Programme Area: Energy Storage and Distribution

Project: Impact Analysis

Title: Future Networks: Impact Analysis Electricity Final Report

Abstract:

This deliverable provides the final report for the electricity case studies that have been assessed as part of the project. Please refer to the Executive Summary on Page 17 for an overview of the report content.

Context:

This project assessed the potential impact of selected, identified innovations on specific types of network (relating to heat, gas, electricity and hydrogen). Generic modelled networks will be developed utilising the 2050 Energy Infrastructure Cost Calculator model developed by a separate ETI project to understand the expected costs of certain types of network. The modelled networks will provide 'business as usual data' and a useful basis for further understanding of the impact of identified innovations in terms of overall cost and network performance.

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Glossary

Term	Definition
Abandonment	A term used in the context of the ICC to refer to the end of life of an asset and the costs associated with its removal / decommissioning. Abandonment costs are included in Lifecycle costs.
Assembly	A term used in the context of the ICC. These are collections of Components compiled using quantity multipliers to produce composite costs for these Assemblies.
Component	A term used in the context of the ICC. This is lowest level to which capital costs are disaggregated.
Distributed Energy	Energy that is generated by a variety of small, grid - connected devices.
DNO interconnection	Creation of a link between two or more DNOs enabling power flow from one distribution network to another.
Fault Current Limiter (FCL)	A device that aids the reduction in circuit fault current, preventing that current from exceeding the fault level of equipment and plant.
Fault level	Fault level is a commonly used parameter that provides a measure of the energy flows experienced during a fault at a point on the network. It can be defined as the current that will result in a particular point in a network in case of a failure.
First costs	In this study, the term first costs refers to the initial capital cost incurred on installation of new equipment or decommissioning of existing commitment. First costs are the indexed costs at the date of installation / decommissioning and are not discounted.
Grid Code	In the UK the Grid Code is a handbook with technical and regulatory requirements for connection to, and use of , the National Electricity Transmission System (NETS). Compliance with the Grid Code is a requirement under the Connection and Use of System Code.
HVDC back to back station	A system than takes electrical power in an AC system and converts it into high voltage direct current (HVDC) and back to AC. Primarily used to connect HVAC circuits which are not synchronised, and/ or of the same frequency.
Lifecycle	A term used in the context of the ICC to refer to the cost profile of an asset over its life including new build, minor and major refurbishment and ultimate abandonment / decommissioning.
Load Diversity	Maximum possible power demand as a ratio of the maximum theoretical power demand at a single point in time. Factor applied to total theoretical connected load to enable calculation of consequential load and different part of a network.
Losses	As energy is transported from generation through to end user, a share of it will get lost from the system through leakage or other factors. These losses are dependent upon a variety of factors and have a cost associated with the value of the energy lost. The value of these losses is not included in the ICC.
Net Present Value	This is the combined value of all future cash flows associated with a project discounted back to 2015. Net Present Value is the term used in the ICC however it should be noted that, as all cash flows in the cost tool are in fact costs (i.e. no 'values' or revenues are included), strictly the term should be Net Present Cost.
Normalised cost	The total cost of undertaking a project divided by a single parameter such as network length (km) to give a cost per km or population (No.) to give a cost per capita.
Pre-saturated core FCL	An FCL that uses a direct current coil to magnetically saturate the iron core, providing a very low impedance during normal operation and a high impedance in response to a network fault.
Primary substation	Step-down substation on the distribution network that generally converts from 132/11kV or 33/11kV.
Project	A term used in the context of the ICC. Projects are collections of Assemblies with specific quantity multipliers combined to produce whole Project cost estimates.
Rapid Charging Unit	Equipment that allows cars to be charged to a high percentage of their capacity in relatively short time.
Refurbishment	A term used in the context of the ICC to refer to the minor and major overhaul of an asset during its life.

Term	Definition
Repurposing	Modifying the system to make it capable of carrying a different substance from the one for which it was originally designed (e.g. natural gas pipeline repurposed to carry hydrogen).
STATCOM (Static Synchronous Compensator)	It is a regulating device used on alternating current electricity transmission networks. They are used for voltage stabilisation by supporting the grid with reactive power.
Suspension Tower	Tower to support overhead power cables with no potential to terminate the line.
Terminal Tower	A structure used to support an overhead power line and to act as a mechanical termination point for conductors, and/ or to enable the transition from overhead to buried or ducted conductors.

Acronyms

Term	Definition
BoQ	Bill of Quantities
Capex	Capital Expenditure
DNO	Distribution Network Operator
ICC	Infrastructure Cost Calculator
MEAV	Modern Equivalent Asset Value
MSOA	Middle layer super output area
NPV	Net Present Value
Opex	Operational Expenditure
Repex	Replacement Expenditure

1 Executive Summary

1.1 Project overview

This study brings together two strands of work within the ETI focused on understanding the cost and performance of energy infrastructure in the UK. On the one hand, the research projects undertaken by various teams looking at specific scenarios and innovations, and on the other, the Infrastructure Cost Calculator (ICC – formerly referred to as the Energy Infrastructure Outlook 2050 Cost Tool), an analysis tool based on an extensive database of energy infrastructure costs.

The research questions addressed can be divided into two broad categories:

- Firstly, questions around the configuration and cost of representative (or 'generic') networks applicable to particular situations.
- Secondly, questions around the potential impact of selected, identified innovations on specific types of network.

This report considers the research questions posed in relation to electricity. Separate reports are available for natural gas, heat and hydrogen.

The work undertaken here made use of the first version of the ICC and as such also acted as a testing phase. Some issues arose in relation to the output of the tool particularly in respect of the treatment of operational and lifecycle costs. These findings are being fed into a parallel project to develop a second version.

1.2 Key findings

Some findings are the same across all projects. These include:

- First costs are higher at later installation dates. This is due to the impact of the real-term cost trends in the ICC applied to labour, material and plant costs. There are clearly alternative views on cost trajectories and these will influence the relative impact of deferring installation.
- NPV[1] (Capex plus Opex) is lower for projects installed at a later date. Two factors come into play here: one, as expected, is the impact of discounting; the other is the way in which lifecycle costs are modelled in the ICC and the fact that the analysis has been undertaken for a fixed period of 60 years (2015 to 2075) irrespective of the installation date. Lifecycle costs include for a major refurbishment (100% of new build costs) at a fixed period after first instalment. For later installation dates, this major refurbishment may be beyond the analysis period and therefore not be included in the NPV calculation.
- Opex costs represent a relatively small proportion of whole life costs. It should be noted that the modelling of Opex is to be revised in the next version of the ICC which may influence the outturn values (see Section 3.2.4). Note also that Opex does not include the cost of losses.

[1] In this study, the term Net Present Value (NPV) refers to the combined cash flows of a project over the project period discounted back to 2015. Note that as all cash flows in this analysis are costs (ie no revenues are included), strictly the term should be Net Present Cost. NPV is used to be consistent with the terminology used in the ICC.

A summary of findings specific to each project is given in Table 1-1.

Table 1-1 Key findings for electricity network research projects

Ref	Research question	Key findings
GENERIC NETWORKS		
E-G-9	Representative electricity transmission network model: Electricity networks modelled for 275kV and 400 kV network capacity	• The increase in the costs is proportional to the increase in the network length for the same network capacity and installation date. For instance, increasing the length 10 times increases the costs approximately 10 times. Fixed costs are not significant versus variable costs associated with increasing length. • For the same installation date, NPV total per km is higher for the higher capacity network. The capital cost of the 400kV OHL is larger, which in turn generates higher lifecycle costs.
E-G-10	Representative Electricity Distribution Model: Electricity network modelled in rural, semi-urban, urban and London context	• The share of costs represented by each of the Assemblies changes slightly from 2020 to 2040, following the same trend in all contexts, except for London. • Residential connections represent one of the highest costs in all contexts. • The LV network makes a high contribution to total cost in the urban context while in London the LV substations make the highest contribution. The primary reason for this is the density of buildings and load in London, resulting in higher capacity substations and reduced length LV networks. • First costs per capita increase as the context changes from rural through to urban areas. The main reason for this is the density of population and building, and consequently load. Secondary reasons for this are that labour, material and plant costs increase from rural to urban, with a further uplift applied to London. • First costs per capita decrease slightly from urban to London contexts. This could relate to the network design and the relative share of LV network length and the number of substations per capita assumed in the two contexts. Again secondary influences will be the difference in labour, material and plant costs between the two contexts. • The NPVs per capita increase as the density increases. • One additional factor that influences costs in different contexts is their different lifecycle profiles. It is assumed that an Assembly in an urban context will need to be replaced more quickly than the same Assembly in a rural context. Lifecycle profiles are the same for London and urban, which leads to a similar NPV per capita for both contexts.
E-G-11	Generic upgrade costs at transmission scale: upgrading existing 275kV and 400kV lines to increase capacity by ~100%	• For the same installation date, Capex NPV per km is higher for the installation of a higher voltage network. Capital cost of the 400kV OHL is larger, which in turn generates higher lifecycle costs. • Opex NPV per km is higher for higher voltages, highlighting the tool's assumption that Opex is 90% of the Capex NPV.
E-G-12a	Rapid car charging: upgrading existing distribution networks to allow for connection of rapid car charging units (1, 5, 10 and 20 units in rural and semi-urban areas)	• Costs for the upgrade of the distribution network are dominant in all variations and contexts. The reason for this is the land take per km of network length as well as the labour costs for the distribution network installation. A refinement of the tool would allow for cost saving associated with multiple cables laid in the same trench to be assessed. • For the same number of connection points at the same installation date the installation of rapid charge connections is more costly in the semi-urban context. The main reason for this is that the costs of labour, material and plant increase from rural to semi-urban. • The first costs and NPV per connection fall as the number of connections increases, which indicates that it is more cost effective to install a group of charging points than isolated single charging points. This is mainly related to the distribution network length required per connection.

Ref	Research question	Key findings
E-G-12b	Rapid car charging: impact of network reinforcement that could be required due to significant increase in electric vehicles in a residential context (semi-urban and urban)	• The analysis is based on the assumption that there is a 50% increase in peak load due to a significant increase in the use of EVs. • The LV network represents the highest share of reinforcement costs in all contexts with costs per capita being higher in urban areas than semi-urban areas. • For lower increases in demand the reinforcement required could be less but it becomes difficult to generalise the trigger points. Without completing more detailed calculations it is suggested that the costs for a 25% increase would be between 60-80% of the costs associated with a 50% increase.
INNOVATIONS		
E-I-13	Storage v reinforcement: analysis to explore the costs of storage compared with conventional reinforcement in three different applications –increase in local demand; distributed energy exporting to grid; installation of rapid car charging units	• The analysis suggests that considering current prices for electricity storage, the counterfactual reinforcement is cheaper both in terms of Capex and Opex. No allowance has been made for additional costs associated with achieving planning consent and abnormals for new OHLs. Where reinforcements are particularly onerous e.g. due to obtaining planning consent or length of OHL, storage may prove to be an economic alternative. • In the case of application 3 (car charging), local generation may improve the potential for storage if the existing OHL has limited potential to charge batteries during periods of low demand. • Further detailed analysis on new battery technology and respective cost of storage may reduce the innovation cost to be competitive with the counterfactual.
E-I-14	Fault Current Limiter v Reinforcement	• Conventional reinforcement is currently more cost effective than refurbishment of the substation with the installation of the FCL. • Only a single FCL (GridOn) has been used in "typified" application. Further analysis is recommended to consider alternative FCL (and fault current management options) and a range of application permutations. • Cost data for FCLs is very limited as very few have been installed in the UK and around the world. There is limited experience of DNOs modelling and analysing potential installation versus counterfactual and more sophisticated fault current management.
E-I-15a	Power electronics: assessing the costs of using power electronics using STATCOMS for rural windfarms with utility scale battery storage	• In the STATCOM case, the costs of the complementary utility scale battery dominate. This is because of the capital costs of the Assemblies as well as their lifecycle. • The impact of the utility scale battery on the costs of the project increases at the later installation date, due to increase in new build costs of the battery in 2040 and additional refurbishment requirements.
E-I-15b	Power electronics: assessing the costs of using power electronics using back-to-back HVDC connection for coupling DNO networks	• As for the STATCOM case, the costs of the back-to-back converter dominate. • Obtaining cost data was difficult due to limited manufacturers in the market place and imminent tendering for DNOs. Indirect benefits and counterfactual costs were not identified for the task, i.e. the alternative measures that DNOs may have to put in place to ensure adequate resilience in networks.
E-I-16	Cost comparison of up grading HVAC vs installing new HVDC at transmission level in rural areas – within an existing wayleave and in a new wayleave	• One of the main differences between HVDC and HVAC is in transmission losses. Although losses are not included in the ICC, some analysis was undertaken separately to assess the impact. • From discussions with Professor Lewin (who supported BuroHappold), and researching National Grid plans, it is clear there is significant uncertainty with the planning consent process for installing new or refurbishing existing HVDC OHLs in the UK. NG are currently progressing with the subsea Western Link which indicates a preference influenced by planning and programme costs of OHLs, although the first costs to "install" subsea are higher.

1.3 Further work

Further work could be undertaken on some of the tasks as follows:

- E-G-9: Exploration of longer distances could be done where it may become necessary to consider HVDC if replacement / upgrade does not provide enough capacity.
- E-G-10: The reliance on single locations remains a limitation of the analysis. Further work could include the analysis of additional locations to better understand and develop general cost trends.
- E-G-11: Further exploration of the impact of scale (i.e. network length) on cost could be undertaken.
- E–I-14: Further cost analysis of other prominent FCL technology and fault current management is warranted, including permutations of counterfactual in different applications. This could be completed in conjunction with Western Power Distribution and ongoing FlexDGrid project funded by the Low Carbon Networks Fund.
- E-I-15: Storage costs are now reducing significantly and although this high level study indicated counterfactual options were generally cheaper this could be tested by assessing range of storage costs and identifying target costs per MWh for different applications. The application of P2-6 should also be reviewed with the application of storage as a means to provide a resilient power supply.
- E-I-15: Alternative applications for power electronics could be explored and more research into indirect benefits, and how cost reduction will make technology more attractive.
- E-I-16: The project team did not have access to feasibility work for the Western Link or Eastern Link and key decision triggers. Adding functionality to assess transmission losses, planning costs and programme delays may be beneficial for larger assets modelled in the tool.

In addition, all tasks could be re-run in the second version of the ICC. This version will use a revised approach to modelling Opex and lifecycle costs which should address the issue encountered in this study in relation to the use of a fixed analysis period. ICC v2 will also incorporate different costs trends which will impact on results.

2 Introduction

2.1 Overview

The ETI and its Members are interested in the cost effective deployment of energy infrastructure in the UK. 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 study brings together two strands of work within the ETI aimed at addressing these issues. On the one hand, the research projects undertaken by various teams looking at specific variations and innovations, and on the other, the Infrastructure Cost Calculator (ICC – formerly referred to as the Energy Infrastructure Outlook 2050 Cost Tool), an analysis tool based on an extensive database of energy infrastructure costs. The tool is being used to enable the research teams to answer specific research questions.

The research questions addressed in this study can be divided into two broad categories:

- Firstly, questions around the configuration and cost of representative (or 'generic') networks applicable to particular situations. These network models are required to understand the expected costs, etc of certain types of typical network, the intention being to enable expedited assessment of certain types of network (at a high level) in future as the need arises, e.g. through making adjustments to the models provided as part of this work.
- Secondly, questions around the potential impact of selected, identified innovations on specific types of network. For example, questions around the difference in cost and performance between repurposing natural gas pipelines to carry hydrogen and building hydrogen pipelines from scratch. The generic networks provide the counterfactual against which the innovations can be compared.

This report considers the research questions posed in relation to electricity. Separate reports are available for natural gas, heat and hydrogen.

The study was undertaken by BuroHappold with the Sweett Group and a team of external specialists to validate the technical scoping (see Appendix A).

2.2 Approach and methodology

An overarching methodology was developed applicable to all research questions. As illustrated in Figure 2-1, key steps were to:

1. Agree the outline scope of each of the research questions with ETI.
2. Develop a detailed scope for each of the research questions including a clearly defined network design and associated Bill of Quantities (BoQ).

An important aspect of this step was to ensure that, as far as possible, the network designs were representative of the particular situation being modelled. To support this, a team of experts was engaged to provide a robust approach to validation and to ensure that assumptions and simplifications made were reasonable. The detailed scoping methodologies are particular to each research question and are covered in the relevant chapter of this report. Full copies of all Detailed Scoping reports are available separately from the ETI.

3. Cost the network design using the ICC, including costing any additional infrastructure elements not already available. For this step, the details of the Bill of Quantities generated during the detailed scoping phase were input to the tool under various contexts, capacities and timescales, thereby generating a number of data points on which to perform the analysis.

4. Analyse the cost data generated by the ICC in the context of the research question and, where relevant, compare the cost of the innovation with that of the generic counterfactual.

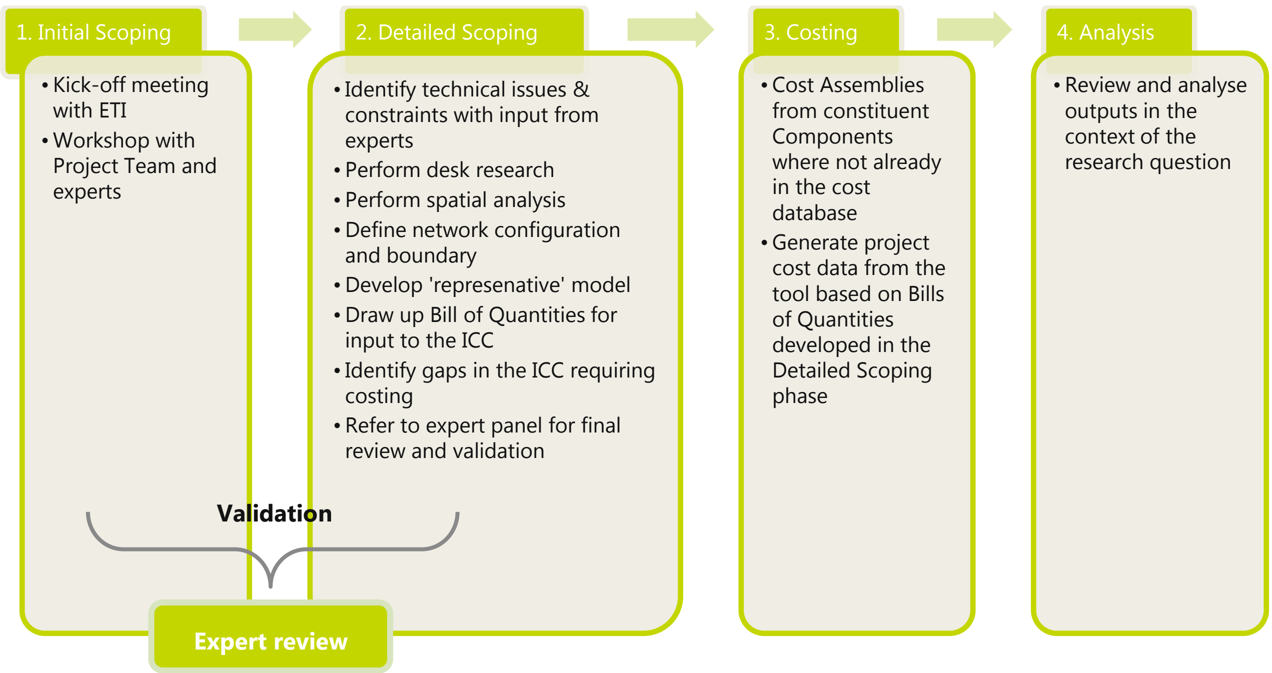


Figure 2-1 Outline methodology applied to all research questions

The ICC that underpins this analysis is a tool that was commissioned by ETI in 2012 and created by Buro Happold and the Sweett Group. It contains a wealth of information on the capital and operational costs of infrastructure related to the four energy vectors, electricity, gas, heat and hydrogen. To provide context for readers of this report, further background information on the structure and functionality of the tool is provided in Chapter 3.

2.3 Scope

A summary of the electricity research questions covered in this study is provided in Table 2-1. As noted above, these questions arose from within ETI's operational and strategic teams, and as such are specific to particular areas of work on which they are engaged. The table outlines the context of each research project and the value this analysis provides.

Table 2-1 Summary of electricity research questions covered in this study

Ref	Title	Description	Context / value added
GENERIC NETWORKS			
E-G-9	Representative electricity transmission network model	Electricity networks modelled for 275kV and 400 kV network capacity	Rural. Derivation of generic transmission network costs.
E-G-10	Representative Electricity Distribution Model	Electricity distribution networks of differing scales	Rural, semi-urban, urban and London. Derivation of generic distribution network costs.
E-G-11	Generic upgrade costs at transmission scale	Upgrading existing 275kV and 400kV lines to increase capacity by ~100%	Rural. Understanding of upgrading costs.
E-G-12	Rapid car charging	Two scenarios were analysed: a) Upgrading existing distribution networks to allow for connection of rapid car charging units (1, 5, 10 and 20 units in rural and semi-urban areas) b) The cost impact of reinforcing distribution networks in residential areas due to an increased penetration of electric vehicles	Rural and semi-urban. Understanding of upgrading costs in relation to increasing vehicle load.
INNOVATIONS			
E-I-13	Storage v reinforcement:	Analysis to explore the costs of storage compared with conventional reinforcement in three different applications – 33kV increase in local demand; 33kV distributed energy exporting to grid; 11kV installation of rapid car charging units	Various contexts. Understanding of impact of using storage rather than having to upgrade a network.
E-I-14	Fault Current Limiter v Reinforcement	Installation of a FCL in a primary substation to reduce higher fault current (due to increased decentralised generation) as an alternative to conventional substation upgrade.	Urban and London Understanding of cost of a FCL installation and complexities of "typifying" their application.
E-I-15	Power electronics:	Assessing the relative costs of using power electronics in two applications: a) use of STATCOMS for rural windfarms with utility scale battery storage b) back to back HVDC connection for coupling DNO networks	Rural Comparison of two alternative power electronics solutions
E-I-16	Cost comparison HVAC vs HVDC at transmission:	Assessment of costs of HVAC vs HVDC to increase capacity of existing transmission OHL	Rural High level assessment of transmission costs included

2.4 Report structure

This report synthesises the work undertaken on each of the research questions and presents and discusses the findings. A chapter is included for each question using the project reference provided in Table 2-1. The analysis is based on the detailed scoping exercise that was undertaken for each project. The Detailed Scoping reports are available separately from the ETI.

An overview of the ICC is provided in Chapter 3 to provide context to the reader when interpreting the results.

3 Infrastructure Cost Calculator

3.1 Introduction

This chapter explains the workings of the ICC in the context of this study. Full details of its structure and operation can be found in the ETI Energy Infrastructure 2050 Final Report, 22 November 2013, available from the ETI.

This chapter should be considered as a reference chapter to provide background to the interpretation of the data.

3.2 Cost Tool overview

The ICC is a structured database containing cost data for a broad spectrum of infrastructure elements for electricity, gas, heat and hydrogen in respect of transmission, distribution, conversion, connection and storage. It was developed over a two year period by Buro Happold in close association with the Sweett Group, combining expertise in technical design and cost modelling. The tool is under development with a second version due to be released towards the end of 2015. The analysis presented in this report was undertaken using the first version, completed in November 2013.

The following sections highlight some of the key features of the tool that are of relevance to this study.

3.2.1 Tool structure

The tool uses a modular approach to build up costs, from Component to Assembly to Project as shown in Figure 3-1.

- **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.
- **Assemblies** are collections of Components compiled using quantity multipliers to produce composite costs for these Assemblies. Components are assembled for new build, refurbishment, re-purposing and abandonment within Assemblies, as appropriate. Assemblies are the key 'building blocks' of the tool with each Assembly being clearly defined in a technical diagram that gives the element boundary, typical configuration and capacity range.

  The name given to each Assembly includes the following descriptors:

  - Vector: Electricity, Gas, Heat, Hydrogen
  - Function: Transmission, Distribution, Conversion, Connection, Storage
  - Mode: AC, DC, HVAC, HVDC, none
  - Rating: eg 275 kV line
  - Installation: Buried, Overhead, Offshore, Tunnelled, None

  This naming structure is used wherever Assemblies are referred to in this report.
- **Projects** are collections of Assemblies with specific quantity multipliers combined 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.

This study makes use of the Project functionality of the tool. A detailed description of how this works and how the data flows from Component to Assembly to Project is provided in Appendix B.

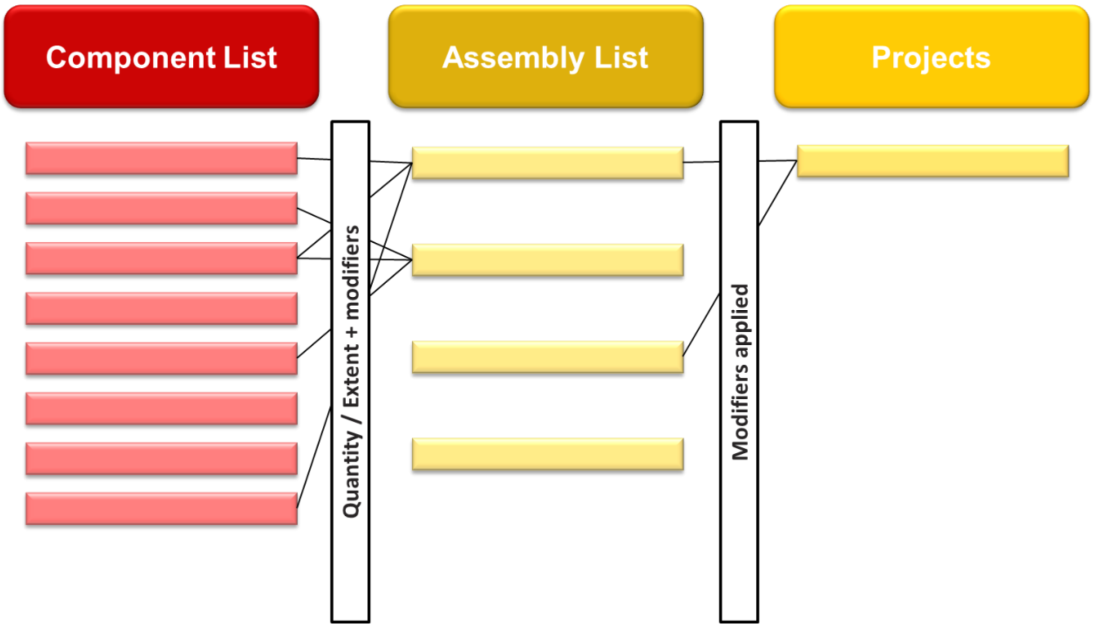


Figure 3-1 Outline of Infrastructure Cost Model structure

3.2.2 Cost data

The approaches to capital and operational costs in the tool are different, primarily due to the difference in availability of data.

Capital costs are derived using a 'bottom up' approach whereby each Component is costed separately as data is generally available at this level. The data has been built up from a number of sources which vary in quality from strong to weak. Items for which data is weakest are generally those which are relatively new and for which there are few precedents. The quality of the data is referenced within the tool.

A more 'top down' approach is used 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. Operational costs include for direct and indirect costs and are based on the published network costs of the Distribution Network Operators (DNOs)[2]. Profiles for changes in operating costs over time are described in Section 3.2.4 below.

[2] For a full description of how operational costs were applied in the tool, see the *ETI Energy Infrastructure 2050 Final Report*, 22 November 2013, available from the ETI, in particular Chapter 7 and Appendix G, *Opex Framework for Energy Infrastructure*, PPA Energy, April 2013.

3.2.3 Component cost rate modifiers

All Components are given a baseline cost, split into materials, labour and plant. In order to reflect the fact that costs vary in different contexts and under different circumstances, modifications (expressed in percentage changes) to this baseline cost are allowed for. Thus for example, while the baseline cost for civils associated with the installation of 12" LP gas pipeline in a rural context might be £135/m, the ICC assumes that semi-urban costs are 130% of this and urban costs are 400%. Similarly, cost rate modifiers are applied for different scales of installation, and different environments such as ground conditions.

To take account of the variation of costs across the UK, the current version of the ICC applies Regional Tender Price Indices as extracted from Building Cost Information Service (BCIS). Thus for example, the cost of projects installed in London are inflated by 122% against the 'All of UK' baseline.

3.2.4 Operational and lifecycle cost profiles

The ICC recognises that different infrastructure elements are likely to have different cost profiles over time. This is accounted for through the application of different operational cost and lifecycle cost profiles.

- **Operational cost profiles**: The most significant impact on operational costs over an asset's life is the failure rate and therefore the need for reactive maintenance. The failure rate is assumed to be mainly influenced by the asset type, either active or passive. On this basis, two profiles are incorporated into the tool to represent the variation in operating cost over the life of the asset (from 0 to 100% of the defined asset life) as illustrated in Figure 3-2. 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[3].

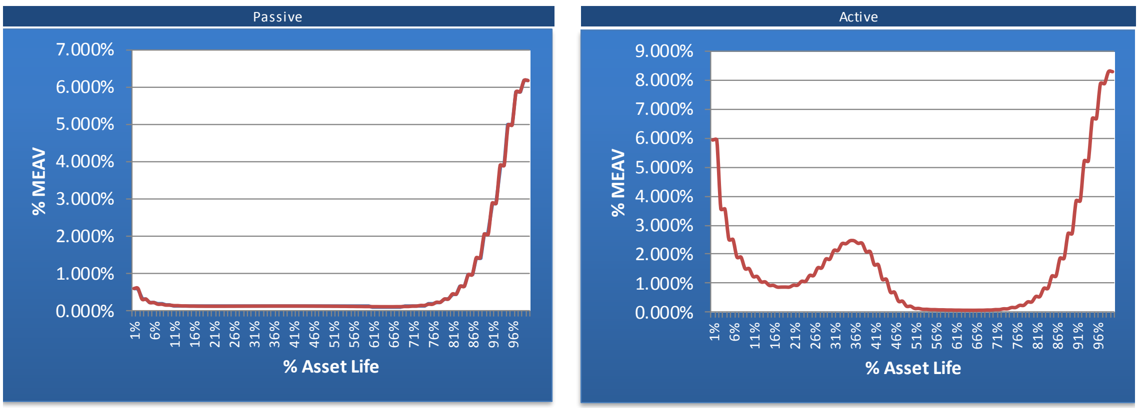


Figure 3-2 Passive and Active Opex profiles in the ICC v1[4]

[3] The modelling of Opex and lifecycle costs will be changed in v2 of the ICC. In v1, Opex comprised failure costs and indirect Opex only, with cyclical replacements of capital equipment and abandonment being modelled through the lifecycle profiles as described here. In v2, the method will use combined Weibull curves to represent failure costs, indirect Opex and replacements of capital equipment, with these latter costs being spread over a number of years, rather than all at once as in v1.

[4] MEAV is the Modern Equivalent Asset Value and is used as the basis for calculating operational costs.

- **Lifecycle cost profiles**: The lifecycle profile defines the periods of major and minor replacement and the percentage replaced in each of these cycles. It also includes abandonment at end of life. The cycles are deemed to differ according to context (ie assets are assumed to have a shorter lifecycle in an urban context than in a rural one). Two examples of lifecycle profiles used in the tool are shown in Figure 3-3[3].

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
Cycle modifier		Urban	Semi-Urban	Rural
		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
Cycle modifier		Urban	Semi-Urban	Rural
		90%	100%	120%

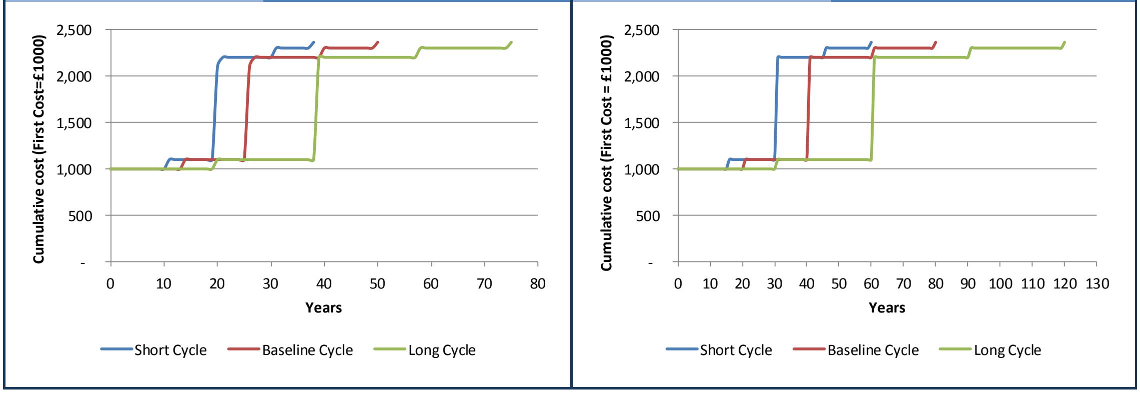


Figure 3-3 Lifecycle profiles in the ICC v1

3.2.5 Trends

The tool includes two specific types of cost trend that are applied to Component data.

The first are general real-term cost trends applied specifically to labour, materials and plant. High, medium and low increase trends are allowed for within the ICC, with the default trend – used in this analysis – being medium (Figure 3-4). Alternative versions of these trends are being developed for future analysis.

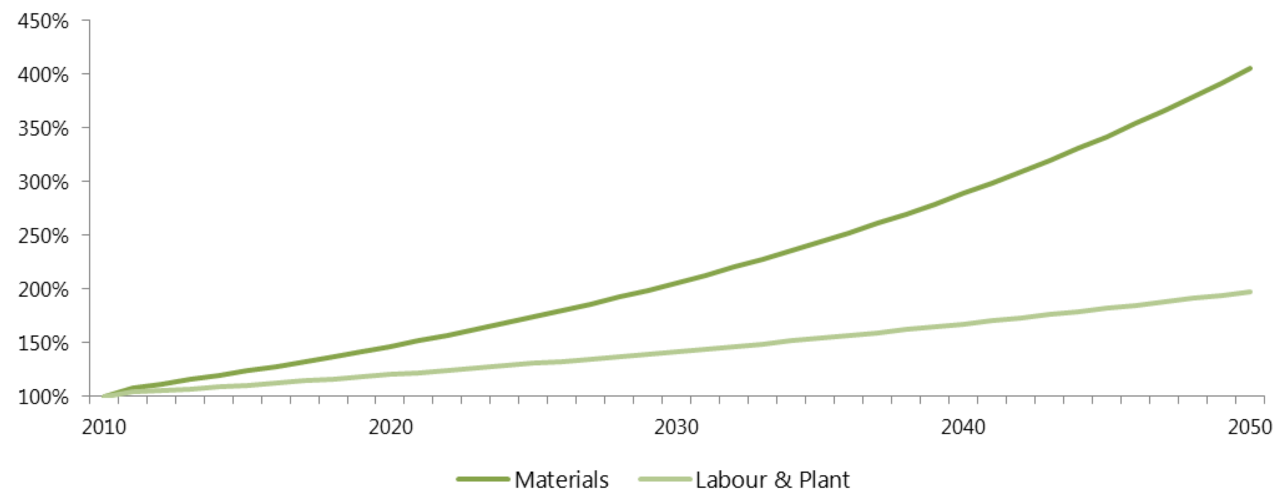


Figure 3-4 Medium general real-term cost trends as applied in the analysis

The second are technology cost curves that relate to the different cost trajectories arising as a consequence of the maturity of the underlying technology. Five curves are available within the ICC as illustrated in Figure 3-5. These are taken from a report prepared by EA Technology for Ofgem[5] and are made up as follows:

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 offshore wind farm costs and flat line)

Type 4; Medium reduction (based on the cost curve for offshore wind farms)

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

The majority of Components are categorised as Type 2 (flat) but steeper reduction curves are applied to more innovative technologies.

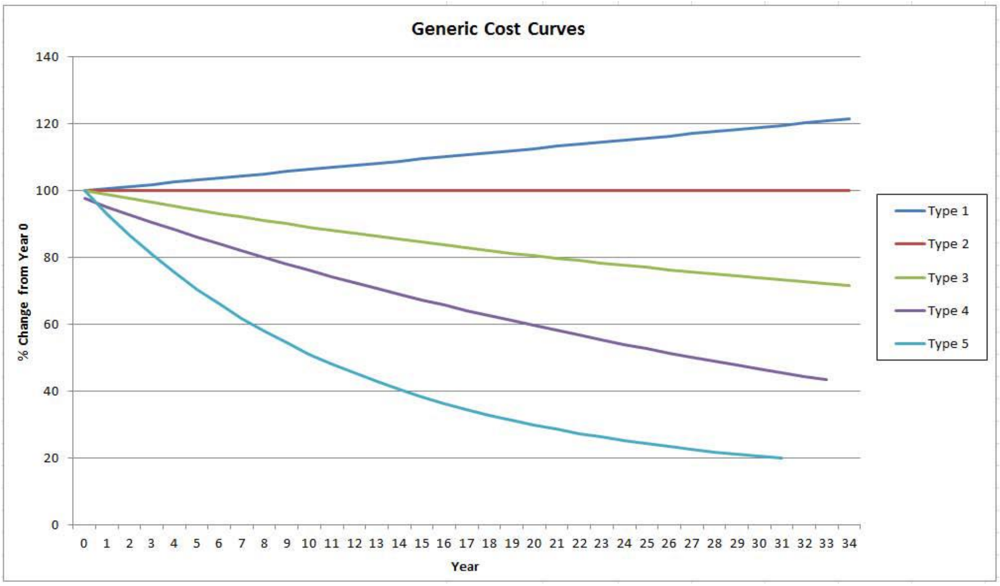


Figure 3-5 Technology cost curves incorporated into the ICC v1

3.2.6 Projects

For the purposes of this study, the key functionality of the tool is the costing of Projects. A Project is essentially a Bill of Quantities (BoQ) based on a specific network design, the BoQ comprising a list of Assemblies each with a particular quantity.

Project costs are built up within the database such that cost data flows from the Components through to the Assemblies and on to the Project. As noted above, the tool allows for baseline costs to be modified according to particular circumstances of installation. Thus for example, different projects may be installed in different ground conditions, or in different contexts (urban, semi-urban, rural) resulting in different out turn costs.

[5] http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/WS3%20Ph2%20Report.pdf

A detailed description of how the cost rate modifiers are applied and the data flows from Component to Assembly to Project is provided in Appendix B.

3.3 Application of the ICC in this study

This section outlines how the ICC has been used in this study, describing the treatment of all input variables and the derivation of outputs.

3.3.1 Inputs

As noted above, the ICC allows for a variety of factors to be specified in order to tailor the analysis to the specifics of a particular project. For this study, some of these have been applied specifically for each project while some have been fixed across all projects as a practical response to managing the amount of data generated. A description of each variable is given below.

1. Add on costs (contingencies etc): these are calculated as a percentage of Capex and have been set at the same rate for all projects in this analysis as detailed in Table 3-1.

Table 3-1 Add on costs applied to all projects

Parameter	Description / details	Value
Project management, Engineering, etc	% to be added to Capex	12%
Preliminaries	% to be added to Capex	15%
Contractor overheads and profit	% to be added to Capex	5%
Contingencies	% to be added to Capex	10%

2. Cost trends for labour, materials and plant: all projects use the Baseline trend (see Section 3.2.5).

3. Technology maturity: these are specified at Component level depending on the nature of the Component (see Section 3.2.5).

4. Installation conditions: excavation difficulty, ground contamination and ground water are the same for all projects as outlined in Table 3-2.

Table 3-2 Ground conditions applied to all projects

Parameter	Condition	% of ground in specified condition
Excavation difficulty	Ground is soft and clean. No rock or hard material	60%
	Intermittent rock / hard material (20% by volume)	30%
	Prolific rock / hard material (75% by volume)	10%
Ground contamination	Ground is clean and inert	50%
	Ground is mildly contaminated	30%
	Ground is heavily contaminated	20%
Ground water	Little or no ground water	80%
	Intermittent dewatering required	20%
	Continuous dewatering required	0%

5. Region: all projects (rural, semi-urban and urban) are designated as 'All of UK' with the exception of the London context which is designated as London (see Section 3.2.3).

6. Context: this is a variable within the analysis, thus projects are defined as urban, semi-urban or rural as specified in the relevant Detailed Scoping document.

7. Optimism bias: this is the same for all projects as outlined in Table 3-3.

Table 3-3 Optimism bias applied to all projects

Parameter	Description / details	Value
Optimism bias	% Increase to estimated NPV to allow for Optimism Bias:	Capital Expenditure
	Lower	6%
	Upper	66%

7. Cash flow parameters: these are the same for all projects as outlined in Table 3-4. In particular it is important to note that cash flows are derived for the period 2015 to 2075 (ie a 60 year period) regardless of installation date. Thus a project installed in 2040 will have cash flows over the period 2040 to 2075 and these cash flows will be discounted back to 2015.

Table 3-4 Cash flow parameters applied to all projects

Parameter	Description / details	Value
Start year	This is the date at which the NPV is calculated.	2015
Lifecycle Assessment Period (years)	This is the total period over which project cash flows are assessed.	60
Discount rate	From 2015	3.5%
	From 2046	3.0%

3.3.2 Outputs

The key outputs from the ICC used in the analysis are the Net Present Value (NPV)[6] of the capital and operational costs over the project life; the first cost, being the initial capital cost, undiscounted; and the relative cost of different Assemblies within the network. These are described below.

- **The capital cost NPV** is the NPV of cash flows associated with the initial installation of the asset plus those associated with replacement and abandonment. Cash flows are initially discounted at 3.5% and at 3.0% from 2046.

[6] Note, throughout this report, the term Net Present Value (NPV) has been used to refer to discounted cash flows as this is a convention as used in the ICC. However, it should be noted that as all cash flows are in fact costs (ie no 'values' or revenues are included), strictly the term should be Net Present Cost.

An example of these cash flows is illustrated in Figure 3-6. This graph is an output of the tool and shows the annual cash flows associated with capital and replacement costs for a new build hydrogen distribution network including pipes, conversion stations and connections. The project assumes all assets are installed in 2020, with subsequent cash flows associated with minor and major replacement cycles occurring periodically thereafter. As noted in Section 3.2.4 above, the minor and major replacement cycles are determined by the lifecycle profile attributed to the Assemblies in the project as annotated in the graph below.

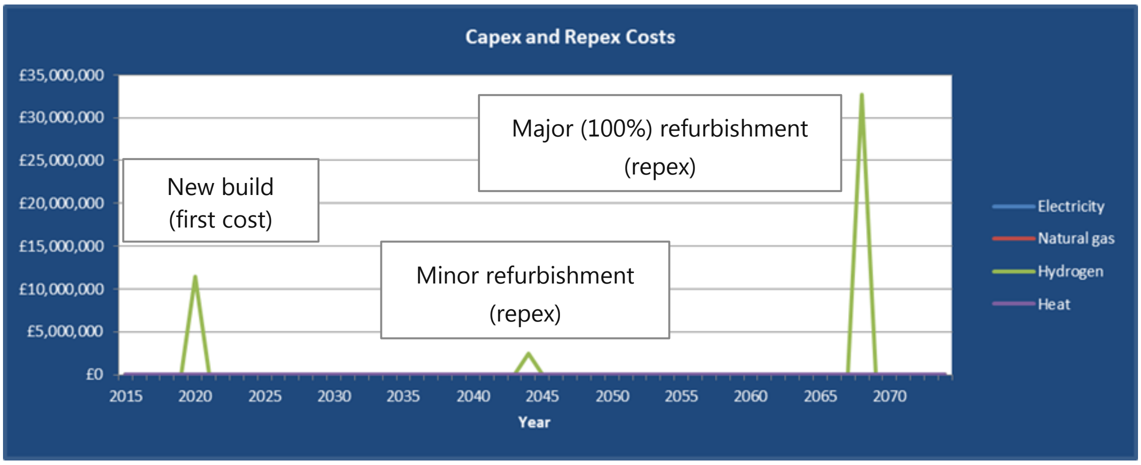


Figure 3-6 Graphical output from ICC showing capital and replacement cost cash flows over the life of a project with assets installed in 2020

An important point to take into account in the interpretation of the results in this report is the impact on lifecycle costs of deferring installation. Thus, if the same network shown above were installed in 2040 rather than 2020, the lifecycle cash flows would be as illustrated in Figure 3-7. The new build costs are now in 2040 and are higher than in 2020 due to the impact of inflation (Figure 3-4) with the minor refurbishment occurring in 2064. However, as the period for calculating the NPV is fixed at 60 years from 2015, the major replacement is beyond the end of the assessment period and therefore not included in the cash flow. This can have a significant impact on NPV when comparing costs at different installation dates.

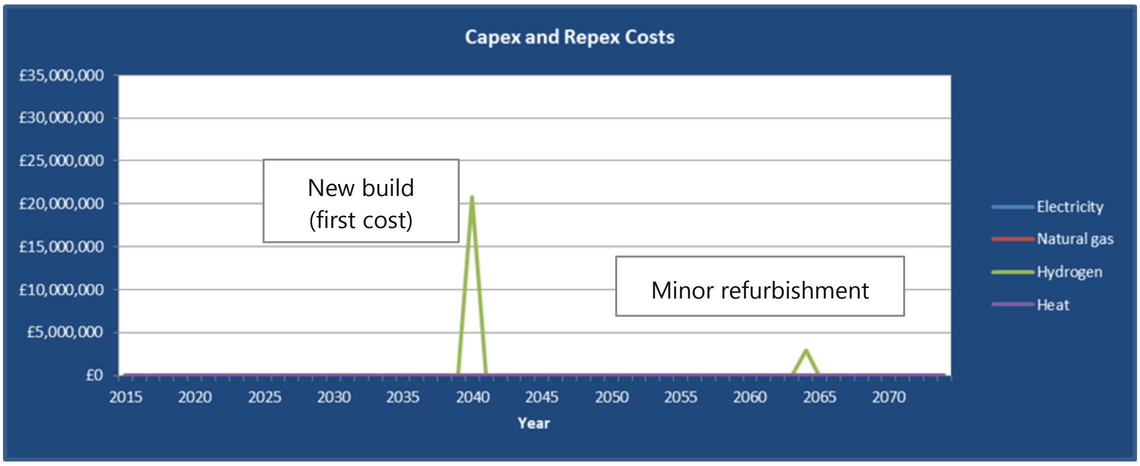


Figure 3-7 Graphical output from ICC showing capital and replacement cost cash flows over the life of a project with assets installed in 2040

- **The Opex NPV** is the NPV of all operational cost cash flows associated with all Assemblies in the Project over the assumed project life.

  An example of these cash flows is illustrated in Figure 3-8. This graph is an output of the tool and shows the annual cash flows associated with operational costs for a new build hydrogen distribution network including pipes, conversion stations and connections. As noted in Section 3.2.4 above, operational costs are determined by the operational cost profile attributed to the Assemblies in the project.

Figure 3-8 Graphical output from ICC Cost Tool showing operational cost cash flows over the life of a project

- **First cost** is the undiscounted cost of the initial installation of the asset including preliminaries and contingencies etc. but without considering replacement and abandonment. This has been included in the analysis to contextualise costs excluding Repex and Opex. First costs are higher at later installation dates due to the impact of the future cost trends (see Figure 3-4.

- **Relative cost of Assemblies:** The analysis also explores the relative costs of different Assemblies within a network to understand key cost drivers. The costs being compared are the total undiscounted costs of all Capex and Repex associated with that Assembly over the project life.

3.4 Considerations and limitations

The cost outputs of the tool and thus the analysis arising need to be viewed with the following issues in mind:

- Technical scope

  As noted above, the key units or 'building blocks' in the tool are the Assemblies. Each Assembly is defined so as to be representative in terms of configuration, capacity, size etc of a 'typical' piece of infrastructure. Given the wide number of alternative designs and configurations available in practice, it is recognised that selecting a single 'typical' design reduces the accuracy of a detailed study. For the purposes of this high level study however, the designs within the tool are considered to be adequate. Where no appropriate Assembly was available in the tool for a particular research question, a new one was added.

- Opex

  The approach taken to operational costs was simplified for the purposes of this first version of the tool. These are being refined for the second version.

- Losses

  No account is taken of losses occurring over the network. Losses were not included in the tool due to their dependence on network design, which is outside the scope of the tool.

- Lifecycle profiles

  Three lifecycle profiles are included in the tool, all of which include for a major (100%) replacement after a certain period. The inclusion of lifecycle costs in the Capex NPV influences results particularly where installation occurs at different dates given that the assessment period remains fixed (ie 60 years from 2015 to 2075).

  It should be noted that the modelling of lifecycle costs will be revised in the next version of the tool, taking a more probabilistic approach and thereby allowing for cash flows to be smoothed. In addition, lifecycle costs will be included in with Opex costs rather than with Capex costs.

- Project cost parameters

  The tool allows for the variation of a number of different parameters in relation to ground conditions, prelims costs, optimism bias etc. For the purposes of this initial study, these have been fixed for all projects. They can however be varied should more detailed analysis be required at a later date.

- Economic trends

  Subsequent to the initiation of this project, the economic trends for materials, labour and plant costs have been revised. These revisions have not been taken into account in this analysis.

Overall, the results of the analysis need to be considered in the context of the first version of the ICC. As well as providing cost information for ETI research teams, the exercise has also identified issues to be addressed in the second version of the tool.

4 E-G-9 Representative Electricity Transmission Model

4.1 Research question overview and scope

This analysis is intended to provide a reference network cost at transmission level in rural areas with overhead lines. The analysis provides the ETI with the basis on which to evaluate the capital and operating costs of transmission networks over different time frames.

4.1.1 Design of representative network

The schematic in Figure 4-1 shows the boundary of this project. This schematic provides the basis of the BoQ used for costing purposes.

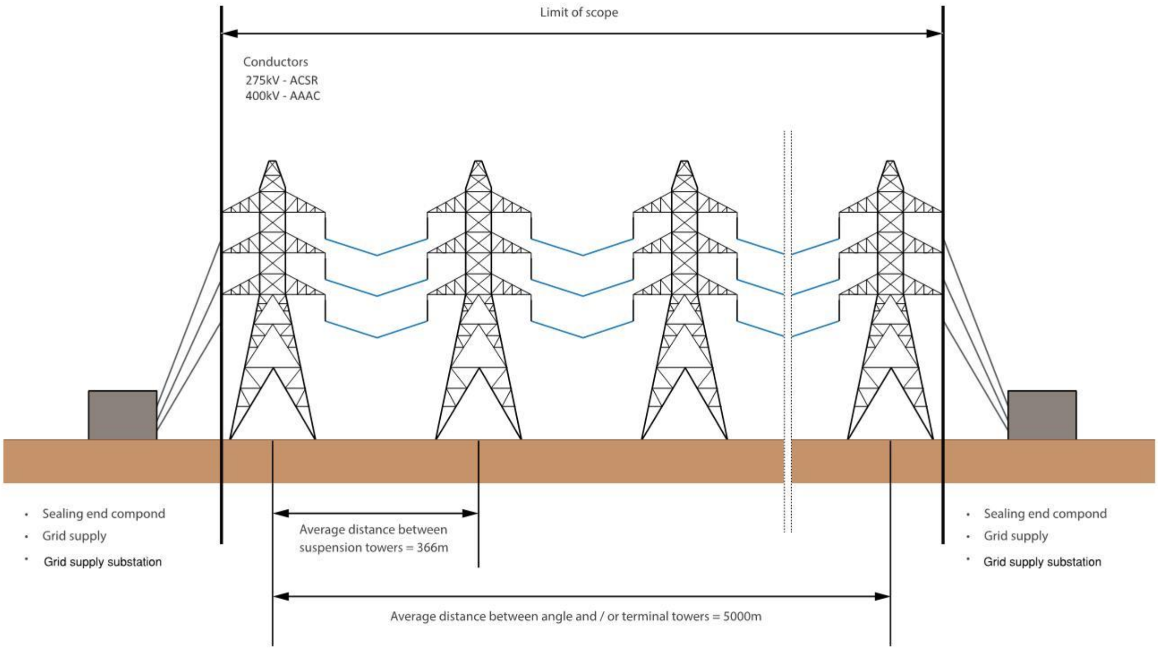


Figure 4-1 Network schematic indicating scope boundary

Table 4-1 outlines the variations that have been costed and analysed.

Table 4-1 Capacity and network length for different installation dates

Installation date	Context	Capacity (kV)	Overhead transmission network length (km)	Mode
2020	Rural	275	10	New build
	Rural		100	New build
	Rural	400	50	New build
	Rural		100	New build
2040	Rural	275	10	New build
	Rural		100	New build
	Rural	400	50	New build
	Rural		100	New build

Based on the schematic in Figure 4-1, Table 4-2 outlines the different infrastructure elements (Assemblies) that make up the network and their respective quantities.

Table 4-2 Assemblies used to generate project costs

Description *	Application	Quantity	Unit
Transmission: HVAC: Overhead: 275kV line [1800 MVA]	Two lengths	10, 100	km
Transmission: HVAC: Overhead: 400kV line [3190 MVA]	Two lengths	50, 100	km

4.2 Results and analysis

Based on the quantities in Table 4-1, eight cost data sets were generated using the Infrastructure Cost Calculator (ICC). Each data set is representative of a different variation e.g. 275 kV transmission network costs, installed in 2020 with 10km length. The project cost parameters (e.g. ground conditions) are the same for each variation.

Table 4-3 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each variation for installation dates of 2020 and 2040. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 4-3 Base output data

Installation date	Context	Capacity (kV)	Overhead transmission network length (km)	First costs £m	Total NPV £m	NPV Capex £m	NPV Opex £m
2020	Rural	275	10	12.1	13.8	12.0	1.8
	Rural		100	120.7	138.5	120.4	18.1
2040	Rural		10	20.0	9.7	8.7	1.0
	Rural		100	200.4	96.9	86.5	10.4
2020	Rural	400	50	70.8	82.9	72.2	10.7
	Rural		100	141.5	165.8	144.4	21.4
2040	Rural		50	118.3	57.4	51.2	6.1
	Rural		100	236.6	114.7	102.4	12.3

Figure 4-2 and Figure 4-3 show first costs, total NPV, Capex NPV and Opex NPV for both installation dates for 275kV and 400kV respectively.

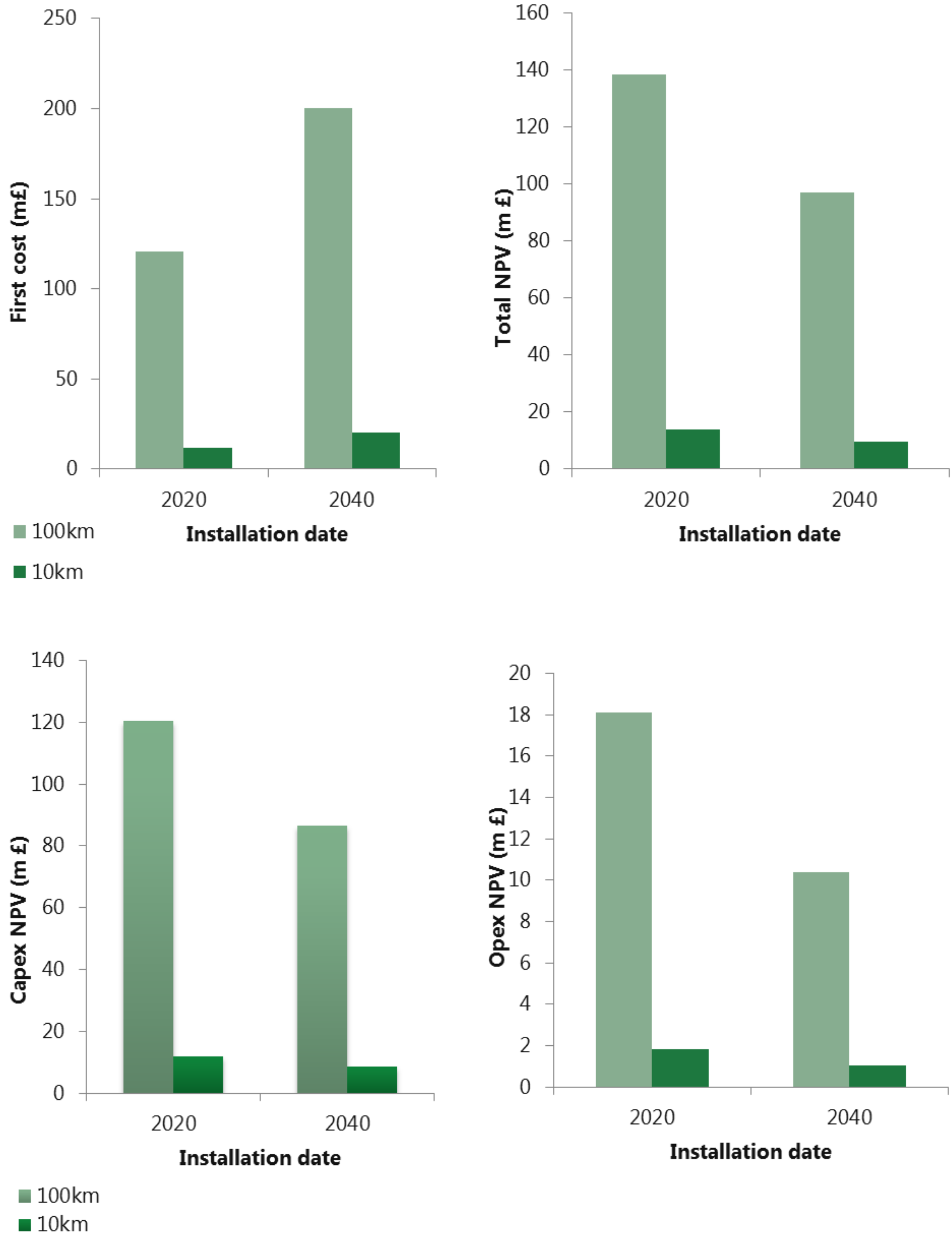


Figure 4-2 Variation of Capex, Opex, Total NPV and first cost with the installation date – 275 kV capacity

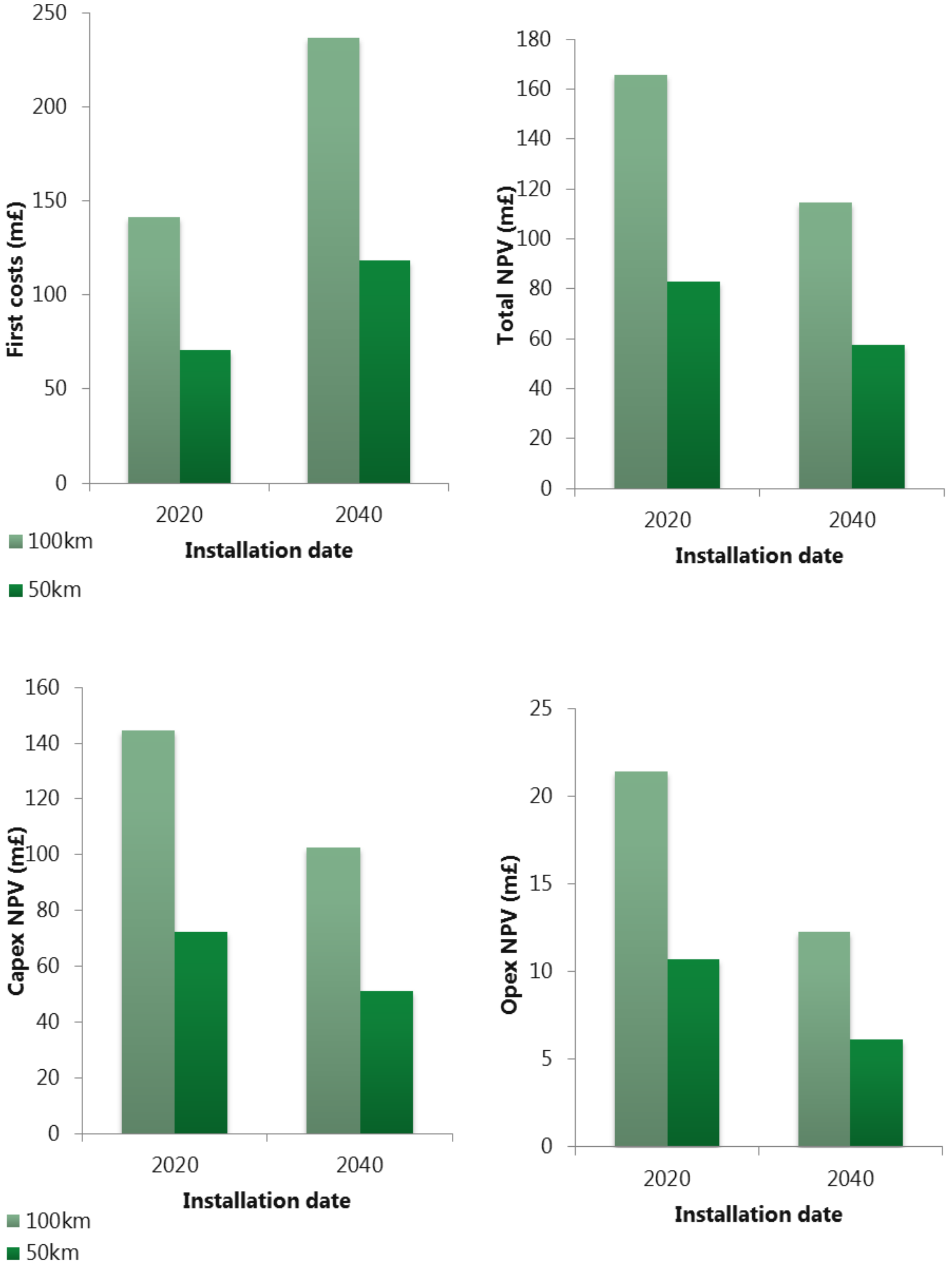


Figure 4-3 Variation of Capex, Opex, Total NPV and first cost with the installation date – 400 kV capacity

The outputs of the cost analysis indicate the following:

- First costs are higher at later installation dates due to the indexation applied in the tool (see Section 3.2.5).
- NPVs are lower for later installation dates. This is partly due to the effects of discounting and partly due to the 40-year life cycle applied to overhead lines, which means that in the 2040 variation the major refurbishment cycle is beyond the end of the assessment period.
- The increase in costs (first costs and NPV total) is proportional to the increase in the network length for the same network capacity and installation date. Thus, increasing the length 10 times increases the costs approximately 10 times. This indicates that fixed costs are not significant versus variable costs associated with increasing length.
- Capex NPV is 90% of the total NPV.

4.2.1 Analysis: Normalised costs

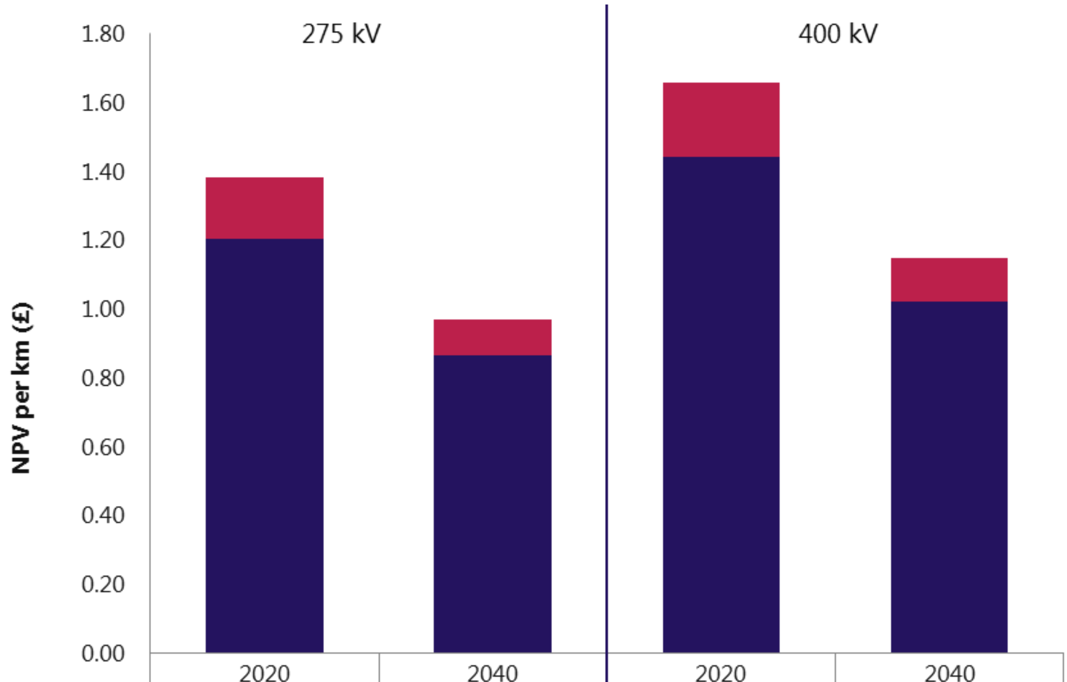
Two sets of normalised costs have been analysed:

- NPV (Capex, Opex, Total) per km of network
- First costs per km of network

Figure 4-4 shows the total NPV per km for the two different capacities and installation dates.

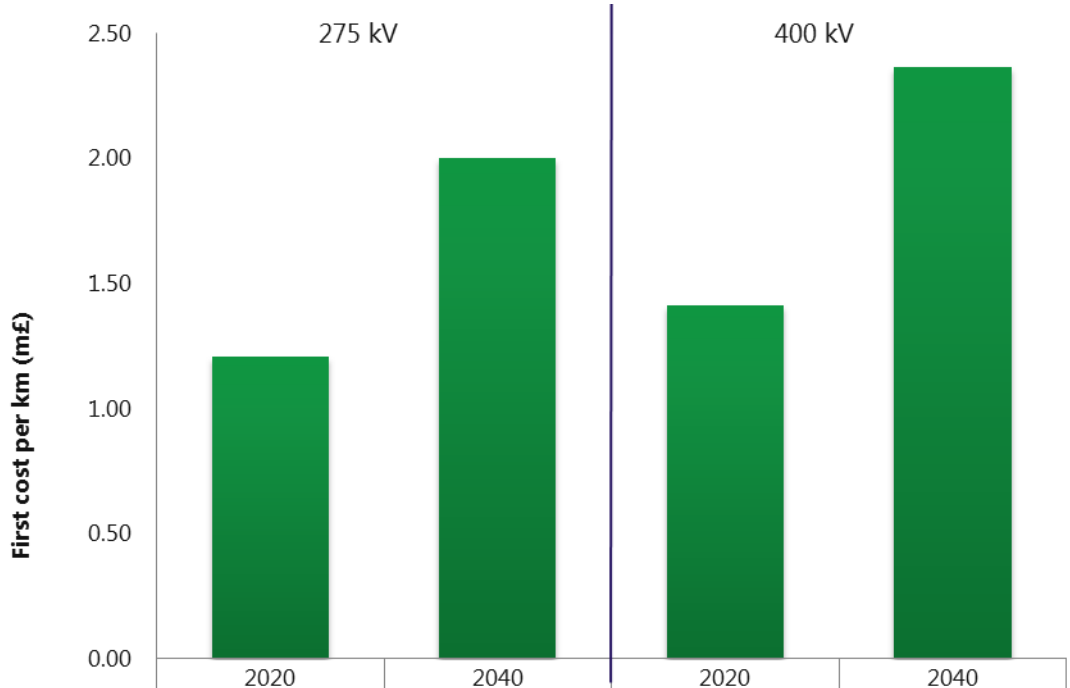
Figure 4-5 shows the first costs per km for the two different capacities and installation dates.

Both these data sets have been calculated using a 100 km network as the starting point.



	2020	2040	2020	2040
NPV Opex per km (m£)	0.18	0.10	0.21	0.12
NPV Capex per km (m£)	1.20	0.87	1.44	1.02

Figure 4-4 NPV per km by capacity and installation date



	2020	2040	2020	2040
First costs per km (m£)	1.21	2.00	1.42	2.37

Figure 4-5 First cost per km by capacity and installation date

The analysis of normalised costs shows that:

- For the same installation date, NPV total per km is higher for the higher capacity network. The capital cost of the 400kV OHL is larger, which in turn generates higher lifecycle costs.

4.3 Limitations and further work

The following limitations and further work are particularly relevant for this task:

- No allowance has been made to reflect potential abnormal legal and planning costs that might be incurred in establishing new wayleaves.
- For longer distances it may become necessary to consider HVDC if replacement / upgrade does not provide enough capacity.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

5 E-G-10 Representative Electricity Distribution Model

5.1 Research question overview and scope

This analysis is intended to provide generic distribution level costs in rural, semi-urban, urban and London areas. It provides ETI with the basis on which to evaluate the capital and operating cost of new distribution networks.

The schematic in Figure 5-1 shows the boundary of this project. This schematic provides the basis of the BoQ used for costing purposes.

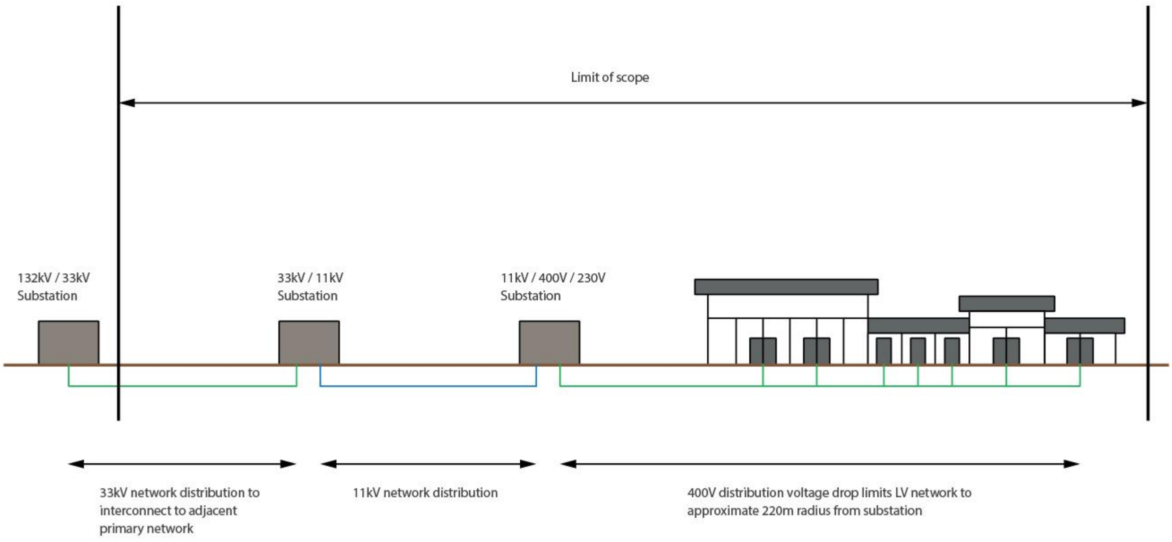


Figure 5-1 Network schematic indicating scope boundary

Table 5-1 outlines the variations that have been costed and analysed.

Table 5-1 Capacity and network length for different installation dates

Installation date	Context	Capacity range (population)	Length of LV network (km)	Length of 11 kV network (km)
2020	Rural	1,000	5.9	2.7
	Semi-Urban	7,500	31.5	14.3
	Urban	20,000	68.7	31.5
	London	50,000	114.9	53.4
2040	Rural	1,000	5.9	2.7
	Semi-Urban	7,500	31.5	14,3
	Urban	20,000	68.7	31.5
	London	50,000	114.9	53.4

Based on the schematic in Figure 5-1, Table 5-2 outlines the different infrastructure elements (Assemblies) that make up the network along with their respective quantities. The number of connections in each context was based on available data for the selected areas in relation to their population as described in the Detailed Scoping report.

Table 5-2 Assemblies used to generate project costs

Description	Unit	Rural	Semi - Urban	Urban	London
Distribution: HVAC: Overhead: 11kV line [6 MVA]	km	2.7	14.3	-	-
Distribution: HVAC: Buried: 11kV line [6 MVA]	km	-	-	31.5	53.4
Distribution: AC: Overhead: 400V line [122 kVA]	km	-	31.5	-	-
Distribution: AC: Overhead: 230V line [70 kVA]	km	5.9	-	-	-
Distribution: AC: Buried: 400V cable [122 kVA]	km	-	-	68.7	114.9
Conversion: HVAC: None: 33kV to 11kV substation [25 MVA]	Nr	0.1	0.4	1.1	4.7
Conversion: HVAC: None: 11kV to 400V pole mounted transformer [75 kVA]	Nr	3	-	-	-
Conversion: HVAC: None: 11kV to 400V ground mounted transformer [500 kVA]	Nr	-	20	53	-
Conversion: HVAC: None: 11kV to 400V ground mounted transformer [1 MVA]	Nr	-	-	-	225
Connection: AC: None: 400V commercial office connection [100 kVA]	Nr	4	34	90	276
Connection: AC: None: 230V residential connection [20 kVA]	Nr	309	3,387	8,917	17,798

5.2 Results and analysis

Based on the quantities in Table 5-1, eight cost data sets were generated using the ICC.

Table 5-3 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each variation for installation dates of 2020 and 2040. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 5-3 Base output data

Context	Installation date	First costs (m£)	NPV Capex (m£)	NPV Opex (m£)	NPV Total (m£)
Rural – 1,000 pop	2020	3.3	3.9	0.5	4.4
	2040	5.8	2.6	0.3	2.9
Semi – Urban – 7,500 pop	2020	29.5	34.0	4.7	38.7
	2040	51.8	22.7	2.7	25.5
Urban- 20,000 pop	2020	99.0	123.0	15.5	138.5
	2040	171.0	76.0	9.0	84.9
London – 50,000 pop	2020	235.3	311.8	37.0	348.8
	2040	413.7	200.0	21.9	222.0

The outputs of the cost analysis indicate that for the same context (e.g. London – 50,000 population):

- First costs are higher at later installation dates due to the indexation applied in the tool (see Section 3.2.5).
- NPVs are lower for later installation dates. This is partly due to the effects of discounting and partly due to the 40-year life cycle applied to most of the Assemblies, which means that in the 2040 variation the major refurbishment cycle is beyond the end of the assessment period.

Understanding differences between contexts is best done with normalised costs due to the differing assumptions regarding population levels (see Section 5.2.2).

5.2.1 Analysis: Assemblies

A breakdown of the key elements of cost within the electricity distribution network in the different contexts is provided in Figure 5-2 to Figure 5-5.

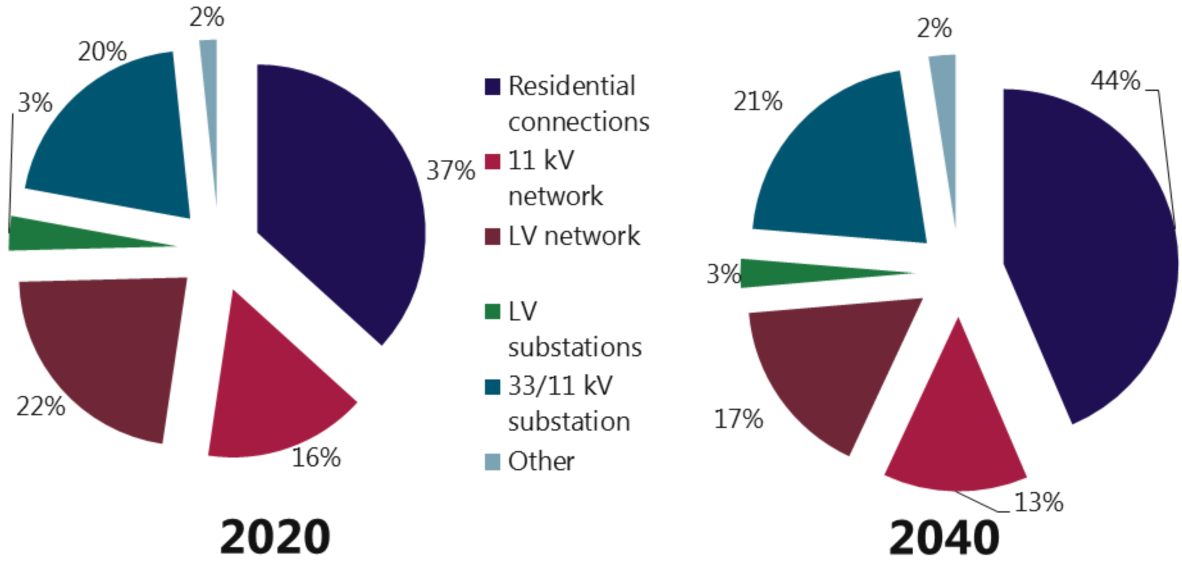


Figure 5-2 Relative share of Assembly costs at installation dates 2020 and 2040 in a rural context

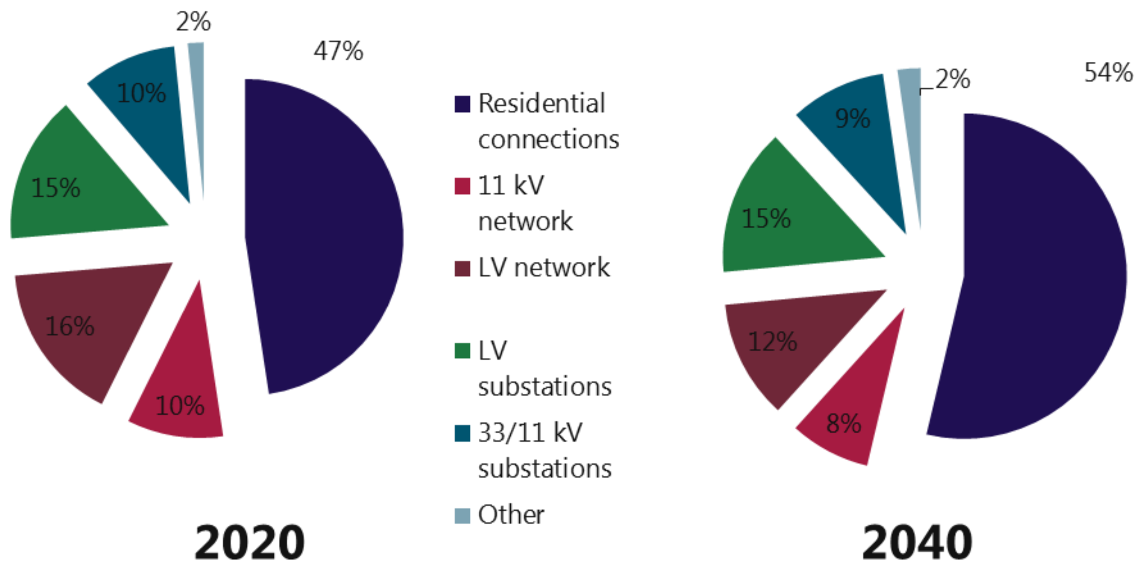


Figure 5-3 Relative share of Assembly costs at installation dates 2020 and 2040 in a semi-urban context

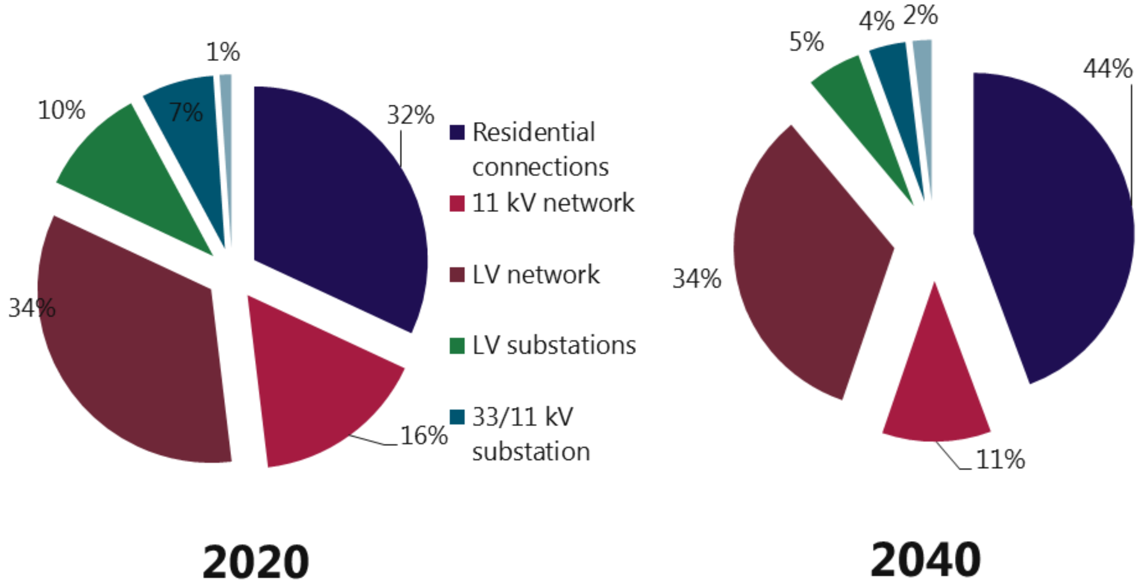


Figure 5-4 Relative share of Assembly costs at installation dates 2020 and 2040 in an urban context

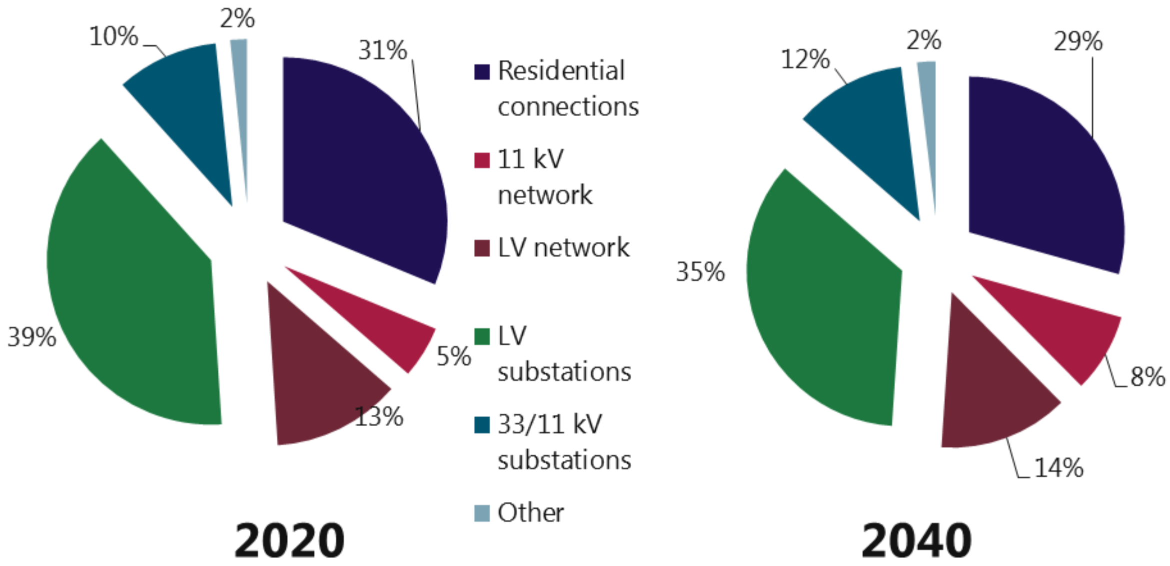


Figure 5-5 Relative share of Assembly costs at installation dates 2020 and 2040 in a London context

The analysis of the Assemblies shows that:

- The share of costs represented by each of the Assemblies changes slightly from 2020 to 2040, following the same trend in all contexts, except for London. For instance, the share of costs of residential connections increases from 2020 to 2040 for rural, semi-urban and urban contexts but decreases in London. Further analysis of the cash flows in the tool is required to fully understand this, although it could relate to the impact of the application of the cost uplift in a London context.

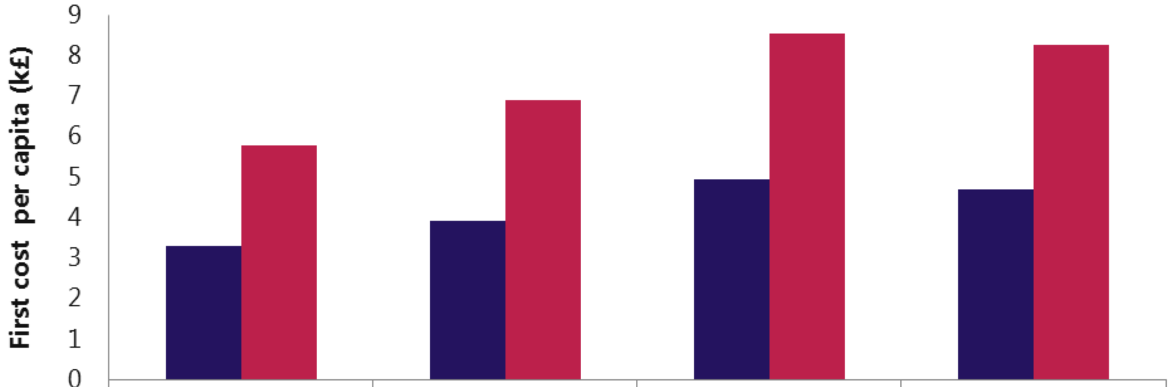
- Residential connections represent one of the highest Assembly costs in all contexts.
- The LV network represents a high share of costs in the urban context while in London the LV substations make the highest contribution. The primary reason for this is that in London the LV substations are of higher capacity (1 MVA versus 500kVA) – and are therefore more expensive – than in other contexts.

5.2.2 Analysis: Normalised costs

Two sets of normalised costs have been analysed:

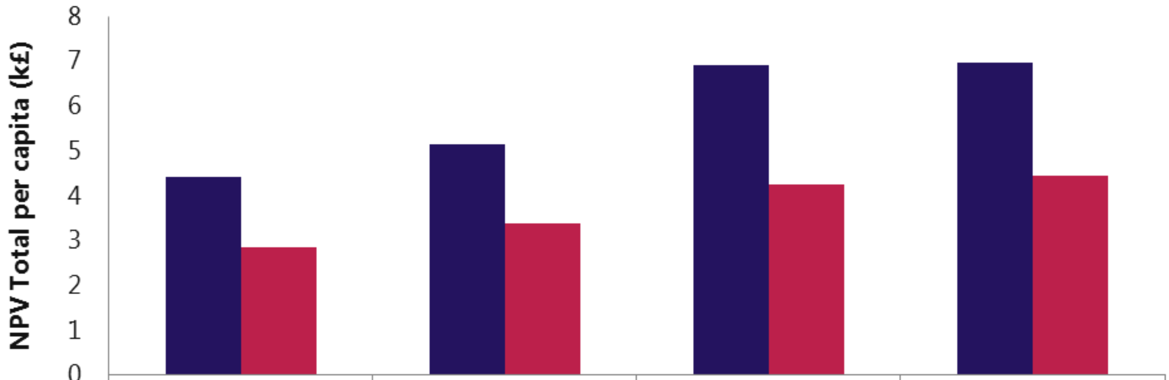
- First costs per capita
- NPV Total per capita

Figure 5-6 and Figure 5-7 illustrate these results by context and installation date.



	Rural	Semi - Urban	Urban	London
2020	3.3	3.9	5.0	4.7
2040	5.8	6.9	8.6	8.3

Figure 5-6 First costs per capita in all contexts for both installation dates



	Rural	Semi - Urban	Urban	London
2020	4.4	5.2	6.9	7.0
2040	2.9	3.4	4.2	4.4

Figure 5-7 NPV Total per capita in all contexts for both installation dates

The analysis of normalised costs shows that:

- First costs per capita increase as the context changes from rural through to urban. The main reason for this is that labour, material and plant costs increase from rural to urban, with a further uplift applied to London. For instance, the unit capital cost of a residential connection in 2010 is £2,600 in a rural context, £3,000 in a semi-urban context and £3,400 in an urban context. In the London area, all unit costs are uplifted by 22% compared with the 'All of UK' urban context (see Section 3.2.5).
- There is a slight drop in first costs per capita between urban and London contexts. This suggests that the London network design – more, larger substations and shorter LV network lengths per capita – is more cost effective than the urban network design – longer LV network lengths and fewer, smaller substations per capita. The NPVs per capita increase as the density increases. For example in 2020 the total NPV per capita in a rural context is £4,400, in semi-urban £5,200, in urban £6,900 and in London £7,000. One additional factor that influences costs in different contexts is their different lifecycle profiles. It is assumed that an Assembly in an urban context will need to be replaced more quickly than the same Assembly in a rural context. Lifecycle profiles are the same for London and urban, which leads to a similar NPV per capita for both.

5.3 Limitations and further work

The following limitations are considered relevant for the level of analysis completed:

- More accurate analysis and further validation could be obtained by using multiple MSOAs for each context.
- In reality a range of different size substations would be utilised which might have an impact on network length and substation costs.
- Increased or reduced resilience may be required in some instances, necessitating additional circuits and/or substations.

As noted in Section 3.4 there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

6 E-G-11 Generic upgrade costs at transmission scale

6.1 Research question overview and scope

This analysis is intended to provide generic upgrade costs at transmission level in rural areas with overhead lines. The primary purpose is to increase capacity by ~100% from the existing capacity as indicated in E-G-9. The assumption is that the existing asset is not at the end of its design life and can be retained for the proposed upgrade. The analysis provides the ETI with the basis on which to evaluate the capital and operating costs of upgraded transmission networks over two time frames.

6.1.1 Design of representative network

The schematic in Figure 6-1 shows the boundary of this project and provides the basis of the BoQ used for costing. The upgrade involves replacement of existing lines with higher capacity ACCC conductor bundles to increase capacity by ~100%.

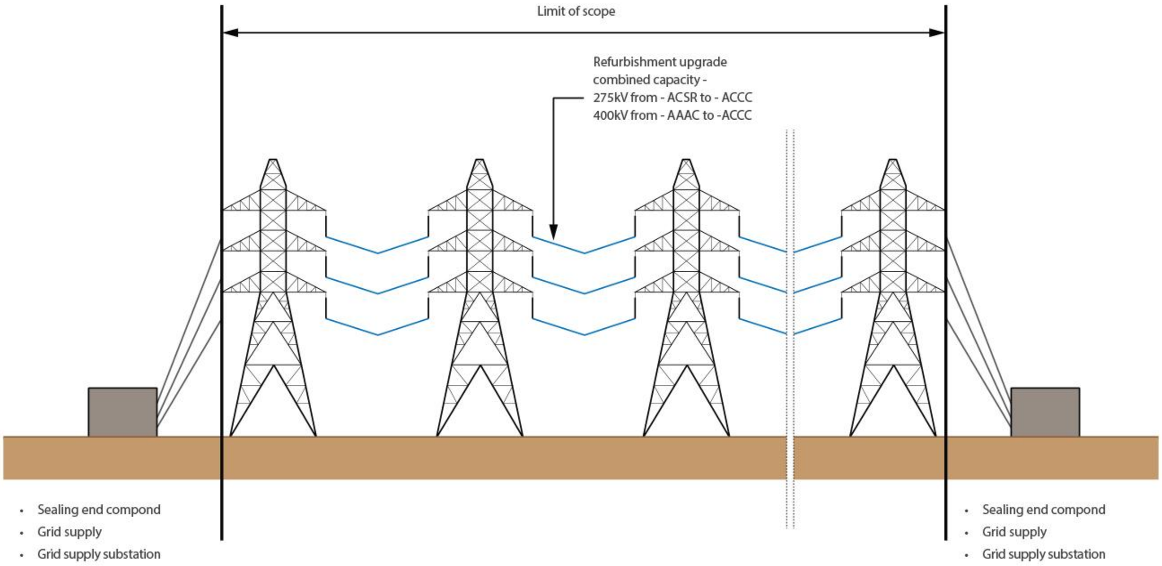


Figure 6-1 Network schematic indicating scope boundary

Table 6-1 outlines the variations that have been costed and analysed.

Table 6-1 Capacity and network length for different installation dates

Installation date	Context	Capacity (kV)	Overhead transmission network length (km)	Mode
2020	Rural	275	10	New build
	Rural		100	New build
	Rural	400	50	New build
	Rural		100	New build
2040	Rural	275	10	New build
	Rural		100	New build
	Rural	400	50	New build
	Rural		100	New build

Based on the schematic in Figure 6-1, Table 6-2 outlines the different infrastructure elements (Assemblies) that make up the network along with their respective quantities.

Table 6-2 Assemblies used to generate project costs

Description	Application	Quantity	Unit
Transmission: HVAC: Overhead: 275kV line (refurbishment using ACCC)	Two lengths	10, 100	km
Transmission: HVAC: Overhead: 400kV line (refurbishment using ACCC)	Two lengths	50, 100	km

6.2 Results and analysis

Based on the quantities in Table 6-2, eight cost data sets were generated using the ICC. Each data set is representative of a different variation e.g. 275 kV transmission network costs, installed in 2020 with 10km length. The project cost parameters (e.g. ground conditions) are the same for each variation.

Table 6-3 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each variation for installation dates of 2020 and 2040. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 6-3 Base output data

Capacity (kV)	Context	Installation date	Overhead transmission network length (km)	First costs m£	NPV Capex m£	NPV Opex m£	Total NPV m£
275	Rural	2020	10	18.5	26.7	2.7	29.5
	Rural		100	151.3	218.8	22.4	241.2
	Rural	2040	10	32.2	14.6	1.6	16.2
	Rural		100	263.2	119.6	13.1	132.7
400	Rural	2020	50	136.2	196.1	17.6	213.7
	Rural		100	245.1	353.0	35.2	388.2
	Rural	2040	50	235.2	106.9	10.3	117.1
	Rural		100	423.4	192.4	20.5	212.9

Figure 6-2 and Figure 6-3 show the first costs, the total NPV, the Capex NPV and the Opex NPV at both installation dates for a 275kV capacity network and 400kV capacity network, respectively.

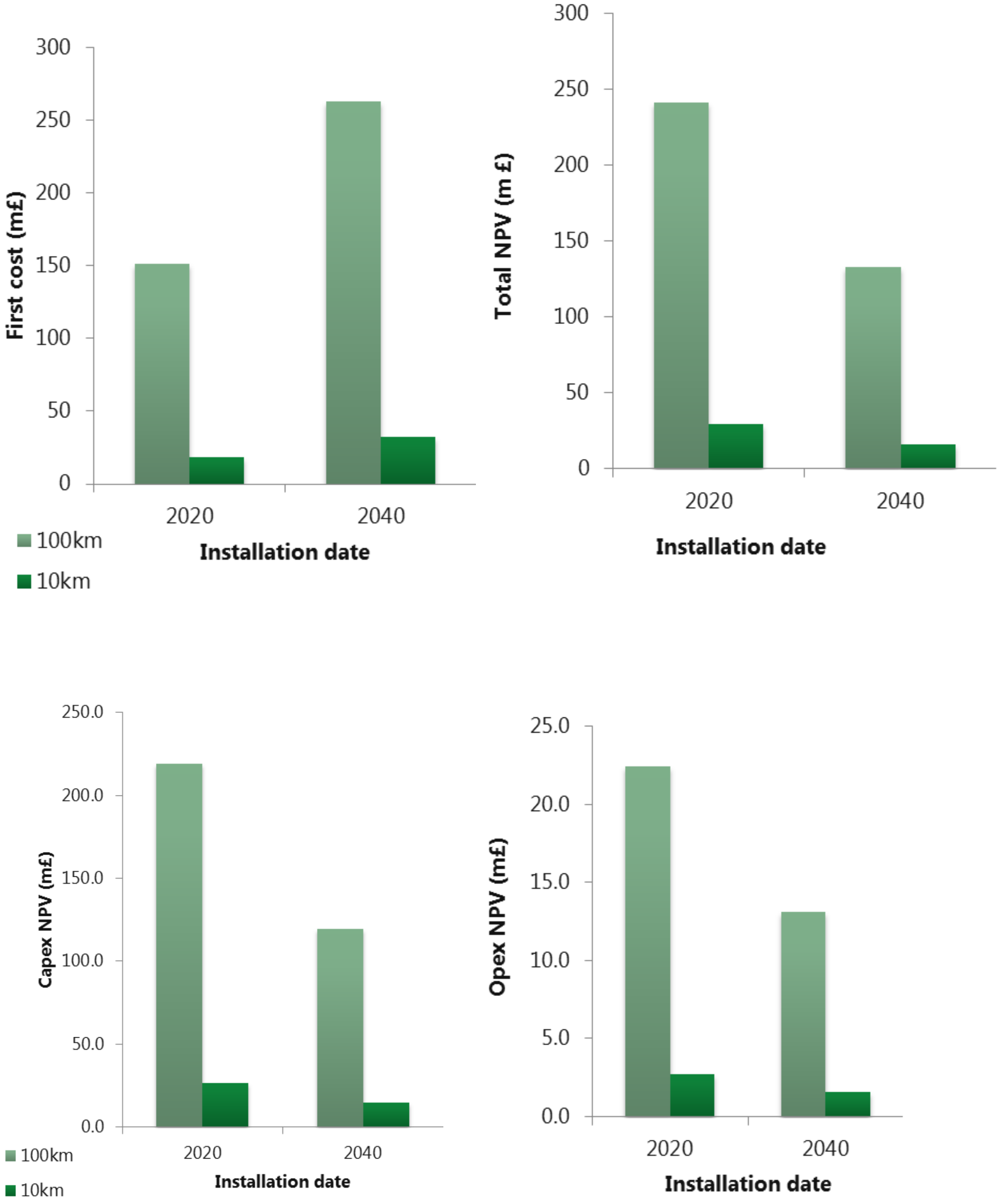


Figure 6-2 Variation of Capex, Opex, Total NPV and first cost with the installation date – 275 kV capacity

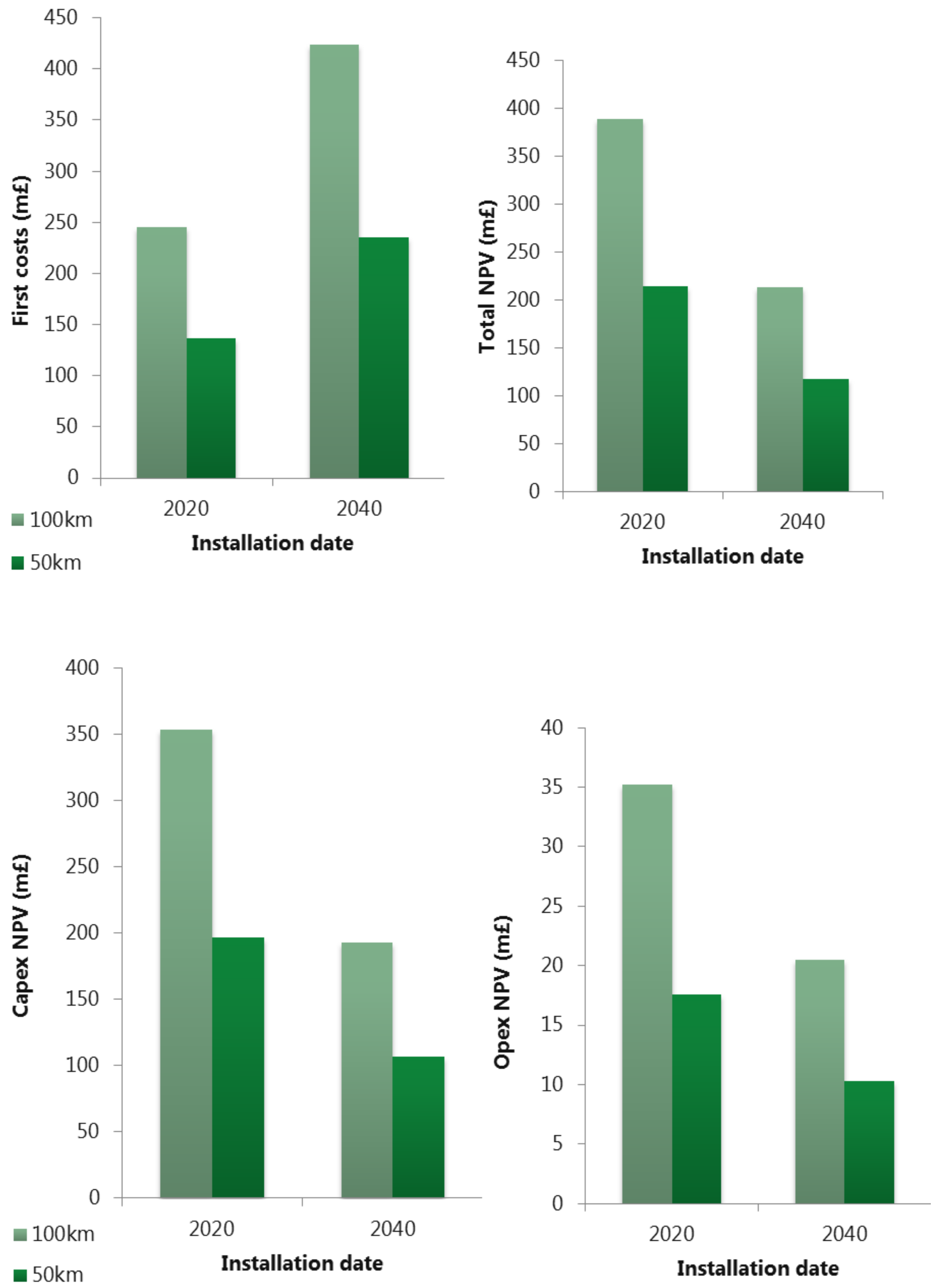


Figure 6-3 Variation of Capex, Opex, Total NPV and first cost with the installation date – 400 kV capacity

The outputs of the cost analysis indicate that:

- First costs are higher at later installation dates due to the indexation applied in the tool (see Section 3.2.5).
- NPVs are lower for later installation dates. This is partly due to the effects of discounting and partly due to the 40-year life cycle applied to overhead lines, which means that in the 2040 variation the major refurbishment cycle is beyond the end of the assessment period.
- Capex NPV is 90% of the total NPV.

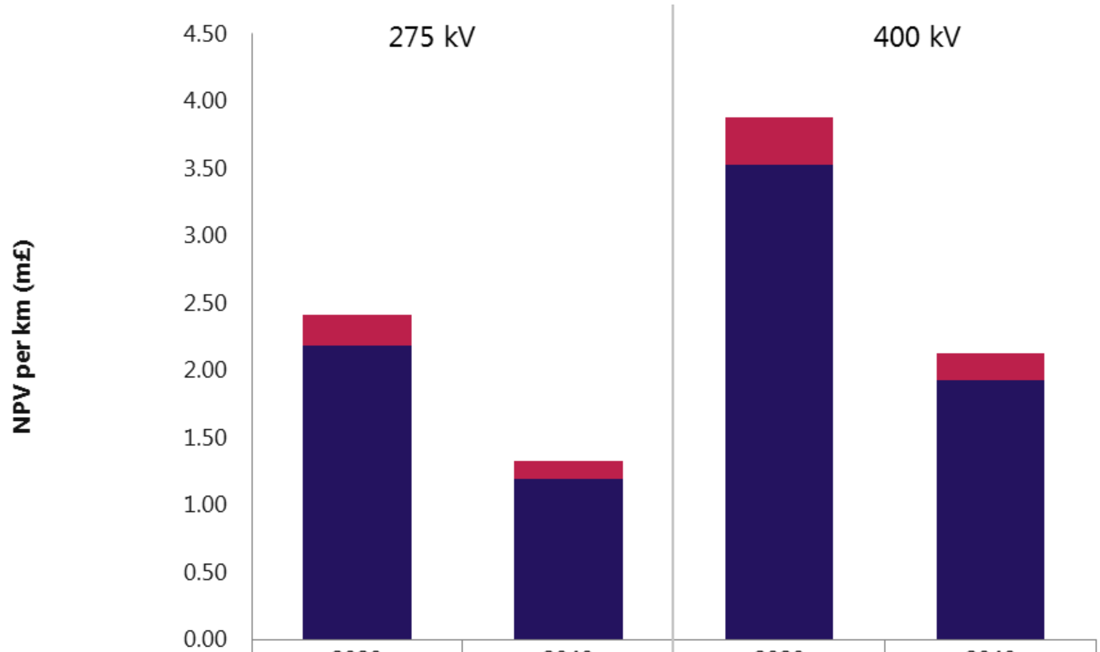
6.2.1 Analysis: Normalised costs

Two sets of normalised costs have been analysed:

- NPV (Capex, Opex, Total) per km of network
- First costs per km of network

Figure 6-4 shows the total NPV per km and Figure 6-5 shows the first cost per km for the two different capacities and installation dates.

Both these data sets have been calculated using a 100 km network.



	2020	2040	2020	2040
NPV Opex per km	0.22	0.13	0.35	0.21
NPV Capex per km	2.19	1.20	3.53	1.92

Figure 6-4 NPV per km by capacity and installation date

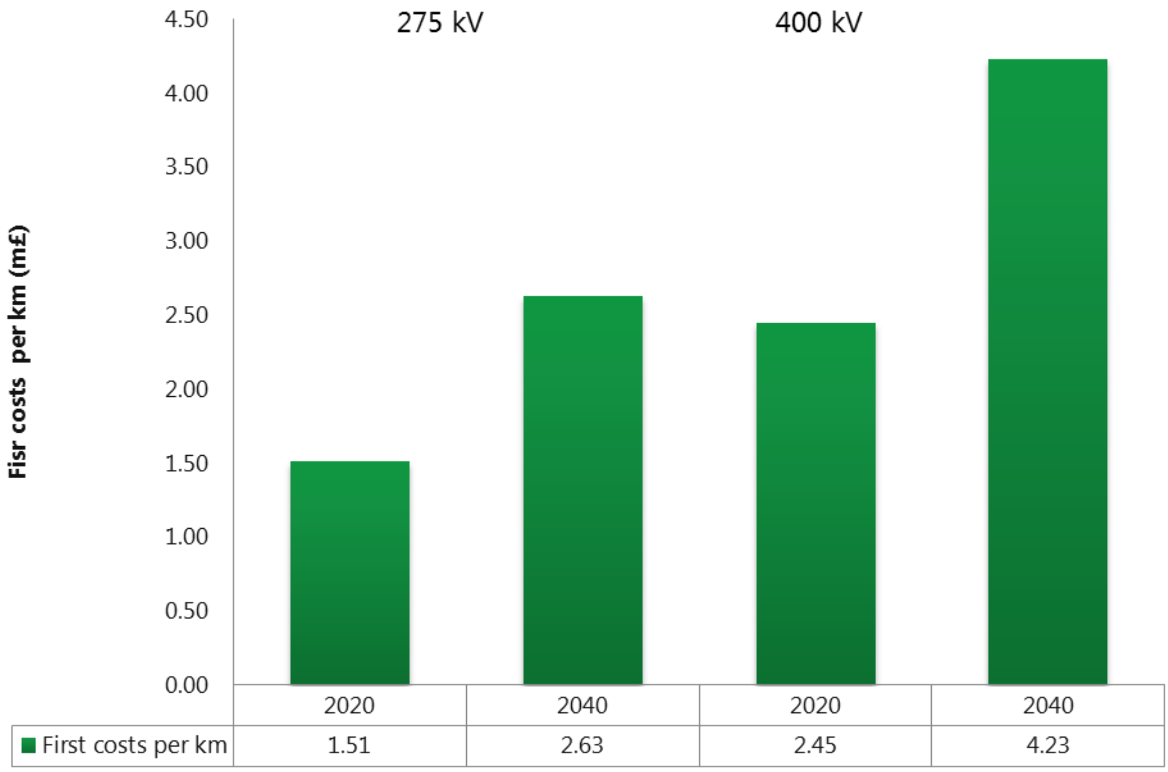


Figure 6-5 First cost per km by capacity and installation date

The analysis of normalised costs shows that:

- For the same installation date, Capex NPV per km is higher for the installation of a higher voltage network. The capital cost of the 400 kV OHL is larger, which in turn generates higher lifecycle costs.
- Opex NPV per km is also higher for higher voltages, highlighting the tool's assumption that Opex is 90% of the total NPV.

6.3 Limitations and further work

There are no significant limitations of the approach although the following should be noted:

- No allowance has been made to reflect potential abnormal legal and planning costs that might be incurred for establishing new wayleaves.
- For longer distances it may become necessary to consider HVDC if replacement / upgrade does not provide enough capacity.
- It has been also noted that the cost and NPV per km of network differ between 10km and 100 km as well as between 50km and 100km, which is not an expected result. This could relate to the application of the scale rate modifier in the ICC. It is recommended that this is explored further using the new version of the ICC.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

7 E-G-12 (a) Rapid Car Charging

7.1 Research question overview and scope

This analysis is intended to provide a reference cost for the installation of rapid car charging points and the required distribution network upgrade. Connection within an existing service station is assumed. The analysis provides the ETI with the basis on which to evaluate the capital and operating cost of installing rapid car charging connection and upgrading distribution networks for different time frames and take up rates.

The schematic in Figure 7-1 shows the boundary and outline network layout of this project. The analysis was undertaken for the connection of 1, 5, 10 and 20 car charging units assuming a range of network lengths in rural and semi-urban contexts. Refurbishment upgrade of the 11kV OHL was included within the analysis boundary on the basis that this could be required by the installation of rapid car charging points under some circumstances. However, following a review of the reinforcement required for the numbers of rapid car charging units specified for this study, it was considered unlikely that such an upgrade would be triggered (Table 7-1). No allowance has therefore been made for additional switchable circuit (OHL or buried) in the analysis.

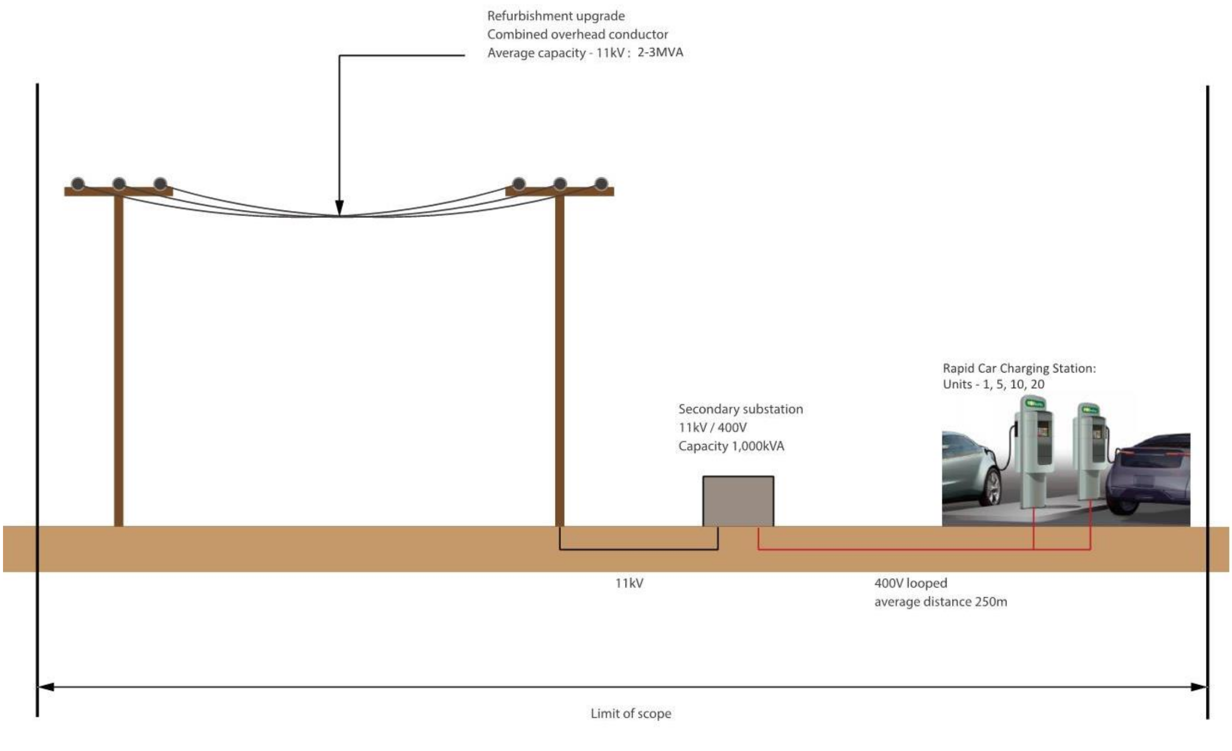


Figure 7-1 Network schematic indicating scope boundary

Table 7-1 Reinforcement Review

Number of rapid charging units	Peak Electricity (kW)	Reinforcement required?
1	850	No
5	1,034	No, only small overload which might be deemed acceptable if only for a short period of time.
10	1,285	Yes – will require additional substation, no additional OHL circuit is assumed*
20	1,785	Yes – will require additional substation, no additional OHL circuit is assumed*

**ENA P2/6 Engineering Recommendations states that, for connected loads of greater than 1MW, in the case of a fault an electricity supply (group demand minus 1MW) must be reinstated within 3 hours. This implies that an alternative supply must be provided to the service station as it is unlikely the DNO will be able to ensure repair within 3 hours in all cases. If adherence to P2/6 is necessary the additional reinforcement will need to include an additional OHL circuit from another Primary Substation. However, if the storage is privately owned and the DNO provide supply up to the existing capacity, then P2/6 could still be adhered to without reinforcement. This would need clarification with the DNO. No allowance has currently been made for additional switchable circuit (OHL or buried) at this stage.*

Table 7-2 outlines the variations that have been costed and analysed.

Table 7-2 Capacity and network length for different installation dates

Installation date	Context	No of connections	Network length (km)	Mode
2020	Rural	1	0.5	New build
2040	Rural	1	0.5	New build
2020	Rural	5	1.5	New build
2040	Rural	5	1.5	New build
2020	Rural	10	2.5	New build
2040	Rural	10	2.5	New build
2020	Rural	20	5	New build
2040	Rural	20	5	New build
2020	Semi-urban	1	0.5	New build
2040	Semi-urban	1	0.5	New build
2020	Semi-urban	5	1.5	New build
2040	Semi-urban	5	1.5	New build

Installation date	Context	No of connections	Network length (km)	Mode
2020	Semi-urban	10	2.5	New build
2040	Semi-urban	10	2.5	New build
2020	Semi-urban	20	5	New build
2040	Semi-urban	20	5	New build

Table 7-3 outlines the different infrastructure elements (Assemblies) and their quantities that make up the network. As indicated in the reinforcement review (Table 7-1), the installation of 1 and 5 connection points to an existing service station do not require upgrade of the transformer and, due to the implications of the ENA P2/ 6 Engineering Recommendations, no allowance has been made for made for additional switchable circuit (OHL or buried).

Table 7-3 Assemblies used to generate project costs

Description	Quantity	Unit	Comments
Conversion: HVAC: 11kV to 400V ground mounted transformer [1,000 kVA]	1	Nr	Only for 10 and 20 connection points.
Distribution: AC: Buried: 400V cable [122 kVA]	1 – 0.5km 5 – 1.5km 10 – 2.5km 20 – 5km	km	Potential for higher rated LV distribution for >5 units to reduce the Nr of cables, or ensure new substation is located next to charging unit area.
Electricity connection vehicle rapid charging points [Siemens 50kW]	1, 5, 10, 20	Nr	
11kV OHL upgrade	-	-	No upgrade allowance made based on reinforcement review outlined in Table 7-1.

7.2 Results and analysis

Based on the quantities in Table 7-3, 16 cost data sets were generated using the ICC. Each data set is representative of a different variation, e.g. installation of 5 connections at rural context in 2020. The project cost parameters (e.g. ground conditions) are the same for each variation.

Table 7-4 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each variation for installation dates of 2020 and 2040.

As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 7-4 Base output data

Installation date	Context	No of connections	LV length (km)	First costs k£	NPV Capex k£	NPV Opex k£	Total NPV k£
2020	Rural	1	0.5	263	454	36	490
2040	Rural	1	0.5	400	231	20	251
2020	Rural	5	1.5	827	1,502	107	1,608
2040	Rural	5	1.5	1,197	774	59	833
2020	Rural	10	2.5	1,674	3,037	221	3,258
2040	Rural	10	2.5	2,494	1,637	124	1,761
2020	Rural	20	5	2,990	5,406	392	5,798
2040	Rural	20	5	4,413	2,859	219	3,078
2020	Semi-urban	1	0.5	370	647	51	698
2040	Semi-urban	1	0.5	565	313	28	341
2020	Semi-urban	5	1.5	1,088	1,949	143	2,093
2040	Semi-urban	5	1.5	1,605	983	79	1,063
2020	Semi-urban	10	2.5	2,108	3,752	282	4,034
2040	Semi-urban	10	2.5	3,178	2,008	159	2,166
2020	Semi-urban	20	5	3,858	6,868	514	7,381
2040	Semi-urban	20	5	5,772	3,573	287	3,860

Figure 7-2 to Figure 7-5 show the variation of first costs and NPV with the number of connections and the installation date in rural and semi-urban contexts.

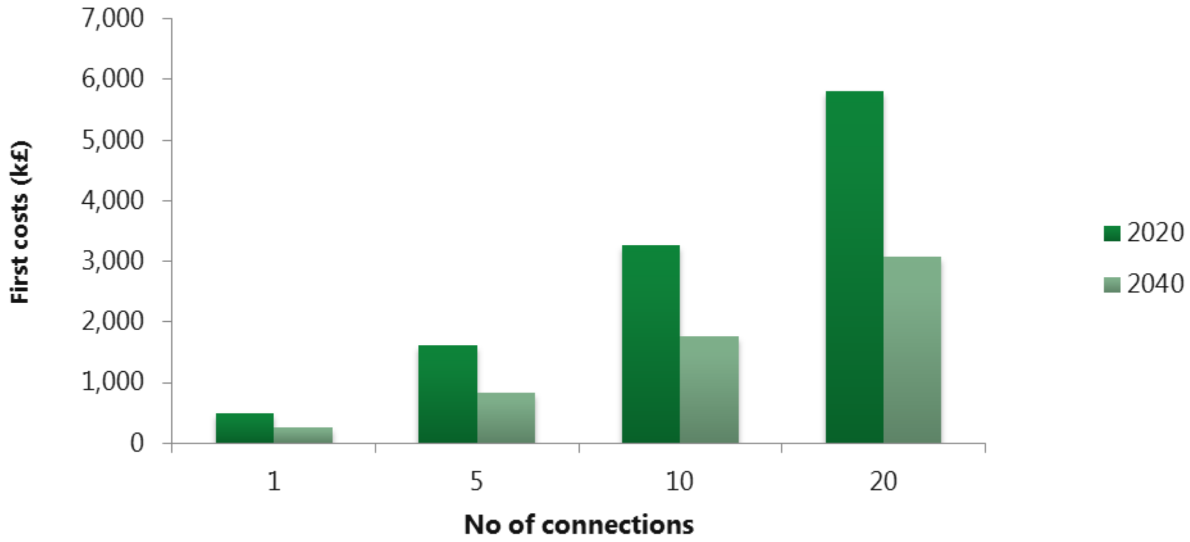
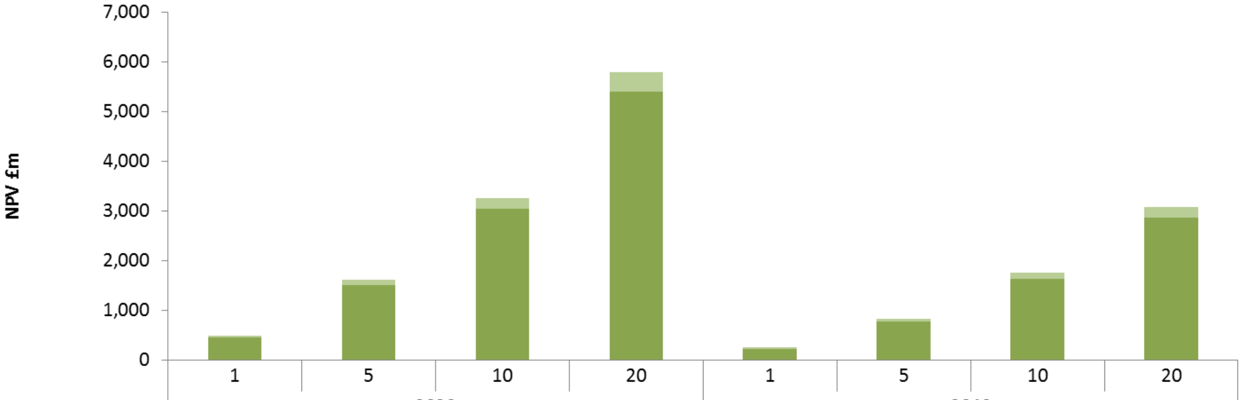


Figure 7-2 Variation of first cost with number of connections in rural context



	2020				2040			
	1	5	10	20	1	5	10	20
Sum of NPV Opex	36	107	221	392	20	59	124	219
Sum of NPV Capex	454	1,502	3,037	5,406	231	774	1,637	2,859

Figure 7-3 Variation of total NPV (Capex and Opex) with number of connections in rural context

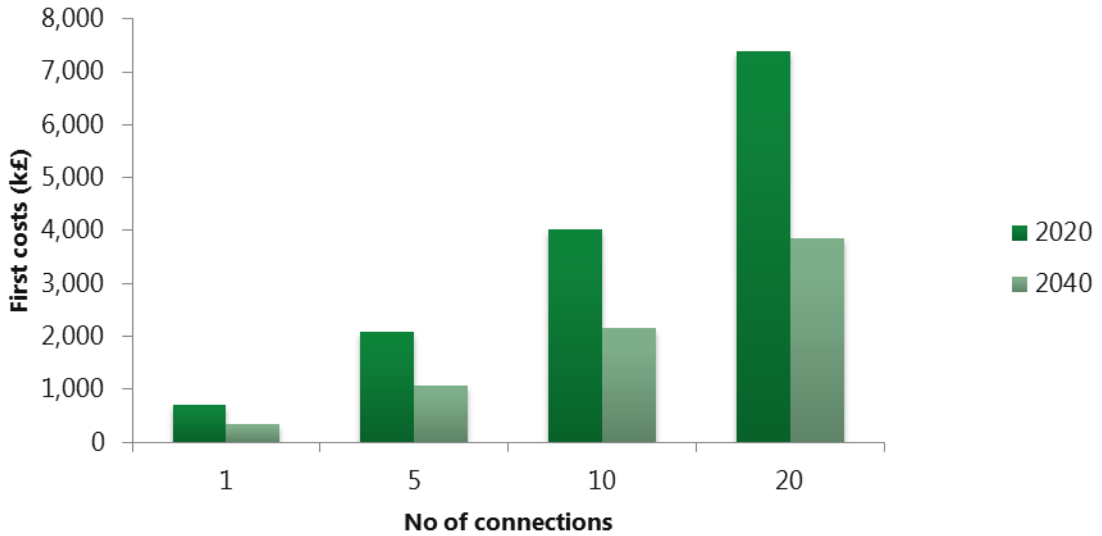
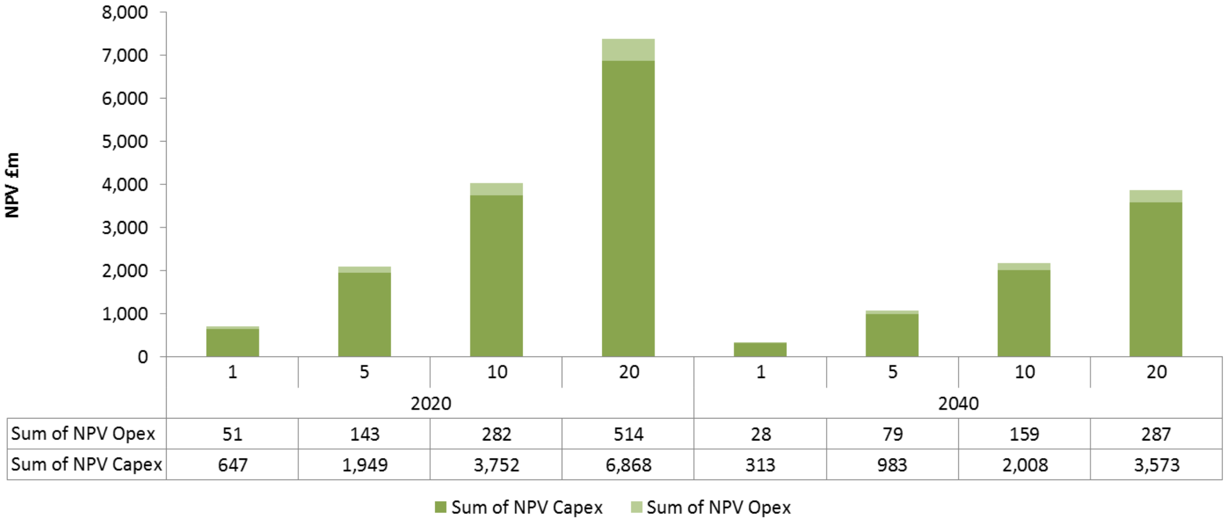


Figure 7-4 Variation of first costs with number of connections in semi-urban context



	2020				2040			
	1	5	10	20	1	5	10	20
Sum of NPV Opex	51	143	282	514	28	79	159	287
Sum of NPV Capex	647	1,949	3,752	6,868	313	983	2,008	3,573

Figure 7-5 Variation of total NPV (Capex and Opex) with number of connections in semi-urban context

The outputs of the cost analysis indicate that:

- First costs are higher at later installation dates due to the indexation applied in the tool (see Section 3.2.5).
- NPVs are lower for later installation dates. This is mainly due to the effects of discounting and lifecycle costs been influenced by tool restricted by a fixed end date.

7.2.1 Analysis: Assemblies

Three Assemblies have been used in this project:

- 11kV to 400V substation (1,000 kVA)
- LV distribution network
- Electricity connections for rapid charging

This section provides a breakdown of the key elements of cost within the network.

Figure 7-6 to Figure 7-7 show the variation in the share of total cost of each Assembly at different installation dates and for various connection points in both contexts.

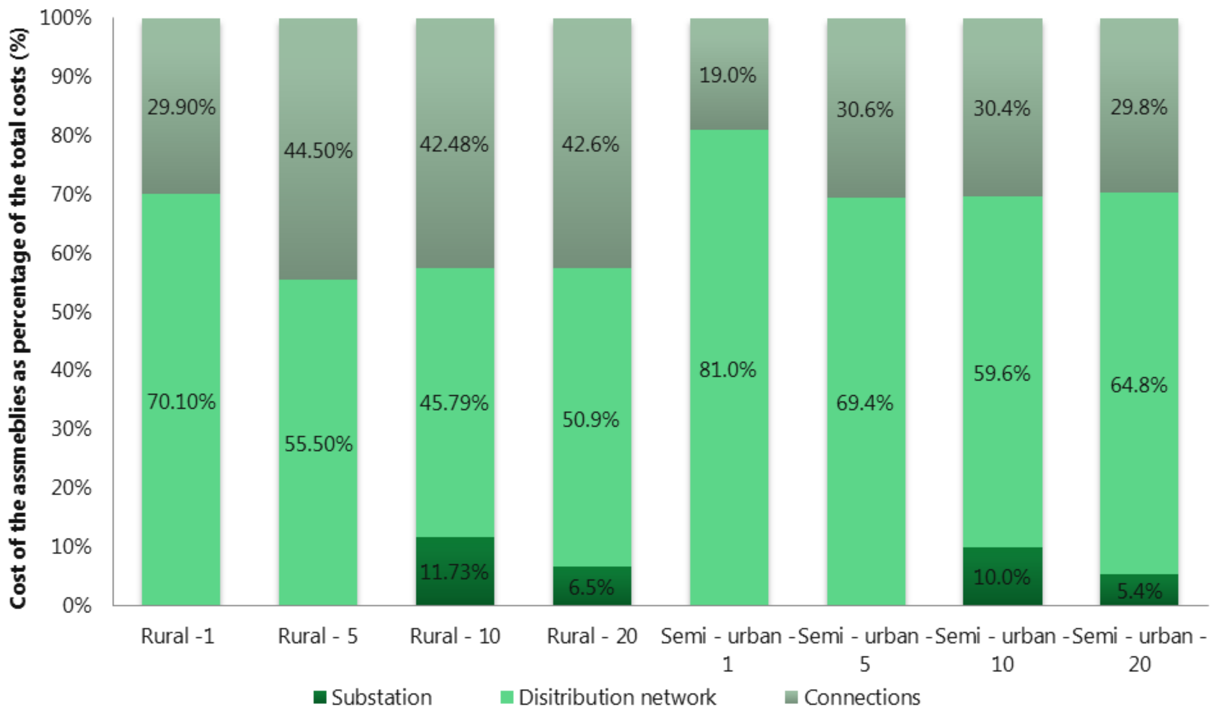


Figure 7-6 Share of costs represented by the three Assemblies in various connections - 2020

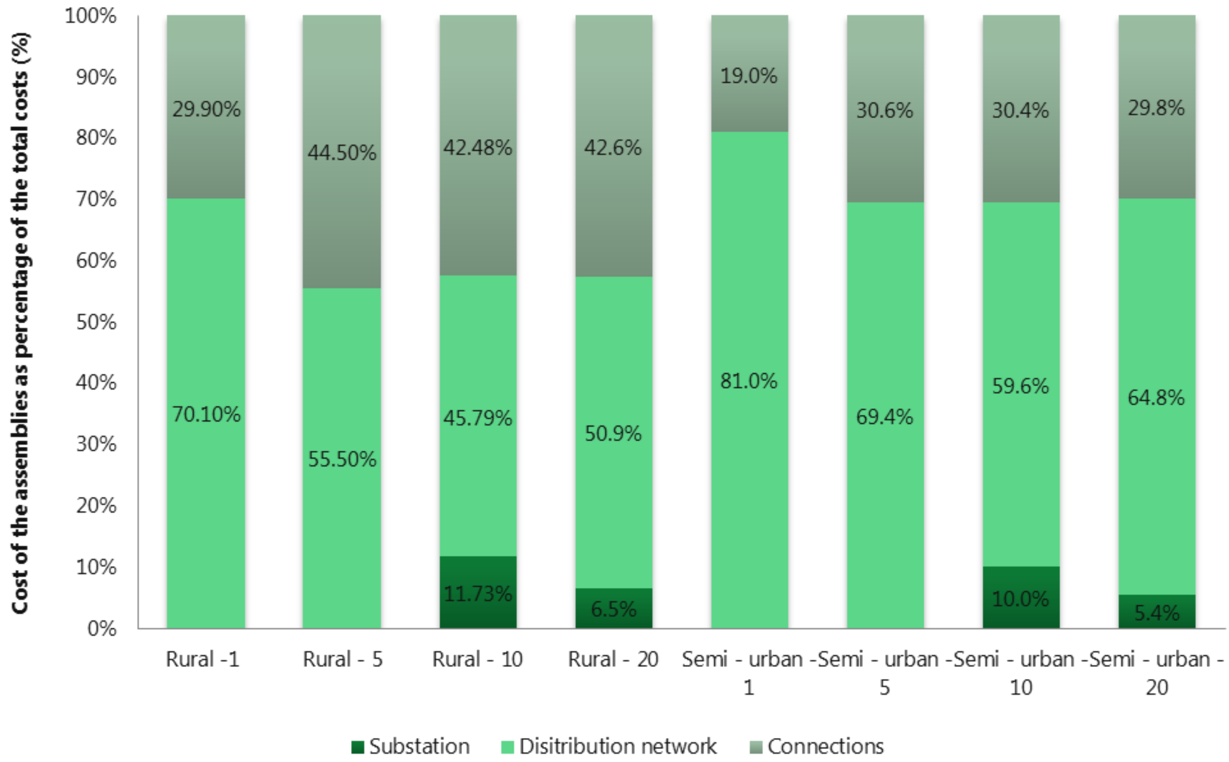


Figure 7-7 Share of costs represented by the three Assemblies in various connections - 2040

The general analysis of the Assemblies shows that:

- As expected, an increase in number of connections increases the relative share of connection costs and network costs.
- Costs for the upgrade of the distribution network are the most significant in all variations and contexts. The reasoning for this is the land take per km of network length as well as the labour costs for the distribution network installation. A refinement of the tool would allow for multiple cables to be laid in the same trench.

7.2.2 Analysis: Normalised costs

Two normalised costs have been analysed:

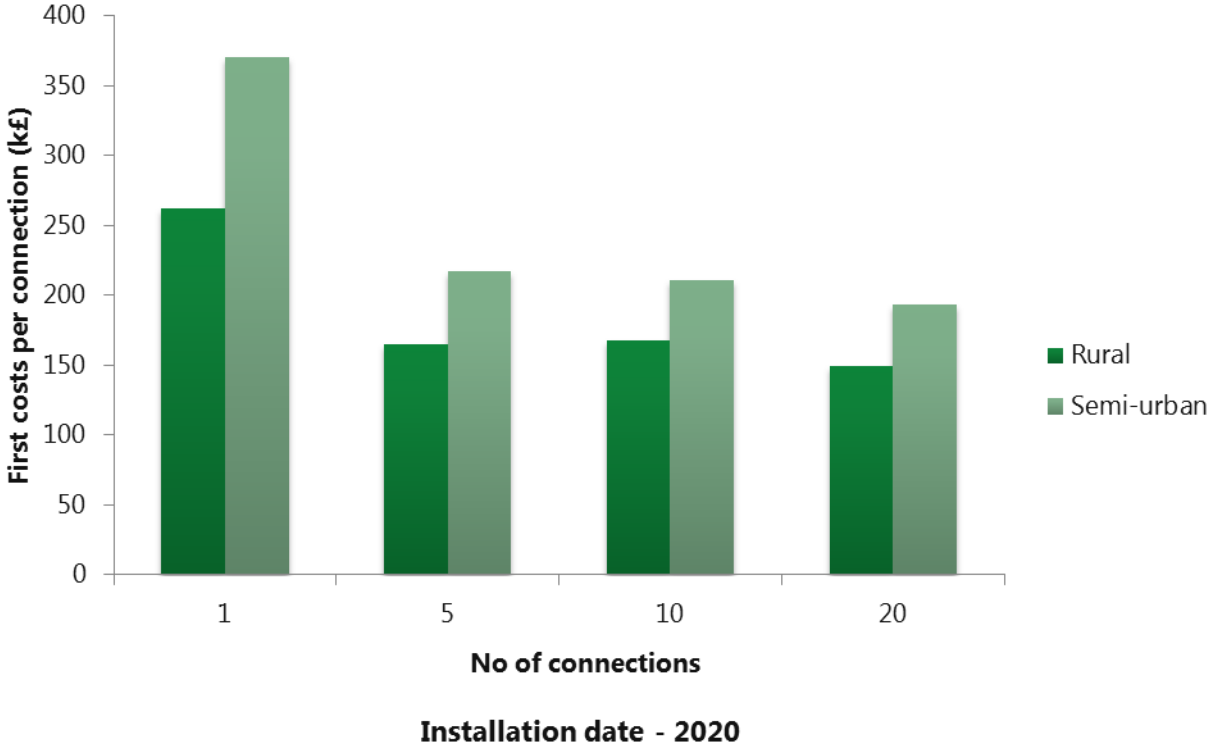
- First costs per connection
- Total NPV per connection

Table 7-5 shows the NPV and first costs per connection at both installations dates in all variations.

Table 7-5 Total NPV and first costs per connection at all variations

Installation date	Context	Number of connections	First costs per connection (£k)	Total NPV per connection (£k)
2020	Rural	1 connection	263	490
		5 connections	165	322
		10 connections	167	326
		20 connections	149	290
	Semi-urban	1 connection	370	698
		5 connections	218	419
		10 connections	211	403
		20 connections	193	369
2040	Rural	1 connection	400	251
		5 connections	239	167
		10 connections	249	176
		20 connections	221	154
	Semi-urban	1 connection	565	341
		5 connections	321	213
		10 connections	318	217
		20 connections	289	193

The variation of normalised costs with the number of connections and the context is presented in Figure 7-8 and Figure 7-9.



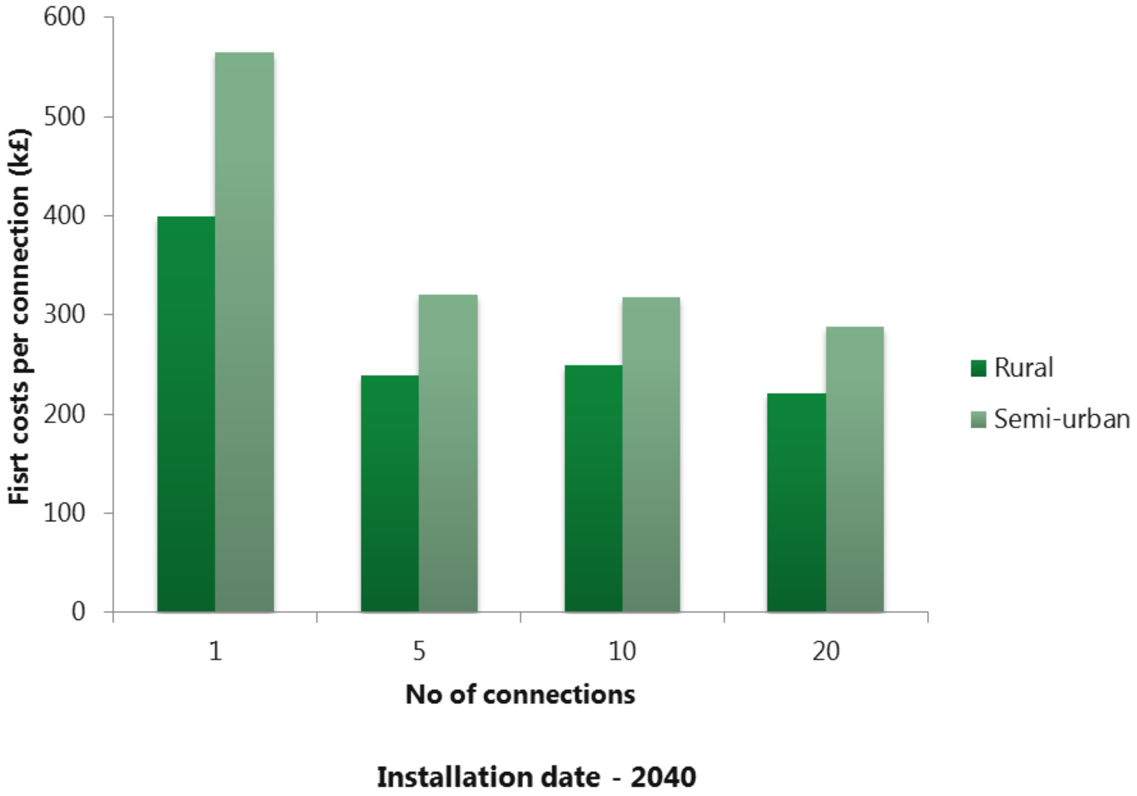
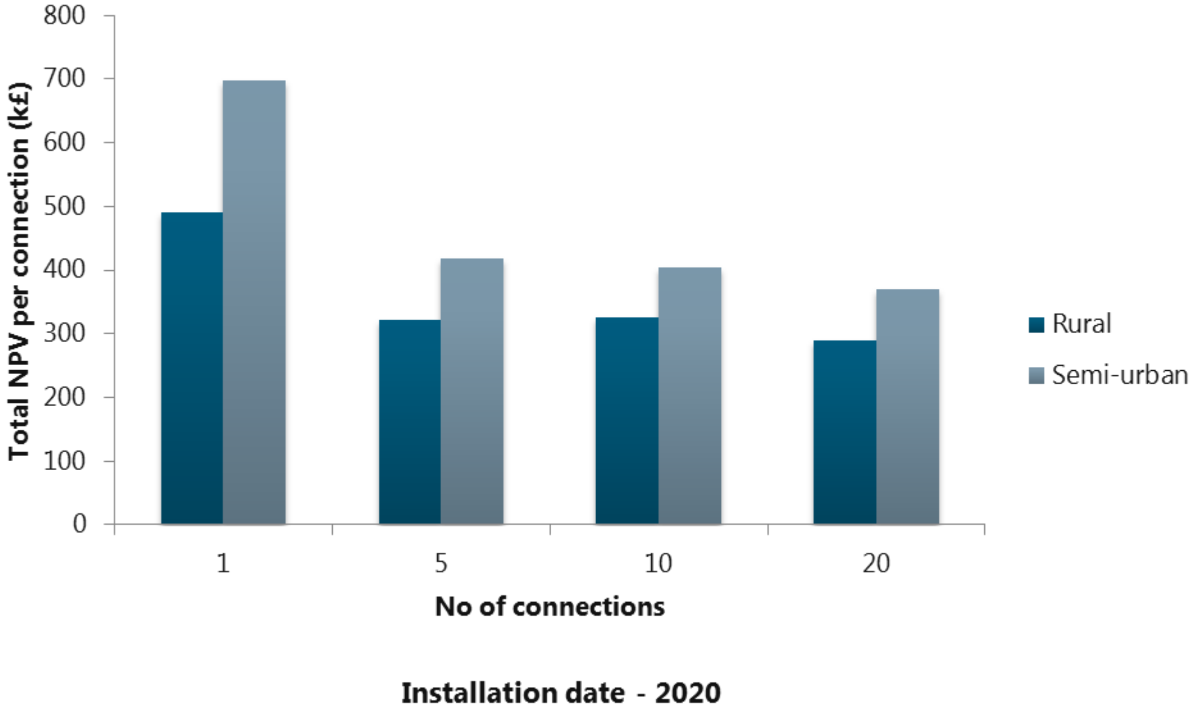


Figure 7-8 Variation of first costs per connection with the number of connections



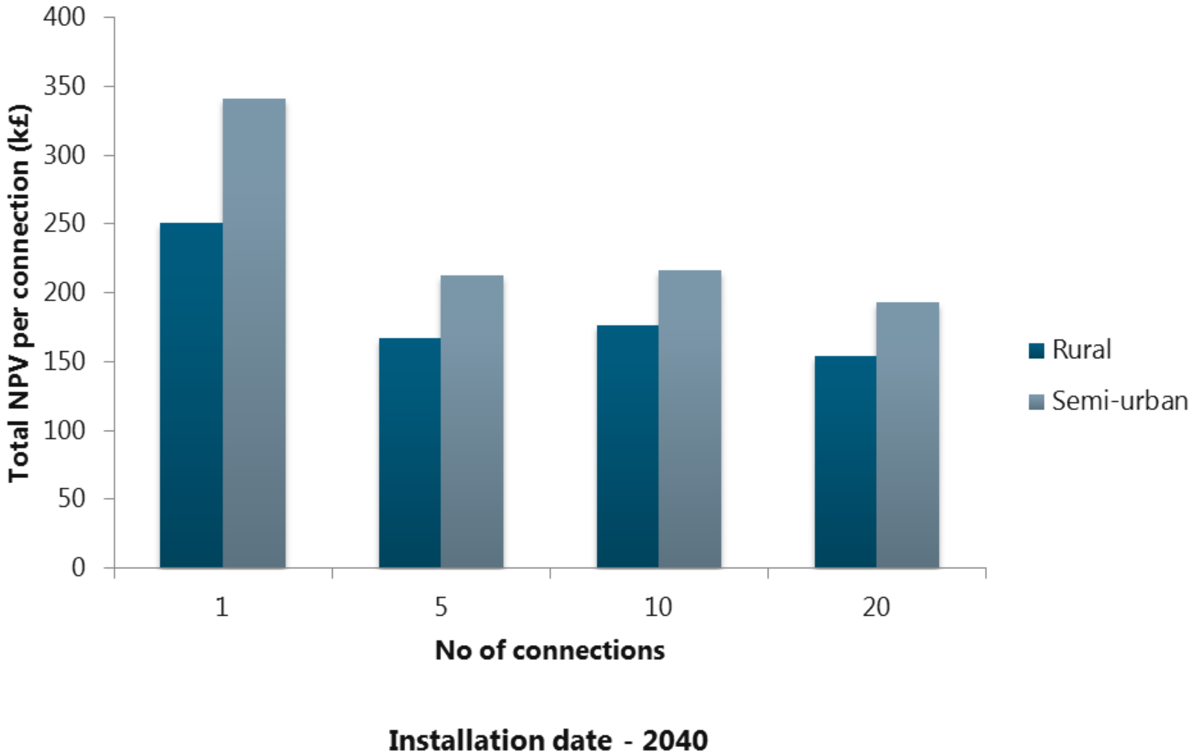


Figure 7-9 Variation of total NPV per connection with the number of connections

The analysis of normalised costs suggests that:

- For the same amount of connection points at the same installation date the installation of rapid charge connections is more costly in the semi-urban context. The main reason for this is that the labour, material, plant and land costs for the distribution network and substation increase from rural to semi-urban.
- The first costs and NPV per connection falls as the number of connections increases, which indicates that it is more cost effective to install a group of charging points than isolated single ones. This is mainly related to the distribution network length requirements per connection.

7.1 Limitations and further work

There are no significant limitations of the approach although the following should be noted:

- For 1 and 5 connections it is assumed that negligible costs are associated with connection to the existing substation. This is based on the assumptions regarding the availability of capacity in the existing substation and P2/6 adherence.
- Additionally, for 1 and 5 connections no replacement or Opex costs are apportioned for continued operation of the existing substation.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

8 E-G-12 (b) Network reinforcement due to Electric Vehicle increase

8.1 Research questions and scope

This analysis is intended to provide initial high level cost data on the impact of network reinforcement that could be required due to a significant increase in electric vehicles in a residential context. The analysis will provide the ETI with the basis on which to evaluate the capital and operating cost of this reinforcement in an existing local residential area over different time frames.

8.1.1 Design of representative network

The schematic Figure 8-1 shows the boundary of this project. This schematic is used to develop the Bill of Quantities used for costing purposes.

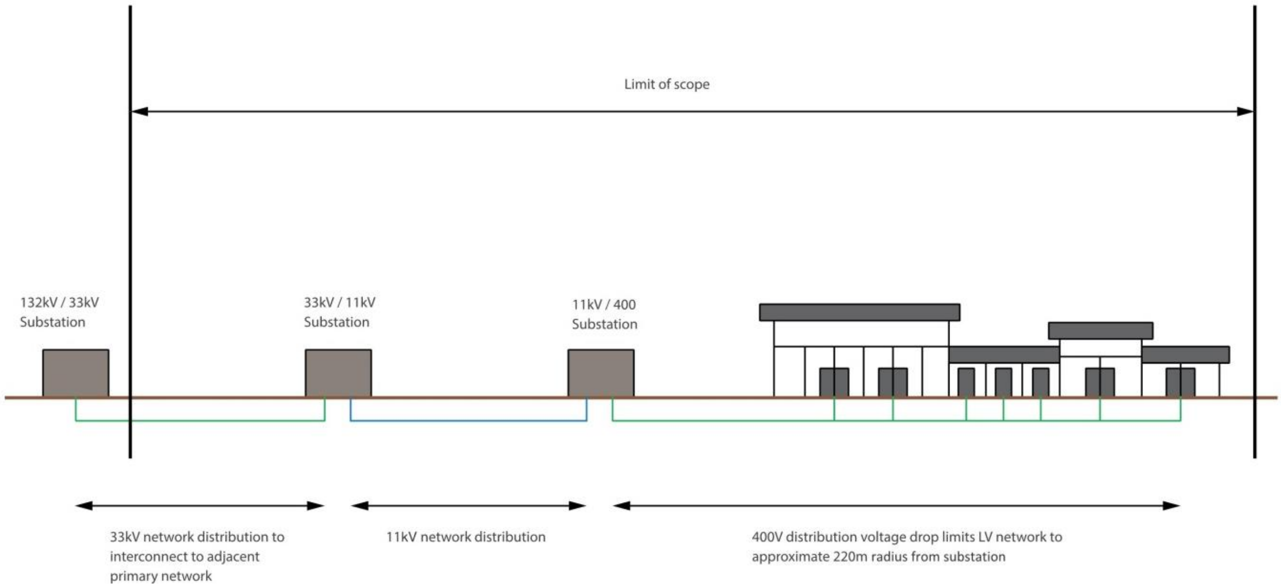


Figure 8-1 Network schematic indicating scope boundary

E-G-10 uses a micro and macro model for developing theoretical networks. Using a series of example reference areas the requirements for distribution are scaled according to context.

The micro and macro models are shown in Figure 8-2 and Figure 8-3. For more information please refer to E-G-10.

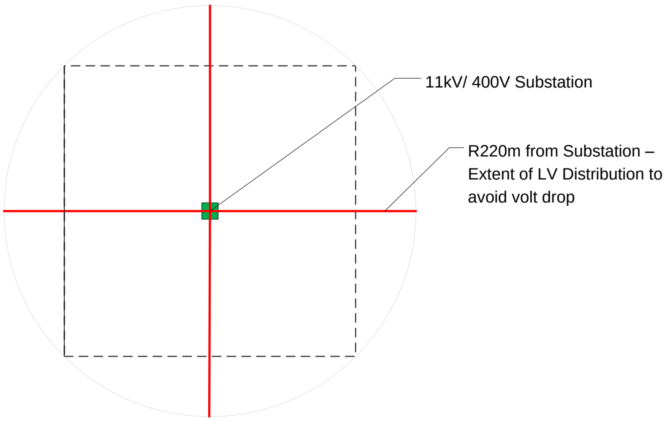


Figure 8-2 Micro Model (from E-G-10)

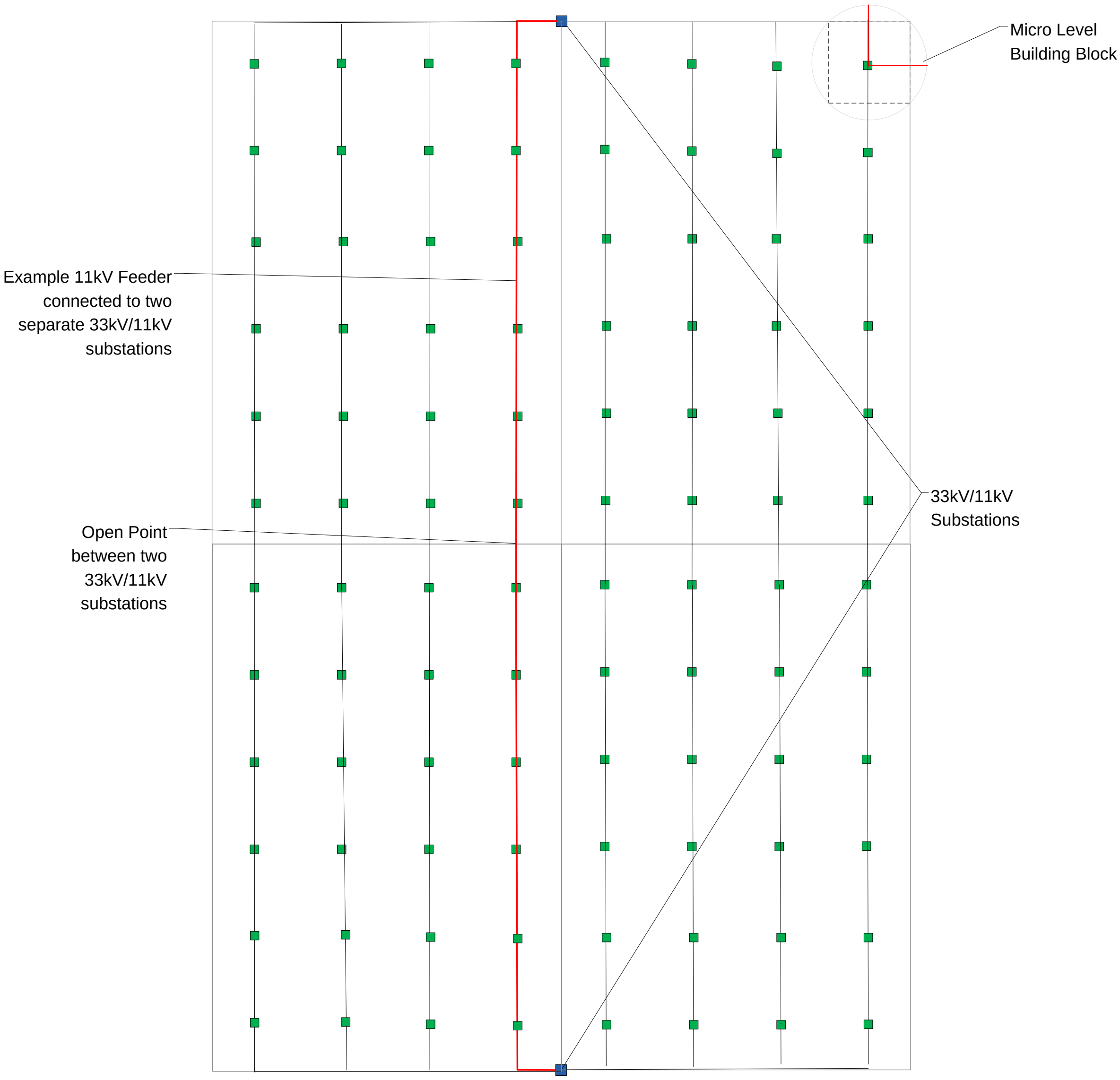


Figure 8-3 Macro Model (from E-G-10)

Table 8-1 outlines the variations that have been costed and analysed.

Table 8-1 Variations analysed

Installation date	Context	Capacity range (population)	Length of LV network (km)	Length of 11 kV network (km)	Length of 33 kV network (km)
2020	Semi –Urban	7,500	31.5	14.3	5.8
	Urban	20,000	68.7	31.5	4.8
2040	Semi –Urban	7,500	31.5	14.3	5.8
	Urban	20,000	68.7	31.5	4.8

The analysis is based on the assumption that there is a 50% increase in peak load due to a significant increase in the use of electric vehicles. The report also provides some qualitative assessment on the potential impact of an increase of 25% in peak load.

To enable the completion of this task the following assumptions have been made:

- Vehicle charging units are not included in costs
- The existing network is operating at near capacity including all primary and secondary substations and feeders
- The wider 132kV and grid network has spare capacity for discrete increase in load to accommodate the increase proposed here
- Existing easements and land-take are sufficient for increased capacity feeders and substations
- Existing substations and feeders are "refurbished" rather than abandoned and being replaced by new

Additional Assemblies have been created to cost the reinforcement as detailed in Table 8-2.

Table 8-2 New Assemblies created to undertaken the costing

Title	Change in capacity
Buried 33kV cable	Al 630mm2
33kV/11kV Primary Substation	• Replacement Transformers rated at 40MVA • Replacement switchgear to accommodate replacement transformers and new 11kV cables
Buried 11kV Cable	Cu 300mm^2
Buried LV cable	Cu 400mm^2

Based on the schematic in Figure 8-1, Table 8-3 outlines the different infrastructure elements (Assemblies) that make up the network.

Table 8-3 Assemblies used to generate project costs

Description	Unit	Semi - Urban	Urban
Distribution: HVAC: Buried: 11kV line (uprated)	km	14.3	31.5
Distribution: AC: Buried: 400V cable (uprated)	km	31.4	68.7
33kV to 11kV substation (uprated)	Nr	0.4	1.1
11kV to 400V Substations (uprated)	Nr	20	53
Distribution : Buried : 33 kV line (uprated)	km	5.8	4.8

8.2 Results and analysis

Based on the quantities in Table 8-3, four cost data sets were generated using the ICC.

Table 8-4 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each variation for installation dates of 2020 and 2040. First costs (undiscounted) include new build costs plus preliminary costs, contractors' costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs. NPV Capex represents the installation costs plus all lifecycle costs which include all replacement cycles and abandonment costs (REPEX), to the extent that these occur before the project end. NPV Opex takes into account operational costs over the life of the project.

Table 8-4 Base output data

Context	Installation date	First costs (m£)	NPV Capex (m£)	NPV Opex (m£)	NPV Total (m£)
Semi-Urban: 7,500 population	2020	45.8	72.9	7.0	79.9
	2040	78.0	37.6	4.1	41.6
Urban: 20,000 population	2020	141.0	236.3	20.9	257.2
	2040	232.7	112.6	12.0	124.6

The outputs of the cost analysis indicate that for the same context (e.g. urban – 20,000 population):

- First costs are higher at later installation dates
- NPVs are lower for later installation dates. This is partly due to the effects of discounting and partly due to the 40-year life cycle applied to most of the Assemblies, which means that in the 2040 variation the major refurbishment cycle is beyond the end of the assessment period.

The differences between contexts has been analysed by normalising the costs per capita, see Section 8.2.2.

8.2.1 Analysis: Assemblies

A breakdown of the key elements of cost within the electricity distribution network in the different contexts is provided in Figure 8-4 and Figure 8-5.

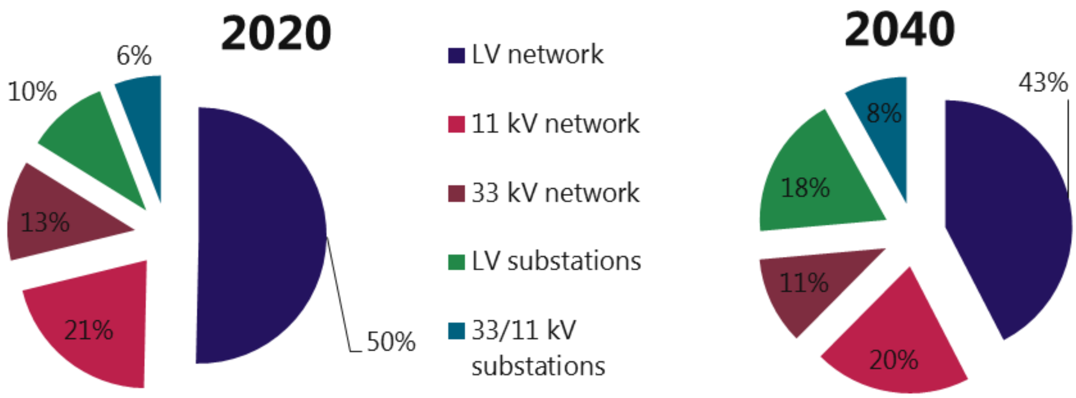


Figure 8-4 Relative share of Assembly costs at installation dates 2020 and 2040 in a semi-urban context

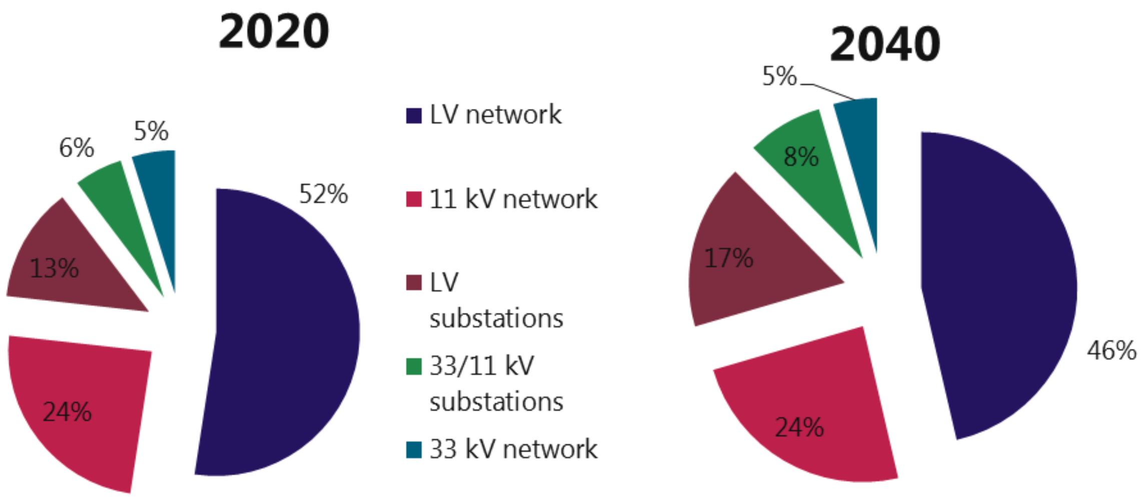


Figure 8-5 Relative share of Assembly costs at installation dates 2020 and 2040 in an urban context

The analysis of the Assemblies shows that:

- The share of costs represented by each of the Assemblies changes slightly from 2020 to 2040, following the same trend in all contexts
- LV networks represent one of the highest Assembly costs in all contexts.

The analysis completed considers a 50% increase in demand only. For lower increases in demand the reinforcement required could be less but it becomes difficult to generalise the trigger points. A 25% increase in load would probably necessitate the following:

- Lower rated LV and 11kV cable replacement (versus 50%)

- Some existing secondary substations could remain within operational limits with existing interconnectivity of 11kV and LV networks to respective primary and secondary substations. A detailed assessment of total diversity may uncover headroom, particularly if adjacent areas do not have a similar increase in demand due to electric vehicles. It is suggested that ~50% of secondary substations would require upgrade.
- Some primary substations could remain within operational limits if adequately interconnected to adjacent primary substations, and further diversity is taken into account. It is suggested that ~50% of primary secondary substations would require upgrade.
- Many fixed costs such as project management, labour etc. would remain the same regardless of the capacity of the replacement feeder or plant.

Considering the above, the resultant reinforcement costs for a 25% increase in demand would not necessarily be 50% of the costs calculated for a 50% increase in demand. Without completing more detailed calculations it is suggested the costs for 25% increase would be between 60-80% of the costs associated with a 50% increase.

8.2.2 Analysis: Normalised costs

Two sets of normalised costs have been analysed:

- First costs per capita
- NPV Total per capita

Figure 8-6 and Figure 8-7 show these results by context and installation date.

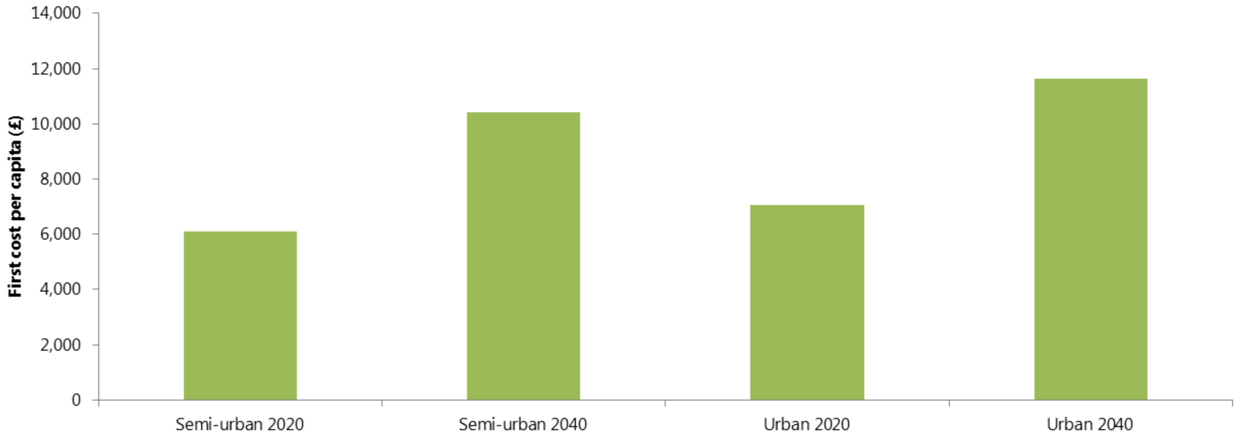


Figure 8-6 First costs per capita in both contexts for both installation dates

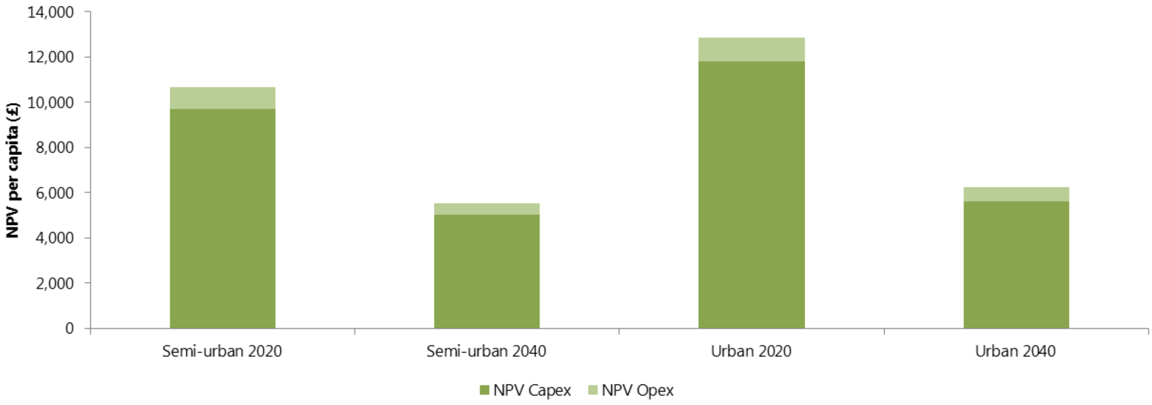


Figure 8-7 NPV Capex and Opex per capita in both contexts for both installation dates

The analysis of normalised costs shows that:

- First costs per capita increase as the context changes from semi-urban to urban. The main reason for this is the increase in labour, material and plant costs in denser areas.
- One additional factor that influences costs in different contexts is their different lifecycle profiles. It is assumed that an Assembly in an urban context will need to be replaced more quickly than the same Assembly in a rural context.

8.3 Limitations and further work

The following limitations are considered relevant for the level of analysis completed:

- Validation is based on limited example reference areas
- The analysis assumes a step change in reinforcement rather than a gradual increase in demand due to uptake in electric vehicles

Further points to consider are:

- Depending on which entity funds the reinforcement, a DNO may consider future proofing a network for a long term future increase, i.e. for 50%, even if a 25% increase is only considered in the short or medium term.
- Key to analysing the reinforcement will be the assessment of projected load profiles and diversity. In a residential context, charging may mostly occur during off-peak periods, i.e. during the night. This could be influenced further by the use of smart meters and tariff structure.

9 E-I-13 Storage vs Reinforcement

9.1 Research question overview and scope

This analysis is intended to provide reference network costs for storage. The analysis provides the ETI with the basis on which to evaluate the capital and operating costs of storage in three example applications compared with the counterfactual of conventional reinforcement.

Three applications are analysed:

- *Application 1.* Rural and semi-urban 33kV – Increase in local demand due to increase in housing or other.
- *Application 2.* Rural 33kV – Distributed Energy (such as wind farm) leading to requirement to export to grid
- *Application 3.* Rural/ Semi-Urban 11kV – Increase in demand at motorway service station due to installation of rapid car charging units

Each application will be discussed separately in the following sections.

9.2 Application 1

Figure 9-1 is a simplified schematic showing the storage variation for application 1 as confirmed during the detailed scoping phase.

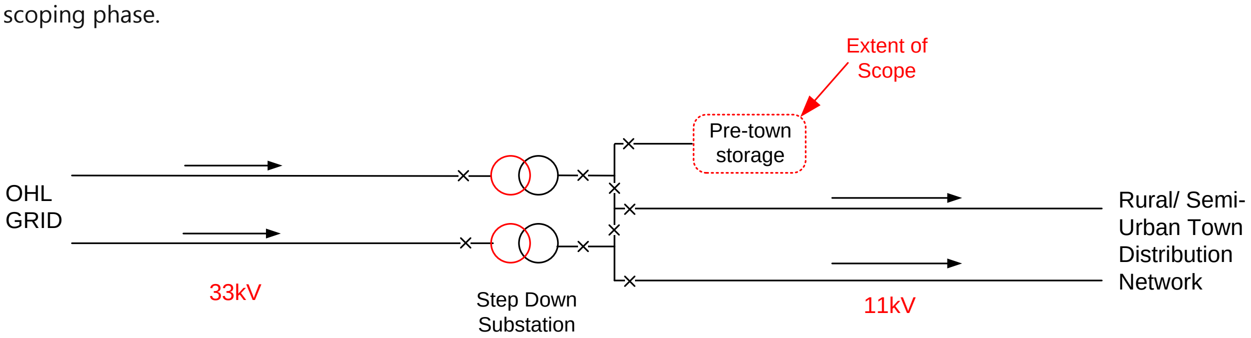


Figure 9-1 Network schematic indicating scope boundary – application 1

The reinforcement alternative to storage used for the counterfactual is reinforcement of the network with replacement with additional 33kV OHL to withstand 25% increase in demand.

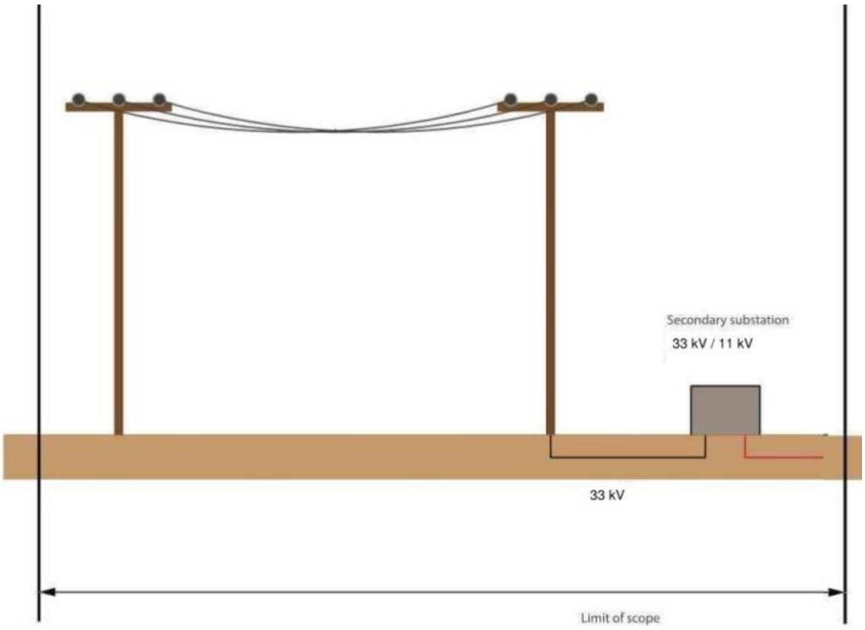


Figure 9-2 Scope boundary of counterfactual – application 1

Following the initial and detailed scoping of this task, four innovation variations were costed against four counterfactuals as shown in Table 9-1.

Table 9-1 Variations that were analysed

Installation date	Context	Application
	Innovation - storage	
2020	Rural	25% increase in demand
	Semi - urban	
2040	Rural	
	Semi - urban	
	Counterfactual - reinforcement	
2020	Rural	25% increase in demand
	Semi - urban	
2040	Rural	
	Semi - urban	

Based on the schematic in Figure 9-1, Table 9-2 and Table 9-3 outline the Assemblies that have been used to generate the cost data sets of the innovation and counterfactual.

Table 9-2 Assemblies used to generate project costs - innovation

Description	Quantity	Unit
Storage: DC: 1MW utility scale battery [14.4 MWh]	2	Nr

Table 9-3 Assemblies used to generate project costs - counterfactual

Description	Quantity	Unit
33/11kV Substation	1	Nr
OHL Distribution 33kV	25	km

9.2.1 Results and analysis

Based on the quantities in Table 9-2 and Table 9-3, 8 cost data sets were generated using the ICC. Each data set is representative of a different variation.

Table 9-4 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each variation for installation dates of 2020 and 2040. As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 9-4 NPV (Capex and Opex) and first cost for each variation

Installation date	Context	NPV Capex (m£)	NPV Opex (m£)	NPV Total (m£)	First costs (m£)
Innovation - storage					
2020	Rural	40.4	3.2	43.5	19.8
	Semi - urban	42.2	3.5	45.7	21.8
2040	Rural	27.6	2.0	29.6	36.6
	Semi - urban	32.5	2.2	34.6	40.2
Counterfactual - reinforcement					
2020	Rural	13.6	1.8	15.4	11.2
	Semi - urban	16.3	2.0	18.3	12.4
2040	Rural	9.0	1.1	10.1	20.3
	Semi - urban	10.0	1.2	11.2	22.5

Figure 9-3 and Figure 9-4 show the NPVs and the first costs of the innovation projects and their counterfactuals in rural and semi-urban contexts at both installation dates.

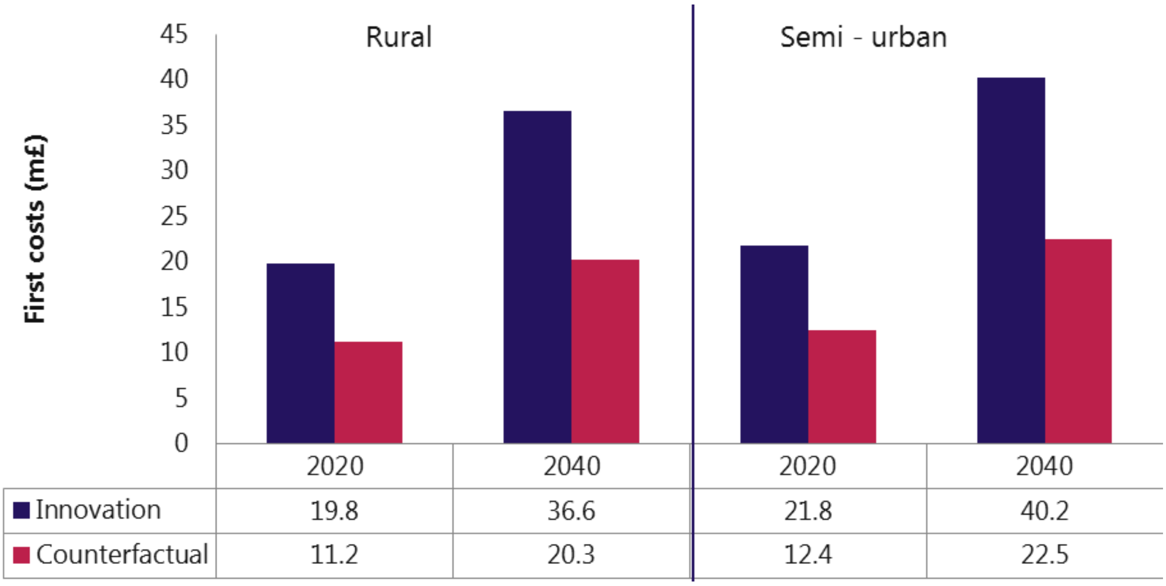


Figure 9-3 First costs of innovation and counterfactual at both installation dates and contexts

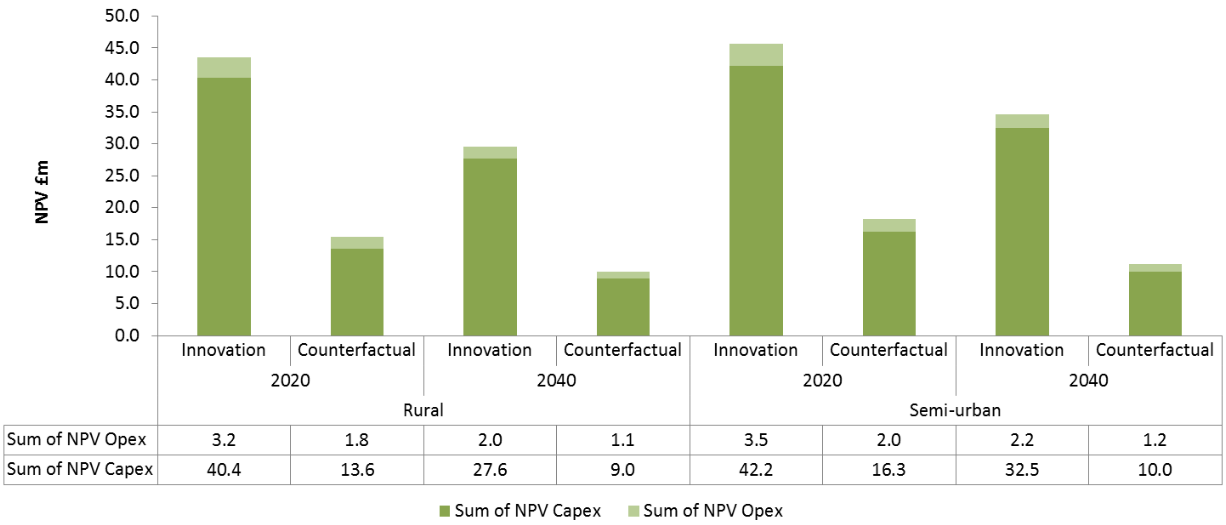


Figure 9-4 Total NPV (Capex and Opex) of innovation and counterfactual at both installation dates and contexts

The analysis of the cost outputs indicates that the innovative approach generates higher costs and NPVs compared with the counterfactual. Utility batteries have a 25-year lifecycle, while the OHL and the substation have a 40-year lifecycle. As a result, the Repex costs are increased in the innovation task.

In addition, material costs are higher for new build in the innovation task. Storage is also more expensive in semi-urban contexts versus rural contexts due to land, labour and material costs.

9.3 Application 2

Application 2 is linked to the introduction of distributed energy (wind farm) and the need to export to the grid. The representative wind farm agreed during the detailed scoping phase generates 36 MW and the configuration of this application is shown in Figure 9-5.

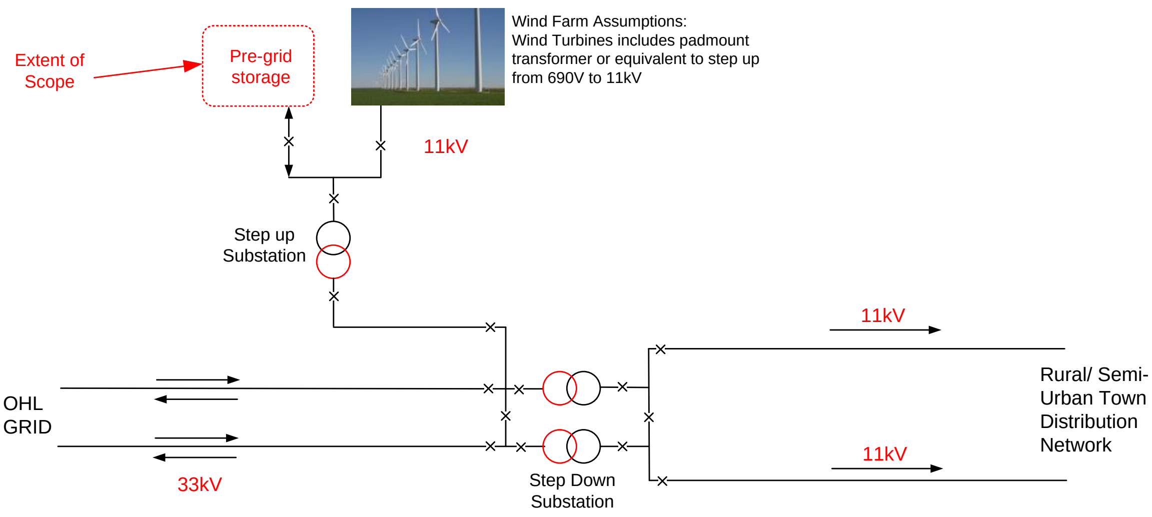


Figure 9-5 Network schematic indicating scope boundary – application 2

The counterfactual is the reinforcement of a new 33 kV OHL as shown in Figure 9-6.

Only a rural context has been considered for this application.

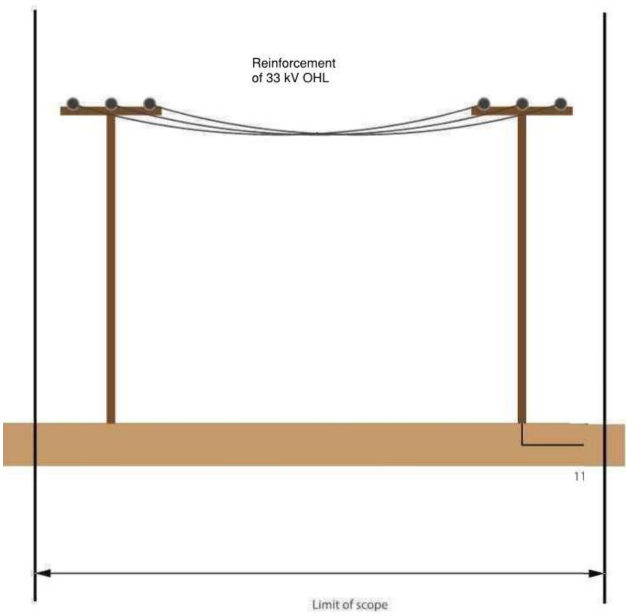


Figure 9-6 Scope boundary for the counterfactual – application 2

Based on the schematic in Figure 9-6, Table 9-5 outlines the variations that have been analysed.

Table 9-5 Variations analysed

Installation date	Context	Application
Innovation - storage		
2020	Rural	Wind Farm 36MW
2040	Rural	
Counterfactual - reinforcement		
2020	Rural	Wind Farm 36MW
2040	Rural	

Table 9-6 and Table 9-7 show the Assemblies that have been used to generate the cost data sets of the innovation approach and the counterfactual.

Table 9-6 Assemblies used to generate project costs - innovation

Description	Quantity	Unit
Storage: DC: 1MW utility scale battery [14.4 MWh]	8	Nr

Table 9-7 Assemblies used to generate project costs - counterfactual

Description	Quantity	Unit
OHL Distribution 33kV	100	km

9.3.1 Results and analysis

The analysis of application 2 has generated 4 cost data sets.

The outputs of these sets are outlined in Table 9-8 and shown graphically in Figure 9-7 and Figure 9-8.

Table 9-8 Base cost output data – innovation vs counterfactual

Installation date	Context	NPV Capex (m£)	NPV Opex (m £)	NPV Total (m£)	First costs (m£)
Innovation - storage					
2020	Rural	161.4	12.6	174.0	79.4
2040	Rural	110.5	7.9	118.5	146.3
Counterfactual - reinforcement					
2020	Rural	59.2	5.8	65.0	39.3
2040	Rural	29.6	3.3	32.9	64.4

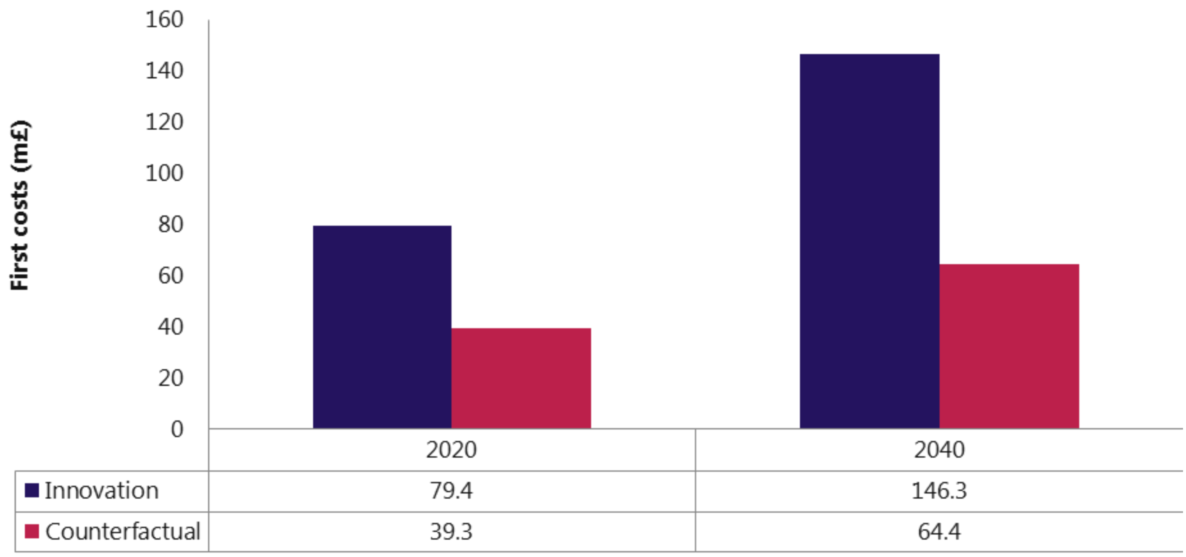
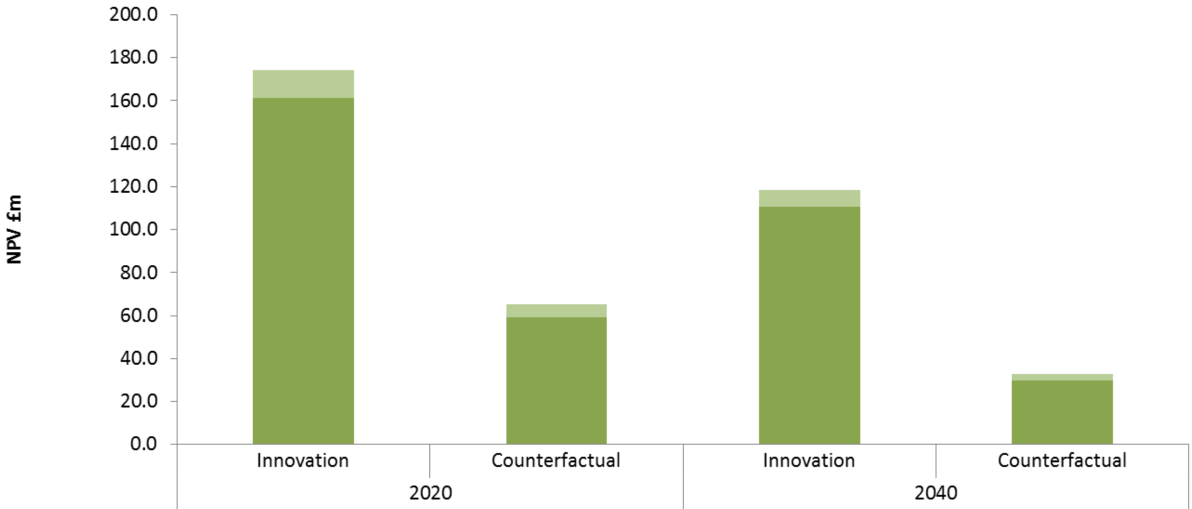


Figure 9-7 First costs of innovation and counterfactual at both installation dates



	2020 Innovation	2020 Counterfactual	2040 Innovation	2040 Counterfactual
Sum of NPV Opex	12.6	5.8	7.9	3.3
Sum of NPV Capex	161.4	59.2	110.5	29.6

Figure 9-8 Total NPV (Capex and Opex) of innovation and counterfactual at both installation dates

The analysis of the cost outputs indicates that the innovative approach generates higher costs and NPVs compared with the counterfactual reinforcement option. This difference derives mainly from the material costs of the storage battery and the lifecycle of the Assemblies. For instance, the utility battery has a 25-year cycle while the OHL has a 40-year lifecycle and consequently the lifecycle costs of the battery lead to higher replacement and refurbishment costs. The high cost of materials for the innovation option is not outweighed by higher costs for land, labour and plant for the counterfactual. This is highlighted as follows:

- Land first costs are 10 times higher than the innovation option
- Labour first costs are 2 times higher than the innovation option
- Plant first costs are 5 times higher than the innovation option

This analysis shows the significance of the material costs (battery storage) as well as refurbishment and replacement costs during the whole lifecycle of the project.

9.4 Application 3

Application 3 examines the requirement for storage or a counterfactual due to the installation of rapid car charging units at a rural service station.

Figure 9-9 outlines the network schematic for the innovation option for application 3.

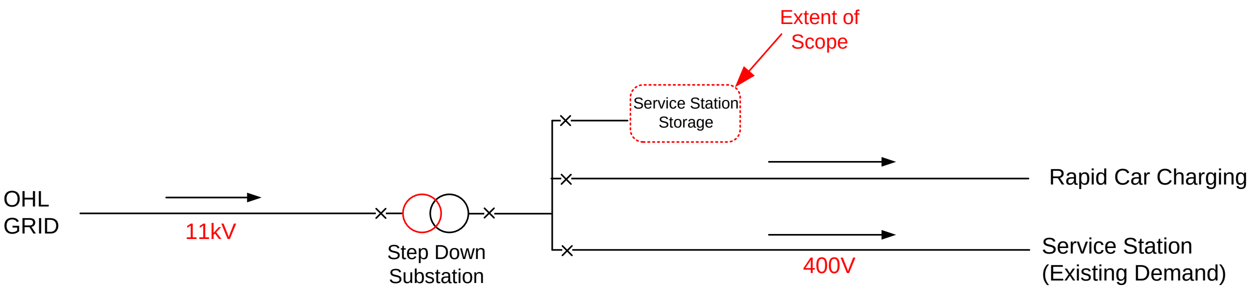


Figure 9-9 Network schematic indicating scope boundary – application 3

The counterfactual for this application is the upgrade of the distribution network for five and ten vehicle connections as analysed in E-G-12. For five connections only the distribution network needs to be upgraded while for ten connections an additional substation is required. The counterfactual scope boundary is shown in Figure 9-10.

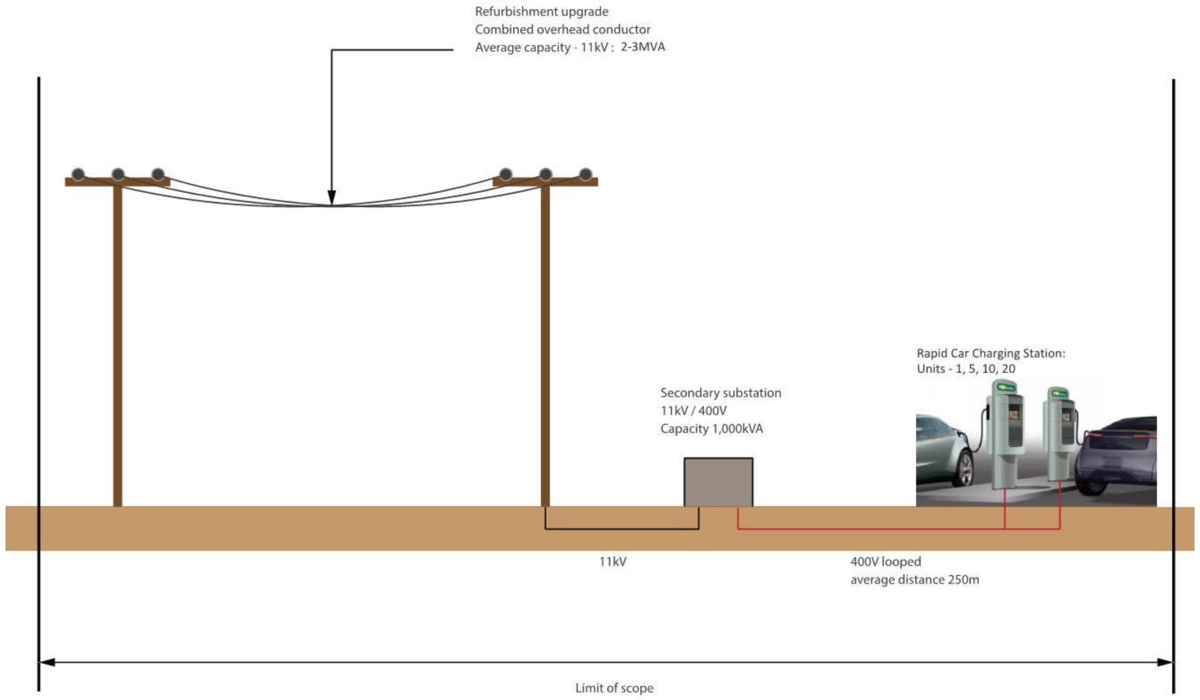


Figure 9-10 Scope boundary of counterfactual – application 3

Table 9-9 lists the variations that have been analysed, whilst the Assemblies that are used for the cost modelling and their quantities are summarised in Table 9-10. It should be noted that for both 5 and 10 connections the Assemblies of the counterfactual remain the same. The only differences in costs in these cases is due to the different contexts and installation dates.

Table 9-9 Variations analysed

Installation date	Context	Number of connections	Application
Innovation - storage			
2020	Rural	5 connections	Increase in demand-charging points
	Semi-urban		
	Rural	10 connections	
	Semi-urban		
2040	Rural	5 connections	
	Semi-urban		
	Rural	10 connections	
	Semi-urban		
Counterfactual - reinforcement			
2020	Rural	5 connections	Increase in demand-charging points
	Semi-urban		
	Rural	10 connections	
	Semi-urban		
2040	Rural	5 connections	
	Semi-urban		
	Rural	10 connections	
	Semi-urban		

Table 9-10 Assemblies and their quantities used to generate project costs

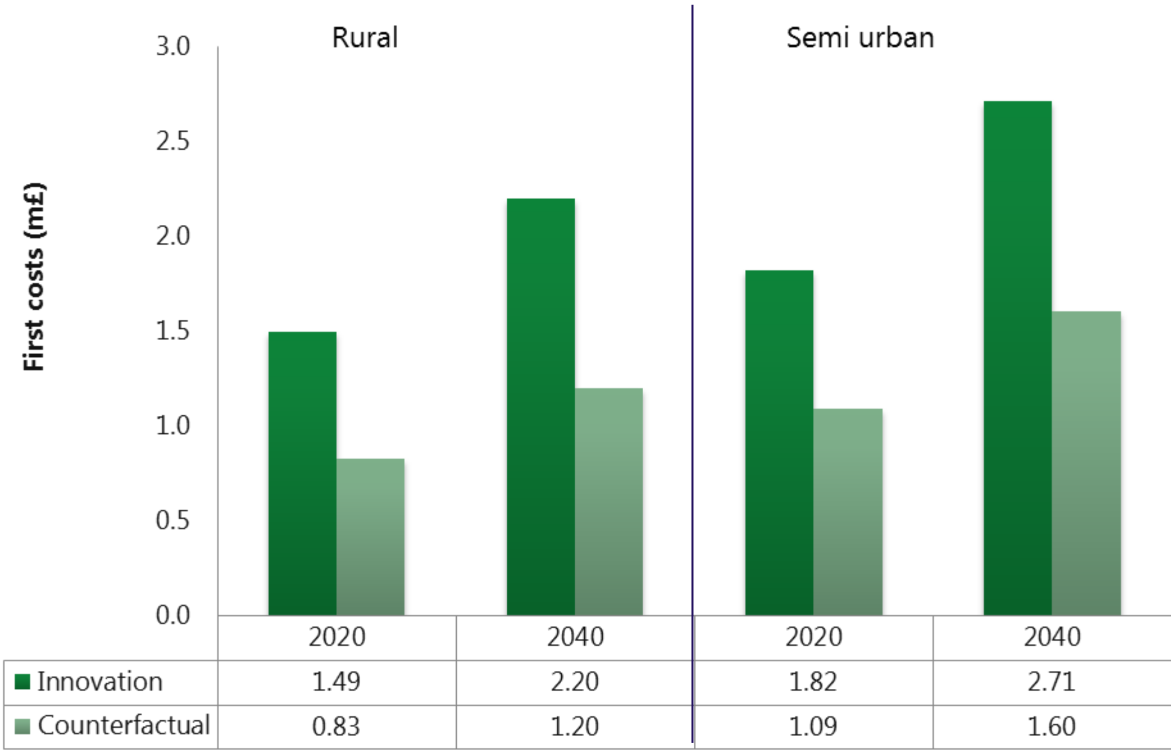
Date	Context	Number of connections	Assembly	Quantity	Unit
Innovation - storage					
2020	Rural	5 connections	Utility Scale Battery (0.5MWh)	1	Nr
	Semi-urban		Electric Vehicle recharge points	5	Nr
			400V distribution network	1.5	km
	Rural	10 connections	Utility Scale Battery (0.5MWh)	3	Nr
			Electric Vehicle recharge points	10	Nr
	Semi-urban		400V distribution network	2.5	km
2040	Rural	5 connections	Utility Scale Battery (0.5MWh)	1	Nr
			Electric Vehicle recharge points	5	Nr
	Semi-urban		400V distribution network	1.5	km
	Rural	10 connections	Utility Scale Battery (0.5MWh)	3	Nr
	Semi-urban		Electric Vehicle recharge points	10	Nr
			400V distribution network	2.5	km

Counterfactual - reinforcement					
2020	Rural	5 connections	1MV substation (11 kV to 400V)	0	Nr
	Semi-urban		Electric Vehicle recharge points	5	Nr
			400V distribution network	1.5	km
	Rural	10 connections	1MV substation (11 kV to 400V)	1	Nr
	Semi-urban		Electric Vehicle recharge points	10	Nr
			400V distribution network	2.5	km
2040	Rural	5 connections	1MV substation (11 kV to 400V)	0	Nr
			Electric Vehicle recharge points	5	Nr
	Semi-urban		400V distribution network	1.5	km
	Rural	10 connections	1MV substation (11 kV to 400V)	1	Nr
			Electric Vehicle recharge points	10	Nr
	Semi-urban		400V distribution network	2.5	km

9.4.1 Results and analysis

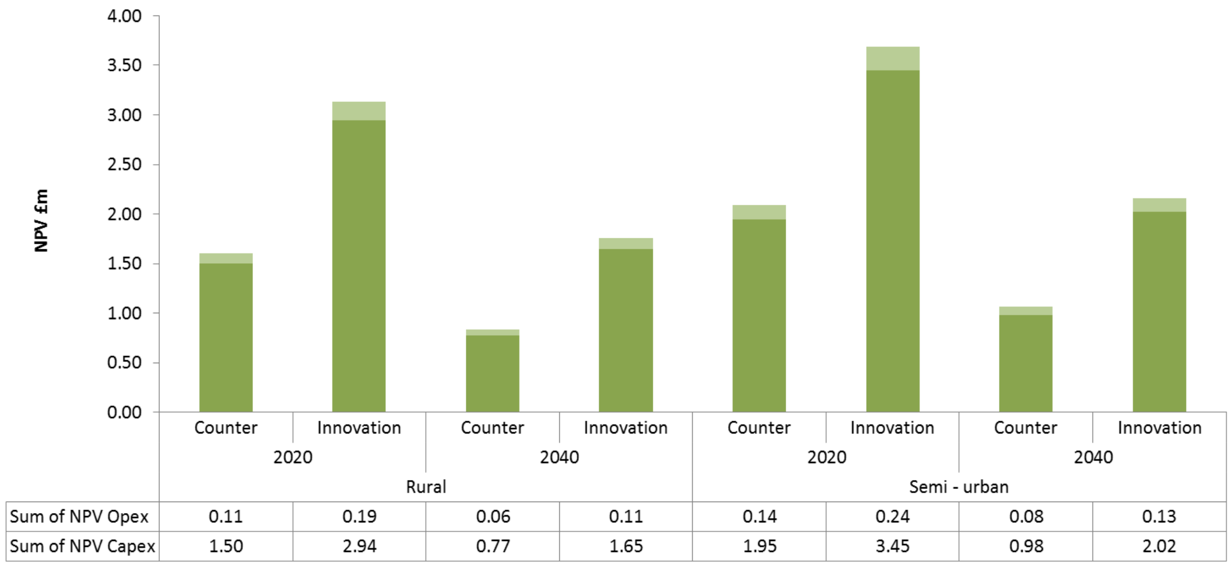
The analysis of the variations generated 16 cost data sets using the ICC.

Figure 9-11 to Figure 9-14 show the Capex NPV, Opex NPV, total NPV and first costs of the innovation projects compared with their counterfactuals in rural and semi-urban contexts for both the five connection and ten connection variations.



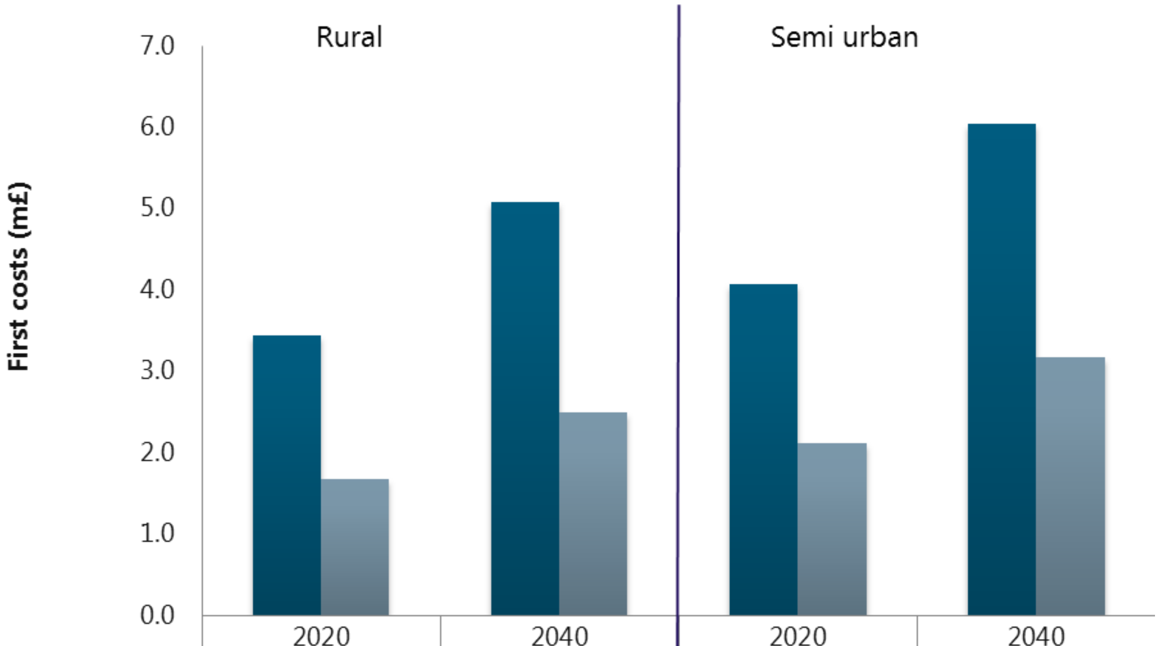
	Rural 2020	Rural 2040	Semi urban 2020	Semi urban 2040
Innovation	1.49	2.20	1.82	2.71
Counterfactual	0.83	1.20	1.09	1.60

Figure 9-11 First costs of innovation and counterfactual – 5 connections



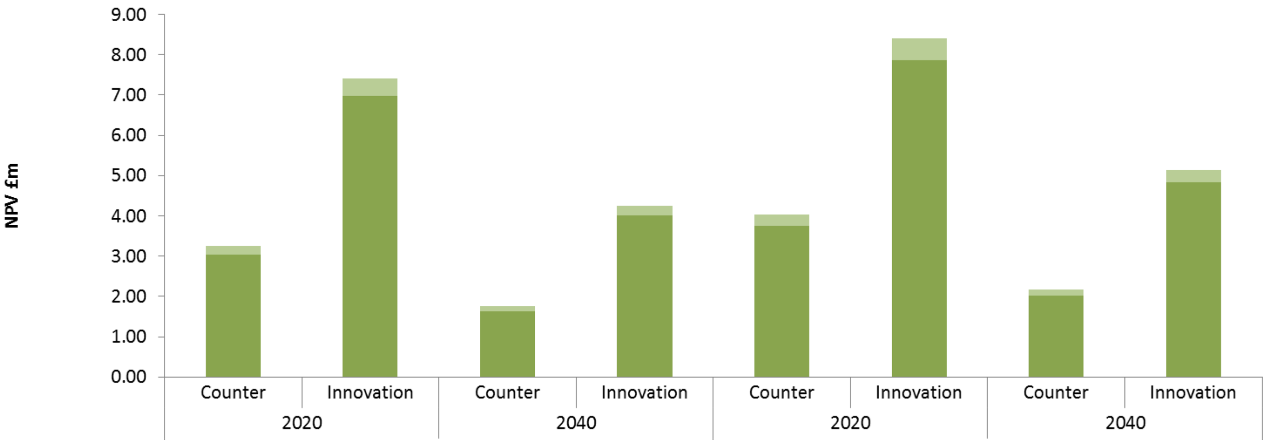
	Rural 2020 Counter	Rural 2020 Innovation	Rural 2040 Counter	Rural 2040 Innovation	Semi - urban 2020 Counter	Semi - urban 2020 Innovation	Semi - urban 2040 Counter	Semi - urban 2040 Innovation
Sum of NPV Opex	0.11	0.19	0.06	0.11	0.14	0.24	0.08	0.13
Sum of NPV Capex	1.50	2.94	0.77	1.65	1.95	3.45	0.98	2.02

Figure 9-12 Total NPV (Capex and Opex) of innovation and counterfactual – 5 connections



	Rural 2020	Rural 2040	Semi urban 2020	Semi urban 2040
Innovation	3.44	5.07	4.06	6.04
Counterfactual	1.67	2.49	2.11	3.18

Figure 9-13 First costs of innovation and counterfactual – 10 connections



	Counter	Innovation	Counter	Innovation	Counter	Innovation	Counter	Innovation
	2020		2040		2020		2040	
	Rural				Semi - urban			
Sum of NPV Opex	0.22	0.44	0.12	0.25	0.28	0.53	0.16	0.30
Sum of NPV Capex	3.04	6.97	1.64	4.00	3.75	7.87	2.01	4.84

Sum of NPV Capex Sum of NPV Opex

Figure 9-14 Total NPV (Capex and Opex) of innovation and counterfactual – 10 connections

The analysis of the outputs shows that all the innovation variations generate higher NPVs and first costs compared with the relevant counterfactual. This difference is related to the high material, plant, labour and land costs of the utility battery. The Assembly's unit capital cost in 2010 in a semi-urban context for new build has been estimated at £388,400 while, for the substation, the respective cost is £114,700.

9.5 Limitations and further work

There are no significant limitations of the approach although the following should be noted:

- The analysis suggests that considering current prices for electricity storage, the counterfactual reinforcement is cheaper both in terms of Capex and Opex. No allowance has been made for additional costs for achieving planning consent and abnormals for new OHLs. Where reinforcements are particularly onerous e.g. due to obtaining planning consent or length of OHL, storage may prove to be an economic alternative.
- In the case of application 3 (car charging), local generation may improve the potential for storage if the existing OHL has limited potential to charge batteries during periods of low demand.
- Adherence to P2/6 still needs consideration with DNOs to ensure the service station has adequate and appropriate levels of resilience.
- It is clear from this high level analysis that costs for battery storage are generally prohibitive as an alternative to the counterfactual of reinforcement. However, projects will need to be reviewed on a case by case basis to ensure systems can be compared appropriately.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

10 E-I-14 Fault Current Limiter

10.1 Research questions overview and scope

This analysis is intended to provide reference network costs at distribution level. The analysis will provide the ETI with the basis on which to evaluate the capital and operating cost of using a Fault Current Limiter (FCL) versus conventional reinforcement.

In the initial scoping with ETI, two reference applications were suggested as follows:

- *Application 1*. Rural networks, assuming that wind farms and DNO interconnection are across rural areas.
- *Application 2*. Dense urban networks (MV) and increase in load capacity. In the same context, FCLs are used for paralleling transformers in dense urban networks where small cross section cables have low impedance.

After discussion with Western Power Distribution (WPD), Application (1) was not considered valid due to the inherent high impedance of rural networks which reduces current under fault situation and negates the need for a FCL.

The situation envisaged in Application (2) is that in which an asset (switchgear) has the capacity for peak current but not an increase for a short circuit fault current. This is because the temperature and current would rise above the permitted limit, and the mechanical breaking limit would be experienced.

Consequently, only Application (2) was considered in the Detailed Scoping report and is analysed here.

10.1.1 Design of system schematic

During the detailed scoping phase teleconferences were held with both GridOn and WPD to review the potential application of FCLs and to ascertain key technical parameters for development of this report. GridOn were approached due to their previous work with the ETI on the trial installation of a GridOn device in the UK, and WPD due to their perceived accelerated consideration of fault current management versus other distribution network operators.

WPD are progressing with the FlexDGrid programme supported by the Low Carbon Networks Fund (LCNF) and details of this programme and associated progress reports have been reviewed and discussed with them. The focus of the programme is to analyse fault current management and the introduction of FCL technology as a possible way to manage faults in certain applications in the Birmingham distribution network.

It is clear through research that there are numerous permutations for the application and installation of FCL technology. As it is difficult to typify both the variant of FCL technology and consequent application, for the purpose of this high level study an example has been identified which is considered to be representative in terms of scale and cost. Further more detailed studies will be necessary to fully analysis different approaches to fault current management and the application of different FCL technologies in different scenarios.

The simplified schematic shown in Figure 10-1 outlines the “typified” system configuration incorporating a GridON FCL device. This is adaptable to the transformer arrangement in the 132/11kV substation in the existing cost database and has been reviewed through initial consultation with GridON to assess integration and performance characteristics.

In this instance, the FCL is located on the 11kV side of a 132/11 kV substation. The FCL can be installed off line prior to final connection so security of supply is ensured. Two circuit breakers are required for connection to the existing bus arrangement.

As noted above it is accepted that there are multiple integration permutations and the example is therefore representative for the purposes of this high level study only. To adequately test and ascertain the existing breaking rating of the switchgear a complete fault level study would need to be completed.

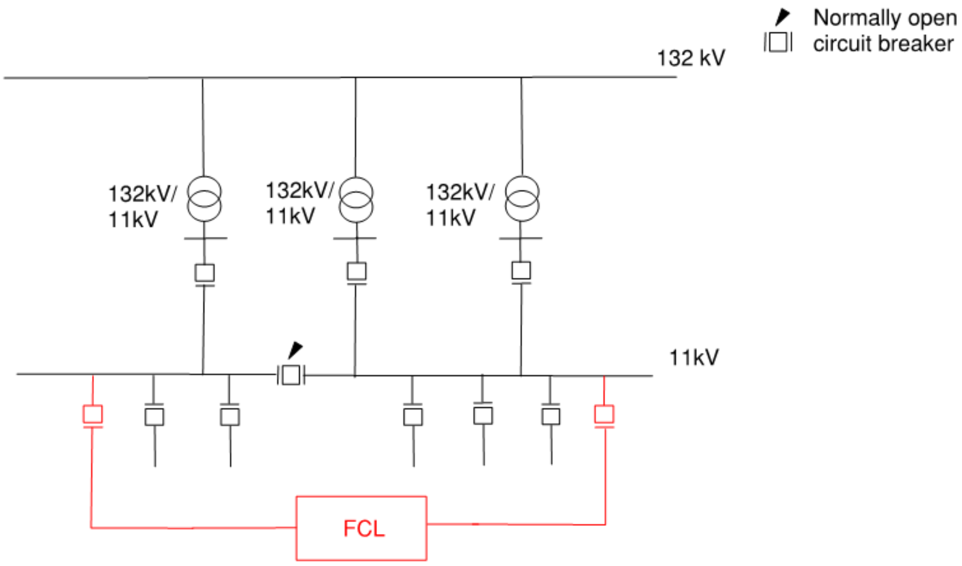


Figure 10-1 Typified FCL connection across Bus-Section

The counterfactual system reinforcement includes the refurbishment of the substation with higher capacity switchgear. Additional to this, the reinforcement includes the replacement of the circuit breakers of the bus bar and attached to the transformers. The existing transformers are assumed to be suitable for the reconfiguration and within design life so do not need replacing.

Table 10-1 outlines the variations that have been costed and analysed.

Table 10-1 Variations analysed

Installation date	Context	Application
Innovation - FCL		
2020	Urban	Dense urban networks (MV) and increase in load capacity and/or distributed generation.
2020	London	
2040	Urban	
2040	London	
Counterfactual - reinforcement		
2020	Urban	Dense urban networks (MV) and increase in load capacity and/or distributed generation.
2020	London	
2040	Urban	
2040	London	

Based on the schematic in Figure 10-1, Table 10-2 outlines the different infrastructure elements (Assemblies) that are used for both the innovation and counterfactual reinforcement. It also includes the quantity of each element to be costed based on the Detailed Scoping document.

- Assembly 1 (innovation) includes the installation of a single FCL and interconnecting 11 kV switchgear including associated circuit breakers
- Assembly 2 (counterfactual) includes the refurbishment of the substation by replacing the switchgear and the related circuit breakers.

Table 10-2 Assemblies used to generate project costs

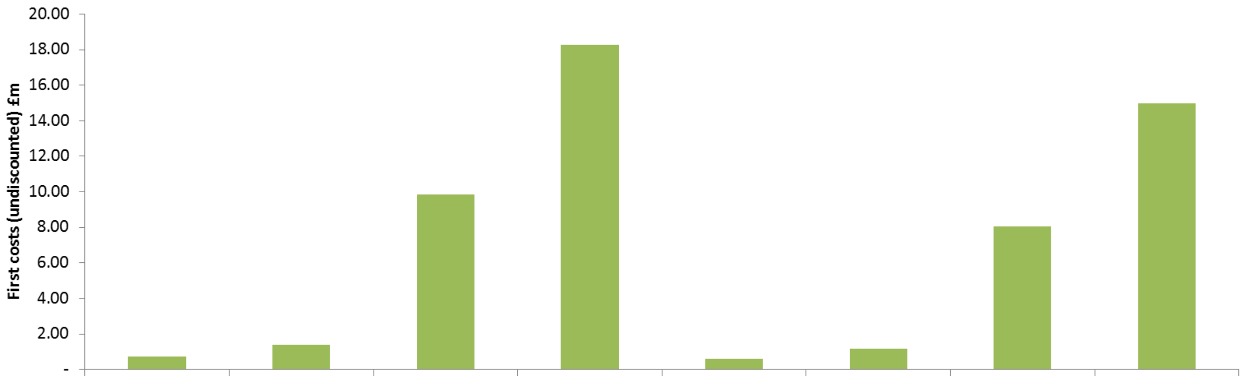
Assembly	Description *	Mode	Quantity	Unit
1. Innovation	Conversion : 132 to 11 kV substation with FCL (50MVA)	Refurbishment	1	Nr
2. Counterfactual	Conversion : 132 to 11 kV substation with reinforcement (50MVA)	Refurbishment	1	Nr

10.2 Results and analysis

Based on the quantities in Table 10-2, 8 cost data sets were generated using the ICC. Each data set is representative of a different installation date.

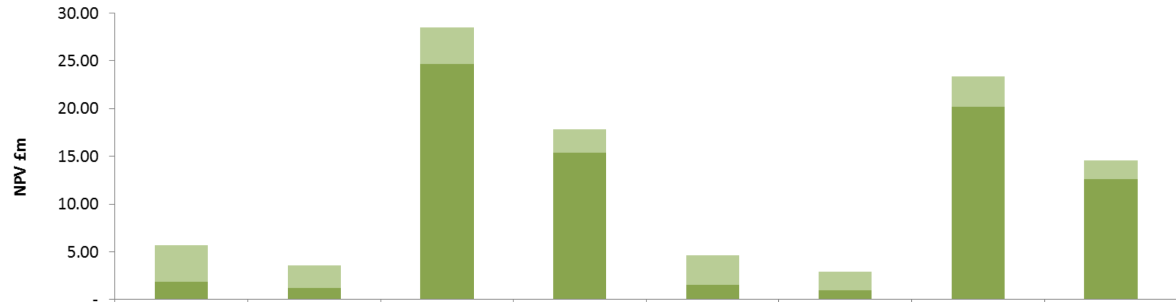
Figure 10-2 and Figure 10-3 show the first costs, the total NPV (Capex and Opex) of the innovation projects against their counterfactuals in urban and London contexts.

As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors' costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs. NPV Capex represents the installation costs plus all lifecycle costs which include all replacement cycles and abandonment costs – (Repex) to the extent that these occur before the project end. NPV Opex takes into account operational costs over the life of the project.



	London				Urban			
	Counterfactual		FCL		Counterfactual		FCL	
	2020	2040	2020	2040	2020	2040	2020	2040
Total	0.74	1.41	9.84	18.25	0.61	1.15	8.06	14.96

Figure 10-2 First costs of innovation and its counterfactual in different contexts at different installation dates



	London				Urban			
	Counterfactual		FCL		Counterfactual		FCL	
	2020	2040	2020	2040	2020	2040	2020	2040
Sum of NPV Opex (m)	3.81	2.42	3.81	2.42	3.13	1.98	3.13	1.98
Sum of NPV Capex (m)	1.89	1.19	24.65	15.38	1.55	0.98	20.21	12.60

Figure 10-3 NPV (Capex and Opex) of innovation and its counterfactual in different contexts at different installation dates

The analysis shows that:

- The conventional reinforcement is currently more cost effective than the refurbishment of the substation with the installation of the FCL. The innovative approach generates higher first costs as well as higher Capex and consequently total NPV. The main reason for this is the high cost of the FCL, a reflection of the device being at an early stage of technological development with low current market penetration. There is the potential for costs to fall in future should there be an increase in use and production of FCL devices.

- The Opex NPVs are assumed to be the same in each variation (context, installation date). The operational costs refer to the whole substation and, at this stage, without more operational experience of FCL plant, the costs are considered to be similar with negligible differences. NPV Capex, including all replacement cycles and abandonment costs, differentiate between scenarios due to the different components that are used in each case. Note, no losses are currently accounted for the in ICC model, so losses associated with the FCL (~0.5%) are not included.
- The costs increase as the context changes from urban through to London. As already discussed, in general labour, material and plant costs increase from rural to urban, with a further uplift applied to London.

10.2.1 Analysis: Components

This section provides a breakdown of the key elements of Component cost in the cases of FCL installation or conventional reinforcement.

Figure 10-4 shows the share of costs in each case. Although the absolute numbers between urban and London costs are different the share remains the same in each context.

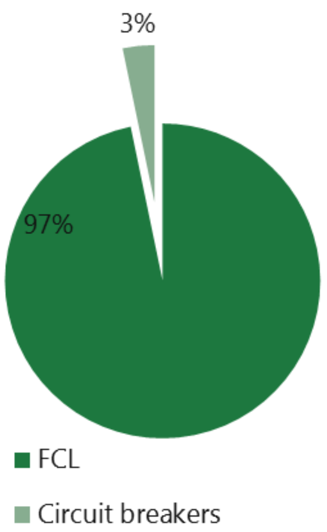


Figure 10-4 Share of costs represented by the components – innovation vs counterfactual

The analysis of the components indicates that the whole life cycle costs of the Fault Current Limiter represent the highest share of total cost for the innovation.

10.3 Limitations and further work

Limitations associated with this task are as follows:

- Only a single FCL application has been considered as "typical". Different configurations would require different assemblies, components and refurbishment requirements.
- Multiple permutations for installation are apparent and costs may vary significantly for certain applications.
- The technology is new and although there is the potential for cost reductions, this remains uncertain.

- Additional space will be required for the FCL installation in the substation. This may not be possible in some instances particularly in city centre locations.
- Cost information received for the FCL is a range provided by GridOn (£0.5m – £2m). The finalised costs for this application and other permutations could vary.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of opex and lifecycle costs are to be revised in future versions which could impact on these results.

11 E-I-15 (a) Power Electronics - STATCOM

11.1 Research question overview and scope

This analysis is intended to provide reference network costs at distribution level. The purpose of the analysis is to provide the ETI with the basis on which to evaluate the capital and operating cost of using power electronics through the integration of STATCOM and a battery energy storage system.

According to the UK Grid Code there is a need for Reactive Power (VAR) support for distributed generators of a certain size. 50MW is the threshold capacity of wind farms connected to the network in England and 30MW in Scotland. Integrating STATCOM and battery energy storage system is suggested to enable both reactive and real power support.

The schematics in Figure 11-1 and in Figure 11-2 show the boundary and simplified network layout of this project. These schematics provide the basis of the BoQs used for costing purposes. Due to available data the plant used for both Scotland and England and Wales is assumed to be the same. The supplier (ABB) has indicated that there would be no significant difference in cost.

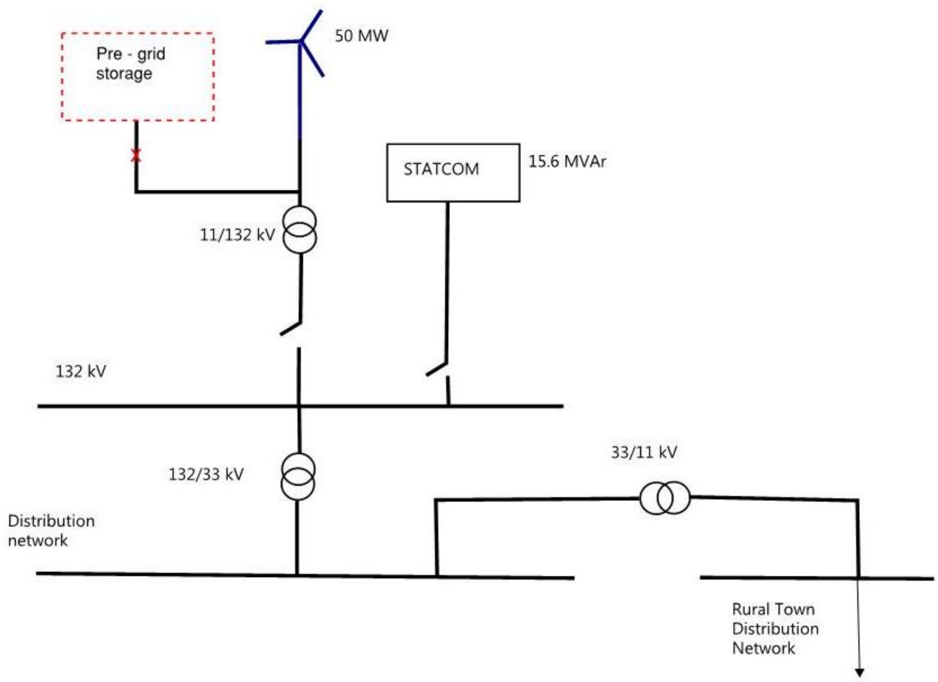


Figure 11-1 STATCOM for 50MW wind farm (England and Wales)

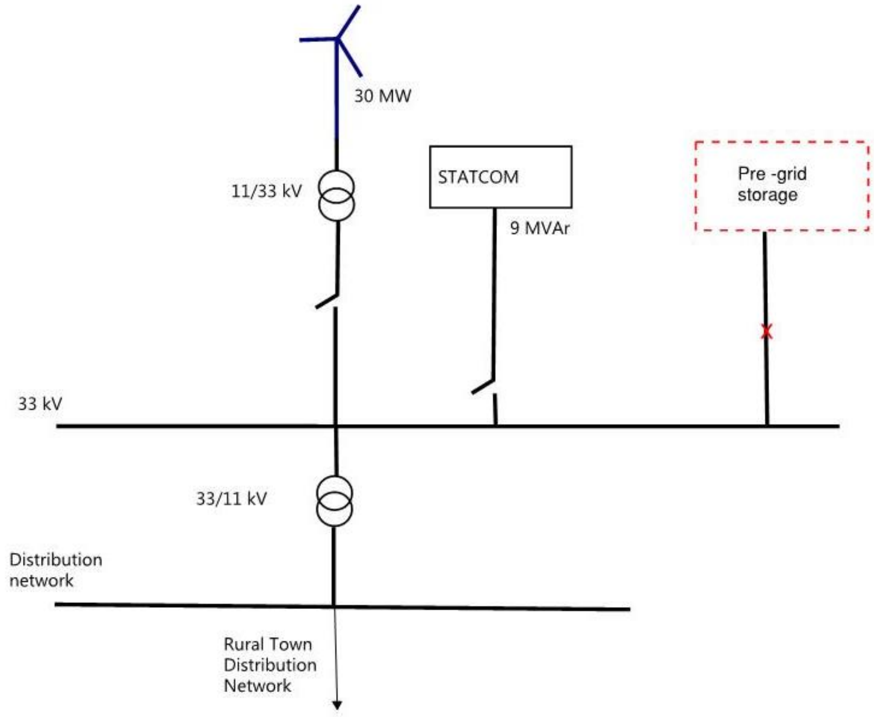


Figure 11-2 STATCOM for 30MW wind farm (Scotland)

Table 11-1 outlines the scenarios that have been costed and analysed.

Table 11-1 Capacity and network length for different installation dates

Installation date	Context	Capacity (MVAr)	Mode
2020	Rural- England and Wales	15.6	New build
2040	Rural- England and Wales	15.6	New build
2020	Rural- Scotland	9	New build
2040	Rural- Scotland	9	New build

Based on the schematics in Figure 11-1 and Figure 11-2, Table 11-2 outlines the different infrastructure elements (Assemblies) that make up the network. It also includes the quantity of each element costed based on the detailed scoping document. Due to the way the ICC is configured, it is not possible to test the difference between installation in England and Wales and installation in Scotland. Although cost indices for different areas are available in the tool, they are split according to region rather than according to country. Thus all costs are the 'All of the UK'.

Table 11-2 Assemblies used to generate project costs

Description	Application	Quantity	Unit
STATCOM ABB PCS 6000	Rural – All of the UK	1	Nr
Storage: DC: 1MW utility scale battery [14.4 MWh]	Rural – All of the UK	1	Nr

11.2 Results and analysis

Based on the quantities in Table 11-2 cost data sets were generated using the ICC. Each data set is representative of a different installation date.

The project cost parameters (e.g. ground conditions) are the same for each scenario.

Table 11-3 shows the NPV Capex, NPV Opex and NPV Total as well as the first costs of each scenario for installation dates of 2020 and 2040. Although the threshold for inclusion of STATCOM in England and Scotland is different, the STATCOM device and the utility battery that is used is the same.

As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project.

Table 11-3 Base output data – generic

Installation date	Context	NPV Capex £m	NPV Opex £m	Total NPV m£	First costs m£
2020	Rural	29.9	2.3	32.2	16.6
2040	Rural	17.4	1.3	18.7	25.8

The outputs of the cost analysis indicate that:

- Later installation dates generate higher first costs and lower NPV due to the end date of the project and lifecycle of the Assemblies.

11.2.1 Analysis: Assemblies

Two Assemblies have been used in this application:

- STATCOM with capacity 16 MVAr (suitable up to 50 MW)
- 1 MW utility scale battery with capacity 14.4 MWh

The share of costs represented by each of the two Assemblies varies from 2020 to 2040 as shown in Figure 11-3.

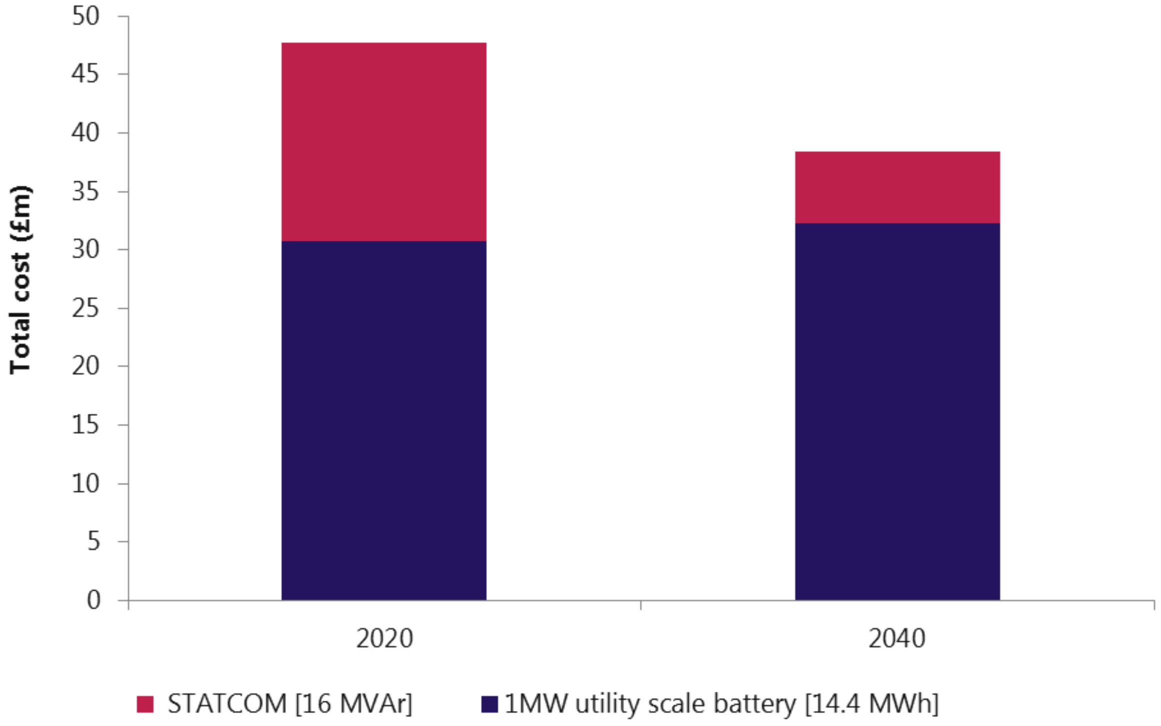


Figure 11-3 Share of the costs represented by utility scale battery and the STATCOM in 2020 and 2040

Figure 11-3 shows that:

- The utility scale battery has greater contribution to the project's costs compared with the STATCOM unit. This is due the capital costs of the Assemblies as well as their lifecycle replacement costs. In particular the unit capital cost in 2010 of a battery in a rural environment is £4,752,000, and the cost for a STATCOM unit is £3,421,900. Additionally, the lifecycle of the utility scale battery is 25 years, while STATCOM has a 40-year lifecycle.
- The impact of the utility scale battery on the costs of the project increases at the later installation date, due to increase in new build costs of the battery in 2040 and additional refurbishment requirements.

11.3 Limitations and further work

The limitations of this analysis are as follows:

- Only a single STATCOM technology has been considered as a baseline
- Multiple permutations for installation may be apparent depending on the grid configuration and costs may vary significantly due to the size of the wind farm

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

12 E-I-15 (b) Power Electronics – back-to-back HVDC

12.1 Research questions overview and scope

This analysis provides the ETI with the basis on which to evaluate the costs in the application of back-to-back HVDC coupling of adjacent DNO networks. For this application no reinforcement or counterfactual is assumed for existing substations and networks to enable the DNO link.

The simplified schematic in Figure 12-1 shows the assumed system configuration.

Figure 12-1 Back-to-back HVDC connection

DNO networks in the UK are currently poorly connected and the application of HVDC back-to-back converter technology has the potential to improve resilience at distribution level.

A back-to-back arrangement is used when two asynchronous systems need to be interconnected for bulk power transmission or for AC system stabilisation reasons. Additional to transmission level applications, the back-to-back HVDC can also be used to couple two different distribution systems at 33kV. Traditionally, it is difficult to connect these systems due to fault level issues, phase angle differences or excessive circulating currents. Future possible projects or demonstrations could include a range of applicable positions for the installation of both 33kV devices and 11kV devices, including:

- At 33kV substations or switching stations to transfer power between grid groups
- At 11kV substations as a bus section to control power flows between different grid groups
- Along 11kV feeders to transfer power between different primary and grid groups

Figure 12-2 presents the high level concept of the back-to-back converter station considered in this “typified” example. Although HVDC converter stations commonly include transformers between the filters and the converters, in this application no transformers are required since the AC voltage is assumed to be the same on both sides. The technology of an HVDC back-to-back station varies from the use of line-commutated transformers or phase-commutated transformers to a very compact modular back-to-back converter station. The main components of the station in both cases are the AC filters and the converters. For this project the costs that have been applied refer to the converter station as a complete entity, and not a breakdown of the different components.

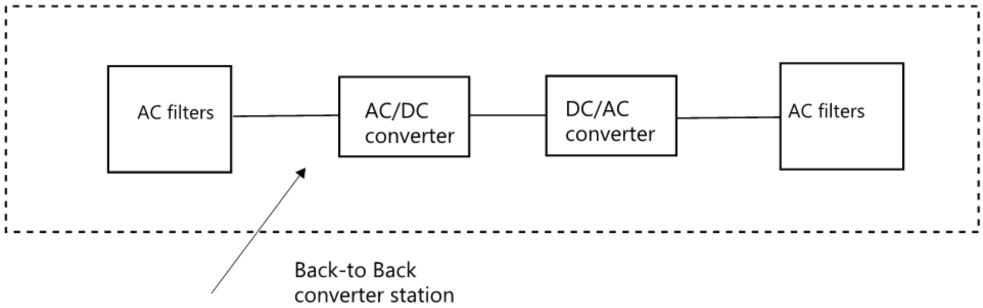


Figure 12-2 Back-to-back converter station

Table 12-1 outlines the variations that have been costed and analysed.

Table 12-1 Variations analysed

Context	Installation date	Length	Application
Rural	2020	25 km	50km and 100km connection between DNO networks 50km connection equates to 2 No. 25km circuits 100km connection equates to 2 No. 50 km circuits
		50 km	
	2040	25 km	
		50 km	

Table 12-2 lists the Assemblies that are used and the quantity of each to be costed.

No counterfactual has been considered for this application.

Table 12-2 Assemblies used to generate project costs

Description	Mode	Quantity	Unit
Distribution: HVDC: None: back-to-back Converter Station for HVDC Application	New build	1	Nr
Distribution: HVAC: Overhead: 33kV line [25 MVA]	New build	50, 100	km

12.2 Results and analysis

Based on Table 12-1 and Table 12-2, four cost data sets were generated using the ICC as given in Table 12-3. The results are illustrated in Figure 12-3 (first cost) and Figure 12-4 (NPV).

First costs (undiscounted) include new build costs plus preliminary costs, contractors' costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs. NPV Capex represents the installation costs plus all lifecycle costs which includes all replacement cycles and abandonment costs (Repex) to the extent that these occur before the project end. NPV Opex takes into account operational costs over the life of the project.

Table 12-3 Base output data

Installation date	Network length	First Cost (£m)	NPV Capex (£m)	NPV Opex (£m)	NPV Total (£m)
2020	50km	55.6	76.0	9.3	85.3
	100km	64.8	87.4	10.8	98.2
2040	50km	102.9	46.2	5.5	51.7
	100km	118.8	53.2	6.4	59.6

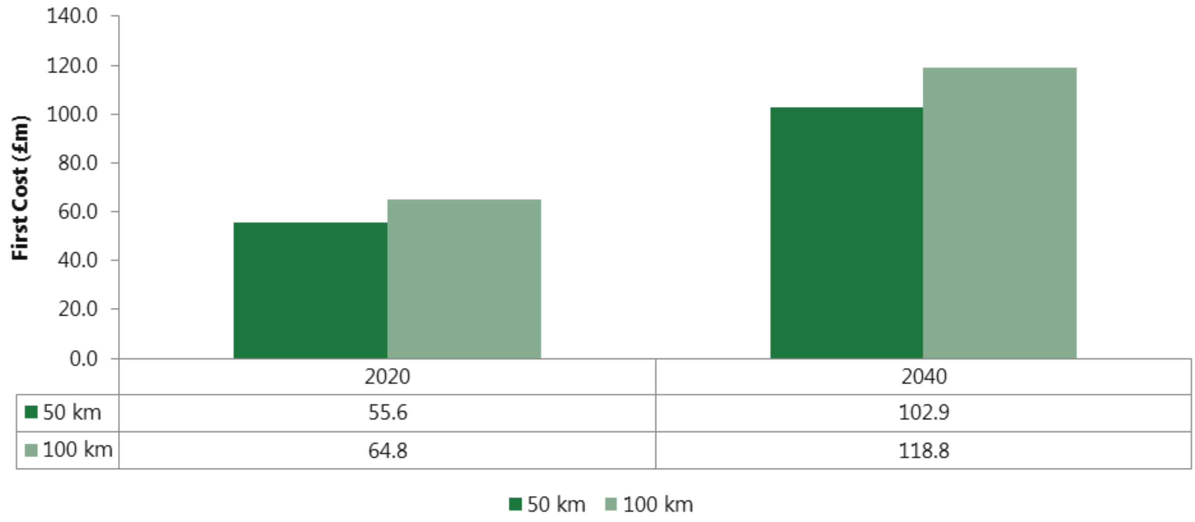


Figure 12-3 Variation of First Cost (£m) with installation date and length

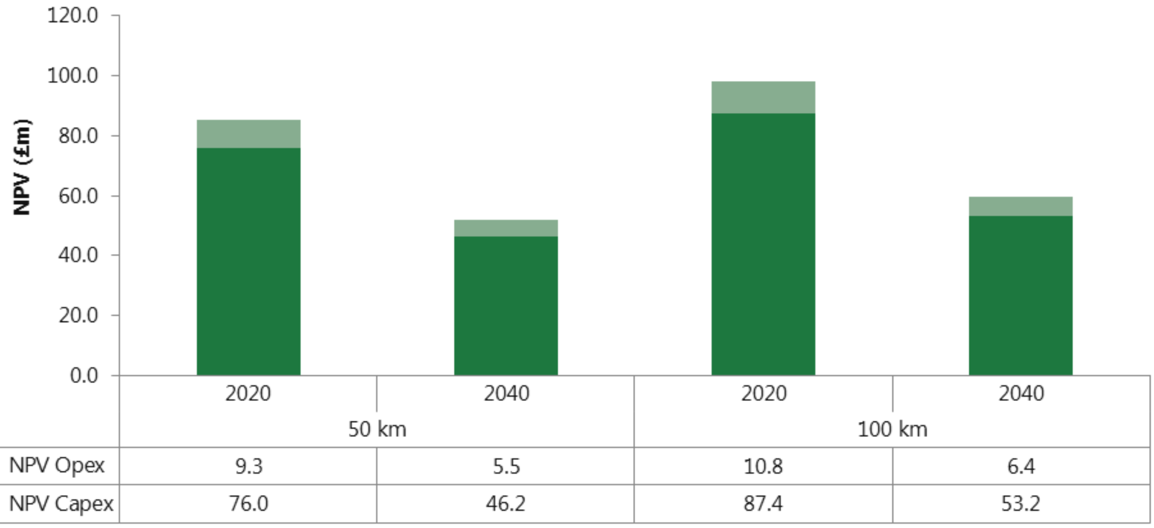


Figure 12-4 Variation of NPV (Capex plus Opex) with installation date and length

The analysis confirms that:

- Although the installation of a back-to-back converter station for a 100km interconnection is more expensive than for a 50km interconnection, the difference is only around 15%. This identifies that the length of the network is of minor importance in terms of costs compared with the high costs of the back-to-back converter station itself.
- The NPVs are lower at later installation dates for both lengths. This is primarily due to the impact of discounting.
- NPV Opex is of the order of 10% of total NPV in all cases.

12.2.1 Analysis: Assemblies

Figure 12-5 provides a breakdown of the key elements of cost for the different connection lengths in 2020 and in 2040.

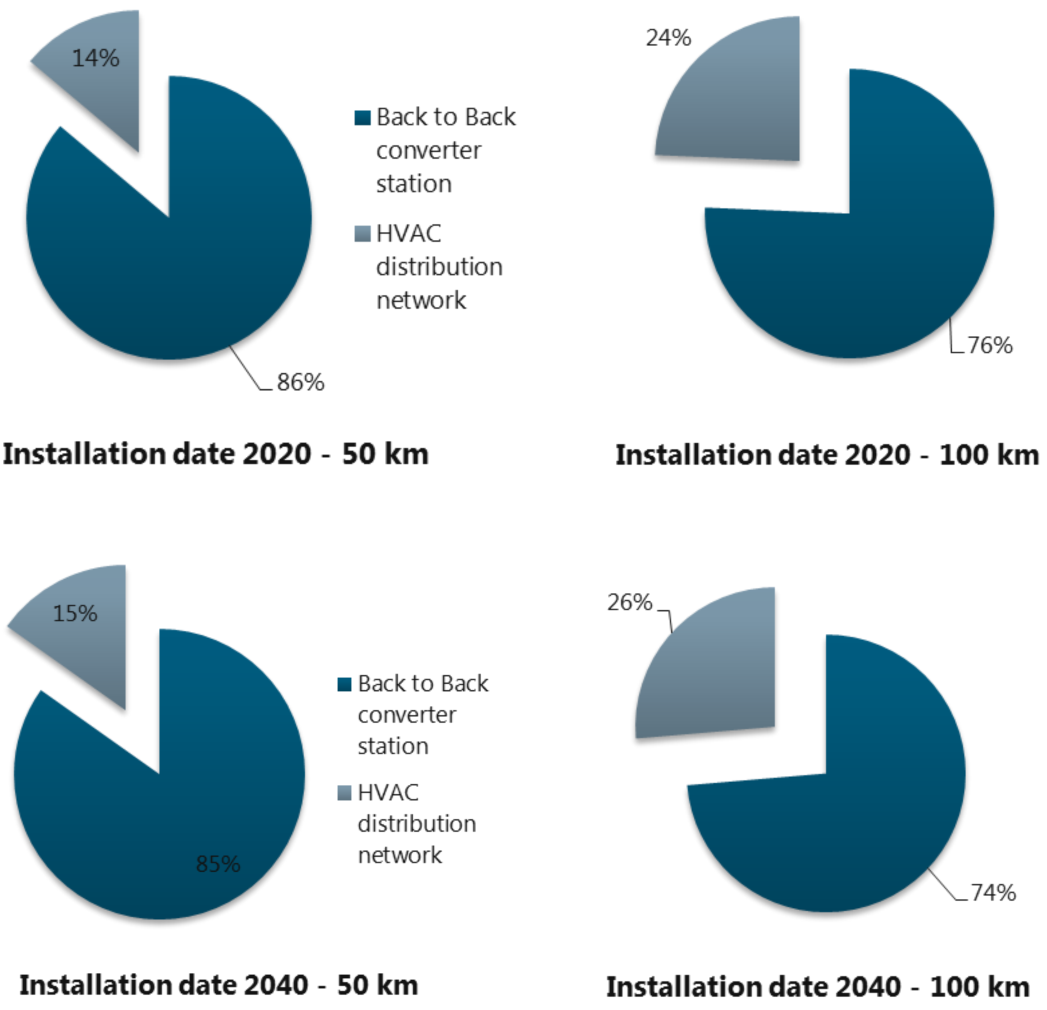


Figure 12-5 Share of total cost represented by each Assembly

The analysis of the Assemblies shows that:

- As suggested by the results in Section 12.2, the HVDC back-to-back converter station represents the major share of cost
- As expected, the 100km distribution network represents a higher share of cost than the 50km network at both installation dates
- For the same length, the installation date does not impact on the relative share of cost of the converter station and network

12.3 Limitations and further work

Limitations associated with this task are as follows:

- No allowance has been made for modifications to the existing substation and networks to enable the connection of an AC OHL to distribute to the back-to-back HVDC station
- No allowance has been made for any potentially significant planning and wayleave agreements that may be required for the HVDC converter station and OHL
- The availability of cost data is limited as no installations have been completed in the UK and manufacturing companies are only just beginning to tender for projects with the DNOs. Hence, an example manufacturers ABB, have only been able to provide approximate costs for the back-to-back converter station
- Although there are precedents for installation of this technology in other countries, the regulator and DNOs will need to agree on the specification and principles of installation in a UK context

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of Opex and lifecycle costs are to be revised in future versions which could impact on these results.

13 E-I-16 Cost comparison HVAC vs HVDC at transmission

13.1 Research questions and scope

This analysis is intended to provide a cost comparison of HVDC vs HVAC at transmission level in rural areas with overhead lines (400kV). The analysis will provide the ETI with the basis on which to evaluate the capital and operating cost of HVDC transmission networks versus HVAC over different time frames.

13.1.1 Design of representative network

Two alternative options to repurposing the towers are presented with their corresponding counterfactuals in Figure 13-1 and Figure 13-2.

- Option 1: Install new HVDC towers and circuits within existing wayleave
- Option 2: Install new HVDC towers and circuits in a new wayleave

It is assumed in both options that that the HVDC will need to be commissioned before decommissioning HVAC line.

In option 1, for the counterfactual, the period that the power will be disconnected is expected to be relatively short if it only includes commissioning of the new circuits and then switching over. This would be specific to the context and strategic importance and resilience of the network. Due to HVDC being relatively new to the UK, and particularly if the route is deemed to be highly strategic, National Grid may keep both circuits operational until the HVDC has been successfully in operation for a period of time.

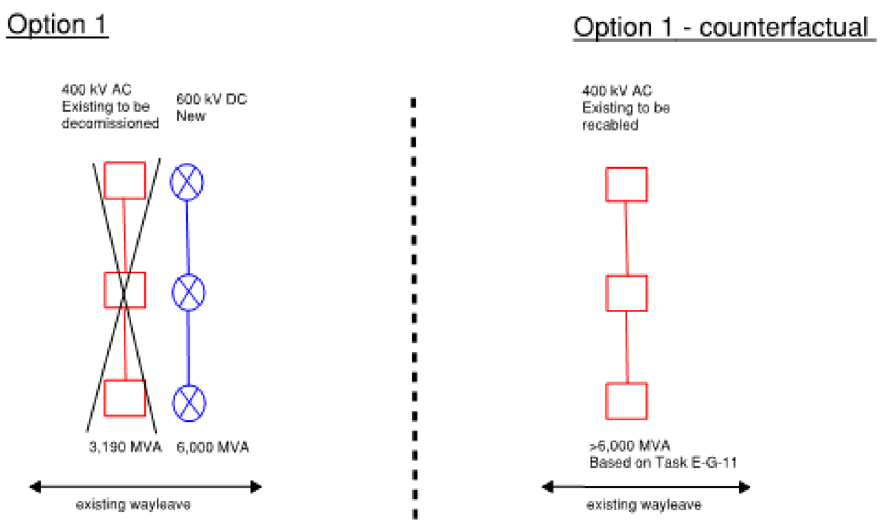


Figure 13-1 Option 1: Install new HVDC towers and circuits within existing wayleave

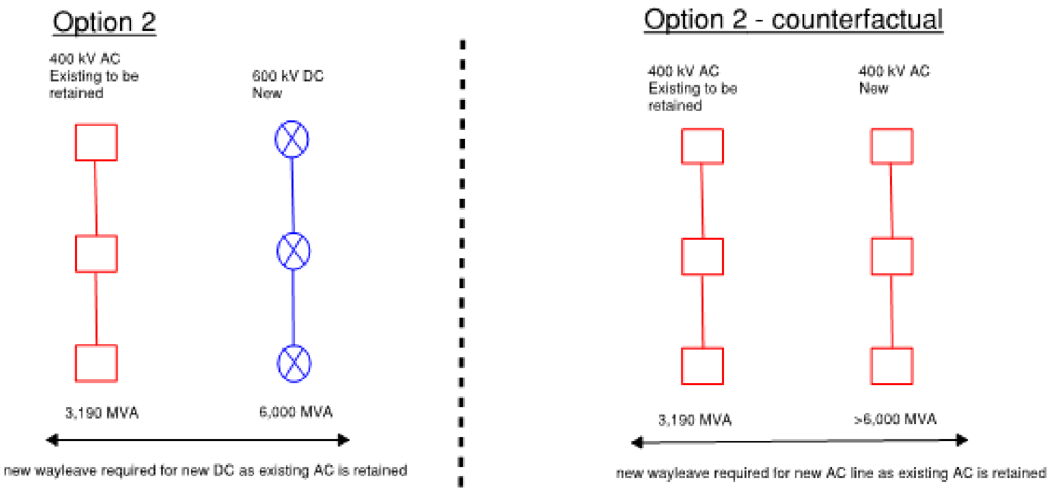


Figure 13-2 Option 2: Install new HVDC towers and circuits in a new wayleave

The high level system schematic for both options and their respective counterfactuals are shown in Figure 13-3 and Figure 13-4.

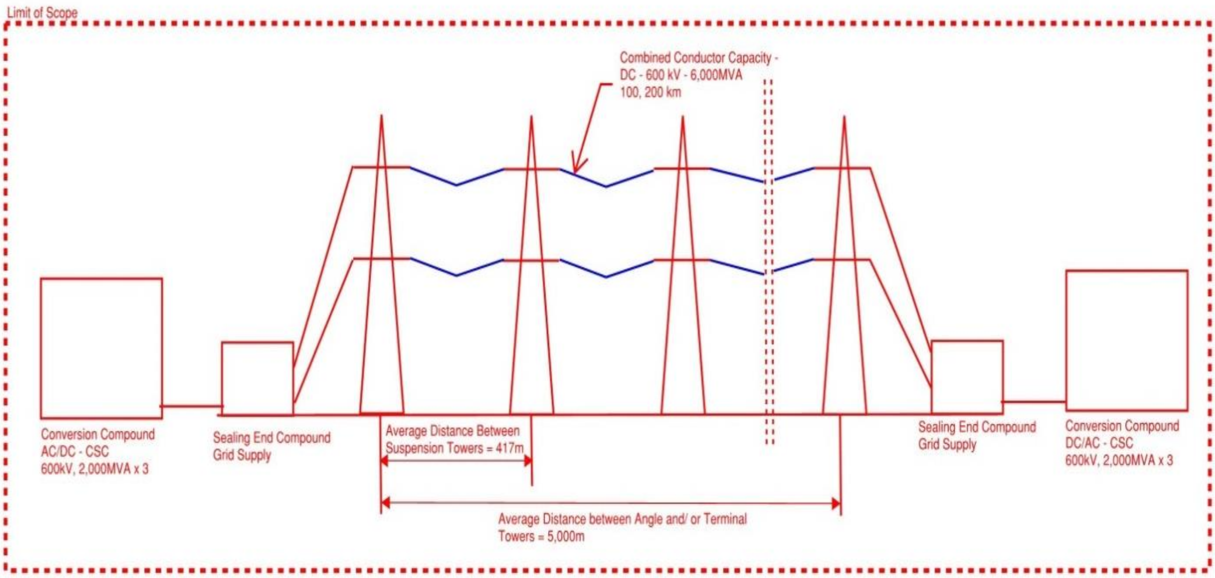


Figure 13-3 Innovation: HVDC Scope

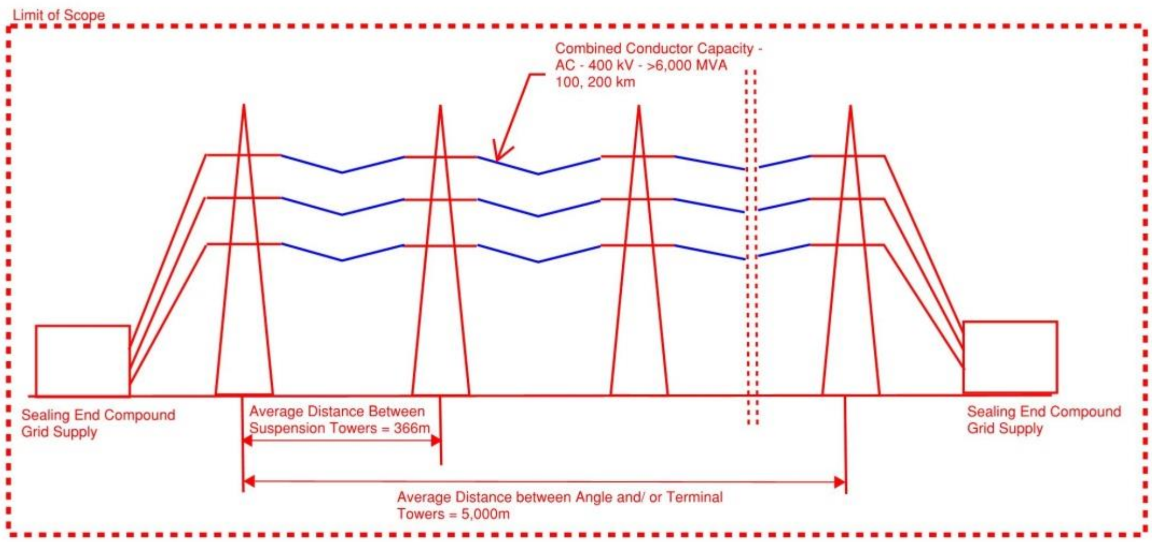


Figure 13-4 Counterfactual: HVAC Scope (Option 1 – re-cabling only, Option 2 – complete new system)

Table 13-1 outlines the variations that have been costed and analysed for both options 1 and 2.

Table 13-1 Variations analysed

Installation date	Context	Capacity	Length
Innovation - HVDC			
2030	Rural	600 kV	100 km
2030	Rural	600 kV	200 km
Counterfactual - HVAC			
2030	Rural	400 kV	100 km
2030	Rural	400 kV	200 km

Based on the schematics in Figure 13-3 and Figure 13-4, Table 13-2 and Table 13-3 outline the different infrastructure elements (Assemblies) that make up the network for option 1 and option 2, respectively. They also include the quantity of each element to be costed.

Table 13-2 Assemblies used to generate project costs – option 1

Description	Mode	Quantity	Unit
Innovation - HVDC			
Conversion: HVDC: None: 6,000MVA HVDC - HVAC VSC Converter	New Build	2	Nr
Transmission: HVDC: Overhead: 600kV line [6,000 MVA] within existing wayleave	New Build	100, 200	km
Transmission: HVAC: Overhead: 400kV line [3190 MVA]	Abandonment	100, 200	km
Counterfactual - HVAC			
Transmission: HVAC: Overhead: 400kV line [6,380 MVA]	Refurbishment	100, 200	km
Conversion: HVAC: None: 400kV Sealing end terminal compound [6,380 MVA]	New Build	2	Nr

Table 13-3 Assemblies used to generate project costs – option 2

Description	Mode	Quantity	Unit
Innovation - HVDC			
Conversion: HVDC: None: 6,000MVA HVDC - HVAC VSC Converter	New Build	2	Nr
Transmission: HVDC: Overhead: 600kV line [6,000 MVA] within new wayleave	New Build	100, 200	km
Counterfactual - HVAC			
Transmission: HVAC: Overhead: 400kV line [6,380 MVA] within new wayleave	New Build	100, 200	km
Conversion: HVAC: None: 400kV Sealing end terminal compound [6,380 MVA]	New Build	2	Nr

13.2 Methodology of losses costs calculation

One of the main differences between HVDC and HVAC are the transmission losses. The analysis in this section considers the costs due to transmission losses between the innovation and its counterfactual.

The study has used references from ABB and Cigre, and papers from Stanford University, to typify the transmission losses profile in relation to length for HVAC and HVDC. Adjustments have been made to reflect the capacity and voltage of the networks analysed.

Due to lack of technical information for DC conductors at 600 kV and 6,000 MVA, specifically for associated corona losses, the same relative losses (%) as indicated by ABB literature for 1,200MW has been assumed. A more detailed analysis is required for the particular capacity and voltage in this study but the results shown are considered to be adequate for this analysis.

Figure 13-5 and Figure 13-6 show the variation of estimated transmission losses with network length for a 600 kV HVDC network with 6,000 MVA capacity and a 400 kV HVAC network with 6,380 MVA capacity.

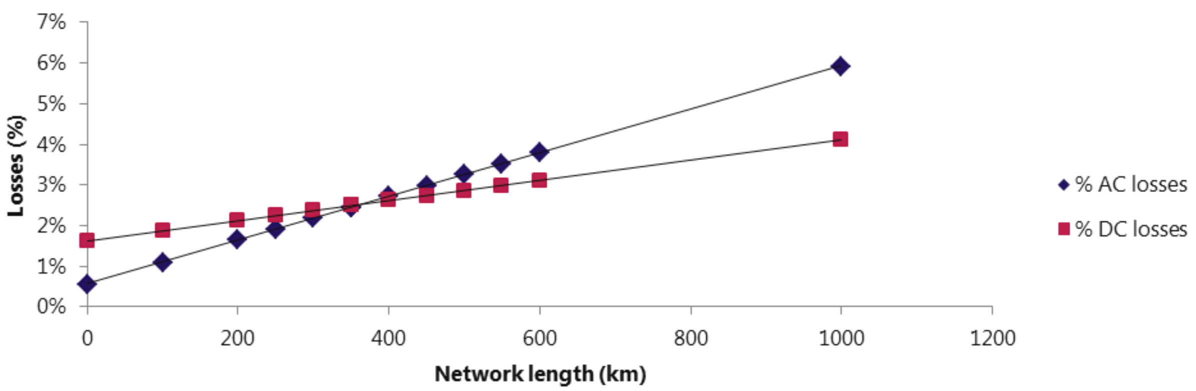


Figure 13-5 Variation of HVAC and HVDC losses (%) with network length

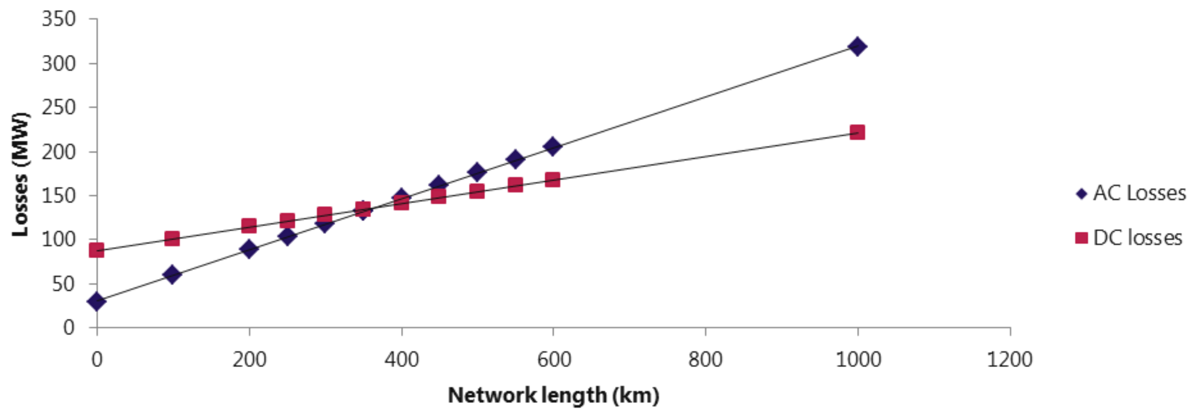


Figure 13-6 Variation of HVAC and HVDC losses (MW) with network length

Figure 13-5 shows that HVAC losses are lower than HVDC losses for shorter network lengths but become more significant as the network length increases. In this application the breakeven point is approximately 300km, such that, for lengths longer than this, DC transmission losses – and hence costs – are lower than AC losses.

The above analysis has been used to calculate the energy losses as percentage of the utilised energy based on the following assumptions:

- The average utilisation factor of 20% has been assumed to calculate the energy transmitted over a year
- Power factor of 0.9

Losses have been valued using electricity wholesale prices published by DECC[7]. A mean of DECC high and low forecasts has been taken up to 2035, with the trend extrapolated to 2074, this being the end date of the project in the ICC tool (Figure 13-7).

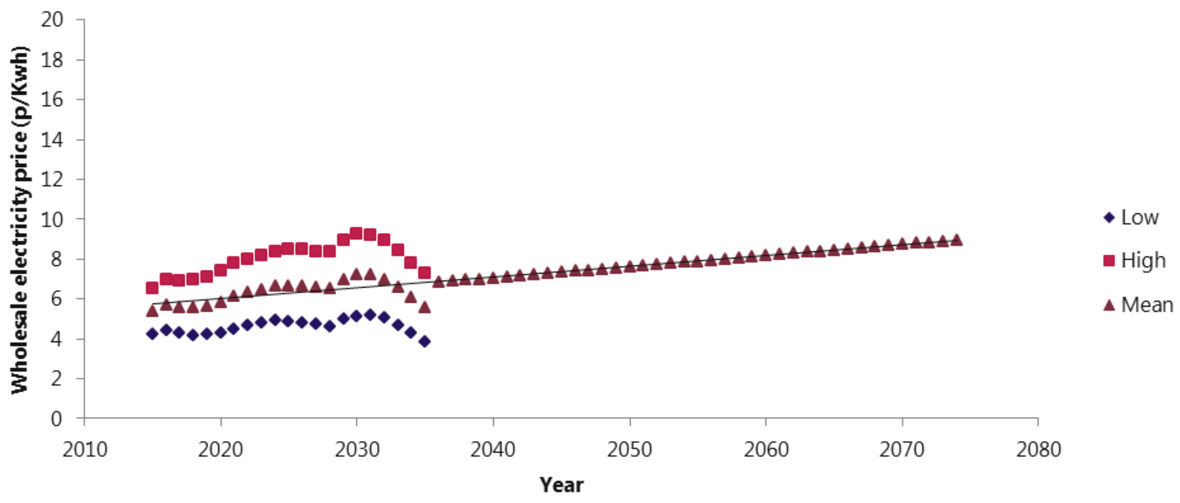


Figure 13-7 DECC wholesale electricity price forecasts as extrapolated for this project

[7] DECC 2014, Appendix M of https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2014

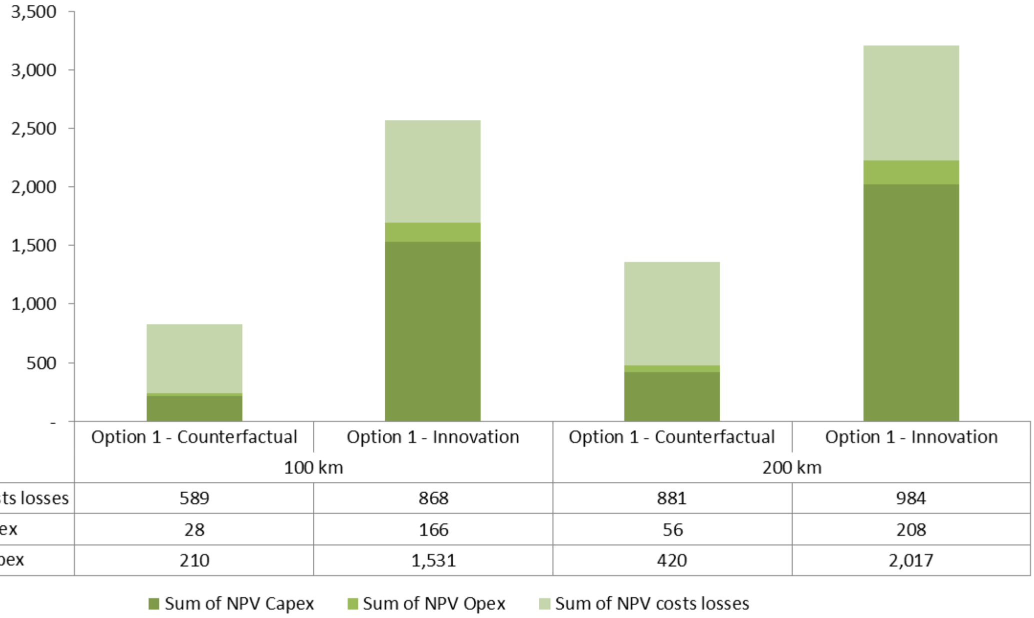
13.3 Option 1

Based on the quantities in Table 13-2 and Table 13-3, four cost data sets were generated using the ICC, two for the innovation and two for the counterfactual.

Figure 13-8 shows the NPV of Capex, Opex, and losses of the innovation and counterfactual for installation date of 2030.

As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project, including losses for both HVAC and HVDC. The abandonment of the HVAC transmission line has been included only in the first costs and capex but not in the opex costs of the project.

The results suggest that although losses are lower for the HVAC counterfactual than the innovation for the network lengths analysed in this study, they make up a higher proportion of total costs.



	Option 1 - Counterfactual	Option 1 - Innovation	Option 1 - Counterfactual	Option 1 - Innovation
	100 km		200 km	
Sum of NPV costs losses	589	868	881	984
Sum of NPV Opex	28	166	56	208
Sum of NPV Capex	210	1,531	420	2,017

Figure 13-8 Option 1: comparison of NPV (Capex, Opex and losses) for innovation and counterfactual

13.3.1 Analysis: Assemblies

Three assemblies have been used for the innovation project:

- New build of HVAC/HVDC converter station (6,000 MVA)
- HVDC transmission network
- Abandonment of HVAC transmission network.

Two assemblies have been used for the counterfactual project:

- HVAC transmission network
- 400 kV sealing end terminal compound

This section provides a breakdown of the key elements of cost within the network.

Figure 13-9 shows the variation of the impact on costs of each of the assemblies at different network lengths for both HVDC and HVAC.

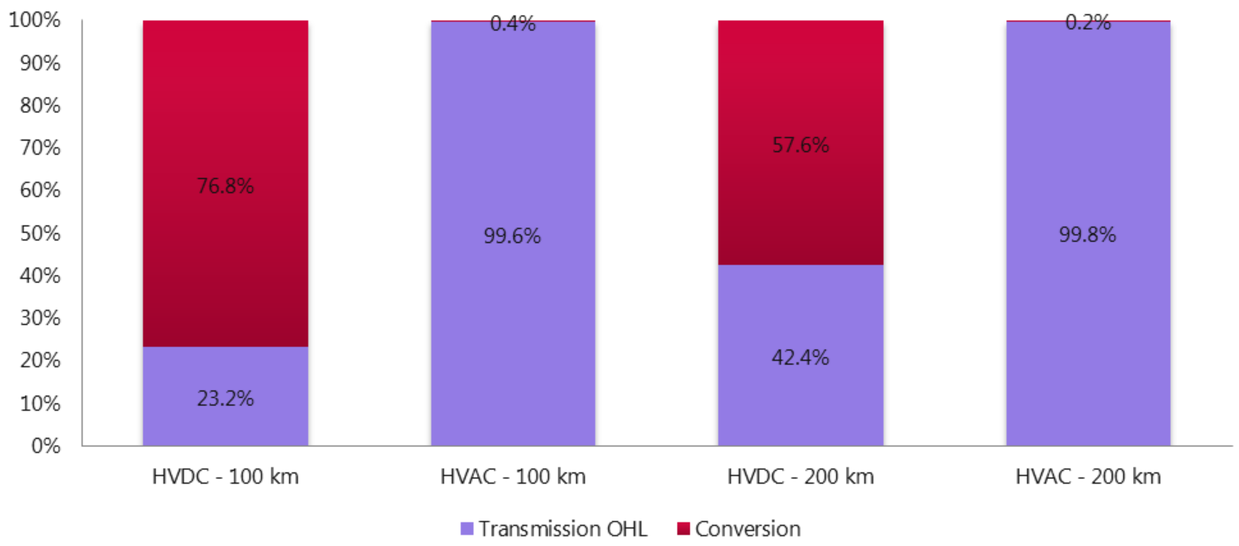


Figure 13-9 Share of costs represented by the assemblies – innovation vs counterfactual

The analysis of option 1 indicates the following:

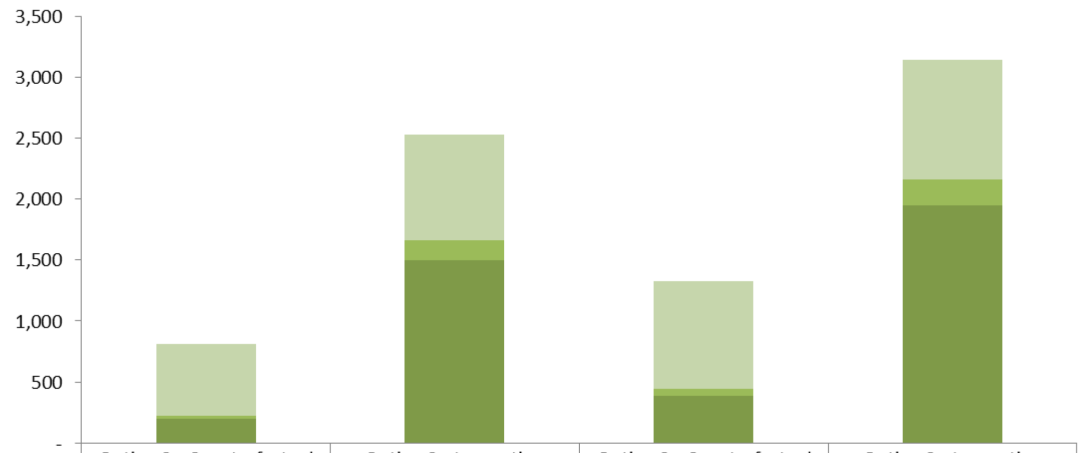
- The innovation system generates higher first costs than its counterfactual.
- NPV costs due to transmission losses are higher in HVDC for both 100 km and 200 km. As described in Section 13.2 above however, it is estimated that an increase in network length results in higher losses for HVAC compared with HVDC network. At a certain point therefore, the additional costs of the HVDC plant and infrastructure would be more than offset by the reduced cost of losses along the network.
- Capex and Opex NPV are higher for the innovation. The analysis of the Assemblies indicates that the high HVDC costs are due to the addition of the HVDC converter stations.

13.4 Option 2

Based on the quantities in Table 13-2 and Table 13-3, four cost data sets were generated using the ICC, two for the innovation and two for the counterfactual.

Figure 13-10 shows the NPV of Capex, Opex, and losses of the innovation and counterfactual for installation date of 2030.

As discussed in Section 3.3.2, first costs (undiscounted) include new build costs plus preliminary costs, contractors costs, PM engineering, land costs and contingencies but exclude any lifecycle replacement costs; NPV Capex represents the installation costs plus all lifecycle costs (which include all replacement cycles and abandonment costs - Repex – to the extent that these occur before the project end); and NPV Opex takes into account operational costs over the life of the project, including losses for both HVAC and HVDC. The abandonment of the HVAC transmission line has been included only in the first costs and capex but not in the opex costs of the project.



	100 km		200 km	
	Option 2 - Counterfactual	Option 2 - Innovation	Option 2 - Counterfactual	Option 2 - Innovation
Sum of NPV costs losses	589	868	881	984
Sum of NPV Opex	28	166	56	208
Sum of NPV Capex	196	1,497	389	1,950

■ Sum of NPV Capex ■ Sum of NPV Opex ■ Sum of NPV costs losses

Figure 13-10 Option 2: comparison of NPV (Capex, Opex and losses) for innovation and counterfactual

13.4.1 Analysis: Assemblies

Three assemblies have been used for the innovation project:

- New build of HVAC/ HVDC converter station (6,000 MVA)
- HVDC transmission network
- Abandonment of HVAC transmission network.

Two assemblies have been used for the counterfactual:

- HVAC transmission network
- HVAC conversion station

This section provides a breakdown of the key elements of cost within the network.

Figure 13-11 shows the variation of the impact on costs of each of the assemblies at different network lengths for both HVDC and HVAC.

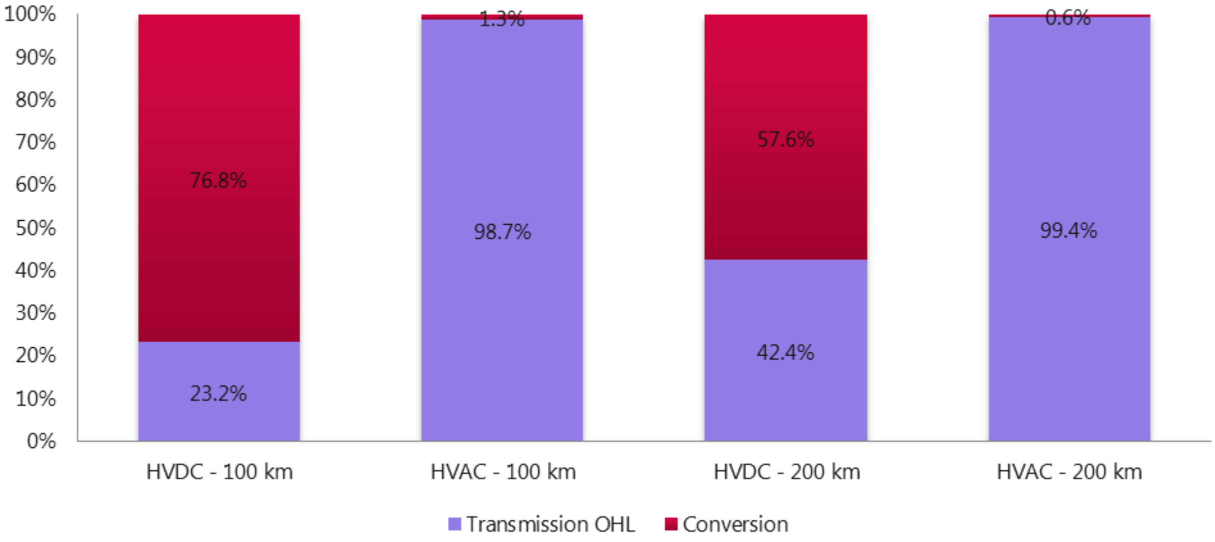


Figure 13-11 Share of costs represented by the assemblies – innovation vs counterfactual

The results of Option 2 are similar to those of Option 1 with first costs being only slightly higher in all cases as shown in Figure 13-12. In particular:

- Innovation generates higher first costs than the counterfactual
- NPV costs due to transmission losses are higher in HVDC for both 100 km and 200 km. As described in Section 13.2 above however, it is estimated that an increase in network length results in higher losses for HVAC compared with HVDC. At a certain point therefore, the additional costs of the HVDC plant and infrastructure would be more than offset by the reduced cost of losses along the network.
- Capex and Opex NPV are higher in the innovation. The analysis of the Assemblies indicates that the high HVDC costs are due to the HVAC / HVDC converter station.

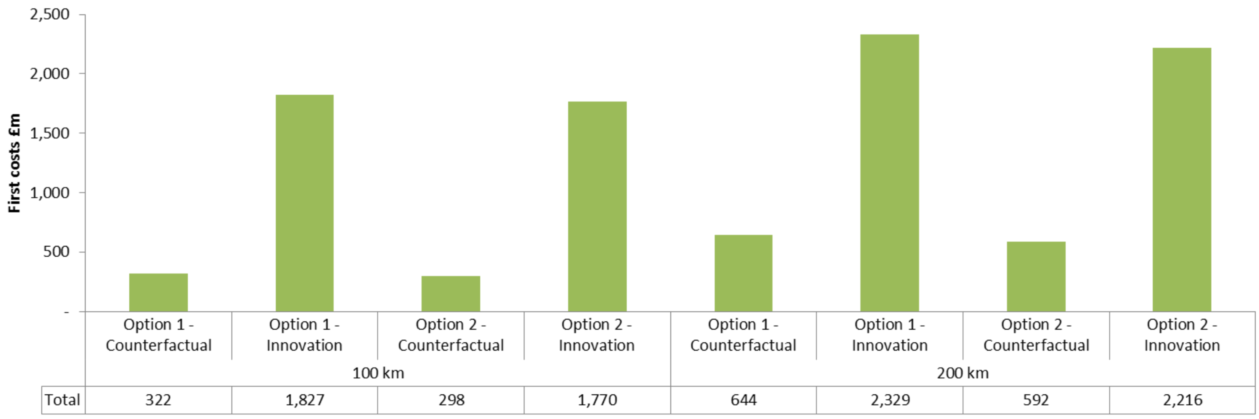


Figure 13-12 Comparison of first costs of Option 1 and Option 2

13.5 Limitations and further work

The following limitations are relevant for this task:

- **Option 1**: technical and planning viability for constructing new pylons and decommissioning existing within the same wayleave needs to be reviewed in more detail with National Grid.
- **Option 2**: Viability for obtaining new wayleave needs to be confirmed. Current indications (e.g. ongoing offshore Western Link) is that offshore DC is preferable. It is not clear on the exact reasoning for this but it is likely to be related to planning approval timescales, installation time and risk, balanced against additional cost for installing offshore. It has not been possible to gain access to the feasibility work that was completed by National Grid for the Western Link, or proposed Eastern Link projects. This work is likely to highlight the justification triggers for DC versus AC.
- There is no specific available technical data for losses associated with the capacity of networks for this task.
- More detailed analysis may show lower or higher costs for HVAC and HVDC which impact on the breakeven point for losses and additional costs for the HVDC infrastructure.

As noted in Section 3.4, there are a number of considerations to be taken into account in relation to the design and modelling assumptions contained in the first version of the ICC used for this study. In particular, cost trends and the treatment of opex and lifecycle costs are to be revised in future versions which could impact on these results.

14 Summary

14.1 Key results

Some findings are the same across all projects. These include:

- First costs are higher at later installation dates. This is due to the impact of the cost trends in the ICC which inflate labour, material and plant costs over time (see Section 3.2.5). There are clearly alternative views on cost trajectories and these will influence the relative impact of deferring installation.
- NPV (Capex plus Opex) is lower for projects installed at a later date. Two factors come into play here: one, as expected, is the impact of discounting; the other is the way in which lifecycle costs are modelled in the ICC and the fact that the analysis has been undertaken for a fixed period of 60 years (2015 to 2075) irrespective of the installation date. Lifecycle costs include for a major refurbishment (100% of new build costs) at a fixed period after first instalment. For later installation dates, this major refurbishment may be beyond the analysis period and therefore not be included in the NPV calculation.
- Opex costs represent a relatively small proportion of whole life costs. It should be noted that the modelling of Opex is to be revised in the next version of the ICC which may influence the outturn values. Note also that Opex does not include the cost of losses.

A summary of findings specific to each project is given in Table 14-1.

Table 14-1 Key findings for electricity network research projects

Ref	Research question	Key findings
GENERIC NETWORKS		
E-G-9	Representative electricity transmission network model: Electricity networks modelled for 275kV and 400 kV network capacity	• The increase in the costs is proportional to the increase in the network length for the same network capacity and installation date. For instance, increasing the length 10 times increases the costs approximately 10 times. Fixed costs are not significant versus variable costs associated with increasing length. • For the same installation date, NPV total per km is higher for the higher capacity network. The capital cost of the 400kV OHL is larger, which in turn generates higher lifecycle costs.
E-G-10	Representative Electricity Distribution Model: Electricity network modelled in rural, semi-urban, urban and London context	• The share of costs represented by each of the Assemblies changes slightly from 2020 to 2040, following the same trend in all contexts, except for London. • Residential connections represent one of the highest costs in all contexts. • The LV network makes a high contribution to total cost in the urban context while in London the LV substations make the highest contribution. The primary reason for this is the density of buildings and load in London, resulting in higher capacity substations and reduced length LV networks. • First costs per capita increase as the context changes from rural through to urban areas. The main reason for this is the density of population and building, and consequently load. Secondary reasons for this are that labour, material and plant costs increase from rural to urban, with a further uplift applied to London. • First costs per capita decrease slightly from urban to London contexts. This could relate to the network design and the relative share of LV network length and the number of substations per capita assumed in the two contexts. Again secondary influences will be the difference in labour,

Ref	Research question	Key findings
		material and plant costs between the two contexts. • The NPVs per capita increase as the density increases. • One additional factor that influences costs in different contexts is their different lifecycle profiles. It is assumed that an Assembly in an urban context will need to be replaced more quickly than the same Assembly in a rural context. Lifecycle profiles are the same for London and urban, which leads to a similar NPV per capita for both contexts.
E-G-11	Generic upgrade costs at transmission scale: upgrading existing 275kV and 400kV lines to increase capacity by ~100%	• For the same installation date, Capex NPV per km is higher for the installation of a higher voltage network. Capital cost of the 400kV OHL is larger, which in turn generates higher lifecycle costs. • Opex NPV per km is higher for higher voltages, highlighting the tool's assumption that Opex is 90% of the Capex NPV.
E-G-12a	Rapid car charging: upgrading existing distribution networks to allow for connection of rapid car charging units (1, 5, 10 and 20 units in rural and semi-urban areas)	• Costs for the upgrade of the distribution network are dominant in all variations and contexts. The reason for this is the land take per km of network length as well as the labour costs for the distribution network installation. A refinement of the tool would allow for cost saving associated with multiple cables laid in the same trench to be assessed. • For the same number of connection points at the same installation date the installation of rapid charge connections is more costly in the semi-urban context. The main reason for this is that the costs of labour, material and plant increase from rural to semi-urban. • The first costs and NPV per connection fall as the number of connections increases, which indicates that it is more cost effective to install a group of charging points than isolated single charging points. This is mainly related to the distribution network length required per connection.
E-G-12b		• The analysis is based on the assumption that there is a 50% increase in peak load due to a significant increase in the use of EVs. • The LV network represents the highest share of reinforcement costs in all contexts with costs per capita being higher in urban areas than semi-urban areas. • For lower increases in demand the reinforcement required could be less but it becomes difficult to generalise the trigger points. Without completing more detailed calculations it is suggested that the costs for a 25% increase would be between 60-80% of the costs associated with a 50% increase.
INNOVATIONS		
E-I-13	Storage v reinforcement: analysis to explore the costs of storage compared with conventional reinforcement in three different applications – 33kV increase in local demand; 33kV distributed energy exporting to grid; 11kV installation of rapid car charging units	• The analysis suggests that considering current prices for electricity storage, the counterfactual reinforcement is cheaper both in terms of Capex and Opex. No allowance has been made for additional costs associated with achieving planning consent and abnormals for new OHLs. Where reinforcements are particularly onerous e.g. due to obtaining planning consent or length of OHL, storage may prove to be an economic alternative. • In the case of application 3 (car charging), local generation may improve the potential for storage if the existing OHL has limited potential to charge batteries during periods of low demand. • Further detailed analysis on new battery technology and respective cost of storage may reduce the innovation cost to be competitive with the counterfactual.
E-I-14	Fault Current Limiter v Reinforcement	• Conventional reinforcement is currently more cost effective than refurbishment of the substation with the installation of the FCL. • Only a single FCL (GridOn) has been used in "typified" application. Further analysis is recommended to consider alternative FCL (and fault current management options) and a range of application permutations.

Ref	Research question	Key findings
		Cost data for FCLs is very limited as very few have been installed in the UK and around the world. There is limited experience of DNOs modelling and analysing potential installation versus counterfactual and more sophisticated fault current management.
E-I-15a	Power electronics: assessing the relative costs of using power electronics using STATCOMS for rural windfarms with utility scale battery storage b) back to back HVDC connection for coupling DNO networks	• In the STATCOM case, the costs of the complementary utility scale battery dominate. This is because of the capital costs of the Assemblies as well as their lifecycle. • The impact of the utility scale battery on the costs of the project increases at the later installation date, due to increase in new build costs of the battery in 2040 and additional refurbishment requirements.
E-I-15b	Power electronics: assessing the relative costs of using power electronics using back to back HVDC connection for coupling DNO networks	• As for the STATCOM case, the costs of the back-to-back converter dominate. Obtaining cost data was difficult due to limited manufacturers in the market place and imminent tendering for DNOs. Indirect benefits and counterfactual costs were not identified for the task, i.e. the alternative measures that DNOs may have to put in place to ensure adequate resilience in networks.
E-I-16	Cost comparison HVAC vs HVDC at transmission:	• One of the main differences between HVDC and HVAC is in transmission losses. Although losses are not included in the ICC, some analysis was undertaken separately to assess the impact. From discussions with Professor Lewin (who supported BuroHappold), and researching National Grid plans, it is clear there is significant uncertainty with the planning consent process for installing new or refurbishing existing HVDC OHLs in the UK. NG are currently progressing with the subsea Western Link which indicates a preference influenced by planning and programme costs of OHLs, although the first costs to "install" subsea are higher.

14.2 Further work

Areas for further work relate to the scope of some tasks and to issues arising from the design of the ICC. These are discussed below.

14.2.1 Scope related issues

- E-G-9: Exploration of longer distances could be done where it may become necessary to consider HVDC if replacement / upgrade does not provide enough capacity.
- E-G-10: The reliance on single locations remains a limitation of the analysis. Further work could include the analysis of additional locations to better understand and develop general cost trends.
- E-G-11: Further exploration of the impact of scale (i.e. network length) on cost could be undertaken.
- E–I-14: Further cost analysis of other prominent FCL technology and fault current management is warranted, including permutations of counterfactual in different applications. This could be completed in conjunction with Western Power Distribution and the ongoing FlexDGrid project funded by the Low Carbon Networks Fund.

- E-I-15: Storage costs are now reducing significantly and although this high level study indicated counterfactual options were generally cheaper this could be tested by assessing a range of storage costs and identifying target costs per MWh for different applications. The application of P2-6 should also be reviewed with the application of storage as a means to provide a resilient power supply.
- E-I-15: Alternative applications for power electronics could be explored and more research into indirect benefits, and how cost reduction will make technology more attractive.
- E-I-16: The project team did not have access to feasibility work for the Western Link or Eastern Link and key decision triggers. Adding functionality to assess transmission losses, planning costs and programme delays may be beneficial for larger assets modelled in the tool.

14.2.2 ICC issues

Analysis undertaken for a number of tasks raises the question as to whether the single assessment window (2015-2075) for all projects is appropriate. The primary reason this has arisen as an issue is the manner in which lifecycle costs are modelled in the ICC. As described in Section 3.2.4, lifecycle profiles are applied to each Assembly such that cash flows associated with minor and major refurbishments and with ultimate abandonment are deemed to occur in full in certain years. The effect of this is that a major refurbishment may be scheduled to occur beyond the analysis period for installations made at a later date. In the new version of the ICC, this approach is to be replaced with one that takes a more probabilistic view of replacement costs such that they are spread over the life of the asset. This approach would mitigate the effect of having a fixed analysis period.

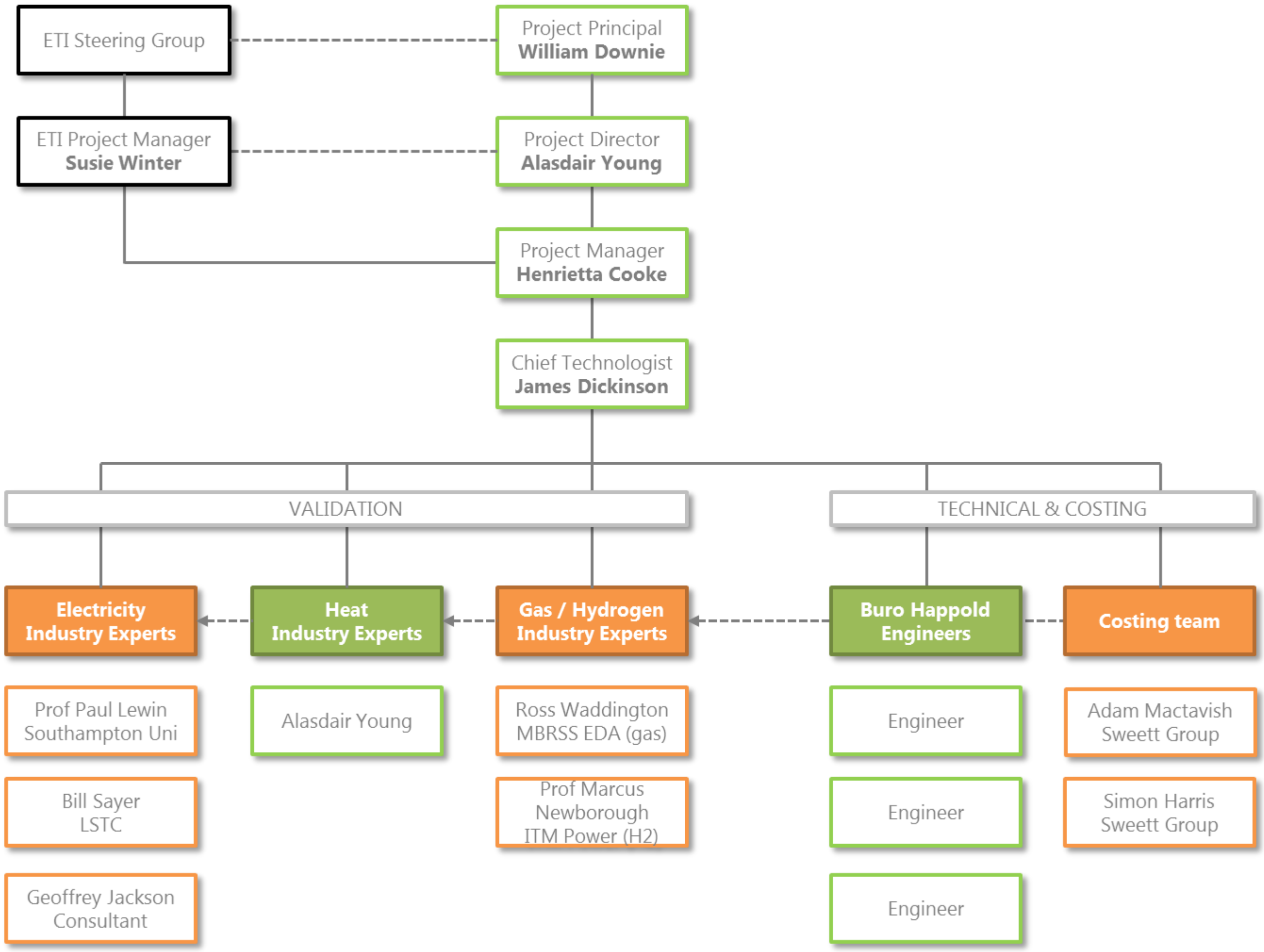
In some instances, the impact of the scale rate modifier within the ICC is unclear (e.g. E-G-11). It is recommended that this is tested further in the new version of the ICC.

Cost trends are being revised in the new version of the ICC.

The impact of the above suggests that further work could include re-running all tasks in the new version of the ICC. Sensitivity to cost trends could also be tested.

Appendix A Project team

The overall project team is given in the organogram with details of the industry experts in the table below.



Role	Individual Experience & qualifications
Industry Expert – Electricity Provision of expert advice and design validation in relation to HVDC and transmission voltage HVAC cabling and power electronics	**Professor Paul Lewin, Southampton University** BSc (Hons), PhD, CEng, FIET, FIEEE Professor Lewin is Professor of Electrical Power Engineering in the School of Electronics and Computer Science, where he is also head of the Tony Davies High Voltage Laboratory. His research interests are within the generic areas of applied signal processing and control. Within high voltage engineering this includes condition monitoring of HV cables and plant, surface charge measurement, HV insulation/dielectric materials and applied signal processing. In the area of automation he is particularly interested in the practical application of repetitive control and iterative learning control algorithms. He is Vice President (Technical) of the IEEE Dielectrics and Electrical Insulation Society as well as an Associate Editor of the IEEE Transactions on Dielectrics and Electrical Insulation.
Industry Expert – Electricity Provision of expert advice and design validation in relation to AC Overhead Lines at all voltages	**Bill Sayer, LSTC Ltd** I. Eng. MIET Bill is currently a consultant with LS Transmission Consultancy Ltd where his key responsibilities are overhead line design, engineering specifications, component design/ specification, product evaluation and formulating construction procedures (wood pole and steel towers up to 400kV). Prior to working at LSTC, he was design manager for overhead lines for Balfour Beatty Utility solutions where he was responsible for the management of all engineering design issues on steel tower and wood pole overhead lines up to 400kV operation. He is Chairman BSI PEL/11 committee - Overhead Lines and UK Delegate CENELEC TC/11 WG9 – Revision to EN 50341 OHL Design > 45kV.
Industry Expert – Electricity Provision of expert advice and design validation in relation to AC Overhead Lines at all voltages	**Peter Papanastasiou, LSTC Ltd** BSc (Hons) C. Eng. MICE, FEANI (Eur Ing) Peter is a Director of LS Transmission Consultancy Ltd which has as its core business feasibility studies, topographical and ground surveys, concept and detailed design for projects for the Railway and High Voltage Electrical Power Engineering industries, in particular Overhead Lines and Substations in the power sector.
Industry Expert – Electricity Provision of expert advice and design validation in relation to electricity distribution focused on below ground electricity cabling at distribution voltages and substations.	**Geoffrey Jackson, Consultant** BSC (Hons) C. Eng Geoffrey has a long career in the electricity distribution sector from the operational level through general supervision to project management, including the installation, commissioning, safe operation, maintenance and dismantling of HV switchgear to 33kV, high and low voltage cables and cablejointing, high and low overhead lines. Other experience includes: • Project management including planning, design, tender issue and appraisal, construction and commissioning. • Extensive experience in asset condition appraisal and asset management with particular emphasis on switchgear, transformers and high voltage lines and cables.
Industry Expert – gas / hydrogen Provision of expert advice and design validation in relation to gas and hydrogen networks at all pressures.	**Ross Waddington, E Donald & Associates** Incorporated Engineer – Institute of Gas Engineers and Managers (IGEM) Ross is an Associated Director at E Donald & Associates. He is a highly experienced Senior Consultant Engineer specialising in all forms of pipeline engineering. As a Senior Manager has led multi-disciplined design teams on major Regeneration and large scale Renewable Energy projects across the UK.

Role	Individual Experience & qualifications
Industry expert – hydrogen Provision of expert advice in relation to hydrogen infrastructure	**Marcus Newborough, ITM Power** FREng CEng MSc PhD Marcus is Development Director at ITM Power where he supervises the analysis of existing and new electrolyser applications, hydrogen system design requirements for business development opportunities and demonstration projects, and the development of electrolyser products. Prior to joining ITM, he was a Research Chair at Herriot-Watt University where he led the Heriot-Watt Energy Academy as a pan-university mechanism for building partnerships in energy-related research. He established a research group which investigated pathways to a lower-carbon energy system, focusing on the assessment of demand side solutions in buildings, micro-generation, DSM and hydrogen energy systems.

Appendix B Project cost functionality

Extract from:

Energy Infrastructure 2050 Final Report, 22 November 2013, available from the ETI

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)[8] of constituent Assemblies. This 'bill of quantities' is used to model various aspects of the Projects for comparative purposes.

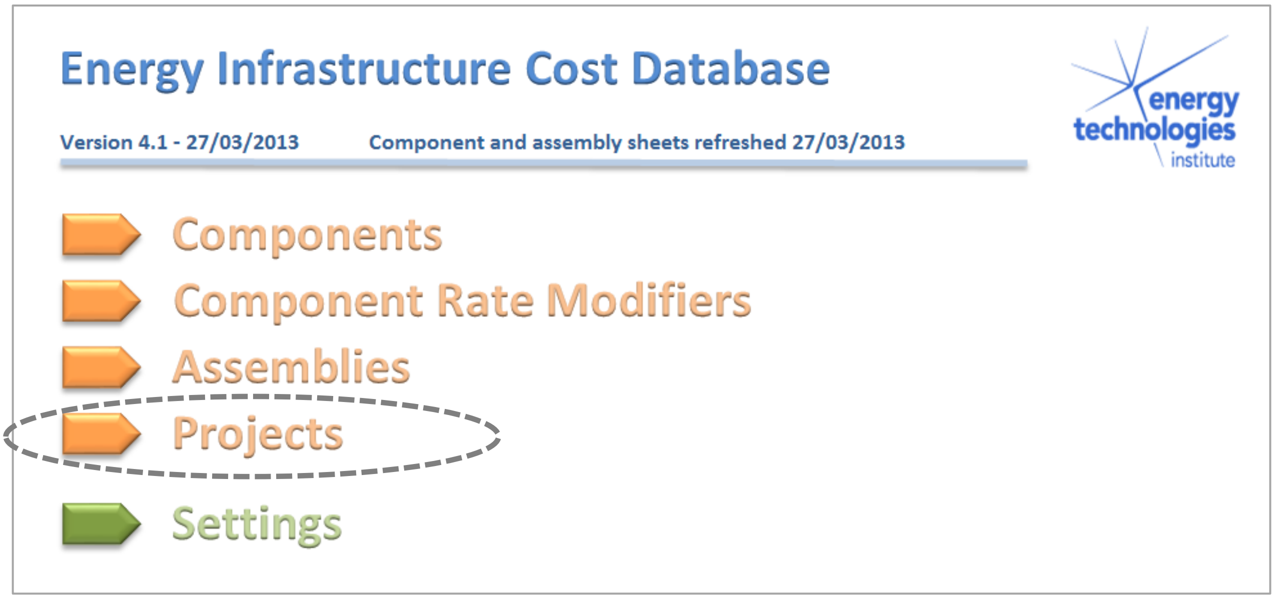


Figure B—1: Screen shot of start page of Infrastructure Cost Model

[8] 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.

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 variations. 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.

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.

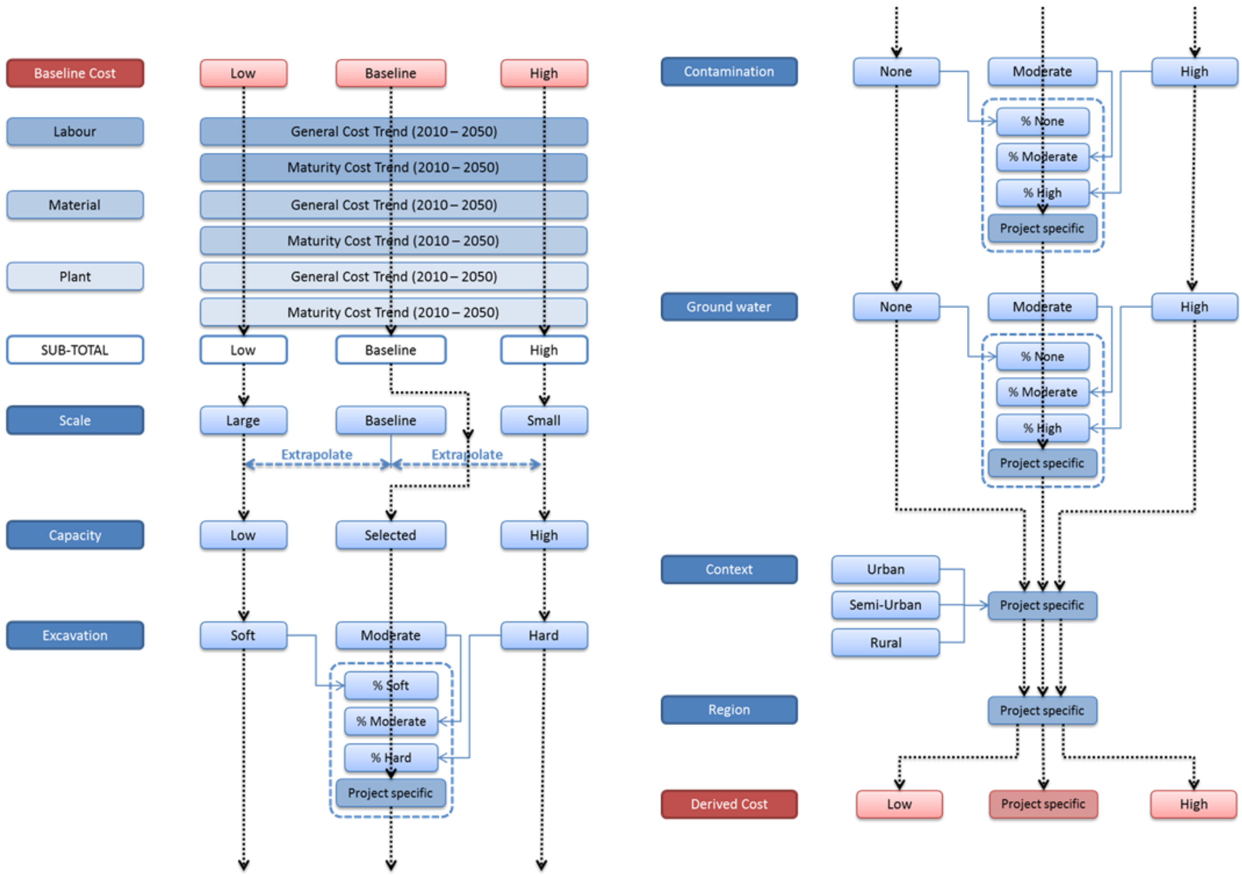


Figure B—2: schematic to illustrate application of Rate Modifiers to Projects

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[9] 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.

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).

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

PROJECT DASHBOARD

Ref	20130801 1313
Description	Electricity transmission - East Midlands - test
Owner	HC

Region	East Midlands Region
Context	Rural
Scale	Baseline
Labour cost	Baseline
Materials cost	Baseline
Plant cost	Baseline

PROJECT COSTS IN 2015	P80	P50	P10
Totals	6,980,531,817	5,806,365,013	2,796,428,255
Electricity	4,689,367,012	3,900,692,082	1,879,007,562
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-
Preliminaries	702,104,635	584,067,594	281,516,961
Contractors Overheads	269,140,110	223,892,578	107,914,835
Contingencies	565,194,231	470,174,413	226,621,154
PM, Engineering, etc.	746,056,385	620,630,226	299,139,923
Land Costs	8,669,443	6,908,121	2,227,819

TOP 5 ASSEMBLIES	
Assembly	% TOTAL
Transmission: HVAC: Overhead: 400kV line [6380 MVA] (New Build)	53.4%
Conversion: HVAC: None: 400kV to 132kV Conversion [670 MVA] (New Build)	36.9%
Transmission: HVAC: Overhead: 275kV line [2600 MVA] (New Build)	7.5%
Conversion: HVAC: None: 275kV to 132kV Conversion [720 MVA] (New Build)	2.2%
#N/A	#N/A

TOP 5 COMPONENTS	
Component	% TOTAL
AA12 - Electricity - Overhead - Conductors - Refurb, Repurpose and Abandon: Refurbish 400kV HVAC overhead transmission line	28.0%
AD12 - Electricity - Conversions - On-shore - Refurb, Repurpose and Abandon: Refurbish 400kV to 132kV conversion (two circuits)	27.9%
AA11 - Electricity - Overhead - Conductors - New: 400kV HVAC Overhead transmission line	25.4%
AD11 - Electricity - Conversions - On-shore - New: 400kV to 132kV conversion (two circuits)	9.0%
AA11 - Electricity - Overhead - Conductors - New: 275kV HVAC Overhead transmission line	4.0%

OPEX COSTS DURING PERIOD 2015 - 2074	P80	P50	P10
Totals	3,874,621,240	2,910,646,056	1,812,783,642
Electricity	3,874,621,240	2,910,646,056	1,812,783,642
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-

NET PRESENT VALUE AT 2015	Project NPV	Optimism Bias Adjusted	Go there
		Lower	Upper
Totals	3,934,378,815	4,170,441,544	6,531,068,832
CAPITAL COSTS IN 2015			
Electricity	2,216,274,185	2,349,250,636	3,679,015,146
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-
Preliminaries	331,826,529	351,736,121	550,832,038
Contractors Overheads	127,200,169	134,832,180	211,152,281
Contingencies	267,120,356	283,147,577	443,419,790
PM, Engineering, etc.	352,598,870	373,754,802	585,314,123
Land Costs	7,284,500	7,721,570	12,092,270
OPEX DURING PERIOD 2015 - 2074			
Electricity	632,074,207	669,998,659	1,049,243,183
Natural gas	-	-	-
Hydrogen	-	-	-
Heat	-	-	-

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

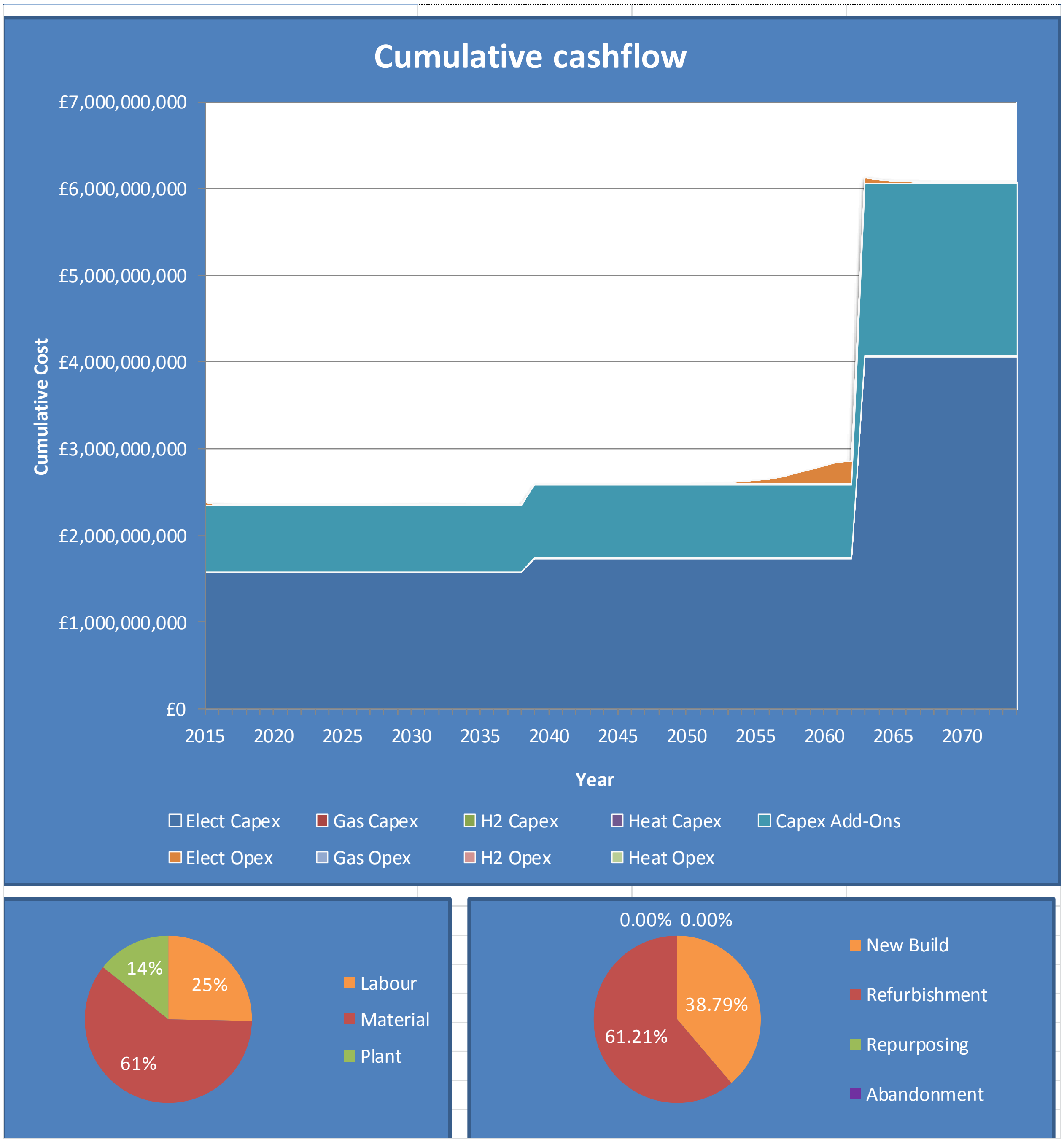


Figure B—4: Screen shot of Project Dashboard - bottom section

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 variations 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 B—2 Examples of variations which could be informed by the model

	Variation / 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).

	Variation / 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).

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