Modelling Interseasonal Energy Storage

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Abstract

Interseasonal energy storage (ISES) is becoming increasingly crucial in the transition towards sustainable energy systems, especially with the growing use of renewable energy sources whose utility is often impeded by intermittency issues. Among the various ISES technologies, thermal energy storage (TES) stands out due to its versatility and potential for large-scale deployment. This study makes use of a mathematical optimisation model to explore whether these TES technologies can be used to help optimally meet energy demands of the UK by storing heat energy for long seasonal periods. The results show that whilst they are used in an optimal combination of technologies to meet UK energy demands, their optimal utility does not involve interseasonal energy storage unless very specific conditions are imposed on the model.

Acknowledgements

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Own Work Declaration

I confirm that the following is my own work except where stated otherwise.

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Chapter 1

Introduction

Unlike traditional energy storage methods such as batteries that are well-suited for daily or weekly storage cycles, interseasonal energy storage (ISES) technologies need to be able to store energy for months at a time to compensate for the seasonal changes in the availability of renewable energy sources such as sunlight.

Among the various ISES technologies, the category of Thermal Energy Storage (TES) is currently one of the most widely researched due to heat being the most demanded form of energy, making up half of global energy consumption according to the International Energy Agency [21]. Furthermore, the requirement to meet these energy demands results in the production of significant amounts of CO_2 emissions - for example in the UK, space heating, which accounts for 40% of the nation's total energy use, is responsible for 20% of it's CO_2 emissions [29]. As a result, modelling the use of different TES technologies in the UK is important to develop an understanding of their economic and operational benefits and drawbacks, and determine whether it is worth investing in these technologies to help meet the UK's energy demands in a more environmentally friendly way.

In this paper, we will investigate the currently existing TES technologies, and determine whether or not it is financially worthwhile investing in these technologies to help meet the energy demands of the UK by developing an optimisation model that simulates their implementation into a simplified version of the UK energy network.

This introductory chapter will begin by looking at the background and context of this study, followed by a discussion of the research problem, aims and objectives. We will then conclude the chapter by discussing the significance of the study and the limitations we encountered while performing the research, and we will provide an outline for the structure of the rest of the report.

1.1 Background

With the UK's commitment to reach net-zero greenhouse gas emissions by 2050, and the corresponding increases in the capacity of renewable energy generation technologies, fossil-fuel based technologies are now being used much less than before. There are now mainly being used to provide energy during intermittency periods of renewable energy sources when the generated power from renewable technologies is not enough to meet the electrical and heating demands of the UK. This is where TES technologies come into play, aiming to help meet the heating demands of the UK during periods of low renewable energy availability, and thus reduce the amount of energy which needs to be generated by non-renewable energy sources, resulting in decreased greenhouse gas emissions.

The TES technologies that are currently available and being researched can be classified into three categories according to how they store energy - these are sensible, latent, and thermochemical.

Sensible TES technologies are those in which energy is stored by increasing the temperature of a storage medium such as water, while the phase and chemical composition of the storage medium remain unchanged [32]. This form of TES is currently the most widely used due to its advanced technological maturity, however, it still comes with a few drawbacks such as its large spatial requirements, high insulation demands to reduce heat loss, and low energy density compared to latent and thermochemical TES.

In latent TES methods heat is stored in a phase change material (PCM) which uses the latent heat of phase changes to provide heat energy. The main advantage of this form of energy storage is that it takes place within a very narrow range of temperatures. Overall however it still requires lots of research and development, in particular to develop new PCMs as many of the ones currently being used have drawbacks such as corrosivity and flammability which makes storing them quite complicated.

Finally, thermochemical TES stores thermal energy by taking advantage of reversible chemical reactions. In particular, energy is stored via an endothermic reaction in which a bond between two molecules is broken, and this energy is then released via an exothermic reaction when the bond between the two molecules is reformed. Whilst thermochemical TES is theoretically capable of 100% energy storage efficiencies, it still needs lots of research and development to achieve anywhere near this level of efficiency, and thus this technology is not ready to be commercially deployed or used in real-life applications.

1.2 Research Problem and Goals

There have been various studies carried out to investigate both the economic and operational advantages and disadvantages of TES technologies. For example, a report by the UK government in 2016 [1] investigated the market gaps and opportunities for the implementation of various TES technologies in the UK. Throughout the paper review process, however, I was unable to find a study that investigated the implementation of TES into the UK energy network through the use of a mathematical optimisation model. Consequently, the goal of this study was to construct such an optimisation model and use it to determine whether TES technologies could be used to help meet UK national energy demands by storing energy interseasonally.

By investigating the economic feasibility of integrating TES technologies into a simplified model of the current UK energy network, the results of this study will provide valuable insights into the potential cost savings, and reduction in reliance on non-renewable energy sources that can be achieved by TES. Such insights will serve to provide possible ideas for improving the environmental sustainability of the UK energy network as the UK continues working towards its goal of reaching net-zero greenhouse gas emissions by 2050. Furthermore, this study will help develop a comprehensive understanding of the different TES technologies and provide a useful approximation for the optimal utilization strategies to maximize their efficacy and utility in real-world operational scenarios.

1.3 Study Limitations

Whilst this study can add valuable information to the body of knowledge on TES and ISES, a nuanced examination of the constraints and challenges faced during the research process is crucial for a comprehensive understanding of the study's scope and potential implications.

The research performed during this study was strictly limited to the TES subcategory of ISES technologies. In particular, only TES technologies were analysed, modelled, and included as possible investment options in the optimisation model, thus whilst the results of the model used in the study may suggest that investment into a certain TES technology may be optimal, this may not be the case in the real world as we cannot rule out the possibility that the inclusion of another type of ISES technology into the model might change these results.

Finally, the assumptions used in the modelling of the UK energy network were significant and need to be kept in mind when interpreting the results. Certainly, this and the lack of a reputably reliable source for certain points of data required to model the current UK energy network meant that the results of this study should not be used explicitly, but they instead can serve as a general guide of which technologies might be more useful to use in the UK.

1.4 Structural Outline

To systematically explore and present the topic and findings of our research, this paper is organized into several key sections.

Having briefly gone over some background knowledge and context for the study in this introductory chapter, we will follow on in Chapter 2 with a literature review in which we critically summarise the existing research on various TES technologies. This chapter will discuss how the technologies work and look at their real-life applications in the UK and other countries.

Building upon this, in Chapter 3 we will discuss how we modelled the UK energy network and three of the TES technologies that were reviewed in Chapter 2. This chapter will present the mathematical equations used in these models and how we were able to combine the models to simulate the implementation of TES technologies into the UK energy network. On top of this, we will study the consequences of some of the assumptions made in the model to help us better interpret its outputs.

In Chapter 4 we present the results obtained from running this mathematical optimisation model. We will delve into the outputs of both the investment part of the model and the operational part of the model, and see how the capacities of the TES technologies and their operational usage varied upon changing certain constraints such as CO_2 emission costs (also known as carbon tax), storage efficiencies, and technology costs to name a few. In this chapter, we will also critically discuss what conclusions we can validly derive from these results given the impact of the assumptions of the model discussed at the end of Chapter 3.

Finally, we will conclude our report in Chapter 5 by summarising the key findings and conclusions of our investigation, as well as exploring how it could have been improved given more time and resources. We will also review the extent to which we were able to achieve the objectives of this study which we set out in this introductory chapter.

Chapter 2

Review of TES Technologies and their Applications

In this chapter, we will be reviewing some of the currently available literature on TES. In particular, we will be studying the classification of TES technologies into three different categories, looking at case studies of real-life implementations of certain TES technologies, investigating the operational usage of these technologies, and researching their associated financial costs to model their implementation into the UK energy network.

The structure of the material in this chapter will be broken down according to the classification of TES technologies into sensible, latent, and thermochemical categories. To begin with, we will look at sensible TES technologies and explain why they are classed under the sensible TES category based on how they store energy. We will also look at the different materials used for sensible TES, and the pros and cons of sensible TES before discussing some examples of sensible TES technologies which are currently being used in real-world applications. When discussing these examples, we will study their operational usage and present figures for the financial costs associated with the construction of these technologies. On top of this, we will look at case studies of these technologies' real-life applications to get an idea of how successful their previous implementations have been.

Following on from this we will review the latent TES category, once again explaining how this class of TES technologies stores energy, as well as its associated advantages and disadvantages. Since latent TES is fairly technologically immature, we will also review what research needs to be done to improve its reliability and make it more viable for real-world usage.

Finally, we will finish the chapter by discussing the thermochemical category of TES technologies. As was done with the other two categories, we will analyse the unique way in which energy is stored which will explain the immense potential of thermochemical TES, and discuss what are currently the limiting factors preventing its effective usage that require further research to improve the technological maturity of thermochemical TES.

2.1 Sensible TES

Sensible TES technologies are characterized by their storage of heat occurring through the increase in temperature of a storage medium [14]. The thermal energy stored by a sensible TES technology can be calculated as

$$Q = m \cdot C_p \cdot \Delta T$$

where m is the mass of the material being used as a storage medium, C_p is its specific heat capacity, and ΔT is the temperature increase of this material during the charging phase. A variety of materials can be used in sensible TES however the most popular ones are water and gravel-water mixtures. These materials are chosen due to their appropriate balance of certain desirable properties such as high specific heat capacities to improve energy storage density, high thermal conductivity to reduce charging and discharging times, and low costs [23].

Compared to latent and thermochemical TES, sensible TES has a very low energy storage density thus much larger dimensions are required to store an equivalent amount of energy. These dimensional requirements become a limiting factor when extremely large amounts of energy need to be stored as would be the case in district heating applications. However, the technological maturity of such systems and the low costs of the materials used mean that sensible TES is currently the most reliable and cheapest form of TES available, and thus is already being widely implemented in real life. The most popular sensible TES systems include Tank, Pit, and Borehole TES, and will be discussed in the following three subsections. It is worth mentioning that Aquifer TES is also a widely used sensible TES technology, however, it is highly dependent on geological conditions due to the need for the existence of an aquifer, and thus we will not be reviewing this technology as its implementation requires a solid understanding of geology which is beyond the scope of this paper.

2.1.1 Tank TES

In Tank TES (TTES) systems, the storage material (typically water) is contained in artificial tanks which are made of either reinforced pre-stressed concrete or stainless steel [13]. To reduce heat loss, these tanks also need to be equipped with a thick layer of insulation for which different materials such as glass wool and polyurethane are used [9].

During the charging phase, cold water leaves the tank via an outlet at the bottom, is heated to a temperature typically between $80 - 90°C$ [37], and re-enters the tank via an inlet at the top. Note that there exist various ways of heating the water in the charging phase for example through the use of a heat pump, energy from solar collectors, or heat produced from burning fossil fuels. During the discharging phase, hot water leaves via the top outlet of the tank and is taken to buildings where it will serve its heating purposes, and the returning cold water re-enters the tank via an inlet at the bottom. Figure 2.1 shows how the tank is charged and discharged.

A key property used to improve the storage efficiency of a TTES system is the

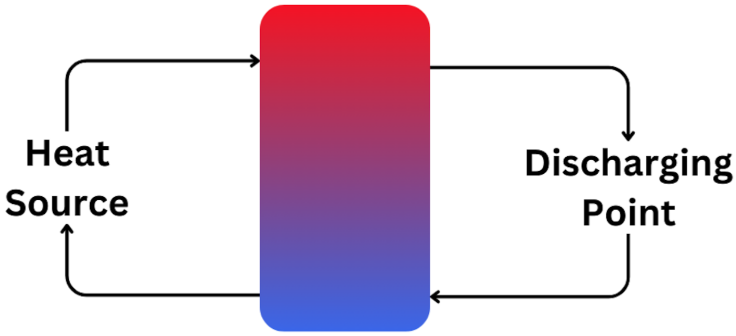


Figure 2.1: Visual Representation of how the TTES system is Charged and Discharged

varying density of water under different temperatures. Hot water naturally rises to the top of the tank due to its lower density than cold water which sinks to the bottom, thus by placing the inlet for the returning cold water at the bottom of the tank, and the inlet for the hot water at the top of the tank, we can create thermal stratification which prevents the mixing of the cold and hot water regions of the tank and thus preserves the heat being stored in the top region of the tank. Even greater thermal storage efficiency can be achieved by artificially separating the hot and cold water regions in two separate tanks, however, such a system can be very expensive to build.

TTES offers the highest energy storage density out of the sensible TES systems that we will review in this report since water, which has a higher specific heat capacity than other sensible TES materials, is used as a storage medium. This technology does however come with greater capital investment costs than others in this category due to its insulation requirements, thus despite its very low operational and maintenance costs it still proves to be one of the more expensive TES technologies. On top of this, the spatial dimensions needed to use TTES in large-scale applications can become a limiting factor for its implementation. Furthermore, the thermal stratification required to successfully implement this technology must also be taken seriously, as mixing of the thermal layers can dramatically reduce its energy storage efficiency and render TTES a non-worthwhile investment.

The construction of these types of tanks can vary from £$91 - 114/m^3$ for large-scale applications in which energy is stored interseasonally [1]. This source also suggests that TTES systems have a heat storage efficiency of $50-90\%$, with efficiency increasing as tank size increases due to the reduced surface-area/volume ratio. As for the maximum operating temperature of TTES, it seems to be in the range of $95 - 98°C$ [32].

TTES systems have been widely tested and implemented in various countries such as Germany, Denmark, and Sweden. An example of such an implementation was in Munich where a system consisting of $2,761m^2$ of solar collectors and a $6,000m^3$ underground tank containing $5,700m^3$ of water was used to store and provide energy for space and water heating to approximately 320 apartments with a combined $30,400m^2$ of living area [34]. This system was designed to cover more than 50% of the annual heat requirements of these residences which amounted to approximately $2,000MWh/yr$, and by the second year of operation it was able to cover 45% of the heating demands of these buildings using solar energy, however, it was believed that the solar fraction could increase to values above 50% after further optimisation of the system.

2.1.2 Pit TES

Pit TES (PTES) involves storing energy in an artificial underground pit with inclined side walls and the top surface at ground level. Despite its lower thermal capacity of $30-50kWh/m^3$ [13], a gravel-water mixture (with a gravel fraction of $60-70\%$) is typically used as the storage medium instead of water to add strength to the structure of the pit, thus allowing the ground surface above it to be used [27]. In this type of storage only the top layer of the pit requires a high level of insulation since the ground itself, which makes up the bottom and side walls, acts as an insulator for these surfaces once it reaches temperature stability (note that in the early stages of using the system before this temperature stability is reached, the heat losses may be high). Often, however, the side walls are covered with a plastic liner to prevent the water portion of the storage medium from being absorbed by the surrounding soil. The charging and discharging of heat in this system occurs in the same way as for TTES, and once again the thermal stratification of water can be taken advantage of to improve storage efficiency.

The main advantage of PTES is its fairly reasonable construction costs, especially compared to its most similar counterpart TTES, which arise from the lack of need to build and insulate the side and bottom walls of the pit. The fact that this technology exists underground also means that spatial dimensions are not too much of a concern. In turn, however, the use of a gravel-water mixture as a storage medium to ensure structural stability of the ground above the pit means that PTES systems have significantly lower energy storage densities than TTES systems. Furthermore, the use of gravel in the storage medium reduces the extent to which thermal stratification can occur [13] which further reduces the storage efficiency of PTES compared to TTES.

The costs of PTES can vary from anywhere between £$24-112/m^3$ [1] depending on the size of the pit being built. Regarding the energy storage efficiency of PTES, this source claims it can reach up to 80%, however as we will see in the following case study, applications of PTES have managed to reach efficiency levels greater than 90%. Finally, the maximum temperature of the water in PTES is limited by the lining layer on the side and bottom walls of the pit and is suggested to be $90°C$ [32].

One of the most successful implementations of PTES was in Dronninglund, Denmark, where a $60,000m^3$ pit was used in combination with $37,573m^2$ of solar collectors and a heat pump to supply heat to a town with approximately $1,350$ district heating users making up a combined $40GWh$ worth of annual energy demand [39]. In the years 2015, 2016, and 2017, this system was able to provide solar fractions of $40\%, 38\%$, and 40% respectively of the total heat supply of the district heating network, and storage efficiency of the pit reached 96% in 2017 [45].

2.1.3 Borehole TES

Borehole TES (BTES) systems use the ground itself as a storage medium for heat. A BTES system is constructed by drilling various evenly spaced vertical boreholes into the ground and then filling them with pipes made out of synthetic materials (such as HPDE) in which water flows to distribute heat. During the charging phase, heated water flows to the bottom of the boreholes where it heats the surrounding ground material, and then in the discharging phase, the heat energy stored in the ground material is used to heat the water in the pipes which is pumped out of the boreholes and taken to buildings to be used for heating.

The use of underground material as a storage medium in BTES means the storage material is usually rock or in good cases rock with groundwater, both of which have a much lower specific heat capacity than water alone, thus BTES has a lower energy storage density than TTES and even PTES whose storage medium contains a much larger proportion of water. To compensate for this, BTES needs to be much bigger than other storage systems (up to 3-5x bigger in volume to store the equivalent amount of energy as TTES [32]), however, this problem can be overcome without too much technical difficulty - indeed the size of the storage can be easily increased by drilling more boreholes and then connecting the pipes in these boreholes to the ones in existing boreholes. This easy extensibility does come with a significant capital cost, however, since drilling these boreholes can be quite expensive. Furthermore, the presence of groundwater flow in the ground surrounding the boreholes can result in significant heat loss from the storage unit, thus thorough investigation into the geological conditions of the ground being used as a storage medium must be carried out before deciding whether or not to install a BTES system. Such investigation often requires expert knowledge and can be quite expensive. BTES systems also have a fairly significant start-up time since the ground being used as a storage medium needs to reach temperature stability, and can take up to 3-4 years until they are operating at full performance.

Estimates for the capital cost of the installation of BTES are highly uncertain, however, [1] suggests a range of £$10 - 46/m^3$. This source also gives estimates for the storage efficiency of BTES units as $6 - 54\%$ based on data taken from the implementation of a BTES system in Drake Solar Landing Community in Canada which we will review. As for the operating temperature of BTES, a range of $40 - 90°C$ seems to be what is commonly used [26].

The most successful implementation of a BTES system took place in Drake Landing Solar Community, Canada, where a BTES system composed of 144 boreholes, each 35m deep, was installed in a district heating system with $2293m^2$ of solar collectors to provide space heating to 52 houses.

Between 2012 and 2017 this system was able to achieve a solar fraction of 96% of the energy demand used for heating, and even achieved a 100% solar fraction during the 2015-2016 charging season. Whilst the project as a whole was very successful, it is worth noting the BTES unit itself did not perform especially well, achieving storage efficiencies of only $6 - 54\%$ in its first four years of operation,

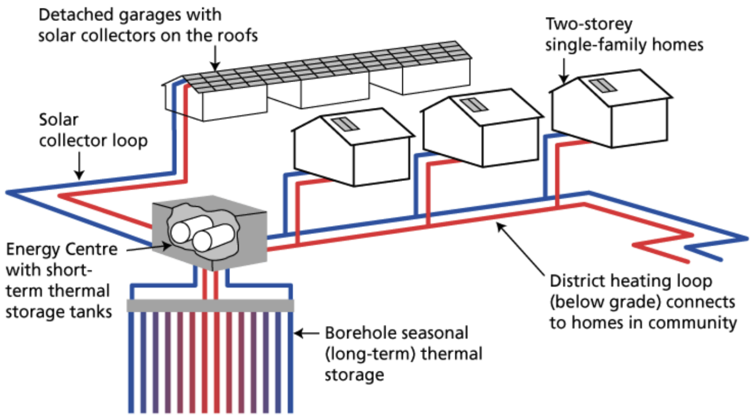


Figure 2.2: Diagram of Drake Solar Landing Community Heating System [28, Figure 4]

as was mentioned earlier.

2.2 Latent TES

Latent heat is the heat absorbed by a material whilst it changes phase, during which the temperature of the material itself does not change. For example, when ice is heated, the temperature of the ice slowly increases until it reaches $0°C$. At this point, upon further heating, the temperature of the ice remains the same but it begins to change phase and turn into water. The heat absorbed by the ice during this period is what we call 'latent heat'. Thus latent heat storage methods make use of the heat energy produced by the phase change of a material to store energy within a very narrow range of temperatures.

During the charging phase in latent TES, a phase change material (PCM) is heated until it changes either from solid to liquid, solid to gas, or liquid to gas. The material is then kept in this phase throughout the storage period. Following this, in the discharging phase, the PCM is allowed to cool down and change back into its original phase. During this phase change process, latent heat is released and used for heating applications. It is worth noting that the solid-to-liquid phase change is most useful for practical applications of Latent TES, as phase changes to gas, despite their larger energy storage density, result in extreme increases in the volume of the PCM and thus require much larger spacial dimensions to store the PCM.

The materials used as PCMs in latent heat storage can be separated into organic and inorganic compounds. Organic PCMs such as waxes, alcohols, and fatty acids offer a wide range of melting points thus allowing latent heat storage to occur at many different temperatures, however, they can be quite expensive and have lower energy density than inorganic PCMs. Inorganic PCMs such as salt hydrates offer this advantage plus lower costs, however, they can often be highly corrosive, meaning that long-term storage of these materials can be quite difficult. However, the key property that makes these materials useful in latent TES applications is their high latent heat capacity.

Compared to sensible TES, latent TES has a much higher energy storage density, and thus much smaller storage volumes are needed. On top of this, the fact that latent TES facilitates the storage of heat within a very narrow range of temperatures makes it very useful in applications such as indoor temperature buffering [31]. However, this narrow temperature range can be a shortfall in applications that allow for a larger temperature difference, as in these cases sensible TES emerges as a more cost-effective alternative. Latent TES is also still a relatively new technology and thus research still needs to be done to find new PCMs with properties suitable for application in TES such as having a suitable melting point, whilst not being corrosive or flammable as many PCMs are. On top of this many of the PCMs currently used in latent TES have a low thermal conductivity thus an effective heat transfer mechanism must be designed to make up for this, which can increase material costs for the construction of a latent TES system due to the need for other tecnhnologies such as heat exchangers required to use the technology effectively[1].

2.3 Thermochemical TES

Thermochemical TES makes use of reversible chemical reactions to store and release heat. During the charging phase, an endothermic reaction occurs in which the storage material is broken down into two constituent components as heat is applied. The discharging process entails recombining the constituent components in an exothermic reaction which produces heat. Some examples of pairs of materials currently being researched for use in thermochemical TES include salt hydrates and water vapour, ammonium chlorides and ammonia, and metal hydrides and hydrogen [32]. Key properties that are required for a material to be suitable for thermochemical TES are low desorption temperatures to allow the storage components to be separated easily, non-corrosivity to facilitate the storage of the different components, and good thermal and molecular stability [22].

Thermochemical TES has the highest energy density of the three TES methods discussed in this chapter, and due to the nature of this process, it theoretically has the potential to achieve a 100% efficiency rate, an ideal trait for interseasonal energy storage. Currently however, thermochemcial TES is still fairly underdeveloped. Many of the materials being used are highly toxic, and their recyclability proves to be a significant issue. On top of this, thermochemical TES can be very expensive to implement. Consequently, much more research and development is necessary. Specifically, this research should be aimed at enhancing the utilization of existing thermochemical TES materials, or discovering novel ones. Additionally, efforts should focus on the design and integration of thermochemical TES systems into a larger energy network. This research also needs to be followed by pilot applications (currently there are no demonstrator plants in the UK [1]) before thermochemical TES can begin to be used commercially and in large-scale applications such as for interseasonal energy storage.

Chapter 3

The Optimisation Model

To measure the practicality of using some of the technologies discussed in the last chapter in the UK, we built a mathematical optimisation model that found the combination of both TES and other popular power generation technologies which minimises the sum of the investment and operational costs for meeting the UK energy demands.

In this chapter, we will present this model. In particular, we will start with two sections that detail the key components that make up the model - the primary investment problem, and the operational subproblem. These sections will present the overall objective function of each model, and the sets, parameters, constraints, and expressions used to define them. These sections will also allow the reader to understand the simplified version of the UK energy network which we are modelling.

Following on from this we will discuss the data that was used in the model. Data from various sources was used to provide realistic values for certain parameters of the model such as the CO_2 tax, costs for increasing the capacity of technologies included in the model, and much more. In this section, we will also show how we modelled the heating demands of the UK by calculating appropriate values for the thermal capacity and conductivity of the house in the heating network, and present the data source we used for the electricity demands.

In the proceeding section, we will discuss how we modelled the use of some of the TES technologies reviewed in Chapter 2. This section will look at the equation which calculates how much energy is stored in these TES units, and go over certain variables and parameters in this constraint whose values varied depending on the TES technology we were trying to model.

Given the fact that we modelled a highly simplified version of the UK energy network, the assumptions used in this simplification and their consequences need to be reviewed to validly interpret the results. As such, we will conclude this chapter by reviewing these assumptions and their effects on the results, and discuss what valid conclusions we can still make from the outputs of the model.

3.1 Explanation of the Optimisation Model

The optimisation model that was used to get results for this study is publicly available on GitHub [16], and is an extension of an existing energy planning model (CESI/sPlan) written by Dr. Rodrigo Garcia Nava [47] in Julia, using the optimisation modelling language JuMP. This linear programming model consists of two parts: an investment master problem that decides how much new capacity to install for each type of generation/storage technology and an operational subproblem that finds the optimal schedule for the usage of these technologies given their capacities. These two models are linked with the overall objective of minimizing the combined sum of the investment and operational costs of meeting the UK's energy demands for one year. In this section of the chapter, we will present the sets, variables, parameters, constraints, and objective functions used in both the investment and operational models. This should also help the reader understand the simplified version of the UK energy network we are modelling, and highlight the assumptions that were made in its construction.

3.1.1 Investment Model

As was previously mentioned, the investment master problem has the objective of minimizing the combined sum of the investment and operational costs of meeting the UK's energy demands. The corresponding objective function for the investment problem is

$$\min Q = f + \beta$$

where f is the sum of the costs of investments made to increase the capacity of the technologies included in the model, and β is the minimised cost of using these technologies to meet the energy demands of the UK, given their capacities after investments have been made. The sets, parameters, variables and constraints used in this model are given below.

- Sets:

$M =$ {Technologies included in the model as either investment options and/or with existing capacity}.

- Variables:

$f =$ total cost of investments (£/hour),

$p_m^N =$ newly installed capacity in generator $m \in M$ (GW, GWh, or $GWh/°C$),

$p_m^C =$ cumulative capacity in generator $m \in M$ (GW, GWh, or $GWh/°C$),

$\beta =$ minimal operational cost of meeting the yearly energy demands given available technologies and capacities after investments have been made (this value is passed up from the operational subproblem).

- Parameters:

$cf_m =$ Fixed operation & maintenance cost of technology $m \in M$ (£$/MW/yr$),

$capex_m =$ Capital Expenditure (CAPEX) cost per unit of capacity for technology $m \in M$ (£/GW, £/GWh, or £/$GWh/°C$),

$lf_m =$ Lifetime of technology $m \in M$ (years),

$imin_m =$ Existing capacity of generator $m \in M$ before investment (GW, GWh, or $GWh/°C$),

$co2lim =$ limit on CO_2 production (tonnes),

$cco2 =$ CO_2 tax (£/tonne of CO_2 produced),

$dsc =$ Scaling applied to demands data,

$yr =$ 8760 - number of hours per year.

- Constraints:

$$f = \frac{1}{yr}\left(\sum_{g\in M}\frac{capex_g p_g^N}{lf_g} + \sum_{g\in M} cf_g p_g^C\right),$$

For $g \in M$: $p_g^C = imin_g + p_g^N$,

Limits on capacity: $p^N_{Nuclear} = 0$, $p^N_{BioEnergy} = 0, p^N_{PumpedHydro\_Storage} = 0$.

There are a few important things to note here. Firstly this model does not account for construction time and assumes that the entire cumulative capacity of the technologies is available to use at all times, and instantaneously after investments have been made. Secondly, the parameter defining the fixed operational and maintenance cost of a technology describes how much it would cost to maintain this technology regardless of whether or not it is used. Such costs come from factors such as staff salaries for running the technology, insurance, and periodic maintenance/inspection to name a few examples. The demand scaling parameter is included as an option to scale the demand data, however, throughout this study it was fixed at 1, thus no scaling of the demands was used. As for the constraints defining the limits on the newly installed capacity of certain technologies, the reasoning behind these will be discussed in a future section.

3.1.2 Operational Model

The operational subproblem aims to minimise the operational cost of meeting the UK's energy demands given the capacities for each technology after investments were made. In order to reduce computational time, the operational problem provides an option of selecting certain slices of the year to represent longer periods (e.g. you could choose to represent the entire year using a two-week slice of winter demands and another two-week slice of summer demands). These slices can also be given different weights to adjust the scale of their impact on the overall cost function. However, due to the availability of a high-power computer provided by the University of Edinburgh, computational power was not an issue in this study, thus runs were made using the full year's data. To clarify, we only used a single slice which consisted of 17,520 time periods representing each half-hour of the year. The operational model has the following mathematical formulation:

- Sets:

$$\begin{aligned}
G &= \{\text{All generation/storage technologies included in the model}\},\\
S &= \{\text{Slices of the energy demand data used for modelling}\},\\
H &= \{\text{Time periods in all slices}\},\\
T &= \{\text{Thermal power technologies}\},\\
R &= \{\text{Renewable power technologies}\},\\
HP &= \{\text{Heat pumps}\},\\
HnS &= \{\text{TES technologies}\},\\
EnS &= \{\text{Electricity stores}\},\\
ES &= \{\text{Electricity stores' charging \& discharging pumps}\},\\
NUC &= \{\text{Nuclear technologies}\},\\
B &= \{\text{Buses in the electrical network}\},\\
D &= \{\text{Energy demands datasets}\},\\
L &= \{\text{Lines in the electrical network}\},\\
G_b &= \{\text{Generation technologies connected to bus } b\},\\
D_b &= \{\text{Energy demands at bus } b\},\\
H_{sl} &= \{\text{Time periods in slice } sl\},\\
S_b &= \{\text{Storage technologies connected to bus } b\},\\
ES_b &= \{\text{Electricity stores' pumps connected to bus } b\},\\
HP_b &= \{\text{Heat pumps at bus } b\ \},\\
T_b &= \{\text{Thermal power technologies at bus } b\},\\
R_b &= \{\text{Renewable power technologies at bus } b\},\\
NUC_b &= \{\text{Nuclear power technologies at Bus } b\},\\
HN &= \{\text{Balance nodes in the heat network (heat nodes)}\},\\
HL &= \{\text{Energy transfer lines in the heat network (heat lines)}\},\\
HOUSES &= \{\text{Houses in the heat network}\}.
\end{aligned}$$

- Variables:

$p^G_{g,h} \geq 0,$ power output of thermal power technology $g \in T$ at time period $h \in H$ (GW),

$p^R_{r,h} \geq 0,$ power output of renewable power technology $r \in R$ at time period $h \in H$ (GW),

$p^{Nuc}_{n,h} \geq 0,$ power output of nuclear power technology $n \in NUC$ at time period $h \in H$ (GW),

$p^{S,in}_{es,h} \geq 0,$ power charged into storage by electric storage pump $es \in ES$ at time period $h \in H$ (GW),

$p^{S,out}_{es,h} \geq 0,$ power discharged from storage by electric storage pump $es \in ES$ at time period $h \in H$ (GW),

$q^{B}_{ens,h} \geq 0,$ stored energy in electricity store $ens \in EnS$ at time period $h \in H$ (GWh),

$p^{H,heat}_{hs,h} \geq 0,$ electric power used by heat pump $hp \in HP$ at time period $h \in H$ (GW),

$q^{H}_{hns,h} \geq 0,$ stored energy in TES technology $hns \in HnS$ at time period $h \in H$ (GWh),

$q^{HS}_{hs,h} \geq 0,$ energy in house $hs \in HOUSES$ at time period $h \in H$ (GWh),

$t^{Int}_{hs,h},$ interior temperature of house $hs \in HOUSES$ at time period $h \in H$ $(°C)$,

$q^{H,Shed,P}_{hns,h} \geq 0,$ positive power shed of house/heat store $hns \in HOUSES \cup HnS$ at time period $h \in H$ (GWh),

$q^{H,Shed,N}_{hns,h} \geq 0,$ negative power shed of house/heat store $hns \in HOUSES \cup HnS$ at time period $h \in H$ (GWh),

$p^{L}_{l,h} \in \mathbb{R},$ power flow in line $l \in L$ at time period $h \in H$ (GW),

$p^{HL}_{hl,h},$ power flow in heat line $hl \in HL$ at time period $h \in H$ (GW),

$\Delta_{b,h} \in \mathbb{R},$ voltage angle of bus $b \in B$ at time period $h \in H$,

$g^{Shed}_{r,h} \geq 0,$ shed/curtail of renewable generation technology $r \in R$ at time period $h \in H$ (GW),

$d^{Shed}_{d,h} \geq 0,$ shed/curtail of demand $d \in D$ at time period $h \in H$ (GW),

$p^{ub}_{t} \geq 0,$ upper bound for power output of thermal power technology $t \in T$ (GW),

$r^{ub}_{g} \geq 0,$ upper bound for power output of renewable power technology $g \in R$ (GW),

$n^{ub}_{g} \geq 0,$ upper bound for power output of nuclear power technology $n \in NUC$ (GW),

$s^{ub}_{es} \geq 0,$ upper bound for power charged/discharged to electrical network by electric storage pump $es \in ES$ (GW),

$e^{ub}_{ens} \geq 0,$ upper bound for stored energy in electricity store $ens \in EnS$ (GWh),

$h^{ub}_{hp} \geq 0,$ upper bound for power consumption of heat pump $hp \in HP$ (GW),

$QMass_{hns} \geq 0,$ thermal capacity of TES unit $hns \in HnS$ $(GWh/°C)$,

$L^{ub}_{l} \geq 0,$ upper bound for power flow in line $l \in L$ (GW),

$HL^{ub}_{hl} \geq 0,$ upper bound for power flow in heat line $hl \in HL$ (GW).

- Parameters:

$PLoss_{hns},$ thermal loss of TES unit $hns \in HnS$ $(GW/°C)$,

$CO_2^{Lim},$ limit on CO_2 production (tonnes),

$CO_2^{Gen},$ CO_2 tax (£/tonne of CO_2 produced),

Var_g^{OM}, variable operation & maintenance cost of technology $g \in G$ (£$/MWh$),

Fix_g^{OM}, fixed operation & maintenance cost of technology $g \in G$ (£$/MW/yr$),

Eff_g, efficiency of technology $g \in G$,

$Availability_{r,h}$, availiability of renewable energy source to be used by technology $r \in R$ at time period $h \in H$ (GW),

$HistCap_g$, capacity of technology $g \in R$ used to calculate availability parameter (GW),

$p_{d,h}^D$, energy demands from demand dataset $d \in D$ at time period $h \in H$ (GW),

Q_{hs}^{mass}, thermal capacity of house $hs \in HOUSES$ $(GWh/°C)$,

P_{hs}^{loss}, thermal loss of house $hs \in HOUSES$ $(GW/°C)$,

T_{hs}^{min}, minimum allowed internal temperature of $hs \in HnS \cup HOUSES$ $(°C)$,

T_{hs}^{max}, maximum allowed internal temperature of $hs \in HnS \cup HOUSES$ $(°C)$,

$CurtCost_g$, curtail cost of technology $g \in G$ (£$/MW$ or £$/MWh$),

$FuelCost_g$, fuel cost of technology $g \in G$ (£$/MWh$),

${CO_2^{Emission}}_g$, CO_2 emissions of technology $g \in G$ (tonne$/MWh$),

$Shedding_d$, cost of shedding from demand dataset $d \in D$ (£$/MW$),

$t_{hs,h}^{Ext}$, external temperature at $hs \in HnS \cup HOUSES$ at time period $h \in H$ $(°C)$,

$Weight_{sl}$, weight of the slice $sl \in S$,

$Length_{sl}$, number of time periods in the slice $sl \in S$,

$TimeStep_h$, length in hours of time period $h \in H$ (since we use half-hourly data in this study this is always set to 0.5 hours),

Imp_l, impedance at line $l \in L$,

$from_l$, start point of line $l \in L$,

to_l, end point of line $l \in L$,

$hfrom_{hl}$, start point of heat line $hl \in HL$,

hto_{hl}, end point of heat line $hl \in HL$,

$hDeliv_{hp}$, heat network balance node $hn \in HN$ to which heat pump $hp \in HP$ is connected,

$hSupp_{hp}$, bus $b \in B$ which supplies power to heat pump $hp \in HP$,

$Slice_h$, slice $sl \in S$ containing time period $h \in H$,

LP_b, electric storage pump $es \in ES$ to which electricy store $ens \in EnS$ is connected,

λ_{hns}, thermal conductivity of $hns \in HnS$.

- Constraints:
  Power Generation Constraints:
  $p^{G}_{g,h} \leq p^{ub}_{g}$ for $g \in T, h \in H$,
  $p^{R}_{r,h} = \frac{Availability_{g,h}}{HistCap_{g}} * r^{ub}_{g}$ for $g \in R, h \in H$,
  $p^{Nuc}_{n,h} \leq n^{ub}_{g}$ for $g \in NUC, h \in H$,

  Electricity Store Constraints:
  $q^{B}_{b,h} \leq e^{ub}_{b}$ for $b \in EnS, h \in H$,
  $p^{S,in}_{b,h} \leq s^{ub}_{b}$ for $b \in ES, h \in H$,
  $p^{S,out}_{b,h} \leq s^{ub}_{b}$ for $b \in ES, h \in H$,
  $q^{B}_{b,h+1} - q^{B}_{b,h} = TimeStep_{h} * (Eff_{LP_b} * p^{S,in}_{LP_b,h} - p^{S,out}_{LP_b,h})$ for $b \in EnS, h \in H$,

  Transmission Line Constraints:
  $p^{HL}_{hl,h} \leq hl^{ub}_{hl}$ for $hl \in HL, h \in H$,
  $p^{L}_{l,h} \leq L^{ub}_{l}$, $p^{L}_{l,h} \geq -L^{ub}_{l}$ for $l \in L, h \in H$,
  $p^{L}_{l,h} = \frac{1}{Imp_{l}}(\Delta_{to_{l},h} - \Delta_{from_{l},h})$ for $l \in L, h \in H$,

  House Temperature & Energy Constraints:
  $t^{Int}_{hs,h} = q^{HS}_{hs,h}/Q^{Mass}_{hs}$ for $hs \in HOUSES, h \in H$,
  $t^{Int}_{hs,h} \leq T^{max}_{hs}$, $t^{Int}_{hs,h} \geq T^{min}_{hs}$ for $hs \in HOUSES$,

  For $hs \in HS, h \in H$:
  $q^{HS}_{hs,h+1} = q^{HS}_{hs,h} + q^{H,Shed,P}_{hs,h} - q^{H,Shed,N}_{hs,h} + TimeStep_{h}(P^{Loss}_{hs}(t^{Ext}_{hs,h} - t^{Int}_{hs,h}) + \sum_{hl \in HL: hto_{hl}=hs} p^{HL}_{hl,h} - \sum_{hl \in HL: hfrom_{hl}=hs} p^{HL}_{hl,h})$,

  TES Temperature & Energy Constraints:
  $q^{H}_{hns,h} \leq QMass_{hns} * T^{max}_{hns}$ for $hns \in HnS, h \in H$,
  $q^{H}_{hns,h} \geq QMass_{hns} * T^{min}_{hns}$ for $hns \in HnS, h \in H$,
  $p^{H,heat}_{hp,h} \leq h^{ub}_{hp}$ for $hp \in HP, h \in H$,

  For $hns \in HnS, h \in H$:
  $q^{H}_{hns,h+1} = q^{H}_{hns,h} + q^{H,Shed,P}_{hns,h} - q^{H,Shed,N}_{hns,h} + TimeStep_{h}(PLoss_{hns} * t^{Ext}_{hns,h} - \lambda_{hns} * q^{H}_{hns,h}) + \sum_{hl \in HL: hto_{hl}=hns} p^{HL}_{hl,h} - \sum_{hl \in HL: hfrom_{hl}=hns} p^{HL}_{hl,h}$,

  Heat Node Power Balance Constraint - For $hn \in HN$:
  $\sum_{hp \in HP: hDeliv_{hp}=hn} p^{H,heat}_{hp,h} * Eff_{hp} = \sum_{hl \in HL: hfrom_{hl}=hn} p^{HL}_{hl,h}$,

Kirchoff's Current Law - For $b \in B, h \in H$:
$\sum_{g \in T_b} p^G_{g,h} + \sum_{r \in R_b} p^R_{r,h} + \sum_{n \in NUC_b} p^{Nuc}_{n,h} + \sum_{l \in L: to_l = b} p^L_{l,h} + \sum_{d \in D_b} d^{Shed}_{d,h} + \sum_{b \in ES_b} p^{S,out}_{b,h} = SDM \left(\sum_{d \in D_b} PD_{d,h} \right) + \sum_{r \in R_b} g^{Shed}_{r,h} + \sum_{s \in ES_b} p^{S,in}_{s,h} + \sum_{hp \in HP_b} p^{H,heat}_{hp,h} + \sum_{l \in L: from_l = b} p^L_{l,h}$,

CO_2 Constraints:
$CO_2^{Gen} = \sum_{h \in H} \frac{Weight_{slice_h}}{Length_{slice_h}} \left(\sum_{g \in T} \frac{CO_2^{Emission}{}_g}{Eff_g} p^G_{g,h} \right)$,
$CO_2^{Gen} \leq CO_2^{Lim}$.

- Expressions:
  Thermal loss of TES:
  For $hns \in HnS : PLoss_{hns} = \lambda_{hns} * QMass_{hns}$,

  Variable cost of meeting energy demands:

$$\begin{aligned} Var\_Cost_h = &\sum_{g \in T} p^G_{g,h} * (Var^{OM}_g + \frac{FuelCost_g}{Eff_g}) + \sum_{r \in R} p^R_{r,h} * Var^{OM}_r \\ &+ \sum_{s \in ES} p^{S,in}_{s,h} * Var^{OM}_s + \sum_{n \in NUC} p^{Nuc}_{n,h} * (Var^{OM}_n + \frac{FuelCost_n}{Eff_n}) \\ &+ \sum_{hp \in HP} p^{H,in}_{hp,h} * Var^{OM}_{hp}, \end{aligned}$$

  Shed/Curtail Cost:

$$\begin{aligned} Sh\_Cost_h = &\sum_{r \in R} g^{Shed}_{r,h} * CurtCost_r + \sum_{d \in D} d^{Shed}_{d,h} * Shedding_d \\ &+ \sum_{hs \in HnS \cup Houses} (q^{H,Shed,P}_{hs,h} + q^{H,Shed,N}_{hs,h}) * CurtCost_{hs}. \end{aligned}$$

- Objective Function:
  $\min \beta = \sum_{h \in H} \frac{Weight_{slice_h}}{Length_{slice_h}} * (Var\_Cost_h + Sh\_Cost_h)$.

Figure 3.1 shows a visual representation of the simplified version of the UK energy network that we modelled. We can see that there are two key components of the model, in particular, the heat network which consists of all components on the right of $HPump$, and the electrical network which consists of all components on the left of $HPump$. We will now review how the sets in the operational model were populated according to what can be seen in this figure, starting with the electrical part of the energy network.

The set B of buses in the electricity network consists of two buses, $B1$ and $B2$, which represent the offshore and onshore parts of the UK energy network respectively. By imposing Kirchoff's current law as a constraint on these buses, we ensure that the energy going into the bus is equal to the energy going out of the bus at any time period $h \in H$, thus they cannot be used to store electrical energy. These two buses are connected by a line $L1$ which begins at $B1$ and terminates at $B2$ and is the only member of the set L.

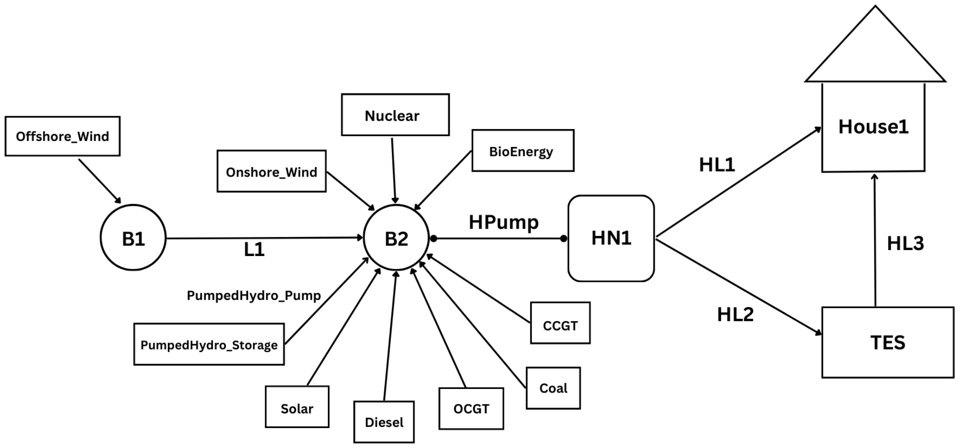


Figure 3.1: Visual Representation of the Model

To determine what technologies to include in the model, we used data from the Digest of UK Energy Statistics (DUKES) [42, 5.11] to identify the technologies that are currently being used in the UK for energy generation, and what their corresponding capacities are. Table 3.1 shows the data we found from this source. The figures in the installed capacity column are the values we used for the parameter $imin_g$ of each technology, and for any other technologies included in the model that are not shown on this table, we assumed there was no existing capacity (i.e. $imin_g = 0$).

Technology	Installed Capacity (MW)
Offshore Wind	14,419
Onshore Wind	15,248
Solar	14,780
Coal	2,604
Pumped Hydro	2,900
Nuclear	5,883
CCGT	30,165
OCGT	1,409
Bioenergy	7,723
Diesel	1,072

Table 3.1: Current Energy Generation Technologies and Installed Capacities in the UK

As can be seen in Figure 3.1, all of these technologies except offshore wind were connected to $B2$. In terms of the sets of the optimization model that each of these technologies fall into; solar, onshore wind, and offshore wind form the set R of renewable technologies. Coal, CCGT, OCGT, diesel, and bioenergy make up the set T of thermal technologies. Pumped hydro falls under the category of electric storage technologies and thus is represented by a pump component $PumpedHydro\_Pump$ in ES and a storage component $PumpedHydro\_Storage$ in EnS. Finally, nuclear as we would expect falls into the set NUC of nuclear generation technologies.

On the other side of Figure 3.1 we see the heating network which consists of a heat balance node $HN1$ making up the only member of the set HN, a single house $House1$ included in the set $HOUSES$ which represents the heating demands of the UK, and a single sensible TES unit labelled TES which represents the TES technologies that were modelled, and are in the set HnS. The details behind the modelling of these units and the house as a representation of the UK's thermal energy demands will be reviewed in the following sections of this chapter. On top of these three main components of the heat network, we can see the various heat lines. $HL1$ connects the heat node $HN1$ to the house $House1$, $HL2$ connects $HN1$ to the TES unit TES, and $HL3$ connects the TES unit to the house. These three lines form the elements of the set HL, and their initial capacities were set to $0GW$.

Finally, the heating network and electrical network are connected by a heat pump $HPump$ in the set HP. This heat pump uses electrical energy from $B2$ and turns it into heat energy which it passes to $HN1$, and is therefore the only supply of thermal energy for both the house and the TES unit in the model. This is a very significant assumption and as such, its implications will be discussed in the final section of this chapter.

The operational and investment problems were linked by the parameters defining the capacities of each technology. A benders decomposition solution method was used in which values for the upper bound on the generation/storage capacity of the technologies, defined by the variable p_g^C were passed down from the investment model to the operational model and used as the value for the parameters defining the maximum generation/storage capacity of each technology. In turn, the minimised cost of meeting the UK's energy demands given these capacities was passed back to the investment problem. This was done repeatedly until an optimal objective function value was reached by the investment master problem.

Finally, a few aspects in the formulation of the operational model which can cause confusion should be addressed. Firstly, the astute reader may have noticed that there is a variable $QMass_{hns}$ which defines the thermal capacity of a TES unit, and a parameter Q_{hs}^{mass} which describes the thermal capacity of a house. This is because the TES systems needed to be included in the model as investment options, unlike the house which existed to represent the heating demands of the UK, and thus always needed to be included in the model. As a result, it was necessary to model them in separate ways, despite the equation governing their energy content being essentially the same, hence the existence of these two very similar components of the model. Secondly, we saw the existence of parameters and variables related to the shed and curtail of energy demands, such as $CurtCost_g, Shedding_d, q_{hns,h}^{H,Shed,P}, q_{hns,h}^{H,Shed,N}, g_{r,h}^{Shed}$, and $d_{d,h}^{Shed}$. Without the presence of these variables and parameters, many of the intermediate iterations in the solution algorithm were unable to be completed due to the infeasibility of the operational problem, and thus no results were able to be obtained. The inclusion of these variables made these intermediate problems feasible, and by assigning extremely large values to the $CurtCost_g$ and $Shedding_d$ parameters to penalise the shedding and curtailing of energy demands, we were able to ensure that the final solution of the operational model did not involve any failures to meet energy demands. To be precise, for all the results discussed in Chapter 4, we ensured that the final values of $q_{hns,h}^{H,Shed,P}, q_{hns,h}^{H,Shed,N}, g_{r,h}^{Shed}$ and $d_{d,h}^{Shed}$ were zero for all time periods $h \in H$ and all values of $hns \in HnS, r \in R$, and $d \in D$.

3.2 Data Used in the Model

After reviewing the setups of the investment master problem and operational subproblem, we can see that there are various parameters for which appropriate values need to be found. In this section of the chapter, we will present the values we chose to use for each of these parameters and where we got these values from.

3.2.1 Costs Data

We will begin by discussing the data regarding the costs of the technologies in the electrical network. The key cost parameters were $capex_m$ in the investment model which described the capital expenditure (CAPEX) required to increase the capacity of the technology $m \in M$ by one unit, cf_m in the investment problem or Fix_g^{OM} in the operational subproblem, which described the fixed operation and maintenance cost per unit of installed capacity of technology $m \in M$ or $g \in G$, and the variable operation and maintenance cost Var_g^{OM} of each technology.

The technologies for which we want to find these fixed values are onshore wind, offshore wind, coal-fired power plants, diesel-fired power plants, OCGT power plants, CCGT power plants, solar panels, heat pumps, and pumped hydro storage. Returning to the constraints $p_{Nuclear}^N = 0$, $p_{BioEnergy}^N = 0$, and $p_{PumpedHydro\_Storage}^N = 0$ we saw in the investment model, these limits were imposed on nuclear generation capacity due to the widespread safety and security concerns that come with nuclear power stations and complicated regulatory framework involved in constructing new nuclear power stations. For the capacity of bioenergy, we chose not to allow further increases beyond what already exists due to the very large CO_2 emissions and lower efficiency compared to other fossil fuel power generation technologies such as CCGT or OCGT. Because of these two features and the UK's goal to achieve net-zero greenhouse gas emissions by the year 2050, we felt it would be a suitable assumption that any bioenergy power capacity will not be further increased. Finally, for the storage capacity of PumpedHydro, we imposed this constraint due to how such capacity could be increased. Indeed any significant increase in the capacity of PumpedHydro storage would require controversial processes such as the flooding of a valley, and thus we decided to avoid the associated complexity of accurately modelling increases in its capacity, and instead focus our efforts on other aspects of the model.

Table 3.2 shows some proposed figures for the CAPEX, fixed operation and maintenance cost (FixOM), and variable operation and maintenance cost (VarOM) of each technology from various sources.

Technology	CAPEX (/MW(h)	FixOM (/MW-yr)	VarOM (/MWh)	Source
Coal	\$ 3,676,000	\$ 4,058	\$ 4.50	[12]
CCGT	£ 439,000-593,000	£ 9,770-14,670	£ 1.22-1.83	[18]
OCGT	£ 283,000-294,000	£ 3,643 - 8,205	£ 0.68-1.02	[18]
Diesel	€ 350,000	€ 100,000	—	[11]
Nuclear	£ 3,682,000 - 5,114,000	£60,784-85,097	£2.62	[18]
Pumped Hydro	£ 747,000 - 1,517,000	£ 7,982 - 16,012	£ 38.96-41.10	[18]
Offshore Wind	£ 2,370,000	£ 76,000	—	[10]
Offshore Wind	\$ 3,871,000	\$ 111,000	—	[40]
Onshore Wind	\$ 1,501,000	\$ 40,000	—	[40]
Solar	£ 950,000	£ 109,500-146,000	—	[20]
Heat Pump	£ 1,530,000	£ 6,000	—	[6]

Table 3.2: Costs of Generation Technologies Included as Investment Options in the Model

Note that where prices were given in terms of dollars, we converted them to the equivalent quantity in pounds assuming a 1.2439 USD/GBP exchange rate, and where they are given in euros we converted them to the equivalent quantity in pounds assuming a 1.1492 EUR/GBP rate (both of these are the average exchange rates in the year 2023 according to [7] and [17]).

The modelling of a district heating network is an extremely complicated and technical matter particularly with regards to the costs of heat transfer lines as these can come in different qualities, and costs of installation depend heavily on where they are being installed. Since the scope of this research is solely restricted to investigating the implementability of TES technologies and the costs of the lines are not related to this, we assumed arbitrary values for the CAPEX, FixOM, and VarOM parameters of lines in our heating network, and we assigned all of them zero initial capacity. In particular, the values we used for these parameters were $CAPEX_{hl} = £10,000/MW$, $FixOM_{hl} = £5,000/MW/yr$ and $VarOM_{hl} = £0/MWh$. As for the line $L1$ in the electrical network connecting $B1$ to $B2$, we assumed fixed parameter values of $CAPEX = £220,000/MW$, $FixOM = £1,600/MW - yr$ and $VarOM = £0/MWh$ based on figures from [10]. We also set its initial capacity to $14,419MW$ thus assuming that all of the existing offshore wind capacity could be transferred to $B2$ and any further increases in offshore wind capacity required an equivalent increase in the capacity of $L1$ if they were to be made.

3.2.2 Operational Data

Within both models, there were several operational parameters for which we needed data such as the CO_2 production costs and limits, efficiencies of technologies, fuel costs, and much more.

The fuel costs used in this study were $£36.51/MWh$ for the cost of coal, and $£62.71/MWh$ for the cost of gas to be used by OCGT and CCGT [43]. The cost of diesel was set to $158.19p/L$ [44] which is equal to £$149.86/MWh$ assuming an energy content of $38MJ/L$ for diesel [19]. As for the nuclear and bioenergy power stations, we assumed the fuels being used were uranium and wood pellets, whose prices were set to \$$4.60/MWh$ [46] which is equivalent to £$3.70/MWh$, and £$34/MWh$ [36] respectively. For wind, solar, and pumped hydro energy we assumed zero fuel costs.

The efficiencies assigned to each of these technologies were 33.4% for coal [42, 4.10], 49% for CCGT[42, 5.10], 35% for OCGT [24] and diesel [35], 39.6% for nuclear [42, 5.10], 80% for Pumped Hydro [15], and 30% for bioenergy [25]. The heat pump was also assigned an efficiency value of 283% in accordance with its in-situ COP value [6].

Part of our study investigated the effect of the CO_2 tax on the installed capacity of the TES technologies and its optimal operational usage, thus the value of this parameter varied across different runs of the model. We did however limit what values could be used to either £51.04 or £97.75/tonne of CO_2 produced to represent the upper and lower ranges of CO_2 tax that are commonly being used in the UK [41]. As for the yearly CO_2 production limit we set it to a fixed value of $965,000,000$ tonnes in line with the sixth carbon budget target whose deadline to be met is between $2033 - 2037$ [8].

3.2.3 Demand Data

To model the heating demands of the UK with a single house that represented the heating demands of all residences in the UK, we had to approximate values for the thermal capacity Q^{mass}_{House1} and thermal loss P^{loss}_{House1} of such a house. To do so we used estimates for the heat loss rate and thermal capacity of $3.15W/m^2K$ [2, 3.17] and $250kJ/m^2K$ [**?**] for an average UK household, and assumed a total of $28,200,000$ households in the UK [38], with an average floor area of $94m^2$ per household [4]. Assuming these values we calculated the thermal capacity parameter of our model's house as

$$\begin{aligned} Q^{mass}_{House1} &= 250kJ/m^2K * 94m^2 * 28,200,000 \\ &= 662,700,000,000kJ/K = 184.08GWh/^\circ C \end{aligned}$$

and the thermal loss parameter as

$$\begin{aligned} P^{loss}_{House1} &= 3.15W/m^2K * 94m^2 * 28,200,000 \\ &= 8,350,020,000W/K = 8.35GW/^\circ C \end{aligned}$$

We additionally set the minimum and maximum allowed internal temperatures of the house to $T^{min}_{House1} = 19^\circ C$ and $T^{max}_{House1} = 24^\circ C$.

Due to a lack of availability of half-hourly temperature data, we used hourly temperature data recorded by the MET office in 2022 at their 'Bingley SAMOS' site [5] which is located in Bradford and was chosen because it is located near the center of the UK and has a large data collection. In the case of any missing instances of data, the average of the preceding and proceeding temperatures was imputed. The half-hourly external temperature variables' values ($t^{Ext}_{hs,h}$) were set to their corresponding hour's temperature value according to this dataset.

As for the electrical demands of the UK, we modelled them using the half-hourly demand data for 2022 provided by the National Grid ESO [3]. In particular, the demand data used was from the *ND* column which National Grid ESO stated is 'the sum of metered generation, but excludes generation required to meet station load, hydro storage pumping and interconnector exports.' On top of this, the dataset included the columns *EMBEDDED_WIND_GENERATION* and *EMBEDDED_SOLAR_GENERATION* which provided estimates of the wind and solar power generated from small-scale wind and solar farms which the National Grid ESO estimated had a capacity of $6,527-6,545MW$ and $13,670-13,861MW$ respectively throughout 2022. This data was used to model the availability of onshore and offshore wind, and solar energy in the following ways:

For the onshore wind farms, we calculated the availability of wind energy at each half-hour time period by dividing the *EMBEDDED_WIND_GENERATION* column value by the installed wind capacity used to produce this figure (i.e. $6,527MW$) and then included a constraint in the model that this much energy could be generated per MW of existing or newly installed wind capacity. In particular, this constraint was

$$p^R_{g,h} = \frac{Availability_{g,h}}{HistCap_g} * r^{ub}_g.$$

Let us explain this process with an example; consider the very first time period ($00:00-00:30$ on January 1st 2022), for which the dataset gives an estimate of the embedded wind generation as $2,412MW$. The corresponding estimate for the embedded wind capacity at this time period was $6,527MW$ - this suggests that for each MW of wind capacity installed onshore at this time period $\frac{2,412}{6,527}MW = 0.37MW$ of wind energy could be generated. The constraint in our model then stated that the total amount of energy that could be generated by the onshore wind technology at this time period was $0.37 * r^{ub}_{Onshore\_Wind}MW$ where $r^{ub}_{Onshore\_Wind}$ is the maximum power generation capacity of the onshore wind technology, whose value is determined by the investment model. This same process was repeated for the embedded solar data to calculate how much power could be generated by the solar technology in our model.

According to the National Grid Group 'An average onshore wind turbine produces around 2.5 to 3 megawatts (MW), in comparison to the offshore average of 3.6 MW' [30]. This translates to onshore wind farms only being able to generate $69.4-83.3\%$ as much power as offshore wind farms, thus to model how much energy could be generated by the offshore wind technology, we multiplied the value of the wind availability per MW of installed capacity for onshore wind by $\frac{1}{0.75}$ to calculate how much power could be generated per MW of installed offshore wind capacity and used the same constraint described for onshore wind to model how much power was generated by offshore wind at each half hour of 2022.

3.3 Modelling TES Technologies

As we saw in Chapter 3.1.2, the equation describing the energy stored in the TES units that we included in the model is

$$q^{H}_{hns,h+1} = q^{H}_{hns,h} + q^{H,Shed,P}_{hns,h} - q^{H,Shed,N}_{hns,h} + TimeStep_h(PLoss_{hns} * t^{Ext}_{hns,h} - \lambda_{hns} * q^{H}_{hns,h}) + \left(\sum_{hl \in HL: hto_{hl}=hns} p^{HL}_{hl,h}\right) - \left(\sum_{hl \in HL: hfrom_{hl}=hns} p^{HL}_{hl,h}\right)$$

As a reminder, in this equation $q^{H}_{hns,h}$ is the amount of energy stored in the TES unit $hns \in HnS$ at time period $h \in H$, $TimeStep_h$ is the length of the time period $h \in H$ which was always equal to 0.5 hours in our runs of the model. $PLoss_{hns}$ is the heat loss factor of the storage unit in $GW/°C$ which denotes how much power is lost depending on the difference between the internal and external temperature of the storage unit and is calculated as $PLoss_{hns} = \lambda_{hns} QMass_{hns}$ where λ_{hns} is the thermal conductivity and $QMass_{hns}$ is the thermal capacity of the storage unit. Finally, $p^{HL}_{hl,h}$ denotes the thermal power flowing through the heat line hl at time period $h \in H$, and the parameters hto_{hl} and $hfrom_{hl}$ denote the end and start points respectively of the line hl.

As was mentioned in the previous section, the time series data collected from Bingley SAMOS by the MET office was used for the $t^{Ext}_{hns,h}$ value at each half-hour time period in the year. Due to a lack of data available on the thermal conductivity of the different TES systems, we were unable to find estimates for the values of λ_{hns}. Instead, using the figures for the efficiency of each TES unit that we found in Chapter 2 as a guide, we ran the model with varying values of λ_{hns} until we found values for which the modelled efficiency of the TES units, which was calculated as the proportion of power provided to the tank by $HL2$ which was discharged by the tank through $HL3$, was close to or within these ranges. The final values of the thermal conductivity parameters used for each technology to produce the results in Chapter 4 were $\lambda_{TTES} = 0.0005, \lambda_{PTES} = 0.001$, and $\lambda_{BTES} = 0.012$ unless otherwise stated.

It is also worth noting that using the equality $PLoss_{TES} = \lambda_{TES} QMass_{TES}$, the equation governing the energy stored in the storage unit simplifies to

$$q^{H}_{TES,h+1} = q^{H}_{TES,h} + q^{H,Shed,P}_{TES,h} - q^{H,Shed,N}_{TES,h} + TimeStep_h(PLoss_{TES} * (t^{Ext}_{TES,h} - t^{Int}_{TES,h}) + \left(\sum_{hl \in HL: hto_{hl}=hns} p^{HL}_{hl,h}\right) - \left(\sum_{hl \in HL: hfrom_{hl}=hns} p^{HL}_{hl,h}\right))$$

which is the same as the equation governing the heat energy of the house. The reason why this equation was not used in the model, however, is because it generated non-linearity through the calculation of the internal temperature parameter for the heat store $t^{Int}_{hns,h} = q^{H}_{hns,h} * QMass_{hns}$ since both $q^{H}_{hns,h}$ and $QMass_{hns}$ were included as variables in the operational model.

The value of the $QMass_{hns}$ variable used to implicitly define the maximum energy storage capacity of the TES units was measured in $MWh/°C$ and was determined by the investment model. Using the prices of the technologies found in the literature review process and stated in Chapter 2, we calculated the CAPEX cost of increasing the thermal capacity $QMass_{hns}$ for each of the TES units as follows:

For TTES, under the assumption that water was used as a storage medium, with a thermal capacity of $4.18kJ/kg/°C$ and a density of $992.2kg/m^3$ [33], we calculated the energy capacity of the storage medium as

$$4.18 * 992.2kJ/m^3/°C = 4147.396kJ/m^3/°C = 1.152kWh/m^3/°C.$$

Using the investment cost of £$91 - 144/m^3$ suggested by [1] for the construction of the Tank, we can calculate a range of values for the CAPEX cost per unit increase in thermal capacity $QMass_{TTES}$ of the storage unit as

$$£\frac{91}{1.152}–\frac{144}{1.152}/kWh/°C = £78,990–125,000/MWh/°C.$$

For PTES, we assumed that a gravel-water mixture was being used as a storage medium which has a thermal capacity of $2.1kJ/kg/°C$ and a density of $2000kg/m^3$ [33], thus giving us a thermal capacity of $4200kJ/m^3/°C = 1.17kWh/m^3/°C$. Combining this with the required investment of £$24 - 112/m^3$ [1] for the construction of the pit allowed us to calculate the CAPEX cost per unit increase in $QMass_{PTES}$ as

$$£\frac{24}{1.17}–\frac{112}{1.17}/kWh/°C = £20,510 - 95,720/MWh/°C.$$

Finally, for BTES we calculated the CAPEX value in a slightly different way. The heat capacity of BTES is estimated to be in the range $15 - 30kWh/m^3$ [26], thus we took an optimistic view that $30kWh/m^3$ was the total amount of energy stored in the BTES unit at its maximum operating temperature, and when it was at its minimum operating temperature it was storing 0 kWh/m^3. Assuming an investment price of £$10 - 46/m^3$ for BTES [1], the cost of increasing the overall capacity of the storage unit was calculated as

$$£\frac{10}{30}–\frac{46}{30}/kWh = £0.33 - 1.53/kWh = £330 - 1530/MWh.$$

Using the further assumption that the operating temperature range of the BTES unit was $40 - 90°C$, meaning that a unit increase in $QMass_{BTES}$ produces a $50MWh$ increase in the overall storage capacity of the BTES unit, we concluded that an appropriate range for the CAPEX cost of a unit increase in $QMass_{BTES}$ was

$$£50 * 330 - 50 * 1530/MWh/°C = £16,500 - 76,500/MWh/°C.$$

Another important part of modelling the TES units was the constraints

$$q^H_{hns,h} \leq QMass_{hns} * T^{max}_{hns}, \text{ and } q^H_{hns,h} \geq QMass_{hns} * T^{min}_{hns}$$

which implicitly forced the internal temperature of the TES unit to lie within its minimum and maximum operating temperatures given by T_{hns}^{min} and T_{hns}^{max} respectively. Using data derived in the literature review section the values of these parameters were set to $T_{TTES/PTES}^{min} = 50°C$ and $T_{TTES/PTES}^{max} = 90°C$ for the TTES and PTES units, and $T_{BTES}^{min} = 40°C$ and $T_{BTES}^{max} = 90°C$ for the BTES unit.

3.4 Assumptions of the Model

As we mentioned at the start of the chapter, the simplified version of the UK energy network that we modelled used various assumptions. Since the scope of this study is focused in particular on the results related to the TES technologies included in the model, we will only discuss the assumptions that might have affected these results.

The first major assumption to discuss is related to how we modelled the heating demands of the UK with a single house. Indeed by assuming that there only exists one house in the UK, the model fails to account for the fact that the implementation of TES systems in real applications would require complicated methods of connecting the storage to the various houses it will be used to supply heat to. Whilst these costs are not directly related to the construction costs of the TES system and thus not are included in their CAPEX figures, they certainly might be capable of turning these TES systems into unworthy investments. However, the fact that we set the initial capacities of the lines in the heat network, in particular those connecting the heat source to the TES unit and the TES unit to the house, to zero did help to diminish some of the effects this assumption had on the reliability of the results. Nonetheless, accurate values for the installation costs of such lines would have been extremely useful in hindsight.

Another feature of the model that affected the reliability of the results is the fact that all onshore power generation technologies were connected to a single bus with no transmission constraints. This combined with the fact that the bus was directly connected to the heat pump which served as the only source of thermal energy to the heating network means the model assumed that power from every type of onshore generation technology was equally available and useful for charging the heat store. Due to the geographical dispersion of the different power generation technologies across the UK, and the costs of transmitting energy from one location to another that fail to be accounted for by the use of a single onshore bus, not every type of power source will be equally available to provide energy to heat the TES system in real-life applications. This means that the outputs of the operational model detailing the optimal way to use the TES technologies might be different from what would be optimal in real life, however, they nonetheless provide a useful approximation of what would be optimal.

Furthermore, the use of the heat pump as the only source of thermal energy for the heating network is highly unrealistic. Indeed in real life, the majority of heat used domestically is provided in other ways such as directly from the heat energy produced by burning fossil fuels. Upon first inspection of this feature, we might want to conclude that the model would thus overestimate the utility of the TES systems because we are not including these other ways of heating the house, however, this is not necessarily the case. Indeed, in our model, the energy produced by the burning of fossil fuels can still be directly supplied to the house through $HL1$, however, it is worth noting that this still requires the installation of capacity in the heat pump which in turn might give some usefulness to the TES system that would not have existed had the energy produced from burning fossil fuels not required a heat pump to supply thermal energy to the house.

The last assumption to discuss is related to how the power outputs of the wind and solar generators were modelled. In particular, we calculated a certain amount of energy that could be generated per MW of installed capacity for these technologies at each half hour of the year based on data provided by the National Grid ESO. In doing so, we assumed that capacity increases of all sizes for these technologies produced equivalent amounts of energy outputs which might not necessarily be the case in real life due to factors such as wind direction and location of solar panels that affect how much power they can generate. This caused the model to favor the installation of these generation technologies which in turn promoted the installation and use of the TES systems to make up for their intermittency issues. Nonetheless, we were somewhat able to make up for this bias by setting limits on the installed capacity of solar and in particular wind generation technologies.

Chapter 4

Results of the Model

Within this chapter, we present the results we got from various runs of the model, with a particular focus on the capacity that was optimal to install for the TES technologies under varying conditions such as; different CAPEX values, limits on capacities of other generation technologies, and more. For cases in which the TES unit did have some capacity installed, we reviewed how it was used in the operational model to help meet the heating demands of the UK by looking at plots of its stored energy at each half- hourly period. Since the purpose of the TES systems we studied is to make up for the intermittency issues associated with renewable energy generation technologies such as wind and solar, we also studied how the storage unit was used in conjunction with these technologies. In particular, we compared plots of the stored energy to plots of the power outputs of these technologies to determine if they were related as expected with the discharging periods of the TES unit corresponding to the intermittency periods of the renewable generation technologies. Other questions of interest were investigated such as how the installed capacity of TES units changed as limits were set on the capacity of renewable technologies that could be installed, and as the tax for CO2 production increased or decreased.

When deriving such results we tested each TES unit individually. That is to say, each technology was included in our investment model one at a time rather than all together. As such, in this chapter, we will begin by looking at the results of the model when TTES was the only TES in vestment option, then when PTES was the only TES investment option, then BTES.

4.1 TTES Results

We began testing the implementation of TTES into the UK energy network by running the model with the CAPEX cost for the system at £$125,000/MWh/°C$, and a CO_2 tax of £51.04/tonne of CO_2 produced. Doing so showed that the optimal investments were $177.72GW$ into Onshore Wind, $0.29GW$ into OCGT, $10.15GW$ into CCGT, and a thermal capacity of $235.84GWh/°C$ for the TTES system itself, suggesting that the TTES unit can be used to help optimally meet the energy and heating demands of the UK.

Under these same conditions, when we decreased the CAPEX of the TTES unit to £78, 990/$MWh/°C$ we saw that it's capacity increased to 246.96$GWh/°C$, and the newly installed capacities of other technologies were now 175.92GW and 8.52GW for Onshore Wind and CCGT respectively. Plots of the energy stored in the tank at each half hour time period of the year for this run of the model can be seen in Figure 4.1 along with the power outputs of the other technologies given their capacities after investments.

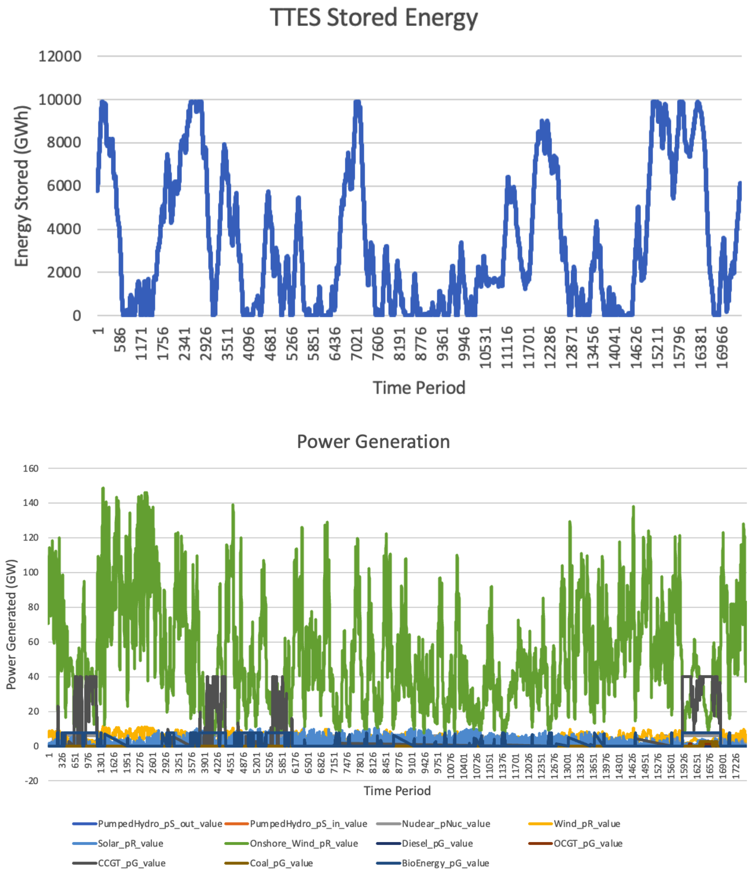


Figure 4.1: Plots of Energy Stored in TTES (Top) and Power Generated by Available Technologies (Bottom) with TTES' CAPEX = £78, 990/$MWh/°C$, and CO_2 Tax = £51.04/tonne of CO_2 produced.

As we can see from these plots, the TTES system was not used to store energy for long, seasonal periods, and instead only stores energy for at most a few weeks at a time, with the longest time during which the stored energy in the TTES unit was non-zero being from time period 10,260 - 12,835 which corresponds to 53 days 15.5 hours. However, the graph shows a dip in the middle of this period which means that two charging and discharging cycles would have occurred during this time. Upon inspection of the power generation plot and comparing it to the stored energy plot, we see that the storage unit was used in relation to the generators as expected - that is, during periods when wind energy generation was higher, the stored energy of the TTES unit increased, and then when the energy generation decreased, we saw that the stored energy decreased since it was being used to heat the house whilst the availability of wind power was low. This can be seen from the fact that the peaks in the stored energy plots consistently occured slightly after peaks in the power generation plot. Indeed, during the stored energy peaks between periods 1,479 - 3,187 and 14,531 - 16,519 which were the main charging periods for the TTES unit, the corresponding average power outputs from onshore wind during these periods was $85.2GW$ and $56.64GW$ respectively, which were both larger than the overall average onshore wind power output of $52.19GW$.

In the following runs of the model we investigated the effect of the CO_2 tax on the installed capacity of the TTES unit by increasing it to the higher value of £97.75/tonne of CO_2 produced, and running the model with CAPEX values of £$125,000/MWh/°C$ and £$78,990/MWh/°C$. In runs with the former CAPEX cost, the capacity installed for the TTES unit was $228.37GWh/°C$ and for the latter cost the installed capacity was $331.46GWh/°C$. The decrease in capacity of the TTES unit in the first result compared to when a lower CO_2 tax was used was definitely unexpected, however, this capacity decrease was not by a significant amount. Despite these changes in capacity, there were no significant changes in the operational use of the TTES unit as can be seen from comparing Figure 4.1 to Figure 4.2 which shows that operational use of the TTES unit under the same CAPEX cost but with a higher CO_2 tax.

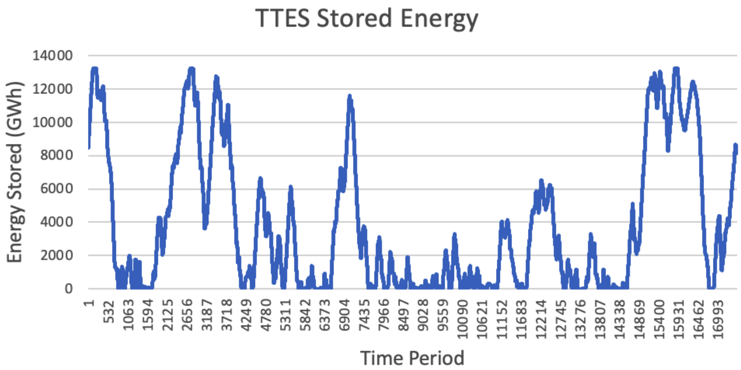


Figure 4.2: Plot of Energy Stored in TTES unit with TTES' CAPEX = £$78,990/MWh/°C$ and CO_2 tax = £97.75/tonne of CO_2 produced.

In the above discussed runs of the model, the increases in capacity for onshore wind were very large, and were a result of the modelling issues that were discussed at the end of chapter 3, thus possibly unrealistic. Consequently, we wanted to investigate whether the TTES unit was still worth using when limits were imposed on the newly installed capacity of wind power. To do so we restricted the newly installed capacity of both onshore and offshore wind to $15GW$, which was roughly equal to their currently installed capacities in the UK as we saw in Chapter 3.1.2, by adding the constraints

$$p^N_{Onshore\_Wind} = 15, \quad p^N_{Offshore\_Wind} = 15$$

to the investment part of the model. Running it with this added constraint, a CAPEX of £$78,990/MWh/°C$ for the TTES unit and a CO_2 tax of £97.75/tonne of CO_2, resulted in a thermal capacity of $36.06GWh/°C$ being installed for the

TTES unit. Both wind technologies received the maximal $15GW$ increases in capacity that they were allowed, and Solar, OCGT, and CCGT had their capacities increased by $51.24GW$, $6.65GW$, and $33.66GW$ to make up for the decrease in wind capacity. These results confirm that the TTES unit is much less useful if non-renewable technologies are used as the main source of power. This is likely due to the fact that these technologies have no intermittency issues associated with them, thus there is no need for energy storage.

Another feature that was present in all both the most recent runs of the model was the lack of installation of solar power capacity. In order to investigate this further, we ran the model with the constraints

$$p^N_{Solar} = 100, \quad p^N_{Onshore\_Wind} = 0, \quad p^N_{Offshore\_Wind} = 0$$

which forced the solar generator to receive an extra $100GW$ of capacity, and prevented any new wind capacity being installed thus simulating the use of solar energy to charge the TTES unit instead of wind power. With a CAPEX of £$78,990/MWh/°C$ for the TTES unit and a CO_2 tax of £97.75/tonne of CO_2 produced, the TTES unit was given a thermal capacity of $37.17GWh/°C$, and CCGT and OCGT received capacity increases of $37.71GW$ and $5.83GW$ respectively. In contrast when these constraints were flipped so that a total of $100GW$ of capacity were invested into for the wind technologies ($50GW$ into onshore wind and $50GW$ into offshore wind) and solar power was not allowed any investment, the thermal capacity of the TTES unit was $104.79GWh/°C$.

Until this point the TTES unit had not been used to store energy interseasonally despite the various different conditions modelled. This led us to hypothesise that the limiting factor preventing the use of the TTES unit to store energy interseasonally was its thermal conductivity. Indeed, a high thermal conductivity would mean that only a small fraction any energy stored for such long periods of time would be available to use months later, thus making it unworthwhile to use these long storage periods. In order to test this hypothesis we ran the model with a significantly lower thermal conductivity of $\lambda_{TTES} = 0.00001$, a CAPEX of £$78,990/MWh/°C$ for the TTES unit, and a CO_2 tax of 97.75/tonne of CO_2 produced. A plot of the stored energy in the TTES unit for this run of the model can be seen in Figure 4.3.

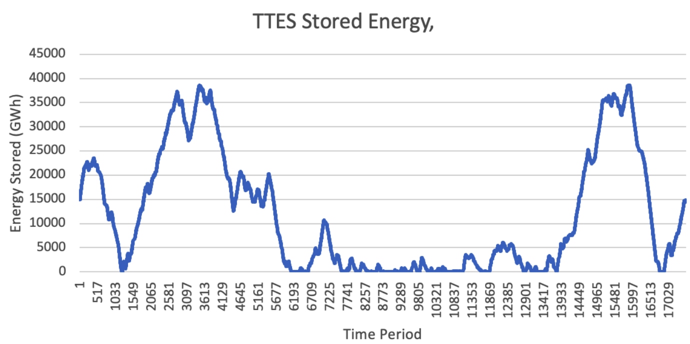
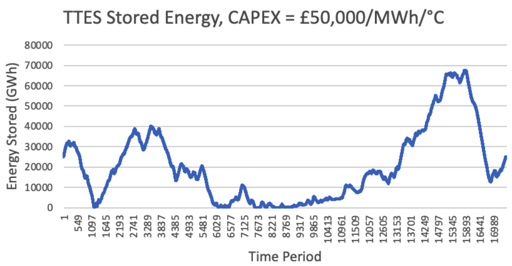


Figure 4.3: Plot of Energy Stored in TTES unit with $\lambda_{TTES} = 10^{-5}$, CAPEX = £$78,990/MWh/°C$, and CO_2 tax = £97.75/tonne of CO_2 produced.

As we can see from this figure, whilst the capacity for the TTES unit increased to $963.43GWh/°C$, which is much higher than what was installed when we had $\lambda_{TTES} = 0.0005$, it still was not used to store energy interseasonally. In fact it wasn't until the CAPEX dropped to $£50,000/MWh/°C$ that we started to notice some interseasonal energy storage occuring. In this case the installed thermal capacity for the TTES unit was $1691.81GWh/°C$, and a plot of how it stored energy can be seen on the left of Figure 4.4. A further decrease in the CAPEX to $£30,000/MWh/°C$ resulted in the TTES unit being used to store energy interseasonally in a much more evident manner as is show on the right of Figure 4.4. In this case the installed thermal capacity of the TTES unit was $2501.55GWh/°C$.



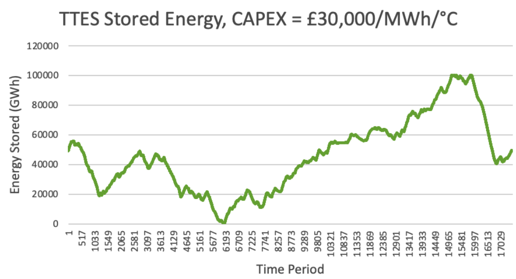


Figure 4.4: Plots of Energy Stored in TTES unit with $\lambda_{TTES} = 10^{-5}$, CO_2 tax $= £97.75$/tonne of CO_2 produced, and CAPEX $= £50,000/MWh/°C$ (left) and $£30,000/MWh/°C$ (right).

4.2 PTES Results

The results-gathering process for the PTES unit was structured in much the same way as the TTES results. To start off, we ran the model with a CO_2 tax of £51.04/tonne of CO_2 produced and a CAPEX of $£95,720/MWh/°C$ for the PTES unit. Under these conditions, the thermal capacity of the PTES unit was set to $143.62GWh/°C$, and the newly installed capacities of OCGT, CCGT, and onshore wind were set to $10.69GW$, $11.54GW$, $175.72GW$.

When the CAPEX of the PTES unit was decreased to $£20,510/MWh/°C$, its installed thermal capacity increased to $191.57GWh/°C$, and the newly installed capacities for OCGT, CCGT, and onshore wind were now $4.55GW$, $12.7GW$ and $180.93GW$. Looking at the stored energy plots for these two cases in Figure 4.5, we see that the PTES unit was used in a fairly similar way to the TTES unit with storage periods lasting up to 70 days 14 hours in the cheaper case, and that the increase in thermal capacity of the TTES unit did not have much of an effect on its usage as both figures in these plots still look fairly similar, with their main peaks occurring during the times when wind power was most available.

Upon increasing the CO_2 tax to £97.75/tonne of CO_2 produced, we saw that the model installed a greater thermal capacity for the PTES unit of $181.46GWh/°C$ when its CAPEX was $£95,720/MWh/°C$, and $223.01GWh/°C$ when its CAPEX was $£20,510/MWh/°C$. On top of this, we saw the capacities of OCGT, CCGT,

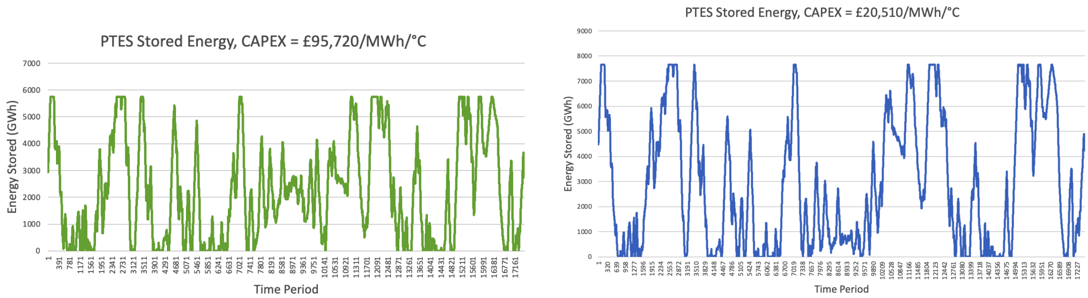


Figure 4.5: Plot of Energy Stored in PTES unit with CO_2 tax = £51.04/tonne of CO_2 produced, and CAPEX = £$95,720/MWh/°C$ (left) and £$20,510/MWh/°C$ (right).

and onshore wind change to $3.16GW$, $13.3GW$, and $200.95GW$ for the higher CAPEX run and $0GW$, $12.97GW$, and $202.97GW$ for the lower CAPEX run. Clearly in the latter case, the increased PTES storage capacity managed to eliminate the neeed for any increases in the capacity of OCGT. Again, there were no noticeable changes in the operational use of the PTES compared to what is shown in Figure 4.5.

When the newly installed capacities for both wind power technologies were limited to $15GW$ each, using a CO_2 tax of £97.75/tonne of CO_2 produced and a CAPEX of £$20,510/MWh/°C$ for the PTES unit, the model decided to invest in a thermal capacity of $9.71GWh/°C$ for PTES, as well as an additional $33.48GW$ for solar, $35.73GW$ for CCGT, and $5.73GW$ for OCGT. The length of storage periods used by the PTES unit also decreased as can be seen in Figure 4.6.

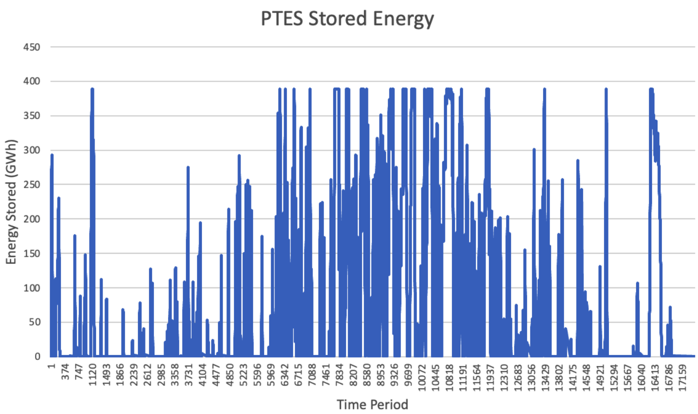


Figure 4.6: Plot of Energy Stored in PTES unit with CO_2 tax = £97.75/tonne of CO_2 produced, and CAPEX = £$20,510/MWh/°C$ Newly Installed Capacity Limits of $15GW$ on both Wind Generation Technologies

Under this same CO_2 tax and CAPEX cost, when the newly installed solar capacity was forced to be $100GW$ and the wind generation technologies were allowed no increase beyond their existing capacity, we saw that the capacity of the PTES unit was $17.19GWh/°C$. Reversing these constraints so that both wind technologies were forced to install $50GW$ of new capacity, and solar power was not allowed any increase, the thermal capacity of the PTES unit became

$79.52GWh/°C$. Plots of how the BTES unit was used in these two cases can be seen in Figure 4.7.

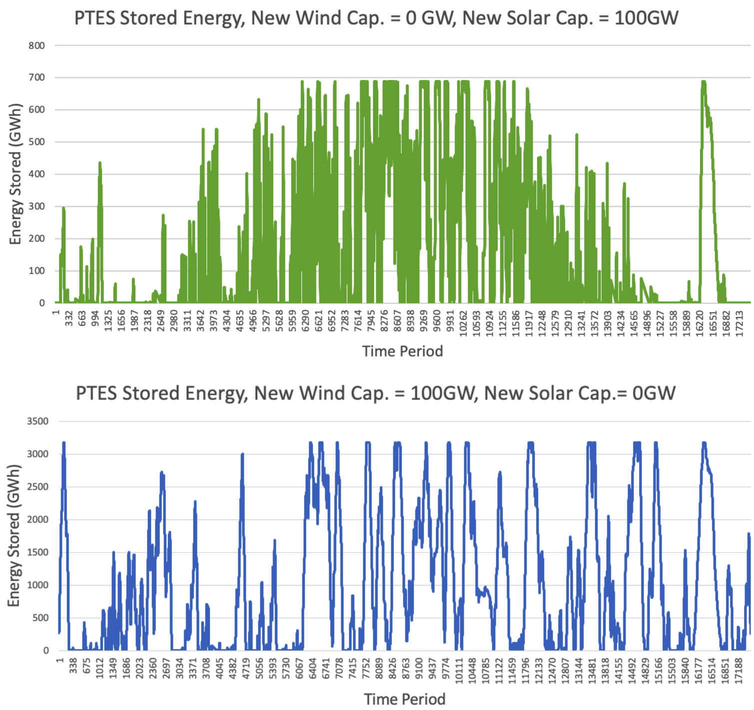


Figure 4.7: Plot of Energy Stored in PTES unit with CO_2 tax = £97.75/tonne of CO_2 produced, CAPEX = £20, 510/$MWh/°C$ and Constraints on Newly Installed Solar and Wind Capacities

Finally, in an attempt to find conditions under which the PTES unit's optimal usage would involve the interseasonal storage of energy (other than by reducing the thermal conductivity), we tried three possible variations of the model parameters which would promote the use of PTES. Firstly, we decreased the CAPEX cost to an unrealistic value of £5, 000/$MWh/°C$, secondly we increased the CO_2 tax to £150/$MWh/°C$ and then we increased it further to £1, 000/$MWh/°C$. Plots of the energy stored in the PTES unit for each of these cases can be seen if Figure 4.8.

As we can see from these plots, the increasing of the CO_2 tax caused significant increases in the thermal capacity of the PTES unit with it reaching $573.44GWh/°C$ when the tax was at £1, 000/tonne of CO_2, however still no use was made of it to store energy interseasonally.

4.3 BTES Results

The final TES technology we included in the model as an investment option was BTES. In the literature review, we saw that reported efficiencies for BTES applications are significantly lower than for other TES technologies, reaching a maximum efficiency of 54%. As a result when running the model with BTES as an investment option we used much larger values for the thermal conductivity

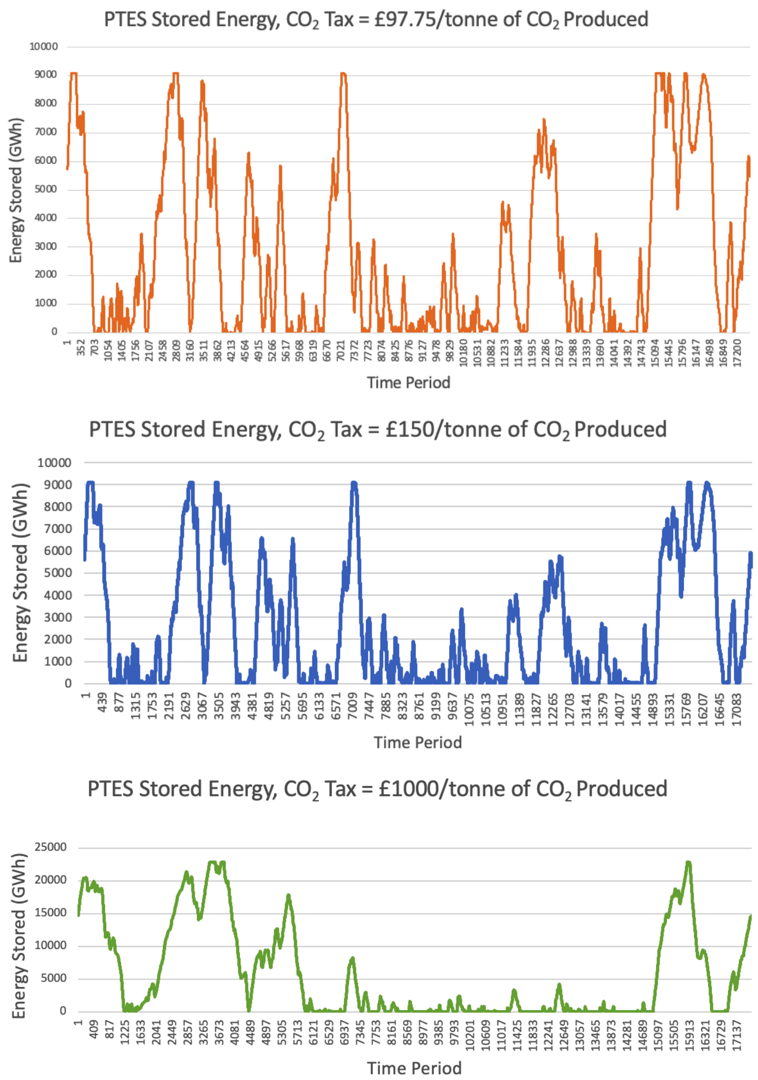


Figure 4.8: Plot of Energy Stored in PTES unit with CAPEX = £$5,000/MWh/°C$, and CO_2 tax = £97.75 (top), £150 (middle), and £1000 (bottom)/tonne of CO_2 produced

parameter and found that setting $\lambda_{BTES} = 0.012$ gave us an efficiency of 58%, where we once again calculated the efficiency as the proportion of power provided to the storage unit by $HL2$ which was discharged by the storage unit through $HL3$ across the entire year. Whilst this is greater than the efficiency range of $6-54\%$ suggested in Chapter 2.1.3, further increases in the thermal conductivity resulted in negligible amounts of capacity being invested in for the BTES unit, thus we decided to use this value of λ_{BTES} as it still produces an efficiency which is close to the suggested range, but also gives us interesting results to discuss.

In the first run of the model, in which we set the CAPEX for the capacity of BTES to £$76,500/MWh/°C$ and used a CO_2 tax of £51.04/tonne of CO_2 produced, we saw that the model decided to invest in a thermal capacity of $1.16GWh/°C$ for the BTES unit, and $190.58GW$, $8.15GW$, and $19.77GW$ for onshore wind, OCGT and CCGT respectively. Then, when we decreased the

CAPEX of the BTES unit to £16,500/$MWh/°C$, the installed thermal capacity of the BTES unit became 1.41$GWh/°C$, and the only power generation technologies that had any increases in capacity were again OCGT by 8.29GW, CCGT by 19.71GW and onshore wind by 190.43. Clearly these results suggest that BTES is less useful than PTES or TTES for meeting the energy demands of the UK, as indicated by its significantly lower installed capacities.

In both these runs, the outputs of the operational model showed that the BTES unit was preferred to be used to store energy for very short periods of time such as hours or days as can be seen in Figure 4.9. This is somewhat unsurprising as we would expect that the low storage efficiency of BTES systems makes using them for long-term seasonal energy storage far less appealing.

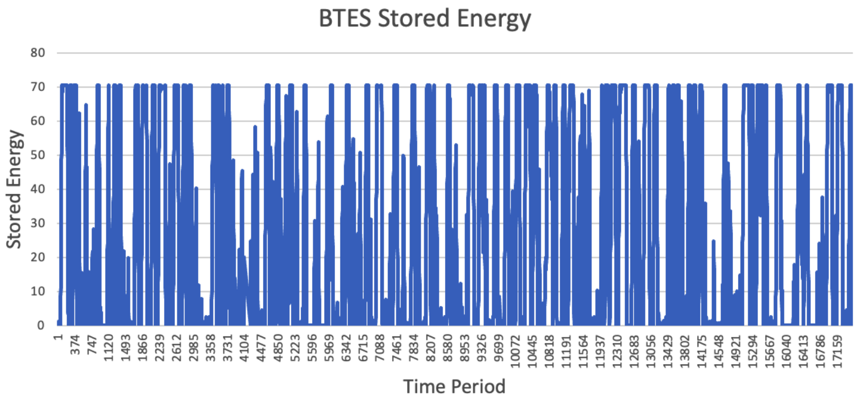


Figure 4.9: Energy Stored in BTES unit with CAPEX = £16,500 and CO_2 tax = £51.04/tonne

As was the case with the other two modelled technologies, BTES saw an increase in capacity when the CO2 tax increased. Indeed when the CO2 tax was increased to £97.75/tonne of CO2 produced, a CAPEX of £76,500/$MWh/°C$ for the BTES unit resulted in a thermal capacity of 2.62$GWh/°C$ being installed, and when the CAPEX was £16,500/$MWh/°C$, the installed thermal capacity was 3.3$MWh/°C$. The operational use of the BTES unit however did not change very much, with storage periods still only lasting up to a few days. As far the other technologies, the newly installed capacity of onshore wind increased to 217.96GW, and for OCGT and CCGT they decreased to 7.39GW and 19.59GW when the BTES was more expensive, and when it was cheaper these technologies' newly installed capacities were 218.31GW, 7.48GW and 19.54GW respectively.

We also saw again that the optimal capacity of the BTES unit decreased when limits were placed on the capacity of wind power that could be installed. Limiting the investments for both wind technologies to 15GW of newly installed capacity, and using a CAPEX of £16,500/$MWh/°C$ for the BTES unit resulted in the model deciding not to invest in the BTES unit at all, no matter whether the CO2 tax was £51.04 or £97.75/tonne of CO_2 produced. In fact, the dual value of the constraint demanding that the installed BTES capacity be non-negative, which indicated how much the hourly cost of the BTES unit would have to decrease in order for it to become a worthwhile investment, was £20/hour whereas the current hourly cost of £0.08/hour. This meant that even if it was free to increase the capacity of the BTES unit, the model would still decide not to use it. In fact, the CAPEX of the BTES unit would have to decrease to $-£4,364,778/MWh/°C$ or less in order for any capacity to be installed when these limits existed on the wind capacity. Unfortunately, the model was infeasible when this CAPEX value was assigned to the BTES unit thus we could not confirm this, however, when the CAPEX was set to $-£10,000/MWh/°C$, we still saw that the model decided not to invest in the BTES at all and instead invested in additional capacities of $3.34GW$ for OCGT, $38.84GW$ for CCGT, and $15.69GW$ for solar.

4.4 Discussion of the Results

In this study, the primary objectives were twofold. Firstly, the research aimed to evaluate the feasibility of employing TES (Thermal Energy Storage) technologies to meet the energy demands of the UK while concurrently minimizing operational and capital expenditures. Secondly, a comprehensive analysis of the most efficient operational strategies for utilizing TES technologies to fulfill these demands were wanted, with specific emphasis on the durations of storage periods. The results of the model suggest that whilst some of the studied TES technologies can be used to optimally meet the energy demands of the UK, they are preferred to be used for shorter storage periods as opposed to interseasonal ones. On top of this, we can see that certain key factors such as the availability of wind power, and the thermal conductivity of the TES technologies has a large influence on the optimal capacity and operational use of these technologies to minimise the costs of meeting the UK energy demands.

For each of the studied technologies, the results from the initial baseline model in which we had the investment CAPEX set to the maximum amount discussed in Chapter 3.3, and a CO_2 tax of £51.04/tonne of CO_2 produced, showed that both TTES and PTES could be used to meet the heat energy demands of the UK in a way that minimised the associated costs of this task, however BTES requires storage efficiencies slightly above what has previously been achieved in order to be considered useful. In the runs of the model with a higher CO_2 tax, we generally saw that the optimal capacities of each of the technologies increased suggesting that they should be considered as possible investments to facilitate the transition to the usage of renewable energy sources. The runs of the model in which the installed capacity of wind technology was limited support this argument since we saw that the corresponding investment into the TES units decreased significantly. These results in particular serve as evidence that the increased use of wind energy should be supported by investments in TES technologies to improve its utility by giving it some flexibility. For BTES in particular, the results showed that this TES technology should certainly not be considered unless there is adequate wind availability as suggested by the fact that even at negative CAPEX values the model did not want to use this technology when limits were imposed on the installed wind capacity.

Another interesting feature seen in the results was that the capacity of solar energy installed had significantly less impact on the installed storage capacity. This was evident in runs of the model for which a minimum capacity of solar power was forced to be installed but wind capacity limited. Indeed, the results showed that the installed capacity for the TES units was noticeably more when the wind capacity was set to $100GW$ and solar to $0GW$, than in the opposite situation. Interestingly this contradicts what is currently being done in real life applications of these technologies where they are usually charged using solar panels. A likely reason for this is due to the modelling error that was discussed at the end of Chapter 3 which may have caused the utility of wind generation to be overestimated. However, many of the implementations studied in the literature review came from applications in warmer countries where solar energy is much more available than in the UK, thus this use of wind rather than solar energy to charge the TES units may not be a coincidence at all. Considering these results, in the future it may be worthwhile to study the use of wind turbines as opposed to solar panels to charge these storage units in darker and windier countries.

The most significant results of this study however were the operational usages of these technologies. These results suggest that using these TES units for interseasonal energy storage is far from optimal given their current technological abilities. Indeed we saw that their storage efficiencies need significant improvement before any long, seasonal storage periods are optimal to be used. Such improvements may not be possible for these sensible TES technologies as they are already at a very high technological maturity, however as we saw in Chapter 2 other technologies such as thermochemical TES might be capable of such storage efficiencies, thus this study further supports the idea that more research should be done to improve the state of the art of thermochemical TES.

The conclusions drawn from this study should however be approached with caution. For starters, whilst the modelling of the TES technologies was done in a calculated manner, further improvements in the accuracy of this modelling are certainly possible. Likewise the simplified model of the UK energy network made use of significant assumptions, which were discussed in Chapter 3.4, and could definitely have been improved given more time and resources. The acquisition of data used in this model also proved to be a problem, as information came from various sources and thus may not be realistic to use in conjunction.

Nonetheless, we can conclude that certain key findings drawn from this study are ceratinly worthy of further research. Most importantly, there is no doubt further research needs to be done to improve the efficiency of TES technologies before they should be used to store energy interseasonally.

Chapter 5

Conclusion

Overall, the results derived in this study suggest that whilst certain TES technologies certainly can be used to help meet the UK's national energy demands while minimizing both operational and investment costs, this optimal usage does not involve the interseasonal storage of energy mainly due to inadequate storage efficiencies. Despite this, the literature reviewed in this study showed there do exist certain types of TES technologies that could be capable of achieving the storage efficiencies required to make the interseasonal storage of energy worthwhile, namely thermochemical TES, and thus further research should be done to improve the capabilities of thermochemical TES its implementation into commercial applications should also be investigated in particular through optimisation models such as the one used in this study determine the optimal usage methods and utility aspects of this technology.

These conclusions certainly fulfill the original objectives that were set out for this research. On top of this, we were able to derive extra results that could be used to develop an operational strategy for real-life implementations of these technologies if they were to be used in the UK - in particular the ideas that TTES and PTES units should be used to store energy for weekly to monthly periods, and BTES units should be used for day to day energy storage. Again, whilst these results give good guidelines for future directions of research in the field of interseasonal energy storage, various issues encountered throughout the study, such as the complexity of the UK energy network, the dispersedness of the data and its difficulty in obtaining, and the lack of inclusion of not only other technologies from the latent and thermochemical categories of TES but other entirely distinct technologies that could be useful for interseasonal energy storage, mean that we cannot conclude whether any of the TES technologies discussed in this study are optimal for inclusion in the UK energy network.

More specifically, to improve the model of the UK energy network, a rigorous investigation process should be undertaken in which data regarding various factors such as energy transfer lines and costs of generation technologies, is collected from experts in these fields or current employees of major UK energy industry companies such as the National Grid ESO. A similar process must be carried out to improve the modelling of the implementation of TES technologies into the UK energy network. Certainly, despite these limitations of the study, we can say that TES technologies in particular the upcoming do provide promising possibilities in terms of improving the UK energy network as the nation continues to transition away from non-renewable energy sources.

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