Programme Area: Energy Storage and Distribution

Project: 2050 Energy Infrastructure Outlook

Title: Final Report

Abstract:

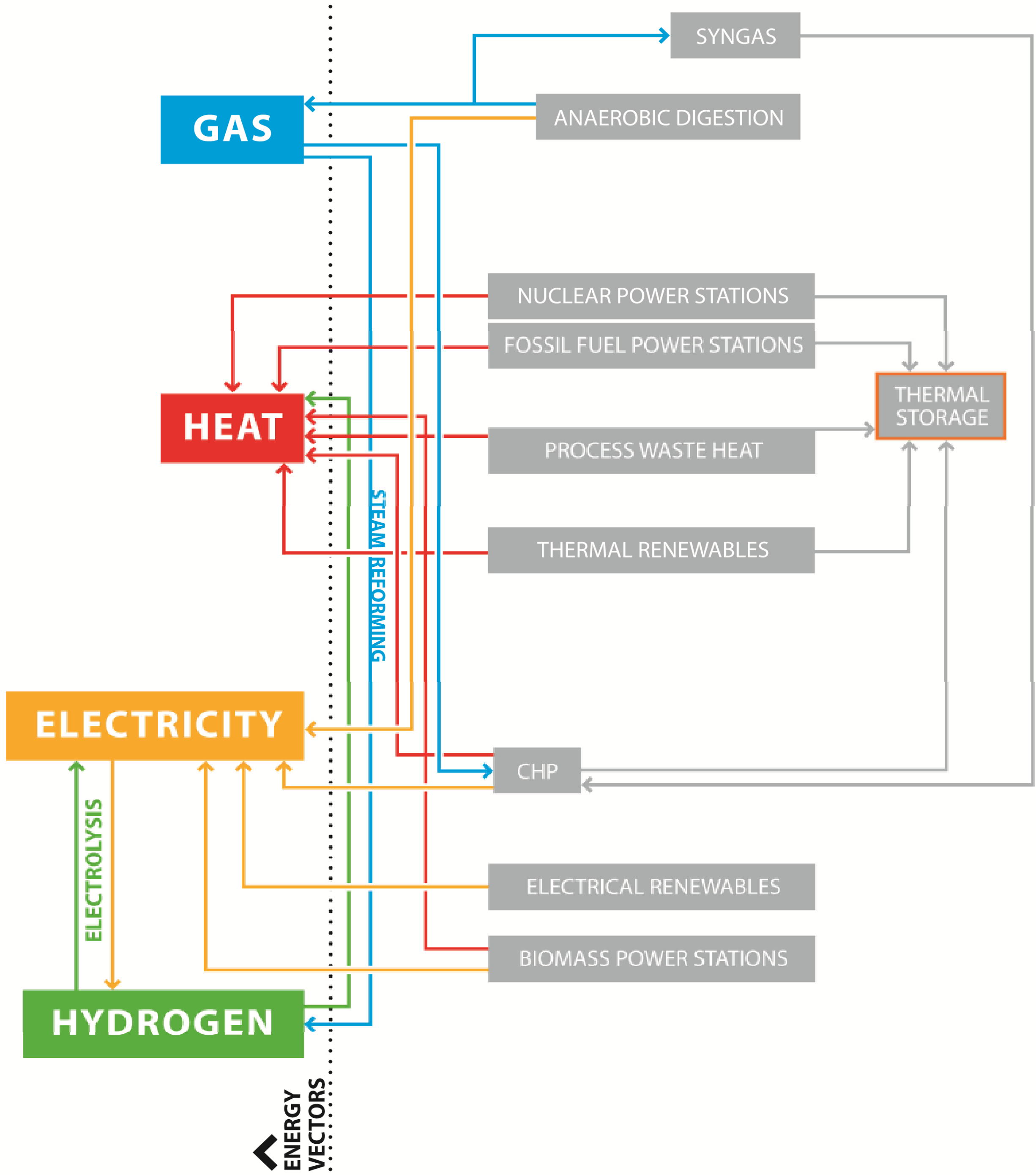
This is the final report summarising the approach to the project, development of the data tool and the findings from evaluating technology development opportunities in the networks. In the report, sections 2 & 3 cover the scope and approach to the project including the test cases that were agreed in the earlier workshops. Section 4 describes the spatial analysis used to determine how the different vectors are affected by geography including a reference to the maps generated for the test projects in the tool. Sections 5 & 6 are concerned with the analysis undertaken by the project team and workshop groups in looking at near and longer term potential implications for network development. Sections 7 & 8 describe the database itself (the user manual will go into more detail on how to use the tool) and finally Sections 9 & 10 describe opportunities for future technology development and developments of the tool outside of the current scope, identified by the project team and the workshop group.

Context:

The 2050 Energy Infrastructure Outlook project provides data on the costs associated with key types of fixed energy infrastructure as well as identifying possible 'grey areas' where technology development could significantly influence cost and performance. The project gathered data on different types of infrastructure associated with electricity, gas, hydrogen and heat. It also looked at infrastructure types: transmission, distribution, storage, conversion and connections. The data itself looked at costs relating to capital, fixed/variable operating and maintenance, abandonment ('infrastructure decommissioning') and repurposing ('altering existing infrastructure').

Programme Area
Energy Storage and Distribution

energy technologies institute



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Abbreviations

Term	Definition
AC	Alternating Current
AGI	Above Ground Installation
ASHP	Air Source Heat Pump
BIS	Department of Business, Innovation and Skills
BEV	Battery Electric Vehicle
CAES	Compressed Air Energy Storage
capex	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture And Storage
CHP	Combined Heat And Power
CNG	Compressed Natural Gas
CO2	Carbon Dioxide
COP	Coefficient Of Performance
CSC	Current Source Convertor
DC	Direct Current
DH	District Heating
DHN	District Heating Network
DNO	Distribution Network Operator
DPCR5	Distribution Price Control Review 5
DSM	Demand Side Management
ECV	Emergency Control Valve
EfW	Energy from Waste
ENSG	Electricity Networks Strategy Group
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
GDN	Gas Distribution Network (Operator)
GIS	Geographic Information System
GIS	Gas Insulated Switchgear
GSHP	Ground Source Heat Pump
GSP	Grid Supply Point
H2	Hydrogen
HDPE	High Density Polyethylene
HEE	Hydrogen Environment Embrittlement
HP	High Pressure
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IDNO	Independent Distribution Network Operator
IGCC	Integrated Gas Combined Cycle
IP	Intermediate Pressure
LCN	Low Carbon Networks (Fund)

Term	Definition
LDZ	Local Distribution Zone
LNG	Liquefied Natural Gas
LP	Low Pressure
LTHW	Low Temperature Hot Water
LTS	Local Transmission System
MEA	Modern Equivalent Asset
MDPE	Medium Density Polyethylene
MP	Medium Pressure
NG	National Grid
NPV	Net Present Value
NTS	National Transmission System
OCGT	Open Cycle Gas Turbine
ODIS	Off-shore Development Information Statement
Ofgem	Office For Gas And Electricity Markets
OHL	Overhead Line
opex	Operating Expenditure
PE	Polyethylene
PRI	Pressure Reduction Installation
RIIO	Revenue = Incentive + Innovation + Outputs
TRL	Technology Readiness Level
TSO	Transmission System Operator
UHV	Ultra High Voltage
VSC	Voltage Source Convertor
XPLE	Cross-linked Polyethylene

Glossary

Term	Definition
Abandonment period	This describes the long-term functional life for an Assembly. This functional life might well exceed the technical life of the Assembly. In this case, the Assembly would be replaced a number of times during the functional life of the Assembly.
Assembly	Assemblies are collections of Components assembled using quantity multipliers to produce composite costs for these Assemblies. Components will be assembled for new build, refurbishment, re-purposing and abandonment within Assemblies, as appropriate.
Baseline cost	Baseline cost forms the basis upon which all cost adjustments for any Component are carried out. The baseline cost should be the ‘normal cost’ expected to be incurred under ‘normal’ procurement and Project delivery conditions, as at 2010.
Capacity	Energy carrying capacity of the Component / Assembly.
Capital cost	Initial construction costs and costs of initial adaptation where these are treated as capital expenditure.
Component	Components represent the lowest level to which capital costs are disaggregated. For example, civil engineering cost Components may include excavation, filling, surface re-instatement, etc. For larger elements within the transmission and distribution networks, these may be transformers, pressure reducing stations, etc. which may be ‘composite Components’.
Contaminated earth	Excavated material which requires specialist handling and disposal as a result of chemical contamination contained within the soil.
Discount rate	Factor or rate reflecting the time value of money that is used to convert cash flows occurring at different times to a common time. This can be used to convert future values to present-day values and vice versa.
Discounted cost	Resulting cost when the real cost is discounted by the real discount rate.
Ease of excavation	Degree of difficulty expected to be encountered in the excavation of trenches and holes during construction. Ground conditions are described as: • Soft and clean; • Intermittent rock (20% by volume); • Prolific rock / hard material (75% by volume).
End of life cost	Net cost or fee for disposing of an asset at the end of its service life or interest period, including costs resulting from decommissioning, deconstruction and demolition of an Assembly; recycling, making environmentally safe and recovery and disposal of Components and materials and transport and regulatory costs.
Ground water	Water requiring intermittent or continuous pumping during construction operations, to keep excavated areas safe and dry.
Lifecycle	Consecutive and interlinked stages of the object under consideration. The life cycle comprises all stages from construction, operation and maintenance to end-of-life, including decommissioning, deconstruction and disposal.
Lifecycle cost	Cost of an asset or its parts throughout its life cycle, while fulfilling its performance requirements.
Lifecycle costing	Methodology for systematic economic evaluation of life-cycle costs over a period of analysis, as defined in the agreed scope.
Maintenance cost	Total of necessarily incurred labour, material and other related costs incurred to retain an Assembly or its parts in a state in which it can perform its required functions. Maintenance includes conducting corrective, responsive and preventative maintenance on constructed assets, or their parts, and includes all associated management, cleaning, servicing, repainting, repairing and replacing of parts where needed to allow the constructed asset to be used for its intended purposes. This cost database considers maintenance costs to be a Component of ‘OPEX’ cost.
Net Present Value	Sum of discounted future cash flows
Operating cost	Costs incurred in running and managing the installation, including administration support services. This cost database considers operating costs to be a Component of ‘OPEX’ cost.

Term	Definition
Optimism Bias	Optimism bias is the demonstrated systematic tendency for appraisers to be over-optimistic about key project parameters. Government requires it to be accounted for explicitly in all appraisals, and can arise in relation to: Capital costs; Works duration; Operating costs; and Under delivery of benefits. The tool has a facility for adjusting for optimism bias at Project level.
Project	Projects are collections of Assemblies, assembled using quantity multipliers to produce whole Project cost estimates.
Rate Modifier	Percentage adjustment to a cost rate to simulate a condition which would result in the cost being be lower or higher than 'normal'.
Real cost	Cost expressed as a value at the base date, including estimated changes in price due to forecast changes in efficiency and technology, but excluding general price inflation or deflation.
Real discount rate	Factor or rate used to relate present and future money values in comparable terms, not taking into account the general or specific inflation in the cost of a particular asset under consideration.
Replacement cycle	Technical life expectancy of an Assembly. Technical life may be influenced by a number of factors, such as quality of materials, workmanship during installation, maintenance regime, accessibility, availability of spares / servicing skills, external environmental factors, aggressive nature of materials transported within the pipe, etc.
Rock in excavations	Rock is considered to be any hard material which required specialist removal such as blasting.
Rural	Locations with <30 dwellings per hectare
Scale	The extent of construction of a particular Component or Assembly. Construction costs may vary for small volumes vs. larger volumes of installation works, based on the procurement and delivery methods employed.
Semi-Urban	Locations with 30 -60 dwellings per hectare
Technology Cost Curve	Technology costs change over time due to different factors such as volume and learning curves. To account for this, five cost curves have been included in the cost model to represent generic changing costs of a spectrum of different types of technology over time. Each assembly has been assigned a Technology Cost Curve that best matches its technology type.
Urban	Locations with >60 dwellings per hectare

1 Executive Summary

The 2050 Energy Infrastructure Outlook project was commissioned by the ETI to deliver data and identify research and development opportunities for the UK on different types of fixed energy infrastructure from now until 2050. The purpose of the study was to compile cost and performance data in relation to the key infrastructure elements of electricity, gas, heat and hydrogen networks to enable the evaluation of different energy scenarios out to 2050.

The study was undertaken by a project team led by Buro Happold in close association with the Sweett Group. Buro Happold undertook technical scoping and analysis and the Sweett Group developed the cost framework and built and populated the cost model. The core team was supported by experts from a number of universities including Southampton and De Montfort, with a Professor from Cambridge University providing a stewardship role.

The project was structured over four work packages undertaken over a 20 month period to November 2013. This is the Final Report for the project and presents the work undertaken, the outputs and key conclusions drawn. The Infrastructure Cost Model is available separately.

Technical Scoping

The project started with an in depth scoping exercise to ensure appropriate coverage of infrastructure types across all four energy vectors. This included a review of near and potential far term technology developments across each vector, exploring the drivers for these developments to ensure as wide as possible a scope was incorporated.

The primary output of this work was an outline technical scope for each infrastructure element included in the database, illustrated using a diagram detailing the boundary of each asset, its key components, land take and efficiencies. These diagrams formed the technical basis for the costing exercise.

Test cases out to 2050

In order to ensure the project reflected the widest possible set of outcomes, a number of test cases of possible energy trajectories out to 2050 were developed with the ETI Steering Group through a workshop and with input from the project team. Key influencing factors taken into consideration were decisions over centralised v decentralised systems, particularly in relation to generation; decisions over ‘pipes v wires’, particularly in relation to hydrogen; and the extent to which space heating is electrified.

The first test case, ‘High Electricity’, reflects a world in which electricity becomes the dominant energy vector requiring upgrading of related electricity infrastructure. This test case assumes a predominantly centralised approach to generation and transmission. The next, ‘High Heat’, reflects a world in which there is considerable progress in rolling out heat networks in urban centres, with the mix of energy vectors otherwise being similar to today. The test case suggests a more decentralised infrastructure with more localised forms of generation. The final test case, ‘High Hydrogen’, is one in which a transmission and distribution network for hydrogen is developed. The key distinction between this and the High Electric case is the upstream conversion of energy to hydrogen and consequent need for hydrogen pipelines. Under this test case, large amounts of hydrogen and produced, mainly by electrolysis that is used as a grid balancing demand load to mitigate the variability of input from renewables.

These test cases were used to ensure the cost model scope included elements that may not necessarily be commonplace today but could be in future (eg. some of the HVDC infrastructure elements, and hydrogen transmission). They also helped to frame the analysis of potential research opportunities undertaken progressively throughout the project.

Developing the Cost Model

The structuring and development of the Infrastructure Cost Model was undertaken iteratively throughout the study period. Initial work involved the exploration of cost influencers and the selection of those that could usefully be incorporated into the model and those that could reasonably be left out. The structure and functionality of the tool was developed to strike a balance between complexity and the need to have something workable. There were particular challenges in relation to operational costs for which data is generally more aggregated reflecting the way in which networks are managed.

The result of this work is a flexible tool that allows for a level of user input to reflect specific views (eg. on future cost trends) and detailed requirements (eg. on ground conditions or region). It is also structured so that new elements can be easily added and existing ones refined should more detailed cost data became available.

The next major step was to populate the Model with cost data. Data was collated from a variety of sources ranging from direct project experience of the project team, to third party data which may or may not have had to be modified so suit the technical scope, to costs derived or synthesised from limited third party data or theoretical costs for a given solution. Each element is indicated with a 'RAG' rating reflecting the quality of data used.

The capital costs were built up from Component level (over 900 elements) which then fed through to Assemblies (over 200) each of which reflects the technical scope of a specified piece of energy infrastructure as described above. As the model is designed to explore costs out to 2050, it also incorporates modifiers to take into account changes over time. Specifically this relates to trends in labour, material and plant costs and changes in relation to technology maturity and deployment scales for which five 'Technology Cost Curves' are incorporated, each reflecting a different technology type. Another time related factor is the technology lifecycle that is the replacement cycle over the life of the asset. Again, this is likely to differ for different infrastructure types and thus a series of options are included in the model that can be selected as they are, or amended by the user as required.

A more top down approach to operational data was used reflecting the nature of the cost data available. The project team was assisted by PPA Energy who explored utility approaches to network operating cost management and reporting. From this were developed a number of operational cost profiles representing different asset types depending on their level of innovation and whether or not they were passive (eg pipes and wires) or active (eg pressure reducing stations), both factors affecting key operational parameters such as failure rates and hence the need for reactive maintenance.

Another aspect of infrastructure operation is its efficiency – that is the quantity of energy out versus the quantity of energy in. This is a complex aspect of infrastructure behaviour and it is not possible to calculate losses and parasitic load in energy terms without knowing more about the design and operation of a network which was outside the scope of this project. Load factor significantly influences losses in electrical networks and parasitic load in gaseous networks and heat networks. Data regarding efficiency (losses and parasitic load) are provided as percentages of annual energy per unit (eg km for linear infrastructure) and are available outside the model.

Using the Cost Model

The data is then available for analysis with a facility for costing individual infrastructure projects. These projects need to be designed outside the tool by a specialist engineer. From this design, a ‘bill of quantities’ can be input to the model, selecting the type and quantity of assemblies that make up the project from the data base. Data is then available on an annual basis (capital cost, operating cost, replacement and abandonment) out to 2050. The data is displayed and analysed through a dashboard, and can also be readily exported for use in other formats.

Research and Development opportunities

Complimentary to this work, research opportunities for each vector were explored. Again, this started with a broad scoping phase, using the near and far term reviews, and scanning the research space for activities in the field including research programmes, demonstrator trials etc. This was undertaken with ETI through a workshop and with input from experts in the field. Establishing priorities from this ‘long list’ of options involved exploring possible cost ‘pinch points’ associated with building out new networks that could indicate a potential area that would benefit from innovation, and a more qualitative analysis looking at what the potential benefits of a particular innovation might be and the ability of the ETI to capture those benefits.

This work identified priority areas for each vector. For all vectors, storage is an area in which there are a number of research opportunities, particularly at transmission level. Possibilities include flywheels and cryogenic liquid air storage for electricity, or geologic interseasonal storage for heat. Condition monitoring is important both for ‘pipes’ and ‘wires’. For ‘pipes’ – which comprise the most significant cost, particularly of transmission networks – maintaining asset condition is important to extend asset life and reduce maintenance and operating costs. For electrical infrastructure, two areas for consideration are, firstly at the individual plant level where there needs to be increased levels of condition monitoring deployment among secondary, auxiliary and lower value primary assets, and secondly at network level where benefits would be seen by improving condition monitoring of the working environment, improving operational real-time assessment of network condition and making full use of smart meter data to assess the condition of the last mile of distribution circuits.

Specific areas for each vector include power electronic technology for electricity which is strongly linked to the concepts of a super-grid and future smart-grid. District heating technologies are relatively mature, however much of the experience is from overseas with some benefit to be gained from transferring techniques effectively to the UK. There are also system design opportunities – such as developing lower temperature networks among existing buildings. For gas, developing improved techniques for pipe handling and trenchless technologies would provide value to the industry reducing the costs of installation and replacement / repair.

The hydrogen innovation space is very broad and incorporates all elements of infrastructure design to some degree. Repurposing of gas pipelines to carry differing purities of hydrogen mix is identified as an important research area. The other area is the conversion of electricity to hydrogen (ie. the electrolyser and associated equipment such as compressors). Although this is not strictly ‘infrastructure’ as defined for this project, it is a key area that would impact upon hydrogen development. Clearly the extent to which hydrogen emerges as an energy vector will have a major influence on pathways for technology development.

Summary

This pioneering project has brought together detailed infrastructure costs across four energy vectors in the UK, developing a valuable and accessible dataset for use by ETI members and others. It will support the development of energy scenarios that take into account not only supply and demand but also the means of transporting energy in a variety of forms from one to the other.

2 Introduction

2.1 The 2050 Energy Infrastructure Outlook Project

By 2050 the UK will need to be meeting stringent targets requiring an 80% reduction in CO_2 emissions, whilst maintaining a sufficient supply of energy. In order to appropriately assess the opportunities for meeting these targets it is necessary to understand, amongst other things, the costs and performance of the energy infrastructure that will carry energy from where it is generated to where it is consumed.

The 2050 Energy Infrastructure Outlook project was commissioned to deliver data and identify research and development opportunities for the UK on different types of fixed energy infrastructure from now until 2050. The purpose of the study was to compile cost and performance data in relation to the key infrastructure elements of electricity, gas, heat and hydrogen networks to enable the evaluation of different energy scenarios.

Key aspects of the study brief are as follows:

- Existing Infrastructure Review, and Scenario Confirmation for Study in conjunction with ETI:
  - Literature Review of Existing Infrastructure and Baseline Technological Solutions
  - Scenarios (later referred to as 'test cases') to identify a basis for study (defined by supply, demand and key energy vectors)
- Implications for Transition
  - Identification of key technological challenges and constraints with existing infrastructure with respect to changing demand and supply characterisation for each scenario.
- Technical Options and Research Opportunities
  - Construction of scope diagrams of 'typical' or indicative energy infrastructure with respective performance and efficiencies for each section and conversion point
  - Outline status reports of research and development opportunities for each energy vector and section to improve efficiency and allow transition to realisation of each scenario.
- Costing Data
  - Procurement models for infrastructure development
  - Model of costs for each infrastructure element with appropriate range and sensitivity

This is the Final Report of the project, prepared to provide background and context to the Infrastructure Cost Model and the associated research opportunities which have been developed as the primary outputs of the study. In providing an overview of the project, it is intended as a guide to users of the model to help understand both its potential and its limitations, and for the wider ETI community to understand the scope and value of the project as a whole.

The study was undertaken by a project team led by Buro Happold in close association with the Sweett Group. Buro Happold undertook technical scoping and analysis and the Sweett Group developed the cost framework and built and populated the cost model. The core team was supported by experts from Southampton University (high voltage electricity), De Montfort University (hydrogen), and individual gas and heat experts. Input from PPA Energy was provided to support the development of the operating costs aspect of the model. A Professor of Engineering from Cambridge University also provided a stewardship role in developing and implementing the project. Overall project management was undertaken by Buro Happold.

2.2 Approach and methodology

The Project was undertaken over a 17 month period ending in [August 2013] and was broken down into four work packages with the two key outputs being an Infrastructure Cost Model and an outline of potential research and development opportunities for each vector (Figure 2—1).

The first work package (Interim Work Package 1 – IWP1) was focused on developing the technical scope of the project. A review was undertaken of existing UK infrastructure of the four energy vectors and this provided the basis for the definition of the individual elements to be included in the cost model.

In order to set the scene for the research aspect of the project, reviews were also undertaken of near term developments and far term research activities. A context for identification of research opportunities was provided by developing 'test cases' of possible future scenarios each with a different bias aimed at pushing the boundaries of the research review.

The second work package (IWP2) developed both strands of work, refining the technical scope and constructing 'typical' or indicative schematics for each element, and undertaking a wider 'scan' of potential research opportunities. During this work package the cost framework was developed and the initial structuring of the cost model undertaken.

The emphasis of the third (IWP3) and fourth (IWP4) work packages was on building and populating the cost model, first for heat as a way of testing the model, and then for electricity, gas and hydrogen. Further work on integrating operating costs into the model was also undertaken. The research opportunities for each vector were reviewed and analysed qualitatively and in respect of outputs from the model to short list candidates that could be of interest to the ETI in future projects.

This final stage is aimed at integrating the outputs of the earlier work packages in order to provide a summary report to guide ETI members and other users of the model as to the background, development and ultimate uses of the model.

Each work stage was accompanied by a detailed Interim Update Note. This Final Report summarises that work and readers are directed to the Update Notes for further detail.

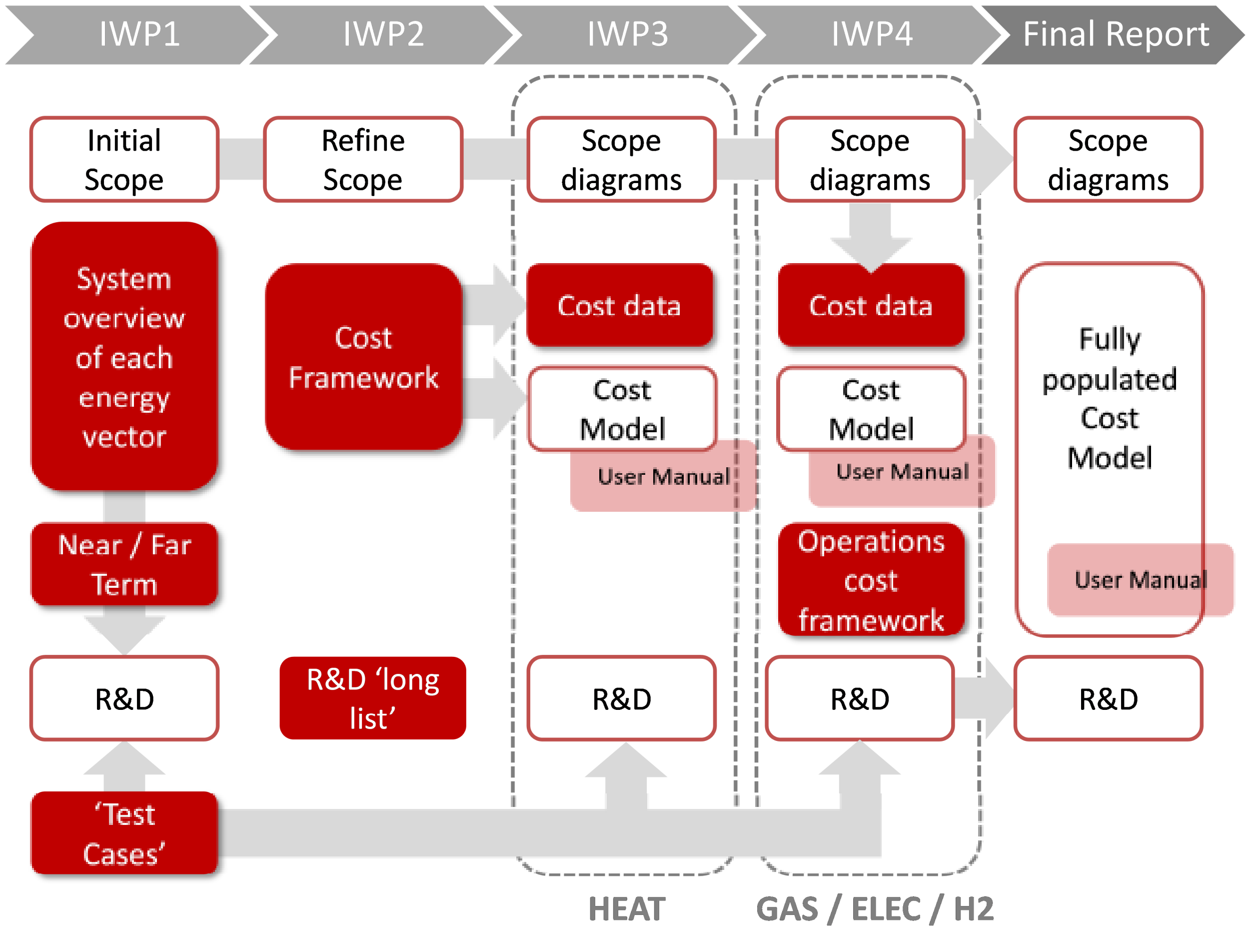


Figure 2—1: overview of project approach and methodology as aligned with the project work packages (IWP1-4 plus Final Report)

2.3 Report structure

The report is structured around the key elements of the work undertaken.

Chapter 3 provides an overview of the technical scope of the project based on the in depth scoping phase. It outlines particular challenges and how these have been addressed. This is followed by some spatial analysis in Chapter 4 that validates the technical scoping in relation to the linear infrastructure. It also contains details of test projects used to validate the model.

Chapter 5 provides a summary of the near term review across each energy vector and leads into Chapter 6 which describes the development and outputs of the test cases.

Chapters 7 and 8 consider the cost model itself. As noted, the development of the model was undertaken on an iterative basis, with these chapters providing an overview of the final outputs. Chapter 7 focuses on how the model is structured, how it relates to the technical scope, its key features and what were particular challenges. Note that information on the detailed mechanics of the model is provided separately in the User Manual issued alongside the model itself. Chapter 8 considers the key user interface of the model in the form of the Project functionality that allows users to create and cost different project types. It outlines potential uses of the model and how the user interfaces have been developed to support detailed analysis.

The identification of research opportunities for each vector is covered in Chapter 9.

Finally, Chapter 10 provides a summary of some issues that arose during the study but that were outside its scope. These are provided for potential follow up by ETI at a later date.

3 Technical Scope

3.1 Overview

This chapter outlines the technical scope of the project and discusses the challenges and associated limitations inherent in the approach.

The scope and model extends to all infrastructure elements associated with the four energy vectors, electricity, natural gas, heat and hydrogen.

The infrastructure elements for each vector are defined as:

- Transmission (including off shore where relevant): high voltage / pressure networks including relevant ancillary equipment (eg. towers for overhead lines; valves and special crossings for pipes). Heat transmission not included.
- Distribution: medium to low voltage / pressure networks including relevant ancillary equipment.
- Conversion: plant and equipment required to convert one pressure / voltage / temperature to another (of the same vector) such as an electrical substation converting power from 400kV to 132kV, or a pressure reduction station converting gas from high pressure to intermediate pressure.
- Connection: all equipment necessary at the consumption end to connect end users to distribution networks. Including industrial, commercial, residential and vehicle connections.
- Storage: utility scale storage upstream of connections.

A summary of the study scope by vector is provided in Table 3-1. For each infrastructure element, the scope covers new build, refurbishment and abandonment and includes detail on performance in relation to losses and / or parasitic load (that is, energy required to operate the asset, for example, to compress gas in a compressor station, or transport water / steam through a district heating network).

An additional aspect of the project is to enable energy analysts to consider the relative cost of new build versus that of repurposed assets. To this end, an analysis is also provided of the technical actions required to enable infrastructure associated with one vector to carry (or transform) another. Further detail on repurposing is provided in Section 3.3.3.

Overall a total of over 200 infrastructure elements are included across the four vectors, each of which is presented in four different stages from new build to abandonment. These elements are built up from around 900 constituent components and include information on operational and lifecycle costs. Variation of each of these items is allowed for within the cost model as discussed in Chapter 7.

An important point to note in the construction of the Infrastructure Cost Model is that it provides cost data on individual elements of infrastructure and does not provide any information on system design. Data can be extracted from the model to inform the cost of a system, however the design of that system has to be undertaken as a separate exercise.

Table 3-1: Outline project scope

	Electricity	Natural gas	Hydrogen	Heat
Stage / process >	*New* | *Refurb* | *Repurpose* | *Abandon*	*New* | *Refurb* | *Repurpose* | *Abandon*	*New* | *Refurb* | *Repurpose* | *Abandon*	*New* | *Refurb* | *Repurpose* | *Abandon*
Off-shore transmission	HVDC >400kV 200-400kV <200kV AC - 400kV - 132kV	n/a	n/a	n/a
On-shore transmission	HVDC >400kV 200-400kV <200kV AC - 400kV - 275kV	34” 32” 28”	34” 32” 28”	n/a
Distribution	- 132kV - 33kV - 22kV - 11kV - 6.6kV - 400V - 230V Overhead, buried and tunnelled versions where appropriate	- HP: 34”, 32”, 30”, 28”, 26”, 24”, 20”, 16” - IP: 8” - MP: 6” - LP: 12”	- HP: 34”, 32”, 30”, 28”, 26”, 24”, 20”, 16” - IP: 8” - MP: 6” - LP: 12”	120°C 150mm 300mm 450mm 70°C 150mm 300mm 450mm 50°C 150mm 300mm 450mm
Storage	- Pumped hydro - Compressed air storage - Flow batteries - Utility scale batteries	- LNG storage - High pressure vessels (‘bullet’) - Low pressure vessels (‘gas holder’) - Salt cavern	- LNG storage - High pressure vessels - Low pressure vessels - Salt cavern	- Large scale aquifer - District level thermal store (large scale accumulator)
Conversions	- HVDC to AC VSC - HVDC to AC CSC - 400kV to 132kV - 400kV to 275kV - 275kV to 132kV - 132kV to 33/22/11kV - 33kV to 11/6.6kV - 11kV to 400V pole & ground mounted - various sealing end terminals	- Compressor station - NTS to HP - HP to IP - IP to MP (‘city gate’) - MP to LP (‘district governor’)	- Compressor station - NTS to HP - HP to IP - IP to MP - MP to LP	120°C to 70°C 120°C to 50°C 70°C to 50°C
Connections	- Residential (230V / 2-5kVA) - Commercial office (400V / 200kVA) - Industrial (33kV / 10MVA) - Vehicle recharging (230V / 3.7kVA)	- Residential (LP/2”) - Commercial office (LP/12”) - Industrial (LTS/20”) - Vehicle refuelling (LP/12”) - Power generation (NTS/34”)	- Residential - Commercial office - Industrial - Vehicle refuelling - Power generation	- Residential - Commercial office / large residential - Industrial

3.2 Approach

For each infrastructure element, a clear description of an indicative piece of infrastructure was developed to inform the cost database. The outcome of this exercise is a series of ‘Scope Diagrams’, each one detailing the boundary of the asset, its key components and land take. An example is shown in Figure 3—1 and a full set of Scope Diagrams is included in Appendix A.

Technical aspects associated with the refurbishment, repurposing and abandonment of each element were developed in order to guide the costing process. All technical data is collated in a Technical Scope Table for each vector which are included as supplementary files with the Cost Model and included in Appendix A. Summary details for each vector are provided in Section 3.4 below.

Wherever possible the scope diagram has been defined to represent a typical network arrangement. In some cases, for example, off-shore transmission, a pragmatic approach has had to be taken due to the lack of existing infrastructure and/or the range of different configurations.

In practice there is an almost infinite range of possible designs. It is not possible to cover all eventualities, nor would this add value as the range of cost variations is unlikely to significantly increase. Using the experience of the project team and the review undertaken in the first work package, indicative designs have been developed. These are not intended to be detailed drawings, but merely serve to accurately define the scope of the cost and performance data. Caution should be exercised in using the diagrams to develop projects in the tool; an experienced engineer is required.

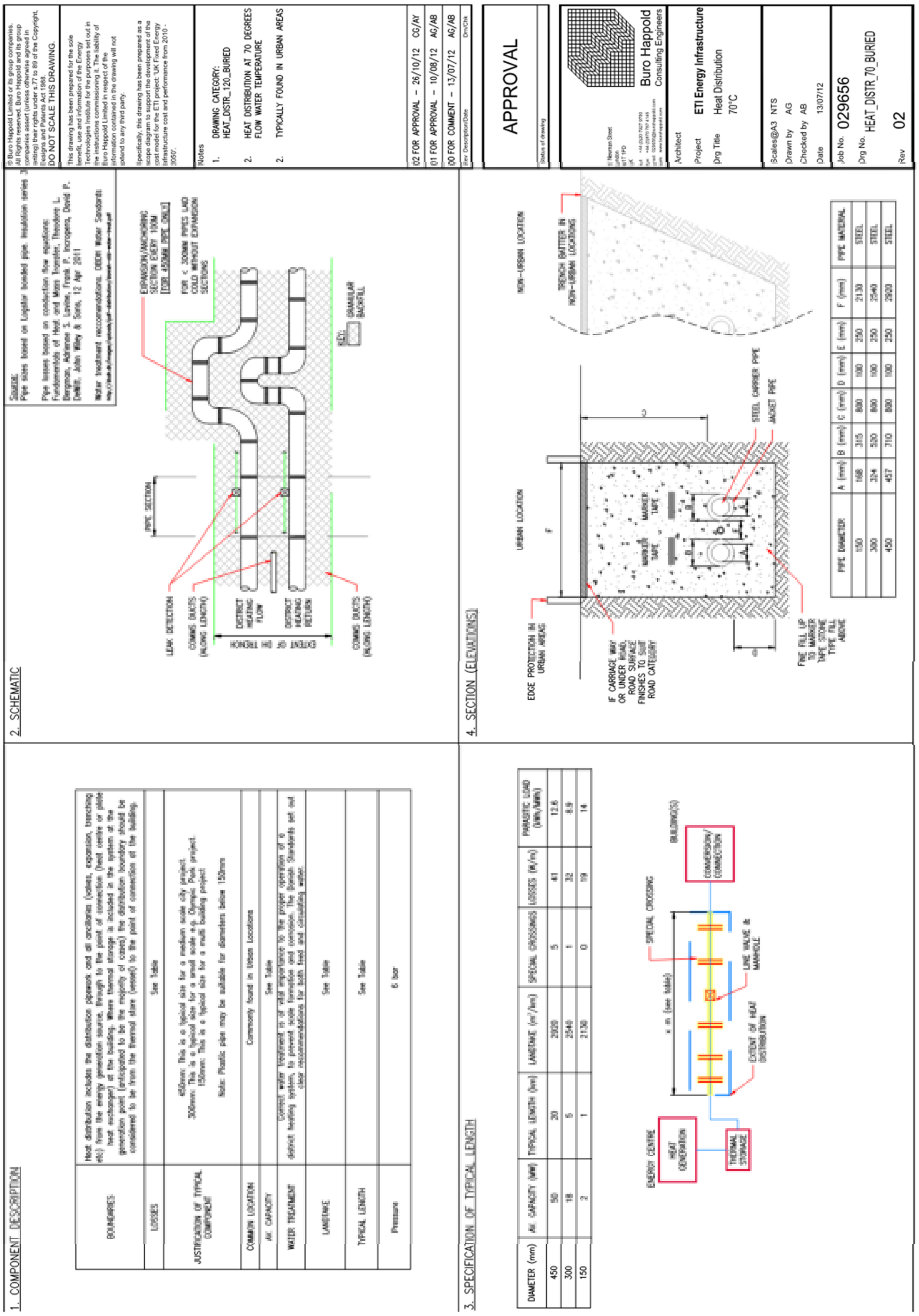


Figure 3—1: Example 'scope diagram' as prepared for each infrastructure element of each vector. A full set is available in Appendix B.

3.3 Challenges

3.3.1 Defining 'indicative'

A significant challenge for the project was to develop technical scopes that could be said to be indicative. Even in the case of the linear infrastructure – such as pipe lines or overhead cables – there are many different variants in terms of the number and type of components. This is even more the case with above ground assets such as substations or different types of storage.

The need to define the different infrastructure types required a trade-off between the complexity of real life and the simplification needed to ensure the final model was usable. To address this issue, industry expertise was relied upon to select the most relevant or typical variant. Where it cannot be said that there is a 'typical' infrastructure unit, such as salt cavern storage for natural gas, a case study approach was used.

The modular nature of the cost model (as described in Chapter 7) ensures that, where users find an asset type critical to their analysis has been omitted, or where the variant selected does not match their needs, additional elements can be added with ease.

3.3.2 Efficiency

The efficiency of a piece of infrastructure is a measure of the energy in versus the energy out. For the purposes of the project, it has split into losses (that is for example energy lost along cables or pipes) and parasitic load (that is where additional energy is required to run a piece of plant such as a gas compressor station) and is presented as a percentage of annual energy. The approach for each vector and infrastructure type is summarised in Table 3-2 below.

It should be noted that efficiency as defined here is treated outside the cost model. It is not possible to calculate losses and parasitic load in energy terms without knowing more about the design and operation of a network which is outside the scope of this project. Load factor significantly influences losses in electrical networks and parasitic load in gaseous networks and heat networks. As these vary depending on the location of the assembly in the infrastructure system and its overall load versus capacity, it is recommended that loss calculations are made once these factors are known. A number of methodologies for calculating losses have been used.[1]

A follow up piece of work would be to allow users to build up losses, and their associated costs, within the tool for a given project, based on inputting a range of assumptions such as load factors, energy load profiles etc.

[1] For example: Negra N.B., Todorovic J. & Ackermann T. (2006). Loss evaluation of HVAC and HVDC transmission solutions for large offshore wind farms. Electric Power Systems Research. 76(11): 916-927.
National Grid Electricity Transmission plc (2010). Offshore Development Information Statement 2010. Appendix 4.:A28-A30

Table 3-2: summary of approach to efficiency (losses and parasitic load) for each vector

Vector	Infrastructure type	Losses	Parasitic load
Electricity	Transmission / distribution 132kV	% of annual energy per 100km. A range is given due to the influence of load factor.	n/a
	Distribution 33kV and below	% of annual energy; blended figure from across all DNOs	n/a
	Conversion	% of annual energy per conversion	n/a
	Connection	% of annual energy per connection	n/a
	Storage	% of annual energy	n/a for most; included in losses figure for pumped hydro
Gas / hydrogen	Transmission	Minimal	n/a
	Distribution	% of annual energy	n/a
	Conversion	% of annual energy per conversion	Compressor station - % annual energy
	Connection	% of annual energy per connection	n/a
	Storage	% of annual energy	n/a
Heat	Distribution	W/m	kWh/MWh
	Conversion	Minimal	n/a
	Connection	Minimal	n/a
	Storage	% of annual energy	% annual energy stored where applicable

3.3.3 Repurposing

Repurposing is deemed to be the alteration of a piece of infrastructure designed to carry one vector to enable it to carry another. For example, natural gas pipe lines can be repurposed to carry hydrogen. It is a complex issue for which a balance has had to be struck between the wide range of alternatives possible and the structure and functionality of the model.

The objective of including repurposing is to enable an understanding of what the lowest cost system for energy delivery might be. At its most straightforward, a scenario in which one energy vector is changed to another may be discounted due to the high cost of removing and replacing the existing infrastructure. On the other hand, this scenario may become plausible if existing infrastructure could effectively be reused at lower cost to carry the new vector. Any repurposing does of course introduce other issues, such as a potentially lower level of performance than if new dedicated infrastructure were installed, which must also be considered.

This highlights two extreme approaches, one being effective replacement (of all the existing infrastructure with new infrastructure), the other being effective reuse (of the existing infrastructure as it is without modification).

For the purposes of this project and to retain the functionality of the model, a specified number of repurposing options has been defined with a maximum of two per infrastructure element[2]. A detailed review confirmed that in almost all cases only two repurposing options were practical. The approach to defining each repurposing option out of the broad range of options that could be considered possible has been to select something that has some technical and pragmatic rationale. Thus options have been discounted where considered not technically feasible. Options selected are summarised in Table 3-3 below with a paper providing the rationale for each included in Appendix C.

It is assumed that the repurposed infrastructure will impact upon the performance of that infrastructure in relation to its new build equivalent. Estimates of losses for repurposed options are included in the Technical Scope Tables. In cases where no precedent for repurposing exists, performance has been estimated.

[2] Note that due to the structure of the model, the second repurposing option has had to be included as a new version of the same Assembly. This will become clear on use of the model.

Table 3-3: Summary of repurposing options included in the model

Vector	Function	Repurposing 1	Repurposing 2	Comments
Electricity	Transmission	400kV HVAC OHL converted to HVDC 275kV HVAC OHL converted to HVDC	-	Technically repurposing is deemed to refer to changes from one vector to another. However, it was considered of value to include estimates of repurposing of electrical transmission infrastructure form AC to DC. Due to converter station costs and losses, HVDC is only currently used over relatively long distances such as are covered by a 400/275kV National Grid transmission system.
	Distribution			Out of scope
	Conversion			Out of scope
	Connection			Out of scope
	Storage			Out of scope
Gas	Transmission	Repurpose to hydrogen	Repurpose to CO_2	
	Distribution	Repurpose to hydrogen	-	It was agreed that repurposing to heat is not achievable for reasonable cost or to a standard which would provide assurance for future reliability without effectively totally replacing the gas mains.
	Conversion	Repurpose to hydrogen	-	It is noted that compression is an important part of transmission and thus repurposing of compressors to CO_2 is relevant. It has however been excluded from scope of the current iteration of the model.
	Connection	Repurpose to hydrogen	-	It was agreed that repurposing to heat is not achievable for reasonable cost
	Storage	Repurpose to hydrogen	Repurpose to CO_2	
Heat	Distribution	Repurpose to gas	Repurpose to hydrogen	
	Conversion	-	-	Out of scope
	Connection	Repurpose to gas	Repurpose to hydrogen	
	Storage	-	-	Repurpose to CO_2 not technically possible
Hydrogen	Transmission	Repurpose to gas	Repurpose to CO_2	
	Distribution	Repurpose to gas	-	As per gas distribution.
	Conversion	Repurpose to gas	-	It is noted that compression is an important part of transmission and thus repurposing of compressors to CO_2 is relevant. It has however been excluded from scope of the current iteration of the model.
	Connection	Repurpose to gas	-	As per gas connection.
	Storage	Repurpose to gas	Repurpose to CO_2	

3.3.4 Hydrogen

The lack of any significant UK hydrogen infrastructure throws up particular challenges for defining indicative elements and then costing those elements. Broadly speaking a technical approach has been taken using natural gas infrastructure as a basis and adapting the design to take into account the different physical characteristics of hydrogen gas. A full paper outlining this approach is provided in Appendix D. Key technical conclusions are summarised below.

- There is a general limited understanding of the practical aspects of hydrogen pipeline construction at the scale associated with natural gas transmission. There are around 3,000km of existing hydrogen pipeline operating at pressures of up to around 100 bar, and diameters of <400mm. Most is repurposed oil pipeline, built from low grade steel.
- For costing purposes, hydrogen pipelines have been assumed to operate at 84bar to give the same energy output as natural gas pipelines of the same diameter at 70bar. The assumptions on pipeline operation (e.g. a ~20% increase in pressure) are supported in the literature, however there is one conflicting view but the majority of sources concur with the approach taken in this Project.
- Centrifugal compressors can be used for hydrogen but they require multi-stage compression due to low compression ratios, and so result in very high compressor energy consumption. A compressor station configuration using 2no. compressor trains, each consisting of 5no. 8 stage barrel compressors arranged in series has been assumed based on industry input.
- A review of the materials suitable for use with hydrogen pipelines concluded that steel grade below X52 should be used, resulting in thicker, more expensive pipe compared to a X70 natural gas lines. There is some research work which suggests that higher grade steels are suitable for use with hydrogen but this is not conclusive. There is conclusive evidence that inclusion of a small amount of pollutant (oxygen or carbon monoxide at around 500ppm) results in significant reduction in higher grade steels' susceptibility to fatigue crack growth. The use of this approach has been assumed for both new build pipelines and repurposing to hydrogen. This means that some low temperature fuel cells would require technology to clean impurities from the hydrogen stream. However, impurities could also be introduced from sources such as compressor lubrication and certain hydrogen production routes.

Further work is recommended on a number of issues. Odorisation of hydrogen is reported as problematic in some sources and should be reviewed. Crack propagation and hydrogen environment embrittlement (HEE) in higher grade steels is still a key challenge. Some work on X80 and X100 steels, which have lower fracture toughness but still give thinner pipelines, has been undertaken and the results suggest these steels could be used subject to higher safety factors. Further work on cyclic fatigue behaviour is still considered to be required. Pressure reduction equipment has not been considered in any references in detail. It was excluded from NaturalHy and only a few papers mention it in passing, stating that the Joule Thompson effect is less pronounced than in natural gas and leads to heating rather than cooling of the gas (but not to the extent that any cooling of the gas is required). A review of the impact of hydrogen on steel used for compression and expansion units is also recommended.

3.4 Technical scope by vector

The following sections provide the context for the technical scope of each vector, commenting on any particular issues that arise in defining the scope. Each section also includes an overall system schematic to show how the individual infrastructure elements connect and interact.

A summary scoping table is provided for each element of each vector. These include a definition of scale based on a combination of an energy carrying / conversion capacity and a physical size (typically a length of linear element, or an area of a connection / conversion where appropriate) as shown in Table 3-4.

Table 3-4: approach to definition of scale for each infrastructure type

Function	Technology type	Energy carrying / conversion capacity	Physical dimensions
Transmission / distribution – electrical	cables	MVA	An indicative cable length is given which includes a defined number of infrastructure elements such as poles, circuits, joints (for buried cables) etc. Land take is also defined. For overhead lines the area of land required for the towers or poles is given, and where significant an approximate corridor of land including safety setbacks is given
Transmission / distribution – gaseous	pipes	m^3/day	An indicative pipe length is given which includes a defined number of crossings, line valves, pigs etc. Land take is also defined.
Conversion – electrical	Sub-station	MVA	Land take (m^2) for the assumed conversion capacity to include all relevant pieces of equipment.
Conversion – gaseous	PRS / compressor	m^3/day	Land take (m^2) for the assumed conversion capacity to include all relevant pieces of equipment.
Conversion - heat	Sub-station	MW	Land take (m^2) for the assumed conversion capacity to include all relevant pieces of equipment.
Connection – electrical	cables	kVA	Land take (m^2) for the assumed connection capacity where appropriate
Connection – gaseous / heat	pipes / valves	m^3/hr (natural gas / H_2) MW (heat)	Land take (m^2) for a single unit (generally small).
Storage - electrical	batteries	MWh	Based on an associated power (MW) and energy power ratio
Storage - gaseous	tanks / underground	m^3	Land take for a unit of defined storage capacity.
Storage – heat	tanks / underground	MWh	Land take for a unit of defined storage capacity.

3.4.1 Electricity

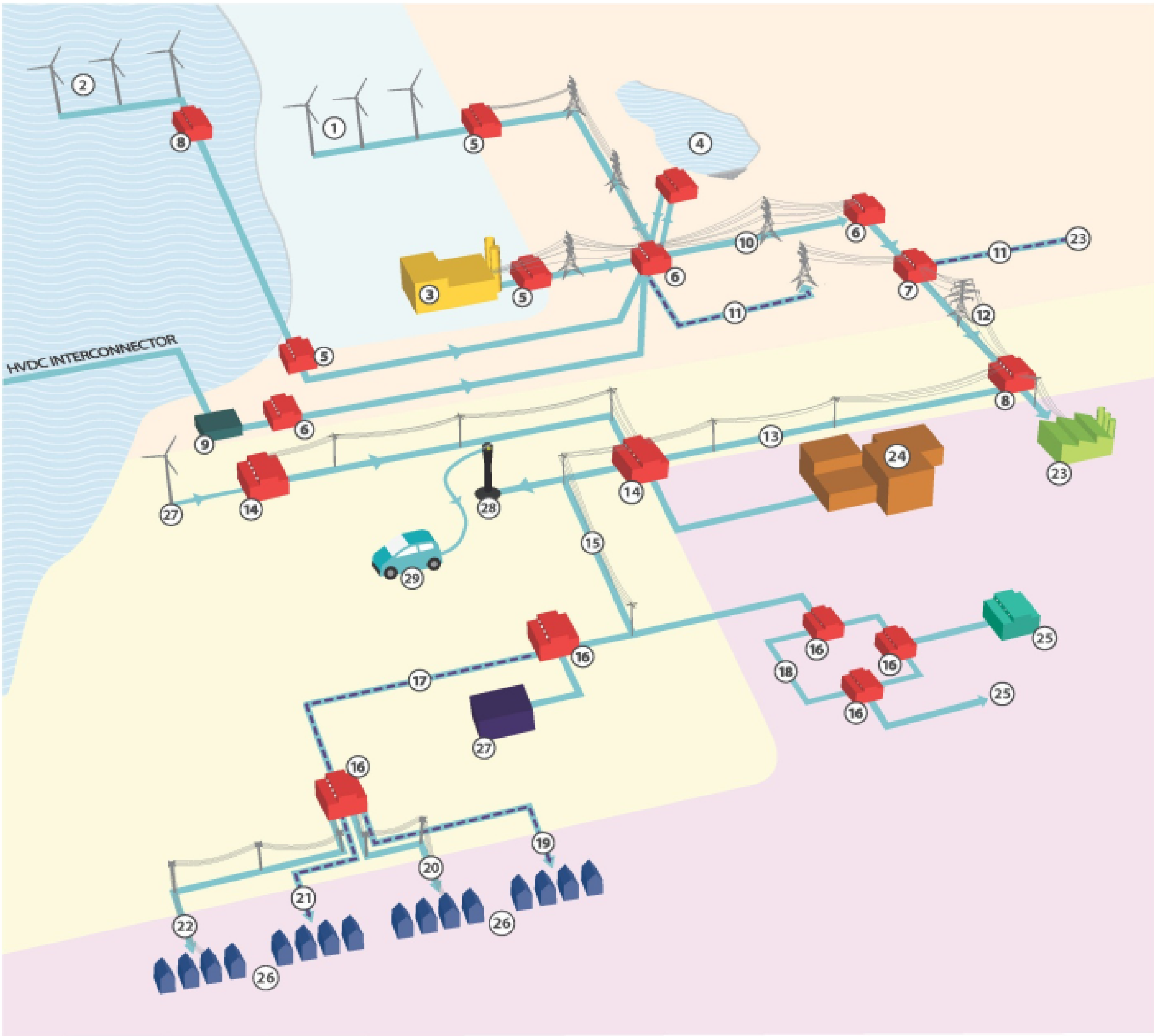
System overview

Electricity infrastructure in Great Britain comprises a transmission network (on-shore and more recently off shore) and a series of regional distribution networks. The existing power transmission system was mainly built during the middle of the last century to provide a method for bulk electricity transmission from large generators to load centres. It has been designed to facilitate conventional generation injecting large amounts of power to the transmission system to be delivered to the end user at a number of voltage levels via passive distribution networks.

Original network design incorporated high levels of resilience, which assured operational security of supply. This has resulted in long life times and low outage rates. In more recent times, all network operators have programmes in place to monitor/assess the health of network assets and have maintenance, repair and replacement strategic plans; however, a significant proportion of the original plant installed during the middle of last century is still in operation today.

A schematic showing existing electricity infrastructure in the UK is provided in Figure 3—2 below.

ETI 2050 Infrastructure - **Electricity Schematic - Existing**



1. ON SHORE WIND FARM
2. OFF SHORE WIND FARM
3. OTHER POWER GENERATION
4. PUMPED-STORAGE HYDRO-ELECTRIC FACILITY (CONNECTIONS TO SUBSTATION FOR IMPORT AND EXPORT OF POWER)
5. TRANSMISSION STEP UP SUBSTATION
6. 400kV SUBSTATION
7. 275 kV SUBSTATION
8. 132 kV SUBSTATION
9. DC/AC CONVERTOR
10. 400kV TRANSMISSION LINES
11. 400 kV UNDERGROUND TRANSMISSION SYSTEM e.g. countryside, bridge, obstacles
12. 275kV OVERHEAD TRANSMISSION SYSTEM
13. 132kV OVERHEAD LINES
14. 33 kV SUBSTATION
15. 33 kV DISTRIBUTION LINES
16. 11 kV SUBSTATION
17. 11 kV DISTRIBUTION LINES
18. 11 kV RING MAIN
19. 400V LV UNDERGROUND
20. 400V LV OVERHEAD
21. 230V UNDERGROUND
22. 230V LV OVERHEAD
23. INDUSTRIAL LOADS
24. HEAVY COMMERCIAL CONNECTION
25. OTHER LARGE NON-DOMESTIC LOADS
26. DOMESTIC LOAD
27. EMBEDDED POWER GENERATION
28. ELECTRIC VEHICLE RECHARGING POINT
29. ELECTRIC VEHICLES

- POWER GENERATION
- TRANSMISSION
- DISTRIBUTION
- DEMANDS

Figure 3—2: Schematic of existing UK electricity infrastructure

Off-shore transmission

Existing off-shore transmission networks consist of three HVDC interconnectors - with France (2,000 MW), the Netherlands (1,000 MW), and a 500MW HVDC interconnector with the Republic of Ireland; and the HVAC connection between the Isle of Man and the UK mainland. In addition there are 132 kV AC export cable connections to some of the Phase 1/2 off-shore windfarms.

The off-shore transmission network is under development. Ofgem and DECC favour a coordinated approach and are developing an appropriate regulatory framework and incentives regime[3].

Each of the off-shore elements included in the model are based on a typical length of 100km of undersea cable bounded by AC/DC conversion stations or substations at either end. High, medium and low capacities are provided for each voltage based on case studies of existing and planned projects taken from publically available data and compared with National Grid Off-shore Development Information Statement (ODIS)[4].

A summary of the off-shore electrical transmission scope is provided in Table 3-5.

Table 3-5: electricity off-shore transmission technical scope

Function	Mode	Rating	Installation	Capacity (low / med / high) MVA	Boundary
Transmission	HVDC	>400kV	Off-shore	1,500 2,200 3,000	Includes bipole i.e two cables side by side buried 1-2m deep. Layout differs slightly depending on depth of water. Based on National Grid's Western Link Scheme +-600kV bipole.
Transmission	AC	400kV	Off-shore	900 1,800 3,600	Includes double circuit, with 3 single core cables per circuit buried in separate trenches, with spare 4th conductor per circuit. Limited to around 50km length due to charging currents.
Transmission	AC	132kv	Off-shore	183 366 549	AC power take-off from off shore wind farms is at 132kV. Assumed that cable length is less than 50km and so no joint required.
Transmission	HVDC	200-400kV	Off-shore	300 700 1,000	Includes bipole i.e two cables side by side buried 1m deep. Layout differs slightly depending on depth of water. Based on ABB HVDC Light (similar to EstLink but smaller diameter cables used).
Transmission	HVDC	<200kV	Off-shore	200 400 600	Includes bipole i.e two cables side by side. Layout differs slightly depending on depth of water. Based on Estlink HVDC link +/-150kV uprated to account for technology development.

[3] Off-shore Transmission Coordination Project Conclusions Report, Ofgem / DECC, 2012.
[4] Note that ETI requested data for 400kV HVAC cables but 50km represents a practical limit to them due to impedance.

On-shore transmission

The UK transmission system is operated by four different Transmission System Operators (TSOs). Each network is bounded by connections to generators and interconnectors at one end and connections (via substations) to the distribution network at the other. These boundaries are reflected in the definition of the different elements included in the project in this category.

In all cases, power from the generators is stepped up to transmission voltage levels through step up transformers at generator station substations. Power flows between the different voltage levels on the transmission system through transmission substations – which also act as interconnection nodes for the system. Power is delivered to the distribution interface via substations called Grid Supply Points (GSP) which step down the voltage to distribution levels.

Elements included in this category include both AC (400kV and 275kV in England and Wales with the addition of 132kV in Scotland) and DC (600kV, 350kV and 150kV). As for off-shore transmission, high, medium and low capacities are included for each voltage. For on-shore HVDC the lack of precedents in the UK means that international case studies have had to be used.

A summary of the on-shore electrical transmission scope is provided in Table 3-6.

Table 3-6: electricity on-shore transmission technical scope

Function	Mode	Rating	Installation	Capacity (low / med / high) MVA	Boundary
Transmission	HVDC	>400kV	Overhead	1,100 2,200 3,000	Tower mounted bipole. 4 no. twin conductors, ~417m spacing based on increased distance versus 400kV HVAC legacy network.
Transmission	HVDC	>400kV	Buried	1,000 2,200 4,400	Includes HVDC transmission cables at +-600kV found in between AC/DC converter stations. Joint boxes will be found along the network. Based on National Grid's Western Link Scheme (Wirral end) +-600 kV bipole.
Transmission	AC	400kV	Overhead	3,190 6,380 6,930	To include suspension towers every 366m.
Transmission	AC	400kV	Buried	3,190 6,380 6,930	Buried transmission system cables including joints, laid in twin double circuit configuration (e.g. Four sets of single core cables, three cables per circuit)
Transmission	AC	400kV	Tunnelled	1,100 1,600 2,400	To include at least 2 head houses.
Transmission	AC	275kV	Overhead	1,800 2,600 4,200	To include suspension towers every 366m.
Transmission	AC	275kV	Buried	1,420 1,580 1,740	Includes 275kV electricity transmission cables from Grid Substation to a 275kV /132kV transformer which will reduce the voltage down to 132kV. Joint boxes can be found along the network.

Function	Mode	Rating	Installation	Capacity (low / med / high) MVA	Boundary
Transmission	AC	275kV	Tunnelled	750 1,100 1,650	To include at least 2 head houses.
Transmission	HVDC	200-400kV	Overhead	300 700 1,000	Tower mounted bipole. Standard spans between suspension towers 366m. Based on ABB HVDC Light.
Transmission	HVDC	200-400kV	Buried	300 700 1,000	HVDC cables between AC/DC convertors, +-300kV. Based on Nordbolt HVDC light system being developed by ABB.
Transmission	HVDC	<200kV	Overhead	200 400 600	Tower mounted bipole. Based on voltages used for Estlink, with uprated capacity. HVDC link +/-150kV.
Transmission	HVDC	<200kV	Buried	200 400 500	Includes bipole i.e two cables side by side buried 1m deep. Based on Estlink HVDC link +/-150kV uprated to account for technology development

Distribution

The UK electricity distribution system is divided into a number of independently operated networks. There are currently (2013) 14 licensed distribution network operators (DNOs) in England, Scotland and Wales, each responsible for a distribution services area, and four independent network operators who own and run smaller networks embedded in the DNO networks. There is a separate DNO in Northern Ireland.

These networks have been designed to function as passive networks to transport power from transmission system grid / bulk supply points to the end user. Voltage levels tend to be:

- Sub-transmission – 132kV, 33kV and 22kV
- Distribution 11kV and 6.6kV down to LV (400V and 230V) to deliver to customers.

Electricity enters the distribution network at a number of points including Grid Supply Points (England and Wales) or Bulk Supply Points (Scotland) which are the interface with the transmission system. It also enters via generators connected directly to the distribution system rather than to the transmission system (so called 'embedded' generators) and some cross border arrangements with neighbouring distribution networks.

Electricity leaves the network at the premises of end users and is metered at that point. The boundary of the distribution elements in the model ends at their points of connection to substations or consumer connections.

A summary of the electricity distribution scope is provided in Table 3-7. For distribution, unlike for transmission, only one capacity has been included for each voltage.

Table 3-7: electricity distribution technical scope

Function	Mode	Rating	Installation	Capacity	Boundary
Distribution	AC	132kV	Overhead	670 MVA	Includes electricity distribution cable from a step-down substation. Suspension, angle and terminal towers can all be round along the network
Distribution	AC	132kV	Buried	335 MVA	Includes electricity distribution cable from a step-down substation. Joint boxes can be found along the network.
Distribution	AC	132kV	Tunnelled	320 MVA	Includes tunnelled portions of 132kV distribution cables. Headhouses can be found along the network. Excludes control room, communication room, storage room, ventilation shaft etc
Distribution	AC	33kV	Overhead	25 MVA	Includes Section Poles and Intermediate Wooden Poles
Distribution	AC	33kV	Buried	25 MVA	Includes joint boxes along the network
Distribution	AC	22kV	Overhead	16 MVA	Includes Section Poles and Intermediate Wooden Poles
Distribution	AC	22kV	Buried	16 MVA	Includes joint boxes along the network
Distribution	AC	11kV	Overhead	6.6 MVA	To include section poles and intermediate wooden poles
Distribution	AC	11kV	Buried	6.0 MVA	Will include ring main units including circuit breakers and switches
Distribution	AC	6.6kV	Overhead	4 MVA	To include section poles and intermediate wooden poles
Distribution	AC	6.6kV	Buried	3.5 MVA	Will include ring main units including circuit breakers and switches
Distribution	AC	400V	Overhead	122 kVA	To include 5 x section poles and 15 x intermediate wooden poles
Distribution	AC	400V	Buried	122 kVA	To include 2 x circuits, 1 x link box, 5 x straight joints, 80 x Tees
Distribution	AC	230V	Overhead	70 kVA	To include 5 x section poles and 15 x intermediate wooden poles
Distribution	AC	230V	Buried	70 kVA	To include 2 x circuits, 1 x link box, 5 x straight joints, 80 x Tees

Conversion

In the context of electricity infrastructure, the conversion technologies are primarily substations which act as an interface between the different voltage levels within the network as well as acting as interconnection nodes. In addition there are convertor substations which convert Alternating Current (AC) power from the grid to Direct Current (DC) power to transmit across interconnectors and vice versa.

Generally, substations will contain busbars of the different voltage levels. Incoming and outgoing conductors will be connected to the busbars of the same voltage level. Transformers will be connected between the busbars – these are the central component of any substation and provide the interface between the different voltage levels. Other crucial components are circuit breakers and switches. Substations may also contain capacitor banks and other devices to provide voltage support and reactive power compensation.

Specifying what might be considered an indicative substation was difficult in this category particularly at the larger scales as they tend to be bespoke depending on their location within the network. No allowance has been made for reactive power compensation or other devices.

A summary of the electricity conversion scope is provided in Table 3-8.

Table 3-8: electricity conversion technical scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Conversion	HVDC-AC VSC	350kV	above ground	1,000 MVA	8,400m^2	Includes AC filter compound and converter station buildings
Conversion	HVDC-AC CSC	600kV	above ground	2,000 MVA	48,125m^2	Includes AC filter compound and converter station buildings
Conversion	AC	400kV	Sealing end terminal	6930 MVA	4,000m^2	Interface between 400kV overhead and 400kV buried
Conversion	AC	400kV	132kV	720 MVA	22,500m^2	Includes everything in between and including the 400kV and 132kV switchboards
Conversion	AC	400kV	275kV	1100 MVA	22,500m^2	Includes everything in between and including the 400kV and 275kV switchboards
Conversion	AC	275kV	132kV	720 MVA	22,500m^2	Includes everything in between and including the 275V and 132kV switchboards
Conversion	AC	132kV	Sealing end terminal compound	335 MVA	540m^2	Interface between 132kV overhead and 132kV buried; more land hungry than platform
Conversion	AC	132kV	Sealing end terminal platform	335 MVA	176m^2	Interface between 132kV overhead and 132kV buried; less land hungry than compound
Conversion	AC	132kV	33/22/11kV	120 MVA	3,068m^2	Includes everything in between and including the 132V and 33/22/11kV switchboards
Conversion	AC	33kV	11kV	25 MVA	630m^2	Includes everything in between and including the 33V and 11kV switchboards
Conversion	AC	33kV	6.6kV	10 MVA	630m^2	Includes everything in between and including the 33V and 6.6kV switchboards
Conversion	AC	11kV	400V (ground mounted)	500kVA	16m^2	From switchboard to switchboard including protection. Ground mounted
Conversion	AC	11kV	400V (pole mounted)	200kVA	16m^2	From switchboard to switchboard including protection. Pole mounted

Storage

The only type of utility scale, grid connected electricity storage in the UK is in the form of pumped hydro with four major schemes offering 27.6 GWh[5]. Other forms of storage exist, such as compressed air energy storage (CAES), flow batteries and utility scale batteries but these are not yet grid connected in the UK.

For the purposes of the project, a range of large scale storage options were included from pumped hydro, to different forms of battery. Again, the difficulties of specifying an ‘indicative’ element were significant, particularly in the case of pumped hydro which is highly dependent on geography. An indicative pumped hydro plant was therefore described by taking the average GWh capacity of the four major UK plants. The associated power and working volume were then calculated by taking Dinorwig plant values and multiplying by the ratio of average UK plant GWh capacity to Dinorwig GWh capacity. This ensured all parameters were consistently scaled for the indicative case.

A summary of the electricity storage scope is provided in Table 3-9.

Table 3-9: electricity storage technical scope

Function	Mode	Rating	Installation	Capacity (low / med / high)	Land take	Boundary
Storage	DC	4MW	Flow Batteries	10 MWh 20 MWh 40 MWh	27.5kWh/m^2	Based on typical 4MW VRB demo projects and 5:1 energy power ratio for flow batteries
Storage	DC	1MW	Utility Scale Batteries	7.2 MWh 14.4 MWh 28.8 MWh	250m^2	Based on 2 units, each with 7.2MWh capacity and 1MW peak output
Storage	AC	135MW	Compressed Air	800 MWh 1,600 MWh 3,200 MWh	1,200m^2 for turbo machinery	Associated output 135MW
Storage	AC	1.36GW	Hydro pumped	3.45 GWh 6.9 GWh 13.8 GWh	variable	Mean of 4 major UK plants. Associated power 1.36GW and based on 5:1 energy to power ratio at Dinorwig

Connections

Connections are varied depending on end user scale and type, however are deemed to end at the fiscal meter entering the customer’s property. For domestic dwellings, they generally involve a 230 V single phase supply incorporating a 100 Amp fuse prior to the meter. For industrial and other users, 3 phase connection can occur at 400 V, 11 kV or 33 kV dependent on customer requirements. Very large industrial connections may be made at 132kV (e.g. paper mills, steel works) however these would be largely equivalent to 132/11kV substations. Storage after the meter is excluded from the scope of the study.

A summary of the electricity connections scope is provided in Table 3-10.

[5] ERP (2011) http://www.energyresearchpartnership.org.uk/energystorage

Table 3-10: electricity connections technical scope

Function	Mode	Rating	Installation	Capacity	Land-take	Boundary
Connections	AC	400V	Commercial Office	200kVA	nil	Connected at LV, assuming nearby 11kV substation. 3 phase supply.
Connections	AC	33kV	Industrial	10MVA	240m^2	Assumed to be medium industrial consumer, connected via 33kV network
Connections	AC	230V	Residential	2-5kVA	nil	Drawings will include individual single phase, individual 3 phase and multi-residential
Connections	AC	230V	Vehicle recharging	3.7kA	1.785m^2 recharge area	Assume uses feeder pillar to connect to dedicated charging pillar

3.4.2 Gas

System overview

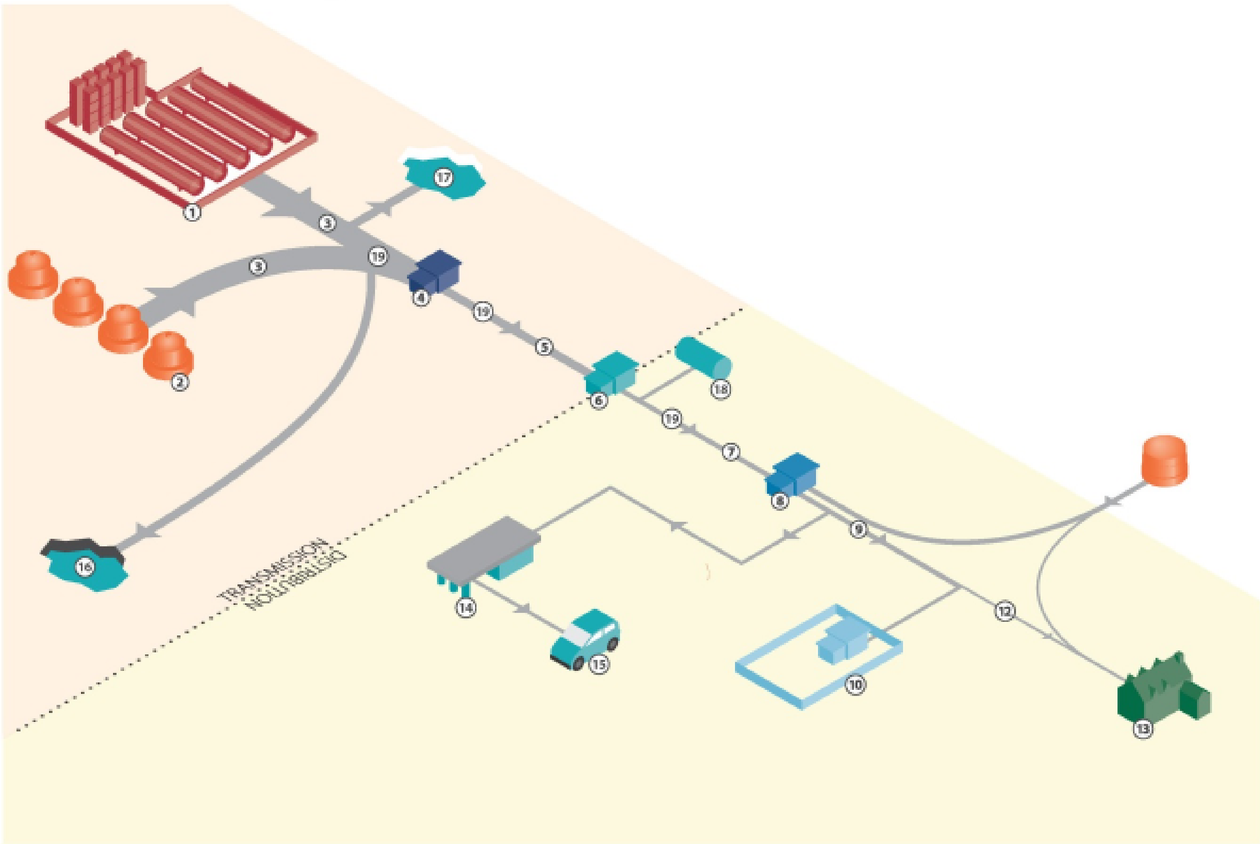
Natural gas pipelines in the UK are divided into two categories: high-pressure, larger-diameter transmission pipelines and lower-pressure distribution mains. Gas flows through these pipelines from import terminals to the end users, the flow being supplemented by storage facilities and controlled and regulated through compressor stations and pressure reduction installations (PRIs).

Gas infrastructure assets can be divided into three categories:

- those that have a long history dating back to the “town gas” era of local gas manufacture and distribution, i.e. low pressure gas holders, district governors and cast iron mains;
- those that date back to the 1970s, when natural gas was introduced, and the transmission system had to be constructed, i.e. the transmission system itself, national off-takes; and
- those built since the early 1980s, the Local Transmission System (LTS) and Pressure Reduction Installations (PRI’s) and the new Polyethylene (PE) network.

A schematic showing existing gas infrastructure in the UK is provided in Figure 3—3 below.

ETI 2050 - **Gas Schematic - Existing**



1. NORTH SEA TERMINAL INCLUDES INLET VALVES / METERING
2. LNG TERMINAL + COMPRESSORS
3. NATIONAL GRID TRANSMISSION 75-100 BAR
4. PRESSURE REDUCTION INSTALLATION (PRI)
5. NATIONAL GRID HIGH PRESSURE (HP) 35 BAR
6. PRI (NETWORK OPERATOR E.G. WALES & WEST UTILITIES)
7. INTERMEDIATE PRESSURE (IP) 2-7 BAR
8. PRI
9. MEDIUM PRESSURE (MP) DISTRIBUTION 2 BAR
10. COMMERCIAL SITE WITH INDIVIDUAL PRI
11. POSSIBLE LOCAL BIO GAS PRODUCTION SUCH AS DIDCOT PROJECT
12. LOW PRESSURE (LP) DISTRIBUTION 55 - 70mBAR
13. ENTER HOUSE AT 23mBAR
14. COMPRESSED NATURAL GAS (CNG) VEHICLE REFUELING STATION
15. CNG VEHICLES
16. GAS STORAGE (OFFSHORE)
17. GAS STORAGE (SALT CAVERN)
18. GAS STORAGE (HIGH PRESSURE VESSEL -'BULLET')
19. LINE PACKING

Figure 3—3: Schematic of existing UK gas infrastructure

Transmission

Gas enters the system via the seven UK gas terminals (six in England and one in Scotland) and the five Liquefied Natural Gas (LNG) stores (three in England, one in Wales and one in Scotland) with one terminal in England using LNG carriers connected to LNG piers and similar terminal in Wales. LNG plants include evaporation equipment to return the liquefied gas to gas form, as well as compressors.

From the import terminals, gas is transferred to the high-pressure National Transmission System (NTS). The NTS comprises pipelines made of high grade welded steel that transport gas from the entry points to major centres of population and some large industrial users, such as power stations. The NTS is owned and managed by National Grid Gas. Northern Ireland is connected to the Great Britain NTS via a pipeline from Scotland.

There are 175 off-take points through which the NTS supplies gas to:

- the twelve local distribution zones (LDZ) that contain pipes operating at lower pressure which eventually supply the smaller end consumers, including domestic customers
- some end users which are primarily large industrial consumers and power stations

Most of the NTS was built in the 1970s and early 1980s after major increases in North Sea production. The total length of the NTS is around 4,720 miles and operates at pressures up to 85 bar. The gas is pushed through the system by 23 (mostly gas turbine driven) compressor stations and fifteen pressure regulators located around the country. Gas moves through the system at an average of 25mph.

For the project, differing capacities for gas transmission are taken into account by including different pipe diameters. A key determinant of cost of transmission pipelines is the number of special crossings encountered in a particular stretch. For the study average numbers of river, rail and road crossings were assessed for a 100km stretch using GIS mapping of the gas transmission network and counting actual numbers of crossings over three different sections. Clearly these numbers will vary according to geography.

A summary of the gas transmission scope is provided in Table 3-11.

Table 3-11: gas transmission technical scope

Function	Mode	Rating	Installation	Capacity	Length	Boundary
Transmission	NTS	34"	Buried	30mill m^3/day	100km	Includes 1 x CP; 17 Special Crossings; 5 x Line Valves and 2 pigs
Transmission	NTS	32"	Buried	25mill m^3/day	100km	Includes 1 x CP; 17 Special Crossings; 5 x Line Valves and 2 pigs
Transmission	NTS	28"	Buried	20mill m^3/day	100km	Includes 1 x CP; 17 Special Crossings; 5 x Line Valves and 2 pigs

Distribution

There are eight gas distribution networks (GDNs) in Great Britain, which each cover a separate geographical region. There are also a number of Independent Gas Transporters who mostly supply residential developments. The Northern Ireland distribution system is operated by Phoenix Natural Gas.

Pipes in the distribution system were mostly ductile iron. These are now being replaced Polyethylene (PE). High Pressure (HP) pipework will remain in steel. A summary of network pipes and pressures is given in Table 3-12.

Table 3-12: Distribution network pipeline pressures and materials

Rating	Symbol	Pressure	Typical Pipe Material
High pressure	HP	10 – 38 bar	High grade steel
Intermediate pressure	IP	2 – 7 bar	Steel/polyethylene
Medium Pressure	MP	75 mbar – 2 bar	Steel/polyethylene/cast iron/ductile iron
Low Pressure	LP	30 – 75 mbar	Polyethylene/cast iron/ductile iron

A number of different pipe diameters are included in the project at different pressures from the off-take from the NTS down to connection to end consumers. Special crossings are only included at the higher pressures; at the lower ones, crossings are deemed to be 'standard' and included in the cost of the pipe work.

A summary of the gas distribution scope is provided in Table 3-13.

Table 3-13: gas distribution technical scope

Function	Mode	Rating	Installation	Capacity	Length	Boundary
Distribution	HP	36"	Buried	30mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	HP	34"	Buried	28mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	HP	32"	Buried	25mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	HP	30"	Buried	23mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	HP	28"	Buried	20mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	HP	26"	Buried	18mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	HP	24"	Buried	15mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and pigs
Distribution	HP	20"	Buried	13mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs

Function	Mode	Rating	Installation	Capacity	Length	Boundary
Distribution	HP	16"	Buried	10mill m^3/day	100 km	Includes Special Crossings; 7 x Line Valves and 3 pigs
Distribution	IP	8"	Buried	400,000 m^3/day	Urban 10km; rural 15km	Typical length for urban to include 3 x special crossings; 3 x Line Valves. Rural to include: 5 x special crossings; 2 x Line Valves
Distribution	MP	6"	Buried	Urban 300,000 m^3/day Rural 75,000 m^3/day	10km	2 standard crossings; 11 line valves
Distribution	LP	12"	Buried	Urban 20,000 m^3/day Rural 5,000 m^3/day	Urban and rural 10km	Urban to include: 2 x standard crossings; 21 x Line Valves; rural to include: 2 x standard crossings; 11 x Line Valves.

Conversions

Gas flow through the system is regulated by a series of installations. These are:

- Compressor stations to maintain pressure in the system. They are all within the NTS. There are 23, mostly gas turbine driven.
- Pressure Reduction Installations (PRIs), at both transmission and distribution level, that manage pressure reduction through the system as the gas approaches end users. PRIs are of varying scales.
- Gas governors, at the distribution level. These perform a similar role to PRIs but operate at lower pressures and do not require any pre-heating technology. Also known as Pressure Reduction Stations (PRS), and analogous to a transformer in the electricity system.

There is a large variety of possible capacities for conversion and only a relatively limited number have been specified. A summary of the gas conversion scope is provided in Table 3-14.

Table 3-14: gas conversion technical scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Compressor station	NTS	n/a	Above ground	50 mill m^3/day	15,000m^2	Includes 2 gas fired turbines in acoustic housing; filters, condensate tanks, compressors, fan coolers, standard control and SCADA rooms.
Conversion	NTS/HP	n/a	Above ground	10 mill m^3/day	40,000m^2	Includes filters; a heat exchanger and a water bath to preheat gas and control temperature drop; Pressure Reduction sub-component and standard Control and SCADA rooms. Odour will be injected at this point.
Conversion	HP/IP	n/a	Above ground	1 mill m^3/day	5,625m^2	Includes filters; a heat exchanger and a water bath to preheat gas and control temperature drop; Pressure Reduction sub-component and standard Control and

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
						SCADA rooms.
Conversion	IP/MP	n/a	Above ground	30,000 m^3/hr	50m^2	Includes filters and valves
Conversion	MP/LP	n/a	Above ground	5,000m^3/hr	25m^2	Includes filters and valves

Storage

Gas is stored in a number of different ways, including as LNG (5 stores in GB), underground (salt caverns) (7 stores), High Pressure Storage (so-called 'bullets') and Low Pressure Storage ('gas holders'). There is also a technique known as line packing which is increasingly used, making use of excess capacity in the network, increasing the pressure overnight to build up supplies and making use of this at peak demand periods. Line packing was not covered by the project.

A summary of the gas storage scope is provided in Table 3-15.

Table 3-15: gas storage technical scope

Function	Mode	Rating	Installation	Capacity (low / med / high)	Land take	Boundary
Storage	n/a	n/a	LNG on-shore storage	100,000 m^3 150,000 m^3 200,000 m^3	60,000m^2 for 4 nr tanks; 15,000m^2 average per tank	Average of four 85m diameter tanks (150,000m3 per tank). Boundary does not include unloading jetty, LNG gasification and gas export facilities
Storage	n/a	n/a	Salt cavern storage	330 mill m^3 400 mill m^3 900 mill m^3	40,000m^2 plant area; 475ha overall	Includes above ground pumping equipment; brine pump and reservoir; brine disposal / water intake.
Storage	n/a	n/a	High pressure vessel - 'bullet'	100 m3 150 m^3 200 m^3	300m^2	1 compound, average of 3 tanks (50m^3 per tank) including valves, piping, drains, regulators, water sprinkling system , gas leak detection system & suitable control panel
Storage	n/a	n/a	Low pressure vessel - 'gas holder'	100,000 m^3 150,000 m^3 200,000 m^3	2,800m^2	includes storage tank (60m diameter), support frame, working room allowance

Connections

Connections are varied depending on end user scale and type, however are deemed to end at the fiscal meter entering the customer's property. They generally involve an emergency shut off valve and possibly a governor to regulate flow.

A summary of the gas connections scope is provided in Table 3-16.

Table 3-16: gas connections technical scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Connections	LP	12”	Commercial Office	350 m^3/day	4m^2	Typically connections for commercial or small industry may be taken off IP/MP or LP mains and will require U16-U160 meters
Connections	LTS	20”	Industrial	100,000 m^3/day	625 - 2,500m^2	Typically Large Industry connections are taken off the LTS and will incorporate a Daily Metered site and a PRS
Connections	NTS	34”	Power generation	1 mill m^3/day	2,500m^2	Typically taken off NTS, includes daily metered site and AGI (pressure reduction station); filter and valves
Connections	LP	2”	Residential	6 m^3/hr	n/a - internal	Typically taken off LP mains; includes valve and meter (excludes service pipe).
Connections	LP	12"	Vehicle refuelling stations - CNG	300 m^3/hr	n/a - internal	Assumes an inlet pressure of 13 bar and a connection of 45 kW

3.4.3 Heat

Heat is not currently a regulated public utility akin to mains grid gas or electricity. Due to the disparate nature of heat distribution networks in the UK it is difficult to state the exact extent and cumulative distance of existing installations. A large percentage of the heat infrastructure is privately owned and, furthermore, there are no utility type record drawings for existing heat networks. Some local information is available, such as the Greater London Authority (GLA) London Heat Map, showing existing and planned district heating networks (DHN) across the city.

Although significant networks exist in major cities, it is estimated that less than 2% of the UK’s heat demand is supplied by DHNs. The UK has no examples of conveyance of heat from conventional large scale power stations, a strategy that is commonplace in Scandinavia and other European countries.

A typical schematic showing heat infrastructure is provided in Figure 3—4 below. Heat can be distributed over tens of kilometres and there are precedents for this. Provided sufficiently large capacities are used losses in percentage terms can be small. Capacity increases with the square of the pipe diameter, losses with diameter. However, compared to gas and electricity, distances are small and so for the purposes of this project all heat networks are considered to be distribution rather than transmission.

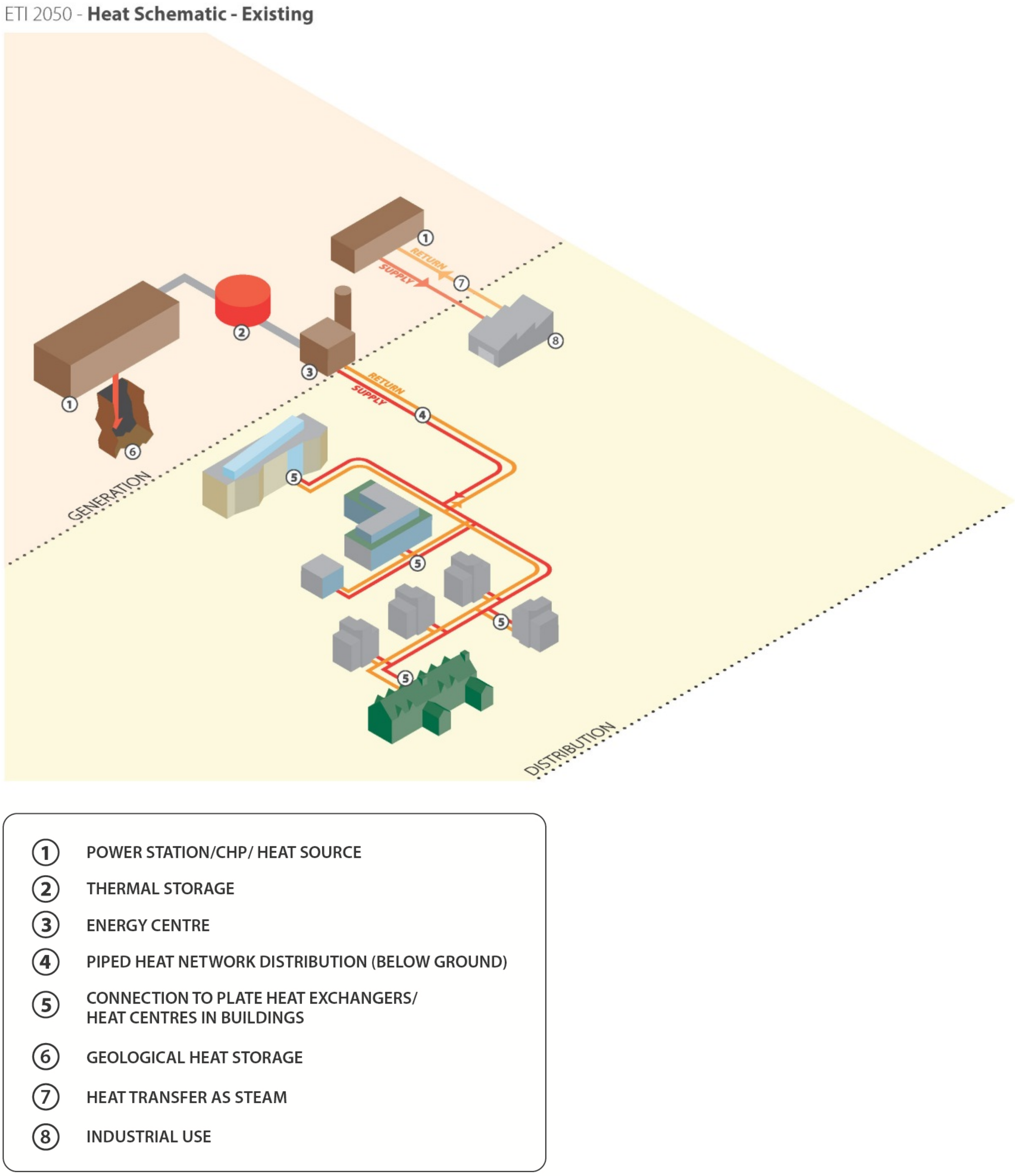


Figure 3—4: Schematic of heat network infrastructure

Distribution

DHNs can be categorised into three types as described below. A fourth category has been proposed which could be categorised as local transmission networks. These would connect large scale thermal power stations, such as a carbon capture and sequestration (CCS) cluster in the Thames Gateway and Bradwell nuclear plant, into a large heat demand area, such as London. No such large scale networks exist in the UK at present. The anticipated scale of this type of network is 500MWth to 1GWth with pipe diameters of 800mm being expected depending on temperature. Networks of this scale are not included in the study.

The following network definitions are based on work done by the Greater London Authority[6]:

- Type 1 Networks

  Type 1 networks are small-scale systems, between 0.1 and 3MWe, consisting of CHP units in building plant rooms. These can serve two or more commercial or public sector buildings and/or up to approximately 3,000 residential units (or equivalent), in a local area. Examples include the Barkantine Heat and Power scheme and the King’s Cross scheme which are both operational.

- Type 2 Networks

  Type 2 networks represent medium size CHP units, between 3 and 40MWe based in an adjacent energy centre. They can serve several areas of demand and anchor loads, about 3,000 to 20,000 residential buildings or equivalent, possibly connecting into an existing heat distribution system. Heat sources include large-scale gas engines, biomass heat only boilers, energy from waste (EfW) or waste heat from local industry. Operational examples include the Olympic Park scheme or the Citigen scheme.

- Type 3 Networks

  Type 3 networks consist of large-scale generators and industrial sources of waste heat linked to areas of demand economically suitable for district heating via longer distance heat distribution lines, serving the equivalent of >100,000 homes. This includes large heat customers such as industry and commercial centres, and combinations of smaller-scale heat networks (e.g. Type 1 or 2 schemes). Heat sources include larger scale natural gas CHP plant (typically combined cycle gas turbine (CCGT)), waste heat from existing power stations or larger EfW plant. Examples include the London Thames Gateway Heat Network, which is under development.

The pipe diameters included in the study reflect this variety of network scales by spanning from the larger diameter 450mm pipe down to the smaller 150mm approximately corresponding to Type 3 and Type 1 respectively. A range of different temperatures are also included. These would meet the needs of the three different network types described although clearly in reality, a wide range of different pipe sizes are used. Service pipes (eg. from distribution mains to consumer premises) are included within the connections category.

A summary of the heat distribution scope is provided in Table 3-17.

[6] These scales were originally developed by the GLA in their 2009 report “Powering ahead: Delivery low carbon energy for London”, and were subsequently revised in the 2011 study “Decentralised energy capacity study”
http://www.london.gov.uk/priorities/environment/climate-change/decentralised-energy

Table 3-17: heat distribution technical scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Distribution	120°C	450mm	Buried	75 MW	2,920 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	120°C	300mm	Buried	27 MW	2,540 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	120°C	150mm	Buried	3 MW	2,130 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	70°C	450mm	Buried	50 MW	2,920 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	70°C	300mm	Buried	18 MW	2,540 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	70°C	150mm	Buried	2 MW	2,130 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	50°C	450mm	Buried	25 MW	2,920 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	50°C	300mm	Buried	9 MW	2,540 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)
Distribution	50°C	150mm	Buried	1 MW	2,130 m^2/km	Pipework including ancillaries (valves, expansion, trenching etc)

Conversion

District heating conversion temperatures are driven by three primary factors:

1. **Heat generation temperatures** – process heat will normally be at the higher end of the scale, whereas heat from renewable sources is generally in the range of 70°C – 90°C or lower.
2. **Distribution temperatures** – higher distribution temperatures are generally used to distribute over longer distances. The higher the distribution temperature the greater the heat losses, although the majority of losses occur in the service pipes to consumer premises.
3. **Final use temperatures** – older buildings traditionally operate space heating systems at 82/71°C, newer buildings have a wider delta T and often operate at 80/60°C or 70/50°C, however, underfloor heating will be significantly lower, operating at circa 50/40°C. The required domestic hot water generation temperature is 65d^{0}C throughout the UK.

Typical distribution temperatures for district heat networks are:

- Medium Temperature Hot Water (MTHW) – flow temperatures 105 to 120°C
- Low Temperature Hot Water (LTHW) – flow temperatures 70°C to 95°C

- Very Low Temperature Hot Water (VLTHW) – flow temperatures 45°C to 70°C

The main conversions from each of these distribution temperatures are:

- 120°C to 70°C
- 120°C to 50°C
- 70°C to 50°C

In practice, return temperatures and flow rates as well as pipe diameters govern capacity. Assumptions based on common practice have been used to estimate capacity but these should be checked by users of the cost model.

A summary of the heat conversion scope is provided in Table 3-18.

Table 3-18: heat conversion technical scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Conversion	120°C	n/a	50°C	12 MW	50 - 100m^2	Connections up to isolation valves from DHN
Conversion	120°C	n/a	70°C	18 MW	50 - 100m^2	Connections up to isolation valves from DHN
Conversion	70°C	n/a	50°C	12 MW	50 - 100m^2	Connections up to isolation valves from DHN

Storage

Existing thermal storage for DHNs in the UK is predominantly limited to district level above ground accumulators (large tanks). Stores are provided for CHP systems as a means to store heat when there is no or low direct heat demand on the network; this heat can then be discharged when demand increases allowing electricity and heat production to be decoupled. Stores also act as a buffer during periods of peak demand to allow a greater proportion of the peak load to be delivered by the CHP plant versus “top up” peak load boilers. This increases return on investment and environmental benefits. Storage can also be used to capture heat from intermittent sources, or used to dump excess energy from intermittent electricity producing plant such as wind turbines.

Typical campus scale thermal stores are in the order of 50 – 100m^3. Large-scale thermal stores are installed in many cities in Denmark, reaching 65m in height and a height-to-width ratio of 1.5. The largest thermal store in Germany is 30,000m^3 in volume. Such stores can also be used to pressurise the heat network. The Olympic Park and Pimlico schemes in London both have large thermal storage tanks of around 800m^3 in volume.

Future thermal storage is likely to include the greater exploitation of below ground aquifer and borehole systems. These allow large scale interseasonal storage captured in summer / low load conditions and used to reduce the impact on peak load requirements.

A summary of the heat storage scope is provided in Table 3-19.

Table 3-19: heat storage technical scope

Function	Mode	Rating	Installation	Capacity (low / med / high)	Land take	Boundary
Storage	n/a	n/a	District level thermal store	800 m^3 5,000 m^3 20,000 m^3	110m^2	Low capacity, 800m^3 tank above ground steel insulated tank; connections up to isolation valves from DHN
Storage	n/a	n/a	Large scale aquifer storage	20 GWh 25 GWh 30 GWh	75,000m^2 for above ground plant	Medium capacity, 25MW charge, over 3 months, 24/7, with around 50% capacity. Note above ground area is only partially occupied. Losses assume store has reached close to equilibrium with surrounding ground.

Connections

District heat networks are predominantly suitable for connection to building space heating and domestic hot water systems. Low pressure steam systems do exist but are not generally used for new build systems. They are not suitable for process heating applications due to the higher temperature generally required. Public sector and commercial buildings use a mixture of indirect connections e.g. plate heat exchangers (PHX), and direct 'heat station' connections, usually built into pre-fabricated heat stations.

- Direct Connection

  The direct connection method is normally used in systems where temperatures are below 90°C and pressures below 6 bar. Direct systems tend to be associated with systems that are predominantly made up of domestic dwellings.

- Indirect Connections

  The indirect connection method is normally used in large systems whose temperatures and pressures are not suitable for the direct connection method or a hydraulic break is preferred for contractual reasons. A larger system could involve temperatures above 90°C and pressures above 6 bar, i.e. higher than a typical building heating system can operate. Hydraulic breaks are also required for connection to tall buildings and in topographically varied areas.

A summary of the heat connections scope is provided in Table 3-20.

Table 3-20: heat connections technical scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Connections	n/a	n/a	Industrial	0.5 MW	n/a - internal	Connections are all assumed to be indirect
Connections	n/a	n/a	Commercial Office	0.25 MW	n/a - internal	Connection from tee off in the street to main isolation valve and heat meter, PEX on consumer side
Connections	n/a	n/a	Residential	0.03 MW	n/a - internal	Connection from tee off in the street to main isolation valve and heat meter, PEX on consumer side

3.4.4 Hydrogen

System overview

The UK's current hydrogen infrastructure is extremely sparse compared to electricity and natural gas networks; however it does exist and can be categorised under three classes: industrial pipelines, merchant gas supplies and new energy infrastructures. These are outlined in the following sections.

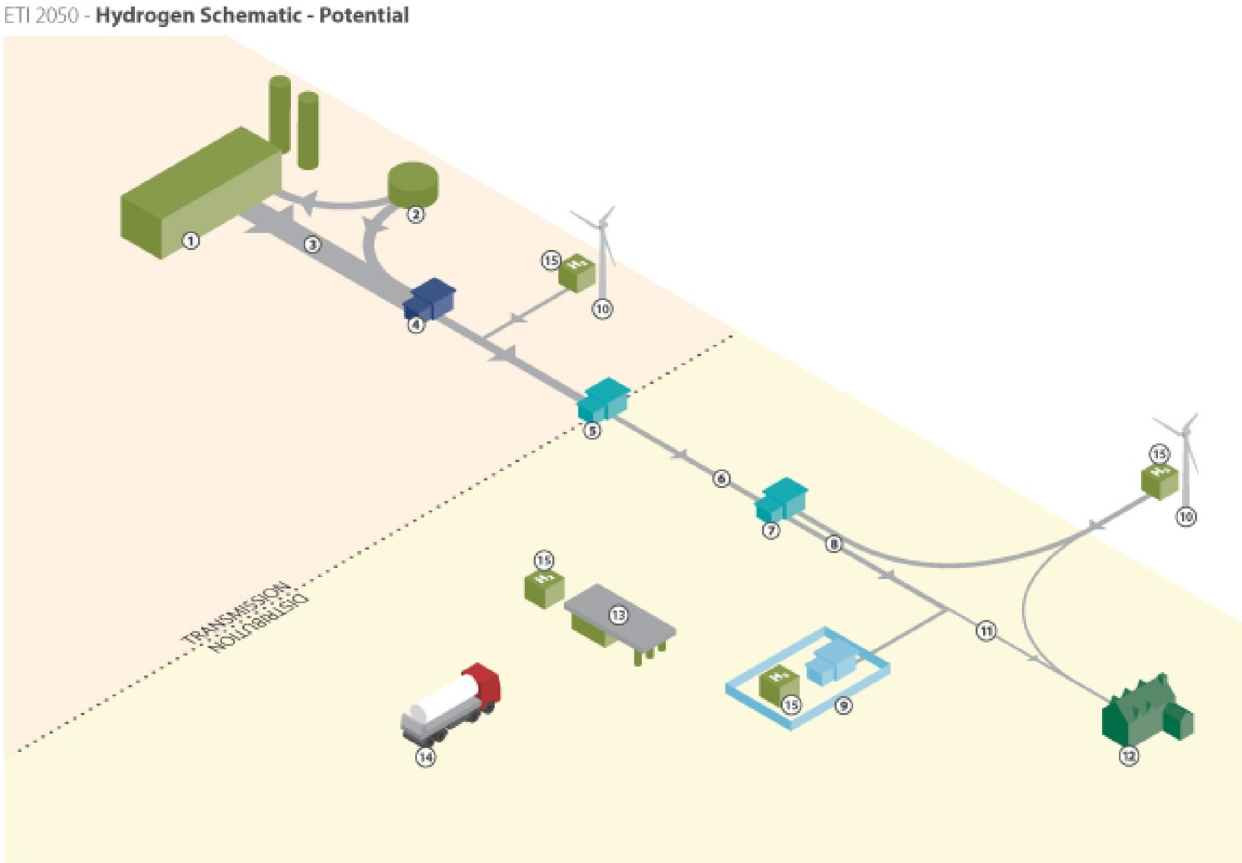
In order to 'set the scene', the schematic in Figure 3—5 illustrates the *potential* role(s) that hydrogen could play within the UK energy system. For this project, the important aspect to consider is the mode of delivery (rather than end use). The choice is essentially between the pipes (ie. energy transported in the form of hydrogen gas) and wires (ie. energy transported in the form of electricity). In the former case, the scenario could be that hydrogen was generated upstream (for example alongside pre-combustion CCS gas power stations) from where it could be moved through pipes to end users. And in the latter case, hydrogen would be generated downstream from electricity in smaller units closer to the point of use (be this for vehicles or on-site industrial use).

Transmission / Distribution

Hydrogen is delivered by pipeline in several industrial areas of the United States, Canada, and Europe however there is only one relatively short section in the UK.

As discussed in Section 1.1.1 above, due to the limited precedents for hydrogen infrastructure in the UK, a technical approach was taken to defining the different pipe diameters required. Based on the assumption that a hydrogen transmission / distribution system would operate on a similar scale to that of gas, pipe diameters for hydrogen transport are assumed to be the same as for natural gas with pressures and pipe thicknesses being altered to allow for the transmission of the same energy capacity. The literature review undertaken suggested a pressure increase of around 20% would be required (see Appendix D for details).

A summary of the hydrogen transmission and distribution scope is provided in Table 3-21.



1. CCGT + PRE COMBUSTION CCS - H_2 PRODUCTION
2. H_2 STORAGE
3. H_2 TRANSMISSION (HIGH PRESSURE) +/- NATURAL GAS
4. PRESSURE REDUCTION INSTALLATION (PRI)
5. PRI
6. H_2 DISTRIBUTION
7. PRI
8. H_2 DISTRIBUTION
9. COMMERCIAL SITE WITH ON-SITE H_2 PRODUCTION / USE
10. UPSTREAM H_2 PRODUCTION LINKED TO RENEWABLE GENERATION
11. H_2 DISTRIBUTION – LOCAL
12. H_2 DOMESTIC SUPPLY
13. GARAGE FORECOURT WITH ON-SITE H_2 PRODUCTION
14. TANKER TRANSPORT OF H_2
15. ELECTROLYSER

Figure 3—5: Schematic of potential hydrogen infrastructure

Table 3-21: hydrogen transmission and distribution scope

Function	Mode	Rating	Installation	Capacity	Length	Boundary
Transmission	NTS	34"	Buried	35 mill m^3/day	100 km	Includes 1 x CP, 5 x Line Valves and 2 pigs; 17 special crossings; 5 x rail, 2 x road, 10 x river
Transmission	NTS	32"	Buried	29 mill m^3/day	100 km	as above
Transmission	NTS	28"	Buried	23 mill m^3/day	100 km	as above
Distribution	HP	36"	Buried	35 mill m^3/day	100 km	7 x Line Valves and 3 pigs; Special Crossings include: 3 x rail, 4 x road, 1 x canal, 2 x river
Distribution	HP	34"	Buried	32 mill m^3/day	100 km	as above
Distribution	HP	32"	Buried	29 mill m^3/day	100 km	as above
Distribution	HP	30"	Buried	27 mill m^3/day	100 km	as above
Distribution	HP	28"	Buried	23 mill m^3/day	100 km	as above
Distribution	HP	26"	Buried	21 mill m^3/day	100 km	as above
Distribution	HP	24"	Buried	17 mill m^3/day	100 km	as above
Distribution	HP	20"	Buried	15 mill m^3/day	100 km	as above
Distribution	HP	16"	Buried	12 mill m^3/day	100 km	as above
Distribution	IP	8"	Buried	464,000 m^3/day	10 km (urban) 15 km (rural)	Urban to include 3 x line valves, 3 x special crossings; 1 x rail, 1 x road, 1 x river. Rural to include 2 x line valves, 5 x special crossings; 2 x rail, 2 x road, 1 x river
Distribution	MP	6"	Buried	348,000 m^3/day (urban) 87,000 m^3/day (rural)	10 km	2 x standard crossings, 11 x line valves
Distribution	LP	12"	Buried	23,200 m^3/day (urban) 5,800 m^3/day (rural)	10 km	Urban to include: 2 x Standard Crossing; 21 x Line Valves Rural to include: 2 x Standard Crossing; 11 x Line Valves

Conversions

The technology required to convert hydrogen from one pressure to another is perhaps the most different from that used for natural gas as discussed under the Approach Section 3.2 above.

For compression, the use of multi-stage barrel type compressors is assumed with around five compressor stages rather than 1-2 usually used for natural gas.

For PRI/PRS no pre-heating is required. Unlike gas, hydrogen heats up on expansion but only very slightly. Air blast coolers have been allowed for but may not be required.

A summary of the hydrogen conversion scope is provided in Table 3-22.

Table 3-22: hydrogen conversion scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Compressor station	NTS	n/a	Above ground	58 mill m^3/day	15,000m^2	Includes 2 gas fired turbines in acoustic housing; filters, condensate tanks, compressors, fan coolers, standard control and SCADA rooms.
Conversion	NTS/HP	n/a	Above ground	12 mill m^3/day	40,000m^2	Includes filters; a heat exchanger and a packaged temperature control unit to control temperature drop; Pressure Reduction sub-component and standard Control and SCADA rooms. Odour will be injected at this point.
Conversion	HP/IP	n/a	Above ground	1.16 mill m^3/day	5,625m^2	Includes filters; a heat exchanger and cooler to control temperature increase on expansion; Pressure Reduction sub-component and standard Control and SCADA rooms.
Conversion	IP/MP	n/a	Above ground	34,800 m^3/hr	50m^2	Includes filters and valves
Conversion	MP/LP	n/a	Above ground	5,800 m^3/hr	25m^2	Includes filters and valves

Storage

There are a number of different approaches to large scale storage of hydrogen, none of which are currently used in the UK on any scale. There are some smaller scale storage units attached to hydrogen vehicle fuelling stations, mostly as part of a trial or test site. As a proxy for the utility scale storage that would be required for a national hydrogen system, natural gas equivalents have been used. It should be noted that hydrogen needs to operate at higher pressures to store the same amount of energy as natural gas.

A summary of the hydrogen storage scope is provided in Table 3-23.

Table 3-23: hydrogen storage scope

Function	Mode	Rating	Installation	Capacity (low / med / high)	Land take	Boundary
Storage	NA	NA	Liquefied H2 storage	122,000 m^3 174,000 m^3 226,000 m^3	60,000m^2	Average of four 85m diameter tanks (174,000m3 H2 per tank). Boundary does not include unloading jetty, LH2 gasification and gas export facilities
Storage	NA	NA	Salt cavern / geologic storage	380 mill m^3 460 mill m^3 1,035 mill m^3	40,000m^2 plant area; 475ha overall	Includes above ground pumping equipment; brine pump and reservoir; brine disposal / water intake.
Storage	NA	NA	High Pressure Vessel - tanks	1,500 m^3 2,000 m^3 2,500 m^3	800 m^2	1 compound, average of 3 tanks (667m3 per tank) including valves, piping, drains, regulators, water sprinkling system , gas leak detection system & suitable control panel
Storage	NA	NA	Low Pressure Vessel	122,000 m^3 174,000 m^3 226,000 m^3	2,800m^2	Includes storage tank (60m diameter), support frame, working room allowance

Connections

As for natural gas, connections for hydrogen will be varied depending on end user scale and type. Again, in the absence of actual precedents, natural gas equivalents have been used as a proxy. Research such as the NaturalHy project[7] suggests this approach is feasible.

Table 3-24: hydrogen connections scope

Function	Mode	Rating	Installation	Capacity	Land take	Boundary
Connections	LP	12”	Commercial Office	400 m^3/day	4m^2	Connections for commercial or small industry likely to be taken off IP/MP or LP mains and to require U16-U160 meters
Connections	MP	20”	Industrial	116,000 m^3/day	625 - 2,500m^2	Large Industry connections likely to be taken off the LTS and to incorporate a Daily Metered site and a PRS
Connections	NTS	34”	Power generation	1.2 mill m^3/day	2,500m^2	Taken off NTS, including daily metered site and AGI (pressure reduction station); filter and valves
Connections	LP	2”	Residential	7 m3/hr	n/a - internal	Likely to be taken off LP mains; including valve and meter (excludes service pipe).
Connections	LP	12"	Vehicle refuelling stations	350 m3 /hr	n/a - internal	Assumes an inlet pressure of 15 bar

[7] NaturalHy is a project co-funded by the European Commission to support the transition to a hydrogen economy. www.naturalhy.net

4 Spatial Analysis

4.1 Overview

Spatial analysis was undertaken to support the validation process of the cost tool. The initial exercise was to review linear infrastructure in the context of its geographical distribution to validate technical assumptions particularly in relation to special crossings.

Supplementary to this, once the cost model was complete, geographical data and associated ‘bills of quantities’ for a number of projects for transmission and distribution networks for each vector (distribution only for heat) were compiled. The maps and project data are summarised in Section 4.3.1 of this chapter with details included in Appendix E. ArcGIS files are available separately.

4.2 Linear infrastructure review: special crossings

4.2.1 Gas

Gas transmission

The national networks of motorways, A Roads, railways and rivers were sourced from the Ordinance Survey (OS) and the existing Gas Transmission network was sourced from the National Grid website. All networks were mapped in ArcGIS. The mapping of this data allowed for the selection of representative 100km stretches of gas network to explore intersections with roads, rail and rivers.

Three 100km stretches were selected (Figure 4—1). Special crossings as defined for this study are motorways and major A roads (estimated to be approximately 95% of all A roads), rivers and railways. So, for each 100km stretch, intersections with these elements were counted. The results of this exercise are shown in Table 4-1 along with the number of special crossings included in the relevant infrastructure scope to confirm alignment.

Table 4-1: assessment of numbers of special crossings for each 100km stretch compared with that included in the transmission pipeline scope diagram

Feature	Count per 100km case study stretches				Included in scope diagram
	Area A	Area B	Area C	Average	
Rail	4	6	5	5	5
Motorway	2	2	0	1-2	1
Major A roads	~ 1	~1	~1	~1	1
Rivers	5	11	9	8-9	10
Total	11	18	14	14-15	17

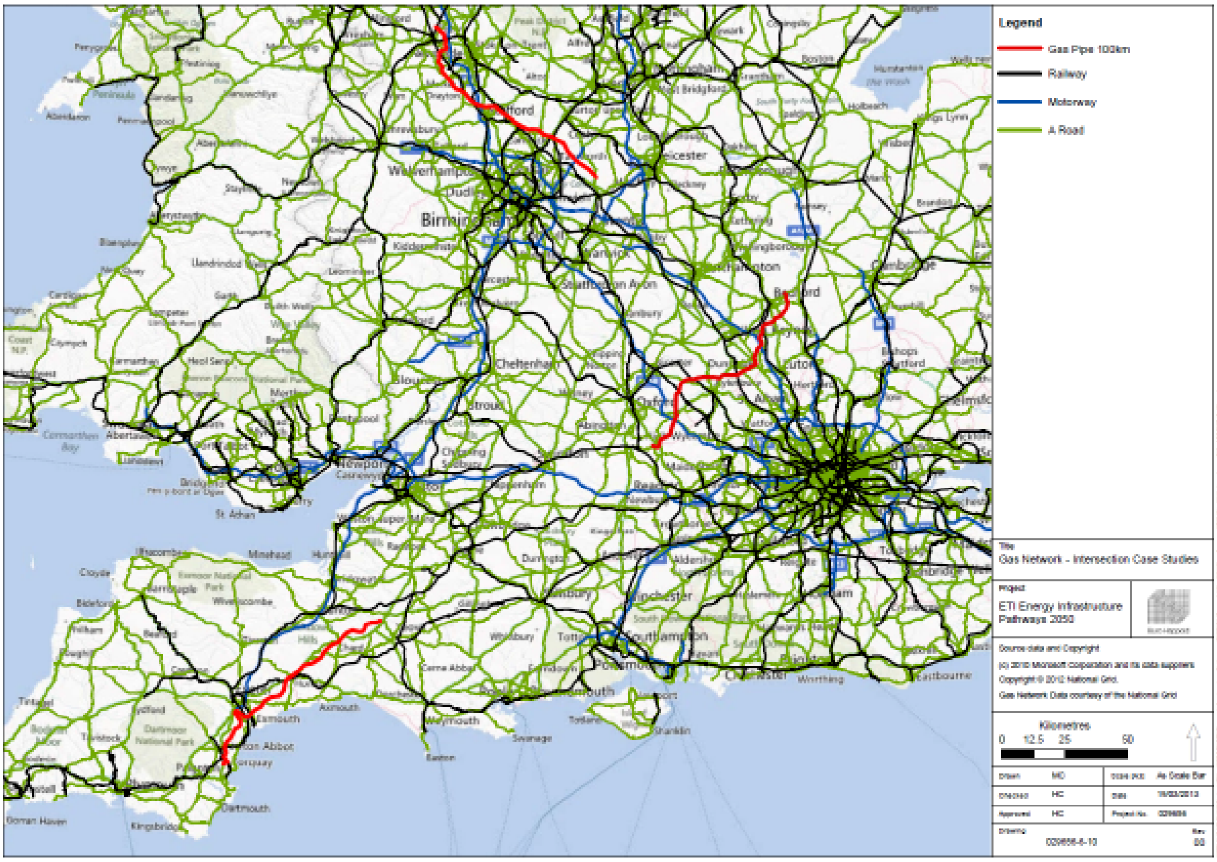


Figure 4—1: map showing location of 100km stretches of gas transmission pipeline taken as test cases for exploring numbers of special crossings (note rivers not shown here but are included as a layer in the ArcReader file in Appendix E).

Gas distribution

The gas distribution network for the south-west was sourced from Wales and West Utilities. As for transmission, this was then mapped alongside major rivers, motorways and A roads to give an indication of the likely level of special crossings required for both rural and urban areas. The case studies selected are shown in Figure 4—2.

Assessing and validating numbers of special crossings at this level is more complex due to the more convoluted nature of the pipe lines on the maps and the differing scopes for differing pipe diameters down the pressure scale.

For the HP network, a typical length of 100km is assumed to include ten special crossings. A review of two 50km stretches suggests an estimated four to five crossings on each (Figure 4—2).

For the smaller diameter pipes (MP and LP) crossings are assumed to be 'standard' rather than 'special' and are included in the pipe cost. The gas main would cross rivers strapped to a bridge or with the culvert or traverse rail line within the highway.

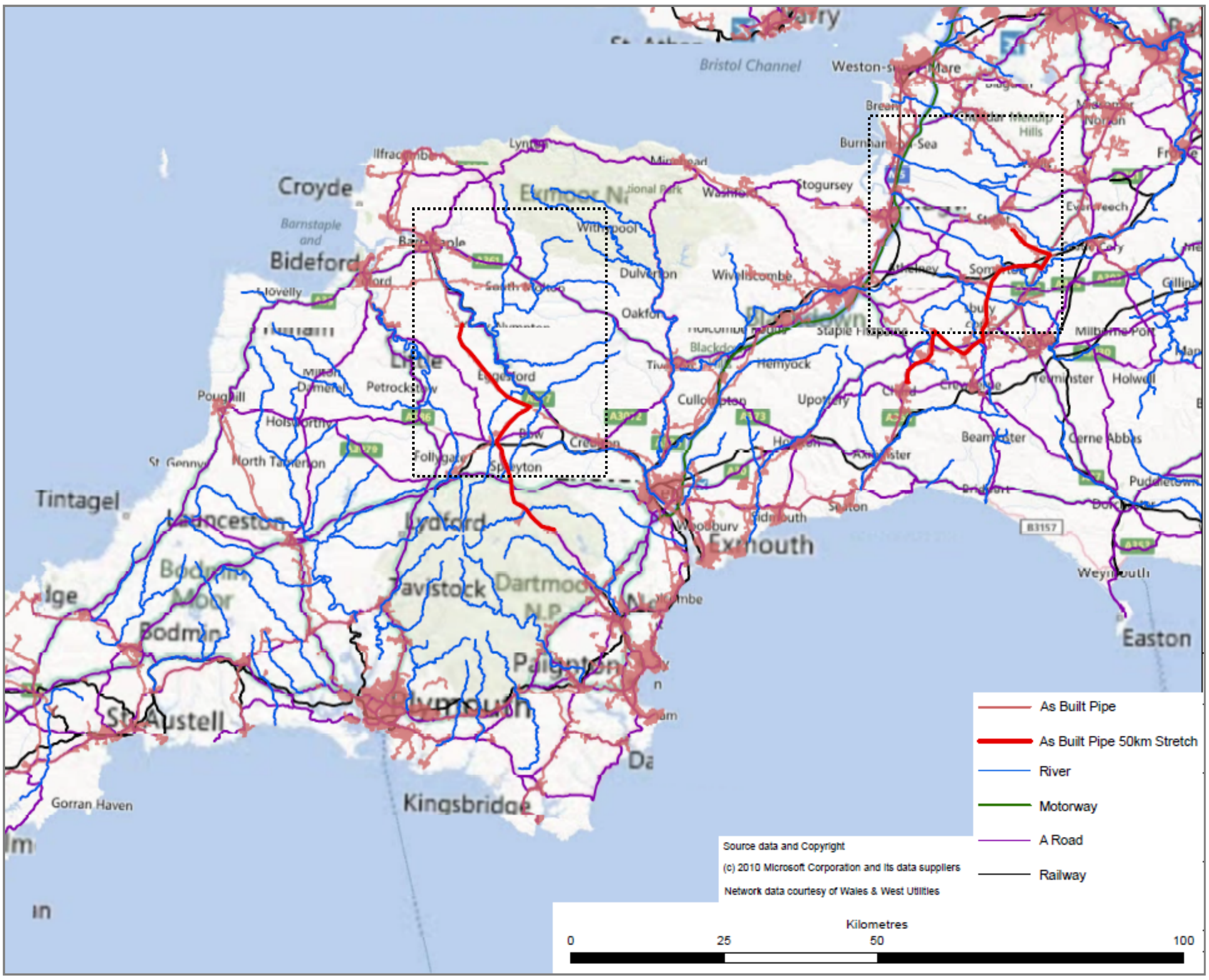


Figure 4—2: rural gas distribution case study area (Cornwall) showing gas distribution network, major roads, rivers and railways. A distance of 100km is shown for scale. Two approximately 50km lines are indicated in red within the dotted line boxes.

4.2.2 Electricity

Electricity transmission

The majority of the electricity transmission network is in overhead lines as illustrated in Figure 4—3. The electricity scoping diagrams for both overhead lines and buried cables do not consider special crossings.

For overhead lines there is no additional cost associated with towers as these are constructed on either side of obstacles. There is some additional cost associated with installing conductors over obstructions due to the need to install protective scaffolding structures and for closures. However, this cost is not thought to be significant compared to the cost of the conductors and the labour required to install them. The additional cost is therefore considered to be absorbed within the unit rate.

For buried cables additional costs are incurred where special crossings are required. These are considered further in Table 4-2 below:

Table 4-2: Buried cable crossings

Type of crossing	Engineering approach	Occurrence	Treatment in the cost model
Motorways	Crossings usually undertaken through thrust boring or pipe jacking conduit beneath the motorway	Relatively rare as by far greatest length of motorway in rural areas where cables are not generally used, or when in cities on elevated sections	Not considered sufficiently common to include in cost model
Rivers	Smaller rivers may be crossed by thrust boring or pipe jacking	Cables not generally installed in rural areas apart from where access to substations from OHL terminal towers with cable sealing ends used. Typically location of sealing ends chosen to avoid crossing such obstacles, though in some cases this is not possible.	Not considered sufficiently common to require specific cost
	Larger rivers crossed at a point where a bridge exists, and hence located within the roadway using similar approach to direct buried installation	Likely to be relatively common	Cost allowed for in the general per km cost for buried cables
	Where no suitable bridge exists a utility bridge may be installed	Considered unique to the specific location	Therefore not costed within the scope of this project
	Tunnels are used for crossings of major rivers, particularly in major urban conurbations e.g in London where relatively small diameter tunnels <2m are used for 132kV cables	Common for new cable circuits in very dense urban areas	Included as separate assembly for tunnel costs
Railways	Crossings usually undertaken through thrust boring or pipe jacking conduit beneath the permanent way	Relatively rare as by far greatest length of railway in rural areas where cables are not generally used, or when in cities on elevated viaducts or in tunnels	Not considered sufficiently common to include in cost model

Figure 4—3: National Grid electricity transmission network for England showing overhead lines (red) and cables (yellow).

Electricity distribution

Where electricity distribution networks are installed as OHL the treatment of crossings is as per that for OHL in transmission. Whilst crossings of motorways and major rivers using 33kV or 11kV OHL is unlikely due to the shorter spans involved, such crossings are more likely to make use of existing bridges and subways than the transmission network. These crossings are therefore not costed separately.

Where electricity distribution is directly buried within urban and sub-urban areas it is most commonly installed within the public highway or footway. Cabling is relatively easy to incorporate within an existing bridge or subway and therefore most likely to use such routes. In contrast to pipeline infrastructure which is more difficult to incorporate within existing structures and therefore crossings have been costed separately and added to the rates, the cost rates for buried electricity distribution networks incorporate an allowance for crossings.

4.2.1 Heat

As heat networks are only likely to be installed in urban areas they are almost always installed beneath the public highway, particularly where crossing existing linear infrastructure such as rivers, canals and motorways. The cost rates therefore include an allowance for installation within the highway and an allowance for crossings has been made within the rates.

Although generally heat networks will be in urban areas, the tool includes the possibility of selecting a rural context. Costs are modified according to the applied cost modification rates.

4.2.2 Hydrogen

The approach for hydrogen is based on the approach for gas networks.

4.3 Maps

4.3.1 Test projects

Test projects have been compiled to support the validation of the cost model. A summary of these is given in Table 4-3 below.

For each project, a map has been produced and is included in Appendix E in pdf and ARCReader file format. It was not possible to source any electrical distribution maps[8].

Each map is supported by a ‘bill of quantities’ for input to the cost model. These are included in Appendix F and have been set up in the cost model. They have been used for the cost analysis undertaken in the research section outlined in Chapter 9.

[8] Attempts were made to procure digital maps from Western Power Distribution and Northern Power Grid and via the National Grid. In some cases separate agreements are likely to be required with the relevant DNO where digital maps are available. In the case of National Grid, electricity distribution data for Loughborough was based on the gas grid network data as they had not been able to source electrical distribution data directly.

Table 4-3: summary of test projects compiled for cost model validation

Vector	Function	Test project	Context	Map ref	Key source
Gas	Transmission	East Midlands region	Rural	029656-1-7	National Grid
	Distribution	Loughborough	Urban / semi-urban	029656-1-9	National Grid
		Exeter	Urban / semi-urban	029656-1-8	Wales & West Utilities
		South West region	Rural / semi-urban	029656-1-3	Wales & West Utilities
Electricity	Transmission	East Midlands region	Rural	029656-2-3	National Grid
	Distribution	Loughborough	Urban / semi-urban	*not available*	National Grid
Heat	Distribution	Citigen, London	Urban	029656-3-1	London Heat Map
Hydrogen	Transmission	East Midlands region	Rural	029656-4-1	Derived from gas
	Distribution	Exeter	Urban / semi-urban	029656-4-2	Derived from gas

4.3.2 Other

Where other maps have been sourced for the project these have also been supplied. These include the National Grid gas and electrical transmission networks and OS road, river and rail networks. Details of all maps and ARCReader files are given in Appendix E.

5 Future near term review

5.1 Overview

In order to start to inform the innovation piece, a review of near term developments was undertaken for each vector.

Near term was taken as the period out to 2020. For regulated utilities (electricity and gas) this largely coincides with the time frame of the latest Price Control Review (PCR) periods. The PCR process, managed by the UK regulator, Ofgem, was changed for the period starting in 2013 (2015 for electricity distribution) to focus on issues of sustainability, reliability and value and is now referred to as RIIO – Revenue = Incentives + Innovation + Outputs)[9]. As its name suggests, innovation is now a key aspect of the regulatory environment recognising the changing drivers influencing utility provision and in particular the need to improve performance and drive down cost.

For the electricity and gas vectors therefore the near term view was guided by the work identified within the business plans of the relevant network operators where available. Driven in part by the RIIO process, all operators have identified areas for innovation, some with projects already being trialled. The review was also guided by scenarios of future supply and demand developed by National Grid, the two primary ones being referred to as 'Gone Green' and 'Slow Progression' [10].

For the unregulated and more innovative vectors, heat and hydrogen, the review started with looking at what was already in place in the UK (in the case of hydrogen, very little) and then considered policy and market influences that might affect future development.

5.2 Electricity

Under the National Grid scenarios[10], generation in total is forecast to fall to 2020 (before increasing again out to 2030). However within that overall fall there is a major change in the source and nature of generation capacity. This will have significant impacts on the electricity transmission and distribution networks.

At transmission level, the number of interconnectors between the UK and other networks will increase with potentially 5 GW of new connection in addition to the existing 3.5 GW. Additional 'bootstraps' from Scotland to England will also be installed and connection to Phase 3 wind farms established (potentially as a radial offshore network).

Existing networks will require reinforcement to accommodate the increase in amount of interconnection and offshore generation. It will also be necessary to include additional compensation as there will be increasing use of cable circuits, significantly more HVDC convertor stations and change in the generation mix.

Network reinforcement will drive the need for new substations, which at transmission level may just require additional transformers/switchgear within or adjacent to existing outdoor substations, but may also include greater use of indoor gas insulated switchgear (GIS) technology.

9 http://www.ofgem.gov.uk/Media/FactSheets/Documents1/re-wiringbritainfs.pdf
10 National Grid, *UK Future Energy Scenarios*, September 2012 http://www.nationalgrid.com/NR/rdonlyres/C7B6B544-3E76-4773-AE79-9124DDBE5CBB/56766/UKFutureEnergyScenarios2012.pdf

At distribution level, the challenges will be particularly around connecting new smaller scale low carbon generation technologies. This challenge will be exacerbated by the uncertainty over the speed of development and their spatial distribution. They need to strike a balance between ensuring sufficient capacity is available but avoiding building assets that later become redundant. There will also be system operator challenges whereby networks are required to become more 'active' in terms of demand management and flexibility. A further challenge will be the potential electrification of transport, but this may not occur widely before 2020.

Table 5-1 summarises key challenges and drivers faced by the sector and resulting upgrades and new technologies being considered.

Table 5-1: summary of near term technology developments - electricity

Infrastructure element	Key challenges / drivers	Upgrades and new technologies
Off shore transmission / conversions	Increasing emphasis on off shore wind generation; expansion of interconnections.	A number of interconnections are being developed to connect to other Transmission System Operators. The development of future offshore HVDC radial network is dependent on the development (in the very near term) of HVDC breaker technology in order to realise multi-point HVDC transmission.
On shore transmission	Reinforcement of existing infrastructure to account for offshore generation and interconnection.	The continued use of existing (aged) AC assets, will increase the demand for condition monitoring technology that is reliable, accurate and useful.
Distribution	Smart grid technologies and greater need for demand side management.	Much of the emphasis will be on systems operation technologies and on facilitation of connections. Low Carbon Networks (LCN) fund projects include exploration of impact of new tariff structures on demand patterns; trials of EV charging points; dynamic voltage control; monitoring equipment installed in substations to evaluate 'headroom' to accommodate low carbon technologies.
Conversions	Improved efficiency of large HVDC convertor stations. Need to supply increased bulk electrical energy into areas of high population density.	In terms of HVDC convertor stations the development of power electronic devices on SiC as direct replacements for Thyristors and IGBTs – could lead to reduction in convertor station losses of 10-15%. Greater use of indoor GIS substations in urban environments where future GIS technology may have to use electronegative gases that are more environmentally friendly than SF6 (potential candidates are under evaluation at research level).
Storage	Intermittent renewables; electric vehicles.	Technology development will be mostly made by investment in batteries driven by investment in the electric vehicle market. At larger scales that may be needed to support large quantities of intermittent renewable energy sources, pumped hydroelectric power and CAES will be the only viable options before 2020.

5.3 Gas

Until recently the UK has been self-sufficient in gas, however this is no longer the case. The offshore fields are decreasing in output such that the UK will become increasingly dependent upon imported gas over the coming years. This, combined with the increased flexibility that is likely to be required by gas fired electricity generators as more wind is introduced to the system, will lead to changes in gas flows and a need for greater flexibility in the transmission system.

Infrastructure developments in the near term (to 2021) are currently being planned by National Grid (transmission and distribution) and other distribution companies as part of their PCR. There is generally forecast to be a decline in gas usage over this period.

At transmission level, investment revolves around the need for greater flexibility of systems required in response to changing sources of supply and hence flows of gas (traditionally north-south, but increasingly east-west) and more variable demand (particularly in response to the need for flexible gas fired electricity generation to offset intermittency of wind).

At distribution level, much investment and research is focused on incremental efficiencies such as improved trenchless technologies (for pipe replacements); PRI upgrades; replacement of obsolescent equipment (eg. some telemetry).

A summary of technology developments across the different infrastructure elements is provided in Table 5-2 below.

Table 5-2: summary of near term technology developments – gas

Infrastructure element	Key challenges / drivers	Upgrades and new technologies
Transmission	Greater variability in sources of supply and consequent direction of flow; development of CCS and need to transport CO_2.	Various reinforcement programmes; repurposing of gas infrastructure for CO_2.
Distribution	Age of assets and need for upgrade / repair, particularly replacement programme for old iron mains.	Major pipe replacement programme in place whereby new PE pipes replace or are inserted inside old iron mains. Technology development related to: - Installation: eg. making trenchless technology more efficient thereby reducing disruption and hence cost; use of in-line cameras; better pipe handling equipment such as trailers; - Materials: eg thinner PE pipes with wider diameters able to take same pressure of gas; - Some new build such as 'infill' in rural areas.
Conversions	Age of assets and need for upgrades; changes to direction of flow; few new assets likely to be required.	Improving efficiency of systems such as more efficient pre-heating of gas in PRIs (eg. via use of renewable energy systems such as ground source heat pumps); and utilising waste heat from PRIs through a turbo expander. Compressor stations require adapting to enable bi-directional flow of gas.
Connections	Entry point connections eg. for biomethane; car fuelling points; introduction of smart meters.	Innovations on the demand and production side impact on network infrastructure mostly in terms of process eg. improving 'customer service' around biomethane connections; being proactive and helping connections be made; ensuring appropriate gas quality through reviewing all aspects of the connection process; enabling connections for vehicle fuelling, particularly compressed natural gas (CNG).
Storage	Decommissioning of old gas holders around distribution network; need for greater flexibility hence for more storage sites particularly at high pressure sections of network.	Safe decommissioning of old assets (particularly gas holders); related abandonment. Investigation of new underground storage sites. Some are in planning but progress is slow. Potential for more storage capacity at import terminals.

5.4 Heat

Unlike gas and electricity, heat provision is currently unregulated, however the government is keen to address the issue and launched its heat strategy in 2012, updated in March 2013[11] . Primary concerns in relation to the development of District Heating Networks (DHNs) in the UK are:

- Procurement and costs of new infrastructure (public / private models required for funding)
- Heat demand density and economic and practical viability of different areas
- Long term availability of waste heat sources (eg. coal power stations)
- Reduction of building heat loads through improved fabric performance standards due to Building Regulations modifications
- The extent to which space heating demand might be met electric heat pumps, particularly if the electricity grid is decarbonised
- The development of a hydrogen economy: will small scale hydrogen fuel cells replace gas fired boilers within homes and commercial buildings?

In the shorter term there is undoubtedly a role for heat that is recovered or generated being used to serve homes and commercial buildings, especially where this is coupled with cogeneration of electricity to improve the financial model and potential environmental benefits.

It should also be highlighted that DHNs are only likely to be economically viable in built up areas with heat densities in the order of 30 – 50kWh/m^2. Hence, DHNs would not be rolled out UK wide but rather in more densely populated areas, and realistically in close proximity to existing or new power stations or industry where waste heat is available.

Low carbon building regulations are currently driving the development of heat networks for new developments. Connections to existing loads and so-called anchor loads are also being promoted. There are a number of constraints on development both physical, e.g. installing underground pipe work, and commercial related, e.g. legal and regulatory, incentive structures etc.

Opportunities exist for large-scale generators remote from cities, potentially up to 100km, supplying heat through large capacity transmission heat mains into a city-wide network of transmission lines distributing heat to smaller schemes. This would be dependent on the development of new low or zero carbon power plants sufficiently close to large cities, and would utilise the large quantities of waste or low carbon heat that may be available from such plants. Examples might include the new nuclear plant at Bradwell, or replacements for the power plants which are nearing the end of their lives at Tilbury (2015) or Kingsnorth (2015). These could also include CCS plants in a proposed Thames Estuary cluster.

Ideal opportunities exist to connect to both homes and commercial developments over the coming years:

[11] https://www.gov.uk/government/publications/the-future-of-heating-meeting-the-challenge

- New buildings can be designed to suit incoming connections, with plate heat exchangers and building heating circuit temperatures designed to maximise efficiency. Low carbon heat supplies will also assist in meeting Building Regulations and planning requirements.
- As the heating systems for existing building stock come to the end of their economic life the building can be retrofitted for DHN.

Although research and development of heat distribution networks (e.g. pipework) is likely to be limited, possible improvements include pre-insulated thin walled steel pipe systems and flexible pipe for higher temperature distribution.

It is anticipated one of the major areas of research and development for heat will be below ground storage. The larger scale options for heat storage centre around Aquifer Thermal Energy Storage (ATES) and Borehole Thermal Energy Storage (BTES)

These techniques could be used to store the heat produced from CHP or power stations, or other heat sources, as part of the transmission and distribution network to buildings. The ATES or BTES systems could be multiple, i.e. adjacent to the power station, or as part of the distribution network and locally at the buildings – see Figure 5—1.

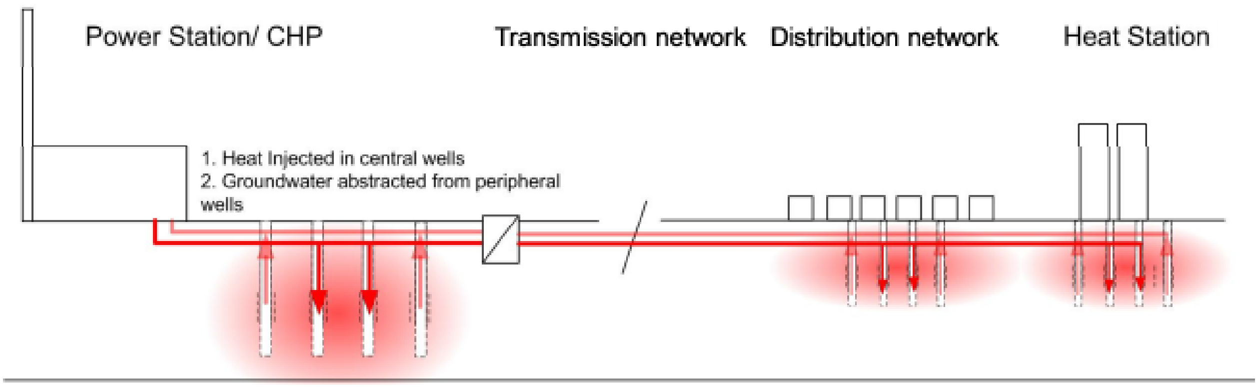


Figure 5—1: District Heat Networks with integrated Heat Storage. Source: ETI Heat Storage Study

Table 5-3: summary of near term technology developments - heat

Infrastructure element	Key challenges / drivers	Upgrades and new technologies
Distribution	Cost of laying pipes a key challenge; heat losses	Cheaper materials, improving trenching techniques; system design eg to make better use of lower temperature sources
Conversions		Move towards more direct connections
Connections	Driven mostly by new developments; connections to existing buildings requires retrofit and potentially differing space requirements	Multiple consumers per connection
Storage	Space requirements are a constraint; however provide improvement to DHN operating efficiency and hence reduction in cost	Exploration of geologic heat storage particularly for interseasonal storage; alternative forms of heat storage such as use of phase change materials

5.5 Hydrogen

Of the four vectors included in the study, the technology associated with hydrogen infrastructure in the UK is the least mature. The development of this infrastructure over the next decade will be dependent upon the interplay of various factors:

- The rate of deployment of renewable, new nuclear and 'clean fossil' generation

  Policies are in place to increase the proportion of renewable energy supplying electricity. The extent to which targets are met will have implications for the management of the national grid such as reducing stability due to the intermittent nature of renewable power. It is hard to predict the point at which such issues could become a noticeable problem, but it is likely that a range of smart grid measures will need to be introduced to address them in the lead up to 2020 or soon afterwards. Whether the smart grid techniques deemed necessary include the use of hydrogen at this point, or a later date, is yet to be resolved by the industry and policy makers, as the answer is a complex one.

- The uptake of hydrogen powered vehicles

  Rollout of hydrogen as a smart-grid-enabling energy vector is dependent upon the uptake of hydrogen powered vehicles. It is likely that the coordination of hydrogen vehicle deployment with renewables rollout will be an important factor for both sides of the market. It would appear that the automotive industry is committed to Fuel Cell Electric Vehicles (FCEVs) as their 'engine' of the future, with Battery Electric Vehicles (BEVs) fulfilling specific niches (e.g. urban duty vehicles) alongside. Most Original Equipment Manufacturers (OEMs) are looking to introduce market ready, volume produced FCEVs by 2015.

  It should be noted that this is 'volume production', as distinct from 'mass production'. The vehicles will be technically market ready, if not financially so (ie. they are likely to cost more than the internal combustion engine equivalent with manufacturers initially selling them at a loss to kick-starting the market).

- Political will and commercial innovation

  An issue of such scale and cross-cutting nature cannot be addressed by industry and the market alone, it is likely to require government intervention.

If hydrogen fuelled vehicles are developed in the near term this would involve developing refuelling infrastructure. At the same time, the challenges of grid balancing with the increasing input from renewables could in theory partially be met by electrolysis as a dispatchable, bulk demand load linked to intermittent renewables and base load electrical generation. If pre-combustion CCS techniques are developed, these could also provide low-carbon-derived hydrogen into the market, with the need either for distribution (centralised production) or decentralised production.

The UK already has saleable technologies and knowledge 'green' hydrogen production through electrolysis and pre-combustion CCS. Transmission systems for hydrogen would be unlikely in the near term due to lack of demand and the need to establish large scale infrastructure. There is potential for more centralised production of hydrogen requiring a distribution system in specific areas (e.g. a low pressure hydrogen network in a city). This could involve repurposing of a MP natural gas network. CCS deployment is unlikely until beyond 2020.

There would need to be considerably more investment in developing the demand for hydrogen (e.g. in developing hydrogen internal combustion engine vehicles (HICEVs) as a transition step) to stimulate demand for network infrastructure, electrolyser and fuel cell industries, hydrogen storage system developers, system integrators, etc,. Whether this approach would actually require network infrastructure is still unclear.

Near term deployment is likely to focus on relatively small scale electrolyser and gas reformer installations to provide hydrogen for fleet vehicles. These would require electrical connections or natural gas connections respectively. If located at vehicle fuelling stations these connections would likely involve reinforcement to these non-hydrogen vectors at local distribution level as well as the connection itself. This is dependent on developing some new technology; for example the right scale of electrolysers or affordable local storage systems to enable the electrolysers to operate at a base load.

Table 5-4: summary of near term technology developments - hydrogen

Infrastructure element	Key challenges / drivers	Upgrades and new technologies
Transmission	Development of a hydrogen transmission network unlikely in near term; challenges around cost; more likely to be repurposing of gas assets where required. Challenges over pipe materials and safety	Repurposing of gas assets; injection of hydrogen mix into gas grid; materials and pipeline safety to be addressed eg. embrittlement
Distribution	Development of smart grids and role for hydrogen in this	Repurposing of gas assets; injection of hydrogen mix into gas grid; materials and pipeline safety to be addressed; trenchless technologies to reduce costs (same as for natural gas)
Conversions	Compression particularly challenging for hydrogen	Improved compression technologies particularly in relation to hydrogen production (electrolysis) and storage
Connections	Vehicle refuelling connections will depend on roll out of hydrogen vehicles; connections for space heating to depend on ability to utilise hydrogen in appliances	Improved vehicle connections
Storage	Need for electricity storage following increasing role for intermittent renewable generation	Improvements to compressed gas storage; alternative forms of storage such as metal hydrides, nanomaterials and composites, chemical carriers

6 Longer Term View and Test Cases

6.1 Overview

In order to guide the data collection process and to ensure that as wide as possible a range of technology options was explored both within the tool and through the innovation piece, three contrasting ‘test cases’ were developed to describe energy infrastructure out to 2050. The term ‘test cases’ was adopted to differentiate the process from that of more formal and thorough scenario development, with the intention being to explore boundaries rather than to develop anything prescriptive. Each case highlights feasible combinations of contextual parameters and infrastructure progression up to 2050.

This work follows on from the near term review described in Chapter 5 and starts with a review of factors that are influencing technology developments for both supply and demand, and what these approaches are.

6.2 Technology approaches and influencing factors

There are a number of technology approaches being developed in relation to both demand and supply that could impact on energy infrastructure. These can be related to three ‘types’ of energy:

- Heat
- Transport (motive power)
- Electricity

Running in parallel to these technology approaches are three particular influencing factors:

- Decisions over centralised v decentralised systems, particularly in relation to electricity generation. This will impact on the relative emphasis of change and reinforcement of transmission v distribution networks.
- Decisions over ‘pipes v wires’. Particularly in the case of hydrogen, were this to be introduced at scale, one model is for it to be produced close to large power generators (using pre combustion CCS) with the energy being transported through pipes in the form of gas to end users. Or for the energy to be transported through wires in the form of electricity to the end user and for hydrogen to be generated locally.
- Decisions over how heating is supplied. If heating is switched from gas to electricity (via heat pumps) the impacts on both gas and electrical infrastructure would be significant

6.2.1 Demand

Key factors relating to energy demand technologies which could influence network infrastructure requirements are described below (and outlined in Figure 6—1).

- **Smart technologies**. So-called ‘smart’ technologies that enable more active demand management at different levels (ie. both system operator level as well as end user level) through the transfer of and accessibility to data. Extent to which demand side response through use of smart technologies are deployed will impact on peak loads and hence on the need for increase in infrastructure capacity. This is particularly the case for electricity where storage is more difficult and less inherent than for heat, hydrogen and natural gas infrastructure. Demand response and aggregation services to enable this are a critical factor. Currently around 25% of residential electricity use is considered ‘discretionary’, including uses such as dishwashers, refrigeration and washing machines. Use of smart thermostats and improved controls for HVAC systems can be applied in the commercial/non-domestic building sector. This could significantly impact peak loads.

- **Space heating.** The choice of technology for space heating has perhaps the greatest impact on infrastructure requirements. Switching away from natural gas to other sources requires deployment of new infrastructure, either higher capacity electricity networks, hydrogen networks or heat networks. This is discussed in more detail under supply.

- **Building energy efficiency measures**. These differ for different sectors, for example in residential buildings it might include measures such as insulation, glazing and airtightness; for non-residential buildings HVAC system and internal gains may have more influence on peak load and annual demand.

- **Road vehicle type**. Transport influences infrastructure in a variety of ways. Overall energy demand is affected by vehicle and engine efficiency and choice of drive train. More importantly the choice of electricity, liquid biofuel, hydrogen or natural gas as the fuel(s) of choice will influence the demand for infrastructure to transport these energy vectors. There is a close link with supply technology approaches as local storage systems (e.g. hydrogen electrolysis using off peak electricity and vehicle to grid). Liquid fuels can make use of existing infrastructure. Use of natural gas could be via existing gas networks (for CNG) or via tanker infrastructure and local storage (for LNG). Use of hydrogen could be via pipeline or tanker infrastructure, or through electrolysers at filling stations. Battery electric and plug in hybrid vehicles could require high capacity charging points, both at filling stations and local to homes and workplaces. Deployment of charging points in car parks and other locations where vehicles are left for short periods of around an hour could also be good locations for charge points.

- **Industry**. For the industrial sector many efficiency improvements have been made as a result of high energy prices and market pressures. Improving motor and motor control technology will have an ongoing effect in improving efficiency but more fundamental technology development could have greater effects. The development of rapid prototyping technologies into on demand manufacturing could reduce the size of production plants and enable more local manufacturing. Use of biotechnology may supplant more traditional energy intensive chemical and mechanical processes. New materials, particularly composites, may also change the type and scale of energy demand in manufacturing.

- **Consumer goods**. Residential technology with significant potential to influence demand and the use of network infrastructure includes the increasing use of ICT and entertainment systems, and their convergence. Usage is not discretionary and so contributes to peak load events. Convergence (e.g. television/music streaming over internet) may reduce the number of different types of devices. This may be offset by the increased ownership of such devices.

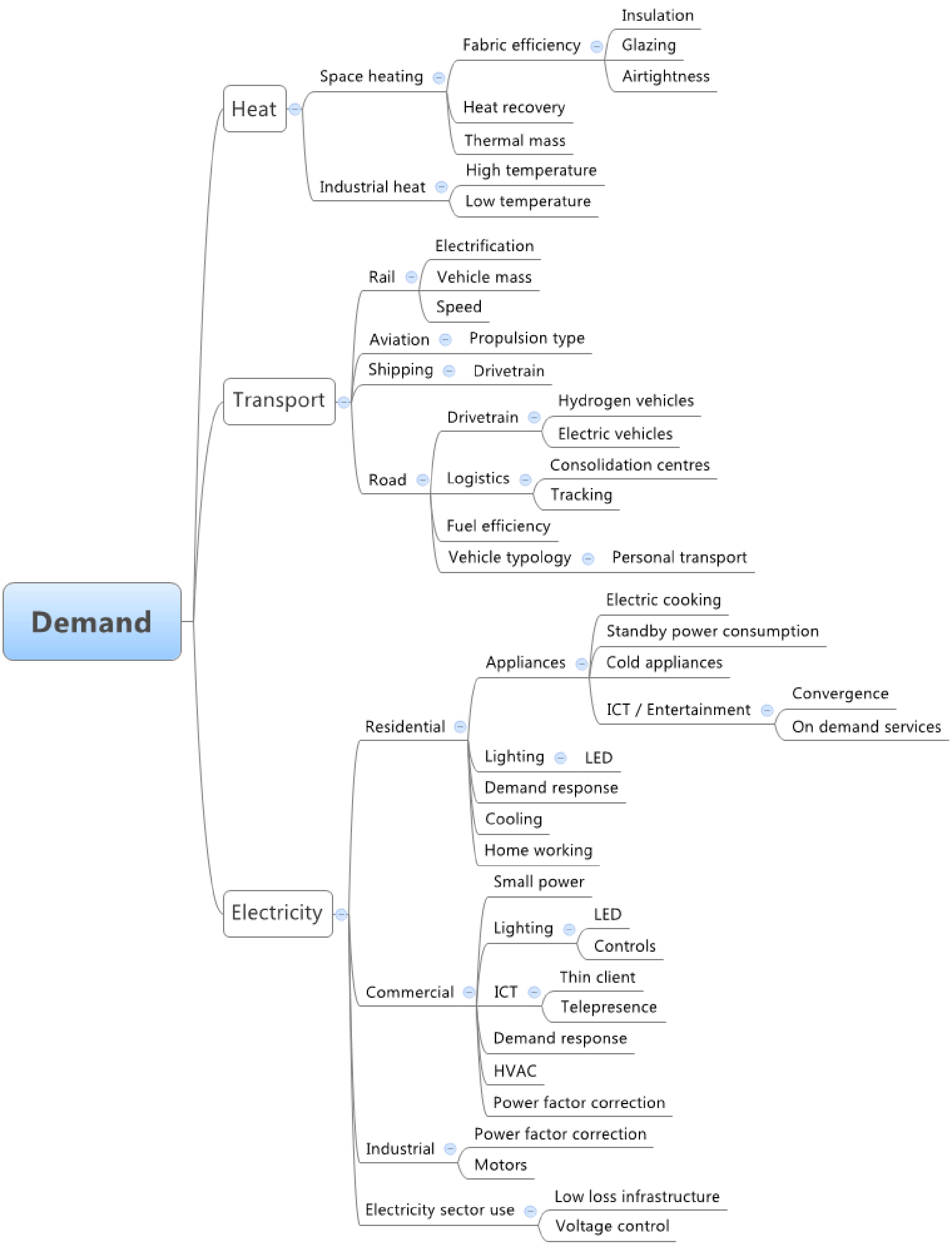


Figure 6—1 - Technology approaches - demand

- **Commercial buildings**. Commercial building technology, particularly an increase in the use of mechanical ventilation and air conditioning influence electricity use. New commercial buildings use very little heat, and tend to have high electricity use. High penetration of air conditioning has a marked effect on seasonal peak demands in climates similar to that potentially found in the UK by 2050.
- **Lighting**. Lighting is provided by electricity. Significant advances in efficiency through LEDs are expected to reduce peak demand and annual consumption. This may be offset by higher light levels in buildings. Some relatively modest reductions in peak loads may occur, but these will be insignificant compared to other changes. Reductions in annual demand could be significant.
- **Home working**. Home working is likely to change the pattern of consumption, increasing residential electricity and space heating demands during the day. However, as these will need to be catered for within the infrastructure no significant impacts on networks are expected
- **Electricity sector**. The use of energy within the electricity sector represents a significant demand. Reducing it could provide some marginal capacity improvements, but the influence on reducing annual demand is likely to be more significant.

6.2.2 Supply

Key factors relating to energy supply technologies which could influence network infrastructure requirements are described below (and outlined in Figure 6—2).

- **Renewables**. Extent of renewable generation technologies many of which will lead to intermittent energy supply. This will have a major impact on the way in which natural gas is supplied to gas generators (assuming this is used for balancing). Far more flexibility of supply will be required impacting particularly on storage technology. Alternatively high penetration of intermittents could be dealt with by increasing storage capacity
- **Decentralisation of electricity**. Changes of scale in generation technology – ie. smaller units being developed which will require connection to local distribution networks rather than the transmission network. CCS, nuclear and offshore intermittent renewables would tend to require a centralised transmission network, with reinforcement if demand increased due to electrification of transport and space heating. Decentralisation will require more active network management, including use of supply aggregation technologies such as virtual power plants. These can also be used for network management and may suggest that 'distribution systems operators' are required.
- **Waste heat sources**. Decentralised thermal electricity sources should be combined with heat networks to maximise overall fuel efficiency. Purpose designed steam turbines can provide heat via extraction ports in the turbine casing at higher 'heat pump' co-efficients than air source heat pumps (e.g. losses in electricity output are offset by gains in overall fuel efficiency). Where engines or turbines are used there are minimal efficiency penalties for using waste heat.

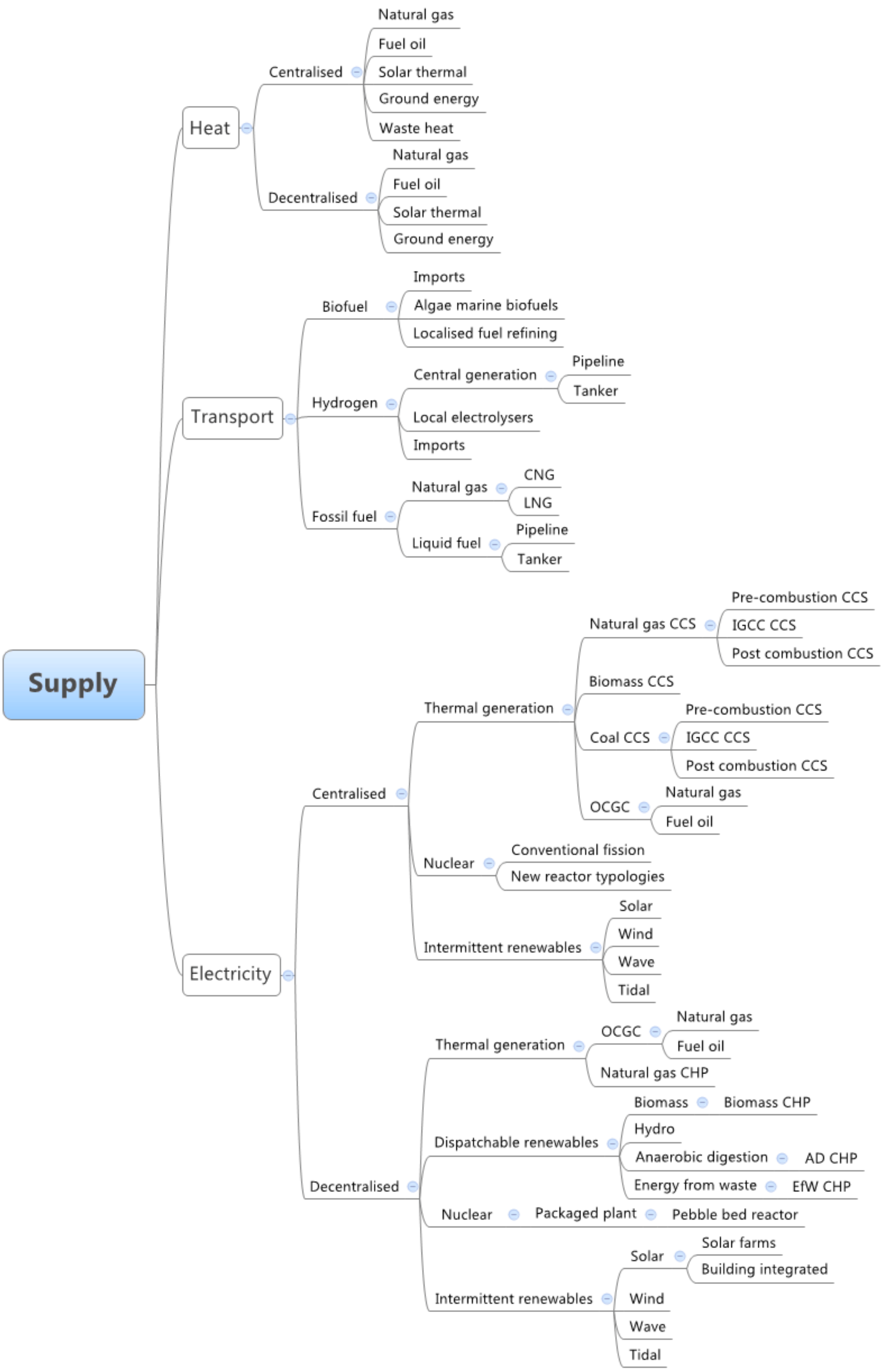


Figure 6—2 - Technology approaches - supply

- **Heat supply**. The choice of energy vector for space heating will significantly impact the 'final mile' of energy network infrastructure. Electrification of space heating would require massive upgrading of local distribution networks, and possible three phase connections for residential dwellings. This would also require deployment of demand response technologies to control, or at least limit, seasonal peak loads which would drive the sizing of the entire electricity system. Re-purposing gas networks to provide hydrogen transmission and distribution may be possible but the transition arrangements may be impractical (e.g. switching over appliances in a given area at the same time).

- **Decentralisation of heat**. Centralising heat production (at least on a local level) would require extensive deployment of heat networks. This could be driven by available heat supply (e.g. energy from waste, biomass CHP, industrial waste heat, nuclear) or the need to combine multiple sources of heat (e.g. base load industrial scale electric heat pumps with peak load natural gas or fuel oil boilers). Integration of solar thermal water heating may be more cost effective using an existing heat network where present. Heat networks could reduce the requirement for electricity reinforcement for space heating.

- **Storage technologies**. Storage could be included within demand or supply. The location of storage within the energy network infrastructure (transmission vs distribution) has a significant impact. Centralised storage (e.g. pumped hydro, IGCC hydrogen generation) would require transmission infrastructure sized to cope with peak demands. Distributed storage would reduce the peak capacity of infrastructure, stepping down through the system. Location of storage at the final point of demand would minimise network capacity but may be less efficient and/or impractical.

- **Electrification of transport**. High penetration of electric vehicles would require increased capacity distribution networks and connections at dwelling, workplace and other locations (e.g. filling stations, supermarkets, service stations). Alternatively battery swap centres may require large capacity electrical connections.

- **Alternative liquid/gaseous fuel**. Development of alternative fuels, particularly biomethane and hydrogen for injection into the gas grid. Biomethane is most likely to be generated locally at relatively small scale thus will require connection to the natural gas distribution network. Hydrogen has implications for pipe materials (e.g. leakage, and embrittlement) and could lead to the repurposing of existing natural gas networks. Hydrogen could be generated locally at filling stations using electrolysers or steam methane reformers. Central hydrogen generation could make use of pipelines. Algal fuels generated in marine environments would tend to increase the need for pipeline or tanker infrastructure serving coastal areas; these could be located near existing oil terminals.

- **CCS**. Development of CCS which would enable gas fired generation to be increased while still meeting emission reduction targets. This could lead to changes in gas transmission networks including expansion of the high pressure networks to accommodate greater peak demand and/or repurposing of offshore networks for carbon sequestration. More LNG terminals could be required if natural gas is imported. Should shale gas become a significant source more decentralised gas input into distribution networks is likely.

- **Pre-combustion CCS**. Pre-combustion CCS could provide a readily available supply of hydrogen, particularly during off peak periods. This could be used via a pipeline or tanker infrastructure for vehicle fuelling, via pipelines for heating or as a storage medium before being converted back into electricity.

- **Nuclear**. Increased penetration of nuclear for electricity generation is likely to encourage centralised transmission networks with possible need for reinforcement. Decentralised nuclear typologies have been proposed and some tested, but the high fixed costs of nuclear and the potential consequences (or at least the perception of consequences) suggest centralised large scale reactors which can absorb such costs are more likely.

6.3 Test cases

In recognising the key influencing factors and technology approaches affecting demand and supply as outlined above, three 'test cases' were developed for the project to help frame a longer term review of possible research opportunities. The test cases were primarily developed through a workshop held with the ETI Project Steering Group and were further developed by the project team.

The three test cases developed had the following biases:

- High electricity: maximum electrification of space heating and transport; includes decentralised generation of hydrogen
- High heat: maximum penetration of heat networks in suitable urban areas; an emphasis on a more decentralised approach to all energy systems
- High hydrogen: maximum penetration of hydrogen with an emphasis on the development of hydrogen transmission and distribution networks

A separate gas test case was not developed. Instead, different assumptions regarding gas were applied across the three given above.

In order to frame the development of the test cases, some overall assumptions were made in relation to peak demand and maximum penetration levels.

End use demands were assumed to be the same in each case and are shown in Table 6-1.

Table 6-1: maximum and minimum end use demands assumed for all test cases

End use demand	Maximum (GW)	Minimum (GW)
Electricity	75	35
Heat	250	10
Transport	30	5

The maximum penetration levels for supply by each vector are shown in Table 6-2, as a % of end use demand, and as a supply (in GW) including conversion factors where one vector is converted to another. Note, as gas and hydrogen can be converted to electricity, but may need transmission networks to do so, the electricity end use total does not sum to 100%. A conversion factor based on CCGT or fuel cell is assumed. Similarly conversion of electricity to heat is assumed using a heat pump with COP2.5. The numbers are not intended to be exact or to replicate other work. They are provided as indicative only based on suggestions made at the test case development workshop and subsequent feedback from ETI and the project team. The penetration levels of each vector by test case are summarised within the individual test case summaries.

Table 6-2: maximum penetration levels of each energy type (% and GW) for each vector assumed for all test cases

Vector supply	Electricity	Natural gas	Heat	Hydrogen	Vector supply	Electricity	Natural gas	Heat	Hydrogen
%					*GW*				
Electricity	100%	70%	0%	70%	**Electricity**	75	95	0	105
Heat	80%	90%	40%	90%	**Heat**	80	225	100	225
Transport	80%	20%	0%	50%	**Transport**	24	6	0	15

6.3.1 Test Case 1: 'High Electric'

This case represents a very high electrification scenario with maximum impacts on both the transmission and distribution electrical network infrastructure.

Transition is gradual initially with reinforcement costs for individual households increasing and becoming a barrier. At this stage planning of reinforcement on a district by district approach is undertaken. Huge investment in the final mile electricity networks is made, followed by new connections and switch over of appliances, with eventual abandonment of the natural gas MP and LP distribution network.

Table 6-3: Summary of key variables of high electric test case

Variable	Scenario
Scale of energy demand (taken from existing range of demand scenarios) Extent of energy efficiency measures Penetration of demand side management measures	• Peak demand by vector: – Electricity 300GW – Natural gas 60GW – Heat 50GW – Hydrogen 15GW • Relatively unconstrained response with limited but increased demand side participation; • Highest connections to dwellings – 3-phase connections • Limited building insulation improvements • Cooling requirements – increase?
Type of energy vector Extent of fuel changes for space heating and transport	• Major shift to electric vehicles and hybrids displacing petrol / diesel for urban use with fuel cell hydrogen/CNG for heavy commercial. Maximum possible penetration of electricity to be 80% • Major transition from gas heating to electric heating (mainly

Variable	Scenario
	ASHP, but some GSHP and resistive heating – major change 2030/35). Maximum possible penetration of electricity to be 80% • Limited shift to heat networks in some dense urban areas • Some shift to hydrogen for long range heavy vehicles.
Sources of energy generation / storage	• Generation: nuclear, renewables, coal and gas CCS (most likely post combustion), biomass and biomass CCS • Storage: high penetration of storage options throughout the network ie. at both transmission and distribution level. CAES, pumped storage for generation balancing; electric storage systems at distribution and building scale to manage residual demand; some hydrogen at point of use for diurnal fluctuations and for balancing intermittent renewables; possible need for increased use of storage for frequency control and regulation eg. flywheels, capacitors. • Limited small scale CHP networks running on biomass or other renewable fuels
Energy generation vector types and opportunities for conversion into other vectors for onward transmission	• Conversion for transport, heating and other uses
Location and scale of energy generation sources Physical In relation to the energy infrastructure (e.g. connection at transmission vs. distribution level)	• Large scale, transmission connected ie. extension of existing electrical infrastructure with most generation being large scale connected at transmission level • Off shore HVDC backbones down east and west coast ('bootstraps') to transmit wind / marine from Scotland/North Sea

The schematic in Figure 6—3 outlines key themes of this test case. The main implications for infrastructure can be summarised as follows:

- Main vectors affected are electricity (expansion) and gas (contraction). Some expansion of hydrogen infrastructure downstream (at the point of use eg. garage forecourts)
- Considerable changes likely in 'the last mile' ie. connection to end users, particularly domestic where significant uprating of LV distribution network is required
- Upgrade and increased electrical transmission and distribution capacity
- Abandonment / decommissioning of gas distribution infrastructure; repurposing of gas infrastructure to carry CO_2
- Increased need for storage infrastructure, particularly to deal with high wind penetration
- Transport transition unclear, likely to involve hydrogen, continued use of fossil fuels (more efficient vehicles), or improvements to battery technology and plug in electric hybrids

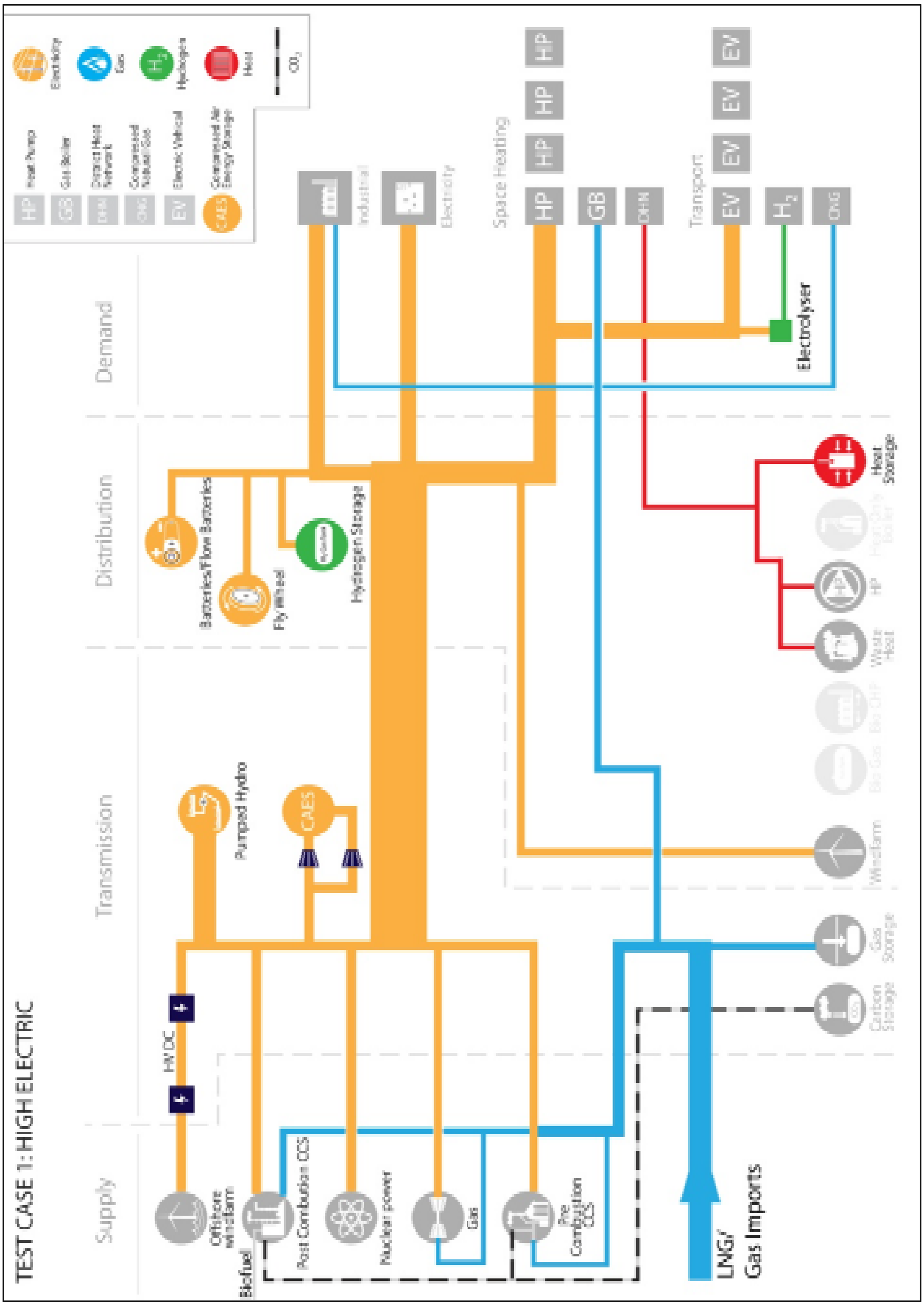

TEST CASE 1: HIGH ELECTRIC
Supply
Transmission
Distribution
Demand
Offshore windfarm
Biofuel
Post Combustion CCS
Nuclear power
Gas
Pre Combustion CCS
LNG/ Gas Imports
HVDC
Pumped Hydro
CAES
Batteries/Flow Batteries
Flywheel
Hydrogen Storage
Industrial
Electricity
Space Heating
Transport
HP
GB
DHN
EV
CNG
Electrolyser
Heat Storage
HP
Waste Heat
Windfarm
Gas Storage
Carbon Storage
Heat Pump
Gas Boiler
District Heat Network
Compressed Natural Gas
Electric Vehicle
Compressed Air Energy Storage
Electricity
Gas
Hydrogen
Heat

Figure 6—3: Schematic of the 2050 High Electric test case. The thickness of the lines indicates the relative importance of each vector.

Based on the above, key impacts on the infrastructure associated with each vector in the longer term are summarised in Table 6-4.

Table 6-4: impacts by infrastructure of the high electric test case

	Electricity	Gas	Hydrogen	Heat
Transmission	Major upgrades needed to connect remote renewable sources; HVDC bootstraps	Limited change on basis still need gas (with CCS) for generation; possible repurposing of gas pipes for CO_2 transport	n/a	n/a
Distribution	Major change in 'last mile'	Major change – gas networks abandoned due to switch to electricity; use of same routes for 33kV or 11kV reinforcement	Reinforcement of last mile to garage forecourts for onsite H_2 production of transport fuel	Some local networks in urban areas
Local distribution	Massive reinforcement	Major change – gas networks abandoned due to switch to electricity; use of same routes to accommodate increase in 11kV network feeders or 400V supplies, running along wayleaves	None	As above
Conversion	Smart sub-stations; more land required for substations	IP to MP and LP abandoned, replaced by new electricity substations to support expanded electricity networks. Substations need to be compact to fit into constrained sites	Conversion to H_2 by hydrolysis	Direct connections
Storage	Increased need	No change	Some local storage for vehicle use?	Local storage only
Connections	Introduction of 3 phase supply to domestic dwellings; extensive use of demand side management; Higher power ratings needed for connections to forecourts due to electrolysis plant (and rapid BEV charging facilities)	Abandonment	None	New heat connections domestic and commercial using heat exchanger units

6.3.2 Test Case 1: 'High Heat'

This assumes widespread development of heat networks in most cities and towns of, say, a population of 10,000 and above. Some smaller rural schemes where fuel available locally (e.g. Surrey, Scottish Borders, mid-Wales). Widespread deployment of thermal efficiency improvements to dwellings and commercial buildings. Residual heat loads in non-heat network areas met by combination of existing gas networks and heat pumps. Smart demand management system implemented to control electric vehicle penetration and other space heating.

This test case assumes widespread use of thermal generation at existing sites using CCS. It also assumes increased penetration of distributed sources and the coordination of waste and energy policy including the introduction of biomethane, making use of existing natural gas infrastructure.

Existing schemes are taken into account. Transition to a wider adoption of heat networks happens in a centrally planned way. Zones for heat networks are selected based on density of heat demand. Heat networks installed, starting with densest core areas of conurbations, expanded outwards. Heat price competitive with natural gas due to taxation / policy instruments.

Table 6-5: Summary of key variables of high heat test case

Variable	Scenario
Scale of energy demand (taken from existing range of demand scenarios) Extent of energy efficiency measures Penetration of demand side management measures	• Peak supply by vector: – Electricity 130GW – Natural gas 105GW – Heat 100GW – Hydrogen 45GW • Energy efficient dwellings – heat side – also help to limit heat peak demand • Significant demand side response for non-heat network connected dwellings
Type of energy vector Extent of fuel changes for space heating and transport	• Most city and towns have heat grids with a target of 70-80% of space and water heating to come from heat networks • Rural / isolated buildings use electric heat pumps, natural gas (and biomethane) and electric heating for non-heat network connected dwellings • Possible use of GSHP/hybrids for low demand users where gas grids currently exist and are not displaced by heat networks • Natural gas (and biomethane) for heavy vehicles and some local CHP peak loads (negative emissions from biomass CCS balances this) • Less EV penetration than in the high electric test case • Biofuel for transport to maximum extent possible • Abandonment of LP gas networks in towns and cities where these can be replaced with heat network (stacked configuration or twin pipe flow and return to fit existing wayleave); balance of LP network retained • MP and IP gas networks retained to connect service stations and CHP plants
Sources of energy generation / storage	• Baseload – CCS (gas + coal), nuclear, biomass CCS – all with heat takeoff via extraction / condensing steam turbines (effective heat COP of 5-10) • Peak load electricity managed via DSM, OCGT, bio-energy (without CCS) and storage • Local gas CHP (possibly OCGT – peak power and heat demand coincide? Or with CCS) for initial 20 years • Integration of waste and energy policy leading to potential for waste fired CHP and injection of biomethane to grid • Industrial waste heat • Heat pumps charging large thermal stores using off-peak power (high COP and no storage in home) • Peak load heating from heat grids undertaken by storage tanks + fossil or hydrogen boilers (load smoothing due to efficiency retrofits) • Massive penetration of electric storage systems at distribution and building scale to manage residual demand; potential for geological heat storage
Energy generation vector types and opportunities for conversion into other vectors for onward transmission	• Heat can't be converted except for building air conditioning if >85°C
Location and scale of energy generation sources Physical In relation to the energy infrastructure (e.g. connection at transmission vs. distribution level)	• Large scale central plants located on Eastern side of UK for CCS balance of location vs CCS pipeline and heat pipeline, with exception of some nuclear and biomass plants. • Some CCS in north west using saline aquifers • 'Local heat transmission' systems linking major urban conurbations to clusters of power stations e.g. London to Thames Estuary plants + Bradwell, M8 heat link for Glasgow + Edinburgh • High penetration levels of distributed generation of various scales

The schematic in Figure 6—4 outlines key themes of this test case. The main implications for infrastructure can be summarised as follows:

- Potential to be most efficient use of primary energy as waste heat captured and used
- Decentralised model for electricity implies some upgrade to transmission capacity but not as significant as in the high electrification scenario; spatial distribution of upgrades different from the high electrification scenario
- Considerable change to distribution networks to allow for connection to more local generators and producers (biomethane); also additional supplies for possible local hydrogen production (eg. garage forecourts)
- Considerable changes in ‘the last mile’ ie. connection to end users, particularly domestic
- Abandonment of much local distribution LP and MP gas infrastructure, but less than in the high electrification scenario
- More distributed CHP generation using various fuels
- Replacement of gas infrastructure with heat networks – LTHW (70°C) to the home
- Retrofitting of heat take off connections to large power stations to accommodate heat networks
- Considerable investment in heat network infrastructure – cost and disruption
- Big differences between rural and urban infrastructure requirements

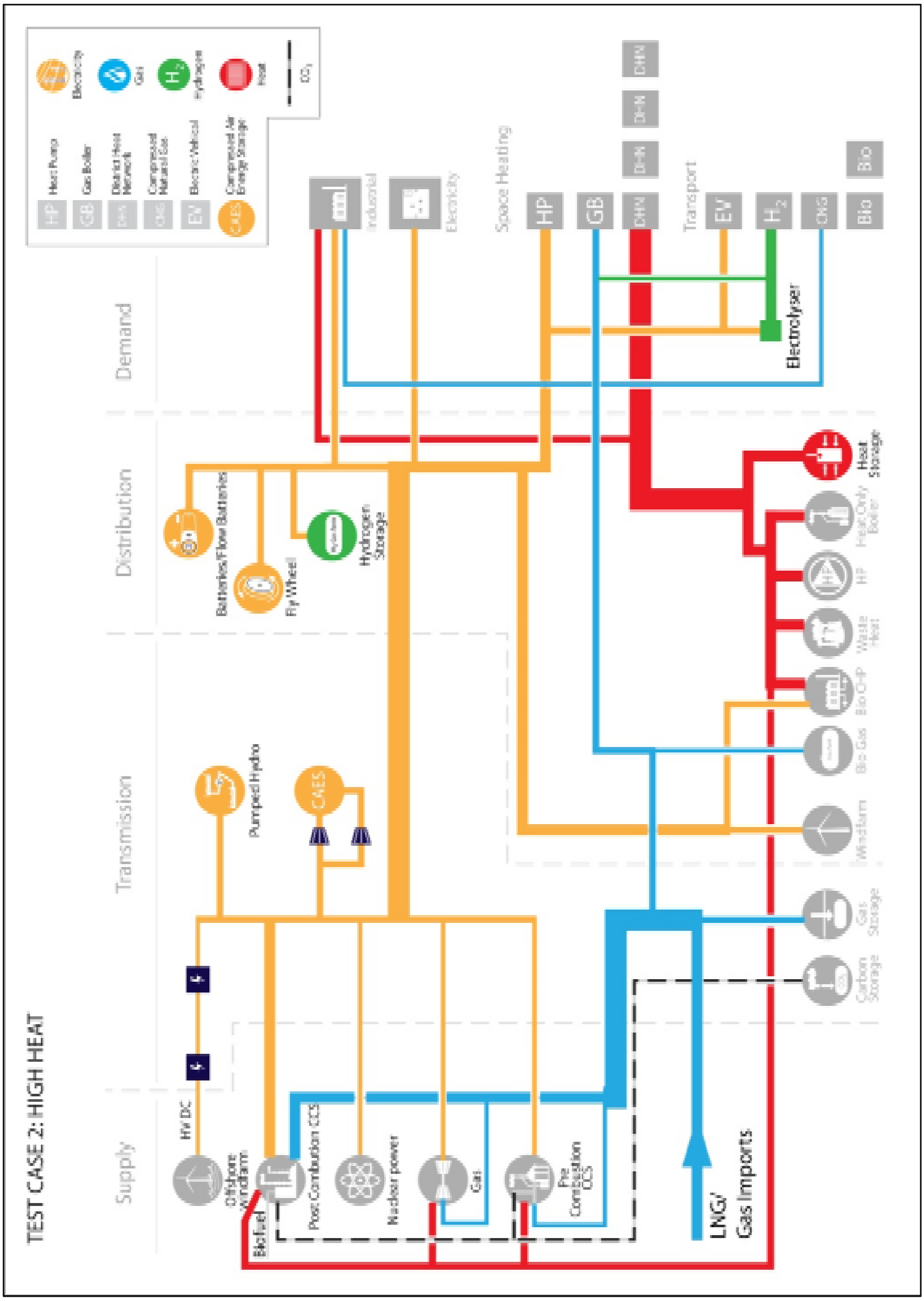


Figure 6—4: Schematic of the 2050 High Heat test case. The thickness of the lines indicates the relative importance of each vector

Based on the above, key impacts on the infrastructure associated with each vector in the longer term are summarised in Table 6-6.

Table 6-6: impacts on infrastructure in high heat test case

	Electricity	Gas	Hydrogen	Heat
Transmission	Upgrade / reinforcement to cope with some increase in demand	No change	Pre-combustion CCS enables continued use of fossil fuels for power generation and produces hydrogen for potential use in CHP plant.	Maximum penetration based on waste heat from CCS and industry and waste (biomass) (likely to significantly limit penetration). Local Transmission into cities at local level.
Distribution	Some local electric distribution reinforcement where heat pumps deployed. Consideration of control issues and particularly development of a smart grid to overcome reduced dispatchability of power. Upgrade of distribution networks to cope with embedded generation.	Upgrade to all HDPE – supply local CHP for transition period and future switch to hydrogen fuel cell CHP linked to heat networks. Development of improved connections to biomethane producers.	Increased heat networks likely to lead to more use of hydrogen for power generation (CHP) in long term	Constrained by supply of heat Heat networks at 70degC New build heat networks at 50degC Cooling networks
Local distribution	demand manage / response	Abandonment + repurposing of trenches	None	All buildings in dense parts of towns and cities connected
Conversion	Smart transformers + demand manage / response	No IP to MP and LP PRS	None	Conversion stations linking local transmission to distribution temperature and pressure
Storage	Massive deployment of local and building storage to provide diurnal load smoothing	No change	Limited to local balancing + storage – no network	Interseasonal aquifer based, or H2-based, storage where feasible. 'Gas holder' type storage at heat distribution level (minimises size of transmission mains)
Connections	Upgrade to properties with HP. Hard to treat buildings (e.g. heritage) not upgraded.	Abandonment in higher density areas of towns and cities. Continued usage in suburbs and rural areas. IP and MP connect to filling stations.	Limited direct consumer connections	New connections to all buildings in towns and cities

6.3.3 Test Case 3: 'High Hydrogen'

The key distinction between this case and the high electric case is the upstream conversion of energy to hydrogen and consequent need for hydrogen pipelines.

Under the test case, large amounts of hydrogen are produced, mainly by electrolysis that is used as a grid-balancing demand load, which is required to mitigate the variability of input from renewables, particularly dominated by high wind power penetrations. Most of the hydrogen thus produced is used as a low-carbon fuel in the transport sector by vehicles that need longer range, greater carrying capacity or faster refuelling than is achievable with battery electric vehicles (BEVs). Some hydrogen is produced by pre-combustion CCS of fossil fuels and some is used to fuel responsive peaking generators (e.g. OCGTs) and as a chemical feedstock (e.g. fertiliser and food production, carbon-neutral hydrocarbon fuel synthesis). HVDC links and CCS pre-combustion plants are located near to natural gas transmission assets, and pump hydrogen gas into this during the off-peak periods, packing out the network and significantly reduction the carbon intensity of natural gas.

Electrolytic hydrogen production may take place upstream (near the point of primary energy generation) or downstream (near the point of use). In the former case, an extensive hydrogen infrastructure may be required, but in the latter case, relatively little hydrogen infrastructure is required. This test case is based on the former. Combined electrical and hythane fired heat pumps provide space heating, smoothing loads. Transition occurs gradually with more and more hydrogen being fed into the gas grid. Appliances upgrade on accelerated basis. Hythane capable boilers become part of building regulations. Difficulty of transition from natural gas to 100% hydrogen suggests incremental approach.

Table 6-7: summary of key variables of high hydrogen case

Variable	Scenario
Scale of energy demand (taken from existing range of demand scenarios) Extent of energy efficiency measures Penetration of demand side management measures	• Peak supply by vector: – Electricity 130GW – Natural gas 25GW – Heat 27GW – Hydrogen 175GW • Penetration of energy efficiency measures, more insulated homes etc. • Demand side management – rely on storage (mainly 'virtual storage' of heat and transport fuel/elec, far greater than grid elec storage)
Type of energy vector Extent of fuel changes for space heating and transport	• Switch to electric heating, as under high electric. Demand side management through resistive heating and use of hybrid heat pump systems. • Transport switch to hydrogen for most vehicles, except urban duty vehicles that can be battery electric (BEVs). Note that 'electric vehicles' includes BEVs and fuel cell electric vehicles (FCEVs). As a transitional step, hydrogen powered internal combustion engine vehicles (HICEVs) may be deployed to aid in the establishment of low carbon vehicle markets and infrastructures. Biofuel may also play a role in the transition, but longer term will be used (with the addition of hydrogen) in the synthesis of aviation and perhaps marine fuels. Hybrid vehicles running on fossil fuels are an early transitional step as a precursor to FCEVs (which are also hybrids). • Displacement of gas by hydrogen for space heating is a possibility, but does not figure strongly in this proposed scenario, because the functional practicalities and efficiencies suggest that hydrogen production is mainly downstream. If significant hydrogen were to be produced upstream or centrally, there would be potential to inject it into the natural gas system to create 'hythane' as a transitional step. The full conversion of the gas grid from

Variable	Scenario
	natural gas to hydrogen would be technically possible, but fraught with practical challenges in coordinating the switchover. Furthermore, it would be an energetically and financially expensive way of turning high quality energy (or more accurately, 'exergy') in to low quality heat energy (even if achieved through local or domestic CHP). • Mostly local electrolysers at filling stations. Here the hydrogen infrastructure is only that found on the forecourt site and in the vehicles. The major infrastructure issues are about delivering large amounts of electrical power to forecourts in order to run the electrolysers. Hydrogen is produced from pre-combustion CCS plants, which may create a need for hydrogen transmission and distribution infrastructures (e.g. pipelines, trucks, etc)
Sources of energy generation and storage	• Generation: nuclear, high renewables penetration, pre-combustion coal and gas CCS, bio-CCS. • Storage: CAES, pumped storage (current capacity, plus additional 500GWh possible) for storage up to c. 2-days. Conversion to other sectors (heat and transport) that have intrinsic methods of energy storage, reduces the need for electricity storage. • Hydrogen OCGTs used for system flexibility (i.e. pre-combustion CCS of coal or gas) • Little use of hydrogen for electricity storage. Most stored energy used in heat applications and as a transport fuel. Reliance of heat and transport sectors on grid for primary energy creates general oversupply for electric end uses, thus undersupply is rare. Note: this necessitates huge primary generation capacity (c. 3 x today's) and relatively unconstrained grids. Any grid constraints would encourage the further uptake of hydrogen and associated infrastructures. Limited use of waste and biomass for synthetic fuel production.
Energy generation vector types and opportunities for conversion into other vectors for onward transmission	• Electricity to hydrogen for transmission scale balancing only needed if grid is not reinforced sufficiently to carry, for example, large wind power inputs from Scotland to SE. • Hydrogen for transport and as an industrial feedstock (for fertiliser, food, syn-fuels, etc)
Location and scale of energy generation sources Physical In relation to the energy infrastructure (e.g. connection at transmission vs. distribution level)	• In cases where hydrogen is produced in pre-combustion CCS, it is likely to happen in large scale central plants located on Eastern side of UK. • There may be a case for some large, centralised facilities producing hydrogen by electrolysis in response to wind power variability or nuclear inflexibility. These necessitate hydrogen transmission and distribution infrastructures using the gas grid. Some hydrogen may be produced at nuclear plants via direct thermochemical processes, or even electrolysis, and this would necessitate infrastructure to bring the hydrogen to the point of use.

The schematic in Figure 6—5 outlines key themes of this test case. The main implications for infrastructure can be summarised as follows:

- Development of new hydrogen transmission and distribution infrastructure along with repurposing of gas infrastructure for hydrogen either relatively pure or mixed with natural gas (hythane) and conversion to all HDPE
- Pipelines serving filling stations with hydrogen from centralised production facilities (e.g. CCS plants, industrial by-product hydrogen or large, centralised electrolyser hubs).
- Increased need for storage infrastructure, particularly to deal with high wind penetration
- Heat network penetration is insignificant

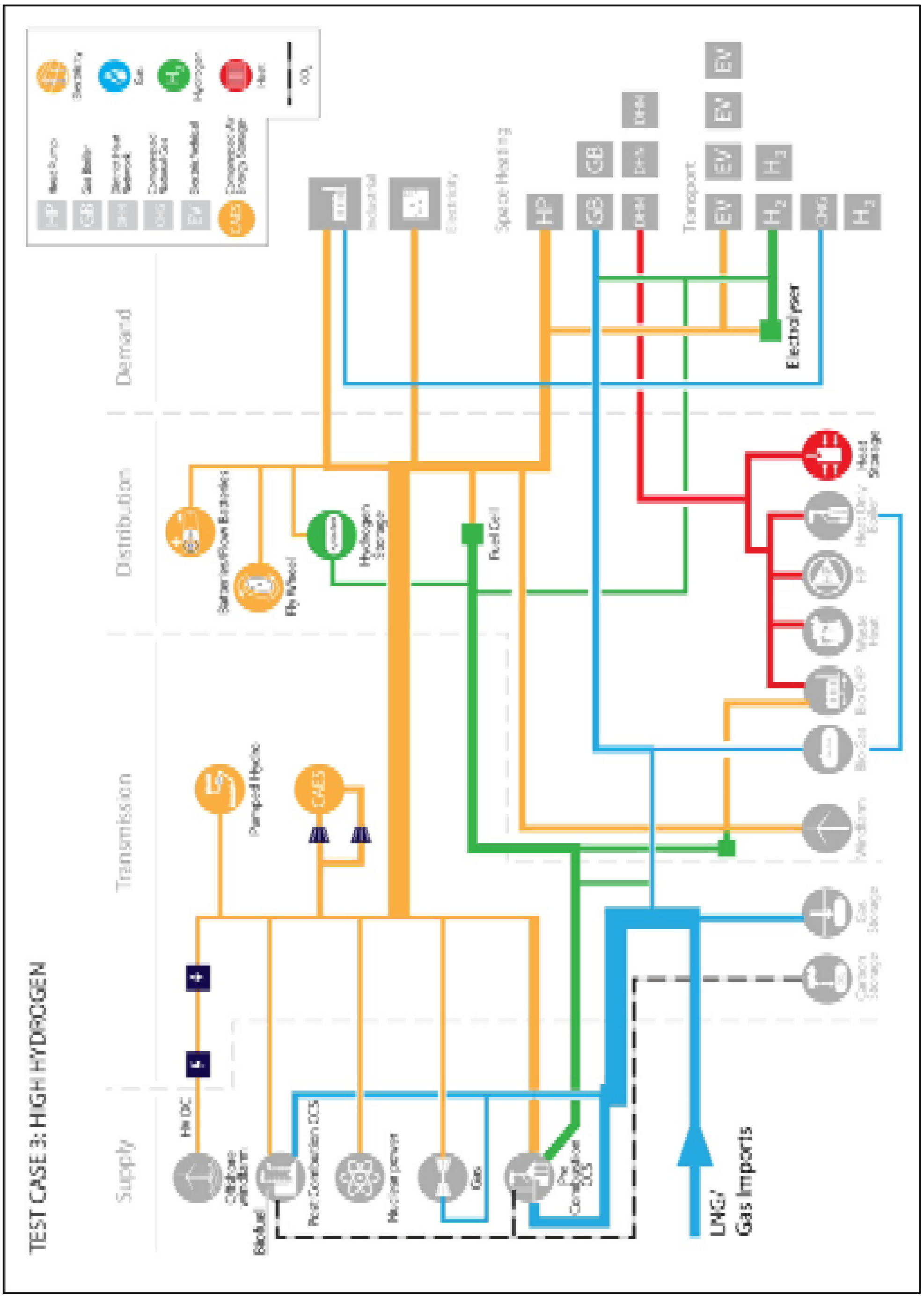


Figure 6—5: Schematic of the 2050 High Hydrogen test case. The thickness of the lines indicates the relevant importance of each vector

Based on the above, Table 6-8 summarises key impacts on the infrastructure associated with each vector in the longer term.

Table 6-8: impacts on infrastructure of high hydrogen case

	Electricity	Gas	Hydrogen	Heat
Transmission	Some change as for high electric (e.g. reinforcement to accommodate more renewables in locations far removed from centres of demand)	Retained for hythane as transitional step. No 100% H_2 pipelines in network equivalent to today's gas grid, except as links between certain specific sites.	H_2 pipelines needed for links from bulk H2 producers to areas of large scale usage. Transitional use of hythane in old NG network	n/a
Distribution	Reinforcement of connections to garage forecourts to accommodate MW-scale electrolysers (plus, probably, rapid chargers for BEVs). Reinforcement minimised by smart use of heat and transport loads.	Repurpose for hythane as transitional step	H_2 pipelines needed for links from bulk H_2 producers to areas of large scale usage (e.g. industrial users or city centre forecourts with no space for electrolysers and storage)	Limited to very dense city centres (district CHP, natural gas, hythane or potentially H_2 fuelled)
Local distribution	Reinforcement to accommodate electrolysers, BEV chargers and increased utilisation of electric heat pumps and resistive heating. Reinforcement minimised by smart operation of heat and transport loads.	Repurpose for hythane as transitional step.	Intra-site hydrogen production, storage and dispensing infrastructure (e.g. at forecourts).	Limited deployment. Local and domestic CHP (natural gas initially, then hythane, possibly eventually H_2 in certain circumstances).
Conversion	Some smart substations, limited to areas where largely electric heat pumps and resistive heating, plus electrolysis	Repurpose for hythane. Use existing PRS locations.	Site-specific H_2 systems (e.g. garage forecourts).	Direct connections in small scale schemes.
Storage	Limited to central storage for transmission scale balancing (additional 500GWh pumped storage available)	Line packing of network using hydrogen (within limits) at times of surplus power generation	Hydrogen stores around country adjacent to production centres and in filling stations (and, of course, on board vehicles)	Linked to heat pumps and resistive heaters for use of off-peak electricity
Connections	Increase in electrical connection sizes due to increased primary energy generation on grid and use of power across all three sectors (power, heat and transport). Reinforcement of connections minimised by smart operation of grid and demand side response.	Partial repurposing to utilise a hythane gas	New filling station connections	Limited connections

7 Infrastructure Cost Model

This chapter provides an overview of the structure, functionality, assumptions and limitations of the Infrastructure Cost Model. For detail on how to interact with and use the model, see the User Manual.

7.1 Overview

This chapter introduces the Infrastructure Cost Model, outlining its structure and how costs – capital and operational – have been compiled and are presented. The development of the model was an iterative process undertaken throughout the study period. This chapter describes the final output of that process.

7.2 Cost Model structure

The Infrastructure Cost Model is a structured database containing cost data for each individual infrastructure element as defined by the Technical Scope. It uses a modular approach, building up from Component to Assembly to Project as shown in Figure 7—1.

- **Components** represent the lowest level to which capital costs are disaggregated. For example, civil engineering cost Components may include excavation, filling, surface re-instatement, etc.

  In some cases, where it is not helpful to break an asset down into its constituent Components – for example due to a lack of granularity of cost data – it is included as a single, 'composite' Component. Such 'composite' Components are mostly larger elements within the transmission and distribution networks, such as electricity substations, gas pressure reducing stations, etc. These Components can be broken down in future if more granular data is available. This approach is taken to maintain the structure of the Cost Database and ensure a consistent methodology.

- **Assemblies** are collections of Components compiled using quantity multipliers to produce composite costs for these Assemblies. Components will be assembled for new build, refurbishment, re-purposing and abandonment within Assemblies, as appropriate.

- **Projects** are collections of Assemblies, assembled using quantity multipliers to produce whole Project cost estimates. Projects can be attributed with specific context (urban, rural, etc), scale and region to allow Assembly costs to be appropriately modified during calculations.

The key functional units are the Assemblies, each of which relates to an infrastructure element as detailed in Chapter 3. Over 200 Assemblies are included in the model based on detailed cost data attached to around 900 Components. Components and Assemblies are discussed in this Chapter. Projects are covered in Chapter 8.

The approaches to capital and operational costs are different, primarily due to the difference in availability of cost data. A detailed 'bottom up' approach has been taken to capital costs whereby each Component is treated separately as cost data is generally available at this level. The model allows for variation in Component cost rates in relation to a number of different parameters as described in Section 7.3.2 below.

A more 'top down' approach has been adopted for operational costs, based on regional and / or network wide data that reflects the way that networks tend be managed and reported upon, particularly in the case of the regulated utilities. The approach is believed to provide a representative assessment of the impacts of investment in an infrastructure Project (as input to the model) on operating costs within the tolerance of the available data and industry knowledge. It is also worth noting that applicable annual operating costs are typically less than 1% of Modern Equivalent Asset (MEA) value and that even relatively significant variances in overall operating costs are unlikely to have a substantial impact on the Net Present Value (NPV) of a specific Project.

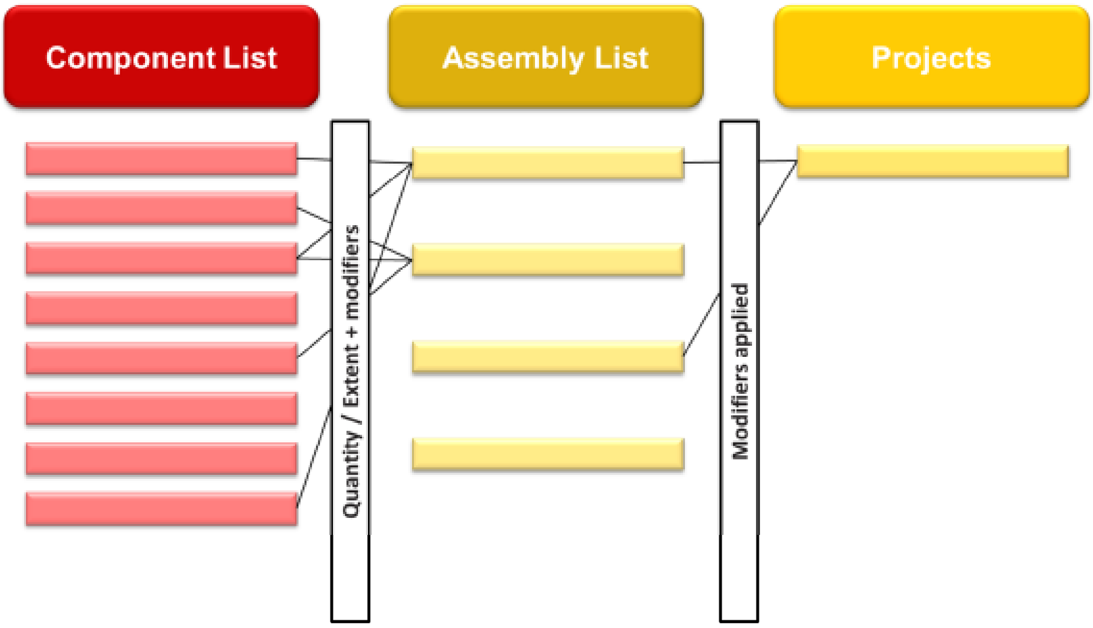


Figure 7—1: outline of Infrastructure Cost Model structure

There is a wealth of information contained within the model and it has been designed to be as flexible as possible and to enable users to adapt and tailor it to their own needs should they so wish. The following sections start with a review of key cost variables and goes on to discuss how the information is built up and any limitations arising from the approaches taken that should be taken into account when interpreting results.

7.3 Capital costs

Capital cost is determined at Component level. From there it flows through to Assemblies and thence to Projects. This section reviews cost at Component and Assembly level as the core building blocks of the model. The development of Projects, which is totally user controlled, is considered in Chapter 8.

7.3.1 Baseline Component costs

Component costs are broken down, where possible and/or appropriate, into material, labour and plant cost fractions. The cost relates to the construction, installation and commissioning of one unit of the Component, where a unit could be a metre of gas pipeline or a single compressor station. It should be noted that overhead costs such as preliminaries and project management are not assigned to Components and instead are applied at the point when a Project is compiled (see Section 8.2.1).

The Component baseline cost is deemed to be the 'normal cost' expected to be incurred under 'normal' procurement and project delivery conditions. As such it forms the basis upon which all cost adjustments for the Component are carried out. In order to allow for typical market variances in this 'normal cost', an upper and lower limit is set indicating the range over which it might be expected to vary. These upper and lower bands reflect the price variability that might be expected when a given component is priced by a number of constructors in a competitive pricing environment.

Market variances are provided for material, labour and plant costs within the component's normal, or baseline, cost.

7.3.2 Data quality

The capital costs of each Component have been built up from a number of sources. These vary in quality from strong (green) to weak (red) as described in Table 7-1. Items for which data is weakest are generally those which are relatively new and for which there are few precedents.

Table 7-1: Quality rating applied to capital cost data included in the cost model

Key	
	Costs derived or synthesised from limited third party data or theoretical costs for a given solution
	Costed from third party sources or limited internally held data where modification was required
	Costed from internally held historic data from past Projects or cost plans, using multiple sources where possible; or from published third party sources where these could be used without modification

The model deals with this uncertainty to some degree through the application of high and low limits to the baseline cost which then flow through to a probabilistic approach to overall Project costs (see Chapter 8).

A particular note has to be added in respect of hydrogen. In the latest version of the tool, cost data has been compiled using the investigation work undertaken and described in the hydrogen paper included in Appendix D where possible.

In the case of pipelines and ancillaries, a market test has been carried out to source pipeline prices for the specifications set out in the report. These have been factored into the prices appearing within the tool together with considerations as to labour and plant pricing where the pipe wall thickness is likely to make welding and installation more demanding than the equivalent size gas line.

In regard to the compressor station, indicative budget prices have been received for the required compressors detailed in the paper. Consideration has been given to other equipment and balance of plant needed for the assembly together with allowances for installation labour. Allowances are judgement based given the differences between a gas compressor station and the technical details of the hydrogen facility, a fact that is reflected in the data quality indicator used for this component.

Costs for pressure reduction stations and other AGIs have generally been influenced by the comparative analysis of gas and hydrogen pipelines given the potentially similar effect on the materials that will be needed in construction.

Some hydrogen components scheduled in the tool have characteristics in common with gas installations. Where this is the case the price for the equivalent case component has been used. For instance, civil engineering excavation work for laying pipelines is considered to be the same between vectors.

7.3.3 Component cost 'rate modifiers'

The project is designed to provide ETI with a library of cost data for use within ESME and similar scenario cost modelling tools. Out-turn costs modelled by these tools will be influenced by a number of factors. Literature published by the EU as regional guidance for large infrastructure projects[12] outlines influencers of cost as summarised in Table 7-2. Certain of these aspects will directly impact unit costs of elements whilst others will influence overall system design which is beyond the scope of this project. Some are dealt with by an Optimism Bias tool included in the model, discussed later in Section 8.2.1.

Table 7-2: outline of influences on cost outturns of large infrastructure projects[13]

Process		Cost considerations
Consents and site acquisition	Public consultation	Consultancy support, venue costs, media and publishing, data collection and analysis. Cost not entirely linked to total technical project value.
	Environmental Impact Assessment	Consultancy costs, surveys and consultation with key interest groups. Avoidance and mitigation of environmental impacts may require investment in elements of work outside of the technical project scope.
	Development rights	Procurement of land or access rights; Appeal costs and supporting consultancy costs.
Detailed design	System design – core elements	Not known at this stage. Complex inter-relationships between system components will impact core costs. i.e.: sizing / capacity of components.
	Non-core elements	Extent of land take, compound works, access roads, housings / buildings, shared zones, etc. will be unknown.
	Site characteristics	Ground conditions; contaminated ground; Topography; Urban / Rural.
Procurement	Purchasing	Availability of suitable construction partners; purchasing agreements; tendering / economic climate.
	Materials	Commodity prices; scarcity; global/national/regional supply and demand.
	Labour	Skills availability; complexity of installations; regional labour costs.
	Geographic context	Transportation costs; temporary compounds.

[12] Summarised from EU Regional Policy Guidance, Understanding and Monitoring the Cost-Determining Factors of Infrastructure Projects. Available at http://ec.europa.eu/regional_policy/sources/docgener/evaluation/pdf/5_full_en.pdf

	Project duration	Site establishment and dis-establishment costs as a proportion of total overhead cost; Seasonal considerations / special plant and accommodation requirements.
	Inflation	Cost increases over time.
	Exchange rates	Foreign exchange fluctuations on imported labour, materials and plant.

As well as understanding the process by which cost estimates are calculated and how they may vary during construction, it is worthwhile having some understanding of how important the different cost elements are, and how sensitive they may be to a range of cost varying factors. Figure 7—2 below from the EU Regional Guidance gives an indication of the degree to which some of the cost categories may change in response to the influences of the main cost-changing factors identified.

	Cost-changing Factors					
Cost Elements	Design Changes	Land Acquisition Problems	Poor Project Management	Unexpected Ground Conditions	Inflation / Relative Price Rise	Difficulties with Contractors
Planning / Design Fees	●	—	●	—	•	—
Land Purchase	•	●	•	—	•	—
Site Preparation (2)	•	—	•	●	•	•
Building & Construction	●	—	●	•	●	●
Plant & Machinery	●	—	•	—	●	•

Notes:

1. Large dot denotes a major effect – potentially 20% change for affected cost elements; small dot denotes a minor effect – typically 5% change of less for each cost element affected.

2. "Site Preparation" is identified as a separate element of Building & Construction costs because it is here where the main effect of unexpected ground conditions is experienced.

Figure 7—2: Effects of cost changing events on key cost elements.[13]

Based on this literature and factors, a Rate Modifier tool is included in the Cost Model to allow the impacts of multiple changes to cost modifiers to be cascaded into the elemental cost analysis of each vector's installation cost.

[13] Source: Extracted from EU Regional Guidance. Table researched by consultants, Ove Arup & Partners, based on experience of public and private sector procured projects in various EU Member States

The ‘rate modifiers’ included in the model are:

- Site context: urban, semi-urban, or rural locality
- Capacity (where appropriate to the Component, eg. electricity transmission, storage)
- Scale
- Ground conditions: ease of excavation; ground contamination; ground water (where the Component cost includes ground works)
- Cost trends:
    - Low, medium, high trends applied to material, labour and plant
    - Technology maturity

The following sections provide an overview of how these variations function within the model. The reader is directed to the User Manual for more specific detail as to how to implement them.

Context

Context rate modifiers provide the user with the facility to allow adjustments to be made to the baseline Component cost resulting from its construction / installation within different locational contexts (Table 7-3). Thus for example, a gas pipeline installed in an urban setting is likely to cost more than the same pipeline installed in a rural setting.

Table 7-3: context rate modifiers

Context	Description
Urban	Installation within locations with >60 dwellings per hectare
Semi-Urban	Installation within locations with 30 -60 dwellings per hectare
Rural	Installation within locations with <30 dwellings per hectare

This class of modifiers is used to identify the factors to apply to the base cost as a result of the environment that the work is being undertaken within. One of the three fields within this set represents the base case scenario and is therefore set to 100% of base cost. The other two contain a percentage to reflect the additional difficulty or ease of working against the base cost based upon our experience and expectations of the cost premiums or savings experienced. Factors taken into consideration when determining this percentage include productivity rates for work in congested areas, the need to remove and reinstate hard finishes when carrying out civil engineering works, the inability to deploy economies of installation scale in urban and suburban areas when compared to rural and the like.

In most cases the Components are set so that the baseline cost is the rural cost (ie. set at 100%) with semi-urban and urban costs being increased by an appropriate percentage relative to this. As said however, users can adjust this if they so wish.

Note that the Component cost excludes overheads associated with the installation contract. These overheads are dealt with in the Cost Model at Project level (see Section 8.2.1). These overheads may vary significantly between contexts.

Capacity

The baseline cost of each Component can also be adjusted for different capacities, although in fact, few Components lend themselves to this application. The Components for which it is relevant and which are included in the model are those for electricity transmission where a particular voltage may be installed with various cable capacities. Capacities can be modified to suit a specific application if the capacity sought falls outside the range currently in the tool. In other cases, introducing capacity variations is generally best done by creating a whole new Component / Assembly with a different capacity. Thus, capacity variations for gas, hydrogen and heat are dealt with by including a number of Assemblies, each for a different pipe diameter.

The Cost Model does not extrapolate capacity values and costs beyond or between those values held in the Component's data sheet.

Capacity modifiers have, where used, been based upon Project Team experience of what is likely to happen to cost as a result of variations to capacity.

Where third part data has been used as a source for costs, consideration has been given to whether any capacity driven cost ranges quoted are sufficiently robust to be reproduced in the tool and used these to inform the population of the data fields if appropriate.

Scale

The impact of scale on Component cost is taken into account by setting lower, baseline and upper values to the quantity of the Component being installed and then applying an estimation of what impact these different values could have on cost, with the baseline quantity being 100% of the baseline cost. Thus for example, for a 400V overhead conductor, a small scale installation limit could be 250m, baseline 500m and large 1,000m. The impact on baseline cost is estimated as an increase against baseline of 10% for the small scale installation and a reduction of 10% for the large scale. There is scope for the user to vary all these parameters should they wish to create a more bespoke costing for a particular Project.

The Cost Model applies scale rate adjustments as closely as possible to the scale values within the Component datasheet – that is, where a project requires a component quantity well beyond the upper scale value supplied for that component, the rate adjustment will be limited to the upper value within the data sheet. No extrapolation is applied beyond this value. Scale and price sensitivity have been populated based upon scale range and cost relationships that are reasonably well understood. Care has been taken not to make the bands too wide and go outside of current experience in terms of how cost is affected.

Scale modifiers have been selected using Project Team expectations of cost variability when the overall size of an installation or number of units deployed changes.

Where third part data has been used as a source for costs, consideration has been given to whether any scale driven cost ranges quoted are sufficiently robust to be reproduced in the tool and used these to inform the population of the data fields if appropriate

Ground conditions

Ground conditions clearly affect some Components more than others, and for those that it does affect, costs could vary significantly. In the case of contaminated land, the tool assumes that fresh fill is brought in to replace contaminated material taken away. If more innovative remediation solutions are likely to be used then the specifics of these need to be introduced by the user. The model incorporates the facility to alter Component base costs by a percentage based on assumed conditions. These modified costs are then carried through to Projects based on the ground conditions described within the Project.

Ground condition cost variability has been modelled using trends determined from more detailed modelling of the cost premiums arising from the presence of the influencers described. The detailed modelling uses assessments of the quantum of rock, contamination and ground water and applies historic rates per m3 to determine the cost likely to be experienced.

Cost trends

The database is intended to provide cost guidance from 2010 through to 2050. Forecasting how costs may develop over time is clearly complex and could differ for different infrastructure elements as well as for their different constituent parts. There are also a number of different drivers for cost evolution such as commodity rates, availability of skilled labour, the rate and scale of deployment or the technological maturity of the Component, with new, innovative technologies having the potential to reduce cost over time more than mature ones.

The challenge was to take into account this complexity while ensuring that modifications are relatively transparent and simple to understand and do not produce projections with spurious accuracy. The approach adopted therefore:

- Adjusts base cost projections for each Component (i.e. including those that focus on refurbishment or abandonment activities) in the database using the principles of technology maturity
- Allows users to modify ‘global’ assumptions about the relative cost of specific components (i.e. to take into account the user’s view on future costs based on their own scenarios)
- Enables new more cost effective innovations / efficiency improvements to be ‘made available’ for selection after certain specific time periods. Once these technologies are available then Assemblies containing these Components will be available for inclusion within Projects with resulting impact on the overall costs of delivery.

Two specific model features embody the approach, one which allows for alterations in annual cost trends of labour, material and plant; and the other which allows for alterations in cost trends according to the level of technological maturity of the Component and its rate of deployment. These are described below.

Cost trends: labour, material, plant

The cost trends for labour, material and plant can be modified either globally for a Component so that the trend affects all Assemblies and Projects in which the Component appears, or more specifically when defining a particular Project.

At the Project level users are able to determine whether they want to use high, medium or low cost projections for materials, plant or labour and can adjust these for their Project specifically.

If they wish to consider a scenario whereby specific Components have higher or lower costs then they can select either a flat, low or high increase as required (for current settings see Economic Assumptions in Section 7.5). There is also the option for users to add their own 'bespoke rate'.

Cost trends: technological maturity and innovations

Cost trends that take into account the technological maturity of a Component are incorporated into the model as a series of S-curves. These curves represent changes in cost due to technological maturity and implementation factors, independent of external factors such as inflation, commodity prices and exchange rates, etc.

Five curves[14] as illustrated in Figure 7—3 have been incorporated into the model. These are described as:

Type 1 - Rising (based on an average of the Steel and Aluminium cost curves)

Type 2 - Flat (to represent no change in cost)

Type 3 - Shallow reduction (based on an average of off-shore wind farm costs and flat line)

Type 4 - Medium reduction (based on the cost curve for off-shore wind farms)

Type 5 - High reduction (based on the cost curve for laptops)

It should be noted that the trends assigned here are based on the literature from a single case study only and were derived from research into a number of consumer goods and market facing renewable technologies. No research relating to infrastructure costs of specialist installations such as hydrogen was found. In the absence of anything more specific to energy infrastructure, the current trends should provide some comfort to the user, however, the tool does also allow the user to define an additional three maturity cost curves if required.

[14] Source: Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks – Version 3.1 July 2012, prepared for Energy Networks Association on behalf of Smart Grids Forum – Work Stream 3. http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/WS3%20Ph2%20Report.pdf

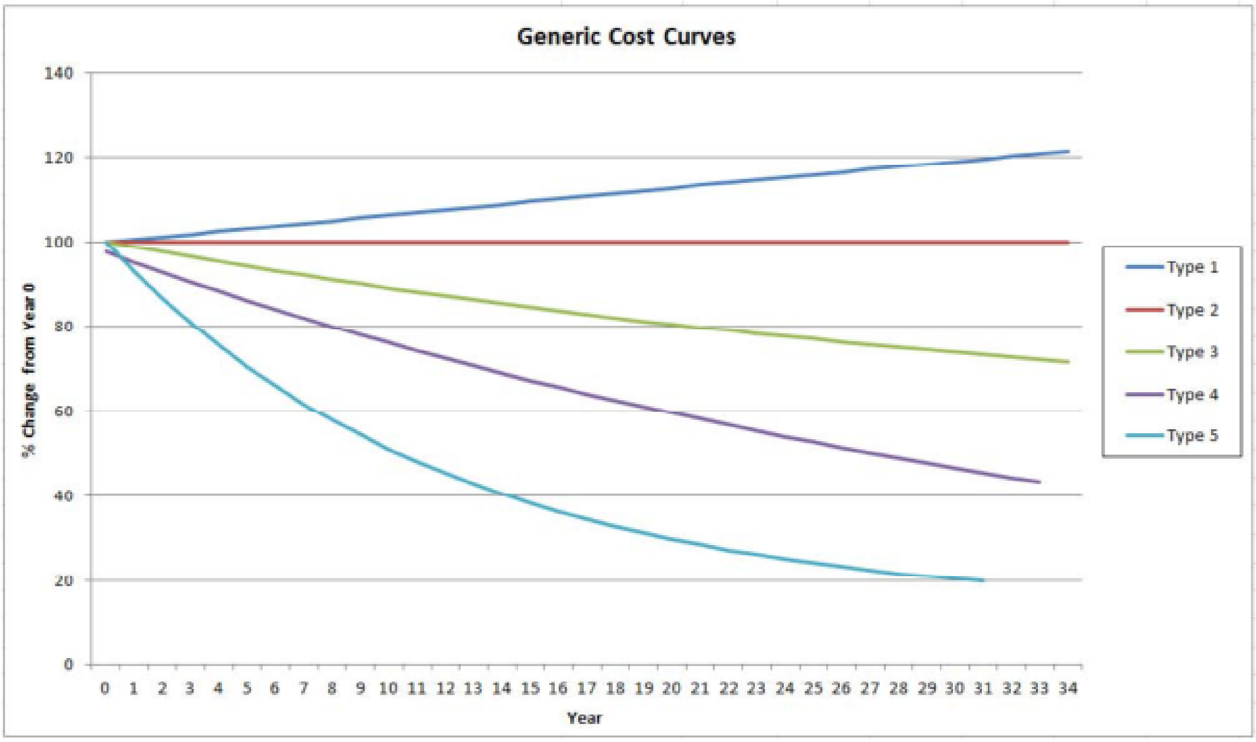


Figure 7—3: illustration of Technology Cost Curves incorporated into the database at Component level[14]

By placing each Component technology within one of these curves, the approach provides an indication of future trends in cost that might be expected from 'within technology' efficiency measures, i.e. economies of scale or other efficiencies. For example, ground works or other mature activities where there is likely to be relatively little change in current activity levels would show very little change in cost while new technologies where there is likely to be a high or very high expansion in activity (e.g. HVDC circuit breakers) would see a much faster reduction in cost.

This would not include the impact of disruptive innovations. Such innovations that will, in the future, offer a more efficient way of delivering a specified Project, can be incorporated as new Components that are 'available' from a defined date and have their own maturity and growth trajectories. Users can include these Components within Assemblies (which can carry forward into Projects where the projected Project date is after its first availability). By creating new Components which include innovations it will be possible to show how these Assemblies offer lower cost approaches compared to incremental improvements that might be expected using the current approach.

7.3.4 Assemblies

The cost of an Assembly is built up by selecting the number and type of Components that it comprises as defined by the relevant Scoping Diagram. In some cases the Assembly may comprise a number of Components, for example, gas pipe lines include the pipe, valves, special crossings, civils and trenching. In others which are more complex and for which more detailed cost data may not be available, it is treated as a single Component, such as a gas compressor station. The structure of the model allows this level of disaggregation of an Assembly into Components to be modified and refined when / if more detailed cost data becomes available.

Each Assembly has four 'operations' attached to it: new build, refurbishment, repurposing and abandonment. Each operation may be made up of differing Components depending on the assumed technical scope as described in Chapter 3.

The application of rate modifiers to the Component cost as described above determines a baseline cost, maximum cost and minimum cost for each Component within the Assembly. Component rates are extracted from the Component Database to produce a matrix of Assembly rates as shown in Figure 7—4 below.

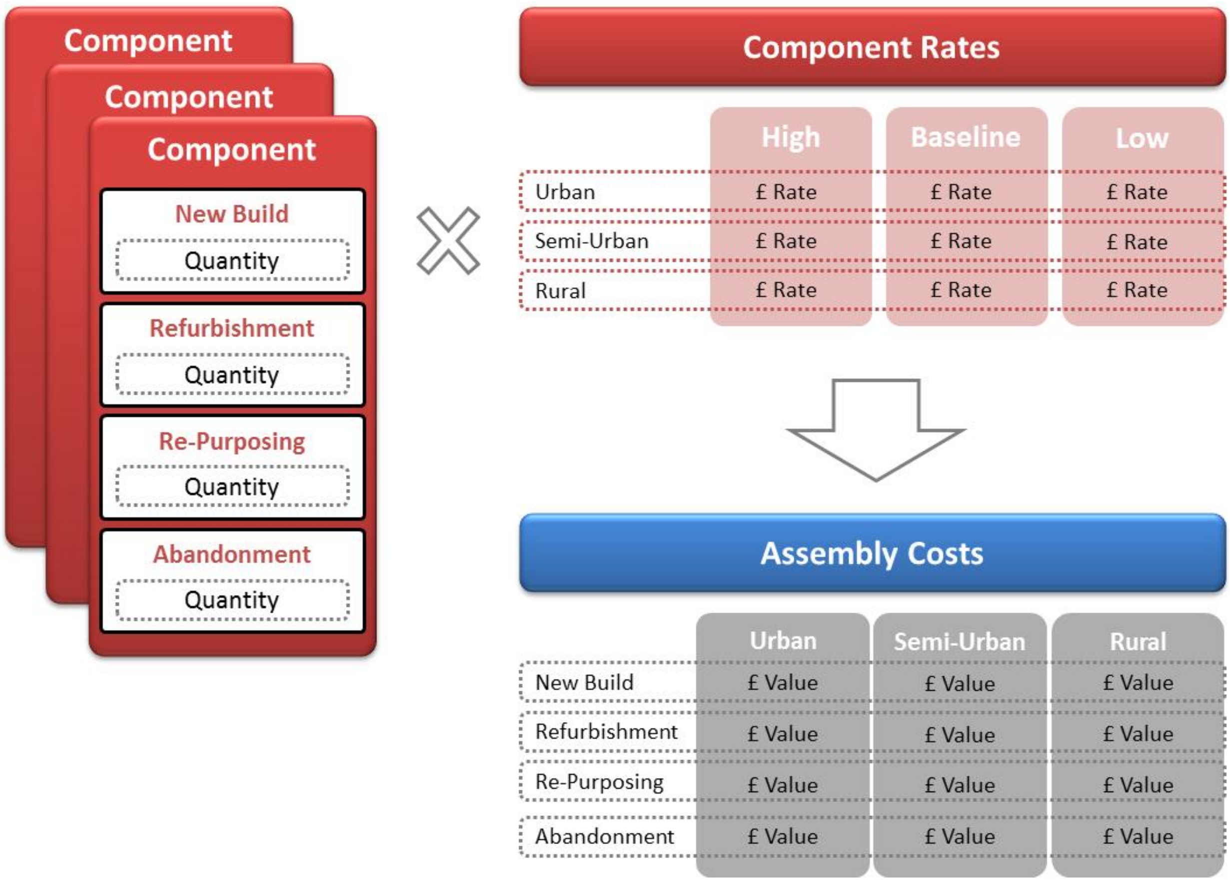


Figure 7—4: Assembly cost calculation process

Costs are then displayed as a range as illustrated in Figure 7—5 (left hand graph) which shows the cost per unit for each operation (new build etc) and in each context (urban, rural etc). Costs comprise all Component costs calculated using baseline cost, highest and lowest costs multiplied by the stated quantity of each Component that makes up that Assembly. The red dot indicates the baseline cost and upper and lower 'whiskers' indicate the high and low cost range resulting from applying high and low cost multipliers to all Component costs.

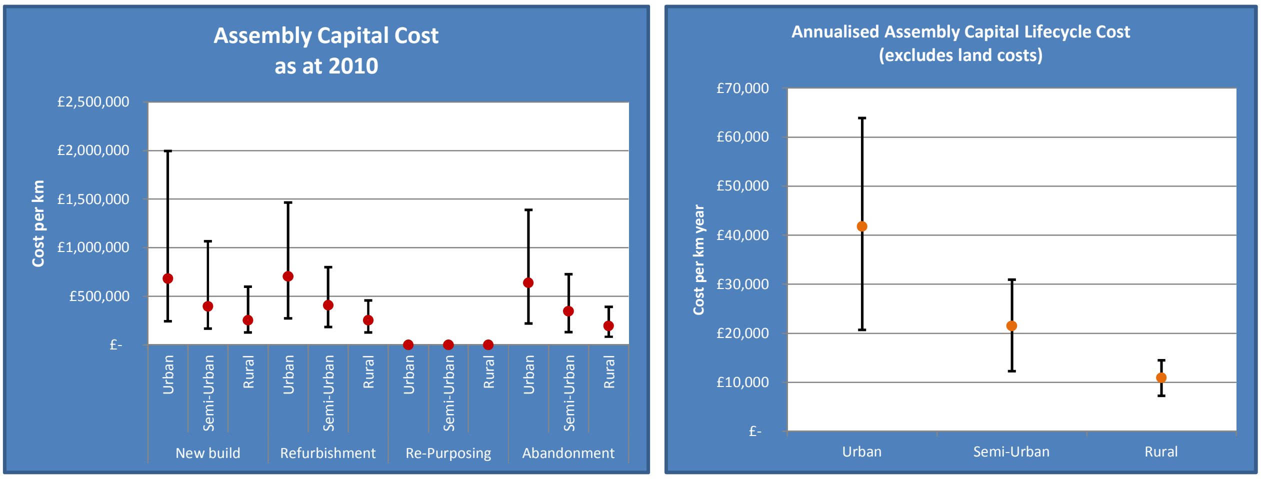


Figure 7—5: example of Assembly capital cost as displayed within the model

The graph on the right hand side of Figure 7—5 shows the annualised Assembly Capital Lifecycle Cost. This takes into account the 'lifecycle profile' of the Assembly. The 'lifecycle profile' defines the periods of major and minor replacement and the percentage replaced in each of these cycles. A number of profiles have been set up in the model (see Figure 7—6), however the user can create their own if they wish.

Profile 1: 25 Year asset life

Lifecycle Parameters	% Replaced	Cycle (Years) Short	Baseline	Long
Major Replacement	100%	19	25	38
Minor Replacement	10%	10	13	19
Abandonment		38	50	75
		Urban	Semi-Urban	Rural
Cycle modifier		90%	100%	120%

Profile 2: 40 Year asset life

Lifecycle Parameters	% Replaced	Cycle (Years) Short	Baseline	Long
Major Replacement	100%	30	40	60
Minor Replacement	10%	15	20	30
Abandonment		60	80	120
		Urban	Semi-Urban	Rural
Cycle modifier		90%	100%	120%

Profile 3: 60 Year asset life

Lifecycle Parameters	% Replaced	Cycle (Years) Short	Baseline	Long
Major Replacement	100%	45	60	90
Minor Replacement	10%	23	30	45
Abandonment		90	120	180
		Urban	Semi-Urban	Rural
Cycle modifier		90%	100%	120%

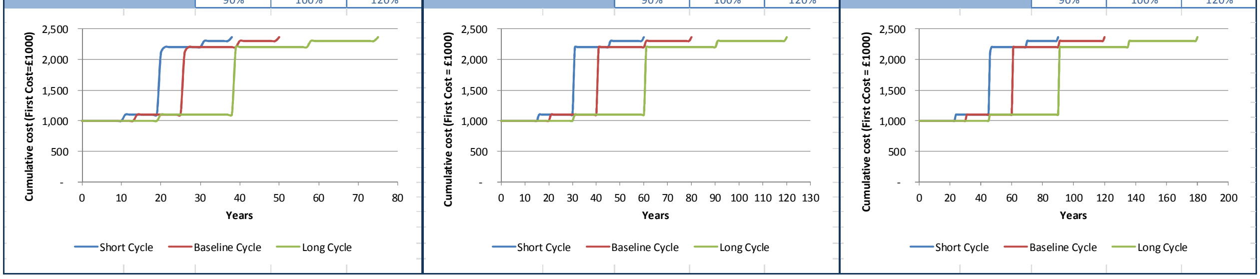


Figure 7—6: life cycle profiles available for use within the model.

Note that operational costs (ie. as distinct from lifecycle costs) are not reflected in any of the outputs at Assembly level. Although an operational cost profile is allocated at Assembly level, the impact of this is only shown at Project level. This is discussed further in Section 7.4 below and in Chapter 8.

7.4 Operational costs

As noted above, the approach taken to modelling operational costs differs from that used for capital costs in that it is more ‘top down’ than ‘bottom up’. This is primarily due to the level of data available which in turn relates to the way in which assets are managed collectively as networks, and where relevant, to the way in which network operators are regulated. In developing a modelling approach, the aim was to enable an indicative assessment of the impact of investment in new / refurbished or repurposed assets on the overall operating costs of each energy vector.

Investment in new, refurbished, repurposed or abandoned infrastructure will impact operating costs in many ways. These can be summarised as:

- Adding to the asset base and thereby increasing the overall operating cost
- Reducing the asset base and thereby decreasing the overall operating cost
- Changing the asset base and thereby changing the overall operating cost within one or more vectors

Key challenges were:

- To understand what operating costs currently are and, to the extent they are aggregated over a network, how they can be allocated to asset value
- To understand how operating costs might vary over the asset life

The approach to modelling operating costs has been developed from work undertaken by Sweett Group with support from PPA Energy whose full report is included in Appendix G.

7.4.1 Definition of ‘operating costs’

Most energy network operators account for their operating costs in similar, if not identical, terms:

- Direct costs - incurred on or close to the network such as, for example, maintenance costs or tree and vegetation management for overhead electricity networks
- Indirect costs, split into:
    - Closely associated costs - those elements which are closely related to the network such as certain IT costs, training, drawing office, maintenance support, etc
    - Business support (not directly linked to assets) - more distant to the network itself but still need to be incurred. This would include, for example, finance, HR, and corporate costs
    - Pass through / uncontrollable costs - substantially outside of the control of the utility. Examples include regulatory licence fees and local government taxation (rates)
    - Depreciation - the non-cash charge to operating costs of previous capital expenditure.

From these categories only direct and closely associated indirect costs are closely proportionate to the scale of infrastructure assets in a region. Over the long term, changes in asset base could affect the other elements of operating costs. It has been assumed that such changes are marginal and outside the level of accuracy of the overall assessment. Further detail is shown in Table 7-4 below.

Table 7-4: types of direct of closely associated indirect operating costs as extracted from PPA Energy report

<table>
<tr><th colspan="2"></th><th>Electricity Distribution (DNO)</th><th>Electricity Transmission (TO)</th><th>Gas Distribution (GDN)</th><th>Gas Transmission (GTO)*</th></tr>
<tr><td rowspan="3">Controllable</td><td>Direct Opex</td><td>• Inspection and maintenance (planned and unplanned)
• Trees and vegetation management</td><td>• Inspection and maintenance (planned and unplanned)
• Trees and vegetation management
• Tower painting
• Management of HVDC and New technology</td><td>• Inspection and maintenance (planned and unplanned)
• Work management
• Emergency Repairs
• Independent networks
• Xoserve</td><td>• Inspection and maintenance (planned and unplanned)
• Innovation costs (e.g. IFI).[15]
• Armed guards (at key operational sites)
• Operational property management
• Quarry and loss.[16]
• CNI (Critical National Infrastructure) security
• Quasi capex (e.g. costs of decommissioning assets and asbestos removal)</td></tr>
<tr><td rowspan="2">Closely Associated Indirect</td><td colspan="4">• Network Design and Engineering
• Project Management
• Engineering Management and Clerical Support
• System Mapping
• Operational Training
• Vehicles and Transport
• Stores and logistics</td></tr>
<tr><td>• Control Centre
• Call Centre</td><td>• Network policy (inc. R&D)
• Health, Safety and Environment
• Network planning</td><td>• Research and development</td><td>• IT support for systems used to manage network assets
• Gas drawings</td></tr>
<tr><td></td><td>Business Support</td><td colspan="4">• Procurement
• HR
• Insurance
• Finance, audit and regulation
• Corporate
• IT & Telecoms
• Property Management</td></tr>
</table>

[15] The opex figures contained in this report are unlikely to include innovation competition funding, e.g. the Low Carbon Networks Fund, as in general they have taken place or will take place after the price control allowances have been agreed
[16] Compensation for landowners for loss of earnings due to pipeline development – under the RIIO framework these costs are treated as controllable

		Electricity Distribution (DNO)	Electricity Transmission (TO)	Gas Distribution (GDN)	Gas Transmission (GTO)*
		• Non-Operational Training • CEO costs			
Uncontrollable / pass through		• Licence fee • Network rates	• Licence fee • Network rates	• Licence fee • Network rates • NTS Flat (exit charges) • Interruptions • Shrinkage (losses) • Pension deficit / surplus	• Licence fee • Network rates

*For the GTO a number of costs have moved from “pass-through” or “logged up” to controllable

7.4.2 Approach

Relationship between asset value and operating cost

Analysis of the regulatory accounts of electricity and gas transmission and distribution operators suggests that operating costs comprise between 0.5 and 2.6% of Modern Equivalent Asset (MEA) value[17]. Operating costs as a % of MEA value are significantly higher for gas distribution than for electrical distribution or transmission. Further information on these figures is available from the PPA Energy report in Appendix G.

For the portion of operating costs that are linked to asset management it is assumed that a direct relationship exists between MEA value and operating cost i.e. the impact on operating cost is proportional to the value of new infrastructure as a proportion of the overall MEA value[18] of the infrastructure in a given region.

Recognising that operating costs may vary depending on the nature of the asset, the operating cost model allows costs to be adjusted depending on whether the asset is ‘active’, such has a transformer or compressor, or ‘passive’, such as a pipeline or overhead conductor[19].

For the portion of operating costs not directly or closely linked to assets such as corporate administration (IT, HR, etc), planning, reporting and licensing functions, it is assumed that they are not impacted to any meaningful extent by discrete Projects. Although this is reasonable for existing vectors (ie. electricity, gas and heat), when a new vector such as hydrogen is created, these operational overheads would also need to be created to support the asset owner. For hydrogen, an indicative estimate of these overheads is between a third and half of the total operating cost reflecting the current ratio of these costs in gas infrastructure[20].

[17] Ofgem’s definition of the Modern Equivalent Asset (MEA) value is: the current replacement value of an asset https://www.ofgem.gov.uk/ofgem-publications/53855/glossary.pdf
[18] The MEA is higher than the network’s gross asset value, the latter being based upon historic cost accounting which does not provide a fair means of using value to describe the scale of the asset base.
[19] Analysis of a sample regulatory account showed that the direct operating costs, as a proportion of MEA, are similar for both passive and active asset types. Therefore, the model default is set up to assign equal weighting to both passive and active assets.
[20] This estimate is a simplification of the relationship between direct and indirect operating costs. However, the approach is considered reasonable in the absence of examples of UK hydrogen network of scale and of the regulatory framework that might be applied.

Profile of operating costs over time

A portion of the operating costs of an asset will vary over the asset life. Assuming a flat distribution of operating costs would therefore give a poor reflection of the impacts of replacing existing assets with new assets as the immediate impact could be positive or negative depending on the shape of profile and the age of the asset to be refurbished / repurposed. A classic example of this variation is the 'bathtub' profile whereby failure rates are higher at the start and end of the asset lifecycle with a period of relatively low operating costs in between these periods. However, a range of potential profiles exist with shapes that reflect differing characteristics.

The most significant impact on the operating cost profile of an asset is its failure rate and therefore need for reactive maintenance. The failure rate is assumed to be mainly influenced by the asset type (active or passive).

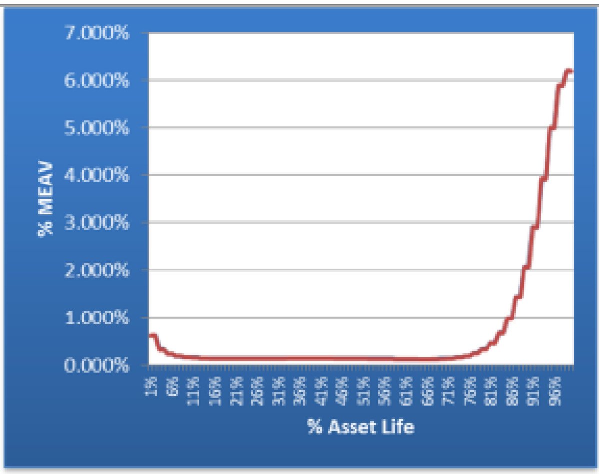
Whilst there are very many different profiles of operating costs that could be developed, the 'active' and 'passive' options provide reasonable coverage of the different scenarios and are in keeping with the current state of knowledge on specific infrastructure components.

A distribution profile can be used to show how operating costs vary around the average over time. Using the most suitable profile, the direct and closely associated operating costs can be estimated for each year of an asset's life.

Two such profiles have been developed to represent the variation in operating cost over the life of the asset (from 0 to 100% of the defined asset life) (Figure 7—7)[21]. Each profile comprises three 'phases' of operating cost, the early phase of 'infant mortality' where operating cost levels decrease over time, a central period of normal operations where costs are relatively consistent and end of life decay where the rate of failures increases.

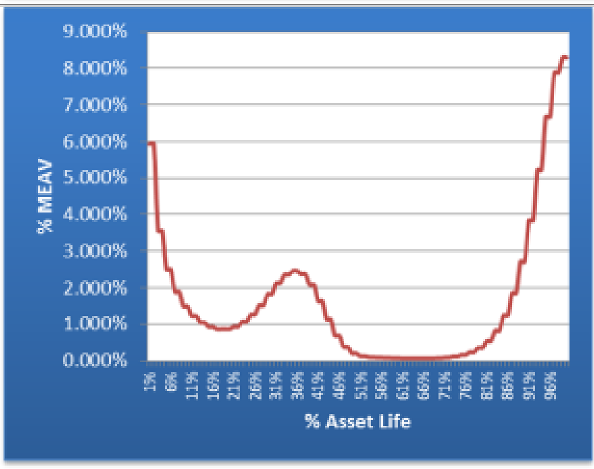
The area under each profile curve is taken as the total operating cost for the asset over its life and the operating cost in any given year is determined as a proportion of the total operating cost that is applied in that year.

[21] Note that operating cost profiles ('opex profiles') are assigned at Assembly level along with 'lifecycle profiles' (Section 7.3.4). No operating costs are assigned at Component level.



Passive Assembly

Minimal infant mortality, due to high level of industry experience and expertise in the installation of these assets. End-of-life decay follows a profile of increasing failure rate until end of life.



Active Assembly

Higher infant mortality, due to the active nature of the asset and settling in period required for active components. End-of-life decay follows a profile of increasing failure rate until end of life.

Figure 7—7: Operating cost profiles used in the cost model

Table 7-5 shows the Assembly types that have been assigned to each profile.

Table 7-5: Operational cost profiles as applied within the model to the different infrastructure types of each vector

Vector	Assembly Type	
	Passive	**Active**
Electricity	AC Buried HVAC Buried AC Overhead HVAC Tunnelled HVAC Overhead HVDC Buried HVDC Overhead HVDC Off-shore HVDC Tunnelled	AC Connections AC Conversions HVAC Conversions HVDC Conversions
Gas	Buried pipelines – transmission and distribution Connections	Conversions Storage
Heat	Buried pipelines	Conversions Connections Storage
Hydrogen	Buried pipelines – transmission and distribution Connections	Conversions Storage

Assessing the net impact of a Project on operating costs

The model is structured so as to take into account Projects that may include Assemblies that are new, repurposed, refurbished or abandoned. The net impact of a Project on operating costs is estimated as follows:

- New build Assemblies are assumed to add to the MEA value of the regional network and therefore increase direct and closely associated operating costs by the percentage of MEA value that they represent
- Refurbishment Assemblies assumed to restart the operating cost profile for this portion of the regional network, i.e. if the existing asset is 20 years old, the refurbished asset would be assumed to be 0 years old and the % of its average operating cost that is included in year 1 of the Project adjust accordingly. The change in operating cost might be up or down depending on the age (i.e. the position on the cost profile) of the existing asset
- Re-purposed Assemblies reduce the regional operating cost for the outgoing vector and assumes a New Build profile for the new vector.[22]
- Abandoned Assemblies reduce the regional operating cost by the appropriate MEA value as adjusted for the age of the abandoned asset (i.e. its position on the operating cost profile) and therefore the applicable proportion of its average operating costs.

[22] Although there could be some difference in operating costs between new and repurposed assets no data was found to support what these differences would be.

Calculation of Opex Costs

The calculation of opex is based on percentage costs contained in PPA Energy's report included in Appendix G. A summary of reported opex costs as a percentage of MEA value, split into costs attributable to faults / failures and other, general opex costs, is shown Table 7-6:

Table 7-6: summary of reported opex costs as a percentage of MEA Value from PPA Energy Report (Appendix G)

	Opex as % of MEA Value			Split	
	Fault Repairs *FaultOpex%*	Other Opex *NonFaultOpex%*	Total Opex	Direct	Indirect
Electricity Distribution	0.194%	0.602%	0.797%	53%	47%
Electricity Transmission	0.129%	0.400%	0.529%	41%	59%
Gas Distribution	0.406%	0.910%	1.316%	83%	17%
Gas Transmission	0.327%	0.733%	1.060%	79%	21%

In order to determine the proportion of opex attributable to active system elements and passive system elements, the total asset values, for gas and electricity networks, have been summarised from a 2010 report by Cambridge Economic Policy Associates[23]. These network values are summarised in Table 7-7, in £ billions, in 2009/10 prices:

Table 7-7: summary of MEA Values in 2009/10 prices as extracted from Cambridge Economic Policy Associates, 2010

Vector Group	MEAV of Active Elements (£bn)	MEAV of Passive Elements (£bn)	Total MEAV (£bn)
	$MEAV_{Active}$	$MEAV_{Passive}$	$MEAV_{Total}$
Electricity Distribution	27.0	109.0	136.0
Electricity Transmission	12.0	25.0	37.0
Gas Distribution	2.5	53.5	55.0
Gas Transmission	9.2	52.0	61.2

The totals of probability of failure over the assembly lifecycle (as described previously for passive and active assemblies) are as follows:

Active assemblies $Probability\%_{Active}$ = 166.6%

Passive assemblies $Probability\%_{Passive}$ = 71.6%

The "fault related" and "non-fault" opex factors attributable to active and passive assemblies have been calculated as follows:

[23] Cambridge Economic Policy Associates, The Economic Lives of Energy Network Assets, December 2010.

For each Vector Group:

1. Electricity Distribution
2. Electricity Transmission
3. Gas Distribution
4. Gas Transmission

Calculation of Fault related annual Opex % for Active Assemblies:

$$OpexCost_{Fault} = MEAV_{Total} \times FaultOpex\%$$

$$OpexCost_{NonFault} = MEAV_{Total} \times NonFaultOpex\%$$

$$ActiveOpexCost_{Fault} = \frac{\left(MEAV_{Active} \times \Pr obability\%_{Active}\right)}{\left(MEAV_{Active} \times \Pr obability\%_{Active}\right) + \left(MEAV_{Passive} \times \Pr obability_{Passive}\right)} \times OpexCost_{Fault}$$

$$ActiveOpex\%_{Fault} = \frac{ActiveOpexCost_{Fault}}{MEAV_{Active}} \times \frac{100}{1}$$

This principle is repeated for non-fault and passive assemblies, to derive the values given in Table 7-8:

Table 7-8: Operating costs as a % of MEA Value for active and passive assemblies for each infrastructure type

	Opex Cost as % MEAV			
	Non-Fault Opex		Fault Opex	
	Active Assemblies	**Passive Assemblies**	**Active Assemblies**	**Passive Assemblies**
Electricity Distribution	0.602%	0.602%	0.358%	0.154%
Electricity Transmission	0.400%	0.400%	0.210%	0.090%
Gas Distribution	0.910%	0.910%	0.892%	0.383%
Gas Transmission	0.733%	0.733%	0.635%	0.273%

These Opex% costs are applied to MEAV values of assemblies across the lifecycle period being modelled to derive a total Opex cost per assembly, totalled for the project.

The calculation of annual Opex cost per assembly is as follows:

$$OpexCost_{year.n} = \left(Fault \Pr obability\%_{year.n} \times ActiveOpex\%_{Fault} \times MEAV_{year.n}\right) + \left(ActiveOpex\%_{NonFault} \times MEAV_{year.n}\right)$$

or:

$$OpexCost_{year.n} = \left(Fault \Pr obability\%_{year.n} \times PassiveOpex\%_{Fault} \times MEAV_{year.n}\right) + \left(PassiveOpex\%_{NonFault} \times MEAV_{year.n}\right)$$

Annual Opex cost is further split into Direct and indirect Opex for reporting purposes.

7.5 Economic assumptions

Economic assumptions impacting on model outputs are labour / material / plant trends, discount rate, regional tender price indices and land costs. Each of these are clearly labelled and can be adjusted by the user if required.

Values included in the current version of the model are as follows:

- Labour / material / plant trends: The default cost trends contained within the tool have been calculated based upon historic cost trend of labour and plant, and materials, published by the BCIS and adjusted for removal of annual increase in the Consumer Price Index (CPI). Details of rates and calculations are included in Appendix H. The increases are applied to the respective fraction of each Component cost as described in Section 7.3.2 above.
- Discount rate: a value of 3.5% is used by default in the calculation of Project NPV.
- Regional tender prices: these are extracted from the Building Cost Information Service (BCIS) Regional Tender Price Indices and provide indicative variances in tender price expected within the various regions and are shown in Table 7-6. Off-shore works have been defaulted to a 100% factor in line with the 'All of UK' index. These variances are applied when a particular region is applied at Project level.
- Land costs per hectare: these are calculated based on the land take of each Assembly and are shown in Table 7-6. Land costs are for land only and exclude the cost of way leaves.

Table 7-9: Regional cost indices and land costs included in the model. These can all by changed by the user.

REGION	Regional Cost Indices	Land Cost per hectare								
		Urban			Semi-Urban			Rural		
	BCIS Tender price index	High	Baseline	Low	High	Baseline	Low	High	Baseline	Low
All of UK	100%	£ 150,000	£ 100,000	£ 75,000	£ 90,000	£ 75,000	£ 40,000	£ 40,000	£ 25,000	£ 5,000
East Midlands Region	91%									
Eastern Region	91%									
London Region	122%	£ 250,000	£ 120,000	£ 95,000						
North East Region	93%									
North West Region	91%									
Northern Ireland Region	64%									
Scotland Region	104%									
South East Region	107%									
South West Region	101%									
Wales Region	97%									
West Midlands Region	94%									
Yorkshire and the Humber Region	93%									
#Offshore - Channel Islands	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Dogger Bank	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - East Sccotland	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Hebrides	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Irish Sea	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Lundy	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Norfolk	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Pentland	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore - Shetlands	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore Storage - Humber	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000
#Offshore Storage - North Sea	100%	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000	£ 10,000

8 Uses of the Infrastructure Cost Model

8.1 Overview

The model contains a wealth of information and is provided with a number of tools and interfaces to enable users to adapt it to their needs and to extract data in ways that are both meaningful and useful. Its modular structure ensures that it is 'future proof' in that new Components and Assemblies can be added as required, either as more detailed cost data becomes available or an innovative technology becomes available. Data is also available to be extracted for use in other models or form as it is all in Excel cells which can be read by other applications or spread sheet tools.

It is anticipated that the primary use of the model will be in exploring the costs of projects and comparing options to help determine an optimal solution. In this chapter an overview of the Project functionality is provided along with some specific examples of questions the model can help in answering.

As mentioned elsewhere in this report, it must be noted that **the cost model does not allow for any form of system design.** Projects need to be designed as a separate exercise such that they can be expressed as a 'bill of quantities' (BoQ).[24] of constituent Assemblies. This 'bill of quantities' is used to model various aspects of the Projects for comparative purposes.

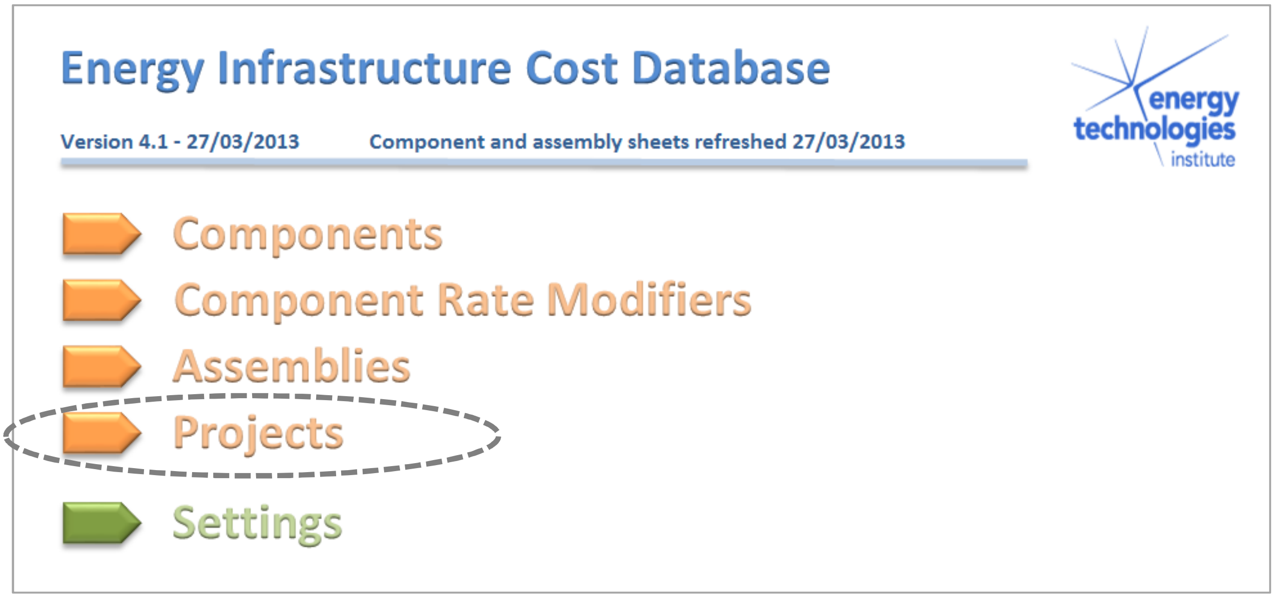


Figure 8—1: Screen shot of start page of Infrastructure Cost Model

[24] The term 'bill of quantities' is used to refer to the data required to be input to the cost model in order to extract overall project costs. The quantity of each Assembly used to build the Project is required and this is input via the Project Data sheet of the model. This is further explained in the User Manual.

8.2 Project functionality

The Project functionality is a key analytical tool within the Cost Model. It enables users to cost systems of Assemblies which can be compared under different scenarios. In particular it allows for:

- The analysis of Projects of any scale or level of complexity from a single Assembly of a single vector to a multiple range of Assemblies across different vectors
- The creation of Projects that involve a transition over time such as the repurposing of gas to hydrogen over a 20 year period, or the inclusion of a transformative technology mid-way through the analysis period
- The modification of future cost trends so as to take into account the user's view of market factors both at a Project wide scale and individually for differing technologies as encapsulated by Components. These modifications can reflect general economic assumptions (such as labour rates / skills shortages) and technology specific assumptions such as the impacts of technology maturity and rates of deployment.

The details of how Projects are created within the model are provided in the User Manual. Key aspects of their structure and use are provided below.

8.2.1 Project cost calculation

Cost build up from Components and Assemblies

The calculation of Project costs uses the maximum and minimum capital cost of all Components to determine upper and lower bounds of total Project cost over the Project life. Project baseline cost is determined using rate modifiers, described in Section 7.3.3 and as outlined schematically in Figure 8—2, applying a simplified triangular Monte Carlo simulation model using the maximum, minimum and most likely cost values and allowing the user to interrogate cost probabilities based on Component cost variability.

A Project can specify quantities of Assemblies at different operational stages, that is new build, refurbished, repurposed or abandoned, each to be added at a specific period. Costs of each operational stage are built up for each Assembly and then for the Project as a whole based on:

- Capital costs
- Lifecycle costs
- Operating costs

The build-up of each of these cost profiles at the Component and Assembly level is described in Chapter 7. The user has the option to define each of the rate modifiers at the Project level or for individual Assemblies. The Project contains cost profile information for each Assembly covering each year of the defined lifecycle period.

Operating costs over this period will vary as the asset ages in line with the operating cost profile assigned to the Assembly and the major and minor replacements scheduled in the assembly lifecycle plan. For new build Assemblies there is no existing asset to be replaced, repurposed or abandoned, however for other Assembly options the operating costs presented are the net cost after an existing Assembly has been removed. The impact of this is the removal of the annual operating costs associated with the existing Assembly that is being refurbished, repurposed or abandoned.

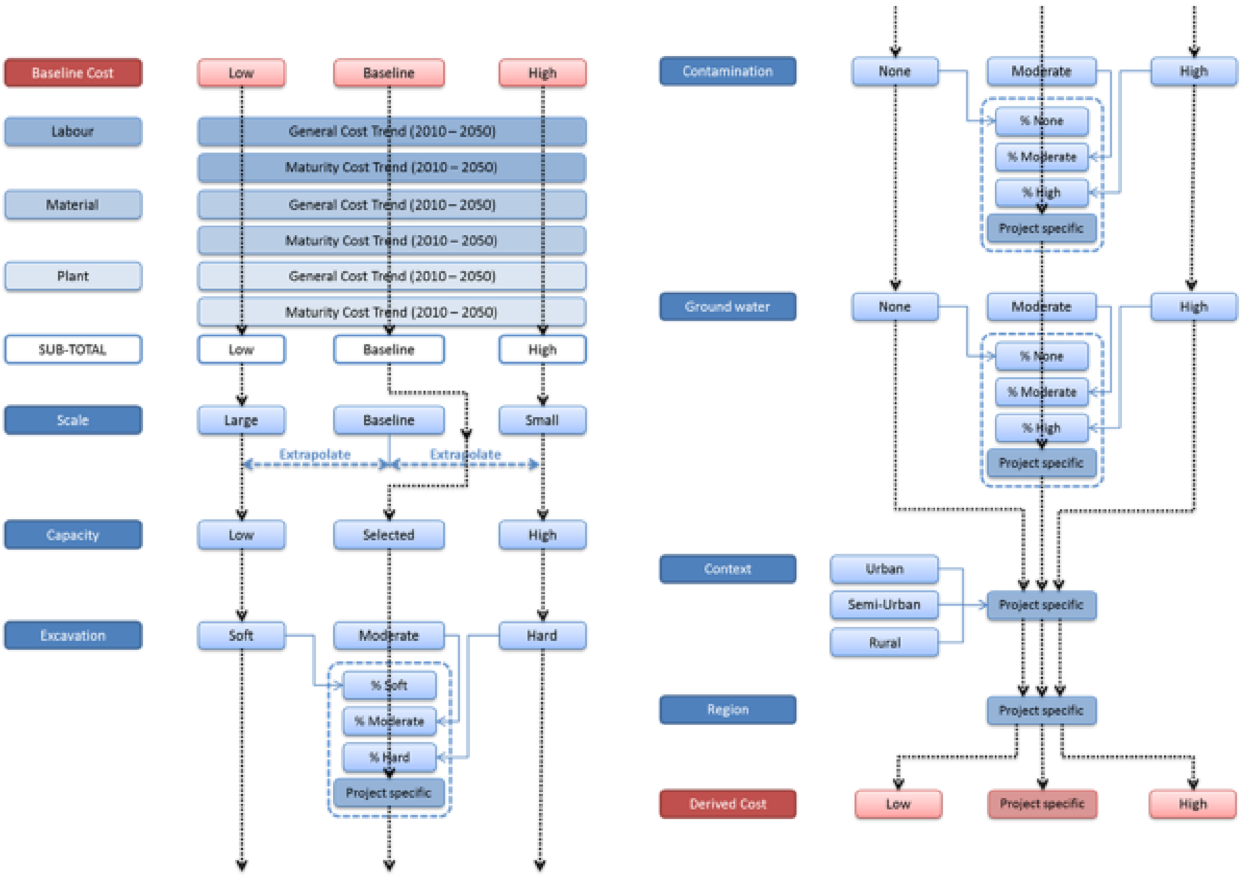


Figure 8—2: schematic to illustrate application of Rate Modifiers to Projects

Project Level costs and adjustments

There are a number of costs that are applied directly at Project level. These include project management, preliminaries, contractor overheads and profit, and contingencies. These are added as a percentage mark-up applied to the capital and lifecycle costs incurred in each year of the project once the project Assembly costs have been calculated.

It is also possible to modify costs specifically for the Project. Key adjustments include:

- Cost trends: labour / materials / plant. For each a high, baseline or low rate increase can be selected.
- Ground conditions: excavation difficulty, ground contamination and ground water. For each factor, a percentage can be specified to reflect the proportion of ground conditions expected to be encountered on the Project.

- Optimism bias: There is a demonstrated, systematic, tendency for project appraisers to be overly optimistic. The HM Treasury Green Book[25] advises that, to address this tendency, "appraisers should make explicit, empirically based adjustments to the estimates of a project's costs, benefits, and duration". The Infrastructure Cost Model includes the facility for users to apply Optimism bias factors following HM Treasury Green Book guidance. The model includes a default upper and lower bound however this can be adjusted by the user if required.

8.2.2 Project Dashboard

The Project Dashboard presents total Project costs over the specified project life by vector and by cost type (capital and operational) (Figure 8—3) and displays these graphically as a cumulative cash flow (Figure 8—4).

A breakdown of the top five Assemblies and Components in terms of their percentage of total cost is provided to give a view on which aspects of the Project might be deemed critical and potential targets for innovation.

A Net Present Value (NPV) calculation is also calculated. NPV is a useful tool to provide comparative costs to enable comparison of two different projects bringing them back to the same year. Effectively this provides a discounted life cycle cost and will always be negative as there are no revenues. The discount rate set in the model is 3.5% however this can be changed by the user as required (Figure 8—3).

25 https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

Figure 8—3: Screen shot of Project Dashboard - top section

Figure 8—4: Screen shot of Project Dashboard - bottom section

8.3 Examples of uses

There are a number of ways in which the model can support analysis and decision making in respect of energy projects and strategy. Table 8-1 outlines a variety of potential scenarios along with an explanation of how the cost model can be used. Limitations in each case are also discussed. Note that for all these, the data can be exported directly from the model (capital and operational costs on an annual basis) for analysis in other models and tools.

Table 8-1: Examples of scenarios which could be informed by the model

	Scenario / objective	Model capability	Limitations / factors to consider
1	To compare the cost of implementing a new hydrogen system vs repurposing of existing gas system over any period up to 2050	Two separate Projects need to be input by the user developed based on a 'bill of quantities' for each system. The detail attached to each BoQ should include the dates of the addition or repurposing, and provide any relevant context regarding locality, ground conditions etc. The user can adjust cost rate modifiers as required to match system design assumptions and views of cost trends for each vector. The model will provide cost out turns for each Project which can be compared.	Given that the system is designed outside the model, the results should be straightforward to achieve. There could be issues over the availability of all Assemblies included in the relevant system designs. Either the 'next best' can be selected or new Components and Assemblies can be added. The model will not give any information on relative system efficiency as this is provided separately in the Technical Scoping Tables (see Section 3.3.2).
2	To compare the cost of implementing a new electrical network to support a certain level of demand vs a gas network or heat network to support the same demand	As above, separate Projects can be input to the model based on appropriate BoQs for the system design for each vector.	As above, the results should be straightforward to achieve. Note that the Project functionality does not allow for capital costing only and is set up to provide whole life costs for the specified project period. However data can be readily extracted for analysis elsewhere.
3	To compare the ratio of opex vs capex for an electrical network, a gas network and a hydrogen network for supporting a certain level of demand for a particular region within the UK	As above, separate Projects can be input to the model based on appropriate BoQs for the system design for each vector. Opex and capex are presented separately on the Project dashboard and can be extracted for analysis elsewhere.	The relevant ratio would have to be calculated outside the model. The model will not give any information on relative system efficiency as this is provided separately in the Technical Scoping Tables (see Section 3.3.2).
4	To explore the transitional cost differences of developing an electrical network over a period of 30 years based on small capacity increments vs large scale deployment at strategic intervals	The model allows for input of different Assemblies at different time periods over any period up to 150 years. Thus it can accommodate alternative assumptions regarding the time and scale of deployment. Again, it relies upon the development of suitable BoQs and the relevant time of their deployment. In this case, two separate Projects would be input by the user and the two sets of results compared.	Given that the system is designed outside the model, the results should be straightforward to achieve. There could be issues over the availability of all Assemblies included in the relevant system designs. Either the 'next best' can be selected or new Components and Assemblies can be added. The model will not give any information on relative system efficiency as this is provided separately in the Technical Scoping Tables (see Section 3.3.2).

	Scenario / objective	Model capability	Limitations / factors to consider
5	To examine the cost of decommissioning the UK gas network between now and 2050 and determining the optimum cost path to do this.	The user would need to input the quantities of the existing gas assets into a Project. For each Assembly, a start date before the Project start would need to be specified to reflect the age of the asset. The model will then calculate refurbishment and abandonment costs according to the life cycle profile adopted for that Assembly. A bespoke life cycle profile could be added if required.	The model cannot determine an 'optimum' cost pathway as it is not constructed as an optimisation tool in this sense. The user would have to experiment with alternative pathways and compare costs by inputting a new Project for each individually.
6	To explore how the losses of a network determine its feasibility on a regional basis in supporting certain supply and demand infrastructures – do this analysis across different vectors.	Not possible within the model as losses are provided separately as percentages of annual energy flow within the Technical Scoping Tables and would require a better understanding of network configuration and energy flows through the network. A detailed system analysis is required.	Losses are provided as percentages in the Technical Scope Tables attached to the model (see Section 3.3.2).

9 Research opportunities

9.1 Methodology

A key aspect of the project was the identification of potential research opportunities within each energy vector that may be of interest to ETI and its members. This was undertaken progressively throughout the project and sought to combine external research with quantitative outputs from the cost model. Figure 9—1 outlines the overall approach.

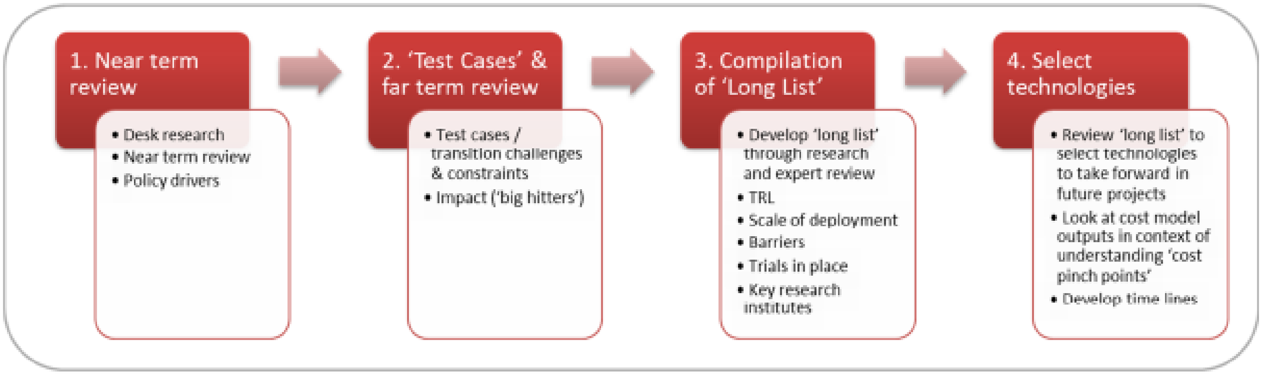


Figure 9—1: outline of approach to developing research opportunities

As described in Chapter 5, a review of near term developments for each vector was undertaken to understand the main drivers affecting infrastructure technology innovation and where research activities were taking place.

To help develop a long term view, three scenarios or 'test cases' out to 2050 were developed as described in Chapter 6. These test cases were framed in order to push the boundaries of particular solutions emphasising one or other vector to help identify key areas of energy infrastructure research and development that may be needed to ensure the transition described could occur successfully, with minimal capital and operational cost, and maximum efficiency.

This process led to the development of a 'long list' of technology innovations across the different vectors and infrastructure types.

In order to shortlist research opportunities from this 'long list', both a qualitative and quantitative approach was taken. The qualitative analysis involved categorising each opportunity according to potential value of benefits and the extent to which these benefits might be captured by the ETI, while the quantitative analysis involved exploring the outputs of the cost model to determine possible cost 'pinch points' that might indicate infrastructure areas that could benefit from innovation.

The sections that follow summarise the outputs of the work undertaken and present the opportunities identified.

9.2 Research opportunities – the 'long list'

Building on the near and far term reviews, a 'long list' of areas of innovation was developed. This involved seeking expert opinion, reviewing published research outputs and consulting with industry. A workshop was held as part of this work in order to also garner the opinion of members of the ETI. Having identified potential areas, evidence was sought regarding the innovation benefits, current Technology Readiness Level[26] (TRL), possible barriers to delivery, potential scale of deployment, any technology trials in place and primary research centres.

The output of the scanning exercise is summarised in Table 9-1 below with details of each innovation and all supporting references available in Appendix I. The technologies are listed per vector and allocated to an infrastructure type (ie. transmission, distribution etc.) where possible. In many cases, the innovation will impact upon multiple types, and in some cases will impact upon more than one vector (eg. pipe line monitoring technologies).

Table 9-1: summary of 'long list' of technology innovations for each vector

Vector	Infrastructure type	Opportunity reference and name	Description **[references in brackets can be found the relevant section of the Appendix I]**
ELECTRICITY	Multiple / combined	E1 Cable Insulation	There is significant technological development into new composite insulation systems using nano-metric scale fillers to design dielectrics with enhanced properties [3]. Although much of this (reported) activity is open t question, there is the possibility of insulators with improved thermal, electrical and mechanical properties being developed in the future. The primary advantage is most likely to be a capability to operate cables at higher temperatures of the core conductor. Possibly future cables may be developed whose thermal rating will not be the limiting factor of any given circuit. There is a need to develop new insulation systems to replace existing (high carbon/greenhouse gas) technology; in particular the replacement of mineral oil and SF6 [1] as dielectrics. There is a lot of work worldwide in this area however, to date no-one has found a straight replacement for SF6 and many of the candidate oils [2] under consideration solidify at (relatively) high temperatures (i.e are not suitable for use during extremely cold winters).
	Multiple / combined	E2 High Temperature Superconducting (HTS) cable technology	The need to transmit increased levels of power into densely populated areas may make the development of HTS cable technology more attractive; again worldwide there are several trials on-going. This technology could also be applied in substation plant, such as for increased power densities and smaller footprint transformers say [1]. However, there is little European investment in research in this area and the US recently significantly cut its R & D funding for HTS power apparatus. There is strong activity in Korea, Japan and China.
	Multiple / combined	E3 Power Electronics	Power Electronics could help to increase power density. An example could be an all Power Electronics transformer. This is getting some attention (EPSRC Power Networks Grand Challenge) [1]
	Transmission	E4 Ultra High Voltage (UHV) DC cable technology	In terms of offshore transmission UHV DC cable technology will receive increasing attention as it could reduce overall installation cost (less Cables required per tens of GW). This is also being addressed in the EPSRC Power Networks Grand Challenge (Design of the 5 GW cable) [1].

[26] Technology Readiness Level is a measure used to assess the maturity of evolving technologies. For the purposes of this study, the NASA TRL definitions were used: http://esto.nasa.gov/files/trl_definitions.pdf See Appendix J.

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
	Conversion	E5 Alternatives to Si technology	Network operators' attitude to transmission and distribution losses would significantly change if they were penalized for excessive loss (e.g in the same way that Water Companies are fined for leaks). Biggest losses are probably associated with power convertor stations and consequently there is a need to develop power switches that are not based on Si technology. Currently Silicon Carbide is receiving considerable attention; this technology may reduce switching loss by 10-15% [1].
	Multiple / combined	E6 Replacement XPLE technology	There are various drivers towards the development of new solid dielectric materials that are environmentally friendly, recyclable at end of life. For example, the Dutch TSO has publicly stated that its policy will be to employ non XLPE technology in all future cable circuits [1]. Product examples include Prysmian Cables p-laser products (Polypropylene replacement for XLPE). This innovation also relates to the cable insulation issue described in opportunity E1.
	Multiple / combined	E7 Condition monitoring	In the future there will be greater need to accurately know the health and likely future performance of transmission assets due to the impact of HVDC and (possibly) the Smart grid. Most technological development is focused on data analysis and interpretation as the various forms of sensing technology have become fairly well established [1]. Long offshore cables present particular challenges. Anything longer than 160 km will be very difficult to monitor continuously. There will be a need to develop technology capable of ensuring any incipient fault is quickly identified and located. Potential impact on operational security of supply could be significant if it takes substantial time to effect a repair (see for example recent history of the Moyle interconnector). In the case of HVDC cables, at present in UK waters there are now 2 circuits with faults where current technology has proven ineffective in providing accurate details re location (The Moyle Interconnector and the Jersey-France Interconnector) in both cases outages have lasted weeks/months. This is evidence that there is a clear business need for monitoring technology (probably centred on optical fibres) that can be incorporated into either the cable design itself or installed in the cable trench at the same time as the bipole which will allow continuous monitoring of HVDC cable health. Temperature monitoring is currently possible over the first 50-80km of a subsea cable, but with planned circuits such as western link being in excess of 450 km there is no technology capable of providing on-line monitoring of a substantial proportion of the circuit. TRL1 and 2 research has shown that fibres can be designed and used either in a sacrificial mode (to indicate damage by anchors or trawling activities) or to produce measurements of magnetic field, acoustic noise or temperature with positional accuracies of the order of 10s of meters, development of this technology would find wide application in interconnectors as well as round 3 offshore windfarm export cable circuits. Analysis of on-line measurements would also give indication of the development of incipient faults, which in turn could be rectified during planned outages without reaching the point of cable failure.
	Distribution	E8 Virtual Power Networks	In principle, a Virtual Power Plant consists of a portfolio of aggregated distributed energy resources that can be remotely monitored and operationally controlled just like a conventional large-scale power plant, owing to the application of advanced information and communications technology. Benefits would include system optimisation; integrating many smaller and intermittent generating sources into existing grid infrastructure. The approach could also help in balancing the grid and with developing utility scale power from renewable sources ie. bundling renewable energy so it can

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
			be sold on a more competitive basis on existing power markets.
	Storage	E9 Cryogenic Liquid Air Storage	Cryogenic liquid air storage (special case of CAES – see E15 below) is the conversion of air / nitrogen into a liquid and then reheating it to drive a turbo expander. Potentially cost effective, scalable and compact energy storage developed using proven technology.
	Multiple / combined	E10 Static synchronous compensator (STATCOM)	STATCOM is a power electronics voltage-source converter used to control power factor and voltage on AC transmission systems. They can act as either a source or sink of reactive AC power. Benefits include being more compact and having a faster response time than alternatives.
	Distribution	E11 Active network management	More of an overarching concept than a single specific technology. The integration of multiple smaller generators along with 'negative' sources of generation implies bi-directional power flows and the need to manage fluctuating levels of power quality. An active distribution network would include: more sensors, shorter sampling periods, state estimation, active control systems and flexible protection settings.
	Distribution	E12 Communication and control	Active network management and other smart grid applications imply use of extensive communications and control systems at distribution level. As a minimum a SCADA type system would be expected. However, such systems are expensive and do not provide real time control. Other technologies for embedding communication and control into the low and medium voltage parts of the distribution networks are emerging. There is a tension between two possible approaches to distribution automation: distributed intelligence versus central control. Switchgear manufacturers tend to favour embedded intelligence at device level. The alternative is a distribution system operator actively managing voltage, frequency etc. Manufacturers of metering systems tend to favour the latter approach.
	Conversion	E13 SF6 insulation gas replacement	There is an on-going search for a replacement of SF6 (a potent greenhouse gas with corrosive by-products), with an extensive body of research going back to the mid-1970s. ABB and EPRI have both conducted detailed studies. Outcomes of academic research include an experimental power circuit breaker fitted with a PTFE shield to confine the arc operated over a range of low background gas pressures. The chemical puffer action resulting from enhanced PTFE ablation showed that arc extinction could be achieved using environmentally friendly background gases such as nitrogen.
	Storage	E14 Li-ion batteries	Storage technologies could help manage intermittent renewable energy. Utility scale battery storage is an option. Common in consumer electronics, rechargeable Li-ion batteries are being developed with a view to supplying the electric vehicle market. However, there is increasing interest in developing them for grid scale use.
	Storage	E15 Compressed Air Energy Storage (CAES)	Large scale electricity storage is likely to be required to meet increasingly large scale intermittent generation from renewables. Along with pumped hydro, CAES is one of the few storage solutions available at scale. CAES uses off-peak electricity to compress air and store it in a reservoir, either an underground cavern or aboveground pipes or vessels. When electricity is needed, the compressed air is heated, expanded, and directed through a conventional turbine-generator to produce electricity [1].
	Storage	E16 Flywheels	Flywheels are shorter energy duration systems that are not generally attractive for large-scale grid support applications, which require many kilowatt-hours or megawatt-hours of energy storage. They operate by storing kinetic energy in a spinning rotor made of advanced high strength materials

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
			that is charged and discharged through a generator [1 - p. 4-14]
	Storage	E17 Flow batteries	Redox battery systems can be sized for a wide range of power and duration of energy storage. In flow batteries, energy is stored as charged ions in two separate tanks of electrolytes, one of which stores electrolyte for positive electrode reaction while the other stores electrolyte for negative electrode reaction. Vanadium redox systems are unique in that they use one common electrolyte, which provides potential opportunities for increased cycle life. When electricity is needed, the electrolyte flows to a redox cell with electrodes, and current is generated. The electrochemical reaction can be reversed by applying an overpotential, as with conventional batteries, allowing the system to be repeatedly discharged and recharged [1].
GAS	Transmission	G1 Repurposing for CO_2	Repurposing of fully depreciated gas assets for use in CO2 transport would both mitigate costs of decommissioning these assets and support wider climate change objectives through supporting lower cost deployment of CCS. Actively being pursued by the National Grid [1] through £2.5m R&D programme. Aim is to understand changes to pipeline design and operation that would be needed if switching from transport of natural gas to CO2. National Grid states that it can now "define pipeline operating conditions to ensure pipeline operation is always in the gaseous phase and have a validated method for setting toughness levels to ensure crack arrest in pipelines operating with gaseous phase CO_2 and mixtures based on the detailed shock tube test programme conducted." [1]
	Connections	G2 CNG Vehicle refuelling	Development / roll out of commercial vehicle refuelling stations using CNG. National Grid has highlighted the development of CNG / LNG refuelling Network as one of their innovation aims [4]. Through this project, they aim to review the potential of establishing a national / regional network of fuelling stations open to the public for refuelling with CNG and LNG.
	Distribution	G3 Trenchless technologies	Development of techniques and technologies to enable small-dimensioned trenching and new, mechanised, network installation techniques, for security and for the reduction of disruption, pollution, working time and cost. GERG has identified such technologies as a key are of research within their gas research roadmap [2].
	Multiple / combined	G4 Repurposing for hydrogen	Change of use of existing natural gas pipelines to transport hythane - both transmission and distribution. The replacement of increasing volumes of natural gas with hydrogen is a potential cost effective way of transitioning to a low carbon economy, alternatives being to build whole new infrastructure assets [1]. National Grid Gas has announced a research project to review and demonstrate two aspects in relation to the wider use of hydrogen using existing gas assets [2]. Initially they aim to further develop the NaturalHY [3] project and look into potential to use spare wind farm capacity to produce renewable Hydrogen and distribute as part of a hydrogen-enriched natural gas (HENG) blend to customers. The project will assess the concept feasibility and economic analysis of hydrogen injection (HENG) directly into gas network. Hydrogen enrichment is viewed as a viable option for existing gas customers. However, given the expectation that between 2050 and now most gas users will have replaced their heating appliances 3 to 4 times, NG aim to review the feasibility of 100% Hydrogen distribution and repurposing existing low pressure gas distribution pipeline assets.
	Connections	G5 Shale Gas connection	Connection of shale gas to the Local Transmission System (LTS) There is potential for shale gas to be fed into the NTS or LTS depending on

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
			location of supply [1]. Shale gas connection to LTS has been suggested as an area of future innovation for National Grid Gas [2]. The proposal is described as follows: "This area remains the less developed of all areas we have considered to date. However, we believe that should shale gas production become an acceptable method of gas extract there are maybe considerable benefits to connecting such gas fields into the Local Transmission network. We remain at a very early stage in developing our thinking in this area but believe it would be inappropriate to ignore such potential that may arise over the next decade. We envisage a project to review the operational control, longevity of connection, gas quality and capacity implications of embedded unconventional gas entry points."
	Multiple / combined	G6 Pipeline inspection techniques	Condition monitoring using sophisticated inspection techniques, particularly wireless and nanotechnologies. Condition monitoring - in particular leak detection - is critical for the gas transport industry. There are a number of different techniques in use, Murvay provides a useful overview of state of the art technologies [1] (figure below extracted from that paper). Research spans a number of different disciplines and techniques such as wireless technologies / computing [eg. ref 2 and 3 on wireless sensors/networks] and nanotechnologies [eg ref 4].
	Conversion	G7 Improved venting techniques	Natural gas is vented from compressor stations on the National Grid as part of planned system management techniques. As natural gas is a major contributor to greenhouse gas emissions any improved venting techniques can contribute to climate change mitigation. National Grid Transmission has a research project exploring a range of alternatives including flaring, recompression and gas capture using Absorbed Natural Gas technology [1]. An evaluation has been undertaken if the different techniques has been undertaken with trials and deployment the next steps.
	Storage	G8 Development of gas storage	Development of new and improved storage techniques, particularly underground. "Gas storage is noted as an important aspect of energy security strategies globally but particular in the UK [1]. GERG has noted it as a priority research area as part of its road map [2]: "Research in this area requires a necessarily multifaceted approach, which considers geological studies, surface technologies, economics, safety and environmental protection, in particular: • development of micro-storage in thin salt domes; • adaptation of gas or oil depleted fields or coalmines for gas storage; • a new concept for LNG storage in large quantities in mining cavities.
	Multiple / combined	G9 Mains replacement with PE	Mains replacement - steel replacement with PE particularly at larger pipe sizes. Historically gas pipelines have been metallic systems. These are now aging and being replaced by polyethylene (PE) materials, with good performance particularly at the smaller diameters. New advanced plastic materials are now being developed, such as PE4710, with step-change improvements in material properties, and large diameter implications [1]. In 2009 in the US only 10% of new distribution gas pipelines were over 6" [2].
	Distribution	G10 Pipe handling techniques	With increasing use of PE pipes, there is potential to improve pipe handling techniques for example developing larger pipe trailers that can take longer lengths of pipe to reduce wastage. More efficient pipe handling can also reduce time taken to undertake works thereby reducing cost and disruption in the highways.

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
	Conversion	G11 Turbo expanders energy generation	Considerable energy is wasted as pressure is reduced along the gas network. The use of turbo expander technology is being applied at pressure reduction installations to harvest this energy through the generation of electricity.
	Storage	G12 Line packing	Existing pipeline capacity can be used for short term storage through use of 'line packing'. Flexibility of supply within the gas network is important. The existing natural gas network has spare capacity which can be used for storage particularly useful for managing within-day variations. The innovation is around flow management and sharing of economic gain rather than technology per se (for economic discussion see MIT paper in ref [1] below).
	Distribution	G13 Advanced robotic techniques	Advanced robotic techniques for inspection and repair of distribution pipelines. These are at an early stage of development but offer potential benefits for condition monitoring.
	Connections	G14 Biogas / Syngas Connection to network	Renewable gas (also referred to as biomethane) is produced mainly via a process of anaerobic digestion (AD) or thermal gasification of biodegradable waste. The ‘raw’ biogas produced through AD is a roughly 60:40 mix of methane and CO2. This biogas can then be upgraded to biomethane to meet the required specification to allow it to be injected into the grid. One of the benefits of renewable gas is that it uses existing infrastructure for delivery and as such can provide a relatively cheap contribution to reducing carbon emissions. Innovation is required around connection technologies at different pressures within the local transmission system (LTS).
HEAT	Distribution	HT1 Plastic pipework systems	The predominant piping system in the District Heating (DH) industry over the last century consists of a steel medium pipe, polyurethane (PU) insulation and a polyethylene (PE) outer casing (abbreviated to St/PU/PE). This system performs very well. However, steel may rust and the insulation properties of PU may suffer under the influence of water. Therefore, joints have to be made with care and require a certain level of workmanship. [1] From this perspective, an all plastic piping system might have some distinctive advantages. Plastics do not corrode (that is, a lot slower than steel). Some plastics are extremely flexible and allow for transportation on reels for rather large diameters, thus reducing the number of joints. Some plastics may even be welded. Further potential but less developed includes use of higher performance / thinner insulation materials such as vacuum insulated panels (VIP).
	Distribution	HT2 Low temperature networks for new and existing buildings	Buildings are being designed to ever higher specifications thereby reducing their heat demand. Heat losses associated with heat networks therefore become increasingly significant. Research is being carried out to establish how the benefits of district heating (eg. utilising waste heat, introducing more renewable heat sources) can be retained when supplying low energy buildings [1],[2]. Supply temperatures for district heating schemes are decreasing; previously steam, then HTHW (120°C), then MTHW (90°C). There are now examples of Low Temperature Hot Water (LTHW) with temperatures down to 55°C. [4]
	Distribution	HT 3 Cold Lay	Laying DHN pipework without pre-stressing or without using expansion devices (bellows, compensators, u-bends). Cold lay is a simple installation method that reduces cost and time. The heating pipework does not need to be pre-stressed prior to installation and does not require expansion devices such as bellows, u-bends etc. A consequence of cold lay is that the pipe endings (that are normally located

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
			within the expansion zone) undergo major displacement during operation.
	Distribution	HT4 Reducing trenching requirements (civils works)	Groundwork can account for over half the cost of installing district heating networks. That means that a lot can be saved by decreasing both the length of the trench and the area of the trench section. The primary areas of research would be; - reduction of pipe dimensions (reduce future capacity and accept higher pumping energy) - reduction of trench area (twin pipes, shallow trenches in areas of low traffic, omit drainage if not required) - reduction of trench length (house-to-house routing via gardens, installation of pipework in colums/ crawl spaces under floors) - choice of digging method (utilise soft areas where possible, minimise tarmac/ hard areas) - pipe installation (use flexible pipes, press fit joints, join pipes above ground to limit working space required, use of smaller digging equipment in gardens or soft areas)
	Connections	HT 5 Compact substations	Use of direct connections and small plate heat exchangers
	Connections	HT 6 Multiple consumers per connection	Traditional DHN connections at buildings provide a single heat exchanger per consumer; therefore requiring multiple heat exchangers with associated space take and cost to serve multiple consumers. By providing multiple connections per heat exchanger both cost and space take can be reduced i.e. more than one consumer can be served from a single heat centre.
	Storage	HT7 Multi-function thermal storage	Larger thermal storage tanks provide an opportunity to combine the storage and pressurisation of district heating networks; they can also offer the opportunity to pressurise the network. An example of this would be larger scale thermal storage tanks, with a significant height (e.g. 10m plus). The tank stores hot water during periods of low heat demand on the network, the volume of water provides expansion for the network and the height of the store creates a natural static head (pressure) for the network.
	Storage	HT 8 Interseasonal storage	Solar energy or excess/ waste heat can be captured during summer months and stored for use during the heating season in Winter months. This is energy that would otherwise be wasted. The strategy can also be used for system balancing. Geological heat storage is already being explored by the ETI.
	Storage	HT 9 Connection level storage	Existing district heating systems generally provide thermal storage at the point of generation e.g. a CHP energy centre serving a district heating network will utilise thermal storage tanks as part of the overall energy centre installation, prior to serving the distribution network. In addition to this central thermal storage, connection level storage could be employed at/ closer to the point of district heat network connection to the buildings.
	Distribution	HT 10 Pipeline configuration	District heating pipework has traditionally involved single insulated pipes for both flow and return. These are laid side by side within the district heating trench. By combining both pipes into a single insulated pipe configuration there are various advantages in efficiency and space take.
	Distribution	HT 11 Network configuration	The majority of heat losses within a typical DH network serving residential properties occur in the final service connection to the dwelling. The length of

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
			the final connections could be limited (hence losses reduced) by running connection pipework through front gardens. This would only require a single service pipe to a group of dwellings, which would then pass through the gardens serving each individual property.
	Distribution	HT 12 Hot working	Hot working allows maintenance and repairs to be carried out whilst the network is operational. The use of hot working also allows new connections into the network to be made without any major downtime to the service.
	Conversion	HT 13 Direct connections	The point of connection between the incoming primary district heating network and the secondary building heating/ hot water circuits generally involves the use of a plate heat exchanger (PHX). The PHX serves two primary functions; firstly to provide a pressure break between the primary and secondary networks and, secondly, to allow a temperature conversion. However, it is possible to have a 'direct connection' between the primary and secondary circuits, with nothing more than a valving/ metering arrangement.
	Distribution	HT 14 District energy sharing	District energy sharing involves moving both heat and cooling between buildings using low temperature networks. This arrangement involves a heat exchanger at each building to enable to transfer of heat from the network to the building heating circuits. Where there are simultaneous demands for heat and cooling within a network of buildings this allows the energy to be delivered to where it is required.
HYDROGEN	Multiple / combined	HY1 Pipeline materials - embrittlement	Pipeline issues are similar to those for natural gas. Embrittlement is a key exception. Embrittlement is the term used to describe the effect of hydrogen on some steels. It is characterized by a loss of ductility of a steel on slow application of strain, and can yield severe cracking of the material. In addition, the material can fracture after some time in use, when subjected to a stress level that is well below the yield strength of the steel. Hydrogen embrittlement is by far the strongest matter of concern in view of hydrogen transport through steel pipelines [1]. It is generally agreed that the effects of hydrogen embrittlement tend to be more pronounced where high-strength materials are employed. [1]
	Multiple / combined	HY2 Pipeline materials – jointing; permeation	Due to the small molecular size of hydrogen, it is more prone to leakage than natural gas, therefore higher quality welding may be required and compression joints will certainly have to be of a higher standard (e.g. using double olives, etc). As a consequence of the above (and embrittlement), monitoring for leakage and fatigue will be important to understand long term performance.
	Connections	HY3 Vehicle refuelling	A number of vehicle refuelling stations exist around the world. Technologies involved include compression and storage. Innovation is around improved performance to reduce costs of delivery. Research into vehicle performance and associated delivery infrastructure is linked (eg see HyFLEET project in Europe [1]).
	Storage	HY4 Storage	Practical, safe and affordable storage for hydrogen is important for development of hydrogen as an energy vector. Today's compressed gas storage systems are adequate for trials and early market development, but need to be refined for a mature product, much as early mobile phones were far less elegant before the quantum leaps in battery technologies allowed today's highly refined versions to evolve. UK research into finding alternative methods of hydrogen storage, such as metal hydrides, nanomaterials and composites, chemical carriers (e.g. ammonia, methanol, borohydrides, etc) is strong, but most are a long way from leaving the laboratory.

Vector	Infrastructure type	Opportunity reference and name	Description [references in brackets can be found the relevant section of the Appendix I]
	Conversion	HY5 Compression	The physical properties of hydrogen, particularly its small molecular size, mean that there are particular challenges for compression. US DoE has identified it as a key area for research in order to improve reliability (and hence reduce the need for system redundancy) as well as performance [1].
	Multiple / combined	HY6 Safety	Hydrogen gas has different properties from methane and different risks attached. As it is non-toxic, the main risk is related to explosion due to build-up of uncontrolled release. Key parameters for comparing hydrogen safety with that of conventional fuels are flammability, detonability, ignition energy, materials compatibility, diffusivity and buoyancy. The flammability range of hydrogen in air covers a much wider range of concentrations than for methane, propane, or gasoline vapour. Furthermore, it can be much more readily ignited under most circumstances. Hydrogen is also detonable over a very wide range of concentrations when confined. The combination of these properties makes hydrogen potentially more hazardous than conventional fuels in confined situations. [1] US has been developing safety guidelines, particularly in relation to fuel cell vehicles [2]. An overview of the status of research into hydrogen safety is provided in ref [3].
	Distribution	G3 Trenchless technologies	Same as for natural gas.
	Multiple / combined	G4 Repurposing for hydrogen	Same as for natural gas.
	Distribution	G9 Mains replacement with PE	Same as for natural gas.
	Storage	G12 Line packing	Same as for natural gas.

9.3 Research opportunities – the shortlist

In order to prioritise opportunities and develop a potential shortlist for further review, both quantitative and qualitative analysis was undertaken.

For the quantitative analysis, illustrative projects for each vector at transmission and distribution level were developed and input to the cost model. This generated a total project cost and within that, those components and assemblies that comprised the largest proportion of the total cost. This work gives some indication of those areas at overall network level that could benefit from innovation in terms of capital cost of improvements. It should be noted that these projects are highly simplified, there being a huge number of variations that could be applied.

To complement the quantitative analysis, a qualitative review was also undertaken. For this aspect of the work, the TRLs and other information relating to each opportunity was used to inform the process of establishing the potential benefit to ETI and the likely timeframe. In establishing a measure of value of the technology, consideration was given to likely impact on networks as well as the drivers for ensuring significant levels of implementation. The primary output of this work is a graph plotting the potential value of the benefit ('size of prize') against the ability of the ETI to capture that benefit.

The output of these two strands of work is summarised below for each vector.

9.3.1 Electricity

Quantitative analysis

The electricity projects used for cost hot spot analysis are summarised Table 9-2 below and are derived from the project data included in Appendix F.

Table 9-2: summary of electricity project details used to explore cost 'hot spots'

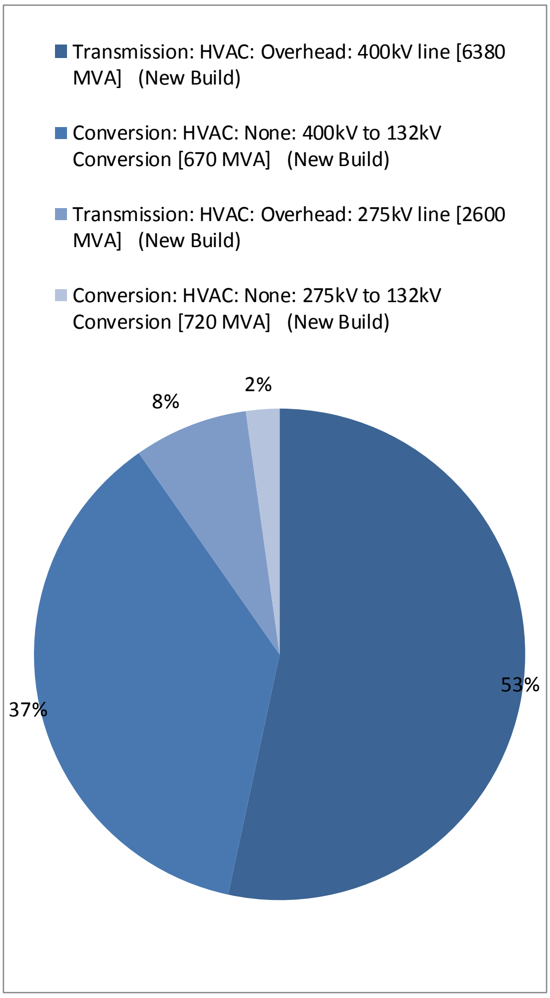
Function	Region	Description
Transmission	East Midlands	Approximately 1,500km of 400kV and 275kV overhead cable; 18 substations; mainly rural; assume all new build; 2015 – 2075; baseline cost trends for labour, material and plant
Distribution	Loughborough	Almost 200km of 11kv and 400kV overhead cable; approx 21,000 connections; mainly urban; assume all new build; 2015 – 2075; baseline cost trends for labour, material and plant

An analysis of key cost elements (assemblies and components) is shown in Figure 9—2 and Table 9-3. The costs include all capital and refurbishment / replacement costs over a 60 year life.

For electricity transmission the major cost lies in the conductors themselves and is dominated by the 400kV overhead line (53% of total cost). The components associated with this are the conductors (25%) and their periodic refurbishment (28%)[27]. The significance of this cost is mostly driven by the assumed deployment scale for the project (1,313km). Looking out to 2050, deployment scale will depend upon a range of factors as discussed in Chapter 6. After the 400kV overhead lines, the next most significant cost is that of the substations which together represent almost 39% of total cost.

At distribution level the overall project costs are dominated by connection costs, with residential building connections comprising 55% of total costs in this example. Overhead lines represent around 24% of total cost.

[27] Note that in this project, default lifecycle profiles have been used whereby new Assemblies are refurbished at specified periods. These costs will increase over time based on the labour, materials and cost trends incorporated in the model. As these periods are 40 years out, the increase is significant thereby increasing the cost of refurbishment relative to new build.



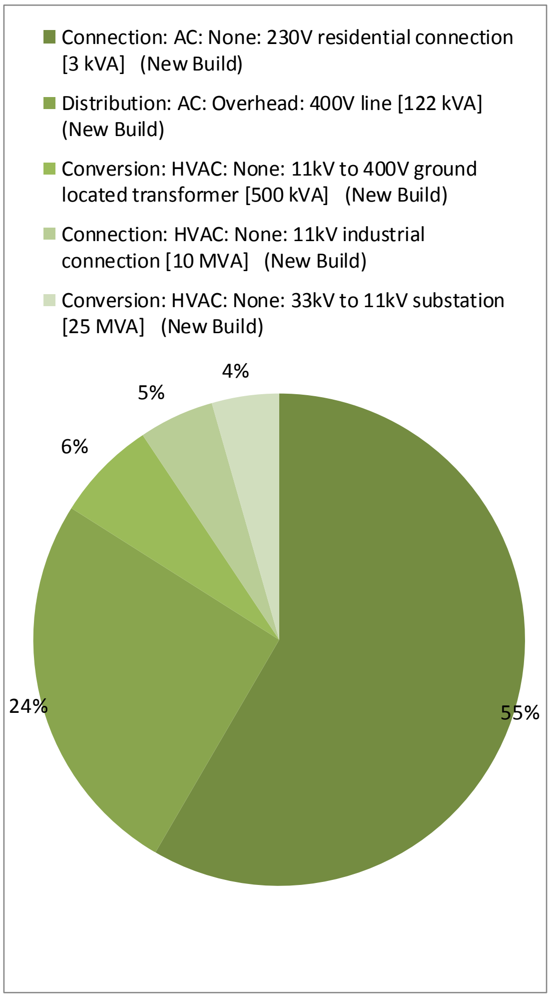


Figure 9—2: top five Assemblies as a proportion of cost: electricity transmission (left) and electricity distribution (right)

Table 9-3: top five Assemblies and Components as a proportion of cost for electricity transmission (top half) and electricity distribution (bottom half); also showing quantity represented

TOP 5 ASSEMBLIES TRANSMISSION		
Assembly	Quantity	% TOTAL
Transmission: HVAC: Overhead: 400kV line [6380 MVA] (New Build)	1,313 km	53%
Conversion: HVAC: None: 400kV to 132kV Conversion [670 MVA] (New Build)	14	37%
Transmission: HVAC: Overhead: 275kV line [2600 MVA] (New Build)	255 km	8%
Conversion: HVAC: None: 275kV to 132kV Conversion [720 MVA] (New Build)	2	2%
TOP 5 COMPONENTS TRANMISSION		
Component	Quantity	% TOTAL
AA12 - Electricity - Overhead - Conductors - Refurbish 400kV HVAC overhead transmission line	1,313 km	28%
AD12 - Electricity - Conversions - On-shore - Refurbish 400kV to 132kV conversion (two circuits)	14	28%
AA11 - Electricity - Overhead - Conductors - New: 400kV HVAC Overhead transmission line	1,313 km	25%
AD11 - Electricity - Conversions - On-shore - New: 400kV to 132kV conversion (two circuits)	14	9%
AA11 - Electricity - Overhead - Conductors - New: 275kV HVAC Overhead transmission line	255 km	4%
TOP 5 ASSEMBLIES DISTRIBUTION		
Assembly	Quantity	% TOTAL
Connection: AC: None: 230V residential connection [3 kVA] (New Build)	20,452	55%
Distribution: AC: Overhead: 400V line [122 kVA] (New Build)	197 km	24%
Conversion: HVAC: None: 11kV to 400V ground located transformer [500 kVA] (New Build)	49	6%
Connection: HVAC: None: 11kV industrial connection [10 MVA] (New Build)	2	5%
Conversion: HVAC: None: 33kV to 11kV substation [25 MVA] (New Build)	1	4%
TOP 5 COMPONENTS DISTRIBUTION		
Component	Quantity	% TOTAL
AE12 - Electricity - Connections - On-shore - Refurbish residential connection	20,452	33%
AE11 - Electricity - Connections - On-shore - New: 230V Residential connection	20,452	22%
AA12 - Electricity - Overhead - Conductors - Refurbish 400V overhead distribution line	197 km	18%
AA11 - Electricity - Overhead - Conductors - New: 400V AC Overhead distribution line	197 km	6%
AD12 - Electricity - Conversions - On-shore - Refurbish 11kV to 400V ground mounted transformer	49	4%

Qualitative review

Over the last dozen years, there has been significant investment in research and development by the transmission system and distribution network operators. Initially through Ofgem's Innovation Funding Initiative (IFI) which provided funding for projects primarily focused on the technical development of the networks to deliver value to consumers and, more recently, through the Low Carbon Networks (LCN) fund which will run until March 2015.

As noted above, Ofgem has recently implemented a new regulatory framework known as RIIO. This includes a network innovation competition (TRL7/8 projects) and replaces the IFI with a Network Innovation Allowance (NIA). As such the industry is driving a continual process of research and innovation which in many cases is world leading (examples include Scottish and Southern Energy's Orkney Smart Grid project[28]). These mechanisms have ensured that many research opportunities are being actively supported by the industry and also that there is a clear route to the development of electrical plant and supporting infrastructure over the regulatory review period.

For the qualitative review, each innovation was categorised as low/medium or high in terms of potential value and in terms of the ability of ETI to capture this value as shown in Table 9-4.

In performing this review with the need to identify clear benefit for the ETI, it became clear that in the case of electrical networks there has been significant investment in infrastructure development by the electrical industry driven by Ofgem's regulatory review process as noted above. In many cases there are examples of on-going demonstrator projects. Where this is not the case, the TRL level of current activity is fairly low (e.g. 1-3) and consequently it is not straightforward to quantify future benefit to ETI.

Table 9-4: commentary on value of electricity innovations to ETI

Category	Technology	Potential value	Ability of ETI to capture benefits	TRL	Timeframe
Green Technology	E6 Replacement XPLE technology	Medium/Low at the moment but could be high if operators have to manage the whole life cycle of plant	Medium – some products already in the market place. Existing patents cover certain materials and their potential use as electrical insulation.	7	<5 years
	E13 - SF6 replacement	Low/Medium - current research focussed on alternatives that have reduced environmental impact but no commercial interest in replacing SF6	Low/Medium – difficult to see benefits as need changes in regulation to force moves away from SF6 and many candidates have already been effectively identified and tested.	4	<8 years
Control and Communications	E8 Virtual Power Networks	Medium – potentially significant as penetration of smaller scale renewable energy generation increases in the UK and worldwide.	Medium – systems under development	7	<5 years
	E10 Static synchronous compensator	Medium – will become an important Component in future networks , with the loss of conventional spinning reserve, increase in cable circuits and intermittent generation	Low – already being implemented	9	now

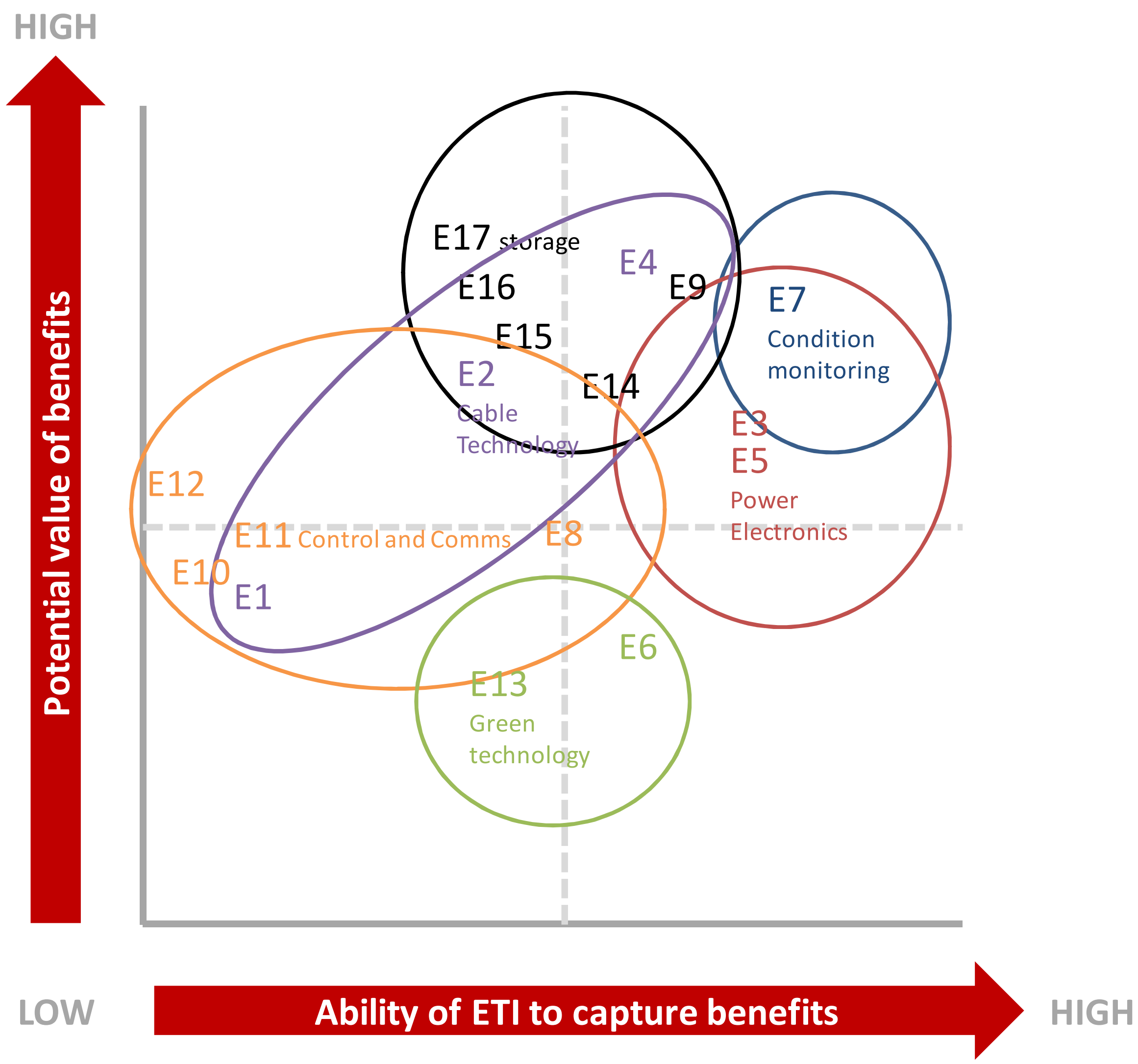
[28] See http://www.ssepd.co.uk/OrkneySmartGrid/ProjectInformation/

Category	Technology	Potential value	Ability of ETI to capture benefits	TRL	Timeframe
	E11 Active Network Management	Medium – difficult to implement on national scales – very good for islanded systems	Low – systems already developed and being demonstrated	7	<5 years
	E12 Communication and control	Medium – High risks in terms of widespread implementation, issues with system security	Low – significant investment already in this area although no reported results from demonstration at time of writing	8	<5 years
Cable Technology	E1 Cable Insulation	Medium – candidates to replace mineral oil have been identified but do not compete in terms of performance either over a wide temperature range or cost	Low – raw material suppliers already hold a range of patents limiting commercial exploitation. Inertia in industry to move away from proven insulation technologies	6	<10 years
	E2 HTS cable technology	Medium/High – potential to provide effective method to transmit high levels of power into dense urban environments	Medium – this technology has promised much and despite significant investment and a few demonstration Projects worldwide has yet to deliver. Really need to develop HTS materials that can operate at higher temperatures.	4	>10 years
	E4 UHV DC cable technology	High – seen as solution to problems associated with additional OHL circuits on land	Medium/High – development of next generation subsea cable technology offers many advantages to operators and consumers but not necessarily cable manufacturers – so requires external drivers if to be realised but offers significant rewards.	5	>10 years
Storage	E9 Cryogenic Liquid Air Storage	High – use of cryogenics but fairly proven technology could find wide application	Medium/High – yet to be demonstrated although attracting some interest	6	<8 years
	E14 Li-ion batteries	Medium/High - fairly proven technology could find wide application - but issues with loss of charging efficiency over time	Medium – some commercial exploitation already	7	<5 years
	E15 CAES	Medium/High – second best solution (after pumped storage) for electricity storage on a large scale.	Medium – demonstrator plants already exist	8	now
	E16 Flywheels	High – potential to deal with peak demand and issues relating to intermittent generation from renewables	Medium – need to reasonable cost solutions to ensure widespread application. Several technological challenges need to be addressed (e.g. failsafe operation?)	6	>10 years
	E17 Flow batteries	High – offers electricity storage at distribution level	Medium – technology fairly well developed some demonstrators planned	7	<5 years
Power Electroni cs	E3 Power Electronics	Medium – greater use of power electronics in networks inevitable	Medium/High – significant international development in this area (BIS have announced a £250M programme)	3	>10 but could be sooner due to levels of

Category	Technology	Potential value	Ability of ETI to capture benefits	TRL	Timeframe
					investment
	E5 Alternatives to Si technology	Medium – improving power electronic device efficiency will increase range of potential applications in networks.	Medium/High – same as E3	3	Same as E3
Condition Monitoring	E7 Condition monitoring	High – changing nature of networks will need greater levels of condition monitoring and integration	High – from a systems viewpoint (eg prognostic monitoring of whole circuits. High – from a new technology viewpoint (eg need to develop condition monitoring strategies for long HVDC cables). Low – from a viewpoint of individual plant diagnostics as market already full of 'solutions'	3	>10 years

A visual representation of Table 9-4 is shown in Figure 9—3. Here the opportunities have been plotted graphically such that those in the top right hand corner represent those with the largest potential value of benefits that could be captured by ETI.

In developing the analysis summarised in the Table 9-4 it became clear that there are interdependencies, eg. improved efficiency of power electronic devices and development of next generation HVDC cable systems are both required for wider application of HVDC transmission / interconnection. Hence the identified technologies have been grouped into broader subject areas and these areas also defined in terms of their potential value and ability of ETI to capture benefits. Therefore Figure 9—3 is a summary of both individual technologies and broader disciplines on the same graph.



E1	Cable Insulation	E10	Static synchronous compensator
E2	HTS cable technology	E11	Active network management
E3	Power Electronics	E12	Communication and control
E4	UHV DC cable technology	E13	SF6 insulation gas replacement
E5	Alternatives to Si technology	E14	Li-ion batteries
E6	Replacement XPLE technology	E15	CAES
E7	Condition monitoring	E16	Flywheels
E8	Virtual Power Networks	E17	Flow batteries
E9	Cryogenic Liquid Air Storage		

Figure 9—3: comparison of the potential value of the benefits of innovation with ability of ETI to capture those benefits: electricity

Research priorities

In identifying key areas, consideration was primarily given to identifying current activity at TRL1 and TRL2 that may lead to opportunities for ETI. Considering those innovations in the top right hand corner of Figure 9—3, three priority areas are discussed below.

Power Electronics

The future development of power electronic technology is strongly linked to the concepts of a super-grid and future smart-grid. At current transmission levels (and beyond) the need for efficient AC/DC and DC/AC conversion is of paramount importance if there are to be point to point HVDC connections over increasing distances (e.g. Iceland/Scotland). If the concept behind a subsea HVDC transmission network connecting round 3 wind farms to the UK and elsewhere, then there is need for the development of HVDC breaker technology.

In terms of distribution levels and Smart-grid applications there is a need to develop interconnection points that allow (say) DC energy storage (batteries, fuel cells) within the existing AC network. Further, future compensation and protection equipment are likely to use increasing levels of power electronic technology. Consequently, a key research area is the development of next generation higher efficiency power electronic devices as well as development of topologies for a range of applications including solid state transformers. This has been recognised by both the EPSRC in terms of the electrical power network grand challenge and TSB which has identified power electronics as a key area for future business development.

Condition Monitoring

Recent work by the EPSRC HubNet consortium has identified that the need to develop condition monitoring (CM) within existing networks and new plant is also a requirement for future electrical networks. Key areas for consideration have been identified and are summarized in two specific areas: Firstly at the individual plant level there needs to be increased levels of CM deployment among secondary, auxiliary and lower value primary assets, CM strategies for some existing plant need to be improved and new plant (eg HVDC cables including for fault location) need to have integrated CM in order to learn normal behaviour prior to the onset of any degradation activity. Secondly, there are network level CM requirements including improved circumstance monitoring of the working environment, improving operational real-time assessment of network condition (e.g. CM data combined with dynamic rating information) and making full use of smart meter data to assess the condition of 'the last mile' of distribution circuits.

Storage

With regard to energy storage, cryogenic liquid air storage and flywheels could be applied at transmission level, whereas battery technologies etc. are more suited for lower voltage level applications and there are already demonstration projects using compressed air storage. The growing number of offshore wind farm connections (c 500 MW each) will increase the need for transmission level energy storage to provide short term load smoothing, which could be provided using flywheel technology. Whereas cryogenic liquid air storage offers the ability to store significant quantities of energy at reasonable efficiencies if sited near to a source of low grade heat (eg. conventional power stations). This storage could also be used to provide load smoothing, or to reduce constraint costs within the transmission network or allow time for additional generation to come on line in the event of significant periods of low renewable generation.

9.3.2 Gas

Quantitative analysis

The gas projects used for cost hot spot analysis are summarised in Table 9-5 below. They are derived from the project data included in Appendix F.

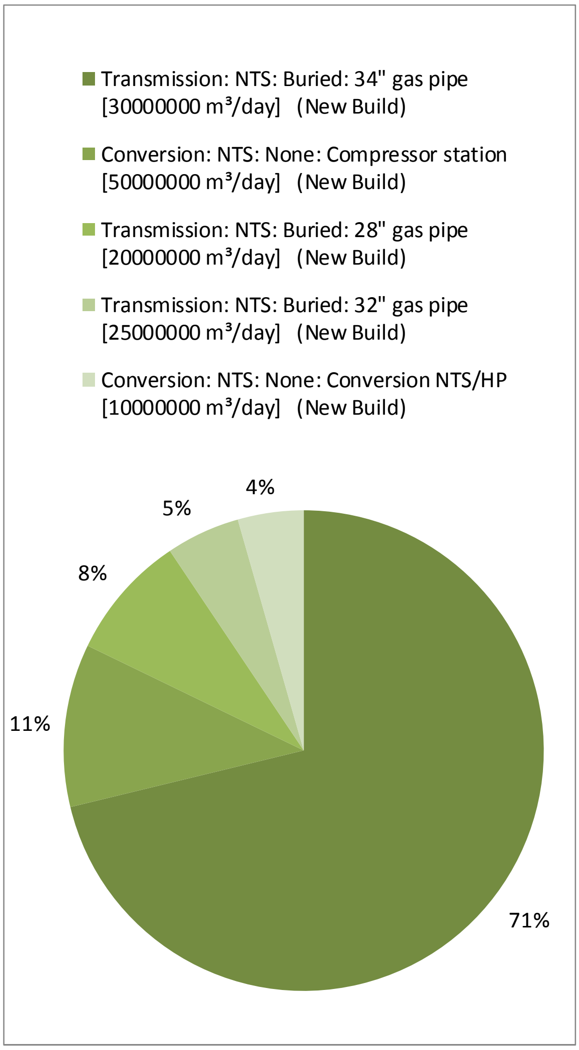
Table 9-5: summary of project details used to explore cost 'hot spots'

Function	Region	Description
Transmission	East Midlands	Almost 750km of pipe work plus LTS off takes and 2 compressor stations; mainly rural; assume all new build; 2015 – 2075; baseline cost trends for labour, material and plant
Distribution	Loughborough	Around 230km pipe work (MP and LP); district governors; industrial, commercial and residential connections; urban; assume all new build; 2015 - 2075; baseline cost trends for labour, material and plant

An analysis of key cost elements (assemblies and components) is shown in Figure 9—4 and Table 9-6. The costs include all capital and refurbishment / replacement costs over a 60 year life.

For gas transmission the major cost lies in pipe lines (96% across the different pipe diameters). This cost includes both new build (pipes and civils) and periodic refurbishment (lifting out and replacing pipes). The refurbishment is the most costly aspect in this simplified case where the lifecycle of pipework is 40 years and costs increase over that period based on the cost trends for labour, material and plant in the database (see Section 7.5).

At distribution level, again pipe lines dominate based on a combination of refurbishment costs and installation civils of new build. Residential connection costs (20,452 in number) are only 6% of total project costs.



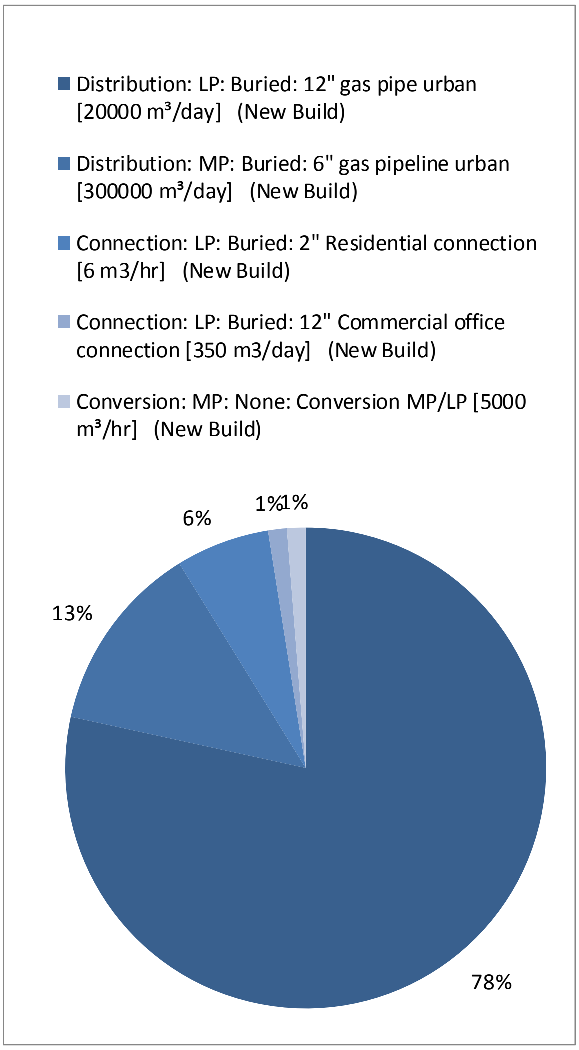


Figure 9—4: top five Assemblies as a proportion of cost: gas transmission (left) and gas distribution (right)

Table 9-6: top five Assemblies and Components as a proportion of cost for gas transmission (top half) and gas distribution (bottom half); also showing quantity represented

TOP 5 ASSEMBLIES TRANSMISSION		
Assembly	Quantity	% TOTAL
Transmission: NTS: Buried: 34" gas pipe [30000000 m³/day] (New Build)	634 km	71%
Conversion: NTS: None: Compressor station [50000000 m³/day] (New Build)	2	11%
Transmission: NTS: Buried: 28" gas pipe [20000000 m³/day] (New Build)	72 km	8%
Transmission: NTS: Buried: 32" gas pipe [25000000 m³/day] (New Build)	37 km	5%
Conversion: NTS: None: Conversion NTS/HP [10000000 m³/day] (New Build)	11	4%
TOP 5 COMPONENTS TRANMISSION		
Component	Quantity	% TOTAL
BA12 - Natural Gas - Buried and tunnelled - Pipelines - Refurbish 34" NTS pipeline	634 km	34%
BA32 - Natural Gas - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 34" NTS Gas pipeline ground works	634 km	13%
BA11 - Natural Gas - Buried and tunnelled - Pipelines - New: 34" NTS gas pipeline	634 km	9%
BB2 - Natural Gas - Above ground installations - Refurbish NTS Compressor Station	2	8%
BA31 - Natural Gas - Buried and tunnelled - Installation civils - New: 34" NTS River crossing	634 km	7%
TOP 5 ASSEMBLIES DISTRIBUTION		
Assembly	Quantity	% TOTAL
Distribution: LP: Buried: 12" gas pipe urban [20000 m³/day] (New Build)	197 km	78%
Distribution: MP: Buried: 6" gas pipeline urban [300000 m³/day] (New Build)	32 km	13%
Connection: LP: Buried: 2" Residential connection [6 m3/hr] (New Build)	20,452	6%
Connection: LP: Buried: 12" Commercial office connection [350 m3/day] (New Build)	407	1%
Conversion: MP: None: Conversion MP/LP [5000 m³/hr] (New Build)	10	1%
TOP 5 COMPONENTS DISTRIBUTION		
Component	Quantity	% TOTAL
BA32 - Natural Gas - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 12" LP Gas pipeline ground works	197 km	47%
BA31 - Natural Gas - Buried and tunnelled - Installation civils - New: 12" LP gas pipeline ground works	197 km	15%
BA22 - Natural Gas - Buried and tunnelled - Pipeline sundries - Refurb, Repurpose and Abandon: Remove and replace 12" LP valve and civils	197 km	9%
BA32 - Natural Gas - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 6" MP Gas pipeline ground works	32 km	9%
BD2 - Natural Gas - Connections - Refurb, Repurpose and Abandon: Refurbish 1" Residential connection	20,452	5%

Qualitative review

As outlined in the near term review, at transmission level, drivers for change relate primarily to the source of gas (ie increasingly from outside the UK, but potentially from shale gas within the UK) and the increased flexibility that is likely to be required by gas fired electricity generators as more wind is introduced to the system.

Infrastructure developments to 2021 are currently being planned by National Grid (transmission and distribution) and other distribution companies as part of their Price Control Review. As for electricity, the distribution PCR has recently been restructured to take more account of innovation and sustainability.

At distribution level, much investment and research is focused on incremental efficiencies such as improved trenchless technologies (for pipe replacements); PRI upgrades; replacement of obsolescent equipment (eg. some telemetry) with considerable investment in the near term in replacement of old iron mains with PE pipes.

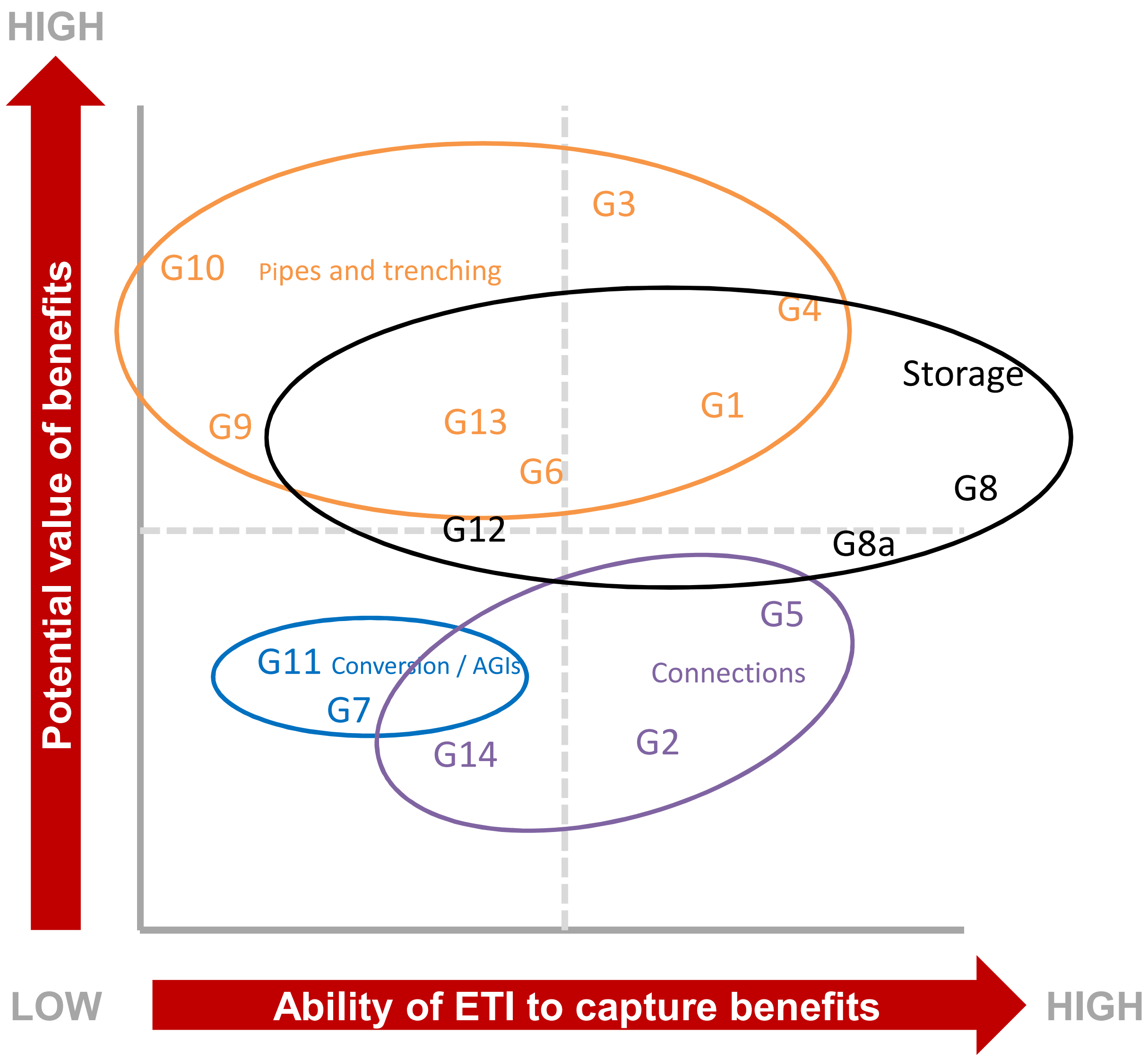
Potential areas for research development have been identified and are summarised in Table 9-7 below. Assessing the potential value of benefits depends on views on volume of deployment and the impact that an innovation may ultimately have on cost. Given the uncertainty of both factors, the assessment is necessarily high level. Ability of ETI to capture benefits has been based mostly on the TRL level, on the assumption that ETI is most interested in TRL levels of 3 to 6.

Table 9-7: commentary on value of gas innovations to ETI

Category	Technology	Potential value of benefits	Ability of ETI to capture benefits	TRL	Timeframe
Conversion/AGIs	G11 Turbo expanders	Low - some potential across gas industry in UK and internationally but relatively low value.	Low - may have some specialist knowledge but relatively low value; also fairly well developed technology.	>7	< 5 years
	G7 Venting techniques	Low - some potential across gas industry in UK and internationally but limited to compressor stations	Low - may have some specialist knowledge but relatively little value overall. Relatively developed technology already being explored by National Grid.	6	< 5 years
Pipelines	G3 Trenchless Technologies	High - cross-cutting, widespread demand. Potentially large market across vectors and internationally.	Medium – due to high potential value, consider of medium interest to ETI. This is tempered by the fact that technologies and approaches are relatively mature (although varied) and demonstrator and commercial operations may be in place.	7	< 10 years
	G4 Repurposing natural gas pipelines for hydrogen	High - potential high demand across developed world. Interdependent with development of hydrogen as fuel.	Medium / high – both potential value and low TRL suggest of interest to ETI. Early stage development suggests could be opportune time to become involved although some policy risk. Long lead times.	2	20+ years

Category	Technology	Potential value of benefits	Ability of ETI to capture benefits	TRL	Timeframe
	G1 Repurposing natural gas pipelines CO_2	High - potential high demand across developed world	Medium / high – already some interest / expertise through CCS team. Technology more developed than for hydrogen and more commercial operators already in space.	5	10+ years
	G6 Pipeline inspection	Medium / high - cross-cutting, widespread demand and technology approaches. Large market both UK and internationally.	Medium – a wide variety of technologies and approaches some of which may be of interest to ETI.	2-7	10+ years
	G10 Pipeline handling techniques	Medium / high - cross-cutting, widespread demand. Large market with many existing players. Civils costs major element of infrastructure deployment	Low – generally fairly well developed technologies requiring less development funding / investment.	9	< 10 years
	G9 Pipe Replacement - Steel Mains	Low / medium - little innovation. Significant niche market.	Low – relatively well developed technology for small size pipes, however less mature for larger sizes.	5-7	< 10 years
	G13 Robotics for Pipeline Repair	High - widely applicable in any pipeline infrastructure.	Low / med – varied technologies with potentially large market however likely to be long lead times for some technologies to be market ready.	3	20+ years
Storage	G8 Underground storage	Medium / high - modest challenge. Significant niche.	Medium / high – ETI already have experience of underground, bulk gas storage. Geologic storage projects already undertaken.	6	10+ years
	G8a Above Ground Storage	Medium - modest challenge. Storage overall of value	Medium - may have some relevant experience and expertise and may link with existing programmes.	7	< 5 years
	G12 Line Packing Storage	Medium - modest challenges. Large market.	Low – already being actively explored by National Grid as part of grid operational management, however potential to link knowledge to new fuels / gases.	9	< 5 years
Connections	G5 Shale gas connections	Medium - some innovation challenge. Government attitude to shale gas will be key driver. Some potential for overseas markets.	Medium - Gaining momentum although considerable uncertainty remaining. TRL levels and timeframe applicable to ETI.	3-4	< 10 years
	G14 Biogas connections	Low - modest innovation challenge. Significant niche.	Low - may have some relevant experience and expertise although value of benefits not likely to be significant. Also relatively mature technologies.	6-8	< 5 years
	G2 CNG fuelling	Low / medium - difficult to assess as depends on range of market drivers, eg. hydrogen, EV. Likely to be low.	Medium - already have projects in transport sector but mostly focused on EVs. May have specialist knowledge.	5	< 10 years

A visual representation of Table 9-7 is shown in Figure 9—5. Here the opportunities have been plotted graphically such that those in the top right hand corner represent those with the largest potential value of benefits that could be captured by ETI. Technologies have been grouped mostly around infrastructure type.



G1	Repurposing for CO2	G8a	Storage – above ground
G2	CNG Vehicle refuelling	G9	Mains replacement with PE
G3	Trenchless technologies	G10	Pipe handling techniques
G4	Repurposing for hydrogen	G11	Turbo expanders energy generation
G5	Shale Gas connection	G12	Line packing
G6	Pipeline inspection techniques	G13	Advanced robotic techniques
G7	Improved venting techniques	G14	Biogas / Syngas Connection to network
G8	Storage - saline aquifers		

Figure 9—5: comparison of the potential value of the benefits of innovation with ability of ETI to capture those benefits: natural gas

Research priorities

Unlike with electricity, gas technology is generally more mature with there being fewer TRLs at the lower end of the scale. Considering those innovations in the top right hand corner of Figure 9—3, four priority areas are discussed below.

Pipeline trenchless technologies

This research area involves a wide range of activities aimed at developing techniques and technologies that would enable small-dimensioned trenching and new, mechanised, network installation techniques. This would address the issues of security and the need to minimise disruption particularly in urban areas, and would reduce pollution, working time and cost. Innovations can be applied to other gases as well as to water. Due to the wide range of innovation areas no specific research requirements can be specified here. It is recommended that a more detailed assessment of this technology area is undertaken.

Repurposing for other gases

Given the extent of existing gas networks already in place, and the difficulties of operating in an already congested utility space, there is likely to be potential for repurposing existing assets rather than building them from scratch. Repurposing to hydrogen and CO_2 will have different drivers, and the detail of the innovation will be different due to the physical properties of each gas. However it is an area that could have wide application both within the UK and elsewhere and may feed into existing ETI projects (such as on CCS).

An additional area of research which should be considered is the potential importance of using plasma to create synthetic gas from waste materials. It may offer an alternative to hydrogen when repurposing the gas network.

Condition Monitoring

The development of pipe line inspection techniques including advanced robotics is a key aspect of condition monitoring, likely to become increasingly important as greater emphasis is placed on ensuring the longevity of plant and equipment. As for trenchless technologies commented upon above, this research area involves a wide range of activities. No particular ‘big hitters’ within this overall landscape have been identified. Further analysis beyond the scope of this Project is recommended.

Storage

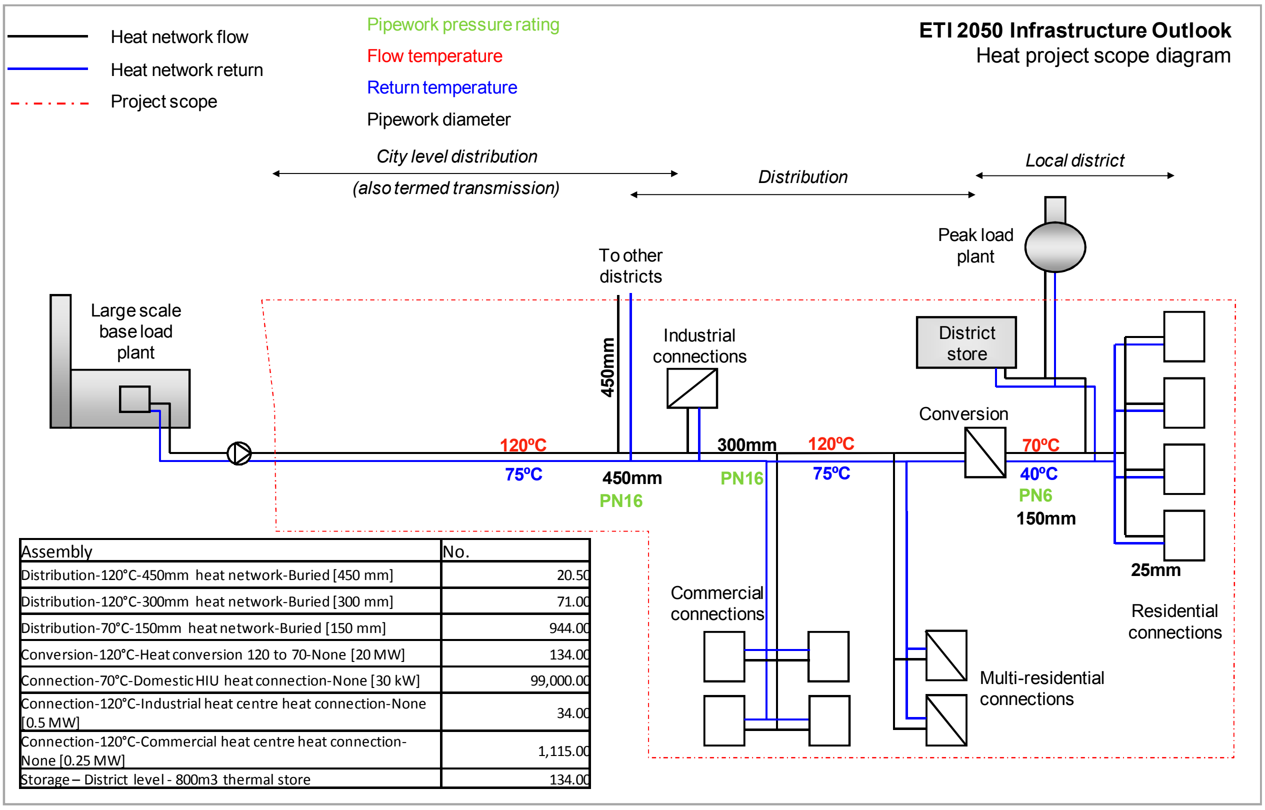
Energy storage has already been identified as a key area for research and investment by ETI. In order to increase the volume of gas storage available to meet strategic need, the emphasis on gas storage research is to drive down the cost of ownership and maintenance of infrastructure. Much of it is about using technology available today such as wireless technology and instrumentation and control system technology to decrease capital expenditure costs and decrease project times thereby driving down installation times. Operational cost savings can also be realised by using innovative remote monitoring and automated diagnostic solutions. A major barrier to storage is the current reliance on market driven solutions.

Other

9.3.3 Heat

Quantitative analysis

For the quantitative analysis for heat a theoretical heat network project was drawn up as illustrated in Figure 9—6.[29] The project is scoped for a city wide network comprising over 1,000km of pipe work serving over 100,000 properties.



Assembly	No.
Distribution-120°C-450mm heat network-Buried [450 mm]	20.50
Distribution-120°C-300mm heat network-Buried [300 mm]	71.00
Distribution-70°C-150mm heat network-Buried [150 mm]	944.00
Conversion-120°C-Heat conversion 120 to 70-None [20 MW]	134.00
Connection-70°C-Domestic HIU heat connection-None [30 kW]	99,000.00
Connection-120°C-Industrial heat centre heat connection-None [0.5 MW]	34.00
Connection-120°C-Commercial heat centre heat connection-None [0.25 MW]	1,115.00
Storage – District level - 800m3 thermal store	134.00

Figure 9—6: heat project scope outline for purposes of analysing cost 'hot spots'

An analysis of key cost elements (assemblies and components) is shown Figure 9—7 and Table 9-8. The costs include all capital and refurbishment / replacement costs over a 60 year life.

In general it is clear that for such a city wide urban network it is the buried pipes that represent the most costly aspect of the project (around 60% at Assembly level, including new build and refurbishment costs), an observation supported by other analyses. However, in this analysis, assuming almost 100,000 domestic connections, these also comprise a significant proportion (33% at Assembly level, this includes domestic HIUs).

[29] The project is based on 'average city' from IEA-DHC ANNEX VII Report 8DHC-05.01: A comparison of distributed CHP/DH with large scale CHP/DH

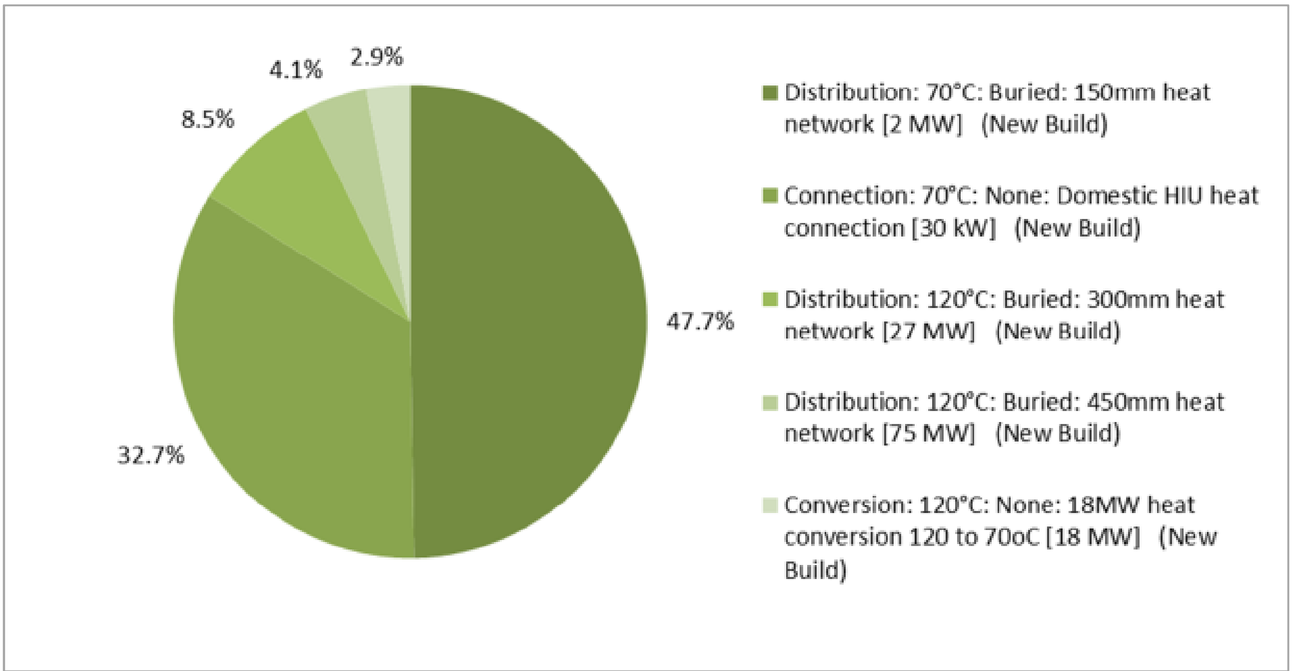


Figure 9—7: top five Assemblies as a proportion of cost: heat distribution

Table 9-8: top five Assemblies and Components as a proportion of cost for heat distribution; also showing quantity represented

TOP 5 ASSEMBLIES DISTRIBUTION		
Assembly	Quantity	% TOTAL
Distribution: 70°C: Buried: 150mm heat network (with gas repurpose) [2 MW] (New Build)	944 km	48%
Connection: 70°C: None: Domestic HIU heat connection with gas repurposing [30 kW] (New Build)	99,000	33%
Distribution: 120°C: Buried: 300mm heat network (with gas repurpose) [27 MW] (New Build)	71 km	8%
Distribution: 120°C: Buried: 450mm heat network (with gas repurpose) [75 MW] (New Build)	21 km	4%
Conversion: 120°C: None: 18MW heat conversion 120 to 70oC [18 MW] (New Build)	134	3%
TOP 5 COMPONENTS DISTRIBUTION		
Component	Quantity	% TOTAL
DA11 - Heat networks - Buried and tunnelled - Pipelines - New: 70oC 150mm F&R heat pipework - supply, install and sundries	944 km	28%
DC2 - Heat networks - Connections - Refurbishment - remove and replace 0.03MW capacity Residential heat interface unit, heat meter and associated works	99,000	14%
DC2 - Heat networks - Connections - Refurbishment - remove and replace pipework connection to residential heat interface unit including valves	99,000	12%
DA32 - Heat networks - Buried and tunnelled - Installation civils - Refurbishment - Excavate trench for F&R 150mm pipework	944 km	8%
DA12 - Heat networks - Buried and tunnelled - Pipelines - Refurb, Repurpose and Abandon: Refurbishment - removal and disposal of existing 150mm heat pipework generally	944 km	8%

Qualitative review

Low carbon building regulations are currently driving the development of heat networks for new developments. Connections to existing loads and so-called anchor loads are also being promoted. There are a number of constraints on development both physical, e.g. installing underground pipe work, and commercial related, e.g. legal and regulatory, incentive structures etc.

Initial observations are that:

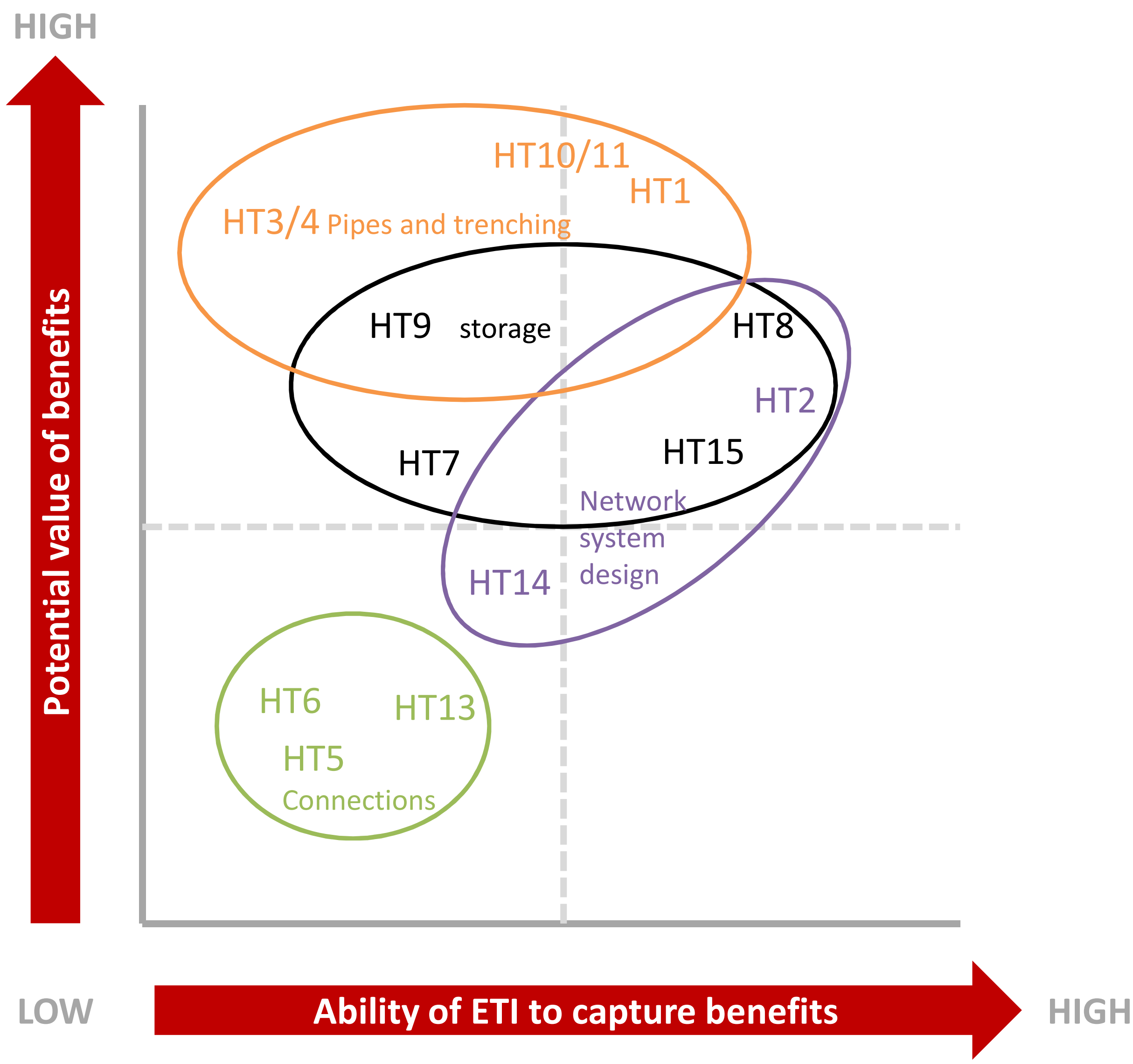
- heat infrastructure technology identified in the scan of the innovation space is relatively mature
- the likely deployment of each technological change is not particularly high, though under the High Heat test case could be significant
- many of the innovations are technologically mature and widely deployed outside of the UK BUT have low levels of deployment in the UK due to the low level of heat network penetration in the heat market

Potential areas for research development have been categorised in relation to potential value and in terms of the ability of ETI to capture the benefits of that value as outlined in Table 9-9. Value here is relative within the context of heat networks. Overall, due to lower anticipated levels of deployment, values are likely to be lower than those for electricity. Also, as many of these technologies are already more mature in other markets, potential for the UK to expand internationally is more challenging. Due to the maturity of many of these technologies, it is possible that the ability of ETI to capture benefits (apart from storage where ETI is already active) could be reduced. Many of the barriers to heat network deployment are around commercial and legal issues, combined with supply chain issues.

Table 9-9: commentary on value of heat innovations to ETI

Category	Technology	Potential value	Ability of ETI to capture benefits	TRL	Timeframe
Pipes & trenching	HT1 Plastic pipework systems	Medium – dependent on roll out of heat networks	Low – small diameter pipes already fairly well developed. Medium / high – large diameter pipes, barriers to overcome through research.	4 (large diameters) 9 (small diameters)	> 10 large diameters < 5 small diameters
	HT 3 Cold Lay	Medium – dependent on roll out of heat networks	Low/ medium – no significant innovation, already deployed in Scandinavia. Main issue in UK is lack of contractor experience.	9	< 5 years
	HT4 Reducing trenching requirements (civils works)	Medium – dependent on roll out of heat networks	Low / medium – exploration of application of existing techniques to heat networks which are particularly challenging	9	< 5 years
	HT 10 Pipeline configuration	Medium – dependent on roll out of heat networks	Low / medium – mostly a system design issue.	9	< 5 years
	HT 11 Network configuration	Medium – dependent on roll out of heat networks	Low / medium – mostly a system design issue; used in some systems in Scandinavia	9	< 5 years
	HT 12 Hot working	Medium – dependent on roll out of heat networks	Low – currently in use in emergency uses although not known to be used in the UK	8	< 10 years

Category	Technology	Potential value	Ability of ETI to capture benefits	TRL	Timeframe
Network system design	HT2 Low temperature networks for new and existing buildings	Medium / high – driven by need for increased efficiency and desire to use lower temperature lower carbon sources of heat	Medium / high for existing buildings – lower TRL although significant barriers mostly related to need to retrofit. Low for new buildings – little innovation.	9 – new 4 - existing	< 5 years new > 10 years - existing
	HT 14 District energy sharing	Medium / high – driven by need for increased efficiency and utilisation of waste heat, particularly from buildings	Medium – innovative approach pioneered in Canada; however restricted to certain sites and developments	8	< 10 years
Storage	HT7 Multi-function thermal storage	Medium	Low – already deployed in the UK	9	< 5 years
	HT 8 Interseasonal storage	Medium / high	Medium / high – ETI already operating in this space; level of technology maturity suitable	5	> 5 years
	HT 9 Connection level storage	Medium / high	Low – technology generally available, however deployment could be increased	9	< 5 years
	HT 15 Phase Change Materials	Medium / low	Medium – TRL suitable for ETI, however potential value of benefits may mitigate against it	6	> 5 years
Connections	HT 5 Compact substations	Low -	Low – no significant innovation, already deployed in Scandinavia.	9	< 5 years
	HT 6 Multiple consumers per connection	Medium – dependent on roll out of heat networks	Low – already deployed in some new build DHNs in low heat density demand areas. System design approach rather than technology.	9	< 5 years
	HT 13 Direct connections	Low -	Low – widely used, particularly in Finland.	9	< 5 years



HT1	Plastic pipework	HT9	Connection level storage
HT2	Low temperature networks	HT10	Pipeline configuration
HT3	Cold lay	HT11	Network configuration
HT4	Reducing trenching requirements	HT12	Hot working
HT5	Compact substations	HT13	Direct connections
HT6	Multiple consumers per connection	HT14	District energy sharing
HT7	Multi function thermal storage	HT15	Phase change materials
HT8	Interseasonal storage		

Figure 9—8: comparison of the potential value of the benefits of innovation with ability of ETI to capture those benefits: heat

Research priorities

Research required to progress these innovations is outline in Table 9-10 below. Using trenchless technology for heat networks is not common, therefore the inclusion of reduced trenching technologies in the TRL9 category may be misleading. It is now an established and mature approach for electricity, water and natural gas networks. However, it may not be possible with heat networks. For example, the integrity of the outer casing of pre-insulated pipes is important to protect from moisture ingress. Pipe jacking or thrust boring may therefore not be appropriate. This innovation would meet the shortlist criteria if the TRL was reduced. The benefits could be very large should a high penetration of heat networks develop.

Table 9-10: summary of research required in respect of research opportunities identified.

Innovation	Research required
Highest priority	
HT1 Large diameter plastic pipe work	Research into this would need to identify the viability of using larger diameter plastic pipe in terms of material properties and installation techniques, and benefits associated with this. Plastic pipe limited to maximum temperature of around 95degC and 125mm nominal diameter. Use of on-reel installation reduces costs provided pipe material has scope for cost savings from greater volumes of manufacture.
HT2 Low temperature heat networks – existing buildings	Low temperature networks, with flow temperatures around 70degC, are common in new district heating schemes in Scandinavia. Their application in the UK is relatively limited, perhaps due to industry inertia and concerns regarding use of new technology. Provision of best practice material on low temperature network design from Scandinavia maybe enough to see them more widely adopted in the UK for new buildings. For existing buildings their use is more difficult and requires the determination of whether buildings can be adapted to use lower temperature heating circuits. Research is required into the opportunities for retrofit of building heating systems to use lower temperatures. The IEA currently have a research Project titled *Towards Fourth Generation District Heating: Experiences with and Potential of Low Temperature District Heating* which includes UK based BRE and SSE as participants. Outcomes will not be available until 2014 but this is likely to be a substantial piece of research.
HT8 Inter-seasonal storage	Research into this would require the establishment of a pilot scale plant to test the storage of heat as identified in the ETI Geological Heat Storage Project
HT15 Phase change materials for storage	Phase change materials have been used for thermal storage but not at significant scale. Use of organic compounds has fire risk, whereas use of in-organic salts presents shorter lifecycles and potentially toxic materials. Applications of phase change materials to improve energy density of above ground storage are extremely limited as benefit mitigated by low cost of land in many locations where larger scale energy plants located Where land value is a significant constraint then there is more benefit from having a more compact thermal store. This application may be more suited to providing thermal storage within buildings where space is at a premium.
Lower priority	
HT 3 Cold Lay	Cold laying of upto 300mm diameter steel district heating pipe is now commonly done in new build systems in Scandinavia. This reduces the space requirement and additional costs of expansion u-bends, bellows or other compensation equipment. This approach requires detailed stress calculations by the pipework supplier and is not typically used in the UK. Market innovation is required in the UK to encourage the use of this system. It is difficult to use where networks are installed in small sections due to phasing or land availability.
HT4 Reducing trenching requirements (civils works)	This is a common issue for all buried utilities services. Heat networks are particularly challenging as the outer casing of the insulation is at risk of scoring and letting in moisture causing corrosion and reduced insulation performance. Research is required into techniques which allow narrower trenches (e..g no welding done in the trench). Techniques such as direction drilling may require some form of sleeving or steel in steel pipe construction.
HT 10 Pipeline	Much of the innovation in heat networks is in how networks are designed. Use of approaches such as running

Innovation	Research required
configuration/HT 11 Network configuration	pipework through front gardens, shared connections between houses, twin and triple pipes and provision of loops for resilience have limited or no deployment in UK systems at present. These and other measures should be evaluated for use in the UK as they have the potential to reduce costs and improve performance. These innovations are crucial should heat networks require extension to lower density sub-urban areas.
Novel technology	
HT14 District energy sharing	District energy sharing uses close to ambient temperatures to provide a warm and cool pipe. Buildings are equipped with reversible heat pumps which use the district pipes to extract or reject heat according to whether the building requires heating or cooling. District energy sharing has been demonstrated at relatively small scales, and most often connecting new buildings together, which have been designed for this purpose. Urban areas with significant mixed uses and where simultaneous heating and cooling are common, are ideally suited. Secondary heat sources such as cooling towers and sewage treatment plants can also be used to harvest waste heat. Building systems must be adapted by installation of heat pumps to replace boiler plant, but even then heat temperatures in the building are limited to around 70°C. This will require modifications to building internal systems, acting as a constraint to deployment. Research is required into the opportunities for retrofit of building heating systems to use lower temperatures. A significant scale feasibility study into this technology is required to identify a suitable area in the UK. Using such a study the performance and potential benefits can more closely be evaluated. This system could be relatively highly scaled in deployment terms in combination with the deployment of water source heat pumps.

9.3.4 Hydrogen

Quantitative analysis

The hydrogen projects used for cost hot spot analysis are summarised in Table 9-11 below. They are derived from the project data included in Appendix F and derive from the equivalent for natural gas.

Table 9-11: summary of project details used to explore cost 'hot spots'

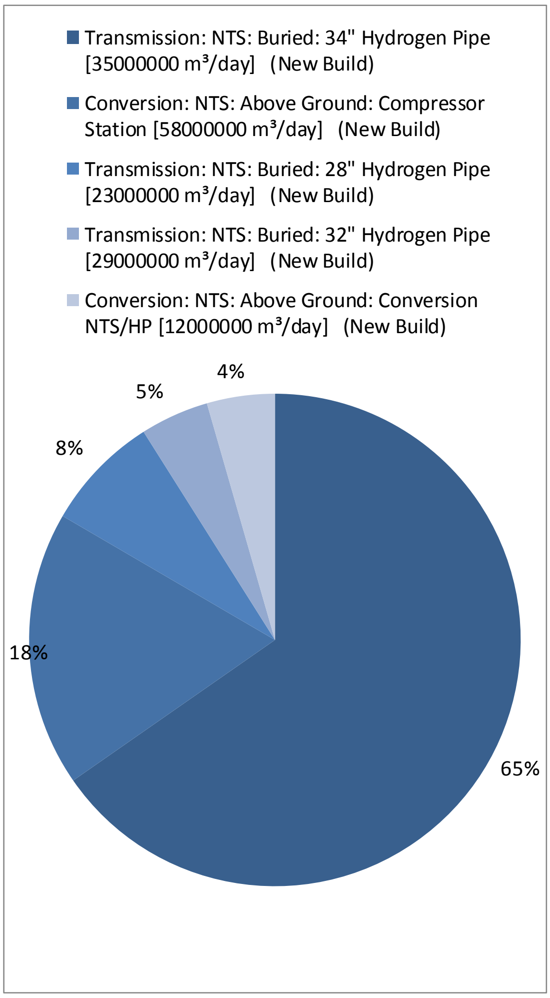
Function	Region	Description
Transmission	East Midlands	Almost 750km of pipe work plus LTS off takes and 2 compressor stations; mainly rural; assume all new build; 2015 – 2075; baseline cost trends for labour, material and plant
Distribution	Loughborough	Around 230km pipe work (MP and LP); district governors; industrial, commercial and residential connections; urban; assume all new build; 2015 - 2075; baseline cost trends for labour, material and plant

An analysis of key cost elements (assemblies and components) is shown in Figure 9—9 and Table 9-12 . The costs include all capital and refurbishment / replacement costs over a 60 year life.

For hydrogen transmission the major cost lies in pipe lines (78% across the different pipe diameters). This cost includes both new build (pipes and civils) and periodic refurbishment (lifting out and replacing pipes). The refurbishment is the most costly aspect in this simplified case where the lifecycle of pipework is 40 years and costs increase over that period based on the cost trends for labour, material and plant in the database (see Section 7.5).

Unlike gas, for hydrogen the cost of conversions (compressor stations and NTS/HP conversion) represent a more significant share at 22%.

At distribution level, again pipe lines dominate based on a combination of refurbishment costs and installation civils of new build. Residential connection costs (20,452 in number) are only 7% of total project costs.



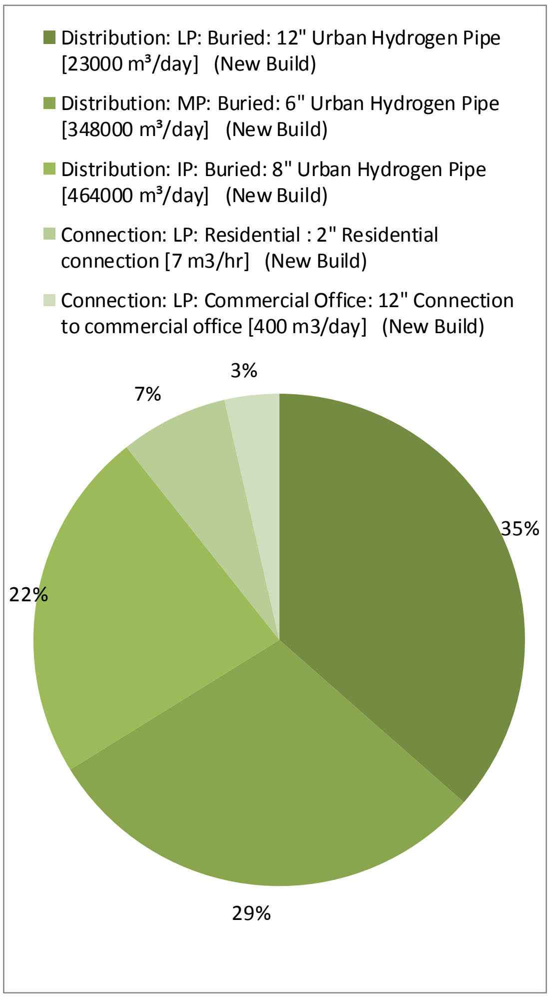


Figure 9—9: top five Assemblies as a proportion of cost: hydrogen transmission (left) and gas distribution (right)

Table 9-12: top five Assemblies and Components as a proportion of cost for hydrogen transmission (top half) and hydrogen distribution (bottom half); also showing quantity represented

TOP 5 ASSEMBLIES TRANSMISSION		
Assembly	Quantity	% TOTAL
Transmission: NTS: Buried: 34" Hydrogen Pipe [35000000 m³/day] (New Build)	634 km	65%
Conversion: NTS: Above Ground: Compressor Station [58000000 m³/day] (New Build)	2	18%
Transmission: NTS: Buried: 28" Hydrogen Pipe [23000000 m³/day] (New Build)	72 km	8%
Transmission: NTS: Buried: 32" Hydrogen Pipe [29000000 m³/day] (New Build)	37 km	5%
Conversion: NTS: Above Ground: Conversion NTS/HP [12000000 m³/day] (New Build)	11	4%
TOP 5 COMPONENTS TRANSMISSION		
Component	Quantity	% TOTAL
CA12 - Hydrogen - Buried and tunnelled - Pipelines - Refurbish 34" NTS pipeline	634 km	35%
CC2 - Hydrogen - Conversions - Refurbish NTS compressor station	2	14%
CA32 - Hydrogen - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 34"	634 km	10%
CA21 - Hydrogen - Buried and tunnelled - Pipeline sundries - New: 34" NTS Hydrogen Pipeline	634 km	9%
CA31 - Hydrogen - Buried and tunnelled - Installation civils - New: 34" NTS River crossing	634 km	5%
TOP 5 ASSEMBLIES DISTRIBUTION		
Assembly	Quantity	% TOTAL
Distribution: LP: Buried: 12" Urban Hydrogen Pipe [23000 m³/day] (New Build)	197 km	35%
Distribution: MP: Buried: 6" Urban Hydrogen Pipe [348000 m³/day] (New Build)	32 km	29%
Distribution: IP: Buried: 8" Urban Hydrogen Pipe [464000 m³/day] (New Build)	96 km	22%
Connection: LP: Residential : 2" Residential connection [7 m3/hr] (New Build)	20,452	7%
Connection: LP: Commercial Office: 12" Connection to commercial office [400 m3/day] (New Build)	407	3%
TOP 5 COMPONENTS DISTRIBUTION		
Component	Quantity	% TOTAL
CA32 - Hydrogen - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 12" LP Hydrogen pipeline ground works	197 km	21%
CA32 - Hydrogen - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 6" MP Hydrogen pipeline ground works	197 km	19%
CA32 - Hydrogen - Buried and tunnelled - Installation civils - Refurb, Repurpose and Abandon: 8" IP Hydrogen pipeline ground works	96 km	11%
CA31 - Hydrogen - Buried and tunnelled - Installation civils - New: 12" LP Hydrogen pipeline ground works	197 km	7%
CA31 - Hydrogen - Buried and tunnelled - Installation civils - New: 6" MP Hydrogen pipeline ground works	197 km	6%

Qualitative review

Of the four energy vectors considered in this study, hydrogen is the only entirely 'new' one (if one does not include hydrocarbon fuels, in which carbon provides an exceptionally convenient 'hydrogen carrier') and so its future is typically perceived as the most difficult to predict. However, there appears to be a growing consensus about the dual role it could play as a clean fuel and as a key grid balancing technique (using electrolysis as responsive demand),

Progress in the development of hydrogen-consuming devices – most notably fuel cells – has been impressive and significant investment has brought the technology to the brink of commercialisation. However, being based upon standard, well-established equipment and techniques, hydrogen production technology and delivery infrastructure has developed iteratively and seen only modest investment to date. There is therefore scope for advances to be achieved with significant return on investment possible due to the likely widespread uptake of this energy vector.

Establishing which of these areas of innovation could be of most interest to ETI is difficult / complex because it requires a fully integrated, multi-sectoral perspective that is rarely found in the silos of energy production, delivery and end-use markets. Hydrogen viewed from either the power sector or transport sector alone looks like a flawed proposition. It is only when seen simultaneously from both sectors that the symbioses it creates become apparent. Its cross-cutting, wide-ranging applicability also means that the hydrogen energy landscape can appear highly complex. These factors combine to make an area of great uncertainty to most observers.

On this basis, the approach taken to prioritising the different opportunities was to assess the potential value of the benefits a particular innovation could bring overall and the potential for ETI to capture those benefits.

In respect of potential value of benefits, key factors taken into consideration were the certainty of future markets, their likely structure, the innovations required to make such markets viable, the contribution that the ETI could make to facilitating such innovations and the potential return on investment to the ETI should it choose to participate in the development of technologies and practices.

In respect of ability of ETI to capture benefits, key factors taken into consideration were the alignment with the ETI's core competencies, its potential to have a significant catalysing effect and the extent to which it can develop a convincing business case.

The output of this exercise is summarised in Table 9-13. The table also indicates TRL and timeframe over which the technology is likely to be developed.

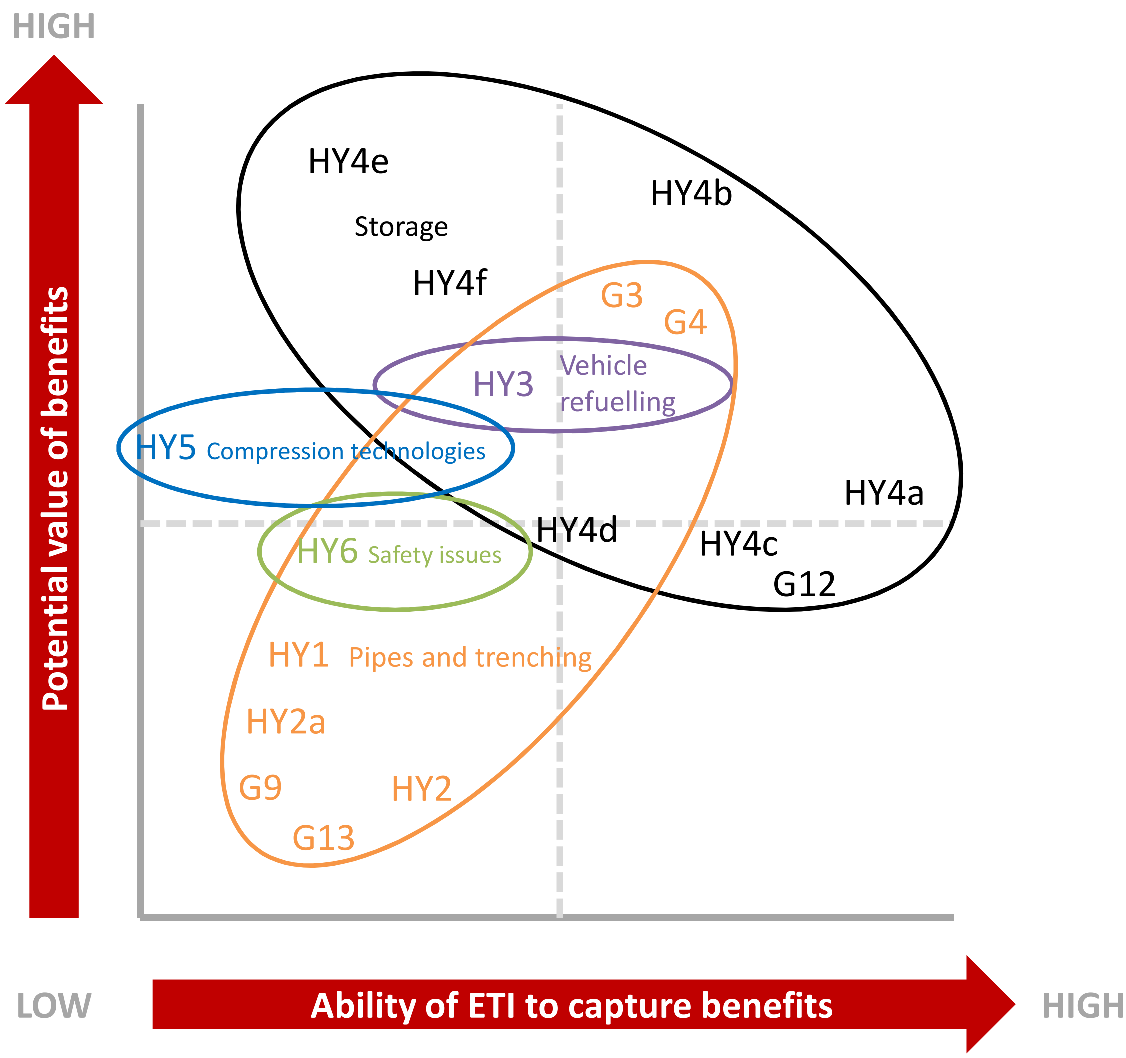
Table 9-13: commentary on value of hydrogen innovations to ETI

Category	Technology	Potential value of benefits	Ability of ETI to capture benefits	TRL	Timeframe
Safety	HY6 Various	Medium / low - wide ranging and essential. Significant niches.	Low – although may have some relevant experience and expertise (oil & gas, utilities, etc).	7	< 10 years
Pipelines	G3 Trenchless Technologies (also applies to natural gas)	High - cross-cutting, widespread demand. Large market.	Medium - may have some relevant experience and expertise.	7	< 10 years

Category	Technology	Potential value of benefits	Ability of ETI to capture benefits	TRL	Timeframe
	G4 Repurposing natural gas pipelines for H_2	High - potential high demand across developed world	Medium / high – relatively new area, depends on pipeline experience, expertise, assets.	2	20+ years
	HY1 Embrittlement	Medium / low - scale of challenge not well known.	Low – although may have some materials expertise. Commercially exploitable.	8	< 5 years
	HY2a Materials - Permeation reduction	Low - modest challenge. Widely applicable.	Low – although may have some materials expertise. Commercially exploitable.	3	10+ years
	G9 Pipe Replacement - Steel Mains (also applies to natural gas)	Low / medium - little innovation. Significant niche market.	Low – already being developed by industry incumbents although remains commercially exploitable.	7	< 10 years
	G13 Robotics for Pipeline Repair (also applies to natural gas)	Low in medium term - widely applicable in any pipeline infrastructure.	Low – currently at early stages of development, outside ETI time frame although may have some specialist knowledge.	3	20+ years
	HY2 Pipe Jointing / Sealing	Low - modest challenge. Widely applicable.	Low – although may have some relevant experience and expertise.	9	< 5 years
Storage	HY4e Solid State Storage	High - Hydrogen's 'Holy Grail'! Game-changing. Vast market.	Low - unlikely to have relevant knowledge. Quantum leap (and major, long-term investment) needed.	3	20+ years
	HY4b Interoperability with Intermittents	High - fundamental value of using hydrogen. Potentially vast market.	Medium / high – due to importance of technology for future business case for hydrogen: utilities' need for demand response, oil companies' need for clean fuel.	6	< 10 years
	HY4f Underground Storage	Medium/high - modest challenge. Significant niche.	Medium - experience of underground, bulk gas storage. Could be major 'smart grid' enabler.	6	10+ years
	HY4a Bulk Forecourt Storage	Medium - modest challenge. Large market.	Medium/high - experience of fuel storage. Could be major 'smart grid' enabler. Vital Component of future fuel infrastructure.	8	< 5 years
	HY4c Gaseous Storage	Low / medium - modest challenges. Growing early-adopter market.	Medium - important part of transition to new, low-carbon fuels - key to future of ETI members	7	< 10 years
	HY4d Liquid Storage	Low / medium - modest challenges. Uncertain market potential.	Low / medium - may become an important part of transition to new, low-carbon fuels - key to future of ETI members.	3	< 10 years
	G12 Line Packing Storage (same as for natural gas)	Low / medium - modest challenges. Large market.	Medium - experience of application. Continuation of established benefits, but with new fuels.	9	< 5 years

Category	Technology	Potential value of benefits	Ability of ETI to capture benefits	TRL	Timeframe
Connecti on / refuelling	HY3 Compressed Gas / Liquid Refuelling	Medium - modest challenge. Large market.	Medium - experience and expertise in refuelling. Vital for oil companies' future with clean fuels but longer development period likely.	8	< 5 years
Conversion	HY5 Compression Technologies	Medium – moderate challenge. Vital for development of transmission and distribution systems as well as storage and refuelling. Vast market.	Medium – depends on experience and expertise. Commercially exploitable.	3	10+ years

A visual representation of this table is shown in Figure 9—10. Here the opportunities have been plotted graphically such that those in the top right hand corner represent those with the largest potential value of benefits that could be captured by ETI.



HY1	Pipeline materials – embrittlement	HY4f	Storage - saline aquifers
HY2	Pipeline materials – jointing	HY5	Compression
HY2a	Pipeline materials – permeation	HY6	Safety issues
HY3	Vehicle refuelling	G3	Trenchless technologies
HY4a	Storage - bulk vehicle storage	G4	Repurposing for hydrogen
HY4b	Storage - interoperability with intermittents	G9	Mains replacement with PE
HY4c	Storage – gaseous	G12	Line packing
HY4d	Storage – liquid	G13	Robotics for pipeline repair
HY4e	Storage - solid state		

Figure 9—10: comparison of the potential value of the benefits of innovation with ability of ETI to capture those benefits: hydrogen

Research priorities

The rationale used for selection of hydrogen innovation opportunities takes into account the following:

1. Certainty of market demand

   a. Dispatchability of electricity supply is arguably the biggest challenge faced by low carbon energy systems. There are three routes to achieving it:

      i. Generate dispatchable power from fuels (stored primary energy)

      ii. Store electricity mid-energy-supply-chain (batteries, flywheels, supercapacitors, flow cells, CAES, pumped hydro, etc)

      iii. Use non-dispatchable electricity (e.g. from wind, solar, marine, nuclear) to synthesise fuel that introduces dispatchability downstream.

   b. Analysing those options reveals the potential for hydrogen to become a major energy vector:

      i. Bio-energy's potential to fulfil the first of these roles is limited by constraints on the resource and other concerns about its sustainability. The other low-carbon option for generating dispatchable electricity is to use pre-combustion CCS with fossil fuels, since post-combustion methods reduce dispatchability. Pre-combustion CCS involves the production of hydrogen by gasification so that the CO2 by-product can be sequestrated and the hydrogen used to fuel a gas turbine.

      ii. Electricity storage at small capacities or at short timescales (e.g. to provide ancillary services) can be cost-effective and efficient, but in bulk or at longer timescales (e.g. for arbitrage) is less so, to the point that beyond a couple of days storage, even pumped hydro becomes unattractive. Hydrogen is technically applicable and, in certain situations, may be a commercially viable option for long timescale and large capacity electricity storage.

      iii. Production of hydrogen by electrolysis introduces dispatchability to power networks from the demand side and is suitable for long- term and large scale energy storage, albeit rarely for primarily for use in other sectors (typically transport) rather than reconversion to grid electricity.

   c. This suggests two main roles for hydrogen in low-carbon energy systems: dispatchable power supply and dispatchable demand. It also produces two types of hydrogen: high purity and very high purity.

      i. The fossil-derived hydrogen produced through pre-combustion CCS will be around 95 - 99% pure, which would need further purification for use in low-temperature fuel cells that are typically used in vehicle drive trains, but is eminently suitable for use in gas turbines or high temperature fuel cells for power generation.

      ii. The electrolysis-derived hydrogen is 99.999% pure and therefore suitable for use in transport applications where low temperature fuel cells are typically used.

d. These two routes to hydrogen production, with the two hydrogen types that result and which are suited to two end-use sectors, suggests that two parallel hydrogen infrastructures might arise.

   i. CCS-derived hydrogen may be injected into the natural gas network (probably at distribution level), which offers huge storage capacity through line packing, thereby lowering the carbon intensity of the gas while offering huge storage capacity through line packing. This hythane mix may be used in any gas appliances with little or no modification (depending on the proportions of hydrogen and methane) to the devices. Alternatively, the hydrogen may be used locally to the gasification plant where it is produced, without mixing it with any other gas, in a hydrogen-compatible gas turbine or high temperature fuel cell. The location of the gasification plant will, in large part, be dictated by its proximity to a CO2 storage facility or associated pipeline.

   ii. Electrolytically-derived hydrogen may be produced anywhere on the electricity network, usually at garage forecourts, but also potentially in large, centralised plants. (The option of locating electrolysers close to renewable energy sources such as wind farms has been explored, with the aim of creating a dispatchable power output, but this essentially equates to an inefficient method of mid-energy-supply-chain storage that would rarely be commercially viable.)

   There would no doubt be some overlapping of these two parallel hydrogen pathways where particular circumstances make such variations on the broad trend commercially viable. Indeed, there is currently significant interest in the use of electrolytic hydrogen for injection into natural gas pipelines (e.g. German Power-to-Gas (“P2G”) Strategy Platform and Hydrogenics and E.On's 1MW P2G plant in Hamburg). Given the current immaturity of hydrogen energy markets and infrastructures, this represents a significant opportunity for early market development, but as the above discourse implies, may revert to a minor niche in the longer team.

2. Innovation needs

   The two parallel infrastructures described above can be broadly characterised as 'energy by pipes' (CCS-derived hydrogen) and 'energy by wires' (electrolytic hydrogen). Both make use of current infrastructures, around which some innovation is required to implement the two energy supply chains.

   i. Initial innovations relate to the injection of CCS-derived hydrogen into natural gas pipelines and accommodation of the different characteristics of the resultant hythane mix. In the longer term, the repurposing of natural gas pipelines to carry >90% pure hydrogen becomes the key challenge.

   ii. In the case of electrolytic hydrogen, infrastructural innovation required is in the conversion from electricity to hydrogen (i.e. the electrolyser and associated equipment such as compressors), not so much the electricity network. Some financial innovation is also required to develop suitable time of use (ToU) tariffs that reward the demand response services electrolysis provides.

3. Benefits of ETI intervention

   a. Having established that the markets exist and that certain key areas of innovation will give access to such markets, the question is whether the ETI's intervention would facilitate or accelerate the required innovations.

   b. Assuming that certain innovation paths would benefit from the ETI's support, the ETI needs to be confident that it will get a return on that investment, and to do so within a reasonable timescale. This analysis is intended to provide that confidence and minimise the risk in making such investments. The intervention of the ETI could contribute significantly to the de-risking of various innovation and development drives across the sector.

      i. The above assessment reduces considerably the uncertainty about the existence, or otherwise, of future hydrogen energy markets.

      ii. Choosing interventions that play to the ETI's strengths improves the likelihood of successful outcomes and therefore returns on investment, hence this consideration is also included in the assessment.

Research required to progress these innovations is outlined in Table 9-14 below.

Table 9-14: summary of research required in respect of research opportunities identified.

Innovation	Research required
Highest priority	
G4 Pipelines – repurposing NG for H2	Iterative progress needed on gas-tightness issues (jointing, permeability), durability (embrittlement, pressure cycling), understanding differences of H2 compared to NG and re-spec-ing accordingly, and switch-over issues. None of these are major barriers, but timescale is dominated by demand rather than technical difficulty.
HY4a Bulk forecourt storage	Existing technology is 'good enough' for early markets, but anticipated mass uptake will require improvements: e.g. footprint, safety, cost. Areas to investigate include, underground storage, liquid H2, on-site production (see dispatchable electrolysis), novel storage (solid state), delivery infrastructures (pipelines, trucks) and interoperability with intermittents.
HY5a Compression / refuelling	Compression: see below. Refuelling is also just about 'good enough' for early adopter markets, but research is required to speed up refuelling rates (should take 5 mins to refuel a car, but may take 15 mins. Buses can take much longer) and improvements in cost, efficiency and safety could also be achieved through further research.
Lower priority	
HY5 Compression	Little development required for conventional hydrogen compression (piston or diaphragm pumps), which is good enough for early markets, but could benefit from cost reductions and efficiency, reliability and durability improvements. The richest area for research is in the potential for step-change improvements (ionic compression, metal hydride/thermal compression).
HY4f Underground storage	The concept is understood and proven, but not yet widely practiced. Research could bring better understanding, plus lower cost, greater efficiency and safety.

9.4 Technology road maps

Technology road maps out to 2050 have been developed for each vector (except electricity – see Section 9.4.1) taking into account the innovations described for this project. Those developed here are based on an approach used in a recent government study for the automotive industry[30]. There are clearly an extensive number of variables at play both within and between vectors. The exercise undertaken here is high level and cannot be taken as in any way definitive. It is presented as a departure point for discussion.

The key for reading these roadmaps is given in Figure 9—11 below.

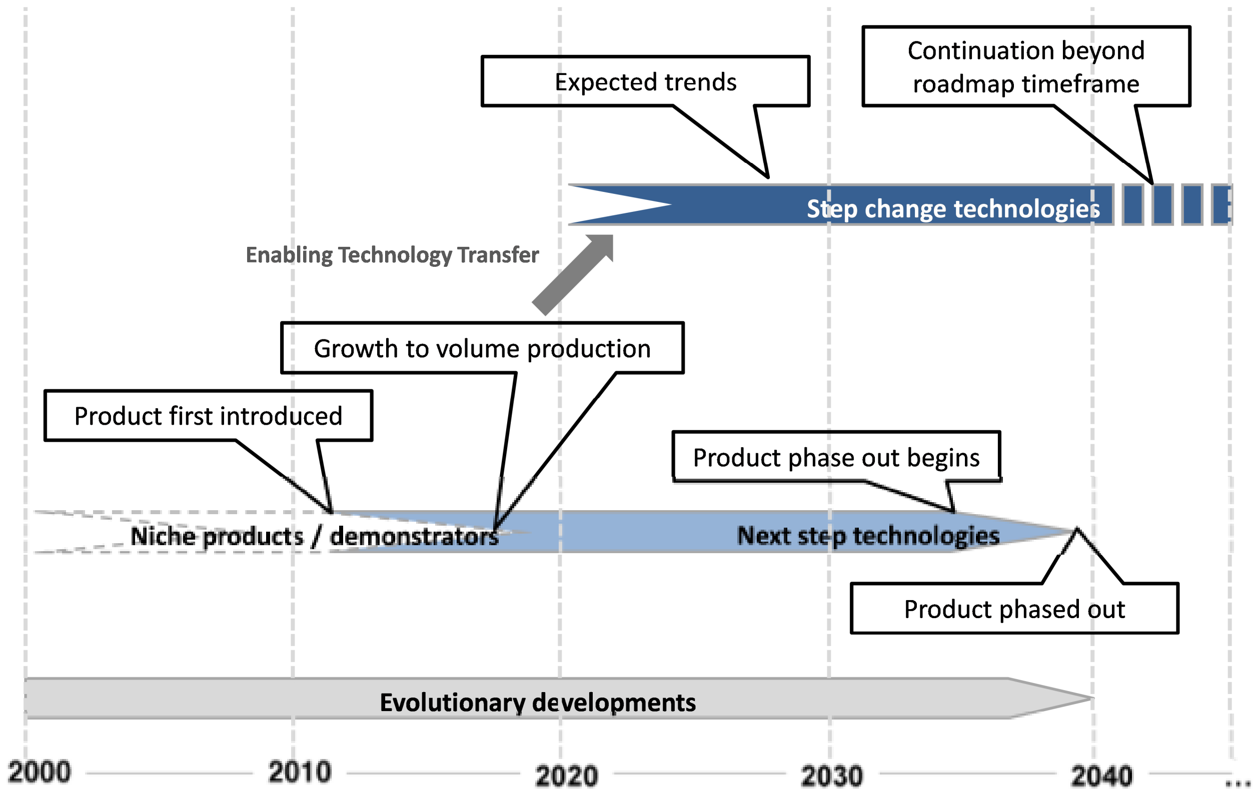


Figure 9—11: key for technology roadmaps[30]

9.4.1 Electricity

No ‘road map’ has been prepared for electricity. Unlike what appears to be the development of a completely new technology for the realisation of, for example, hydrogen networks, developments in the existing electrical transmission and distribution networks are likely to be far more incremental. The low carbon initiative and the introduction of RIIO are having an impact on timeframes and any ‘roadmap’ for technological development over the next decade will be skewed by the RIIO Network Innovation Competition Projects and BIS funded activities including catapult centres.

[30] *An Independent Report on the Future of the Automotive Industry in the UK New Automotive Innovation and Growth Team (NAIGT),* BERR, May 2009 available from http://www.berr.gov.uk/files/file51139.pdf

In some areas (such as new insulation materials) because of differences in methods and processes of 'sample' production, there is a disconnect between systems developed within research laboratories (i.e. TRL1 and 2) and the requirement to scale for manufacture (even of prototypes for demonstration) and this introduces an uncertainty into a potential timeline that is difficult to quantify. Examples include production on a significant scale of next generation HTS tapes and composite insulation systems that contain nano-metric scale fillers to control dielectric properties.

With the exception of the two identified technological areas involving power electronics, the other technological areas are generally standalone and can be considered as 'siloed' in that the relative success of one is not dependent on technological developments within another area. In the case of power electronics – developments in this area and the need to create a UK power electronics industry have been identified by BIS[31] and significant government investment is likely to greatly affect the rate of development.

In summary, there are an increasing number of programmes for driving the development of new network technologies that encompass system operators, manufacturers and suppliers as well as consultants and research institutes. This in turn is having an effect in accelerating the technological roadmaps associated with electrical transmission and distribution technologies. In some cases the problems with transformation of technology from a research environment to scaleable levels of manufacture are difficult to quantify and hence it is impossible to associate realistic timescales with higher TRL levels of development. For the technologies identified in this study, with the exception of power electronics, there are not significant levels of dependency. Consequently any roadmap would be highly speculative and unlikely to offer useful insight.

9.4.2 Gas

There is currently much debate about the extent to which natural gas should be relied upon in the UK energy mix and hence in understanding what the deployment targets and rates might be[32].

In terms of gas transmission, the direction taken by government will impact significantly on deployment of gas fired generation which in turn will impact upon the deployment of gas infrastructure. It is likely that gas will be relied upon in the near term due to concerns over reducing capacity margins and the relative speed with which gas generation can be brought on stream. This, combined with a need for greater flexibility to deal with increasing volumes of intermittent renewable generation, suggests that storage has a key role to play[33].

At the consumer end, the government heat strategy published in March 2013 places increasing emphasis on electric forms of heating and heat networks. This would reduce the need for deployment of significant new gas distribution infrastructure with a result that the emphasis is likely to be on maintenance and upgrades of existing assets.

[31] *Power Electronics: A Strategy for Success*, BIS, 2011
see https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/31795/11-1073-power-electronics-strategy-for-success.pdf
[32] A specific test case for gas was not developed for this study. Test cases developed for 'high electricity', 'high heat' and 'high hydrogen' each assume gas is part of the generation mix but have differing assumptions regarding end use. In the high electric test case, gas heating is replaced to a large degree by electric heating and in the high heat case by heat distribution networks. Hydrogen replaces gas in many aspects of the high hydrogen test case.
[33] See DECC's *Gas Generation Strategy* published on 5 December 2012.

There is considerable research being undertaken within the gas industry on the generation, transport and utilisation of gas from lower carbon sources. It is not clear that any research into the requirement to repurpose (or abandon) existing infrastructure is underway. One such area is research into the impact of biomethane on steel and PE pipes[34]. Another is the development of plasma arc technology to break down waste to its constituent elements and co-generating syngas[35]. Were this to be successful low carbon syngas could be generated which would obviate the need to repurpose gas networks thereby influencing future infrastructure costs.

The road map below seeks to provide an overview of the key technology innovations identified in this Project and their development timeline. As for electricity (discussed below) developments in the existing gas transmission and distribution networks are likely to be incremental with limited links between individual technology pathways. The map shown here is a high level approach which can be developed further by the ETI should this be considered useful.

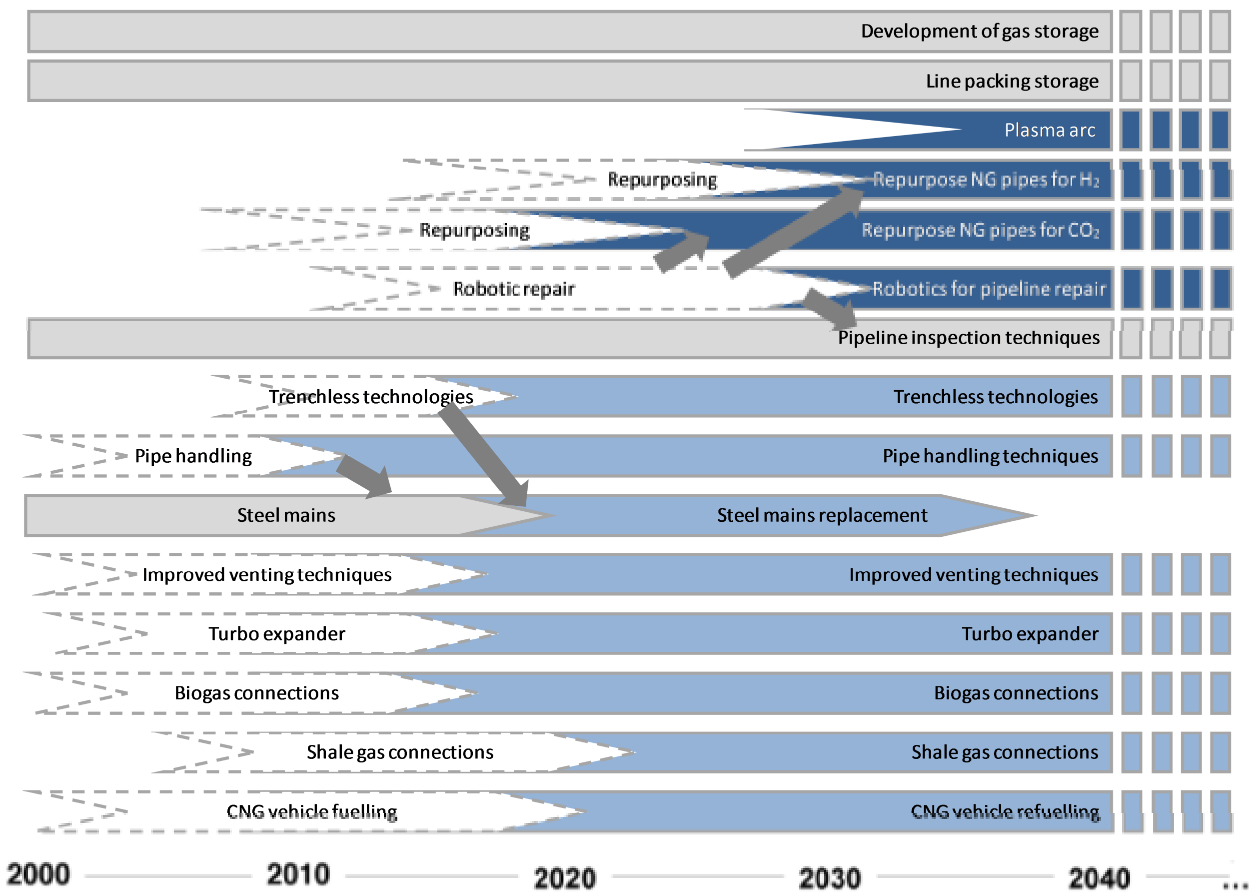


Figure 9—12: technology road map for gas innovations

[34] Research currently being undertaken by Wales & West Utilities.
[35] A related EPSRC Project is the Low-Temperature Plasma Production of Hydrogen from Methane (Supergen 14; Grant ref EP/G01244X1). Other related funded research includes 'Efficient Power from Fossil energy and carbon Capture' (EP/G037345/1) and 'Technologies for a low carbon future'(DTC Energy; EP/G036608/1).

9.4.3 Heat

The high heat test case assumes widespread development of heat networks in most cities and towns with some smaller rural schemes where fuel is available locally. This is combined with widespread deployment of thermal efficiency improvements to dwellings and commercial buildings. Residual heat loads in non-heat network areas are met by a combination of existing gas networks and heat pumps.

In order to meet the 2050 conditions outlined in the test case, it is necessary to understand the transitional steps required. These can be described in relation to the development, expansion and interconnection of different network types which have been categorised in previous studies as follows:

- Type 1: CHP plants located in a building, serving up to 3,000 homes
- Type 2: Dedicated energy centre serving up to 20,000 homes on multiple sites
- Type 3: Longer distance network linking major heat source(s) to around 100,000 homes
- Type 4: Heat captured and transmitted from power stations outside urban areas.

A deployment route map suggests that Type 1 and Type 2 networks continue to develop over the next five years with increasing interconnection over a longer time period to gain economies of scale. Type 3 networks would come into play later, connecting with Types 1 and 2 in the far term period (ie. after 10 years). The Type 4 networks could come on stream at a still later date, possibly from 2020, and ultimately connecting with Type 3 networks, again gaining advantages of economies of scale.

The barriers to the deployment of heat networks tend to be more institutional than technical, relating to financing structures, uncertainty over demand, complexity of systems and management / sharing of risk, skills and capacity, policy and incentives particularly in relation to heat, issues over routing in already congested dense urban areas etc[36]. However, some higher level technical barriers have been identified. These are outlined in Table 9-15.

Table 9-15: summary of key technical barriers associated with each network scale. Source: GLA (2011) *Decentralised energy capacity study Phase 3: Roadmap to deployment.*

Type	Technical barrier in relation to heat networks
1	Heat losses can be high in low heat demand density areas. Connection of existing buildings and ensuring adequate cooling of district heating network return water for an efficient system is critical and may require alterations such as direct water heating via plate heat exchangers and variable speed pumping on buildings HVAC circuits. What happens to gas networks is a key question. Under low levels of penetration of heat networks and electric heat pumps their operation would remain economical. However, if penetration of heat networks increased and utilisation of gas networks reduced the fixed costs of gas networks could become punitive on the remaining consumers.
2	Question of whether interconnection of smaller schemes to form larger networks is lower cost than plant renewal; physical route for connection must be available. Without aggregation of smaller networks growth into larger networks capable of making investment in longer distance, larger diameter distribution mains connecting to zero carbon heat sources such as nuclear, CCS or energy from waste plants is less likely.

[36] It is understood that DECC have recently commissioned a study to gain a deeper understanding of barriers to deployment of heat networks. The output of this study will be of relevance to this report and will be included once available.

Type	Technical barrier in relation to heat networks
	Issues around interconnection can be solved technically but are easier if common standards are adopted from the outset, particularly for temperature and pressure ratings of networks.
3	Physical routing of network becomes more difficult for larger scale schemes and technical barriers include the scale and complexity of realignment of existing services beneath roads and footways.
4	Large diameter, high pressure, long distance heat distribution connections (also referred to as heat transmission in the literature) would be amongst the largest and longest ever constructed worldwide; controlling water hammer resources requires careful design; physical scale may require routing via tunnel as the only feasible option into dense urban areas to connect with Type 2 and Type 3 heat networks.

The potential deployment route to market maturity outlined above has been developed into a technology road map for heat as illustrated in Figure 9—13.

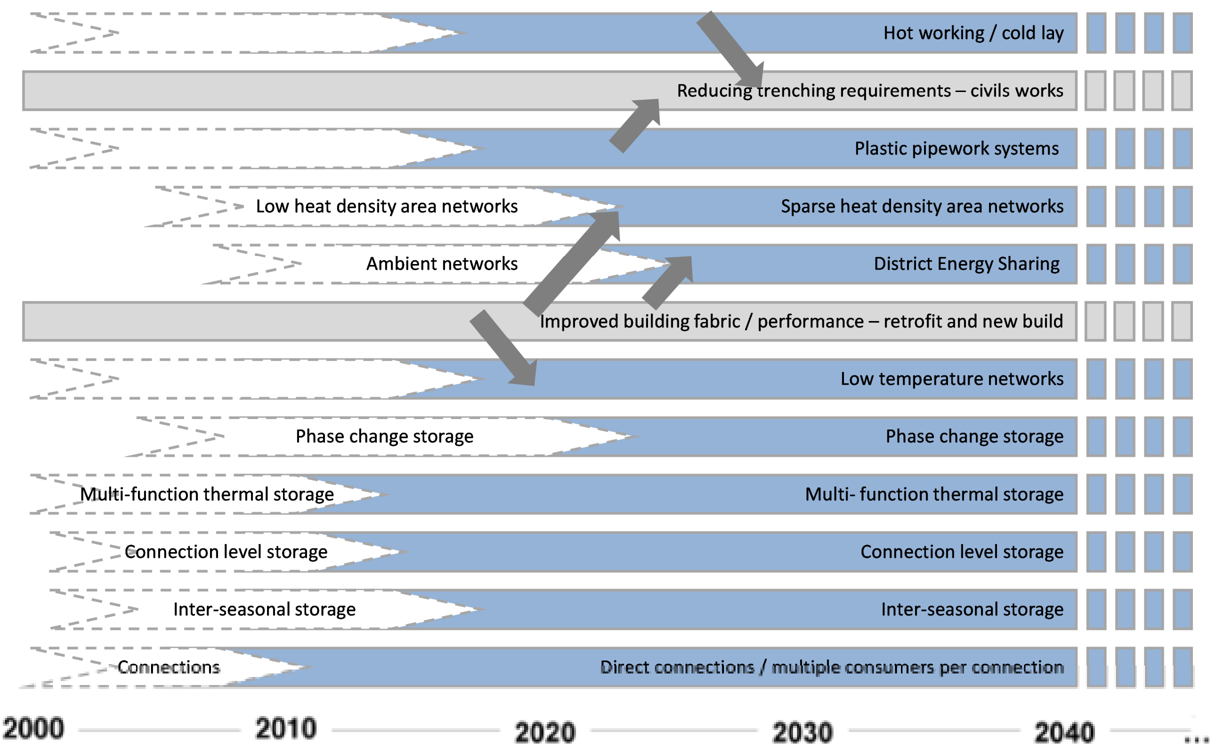


Figure 9—13: technology road map for heat innovations

9.4.4 Hydrogen

The road map below (Figure 9—14) seeks to provide an overview of the key technology innovations identified in this Project and their development timeline. This is a very high level approach which can be developed further by the ETI should this be considered useful. A rationale to support the road map is provided in Table 9-16.

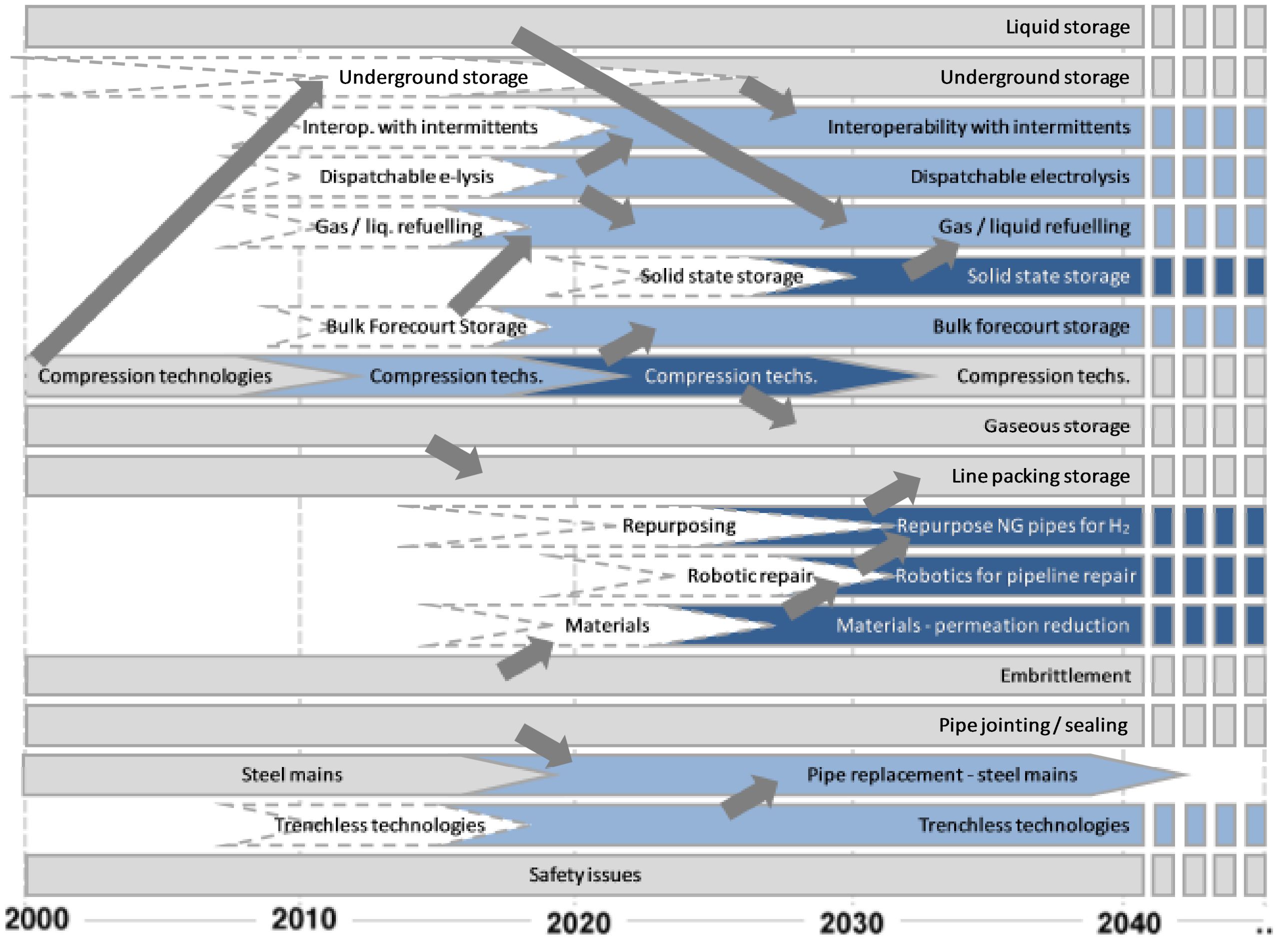


Figure 9—14: technology road map for hydrogen innovation

Table 9-16: summary providing rationale in support of hydrogen technology road map

Technology	Current status	Prognosis
Compression technologies	Conventional technology is mature, but requires optimising for hydrogen.	Ionic compressor could be game-changing, but is still experimental.
Dispatchable electrolysis	Conventional technology is mature, but requires optimising for demand response and interoperability with intermittents.	Iterative development likely, cost reduction necessary. Awaiting deep renewables penetration.
Gas / liquid refuelling	Adequate for early adopters, but requires (rate) optimisation for mass roll-out.	Iterative development, cost reduction necessary. Awaiting H2 vehicle penetration.
Interoperability with intermittents	Adequate for early adopters, but requires optimisation for mass roll-out.	Iterative development, cost reduction necessary. Awaiting deep renewables penetration. H2 production (by dispatchable electrolysis) offers cost-effective large-scale demand response and alternative to (esp. bulk) electricity storage.
Underground storage	Fundamentals understood. Few examples of significant operational experience.	Little development needed. Awaiting growth of demand.
Liquid storage	Conventional technology is mature, but requires optimising for efficiency.	Game-changing advance looks unlikely, so conventional techniques will probably persist.
Gaseous storage	Conventional technology is mature, but requires optimising for cost, weight, safety.	Game-changing advance looks unlikely, so conventional techniques will probably persist.
Line packing storage	Already in widespread use with natural gas, but adjustments needed for H2.	Little development needed. Awaiting growth of demand (initially, as hythane). Key to large-scale demand response and interoperability with intermittents. A cost-effective alternative to (esp. bulk) electricity storage.
Bulk forecourt storage	Fundamentals understood, optimisation required. Several pilot systems in use.	Iterative development. Awaiting H2 vehicle penetration.
Steel mains	Conventional technology is mature, but requires optimising for H2.	Little development needed. Awaiting growth of demand.
Solid state storage	At fundamental research stage.	The most dramatically game-changing issue for H2 - if it can be achieved!
Robotics for pipeline repair	Basic systems in use (e.g. for NG).	Continual long term development and growing sophistication likely
Materials - permeation reduction	Novel technologies in early development.	Significant advances required for widespread application.
Repurpose NG pipes for H2	Many uncertainties, scant experience.	Significant investigation (and, possibly, adaptation) required.
Embrittlement	Many uncertainties. Extent of problem not yet known.	Further investigation required. May require a degree of optimisation of materials or techniques.
Safety issues	A variety of issues requiring continuous improvements.	Continuous improvements will always be desirable.
Pipe jointing / sealing	Conventional technology is mature, but would benefit from optimisation.	Continued improvements would be beneficial.
Trenchless technologies	A variety of techniques in use. Would benefit from optimisation.	Continued improvements would be beneficial.

9.5 Research Opportunities overview

The opportunities for research have been clearly articulated by vector above. There is however a range of different future scenarios which are credible and each of which would benefit from different directions of research programmes. The underpinning questions mentioned in respect of the test cases described in Section 6.3 are indicative of the kind of options that are as yet unresolved. In this context then the design of future research should be such as to allow for flexible responses to changing directions in strategic options which may emerge. It may be that some work is needed now, to scope out in a strategic sense the extent to which different futures might be definable, and the degree to which they differ. Such an exercise would allow the architecture of the research programmes then to be developed to produce improved resilience and effectiveness whatever the future direction of energy vectors proves to be. The essence of the available options is contained in this report, and this work could be used to inform the futures planning work. Such work would set priorities and establish an order of strategic progress for research programmes. Once this work has been completed, the more specific gaps in knowledge can then be filled with research projects which are consistent with the overarching programme. A number of decisions may need to be taken without adequate underpinning information; in other words some decisions will need to be based on choice and political preference.

10 Issues outside scope

A summary of issues raised at workshops and other events in relation to the project but which are out of scope are outlined in Table 10-1 below.

Table 10-1: Summary of topics outside scope that may be of future interest to ETI

TOPIC	COMMENTS	Ref
Conversion / linkages between one vector and another	The current study looks only at conversion technologies within one vector; however there is scope for conversion between one vector and another eg electricity to hydrogen and vice versa. Hydrogen fuel cells are a particular case.	Scenarios workshop minutes 26/03/12; IWP1 workshop 11/05/12
Storage at building level	This is excluded from scope but could have value in future	Scenarios workshop minutes 26/03/12
High temperature steam	Higher temperature systems were outside the scope of the project (eg. for supply of heat to specialist industries, eg. greater than 150°C) however it could be raised as an area for review under a future study.	Scenarios workshop minutes 26/03/12
Cooling networks	Cooling networks could be used within dense urban areas with a high concentration of non-domestic buildings. Commercial office and retail buildings often have almost year round cooling loads. New buildings of this type have decreasing heat demands due to improvements in energy efficiency driven by updates to Building Regulations Approved Documents Part L. There are opportunities to utilise low grade energy sources, such as seawater cooling or ground coupling to provide cooling with very high efficiencies. Anecdotally co-efficients of performance of up to 20 are available from seawater systems, with 5 more typical for ground coupling. Buildings with year round cooling loads can also act as heat sources for buildings which require heat. There are examples of such energy sharing systems in Whistler, Canada and systems within buildings, such as 'versatemp' have been used for many years.	Scenarios workshop minutes 26/03/12
Hydrogen transport in tankers	Road transport of hydrogen is excluded from this project however it is a potential area for development, particularly during transitional stages to a more extended hydrogen economy.	Scenarios workshop minutes 26/03/12
Multi-utility civils	There is potential for different utilities to share the same trenching and other civils work. This could be cost saver but is complex in practice.	Stage Gate?
Licensing, land acquisition, planning process issues	These issues have not been reviewed in any depth in this project however they will have impact on the costs of infrastructure deployment.	

TOPIC	COMMENTS	Ref
CO_2 networks	There may be opportunities to re-purpose natural gas networks or hydrogen network for the transport of CO_2. This is likely to be limited to high pressure NTS infrastructure which can transport large quantities of gas at high pressure. In future the use of more distributed, local carbon capture and storage could require using local CO2 networks. However, at present the development of CCS is largely focused on utility scale power plants and local, small scale CCS is considered less likely to develop.	
Cost model development	The model is currently in Excel available for installation on user's individual computer. However there is potential for wider sharing and use possibly through a web-based interface.	Various discussions
Additional resolution	The assemblies selected represent a cross-section of components of network infrastructure which can be used to represent real networks. Inevitably there is some simplification involved. For example there is a huge variety of scope and capacity involved in electricity substations at transmission voltages. These could be disaggregated and represented by more detailed components. Other vectors have similar levels of detail which could be added were this felt to be of value; this being largely determined by the usage proposed for the tool by various ETI Members.	Post workshops note
Losses	Calculations which represent system modelling etc were outside the scope of this project. Developing a project level losses calculator would be a potentially valuable piece of additional work.	Post workshops note

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