Programme Area: Energy Storage and Distribution

Project: Transportable Storage

Title: Techno-economic Evaluation of Transportable Energy Storage Final Report

Abstract:

With increasing utilisation of renewable energy sources there are many cases where the ability to site generation within easy reach of demand becomes more limited. In these situations, how the energy is moved from where it is generated to where it is needed becomes a more critical aspect of the overall energy system. More remote locations are more costly to connect to transmission lines, be they electricity networks or pipelines. At the same time the intermittency of renewable energy sources places a greater emphasis on the use of energy storage to balance the different variations in supply and demand over time. Transporting stored energy is one possible way to address both of these concerns simultaneously.

Context:

With increasing utilisation of renewable energy sources, there are many cases where the ability to site generation of electricity within easy reach of demand becomes more limited (e.g. offshore wind farms). More remote locations are more costly to connect to electricity networks or pipelines. Additionally, intermittency of renewable energy sources places a greater emphasis on the use of energy storage to balance the different variations in supply and demand over time. Transporting stored energy is one possible way to address these concerns simultaneously. The aim of the project was to understand and quantify transporting energy for a number of different scenarios. Cases were developed for offshore wind farms located off the UK and concentrated solar in the Sahara. A range of options were then analysed for transporting and transmitting energy from source to demand with the different approached quantified and compared.

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Techno-Economic Evaluation of Transportable Energy Storage: Final Report

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Techno-Economic Evaluation of Transportable Energy Storage: Final Report

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Glossary

AC	Alternating Current
Al	Aluminium
BPLA	Bipolar Lead Acid
CSP	Concentrated Solar Power
CH_2	Compressed Hydrogen (gas)
CH_n	Hydrocarbon Chain
CHP	Combined Heat and Power
CO_2e	Carbon Dioxide Equivalent
DC	Direct Current
DUoS	Distribution Use of System
ETI	Energy Technologies Institute
GSP	Grid Supply Point
H_2	Hydrogen
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
LH_2	Liquid Hydrogen
LNG	Liquid Natural Gas
MCH	Methylcyclohexane
MTH	Methylcyclohexane-Toluene-Hydrogen
NH_3	Ammonia
O_2	Oxygen
OHL	Overhead Line
PCM	Phase Change Material
SF_6	Sulfur Hexaflouride
TNUoS	Transmission System Use of System
TRL	Technology Readiness Level
Zn	Zinc

Units and Conversion Factors

	From	**To kWh**
Energy	Wh	0.001 kWh
	kWh	1 kWh
	MWh	1,000 kWh
	GWh	1,000,000 kWh
	TWh	1,000,000,000 kWh
	kJ	3.6 kWh
	MJ	3,600 kWh
	From	**To kg**
Mass	1 metric tonne	1000 kg
	1 short ton	907 kg
	From	**To m^3**
Volume	1 litre	.001 m^3
Distance	**From**	**To km**
	1 mile	1.6 km

Exchange Rates

Unless otherwise stated the following exchange rate is assumed.

GB£1 = US$1.5

Summary

Background

To drive the UK's transition to a low carbon economy, HM Government has put in place a legally binding target to cut emissions of greenhouse gases by 80% (compared to 1990 levels) by 2050. Achieving this target will be extremely challenging and will require changes to the way energy is both used and supplied. This includes the move to a greater reliance on energy from renewable sources. For example, the plan to 2020 is for 40% of electricity to be supplied from low carbon sources. This reliance on renewable energy resources places a number of onerous demands on the energy infrastructure, not least of which is determining the optimum method for transferring the energy from the generation sites to where it is required. This is especially problematical in the case of renewable generation resources that are typically located in remote regions.

Options for transferring energy from one location to another can be classified into one of the following two options:

- The direct and immediate transfer of energy to the point where it will be used via electricity networks or pipelines, i.e. transmission; or
- The generation and storage of energy in a mobile device that can be transported further down the supply chain where it can either be used continuously or intermittently as required, i.e. a transportable energy solution.

Recognising the need to identify whether transportable energy storage has the potential to offer advantages over transmission solutions, the Energy Technologies Institute (ETI) commissioned a project to evaluate the techno-economic aspects of candidate transportable storage technologies.

Approach

This project, therefore assesses whether transportable energy storage technologies and systems have the potential to economically access the resources from three example remote generation sites, namely: wind resources in the Outer Hebrides, wind resource in the Orkneys and Concentrated Solar Power resource (CSP) from the Sahara region.

The demand for energy in 2050 at a range of demand sites has been defined for four low carbon energy scenarios. These scenarios show that by 2050, consumption of electricity could increase to around 1.5 times to 2.5 times that of current levels. Analysis also shows that there is significant potential for flattening of the overall pattern of demand, both within an individual day and across seasons, although the extent of this flattening depends on the charging profile of electric vehicles. Under all the scenarios, the summer peak demand is only modestly less than that in the winter.

A wide range of potential storage media were considered in terms of their suitability for transporting energy from the remote generation sites. Preliminary assessment of the technical suitability led to the selection of the following candidate storage media:

- hydrogen;
- hydrocarbons produced via the Fischer-Tropsch process;
- ammonia;
- zinc air batteries; and
- aluminium.

Results

Costs are considered in terms of the lifetime costs (i.e. the amount required to return the upfront investment over the expected lifetime of the asset) per unit of energy delivered (referred to as a levelised cost). On this basis, the results demonstrate that electricity transmission represents the least cost solution if electrical energy is required at the demand site. This is particularly true in the case of the two Scottish generation sites. For example, the cost associated with transferring electricity via transmission from the Outer Hebrides to the UK mainland is just over £70/MWh compared to between £232/MWh and £281/MWh for the chemical energy carriers, or over £500/MWh for the battery ship concept. For the CSP sites in the Sahara, the costs of transferring energy using the chemical energy carriers is similar to those for the Scottish site (i.e. between £228/MWh and £270/MWh), but the electricity baseline is £139/MWh.

In the case of the chemical energy carriers, the results suggest that there is a strong case for delivering the energy as a fuel for direct use. For example, hydrogen can be delivered to the UK from the Sahara at a cost of £124/MWh by ship or £120/MWh by pipeline, which is slightly less than that for direct electricity transmission (i.e. £139/MWh). The case is even stronger for the Fisher Tropsch hydrocarbons, which can be delivered to the UK at a cost of £93/MWh of energy delivered, a saving of around 33% compared to the electricity transmission baseline.

Thus, there is evidence for focusing on delivering energy using hydrogen or a hydrocarbon, particularly for end uses such as transport, rather than converting the media back into electricity.

The economic case is broadly similar for the three chemical energy storage media considered. Overall, the analysis shows ammonia to be slightly more costly than the other options. This is because increases in capital costs and losses associated with the manufacture of ammonia and hydrocarbon, are offset by their improved transportability (i.e. energy density) when compared to hydrogen.

A number of options for matching electricity generation to demand were considered. The results showed that, in general, electricity transmission with battery storage is the least cost option for providing peak daytime energy from the three generation sites considered. However, in the case of the CSP sites in the Sahara, the results show that if the energy storage is provided at the demand site, then the costs are broadly comparable in the case of Hydrogen and Fischer Tropsch. This would suggest that chemical energy storage media may have the potential to play an important role in meeting peak electricity requirements. They also offer the only viable solution to providing seasonal energy storage.

Recommendations

The results of this study indicate that, for the three generation sites considered, transmission represents the least cost option where the electricity can be used directly. It is, therefore recommended that the ETI focuses on the development of DC Transmission technology; improving efficiencies and lifetime of AC to DC converters and reducing costs.

The chemical energy carriers do, however, compare favourably with electricity transmission where they can be used directly for example for transport fuels or heating fuels. They also have the potential to provide a viable alternative to transmission and battery storage for matching fluctuations in demand. Therefore, it is recommended that the ETI also considers developing hydrogen and hydrocarbon fuels as alternatives to electricity for transport end uses, and for providing peak load and seasonable storage.

It is recommended that the ETI consider investing in a demonstration project concerning renewable base hydrogen production, storage and re-use (both for use as a transport fuel and potentially for reconversion via a fuel cell to grid electricity). Such a demonstration would seek, uniquely, to make use of the 'waste' oxygen from such a process, and to examine in detail the revenue potential (as opposed to the cost basis of this technology as per the work carried out in the study) of such a scheme. The timeliness of such a demonstration is significantly enhanced at present via the recent announcement of a new demonstrator programme to speed-up the adoption of hydrogen and fuel cell technologies.

The ETI may also wish to also consider a demonstration of a renewable electricity driven Fischer Tropsch system of around 1MW capacity utilising CO_2 from a local cement works in a windswept location, for example Dunbar in Lothian.

The analysis shows that the transportable energy options become more favourable over the longer distances associated with the Sahara, due to the apparent insensitivity of shipping costs over the distances considered in this study. Therefore, it is recommended that the ETI should assess the potential opportunities for developing transportable energy solutions for other remote generation sites with valuable renewable energy resources.

It is recommended that the ETI maintain a watching brief on renewable technologies, including the costs and performance of electrolysers using renewable energy resources, and the storage and transport costs of chemical energy carriers.

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1 Introduction

To drive the UK's transition to a low carbon economy, HM Government has put in place a legally binding target to cut emissions of greenhouse gases by 80% (compared to 1990 levels) by 2050. Achieving this target will be extremely challenging, and will require changes to the way energy is both used and supplied. This includes the move to a greater reliance on energy from renewable sources. For example, the plan to 2020 is for 40% of electricity to be supplied from low carbon sources. This reliance on renewable energy resources places a number of onerous demands on the energy infrastructure, not least of which is determining the optimum method for transferring the energy from the generation sites to where it is required. This is especially problematic in the case of renewable generation resources that are typically located in remote regions.

Options for transferring energy from one location to another can be classified into one of the following two options:

- The direct and immediate transfer of energy to the point where it will be used via electricity networks or pipelines, i.e. transmission; or

- The energy is generated and stored in a mobile device that can be transported further down the supply chain where it can either be used continuously or intermittently as required, i.e. a transportable energy solution.

Recognising the need to identify whether transportable energy storage has the potential to offer advantages over transmission solutions, the ETI commissioned this project to evaluate the techno-economic aspects of candidate transportable storage technologies.

The overall objective of the project is to assess which transportable energy storage technologies and energy systems could be used to economically access remote renewable resources. The scope is to identify solutions that have the potential to enhance the UK's energy supply over the period to 2050.

A wide range of potential storage media were identified and assessed for their suitability for transporting energy between a number of energy generation sites and demand sites. Based on this initial screening process, a short list of candidate solutions was drawn up. For each of these candidate solutions, a high level assessment has been conducted to compare the feasibility of each option to conventional transmission solutions.

This project has been undertaken by a consortium comprising EA Technology (who is the Prime Contractor), assisted and supported by the University of St. Andrews, the University of Strathclyde and National Grid.

1.1 Project Overview

The project comprises three Stages, as described below:

- Stage 1: The first Stage focuses on determining the key characteristics for selected generation and demand sites, and the identification of potential transportable storage media. The results are summarised in Interim Report 1[1];

- Stage 2: The second Stage of the project describes the context within which transportable energy solutions must operate, including the overall UK energy balance and generation mix to 2050 and the baseline costs for conventional transmission. This Stage also incorporated a preliminary screening of the potential transportable storage media to assess their suitability for transferring energy between the generation and demand sites. The results are summarised in Interim Report 2[2]; and

- Stage 3: The third and final Stage of the project assesses the feasibility of the selected transportable storage solutions and considers their scope for UK energy supply. The present report presents the output for Stage 3.

1.2 Report Structure

This report builds upon the findings of Interim Reports 1 and 2[1,2] and represents the final output for the project. The report is structured as follows:

- Section 2 provides a high level summary of the key findings from Interim Reports 1 and 2. It includes descriptions of the generation and demand sites, their key characteristics and the overall energy landscape within which the transportable solutions must operate. It also describes the key parameters for the transportable storage media identified as potential candidates for transferring energy between the demand and generation sites;

- Section 3 describes the approach used to assess the feasibility of the transportable energy solutions;

- Sections 4 to 10 present the results of the feasibility assessment for transmission and for the candidate transportable energy solutions. The results are summarised in Section 11; and

- The conclusions and recommendations are presented in Sections 13 and 14 respectively.

[1] Techno-Economic Evaluation of Transportable Energy Storage: Interim Report 1, Issue 2, May 2011, EA Technology Report No. 6502

[2] Techno-Economic Evaluation of Transportable Energy Storage: Interim Report 2, June 2011, EA Technology Report No. 6505

2 Background

This Section provides a high level summary of the key findings from Interim Reports 1 and 2.

2.1 Generation Sites

Three generation sites are under consideration as part of this project. These are described in detail in Interim Report 1, and the main characteristics of each site are summarised within this Section. The sites are:

- Concentrated Solar Power (CSP) generated in the Sahara to be imported to the UK;
- Wind energy generated in the Outer Hebrides to be imported to the UK; and
- Wind energy generated in the Orkney Islands to be exported to Norway.

2.1.1 Concentrated Solar Power in the Sahara

There is currently 1GW of installed capacity for CSP sites worldwide, with an additional 15GW under construction. The DESERTEC concept envisages that 470GW of CSP capacity could be operational by 2050, from 36 separate sites in the Middle East and Northern Africa, with an average site rating of 13GW. This generation would be connected to demand sites via HVDC transmission lines under the DESERTEC concept.

The location of the 36 sites within the DESERTEC concept is shown in Figure 2.1 below.

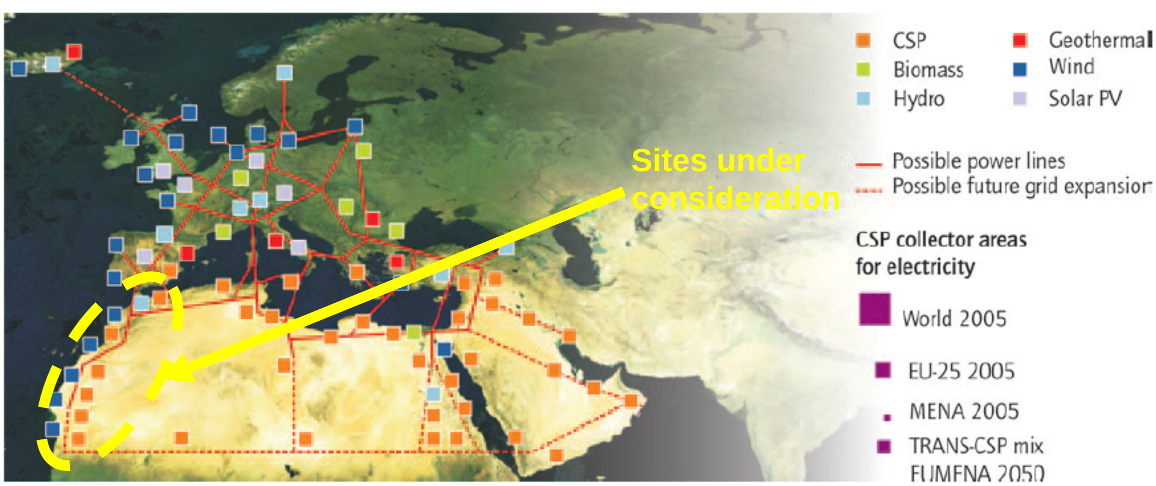

Figure 2.1 DESERTEC Renewable Energy Concept

For the purposes of this study, a group of sites on the North Western coast of Africa have been considered. By virtue of their location, these sites are deemed to be the most favourable for exporting their output, via transportable energy storage media, to the UK. As highlighted in Figure 2.1, there are six sites with an overall capacity of 78GW that meet this criteria.

The energy generated from these sites can be estimated from their capacity factors. A figure of 45% for the capacity factor is used, which represents a central estimate from a number of studies. The main factor affecting the variability of output from the CSP sites are sandstorms and cloud cover. Sandstorms are typically caused by winds blowing eastwards from the desert, which make up less than 5% of the normal wind regime, and not all of this 5% will cause sandstorms. Individual storms can range from a few hours to several days. Given the infrequent and relatively short duration of sandstorms it assumed that such an event which causes the output to fall to zero would be 'exceptional'. For the purposes of this study, it is assumed that there is no variability in the level of output from CSP sites on a day-to-day basis. Through the use of thermal storage it is possible to smooth the output of CSP sites through the day. It is therefore assumed that there is little to no variation in the output of the CSP sites across a typical day.

The characteristics of the CSP sites are summarised in Table 2.1 below.

Table 2.1 Characteristics of CSP Generation in the Sahara

Number of sites	1	6
Installed capacity	13	78
Capacity factor	45%	45%
Area (km^2)	1,300	7,800
Annual output (GWh/year)	51,200	307,476
Minimum daily output (GWh/day)	-(*)	-(*)
Maximum daily output (GWh/day)	-(*)	-(*)
Average daily output (GWh/day)	140 GWh/day	842GWh/day

(*) Although cloud cover and sandstorms could affect daily output, for the purposes of this study it is assumed that the daily output is approximately constant

2.1.2 Wind Generation from the Outer Hebrides and Orkney Isles

Many of the outlying islands from Northern Scotland (the Outer Hebrides, Orkney and Shetland Isles) have a high wind resource, but are either very poorly connected to the national transmission network, or not connected at all. This study considers wind generation from the Outer Hebrides and the Orkney Isles. The location of these generation sites is shown in Figure 2.2.

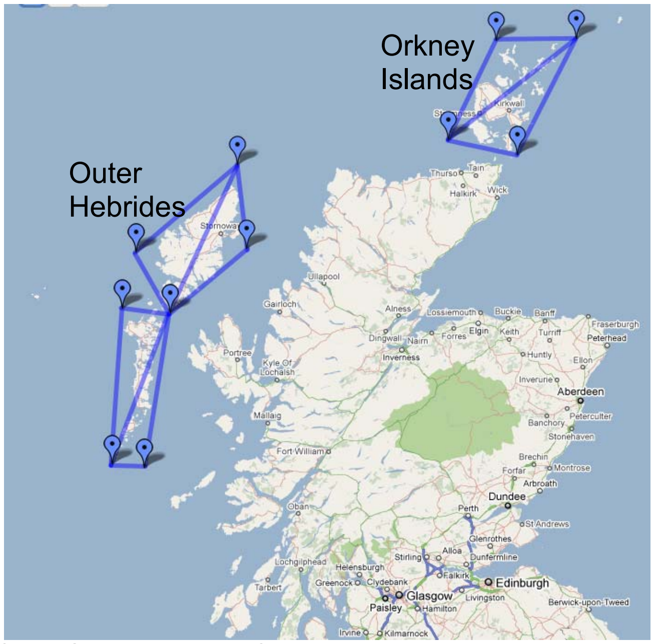

Figure 2.2 Location of Wind Generation Sites

It has been assumed that turbines with an average output of 3.5MW would be used, spaced a minimum of 750m apart. The maximum potential installed potential capacities for Orkney and the Outer Hebrides are in the range 0.75-1.5GW and 1.35-2.7GW respectively.

While the wind resource available in both the regions under analysis is considerable and the maximum potential generation significant, the output from wind farms will be subject to variability as the wind speed varies over time. There are a number of causes of this variability with timescales between a few hours and several days. The output of an individual turbine will vary between zero and its rated power due to these different causes of variability. Within a single wind farm, some more short term aspects of variability can be 'smoothed out' to an extent. Between a number of wind farms which are geographically remote from one another, the effects of more long term aspects of variability can be 'smoothed out' significantly.

In order to quantify the potential output variability, University of Strathclyde used wind speed data over 16 years at three locations in the target regions in conjunction with a standard wind farm power curve. Due to the geographical spread of wind farms in both locations, it has been assumed that the maximum hour on hour variation is 40% and the average 5%.

The average capacity factor for Scottish wind farms was 0.30 in 2009, whilst higher capacity factors are estimated for offshore wind farms in the most favourable conditions. For the purposes of this study the capacity factor has been estimated using actual wind speed at sites and the standard power curve. The capacity factors at Kirkwall (Orkney), Stornoway Airport and South Uist (the Outer Hebrides) are 0.37, 0.31 and 0.41 respectively.

The characteristics of the wind generation sites are summarised in Table 2.2 below.

Table 2.2 Characteristics of Wind Generation Sites

Site	Orkney	Hebrides (two sites)
Installed capacity (GW)	1.5	2.7
Capacity factor	40%	40%
Area (km^2)	250	450
Annual output (GWh/year)	5,256	9,461
Average Daily Output (GWh/day)	14,400	25,920
Greatest Hourly Fluctuation	40% of output	40% of output

2.2 Demand Sites (Current and 2050)

Five demand sites, and the level of demand for each are considered within this study, as follows:

- A re-entry point on the transmission system such as a grid supply point;
- Other possible re-entry points on the transmission system near end-users;
- A suitable distribution system primary substation;
- Distributed electricity energy systems- e.g. fuel for combined heat and power (CHP) systems; and
- Distributed energy uses other than electricity- e.g. for transport, distribution via refuelling.

The level of future demand at these sites can be estimated using a number of various ‘pathways’ also described within this Section.

2.2.1 Grid Supply Points

Grid Supply Points (GSPs) are the points of connection between the Great Britain (GB) electricity transmission system and distribution networks, large power stations and other non-embedded customers. There are around 475 GSPs providing power to the distribution network. The current peak demand at these GSPs varies between a few MVA to 700MVA (or more in some cases), with the majority having a winter peak demand in the region of 100 to 400MVA. Base load is typically around 60% of the system peak demand over a day. The overall pattern of electricity consumption within GB provides a useful proxy to the way demand is likely to fluctuate at individual GSPs.

Except in very urban areas, most GSPs will not be constrained in terms of the space available for the conversion technology needed to produce electricity from the storage media and store the media until such a time as conversion is complete so that it can be returned to the generation site. However, other restrictions such as the production or storage of potentially hazardous materials will need to be taken into consideration. The characteristics of these demand sites are provided in Table 2.3 (page 12).

2.2.2 End-Users connected to the transmission system

Data from National Grid's Seven Year Statement indicates that there are very few load connections to the transmission network[3]. Of those GSPs that do not supply the distribution network, most provide power to large generators (power stations). There are around 30 GSPs that provide power directly to end-users; these include aluminium and steel works, together with some chemical installations. The power supplied to these industrial users varies from a few MW up to over 300MW. It is difficult to estimate the total energy requirement for individual sites based upon their peak demand, and no information is provided on the energy consumption for these sites

The total annual energy consumption of those users connected to GSPs is estimated to be 10TWh/year, representing around 3% of total UK electricity demand. The average annual demand of a single site is 285 GWh/year, with individual site consumption varying between 26 GWh/year and 1,492 GWh/year. Further details of the underlying assumptions made are provided in Interim Report 1. Further characteristics of these demand sites are provided in Table 2.3 on page 12.

Transmission connected end users have the potential for energy to be used at generation sites to produce materials or chemicals at source that are transported to industrial sites, rather than transport electricity, for example electricity for the production of chemicals such as oxygen or ammonia.

2.2.3 Primary Substations

Primary substations typically step voltage down from 33kV to 11kV. Other voltage levels may also be used, but nevertheless the range of possible characteristics of the loads profiles will be the same. The 33kV network distributes power to towns and villages with the 11kV network typically taking power a few kilometres at most.

The level of load and the load profile can vary considerably, in terms of peak loading over the day and seasonally, depending on the capacity of the transformers at the substation and the type of loads that are supplied (e.g. predominately industrial loads will have a very different profile to those supplying predominately domestic customers). Across the country, it is estimated that there are in the region of 8,000 to 10,000 primary transformers with a total capacity of around 160,000 MVA. It is assumed that given the majority of the population lives in urban environments, 80% of the capacity will be feeding urban or suburban environments.

Daily demand at a typical primary substation is in the region of 300-500MVAh (300-500MWh where power factor=1). The extent to which the load varies from day to day will be highly dependent upon the mix of customers supplied by the substations. Further characteristics of these demand sites are provided in the previously referenced Table 2.3.

[3] National Grid Electricity Transmission System (NETS) Seven Year Statement 2010, Appendix E

2.2.4 Distributed Energy Users

Rather than convert the transported energy back into electricity to be injected back into the transmission or distribution system near to end users, it may be more appropriate to provide the storage media directly to end-users, either as a fuel stock or a material feed-stock for a manufacturing process. The list of potential media for transporting energy in this way is potentially vast. The following have been considered within this project, as they are seen as offering the greatest potential:

- Fuel for micro-CHP/heating units not connected directly to the mains gas network: supplying a liquid or gaseous fuel for microCHP units could be an alternative means to transport energy from renewable sources. Currently around 4 million homes in the UK are not connected to the gas network, approximately half of these use external gas or oil supplies or solid fuels. It is therefore estimated that around 2.7 million homes could be heated using a fuel such as hydrogen;

- Fuel for large CHP schemes or district heating schemes- the total energy input to CHP schemes in 2009 amounted to 117TWh, with the majority (over 70%) provided by natural gas. The provision of alternative liquid or gaseous fuels for CHP schemes represents a potential opportunity for transportable energy storage.

- Liquefied Industrial Gases (nitrogen, hydrogen and oxygen) for Industrial Users- liquefied gases are supplied by seven air separation units for industrial use. They are used for large volume industrial users requiring around 1,000m^3 of gas a month; and

- Production of ammonia- over 1 million tonnes of ammonia (NH_3) were produced in the UK in 2009, typically for the production of fertilisers, nylon and nitric acid. Hydrogen to make ammonia or ammonia itself could be produced at the generation site and transported to the demand site.

- Transport- demand for energy for transport represents roughly 30% of total energy consumed in the UK, with 99% of this coming from oil. The key sectors focussed on within this study are private passenger cars, passenger transport fleets and freight transport fleets. These vehicles could be fuelled by either electricity or hydrogen.

The demand characteristics for these options are summarised in detail in the composite Table 2.3.

2.2.5 Summary of Demand Sites (Current)

The composite Table 2.3 summarises the characteristics of the demand sites discussed in the preceding Sections. Further details of each of the demand sites are given in Interim Report 1.

Table 2.3 Characteristics of Demand Sites (Current)

Type	GSPs	Large Users	Primaries	MicroCHP	Large CHP/district heating	Passenger vehicles(♦)	Fleet vehicles
Number of sites	475	~30	8,000 to 10,000	2.7 million	100,000 (10 – 1000kWe) 26, 000 (1 to 5MWe)	9,300	1.2 million total
Peak demand(*)	20 - 700 MVA	Up to 300 MVA, average ~60MVA	24 to 40 MW	7.2kW	2.5MW – 19MW	1,200 – 3,200 litres/hour	Depends on size of fleet and timetable of use.
Annual demand(*)	105 - 3,680 GWh/year	26 - 1,490 GWh/year Average 285 GWh/year	110 GWh/year	18.7 MWh/year	Site dependent	-	Depends on size of fleet and timetable of use.
Average daily demand(*)	216 - 13,790 MWh/day	Up to 4,100 GWh/day Average 780 MWh/day	0.3 to 0.5 GWh/day	70 kWh/day (winter) 35 kWh/day (summer)	Site dependent	6,000 to 20,000 litres/day	Depends on size of fleet and timetable of use.
Form of energy	Electrical	Electrical	Electrical	Gaseous or liquid fuel	Gaseous or liquid fuel	electric / liquid / gas	Suitable for vehicles, electric/liquid/ gas
Available storage space / limitations	Space available, but limited due to proximity to high voltage	Space available, no restrictions likely	Location specific, could be limited in urban areas	Some, depending on the site	Some, depending on the site	Some, depending on the site	Some, depending on the site

(*) At an individual site
(♦) Filling Station Characteristics, figures based on estimates of fuel requirements at current network of filling stations

2.2.6 Characteristics of Demand (in 2050)

This study concerns the period to 2050, so it was therefore necessary to consider the changes in the demand sites over this period. Rather than develop tailored energy scenarios, this project has sought to build upon existing work wherever possible and has selected DECC Pathways to 2050 as the basis for the forward projections. Further details of the modelling approach are given in Interim Report 2. Four of the DECC 2050 pathways were studied, as these are of most relevance to this project. The key features of the scenarios are as illustrated here.

- **Alpha**: all sectors would help to make the transition to a low carbon economy. This would require increasing and sustained investment in low carbon electricity generation. Demand for electricity would double by 2050 as a result of electrification of much of industry, heating and transport. Total energy demand would remain relatively stable.

- **Beta:** CCS is not implemented further beyond 2018. Significant effort to increase generation from offshore wind is undertaken. Bioenergy imports are significantly increased, mostly as liquid biofuels. Overall energy demand falls slightly, and demand for electricity generation nearly doubles.

- **Epsilon:** 5% of UK land is used for biocrops. UK energy needs are met by significantly increasing solar thermal energy provision compared to Pathway Alpha. Extremely high levels of electrification of heating and transport are assumed. Total energy demand falls, whilst demand for electricity increases although to a lesser extent then Pathways Alpha or Beta.

- **Zeta:** it is assumed that no effort is made to adapt behaviours in response to the threat of climate change and energy security concerns. Very few improvements in energy efficiency are made. Electricity demand increases more significantly than in the other scenarios. All generation technologies are required to meet demand and imports of both electricity and bioenergy are high. Overall energy demand increases slightly.

These pathways influence the demand for energy at each of the demand sites outlined above. For demand at GSP and Primary substations, the level of demand will vary between pathways. The levels of demand under each pathway are shown in Table 2.4.

Table 2.4 Characteristics of Demand Sites (2050)

	Alpha Pathway		Beta Pathway		Epsilon Pathway		Zeta Pathway	
Type	**GSP**	**Primaries**	**GSP**	**Primaries**	**GSP**	**Primaries**	**GSP**	**Primaries**
Number of sites	475	12,305	475	11,844	509	13,385	635	16,705
Peak load at an individual site (MVA)	30 – 1,034	29 - 48	28 - 995	29 - 48	30 – 1,050	29 - 48	30 – 1,050	29 - 48
Annual demand at individual site (GWh/year)	1,712 – 6,011	179	163 – 5,721	170	162 – 5,668	169	234 – 8,183	244
Average daily demand at an individual site (MWh/day)	353 – 22,526	490 - 817	336 – 21,437	466 - 777	333 – 21,239	462 - 770	480 – 30,663	667 – 1,112
Seasonal variation in peak demand (%)	Summer peak 80%of winter peak	Summer peak 80%of winter peak	Summer peak 80%of winter peak	Summer peak 80%of winter peak	Summer peak 70%of winter peak	Summer peak 70%of winter peak	Summer peak 85%of winter peak	Summer peak 85%of winter peak
Daily variation in demand	Base load 90% of peak load	Base load 90% of peak load	Base load 90% of peak load	Base load 90% of peak load	Base load 85% of peak load	Base load 85% of peak load	Base load 90% of peak load	Base load 90% of peak load

The projected future demand site characteristics for passenger vehicle fuel supplies are the same in each scenario, and are shown below.

Table 2.5 Passenger Transport Demand Characteristics (2050)

Type	**Passenger vehicle fuel supply**
Number of sites	1,000
Peak load at an individual site (MVA)	200kW electric 108 kg of H_2 / hour
Annual demand at individual site	1,830 MWh electric 650,000 kg of H_2
Average daily demand at an individual site	58 –190 MVAh/day 5,000 kWh/day electric 1,780 kg/day of H_2
Seasonal variation in peak demand (%)	Little
Daily variation in demand	25% or 100%

2.3 Storage Media

There are a wide range of potential storage media that could provide a transportable energy solution for the UK. These media divide into the general categories listed below:

- Chemical storage media, such as hydrogen, ammonia and Fischer Tropsch (a liquid hydrocarbon synthesised from carbon monoxide and hydrogen);

- Biological storage, such as the production of food sources for human and animal consumption or production of biofuels from algae;

- Electrochemical storage in batteries and flow cells;

- Electrical energy storage which encompasses capacitors, supercapacitors and superconducting magnetic energy storage;

- Mechanical energy storage systems such as flywheels, compressed air energy storage and hydro-electric storage; and

- Thermal energy storage such as phase change materials and zeolites.

Descriptions of each of these storage media can be found in Interim Report 1. Supplementary information on Zinc-Air and aluminium-Air batteries, which have also been considered since the original Interim Report 1, is contained in Appendix 1.

Energy density is a key factor in the transportability of these media; the higher the gravimetric and volumetric energy densities then the more energy can be transported within a given mass and volume envelope. Figure 2.3 compares the gravimetric and volumetric energy densities of a range of chemical storage media, selected battery technologies and phase change materials (PCMs)[4].

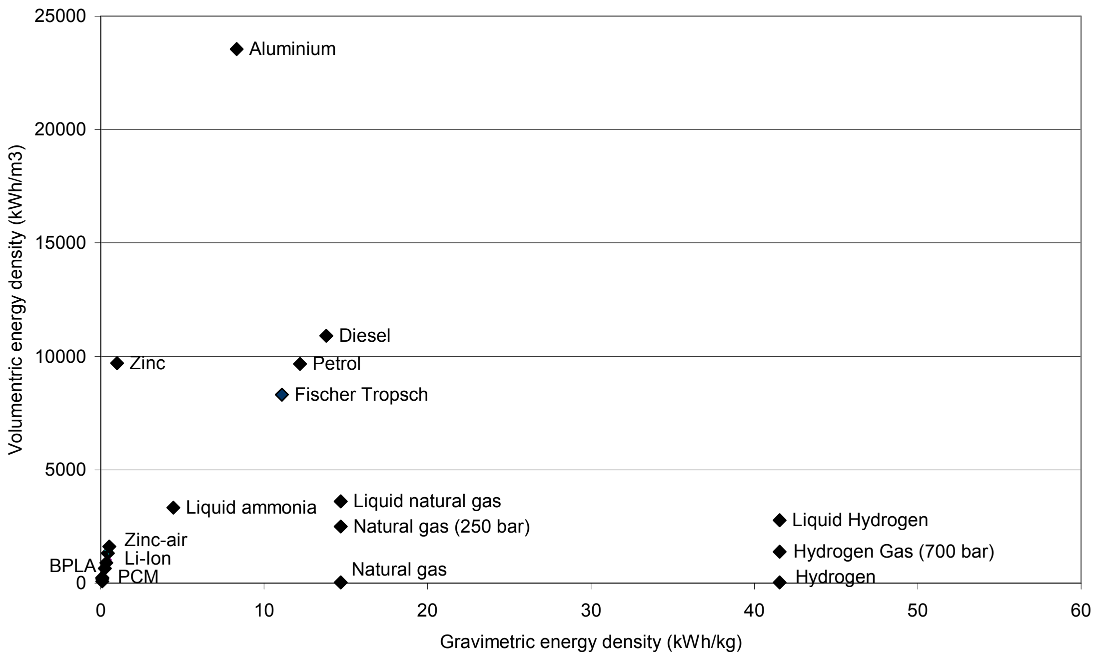

Figure 2.3 Volumetric Energy Density vs. Gravimetric energy density for selected storage media[5]

As indicated, the energy density of chemical storage media is typically several times that of batteries and / or PCMs, making chemical storage media the most likely candidates for transportable energy storage. However, energy density is not the only factor, energy losses, capital costs and safety / licensing considerations are also important factors influencing the overall feasibility of transportable energy solutions. Therefore, it was considered sensible to broaden the feasibility study to include other transportable storage media. Battery technologies represent a feasible solution (in terms of transportability). As indicated in Figure 2.3, zinc air and aluminium air batteries have the highest energy density of the various battery technologies, and therefore these are included as candidate storage media.

As described in Appendix 1, these are still emerging technologies, therefore established bipolar lead acid (BPLA) batteries are also briefly considered for reference purposes.

4 Although PCMs were identified as a potential candidate storage media in Interim Report 2, they have not been further considered in this final report due to their limited application to heating and cooling applications.

5 Collated using information from various sources

3 Assessing Feasibility of Transportable Storage – Overview of Approach

A wide range of potential storage media were assessed in terms of their suitability for transporting energy from remote generation sites. Sections 5 to 9 focus on comparing the economic feasibility of those determined to represent a technically viable solution. An overall estimate of the costs associated with transferring energy from the three generation sites (as described in Section 2.1) to the various demand sites (as described in Section 2.2) is determined for each potential storage medium.

The process diagram below provides a high level overview of the approach used to identify the overall costs of the various transportable options. Not all elements of the process will be applicable to all the case studies considered.

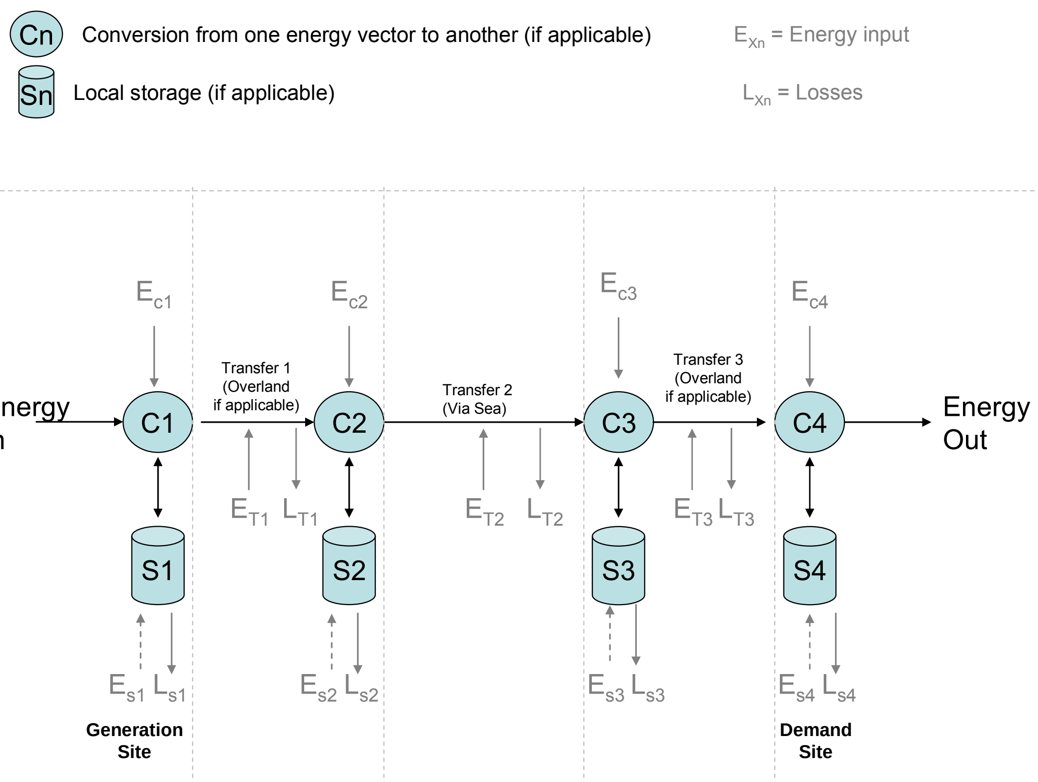

Figure 3.1 Process Diagram for Transportable Energy Storage Options

The journey is broken up into the following three elements:

- **Transfer 1**: The transfer of energy from the generation site to the coast;
- **Transfer 2:** The transfer of energy to mainland GB or to Norway; and
- **Transfer 3:** The transfer of energy across mainland GB or Norway to the demand sites.

In general, only transmission (via electricity networks or pipelines) is considered for the overland routes, with shipping and pipelines considered for the oversea routes. For distribution to dispersed sites, tanker delivery is also included.

The conversion of energy from one form to another could, therefore, take place at up to four points in the overall transport process, as follows:

- **C1:** i.e. at the generation site;
- **C2:** i.e. at the transfer point to the sea route;
- **C3:** i.e. at the transfer point at the coast of mainland GB; and
- **C4:** i.e. at the demand site.

Storage may or may not be required at each of these locations.

Thus, for each conversion, transfer and storage process, estimates are provided for the following (where applicable):
- Capital costs of any plant required
- The energy input required (E_{xi} in Figure 3.1);
- Energy losses (L_{xi} in Figure 3.1)

These are used to produce an estimate on a 'per unit cost' basis (often referred to as a levelised cost of electricity, lcoe) of delivering energy to each site.

The levelised cost is determined as follows.

$$\text{lcoe} = \frac{\sum P_{an}\ (\text{£/year})}{\text{Total energy delivered to demand site (MWh/year)}}$$

Where P_{an} (£/year) is the amount required to return the upfront investment (P_T) based on a discount rate and a payment schedule of each component (i.e. conversion, storage or transmission component as highlighted in Figure 3.1). This is referred to as an annualised cost.

Thus, P_{an} for each component is determined according to the following equation:

$$P_T = \frac{\sum_1^n P_{an}}{(1+\text{rate})^n}$$

Unless otherwise stated, a discount rate of 10% is assumed and payments are spread evenly over the expected lifetime (n) of the relevant component. This is considered to be reasonably indicative of the investment cost of an investor facing the financial, technological and price risks that might be associated with the type of investments under consideration in this study.

3.1 Generation costs

In order to compare the transport of energy from the different generation sites for the range of candidate storage media, it is important to also consider the cost of generation at each of the sites. As the income at the demand sites is not considered, including the generation cost makes it possible to compare the financial impact of energy losses/inputs during transportation and those associated with converting energy from one form to another.

In 2010, the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA) published projections for the costs of generating electricity based on data obtained from 21 countries[6]. The report includes levelised costs of electricity for a range of generation sources, and the data for off-shore wind is shown in Table 3.1 below.

Table 3.1 Projected Offshore Wind Generation Costs[7]

	RAE 2004	IEA / NEA 2005	UK DTI 2008	EC 2008	House of Lords 2008	EPRI 2008
\$/MWh	140	71 to 134	101	110 to 181	162	91
£/MWh	91	46 to 87	66	72 to 118	105	59

As shown above, the costs range significantly from £46/MWh to £118/MWh. This study considers the period to 2050, over which time it might be expected that costs will decline as the installed capacity of off-shore wind increases. Therefore, wind generation costs of £50/MWh are assumed for this study. Although these may include transmission costs, it is assumed that these will be short, and therefore represent only a small proportion of the overall costs quoted here. Likewise the assumed capacity factors may be lower.

The IEA Technology Roadmap for Concentrating Solar Power[8] provides projections for the levelised costs of electricity for the period to 2050. Whilst current costs are reported to be between \$200/MWh and \$295/MWh, costs are projected to reduce to around \$50/MWh by 2050. This represents a significant level of cost reduction over the period to 2050, much more so than for wind generation. Therefore, for consistency, a more modest level of cost reduction from current levels to \$100/MWh, or £65/MWh is assumed.

Whilst very much estimates, these costs provide a useful means to compare the different options.

3.2 Plant and Battery Capital Costs

Table 3.2 summarises the capital costs of the plant used in the case studies presented in Sections 5 to 9. The costs of plant required to undertake the Haber Bosch process or the Fisher Tropsch process are based on existing plant, whereas those for hydrogen electrolysers, fuel cells and reformers represent target costs. This is because Haber Bosch and Fisher Tropsch are mature technologies, whereas electrolysers and fuel cells are not. Also, in the case of electrolysers and reformers, whilst the technology is mature, the present technology is not designed for using renewable power resources or for the scales envisaged here. It is therefore expected that there will be reductions in cost as designs improve and economies of scale are made.

[6] Projected Costs of Generating Electricity, 2010 Edition, International Energy Agency and OECD Nuclear Energy Agency
[7] See reference 6 for details of sources of range of levelised cost of electricity for off shore wind
[8] Technology Roadmap for Concentrating Solar Power, International Energy Agency, 2010

Table 3.2 Capital Costs of Plant and Battery Technologies

	£/kW	£/kWh	Source
Haber Bosch	50	n/a	Based on costs of the Jose Anzoategui ammonia and Urea Plant commissioned in 1998. Capital cost was US$1.1 billion, producing 4.6 million tonnes per year of ammonia and Urea. http://www.chemicals-technology.com/projects/jose_anzoategui/
Fisher Tropsch	80	n/a	Design/Economics of a Once-Through Natural Gas Fischer-Tropsch Plant With Power Co-Production, Gerald N. Choi, Sheldon J. Kramer, Samuel S. Tam (Bechtel Corporation), Joe M. Fox (Consultant), Norman L. Carr, Geoffrey R. Wilson (Syncrude Technology, Inc.)
Hydrogen Electrolyser	195	n/a	Based on National Renewable Energy Laboratory long term target cost of $300/kW. Near term costs for an Electrolyser are in the region of $700/kW[9].
Fuel Cell	490	n/a	Based on US Department of Energy target of $750/kW[10] Current costs are a factor of 10 higher[11].
PEM Fuel Cell	20	n/a	Based on US Department of Energy prediction that cost of a PEM fuel cell would need to drop to $30/kW by 2015. It is assumed that this target is achieved.
Reformer	1,800	n/a	Approximately equivalent to target price of hydrocarbon reformer at €2,700/kW[12]
Zinc Air Batteries	n/a	130	EPRI White Paper[13] provides estimates in the range $290 to $340/kWh for the cost of Zinc/Air batteries for Bulk Energy Storage. Private communication from Caterpillar suggests target production costs of less that $100/kWh for Grid Energy Storage. Analysis based on a target cost of $200/kWh.
BPLA Batteries	n/a	70	
Aluminium Processing Plant	1,800		Based on Bechtel's recent aluminium smelter plant built in Iceland with a capacity of 346,000 tonnes / year at a cost of $1 billion

The criteria used to determine the size of plant / battery required is summarised below.

- For chemical conversion processes that are undertaken at or near the generation site, i.e. electrolysis for hydrogen, Haber Bosch and Fisher Tropsch, these plant items are sized to meet the peak output of the generation site. Where processes are in series, i.e. electrolysis and Haber Bosch, the peak capacity is adjusted to take account of losses for upstream processes.
- For chemical conversion processes that are undertaken at or near the demand site, i.e. reforming of the synthetic hydrocarbon to hydrogen to power a fuel cell, these plant items are sized to meet the average capacity.
- For battery technologies, the required storage capacity is dependent upon the round trip journey time. Thus, for a journey time of D_{trip} (days), the total storage capacity in transit at any time (GWh) is determined as follows:

$$\text{Storage capacity in transit} = \frac{E_{Total}}{365/D_{trip}}$$

Where E_{Total} = Total energy to be transferred by ship (GWh / year)

[9] Wind Energy and Production of hydrogen and Electricity — Opportunities for Renewable hydrogen, Conference Paper, NREL/CP-560-39534, March 2006, Pre-print, March 2006
[10] http://www.hydrogen.energy.gov/pdfs/2_gao_slides.pdf
[11] http://www.fossil.energy.gov/programs/powersystems/fuelcells/
[12] http://ec.europa.eu/research/energy/pdf/efchp_fuelcell15.pdf
[13] Electricity Energy Storage Technology Options, A White Paper Primer on Applications, Costs, and Benefits, 1020676, EPRI

3.3 Efficiency of Energy Conversion and Battery Charging/ Discharging

Table 3.3 summarises the efficiency associated with the various processes to convert energy from one form to another. In each case, the efficiency represents the ratio between the energy output and the energy input. However, the efficiency of technologies such as batteries and fuel cells may improve over time.

Table 3.3 Efficiencies of Plant and Battery Technologies

	Efficiency
Ammonia Production (Electrolysis + Haber Bosch)	50%
Synthetic Hydrocarbon Production (Electrolysis + Fischer Tropsch)	70%
Hydrogen Electrolyser	70%
Fuel Cell (i)	60%
Reformer	75%
Zn-Air Batteries (ii)	75%
BPLA Batteries (ii)	78%
Aluminium production (iii)	70%

(i) For electricity production only. If combined heat and power efficiency could be around 85%
(ii) Represents the round trip efficiency of a charge / discharge cycle
(iii) Equivalent to an energy input of 46 MJ/kg to produce aluminium with energy density of 32MJ/kG

3.4 Lifetimes

The assumed lifetime of the various items of plant and equipment are as shown below.

Table 3.4 Expected Lifetime of Plant and Transmission Assets

	Life (Years)
Ammonia Production (Electrolysis + Haber Bosch) (i)	10
Synthetic Hydrocarbon Production (Electrolysis + Fischer Tropsch) (i)	10
Hydrogen Electrolyser	10
Storage Facilities	20
High Temperature Fuel Cell	10
Fuel Cell	10
Reformer	20
Zn-Air Batteries (*)	10
BPLA Batteries (*)	5
Aluminium production(**)	40
Electricity Transmission / Distribution Assets	60
Pipeline Assets	40

(i) based on the lifetime of the electrolyser, the remaining balance of plant would in practice have a longer lifetime.

These lifetimes represent the period over which the plant could reasonably be expected to operate, rather than the period over which the value of the investment is depreciated on a company's balance sheet. For example, distribution network assets are typically depreciated over a period of 20 years, although it is not uncommon for assets such as cables and grid transformers to remain in service for up to 60 years. Assets such as electrolysers used with wind power may last longer in the future.

3.5 Pipelines

Considerable uncertainty exists over the level of costs associated with pipeline infrastructures. Factors influencing the costs include the terrain over which pipeline is to be constructed, materials and labour costs. These uncertainties are not restricted to pipelines for new media such as hydrogen. For example, a review of the costs of a new gas transmission pipeline in Dawson Valley, Australia in 2007 showed costs estimates ranging from AUS$15,000 per inch diameter per km to AUS$40,000/in/km.

Data provided in Interim Report 2 showed pipeline costs (for natural gas) ranging from £1.91 million per km (for a diameter of 610mm) to £2.31 million per km (for a diameter of 1,220 mm).

Of particular relevance to this project, a study was conducted in 2009 to assess the feasibility of a Trans-Saharan gas pipeline running North-South between Nigeria and Algeria, a distance of some 4,100km[14]. The cost was estimated to be $10 billion for a pipeline of diameter between 1,220 mm and 1,420 mm. Thus, the indicative pipeline cost for this scenario is £3.2 million per km (for a diameter in the range 1,220 mm to 1,420 mm), which is around 40% higher than figures for the UK. The data provided in Interim Report 2 does not include any compressor assets, which are thought to be included in the costs of the Trans-Saharan pipeline project. Therefore, pipeline costs are based on those in the Trans-Saharan project, but scaled according to the energy densities of the different storage media as described below.

Gillette and Kolpa[15] propose that although hydrogen gas has a third the volumetric energy density of natural gas at the same pressure, (see Figure 2.3), it travels faster as it is much lighter and therefore a similar sized diameter pipe could be used for the same volume. Nevertheless the cost of a hydrogen pipeline would be greater to prevent such a small molecule escaping. To take this into account an uplift in costs of 20% is included in the estimates of cost below.

Hydrocarbons produced by the Fischer Tropsch process will have a volumetric energy density approximately 3 times that of natural gas at 250bar. Ammonia has about twice the volumetric density of natural gas at 250bar. Therefore, the cross-sectional area of a pipeline carrying the output of the Fisher Tropsch process would need to be approximately one third that carrying Natural Gas, and for ammonia it would need to be half. However, as noted above, the speed of liquids may be slower than a gas and therefore the difference in diameter of the pipe may not be as great. These uncertainties are not included in the estimates of cost. It is also important to note that it is difficult to compare the cross-sectional area of pipe carrying a fluid to one carrying a gas without undertaking a detailed analysis which is outside the scope of this study. Using this approach and the costs based on the Trans-Saharan gas pipeline, the pipeline costs assumed for this study are as shown in Table 3.5. As the data presented in Interim Report 2 shows, pipeline costs do not vary proportionately with the diameter. Therefore, it is assumed that costs vary in the same proportion as those shown in Interim Report 2. Thus, the cost of a 915 mm pipeline is approximately 95% that of a 1,200 mm pipeline.

14 http://www.baobabafricaonline.com/African_nations_agree_on_10_billion.htm accessed May 2011

15 Overview of Interstate hydrogen Pipelines. J Gillette, R Kolpa. Argonne National Laboratory November 2007 http://corridoreis.anl.gov/documents/docs/technical/APT_61012_EVS_TM_08_2.pdf accessed 23rd August 2011.

Table 3.5 Pipeline Costs

Diameter (mm)	£million / km	Applicable to:
1,220	3.20	Natural Gas
1,220	3.84[(i)]	Hydrogen gas
915[(ii)]	3.03	Ammonia
610[(ii)]	2.91	Fisher Tropsch

(i) 20% uplift on Natural Gas pipeline costs
(ii) Nearest 'standard' pipeline diameter is used, rather than actual diameter required based on cross-sectional area compared to Natural Gas pipeline

The length of pipeline assumed for each case study is as shown in Table 3.6. The distances are estimates of typical lengths of routes required. Detailed consideration of the actual route is thought to be inappropriate for this study.

Table 3.6 Pipeline Lengths

	Pipeline length (km)		
Generation Site	**Outer Hebrides**	**Orkneys**	**Sahara**
Transmission Baseline			
Generation site to demand site	500	500	2000
Transportable Energy Storage			
Generation site to remote coast	30	30	80
Remote coast to demand site	100	100	100

Whilst there will be losses from a pipeline, the amount is uncertain and likely to be small compared to those incurred during the production of the storage media. Therefore, pipelines losses are assumed to be included within the losses incurred during manufacture.

3.6 Storage Costs

There is considerable uncertainty associated with the cost of storing various chemical energy storage media. Estimates on the storage costs range considerably, as indicated below.

- Based on the cost of peak shaving plant suitably adjusted for hydrogen (i.e. assuming an uplift of 20%), approximate storage costs for hydrogen are estimated to be £0.34/kWh[16].

- A paper by Leighty[17] estimates that the capitals costs are in the range of £90/MWh (or £0.09/kWh). This is based upon the assertion that it costs around $90 million to store 630,000 MWh of energy using gaseous hydrogen in natural salt caverns or using ammonia in large refrigerated above ground tanks.

16 http://www.aglr.com/about/LNG.aspx
17 Alternatives to Electricity for Transmission and Annual-Scale Firming Storage for Diverse, Stranded, Renewable Energy Resources: Hydrogen and Ammonia, William C. Leighty, The Leighty Foundations

- A paper by Iowa State University[18] suggests that it is 25 times less expensive to store ammonia at low temperatures than it is for hydrogen. In this paper, the total specific capital costs are estimated to be $36/GJ for ammonia (approximately £0.01/kWh) compared to $878/GJ for hydrogen (approximately £0.24/kWh).

- A recent paper looking at the storage of hydrogen for automotive systems estimated that on board storage of 5.6 kg of hydrogen would cost around $20/kWh at 700 bar (approx £13/kWh) or $13/kWh at 350 bar (approx £9/kWh). These costs are significantly higher than those quoted in the earlier papers, but it is worth noting that the costs relate to a small tank on a vehicle, whereas the others are bulk storage for stationary applications.

- Tanks for storing ammonia capable of storing 4,190 US gallons are commercially available for $69,000, which is equivalent to around £3/litre or around £0.08/kWh[19].

- Storage for hydrocarbons is considerably cheaper than the other storage media considered here, and there is considerable infrastructure already in place. Storage costs are around £0.50/litre, equivalent to 0.4p/kWh[20].

Costs for commercially available tanks for large scale storage have been obtained for storing hydrocarbons and ammonia (i.e. £0.004/kWh and £0.08/kWh respectively), and therefore these figures are used. However, this is not the case for hydrogen, and there is significant variation between the various estimates for the storage costs. The storage costs vary from £0.09/kWh for the Leighty study which suggests the costs are likely to be similar to that for ammonia (for storage in a natural salt cavern) up to £20/kWh for small scale storage for automotive application (and therefore not inapplicable to this current study). Therefore, the figure used in this study is that based on the large scale Natural Gas Storage for peak shaving, with a 20% uplift applied. Thus, the storage costs used in the analysis presented in Sections 5 to 7 are summarised in Table 3.7

Table 3.7 Upfront Investment Costs for Storage Facilities

	£/kWh
Hydrocarbon	0.004
Ammonia	0.080
Hydrogen	0.340

In the case of hydrogen and ammonia, there is an additional requirement for plant to liquefy/compress the media prior to storage. For this study, the costs are determined from those associated with liquefying/compressing natural gas (assuming an uplift of 20% for hydrogen) thereby giving a cost of around £220/kW. This cost is based on a fairly modestly sized plant (30,000 gallons / day), therefore economies of scale may lead to lower costs for much larger plant[21]. Ammonia is easier to liquefy, and therefore, the costs are assumed to be approximately half those for hydrogen, although in practice they could be even lower. However, as these costs represent a relatively small proportion of the overall costs, the impact will be minimal on the overall results for ammonia.

The liquefaction / compression process requires energy. For this analysis, this energy input is expressed in terms of an overall efficiency. Thus, an efficiency of 80% implies that the

[18] A feasibility study of implementing an ammonia Economy Iowa Energy Center Project Title: Implementing the ammonia Economy Grant Number: 07S-01 Iowa State University Jeffrey R. Bartels Michael B. Pate, PhD December 2008

[19] http://ammoniatanks.com/ accessed 24 August 2011

[20] http://www.commercialfuelsolutions.co.uk/systems/fuel_tanks/bunded/

[21] https://inlportal.inl.gov/portal/server.pt/community/natural_gas_technologies/437/liquefaction_plants

energy input to the liquefaction/compression process is equivalent to 20% of the total energy stored. In practice, the volume of energy extracted from the store will be equal to the energy input, but there will be an additional cost associated with the energy input required.

Table 3.8 Upfront Investment Costs and Energy Input for Liquefaction/Compression Plant

	£/kW	Efficiency (%)
Ammonia	110	90%
Hydrogen	220	80%

3.7 Shipping and Road Transport Costs

A number of different possible transport routes have been hypothesised from the three generation centres according to where the media is expected to be utilised and in what form. Four main areas for landfall have been considered namely:

1. Central Belt of Scotland – this represents the area of significant population density and economic activity closest to the generation sites in Scotland. Approximately 4 million people live in the region which is also home to a large number of Scotland's industrial and services industries. It would be feasible to inject chemical energy carriers (hydrogen, ammonia or hydrocarbons) or electricity into the demand networks but since there is already currently an oversupply of electricity in Scotland and limited transmission capacity to the rest of the UK it might be more logical to assume that chemical energy carriers may be favoured in the short term. However, in 2050 the electrical transmission issue will have been addressed. A number of deep water ports already exist for handling large quantities of liquid and gaseous fuels on both the East and West Coasts.
2. Northern England – This represents the nearest location in England to the generation sites in Scotland. This provides access to the electricity and gas networks in England and is closer to larger demand centres. Existing deep water facilities exist which could be adapted for the unloading and processing of chemical energy carriers.
3. South of England – This represents the closest location in England to the generation sites in North Africa and provides good access to the electricity and gas networks. It is close to larger demand centres and has existing deep water facilities which may be adapted for the unloading and processing of chemical energy carriers.
4. South East England – Provides the closest access to the largest demand centre (i.e. London). Deep water port facilities exist as do connections into the electricity and gas networks. It is also closest to the generation centres in North Africa.
5. Norway – The Orkneys is the only generation site suitably located for it to be valuable to ship chemical energy carriers to the Scandinavian market; Orkney is roughly equidistant from the Northern UK sites and Scandinavia. Deep water port facilities exist at numerous locations along the Norwegian coast and hydrogen-based transport is under development in Norway. However, the country is generally an exporter of electricity.

A single shipping port location has been chosen for each of the generation sites, namely Stornoway for the Outer Hebrides, Kirkwall for Orkney and Casablanca for North Africa. The possible routes are shown in Figure 3.2 to Figure 3.4.

Figure 3.2 Sea Routes from Stornoway

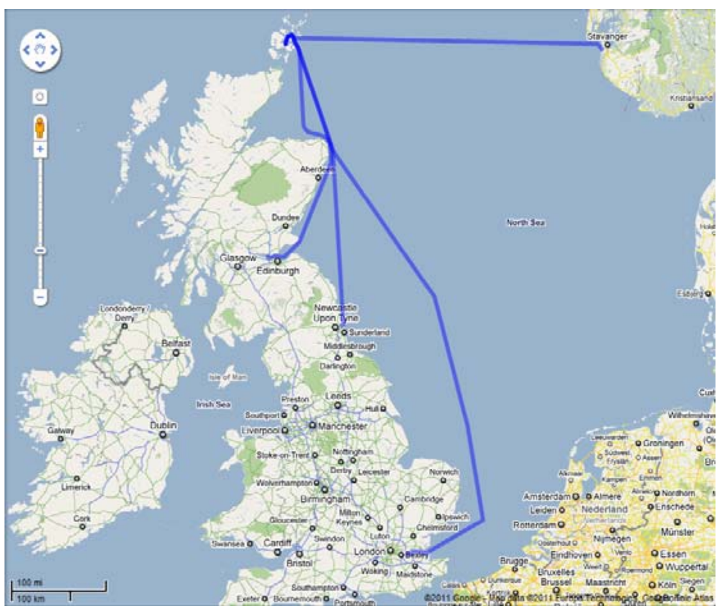

Figure 3.3 Sea Routes from Orkney

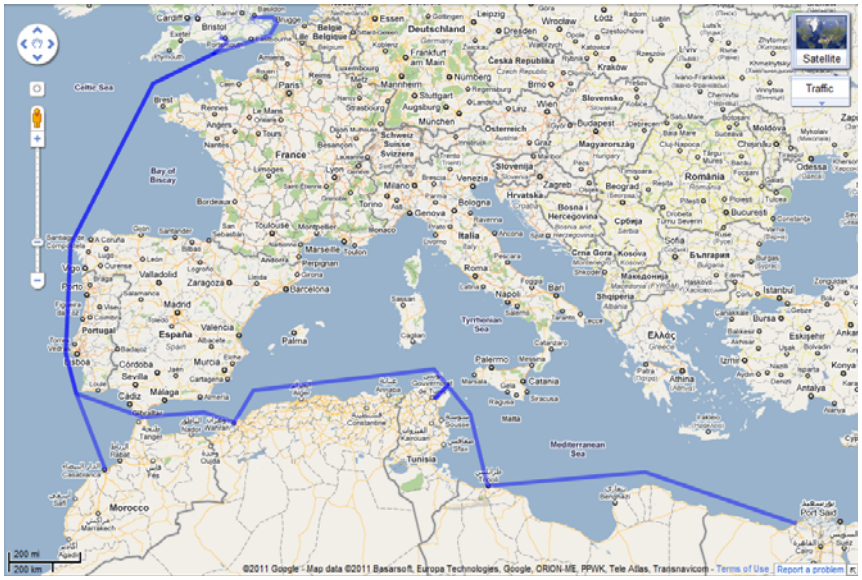

Figure 3.4 Sea Routes from North Africa

The distance for each of the routes is provided in Table 3.9.

Table 3.9 – Distances for Sea Routes

Route	Distance (km)	Round Trip Journey Time (days)
Outer Hebrides		
Stornoway - Greenock	515	5
Stornoway - Rosyth (Alternative route to Central Belt)	590	5
Stornoway - Liverpool	677	7
Stornoway - Tilbury (East Coast)	1,197	7
Stornoway - Tilbury (West Coast)	1,691	9
Orkney		
Kirkwall - Stavanger	501	5
Kirkwall - Rosyth	440	5
Kirkwall - Newcastle	486	5
Kirkwall - Tilbury	1,040	7
North Africa		
Casablanca - Southampton	2,205	11
Casablanca - Tilbury	2,498	13

These journey times are based on a vessel travelling at an anticipated average speed of 25km/h or roughly 14 knots; with travel times rounded up to the nearest day. Loading and unloading times are set to 1.5 days each. Therefore, based on the above data the round trip journey times from the Scottish generation sites is assumed to be 7 days, or 12 days for the Sahara.

It is difficult to provide indicative benchmarks on the associated costs of shipping large quantities of the storage media. The following table shows that costs vary significantly depending upon the media being shipped, the quantities and the route. Example shipping costs for a selection of media are shown in Table 3.10.

Table 3.10 Indicative Shipping and Transport Costs

Details	Quoted Data	Equivalent £ / tonne	Source
Coal from South Africa to Rotterdam	$31.17 / ton	22	PowerPoint presentation "Coal Purchasing scenarios", Ceskomoravsky Cement, HeidlebergyCement Group, UWA IFP and Pre-master Students (Date unknown)
Coal from Australia to Rotterdam	$34 / ton	24	
Shipping coal by barge from Hamburg	$81 - $88 / 25 tonnes / 1000km	~2	
Liquid hydrogen Delivery by Ship	$2 to $3 / kg	1,500 to 2,250	Costs of Storing and Transporting hydrogen, Wade. A. Amos, National Renewable Energy Laboratory, November 1998
Liquid hydrogen delivery by truck	$2.41 to $0.49 / kg	370 to £1,800	
Liquid Natural Gas Shipping – day rates	$65,000/day	44 (Hebrides/GB) to 195 (Africa/GB)	http://www.eia.gov/oiaf/analysispaper/global/lngindustry.html
Chemical Tanker Shipping Rates (Asia)	$25 to $38 / tonne	16 to 25	ICIS Pricing Sample Report 28 January 2011, Chemical Tanker Shipping Report (Asia Pacific), http://www.icispricing.com/il_shared/Samples/SubPage2.asp

There is significant variation in shipping costs shown in Table 3.10. The information for hydrogen is based on the costs of shipping using vessels designed specifically to transport hydrogen but never built. However, the other information is predominately based on commercial shipping rates, with a baseline standard shipping rate of around £25 / tonne and this has therefore been used as the basis for the estimates used in this study. The values obtained on the costs per tonne for various commercial routes suggest that the length of route has little impact on the overall costs (rather a cost per tonne is used), particularly so for the distances and geographical regions considered in this study.

Therefore, using the information in Table 3.10, a baseline standard shipping cost of £25/tonne is used. From this the following shipping costs are estimated:

- For hydrocarbons produced by the Fisher Tropsch process, zinc air batteries and aluminium, a cost of £25/tonne is assumed, i.e. equivalent to the baseline standard shipping cost.
- For ammonia, the costs are assumed to be slightly higher, at £30/tonne reflecting the greater hazards and difficulties associated with transporting this media compared to solids and the battery technologies.
- For hydrogen, the costs are assumed to be £40/tonne, reflecting the additional complexities associated with its transport.

Shipping is regarded to be one of the cheapest forms of transporting products in bulk. Therefore, for simplicity, road transport costs are assumed to be 20% higher than the corresponding shipping costs. These costs are summarised in Table 3.11.

Table 3.11 Shipping and Road Transport Costs

	Transport costs £/tonne		
Media	**Aluminium / Batteries/ Fischer Tropsch**	**Ammonia**	**Hydrogen**
Shipping costs	25	30	40
Road transport	30	36	48

In all cases, the storage media itself could provide the fuel source required by the ships themselves. However, the shipping costs shown in Table 3.11 already include an element of fuel costs, therefore, with the exception of the battery ship concept; this possibility is not considered in the case studies.

3.8 Carbon Life Cycle Analysis

An analysis of the carbon life cycle associated with the transfer of energy via the different storage media is presented in Appendix 2 and the results in Section 10. Comparing the carbon life cycle of different options is very difficult. A number of the issues are listed below:

- In any lifecycle analysis, the boundaries of the system can be very influential on the result. For the cases considered, the different storage and transport methods makes it very difficult to ensure that the boundaries in each case are the same.
- Much work has been done on life cycle analysis but the results are very specific to the size and technology in hand. How the results scale is difficult to determine.
- As technologies become more mainstream, the energy required for production typically reduces and material costs are saved however this is hard to predict.
- The carbon intensity of power for manufacturing varies across the world and will change in the next 40 years.

For these reasons, the analysis focuses on the key issues that increase or decrease the carbon lifecycle and how these affect the different transportable energy storage options. A number papers were used as a basis for this comparison. These provide at least some data on all the options, but has the disadvantage of combining results that use different analytical techniques. As previously referred to in the second interim report, the work by Gareth Harrison et al[22] studies the carbon emissions life cycle of the Transmission System in the UK. Work sponsored by Department of Energy in the United States studies the life cycle analysis of hydrogen from liquid natural gas (LNG) and Coal[23]. This draws on a number of other studies. A third study by the same authors analysed the 'Carbon Life Cycle of Renewable hydrogen Production via Wind/Electrolysis'[24]. In all cases, all greenhouse gases are equated to carbon dioxide emissions equivalent (CO_2e)

The carbon lifecycle of batteries is particularly hard to estimate given that the technologies are still very new, particularly for very large scale storage. Two papers discuss the carbon lifecycle of batteries designed for cars. The first examines traditional lead acid and zinc air although many of the figures for zinc air with regard to its manufacture are unavailable[25][1]. It is assumed that bipolar lead acid will have a similar footprint to traditional lead acid. The second examines the use of lithium ion batteries[26].

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[22] Life cycle assessment of the transmission network in Great Britain. G. Harrison, E. Maclean, S. Karamanlis, L. Ochoa. Energy Policy Volume 38 (2010).

[23] Life-Cycle Analysis of Green House Gas Emissions for hydrogen Fuel Production in the United States from LNG and Coal Pamela L Spath and Margaret K Mann DOE/NETL-2006/1277

[24] Life Cycle Assessment of Renewables hydrogen Production via Wind/Electrolysis February 2004 NREL/MP-560-35404

[25] Life Cycle Assessment for five electric vehicle batteries under different charging regimes. Michail Rantick, Chalmers University of Technology December 1999 ISSN 1401-1271

[26] Life Cycle Assessment LCA of Li-Ion batteries for electric vehicles, M. Gauch et al Federal Laboratories for Materials Testing and Research TSL Technology and Society Lab http://www.cars21.com/files/news/LCApresenation.pdf

4 Baseline Transmission Costs

This Section considers investment costs for the transmission infrastructure required to transfer the energy from each of the three generation sites to the demand sites. Using the data gathered in the earlier stages of the project, reasonable assumptions of the costs and carbon emissions from electricity transmission lines were chosen. These have been used to calculate the cost and carbon emissions of transporting the power from the remote generation sites to the demand sites. For electrical energy, the baseline costs and carbon emissions are considered in terms of the following two components:

- Transmission system costs (i.e. for voltages above 132kV); and
- Distribution network costs (i.e. for voltages at or below 132kV).

Carbon emissions are presented in Section 10.

For the transfer of energy using a chemical energy carrier, the alternative transmission technique via a pipeline is also considered. In these cases, a single pipeline is considered for the whole of the distance. The size of pipeline required depends on the fuel transported. The costs and lengths are given in Section 3.5.

By adopting this approach, the transmission costs will be fixed for any one generation site, whilst the distribution costs will vary according to the demand site. Section 4.1 and 4.2 consider the baseline costs for transferring electrical energy via transmission and distribution networks respectively. Section 4.3 considers the baseline costs for a single pipeline.

4.1 Transmission Networks

For the purposes of this study, transmission networks are categorised according to the type of current transferred, i.e. either direct current (DC) or alternating current (AC), and according to the where the network is placed, i.e. overhead lines, underground cables or sub-sea cables.

The reactance of HVAC cables is a major factor that affects their ability to transfer energy over large distances. Reactance causes a reactive power to flow along the length of the cable, which must be carried in addition to the real power. The longer the cable, the higher the reactance and hence the higher this reactive power reducing the capacity to carry real power. Consequently, AC cables are not a feasible option for transferring energy from the Sahara to the UK, or between the UK and Norway.

With significant improvements in DC cable technology anticipated in future years, it is considered unlikely that power from the Hebrides would be transferred to mainland GB via AC cable. However, this option has been considered for comparative purposes. Therefore, four transmission options have been considered, as follows:

- Transmission from the Hebrides to England via subsea DC cable;
- Transmission from the Hebrides to England via a short section of subsea AC cable and then overland via AC overhead line;
- Transmission via subsea DC cable from the Orkneys to Norway; and
- Transmission from the Sahara to England via DC cable, overland and subsea.

Table 4.1 summarises the assumptions made on the capital costs for transmission infrastructure assets. These costs include the costs of transformers, converters and switchgear and are typical values taken from examples and data available gathered in the second Stage of this project. Cable laying technology may improve significantly and reduce costs over time, however material costs may increase.

Table 4.1 Characteristics of Transmission Infrastructure Assets

Asset type	Capital Costs (£/MWkm)	Lifetime (Year)*	Losses (%/1000km)
HVAC cable	3,993	60	8[27]
HVAC OHL	312	60	8[27]
HVDC cable	1,300	60	3[28]
HVDC subsea cable	1,300	60	3[28]

(*) Excluding impacts of failure due to 3rd party damage

The costs shown in Table 4.1 are in today's prices. In addition to the effects of monetary inflation, shortages of materials, increased costs of energy and the need to protect against the impact of climate change are expected to result in increased costs in real terms in future years. These costs also do not properly account for the significant challenges associated with deep subsea transmission and the considerable issues involved in obtaining wayleaves for overland routes.

It is not possible to predict variations in the increases in costs from one technology to another. In addition, it is reasonable to suggest that any increases will affect all energy transport costs; therefore, it has been decided to use the capital costs shown above, without any adjustments. As shown in Table 4.1 the expected lifetime of these assets is assumed to be 60 years, unless subject to third party damage.

Also included in Table 4.1 are the losses associated with each type of asset, which shows the losses associated with DC cable are assumed to be 3% per 1000km compared to 8% per 1000 km for AC. In addition to the losses per 1000 km of cable shown in Table 4.1, losses also occur when voltages are stepped up or down or when AC power is converted to DC (or vice versa). Here is it assumed that each transformation between AC voltage levels typically account for around 0.25%[27] of losses, whilst converting AC to DC and back again or to a higher or lower DC voltage accounts for around 2%[28] of losses as shown in Table 4.2. Although the efficiency of converters may improve over time, higher temperatures (due to climate change effects) may reduce their efficiency. Therefore, no adjustment is assumed for advances in converter technology in terms of losses.

Table 4.2 Transformation Losses

Asset type	Losses
Transformers	0.25%
Converter (AC to DC and back again)	2.00%

[27] Trans-Mediterranean Interconnection for Concentrating Solar Power, Final Report, by German Aerospace Center (DLR), Institute of Technical Thermodynamics, Section Systems Analysis and Technology Assessment

[28] http://www.trec-uk.org.uk/elec_eng/grid.htm

On this basis, the transmission costs associated with each generation site are as indicated in Table 4.3 range between around £17/MWh for the transfer of electricity from the Outer Hebrides to £69/MWh for transmission from the Sahara (excluding the costs of generating the electricity itself). See Appendix 3 for a more detailed breakdown of how these costs were determined.

Table 4.3 Transmission Costs from Each Generation Site

Generation Site	Outer Hebrides		Orkneys	Sahara
	(AC)	(DC)		
Capacity (GW)	2.7		1.5	78
Annual Output (GWh/year)	9,461		5,526	307,476
Total Investment Costs (£ million)	1,439	2,808	975	192,660
Total units delivered (GWh/year)	8,823	9,045	5,072	283,800
Transmission Investment Cost (£/MWh)	14.9	28.3	17.5	61.9
Adjustment for operating costs (£/MWh)	1.7	3.1	1.9	6.9
Total Transmission Cost (£/MWh)	16.5	31.5	19.5	68.8
Total Costs (including generation costs) £/MWh	70.1	83.8	71.3	139.2

For the Outer Hebrides, both AC and DC transmission have been considered. In this case, transmission via AC represents the lowest cost, and therefore this is the baseline figure against which the transportable options will be compared.

4.2 Distribution Networks

The additional distribution network required to transfer energy from the remote sites will depend on the energy source that is displaced. If the output from the remote generation sites is displacing electricity from an alternative source, then there will be no requirement for additional distribution capacity (other than that required due to growth in consumption). If, however, the electrical power is used to displace non electrical fuel sources, e.g. fuels for transport or heating, then additional distribution circuits and costs will need to be considered. No allowances are made for the impact of demand side management, which could lead to better utilisation of assets in the future.

The costs of transferring electricity over a distribution network have been determined by consideration of the basic requirements for circuits and each voltage level. From a single GSP point, the cost of distributing electricity to the 11kV network is assumed to be £8.19/MWh. See Appendix 4 for a detailed description of how this cost has been determined.

Network losses across the distribution network as a whole are currently around 5%[29]. Although losses are likely to decrease in future due to improvements in network design, these could be largely offset by the effects of climate change. Therefore, losses are assumed to remain at 5%.

[29] Electricity Distribution System Losses, Non-Technical Overview, A paper prepared for Ofgem by Sohn Associated Limited, 31/03/2009

4.3 Pipelines

Using the assumptions for distance, size of pipe, efficiencies and costs given in Section 3, the cost of a pipeline for hydrogen, ammonia or a hydrocarbon produced by Fischer Tropsch process are given in Table 4.4, Table 4.5 and Table 4.6

Table 4.4 Cost of Transporting Hydrogen by Pipeline

	Outer Hebrides	Orkneys	Sahara
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	50
Generation Costs (£million/year)	473	263	15,374
Conversion to Hydrogen and Storage			
Energy Losses (GWh/year)	4,428	2,460	143,899
Upfront Investment (£million)	1,143	725	27,423
Levelised Investment (£million/year)	144	89	3,554
Pipeline to Demand Site			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	1,920	1,920	7,680
Levelised Investment (£million/year)	178	178	714
Total Annual Costs (£million/year)	795	531	19,642
Energy Delivered to Demand Site	5,033	2,796	163,577
Cost per Unit of Energy Delivered (£/MWh)	158	190	120

Table 4.5 Cost of transporting Ammonia by Pipeline

	Outer Hebrides	Orkneys	Sahara
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	50
Generation Costs (£million/year)	473	263	15,374
Conversion to Ammonia and Storage			
Energy Losses (GWh/year)	5,416	3,009	176,030
Upfront Investment (£million)	857	497	23,447
Levelised Investment (£million/year)	119	68	3,290
Pipeline to Demand Site			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	1,515	1,515	6,060
Levelised Investment (£million/year)	141	141	563
Total Annual Costs (£million/year)	733	472	19,228
Energy Delivered to Demand Site	4,045	2,247	131,446
Cost per Unit of Energy Delivered (£/MWh)	181	210	146

Table 4.6 Cost of Transporting Hydrocarbon by Pipeline

	Outer Hebrides	Orkneys	Sahara
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	50
Generation Costs (£million/year)	473	263	15,374
Conversion to Hydrocarbon and Storage			
Energy Losses (GWh/year)	3,169	1,761	103,004
Upfront Investment (£million)	790	460	21,497
Levelised Investment (£million/year)	115	66	3,179
Pipeline to Demand Site			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	1,455	1,455	5,820
Levelised Investment (£million/year)	135	135	541
Total Annual Costs (£million/year)	723	464	19,093
Energy Delivered to Demand Site	6,292	3,495	204,472
Cost per Unit of Energy Delivered (£/MWh)	115	133	93

5 Hydrogen

Hydrogen could be transported by pipeline, sea tanker or road tanker depending on the particular route to be taken and the quantities being shipped. As a general rule, the number of conversion stages should be minimised given the significant losses incurred at each stage and transport distances should be minimised wherever possible given the technical complexities involved in transporting hydrogen.

Therefore, the following stages are defined for each of the three generating sites:

- Electricity produced at the generating sites is transmitted by HVDC cable to a site close to the coast;
- An electrolyser is located at the coast and adjacent to a liquefaction or gas compression plant, with liquid hydrogen or compressed gas storage tanks equal to the volume of the transport vessel;
- Hydrogen is shipped by liquid hydrogen (LH_2) or compressed gas (CH_2) carrier which would closely resemble today's LNG carriers. It is not currently considered feasible to transport hydrogen gas by pipeline across sea areas;
- Hydrogen liquid or gas may be delivered to a variety of geographical locations where the hydrogen would be taken ashore and either converted back into electricity via a fuel cell (or other conversion device) or shipped as hydrogen overland for use in the transport or heating networks. This would be achieved by means of road tankers or pipeline. Storage would probably also be required, once again equal to the size of the LH_2 / CH_2 carrier payload.

The steps are illustrated in Figure 5.1.

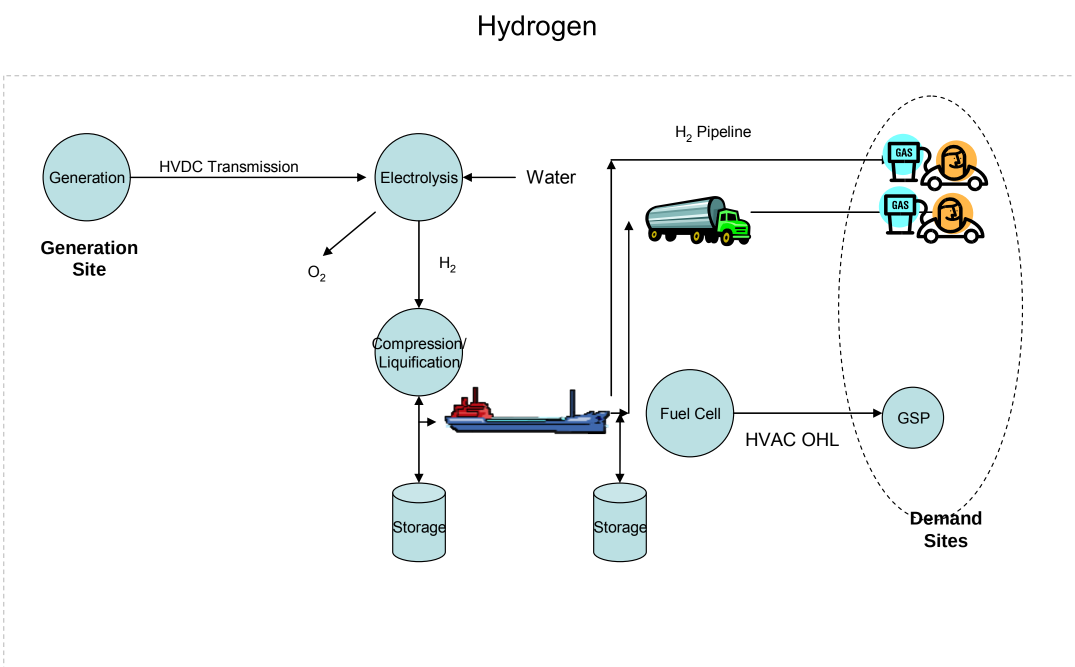

Figure 5.1 Hydrogen Transport

The results are summarised in Table 5.1 and Table 5.2, which show the upfront investment, annualised costs and energy losses associated with each of the steps shown in Figure 5.1.

5.1 Comparison with Electrical Transmission

Using hydrogen as the means to transport energy results in a levelised cost per unit of electricity delivered of around £240/MWh, which is equivalent to between 1.6 and 3.4 times that of the baseline electricity transmission scenario. The results demonstrate that the case for hydrogen is more favourable over the longer distance involved with transporting energy from the Sahara.

The results summarised in Table 5.1 show that the costs are dominated by the cost of the electrolyser and associated plant required to liquefy, compress and store the hydrogen. Investment in these plant items accounts for around 15 to 30% of the total investment costs. The other factor influencing the overall costs is the losses associated with the conversion from electricity to hydrogen and then back to electricity again. Over two-thirds of the energy generated is lost during these conversion processes.

Note that the bi-product from electrolysis is oxygen which could be valuable, although the possible income is not included in this analysis.

Table 5.1 Costs associated with Delivery of Electricity (via hydrogen) to a Grid Supply Point

	Outer Hebrides	Orkneys	Sahara
Generation			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Transmission to Remote Coast			
Energy Losses (GWh/year)	198	110	6,887
Upfront Investment (£million)	105	59	8,112
Annualised Investment (£million/year)	10	5	740
Conversion Electricity to Hydrogen and Storage			
Energy Losses (GWh/year)	4,335	2,408	140,675
Upfront Investment (£million)	1,143	725	27,423
Annualised Investment (£million/year)	144	89	3,554
Shipping			
Annual costs (£million/year)	5	3	160
Conversion Hydrogen to Electricity			
Energy Losses (GWh/year)	1,971	1,095	63,965
Upfront Investment (£million)	276	153	8,945
Annualised Investment (£million/year)	41	23	1,323
Transmission to GSP			
Energy Losses (GWh/year)	88	49	2,860
Upfront Investment (£million)	18	10	570
Annualised Investment (£million/year)	2	1	52
Total Annual Costs (£million/year)	674	384	21,203
Electricity Delivered to Demand Site (GWh)	2,869	1,594	93,088
Cost per Unit of Electricity Delivered (£/MWh)	**235**	**241**	**228**
Ratio to electricity transmission baseline cost	*3.3*	*3.4*	*1.6*

5.2 Comparison with a Pipeline

As would be expected, the economic case for transporting hydrogen becomes much stronger when it is used directly at the demand site, rather than converted back into electricity. This is particularly true over the longer distance involved with transporting energy from the Sahara, for which the cost of each unit of energy delivered to the UK is £124/MWh (as hydrogen fuel) compared to £139/MWh (as electricity).

If it is assumed that vehicles using hydrogen have a similar efficiency to that of Plug-In electric vehicles, then there is a compelling case for using hydrogen rather than electricity for transport.

The case is less clear, however, for heating. Under the low carbon energy scenarios discussed in Interim Report 2, domestic and commercial space heating is dominated by heat pumps, which can be expected to have a Coefficient of Performance of 2 or more. (Coefficient of Performance is the ratio of heat output to electricity input). Therefore, any heating fuel would need to be at least half the cost of electricity to be equivalent in terms of running costs. Alternatively, if fuel cells or other local CHP were used (rather than simple heat generating boilers), the electricity generated from the CHP plant must be of a high enough price to justify the more expensive fuel.

Where hydrogen is to be delivered in the form of a fuel, then it is useful to also compare the costs of the transportable option against those of a pipeline. In the case of hydrogen, the costs are broadly equivalent. However, transport via a pipeline is less flexible in terms of the destinations to which the energy can be delivered.

Table 5.2 Costs associated with Delivery of Hydrogen to the UK

	Outer Hebrides	Orkneys	Sahara
Generation Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Transmission to Remote Coast			
Energy Losses (GWh/year)	198	110	6,887
Upfront Investment (£million)	105	59	8,112
Levelised Investment (£million/year)	10	5	740
Conversion to Hydrogen and Storage			
Energy Losses (GWh/year)	4,335	2,408	140,675
Upfront Investment (£million)	1,143	725	27,423
Levelised Investment (£million/year)	144	89	3,554
Shipping			
Annual costs (£million/year)	5	3	160
Pipeline to Demand Site			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	384	384	384
Levelised Investment (£million/year)	36	36	36
Total Annual Costs (£million/year)	667	396	19,864
Energy Delivered to Demand Site	4,928	2,738	159,913
Cost per Unit of Energy Delivered (£/MWh)	**135**	**145**	**124**
Ratio to electricity transmission baseline cost	*1.9*	*2.0*	*0.9*
Ratio to hydrogen pipeline baseline cost	*0.9*	*0.8*	*1.0*

5.3 Water Required for Electrolysis

Whilst fresh water is available at the Scottish generating sites, it is possible that saltwater maybe the only water available in sufficient quantities in the Sahara. Electrolysing saltwater gives half the amount of H_2 compared to using fresh water.

$$2\ NaCl + 2\ H_2O \rightarrow Cl_2 + H_2 + 2\ NaOH$$

At least twice as much energy will be required to achieve the same amount of hydrogen. The Chlorine is a potentially valuable bi-product but a hazardous substance if there is no use for it.

The alternative is to desalinate water before the electrolysis. The molecular weight of water is 18 compared to 2 for hydrogen. Therefore nine times as much water is needed as hydrogen. Theoretically, 0.86kWh of energy is need for each tonne of water desalinated however in reality 5kWh is more realistic in practice[30]. Just under 4 tonnes of hydrogen are shipped each year costing about £12 million at £65/MWh in terms of water required.

Removing water from an area where there is a shortage may not seem ethical. In addition there are environmental problems if too much of the brine residue is pumped back to sea.

In addition the energy requirements associated with pumping water over long distances could represent a significant energy penalty, which could be particularly relevant for the CSP sites in the Sahara. This is not included in the results.

5.4 MTH Transmission

A methylcyclohexane-toluene-hydrogen (MTH) system provides an alternative to transporting pure hydrogen. Unlike the pure hydrogen system where the gas is either compressed or liquefied, the MTH delivery system involves attaching hydrogen to toluene to create methylcyclohexane (MCH); in a similar fashion to the way it may be “attached” to nitrogen to produce ammonia. The principal benefit of the MTH system is that MCH may be transported more easily than hydrogen since it is, in effect a simple liquid hydrocarbon. The hydrogenation process is relatively simple and well understood as is the dehydrogenation process. The products of dehydrogenation reaction are cooled and toluene is condensed and separated in situ while the hydrogen can be utilised in the normal way in a spark-ignition engine or in a fuel cell stack. A number of possible schemes for rehydrogenation could be envisaged but these would be either centralised or decentralised in nature. For example, the separation process could be integral to a fuel cell vehicle’s on board system and the toluene could be removed at the time of refuelling. Alternatively, the separation could be carried out at a centralised plant and the hydrogen either transported in gaseous / liquid form or utilised directly at the same location. Toluene could be transported back to the hydrogenation plant where it would be hydrogenated back to methylcyclohexane. However, it could also be used in other processes at the point of arrival if that were more practical.

[30] http://solveclimatenews.com/news/20100407/ibm-launches-solar-powered-desalination-saudi-arabia. Accessed 16th August 2011

The concept has been studied for a number of years, for example for providing seasonal energy storage for hydropower plants[31], or the MCH can be transported via pipeline or container. Thus, MCH is exploited in the MTH system as a hydrogen energy storage material [32] [33] [34] [35].

Thus, certain cost elements of the MTH system are virtually the same as for the transport of hydrogen. Where it differs is in the need to construct the hydrogenation and dehydrogenation plant at the generation and landing sites respectively and to adjust the transport costs to reflect the amount of liquid methylcyclohexanetoluene and toluene that must be transported in each direction. In this sense, it is a similar comparison to the one made previously with ammonia. However, unlike for ammonia, this is not a process which is carried out on a significant scale and consequently, little is known about the potential costs of the plant. Furthermore, very little is known about the comparative costs of the various different possible approaches to the dehydrogenation process as outlined. In light of the fact that the scheme is so speculative no detailed analysis is performed here. However, it might be reasonable to say that the cost of hydrogen delivery calculated above represents the minimum boundary on the cost.

[31] Seasonal storage of hydrogen in stationary systems with liquid organic hydrides, E. Newson, Th. Haueter, P. Hottinger, F. Von Roth, G. W. H. Scherer and Th. H. Schucan, Department for General Energy Technology, Paul Scherrer Insitut, CH-5232, Villigen PSI, Switzerland, October 1998.

[32] Usma, Muhammad R., Methylcyclohexane Dehydrogenation over Commercial 0.3 Wt% Pt/Al2O3 Catalyst, Proceedings of the Pakistan Academy of Sciences 48 (1): 13–17, 2011

[33] Bustamante, G.V.S.C., Y. Swesi, I. Pitault, V. Meille & F. Heurtaux. A Hydrogen Storage and Transportation Mean. Proc. Int. Hydrogen Energy Cong. Exh. IHEC, Istanbul (2005).

[34] Cresswell, D.L. & I.S. Metcalfe. Energy Integration Strategies for Solid Oxide Fuel Cell Systems. Solid State Ionics 177: 1905−1910 (2006).

[35] Yolcular, S. & Ö. Olgun. Hydrogen Storage in the Form of Methylcyclohexane. Energy Sources 30: 149−156 (2008).

6 Fischer Tropsch

The Fischer Tropsch process is used for the synthesis of a liquid hydrocarbon from a mixture of carbon dioxide and hydrogen. Thus, the feedstocks required for the Fisher Tropsch process are carbon dioxide (CO_2) and hydrogen.

Water is readily available at the generation sites (either fresh water at the Scottish sites or saltwater from the nearby coast for the CSP sites), thus providing a source of hydrogen via electrolysis. As with hydrogen, there are issues with desalinating water in Africa (see Section 5.3). The source of carbon dioxide is, however, more problematical. For the initial implementation, co-location with an industrial source of CO_2 makes most sense, such as cement production. There is significant cement production in Morocco, for example at Agadir and Casablanca on the West coast, and at Marrakesh which is around 100km inland, thus providing a local source of CO_2 for the CSP sites in the Sahara. The source of CO_2 at the Scottish sites is less clear. In future years, it may be possible to make use of sequestered CO_2 or alternatively, it may be possible for CO_2 to be captured directly from the air (although this is currently far from being proven to be feasible).

The Fischer Tropsch process requires heat. Therefore, under a transportable energy scenario, it is considered optimal for the process to be co-located at the generation site. This is particularly true for the CSP sites which could provide heat directly rather than generating electricity. Thus the Fisher Tropsch process could use heat directly from the CSP plant itself (as shown by the dashed line in Figure 6.1). Alternatively, for the Scottish sites, the hydrogen itself could be used as the heat source.

It is assumed that the liquid hydrocarbon is piped to the port where it would be tankered (shipped) to the UK, as indicated in the schematic below.

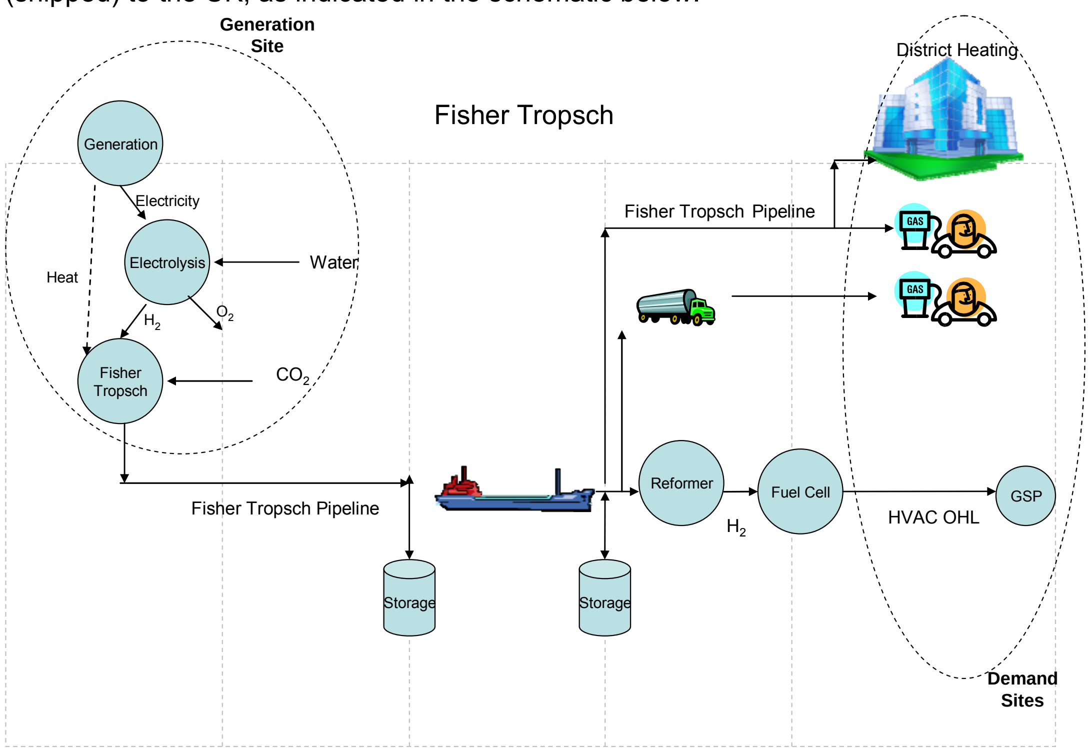

Figure 6.1 Fisher Tropsch Transport

Once transported to the UK, the hydrocarbon can be used directly as a fuel for transport (in a fuel cell or internal combustion engine) or for heating (via boiler or CHP). Alternatively, the fuel can be converted back to electricity via a fuel cell. In this case, the hydrocarbon must first be converted back to hydrogen via a reformer. Alternatively, high temperature fuel cells can run off hydrocarbons directly without any need for an interim conversion stage.

6.1 Comparison with Electrical Transmission

Based on the assumptions shown in Section 3, using hydrocarbons produced via the Fisher Tropsch process as the means to transport energy to the UK results in a levelised cost per unit of electricity delivered that is between approximately 1.6 and 3.3 times greater that of the baseline electrical transmission scenario.

The results demonstrate that the case for transporting energy as a hydrocarbon is very similar to that for hydrogen. This is because the reduced shipping costs due to the improved energy density compared to hydrogen are offset by the additional capital costs and energy losses incurred in producing the hydrocarbon.

Energy losses are also a major factor influencing the overall costs. The energy delivered to the UK (in the form of electricity) is around 30% of that generated which is very similar to that for hydrogen. There are additional losses associated in producing the hydrocarbon via Fischer Tropsch compared to producing hydrogen, but there are additional losses incurred in liquefying and/or compressing hydrogen so that it can be more readily transported.

The by-product from electrolysis is oxygen, which could be valuable, although the possible income from its sale is not included in this analysis.

Table 6.1 Costs associated with Delivery of Electricity (via Hydrocarbons) to a Grid Supply Point

	Outer Hebrides	Orkneys	Sahara
Generating Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Conversion to Fisher Tropsch and Storage			
Energy Losses (GWh/year)	3,169	1,761	103,004
Upfront Investment (£million)	745	415	21,452
Levelised Investment (£million/year)	110	61	3,174
Pipeline to Remote Coast			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	87	87	233
Levelised Investment (£million/year)	8	8	22
Shipping			
Annual costs (£million/year)	12	7	393
Conversion to Electricity			
Energy Losses (GWh/year)	3,460	1,922	112,459
Upfront Investment (£million)	211	117	6,862
Levelised Investment (£million/year)	31	17	1,015
Transmission to GSP			
Energy Losses (GWh/year)	91	51	2,971
Upfront Investment (£million)	22	12	728
Levelised Investment (£million/year)	2	1	66
Total Annual Costs (£million/year)	637	357	20,044
Electricity Delivered to Demand Site (GWh/year)	2,740	1,522	89,041
Cost per Unit of Electricity Delivered (£/MWh)	**232**	**235**	**225**
Ratio to electricity transmission baseline cost	*3.3*	*3.3*	*1.6*

6.2 Comparison with a Pipeline

As shown in Table 6.2, the economic case becomes much stronger when the hydrocarbon fuel is not converted back into electricity. This is particularly true over the longer distance involved with transporting energy from the Sahara. Here, the analysis shows that the cost of each unit of energy delivered to the UK is £93/MWh (as a hydrocarbon) compared to £139/MWh (as electricity). This makes a compelling case for transporting energy for direct use, particularly for transport.

Where the hydrocarbon produced via the Fisher Tropsch process is to be delivered in the form of a fuel, then it is useful to also compare the costs of the transportable option against those of a pipeline. In this case, the costs associated with the transportable scenario are broadly equivalent to those associated with delivery via a pipeline. However, as noted previously, transport via a pipeline is less flexible in terms of the destinations to which the energy can be delivered.

Table 6.2 Costs associated with Delivery of Hydrocarbons Synthesised via the Fisher Tropsch Process to the UK

	Outer Hebrides	Orkneys	Sahara
Generation Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Conversion to Hydrocarbon and Storage			
Energy Losses (GWh/year)	3,169	1,761	103,004
Upfront Investment (£million)	790	460	21,497
Levelised Investment (£million/year)	115	66	3,179
Pipeline to Remote Coast			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	87	87	233
Levelised Investment (£million/year)	8	8	22
Shipping			
Annual costs (£million/year)	12	7	393
Pipeline to Demand Site			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	291	291	291
Levelised Investment (£million/year)	27	27	27
Total Annual Costs (£million/year)	635	371	18,994
Energy Delivered to Demand Site	6,292	3,495	204,472
Cost per Unit of Energy Delivered (£/MWh)	**101**	**106**	**93**
Ratio to electricity transmission baseline cost	*1.4*	*1.5*	*0.7*
Ratio to hydrocarbon pipeline baseline cost	*0.9*	*0.8*	*1.0*

7 Ammonia

As previously discussed in Interim Report 1, ammonia (NH_3) production represents an interesting option for transporting energy from one location to another. It can easily be converted back into hydrogen, which can then be used to produce electricity via a fuel cell. Alternatively, high temperature fuel cells can run off ammonia directly without any need for an interim conversion stage. Ammonia can also be used as a fuel in internal combustion engines and is the primary feedstock for a vast range of critical and commercially valuable products.

As with Fisher Tropsch, the production of ammonia via the Haber Bosch process requires heat, therefore it is considered optimal for the process to be co-located at the generation site. It is assumed that the liquid is piped to the port where it would be tankered (shipped) to the UK, as indicated in the schematic below. In the Sahara, the ammonia production process uses heat directly from the CSP plant (as shown by the dashed line in Figure 7.1). Alternatively, the hydrogen itself could be used as the heat source.

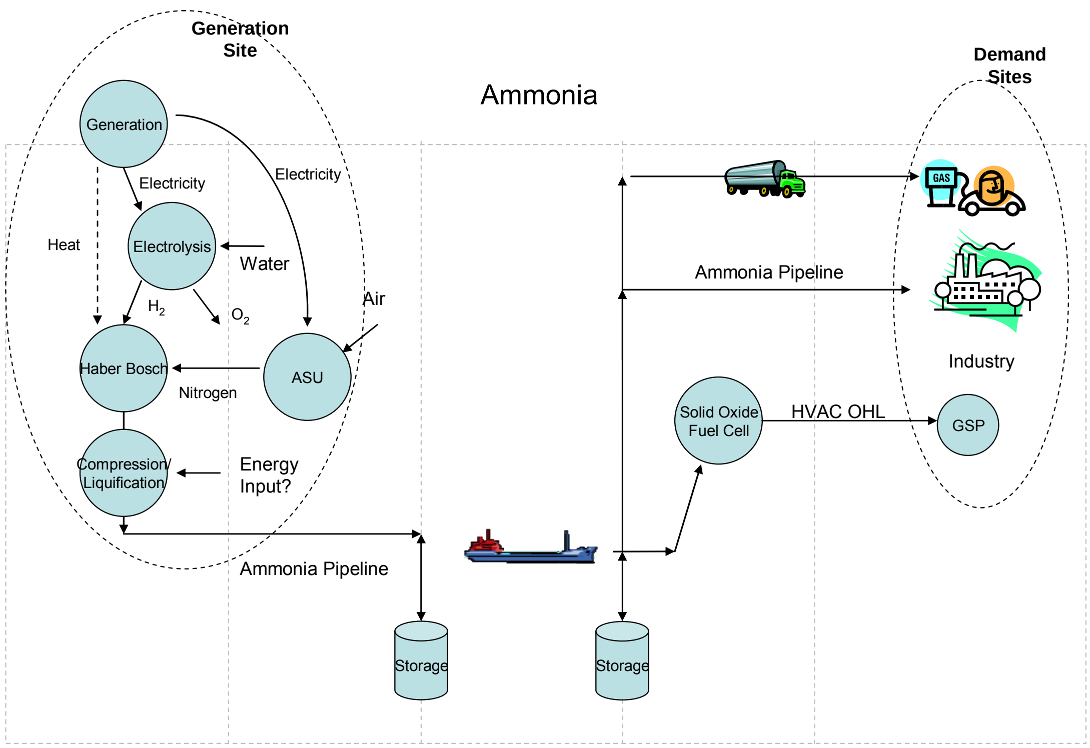

Figure 7.1 Ammonia Transport

7.1 Comparison with Electrical Transmission

Thus, based on the assumptions shown in Section 3, using ammonia produced via the Haber Bosch process as the means to transport energy to the UK results in a levelised cost per unit of electricity delivered that is approximately 2 and 4 times greater that of the baseline transmission scenario.

As with the other chemical energy storage media (i.e. hydrogen and hydrocarbons), the energy losses are a major factor influencing the overall economic viability. The energy delivered to the UK (in the form of electricity) is around 25% of that generated. This is less favourable than that for hydrocarbon due to the reduced efficiency of the Haber Bosch process compared to the Fischer Tropsch process.

Table 7.1 Costs associated with Delivery of Electricity (via Ammonia) to a Grid Supply Point

	Outer Hebrides	**Orkneys**	**Sahara**
Generating Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Conversion to Ammonia and Storage			
Energy Losses (GWh/year)	5,416	3,009	176,030
Upfront Investment (£million)	857	497	23,447
Levelised Investment (£million/year)	119	68	3,290
Pipeline to Remote Coast			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	91	91	242
Levelised Investment (£million/year)	8	8	23
Shipping			
Annual costs (£million/year)	22	12	717
Conversion to Electricity			
Energy Losses (GWh/year)	1,618	899	52,578
Upfront Investment (£million)	226	126	7,353
Levelised Investment (£million/year)	33	19	1,088
Transmission to GSP			
Energy Losses (GWh/year)	86	48	2,788
Upfront Investment (£million)	14	8	468
Levelised Investment (£million/year)	1	1	43
Total Annual Costs (£million/year)	657	371	20,534
Electricity Delivered to Demand Site	2,341	1,300	76,079
Cost per Unit of Electricity Delivered (£/MWh)	**281**	**285**	**270**
Ratio to electricity transmission baseline cost	*4.0*	*4.0*	*1.9*

7.2 Comparison with a Pipeline

As with the other chemical energy carriers, there is a much stronger case where the ammonia is not converted back into electricity, as shown in Table 7.2. This is particularly true over the longer distance involved with transporting energy from the Sahara. Here, the analysis shows that the cost of each unit of energy delivered to the UK is broadly equivalent to that for the baseline transmission scenario i.e. £148/MWh (as ammonia) compared to £139/MWh (as electricity). In terms of the cost per unit of energy delivered, the results for transporting energy using ammonia are not as favourable as those for hydrogen or a hydrocarbon if the energy is required in the form of heat.

There could, however, be a compelling case for the manufacture of ammonia in the Sahara; the cost of production of ammonia at the generating site is almost equivalent to the cost of transporting the electricity required to make it in at the demand site. This of course assumes that electricity is the main fuel source for ammonia production in the future. It is important to note, that in the case of liquid fuels used for industrial purposes, the losses in their manufacture would be incurred at the demand site, rather than at the generation site.

Although not considered here, it would seem sensible for the production of fertilizers and other materials reliant on ammonia to be co-located at the generation site.

Using a pipeline to transport ammonia is approximately the same cost as transporting the medium via ship.

Table 7.2 Costs Associated with Delivery of Ammonia to the UK

	Outer Hebrides	Orkneys	Sahara
Generation Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Conversion to Ammonia and Storage			
Energy Losses (GWh/year)	5,416	3,009	176,030
Upfront Investment (£million)	857	497	23,447
Levelised Investment (£million/year)	119	68	3,290
Pipeline to Remote Coast			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	91	91	242
Levelised Investment (£million/year)	8	8	23
Shipping			
Annual costs (£million/year)	22	12	717
Pipeline to Demand Site			
Energy Losses (GWh/year)	0	0	0
Upfront Investment (£million)	303	303	303
Levelised Investment (£million/year)	28	28	28
Total Annual Costs (£million/year)	651	380	19,432
Electricity Delivered to Demand Site	4,045	2,247	131,446
Cost per Unit of Energy Delivered (£/MWh)	**161**	**169**	**148**
Ratio to electricity transmission baseline cost	*2.3*	*2.4*	*1.1*
Ratio to hydrocarbon pipeline baseline cost	*0.9*	*0.8*	*1.0*

8 Battery Technologies

Zinc is a metal that oxidizes in air. Generally this oxidation layer passivates (is protective to the base material by no longer being electronically conductive) which is the basis for zinc coating for corrosion protection. Zinc can be oxidized continuously under the right conditions. Alkaline salts are used to oxidize zinc to zincate which then decomposed to zinc oxide and water. See Appendix 1 for an overview of zinc air battery technology.

The gravimetric energy density of zinc is about 6MJ/kg. Zinc metal can be ground into a powder and mixed with hydroxide salts and stored sealed from the air. When later reacted with air, energy can be recovered as electricity. This is the basis for a zinc air battery. Zinc is easy to electro-win at low temperatures from a variety of the soluble salts by standard electroplating techniques with very good electrical efficiencies.

Zinc air batteries can be reversible or non reversible. In both cases the actual gravimetric energy density is about 2MJ/kg or 550 Wh/kg[36]. In non reversible units, the above mentioned mixture of zinc and hydroxide salts is consumed and then thrown away. For mechanical recharging of zinc air batteries, the above slurry is pumped in to replace the spent solution. With rechargeable zinc air batteries, the spent solution is returned to zinc metal in situ. This requires reversing the processes of discharge. Unfortunately, most air electrodes are not suited to reversing and fail[37]. This is particularly the case of carbon electrodes which convert to CO_2. However, a number of organisations are currently developing technologies that are reversible. Zinc air batteries are considered alongside BPLA batteries.

Two scenarios were considered, transportation of zinc metal slurries for use as electrodes in Zinc air batteries and transportation of zinc air batteries. In both cases, it is thought that the overall economics will be very similar. The shipping costs of the zinc slurry would be less than that of the transporting zinc air batteries, and the savings would be offset to some extent by the additional pumping costs. Thus, for simplicity, only the transport of zinc air batteries is considered here.

Transmission lines would be used to recharge the batteries in the barges without the batteries being removed. Thus, in essence the ship itself is a large battery that travels between the remote site and the UK. The overall steps involved are as illustrated in Figure 8.1.

[36] For comparison, ReVolt claim an energy density target of 400Wh/kg for batteries for electric vehicles and 200Wh/kg for batteries up to 100kWh in capacity. Confidential correspondence provided by Caterpillar.

[37] ReVolt is currently developing a reversible battery based on new technology. Confidential information provided by Caterpillar.

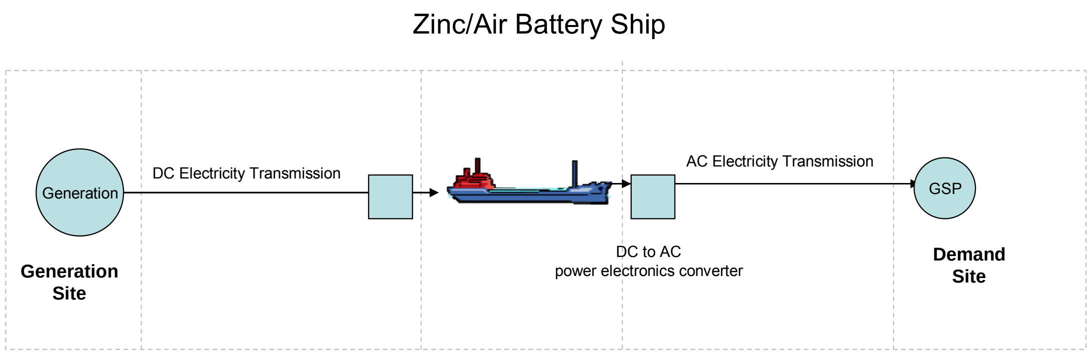

Figure 8.1 zinc air Battery Ship Concept

This approach would require a DC cable to the coast and a DC to DC converter to charge the ship. At the receiving point, it is expected that induction charging would be the most appropriate means to discharge the ship. This is because designing a physical link or socket for such a large energy rating, that could be decoupled and coupled many times, would be difficult. Induction charging does not require such a physical link or socket. Given the size of the ship, this may need to be carried out offshore. Such infrastructure could be combined with offshore grids for renewables.

As yet, no studies have been undertaken to assess the likely costs associated with building a battery ship. Therefore, it is assumed that the ship itself can be constructed at the same cost as the target cost for stationary Zinc-Air batteries, i.e. at £150/kWh. This is an extremely ambitious target, and therefore the results shown here represent the '*best case*' scenario for the concept.

Unlike the other case studies, it is assumed that some of the stored energy is used to power the ship. Here it is assumed that the energy required for traction is 0.015 kWh/ton-mile (or 0.017 kWh/tonne –mile)[38].

The life of the battery is assumed to be 10 years, which although unproven, represents a reasonably life in terms of the number of cycles. In the worst case scenario, it is assumed that the round trip time for a ship travelling between the Orkneys and the GB mainland is 7 days, Thus a single vessel would be able to undertake just over 50 trips per year – equivalent to 500 trips (or cycles) over 10 years.

The costs per unit of electricity delivered with the zinc air battery ship concept are dominated by the cost of the batteries themselves. Even assuming an extremely ambitious cost target of £150/kWh, the levelised cost per unit of electricity delivered is around six times that of the baseline transmission option.

However, it is important to note that the costs are extremely sensitive to the length of journey time. If the journey times are reduced by half (3.5 days round trip for Scotland/Norway and six days for the Sahara, the costs shown in Table 8.1 reduce to just below £300/MWh for the Scottish sites or around £480/MWh for the Sahara.

The levelised cost per unit of electricity delivered via a BPLA battery ship is very similar to that for a Zinc-Air Ship. In essence, the reduced energy storage density and reduced lifetime of this electrochemistry (around 100Wh/kg and 5 years respectively) compared to

[38] Sustainable Energy Without the Hot Air, David MacKay

Zinc-Air (around 500Wh/kg and 10 years respectively) are offset by the reduced capital costs (assumed to be £70/kWh compared to £130/kWh for Zinc-Air).

Table 8.1 Costs associated with Delivery of Electricity (via Zn-Air Battery Ship Concept) to a Grid Supply Point

	Outer Hebrides	Orkneys	Sahara
Generation Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Transmission to Remote Coast			
Energy Losses (GWh/year)	198	110	6,887
Upfront Investment (£million)	105	59	8,112
Levelised Investment (£million/year)	10	5	740
Battery Charging			
Energy Losses (GWh/year)	1,241	689	40,271
Shipping			
Energy Used for Traction (GWh/year)	166	92	21,526
Upfront Investment (£million)	20,001	11,111	1,112,589
Levelised Investment (£million/year)	2,959	1,644	164,608
Battery Discharging			
Energy Losses (GWh/year)	1,218	677	53,518
Transmission to GSP			
Energy Losses (GWh/year)	96	53	3,111
Upfront Investment (£million)	29	16	927
Levelised Investment (£million/year)	3	1	85
Total Annual Costs (£million/year)	3,444	1,913	180,806
Electricity Delivered to Demand Site	6,708	3,727	203,689
Cost per Unit of Electricity Delivered (£/MWh)	**513**	**513**	**888**
Ratio to electricity transmission baseline cost	*7.3*	*7.2*	*6.4*

9 Aluminium

Aluminium is a metal with an energy density of 32MJ/kg, which is five times that of Zinc and 16 times that of a Zinc-Air battery.

Aluminium production is more energy intensive than Zinc production, requiring reaction temperatures in the region of 2000°C. The energy required to produce aluminium from bauxite is between 46 and 56 MJ/kg depending upon the process. This makes the production of aluminium near to sources of bauxite and renewable energy very appealing.

Aluminium air batteries have been investigated since the 1970s, and have been developed by the US military. They are considered primary batteries because recharging them requires much additional heat. There are some technical challenges to overcome, such as hydroxide layer removal from the reaction site, which if not addressed can greatly reduce the output voltage. Researchers have found that aluminium batteries have 15 times the gravimetric density of lead acid batteries, making aluminium air comparable to gasoline for range/fuel mass in a vehicle[39].

If aluminium were produced at any of the generation sites, it would almost certainly be used as a metal, displacing other forms of input energy. Although it would not transport additional energy resource to the UK to meet future energy needs, it is considered a useful scenario. For this reason, the potential feasibility of aluminium air batteries has not been considered.

A solid such as aluminium, if manufactured in the Sahara to take advantage of the available CSP would need to be transported by truck from the manufacturing plant to the port and then shipped to the UK. If using the bauxite from the Sahara, the returning trucks and ships would be empty, or could take another cargo. The energy required for transport is assumed to be reflected in the price of shipping and road transport. Handling of the solid would likely be by hopper for large ingots or crane for large bars. For smaller bars (or bundles of bars) forklift trucks would be needed. The overall process assessed is depicted in Figure 9.1.

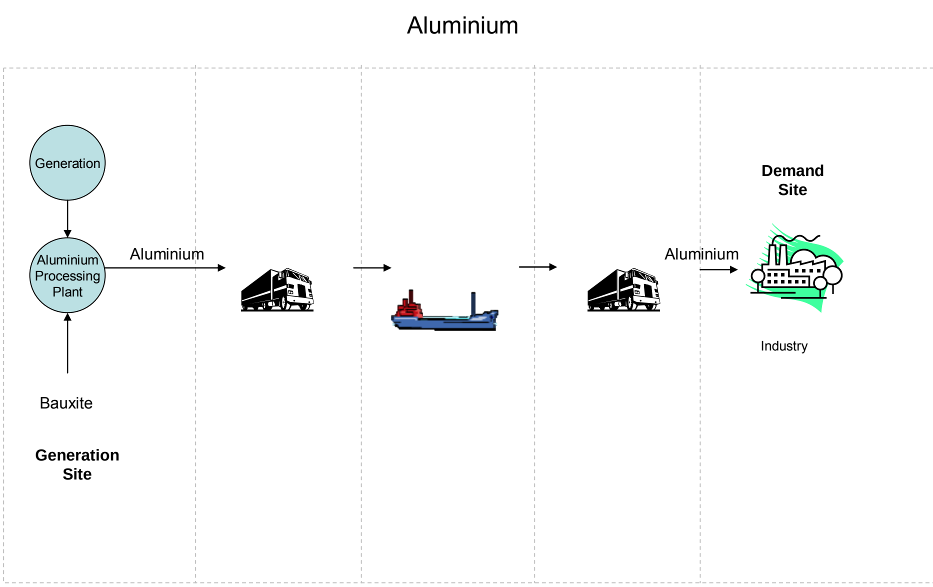

Figure 9.1 Aluminium Transport

39 Design and analysis of aluminium/air battery system for electric vehicles. Yang and Knickle, 2002, Journal of Power Sources 112(1) 162-173

The results show that whilst the cost of producing aluminium is broadly constant across all three of the generating sites, the baseline cost of electricity transmission varies by a factor of two (i.e. the cost per unit of electricity transmitted via HVDC from the Sahara is broadly double that from the Scottish sites).

This makes the cost of producing aluminium in the Sahara equivalent (on a £/MWh basis) to transferring the energy via an electricity transmission line. As evidenced elsewhere, there is a strong economic argument for locating aluminium production close to sources of low cost generation, particularly hydro-generation. Thus, until wind and CSP sites can match the generation costs of low cost hydro, it would seem unlikely that aluminium production would shift to the generation sites.

Table 9.1 Costs associated with Delivery of Aluminium to UK

	Outer Hebrides	Orkneys	Sahara
Generation Site			
Capacity (GW)	2.7	1.5	78.0
Annual Output (GWh/year)	9,461	5,256	307,476
Generation Cost (£/MWh)	50	50	65
Generation Costs (£million/year)	473	263	15,374
Conversion to aluminium			
Energy Losses (GWh/year)	2,879	1,600	93,580
Upfront Investment (£million)	4,860	2,700	140,400
Levelised Investment (£million/year)	452	251	13,052
Transport to Remote Coast (Truck)			
Energy Losses (GWh/year)	0	0	0
Annual Costs (£million/year)	18	10	572
Shipping			
Annual costs (£million/year)	18	10	572
Transport within UK (Truck)			
Energy Losses (GWh/year)	0	0	0
Annual Costs (£million/year)	18	10	572
Total Annual Costs (£million/year)	978	543	30,142
Electricity Delivered to Demand Site	6,582	3,656	213,896
Cost per Unit of Electricity Delivered (£/MWh)	**149**	**149**	**141**
Ratio to electricity transmission baseline cost	*2.1*	*2.1*	*1.0*

10 Carbon Life Cycle

The Carbon Life Cycle represents all the carbon emissions and other green house gases associated with the whole life cycle of a process or product. That is, all the emissions associated with extraction of materials, manufacture, transport, use and decommissioning. The impact of different gases emitted is normally expressed in terms of the amount of carbon dioxide that would have the equivalent global warming impact. The amount is expressed as an intensity, in this work per kWh of energy delivered.

The full details of the carbon life cycle analysis including references are presented in Appendix 2. Below is a summary for each technology.

For the carbon life cycle analysis, it is assumed that all transport fuel is renewable and therefore does not contribute to the Global Warming Potential (GWP) of the system. However, it is assumed that reforming a hydrocarbon will emit carbon and the energy used for manufacture may not be from renewable sources. This carbon could be captured but this would require energy.

10.1 Transmission and Plant Items (Electrolysers, Compression, Storage, Reformation)

The Tables below give the carbon lifecycle for the building of transmission cables and alternative chemical means of transport.

Table 10.1 Approximate Carbon Life Cycle Data

Component	gCO_2e/kWh
Electrolysis, compression, storage and shipment of hydrogen	5.2
Hydrocarbon liquefaction, reformation and storage	14
Transmission – GB Transmission, for present use and capacity, excludes losses	2.0

Table 10.2 Approximate Carbon Life Cycle Data for Cables and Overhead Lines

Details	gCO_2e/kWh
Cable Orkney to Sweden 500km 2GW	1.86
Cable Hebrides to England 800km 3GW	2.77
Cable Sahara to UK 1900km 78GW	4.7
Cable across to African coast 200km 78GW	0.49

10.2 Carbon Footprint for Pipelines

Given that the sources of the data used are different to those for the costs of pipelines, the exact distances and diameters of pipe are different to those used for the costs. The estimates of carbon emissions and costs are not sufficiently sensitive for such discrepancies to be significant.

Table 10.3 Carbon Footprint for Pipelines

Pipeline distance (km)	Carbon Footprint H_2 gCO_2e/km	Carbon Footprint NH_3 gCO_2e/km	Carbon Footprint CH_n gCO_2e/km	Carbon Footprint H_2 gCO_2e/kWh	Carbon Footprint NH_3 gCO_2e/kWh	Carbon Footprint CH_n gCO_2e/kWh
500	325,000,000	24,000,000	200,000,000	0.77	0.57	0.48
800	325,000,000	240,000,000	200,000,000	0.77	0.57	0.48
1900	5,040,000,000	3,078,000,000	2,000,000,000	0.78	0.58	0.31

10.3 Batteries

Using calculations for batteries for vehicles, the figures for carbon emissions from mining, manufacture and recycling are in the same for both lead acid and zinc air batteries. They are between 300 and 400kg for a battery that would fuel a car for between 150,000 and 200,000km. Assuming that travelling this distance requires between 38,000kWh and 43,000kWh, this gives the carbon emissions at between 7.9gCO_2e/kWh and 9.3gCO_2e/kWh.

It should be noted however that the pack design and charging regime will be completely different for transportable storage compared to electric vehicles and that this should extend the life of the battery and increase its efficiency.

These figures are of a similar order of magnitude to the other transportable options.

Note that any battery technology may be in competition for materials with the vehicle industry in future. Zinc has the advantage that it is more abundant that lead.

10.4 Road Transport[40]

Defra quote a figure of 0.89$kgCO_2e$ per £ spent for the embodied carbon in road transport. This should give an indication of the embodied carbon. If a lorry costs £100,000 and transports 500,000kWh in 10 years, this gives 0.000178gCO_2e/kWh.

This assumes that all the fuel is renewable.

10.5 Shipping

It is assumed that the fuel to drive ships will be renewable by 2050; indeed the generation source may provide this fuel. The carbon emissions from shipping chemical fuels will be associated with the manufacture and maintenance of the ships.

Unfortunately it is difficult to find an estimate of the carbon emissions associated with shipyards. The main source of carbon emissions from shipping at present are from the fuel used and the focus on work to carbon footprint and reduce emissions from shipping.

[40] http://archive.defra.gov.uk/environment/business/reporting/pdf/101006-guidelines-ghg-conversion-factors.pdf

The National Maritime Laboratory in Japan developed software[41] to carry out carbon lifecycle analysis of the whole of their shipping industry. It estimates that the carbon emissions from building a 76000 dead weight tonne (dwt) sized ship as 15 000 tonnes of CO2e. The majority of the emissions are due to the manufacture of steel. As the ships envisaged are larger than the 76000 dwt cargo capacity, this figure is multiplied by 1.5. It is assumed that 1 ship is needed from Orkneys and the Outer Hebrides, and 10 are required for the Sahara routing. The emissions are summarised in the Table below.

Table 10.4 Carbon Footprint for Shipping

Shipping emissions	gCO_2e/kWh
Hebrides	0.213
Orkney	0.171
Sahara	0.029

There is significant interest in developing more efficient ships and introducing new materials. Therefore these numbers are likely to reduce in future. The additional carbon cost of shipping is small compared to the manufacture of other plant used in creating chemical fuels.

10.6 Overview

In all the studies reviewed, despite the difference in scale and carbon intensity of the power used, the construction of the storage and transport systems, including electrolysers and reformers etc, is a very small part of part of the overall carbon emissions. Examples of this small contribution are demonstrated in some of the original papers:

- For the study of hydrogen from LNG, the construction costs were 1% without carbon capture and 4% with carbon capture.[42]
- In the case of hydrogen from wind, the construction and operation of three wind turbines caused 78% of the global warming potential (GWP) compared to the electrolyser, hydrogen compression and storage that accounted for 21% of the GWP[43].
- In the case of transmission, construction accounted for 3% of the total GWP. In this case, the release of SF6 and other losses were more significant[44].

[41] 'Development of LCA software for ships and LCI Analysis based on actual shipbuilding and operation' Kameyama M, Hiraoka K, Sakurai A, Naruse T, Tauchi H, National Maritime Research Institute http://www.nmri.go.jp/env/lca/Paper/pdf/44.pdf accessed 21st September 2011

[42] Life-Cycle Analysis of Green House Gas Emissions for hydrogen Fuel Production in the United States from LNG and Coal Pamela L Spath and Margaret K Mann DOE/NETL-2006/1277

[43] Life Cycle Assessment of Renewables hydrogen Production via Wind/Electrolysis February 2004 NREL/MP-560-35404

[44] Life cycle assessment of the transmission network in Great Britain. G. Harrison, E. Maclean, S. Karamanlis, L. Ochoa. Energy Policy Volume 38 (2010).

10.6.1 Carbon Life Cycle Sensitivity Analysis

The GWP of each method is highly sensitive to size of the system, materials used and carbon intensity of the electricity for manufacture or construction:

- For the hydrogen from wind system, including the construction of the wind turbines, a reduction in materials of 25% results in a drop of 11% in the overall GWP[43].
- A 30% change in carbon intensity of the electricity used for construction of the GB transmission causes a change of 36% in GWP potential. This is validated by the equivalent calculation for the Swedish transmission network where the construction emissions are 0.25g CO_2e/kWh compared to 0.4 gCO_2e/kWh in Great Britain, reflecting the low carbon intensity of their hydro generated electricity[44].
- Whilst the carbon emissions for construction of small cables are greater than the equivalent overhead line, at larger capacities this is reversed. At a voltage of 275kV and for a capacity of 1,000MVA, a cable accounts for 2,600 tonnes CO_2e/km in carbon compared to 5,200 tonnes CO_2e/km for an OHL[44].

10.7 Conclusions of Carbon Life Cycle Analysis

The figures above are drawn from different sources using different methods and extrapolated for sizes or technologies where figures are not available. New technologies are likely to significantly reduce their carbon footprint over time and manufacturing and efficiency in use of materials improves. These variations could alter the carbon foot prints that could change the differences in the size of the footprints of the difference options.

The estimates above are about 1% of the carbon intensity of our present electricity (around 540g CO_2e/kWh). The figures above do not include the carbon emissions of building the renewable generation plant itself, but the total emissions would not be more than a few percent of our present generation emissions.

All the estimates are of a similar order of magnitude and none of the figures indicate that the carbon lifecycle should be a significant factor in the choosing between different options.

11 Comparison of Different Storage Media

The case studies presented in Sections 4 to 9 consider the levelised costs of delivering energy to the UK or to Norway using the selected energy storage media. The results, summarised in Table 11.1, indicate that electricity transmission represents the least cost solution if electrical energy is required at the demand site. This is particularly true in the case of the two Scottish generating sites. For example, the cost associated with transferring electrical energy via a transmission network from the Outer Hebrides to the UK mainland is just over £70/MWh compared to between £232/MWh and £281/MWh using chemical storage media.

The analysis of the carbon emissions presented in Section 10 indicates that the carbon lifecycle should not be a significant factor in the choosing between different transportable energy storage media options.

Table 11.1 summarises the levelised costs of the different options considered.

Table 11.1 Costs associated with Delivery of Energy Using Selected Storage Media

		Cost per Unit of Electricity Delivered (£/MWh)		
		Outer Hebrides	**Orkneys**	**Sahara**
Baseline (Electricity Transmission)		70	71	139
Hydrogen	**Transport**			
	Electricity	235	241	228
	Fuel	135	145	124
	Pipeline (fuel)	158	190	120
Fisher Tropsch	**Transport**			
	Electricity	232	235	225
	Fuel	101	106	93
	Pipeline (fuel)	115	133	93
Ammonia	**Transport**			
	Electricity	281	285	270
	Fuel	161	169	148
	Pipeline (fuel)	181	210	146
Zinc Air Battery Ship (Electricity)		513	513	888
Aluminium (Feedstock)		149	149	141

11.1 Delivery of Electricity

As indicated in Table 11.1, electricity transmission represents the least cost solution if electrical energy is required at the demand site. This is particularly true in the case of the two Scottish generation sites. For example, the cost associated with transferring energy via a transmission network from the Outer Hebrides to the UK mainland is just over £70/MWh compared to between £232 /MWh and £281 / MWh for the chemical energy storage media or over £500 / MWh for the battery ship.

Total transmission infrastructure costs increase as the distances involved increase; however the same is not true for commercial shipping costs which appear to be insensitive to distances travelled. Therefore, the economic case for transporting energy using a chemical energy carrier is stronger over the longer distance associated with the Sahara generation sites. Nevertheless, hydrogen, ammonia or a hydrocarbon are still not able to compete directly with electricity transmission. For example, producing a hydrocarbon using the Fisher Tropsch process in Africa, transporting it 2,000km by ship and then converting it back into electricity at the UK coast provides electricity at £225/MWh compared to £139 for the transmission option, i.e. an uplift of around 60%.

It is important to note that, where electrolysis is used there is an additional by-product (oxygen) which could have value. This potential benefit has not been factored into the calculations.

The results indicate that using electro-chemical energy storage media (i.e. a Zinc-Air Battery ship concept) is unlikely to represent an economically viable concept. The overall costs are dominated by the cost of the batteries themselves. Even assuming an extremely ambitious cost target of £150/kWh for the battery ship, the levelised cost per unit of electricity delivered is over six times that of the baseline transmission option. Here, costs are extremely sensitive to the length of journey time. If the journey times are reduced by half (3.5 days round trip for Scotland and six days for the Sahara, the costs shown in Table 11.1 reduce to just below £300/MWh for the Scottish sites or around £480/MWh for the Sahara. This is because the total battery capacity required is halved. It is also interesting to note that the levelised cost per unit of electricity delivered via a BPLA battery ship is very similar to that for a Zinc-Air Ship. In essence, the reduced energy storage density (around 100Wh/kg) and reduced lifetime of this electrochemistry (5 years) compared to Zinc-Air (around 500Wh/kg and 10 years respectively) is offset by the reduced capital costs (assumed to be £70/kWh compared to £130/kWh for Zinc-Air).

11.2 Energy for Non Electrical Uses

If energy can be supplied as a fuel rather than electricity, the case for the chemical energy storage media becomes economically viable. For example, hydrogen can be delivered to the UK from the Sahara at a cost of £124/MWh by ship or £120/MWh by pipeline, which is slightly less than that for direct transmission (i.e. £139/MWh). The case is even stronger for the Fisher Tropsch hydrocarbons, which can be delivered to the UK at a cost of around £90/MWh of energy delivered, a saving of around 33% compared to the electricity transmission baseline.

Thus, there is a strong case for delivering the energy as either hydrogen or a hydrocarbon for end uses such as transport, rather than converting them back into electricity. The case is less clear for heating or CHP applications. Under the low carbon energy scenarios discussed in Interim Report 2, domestic and commercial space heating is dominated by heat pumps, which can be expected to have a Coefficient of Performance of 2 or more. (Coefficient of Performance is the ratio of heat output to electricity input). Therefore, any heating fuel would need to be at least half the cost of electricity. However, this does not take into account any increase in the capital cost of the heating system or the impact on the distribution network.

It is important to note that the economic case is broadly similar for the three chemical energy storage media considered, albeit with ammonia being slightly more costly than either hydrogen or the hydrocarbon option. This is because increases in capital costs associated with the manufacture of ammonia and the hydrocarbon compared to hydrogen, and the increased losses associated with the additional production steps, are offset by the improved transportability (i.e. energy density) of these media compared to hydrogen. However, due to the uncertainties associated with the costs and efficiencies of the processes involved, care should be taken when drawing direct comparisons between these media.

11.3 Sensitivity Analysis

In order to understand the sensitivity of the results (summarised in Sections 11.1 and 11.2) to the various assumptions and cost estimates used (see Section 3), key costs have been reduced by 20% and/or the efficiency of key components or processes have been increased by 20%. The impact of these on the levelised cost per unit of energy delivered is considered below.

11.3.1 Impact of Potential Cost Savings

The costs of that were reduced were
- Pipeline
- DC cable
- Batteries
- Fuel cells
- Electrolyser
- Hydrogen storage

As ammonia and the output from Fischer Tropsch are already used widely, it is assumed that the costs of storage and plant for these products are unlikely to be reduced significantly in the future.

Table 11.2 shows the impact on the levelised costs if the costs of the key components listed above are reduced by 20% compared to the values quoted in Section 3. Thus, reducing the cost of DC cables by 20% results in a 10% reduction in the cost per unit of electricity delivered via transmission from the Sahara.

Table 11.2 Reduction in levelised costs for a 20% reduction in cost of key components

		Change in levelised cost		
		Outer Hebrides	Orkneys	Sahara
Baseline		0%(i)	5%	10%
Hydrogen	**Transport**			
	Electricity	4%	5%	4%
	Fuel	4%	5%	3%
	Pipeline (fuel)	7%	9%	3%
Fisher Tropsch	**Transport**			
	Electricity	4%	4%	3%
	Fuel	4%	4%	2%
	Pipeline (fuel)	6%	8%	3%
Ammonia	**Transport**			
	Electricity	4%	4%	3%
	Fuel	4%	4%	2%
	Pipeline (fuel)	6%	8%	3%
Zinc Air Battery Ship (Electricity)		17%	17%	18%

(i) Baseline transmission based on AC, for which no cost reduction is assumed

Taking these savings as a whole, the cost reductions in transporting chemical fuels is most significant. The costs become close to that of transmission for the links to Orkney and Hebrides if all the savings are made. Similarly pipelines become slightly less favourable. The fact that there are more stages to manufacture and transport chemical fuels offer more stages in which savings might be made. There are also more components that have not been made on a large scale or still require development, and thus represent greater potential for cost saving in the future. In reality, the cost savings may be location specific, for example electricity and transmission links may be cheaper as a result of terrain that is easier to construct such links. For the longer distance to the Sahara, distance dependant savings become more significant. For example for the baseline electricity transmission example, the costs for the Sahara falls by 10% compared to 5% from Orkney.

11.3.2 Impact of Potential Energy Efficiency Improvements

The impact of increasing the efficiencies by 20% was considered for the following components:

- Electrolyser
- Fuel cell
- Battery

Thus, the efficiency of an electrolyser is increased from 70% to 84%, the efficiency of a fuel cell is increased from 60% to 72%, and the efficiency of the battery charge / discharge cycle is increased from 75% to 90%.

Table 11.3 Reduction in levelised costs for a 20% improvement in the efficiency of key components

		Change in levelised cost		
		Outer Hebrides	**Orkneys**	**Sahara**
Baseline		0%	0%	0%
Hydrogen	**Transport**			
	Electricity	29%	29%	29%
	Fuel	15%	16%	15%
	Pipeline (fuel)	16%	16%	16%
Fisher Tropsch	**Transport**			
	Electricity	16%	16%	16%
	Fuel	13%	13%	13%
	Pipeline (fuel)	13%	13%	13%
Ammonia	**Transport**			
	Electricity	17%	17%	17%
	Fuel	31%	31%	31%
	Pipeline (fuel)	33%	33%	33%
Zinc Air Battery Ship (Electricity)		10%	10%	10%

It is assumed that transmission, pipelines and compression systems are unlikely to improve their efficiency especially as their efficiencies are already high. As with costs, systems where there are more components where efficiency improvements can be made are more significant. Distance is less significant but the amount of energy delivered compared to the capital costs is a key factor and this is increased by increases in efficiency.

Batteries are still much more costly that the other alternatives.

These results demonstrate that changes in costs and efficiencies could make options viable that are at first sight too costly. Therefore the developments in technologies that are relatively immature should be monitored as they could become feasible options.

The costs of different materials could change dramatically either due to world shortages, the energy required to extract them or as alternatives are developed. These developments should be monitored as they could change the feasibility of different options.

11.4 Energy Delivered

Table 11.4 below compares the amount of energy delivered under each of the scenarios considered. Here, it can be seen that the losses incurred via transmission are significantly less than those for any of the other storage media considered. The cost of these losses is a significant factor in the overall economic viability of the different storage media. For example, in the case of electricity delivered to the UK using hydrogen from the Outer Hebrides only 2,869 GWh/year of electricity can be delivered to the demand site from the 9,461 GWh/year generated. With generation costs assumed to be £50/MWh of electricity generation, the cost of these losses is considerable. However, it is important to note that the efficiency of the fuel cell is based only the electrical efficiency (i.e. the ratio of the electrical energy output to the chemical energy input). If the overall efficiency is considered (i.e. the waste heat can be utilised, for example by co-locating the fuel cell with a demand for heat), the overall efficiency will be much improved, although not sufficient to match the baseline scenario.

It is important to note, that in the case of liquid fuels used for industrial purposes, the losses in their manufacture would be incurred at the demand site, rather than at the generation site.

Table 11.4 Amount of Energy Delivered Using Selected Storage Media

		Energy Delivered to Demand Site (GWh/year)		
		Outer Hebrides	**Orkneys**	**Sahara**
Generated		9,461	5,256	307,476
Baseline		8,823	5,072	283,800
Hydrogen	**Transport**			
	Electricity	2,869	1,594	93,088
	Fuel	4,928	2,738	159,913
	Pipeline (fuel)	5,033	2,796	163,577
Fisher Tropsch	**Transport**			
	Electricity	2,740	1,522	89,041
	Fuel	6,292	3,495	204,472
	Pipeline (fuel)	6,292	3,495	204,472
Ammonia	**Transport**			
	Electricity	2,341	1,300	76,079
	Fuel	4,045	2,247	131,446
	Pipeline (fuel)	4,045	2,247	131,446
Zinc Air Battery Ship (Electricity)		6,708	3,727	203,689
Aluminium (Feedstock)		6,582	3,656	213,896

11.5 Carbon Emissions and Climate Change

There is not much difference in the carbon emissions of the different options and the infrastructure of each one will be vulnerable to climate change. As discussed in Interim report 2, the cost of the additional design features to protect against extreme weather events is likely to be similar for all the options. Shipping may be more vulnerable to storms than static infrastructure.

Road and shipping are more flexible in that cargoes can be taken to different locations that may be of use if areas which are currently inhabited have to be abandoned due to climate change.

12 Impact of the 2050 Scenarios and Flexibility

The different possible scenarios for the UK's energy uses in 2050 may make one technology more attractive than another. If energy needs such as heating and transport are electrified, then use of hydrogen, ammonia and/or hydrocarbons produced via the Fisher Tropsch process would be discouraged. On the other hand, if hydrogen for transport and CHP become more significant this may make hydrogen more attractive.

Using different energy networks results in a more secure energy supply which may make slightly more costly options more attractive. The following Table provides a summary of the overall energy needs in the UK (by fuel source) under the four low carbon pathways explored in Interim Report 2.

Table 12.1 Energy Demand by Fuel Source in 2050

		TWh/year		
	Alpha	**Beta**	**Epsilon**	**Zeta**
Electricity	791	761	635	1,015
of which transport	*88*	*88*	*33*	*65*
Petrol/Diesel/Kerosene etc	218	218	100	195
of which transport	*51*	*51*	*74*	*70*
Hydrogen	22	22	22	22
of which transport	*22*	*22*	*22*	*22*
CHP	0	0	0	0
Others	148	148	40	105
Total (all fuel sources)	1,179	1,149	797	1,337
of which transport	*161*	*161*	*129*	*157*

Table 12.2 below compares the energy delivered to the UK with the total energy requirements in 2050 for electricity and the various transportable options considered[45]. The comparison is made for the Alpha low carbon energy scenario, i.e. approximately mid way between the extremes of the Epsilon (low demand) and Zeta (high demand) scenarios.

[45] Not including the Zinc-Air Battery Ship concept, which the results show not to be economically viable.

Table 12.2 Energy Delivered via Transport as a Proportion of UK Energy Requirements

		Proportion of UK Energy Requirements in 2050 (Pathway Alpha)			
		Outer Hebrides	Orkneys	Sahara (six sites)	Sahara (single site)
	Relative to				
Electricity Transmission Baseline	UK electricity demand	1%	1%	39%	1%
Transport of hydrogen to UK	UK electricity demand	<1%	<1%	15%	2%
	UK Demand for H_2 for Transport	22%	12%	727%	121%
Transport of hydrocarbons produced via Fisher Tropsch to UK	UK electricity demand	<1%	<1%	14%	2%
	UK Demand for HC for transport	12%	7%	401%	67%
Transport of ammonia to UK	UK electricity demand	0%	0%	12%	2%
	Current UK manufacture of ammonia UK[(i)]	61%	34%	1,968%	328%
Aluminium	Current worldwide Aluminium production[(ii)]	3%	2%	95%	16%

(i) 1 million metric tonnes of NH3 (measured as contained nitrogen), see Interim Report 1 (Section 3.4.5)
(ii) 33.9 million tonnes of aluminium per year, http://www.eaa.net/en/statistics/primary-aluminium/

The electricity that could be supplied to the UK from the two Scottish wind sites represents a very small proportion (around 1% or less) of total UK demand for electricity in 2050. Therefore, the output from these sites could be injected into a small number of Grid Supply Points near to the coast, and then distributed to final end users via the distribution system. For this reason, no allowances have been made for distribution network costs, as it is assumed that the transported energy simply displaces an alternative generation source, i.e. no additional distribution network is required.

The electricity that could be delivered from six CSP sites located in the Sahara via a transmission line represents 39% of total UK electricity requirement in 2050, which could be injected directly into GSPs for distribution via the existing distribution network. Although it is likely that the distribution system would need to be reinforced, this is due to the overall increase in electrification of our energy needs and not due to using remote renewable sources. The demand at a single GSP could vary between approximately 1,700 GWh/year to around 6,000 GWh/year (see Table 2.4 in Section 2.2.6). Thus, the electrical energy that could be delivered from the Sahara would meet the needs of around 50 of the larger GSPs.

Hydrogen produced at the Scottish generation sites represents a modest proportion (12% to 22%) of the UK's demand for this fuel for transport in 2050. However, the output of six CSP sites in Sahara would exceed the likely demand for hydrogen for transport in 2050 by a factor of more than seven.

Due to the higher demand for hydrocarbon based fuels for transport in 2050 compared to hydrogen fuel, the output of the Fisher Tropsch process represents a smaller proportion of the requirement for hydrocarbon based fuels in 2050. For the two Scottish wind sites, the output represents between 7% and 12% of UK demand. For the CSP sites in the Sahara, the output exceeds the UK demand by a factor of four.

As demonstrated in Section 7 there is a compelling case for relocating the manufacture of ammonia from the UK to the Sahara. In this case, all of the UK production of ammonia could potentially be undertaken in the Sahara. Similarly, a significant proportion of worldwide aluminium production could take place in the Sahara.

12.1 Matching Generation and Demand

The low carbon scenarios work undertaken in Task 3, Work Package 2 showed that whilst there will be a significant increase in demand for electricity over the period to 2050, there is considerable uncertainty over the pattern of that demand.

In particular, the pattern of demand associated with heat pumps and electric vehicles has a significant impact on the overall pattern of demand in the UK.

The analysis conducted in Work Package 2 produced load profiles for 2050 for each of the four pathways based on a number of underlying assumptions on the pattern of different end use loads. The demand profile is very much flatter than it is today, with much less variation across the day and from summer to winter. The peak during the winter is less of a pronounced, and there is less variation from summer to winter. Therefore, there are fewer peaks in demand to be managed. This is not to say however that there will not be short peaks and fluctuations on a day to day basis.

The following section considers three potential scenarios for the pattern of demand in 2050.

12.2 Energy Demand Scenarios for 2050

The diagrams below show the current profile of demand and the winter peak and summer peak profile for pathway alpha (the mid-point pathway in terms of demand growth).

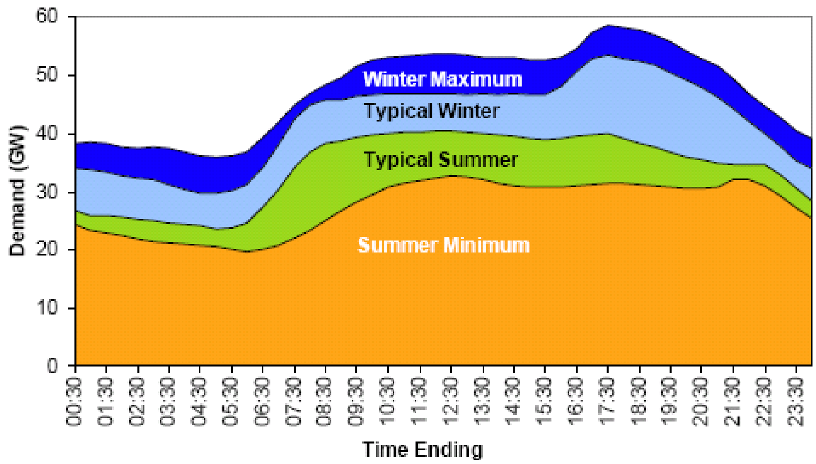

Figure 12.1 GB Summer and Winter Daily Demand Profiles in 2009/10[46]

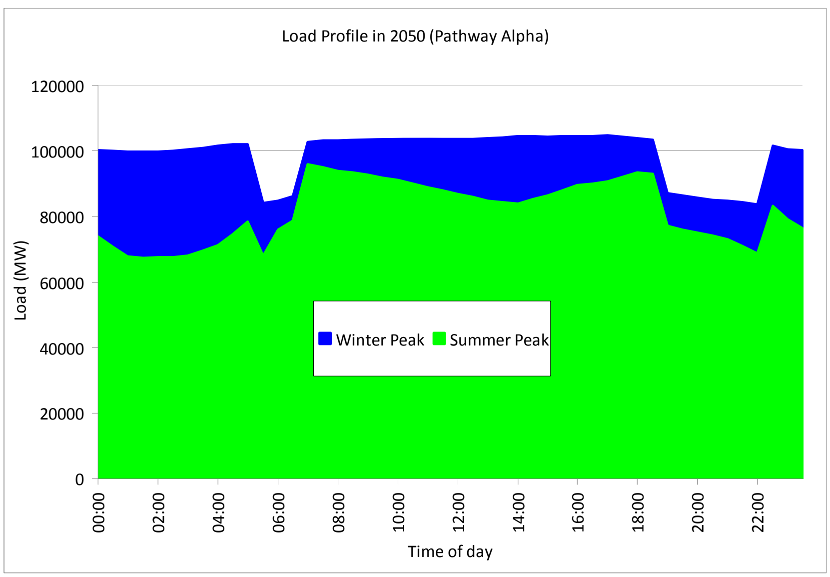

Figure 12.2 UK Summer and Winter Daily Demand Profiles in 2050[47] - Scenario 1

The baseload in the winter is around 80 GW, corresponding to minimum demand on a winter day. This is represented by the two 'notches' signifying the end of the electric vehicle

[46] National Electricity Transmission System (NETS) Seven Year Statement 2010, Chapter 2 Demand, Figure 2.2
[47] Work Package 2

charging period during the night but before the onset of industrial loads. The winter peak demand is around 100GW and occurs between around 7:00 and 18:00, i.e. 20GW above this baseload. There is also a second peak of around 95GW which occurs between 22:00 and 5:00, i.e. 15GW above the baseload. Thus the daily demand for peak energy during the winter (i.e. energy demand above the base load) is around 220GWh during the day and around 105GWh during the night, or 325GWh in total.

In summer the baseload is around 70 GW, compared to a daytime peak of around 90GW which occurs between 7:00 and 18:00, i.e. around 20GW above the baseload. There is no night time peak during the summer. Thus, the daily demand for peak energy during the summer (i.e. energy demand above the base load) is around 220GWh.

The winter load is around 2,250 GWh/day and the summer load is around 1,900 GWh/day. The total summer load each day between 7:00 and 18:00 is around 990GWh. The total winter load each day between 7:00 and 18:00 is around 1,100GWh.

The pathways also include the mix of generation required to deliver the carbon emissions by 2050. Under pathway alpha, electricity from renewable sources accounts of 37% of total electricity generation, with the remainder met by nuclear power and fossil fired generation with carbon capture and storage. None of these generation resources are well place to the provide flexibility to ensure that generation matches demand.

It was recognised during Stage 2 of the project, that considerable uncertainty surrounds the pattern of demand in 2050, particularly in relation to the load pattern for vehicle charging. Therefore, an alternative scenario was considered in which vehicle charging was assumed to remain at the average load level throughout the day, rather than primarily occurring during the night time period. The emergent profile is shown below, and it can be seen that the peak demand is now much higher (110GW) but with significantly lower night time demand (85GW), i.e. the compensating effects of vehicle charging and industrial demand are no longer present.

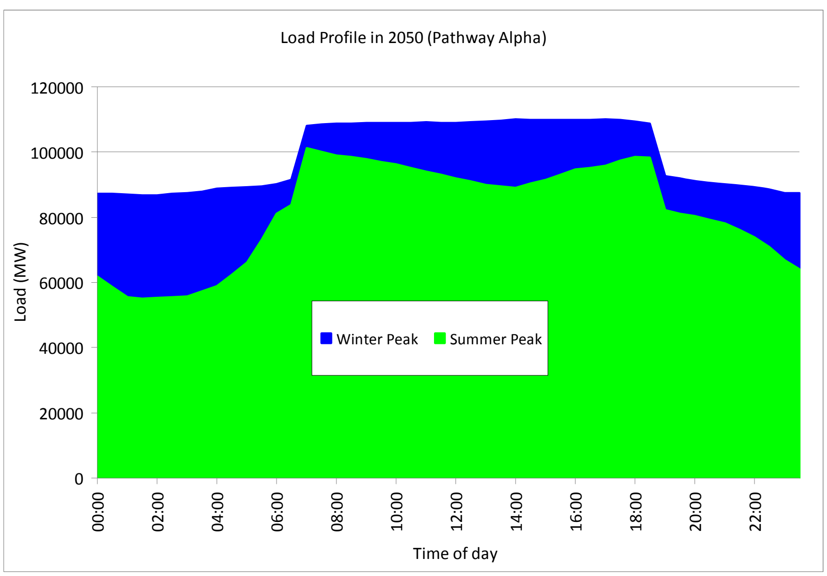

Figure 12.3 Scenario 2 profile for 2050 – Pathway Alpha

Under this scenario (referred to as Scenario 2), the baseload in the winter remains at around 85 GW, corresponding to minimum demand on a winter day, but the winter peak is now around 110GW and occurs between around 7:00 and 18:00, i.e. 25GW above this baseload. Thus the daily demand for peak energy during the winter (i.e. energy demand above the base load) is around 275GWh each day.

In summer the baseload is around 60 GW, compared to a daytime peak of around 100GW which occurs between 7:00 and 18:00, i.e. around 40GW above the baseload. Thus, the daily demand for peak energy during the summer (i.e. energy demand above the base load) is around 440 GWh each day.

The total daily load in winter and summer is unchanged at around 2,250 GWh/day and 1,900 GWh/day respectively.

The ETI also requested that the impact of a significantly more peaky demand profile on be considered, as indicated below.

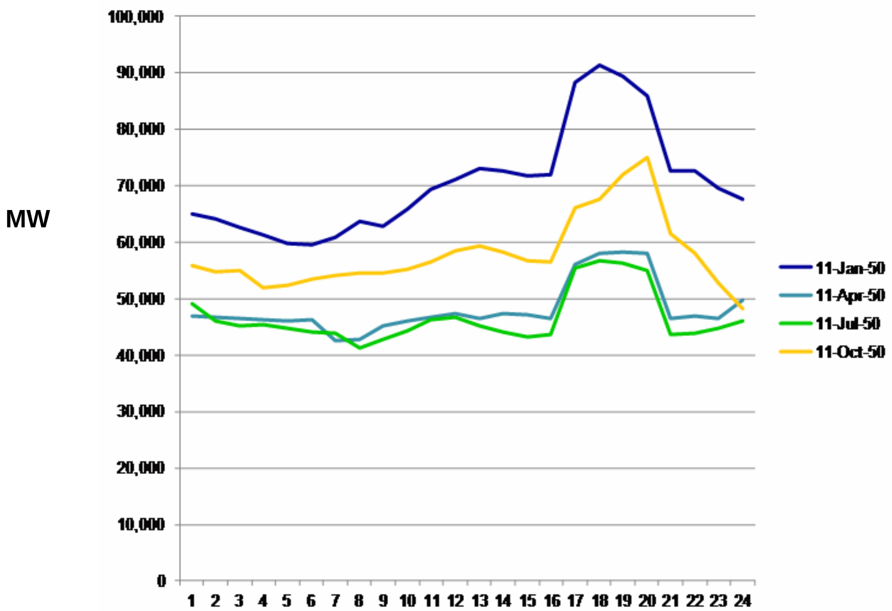

Figure 12.4 Scenario 3 profile for 2050[48]

Under this scenario (referred to as Scenario 3), the baseload in the winter (i.e. the minimum demand on a winter day) is around 60GW, but the winter peak is now around 90GW and occurs between around 16:00 and 20:00, i.e. 30GW above this baseload. Thus the daily demand for peak energy during the winter (i.e. energy demand above the base load) is around 120GWh each day.

In summer the baseload is around 40GW, compared to a daytime peak of around 58GW which occurs between 16:00 and 20:00, i.e. around 18GW above the baseload. Thus, the daily demand for peak energy during the summer (i.e. energy demand above the base load) is around 72GWh each day.

[48] Provided by Liam Lidstone, ETI via e-mail 30th September 2011

12.3 Cost of providing flexibility to match generation to demand

Options for providing the flexibility required to ensure that generation and demand are kept in balance at all times include:

- Use of fast acting generation plant, such as gas turbines or pumped hydro;
- Use of demand side flexibility, and
- Use of storage.

Fast acting partly or whole fossil fired generation are the methods by which most of the balancing between supply and demand is currently undertaken. However, by 2050, the cost of carbon could be prohibitively high, making this approach undesirable (from a carbon emissions perspective) and expensive (due to the high price of carbon). The technology may still be used with carbon neutral fuels.

Pumped hydro capacity in the UK is unlikely to increase significantly in future years, and can only meet a very small proportion of UK demand. It is best suited to meeting short duration balancing until other resources are brought ‘on-line’. As such, it is not well suited to providing balancing services during extended periods of low wind resource.

Demand side flexibility is a potentially valuable resource for short term mismatches between generation and demand. It is unlikely to be suitable for extended periods of low wind resource.

Network storage therefore provides a valuable resource for managing the mismatch between generation and demand. It provides the opportunity for energy generated during periods of, say, excess wind and low demand, to be stored for use during periods of low wind / high demand.

The renewable resources from the three generation sites could be designed to provide the flexibility needed to match demand to generation, this might include:

- Transferring electricity via a transmission line, with storage provided by electro-chemical technologies, i.e. batteries and flow cells. The storage could be located at the generation site, the demand site or at various points on the distribution or transmission networks; or
- Transporting energy using a chemical energy carrier, which can then be stored close to the demand site until required.

Comparing transmission / network storage and transportable energy storage for the provision of such balancing is complex. It depends on:

- How much storage capacity is needed i.e. if it is required to meet much shorter term peak demands (e.g. few hours per day), or is it required to cope with seasonal variations in demand. It is assumed that by providing this kind of storage, fluctuations in output from the generation would also be managed.
- How often the stored energy is utilised, i.e. is energy stored for a relatively short period of a few hours, a few days or from one season to another;
- The rate at which energy is input or extracted to / from the store;
- Proportion of generation output that is put into storage rather than used instantaneously / upon delivery; and
- Whether one large or a number of smaller, distributed storage units are used

Determining whether it is best for the output of a particular generation site to be utilised instantaneously (or on delivery for a transportable solution) or be stored for later use is complex. The optimum solution depends very much on the characteristics of the energy system as a whole, the range of energy sources and overall operation of the energy market rather than on the characteristics of one generation technology and transport link. It is also likely to depend on the characteristics of individual storage technologies deployed, i.e. hydrogen storage is likely to be more suited to longer term storage than, say, electro-chemical technologies such as batteries. This, therefore, makes it difficult to compare one storage technique with another.

A simple approach of assessing the costs associated with storing energy could be undertaken by assuming a size of store required (both in terms of the capacity and the maximum charge/discharge rates), and comparing the cost associated with using different storage media. The example below are a few plausible options given the characteristics of the generation sites, there are many more. The attractiveness of different options will vary according to the cost per MWh or MW of the different components.

It is important to note that the size of storage required is not determined with reference to the pattern of generation output and/or the pattern of demand at a particular site, e.g. a Grid Supply Point. This is particularly so when the demand site is part of an integrated energy system. The storage requirements can only be determined with reference to the needs of the energy market as a whole.

12.3.1 Concentrated Solar Power (CSP)

This provides a fairly constant output of around 842GWh/day suitable for base load. However the price to meet a peak may be higher than the base load price.

Solar energy resource is only available during the day, but the inherent storage capability of CSP enables electricity to be generated for up to 24 hours per day, making it well suited to baseload operation. However, it would be possible for some of the energy produced to be stored specifically for use during the peak periods, i.e. some of the energy produced at times of low demand could be stored for use times of peak demand.

Supplying peak energy during the day-time – Transmission option

If the storage is provided at the generation site, the additional costs of the storage would be minimal due to the inherent storage capability associated with CSP. However, the capacity of the DC transmission would need to be sized to meet the maximum demand to be supplied, i.e. between 90W and 110GW depending upon the load profile. The levelised cost of the baseline electricity transmission option ranges from £150/MWh for a 90GW HVDC cable increasing to £170/MWh for a 110GW HVDC cable.

If the storage is at the demand site, the DC transmission can be sized to the average output of the generation site, i.e. 78GW. Thus, the cost of transferring the electricity to the UK would be £139/MWh. In this case, energy flexibility would be supplied via a battery in the demand site, with an upfront cost of £283/kWh. The total storage capacity required would range from 120 GWh (Scenario 3 profile) to 275GWh[49] (Scenario 1 profile).

The levelised cost of storage per unit of electricity supplied during the peak time therefore around £160/MWh, which is in addition to the transmission cost of £139/MWh, i.e. giving a total cost of £300/MWh of electricity delivered.

[49] Winter day time peak energy requirement

Table 12.3 Day-time Peak Energy Provision Using HVDC Transmission Upfront investment costs and Levelised Cost Per Unit of Electricity Delivered

		Scenario 1	Scenario 2	Scenario 3
Storage at generation site	Capacity HVDC link	100GW	110GW	90GW
	Levelised cost of energy supplied	**£160/MWh**	**£170/MWh**	**£150/MWh**
Storage at demand site	Capacity HVDC link	78GW	78GW	78GW
	Levelised cost of HVDC link	£139	£139	£139
	Storage volume required at demand site	220GWh	275 GWh	120 GWh
	Upfront storage cost (i)	£623 billion	£779 billion	£340 billion
	Levelised cost of storage	£161/MWh	£161/MWh	£161/MWh
	Total levelised cost of energy supplied	**£300/MWh**	**£300/MWh**	**£300/MWh**

Supplying peak energy during the day-time – Transportable option

Providing storage at the demand site will incur additional costs for the additional storage and fuel cell capacity required to meet the peak load rather than the average generation output. A summary of the additional upfront investment costs and the levelised cost per unit of electricity delivered is shown below.

Table 12.4 Day-time Peak Energy Provision Using Transportable Energy Storage Upfront investment costs and Levelised Cost Per Unit of Electricity Delivered

	Scenario 1	Scenario 2	Scenario 3
Storage volume required	220GWh	275 GWh	120 GWh
Upfront storage cost (i)	£0.9 to 74.8 million	£1.1 to 93.5 million	£0.5 to 40.8 million
Fuel cell size required	100GW	110GW	90GW
Upfront fuel cell cost (ii)	£49 billion	£53.9 billion	£44.1 million
Levelised cost of storage and fuel cell	~£90/MWh	~£80/MWh	~£150/MWh
Levelised transportation costs	£230 to £270/MWh	£230 to £270/MWh	£230 to £270/MWh
Total levelised costs	**~£320 to 360/MWh**	**~£310 to 370/MWh**	**~£380 to 420/MWh**

(i) assuming storage costs of between £0.004/kWh and £0.34/kWh depending upon storage media

(ii) assuming fuel cell costs of £490/kW

The levelised cost of the fuel cell and storage per unit of electricity delivered would therefore be around £80/MWh to £150/MWh of electricity delivered. This would be in addition to the cost of transporting the energy to the UK from the Sahara, which is around £230/MWh[50] to £270/MWh[51] depending upon the storage media employed. Thus, the total cost of providing day time peak energy from the Sahara would be around £320/MWh to £420/MWh. The lower range of costs (i.e. assuming the use of either Hydrogen or Fisher Tropsch) is broadly comparable to providing a HVDC link and battery storage at the demand sites, but more than a direct HVDC link sized to meet the peak capacity.

Providing seasonal energy storage
The size of concentrated solar resource and its year round production makes it unfeasible for seasonable storage.

12.3.2 Wind

The wind sites considered have an output of between 7.2 and 25.9 GWh/day. This size of generation would be useful for short term peak lopping. For example, a wind farm that could guarantee the delivery of 5GWh of energy, capable being discharging in 0.5 hours (i.e. peak discharge rate of 10GW), would provide valuable reserve service or peak lopping generation.

Peak lopping / Reserve Generation – Transmission option
If the energy is stored at the generation site, then the transmission link would need to be sized to meet the peak demand (i.e. 10 GW). However, if the energy is stored at the demand site, the transmission link can be stored to meet the average output of the generation site, thus reducing the overall costs incurred.

In both cases, the electrical storage would need to be capable of storing 5GWh of energy and discharging at a peak rate of 10GW.

For a cost of electrical storage of £283/MWh, the levelised cost per unit of energy delivered is £161/MWh, which is in addition to the £70/MWh transmission cost. Thus, the total cost of delivering reserve power via a transmission line and electrical storage would be £231/MWh. This is assuming that the storage is at the demand site.

Peak lopping / Reserve Generation – Transportable option
Providing storage at the demand site will incur additional costs for the increased storage and fuel cell capacity required to meet the peak load rather than the average generation output.

The cost of additional chemical storage vessel ranges between £0.004/kWh and £0.34/kWh depending upon the storage capacity required. The fuel cell would need to be sized to meet the peak demand, i.e. 10 GW, compared to 0.2 to 0.6GW. A summary of the upfront investment required for storage and the fuel cell is shown below.

[50] Hydrogen and Fisher Tropsch
[51] Ammonia

Table 12.5 Reserve Generation via Transportable Energy Media

	Reserve Generation Capability
Storage volume required	5GWh
Upfront storage cost (i)	£0.02 to 1.70 million
Additional fuel cell size required	9.5GW
Upfront fuel cell cost (ii)	£4.9 billion
Levelised cost of storage and fuel cell	£380/MWh

(iii) assuming storage costs of between £0.004/kWh and £0.34/kWh depending upon storage media
(iv) assuming fuel cell costs of £490/kW

The levelised cost per unit of electricity delivered would therefore be around £380/MWh of electricity delivered, assuming that 5GWh of energy was provided once per day. This would be in addition to the cost of transporting the energy to the UK from the Scottish sites, which was around £230/MWh to £280/MWh depending upon the storage media. Thus, the total cost of providing reserve generation capability from the wind sites using a chemical energy carrier would be around £610/MWh to £660/MWh. This is significantly greater than the transmission option.

Seasonal Storage

The wind farms provide an output of between 2.6 and 9.5 TWh/year. If a third was stored for winter use, this would require 0.7 to 3TWh/year of storage. This could only be provided using chemical storage. The Table below provides a summary of the upfront investment costs associated with providing storage on this scale, together with the levelised cost per unit of electricity delivered.

Table 12.6 Seasonal Storage via Transportable Energy Media

	Seasonal Storage	
Storage volume required	0.7 TWh	3 TWh
Upfront storage cost (i)	£3 million to £1 billion	£0.01 billion to £0.2 billion
Additional fuel cell size required	0.3 GW	1GW
Upfront fuel cell cost (ii)	£0.2 billion	£0.5 billion
Levelised cost of storage and fuel cell	£34/MWh to £70/MWh	£25/MWh to £60/MWh

Thus, the levelised cost of providing seasonal storage would be in the region of £25/MWh to £60/MWh, in addition to the £230/MWh to £280/MWh cost of transporting the energy to the UK. Thus, the total cost of seasonal energy storage would be in the region of £250/MWh to £340/MWh depending upon the chemical energy carrier and the amount of storage provided.

12.4 Comparison of costs for matching generation output to demand

The following table provides a summary of the costs of matching generation output to demand for the various options considered above. The costs represent the total levelised cost per unit of electricity delivered, including the cost of transferring the energy to the UK from the generation site and the cost of additional storage and any fuel cell capacity required to meet the peak demand.

Table 12.7 Costs of providing peak load generation and seasonal energy storage

	Levelised cost per unit of electricity delivered
Provision of peak day time energy from the Sahara	
Via transmission of electricity sized to meet peak demand	£150/MWh to £170 /MWh
Via transmission of electricity with battery storage at demand site	~£300/MWh
Using chemical energy carrier	£320/MWh to £420/MWh
Provision of reserve generation from the Scottish wind sites	
Via transmission of electricity	£231/MWh
Using chemical energy carrier	£610/MWh to £660/MWh
Provision of seasonal energy storage from the Scottish wind sites	
Using chemical energy carrier	£250/MWh to £340/MWh

The results summarised above indicate that direct transmission via a HVDC link is the least cost option to utilise the solar resources in the Sahara to provide peak day time energy. However, this requires that the energy is stored at the generation site. If the energy is stored at the demand site, then the cost of the transportable option becomes broadly comparable to combining HVDC Transmission with battery storage.

Utilising the wind energy resources from the two Scottish wind sites to provide peak day time energy is approximately three times more expensive than providing that flexibility using a HVDC link and battery storage.

The costs of providing seasonal energy storage via the Scottish wind sites is calculated to be between £250/MWh and £340/MWh. None of the other options considered are suitable for seasonal storage, and as such no benchmarks are available for comparison.

Transportable energy solutions provide the opportunity for electricity delivery to be matched to demand, therefore represent a potentially more valuable resource than directly transmitted electricity. However, the value placed on the additional flexibility depends very much on the other competing resources and technologies available, such as network storage or demand side flexibility. Estimating the value attributed to such flexibility requires extensive modelling of the energy system as a whole and all appropriate interactions between all market stakeholders; which is outside the scope of this current project. It is not valid to compare transportable storage against transmission combined with storage from a particular generation site, as the storage is likely to be sized and located with regard to the needs of the whole of the electricity system not for one source. To keep the study entirely in the cost domain would require understanding the cost of spinning reserve, reinforcement of the network, total network storage required and other balancing costs. The price paid for balancing costs or peak electricity spot prices are the closest estimate to evaluating these costs. However, a useful indication of the how such flexibility might be valued can be inferred from another study that focused on the impact of intermittency and also by consideration of the current prices paid for balancing services and this provides, as outlined below.

Work undertaken by Poyry[52] has investigated the impact of intermittency on electricity market prices in 2030. Their results show that electricity prices could spike to £500/MWh or even considerably higher during periods of low wind. These prices represent the high cost associated with operating fossil fired generation plant for only a few hours per year, and are very much higher (by a factor of two) than the cost associated with transporting energy using the chemical carriers considered in this study.

It is also useful to consider the current prices paid for balancing services by National Grid to meet the mismatch between supply and demand. In the case of Short Term Operating Reserve, the average payments are in the region of £220 to £250 /MWh[53], which is broadly similar to the lower range of costs associated with seasonal energy storage using the output of the Scottish wind sites.

52 Impact of Intermittency, How Wind Variability Could Change the Shape of British and Irish Electricity Markets, Summary Report, Poyry Energy Consulting, July 2009.

53 Monthly Balancing Services Summary, National Grid for January 2011 and July 2011

13 Conclusions

The report considers the costs associated with transferring energy from a number of remote generation sites to either the UK or to Norway, or relocating aluminium or ammonia manufacture to the generation sites. Three remote generation sites have been considered, namely:

- CSP generation in the Sahara, to be imported to the UK;
- Wind generation in the Outer Hebrides, to be imported to the UK; and
- Wind generation in the Orkney Islands, to be exported to Norway.

The options for transferring the energy from these remote generation sites were as follows:

- Transmission of electrical energy via a HVAC or HVDC transmission network (as appropriate);
- Transmission of chemical energy carriers (hydrogen, hydrocarbons produced via the Fisher Tropsch Process and ammonia) via a single pipeline;
- Transport of chemical energy carriers (hydrogen, hydrocarbons produced via the Fisher Tropsch Process and ammonia);
- Transport of electrochemical energy using a battery ship concept (Zinc air and BPLA battery technologies); and
- Production of aluminium.

In terms of the levelised costs of delivering energy to the UK or to Norway using the selected energy storage media, the results demonstrate that electricity transmission represents the least cost solution if electrical energy is required at the demand site at the time of delivery. This is particularly true in the case of the two Scottish generating sites. For example, the cost associated with transferring electricity via transmission from the Outer Hebrides to the UK mainland is just over £70/MWh compared to between £232/MWh and £281/MWh for the chemical energy carriers, or over £500/MWh for the battery ship concept. For the CSP sites in the Sahara, the costs of transferring energy using the chemical energy carriers is similar to those for the Scottish site (i.e. between £228/MWh and £270/MWh), but the electricity baseline is £139/MWh.

However, in the case of the chemical energy carriers, the results suggest that there is a strong case for delivering the energy as a fuel for direct use. For example, hydrogen can be delivered to the UK from the Sahara at a cost of £124/MWh by ship or £120/MWh by pipeline, which is slightly less than that for direct transmission (i.e. £139/MWh). The case is even stronger for the Fisher Tropsch hydrocarbons, which can be delivered to the UK at a cost of £93/MWh of energy delivered, a saving of around 33% compared to the electricity transmission baseline. It is important to note that this analysis does not reflect the potential revenues to be gained by selling the energy as either grid electricity or hydrogen as a vehicle fuel; hence any of the ‘energy as a fuel’ routes could be commercially viable and indeed more profitable than the base case of delivering the energy as electricity.

Thus, there is evidence for focusing on delivering energy using hydrogen or a hydrocarbon for end uses such as transport, rather than converting the media back into electricity. The case is less clear for heating or CHP applications. Under the low carbon energy scenarios discussed in Interim Report 2, domestic and commercial space heating is dominated by heat pumps, which can be expected to have a Coefficient of Performance of 2 or more. (Coefficient of Performance is the ratio of heat output to electricity input). Therefore, any heating fuel would need to be at least half the cost of electricity. However, this does not take account of the capital costs of heat pumps or the impact of the additional load on the distribution network.

The economic case is broadly similar for the three chemical energy storage media considered, albeit with ammonia being slightly more costly than the other options. This is because increases in capital costs and losses associated with the manufacture of ammonia and hydrocarbons compared to hydrogen, are offset by their improved transportability (i.e. energy density) compared to hydrogen.

A number of options for matching energy generation to demand were considered. The results showed that, in general, electricity transmission with battery storage was the least cost option for providing peak daytime energy from the three generation sites considered. However, in the case of the CSP sites in the Sahara, the results show that if the energy storage is provided at the demand site, then the costs are broadly comparable in the case of Hydrogen and Fischer Tropsch. This would suggest that chemical energy storage media may have the potential to play an important role in meeting peak energy requirements. They also offer the only viable solution to providing seasonal energy storage.

The use of chemical fuels increases the diversity of our energy media making our energy networks less vulnerable to extreme weather events or sabotage. It is difficult to put a value of this diversity but should be investigated further.

It was not within the scope of this project to model the electricity system as a whole and the various interactions between all the stakeholders. Without such a model, it is not possible to fully explore the impact of one element (i.e. transportable energy storage solutions). However, the results of this study indicate that there is enough evidence to suggest that chemical fuels should be considered as energy media for meeting some of the UK energy demands in the future.

14 Recommendations

In terms of the levelised costs per unit of energy delivered to the UK, the analysis demonstrates that electricity transmission represents the least cost solution if electrical energy is required at the demand site at the time it is delivered. Therefore, it is recommended that the ETI focus on the development of DC transmission technology; improving efficiencies and lifetime of AC to DC converters and reducing costs.

The results also suggest there is enough evidence to indicate that chemical fuels could provide a viable alternative, particularly for meeting peak energy demand requirements, energy storage and as a means to increase energy diversity.

The Fisher Tropsch process is believed hampered at present due to the lack of a ready CO_2 source required for the process, which effectively implies that hydrogen production, for use as a fuel, is at a higher technology readiness than Fischer Tropsch. On this basis, and recognising that large scale (>2MW) electrolyser plant is well established and commercially available, it is recommended that ETI consider investing in a demonstration project concerning renewable base hydrogen production, storage and re-use (both for use as a transport fuel and potentially for reconversion via a fuel cell to grid electricity). Such a demonstration would seek, uniquely, to make use of the 'waste' oxygen from such a process, and to examine in detail the revenue potential (as opposed to the cost basis of this technology as per the work carried out in the study) of such a scheme. The timeliness of such a demonstration is significantly enhanced at present via the recent announcement of a new demonstrator programme to speed-up the adoption of hydrogen and fuel cell technologies. The £7.5million call for projects on 'whole system integration' is planned to open in January 2012[54].

Although aspects of such a demonstration project exist around the world e.g. Utsira in Norway, PURE in Shetland, it is clear that further study into larger scale systems, and with reuse of the oxygen produced, is required to permit full demonstration and study of both technology and economics.

It is believed that with ETI investment, such a large scale (~2MW+) renewable to hydrogen system would generate considerable intellectual property, know how and commercial/trading understanding of the applicability of hydrogen storage within future electrical grids.

The results indicate that Fischer Tropsch has the potential to offer a lower cost solution than Hydrogen, and much of the infrastructure to transport it and store it is already in place. Therefore, the ETI may also wish to also consider a demonstration of a renewable electricity driven Fischer Tropsch system of around 1MW capacity utilising CO_2 from a local cement works in a windswept location, for example Dunbar in Lothian.

The analysis shows that the transportable energy options become more favourable over the longer distances associated with the Sahara, due to the apparent insensitivity of shipping costs over the distances considered in this study. Therefore, it is recommended that the ETI should assess the potential opportunities for developing transportable energy solutions for other remote generation sites with valuable renewable energy resources.

It is recommended that the ETI maintain a watching brief on renewable technologies, including the costs and performance of electrolysers using renewable energy resources, and the storage and transport costs of chemical energy carriers.

[54] Technology Strategy Board, www.innovateuk.org

Appendix 1 Description of Potential Candidate Storage Media

The potential storage media considered as part of this project were identified in Section 4 of Interim Report 1. The key characteristics of those identified as potential candidates for the transfer of energy from a remote generation site were provided in Section 4 of Interim Report 2.

In addition to those media highlighted in Interim Report 2, the list of potential candidate technologies has now been expanded to include:

- Bipolar lead acid (BPLA) battery energy storage;
- Zinc-air battery energy storage; and
- Aluminium-air battery energy storage.

The following subsections describe each of these potential candidate storage media.

Bipolar Lead Acid (BPLA) Battery Energy Storage

This technology is an improvement to the conventional lead acid batteries described in Interim Report 1. Instead of separate anodes and cathodes, each plate is anodic on one side and cathodic on the other. In addition to reducing the mass of the battery and therefore increasing its energy density, it also dispenses with the top busbars that are present in all standard lead acid batteries.

Bipolar lead acid batteries are between a third and half the mass of standard lead acid batteries for the same current and power. This is, however, an emerging technology.
In the case of all lead acid batteries, the materials are 100% recyclable with the infrastructure for recycling already in place. Battery management is minimal when compared to lithium ion, and the round trip efficiency is close to 80%.

Although this is an emerging technology, the basis for the technology has been around since the 1920s. Several battery systems based on this technology are already in production.

Zinc Air Battery Energy Storage

Zinc metal can be recovered from its ores (such as Sphalerite) by the process of ‘electrowinning’ i.e. the electrodeposition of metals from ores which have been put in a solution or liquefied. Zinc can be easily ‘electrowon’ at low temperatures from a variety of soluble salts.

In ‘electrowinning’, a current is passed from an inert anode through the solution containing the metal. The metal is then electroplated onto the cathode and typically oxygen is evolved at the anode.

The reverse of this ‘electrowinning’ process is the principle behind a zinc-air cell. The concept is illustrated in the following pair of diagrams.

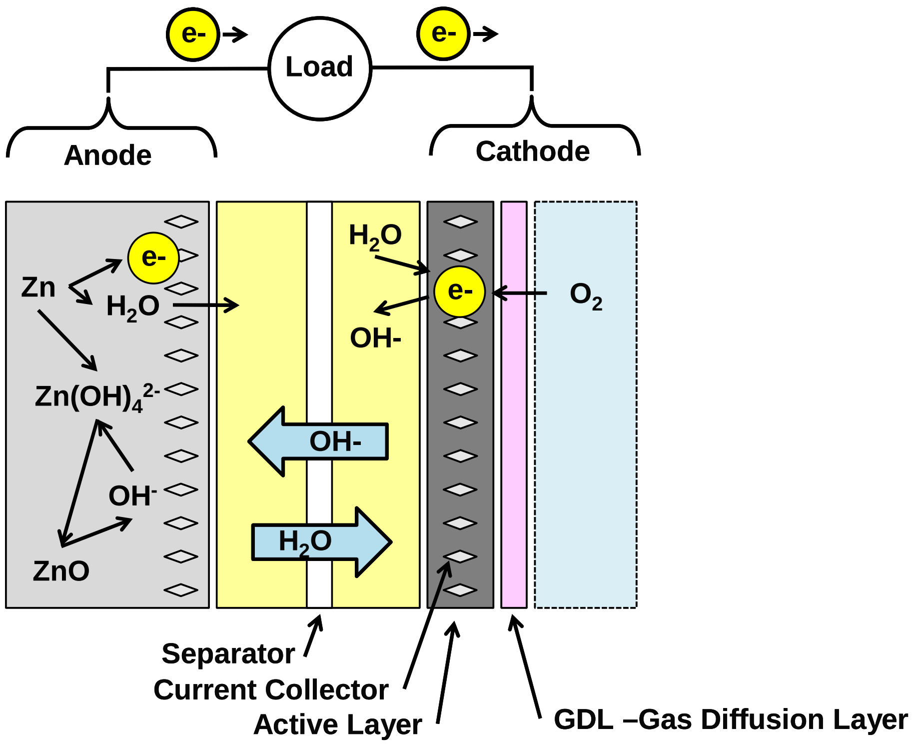

Figure A.1 Zinc Air Concept[55]

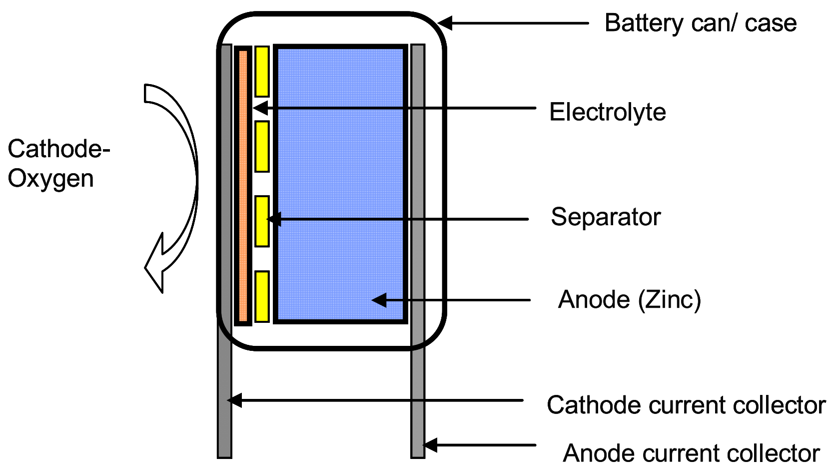

Figure A.2 Zinc Air Battery Schematic[55]

Zinc metal is present in the form of a 'slurry' of ground zinc metal powder mixed with hydroxide salts. When reacted with air, energy can be recovered as electricity. A rechargeable Zinc Flow Air Battery is under development by ReVolt Technology. This makes use of a zinc 'fuel/ gas tank' to hold the active slurry. This slurry is then pumped through reaction tubes to generate electricity. The capacity can be varied with the size of the storage tank, whilst the power rating depends on the length and number of reaction

[55] Information provided through private correspondence with Caterpillar

tubes. ReVolt has the following Beta performance targets for Zinc Flow Air Batteries[55] for energy storage applications:

- 100kWh capacity;
- Energy Density of 200Wh/kg, 400Wh/ litre (for the complete system);
- 'Power' Density of 500W/ litre, 250W/kg (for the complete system);
- Cycle life of 5000 cycles to 80% of initial capacity; and
- Cost of less than $100/kWh for the system.

The energy capacity figures above include the impact of an 80% round trip efficiency, such that whilst the energy carrier is capable of providing 650Wh/kg, in reality 520Wh/kg would be delivered due to conversion losses.

Aluminium and Aluminium Air Batteries

Aluminium metal could potentially be made at the generation sites in the Sahara and northern Scotland, where bauxite supplies exist. Bauxite can be purified to produce aluminium oxide (Al_2O_3). Aluminium is then obtained by electrolysis of the aluminium oxide in molten cryolite (Na_3AlFe_6), at a working temperature of around 1000^oC[56]. The process requires very high currents, in the order of 100,000A and therefore generation using electricity from a cheap, renewable source such as the generation sites under consideration in this study, or more traditionally, hydroelectric power, is preferable.

The energy density of aluminium metal is around 32MJ/kg, and it requires approximately 46-56MJ/kg to produce from bauxite. The higher energy density of aluminium compared to zinc, and the presence of bauxite reserves in the Sahara make the production of aluminium metal a potentially attractive option for transportable energy storage, in comparison with the production of zinc metal.

The aluminium produced would then be transported to the demand site via large shipping containers. It would be necessary for the ships to return to the generation site empty, unless a suitable return load could be identified.

Aluminium has a number of uses at the demand site and is consistently in high demand for the construction and manufacturing industries. A further use of aluminium produced at the generation sites could be for use as the anode material in aluminium-Air batteries. The cost for aluminium in this application can be as low as $ 1.1/kg when the reaction products from the cell are recycled[57].

Aluminium-air batteries have been under investigation since 1970s, principally for military applications. The half-equations for the oxidation (loss of electrons by anode material) and reduction (gain of electrons at the cathode) are as follows:

$$\text{Oxidation at the anode: } Al + 3OH^- \rightarrow Al(OH)_3 + 3e^- + -2.31V$$
$$\text{Reduction at the cathode: } O_2 + 2H_2O + 4e^- \text{-}\!\!\rightarrow 4OH^- + +0.40V$$

As can be seen by the equations above, aluminium is used up in the process, as it is converted to hydrated aluminium oxide ($Al(OH)_3$). Where potassium hydroxide is used as the electrolyte material, a potential difference of 1.2V is created by the reactions across the cells. In previous designs, the batteries had a limited shelf life as the aluminium reacted with the electrolyte when not in use, generating hydrogen gas. This has been overcome by storing the electrolyte outside of the battery and only transferring it to the battery when

[56] Aluminium Extraction. From 'The Complete A-Z Chemistry Handbook'. 2nd Edition. Andrew Hunt.
[57] Design and analysis of aluminium/ air battery systems for electric vehicles. Yang, S. and Knickle, H. 2002. Journal of Power Sources 112 (1): 162-173.

required. The aluminium anode is also corroded by the electrolyte and so aluminium is typically alloyed with tin or other elements[58]. The hydrated aluminium oxide can form a gel-like substance which coats the aluminium, reducing the electricity output. This can be partially overcome by using additives which form the hydrated aluminium oxide as a powder rather than a gel[58].

Air cathodes typically consist of a reactive layer of carbon with a nickel-grid current collector, a catalyst and a porous hydrophobic PTFE film to prevent electrolyte leakage. Oxygen can pass through the PTFE film and reacts with water to create hydroxide ions.

It may be possible to mechanically recharge aluminium-air batteries by recycling the hydrated aluminium oxide to make new aluminium anodes. However, this requires a large amount of additional heat, in common with the production of aluminium from bauxite.

Aluminium-air batteries have the potential to offer high energy densities, currently in the region of 1300Wh/kg and projected to reach a maximum of 2000 Wh/kg. Costs are estimated to be around $30/kW[57].

[58] http://aluminium.org/AM/Template.cfm?Section=Home&template=/CM/HTMLDisplay.cfm&ContentID=15793 Accessed 18/07/11

Appendix 2 Life Cycle Carbon Analysis

The Carbon Life Cycle represents all the carbon emissions and other green house gases associated with the whole life cycle of a process or product. That is, all the emissions associated with extraction of materials, manufacture, transport, use and decommissioning. The impact of different gases emitted is normally expressed in terms of the amount of carbon dioxide that would have the equivalent global warming impact. The amount is expressed as an intensity, in this work per kWh of energy delivered.

Comparing the carbon life cycle of different options is very difficult. A number of the issues are listed below:

- In any lifecycle analysis, the boundaries of the system can be very influential on the result. For the cases considered, the different methods for storage and transport methods makes it very difficult to ensure that the boundaries in each case are the same.
- Much work has been done on life cycle analysis but the results are very specific to the size and technology in hand. How the results scale is difficult to determine.
- As technologies becomes more mainstream, energy of production typically reduces and material costs are saved; however this is hard to predict.
- The carbon intensity of power for manufacture varies across the world and will change in the next 40 years.

For these reasons, the analysis focuses on the key issues that increase or decrease the carbon lifecycle and how these affect the different transportable energy storage options. A number papers were used as a basis for this comparison. These provide at least some data on all the options, but has the drawback of combining results that use different analytical techniques. As previously referred to in the second interim report, the work by Gareth Harrison et al[59] studies the carbon emissions life cycle of the Transmission System in the UK. Work sponsored by Department of Energy in the United States studies the life cycle analysis of hydrogen from LNG and Coal[60]. This draws on a number of other studies. A third study by the same authors analysed the 'Carbon Life Cycle of Renewable hydrogen Production via Wind/Electrolysis'.[61] In all cases, all greenhouse gases are equated to the equivalent carbon dioxide emissions that would have the same impact.

In all the studies reviewed, despite the difference in scale and carbon intensity of the power used, the construction of the storage and transport systems, including electrolysers and reformers etc, is a very small part of part of the overall carbon emissions. Examples of this small contribution are demonstrated in some of the original papers:

- For the study of hydrogen from LNG, the construction costs were 1% without carbon capture and 4% with carbon capture.
- In the case of hydrogen from wind, the construction and operation of three wind turbines caused 78% of the global warming potential (GWP) and the electrolyser, hydrogen compression and storage accounted for 21% of the GWP.

[59] Life cycle assessment of the transmission network in Great Britain. G. Harrison, E. Maclean, S. Karamanlis, L. Ochoa. Energy Policy Volume 38 (2010).
[60] Life-Cycle Analysis of Green House Gas Emissions for hydrogen Fuel Production in the United States from LNG and Coal Pamela L Spath and Margaret K Mann DOE/NETL-2006/1277
[61] Life Cycle Assessment of Renewables hydrogen Production via Wind/Electrolysis February 2004 NREL/MP-560-35404

- In the case of transmission, construction accounted for 3% of the total GWP. In this case, the release of SF_6 and other losses were more significant.

In general the use of metal and concrete are significant contributors to the carbon emitted in construction. It should be noted that in the case of transmission systems, where the electricity is from renewable sources, electrical losses will not contribute to global warming.

A2.1 Sensitivity Analysis

The GWP of each method is highly sensitive to size of the system, materials used and the carbon intensity of the electricity:

- For the hydrogen from wind system, including the construction of the wind turbines, a reduction in materials of 25% results in a drop of 11% in the overall GWP.
- A change in carbon intensity of the electricity used for construction and manufacture of the GB transmission causes a change of 36% in GWP potential. This is validated by the equivalent calculation for the Swedish transmission network where the construction emissions are 0.25 gCO_2e /kWh compared to 0.4 gCO_2e/kWh in Great Britain, reflecting the low carbon intensity of their hydro generated electricity.
- Whilst the carbon emissions for construction of small cables is greater than the equivalent overhead line, at larger capacities this is reversed. At a voltage of 275kV and for a capacity of 1,000MVA, a cable accounts for 2,600 tonnes CO_2e/km in carbon compared to 5,200 tonnes CO_2e/km for an OHL.

For the carbon life cycle analysis, it is assumed that all transport fuel is renewable and therefore does not contribute to the GWP of the system. However, it is assumed that reforming a hydrocarbon will emit carbon and the energy used for manufacture may not be from renewable sources. This carbon could be captured but this would require energy.

The wind to hydrogen calculation uses 3 x 50kW turbines. Scaling is likely to reduce the carbon emissions although it is hard to predict by how much given that such large scale electrolysis from renewables has not been demonstrated. However to reflect this, the value is reduced by 20%.

The following Sections therefore consider the carbon emissions associated with construction of the plant, storage and transport systems (Section A2.2), pipelines (Section A2.3), batteries (Section A2.4) and road transport (Section A2.5).

A2.2 Transmission and Plant Items (Electrolysers, Compressors, Storage, Reformers)

The work by Gareth Harrison et al[62] includes all construction, operation and maintenance work, SF_6 losses and transmission losses. As the 132kV network is considered as "Transmission" in Scotland, the contribution from this network is included for Scotland. On this basis, 85% of the carbon emissions associated with transmission are from losses, assuming carbon intensity of electricity in the UK over 40 years remains constant. Thus, the impact of renewable generation sources can be incorporated by reducing the emissions

[62] Life cycle assessment of the transmission network in Great Britain. G. Harrison, E. Maclean, S. Karamanlis, L. Ochoa. Energy Policy Volume 38 (2010).

associated with transmission by 85%, as renewable electricity is carbon free. With the points above, the following approximate lifecycle figures are shown below.

Table A.1 Approximate Carbon Life Cycle Data

	$gCO_2e/kWh^{(*)}$
Electrolysis, compression, storage and shipment of hydrogen	5.2
Hydrocarbon liquefaction, reformation and storage	14
Transmission – GB Transmission, for present use and capacity, excludes losses	2.0

(*) To two significant figures

The Gareth Harrison paper demonstrates that although at lower capacities, overhead lines are less carbon intensive than cables, at high capacity the reverse is true. Figures for cable and OHL loaded at 1000MVA on average are shown in Table A.2. Scaling these figures provides an estimate for the associated carbon footprint for the transmission of electricity from the three generation sites.

Table A.2 Approximate Carbon LifeCycle Data for Cables and Overhead Lines

Details	Units	Value
275kV overhead line, loaded at 1000MVA on average over 40 years (without transmissions losses	gCO_2e/km	780,000,000
275kV cable, loaded at 1000MVA on average over 40 years (without transmissions losses)	gCO_2e/km	390,000,000
275kV cable emissions per kWh (assuming 175GWh carried)	$gCO_2e/kmkWh$	2.23
cable Orkney to Sweden 500km 2GW	gCO_2e/kWh	1.86
cable Hebrides to England 800km 3GW	gCO_2e/kWh	2.77
cable Sahara to UK 1900km 78GW	gCO_2e/kWh	4.7
cable across to African coast 200km 78GW	gCO_2e/kWh	0.49

The calculations for the cables from the demand sites have used the figure for the 275kV cable per km. This value is divided by the assumed load of 175GWh carried over 40 years to get the value of $gCO_2e/kmkWh$. This value is scaled to reflect the larger capacity and load carried over 40 years for transmission from each of the generation sites and multiplied by the distance to get a value in $gCO_2e/kmkWh$ for each of the generation sites.

These figures are very approximate and demonstrate that the carbon lifecycle of the different options are within the same order of magnitude.

- Electrolysis may be carried out near the sea and a transmission line may be required even if hydrogen is used as a storage media.

- The sensitivity of the figures to materials and the carbon intensity of power used in construction means that there may be very little difference between transmission electrolysis and reforming.
- The efficiency of different systems should be taken into account as well as their carbon lifecycle.

A2.3 Pipelines

Factors affecting the size of pipeline used for different chemicals are:

- Variation in capital cost of the pipeline for different lengths and sizes.
- Cost of compression and pumps for different sizes.
- Energy density of the chemical transported.
- Energy losses in the pipe at different sizes.

The company Nacap carried out an investigation into the carbon emissions of pipelines.[63] It is assumed that the operation and maintenance of a pipeline is very small and is therefore not included. Five different diameters of pipeline were studied. By far the most significant emissions were from the steel manufacture. The percentage of the footprint due to steel increases as the diameter of pipe increases. However, these manufacturing costs will reduce as power is decarbonised.

Table A.3 Steel footprint vs. pipe diameter

Pipe diameter	tonnes/km (steel)	tonnes/km (total)	% of steel
416	133.7	240.4	0.56
520	206.4	325.1	0.63
624	258.6	415.9	0.62
936	543	768	0.71
1248	973.7	1260.4	0.77

It is assumed that whilst the cost of a hydrogen pipeline may be greater due the better seals and type of metal required, the carbon footprint of a pipeline will be similar regardless of the gas or liquid carried as the steel is the major contributor to the carbon footprint. However for the same size pipe, as the energy density of ammonia and synthetic hydrocarbon is much higher than hydrogen, more energy and mass of gas can be supplied.

Hydrogen

A study for WHEC[64] showed that for a 2GW wind farm at 40% capacity, the most appropriate diameter of pipeline carrying hydrogen depended on the length. For example a 520mm diameter 800km pipeline is sufficient if no compression is used. The capacity reduces if the length is increased. Compression would increase the capacity. Therefore from the table above the carbon footprint for a pipeline from the wind farms considered is estimated to be around 325 tonnes/km for 2 GW. Figures for the optimum diameter pipe are not available but the carbon footprint is likely to be similar.

[63] Carbon Footprint of Pipeline Projects How does Nacap decrease the emission of carbon dioxide while bringing energy to its destination? 44th Annual IPLOCA Convention, Venice, 27 September -1 October 2010

[64] Compressorless hydrogen Transmission Pipelines Deliver Large-scale Stranded Renewable Energy at Competitive Cost 16th World hydrogen Energy Conference, W. Leighty et al Lyon, 13-16 June 2006 Lyon France

Making approximate extrapolations from the numbers available to transport hydrogen from the Sahara and the higher capacity factor of 45%, 4 x 1,248mm diameter pipes would be required, each with a carbon footprint of 1,260 tonnes/km footprint.

Ammonia

Ammonia is normally carried as a liquid. Due to its molecular structure, ammonia contains 48% more hydrogen per unit volume when liquefied than does the H_2 itself, i.e. a cubic metre of liquid hydrogen contains 71kg of hydrogen compared to 105kg in ammonia. It is assumed, therefore, that the size of pipe required for ammonia has a cross section that is about 67% that required for hydrogen. In practice the diameter may be even smaller as the ammonia will be in liquid form and therefore denser that hydrogen gas. How much denser depends on the pressure applied to the hydrogen. However ammonia may not pass through the pipe as quickly and therefore require a larger total cross section.[65]

Taking these factors into account it is estimated that a pipe of approximately 416mm diameter is required for transporting the energy as ammonia from Orkney or the Hebrides with a carbon footprint of 240 tonnes/km. From Sahara the number of 1,248mm diameter pipes could be reduced to three, each with a carbon footprint of 1,260 tonnes/km footprint.

Figures for the optimum diameter pipe are not available but the carbon footprint is likely to be similar in all cases.

Hydrocarbons

Liquid hydrocarbons could be produced by the Fischer Tropsch process. Examples of the volumetric energy density of different hydrocarbons, hydrogen and ammonia are given below for comparison[66]:

Table A.4 Volumetric Energy Densities of Hydrocarbons

Material	Volumetric Energy Density (Wh/litre)
Diesel	10,942
Gasoline	9,700
LNG	7,216
Propane (liquid)	7,050 +/-450
Ethanol	6,100
Methanol	4,600
Ammonia	4,325
Liquid H_2	2,600

Thus, output from the Fischer Tropsch process has a volumetric energy density of around twice that of ammonia and therefore the cross sectional areas of the pipes would be half that required for ammonia. As noted above, the speed that the liquid travels determines the pipe

65 Overview of Interstate hydrogen Pipelines. J Gillette, R Kolpa. Argonne National Laboratory November 2007 http://corridoreis.anl.gov/documents/docs/technical/APT_61012_EVS_TM_08_2.pdf accessed 23rd August 2011.

66 ^ Appendix B, Transportation Energy Data Book from the Center for Transportation Analysis of the Oak Ridge National Laboratory

size as well as the density. For example two pipes of 1,248mm and 936mm could carry the output from the Sahara with a combined carbon footprint of around 2,000 tonnes/km. A pipe less than 416mm in diameter could service the Hebrides or Orkney. Carbon footprint is not available for these sizes however the footprint does not reduce linearly at small diameters and therefore a figure of 200 tonne/km is assumed. The carbon footprint, in terms of gCO_2e/kWh, is calculated by multiplying by the distance and dividing by the energy carried over 40 years.

Table A.5 Carbon Footprint for Pipelines

Pipeline distances (km)	Carbon Footprint H_2 CO_2e/km	Carbon Footprint NH_3 CO_2e/km	Carbon Footprint CH_n CO_2e/km	Carbon Footprint H2 CO_2e/kWh	Carbon Footprint NH3 CO_2e/kWh	Carbon Footprint CHn CO_2e/kWh
500	325,000,000	24,000,000	200,000,000	0.77	0.57	0.48
800	325,000,000	240,000,000	200,000,000	0.77	0.57	0.48
1900	5,040,000,000	3,078,000,000	2,000,000,000	0.78	0.58	0.31

A2.4 Batteries

The carbon lifecycle of batteries is hard to estimate given that the technologies are still very new, particularly for very large scale storage. Two papers discuss the carbon lifecycle of batteries designed for cars. The first examines traditional lead acid and zinc air although many of the figures for zinc air regarding its manufacture are unavailable[67][1]. It is assumed that lead acid bi polar will have a similar footprint to lead acid. The second examines the use of lithium ion batteries[68]. The figures for mining, manufacture and recycling are in the same order of magnitude of between 300 and 400kg for a battery that would fuel a car for between 150,000 and 200,000km. Assuming that travelling this distance requires between 38000kWh and 43000kWh, this gives the carbon emissions at between $7.9gCO_2e/kWh$ and $9.3gCO_2e/kWh$.

It should be noted however the pack design and charging regime will be completely different for transportable storage compared to electric vehicles that should extend the life of the battery and increase its efficiency.

These figures are of a similar order of magnitude to the other transportable options.

Note that any battery technology may be in competition for materials with the vehicle industry in future. Zinc has the advantage that it is more abundant that lead.

[67] Life Cycle Assessment for five electric vehicle batteries under different charging regimes. Michail Rantick, Chalmers University of Technology December 1999 ISSN 1401-1271

[68] Life Cycle Assessment LCA of Li-Ion batteries for electric vehicles, M. Gauch et al Federal Laboratories for Materials Testing and Research TSL Technology and Society Lab http://www.cars21.com/files/news/LCApresenation.pdf

A2.4 Road transport[69]

Defra quote a figure of 0.89kgCO_2e per £ spent for the embodied carbon in road transport. This should give an indication of the embodied carbon. If a lorry costs £100,000 and transports 500,000kWh in 10 years, this gives 0.000178gCO_2e/kWh.

This assumes that all the fuel is renewable.

A2.4 Shipping

It is assumed that the fuel to drive ships will be renewable by 2050; indeed the generation source may provide this fuel. The carbon emissions from shipping chemical fuels will be associated with the manufacture and maintenance of the ships.

Unfortunately it is difficult to find an estimate of the carbon emissions associated with shipyards. The main source of carbon emissions from shipping at present are from the fuel used and the focus on work to carbon footprint and reduce emissions from shipping.

The National Maritime Laboratory in Japan developed software[70] to carry out carbon lifecycle analysis of the whole of their shipping industry. It estimates that the carbon emissions from building a 76000 dead weight tonne (dwt) sized ship as 15 000 tonnes of CO2e. The majority of the emissions are due to the manufacture of steel. As the ships envisaged are larger than the 76000 dwt cargo capacity, this figure is multiplied by 1.5. It is assumed that 1 ship is needed from Orkneys and the Outer Hebrides, and 10 are required for the Sahara routing. The emissions are summarised in the Table below.

Table A.6 Carbon Footprint for Shipping

Shipping emissions	gCO_2e/kWh
Hebrides	0.213
Orkney	0.171
Sahara	0.029

There is significant interest in developing more efficient ships and introducing new materials. Therefore these numbers are likely to reduce in future. The additional carbon cost of shipping is small compared to the manufacture of other plant used in creating chemical fuels.

A2.5 Conclusions of Carbon Life Cycle Analysis

The figures above are drawn from different sources using different methods and extrapolated for sizes or technologies where figures are not available. New technologies are likely to significantly reduce their carbon footprint over time and manufacturing and efficiency in sue of materials improves. These variations could alter the carbon foot prints that could change the differences in the size of the footprints of the difference options.

[69] http://archive.defra.gov.uk/environment/business/reporting/pdf/101006-guidelines-ghg-conversion-factors.pdf
[70] 'Development of LCA software for ships and LCI Analysis based on actual shipbuilding and operation' Kameyama M, Hiraoka K, Sakurai A, Naruse T, Tauchi H, National Maritime Research Institute http://www.nmri.go.jp/env/lca/Paper/pdf/44.pdf accessed 21st September 2011

The estimates above are about 1% of the carbon intensity of our present electricity (around 540g CO_2e/kWh). The figures above do not include the carbon emissions of building the renewable generation plant itself, but the total emissions would not be more than a few percent of our present generation emissions.

None of the figures indicate that the carbon lifecycle should be a significant factor in the choosing between different options.

Appendix 3 Transmission Network Costs

Table A.7 provides a summary of how an equivalent £/MWh network transmission cost has been determined for each of the generation sites.

Table A.7 Capital Costs of Distribution Infrastructure Assets(♦)

Generation Site	Outer Hebrides		Orkneys	Sahara
	(AC)	(DC)		
Demand Site	North West UK		Norway	South Coast UK
Capacity (GW)	2.7		1.5	78
Annual Output (GWh/year)	9,461		5,256	307,476
HVAC Cable				
Distance (km)	80			
Cost (£/MWkm)	3933			
Total Cost (£million)	850			
HVAC OHL				
Distance (km)	700			
Cost (£/MWkm)	312			
Total Cost (£million)	590			
HVDC Cable				
Distance (km)		800	500	1,900
Cost (£/MWkm)		1,300	1,300	1,300
Total Cost (£million)		2,808	975	192,660
Total (£million)	**1,439**	**2,808**	**975**	**192,660**
HVAC Cable				
Losses (%/1000km)	8			
Losses (GWh/year)	61			
Transformer Losses (GWh/year)	24			
Total losses (GWh/year)	85			
HVAC OHL				
Losses (%/1000km)	8			
Losses (GWh/year)	530			
Transformer Losses (GWh/year)	24			
Total losses (GWh/year)	554			
HVDC Cable				
Losses (%/1000km)		3	3	3
Losses (GWh/year)		227	79	17,526
Converter Losses (GWh/year)		189	105	6,150
Total losses (GWh/year)	638	416	184	23,676
Total electricity delivered (GWh/year)	**8,871**	**9,045**	**5,072**	**289,950**
Transmission costs (£/MWh)(*)	**14.9**	**28.3**	**17.5**	**61.9**

(♦) Excluding operating costs
(*) The transmission cost is determined assuming the capital costs are recovered over 60 years at a discount rate of 10%.

For comparison, current Transmission Use of Network tariff for demand customers[71] ranges from around 0.9p/kWh to 3.9p/kWh (or between £9/MWh and £39/MWh).

[71] National Grid Demand TNUoS Tariffs applicable from 1st April 2011 – values shown are for non half-hourly metered customers

Appendix 4 Distribution Network Costs

Table A.7 provides a summary of the capital costs of distribution network assets. As presented in Interim Report 2, these are the costs assumed by Ofgem in the Distribution Price Control Review 5 (DPCR 5). Taking a similar approach to transmission networks, no adjustments are included for future costs due to shortages of materials, increased costs of energy and the need to protect against the impact of climate change.

Table A.8 Capital Costs of Distribution Infrastructure Assets

Cables	**Units**	**£ / unit**
6.6/11kV UG Cable	km	82,900
33kV UG Cable	km	256,800
132kV UG Cable	km	104,7100
Transformers		
6.6/11kV Transformer (GM)	#	13,200
33kV Transformer (GM)	#	377,900
132kV Transformer	#	1,018,700
Switchgear		
6.6/11kV CB(GM)- Primary	#	51,800
6.6/11kV RMU	#	13,000
33kV CB (Outdoor)	#	50,100
33kV RMU	#	259,500
132kV CB	#	679,600
Overhead lines		
33kV	km	274,200
132kV	km	762,500
11kV	km	137,100

The components of the distribution network supplied from a single Grid Supply Point (GSP) are assumed to be as described in Figure A.3. It is assumed that each GSP supplies electricity to four bulk supply points (BSPs), which in turn supply electricity to four primary substations, which then each supply five 11kV feeders. Each GSP is assumed to supply 4,100 GWh/year.

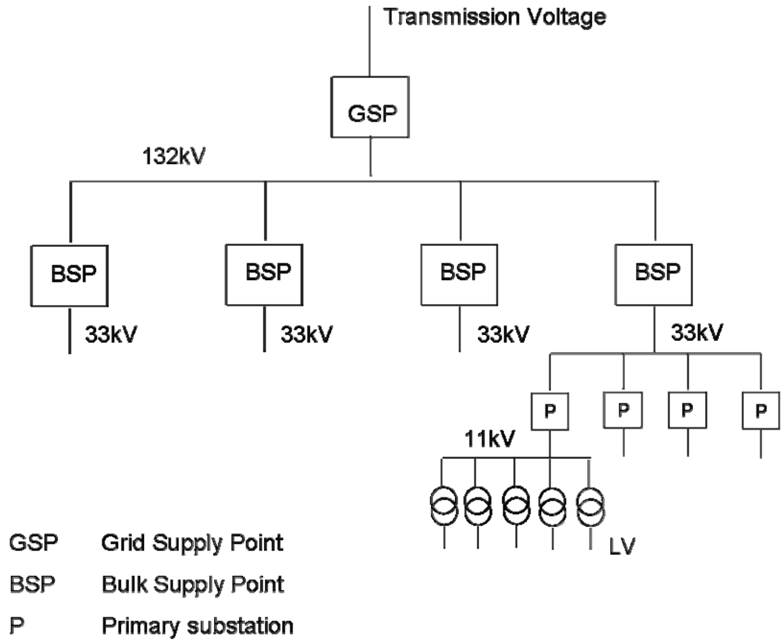

Figure A.3 Distribution network layout

Thus, the costs associated with each voltage level of a distribution network are assumed to range between £55million (for 50km of 132kV cable network) to £300k (for 2km of 11kV cable network), as indicated in Table A.9.

Table A.9 Distribution network circuit costs (for supply to 11kV)

	Number or length		Cost (£)		Total Cost (£)
132kV OHL circuit					
Transformer (132kV/33kV)	2		1,018,700	per unit	2,037,400
132kV Overhead line	50	km	762,500	per km	38,125,000
Switchgear	2		679,600		1,359,200
Total					**41,521,600**
132kV Cable circuit			Cost		
Transformer (132kV/33kV)	2		1,018,700	per unit	2,037,400
132kV Cable	50	km	1,047,100	per km	52,355,000
Switchgear	2		679,600		1,359,200
Total					**55,751,600**
33kV OHL circuit					
Transformer (33/11kV)	2		377,900	per unit	755,800
33kV Overhead line	10	km	274,200	per km	2,742,000
Switchgear	2		50,100		100,200
Ring Main Unit (RMU)	1		259,000		259,000
Total					**3,857,000**
33kV Cable circuit			Cost		
Transformer (33/11kV)	2		377,900	per unit	755,800
33kV Cable	10	km	256,800	per km	2,568,000
Switchgear	2		679,600		1,359,200
Ring Main Unit (RMU)	1		259,000		259,000
Total					**4,942,000**
11kV OHL circuit					
Transformer (11kV/LV)	1		13,200	per unit	13,200
11kV Overhead line	2	km	137,100	per km	274,200
Switchgear	2		51,800		103,600
Ring Main Unit (RMU)	1		13,000		13,000
Total					**404,000**
11kV Cable circuit			Cost		
Transformer (11kV/LV)	1		13,200	per unit	13,200
11kV Cable	2	km	82,900	per km	165,800
Switchgear	2		51,800		103,600
Ring Main Unit (RMU)	1		13,000		13,000
Total					**295,600**

Distribution networks comprise both underground cables and overhead lines, depending upon location specific requirements. For the purposes of this study, it is assumed that the networks are of the same typical proportions of underground and overhead networks[72] as the average on today's UK Network. At present, long circuits are typically overhead lines whilst short circuits are cable. There is already a drive to underground the network and as cable technology improves this is likely to increase. However the lifetime of electricity circuits is 40 years or more and therefore most of the overhead lines are likely to remain until 2050. To try to reflect this slow change in this study, the average lengths of overhead line and cable circuits are assumed to be the same.

Table A.10 Proportion of overhead and underground networks

Voltage Level	% Overhead	% Underground
132kV	85%	15%
33kV	65%	35%
11kV	55%	45%

Therefore, based upon the example costs for circuits at different voltage levels (Table A.9), and the split of networks between overhead and underground (Table A.10), an overall cost for distribution can be determined. As illustrated in Table A.11, this suggests distribution costs of around £6/MWh. It is important to note that this is a simplistic calculation that does not properly allow for any off-take of electricity directly to customers at intermediate voltage levels. Nor does the calculation accurately reflect the way that Distribution Use of System (DUoS) charges are calculated. In future the 33kV circuits may be removed with direct transformation from 132kV to 11kV.

Table A.11 Distribution network circuit – equivalent unit charges

Voltage Level	Number of Circuits	Total Cost per Circuit (£)		Network Type (%)		Network Total
		OHL	Cable	OHL	Cable	(£)
132kV	4	41,521,600	55,751,600	85%	15%	£174,624,400
33kV	16	3,857,000	4,942,000	65%	35%	£67,788,000
11kV	80	404,000	295,600	55%	45%	£28,417,600
Total						£270,830,000
Total units distributed per year (GWh)						4,100
Equivalent Distribution Cost						£6.14 per MWh

For comparison, the distribution tariff for a customer[73] in the Scottish and Southern network region supplied at 11kV is as summarised in Table A.12. Thus, a customer with a maximum demand of 100MVA and an annual consumption of 613MWh/year would pay an equivalent of around £10/MWh. The exact amount paid would vary according to the pattern of consumption across the year, and will also reflect the actual network assets in use in the specific network region.

72 Companies' completed returns for 2001/02 for Information and Incentives Project, Distribution Price Control Consultation, Initial Consultation, July 2003

73 Tariff for a HV Half Hourly Metered Customer, Source: SSE Distribution Use of System Charges, http://www.ssepd.co.uk/uploadedFiles/Controls/Lists/Resources/Delivering_exceptional_service(1)/SEPDUseOfSystemChargesJuly2011.pdf

Table A.12 Illustrative Distribution Use of System Tariff

<table>
<tr><th></th><th colspan="2">Distribution Use of System Tariff</th><th colspan="2">Annual Consumption Details (Illustrative)</th><th colspan="2">Distribution Costs (Illustrative)</th></tr>
<tr><td rowspan="2"></td><td>Fixed (p/day)</td><td>79.2</td><td>Days/year</td><td>365</td><td>Fixed (£/year)</td><td>289</td></tr>
<tr><td>Capacity (p/kVA/day)</td><td>4.84</td><td>Capacity (MVA)</td><td>100</td><td>Capacity (£/year)</td><td>1399</td></tr>
<tr><td>Weekdays 16:30 - 18:30</td><td rowspan="3">Unit Charge (p/kWh)</td><td>4.662</td><td rowspan="3">Consumption (MWh/year)</td><td>60</td><td rowspan="3">Unit Costs (£/year)</td><td>2,797</td></tr>
<tr><td>Weekdays 09:00 - 16:30 18:30 - 20:00</td><td>0.367</td><td>500</td><td>1,835</td></tr>
<tr><td>All other times</td><td>0.069</td><td>80</td><td>55</td></tr>
<tr><td colspan="6">Total Consumption</td><td>613 MWh/year</td></tr>
<tr><td colspan="6">Annual Distribution Charges</td><td>£6,376/year</td></tr>
<tr><td colspan="6">Equivalent Distribution Charge</td><td>£9.96/MWh</td></tr>
</table>

It is also important to note that in addition to the revenues required to repay investments in infrastructure, distribution network use of system (DUoS) charges also need to recover the costs of operating and maintaining the network. These costs are included in the DUoS charges shown in the illustrative tariff shown in Table A.12, whilst no such allowance is included in the figures shown in Table A.11. It is assumed that annual operating expenditure accounts for around 25% of the total distribution network charges[74], i.e. 75% of the costs relate to the recovery of expenditure on infrastructure.

It has been estimated that the capital element of distribution costs equate to £6.14/MWh. Therefore, the overall cost (i.e. including operating costs) associated with distributing energy from a GSP to a primary substation is estimated to be £8.19/MWh (i.e. 6.14 / 0.75 £/MWh)

74 Approximation, based on expenditure allowances in the current distribution price control