestic boilers, then the system will need an external input of hydrogen from another source which will add to the cost of the system in the terms of millions unless grid electricity or another source is used to power the electrolyser. With offshore wind around the UK predicted to increase and the possibility of creating hydrogen offshore then supplying the UK through pipelines Route 2 is possible but not ideal with the system running at such a low efficiency.

The system costs tell a story that while the efficiency of Route 1 is not matched, the cost of installing chemical storage batteries puts it well above Routes 2 and 3 and while the CCGT plant does have moderate costs it is also on a very small scale and has been costed as such, which does not fully reflect the expense or practicality of creating a separate CCGT plant for 900 homes and is a known flaw in the above calculations.

With the levelized costs the results show that all three routes are separated by only £0.1 / kWh (10p / kWh) which is surprising given the gulf in efficiencies for the three routes but reasonable when the system costs are taken into account.

8.0 Further Issues

There are several other issues surrounding the transition from natural gas to hydrogen gas in the UK gas network. A few of these will be discussed in the sections below.

8.1 Safety

Electrical safety will be key to both Routes 1 and 3 with the heat pump requirements meaning an upgrade to the electrical system but this should not affect those living in the houses with the heat pumps being installed.

For Routes 2 and 3, Control of Major Accident Hazards (COMAH) regulations (https://www.hse.gov.uk/comah/) cover sites for both lower and upper tiers of the regulations. If the storage for the peak demand is required to be covered then this will apply to the site for both Routes 2 and 3. This does put extra requirements on the storage site for both inspection and control of the named substances. Routes 2 and 3 do have the largest safety requirements with having hydrogen gas use/storage on a large scale. The HSE have been engaged in talks with the H100 project since pre-construction (NIC Report, p. 39) which should facilitate a good level of risk analysis and control.

Leak detection for hydrogen is another worry but technology currently exists and have already been developed to detect hydrogen. The smell that is added to natural gas is also to be used in the SGN network for hydrogen to enable olfactory detection. Leak detection is relatively straight forward with sensors currently available on the market that can pick up hydrogen at low levels (Crowcon (https://www.crowcon.com), Honeywell (https://www.honeywell.com), Draeger (https://www.draeger.com), etc.).

Issues around hydrogen leaking inside buildings, being odourless, colourless and with a lack of smell as well as burning with an invisible flame (P. E. Dodds, S. Demoullin, 2013, Elsevier, Hydrogen Energy, Conversion of the UK gas system to transport hydrogen) will need to be addressed before it can be used in a domestic setting. The higher flow rate leads to an increased flame speed and could lead to a flashback in the system. Although the current natural gas system may be correctly rated with hydrogen on the Wobbe indices, all burner heads and seals would required to be replaced (P. E. Dodds, S. Demoullin, 2013).

The mix of hydrogen with natural gas while hydrogen production grows in the UK is also an option and the ratio of hydrogen by volume in natural gas without an adverse effect on the system has been put at 2%-3% in the UK (N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing, p. 12)

SGN have taken safety as part of the project in upgrading to hydrogen and have even gone as far as including slides on this in their Energy Futures presentation (A. Scott, 2019, SGN Energy Futures Hydrogen Vision, SGN, SGN Energy Futures Presentation 2019.pdf,) which includes a safety management framework, safety case and some safety statistics for other risks in the home such as electrocution (0.364, twice as high), CO poisoning from a solid fuel appliance (9.40, 64 times as high) and a lightning strike (0.0012, 123 times lower) compared to the one statistic for hydrogen which is that of CO poisoning from a natural gas appliance using the Wobbe Index to gauge hydrogen (51.4 MJ/m^3 = 0.147).

8.1.1 Regulation

There is currently no regulation within the UK around supplying or using hydrogen and so all efforts thus far are being based on best practice. That is why existing companies that are dealing with natural gas have been chosen in this thesis due to their existing expertise in handling gas and knowledge of both the system and delivery requirements.

There has already been some work done by the HSE on the safety regulation side of hydrogen but there are no set regulation or guidelines such as approved codes of practice (ACOP) which exist for gas (HSE, Gas Supply Industry Health and Safety, https://www.hse.gov.uk/gas/supply/index.htm) and other industries.

8.2 Training

Following on from the lack of regulation within the UK, retraining of personnel will be required in order to fit and service hydrogen pipework and appliances. This is not a major issue however as the process is fairly similar to natural gas with many transferable skills. Programs such as the Gas Safe Engineer (Gas Safe Register, https://www.gassaferegister.co.uk) process will need to be adjusted and brought up to speed with whatever regulation is brought into place in order to ensure a safe network is created with reliable installations.

8.3 Insulation of Homes

An option for improving thermal performance of households is also to increase the insulation by various means such as wall cavity filling, double or triple glazed windows and roof insulation. All of these options would reduce the demand described in this thesis and reduce the energy required for heating domestic properties across the UK as a whole.

8.4 UK Wide Energy Use

The business case for the H100 Project opens with the following paragraph:
"Natural gas is currently the main source of energy in the UK economy, supplying 37.7% of primary energy demand in 2018 (DUKES 2018). 509.24 TWh of natural gas was demanded by the UK economy in 2018 at the point of final use for the heat of its combustion (for uses such as space heating and industrial processes), compared to 299.64 TWh of electricity (of which 37.36% was produced by gas generation)." (NIC Report, Project Business Case p. 13). From this it is clear that natural gas is a huge contributor to the UK energy economy. Replacing it with a Net Zero source of energy within the timescales promised by the government would require a rapid shift to an electrical network and a huge uptake by consumer and private companies along with strong backing both in policies and grants from the UK government.

8.5 Future Developments

Large scale hydrogen projects have been proposed by governments both in the UK (www.gov.uk) and US (www.publicpower.org), as well as large private energy companies such as BP planning developments in line with their Teeside project (www.thetimes.co.uk) which aims to make the area a hydrogen hub. If these developments all go ahead within the time scales, they should reduce the cost of hydrogen production to an affordable level. This is especially true if the cost of electricity and natural gas keeps increasing in line with recent trends over the past year (2021-2022).

Should hydrogen production through electrolysis using green energy become large scale in the UK, as is likely with the recent round of Crown Estate leasing (www.thecrownestate.co.uk) going to energy companies looking to develop projects such as the Dolphyn offshore hydrogen generation project (www.ermdolphyn.erm.com, ERM Website) (Doosan Babcock, All Energy Presentation, 2022, 900 T/year per turbine), then there should be enough hydrogen produced to cope with the gaps in production from onshore wind or solar with 4GW of supply being estimated as enough to fuel 1.5 million homes.

9.0 Literature Review

With the Net Zero goals being set by both the UK Government (Net Zero Strategy: Build Back Greener, 2021, UK Government) and the Scottish Government (Climate Change Act, 2019, Scottish Government) and with domestic energy use in the UK being only second to transport (DUKES, 2021) the need to switch away from fossil fuels and towards an alternative green source of energy for domestic use is the subject of much debate. There are many contenders but renewable electric and hydrogen have both made strides to secure funding and research.

This review has looked at academic papers, company papers and websites as well as government papers in order to gauge what is going on in the country and which direction is being chosen while it heads towards Net Zero.

Renewable electric generation in the country has been growing steadily over the past 15 years and with the Crown Estate round 4 leasing (Crown Estate leasing, 2022, Round 4) due to bring new offshore wind turbines into the fold there will be a large generation of renewable electricity. Whether this is used as electrical energy itself or changed into hydrogen for use as gas is still being debated.

If we are to look outside the bounds of pure efficiency there are comparisons to be made between electric and hydrogen systems within the UK:

The use of hydrogen as a gas in the UK network is not an original idea and manufactured hydrogen gas (in a mix with other gases) was used as recently as the 1960’s, at which point it was replaced by the natural gas that had been discovered in the North Sea. This led to a decade long transition in the UK to a natural gas network that still exists today (P. E. Dodds, S, Demoullin, 2013, Elsevier, Conversion of the UK gas system to transport hydrogen).

However, upgrading the electrical network will likely be a top priority in the UK due to the rise of electric vehicles.

With much of the research on the UK gas system focused on blue hydrogen (M. Noussan, et. al., 2021, The Role of Green and Blue Hydrogen in the Energy Transition – A Technological and Geopolitical Perspective, Sustainability, Volume 13, p. 1-26) which is produced from fossil fuels, CCS technologies or biogas as a replacement for natural gas, the switch to green hydrogen has not been well established and researched as a route for the UK to switch to by 2050. With its zero CO_2 emissions and NO_x emissions that could be abated or avoided at lower combustion temperatures it is a far greener and more sustainable option for the future in the UK gas network.

With companies such as Bosch Worcester supplying both hydrogen boilers (https://www.worcester-bosch.co.uk/hydrogen) and heat pumps (https://www.worcester-bosch.co.uk/heat-pumps) as well as companies such as British Gas informing customers that there is not enough hydrogen currently being produced to replace natural gas (https://www.britishgas.co.uk/the-source/greener-living/hydrogen-boilers.html) it would seem that there is a split between supply companies but that generally electric heat pumps are more prominent as they can be installed and used immediately.

9.1.1 Route 1

Research into renewable electric wind power and the use of heat pumps has been fairly well documented with the UK government and private electric companies all publishing various documents on its use and future. It has shown a high efficiency route with moderate costs and variable generation but ultimately one that will and has provided a lot of energy to the UK. The exact details of these systems are often not published however due to them being owned and run privately leaving academic studies to plug the information gap.

For the battery storage in Route 1 this has been modelled very simplistically for a peak demand in kWh over the required period. Studies such as that carried out for sizing batteries for PV and wind technologies by K.S. Sandhu, 2016 (K.S. Sandhu, et.al., 2016, International Journal of Energy Research, 40, 1221-1234) can be used to give far more accurate storage calculations for VRE's than have been used in this study.

Heat pump use being highly efficient even in colder weather and for the same housing type as in the Scottish market has been documented in studies such as (N.J. Kelly, J. Cockroft, 2010, Analysis of retrofit ASHP performance: Results from detailed simulations and comparison to field trial data, Elsevier, Energy and Buildings 43 (2011), 239-245) which did show a drop in performance in colder weather, and the actual modelling of each property can produce very different requirements depending on the model used and information available for the property, giving ranges of up to 80 kWh difference in the system demand (A. Anderson et. Al, A probabilistic Model for Characterising Heat Pump Electrical Demand versus Temperature, University of Strathclyde).

With ground source heat pumps (GSHP) being the predominant market for heat pumps in 2007 (H. Singh et al., 2010, Factors Influencing the Uptake of Heat Pump Technology by the UK Domestic Sector Renewable Energy 35, 873-878) and air source heat pumps (ASHP) rapidly growing in market share up to 75 % in 2017 (J. Love et. al., 2017, The Addition of Heat Pump Electricity Load Profiles to GB Electricity Demand: Evidence from a heat pump field trial, Applied Energy, 204, 332-342) and including April 2022 where they made up 68 % of accredited applications (RHI Report, April 2022) this shows a switch away from the digging and space usage associated with GSHP's (which only made up 13 % in the RHI April 2022 table) and towards more easily installable and retrofittable ASHP's.

With government schemes for installation of new heat pumps which have included the Renewable Heat Incentive (RHI) and Green Homes Grant voucher scheme schemes there is definite backing towards installation of heat pumps of all kinds from the UK Government side, with this being in competition with other systems however such as solar.

Research has shown some customers have found the cost to be "slightly expensive" or even "too expensive" compared to alternatives, but with longer working lives (25 compared to 15 years for a gas boiler) they may overtake any form of gas as the main way to heat an indoor space (H. Singh et al., 2010).

There is of course how the mass electrification of heating will also affect the national grid infrastructure. J. Love et. al. have looked in to this (J. Love et. al. 2017) and found that the evening peak demand for the grid increased by 14 % in line with the usual grid peak in the evening and the ramp rate increased by 6.1 %. With a mean capacity of 8.11-10.9 for the ASHP's this is fairly representative of the study used in this thesis, although this study only goes up to 20% of houses having installed heat pumps that peak demand could be in the region of 70 % higher if all homes had a heat pump installed. They do note that this could have an aggregated impact at a national level which is estimated at 40 GW of additional electrical generation capacity (N. Eyre, P. Baruah, 2015, Energy Policy, Volume 87, 641-653) and so more research would be required.

The use of heat pumps as a behavioural change is acknowledged in some studies (A. Chapman et. al., 2019, International Journal of Hydrogen Energy, 44, 6371-6382) but is not dealt with in depth as the cost of switching between systems has been put at $2,200 for a gas to hydrogen conversion as opposed to $9,600-$14,800 for air pumps. As was discussed in the levelized costs section, the running costs for an electric system should be lower but this capital expenditure, if not funded by a third party, may well dissuade homeowners.

9.1.2 Route 2

The use of electrolysis and hydrogen boilers is also fairly well documented with the UK government and private gas companies all publishing various documents on its use and future. The exact details, again, are often kept private due to private companies running the systems.

Electrolysis has many different forms (Polymer Electrolyte membrane (PEM), Anion Exchange Membrane [AEM], Solid Oxide Electrolyser [SOE]) but all plants are slowly becoming more efficient with aims to reduce energy use and increase efficiency, in turn brining down levelized costs of hydrogen (D. Parra, M.K. Patel, 2016, Techno-economic implications of the electrolyser technology and size for power-to-gas systems, International Journal of Hydrogen Energy, Volume 41, Issue 6, Pages 3748-3761).

Compression technologies may not be entirely necessary given that electrolysers can operate at high enough pressure to allow pressurised storage. The option to have a compressor on site is still a valid one however since transport applications require hydrogen to be compressed to 200 bar, 700 bar or higher in order to fill the tanks for the fuel cells (P. Corbo, F. Migliardini, O. Veneri, 2011, Hydrogen Fuel Cells for Road Vehicles, Green Energy Technology, p. 59). This compression is always going to be a drop in efficiency for the system.

Gas boilers were also in the study conducted by J. Love et. al. 2017 in which they found the boiler system peak to mean ratio 1.67 compared to 1.37 for heat pump and the peak to trough ratio calculated that the boiler fell to 16 % of its peak through the night whereas the heat pumps fell to 41 % of their peak overnight. The peak daily power consumption was surprisingly similar for both boilers and heat pumps at temperatures under 12-13°C, however, over this the boiler required far less energy.

9.1.3 Route 3

The use of hydrogen in a gas turbine plant has been documented mostly in parts such as the burner design to alter the injection nozzles in order to reduce the probability of flashback (Kang h., 2021, Combustion dynamics of multi-element lean-premixed hydrogen-air flame ensemble, Combustion and Flame, Elsevier, 233, 111585) and reduction in NOx emissions (S. Li, et. al., 2016, International Journal of Hydrogen Energy, 42, 7060-7070) (J. Berger, 2021, Scaling of an Aviation hydrogen Micromix Injector Design for Industrial GT Combustion Applications, Aerotec. Missili Spaz) by up to 80 % with the correct pre-mixing of air and design of the burner (A. Haj Ayed, 2016, Propulsion and Power Research, 6(1), 15-24) or emissions capturing and only in a few studies as a whole plant (Pyo, M.-J., et el, 2021). Even when this is done as a whole plant, it is often compared to natural gas for the process instead of against an electric source for the end use as has been done in this thesis. Mixing 30 % natural gas with 80 % hydrogen by volume in a CCGT can reduce CO2 emissions by 50% (N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing, p. 8) which can be made safer by injecting steam to try to prevent flashback in concentrations of hydrogen to above 10 % and up to 35 % in lean pre-mixed micro gas turbines (F. Reale, 2022, Effects of Steam Injection on the

Permissible Hydrogen Content and Gaseous Emissions in a Micro Gas Turbine Supplied by a Mixture of CH_4 and H_2: a CFD Analysis, Energies, Volume 15, 2914) but this will not bring the UK to the net Zero target.

Efficiencies of hydrogen fuel cells between 50%-90% are currently being cited for Proton Exchange Membrane Fuel Cells (PEMFC), Phosphoric Acid Fuel Cells, Molten Carbonate Fuel Cells (MCFC) and Solid Oxide Fuel Cells (SOFC) (I. I. Baldukhaeva et. al. 2021, IOP Conference Series, Earth Environmental Science, 751 012113). All of these technologies could theoretically be used instead of gas in the home to allow for conversion of hydrogen to electrical energy at the end point. Whilst this would involve fuel cells being installed at each home instead of boilers, it would allow the gas to be transported up to the point of use. This may help to ease any strain on the national grid infrastructure whilst still using hydrogen gas for its storage properties over the purely electric system.

10.0 Conclusions

The long-term storage capability of hydrogen mixed with the variability of a renewable energy supply and the requirement for grid curtailment when the energy is not being used, along with the low costs of switching to hydrogen gas for current systems leads to the conclusion that a mixed system in the UK would be the best way forward.

Whilst the efficiency of a purely electric system in Route 1 cannot currently be beaten by hydrogen, the cost of battery storage and the materials involved are both going to increase in the future and so a cheaper and longer-term storage method is required.

With low-cost natural storage of hydrogen in Route 2 and 3 and a relatively efficient use of hydrogen to produce electricity in Route 3 this could help the UK reach its goal of Net Zero by 2050 if all three routes were followed.

Upgrading the current gas network to supply hydrogen is a short to medium term solution in order to reduce reliance on natural gas and allow time to install heat pumps and infrastructure required to support electrification in the long-term would spread the capital investment and workload to enable a smoother transition to a Net Zero energy economy.

There are several areas of study that this thesis has highlighted to better understand these systems and their impact in the UK. These areas include:

- Optimisation of all systems to increase performance and efficiency through in-depth research and cooperation with government and private companies alike.
- Smart grid technology in routes 1 and 3 to increase performance and efficiency.
- Micro-CHP plants using fuel cells (N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing, p. 6) could also be a route for future study to look into.
- From the perspective of those installing heat pumps, it would be prudent to have further research done in this area in order to gauge the market barrier that behaviour would play in replacing gas boilers with heat pumps and to gauge the level of support available from the government in funding.

11.0 References

Digest of United Kingdom Energy Statistics [DUKES], 2021 - https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2021

HM Government, 2021, Net Zero Strategy: Build Back Greener - https://www.gov.uk/government/publications/net-zero-strategy

NIC H100 Fife, 2020, SGN - https://www.ofgem.gov.uk/sites/default/files/docs/2020/11/nic_2020_h100_fife_final_submission_20.10.20_-_redacted_ofgem_publication_applied.pdf

Company Secretary, 2020, NIC Decision Document, OfGem

SGN Website - www.SGN.co.uk (Accessed on 10-Jun-22)

Fife Council Website - www.fife.gov.uk (Accessed on 10-Jun-22)

H100 Project Website - www.h100fife.co.uk (Accessed on 10-Jun-22)

Kiwa Website - H100 Partner - www.kiwa.com (Accessed on 10-Jun-22)

OfGem Regulator Website - www.ofgem.gov.uk (Accessed on 10-Jun-22)

Scottish Government Website - www.gov.scot (Accessed on 10-Jun-22)

Scottish Governments Statistics Hub- https://scotland.shinyapps.io/sg-scottish-energy-statistics - (Accessed on 11-Jun-22)

D. MacKay, 2009, Sustainable Energy – Without The Hot Air, UIT

UN High Commission on Refugees - https://www.unhcr.org

C. Crawford, P. Manfield, A McRobie, 2005, Energy and Buildings, Volume 37, p. 471-483

Energy Lens Website – Degree Day Explanation - https://www.energylens.com/articles/degree-days (Accessed on 25-Jun-22)

CEDA MIDAS Website – Hourly Weather Data - https://catalogue.ceda.ac.uk (Accessed on 24-Jun-22)

A.G. Ter-Gazarian, 2011, IET, Energy Storage for Power Systems, 2nd Edition, Power and Energy Series 63

XE Exchange Rate Website - www.xe.com (Accessed on 01-Jul-22)

UK Government, BEIS, Hydrogen Production Costs, 2021 - https://www.gov.uk/government/publications/hydrogen-production-costs-2021

DOE Establishes Infrastructure Law's $9.5 Billion Clean Hydrogen Initiatives | American Public Power Association. Available at: https://www.publicpower.org/periodical/article/doe-establishes-infrastructure-laws-95-billion-clean-hydrogen-initiatives

Department of Energy seeks to cut cost of hydrogen by 80% | American Public Power Association. Available at: https://www.publicpower.org/periodical/article/department-energy-seeks-cut-cost-hydrogen-80

N.P. Brandon, Z. Kurban 2017, The Royal Society Publishing, Clean Energy and the Hydrogen Economy

Siemens Website – Wind Turbine - www.siemensgamesa.com (Accessed on 26-Jun-22)

N.P. Brandon, Z. Kurban, 2017, Clean Energy and the hydrogen economy, The Royal Society Publishing

N, Bhusal, 2020, IEEE, Optimal Sizing and Siting of Multi-purpose Utility-scale Shared Energy Storage Systems

M. Reaudin et. al., 2010, Energy for Sustainable Development, Volume 14, 302-314

P.A.J. Donkers et. al., 2017, A Review of Salt Hydrates For Seasonal Heat Storage in Domestic Applications, Applied Energy, Volume 199, Pages 45-68

IEEE Insulated Conductors Committee, 2019

Renewable Heat Incentive scheme - https://www.gov.uk/domestic-renewable-heat-incentive

RHI Report, April 2022, UK Government, RHI

Green Homes Grant voucher scheme - https://www.gov.uk/guidance/apply-for-the-green-homes-grant-scheme (Accessed on 20-Jul-22)

OfGem - (www.ofgem.gov.uk/publications/heat-pump-seasonal-performance-factor-spf-calculation-template

N.J. Kelly, J. Cockroft, 2010, Analysis of retrofit ASHP performance: Results from detailed simulations and comparison to field trial data, Elsevier, Energy and Buildings 43 (2011), 239-245

IRENA, Renewable Power Generation Costs, 2021

Renewables First Website – Turbine Costs - www.renewablesfirst.co.uk (Accessed on 18-Jul-22)

W. Cole, 2019, Cost Projections for Utility-Scale Battery Storage, National Renewable Energy Laboratory, www.nrel.gov/docs/fy19osti/73222.pdf

Financial Times Website – Battery Cost Rise as Lithium Demand Outstrips Supply, 2022, https://www.ft.com/content/31870961-dee4-4b79-8dca-47e78d29b420 (Accessed on 18-Jul-22)

Power Cables Website - https://www.powerandcables.com/21st-century-costs-of-underground-distribution (Accessed on 18-Jul-22)

Scottish Power, Leven Primary Fault Level Mitigation, ED2 Engineering Justification Paper, M. Plecas, 2021 - www.spenergynetworks.co.uk/userfiles/file/ED2-LRE-SPD-011-CV3-EJP%20-%20Leven%20Primary%20Fault%20Level%20Mitigation%20-%20Issue%202.pdf

Energy Saving Trust - Website - energysavingtrust.org.uk (Accessed on 19-Jul-22)

Tradesmen Costs - Website - tradesmencosts.co.uk/air-source-heat-pump (Accessed on 19-Jul-22)

OfGem website – Electricity Prices - https://www.ofgem.gov.uk/energy-data-and-research/data-portal/all-available-charts?sort=created (Accessed on 19-Jul-22)

Fife Local Government website - https://www.fife.gov.uk/kb/docs/articles/environment2/climate-change,-carbon-and-energy/h100-fife-hydrogen-heating-network (Accessed on 10-Jun-22)

G. Barnes, L. Bennet, C. Maxwell, Development of early, clean hydrogen production in Scotland, 2021

US Department Of Energy (DOE) - www.energy.gov (Accessed on 19-Jul-22)

Bessarabov et. al., 2016, PEM Electrolysis for Hydrogen Production: Principles and Applications, Taylor & Francis Group

I. Walker, B. Madden, F. Tahir, 2018, Hydrogen Supply Chain Evidence Base, UK Government, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760479/H2_supply_chain_evidence_-_publication_version.pdf

P. E. Dodds, S. Demoullin,2013, Hydrogen Energy, Conversion of the UK gas system to transport hydrogen, Elsevier

CMB. Tech Website – Hydrogen Tools - https://cmb.tech/hydrogen-tools (Accessed on 23-Jul-22)

Tank Shop Website – Tank Sales - https://thetankshop.co.uk (Accessed on 23-Jul-22)

B.D. James et. al., 2016, Final report: Hydrogen Storage System Cost Analysis, https://www.osti.gov/servlets/purl/1343975

H21 Leeds City Gate Report, 2016, Northern gas Networks, Kiwa Gastec, Amec Foster Wheeler, https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf

Cadent Gas Website - https://cadentgas.com (Accessed on 26-Jul-22)

A. Chapman, et al, 2019, A review of four case studies assessing the potential for hydrogen penetration of the future energy system, International Journal of Hydrogen Energy, Volume 44, p. 6371-6382

RAC Website - www.rac.co.uk (Accessed on 28-Jul-22)

AutoTrader Website - www.autotrader.co.uk (Accessed on 28-Jul-22)

WhatCar Website - www.whatcar.com (Accessed on 28-Jul-22)

BBC News Website - www.bbc.co.uk/news (Accessed on 28-Jul-22)

Hydrogen Tools Website - h2tools.org/bestpractices/storage-vessels (Accessed on 26-Jul-22)

Boiler Guide Website - https://www.boilerguide.co.uk (Accessed on 19-Jul-22)

D. Roddy, 2010, Advanced Power Plant Materials, Design and Technology, Wiley, Woodhead Publishing Limited

Pyo, M.-J., et el, 2021, A Comparative Feasibility Study of the Use of Hydrogen Produced from Surplus Wind Power for a Gas Turbine Combined Cycle Power Plant. Energies 2021, 14, 8342

Spirax Sarco Website - https://www.spiraxsarco.com/resources-and-design-tools/steam-tables/superheated-steam-region

Steam Tables Online - www.steamtablesonline.com

W. D. York, W. S. Ziminsky, E. Yilmaz, 2013, Development and testing of low NOx hydrogen combustion system for heavy-duty gas turbines, Journal of Engineering for Gas Turbines and Power, Volume. 135, 02201-4

M. Ditaranto, H. Li, T. Lovas, 2015, Concept of hydrogen fired gas turbine cycle with exhaust gas recirculation: Assessment of combustion and emissions performance, International Journal of Greenhouse Gas Control, 37, 377-383

M. Ditaranto, T. Heggset, D. Berstad, 2019, Concept of hydrogen fired gas turbine cycle with exhaust gas recirculation: Assessment of process performance, Energy, 192, 116646

Control of Major Accident Hazards (COMAH) regulations - https://www.hse.gov.uk/comah (Accessed on 28-Jun-22)

Crowcon https://www.crowcon.com (Accessed on 28-Jun-22)

Honeywell https://www.honeywell.com (Accessed on 28-Jun-22)

Draeger https://www.draeger.com (Accessed on 28-Jun-22)

A.Scott, 2019, SGN Energy Futures Hydrogen Vision, SGN, SGN Energy Futures Presentation 2019.pdf,) HSE, Gas Supply Industry Health and Safety, https://www.hse.gov.uk/gas/supply/index.htm

Gas Safe Register Website - https://www.gassaferegister.co.uk (Accessed on 28-Jun-22)

UK Government Hydrogen Strategy, 2021, - https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

US Hydrogen Projects - https://www.publicpower.org/policy-resolutions-2021 (Accessed on 05-Aug-22)

Crown Estate leasing, 2022, Round 4 - https://www.thecrownestate.co.uk/en-gb/media-and-insights/news/the-crown-estate-commits-50million-to-accelerate-the-uk-s-offshore-energy-ambitions-and-protect-the-marine-environment/

Dolphyn offshore hydrogen generation project - www.ermdolphyn.erm.com, ERM Website

Doosan Babcock, 2022, All Energy Presentation

Net Zero Strategy: Build Back Greener, 2021, UK Government

Scottish Government (Climate Change Act, 2019, Scottish Government

M. Noussan, et. al., 2021, The Role of Green and Blue Hydrogen in the Energy Transition – A Technological and Geopolitical Perspective, Sustainability, Volume 13, p. 1-26

Bosch Worcester – Hydrogen Website https://www.worcesterbosch.co.uk/hydrogen (Accessed on 19-Jul-22)

Bosch Worcester Heat Pumps Website - https://www.worcesterbosch.co.uk/heat-pumps (Accessed on 19-Jul-22)

British Gas – Hydrogen Boiler Website - https://www.britishgas.co.uk/the-source/greener-living/hydrogen-boilers.html (Accessed on 19-Jul-22)

K.S. Sandhu, et.al., 2016, International Journal of Energy Research, 40, 1221-1234

A. Anderson et. al, (No date) A probabilistic Model for Characterising Heat Pump Electrical Demand versus Temperature, University of Strathclyde

H. Singh et al., 2010, Factors Influencing the Uptake of Heat Pump Technology by the UK Domestic Sector Renewable Energy 35, 873-878

J. Love et. al., 2017, The Addition of Heat Pump Electricity Load Profiles to GB Electricity Demand: Evidence from a heat pump field trial, Applied Energy, 204, 332-342

N. Eyre, P. Baruah, 2015, Energy Policy, Volume 87, 641-653

D. Parra, M.K. Patel, 2016, Techno-economic implications of the electrolyser technology and size for power-to-gas systems, International Journal of Hydrogen Energy, Volume 41, Issue 6, Pages 3748-3761

P. Corbo, F. Migliardini, O. Veneri, 2011, Hydrogen Fuel Cells for Road Vehicles, Green Energy Technology, p. 59

Kang h., 2021, Combustion dynamics of multi-element lean-premixed hydrogen-air flame ensemble, Combustion and Flame, Elsevier, 233, 111585

S. Li, et. al., 2016, International Journal of Hydrogen Energy, 42, 7060-7070

J. Berger, 2021, Scaling of an Aviation hydrogen Micromix Injector Design for Industrial GT Combustion Applications, Aerotec. Missili Spaz

A. Haj Ayed, 2016, Propulsion and Power Research, 6(1), 15-24

F. Reale, 2022, Effects of Steam Injection on the Permissible Hydrogen Content and Gaseous Emissions in a Micro Gas Turbine Supplied by a Mixture of CH4 and H2: a CFD Analysis, Energies, Volume 15, 2914

I. I. Baldukhaeva et. al. 2021, IOP Conference Series, Earth Environmental Science, 751 012113

12.0 Appendices

12.1 Weather Data

12.1.1 2020

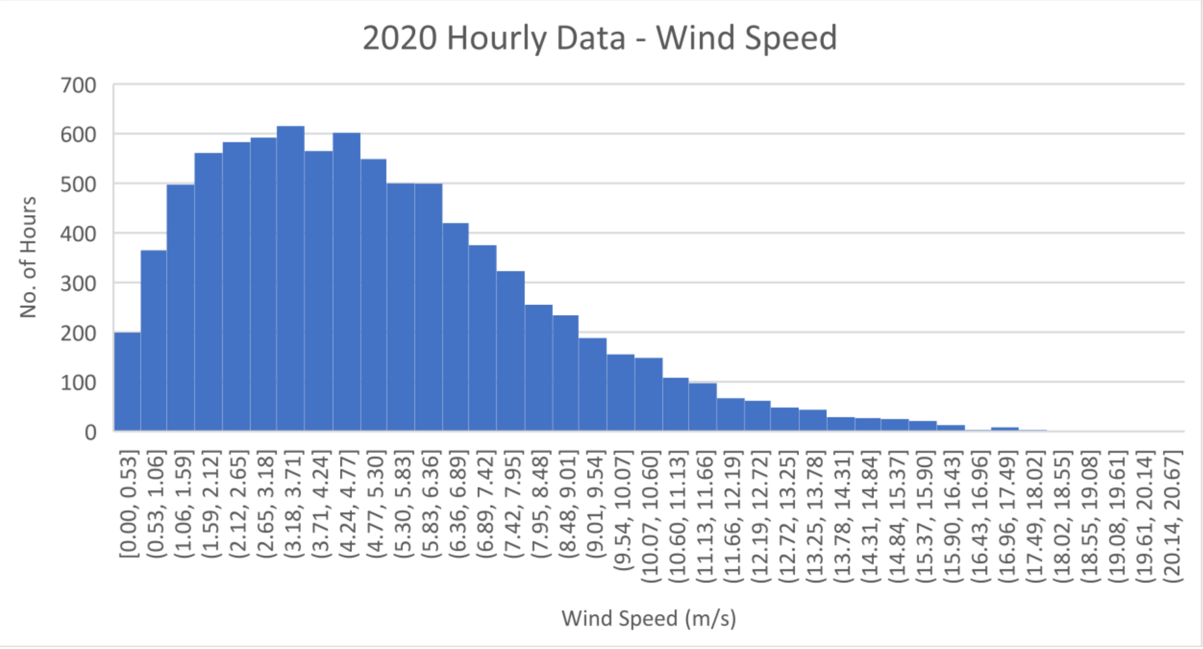

Figure 12 - 2020 Hourly Data - Wind Speed

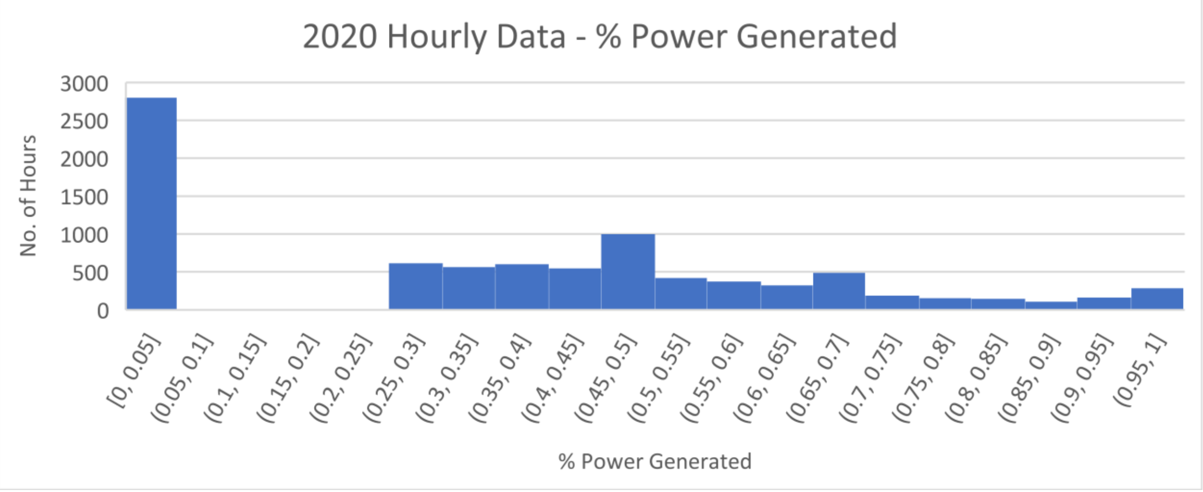

Figure 13 - 2020 Hourly Data - % Power Generated

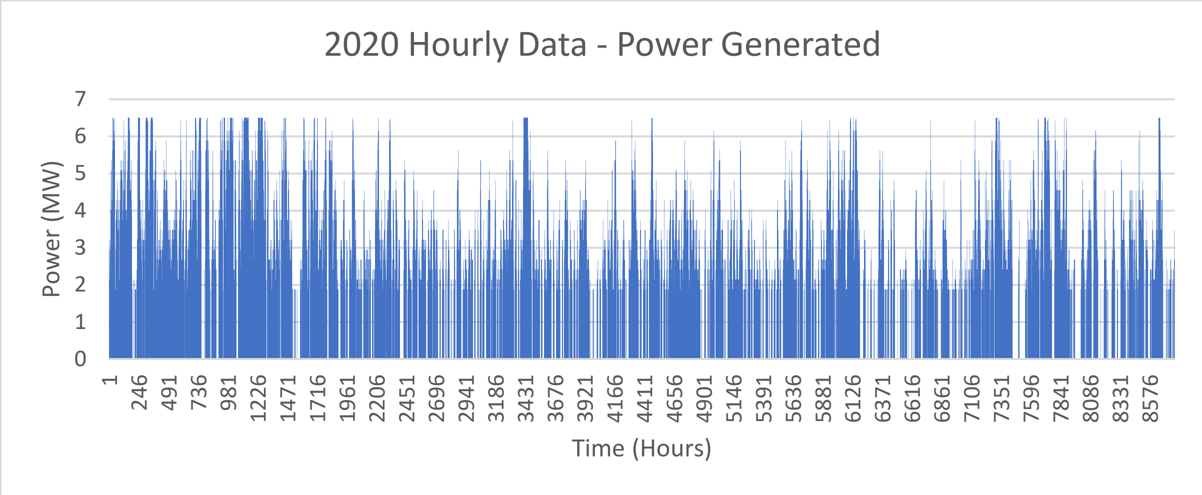

Figure 14 - 2020 Hourly Data - Power Generated

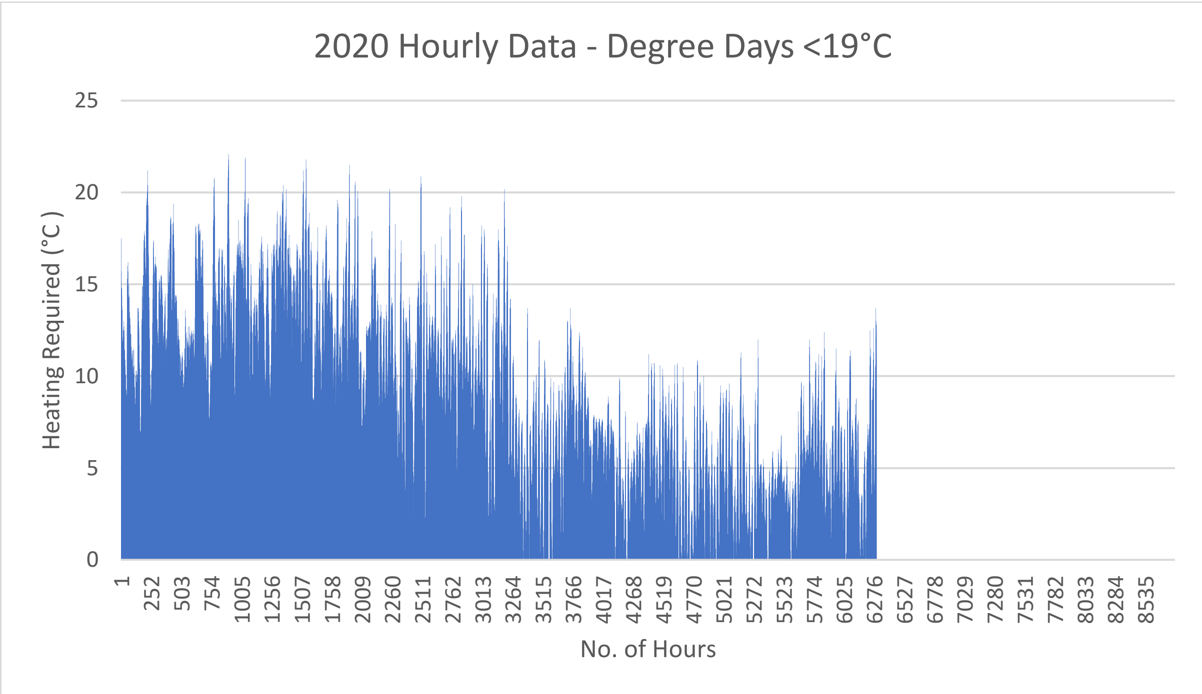

Figure 15 - 2020 Hourly Data - Degree Days <19C

12.1.2 2019

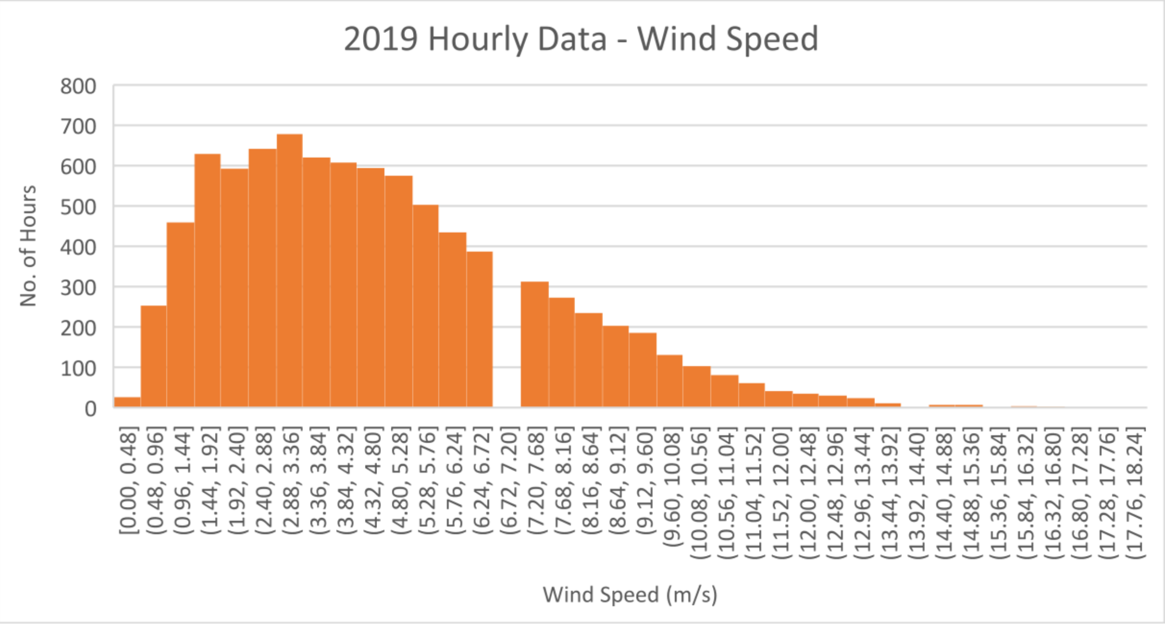

Figure 16 - 2019 Hourly Data - Wind Speed

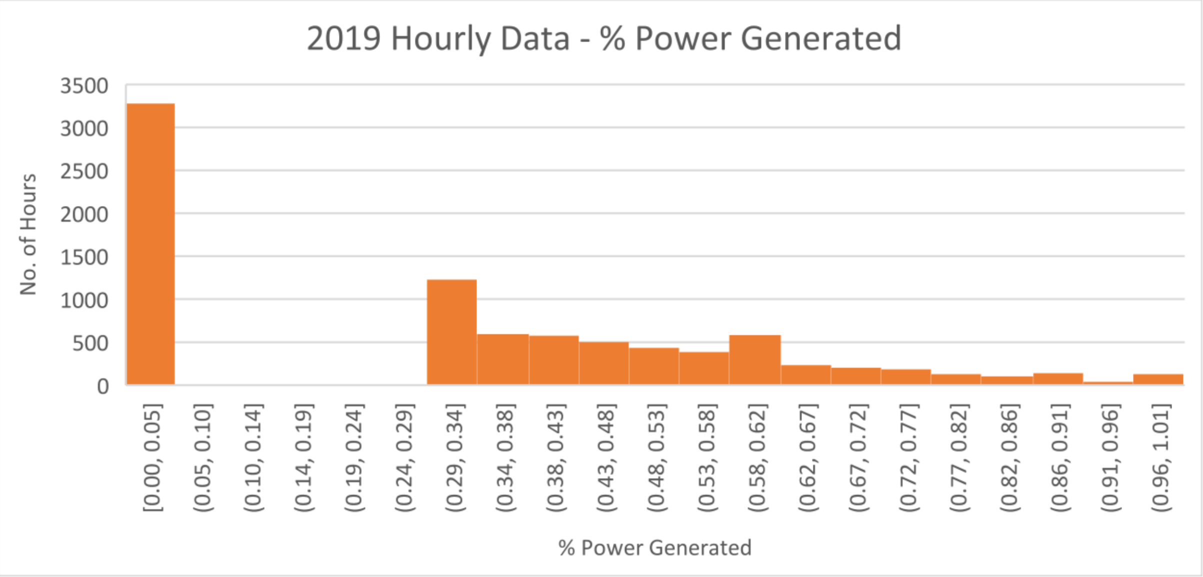

Figure 17 - 2019 Hourly Data - % Power Generated

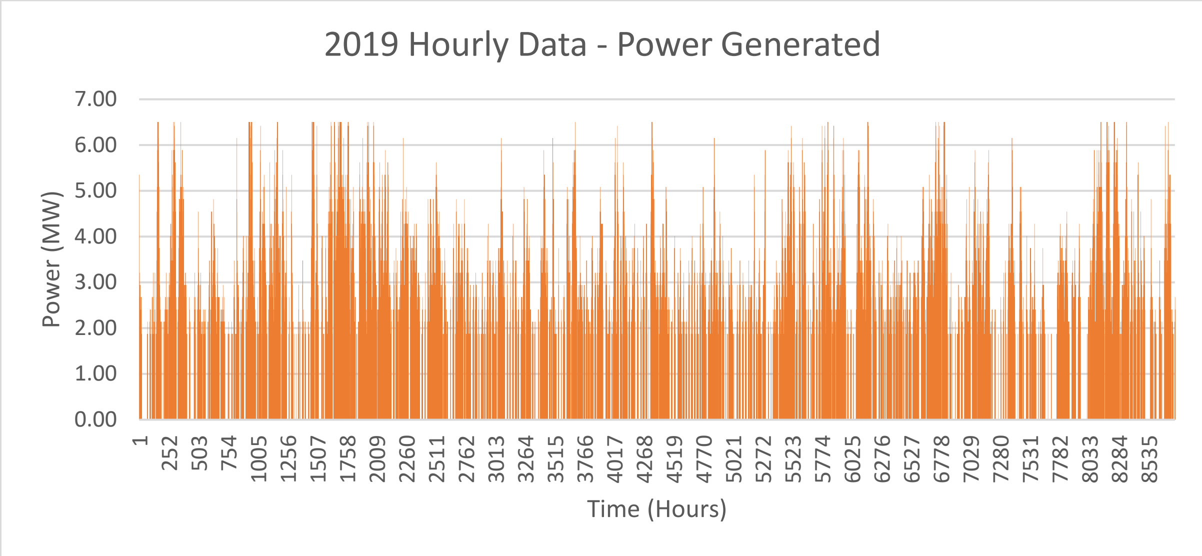

Figure 18 - 2019 Hourly Data - Power Generated

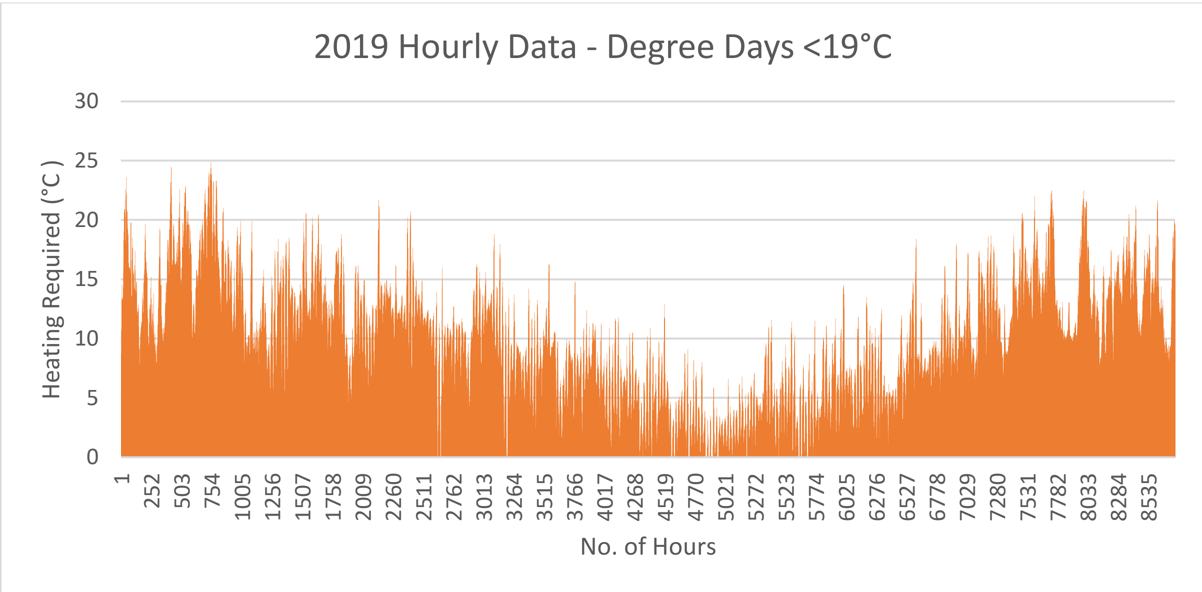

Figure 19 - 2019 Hourly Data - Degree Days <19C

12.1.3 2018

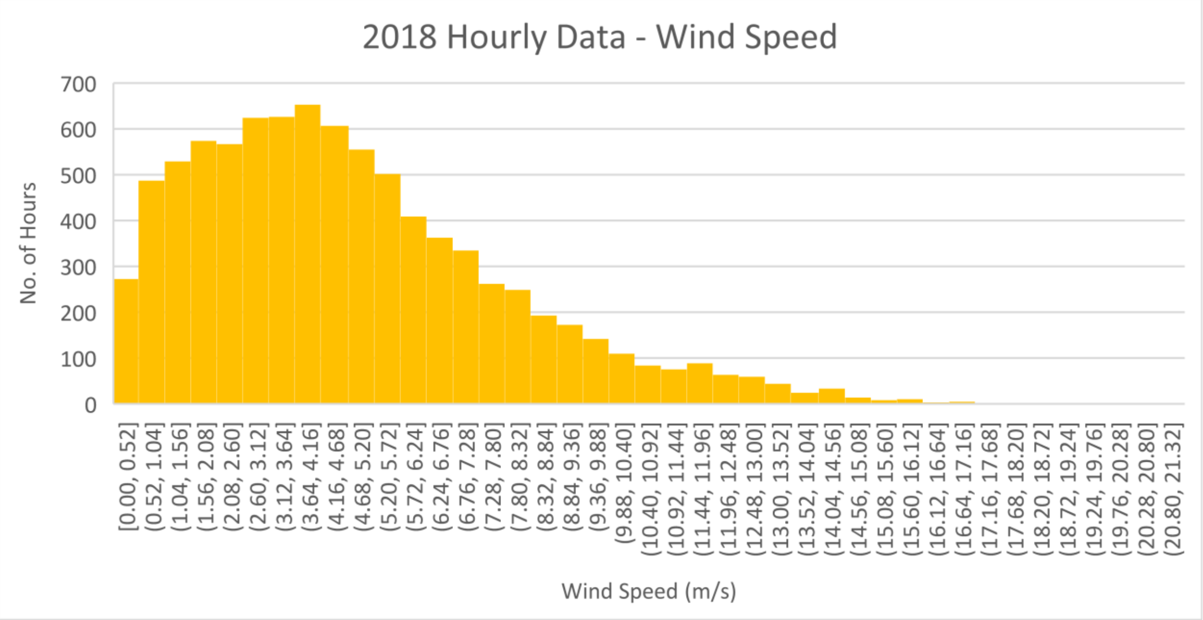

Figure 20 - 2018 Hourly Data - Wind Speed

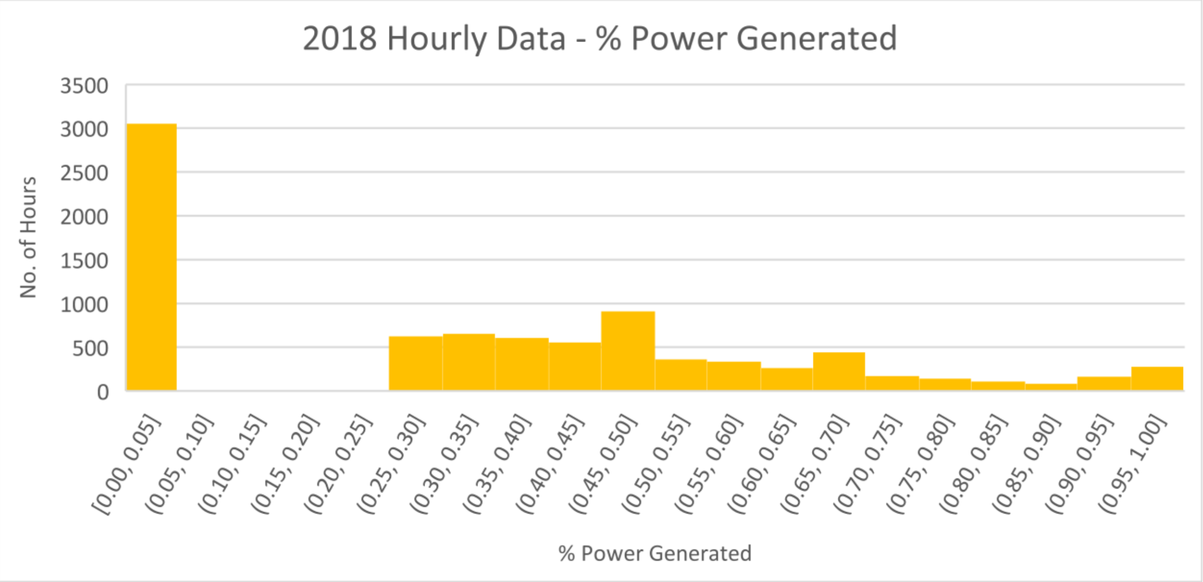

Figure 21 - 2018 Hourly Data - % Power Generated

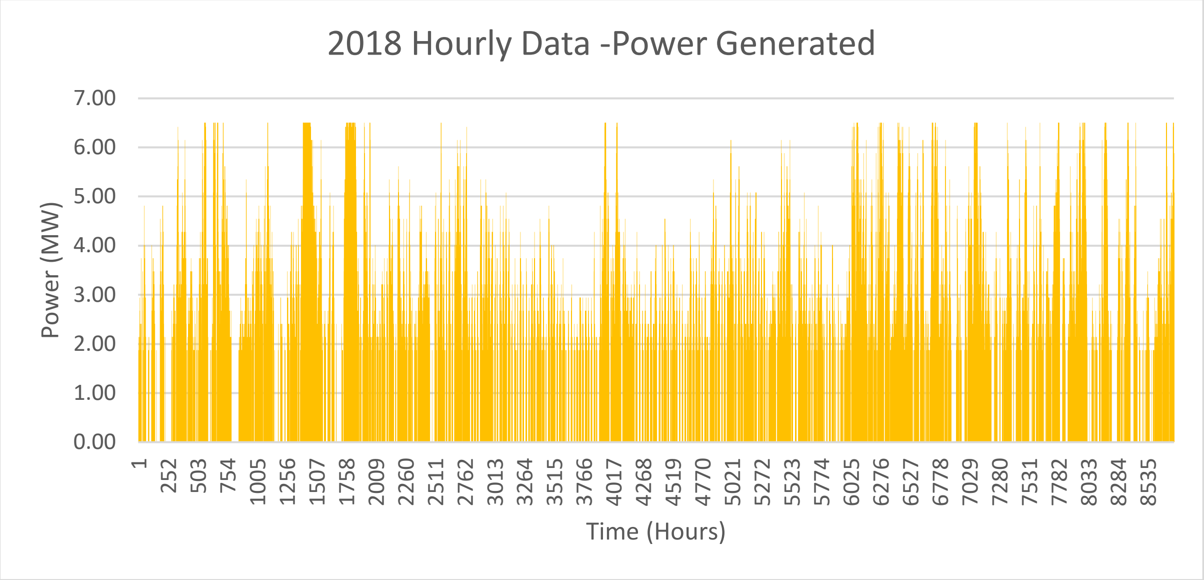

Figure 22 - 2018 Hourly Data - Power Generated

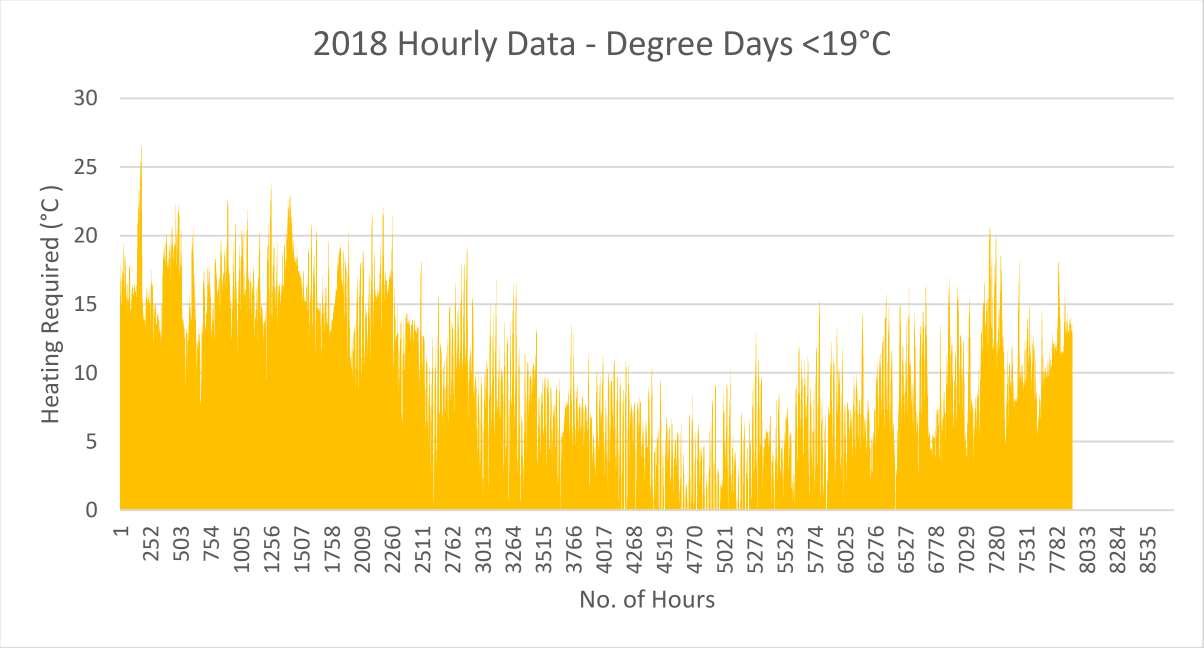

Figure 23 - 2018 Hourly Data - Degree Days <19C

12.1.4 2017

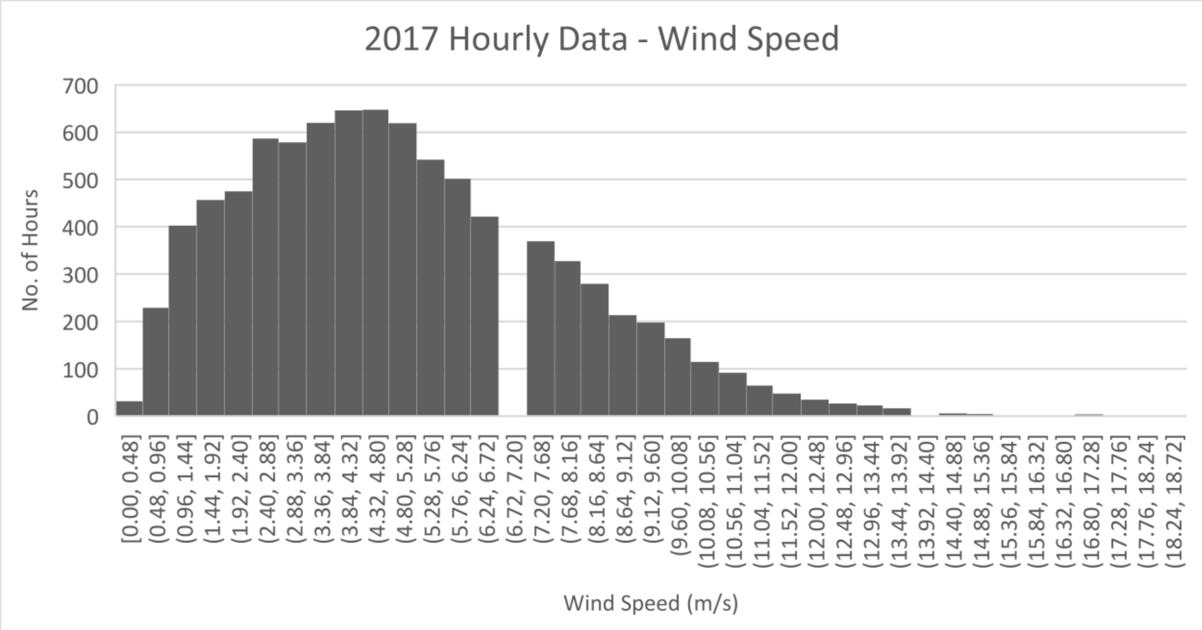

Figure 24 - 2017 Hourly Data - Wind Speed

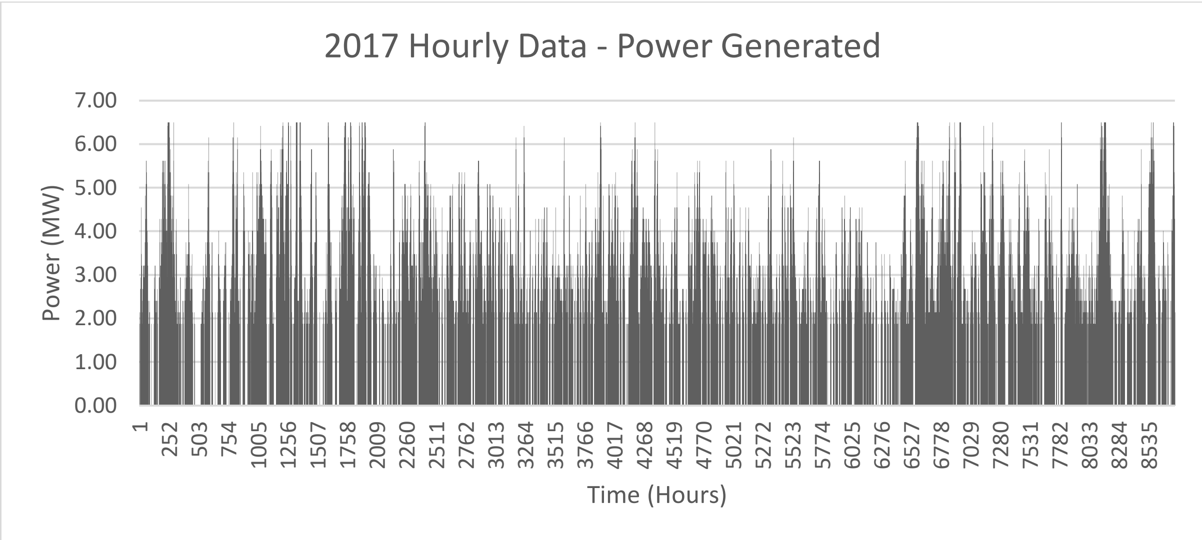

Figure 25 - 2017 Hourly Data - Power Generated

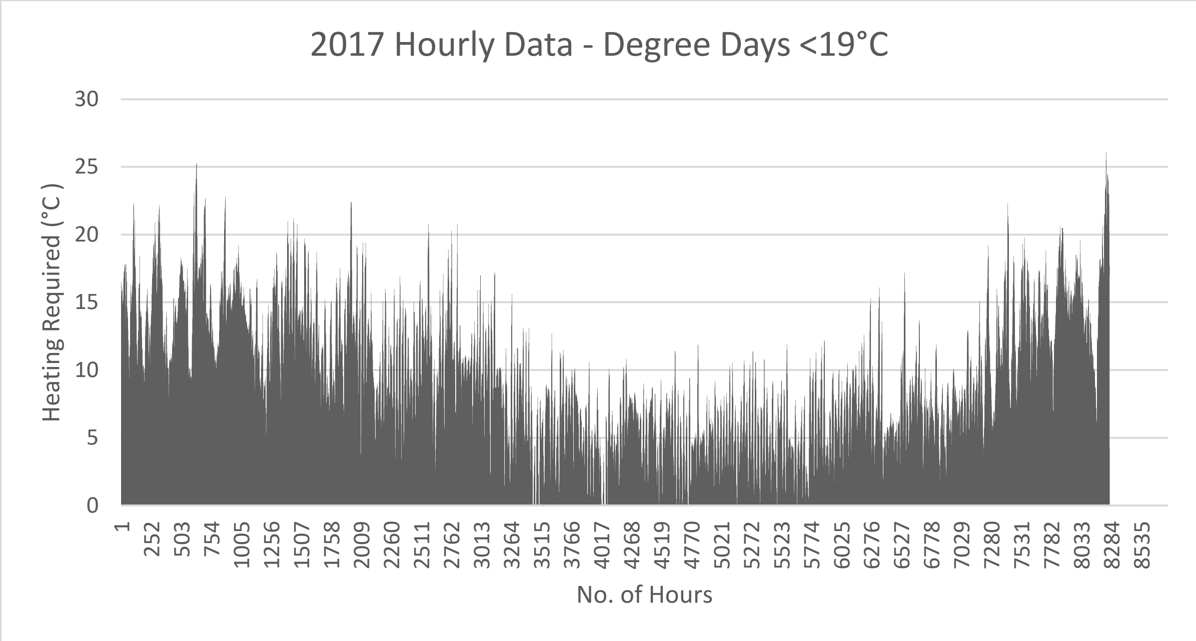

Figure 26 - 2017 Hourly Data - Degree Days <19C

12.2 Gas Calculations

For the gas portion of the CCGT in Section 5, the following calculations were carried out to validate the findings in the Pyo, M.-J., et el, 2021 paper.

Air is being used as the working fluid in this plant with Lamda (γ) = 1.4 for all equations.

Air intake temperature taken as 9.3°C (282.15 K).

12.2.1 Compressor

Air is being used as the working fluid in this plant with Lamda (γ) = 1.4 for all equations.

Compression equation (D. Roddy, 2010, Wiley, p. 9, Fig 1.2):

$$T_2 - T_1 = \frac{T_1((PR)0.286 - 1}{ή c}$$

$$ήc = \frac{T_2 s - T_1}{T_2 - T_1}$$

T_1 = Inlet temperature

T_2 = Discharge temperature

PR = Pressure Ratio

ήc = isentropic efficiency

$$ή = \frac{T2 - T1}{T2s - T1}$$

$$0.88 = \frac{T2 - 282.15}{664.62 - 282.15}$$

$$\frac{P_2}{P_1} = (\frac{T_2 s}{T_1})^{\frac{\gamma}{\gamma - 1}}$$

$$T2s = T1\ (\frac{P2}{P1})^{\frac{\gamma-1}{\gamma}} = 282.15(\frac{20}{1})^{0.286} = 664.62\ K$$

$$T2 = T1 + \frac{(T2s - T1)}{ή} = 282.15 + \frac{(664.62 - 282.15)}{0.88} = 716.78\ K$$

$$Wcomp = Cp\ (T2 - T1) = 1.005(716.78 - 282.15)$$
$$= 436.8\ kJ\ per\ kg(per\ kg\ air)$$

12.2.2 Combustion Chamber

Pressure remains equal to the compression stage but temperature is raised to 1500°C (1773.15 K).

12.2.3 Turbine

$$Wturbine = 436.8 = Cp(T3 - T4)$$

$$T4 = T3 - \frac{Wturbine}{Cp} = 1773.15 - \frac{436.15}{1.005} = 1338.55\ K$$

$$ή = 0.843 = \frac{T3 - T4}{T3 - T4s}$$

$$T4s = T3 - \frac{(T3 - T4)}{ή} = 1773.15 - \frac{(1773.15 - 1338.55)}{0.843} = 1257.65\ K$$

Isentropic Expansion equation:

$$\frac{T3}{T_1} = (\frac{P_2}{P_1})^{\frac{\gamma - 1}{\gamma}}$$

12.2.4 HRSG

$$\varepsilon = \frac{Tout - Tin}{Texhaust - Tin}$$

$$\varepsilon = \frac{1338.55 - 1773.15}{358.05 - 1773.15} = \frac{-434.6}{-1415.1} = 0.307 = 0.31 = 31\ \%$$

12.2.5 Total Gas System

$$ή\ (gas\ end\ to\ end) = \frac{1773.15 - 358.05}{1773.15} = 0.798 = 79.8\ \%$$

12.3 Steam Calculations

All steam temperatures and pressures were checked with the online tool and then used in the gas equations for system performance.

12.3.1 HP-Steam Turbine

Inputs	Pressure and Superheat Temperature	
Output	Single Value / Table	
Pressure	188	bar gauge
Superheat Temperature	595	°C
	Calculate / Reset / Print	
Saturation Temperature	361.040	°C
Degrees Superheat	233.960	°C
Specific Enthalpy of Water (h_f)	1.77201E06	J/kg
Specific Enthalpy of Evaporation (h_{fg})	698154	J/kg
Specific Enthalpy of Superheated Steam (h)	3534.59	kJ/kg
Density of Steam	52.0898	kg/m³
Specific Volume of Steam (v)	0.0191976	m³/kg
Specific Entropy of Water (s_f)	3933.23	J/kg K
Specific Entropy of Evaporation (s_{fg})	1100.86	J/kg K
Specific Entropy of Superheated Steam (s)	6.52669	kJ/kg K
Specific Heat of Steam (c_v)	1933.62	J/kg K
Specific Heat of Steam (c_p)	2752.06	J/kg K
Speed of sound	682.668	m/s
Dynamic Viscosity of Steam	3.36104E-05	Pa s
Isentropic Coefficient (k)	1.28878	
Compressibility Factor of Steam	0.905641	

Figure 27 - HP Steam Properties

12.3.2 IP-Steam Turbine

Inputs	Pressure and Superheat Temperature	
Output	Single Value / Table	
Pressure	50	bar gauge
Superheat Temperature	590	°C
	Calculate / Reset / Print	
Saturation Temperature	265.198	°C
Degrees Superheat	324.802	°C
Specific Enthalpy of Water (h_f)	1.16045E06	J/kg
Specific Enthalpy of Evaporation (h_{fg})	1.63240E06	J/kg
Specific Enthalpy of Superheated Steam (h)	3642.27	kJ/kg
Density of Steam	13.1362	kg/m³
Specific Volume of Steam (v)	0.0761254	m³/kg
Specific Entropy of Water (s_f)	2932.63	J/kg K
Specific Entropy of Evaporation (s_{fg})	3032.23	J/kg K
Specific Entropy of Superheated Steam (s)	7.22390	kJ/kg K
Specific Heat of Steam (c_v)	1783.39	J/kg K
Specific Heat of Steam (c_p)	2322.99	J/kg K
Speed of sound	702.070	m/s
Dynamic Viscosity of Steam	3.24091E-05	Pa s
Isentropic Coefficient (k)	1.26988	
Compressibility Factor of Steam	0.974849	

Figure 28 - IP Steam Properties

12.3.3 LP-Steam Turbine

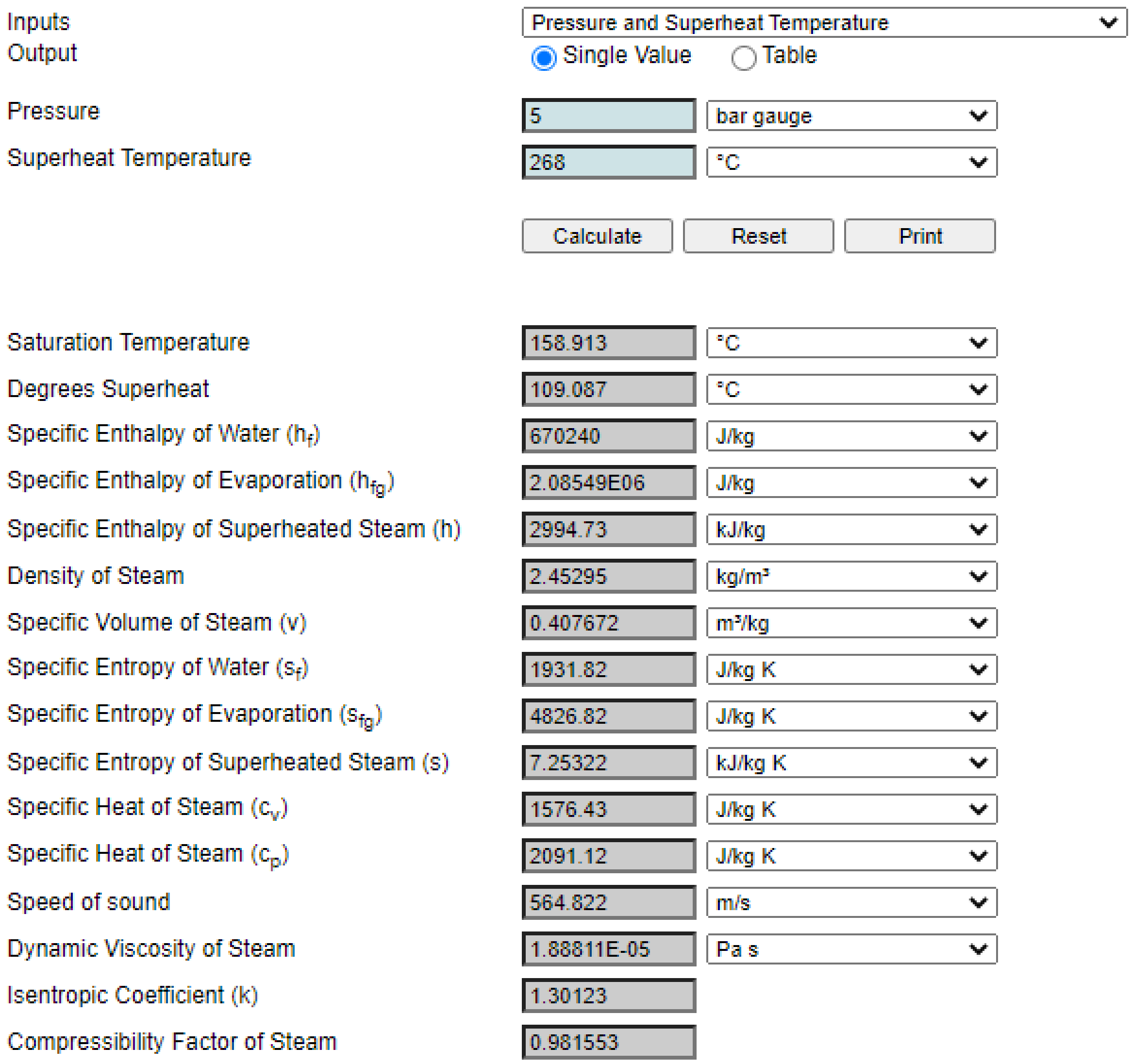

Figure 29 - LP Steam Properties