SCEE11014 Interdisciplinary Group Design Project (Engineering)

Power Station with Carbon Capture and Storage

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Abstract

The transition to low-carbon power generation necessitates critical research into the most viable solutions for achieving net-zero emissions while maintaining grid reliability. This report examines whether a gas-fired Combined Cycle Gas Turbine (CCGT) plant equipped with Carbon Capture and Storage (CCS) offers a more practical option compared to renewable energy sources (wind and solar) with appropriate storage. The study evaluates the economic and operational performance of a CCGT plant retrofitted with CCS, contrasting it with renewable energy alternatives.

A comprehensive analysis was conducted, measuring key variables such as net power output, capital and operational costs, and levelized cost of electricity (LCOE) across both energy sources. The results indicate that while wind and solar technologies are more competitive on an LCOE basis and are ideal for initial decarbonization stages, CCS-equipped CCGT plants become crucial as decarbonization targets approach 80–90% reductions in emissions. The materials requirement for VRE technologies is significantly higher on a per-output basis compared to large dispatchable assets like CCGT plants.

Our findings suggest that CCS is more economical unless the capacity factor is low, and it plays a vital role in achieving deep decarbonization. The report concludes that CCS-based power plants can provide the lowest-cost pathway to net-zero emissions on the shortest timescale, particularly when paired with variable renewable energy sources to ensure grid stability.

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Abbreviations

3PRH Three-Pressure Reheat.

AC Avoided cost.

BCV Basic capacity value.

BESS Battery Energy Storage System.

BFV Base Flexibility Value.

CAPEX Capital Expenditure.

CC Capacity Credit.

CCGT Combined Cycle Gas Turbine.

CCS Carbon Capture and Storage.

CEPCI Chemical Engineering Plant Cost Index.

CF Capacity Factor.

CP Capacity Payment.

CSIRO Commonwealth Scientific and Industrial Research Organisation.

CV Capacity value.

DAC Direct Air Capture.

DCO Development Consent Order.

DH Dispatched Hours.

E Electricity.

EFOR Equivalent Forced Outage Rate.

EIA U.S. Energy Information Administration.

ESS Energy Storage System.

EV Energy Value.

FES Flywheel Energy Storage.

FV Flexibility Value.

FVM Flexibility Value multiplier.

GES Gravity-based Energy Storage.

GTW Gas Turbine World 2024 GTW Handbook.

HES Hydrogen Energy Storage.

HHV Higher Heating Value.

HP High Pressure.

HRSG Heat Recovery Steam Generator.

HTFS HTFS Report.

IEA International Energy Agency.

IP Intermediate Pressure.

IRENA International Renewable Energy Agency.

LACE Levelised Avoided Cost of Electricity.

LAES Liquid Air Energy Storage.

LCC Levelised Capital Costs.

LCOE Levelised Cost of Energy.

LCOS Levelised Cost Of Storage.

LFC Levelised Fuel Costs.

LFP Lithium Iron Phosphate.

LHV Lower Heating Value.

LOM Levelised Operating and Maintenance Costs.

LP Low Pressure.

MEGS Modelling energy and grid services.

MGP Marginal Generation Price.

NCV Net Caloric Value.

NEMO Nucleus for European Modelling of the Ocean.

NETL National Energy Technology Laboratory.

NGCC Natural Gas Combined Cycle.

NMC Nickel Manganese Cobalt.

NREL National Renewable Energy Laboratory.

OM Operation and Maintenance.

OPEX Operating Expenditure.

PNNL Pacific Northwest National Laboratory.

RC Removal cost.

RTE Round Trip Efficiency.

SSE Scottish and Southern Energy.

STG Steam Turbine Generator.

TES Thermal Energy Storage.

VALCOE Value-adjust Levelised Cost of Electricity.

VRE Variable Renewable Energy.

WEP Wholesale Electricity Price.

Nomenclature

$O_{\textbf{x,h}}$ The output of each technology (x) per hour (h) ina year.

AC_{fuel} Annual Fuel Costs.

$A_{CO_2(2019)}$ Auxiliary Load of CO_2 Compression.

C_{2019} Costs in 2019 from NETL Report.

C_{2024} Costs in 2024 from NETL Report.

$C_{CO_2(2019)}$ Cost of CO_2 Compression 2019.

DF Discount Factor.

FC_{CCGT} Fixed Cost of CCGT.

I_{fuel} Inflation Rate of Fuel.

LC_{2024} Levelized Cost in 2024.

N_{worker} Number of Workers.

$P_{\textbf{Total gross output}}$ Total gross output power.

$P_{\textbf{out, GT}}$ Gas Turbine Output Power.

P_{2019} Output Power of Power Plants in 2019.

P_{2024} Output Power of Power Plants in 2024.

$P_{OutReal}$ The Real Output of the Year.

$P_{turbine}$ Output Power of Turbine.

S_{median} AMedian Salary of Workers in CCGT.

$T_{\textbf{entry}}$ Flue gas inlet temperature.

$\dot{Q}_{\textbf{STG}}$ Steam Turbine Generator Output Power.

$\dot{Q}_{\textbf{shaft}}$ Shaft Output Power.

$\dot{m}_{\textbf{90\%,}\,CO_2}$ Captured mass flow rate of CO_2.

$\dot{m}_{\textbf{fuel}}$ Total Gas Turbine Fuel Consumption Rate.

$\dot{m}_{\textbf{FG}}$ Mass flow rate of Flue Gas.

$\dot{m}_{\textbf{FW}}$ Mass flow rate of Feedwater.

$\dot{m}_{\textbf{HP,T}}$ Mass flow rate through the High Pressure Turbine.

$\dot{m}_{\textbf{HP}}$ Mass flow rate of the High Pressure stream.

$\dot{m}_{\textbf{IP,T}}$ Mass flow rate through the Intermediate Pressure Turbine.

$\dot{m}_{\textbf{IP}}$ Mass flow rate of the Intermediate Pressure stream.

$\dot{m}_{\textbf{LP,T}}$ Mass flow rate through the Low Pressure Turbine.

$\dot{m}_{\textbf{LP}}$ Mass flow rate of the Low Pressure stream.

$\dot{m}_{\textbf{RH}}$ Mass flow rate of the Reheat stream.

$\eta_{\textbf{EM}}$ Steam Turbine Electrical and Mechanical Loss.

$\eta_{\textbf{GT}}$ Efficiency of the Selected Gas Turbine.

$\eta_{\textbf{HHV}}$ Higher Heating Value Net Efficiency.

$\eta_{\textbf{LHV}}$ Lower Heating Value Net Efficiency.

$\eta_{\textbf{c}}$ Steam Turbine Correction Factor.

$\eta_{turbine}$ Output Power of Power Plants in 2024.

$\mathbf{E}_{CO_2}$ The emssion of carbon dioxide for two gas turbine.

$\mathbf{E}_{wR}$ The emission of carbon dioxide with removal.

$\mathbf{E}_{woR}$ The emssion of carbon dioxide without removal.

$\mathbf{LCOE}_{wR}$ The LCOE of plant with carbon dioxide capture.

$\mathbf{LCOE}_{woR}$ The LCOE of plant without carbon dioxide capture.

$\mathbf{R}_{CO_2}$ The removal of carbon dioxide for plant with carbon dioxide capture.

$h_{FG,in}$ Flue gas enthalpy at HRSG inlet.

$h_{FG,out}$ Flue gas enthalpy at HRSG outlet.

$h_{\mathbf{FG}}$ Enthalpy of Flue Gas.

$h_{\mathbf{HP}}$ Enthalpy of the High Pressure stream.

$h_{\mathbf{IP}}$ Enthalpy of the Intermediate Pressure stream.

$h_{\mathbf{LP}}$ Enthalpy of the Low Pressure stream.

$h_{\mathbf{RH}}$ Enthalpy of the Reheat stream.

$E_{\mathbf{Total}}$ Total energy input from the fuel.

$HR_{\mathbf{Per\ gas\ turbine}}$ Heat rate.

$\eta_{\mathbf{Cycle}}$ Overall cycle efficiency.

Chapter 1: Introduction

1.1 Background

The Keadby 3 Project, developed by Scottish and Southern Energy (SSE) Thermal in collaboration with Equinor, marks a pivotal step in the UK's journey toward decarbonizing its energy infrastructure. Set to become operational by the mid-2020s, Keadby 3 is projected to play a significant role in the UK's ambition to reduce 10 million tonnes (MT) of CO_2 emissions annually, with this facility alone expected to capture 1.5MT of CO_2. Notably, Keadby 3 achieved a major milestone in December 2022, becoming the first UK power station with Carbon Capture and Storage (CCS) capabilities to receive a Development Consent Order (DCO) from the Secretary of State.

Designed as a Combined Cycle Gas Turbine (CCGT) power station with a gross output of 910 megawatts (MWe), Keadby 3 is expected to operate up to 8000 hours per year and capture 90% of its CO_2 emissions during operation. The captured CO_2 will be transported as a supercritical liquid via the Humber Low Carbon Pipelines, adhering to stringent water content regulations ($\leq$50 ppm H_2O by weight). This project underscores the critical role of CCS in the UK's broader decarbonization strategy, as the technology provides a pathway to reduce emissions from fossil-fuelled power plants while maintaining energy security.

Globally, CCS has been recognized as an indispensable component of achieving net-zero emissions. The International Energy Agency (IEA) estimates that without CCS, global mitigation costs could increase by up to 71% (IEA, 2009). Furthermore, the IPCC warns that excluding CCS from climate strategies could result in even greater cost increases, further emphasizing its importance (IPCC, 2014). However, challenges persist, particularly with public skepticism surrounding CCS. Concerns over CO_2 leakage, the unproven long-term efficacy of storage solutions, and environmental risks have been widely documented (Shackley et al., 2005; Holz et al., 2021). Addressing these issues will be vital for the successful deployment of projects like Keadby 3 and similar future initiatives across the UK.

1.2 Motivation

The global shift toward renewable energy and the rapid expansion of grid networks present significant challenges to power generation stability and reliability. Grid networks now span over 80 million kilometers and are growing by an additional 2.3 million kilometers annually, making balancing generation with fluctuating demand increasingly complex. Recent events, such as Storm Uri in 2021, which caused widespread power failures and over $200 billion in damages, highlight the risks of unreliable power systems (Amelang and Appunn, 2018).

As dispatchable power plants are phased out and reliance on Variable Renewable Energy (VRE) sources like wind and solar increases, grid stability faces heightened risks due to their intermittent and less predictable nature. This unpredictability is compounded by ageing infrastructure, market volatility, and the need for costly energy storage and backup generation solutions. While renewable energy is essential for meeting the Paris Agreement targets (UNFCCC, 2024), these complexities underscore the importance of complementary technologies like CCS.

CCS offers a unique solution by providing dispatchable and reliable power supply, addressing the intermittency of VRE while enabling substantial emissions reductions. It is particularly valuable in sectors where alternative mitigation options are technically or economically limited (Kinyar and Bothongo, 2024). Despite the higher Levelised Cost of Energy (LCOE) associated with CCS compared to renewables, advancements in technology and cost methodologies, such as Value-adjust Levelised Cost of Electricity (VALCOE), are narrowing this gap. Falling CO_2 capture costs, driven by economies of scale, learning-by-doing, and technological optimization, further enhance CCS's economic viability, with costs in some retrofitted plants already reduced to $60–80 per tonne of CO_2 (Yadav and Mondal, 2022).

The deployment of CCS in projects like Keadby 3 has the potential to serve as a benchmark for integrating this technology into existing energy systems. By addressing both technical and public perception challenges, the project provides a blueprint for mitigating the impacts of VRE intermittency and ensuring grid reliability. The successful implementation of CCS not only supports decarbonization efforts but also establishes a viable pathway for the long-term sustainability of fossil fuel plants during the energy transition.

1.3 Report Focus

This report evaluates the viability of a gas-fired CCGT plant with CCS, using Keadby 3 as a case study, and compares it to renewable energy sources within the context of the ongoing energy transition. The analysis focuses on the design and performance of the unabated Keadby 3 CCGT plant, the impacts of retrofitting CCS, and the costs of electricity production, including comparisons with renewable energy options of equivalent output.

The findings of this report will provide critical insights for stakeholders, policymakers, and energy companies considering similar developments across the UK. By assessing the economic and operational impacts of CCS alongside renewables, this report highlights the strategic importance of CCS in achieving national and global decarbonization targets. Additionally, it emphasizes how CCS can address the inherent limitations of VRE, offering a complementary solution to ensure grid stability and reliability.

CCS's potential to mitigate emissions from hard-to-decarbonize sectors such as steel, cement, and heavy industry further reinforces its role in the broader energy transition (Kemper, 2015; Oei, 2016). For these industries, where electrification and other mitigation strategies remain costly or unfeasible, CCS represents one of the most viable solutions. The shared development of CO_2 transport and storage infrastructure between the electricity and industrial sectors could also reduce the average costs associated with CCS deployment (Holz et al., 2021). As such, this report not only informs the feasibility of CCS in the power sector but also underscores its relevance in shaping a decarbonized economy.

Moreover, the report's conclusions will serve as a critical recommendation for current stakeholders, highlighting how CCS can be effectively implemented to meet the dual challenges of decarbonization and energy security. With the IEA projecting an eightfold increase in global CCS capacity by 2030 (IEA, 2020), projects like Keadby 3 take on a transformative present day role in advancing this technology. The insights gained here will inform not just the deployment of CCS in the UK but also its role in global efforts to combat climate change.

Chapter 2: Design Specification

To evaluate the performance of three energy generation systems — an unabated CCGT plant, a CCGT plant with CCS, and a renewable energy plant — the decision was made to base estimations on real-world plant data rather than relying on theoretical calculations. The CCGT plant was modeled using case studies B31A and B31B of Natural Gas Combined Cycle (NGCC), as outlined in the National Energy Technology Laboratory (NETL) report (James, 2019). This was further supported by the latest gas turbine data from the Gas Turbine World 2024 GTW Handbook (GTW) 2024 Handbook (*GTW Volume 39*, 2024). Similarly, the renewable energy system was designed optimised using a range of publications from sources including the IEA, International Renewable Energy Agency (IRENA), and Pacific Northwest National Laboratory (PNNL). The high level design was then modelled using (Lopes et al., 2019).

Economic assessments were conducted using data from the GTW Handbook, Lockwood reports, PNNL, and other reliable online sources. This approach allowed for the derivation of a more realistic LCOE, taking into account factors such as inflation and interest rate fluctuations. For a reliable comparison between the carbon capture system and the renewable energy plant, calculations were standardized to reflect operation within the UK, assuming 8,000 hours of operation per year at full capacity.

2.1 CCGT

2.1.1 Description of approach and key resources used

The general approach used in CCGT calculations involved first determining the performance of a 910MWe gross unabated NGCC plant and then retrofitting it with amine scrubbing CO_2 capture. These sized CCGT plants are based on final selections of the gas turbine and overall configurations, determined through an economic analysis of various modified/fine-tuned power plants.

Case studies B31A and B31B from the James (2019) features an unabated NGCC plant and a NGCC plant with amine scrubbing carbon capture respectively. This made it a suitable choice of CCGT plant case study to scale from.

The *GTW Volume 39* (2024) handbook was used as source to research the most up to date gas turbine models commercially available. This handbook includes detailed technical specifications such as gas turbine ISO baseload rating, efficiency and exhaust gas temperature.

To calculate a reasonable estimate for power output of a bottoming cycle Steam Turbine Generator (STG), the Steam Cycle Simple Calculation in Gülen (2020) Section 5.3.2 was used. This was an appropriate resource as it featured a Three-Pressure Reheat (3PRH) system. This steam turbine power output, with the power output of the gas turbine, provided a rough estimate of the gross power output of the entire plant based on the NETL design.

To verify enthalpy values of steam and flue gas from Case B31A and make relevant scaled adjustments in the final designs, two useful resources were used. First, a steam tables calculator, provided by LearnChemE (2019), provided a quick means of cross-checking steam state and enthalpies through linear interpolation given pressures and/or temperatures. To calculate the flue gas enthalpy, we used a table of gas temperatures and component enthalpies from *HTFS Report DR40* (1980). This table provides accurate enthalpy values for the flue gas over a range of temperatures.

Finally, to work out the accurate compositions of flue gas given specific gas turbine exit conditions, the "Combustion Constants" table found in Kitto (2005) was used. This provides key properties and data related to the combustion of various fuels, with combustion stoichiometry, densities and molecular weights for more precise calculations.

2.1.2 Methods

Determine the performance of a 910MWe gross unabated natural gas fired CCGT

<u>Excel Streamlined Unabated Plant Calculations</u>

An excel document was created to size a sample unabated CCGT plant from the NETL report. This was necessary as it allowed for the streamlining of calculations on multiple iterations of the gas turbines and configurations that would ultimately influence the decision on their choice.

The first spreadsheet used unscaled values, directly from Case B31A of the NETL report to verify the accuracy of the method and check whether any additional streams or losses would need to be accounted for beyond just the High Pressure (HP), Intermediate Pressure (IP), and Low Pressure (LP) streams.

The second spreadsheet would then scale the case study plants in the NETL report. First, this involved adjusting the conditions of the HP steam outlet from the Heat Recovery Steam Generator (HRSG) to maintain the same temperature difference (ΔT) with the gas turbine exhaust temperature. The feed-water flow rate was then adjusted until the heat absorbed by the steam matched the heat available from the flue gas, whilst keeping the proportions of HP, IP, LP streams as well as the gas outlet temperature constant. To ensure the appropriate mass balances between different configurations, the mass flowrate of flue gas was multiplied by the number of gas turbines used.

The heat and mass balance between the flue gas and steam streams were facilitated through use of the main guiding equation below:

$$\dot{m}_{\text{FW}} = \frac{\dot{m}_{\text{FG}}\Delta h_{\text{FG}} + \dot{m}_{\text{RH}}\Delta h_{\text{RH}}}{c1\Delta h_{\text{LP}} + c2\Delta h_{\text{IP}} + c3\Delta h_{\text{HP}}} \tag{2.1}$$

Where constants representing the ratios of mass flowrate between each stream was calculated as per values found in the Case study B31A of the NETL report:

$$c1 = \frac{\dot{m}_{\text{LP}}}{\dot{m}_{\text{FW}}}, \quad c2 = \frac{\dot{m}_{\text{IP}}}{\dot{m}_{\text{FW}}}, \quad c3 = \frac{\dot{m}_{\text{HP}}}{\dot{m}_{\text{FW}}}$$

After sizing the HRSG, the method outlined in (Gülen, 2020) 5.2.3 was used to determine the gross steam turbine output power based on adjusted flowrates. Caution was taken in evaluation of mass flowrates entering each stage of the turbine (LP/IP/HP Turbines), ensuring that they lined up with respective stream as per Case B31A as shown below:

$$\dot{m}_{\text{HP,T}} = \dot{m}_{\text{HP}}, \quad \dot{m}_{\text{IP,T}} = \dot{m}_{\text{HP}} + \dot{m}_{\text{IP}}, \quad \dot{m}_{\text{LP,T}} = \dot{m}_{\text{HP}} + \dot{m}_{\text{IP}} + \dot{m}_{\text{LP}} \tag{2.2}$$

Given the enthalpy values of steam either end of each stage of the steam turbine, and assuming that mass is conserved, the shaft output power of each stage may be calculated through:

$$\dot{Q}_{\text{shaft}} = \dot{m}_{\text{Turbine}}\Delta h = \dot{m}_{\text{Turbine}}(h_{outlet} - h_{inlet}) \tag{2.3}$$

According to (Gülen, 2020) 5.2.3, application of electrical and mechanical losses, as well as a correction factor for leakages produces a more realistic STG output:

$$\dot{Q}_{\text{STG}} = \dot{Q}_{\text{shaft}} \times \eta_{\text{EM}} \times \eta_{\text{c}} \tag{2.4}$$

This streamlined spreadsheet takes inputs of T_{entry}, $h_{FG,in}$, $h_{FG,out}$, and $\dot{m}_{\text{FG}}$ through the HRSG. The enthalpies were determined through their correlations as found in the HTFS Report DR40 (Part 9), January 1980.

Selecting the gas turbine and configuration

Once the streamlined excel spreadsheet was completed, six different CCGT plant configurations, with six appropriate gas turbines, were examined using the excel document to evaluate their performance. The six configurations researched were: 1x1x1, 2x2x1, 3x3x1, 2-off 1x1x1, 2-off 2x2x1 and 2-off 3x3x1. Once all six configurations were analysed, the most suitable configuration was chosen.

To scope each gas turbine model required for each configuration, the rule of thumb that a CCGT power plant's steam turbine typically contributes between one-third and one-half of total gross output was utilised from Gulen's textbook. This meant that for all configurations, the steam turbine typically produced around 303MW. The remaining 606MW would therefore be produced by the gas turbines. The gas turbine model for each respective configuration could then be selected by sourcing a gas turbine that produced 606/N MW where N was the number of gas turbines. *GTW Volume 39* (2024) was used to research different gas turbine models for each configuration. This methodology enabled quick scoping of gas turbine models for each configuration that ultimately all produced a gross unabated power output of 910 ± 20 MWe.

Determining the Overall Plant Efficiency

To determine the overall plant efficiency, the gross unabated power output was divided by the total energy input from both gas turbines. The total energy input from the gas turbine(s) was calculated using the heat rate value provided in the *GTW Volume 39* (2024) and converting the units from Btu to kWh.

Since $1\,\text{kWh} = 3412\,\text{Btu}$, the heat rate per turbine (HR) can be calculated as follows:

$$HR_{\text{Per gas turbine}} = \frac{HR}{3412} = \text{kWh of energy input per kWh of electrical output} \tag{2.5}$$

Using this, the total energy input from the fuel (E_{Total}) can be calculated by multiplying the total gas turbine output power ($P_{\text{Total gas turbine}}$) by the heat rate, where N refers to the number of gas turbines in the configuration:

$$E_{\text{Total}} = N \times (P_{\text{out, GT}} \times HR_{\text{Per gas turbine}}) \tag{2.6}$$

After calculating these values, the overall cycle efficiency (η_{Cycle}) can be determined by dividing the total gross power output ($P_{\text{Total gross output}}$) by E_{Total}:

$$\eta_{\text{Cycle}} = \frac{P_{\text{Total gross output}}}{E_{\text{Total}}} \tag{2.7}$$

It must be noted that the the total gross power output is N times the total output of the 1-off configuration if a N-off configuration is selected.

Determining the HHV and LHV Efficiencies

From the design brief, the values used for Higher Heating Value (HHV) and Lower Heating Value (LHV) were 53,700kJ/kg^{-1} and 48,450kJ/kg^{-1} respectively. Using these values, the thermal input values could be calculated by multiplying the fuel mass flow rate by the HHV and LHV values.

$$HHV_{\text{Thermal Input}} = \dot{m}_{\text{fuel}} \times HHV \tag{2.8}$$

$$LHV_{\text{Thermal Input}} = \dot{m}_{\text{fuel}} \times LHV \tag{2.9}$$

Once the thermal input values were calculated, the HHV and LHV efficiencies could be calculated using the following formulae:

$$\eta_{\text{HHV}} = \frac{P_{\text{net}}}{HHV_{\text{Thermal Input}}} \tag{2.10}$$

$$\eta_{\text{LHV}} = \frac{P_{\text{net}}}{LHV_{\text{Thermal Input}}} \tag{2.11}$$

Once the gas turbine model, with its respective scaled HRSG, closest to the desired power output was selected for each configuration, gas turbine outlet conditions, from *GTW Volume 39* (2024), and the constant HRSG outlet conditions, from Case B31A, were used as inputs to the streamlined excel spreadsheet as detailed above. This provides a more reasonable steam turbine output power as it utilises practical values from the most up-to-date gas turbines and HRSG models.

Once the steam turbine power outputs were calculated for all six configurations, the total gross unabated power output was calculated. This was achieved by adding the steam turbine output power to the gas turbine output power. In order to verify the calculations were approximately correct, Gülen's scoping method for calculating the steam turbine output was used. This confirmed that all calculations were reasonable, determining the configurations which would not meet the gross power output requirement of 910 $\pm$ 20MWe.

Determining Auxiliary Power Losses

Using Exhibit 5-10 of the NETL report, the auxiliary load summary for the unabated plant was calculated by scaling the values. Transformer losses were scaled based on the ratio of gross power outputs. Components related to the HRSG and steam turbine were scaled using the ratio of HRSG capacities between the NETL plant and Keadby 3. The same approach was applied to auxiliary loads associated with the gas turbine.

Determine the performance of a 910Mwe gross unabated natural gas fired CCGT with amine scrubbing CO_2 Capture

To determine the performance of the abated plant, through retrofitting the unabated plant with amine scrubbing carbon capture, a similar methodology was followed. The difference here, is that particular elements were modified to account for the most negative impacts of carbon capture in its overall performance.

- Solvent Regeneration Power Loss
- CO_2 Compression Work
- Additional Scaled Auxiliary Power Losses

Determine the Flue Gas Composition

To accurately determine the flue gas composition, which is essential for calculating carbon dioxide mass flow rates from natural gas combustion, combustion calculations are performed at the gas turbine exhaust. This provides the gas composition prior to CO_2 capture, influencing compressor sizing and steam requirements for solvent regeneration.

The calculations required in finding the overall composition of gas at the exhaust of the gas turbine are called "Combustion Calculations." To find the composition of the gas at the gas turbine exit, and hence the gas composition before the CO_2 is captured, the combustion constants table was used.

The first step is to calculate $\dot{m}_{\text{fuel}}$. This is derived using the power output, turbine efficiency, and Net

Caloric Value (NCV) of the fuel - values presented in *GTW Volume 39* (2024) and the Design Brief:

$$\dot{m}_{\text{fuel}} = \frac{P_{\text{out, GT}}}{\eta_{\text{GT}} \times NCV} \tag{2.12}$$

Next, using typical North Sea gas compositions, the volume fractions of each gas component in natural gas are identified as shown in Appendix A. The volume fractions correlate to the molar fractions, which, combined with molecular weights of each component, yield the absolute mass distribution of a standard 100 moles of flue gas. This enables calculation of the mass distribution for each gas species.

Finally, assuming mass conservation between the turbine exhaust and carbon capture inlet, each gas in the flue stream by combining the mass contributions of excess gas (O_2 and N_2) with combustion products (CO_2, H_2O and N_2) can be quantified. Here, it is assumed that all carbon in the natural gas is converted to CO_2 (James, 2019).This distribution enables recalculating the volume fractions of each gas under dry and non-dry conditions.

Determine Solvent Regeneration Related Power Loss

In retrofitting the unabated plant with amine scrubbing CCS, steam is required to be extracted from the HRSG to regenerate the chemical solvent involved in CO_2 capture. This calculation is important to consider as the steam circulating through the HRSG will reduce as a result, requiring a recalculation of steam turbine power output.

According to Case B31B, which the plant is modelled after, this extraction occurs at the IP/LP crossover and the outlet of the HP Turbine. With minimal relative flow at the HP turbine outlet, both streams are combined as an IP/LP crossover extraction. To scale the value of steam required from Case B31B, the heat requirement to the reboiler was considered with a relevant heat and mass balance. Given the low-pressure steam requirement for the reboiler of 2.9 MJ/Kg CO_2, as in B31B, it is possible to work out the equivalent reboiler heat requirement for the scaled plant, given that 90% of the CO_2 is to be captured:

$$Q_{\text{in, reboiler}} = 2.9MJ/Kg \ \times \ \dot{m}_{\text{90\%, } CO_2} \tag{2.13}$$

Then, to calculate the steam requirement to the reboiler, a heat and mass balance is setup at the inlets and outlets of the CANSOLV carbon capture process with equation (2.14), according to Figure 2.1:

$$Q_{\text{in, reboiler}} = \dot{m}_{\text{reboiler}} \Delta h_{\text{reboiler}} \ + \ \dot{m}_{\text{reclaimer}} \Delta h_{\text{reclaimer}}$$

$$\dot{m}_{\text{reboiler}} = \frac{Q_{\text{in, reboiler}} \times \dot{m}_{\text{reclaimer}} \Delta h_{\text{reclaimer}}}{\Delta h_{\text{reboiler}}}$$

$$\therefore \quad \dot{m}_{\text{reboiler}} = \frac{Q_{\text{in, reboiler}} \times \dot{m}_{\text{reclaimer}} (h_{10} - h_9)}{(h_5 - h_6)} \tag{2.14}$$

Subsequently, the reclaimer stream is scaled in the same proportion to the reboiler stream as in Case B31B and added to the reclaimer stream calculated as per equation (2.14) to determine the

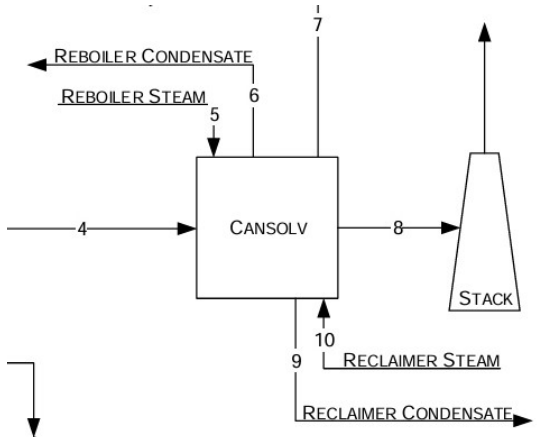

Figure 2.1: Block Diagram representing the inlets and outlets of the CANSOLV Carbon Capture process

total steam extracted from the IP/LP Crossover:

$$\dot{m}_{\text{steam, ex}} = \dot{m}_{\text{reboiler}} + \dot{m}_{\text{reclaimer}} = \dot{m}_{\text{reboiler}} + \left(\dot{m}_{\text{reclaimer, B31B}} \times \frac{\dot{m}_{\text{reboiler}}}{\dot{m}_{\text{reboiler, B31B}}}\right)$$

$$\therefore \quad \dot{m}_{\text{steam, ex}} = \dot{m}_{\text{reboiler}} \left(1 + \frac{\dot{m}_{\text{reclaimer, B31B}}}{\dot{m}_{\text{reboiler, B31B}}}\right) \tag{2.15}$$

To adjust the overall steam turbine output to account for this steam extraction, a similar approach to that used in the unabated CCGT is applied, with a modification to $\dot{m}_{\text{LP,Turbine}}$ in equation (2.2):

$$\dot{m}_{\text{LP,Turbine}} = \dot{m}_{\text{HP}} + \dot{m}_{\text{IP}} + \dot{m}_{\text{LP}} - \dot{m}_{\text{steam, ex}} \tag{2.16}$$

Determine CO_2 Compression Power Requirement

Compression of the CO_2 captured is a crucial process in the design as it ensures that the gas leaves the CCGT plant at a standard 110 barg pipeline pressure. The general method in calculation of compression power involves the modification of the integrally geared 8-stage compressor with intercooling from Case B31B. First, the efficiency of the compression in Case B31B must be defined. Using the values for the interstage outlet pressures and pressure ratios from Case B31B, as seen in Appendix A, the maximum power required for the full compressor could be found.

The guiding equation below, represents the polytropic process work for each stage of the compression where the gas constant of CO_2 (R_{CO_2}) is $0.1889 KJ/Kg\ K$ and the gas constant of CO_2 (n) is 1.3 (Borgnakke, 2022):

$$W_c = \frac{n}{1-n} Z R_{CO_2} T_i \left[\left(\frac{P_e}{P_i}^{\frac{n-1}{n}} - 1\right)\right] \tag{2.17}$$

Where Z is the compressibility ratio, T_i is the CO_2 inlet temperature and P_e/P_i is the pressure ratio

Z was determined through a verified Compressibility Factor Calculator script on MATLAB, where T_i and an average pressure between inlet and outlet of each stage (P_{avg}) was provided as inputs

(Greene, 2024). It was also assumed that the temperature remained constant throughout the compression, in line with Case B31B where temperature differences were negligible.

Using the power required for actual CO_2 compression $(17,090\ kWe)$, an overall efficiency could be defined for the entire interstage compression ($\eta_{\text{int,c}}$). This efficiency is then used in calculation of the power required for the scaled compression.

To find the power required for the scaled compression, the overall pressure ratio was calculated through a fixed inlet pressure and 110 barg of outlet pipeline pressure. For simplification, the pressure ratio of each stage of compression was adjusted so that they were equal to one another. Once the average pressures were defined, the same approach as the analysis of Case B31B was followed, with the equation below yielding the estimated power required to compress the CO_2:

$$W_{\text{c,actual}} = W_{\text{c,scaled}}/\eta_{\text{int,c}} \tag{2.18}$$

Determining Scaled Auxiliary Power Losses

The auxiliary power consumption includes a series of factors including CO_2 compression. The CO_2 capture / removal auxiliaries were scaled according to the flue gas flow entering the capture plant. This involved scaling feedwater flow the NETL Case B31A. The remaining auxiliary performance peramaeters were scaled using the same methodology as with the unabated plant to determine the total auxiliaries.

Due to the CO_2 compression associated with the plant with CCS, this resulted in a reduced steam turbine outpower power. This in turn gave a different scaling ratio between the Keadby 3 plant and the NETL report and hence the auxiliary values calculated for the plant with CCS were different.

2.2 Renewable Energy

2.2.1 Description of approach and key resources used

To determine the most suitable type of renewable energy generation, various options were evaluated based on their distinct characteristics and economic profiles. Additionally, the wind farm's optimal design was developed through thorough analysis of available data to enhance and refine its configuration. Regarding energy storage, first the optimal Energy Storage System (ESS) was identified using several analytical methods to compare various available technologies from which the results were collated to reach a decision. Following this, materials for the selected technology were compared in order to specify the most suitable one for this application.

2.2.2 Method

Selection of Renewable Generation Technology

The most suitable renewable energy source was identified through a comprehensive comparison of four types of renewable energy: offshore wind, onshore wind, solar energy, and geothermal. Each energy type was evaluated through a SWOT analysis to assess its unique characteristics, complemented by an economic analysis to evaluate its financial feasibility and long-term viability.

Following the completion of the SWOT analyses for each renewable energy type, a ranking was assigned based on their strengths and weaknesses. The economic analysis was conducted by gathering detailed data of each energy type. This comprehensive data collection allowed for a thorough assessment of the viability of each energy type, providing a solid foundation for informed decision-making.

Location Selection for Offshore Wind Farm

The optimal offshore wind farm location was identified through the comparison of existing large scale offshore wind farms (each producing upwards of 400MW), Dudgeon Offshore wind farm, Hornsea project one and Triton Knoll.

To establish criteria for comparison, scatter plots were analysed for 20 UK wind farms, highlighting the relationships between cost, capacity, depth, and distance from shore. These results informed the decision-making process.

Installed Capacity

The installed capacity was calculated using the following equation:

$$\text{Installed Capacity} = \frac{\text{Average Output}}{\text{Capacity Factor}} \tag{2.19}$$

The average power output was taken as the nett power output of the CCGT plant with CCS, for fair comparison, and it was assumed that the capacity factor would be the same as for the existing wind farm at Dogger Bank.

Turbine Mooring Strategies

When considering renewable generation method and wind farm location, a mixture of existing fixed and floating wind farms were analysed. The location selected has a maximum depth of 25m which indicates that fixed turbines are more suitable. Comparison of capacity factor and economics of fixed and floating turbines was undertaken to confirm that fixed turbines were the optimal solution.

Selection of Energy Storage System

The analytical methods used to select the most appropriate ESS were SWOT analysis, comparison of round-trip efficiency, and comparison of Levelised Cost Of Storage (LCOS). The storage systems reviewed were Lithium-ion Battery Energy Storage System (BESS), Flywheel Energy Storage (FES), Gravity-based Energy Storage (GES), Hydrogen Energy Storage (HES), Thermal Energy Storage (TES), and Liquid Air Energy Storage (LAES).

The arguments in the SWOT analysis were ranked according to influence, with strengths and opportunities marked positively, and weaknesses and threats marked negatively. Table 3.25 shows the totalled values for each ESS. Round trip efficiencies of the various storage technologies were obtained and plotted to further investigate the results of the SWOT analysis.

LCOS a metric is commonly used to optimize energy storage system costs which in this case will be utilized to determine if lithium-ion batteries are the most economic ESS. It is expressed as the cost per unit of energy stored and delivered, GBP per MWh Mongird et al. (2020). The formula is:

$$\text{LCOS} = \frac{\text{Total Lifetime Costs}}{\text{Total Lifetime Energy Delivered}} \tag{2.20}$$

The total lifetime cost encompasses capital and operating expenditure, and the total lifetime energy delivered depends on storage capacity, efficiency, and usage.

Battery Type

Regarding battery materials, Lithium Iron Phosphate (LFP) batteries and Nickel Manganese Cobalt (NMC) batteries are common examples which use lithium ions as the primary charge carrier. Their different chemical composition and performance characteristics were compared to determine which is more suitable for this application.

High-level Renewable Design

The high-level design integrates a 1650 MW offshore wind farm, consisting of 110 Vestas V236-15.0 MW turbines, with a 4-hour, 788.5 MWh lithium-ion Battery Energy Storage System to enhance grid stability and provide ancillary services. The design ensures seamless operation between wind generation and energy storage, optimizing output delivery to the grid under varying wind conditions. The turbines are designed to have monopile foundations with an optimized layout to minimize wake effects and maximize energy yield.

Regarding electrical specifications, offshore substations shall step up turbine output (66 kV) to transmission voltage (typically 220–400 kV) while medium-voltage inter-turbine cables connect turbines to the offshore substation and high-voltage export cables deliver power to the onshore grid connection point.

2.3 Economics

To evaluate the cost-effectiveness of different power generation technologies, this analysis calculates the levelized cost of electricity (LCOE) for three configurations: an unabated Combined Cycle Gas Turbine (CCGT) plant, a CCGT plant with carbon capture and storage (CCS), and a renewable energy plant.

The LCOE accounts for each option's capital and operating costs over its lifecycle, offering a per-unit electricity cost for comparison. While the unabated CCGT plant has lower upfront costs but emissions exposure, the CCGT with CCS reduces carbon impact at a higher expense. Renewable plants offer low operating costs but face intermittency challenges and higher initial investment. Comparing these LCOEs will clarify which option provides the most economical choice, considering financial and environmental factors.

As the most common method for evaluating electricity generation costs, LCOE combines various expenses, such as capital and Operation and Maintenance (OM) costs, into a single value. Nevertheless, it is not suitable for comparing generation costs across different types of power generation, as it overlooks certain factors. For instance, market conditions of power generation are also ignored, offshore wind has significantly less flexibility than CCGT, Therefore, an alternative evaluation method is required. (Graham, 2018)

There are alternative methods that can be used to extend LCOE to include balancing costs, such as Modelling energy and grid services (MEGS), Levelised Avoided Cost of Electricity (LACE), Nucleus for European Modelling of the Ocean (NEMO), VALCOE, and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) method. These approaches generally incorporate a wide range of balancing solutions for variable renewable energy. Among them, the VALCOE and LACE frameworks provide relative information on the equations used, and as such, this article will primarily focus on VALCOE and LACE.

2.3.1 Description of Approach and Key Resources Used

The primary resource for our economic estimation is the NETL report(James, 2019), which employs the Levelized Cost of Energy (LCOE) method. This approach allows us to compare the costs of CCGT without carbon capture and storage, CCGT with CCS, and renewable power plants. Following the methodology outlined in Case 31A and Case 31B, we derived cost estimations for our power plants. The case study provides detailed spreadsheets that enumerate every cost associated with the power plant.

LCOE is an economic evaluation method that accounts for all capital, fixed, and variable costs, including operating, maintenance, and fuel expenses. It standardizes these costs into a single metric, expressed as £ per MWh, enabling straightforward comparisons of cost-effectiveness between power plants. This simplicity makes it a highly practical tool for evaluating different energy generation options.

For the one of alternative methods, the LACE is a metric introduced by the U.S. Energy Information Administration (EIA) to address limitations of the LCOE when comparing dispatchable and non-dispatchable energy sources. LACE represents the potential revenue a project owner can earn from energy and capacity sales. It is calculated as the weighted average of the marginal cost of electricity dispatch during the project's assumed operating hours. The initial assessment of LACE combines regional marginal generation prices and capacity values.

VALCOE is a metric proposed by the IEA to complement the traditional LCOE. It reflects both the cost and value of electricity within the power system, acknowledging that the value of the same amount of electricity can vary during peak demand periods. Therefore, VALCOE considers both the cost of electricity in various conditions and its value to the system. Based on the average LCOE for each technology, VALCOE incorporates three additional value components: energy, capacity, and flexibility.

For the alternative methods, the detailed analysis are Graham (2018); Beiter et al. (2017); IEA (2024), and the main data are from Iain Staffell and et al. (2024); BMRS (2024).

2.3.2 Economic Assessment Methods

Levelised Cost of Energy (LCOE)

As mentioned above, we have chosen LCOE as the main method to compare the financial performances of the different types of power plant we are going to use.
By using this method, we have considered the following factors that affect the performance of the finance of the power plants: Initial Investment Cost (Capital Cost), Operating and Maintenance Costs, the OM Growth Rate, the Annual Fuel Costs, Annual Fuel Cost Increasing Rate, Annual Electricity Output, Project Lifespan, and the Discount Rate. The formula for calculating LCOE is:

$$LCOE = LCC + LOM + LFP \tag{2.21}$$

We first calculate the Present Value of Costs using the following formula:

$$II + C_{OM} \times (100\% + R_{OMgrowrh}) + C_{fuel} \times (100\% + R_{FuelGrowth}) = AC_{NPV} \tag{2.22}$$

And the Present Value of Output is calculated by the following formula:

$$P_{out} \times DF = P_{OutReal} \tag{2.23}$$

To calculate the NPV of total costs and total output, the values for each year the power plant is in operation were summed using the following equation:

$$\frac{NPV\ of\ total\ costs}{NPV\ of\ total\ output} \tag{2.24}$$

we can have the LCOE.
When talks about the fuel cost we use in the LCOE calculation, we have assumed that the power plant will work 8000 hours a year with full load. In this way, we can compare the LCOE of the CCGT unabated, CCGT with CCS and the renewable power plant. This is because the accurate output power of renewable power plants will be affected by the weather or many other factors, using the same working hours in the year can control the variables to make the comparison more accurate.

LCOE for CCGT

Scaling

From the NETL report Case 31A, we have the spreadsheet of every detailed costs for a CCGT unabated power plant. The example in the report is an NGCC power plant with the output power of 727MWe but our power plant will have the output power of 910MWe. For those equipments in the power plant, we use the ratio between the two power plants to scale the costs. As the report was written in 2019, and the currency in the example is dollar, we consider the inflation rate from 2019 to

2024, which is about 2.3%, and using the currency rate of \$1 = £0.77. Hence we have the equation (2.25).

$$C_{2024} = C_{2019} \times \frac{P_{2024}}{P_{2019} \times 0.77} \times (1 + 2.3\%) \tag{2.25}$$

Using Economics to Determine the Optimal Plant Configuration

Conducting an economic assessment is a critical step in determining the optimal configuration of the plant. To ensure accuracy and consistency, the assessment must be standardized and account for the primary cost components. Here, the two main costs of gas turbine Capital Expenditure (CAPEX) and fuel lifetime costs are considered.

This study evaluates the plants under part-load operation to provide a more realistic estimate of total operational hours. This method follows on from the part-load method in section 3.4 of (Gülen, 2020) on plant operability, with its key assumptions found in Appendix. Based on this approach, the estimated number of operational hours per year is:

$$(52 - 2)weeks/year \times 5days/week \times 17hours/day = 4250hours/year \tag{2.26}$$

Therefore, the total power output will be:

$$50 \times 5 \times P_{turbine} \times \frac{100\% \times 11 + 40\% \times 4 + 50\% \times 2}{\eta_{turbine}} = P_{out} \tag{2.27}$$

In order to get the fuel cost, the information from Office for National Statistics. We got the estimated inflation rate of the gas price using the information from Office for National Statistics, so that we can estimate the fuel costs in the future years and then get the overall understanding with which configuration can be the best choice for us. We calculated the fuel costs for 1 MWh in 2024 and we can get the estimation for the future years by timing (1+inflation rate). So we have the final equation. (2.28)

$$P_{out} \times LC_{2024} \times (100\% + I_{fuel})^{Y_{from2024}} = AC_{fuel} \tag{2.28}$$

Using this part-load method, we can control the other variables other than output power of the configurations, thus we can find out which configuration will be the best choice.

Scaling for Operating and Maintenance Costs

As for the operating costs, we use the data from Talent.com (Cite here) to get the median number of the salary for the labours working in the CCGT power plants. Again using the comparison between our power plant to the plant from the example, we can have the number of workers needed for our power plant. Using equation (2.29)

$$N_{Worker} \times S_{median} = FC_{CCGT} \tag{2.29}$$

For the Variable Operating Costs, e.g. consumables and maintenance materials, we also have the scaling by timing the ratio between two power plants and also consider the inflation rate from 2019 to 2024. The equation is similar to it for capital costs.

2.3.3 LCOE for CCGT with CCS

Scaling

The main scaling method for the CCGT with CCS is similar to it for CCGT unabated. Using the ratio between the output power of the plant in the example and our power plant and then using the up-to-date information of the labour cost and variable costs. The special part for CCGT with CCS is the CO_2 compressor cost is calculated by this equation. (2.30)

$$C_{CO_2(2019)} \times \frac{A_{2024}}{A_{2019}} = C_{CO_2(2024)} \tag{2.30}$$

The CCGT with CCS needs more materials and consumables than CCGT unabted which will increase a lot of costs. For those materials, we use the equation (2.25) as well.

2.3.4 LCOE for Renewable

Operations and Maintenance Costs

NREL's Windfarm Operations and Maintenance cost-Benefit Analysis Tool (Hammond and Cooperman (2022)) was used to give Operating Expenditure (OPEX) costs. Wombat analysed for a 1650MW wind farm, consisting of 110, 15MW turbines and two offshore substations located 32km of the coast of Norfolk, England, with 7 crew transfer vessels, an anchor vessel, diving support vessel, cable lay vessel, remotely operated vessel.

Figure 2.2: 1650MW Offshore Wind Farm Layout.

OPEX modelling assumptions include a full time crew available year round for minor repairs, working hours are 8am – 6pm, Failure rates and costs associated with repairs and replacements informed by COREWIND (2021), and results only include material, labour and equipment costs.

Capital Expenditure Costs

To estimate a reasonable CAPEX cost for the offshore wind farm, data was collected from 20 wind farms located in the United Kingdom as can be seen in appendix E. This data included their respective CAPEX and total output capacities. The costs were then normalised by calculating the cost per unit of capacity. Finally, the average normalised cost was scaled to match the output capacity of a 1,650 MW wind farm.

2.3.5 Alternative Calculations

Levelised Avoided Cost of Electricity (LACE)(Beiter et al., 2017; EIA, 2013)

$$LACE = \frac{\sum_{t=1}^{Y}(MGP_t \times DH_t) + (CP \times CC)}{DH_Y} \tag{2.31}$$

The Marginal Generation Price (MGP)(£/kWh) represents the cost of producing an additional unit of electricity to meet demand during a specific period. This price is influenced by real-time market conditions, fuel costs, and operational constraints.Dispatched Hours (DH)(kWh/kW/yr) denote the estimated number of hours a generating unit is operational within a given timeframe.Capacity Payment (CP)(£/kW/yr) is a financial incentive designed to ensure sufficient generation capacity to meet reliability standards; it compensates the last unit of capacity needed to satisfy regional reliability reserve requirements. Capacity Credit (CC)(%) reflects a unit's contribution to system reliability. For dispatchable units, the full nameplate capacity is considered (Capacity Credit (CC) of 1 or 100%). In contrast, intermittent renewable resources have their CC adjusted based on availability during peak demand and the likelihood of outages in the area.

Value-adjust Levelised Cost of Electricity (VALCOE)

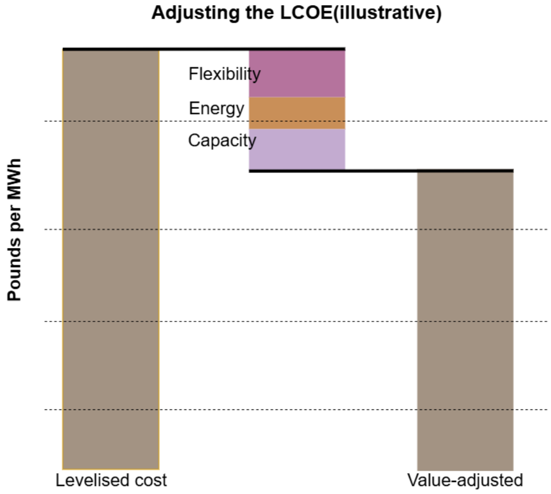

Figure 2.3: Moving beyond the Levelised Cost of Electricity to the value-adjusted Levelised Cost of Electricity .

$$VALCOE_x = LCOE_x + \overbrace{\underbrace{[\bar{E} - E_x]}_{\textit{Energy value}} + \underbrace{[\bar{C} - C_x]}_{\textit{Capacity value}} + \underbrace{[\bar{F} - F_x]}_{\textit{Flexibility value}}}^{\textit{Value adjustment}} \tag{2.32}$$

And the calculation of Energy Value (EV), Capacity value (CV) and Flexibility Value (FV) are as follow:

$$EV_x(\frac{£}{MWh}) = \frac{\sum_{i=8760}^{n}[WEP_h(\frac{£}{MWh}) \times O_{x,h}(MW)}{\sum_{i=8760}^{n} O_{x,h}(MW)} \tag{2.33}$$

For Energy Value (EV), the Wholesale Electricity Price (WEP) and $O_{x,h}$ are simulated. Wholesale Electricity Price (WEP) are based solely on the marginal cost of generating electricity and do not include any scarcity pricing or other additional costs

$$CV_x(\frac{£}{MWh}) = \frac{CC\,x \times BCV(£/kW))}{CF_x \times H_y/1000))} \tag{2.34}$$

Capacity value (CV), used with Basic capacity value (BCV), which reflects the contribution to system adequacy, distinguishes between dispatchable and renewable technologies.
For dispatchable power plants, the Capacity Factor (CF) is modelled as simulated operations in previous year. For wind and solar plants, the capacity factor is aligned with latest performance data from IRENA and other sources.

$$FV_x(\frac{£}{MWh}) = \frac{FVM_x \times BFV(£/kW))}{CF_x \times H_y/1000))} \tag{2.35}$$

Based on available market data for the EU and the US, the Base Flexibility Value (BFV) is a function of the annual share of electricity generated by variable renewables. The Flexibility Value (FV) is assumed to increase as the share of variable renewable energy increases, with a maximum equal to the total fixed capital recovery cost of the peaking plant.

However, the Flexibility Value multiplier (FVM) is not defined directly, and the BFV is poorly defined, moreover, there is no more document or equation provided by IEA for Flexibility Value (FV), so there is not more discussion about FV. In addition, the CV and EV of VALCOE are remarkably similar to the Marginal Generation Price (MGP) and CV of LACE, so the discussion will focus on the LACE in the next content.

Removal cost (RC) and Avoided cost (AC)(Mark C. Woods and et al., 2009; Fout et al., n.d.)

The carbon dioxide removal cost refers to the lowest carbon dioxide gate sales price that can incentivize carbon capture relative to the determined carbon dioxide gate sales price of non-capture plants. The cost of carbon dioxide removal is calculated as follows:

$$RC = \frac{\{LCOE_{wR} - LCOE_{wR}\}£/MWh}{\{R_{CO_2}\}tons/MWh} \tag{2.36}$$

The carbon dioxide avoided cost represents a minimum price on CO_2 emissions that applies to both carbon capture plants and non-carbon capture plants, and that will incentivize carbon capture relative to defined reference non-carbon capture plants. The cost of avoiding CO_2 emissions is calculated using the following formula:

$$AC = \frac{\{LCOE_{wR} - LCOE_{woR}\}£/MWh}{\{E_{woR} - E_{wR}\}tons/MWh} \tag{2.37}$$

2.3.6 Key Price Factors

Fuel Costs

A significant amount of energy is generated each year, primarily by burning gas. This process requires substantial financial resources to purchase the fuel needed for the power plant to operate. Once the power plant is constructed, fuel costs become the largest ongoing expense.

2.3.7 Renewable Costs

Total CapEx and OpEx for the Wind Farm and ESS were separately calculated before being collated into a total CapEx, fixed OpEx, variable OpEx, and lifetime cost for the renewable plant.

CAPEX and OPEX for the ESS were calculated over an estimated 25-year lifetime of the wind farm, with an annual inflation rate of 2% applied across all cost categories. The calculation of OpEx was broken down into fixed OM and variable OM, which includes costs associated with round-trip efficiency (RTE) losses due to system degradation, and battery replacements.

Chapter 3: Analysis and Results

3.1 CCGT

3.1.1 Final Selected Design Solution

After evaluating all six plant configurations, the 1-off 2x2x1 arrangement was determined to be the most suitable for the Keadby 3 plant. This configuration incorporates two GE Vernova Frame 9F.04 (50Hz) gas turbines, each with a capacity of 288 MWe. Based on scaled calculations detailed in the subsequent section, the steam turbine's power output was determined to be 328.4 MWe, resulting in a gross unabated power output of 904.4 MWe. This output satisfies the target gross range of 910 ± 20 MWe. The overall plant efficiency was calculated to be 60.86%.

In addition to meeting performance requirements, this configuration demonstrated the lowest capital cost at £871,000,000 and the most competitive Levelised Fuel Costs (LFC) at £6,891,718,348 of all the configurations which met the 910 ± 20 MWe gross output, as seen in Appendix D. The 2x2x1 configuration ensures redundancy, allowing continued operation of the remaining units during maintenance or mechanical failure of one gas turbine. This minimizes downtime and enhances reliability, supporting consistent energy delivery and grid stability. Among the configurations evaluated, the 1-off 2x2x1 design provided an optimal balance of efficiency, simplicity, and cost-effectiveness, making it the preferred choice for the Keadby 3 project.

3.1.2 Final Design Calculations

This section outlines the key findings for both the unabated and abated plant. For the unabated plant, the calculations include gross power output, steam turbine contribution, and auxiliary loads. For the abated plant, additional analysis was conducted to determine the power loss due to CO_2 capture and its impact on overall performance. These results validate the 1-off 2x2x1 configuration as meeting the design and efficiency targets.

Unabated plant calculations

Based on the methodology mentioned in section 3.1.2 of the report, the following detailed calculations were undertaken to achieve the power output for the selected CCGT unabated design configuration.

Combustion Turbine Power

From *GTW Volume 39* (2024), the gas turbine characteristics were obtained, including the power output:

Model	Power Output [MW]	Efficiency	Mass Flowrate[lb/sec]	Exhaust Temp[F]
GE Vernova Frame (50/60 Hz) 9F.04	288	38.7 %	1459.0	1150

Table 3.1: Gas Turbine Model Values

For selected configuration 2x2x1, N=2 (number of turbines) total power output was:

$$\text{Total Power Output} = 2 \times \text{Turbine Power Output} = \textbf{576 MW} \tag{3.1}$$

Steam Turbine Power

Following the step by step method written in section 3.1.2 the STG power output was obtained: Mass flowrate scaling from NETL report:

Flow Type	Exhibit 5-15	Ratios	Scaled
Main, $\dot{m}_{FW}$ [lbm/hr]	1.384E+06	1.000	1.82E+06
HP, $\dot{m}_{HP}$ [lbm/hr]	1.071E+06	0.774	1.41E+06
IP, $\dot{m}_{IP}$ [lbm/hr]	1.527E+05	0.110	2.00E+05
LP, $\dot{m}_{LP}$ [lbm/hr]	1.601E+05	0.116	2.10E+05

Table 3.2: Scaled Mass Flowrates

Shaft power output of each stage:

Turbine	Flowrate[lb/hr]	h_{inlet}[Btu/lb]	h_{outlet}[Btu/lb]	Q_{shaft}[kW]
HP	1.405E+06	1517	1338	73707.6
IP	1.605E+06	1566	1324	113857.5
LP	1.815E+06	1322	1023	159073.2
Total				**346638.3**

Table 3.3: Shaft Power Outputs-Unabated

By applying the EM and correction factor the realistic STG ouput was obtained:

Q_{shaft}[MW]	$\eta_{EMlosses}$	$\eta_{correction}$	Q_{STG}[MW]
346.6	0.987	0.96	**328.4**

Table 3.4: Steam Turbine Power Output-Unabated

Total Gross Power

Trivially:

$$\text{Total Gross Power} = \text{Combustion Turbine Power} + \text{Steam Turbine Power}$$

Hence, the final power output is found as:

Combustion Turbine Power[MW]	Steam Turbine Power[MW]	Total Gross Power[MW]
576	328.4	**904.4**

Table 3.5: Total Gross Power Output - Unabated

Auxiliary Power Losses

To calculate the auxiliary power losses for the unabated plant these scaling factors were found. According to the nature of the losses a different factor was used:

Scaling Factors	
Gross Power	1.22
Gas Turbine Power	1.21
Steam Turbine Power (HRSG Related)	1.25

Table 3.6: Scaling Factors-Unabated

Example Calculation:

$$\text{Transformer Losses} = \text{Gross Power} \times \text{NETL(value)}$$

Auxiliary load	NETL Report	Keadby 3
Transformer losses, kWe	2250.00	2750.0

Table 3.7: Example Calculation for Transformer Losses-Unabated

Analysis

To justify the power output for the unabated plant, the contribution of the combustion turbines and steam turbine to the total power were identified and the following were obtained:

Technology	Contribution
Combustion Turbine	63.6%
Steam Turbine	36.3%

Table 3.8: Technology Contribution to Power Output

These results align with Gulen's general rule of thumb, which suggests that the steam turbine of a CCGT power plant typically contributes around one-third of the total gross output (approximately 36.3%). Therefore, the findings appear reasonable.

Plant Efficiency

Using the calculations mentioned in the method statement, the overall gross plant efficiency was calculated. Consulting the GTW Handbook, the heat rate for the GE Vernova Frame 9F.04 was found to be 8810Btu/kWh.

$$HR_{\text{Per gas turbine}} = \frac{8810}{3412} = \text{2.58kWh of energy input per kWh of electrical output} \tag{3.2}$$

$$E_{\text{Total}} = N \times (P_{\text{out, GT}} \times HR_{\text{Per gas turbine}}) = (2 \times 288) \times 2.58 = 1486.08 MWe \tag{3.3}$$

$$\eta_{\text{Cycle}} = \frac{P_{\text{Total gross output}}}{E_{\text{Total}}} = \frac{904.4}{1486.08} = \textbf{60.86\%} \tag{3.4}$$

Before the HHV and LHV net efficiencies were calculated, the thermal inputs were calculated as shown below:

$$HHV_{\text{Thermal Input}} = \dot{m}_{\text{fuel}} \times HHV = 30.72 \times 53700 = 1649664kWt \tag{3.5}$$

$$LHV_{\text{Thermal Input}} = \dot{m}_{\text{fuel}} \times LHV = 30.72 \times 48450 = 1488384kWt \tag{3.6}$$

Once the thermal input values were calculated, the HHV and LHV efficiencies could be calculated using the following formulae:

$$\eta_{\text{HHV}} = \frac{P_{\text{net}}}{HHV_{\text{Thermal Input}}} = \frac{887600}{1649664} = 53.80\% \tag{3.7}$$

$$\eta_{\text{LHV}} = \frac{P_{\text{net}}}{LHV_{\text{Thermal Input}}} = \frac{887600}{1488384} = 59.64\% \tag{3.8}$$

Abated plant calculations

Continuing to the abated plant calculations, the power losses due to CO_2 capture and compression were calculated and the flue gas composition was obtained.

Flue gas composition

Initially the mass flow rate of the fuel was identified. Following the method in section 2.1.2 the following was obtained:

P_{out}[MW]	$\eta_{turbine}$	NCV[kJ/kg]	$\dot{m}_{fuel}$[kg/s]
288	0.387	48450	**15.3599**

Table 3.9: Mass Flowrate of Fuel Calculation

Then the volume fractions of each gas under dry and non-dry conditions was identified to obtain the following flue gas composition (see Appendix A):

FLUE GAS COMPOSITION			Per kg				
	Mass	%w/w	Mass Dist	Mole Dist	%v/v	%v/v (dry)	Mol Wt
Nitrogen (N2)	496.657	75.05%	0.7505	0.0268	75.96%	82.44%	28.016
Oxygen (O2)	90.768	13.72%	0.1372	0.0043	12.15%	13.19%	32.000
Moisture (H2O)	33.032	4.99%	0.0499	0.0028	7.86%	0.00%	18.016
Carbon Dioxide (CO2)	41.335	6.25%	0.0625	0.0014	4.02%	4.37%	44.010
	----------	-----------	------------	------------	-----------	------------	
TOTAL	**661.791**	**100.00%**	**1.00**	**0.0353**	**100.00%**	**100.00%**	

Table 3.10: Flue Gas Composition

Solvent regeneration power loss

The overall steam turbine output had to be readjusted to account for the steam extraction due to solvent regeneration. To do that, the following required values were obtained based on the method in section 2.1.2:

$$\dot{m}_{CO_2} = \text{Mass}_{CO_2} \times 2 = 82.669\,\text{kg/s},$$

Then the reboiler power required was found to be:

Reboiler Energy Consumption[MJ/kg]	$\dot{m}_{90\%,CO2}$[kg/s]	Reboiler Power Required[MW]
2.9	74.4021	**215.767**

Table 3.11: Reboiler Power Required

Once the scaled mass flowrate of the reclaimer stream and the mass flowrate of the reboiler stream were obtained,the mass flowrate of the extracted steam was found:

$\dot{m}_{reclaimer}$[lb/hr]	$\dot{m}_{reboiler}$[lb/hr]	$\dot{m}_{steam,ex}$[lb/hr]
6266.9	695972.0219	702240.35

Table 3.12: Mass Flowrate of Extracted Steam

Hence, the new shaft outputs of the turbines (HP/IP/LP) with a modification for the mass flowrate into LP, were found as following:

$$\dot{m}_{\text{LP, turbine}} = 1.113 \times 10^6\,\text{lb/hr}$$

Similarly to the unabated calculations:

Turbine	Q_{shaft}[kW]
HP	73707.6
IP	113857.5
LP (w steam ex)	97537.1
Total	285102.2

Table 3.13: Shaft Power Outputs-Abated

And the steam turbine output for the abated plant:

Q_{shaft}[MW]	$\eta_{EMlosses}$	$\eta_{correction}$	Q_{STG}[MW]
285.1	0.987	0.96	**270.1**

Table 3.14: Steam Turbine Power Output-Abated

Where the loss due to solvent regeneration was found to be:

Shaft Output (MW) - With losses		
TOTAL (w steam extraction)	**TOTAL (w/o steam extraction)**	**Power Loss**
270.1	328.4	**58.3**

Table 3.15: Solvent Regeneration Power Loss

And the total gross power reduced to the following:

Combustion Turbine Power[MW]	Steam Turbine Power[MW]	Total Gross Power[MW]
576	270.1	**846.1**

Table 3.16: Total Gross Power Output- Abated

CO_2 Compression Power Loss

Using the governing equation and important values such as $\dot{m}_{90\%,\text{CO}_2}$, R_{CO_2}, and $n = 1.3$, the work of the compressor at each stage was found as follows (see: Appendix B for full spreadsheet):

Compressor/Stage No.	Pressure ratio	Compressor Work [kJ/kg]	Compressor Power [MW]
1	1.7	35.52686015	2.6
2	1.7	35.35857006	2.6
3	1.7	35.07883919	2.6
4	1.7	34.5916461	2.6
5	1.7	33.77798138	2.5
6	1.7	32.37688351	2.4
7	1.7	29.8240307	2.2
8	1.7	24.74148483	1.8
SUM		**261.3**	**19.4**

Table 3.17: 8-stage CO_2 Compressor Work

The 8-stage intercooling design was chosen as it reduces the work required for compression by lowering the CO_2 temperature between stages, thereby enhancing efficiency and reducing energy consumption.
Increasing the number of stages improves thermodynamic efficiency by approximating isothermal compression, lowering the compression ratio and temperature rise per stage, and reducing mechanical stress. However, beyond the 8 stages, the marginal efficiency gains diminish, while capital and operational costs rise significantly.
The 8-stage configuration strikes an optimal balance between capital expenditure, energy efficiency, and operational reliability for large-scale CCS applications, as identified in the NETL report.
Finally, the actual work of the compressor was found using the efficiency calculated from the NETL values as follows:

Compressor Power [MW]	Efficiency of compressor, η	Actual Compressor Power [MW]
19.4	0.8080	**24.1**

Table 3.18: Actual CO_2 Compression Power

Auxiliary Power Losses

To calculate the auxiliary power losses for the abated plant these scaling factors were used according to the nature of the losses:

Scaling Factors	
Gross Power	1.23
Gas Turbine Power	1.21
Steam Turbine Power (HRSG Related)	1.27
Steam Extraction (Solvent)	1.23

Table 3.19: Scaling Factors-Abated

Example Calculation:

$$\text{Transformer Losses} = \text{Gross Power} \times \text{NETL(value)}$$

Auxiliary load	NETL Report	Keadby 3
Transformer losses, kWe	2200.00	2697.8

Table 3.20: Example Calculation for Transformer Losses-Abated

Plant Efficiency

Similarly to the unabated plant efficiency calculation the following was obtained.

$$\eta_{\text{Cycle}} = \frac{P_{\text{Total gross output}}}{E_{\text{Total}}} = \frac{846.1}{1486.08} = \mathbf{56.94\%} \tag{3.9}$$

Since HHV and LHV thermal inputs were calculated without using the net power output, the same values were used for the efficiency values with CCS. The HHV and LHV efficiencies were calculated as follows:

$$\eta_{\text{HHV}} = \frac{P_{\text{net}}}{HHV_{\text{Thermal Input}}} = \frac{788500}{1649664} = 47.80\% \tag{3.10}$$

$$\eta_{\text{LHV}} = \frac{P_{\text{net}}}{LHV_{\text{Thermal Input}}} = \frac{788500}{1488384} = 52.98\% \tag{3.11}$$

3.1.3 Overall Performance Summary

Determining the performance of a 910Mwe gross unabated natural gas fired CCGT

In summary:

Power Summary		
Plant	**NETL Report**	**Keadby 3**
Combustion Turbine Power, MWe	477.0	576.0
Steam Turbine Power, MWe	263.0	328.4
Total Gross Power, MWe	740.0	904.4
Auxiliary Load Summary		
Circulating Water Pumps, kWe	2810.0	3509.3
Combustion Turbine Auxiliaries, kWe	1020.0	1231.7
Condensate Pumps, kWe,	150.0	187.3
Cooling Tower Fans, kWe	1460.0	1823.3
CO2 Capture/Removal Auxiliaries, kWe	0.0	0.0
CO2 Compression, kWe	0.0	0.0
Feedwater Pumps, kWe	4830.0	6031.9
Ground Water Pumps, kWe	260.0	324.7
Miscellaneous Balance of Plant, kWe	570.0	696.7
SCR, kWe	2.0	2.4
Steam Turbine Auxiliaries, kWe	200.0	249.8
Transformer Losses, kWe	2250.0	2750.0
Total Auxiliaries, MWe	13.6	16.8
Net Power, MWe	726.4	887.6

Table 3.21: Auxiliary Load Summary for Unabated Plant

The auxiliary load summary for the unabated plant came to a total of 16.8MWe in auxiliary power. This gave a net power output of 887.6MWe.

Determining the performance of the plant with CCS

In summary:

Power Summary		
Plant	**NETL Report**	**Keadby 3**
Combustion Turbine Power, MWe	477.0	576.0
Steam Turbine Power, MWe	213.0	270.1
Total Gross Power, MWe	690.0	846.1
Auxiliary Load Summary		
Circulating Water Pumps, kWe	4580.0	5808.6
Combustion Turbine Auxiliaries, kWe	1020.0	1231.7
Condensate Pumps, kWe,	170.0	215.6
Cooling Tower Fans, kWe	2370.0	3005.8
CO2 Capture/Removal Auxiliaries, kWe	10600.0	13022.7
CO2 Compression, kWe	17090.0	24060.3
Feedwater Pumps, kWe	4830.0	6125.7
Ground Water Pumps, kWe	430.0	545.4
Miscellaneous Balance of Plant, kWe	570.0	699.0
SCR, kWe	2.0	2.4
Steam Turbine Auxiliaries, kWe	200.0	253.7
Transformer Losses, kWe	2200.0	2697.8
Total Auxiliaries, MWe	44.1	57.7
Net Power, MWe	645.9	788.5

Table 3.22: Auxiliary Load Summary with CCS

For the auxiliary load summary with CCS, the CO_2 compression was calculated to be 24.1MWe. Scaling the flue gas flow entering the capture plant resulted in the CO_2 Capture/Removal Auxiliaries coming to be 13.0MWe and a total of 57.7MWe in auxiliary power. This gave a net power output of 788.5MWe.

Efficiency Summary

The table below summarises the efficiency metrics for both unabated and CCS plants.

Efficiency Summary		
Metric	Unabated	CCS
HHV , kJ/kg	53700	53700
LHV, kJ/kg	48450	48450
HHV Thermal Input, kWt	1649664	1649664
LHV Thermal Input, kWt	1488384	1488384
HHV Net Plant Efficiency, %	53.80	47.80
LHV Net Plant Efficiency, %	59.64	52.98

Table 3.23: Efficiency Summary

Comparative analysis between CCGT and CCGT with CCS

The analysis carried out here, showcases the distinct percentage differences between the CCGT plant and CCGT with carbon capture. The table below enables a clear overview of the evaluation of the two plants against the steam turbine power output, total auxiliaries and net power output of each. Key findings of this comparison include a 21% decrease of the steam turbine output with added CCS and a 240% increase in total auxiliaries resulting to a 13% decrease in the net power output. Additionally, a comparative analysis is also carried out between the two plants and the corresponding unscaled ones from the NETL report. It is important to note that the combustion turbine power output stays unchanged with or without integrated CCS, as the carbon capture and compression processes occur downstream of the turbine operations and have no impact on the combustion process.
In summary:

System	Technology	Unabated Plant, MWe	Abated plant, MWe	Absolute Difference	Percentage Difference, %
Scaled	Steam Turbine Power Output	328.4	270.1	58.3	**21.6**
NETL	Steam Turbine Power Output	263.0	213.0	50.0	**23.5**
Scaled	Total Auxiliaries	16.8	57.7	40.9	**243.5**
NETL	Total Auxiliaries	13.6	44.1	30.5	**224.3**
Scaled	Net Power	887.6	788.5	99.1	**12.6**
NETL	Net Power	726.4	645.9	80.5	**12.5**

Table 3.24: Comparative Analysis

Furthermore, when compared to the NETL plant, the percentage differences between the unabated and abated plants are consistent with the NETL system values. The decrease in steam turbine power output for the scaled plant (21.6%) closely aligns with the 23.5% reduction observed in the NETL system. This similarity indicates that the decline in steam turbine output is in strong agreement with the NETL system findings.

Similarly, the increase in auxiliary loads for the scaled plant shows close alignment with the NETL system. As a result, the net power output declines by comparable percentages between the two systems (12.6% for the scaled plant and 12.5% for the NETL system). This close agreement suggests that the findings for the scaled system are reasonable and validated by the NETL system's performance.
Another key metric of comparison is the HHV net plant efficiency reduction between CCGT and CCGT with added CCS. From table 3.24, it is observed that the efficiency drops about 6%, from 53.8% for unabated to 47.8% for plant with CCS. Additionally, Table 1 from Edward S. Rubin and Haibo Zhai (2017), showcases examples where the net efficiency reduces on average by 7% with added CCS, hence the efficiency reduction appears reasonable.

3.1.4 Reasoning behind design choices

Results from plant configuration calculations

1-off 1x1x1 Configuration To achieve the required gross unabated power output, a gas turbine with an ISO baseload of approximately 606 MW was needed. The highest power option in *GTW Volume 39* (2024), the Siemens SGT5-9000HL, rated at 593 MW, was insufficient. Scaled calculations from Exhibit 5-15 in James (2019) estimated a total output of 878 MWe, later verified by the Gülen method at 897.209 MWe. As this configuration fell short of the required output, it was excluded from the final design.
1-off 2x2x1 Configuration To meet the 910 MWe gross unabated output, each gas turbine in the 2x2x1 configuration needed to produce approximately 303 MW. Two models were evaluated: the GE Vernova Frame 9F.04 (50Hz) (288 MWe) and the Siemens SGT5-4000F (50Hz) (329 MWe).

For the GE Vernova Frame 9F.04, the steam turbine power output was calculated to be 328.4 MWe, giving a total gross output of 904.4 MWe. This met the 910 ± 20 MWe requirement. The Gülen method corroborated this with a steam turbine output of 317.79 MW, yielding a gross output 893.79 MWe. In contrast, the Siemens model exceeded specifications with a total output of 1006.4 MW, rendering it unsuitable for the Keadby 3 plant.

The 1-off 2x2x1 configuration gave the cheapest LFC (£6,891,718,348.00) of all the configurations that met the required 910 ± 20 MWe as seen as in Appendix D. This combined with the configuration's ability to meet the power requirements made it a great choice for the Keadby 3 power plant.

1-off 3x3x1 Configuration

For the 3x3x1 configuration, the Ansaldo Energia AE94.2 (190 MWe) was selected, achieving 931.5 MWe via scaled calculations and 896.781 MWe per the Gülen method. Although it met the power output requirement, the use of smaller, less efficient turbines increased the LFC (£7,270,834,053) compared to the 2x2x1 configuration.

2-off 1x1x1 Configuration

A dual 1x1x1 setup required gas turbines near 303 MWe. Evaluated models included the GE Vernova 9F.04 (50Hz) (288 MWe) and Siemens SGT5-4000F (50Hz) (329 MWe). The 9F.04 model achieved 876.8 MWe, and the Siemens model 975.4 MWe, both outside the required range. With the GE model, the LFC (£6,891,718,348) matched those of the 1-off 2x2x1 configuration. However, as no suitable 300 MW turbines were available in *GTW Volume 39* (2024), this configuration was deemed unviable.

2-off 2x2x1 Configuration

This configuration required gas turbines producing approximately 150 MWe each. We assessed the GE Vernova Frame 9E.04 (147 MWe) and Mitsubishi Power M701DA (144.09 MWe). Both models met output requirements within the 910 ± 20 MWe range. However, the smaller, less efficient turbines led to a high LFC of (£7,378,480,975.00). As well as this, the complexity and space requirements of the 2-off 2x2x1 configuration further reduced its feasibility.

2-off 3x3x1 Configuration

For a dual 3x3x1 setup, each turbine needed to generate around 95 MW. The GE Vernova Frame 6F.03 (88 MW) and Mitsubishi Power H-100 (116.45 MW) were evaluated. The GE model's output fell short of requirements (826.4MWe), while the Mitsubishi exceeded the specified range (1089.5MWe). Due to the LFC (£8,447,106,529.00), complexity, and space demands, this configuration was also rejected.

Conclusion

The 1-off 2x2x1 configuration with the GE Vernova Frame 9F.04 gas turbine was chosen for the Keadby 3 plant for the following reasons:

- Meets the 910 ± 20MWe gross unabated power output
- High overall cycle efficiency
- Lowest LFC of the configurations which met 910 ± 20MWe
- Good redundancy in the event of component failures / maintenance

3.2 Renewable Energy

In this section lies the analysis used in the design of the renewable generation plant with energy storage. Key resources used in this section are reports from PNNL, and IRENA, as well as National Renewable Energy Laboratory (NREL) modelling tool.

3.2.1 Renewable Generation

Selection of Renewable Energy Source

The SWOT analysis as can be seen in appendix E, reveals offshore wind energy shows strong potential for sustainable and high-output energy generation, supported by government policies and a growing market for renewable energy. However, the high costs of installation and maintenance, as well as environmental impacts on marine ecosystems, present notable weaknesses. While the industry offers significant economic benefits, including job creation, its success depends on advancements in energy storage and resilience to severe weather conditions. Balancing these strengths and weaknesses makes offshore the best option.
Furthermore, Offshore wind energy placed the highest among onshore wind, Solar energy and geothermal in the SWOT ranking criteria, which can be seen in appendix E.

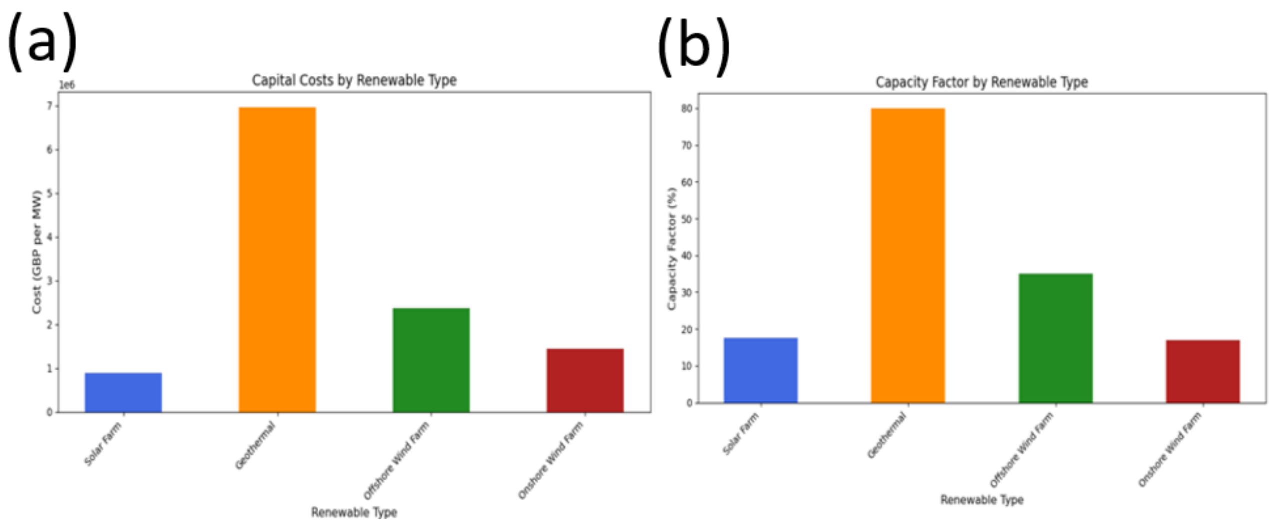

Figure 3.1: (a) CapEx by renewable type. (b) Capacity factor by renewable type

Moreover, from Fig. 3.1, which has data taken from appendix E, offshore wind energy emerges as the best option among the renewable energy sources listed when compared to solar, geothermal, and onshore wind. Solar has the lowest CAPEX but suffers from a low CF of 17.5%, limiting its power generation consistency. Geothermal, with its high 80% CF, provides steady power, yet its high CAPEX and reliance on specific geological conditions make it less feasible for widespread deployment. Onshore wind, while more affordable with a CAPEX of £45900 per MW and a CF of 17%, is less efficient than offshore wind in terms of consistent power generation.
Offshore wind strikes a superior balance with a 35% CF, double that of onshore wind. Altrsgh its CAPEX of £2,370,000 per MW is higher than onshore and solar, offshore wind installations can generate more reliable power due to consistent high-wind conditions at sea, making them economically viable over the long term. This combination of relatively high capacity, moderate cost efficiency, and minimal land impact makes offshore wind an optimal choice for scalable, sustainable energy generation.

Location Selection for Offshore Wind Farm

Using the find farm dataset from appendix E, the trends in Fig.3.2 can be observed.

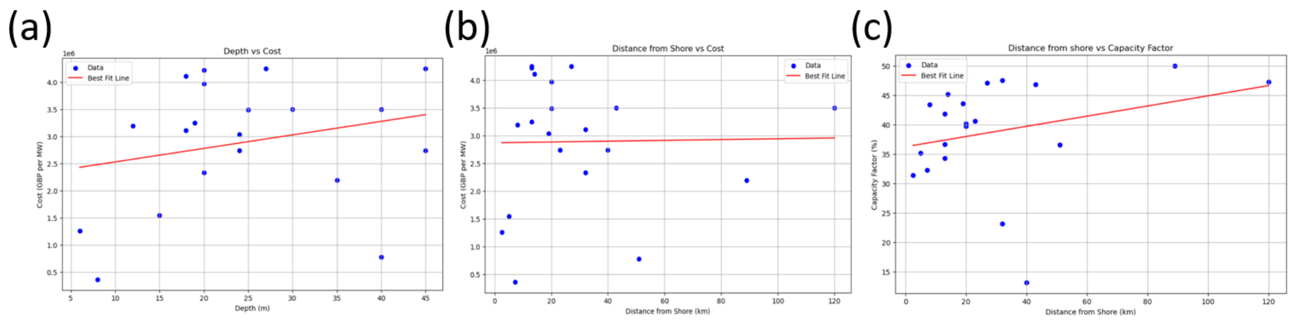

Figure 3.2: (a) Depth impact on cost. (b) Distance from shore impact on cost. (c)Distance from shore impact on capacity factor

Fig.3.2(c) indicates that wind farms situated further offshore generally exhibit higher lifetime capacity factors, reflecting improved power generation availability due to stronger wind resources ABPmer (2024). For instance, in January 2024, Hornsea Two achieved record electricity production with nearly a 100% capacity factor, attributed to strong winds in the North Sea (Insights, 2024). However, increased distance from shore also presents challenges, such as reduced accessibility and complications during the design, installation, operation and maintenance (OM), and decommissioning phases ABPmer (2024).
Fig. 3.2(a),(b) reveals moderate upward trends. Indicating that deeper waters and greater distances from shore wind farms incur higher costs per megawatt (MW). Therefore, cost preference are for shallower locations, closer to shore to manage installation and operational expenses effectively.

These observations are further substantiated by an offshore wind energy costing report (Bureau of Safety and Environmental Enforcement (BSEE), 2024), which identified comparable positive relationships . Notably, the report found a strong correlation with an R^2 of 0.5098 for depth versus cost and an R^2 of 0.2759 for distance versus cost, reinforcing the implications of depth and distance on wind farm expenses.

Among the highlighted wind farms in the dataset found in appendix E, Dudgeon Offshore WF stands out as the optimal choice when compared to Hornsea Project One and Triton Knoll, based on a balance of capacity factor, cost, and logistical feasibility. Dudgeon Offshore WF combines a high CF of 48% with a relatively short distance from shore (32 km), providing strong power generation potential while minimizing logistical complexities associated with transportation and maintenance. This distance is comparable to Triton Knoll (also 32 km offshore) but significantly closer than Hornsea Project One (120 km offshore), making Dudgeon Offshore WF more accessible. In terms of depth, Dudgeon Offshore WF is situated at 18 meters, which is shallower than Hornsea's 30 meters and slightly shallower than Triton Knoll's 20 meters, leading to lower installation and maintenance costs in deeper waters. While Triton Knoll does have a lower cost per MW (£2,333,722.29) than Dudgeon (£3,109,452.74), its CF is substantially lower at 23.2%, reducing its overall energy generation efficiency. Therefore, Dudgeon Offshore WF offers a more favourable combination of high capacity factor, moderate cost, and logistical ease, making it the best choice among the three options.

Installed Capacity

The CF of 48% for the existing wind farm in this location (Dudgeon Offshore Wind Farm) indicates that the designed wind farm will produce an average of 48% of its maximum potential output. To meet an average power output of 788.5 MW, using these values with equation 2.19 results in a finalised installed capacity for the wind farm of approximately 1643 MW.

Turbine Mooring Strategies

The main benefit of floating turbines is their ability to be installed in waters where the depth is greater than 60 meters (the maximum depth for fixed turbines), so for the shallow waters of Dogger Bank fixed turbines suffice. Furthermore, as newer technology capital costs for floating turbines are significantly higher than for fixed turbines and investors are less willing to take a risk on them as opposed to fixed turbines whose reliability has been well established. Overall, the combination of lower capital cost and proven technology makes fixed wind turbines the more economical choice for offshore wind farms at this time (Janipour, 2023).

Turbine Sizing

Purchase, installation, and maintenance costs of six different sizes of floating wind turbines, ranging from 5 MW to 15 MW, were obtained from recent industry publications Angel McCoy, Walter Musial and et al. (2024); International Renewable Energy Agency (IRENA) (2024); BloombergNEF (2024). Turbine costs per MW were adjusted for recent inflation and market fluctuations, as highlighted in IRENA's 2024 Wind Cost Report and BloombergNEF's Offshore Wind Market Outlook. Material costs, specifically steel and rare earth elements, have significantly influenced manufacturing expenses as have supply chain constraints. International Renewable Energy Agency (IRENA) (2024); BloombergNEF (2024) The number of each turbine required to achieve the desired installed

capacity of 1643 MW was calculated and converted to GBP, as presented in Appendix E in Table E.8, before being plotted as seen in Fig. E.1, also located in Appendix E.

The analysis shows that 15 MW turbines are the most cost-effective choice since when installing larger turbines fewer units are required, hence this size results in the lowest overall cost of approximately £561,000,000.

Comparison of 15 MW Turbine Models

Various models of turbines are available around the 15MW mark, Vestas V236-15.0 MW A/S (2024);

Energy Storage System	Strengths	Weaknesses	Opportunities	Threats	Total
Lithium-ion Battery	+10	-7	+6	-7	+2
Flywheel	+10	-10	+8	-12	-4
Gravity-Based	+6	-10	+6	-6	-4
Hydrogen	+2	-10	+5	-6	-9
Thermal	+5	-11	+10	-8	-4
Liquid Air	+12	-12	+8	-8	0

Table 3.25: Energy Storage System SWOT Analysis Rankings

BloombergNEF (2024); International Renewable Energy Agency (IRENA) (2024); asbl (2024), Siemens Gamesa SG 14-222 DD 15MW Gamesa (2024), and GE Haliade-X f 14.7MW General Electric (GE) (2024); BloombergNEF (2024) are popular amongst those on the market. Key features of these models were obtained and compared in Table E.9 located in Appendix E.
From the comparison, the Vestas V236-15.0 MW turbine has the lowest cost per MW, low maintenance costs, highest output, and highest capacity factor. These advantages make it the optimal choice with respect to economics and performance. Because of the fixed 5MW size of the turbines the resulting installed capacity of the wind farm will be 1650MW.

3.3 Energy Storage Technology

Energy Storage SWOT Analysis

Based on the SWOT analysis of various energy storage technologies as seen in Appendix E, the ranking of which is collated in Table 3.25, BESS has the best ranking hence is the optimal storage solution to support wind farm energy storage. The primary advantage of BESS is its round-trip efficiency of 85-95 percent, ensuring minimal energy loss, which is economically beneficial. Furthermore, lithium-ion batteries excel in applications requiring quick cycling and immediate grid response International Renewable Energy Agency (IRENA) (2022); (ESA) which is ideal for maintaining a steady output from the wind farm regardless of wind conditions. Unlike, GES which requires specific geographical conditions and substantial infrastructure, BESS have few location requirements so can be situated in the ideal location -the closest plot of land to the wind farm, on the route to the substation.

While BESS does have limitations such as a shorter lifespan compared to gravity or TES, advancements in battery chemistries (e.g., solid-state and sodium-ion) aim to rectify this. In addition, lithium-ion battery energy storage is a proven technology, used in many applications across the globe. Overall, lithium-ion BESS are a cost-effective, efficient, and readily deployable solution.

ESS Round Trip Efficiency

As shown in Fig. E.2, located in Appendix E, lithium-ion batteries have the highest round-trip efficiency so will have the least energy lost hence maximum energy sold for profit. Therefore, they are the most economic choice of ESS in this respect.

Levelised Cost of Storage

LCOS estimates for various energy storage systems at 788.5 MW/h for durations of both 2 hours and 4 hours were deduced using data from recent reports by LazardLazard (2021) and the Pacific Northwest National Laboratory(Laboratory, PNNL), both of which compare various energy storage technologies based on their duration and scalability. The short term durations selected for comparison are common for accompaniment of renewable generation. For this wind farm the capacities for comparison were 1577MW for the 2hr duration and 3154MW for the 4hr duration. This data was then used in the calculation and plotted as seen in E.3, located in appendix E, confirming Lithium-ion batteries with a duration of 4hr hence capacity of 3164 MW as the most economic ESS.

Battery Material

As shown in table E.16, located in appendix E, LFP batteries are more suited to this large-scale storage application for several reasons, the first of which is their excellent thermal stability hence lower risk of thermal runaway. Another advantage of LFP batteries is their longer cycle life compared to NMC batteries, exceeding 2000 charge-discharge cycles International Energy Agency (IEA) (2024), which is beneficial for the long-term operational costs.

The materials used in LFP batteries are also more abundant and less expensive than those in NMC batteries therefore LFP has lower capital costs. In addition to being cheaper and more common, the materials for LFP are less environmentally damaging than cobalt and nickel which are used in NMC batteries.

Overall, while NMC batteries can store more energy per unit of weight or volume, LFP batteries are the more reliable choice for integration with wind farms to provide stable and efficient energy storage.

3.4 Economics

This section provides a detailed analysis of the costs associated with different power generation technologies, including Combined Cycle Gas Turbines (CCGT) without carbon capture (unabated), CCGT with carbon capture and storage (CCS), and renewable power plants. The evaluation employs the Levelized Cost of Energy (LCOE) as the primary metric, offering a comprehensive assessment of the lifetime costs of energy generation for these technologies. By integrating all significant cost components, LCOE facilitates a robust comparison of their economic performance.

The analysis considers multiple cost factors that influence the overall competitiveness of each technology. Capital costs, encompassing expenditures on equipment, construction, and installation, represent a substantial share of total costs, particularly for technologies with high initial investment requirements, such as renewable energy systems and CCS-equipped CCGT plants. Fuel costs are also a critical component, especially for CCGT technologies, where they contribute significantly to operational expenses. Labour costs, reflecting the workforce requirements for operation and maintenance, vary across technologies, with renewables generally requiring less ongoing intervention compared to fossil-fuel-based systems. Additionally, operating and maintenance costs, which include routine and periodic expenditures to maintain reliability and efficiency, play a key role in determining the overall cost structure.

In this section, we will provide the detailed data of the costs for the three different settlements, comapre them and make decision to do the trade-off.

3.4.1 LCOE

As mentioned in the previous section, we are using LCOE for the comparison between CCGT unabated power plant, CCGT with CCS power plant and renewable power plants. And we assume all of them are working in full-load and work for 8000 hours a year. In this way, the comparison will be more accurate. Assuming they work for 335 days per year and 24 hours a day, leaving a week of maintenance. This assumption successfully controls the variables and we can see the performance of them in the financial perspective clearly.

CCGT Calculations

Capital Costs

Based on the method mentioned in the section 2.3.2, we have the result of the capital costs:

Description	£/1,000		£/kW		£/1,000		£/kW	
	Pre-Production Costs							
	CCGT Unabated				CCGT with CCS			
6 Months All Labor	£	4,683.70	£	6.92	£	8,344.10	£	12.80
1 Month Maintenance Material	£	730.86	£	1.15	£	1,527.58	£	2.13
1 Month Non-Fuel Consumabl	£	311.25	£	-	£	1,291.83	£	2.13
1 Month Waste Disposal	£	-	£	-	£	12.80	£	-
25% of 1 Months Fuel Cost at	£	4,298.68	£	5.76	£	3,977.90	£	6.40
2% of TPC	£	13,071.25	£	18.44	£	27,336.47	£	42.67
Total	£	23,096.89	£	32.28	£	42,491.74	£	66.14
	Inventory Capital							
60-day supply of fuel and cons	£	344.68	£	-	£	2,161.23	£	3.20
0.5% of TPC (spare parts)	£	3,268.10	£	4.61	£	6,834.65	£	10.67
Total	£	3,612.78	£	4.61	£	8,994.81	£	13.87
	Other Costs							
Initial Cost for Catalyst and Ch	£	976.40	£	1.15	£	903.53	£	1.07
Land	£	345.83	£	-	£	320.02	£	-
Other Owner's Costs	£	98,038.42	£	134.87	£	205,027.76	£	317.89
Financing Costs	£	17,646.59	£	24.21	£	36,905.19	£	57.60
Total Overnight Costs (TOC)	£	797,303.65	£	1,097.44	£	1,661,491.92	£	2,572.99
TASC Multiplier (IOU, 33 yea	£	1.26	£	-	£	1.17	£	-
Total As-Spent Cost (TASC)	£	871,171.95	£	1,198.88	£	1,815,423.54	£	2,810.88

Table 3.26: Capital Costs for CCGTs

The capital costs for the CCGT unabated power plant is £87.172 million while it is £1.82 billion for the CCGT with CCS. The big difference between the two is because the equipment costs of carbon capture and storage is much higher.

Fixed Costs

And the fixed costs have the results in this table:

Fixed Operating Costs				
	CCGT Unabated		CCGT with CCS	
	Annual Cost (£)	(£/kW-net)	Annual Cost (£)	(£/kW-net)
Annual Operating Labour:	3192122.41	3.507826824	3901482.95	4.2873439
Maintenance Labour:	1050000	1.153846154	1050000	1.15384615
Administrative & Support Labour:	820000	0.901098901	820000	0.9010989
Property Taxes and Insurance:	11915752.72	13.09423375	11915752.7	13.0942338
Total:	**16977875.13**	**18.65700563**	**17687236**	**19.436523**

Table 3.27: Fixed Costs for CCGTs

The fixed costs of CCGT unabated is £16.9 million annually and for CCGT with CCS, it is about £17.7 million. This is again due to the additional carbon capture equipments, more labour will be needed to control the machines.

<u>Variable Costs</u>

After calculation, the variable costs are shown here:

Variable Operating Costs						
CCGT Unabted						
					(£)	**(£/MWh-net)**
Maintenance Material:					**5490000**	6.032967033
		Consumables				
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2616.093535	3.4		3246572.077	0.356766162
Makeup and Waste Water Treatment Chemicals (tonas)	0	7.785694635	1000		2841778.542	0.312283356
Ammonia (19 wt%, ton):	0	4.318431912	308		485478.1155	0.053349243
SCR Catalyst (ft^3):	7070.962861	3.1	70	494967.4003	1534398.941	1.686152682
Subtotal:				**494967.4003**	**8108228**	**2.408551444**
		Waste Disposal				
SCR Catalyst (ft^3):		3.880330124	1.16	0	1642.931774	0.00180542
Subtotal:				**0**	**1642.931774**	**0.00180542**
Variable Operating Costs Total:				**494967.4003**	**13599871**	**8.443323897**
CCGT with CCS						
					(£)	**(£/MWh-net)**
Maintenance Material:					**17396649.56**	**19.11719732**
		Consumables				
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4841.594427	3.4		6008418.684	0.660265789
akeup and Waste Water Treatment Chemicals (tonas)	0	14.36842105	1000		5244473.684	0.576315789
Ammonia (19 wt%, ton):	0	4.930340557	308		554268.8854	0.060908669
SCR Catalyst (ft^3):	7957.569659	3.1	70	557029.8762	1726792.616	1.897574303
CO2 Capture System Chemicals	Proprietary				8509048.649	1.335800416
Triethylene Glycol (gal):	w/equip.	555.0154799	5.236	0	1017121.368	1.117715789
Subtotal:				**557029.8762**	**23060123.89**	**5.648580756**
		Waste Disposal				
SCR Catalyst (ft^3):	0	4.366873065	1.16	0	1848.934056	0.002031796
Triethylene Glycol (gal):	0	555.0154799	0.29	0	56334.07121	0.061905573
Amine Purification Unit Waste (ton)	0	8.606965944	31.5	0	94891.79954	0.104276703
Thermal Reclaimer Unit Waste (ton)	0	0.764907121	31.5	0	8433.101006	0.009267144
Subtotal:				**0**	**161507.9058**	**0.177481215**
Variable Operating Costs Total:				**557029.8762**	**40618281.35**	**24.94325929**

Table 3.28: Variable Costs for CCGTs

The variable cost of CCGT unabated is about £13.5 million annually while it is over £40.6 million annually for the CCGT power plant with carbon capture and storage sets. This is because there are more waste products need to be disposed and that costs more. Alos, catalyst will be needed for the carbon capture. This is another amount of money spent.

<u>Fuel Costs</u> The fuel costs will be the largest part of the operating and maintenance costs and here is the estimation of it for CCGT unabated power plant with 8000 hours a year, full-loaded working.

Power of the Turbine / MW	Number of the Turbine	Turbine Efficiency	Year	Energy needed annually / MWh	Cost of Natual Gas Annually / M£
288	2	39%	2024	11906976.74	398.1181023
			2025	11906976.74	411.6541178
			2026	11906976.74	425.6503578
			2027	11906976.74	440.12247
			2028	11906976.74	455.086634
			2029	11906976.74	470.5595795
			2030	11906976.74	486.5586052
			2031	11906976.74	503.1015978
			2032	11906976.74	520.2070521
			2033	11906976.74	537.8940919
			2034	11906976.74	556.182491
			2035	11906976.74	575.0926957
			2036	11906976.74	594.6458474
			2037	11906976.74	614.8638062
			2038	11906976.74	635.7691756
			2039	11906976.74	657.3853275
			2040	11906976.74	679.7364287
			2041	11906976.74	702.8474673
			2042	11906976.74	726.7442811
			2043	11906976.74	751.4535867
			2044	11906976.74	777.0030087
			2045	11906976.74	803.4211109
			2046	11906976.74	830.7374287
			2047	11906976.74	858.9825013
			2048	11906976.74	888.1879063
			SUM	**297674418.6**	**15302.00567**

Table 3.29: Fuel Costs for CCGTs

The fuel costs are the largest part of the costs a CCGT power plant will have. It is about £398.1 million for both the CCGT unabated power plant and for the CCGT with CCS.

<u>Overall CCGT Cost</u>

Therefore, the total operating cost of CCGT unabated annually, is £428.5 million. ANd the total operating cost for CCGT with CCS is £456.4 million. Those numbers include the fixed costs, the variable costs and the fuel costs annually.

3.4.2 Renewable Economics

<u>1650MW Wind Farm Cost Analysis</u>

The operational expenditure (OpEx) for 1650MW offshore wind maintenance costs produced over the 19-year simulation period includes two primary components: ”In Situ” maintenance, costing approximately £2.26 billion (£71,391.39 per MW per year), and ”Tow-to-Port” maintenance, which adds around £1.69 billion (£53,528.47 per MW per year). Together, these costs form the total OpEx required for ongoing maintenance, integrating both onsite repairs and transport-based servicing to maintain the efficiency and reliability of the offshore wind installation, resulting in a total OpEx of £124919.9 per MW per year.
For the 1650MW installed capacity of the wind farm the total fixed OpEx is £5,152,944,225 and total variable OpEx is £1,030589175.

Fixed OPEX

It is estimated that the lifetime of the wind farm will be 25 years. Therefore, for an annual cost of £71,391.39 per MW the in situ maintenance over 25 years is £1,784,784.75 per MW. Tow-to-Port maintenance has an annual cost of £53,528.47 per MW, so over 25 years this is £1,338,211.75 per MW. Hence, total Fixed OpEx over 25 years is £3,122,996.5 per MW.

Variable OPEX

It is assumed that variable OPEX is 20% of the total OPEX, therefore annual variable OPEX per MW is £24,983.98 per MW and variable OPEX over 25 years is £624,599.5 per MW.

CAPEX

Upon analysis of existing wind farms. The scaled CAPEX for the 1688MW was determined to be £5697602699.

Storage Cost Analysis

CAPEX and OPEX for the ESS were calculated over an estimated 25-year lifetime of the wind farm, with an annual inflation rate of 2% applied across all cost categories. The calculation of OpEx was broken down into fixed OM and variable OM, which includes costs associated with round-trip efficiency (RTE) losses due to system degradation, and battery replacements.

CAPEX

CAPEX represents the initial investment required to construct and install the BESS. Calculations were based on the total installed cost of of £327,000 per MW, derived from industry benchmarks Institute (2024). The system capacity is 3164 MW.

$$\text{Total CAPEX} = 3164\,\text{MW} \times 327000\,\text{£/MW} = 1,035,228,000\,(\text{£1.035 billion, approx.}) \tag{3.12}$$

The components of CAPEX are as follows: Storage block (£140,000 per MW); Balance of system (£40,000 per MW); Power equipment (70,000 per MW); Controls & communication (£10,000 per MW); Integration, engineering, and development (£67,000 per MW.).

Fixed OPEX

The base value for fixed OM is obtained from industry reports as £10/kW-yr in Year 1, increasing by 2% annually. For 3,164 MW capacity and a 25-year operational period, the cumulative fixed OM cost is calculated using the formula for geometric progression:

$$\text{Fixed OM (Year t)} = \text{Fixed OM (Year 1)} \times (1 + 0.02)^{t-1} \tag{3.13}$$

$$\text{Total Fixed OM} = \sum_{t=1}^{25} \text{Fixed OM (Year t)} \times 3,164,000\,\text{kW} \tag{3.14}$$

Using the formula for a geometric progression, the total fixed OpEx is approximately £1.012 billion.

Variable OpEx

Variable OM

The base variable OM is £0.40/MWh, obtained from PNNL Energy Storage Grand Challenge Cost and Performance Assessment Mongird et al. (2020), and is also estimated to increase with inflation at 2% annually. For a system cycling once daily (365 cycles/year) over 25 years:

$$\text{Variable OM (Year } t) = \text{Variable OM (Year 1)} \times (1 + 0.02)^{t-1} \tag{3.15}$$

$$\text{Total Variable OM } = \sum_{t=1}^{25} \text{Variable OM (Year } t) \times (3164\,\text{MW} \times 365\,\text{cycles/year}) \tag{3.16}$$

Using geometric progression the variable OM for the 25 year lifetime was calculated to be approximately £46 million.

Round Trip Efficiency (RTE) Losses

Since RTE losses increase with the number of cycles or the amount of energy throughput, they are considered a variable cost. The initial RTE is assumed to be 88% and estimated to degrade by 0.5% annually, resulting in an RTE of 76% by Year 25. Applying a 2% yearly inflation and calculating:

$$\text{Total RTE Losses} = \sum_{t=1}^{25} \text{RTE Loss (Year t)} \times \text{Annual Energy Throughput (Year t)} \tag{3.17}$$

The total RTE losses are approximately £44.5 million.

Lifecycle Costs

The system has a calendar life of 10 yearsAlliance (2024), so replacements occur at Year 11 and Year 21. It was assumed that each replacement benefits from a 3% cost reduction per year due to technological advancements. Battery replacement costs are also included in the variable operating cost 50% of the initial CAPEX for battery components only:

$$\text{Battery component of CAPEX} = 140000\,/\text{MW} \times 3164/\text{MW} = 443\text{million} \tag{3.18}$$

Year 11 Replacement:

$$\text{Adjusted Cost (Year 11)} = (443 \times 0.5), \text{million} \times (1 - 0.03)^{10} = 165\,\text{million} \tag{3.19}$$

Year 21 Replacement:

$$\text{Adjusted Cost (Year 21)} = (443 \times 0.5)\,\text{million} \times (1 - 0.03)^{20} = 122\,\text{million} \tag{3.20}$$

The total lifecycle cost is £287 million.

Cost Category	Storage Value	Wind Farm Value	Total Renewable Value
CapEx	£1.012 billion	£5.697 billion	£6.979 billion
Fixed OpEx	£0.46 billion	£5.127 billion	£5.587 billion
Variable OpEx	£0.445 billion	£1.027 billion	£1.472 billion
Lifecycle Costs	£0.287 billion	-	£0.287 billion
Total OpEx	£2.204 billion	£6.154 billion	£8.358 billion

Table 3.30: CapEx and OpEx for Wind Farm with BESS

3.4.3 Loan Repayments

As seen in Appendix F, the loan repayments were calculated by assuming all profits made after OpEx and fuel costs were deducted went towards loan repayments. It was assumed that the interest rate on the loan was 3%, the increase in OpEx was 3% per year, and the increase in fuel costs for CCGT was 3.4% per year.

3.4.4 Overall Economics Summary

In summary:

COST Summary			
	CCGT Unabated	CCGT with CCS	Renewable
Total Plant Cost (2024£/kW)	**718**	**1641**	
Bare Erected Cost	538	1076	
Home Office Expenses	112	235	
Project Contingency	68	245	
Process Contingency	0	85	
Total Overnight Cost (£/kW)	**1035**	**2243**	
Owner's Costs	158	602	
Total As-Spent Cost (£/kW)	**1131**	**2452**	
LCOE (£/MWh)	**54.5**	**116.7**	**122.5**
Capital Costs	6.69	25.3	54.853
Fixed Costs	5.97	8.3	0.047
Variable Costs	8.44	20.9	67.6
Fuel Costs	33.4	62.2	-
Lifecycle Costs (M£)	-	-	**287**

Table 3.31: Economic Summary for Three Power Plants

3.4.5 Compare Analysis between Three Choices of Power Plants

When comparing the three power plants, CCGT Unabated offers the lowest Levelized Cost of Energy (LCOE) at £54.5/MWh, making it the most cost-effective option. This is primarily due to its relatively low upfront capital costs (£6.69/MWh) and the absence of additional equipment such as carbon capture systems. While the fuel cost dominates the LCOE at £33.4/MWh, the overall efficiency of combined cycle gas turbines keeps the operational costs competitive. This makes CCGT Unabated an attractive choice for regions where natural gas is readily available and affordable.

In contrast, CCGT with Carbon Capture and Storage (CCS) has an LCOE of £116.7/MWh, which is more than double that of CCGT Unabated. This higher cost is driven by the significant investment required to install and operate the carbon capture equipment, resulting in capital costs of £25.3/MWh. Additionally, CCS systems have higher variable and fuel costs due to the energy required for the capture and compression of CO_2, which reduces the overall efficiency of the power plant. While CCS is a cleaner alternative with lower emissions, the economic burden makes it less viable for regions prioritizing cost efficiency over emissions reductions.

Renewable energy, with an LCOE of £122.5/MWh, is the most expensive option. The high capital costs (£54.853/MWh) associated with building renewable infrastructure, such as wind turbines or solar panels, are the primary drivers of this cost. Additionally, variable costs are significant (£67.6/MWh), reflecting the integration of energy storage systems to manage the intermittency of renewable sources. Despite the absence of fuel costs and its long-term environmental benefits, the financial investment required for renewables makes it a less practical choice in situations where cost minimization is critical.

Given these comparisons, CCGT Unabated stands out as the best option for immediate power generation needs where cost efficiency is the primary concern. It provides a reliable and consistent source of energy at a fraction of the cost of CCS or renewables. While it does have higher carbon emissions compared to the other technologies, its economic advantage makes it a compelling choice for regions focused on maintaining affordable electricity prices or where regulatory pressures on emissions are less stringent. If future policies demand lower emissions, transitioning to CCS or a hybrid system could be explored, but for now, CCGT Unabated remains the most viable option.

3.4.6 Alternative methods

Drawbacks of LCOE

LCOE has several limitations.(Graham, 2018; Byrom and et al., 2021)

- It fails to consider system-level costs, such as grid balancing, storage, and backup generation, which are critical for integrating variable renewable energy.
- It cannot account for the variability of renewables, as it does not reflect the value of electricity generation during fluctuations in supply and demand (e.g., daily or seasonal changes).
- Moreover, LCOE overlooks geographical context, ignoring site-specific factors like resource quality and proximity to demand centres.
- Additionally, LCOE disregards market dynamics, assuming a flat cost per unit of energy and failing to reflect variations in electricity prices across time and location.
- It also excludes reliability costs, omitting considerations of grid stability and capacity contributions that are especially relevant for dispatchable technologies like gas and coal.
- Furthermore, it does not account for storage and flexibility, ignoring the unique costs and benefits of combined technologies like renewables paired with batteries.
- Finally, LCOE is biased toward dispatchable or non-renewable technologies because it undervalues renewables that require system integration and balancing.

LACE

Capacity Credit (CC) and Capacity Payment (CP)

According the function of LACE, capacity value consists of CC and Capacity Payment (CP). Among them, CC is mainly affected by the negative impact of the penetration of wind farm and the positive impact of energy storage.(Cárdenas and et al., 2021) For Britain, where the penetration of wind farm will reach about 30% in 2024(Decking, September 23rd 2024), The CC for offshore wind is around 20-25% (select 22.5% as origianl value)(C. Ensslin and et al., 2008), and since energy storage can meet demand for four hours, this is almost at CC saturation.

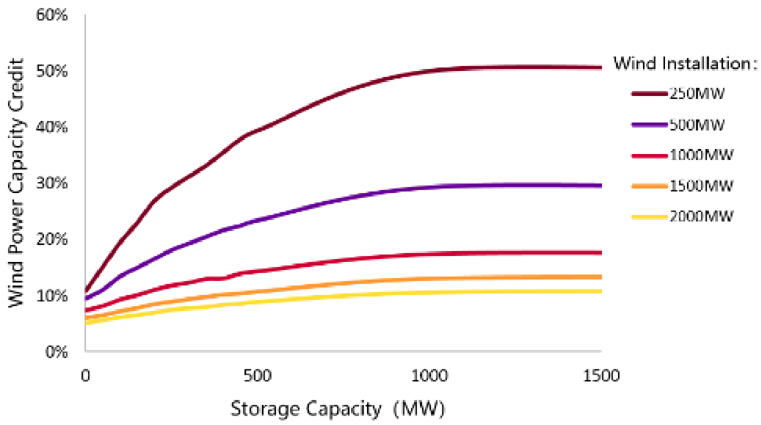

Figure 3.3: The relation between capacity credit and storage capacity

For a wind farm with a capacity penetration rate of 35.09%, the improvement ratio of CC grows to a saturation value of about 240%. For a wind farm with a capacity penetration rate of 17.54%, the improvement ratio of CC grows to a saturation value of about 300%. Therefore, this report uses an estimated 257% as the growth of wind farm CC, which leads that the CC is 57.825%.(Cheng et al., 2019) And for CCGT, the capacity credit is typically high, often close to 100%, and the capacity credit of CCGT is calculated by subtracting its Equivalent Forced Outage Rate (EFOR) from 100%,(IEA, 2024; Lisnianski et al., 2016) so the the capacity credit of CCGT is equal to 98.4%.

For the capacity payment, the overnight capital cost of the advanced natural gas combustion turbine (NGCT) plant can be selected as this use value,(Beiter et al., 2017) and the overnight cost in 2023 is 920.9$/kW,(EIA, 2025) which is reasonable while comparing the overnight cost 682$/kW in 2015.(EIA, 2015; Beiter et al., 2017) In addition, according to rate exchange and Chemical Engineering Plant Cost Index (CEPCI), the overnight cost in 2024 is modified to 709.8£/kW. In addition, the fixed charge factor for wind, accounting for the standard 5-year MACRS1 depreciation, is 9% per year,EIA (2013); Investopedia (2024) and the fixed charge factor for CCGT is 10% per year Department for Business (2018).

$$CV_{Wind} = CC \times CP = 0.57825 \times 709.8 \times 0.09 = 36.94£/kW/year = 36.94k£/MW/year$$

$$CV_{CCGT} = CC \times CP = 0.984 \times 709.8 \times 0.1 = 69.84£/kW/year = 69.84k£/MW/year$$

Marginal Generation Price (MGP) and Dispatched Hours (DH)

The regional marginal generation prices consist of the average MGP and Dispatched Hours (DH), and the formula is as follows.

$$\sum_{t=1}^{Y}(MGP \times DH) = \sum_{t=1}^{8760}(MGP_t \times DH_t) = \sum_{t=1}^{8760}(WEP_t \times E_t)$$

The sum of the MGP and DH is the generation price, which is, the sum of Wholesale Electricity Price (WEP) and simulated electricity output, and the data of WEP (BMRS, 2024) is 2019, because 2019 is before the epidemic and the data is relatively stable. In addition, the price of WEP is roughly adjusted based on the average for the first nine months of 2024 and the average for the first 9 months of 2019. The capacity factor of the simulated electricity output is the capacity factor of the wind turbine (60%), and other losses are not considered, so it is roughly adjusted according to the capacity factor of the wind farm (48%). The simulated hourly selling price, 1:360 average data of selling price and 1:48 average data of wholesale price are shown as below.

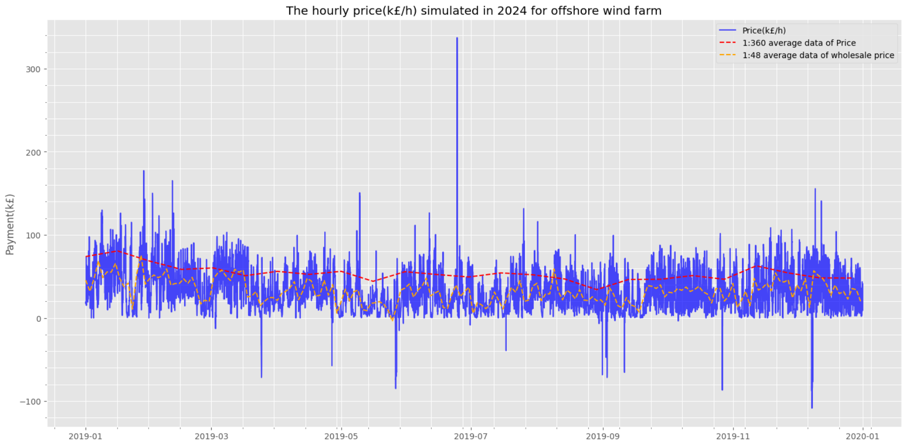

Figure 3.4: The relation between capacity and storage capacity

The results of LACE

$$\sum_{t=1}^{Y}(MGP_{Wind} \times DH_{Wind}) = 224468.66£/MW/year = 224.47k£/MW/year$$

$$LACE_{Wind} = \frac{36.94+224.47}{8760*0.57825} = \frac{261.41}{4204.8} = 0.06217k£/MWh = 62.17£/MWh$$

$$\sum_{t=1}^{Y}(MGP_{CCGT} \times DH_{CCGT}) = 466780.5006£/MW/year = 466.78k£/MW/year$$

$$LACE_{CCGT} = \frac{69.84+466.78}{8000*0.984} = \frac{536.62}{7872} = 0.06817k£/MWh = 68.17£/MWh$$

The unabated CCGT plant has the same LACE value with the abated CCGT plant.

The comparison of LCOE and LACE(Graham, 2018; Beiter et al., 2017)

Aspect	LCOE	LACE
Focus	Costs related to generating electricity at the plant level.	System-level perspective, evaluating the avoided cost of electricity generation and its contribution to grid value.
Components	Capital costs, operational costs, fuel costs, and lifetime generation.	Marginal generation costs, grid system requirements, and the avoided cost of displaced generation.
Utility	A simple metric for comparing the generation costs of different technologies.	A comprehensive metric for evaluating economic competitiveness and grid-level integration of new generation technologies.
Advantages	Easy to calculate and interpret.	Reflects true economic value, including temporal and locational grid impacts.
	Widely recognized and standardized for cost comparisons.	Accounts for variability, integration costs, and regional system value.
Limitations	Ignores grid and system impacts like dispatchability and capacity value.	Complex to calculate, requiring detailed system modeling and assumptions.
	Less effective in high-renewable systems with variable energy sources.	Sensitive to future market uncertainties and regional modeling quality.
Example Technologies	Gas, coal, nuclear, standalone solar or wind.	Solar + storage, wind + storage, flexible grid-support technologies, or high VRE (Variable Renewable Energy) systems.
Complexity	Low	High

Table 3.32: Comparison of LCOE and VALCOE

The limitation for analysing LACE

Due to the lack of specific guidance from professionals and related calculations in this analysis, there may be some misunderstandings regarding the theoretical concepts.
Additionally, there might be flaws in the data sources and data processing, such as potential discrepancies in handling marginal generation prices and marginal prices, which may deviate from the theoretical basis.
Furthermore, the LACE applied here does not take into account policy-related factors or subsidies, whether at the national or regional level, such as support for renewable energy, carbon emission reductions, environmental regulations by relevant authorities, and other influencing factors.(Beiter et al., 2017; EIA, 2015)

Removal cost (RC) and Avoided cost (AC)(Laboratory, NETL)

According the equation of removal cost and avoid cost:

$$\text{(For two gas turbine:) } \mathrm{m}_{CO_2} = 2 \times 41.335 = 82.67\text{kg/s} = 82.67 \times \frac{3600}{1000} = 297.612 tons/hours$$
$$\mathrm{E}_{CO_2} = \mathrm{E}_{\mathrm{woR}} = \frac{297.612}{907.8} = 0.32783 \approx 0.3278 tons/MWh$$
$$\mathrm{E}_{\mathrm{wR}} = 0.3278 \times 0.1 = 0.03278 tons/MWh$$
$$\mathrm{R}_{\mathrm{CO_2}} = 0.3278 \times 0.9 = 0.29502 tons/MWh$$
$$\mathrm{LCOE}_{\mathrm{wR}} - \mathrm{LCOE}_{\mathrm{woR}} = 116.7 - 54.5 = 62.2 £/MWh$$
$$\mathrm{RC}_{\mathrm{CCS}} = \frac{\mathrm{LCOE}_{\mathrm{wR}} - \mathrm{LCOE}_{\mathrm{woR}}}{\mathrm{E}_{\mathrm{wR}} - \mathrm{E}_{\mathrm{woR}}} = 210.833 £/ton$$
$$\mathrm{RC}_{\mathrm{Wind}} = \frac{\mathrm{LCOE}_{\mathrm{Wind}} - \mathrm{LCOE}_{\mathrm{woR}}}{\mathrm{m}_{CO_2}} = \frac{120.777 - 54.5}{0.3278} = 202.187 £/ton$$

For the comparison, the removal cost of the high-temperature liquid-solvent DAC systems could cost about £262.3 per ton.(ETH and et al., 2024)

Chapter 4: Design Solution Discussion

4.1 Economic Assessments for Energy Transition Technologies

As energy systems worldwide undergo a profound transformation, traditional metrics like Levelized Cost of Energy (LCOE) must be reconsidered to account for the complexities of integrating Variable Renewable Energy (VRE) and dispatchable technologies such as Carbon Capture and Storage (CCS). While LCOE is widely used for its simplicity in assessing average electricity production costs over a plant's lifetime, it fails to capture critical system-level costs and benefits, such as grid balancing, storage, and backup generation. This omission becomes particularly significant in the context of VRE technologies, which are highly dependent on weather conditions and require extensive investments in infrastructure like energy storage, synchronous compensators, and grid reinforcements to maintain reliability. For instance, VRE intermittency has been linked to increased consumer electricity prices in areas with high renewable penetration, challenging the perception that wind and solar consistently offer the lowest-cost solutions.

CCS-equipped power plants, despite their higher LCOEs—typically ranging from £116.7/MWh for gas-fired systems to $\$$90–130/MWh for coal-fired configurations in OECD regions—offer significant value in terms of grid stability and dispatchability. Advanced economic methodologies, such as Value-Adjusted LCOE (VALCOE) and Levelized Avoided Cost of Electricity (LACE), better reflect these technologies' contributions by incorporating the economic and operational benefits of displacing expensive peaking plants and ensuring grid reliability during periods of high demand or extreme events. For example, while the LCOE of unabated CCGT remains the lowest at £54.5/MWh, its higher carbon emissions make it less viable under stringent climate policies. In contrast, CCS-equipped plants achieve a LACE value comparable to their unabated counterparts (£68.17/MWh), emphasizing their potential as a reliable low-carbon alternative.

Furthermore, CCS's economic viability continues to improve due to advancements in CO_2 capture technology, with capture costs falling to $\$$30–60 per ton in some regions, driven by economies of scale, learning-by-doing, and modular construction. These developments align with the broader need for dispatchable low-carbon technologies to complement VRE as grids approach high decarbonization levels (80–90$\%$ reduction in gCO_2/kWh). Total system cost analyses underscore this need by incorporating investment and operational costs across diverse weather and demand scenarios, highlighting the indispensable role of CCS in achieving net-zero targets without compromising grid reliability.

The current project employs LCOE as the primary metric due to limitations in accessing proprietary data required for one-to-one LCOE analyses. Based on electricity pricing of 22.36p per kWh and a standing charge of 60.12p per day, the financial assessments reveal annual incomes of £219 per account, with profits per MWh calculated at £169.1 for unabated CCGT, £106.9 for CCS-equipped CCGT, and £101.1 for renewable systems. While these figures emphasize the cost-efficiency of unabated CCGT in the short term, they also highlight the need for more comprehensive economic evaluations to capture the full spectrum of costs and benefits associated with CCS and VRE. This discussion reinforces the necessity of adopting advanced metrics and total system cost analyses to guide energy investments effectively, ensuring both economic viability and grid reliability in the energy transition.

4.2 Grid Stabilisation and Frequency Regulation

CCGT plants are critical in maintaining grid stability and frequency regulation, making them indispensable compared to wind farms which even with BESS, lack the security of supply to ensure ancillary support. CCGT plants offer dispatchable power generation, hence provide consistent and reliable energy that can be rapidly increased or decreased to meet sudden fluctuations in demand. This flexibility is vital for frequency regulation as well as load balancing by grid operators who must balance supply and demand every second to maintain the nominal frequency of the grid (50Hz). The large rotating masses within CCGT plants also contribute significantly to grid inertia, acting as a buffer in the event of sudden changes in supply or demand by reducing the rate of change of the frequency, giving more time for other control mechanisms to be implemented. Wind farms cannot provide the same level of support since even with energy storage systems, they are unable to rapidly alter their output due to the intermittent and variable nature of wind energy. Although BESS can mitigate some variability, it lacks the inertia contributions of CCGT plants Adam Baylin-Stern (2021) so with more renewables integrated into the grid it would be more sensitive to imbalances between supply and demand, leading to more frequent and severe frequency deviations which could lead to grid failures or blackouts ESO (2023). Therefore, CCGT plants with carbon capture are a better option than wind farms with BESS for low carbon power.

4.3 Direct Air Capture as an Alterative Method of CCS

Direct Air Capture (DAC) is an alternative method that can be used for CCS in a CCGT plant. DAC works by capturing CO_2 from the the ambient air, rather than directly from the flue gas of the gas turbine. Typically, DAC has a higher levelized cost (90 GBP/ton of CO_2 to 240GBP/ton of CO_2) (Adam Baylin-Stern, 2021) depending on the size of the plant.

The advantages of DAC over amine scrubbing are its greater flexibility due to the fact it captures CO_2 from the atmosphere. This means it does not need to be implemented at the point source of the emissions (after the gas turbine exhaust). As a result, there is greater flexibility over the location of where DAC is implemented in a CCGT plant. This means that DAC can be retrofitted to existing CCGT plants with minimal changes required to the existing plant.

Although DAC has more flexibility in where it is implemented in a CCGT plant, the higher associated costs and poorer performance in capturing CO_2 means it is a less desirable method of CCS for the Keadby 3 plant. However, DAC has the ability to be retrofitted to existing plants, meaning it can aid in reducing CO_2 emissions around the world.

4.4 Environmental Impact Discussion

When comparing the carbon footprint of a CCGT plant with added CCS, and the renewables solution with storage, the following key differences in lifecycle emissions and environmental impact are found from Asia (2024) and M. F. Deane et al. (2017).

While CCS can reduce operational CO_2 emissions from a CCGT plant by approximately 90%, and has promised to reduce global emissions up to 15%, it still possesses a significant carbon footprint and other risks. Carbon dioxide is not the only harmful gas that can escape in the atmosphere as CCS sites are found to be emitting methane, NO_x and other gases. All of these present a threat to the environment and according to the Oakland Institute, CCS poses additional health risks.

Additionally, the overall lifecycle emissions, which include those from natural gas extraction, processing and energy required to operate CCS systems, remain significant compared to renewables. Estimates place lifecycle emissions for CCS between 100 and 200 grams of CO_2 per KWh, depending on the efficiency of the plant. However, the lifetime of the BESS integrated with the renewable plant is only 10 years, so 2 replacements are required during the lifetime of the wind farm. Since battery cells are currently non recyclable Department for Business (2023) this detracts from the environmental benefits of wind energy.

Wind energy is one of the cleanest sources of electricity with significantly reduced carbon footprint when compared to CCGT plants, even with CCS. The lifecycle emissions of a wind farm are generated by manufacturing, transportation and installation of turbines and are found to account for around 10-20 grams of CO_2 per kWh, which is significantly less than CCS. However, the addition of BESS as opposed to low waste ESS increases the carbon footprint of the overall renewable design.

Chapter 5: Conclusion

5.1 Summary of Work

This report has evaluated the viability of CCGT with CCS, providing a comparative analysis with renewable energy sources in the form of wind energy with BESS, and highlighting the essential role of CCS in maintaining grid stability amid increasing reliance on variable renewable energy. The findings emphasize the economic and operational benefits of CCS, particularly in sectors where other mitigation options are limited.

- Scaled calculations were completed to calculate the steam turbine power output
- Different CCGT plant configurations were evaluated and the 2x2x1 configuration was eventually chosen
- The performances of the unabated and plant with CCS were evaluated

- The renewable energy generator type was determined.
- The location for an offshore wind farm was selected.
- A supporting storage technology was identified.
- The storage capacity of the battery energy storage system was determined.
- Renewable solution was developed to a high-level design.
- Economic analysis of renewable solution was carried out through calculations of OpEx, CapEx and LCOE.
- Economic comparisons where made between CCGT with CCS and renewable solution.

5.2 Optimal Design

It is concluded that an optimal grid incorporates both renewable energy and traditional sources with CCS where possible, as the increase in LCOE is minimal. To maintain grid stability it is not recommended that renewables make up the majority of the grid, however emerging inertial storage technologies such as flywheel could change this in future. As a result, if one technology is to be promoted it is CCGT with CCS.

5.3 Review of Objectives

The project met the key objectives, starting with the establishment of a baseline CCGT plant design without carbon capture, including net power output and capital/operational costs. An amine-based CCS system was then integrated, with its impact on plant performance quantified, showing a reduction in net power output and increased costs. Through detailed analysis, including the assessment of economic performance, operational efficiency, and the Levelized Cost of Electricity (LCOE), this study has successfully addressed the initial objectives.
An economic and environmental assessment revealed higher LCOE and CO_2 capture costs for the CCGT with CCS. A wind farm with energy storage was designed and evaluated, considering its intermittent nature and storage requirements. The comparison between CCGT with CCS and wind energy with storage highlighted wind as a more cost-effective and sustainable solution in the long run.

5.4 General Conclusions

- CCGT provides superior grid stability compared to renewable energy sources, primarily due to the high inertia of CCGT plants, and greater reliability.
- Energy storage compensates for periods where renewable energy can't produce electricity, but is not economically viable for durations ¿4hours.

- Despite higher capital and operational costs, CCS plants demonstrate long-term economic feasibility, particularly as decarbonization goals tighten. The value-adjusted LCOE and material analysis support this conclusion.
- Wind and solar technologies excel in the early stages of decarbonization, but their limitations in grid balancing highlight the need for dispatchable CCS plants as a complementary solution.

5.5 Detailed Conclusions

- The unabated CCGT plant was designed with a gross power output of 904.4 MWe, with a CAPEX of £871,171,950 and the OPEX is £30,577,746.
- The lifetime fuel cost of CCGTs both unabated and with CCS is £15,302,005,670.
- Adding an amine-based CCS system reduced the plant gross power by 58.3 MWe to 846.1 MWe.
- The CCGT with CCS system had the CAPEX of £1,815,423,000 and the OPEX is £58,305,517.
- The HHV net efficiency decreased from 53.8% for unabated to 47.8% for added CCS.
- The 1650 MW offshore wind farm with complementary battery energy storage system, had a CAPEX of £6.969 billion, OPEX of £8.358 billion and LCOE of £122.5 per MWh.

5.6 Outcome Evaluation

- In hindsight, verifying the results of the loan payback calculations would have increased reliability of findings. To remedy this, members should closely follow the Gantt chart.
- Furthermore, it would be beneficial to optimize the design of the compression stage to reduce overall work required and maximize net power output. This could be rectified by even contribution of work by all team members.
- Overall, the report partly led to successful outcome as while it would be desirable to further optimize and verify the results, the topic was investigated sufficiently to reach a valid conclusion.

5.7 Future Work and Recommendations

To better answer the design problem there should be further research into energy systems that optimize the synergies between CCS plants and renewable assets. Advanced grid modeling should be explored to optimize renewable and CCS integration while maintaining stability. Continued research should also target reducing the costs and improving the efficiency of CCS technologies, such as solvent regeneration and CO2 compression.
In summary, this report underscores CCS's pivotal role in achieving a balanced, reliable, and decarbonized energy future. Implementing the recommendations could ensure that CCS and renewables work hand in hand to meet global climate targets.

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Appendix A: Combustion Calculations Spreadsheet

Analysis of dry gas	(%, volume)
CH_4	94.75
C_2H_6	3.0
C_3H_8	0.6
C_4H_{10}	0.1
C_5+	0.05
N_2	1.4
CO_2	0.1
	100.00

Figure A.1: Typical North Sea Gas Composition

COMBUSTION CALCS (1 Gas Turbine)

NATURAL GAS COMPOSITION			Per 100 mol			
	Mol Wt (g/mol)	%v/v	Mole distribution (mol)	Mass distribution (g)	%w/w	moles
Methane (CH4)	16.041	94.75	94.750	1519.88	89.96	861.1528741
Ethane (C2H6)	30.067	3	3.000	90.20	5.34	27.26605406
Propane (C3H8)	44.092	0.6	0.600	26.46	1.57	5.453210812
Butane (C4H10)	58.118	0.1	0.100	5.81	0.34	0.908868469
Pentane (C5H12)	72.144	0.05	0.050	3.61	0.21	0.454434234
Nitrogen (N2)	28.016	1.4	1.400	39.22	2.32	12.72415856
Carbon Dioxide (CO2)	44.01	0.1	0.100	4.40	0.26	0.908868469
		----------	----------		----------	
	TOTALS	100	100.000		100.00	

Required for combustion (kg/kg)			Flue gas products (kg/kg)		
O2	N2	Air	CO2	H2O	N2
3.990	13.275	17.265	2.744	2.246	13.275
3.725	12.394	16.119	2.927	1.798	12.394
3.629	12.074	15.703	2.994	1.634	12.074
3.579	11.908	15.487	3.029	1.550	11.908
3.548	11.805	15.353	3.050	1.498	11.805
-	-	-	-	-	-
-	-	-	-	-	-

Required Individual Combustion	O2/Air Required (kg/kg)		Products of Combustion (kg/kg)		
Dry Air	O2	Dry Air	CO2	H2O	N2
17.265	3.589	15.531	2.468	2.020	11.942
16.119	0.199	0.861	0.156	0.096	0.662
15.703	0.057	0.246	0.047	0.026	0.189
15.487	0.012	0.053	0.010	0.005	0.041
15.353	0.008	0.033	0.007	0.003	0.025
-	-	-	-	-	0.023
-	-	-	0.003	-	-
	----------	----------	----------	----------	----------
TOTAL	3.865	16.723	2.691	2.151	12.882

IMPORTANT VALUES	
Heat to Steam (MW)	861.5
Fuel Mass flow rate (kg/s)	15.3599
Oxygen %wt in air	23%
Density of Natural Gas (kg/m3)	0.754
Volume flow rate (m3/s)	20.371
Mean molecular weight NG (g/mol)	16.9
Total Moles of Natural gas	908.868
Air/Fuel Ratio	42.08571368
Air Flow rate	646.431
Total Air Flow (lb/s)	1459.000
Total Air Flow (Kg/s)	661.791
Mass fraction N2 (Dry Air)	0.767
Mass fraction O2 (Dry Air)	0.233

Flowrates calculations:	
GT specs:	
Pout	288000
efficiency	38.70%
NCV	48450
flowrate(fuel) = Pout/eff*NCV	

FLUE GAS COMPOSITION			Per kg				
	Mass	%w/w	Mass Dist	Mole Dist	%v/v	%v/v (dry)	Mol Wt
Nitrogen (N2)	496.657	75.05%	0.7505	0.0268	75.96%	82.44%	28.016
Oxygen (O2)	90.768	13.72%	0.1372	0.0043	12.15%	13.19%	32.000
Moisture (H2O)	33.032	4.99%	0.0499	0.0028	7.86%	0.00%	18.016
Carbon Dioxide (CO2)	41.335	6.25%	0.0625	0.0014	4.02%	4.37%	44.010
	----------	----------	----------	----------	----------	----------	
TOTAL	661.791	100.00%	1.00	0.0353	100.00%	100.00%	

Flue Gas Component Mass		
Combust	XS Air	Total
197.863	298.794	496.657
0.000	90.768	90.768
33.032	0.000	33.032
41.335	0.000	41.335
----------	----------	----------
272.229	389.562	661.791

Figure A.2: CO2 Compression Spreadsheet

Appendix B: CCGT Plant Operability

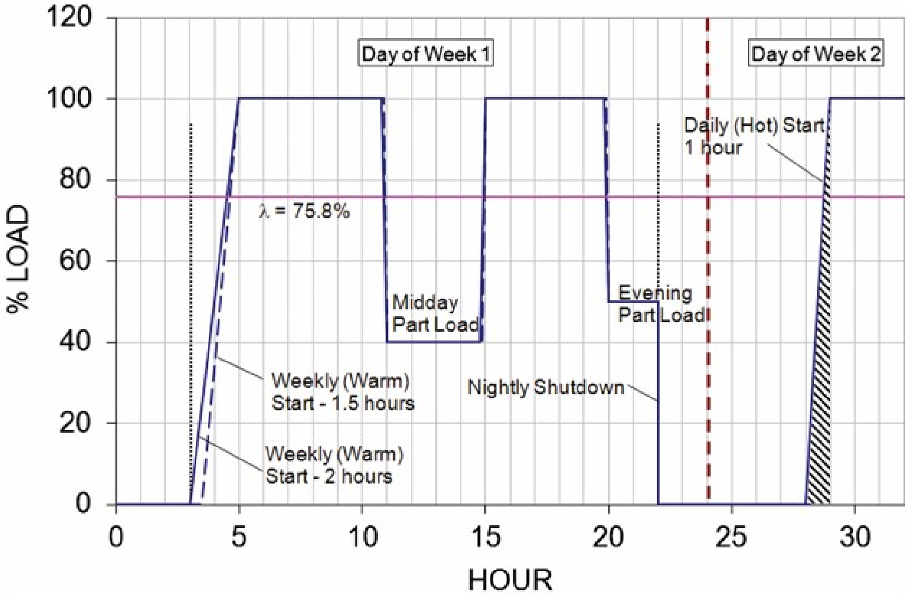

Figure B.1: Example cyclic duty profile for a GTCC power plant

- Every morning, the plant provides baseload between 5 am (obviously the plant starts earlier to be at baseload at that time) and 11 am and is brought down to 40% load until 3 pm (presumably wind and/or solar power generation takes over).
- Between 3 pm and 8 pm, the plant is once again base-loaded to provide rush hour and "nightlife" power to a busy metropolitan area.
- After running at 50% load between 8 pm and 10 pm, the plant is shut down until 5 am next day.
- Every Friday, the plant is shut down at 10 pm for the weekend until next Monday 5 am. Twice a year, the plant is shut down for 1 week to carry out routine (scheduled) maintenance tasks.

Figure B.2: "Two-cycled" daily plant operation assumptions

Appendix C: CO2 Compression

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.26 (38)	2.28
2	0.59 (85)	2.28
3	1.22 (177)	2.21
4	2.51 (364)	2.07
5	3.97 (576)	1.66
6	6.34 (919)	1.60
7	9.87 (1,432)	1.56
8	15.27 (2,215)	1.55

Figure C.1: Case B31B: CO_2 compressor interstage pressures

Compressor/Stage No.	P_inlet (Mpa)	P_outlet (Mpa)	P_avg (Mpa)	Compressibility Factor	Pressure ratio	Compressor Work (KJ/kg)	Mass Flow (kg/s)	Compressor Power (MW)	
1	0.199948	0.3	0.27	0.9926	1.7	35.52686015	74.402	2.6	
2	0.330350	0.5	0.44	0.9879	1.7	35.35857006	74.402	2.6	
3	0.545797	0.9	0.72	0.9801	1.7	35.07883919	74.402	2.6	
4	0.901755	1.5	1.20	0.9665	1.7	34.5916461	74.402	2.6	
5	1.489862	2.5	1.98	0.9437	1.7	33.77798138	74.402	2.5	
6	2.461519	4.1	3.26	0.9046	1.7	32.37688351	74.402	2.4	
7	4.066871	6.7	5.39	0.8333	1.7	29.8240307	74.402	2.2	
8	6.719200	11.1	8.91	0.6913	1.7	24.74148483	74.402	1.8	Actual P_Comp (MW)
					SUM	261.3		19.4	24.1

Figure C.2: CO2 Compression Spreadsheet

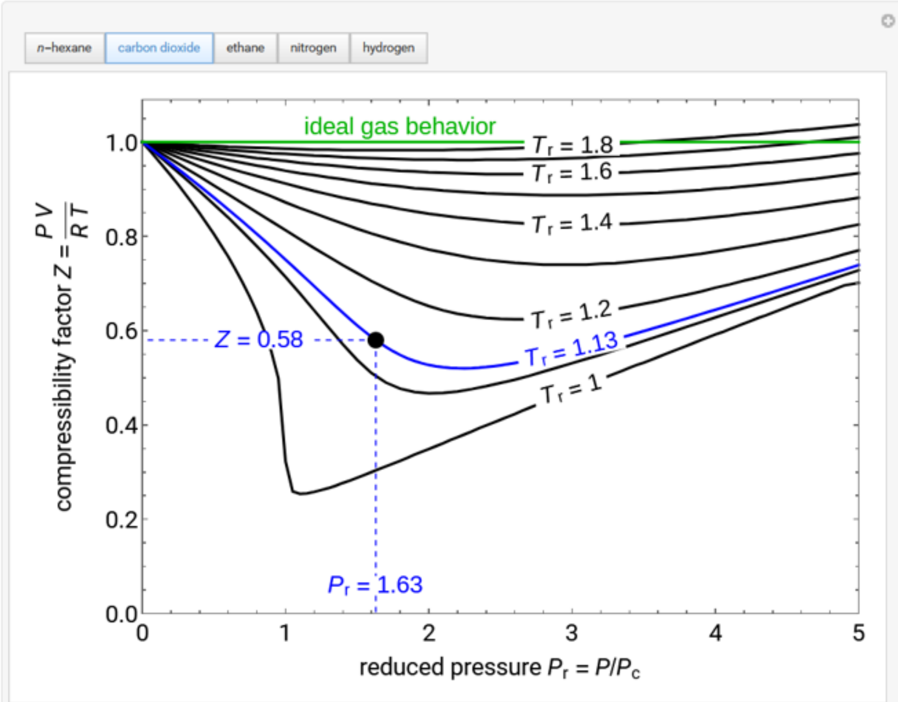

Figure C.3: Compressibility Factor Chart for CO2

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Compression_Compressibility.m | compressibility.m

```
S1 = compressibility('carbon dioxide',303,3.2);
S2 = compressibility('carbon dioxide',303,6.7);
S3 = compressibility('carbon dioxide',303,13.2);
S4 = compressibility('carbon dioxide',303,23.8);
S5 = compressibility('carbon dioxide',303,37.5);
S6 = compressibility('carbon dioxide',303,57.8);
S7 = compressibility('carbon dioxide',303,86.7);
S8 = compressibility('carbon dioxide',303,128.5);
A1 = compressibility('carbon dioxide',355.928,2.7);
A2 = compressibility('carbon dioxide',355.928,4.4);
A3 = compressibility('carbon dioxide',355.928,7.2);
A4 = compressibility('carbon dioxide',355.928,12.0);
A5 = compressibility('carbon dioxide',355.928,19.8);
A6 = compressibility('carbon dioxide',355.928,32.6);
A7 = compressibility('carbon dioxide',355.928,53.9);
A8 = compressibility('carbon dioxide',355.928,89.1);
```

A1	0.9926
A2	0.9879
A3	0.9801
A4	0.9665
A5	0.9437
A6	0.9046
A7	0.8333
A8	0.6913
S1	0.9869
S2	0.9722
S3	0.9438
S4	0.8941
S5	0.8211
S6	0.6788
S7	0.3006
S8	0.3860

Figure C.4: MATLAB Compressibility Function use with corresponding Z values obtained

Appendix D: Final CCGT Design

D.1 Different CCGT Plant Configurations Overview

Configuration	Gas turbine model	Gas turbine efficiency	Total gas turbine output power	Total unabated power output (scaled steam turbine calculations)	Total unabated power output (Gülen calculations)	Capital expenditures per gas turbine (CAPEX)	Lifetime cost of natural gas	Meets 910 ± 20 MWe
		%	MW	MWe	MWe	£/kW	£	
1-off 1x1x1	Siemens SGT5-9000HL	43	593	878	897	123.20	6385607782.00	No
1-off 2x2x1	GE Vernova Frame 9F.04	38.7	576	904.4	893.79	160.16	6891718348.00	Yes
1-off 3x3x1	Ansaldo Energia AE94.2	36.3	570	931.5	896.781	191.73	7270834053.00	Yes
2-off 1x1x1	GE Vernova Frame 9F.04	38.7	576	876.8	893.7792	160.16	6891718348.00	No
2-off 2x2x1	GE Vernova Frame 9E.04	36.9	588	918.6	921.9252	223.30	7378480975.00	Yes
2-off 3x3x1	Ge Vernova Frame 6F.03	36.8	528	826.4	828.3264	280.28	8447106529.00	No

Table D.1: Different CCGT Plant Configurations Overview

D.2 Plant Schematics

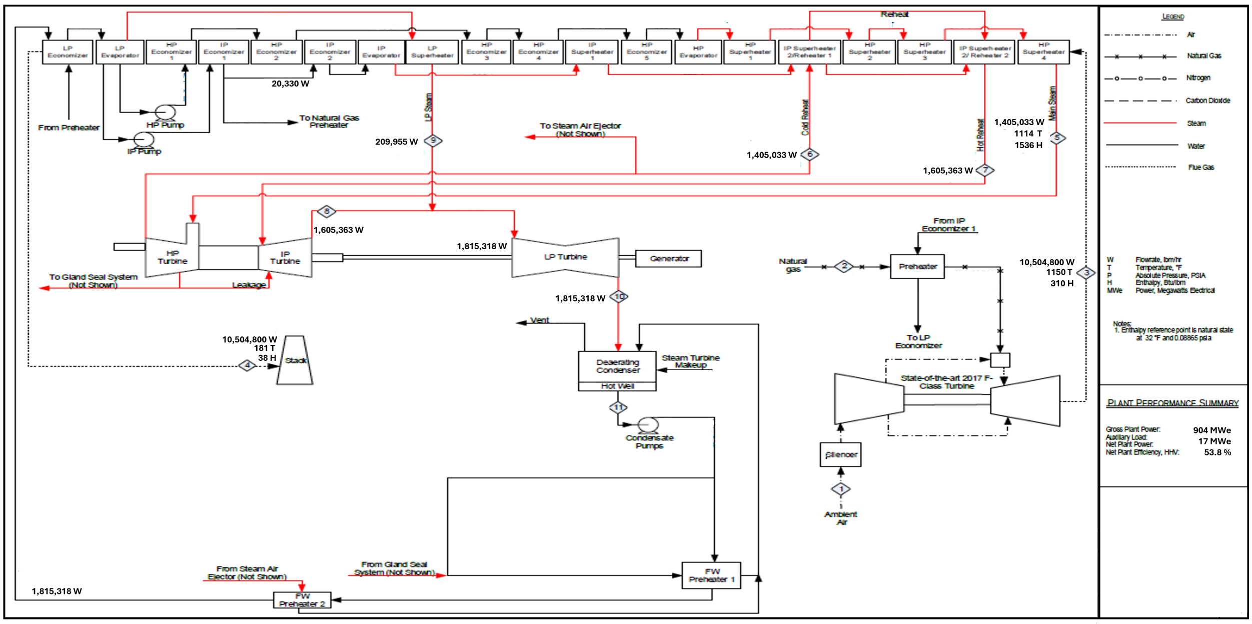

Figure D.1: Schematic for Unabated CCGT Plant

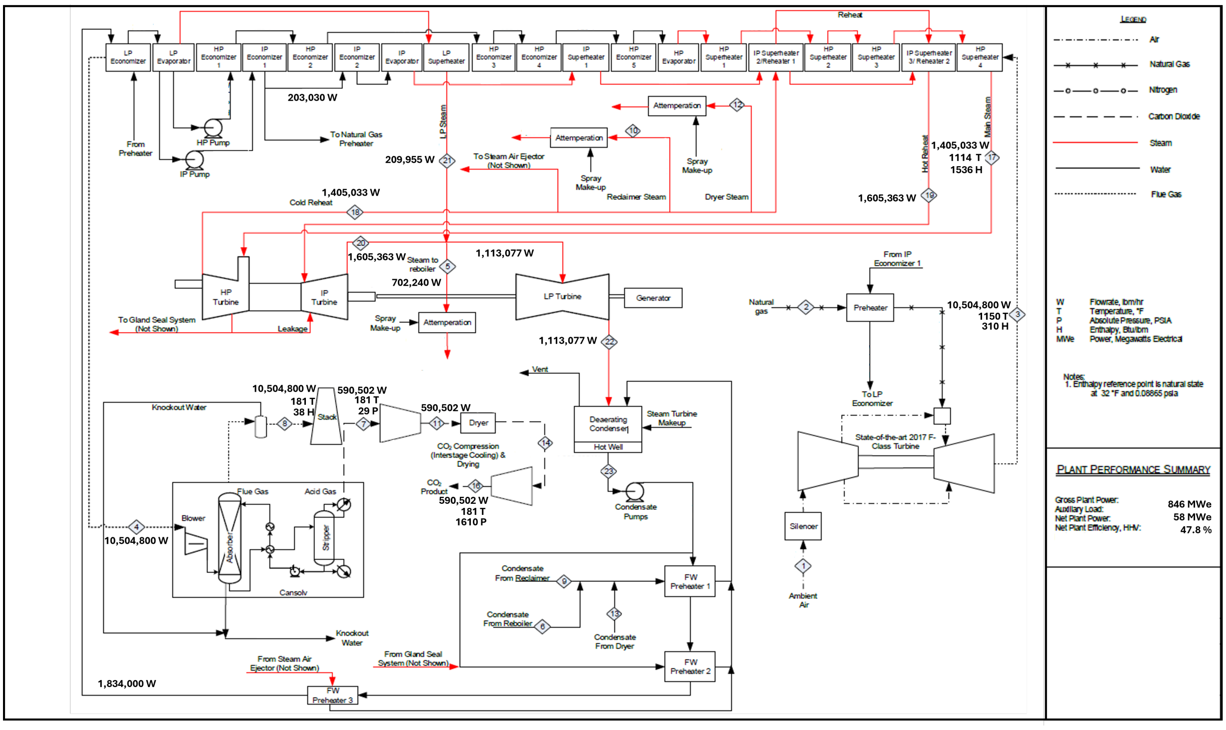

Figure D.2: Schematic for CCGT Plant with CCS

Appendix E: Renewable Analysis

E.1 Renewable Energy Source SWOT Analysis

E.1.1 Renewable Energy Source Scoring

Renewable Energy Type	Strength	Weakness	Opportunity	Threat	**Total**
Offshore wind	7	-5	6	-2	**6**
Onshore wind	6	-3	3	-3	**3**
Solar	7	-6	4	-2	**3**
Geothermal	5	-6	2	-3	**-2**

Table E.1: Offshore Wind Farm SWOT Scoring

E.1.2 Offshore Wind Farm

Strengths (7)	Weaknesses (-5)	Opportunity (6)	Threat (-2)
High Energy Potential (3): Offshore wind speeds are generally faster than on land[1]. Moreover, a turbine in a 15-mph wind can produce twice as much energy as one in a 12-mph wind. This increase in speed means offshore turbines generate substantially more energy overall [The Wind Power (2022)].	High Initial Investment (2): The production and installation of undersea power cables for electricity transmission can incur significant expenses [The Wind Power (2024)] and offshore construction is more expensive [Bureau of Ocean Energy Management (BOEM) (2024)], compared to onshore.	Policy Support and Subsidies (3): The UK Government will incentivise offshore energy to achieve plans of connecting an extra 40GW of energy to the UK national grid by 2030 [U.S. Department of Energy (DOE) (2024)].	Adequate Storage (1): Without efficient storage options, the variability of wind energy generation could lead to supply interruptions, undermining the reliability and viability of offshore wind projects as a consistent energy source [National Grid (2024)].
Resource Availability (3): Oceans and seas provide vast spaces for large-scale wind farms, reducing the land competition seen in onshore renewable projects.	-Maintenance Challenges (2): Offshore wind energy is encountering new operational and maintenance (O&M) challenges due to the increasing size of turbines and the aging of existing assets [Ecotricity (2024)].	-Growing Demand for Green Energy (1): The demand for renewable energy is increasing, particularly from businesses and regions committed to reducing their carbon footprint, which makes offshore wind a desirable investment.	Severe Weather Conditions (1): Wave action and high winds, especially during severe storms or hurricanes, can significantly damage wind turbines. Adverse weather conditions can disrupt construction schedules and increase costs [The Wind Power (2022)].
Environmental Benefits (1): Offshore wind is a clean, renewable source that doesn't produce greenhouse gas emissions during operation, contributing to climate change mitigation efforts [The Wind Power (2022)].	-Environmental Impact on Marine Life (1): Offshore wind farms can affect marine ecosystems, potentially disrupting habitats, migratory paths, and the health of fish and bird populations [4C Offshore (2024)].	Economic Revitalization (2): The construction and maintenance of offshore wind farms require a mix of high- and low-skilled workers, with an estimated 130,000 jobs projected to be created by 2030 through offshore investments [U.S. Department of Energy (DOE) (2024)].	

Table E.2: Offshore Wind Farm SWOT

E.1.3 Onshore Wind Farm

Strengths (+6)	Weaknesses (-3)	Opportunities (3)	Threats (-3)
Low Operating Costs and High Return on Investment (2): Onshore wind farms, once established, have low maintenance costs, minimal fuel costs, and can provide a high return on investment over their lifetime [U.S. Department of Energy (DOE) (2024)].	Intermittent Power Supply (1): Wind energy production depends on wind availability, which is variable and can lead to inconsistent power generation, necessitating backup systems or storage solutions [New Civil Engineer (2024)].	Growing Policy Support and Local Renewable Demand (2): July 2024 elected Labour Government lifted the informal ban on onshore wind development in England on their first full day in office. They have also pledged to establish an onshore wind taskforce aimed at removing barriers to deployment and revitalizing a substantial pipeline of new onshore wind projects across the country [Wind Europe (2024)].	End of Life Turbines (1): turbines typically have an operational lifespan of 20 to 25 years, depending on the effectiveness of the operation and maintenance strategies in place. By 2040, the UK may lose nearly 9 GW of onshore wind capacity as many turbines approach the end of their useful life [Lumify Energy (2024)].
Rapid Installation and Deployment (1): Compared to other renewable energy sources, onshore wind farms can be installed relatively quickly, making them a fast solution to increase renewable energy capacity [U.S. Department of Energy (DOE) (2024)].	Land Use and Visual Impact (1): Onshore wind farms require significant land, and turbines can impact landscapes, leading to potential conflicts with landowners and communities over visual aesthetics and land value [New Civil Engineer (2024)].	Advancements in Noise Reduction Technology (1): New turbine blade designs and software can reduce noise output, making onshore wind farms more acceptable to nearby communities [Wind Europe (2024)].	Erosion and Land Degradation Concerns (1): Installation in certain areas can lead to soil erosion, affecting local ecosystems and agriculture, requiring additional mitigation efforts [GreyB (2024)].
Proximity to Local Power Grids (2): Onshore locations simplify the integration of generated power into local grids, reducing the need for extensive transmission infrastructure and minimizing transmission losses.	Environmental and Wildlife Impact (-): Turbines can disrupt local ecosystems, particularly affecting bird and bat populations, which can result in restrictions and additional costs for mitigation measures [GreyB (2024)].		Grid Congestion and Infrastructure Strain (1): In areas with limited transmission capacity, adding 910 MW of power could strain local grids, requiring costly upgrades or even curtailment.
Wind Energy's Carbon Footprint (1): Wind energy boasts a relatively small carbon footprint, with greenhouse gas emissions primarily resulting from the manufacturing, transportation, and installation of onshore wind turbines at 9gCO2/kWh [New Civil Engineer (2024)].			

Table E.3: Onshore Wind Farm SWOT

Solar Farm

Strengths (7)	Weaknesses (-6)	Opportunities (+4)	Threats (-2)
Abundant and Renewable (2): Solar energy is widely available and renewable, with sunlight being an inexhaustible resource that can be harnessed almost anywhere [From Griffiths and Armour (2024)].	High Initial Investment (2): The initial capital costs for purchasing and installing solar panels, inverters, and other infrastructure can be high, creating a barrier to adoption for some consumers [From Enel Green Power (2024)].	Cost Decline of Solar and Storage Technologies (1): Advances in manufacturing and economies of scale are driving down costs for both solar panels and batteries, making solar increasingly competitive with traditional energy sources [From Powered by Daylight (2024)].	Price Volatility (1): From 2020 to 2022, the solar industry faced supply chain disruptions, leading to cost increases, trade restrictions, and delays or cancellations in projects [From HeatForce (2024)]
Low Operating Costs (3): Once installed, solar systems have low maintenance and operating costs, making long-term operation economically viable [From Enel Green Power (2024)].	Intermittent Availability (3): Solar energy production depends on sunlight, making it inconsistent due to factors like cloud cover, seasonal variations, and night-time non-production [From Constellation Energy (2024)].	Government Incentives and Policies (1): Many governments offer tax incentives, subsidies, and favourable policies for solar energy adoption, which boost its economic feasibility.	Micro-cracking and Durability Issues in Solar Panels (1): Strong winds and environmental factors can cause micro-cracks in the thin silicon of solar panels, decreasing efficiency by allowing dust and moisture to penetrate. Additionally, due to weather and material challenges, solar panels often fall short of their expected 40–50 year lifespan, lasting closer to 20 years, which can impact long-term energy production [From ScienceDirect (2024)].
Long Lifespan of Equipment (2): Solar panels have a long operational life, often over 25 years, which improves return on investment (ROI) and environmental benefits through durable, long-lasting infrastructure [From Griffiths and Armour (2024)].	Lower Efficiency and Space Requirements (1): Solar panels have a limited efficiency rate, usually between 15-22%, necessitating large areas to generate significant power, especially compared to other renewable technologies [From Constellation Energy (2024)].	Improvements in solar technology (2): The future of solar energy looks promising due to rapid advancements in solar panel technology. Innovations in photovoltaic (PV) efficiency, new panel materials, and developments in perovskite solar cell [From Green Match (2024)].	

Table E.4: Solar Farm SWOT

E.1.4 Geothermal

Opportunities (+5)	Weaknesses (-6)	Opportunities (+2)	Threats (-3)
Reliable and Constant Energy Supply (2): Geothermal energy is consistently available, unaffected by time of day, season, or weather. A geothermal plant typically operates around 8,600 hours annually, compared to Solar's 2,000-hour average, making it highly predictable and stable for energy planning [From ScienceDirect (2024)].	High Initial Investment Costs (2): Geothermal energy involves significant upfront costs, typically between £2–£7 million to build a 1 MW capacity plant, making it a costly resource to develop initially [From Enel Green Power (2024)].	High potential for energy output: (1) Geothermal energy holds vast potential, as the heat within just the top 10,000 meters of Earth's surface contains about 50,000 times more energy than all global oil and gas reserves combined [From International Renewable Energy Agency (IRENA) (2024)].	Geopolitical and Regulatory Hurdles (2): Lengthy permitting processes, regulatory hurdles, and potential environmental regulations in certain regions can delay project timelines and increase costs [From TWI Global (2024)].
Exceptional Longevity and Safety (2): Geothermal plants have long lifespans—up to 80–100 years—far surpassing typical domestic boilers. With no fuel involved, they pose minimal fire risk, and decades of experience enhance their reliability	Geographic Limitations (2): Ideal geothermal resources are location-specific and typically found in tectonically active regions, limiting its availability in certain areas and restricting scalability [From Enel Green Power (2024)].	Potentially Cost Effective (1): Geothermal energy is becoming increasingly cost-effective for electricity generation and is expected to see further price reductions through 2050, strengthening its economic appeal [From International Renewable Energy Agency (IRENA) (2024)].	Technological and Drilling Risks (1): Drilling for geothermal reservoirs is inherently risky, with potential for dry wells or lower-than-expected resource availability, leading to financial losses [From Green Match (2024)].
Minimal Carbon Emissions (1): Geothermal energy has low greenhouse gas emissions compared to fossil fuels, contributing to climate change mitigation efforts and cleaner energy production due to it requiring no fuel source.	Risk of Resource Depletion (1): Improper management or over-extraction of geothermal reservoirs can lead to resource depletion, reducing the power output and lifespan of geothermal plants [From TWI Global (2024)].		
	Potential Environmental Concerns (1): Geothermal drilling and extraction can release trace greenhouse gases like methane and hydrogen sulfide, though in lower amounts compared to fossil fuels, and may affect groundwater quality [From Green Match (2024)].		

Table E.5: Geothermal SWOT

E.1.5 Comparison of Renewable Energy Sources

Renewable Energy Type	OpEx	CapEx	Capacity Factor
	£/MW/YR	£/MW	%
Solar	15430	615000	17.5
Geothermal	77000	4370000	80
Offshore Wind	99048	2370000	35
Onshore Wind	45727	45900	17
Solar and Onshore Wind Opex and CapEx from UK Government (2023)			
Geothermal Opex and CapEx from National Renewable Energy Laboratory (NREL) (2022)			
Offshore Wind Opex and CapEx from UK Government (2017)			
All Capacity Factors from International Renewable Energy Agency (IRENA) (2024)			

Table E.6: Comparison of Renewable Energy Sources

E.2 Turbine Selection

E.2.1 UK Offshore Wind Farms Data

Wind Farm	Distance from s	Depth	Life Capacity Factor	Capacity	CapEx	Cost/Capacity	Ref
	(km)	(m)	(%)*	(MW)	(£)	(£/MW)	
Hornsea Project One	120	30	47.3	1200	4.2E+09	3500000	From The Wind Power (2024)
Hornse Project Two	89	35		1320	2.9E+09	2196969.697	From Equinor (2017)
Walney	19	24	43.6	659	2E+09	3034901.366	From RWE Renewables (2022)
Beatrice Offshore WF	13	45	41.8	588	2.5E+09	4251700.68	From Scottish Construction Now (2024)
Rampion WF	13	19	36.7	400	1.3E+09	3250000	From Renewable Technology (2024)
London Array	20	25	40.2	630	2.2E+09	3492063.492	From Blackridge Research (2024)
East Anglia One	43	40	46.8	714	2.5E+09	3501400.56	From European Investment Bank (EIB) (2010)
Dudgeon Offshore WF	32	18	47.5	402	1.3E+09	3109452.736	From Ørsted (2014)
Triton Knoll	32	20	23.2	857	2E+09	2333722.287	From NS Energy (2024)
Moray East	40	45	13.2	950	2.6E+09	2736842.105	From Power Technology (2024)
Gwynt y Môr	13	20	34.3	576	2.4E+09	4218750	From LIDO (2024)
North Hoyle Offshore WF	7.2	8	32.3	219	8E+07	365296.8037	From The Guardian (2015)
The Greater Gabbard Offsh	23	24	40.6	504	1.4E+09	2738095.238	From Power Technology (2008)
West of Duddon Sands	14	18	45.2	389	1.6E+09	4113110.54	From Ørsted (2011)
Sheringham Shoal	20	20	39.7	317	1.3E+09	3974763.407	From NS Energy (2024)
Lynn and Inner Dowsing	5	15	35.2	194	3E+08	1546391.753	From Power Technology (2008)
Humber Gateway	8	12	43.4	219	7E+08	3196347.032	From LIDO (2024)
Galloper WF	27	27	47.1	353	1.5E+09	4249291.785	From The Guardian (2015)
Scroby Sands	2.5	6	31.4	60	7.6E+07	1258333.333	From Power Technology (2008)
Northwester 2 Offshore WF	51	40	36.6	750	5.8E+08	776000	From Power Technology (2021)
							*Life Capacity Factors from Electrical Insights (2024)

Table E.7: 20 UK Wind Farms Data

Turbine Size	Cost per Turbine	Turbines Needed	Total Cost
5 MW	£2,500,000	329	£822,500,000
8 MW	£3,200,000	206	£659,200,000
10 MW	£4,000,000	165	£660,000,000
12 MW	£4,500,000	137	£616,500,000
15 MW	£5,100,000	110	£561,000,000

Table E.8: Cost Analysis by Turbine Size for 1643 MW Floating Wind Farm

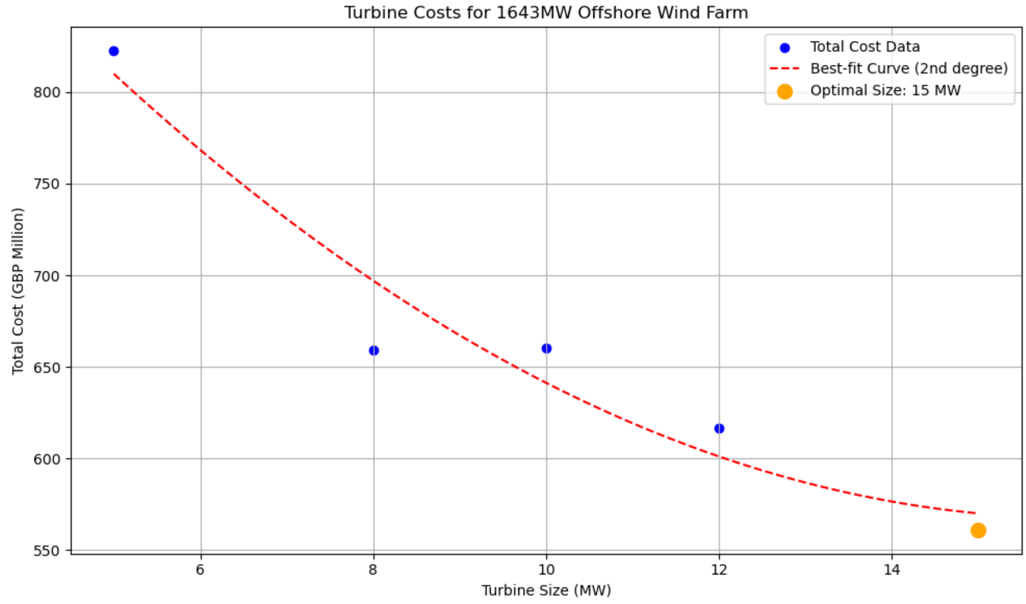

Figure E.1: Total Cost of Turbines for 1643 MW Wind Farm

Parameter	Vestas V236-15.0 MW	Siemens Gamesa SG 14-222 DD	GE Haliade-X 14.7 MW
Capacity Factor	~60%	~59%	~58%
Rotor Diameter	236 m	222 m	220 m
Blade Length	115.5 m	108 m	107 m
Annual Energy Output	80 GWh	79 GWh	74 GWh
Cost per MW	£3.9 million	£4.0 million	£4.2 million
Maintenance Costs	Low	Moderate	Low
Digital Capabilities	AI-driven remote monitoring	Self-diagnostic system	Digital twin optimization

Table E.9: Comparison of 15MW Turbine Models

E.3 Energy Storage System SWOT Analysis

E.3.1 Lithium-ion

Strengths (+10)	Weaknesses (-7)	Opportunities (+6)	Threats (-7)
High Efficiency and Rapid Response (4): Lithium-ion batteries which are the most common type of BESS, offer high round-trip efficiency (typically 85–95%) and rapid response times, making them ideal for energy storage applications (IRENA, 2022; Energy Storage Association, 2023).	**Limited Lifespan (3):** Unlike gravity-based or thermal storage systems, lithium-ion batteries degrade over time, especially under high-use conditions, which affects their lifespan. BESS typically require replacement after 8-15 years, adding to long-term costs (Energy Storage Association, 2023; NREL, 2022).	**Technological Advancements (3):** Ongoing research into alternative battery chemistries (e.g., solid-state, sodium-ion, and flow batteries) promises improvements in lifespan, safety, and efficiency. These innovations could further reduce costs and address the limitations of current lithium-ion systems (NREL, 2022; Wood Mackenzie, 2023).	**Raw Material Supply Risks (2):** The production of lithium-ion batteries relies on critical materials like lithium and cobalt, which face supply constraints and price volatility due to geopolitical factors and limited mining capacity. This dependence could impact battery costs and availability (Energy Storage Association, 2023).
Decreased Costs (3): The costs of lithium-ion and alternative batteries have dropped significantly due to advancements in production and material science. (BloombergNEF, 2023).	**Limited Storage Duration (2):** While BESS performs well in short-duration applications (up to 4 hours), they are less suited for long-duration storage needed for grid resilience over days or weeks. This limits their potential in scenarios that require prolonged energy supply, such as seasonal storage (BloombergNEF, 2023).	**Proven Technology (3):** Lithium-ion BESS were the first ESS to be widely implemented, making it low risk which is attractive to investors (Energy Storage Association, 2023).	**End-of-Life Disposal Challenges (2):** Recycling and disposal of used batteries present environmental challenges, as many recycling processes are still inefficient and costly. Improper disposal can lead to soil and water contamination, adding a regulatory and environmental burden to BESS adoption (NREL, 2022).
Scalability and Versatility (3) BESS are modular and can be scaled from residential to utility-sized systems, supporting a wide range of applications. (Wood Mackenzie, 2023).	**Environmental and Safety Concerns (2):** BESS uses materials such as lithium, cobalt, and nickel, raising concerns over environmental impact, sourcing, and disposal. Furthermore, lithium-ion batteries can be prone to thermal runaway, posing a fire risk if not properly managed (IRENA, 2022; Wood Mackenzie, 2023).		**Competition (2):** Emerging technologies, such as hydrogen storage, gravity-based storage, and pumped hydro, offer different storage durations and efficiency profiles. These alternatives could reduce BESS market share, particularly in grid-scale, long-duration applications (IRENA, 2022; Wood Mackenzie, 2023).

Table E.10: Lithium-ion BESS SWOT Analysis

E.3.2 Flywheel

Strengths (+10)	Weaknesses (-10)	Opportunities (+8)	Threats (-12)
Fast Response (3): FES systems offer high power density, providing rapid discharge and recharge times which makes them suitable for applications such as grid stabilization and frequency regulation (Gyuk et al., 2020).	**High Initial Costs (4):** The upfront costs of FES systems are high due to the cost of high-strength composite materials and magnetic bearings which are required for efficient operation (Gibson et al., 2018).	**Grid Stability (4):** With increased integration of renewables, there is a greater demand for frequency regulation which FES systems can provide (Gyuk et al., 2020).	**Lack of Versatility (3):** Competing technologies, such as lithium-ion batteries and hydrogen storage, offer flexible storage solutions and may attract more investment (Gibson et al., 2018).
Long Lifespan and Low Maintenance (3): Unlike chemical batteries, flywheels have a long operational lifespan with minimal maintenance due to the absence of chemical reactions and the use of durable materials (Gibson et al., 2018).	**Limited Capacity (3):** FES systems are suited to short-duration, high-power applications rather than long-duration storage (Gyuk et al., 2020) since they experience energy loss due to friction and drag, particularly if vacuum maintenance is not optimized (Molina, 2015).	**Technological Advancements (2):** Innovations in magnetic bearings and composite rotor materials can improve efficiency and reduce costs, making FES more competitive with other storage solutions (Gibson et al., 2018).	**Regulatory Issues (4):** Lack of standardized policies or grid codes for FES systems can restrict widespread adoption, particularly in regions without clear frameworks for storage integration (Gyuk et al., 2020).
Environmentally Friendly (2): FES systems are more environmentally friendly compared to batteries, as they do not involve hazardous chemicals and are made of materials which can be reused and recycled (Molina, 2015).	**Complex Installation (3):** FES systems require specialized infrastructure, adding to the complexity and cost (Puchta & Hüttinger, 2021).	**Investment in Recycling (2):** FES systems are increasingly attractive as eco-friendly alternatives to batteries (Molina, 2015).	**Potential Safety Concerns (2):** Flywheels operate at high speeds and store large amounts of kinetic energy so potential safety risks, requiring stringent safety standards and monitoring. (Molina, 2015).
High Efficiency (2): FES systems have round-trip efficiencies ranging from 85-95% (Puchta & Hüttinger, 2021).			**Costly Materials (3):** FES relies on advanced composite materials for rotors which can be costly and subject to supply chain issues or price fluctuations (Puchta & Hüttinger, 2021).

Table E.11: Flywheel ESS SWOT Analysis

E.3.3 Gravity-Based

Strengths (+6)	Weaknesses (-10)	Opportunities (+6)	Threats (-6)
Longevity (3): Unlike chemical battery systems, GBES materials do not degrade over time. (Energy Vault, 2024; Power Technology, 2023).	**High Initial Costs (3):** Initial capital expenditure is high due to the infrastructure required (Energy Vault, 2024).	**Technological Advancements (3):** Innovations in material science and automation could further reduce GBES costs and improve efficiency (Power Technology, 2023).	**Competition (3):** Alternative technologies are evolving rapidly, their decreasing costs and improved efficiency are a threat to GES (ResearchGate, 2021).
Cost-Effectiveness (3): GBES materials are more affordable and environmentally friendly than other ESS such as lithium-ion batteries (PitchGrade, 2024).	**Limited Scalability (4):** GBES are constrained by geography and space, limiting its scalability (Power Technology, 2023).	**Policy Support (3):** Governments are incentivizing green storage solutions through subsidies, regulatory support, and carbon credits, which could improve GBES adoption rates globally (PitchGrade, 2024).	**Geopolitical and Market Risks (3):** Global economic uncertainties and market fluctuations in the energy sector impact the feasibility of large infrastructure projects. Regulatory changes affect long-term profitability and project timelines for GBES installations (Energy Vault, 2024).
	Complexity (3): Although GBES technology is mechanically simpler than some alternatives, managing large-scale systems still involves technical complexities and specialized maintenance, especially with automated systems and heavy lifting equipment (ResearchGate, 2021).		

Table E.12: Gravity-Based ESS SWOT Analysis

E.3.4 Hydrogen

Strengths (+2)	Weaknesses (-10)	Opportunities (+5)	Threats (-6)
Environmental Benefits (2): Hydrogen energy storage does not produce carbon emissions during combustion which makes it highly beneficial for reducing greenhouse gases (Simões & Santos, 2024).	**Low Efficiency (4):** Hydrogen energy systems suffer from energy losses during production (electrolysis), compression, and transportation, making them less efficient than other storage technologies such as batteries (Simões & Santos, 2024).	**Government Support (2):** Government subsidies for green hydrogen production support hydrogen storage development (Pal et al., 2023).	**Safety Risks (4):** Handling hydrogen poses specific safety risks due to its high flammability and storage challenges at high pressures or cryogenic temperatures, which may lead to operational and regulatory issues (Simões & Santos, 2024).
	Infrastructure Challenges (3): Hydrogen requires specialized infrastructure for storage and transportation which is costly to develop. (Oravec et al., 2023).	**Technology Advancements (3):** Ongoing research to improve electrolyzers and fuel cells could lower production costs and improve conversion efficiency. (ResearchGate, 2021).	**Competing Technologies (2):** Rapid advances in battery technology pose a threat (Pal et al., 2023).
	High Production Costs (3): Green hydrogen, which is produced through renewable-powered electrolysis, remains costly compared to other storage solutions (Power Technology, 2023).		

Table E.13: Hydrogen ESS SWOT Analysis

E.3.5 Thermal

Strengths (+5)	Weaknesses (-11)	Opportunities (+10)	Threats (-8)
Reduced Energy Waste (3): TES systems improve energy efficiency by storing excess heat or cold energy during off-peak hours, reducing energy waste (Dincer & Rosen, 2011).	**High Initial Costs (4):** The installation costs of TES systems can be significant, impeding adoption in cost-sensitive markets (IRENA, 2013).	**Government Policies (1):** Many governments incentivize renewable energy projects, which could drive TES adoption (IRENA, 2013).	**Competition (2):** Mainstream energy storage technologies, such as battery storage, pose competition to TES (Xu et al., 2014).
Environmental Benefits (2): By reducing reliance on fossil fuels, TES contributes to lowering greenhouse gas emissions (Xu et al., 2014).	**Space Requirements (3):** Large-scale storage units require substantial space which limits implementation in urban areas (Cabeza et al., 2015).	**Innovations in Storage Materials (5):** Advancements in phase change materials (PCMs) and other storage media can increase TES efficiency (Dincer & Rosen, 2011).	**Material Resource Constraints (4):** TES systems rely on materials that may face resource or cost constraints, such as certain salts for molten storage (Cabeza et al., 2015).
	Efficiency Losses (2): Thermal losses during storage can reduce efficiency, particularly in long-term storage applications (Cabeza et al., 2015).	**Increased Demand (4):** Urbanization drives demand for efficient energy solutions, creating opportunities for TES in building heating and cooling (Rezaie & Rosen, 2012).	**Environmental Concerns (3):** The potential for leakage of storage materials may introduce environmental and safety concerns (Cabeza et al., 2015).
	Complex Integration (2): Integrating TES with existing energy systems can be complex and requires specialized knowledge (Dincer & Rosen, 2011).		

Table E.14: Thermal ESS SWOT Analysis

E.3.6 Liquid Air

Strengths (+12)	Weaknesses (-12)	Opportunities (+8)	Threats (-8)
High Energy Density (3): LAES and LCAES systems can store energy at high densities, which reduces the amount of space required compared to other large-scale options such as pumped hydro storage (PHS) and compressed air energy storage (CAES). This makes LAES ideal for urban or restricted environments (pv magazine, 2024).	**High Initial Costs (4):** Despite using off-the-shelf components, the installation of LCAES systems can still involve significant capital investment due to the need for cryogenic infrastructure and storage tanks which are still relatively expensive. The long payback periods potentially limit broader adoption without significant subsidies (NTNU, 2023).	**Long Duration (2):** LAES's ability to provide energy for 10+ hours make it a valuable asset for supporting renewable-heavy grids (pv magazine, 2024).	**Competition (3):** LAES faces competition from technologies like lithium-ion batteries, which are currently cheaper and more efficient for shorter durations. (RSC Advances, 2023). Batteries also offer quicker response times and lower technical complexity than LAES. (Liu et al., 2023; Emiliano, 2024).
Scalability (2): LAES can be scaled to meet grid demands, from a few megawatts to hundreds of megawatts (RSC Advances, 2023). Furthermore, it does not require specific geographical features so is not constrained by space (RSC Advances, 2023).	**Complexity of System (4):** Handling cryogenic liquids in LAES introduces technical complexity, requiring specialized equipment and maintenance skills. This complexity increases operational costs and presents a barrier to wider adoption (Liu et al., 2023).	**Industrial Heat Recovery (2):** Waste heat from industries can be used to improve LAES efficiency, creating integration opportunities that support both energy storage and industrial process optimization (NTNU, 2023).	**Dependence on Market Conditions (2):** The commercial viability of LAES is highly sensitive to energy pricing structures and supportive policies. (pv magazine, 2024).
Long Lifespan (3): LAES systems have a high durability and low degradation rate, allowing them to operate for decades with minimal loss in performance, which is advantageous for large-scale and long-term energy storage requirements (Chen et al., 2023).	**Lower Round-Trip Efficiency (4):** LAES has a round-trip efficiency between 50–60%, which is lower than alternative ESS such as lithium-ion BESS (RSC Advances, 2023).	**Regulatory Support (2):** Global policies that promote carbon reduction and clean energy investment could drive the adoption of LAES. (Emiliano, 2024; Kondoh et al., 2022).	**Technological Uncertainty (3):** As a relatively new technology, LAES faces uncertainty regarding long-term performance, particularly for large-scale applications (Chen et al., 2023).
Standardized Components (2): LAES systems utilize standard components such as gas turbines and heat exchangers, reducing manufacturing and setup costs compared to technologies requiring custom-built infrastructure (Kondoh et al., 2022). This also makes LAES potentially easier to integrate into existing energy systems, especially in regions with available compatible infrastructure (NTNU, 2023).		**Technology Development (2):** Advances in cryogenic storage and improved heat recovery systems could enhance the efficiency and cost-effectiveness of LAES. Research in these areas promises to reduce operational losses and increase system appeal for broader adoption (RSC Advances, 2023).	
Low Environmental Impact (2): Using air as the storage medium minimizes environmental harm, with less reliance on rare or harmful materials (NTNU, 2023).			

Table E.15: LAES SWOT Analysis

E.4 RTE Analysis

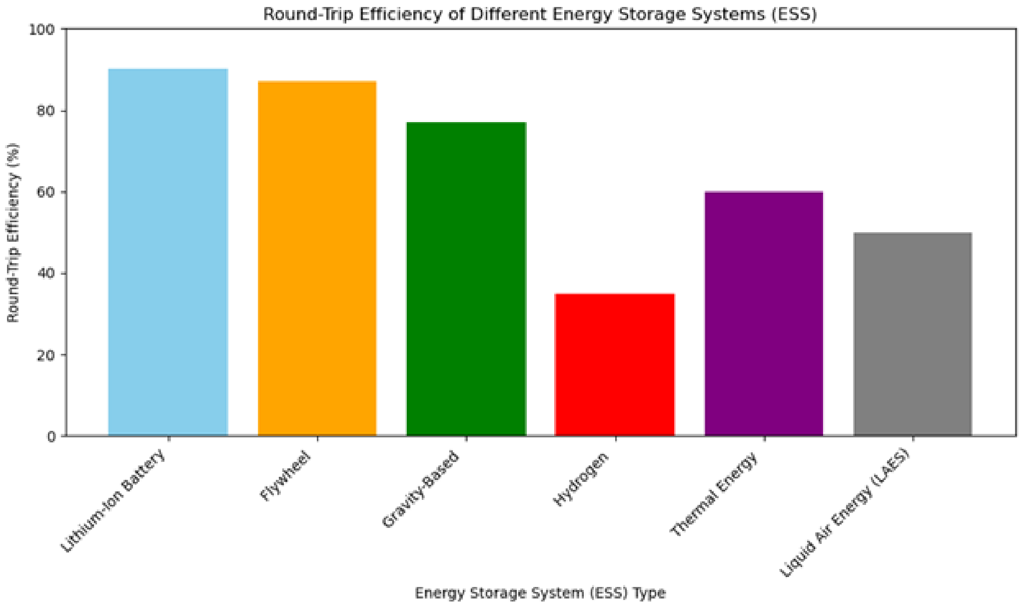

Figure E.2: Round-Trip Efficiencies of Various ESS

LCOS Analysis

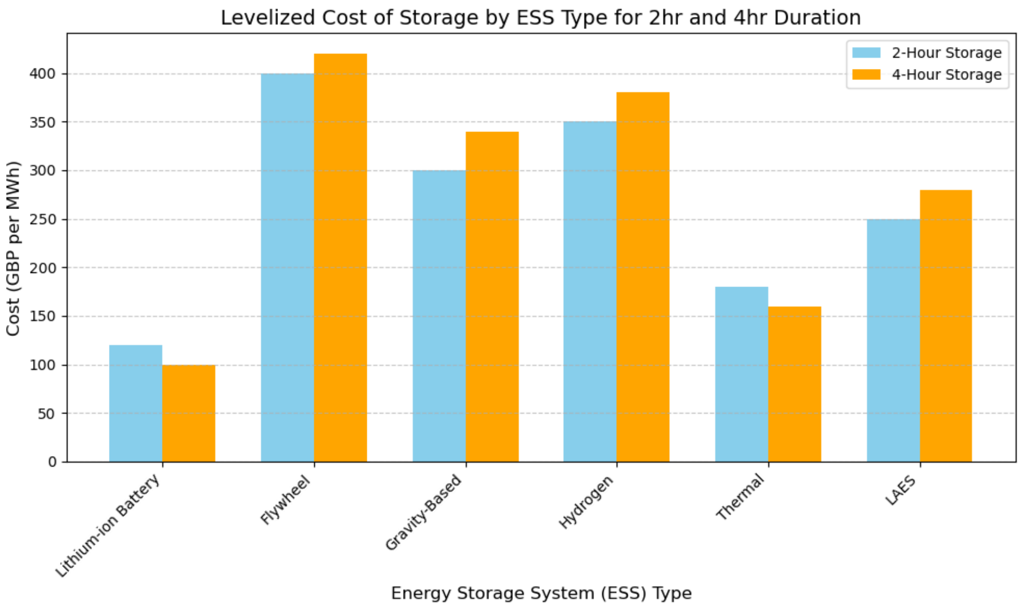

Figure E.3: LCOS for Various ESS

BESS Material Selection

Property	LFP Batteries	NMC Batteries
Thermal Stability	High, thermal runaway temperature > 200°C (TLS Containers, 2024)	Moderate, thermal runaway temperature ~150°C (TLS Containers, 2024)
Cycle Life	2000-4000 cycles (Keheng Battery, 2024; IEA, 2024)	1000-2000 cycles (Keheng Battery, 2024)
Energy Density	90-160 Wh/kg (Keheng Battery, 2024)	150-220 Wh/kg (Keheng Battery, 2024)
Material Abundance	Uses abundant materials (iron, phosphate) (IEA, 2024)	Uses relatively rare materials (nickel, cobalt) (IEA, 2024)
Capital Costs	£54-£77 per kWh (IEA, 2024)	£77-£100 per kWh (IEA, 2024)
Environmental Impact	Easy to recycle (IEA, 2024)	Hard to recycle (IEA, 2024)

Table E.16: Comparison of Lithium-Ion BESS Materials

Appendix F: Loan Repayments

F.1 CCGT Loan Repayments

Year	Price per MWh (GBP)	Annual Revenue (GBP)	Annual Fuel Cost (GBP)	Annual OpEx (GBP)	Loan Outstanding (GBP)	Loan Repayment (GBP)
CCGT Unabated						
1	5.39E+01	3.83E+08	3.98E+08	-	1.82E+09	-
2	5.66E+01	4.02E+08	4.12E+08	5.63E+04	1.87E+09	-
3	5.94E+01	4.22E+08	4.26E+08	5.74E+04	1.93E+09	-
4	6.24E+01	4.43E+08	4.40E+08	5.85E+04	1.98E+09	2.88E+06
5	6.55E+01	4.65E+08	4.55E+08	5.97E+04	2.03E+09	1.01E+07
6	6.88E+01	4.88E+08	4.71E+08	6.09E+04	2.07E+09	1.79E+07
7	7.22E+01	5.13E+08	4.87E+08	6.21E+04	2.11E+09	2.63E+07
8	7.58E+01	5.39E+08	5.03E+08	6.34E+04	2.13E+09	3.54E+07
9	7.96E+01	5.65E+08	5.20E+08	6.46E+04	2.15E+09	4.52E+07
10	8.36E+01	5.94E+08	5.38E+08	6.59E+04	2.16E+09	5.58E+07
11	8.78E+01	6.23E+08	5.56E+08	6.72E+04	2.15E+09	6.72E+07
12	9.22E+01	6.55E+08	5.75E+08	6.86E+04	2.14E+09	7.94E+07
13	9.68E+01	6.87E+08	5.95E+08	7.00E+04	2.11E+09	9.26E+07
14	1.02E+02	7.22E+08	6.15E+08	7.14E+04	2.06E+09	1.07E+08
15	1.07E+02	7.58E+08	6.36E+08	7.28E+04	2.00E+09	1.22E+08
16	1.12E+02	7.96E+08	6.57E+08	7.42E+04	1.91E+09	1.38E+08
17	1.18E+02	8.35E+08	6.80E+08	7.57E+04	1.81E+09	1.56E+08
18	1.24E+02	8.77E+08	7.03E+08	7.72E+04	1.68E+09	1.74E+08
19	1.30E+02	9.21E+08	7.27E+08	7.88E+04	1.54E+09	1.94E+08
20	1.36E+02	9.67E+08	7.51E+08	8.04E+04	1.36E+09	2.16E+08
21	1.43E+02	1.02E+09	7.77E+08	8.20E+04	1.15E+09	2.38E+08
22	1.50E+02	1.07E+09	8.03E+08	8.36E+04	9.18E+08	2.63E+08
23	1.58E+02	1.12E+09	8.31E+08	8.53E+04	6.48E+08	2.89E+08
24	1.66E+02	1.18E+09	8.59E+08	8.70E+04	3.42E+08	3.17E+08
25	1.74E+02	1.23E+09	8.88E+08	8.87E+04	0.00E+00	3.46E+08
CCGT with CCS						
1	5.39E+01	3.40E+08	3.98E+08	-	8.71E+08	-
2	5.66E+01	3.57E+08	4.12E+08	5.63E+04	8.97E+08	-
3	5.94E+01	3.75E+08	4.26E+08	5.74E+04	9.24E+08	-
4	6.24E+01	3.94E+08	4.40E+08	5.85E+04	9.52E+08	-
5	6.55E+01	4.13E+08	4.55E+08	5.97E+04	9.81E+08	-
6	6.88E+01	4.34E+08	4.71E+08	6.09E+04	1.01E+09	-
7	7.22E+01	4.56E+08	4.87E+08	6.21E+04	1.04E+09	-
8	7.58E+01	4.78E+08	5.03E+08	6.34E+04	1.07E+09	-
9	7.96E+01	5.02E+08	5.20E+08	6.46E+04	1.10E+09	-
10	8.36E+01	5.27E+08	5.38E+08	6.59E+04	1.14E+09	-
11	8.78E+01	5.54E+08	5.56E+08	6.72E+04	1.17E+09	-
12	9.22E+01	5.82E+08	5.75E+08	6.86E+04	1.20E+09	6.36E+06
13	9.68E+01	6.11E+08	5.95E+08	7.00E+04	1.22E+09	1.59E+07
14	1.02E+02	6.41E+08	6.15E+08	7.14E+04	1.23E+09	2.62E+07
15	1.07E+02	6.73E+08	6.36E+08	7.28E+04	1.23E+09	3.73E+07
16	1.12E+02	7.07E+08	6.57E+08	7.42E+04	1.21E+09	4.94E+07
17	1.18E+02	7.42E+08	6.80E+08	7.57E+04	1.19E+09	6.24E+07
18	1.24E+02	7.79E+08	7.03E+08	7.72E+04	1.14E+09	7.64E+07
19	1.30E+02	8.18E+08	7.27E+08	7.88E+04	1.08E+09	9.14E+07
20	1.36E+02	8.59E+08	7.51E+08	8.04E+04	1.00E+09	1.08E+08
21	1.43E+02	9.02E+08	7.77E+08	8.20E+04	9.05E+08	1.25E+08
22	1.50E+02	9.47E+08	8.03E+08	8.36E+04	7.84E+08	1.44E+08
23	1.58E+02	9.95E+08	8.31E+08	8.53E+04	6.39E+08	1.64E+08
24	1.66E+02	1.04E+09	8.59E+08	8.70E+04	4.67E+08	1.85E+08
25	1.74E+02	1.10E+09	8.88E+08	8.87E+04	2.67E+08	2.08E+08

Table F.1: CCGT repayments across 25 year lifetime for 3% interest loan

F.2 Renewable and ESS Loan Repayment

Wind Farm with BESS					
Year	Price per MWh (GBP)	Annual Revenue (GBP)	Annual OpEx (GBP)	Loan Outstanding (GBP)	Loan Repayment (GBP)
1	5.39E+01	3.40E+08	3.34E+08	6.98E+09	6.00E+06
2	5.66E+01	3.50E+08	3.44E+08	7.18E+09	6.18E+06
3	5.94E+01	3.61E+08	3.54E+08	7.39E+09	6.37E+06
4	6.24E+01	3.72E+08	3.65E+08	7.61E+09	6.56E+06
5	6.55E+01	3.83E+08	3.76E+08	7.83E+09	6.75E+06
6	6.88E+01	3.94E+08	3.87E+08	8.05E+09	6.96E+06
7	7.22E+01	4.06E+08	3.99E+08	8.29E+09	7.17E+06
8	7.58E+01	4.18E+08	4.11E+08	8.53E+09	7.38E+06
9	7.96E+01	4.31E+08	4.23E+08	8.78E+09	7.60E+06
10	8.36E+01	4.44E+08	4.36E+08	9.03E+09	7.83E+06
11	8.78E+01	4.57E+08	4.49E+08	9.30E+09	8.07E+06
12	9.22E+01	4.71E+08	4.62E+08	9.57E+09	8.31E+06
13	9.68E+01	4.85E+08	4.76E+08	9.84E+09	8.56E+06
14	1.02E+02	4.99E+08	4.90E+08	10130891191	8.81E+06
15	1.07E+02	5.14E+08	5.05E+08	10425468253	9.08E+06
16	1.12E+02	5.30E+08	5.20E+08	10728602136	9.35E+06
17	1.18E+02	5.46E+08	5.36E+08	11040541131	9.63E+06
18	1.24E+02	5.62E+08	5.52E+08	11361540724	9.92E+06
19	1.30E+02	5.79E+08	5.69E+08	11691863805	1.02E+07
20	1.36E+02	5.96E+08	5.86E+08	12031780884	1.05E+07
21	1.43E+02	6.14E+08	6.03E+08	12381570311	1.08E+07
22	1.50E+02	6.33E+08	6.21E+08	12741518501	1.12E+07
23	1.58E+02	6.51E+08	6.40E+08	13111920168	1.15E+07
24	1.66E+02	6.71E+08	6.59E+08	13493078569	1.18E+07
25	1.74E+02	6.91E+08	6.79E+08	13885305746	1.22E+07

Table F.2: Renewable repayments across 25 year lifetime for 3% interest loan