Programme Area: Energy Storage and Distribution

Project: Network Lifecycle Costing PPA

Title: Flexible Opex for an Uncertain Future – Final Report

Context:

The Network Lifecycle Costing project is a knowledge building project to improve the characterisation of OPEX in energy networks. Development of a robust method for the assessment of network asset opex that includes: fixed and variable operation and maintenance costs and cost of required support infrastructure.

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Flexible Opex for an Uncertain Future

Final Report

Submitted to: ETI

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Executive Summary

The Energy Technologies Institute (ETI) has engaged PPA Energy to provide consultancy support to gain insight into the operational expenditure (opex) of energy networks, including four energy vectors; electricity, gas, heat and hydrogen. This project builds on a previous project undertaken by PPA Energy, 'Opex Framework for Energy Infrastructure', in which an understanding of the opex costs associated with the energy infrastructure was developed.

The intention of this project is to understand and document the factors which affect, or may affect, the opex costs of an energy network, and to investigate how these might be modelled. Specifically, this project concentrates on the components of network opex that are directly related to the network assets themselves, known within this report as 'Network Related Opex', which includes direct opex, closely associated indirect opex, and the components of pass through opex that are considered to be related to the network assets themselves, but does not include depreciation or business support costs.

Sources of Uncertainty

The approach used to identify the most significant factors was to first identify the current major components of Network Related Opex within energy networks, and then explore the major influencers on these costs. Each energy vector was assessed separately in order to make certain that both general and vector-specific elements were incorporated. The factors that were considered as being most significant at this time are listed in the table below:

Electricity networks	Gas networks	Heat networks	Hydrogen networks
1. Scale of the network	1. Scale of the network	1. Scale of the network	1. Scale of the network
2. Ease of access	2. Ease of access	2. Level of loading	2. Asset fault rate characteristics
3. Inspection and maintenance requirements	3. Asset fault rate characteristics	3. Ease of access	3. Inspection and maintenance requirement
4. Asset fault rate characteristics	4. Level of loading	4. Urban / Semi-Urban / Rural	4. Level of loading
5. Inside / outside / buried / high	5. Inspection and Maintenance Requirement	5. Energy requirement	5. Ease of Access
6. Urban / semi-urban / rural	6. Urban / semi-urban / rural	6. Energy prices	6. Urban / semi-Urban / rural
7. Level of loading	7. Inside / outside / buried / high	7. Inside / Outside / Buried / High	7. Inside / outside / buried / high
		8. Inspection and maintenance requirements	
		9. Asset fault rate characteristics	

It can be seen that most of the factors are considered relevant for all four energy vectors. However, there are an additional two factors that have been identified as significant to the heat networks. This is because the network energy requirement is a more significant component of network related opex for a heat network, when compared with the other vectors. This means that the energy requirement of the network, and the energy prices, are both significant factors.

Sources of Flexibility

As well as identifying and discussing the areas of uncertainty in opex costs for energy networks, this project also aims to identify potential ways in which the networks may become more flexible and able to meet future challenges.

Within the electricity industry, it is accepted that there may be significant changes required to address future uncertainty, and the term “smart grid” is often used to describe the changes that are required to do this, whist supporting the take up of innovative and low carbon technologies. Similarly, the gas networks are expected to require increased operational capability to address changing flow patterns.

The interaction between capex and opex is expected to change as these industries develop. For example, where techniques such as condition monitoring and real time asset management are deployed, asset lifetimes could be extended thus reducing capex, but associated opex costs might increase. In order to ensure that opex-capex trade-offs are captured in their assessments, Ofgem is utilising “totex” (total expenditure – both capital and opex) benchmarking and modelling in the RIIO price controls.

Unlike electricity and gas networks, heat networks are not widespread within the UK, and hydrogen networks are not well established anywhere in the world. It seems sensible that any development of these industries will be carried out within the context of the current cutting edge thinking regarding energy systems, and so sources of flexibility will be considered at the design stage.

Modelling Opex Costs

A key output of this project was to consider the modelling of energy network opex, particularly regarding potential development of the 2050 Infrastructure Tool developed by Sweett Group for ETI. The current version of the tool uses, buy default, only the network expected life and a distinction between active and passive assemblies to determine an opex profile.

Three options were proposed to develop the opex modelling within the tool, including:

- Use the existing inputs to the tool to revise the existing opex profiles
- Add new inputs for each of the significant opex factors in order to revise the existing opex profiles
- Implement Rate Modifiers for the significant opex factors, which can be used to revise the existing opex profiles

Implementing any of these options will result in an opex model which is adaptable to the project characteristics, beyond a distinction between active and passive assemblies.

Some further work is required to develop a full understanding of energy network opex, such as validating and quantifying the effect that each factor has on the Network Related Opex of energy networks. This would require consultation with, and data from, network companies themselves, as much of this information is not in the public domain.

It is noted that the energy network industry is constantly changing, and this potentially has a significant impact on network opex. It would be essential, therefore, to perform regular validation and updates of the tool as new information becomes available if it is to remain up to date and relevant into the future.

Recommendations for Further Work

The purpose of this project was to gain insight into the operational expenditure of energy networks, in order to scope a further piece of work to develop opex modelling capability. It is recommended that this future work includes furthering the understanding of network opex, in order to develop opex modelling capability. This work would be supported by the initiation and involvement in a wider industry discussion about the development of knowledge and understanding of the opex of energy networks.

CONTENTS

EXECUTIVE SUMMARY **1**

1 INTRODUCTION **7**

1.1 BACKGROUND AND SCOPE 7
1.2 APPROACH 8
1.3 STRUCTURE OF REPORT 8

2 IDENTIFY AREAS OF UNCERTAINTY **10**

3 AREAS OF UNCERTAINTY – ELECTRICITY NETWORKS **12**

3.1 INTRODUCTION 12
3.2 DIRECT OPEX IN ELECTRICITY NETWORKS 12
3.2.1 Electricity Distribution Costs 12
3.2.2 Electricity Transmission Costs 14
3.3 CLOSELY ASSOCIATED INDIRECT COSTS IN ELECTRICITY NETWORKS 15
3.3.1 Electricity Distribution Costs 15
3.3.2 Electricity Transmission Costs 16
3.4 POLICY AND REGULATION CONTRIBUTORS TO ELECTRICITY NETWORK OPEX 16
3.5 FACTORS THAT AFFECT ELECTRICITY NETWORK OPEX 19
3.6 FACTOR ASSESSMENT 23
3.6.1 Engineering Indirects 24
3.6.2 Fault Repairs and Restoration 24
3.6.3 Network/Investment Support 25
3.6.4 Inspection and Maintenance 26
3.6.5 Tree Cutting 27
3.6.6 Other Direct Costs 27
3.6.7 Identification of Key Factors 28

4 AREAS OF UNCERTAINTY – GAS NETWORKS **29**

4.1 INTRODUCTION 29
4.2 DIRECT OPEX IN GAS NETWORKS 29
4.3 CLOSELY ASSOCIATED INDIRECT COSTS WITHIN GAS NETWORKS 31
4.4 POLICY AND REGULATION CONTRIBUTORS TO GAS NETWORK OPEX 32
4.5 FACTORS THAT AFFECT GAS NETWORK OPEX 34
4.6 FACTOR ASSESSMENT 38
4.6.1 Closely Associated Indirects 39
4.6.2 Emergency and Repairs 39
4.6.3 Maintenance 40
4.6.4 Other Direct Costs 41
4.6.5 Shrinkage 41
4.6.6 Identification of Key Factors 41

5 AREAS OF UNCERTAINTY – HEAT NETWORKS **43**

5.1 INTRODUCTION 43
5.2 CASE STUDY – THE MAIN DISTRICT HEATING NETWORK IN COPENHAGEN 43
5.3 DIRECT AND CLOSELY ASSOCIATED INDIRECT OPEX IN HEAT NETWORKS 46
5.4 POLICY AND REGULATION CONTRIBUTORS TO HEAT NETWORK OPEX 47
5.5 FACTORS THAT AFFECT HEAT NETWORK OPEX 48
5.6 FACTOR ASSESSMENT 52
5.6.1 Electricity costs for pumps 53
5.6.2 Preventative and Remedial Maintenance 53
5.6.3 Staff Costs 54
5.6.4 Heat Losses 54
5.6.5 Rental for Storage and Antenna 55
5.6.6 Operations 55
5.6.7 Water Losses 55

5.6.8 Identification of Key Factors ... 56

6 AREAS OF UNCERTAINTY – HYDROGEN NETWORKS ... 57

6.1 INTRODUCTION ... 57
6.2 UK EXPERIENCE IN HYDROGEN NETWORKS ... 57
6.2.1 UK Research and Development ... 57
6.2.2 UK Town Gas ... 58
6.3 HYDROGEN NETWORKS – COMPARISON TO GAS ... 59
6.4 DIRECT OPEX AND CLOSELY ASSOCIATED INDIRECT COSTS IN HYDROGEN NETWORKS ... 60
6.5 POLICY AND REGULATION CONTRIBUTORS TO HYDROGEN NETWORK OPEX ... 60
6.6 FACTORS THAT AFFECT HYDROGEN NETWORK OPEX ... 61
6.7 FACTOR ASSESSMENT ... 61
6.7.1 Emergency, Repairs and Maintenance ... 62
6.7.2 Closely Associated Indirects ... 62
6.7.3 Leakage / Shrinkage ... 63
6.7.4 Other Direct Costs ... 63
6.7.5 Energy Requirement ... 64
6.7.6 Identification of Key Factors ... 64

7 AREAS OF FLEXIBILITY ... 65

7.1 SOURCES OF FLEXIBILITY ... 65
7.2 ELECTRICITY NETWORKS – SOURCES OF FLEXIBILITY ... 65
7.3 GAS NETWORKS – SOURCES OF FLEXIBILITY ... 67
7.4 HEAT NETWORKS – SOURCES OF FLEXIBILITY ... 68
7.5 HYDROGEN NETWORKS – SOURCES OF FLEXIBILITY ... 69
7.5.1 Hydrogen for Transport ... 69
7.5.2 Conversion of UK Gas Network to Deliver Hydrogen ... 71

8 MODELLING OPEX COSTS ... 73

8.1 REVIEW OF 2050 INFRASTRUCTURE TOOL ... 73
8.2 OPTIONS FOR DEVELOPING OPEX MODELLING ... 76
8.2.1 Use Existing Inputs to Revise Existing Opex Profiles ... 77
8.2.2 Add Inputs for All Significant Opex Factors ... 77
8.2.3 Implement Rate Modifiers for Opex Factors ... 79
8.2.4 Recommendations for Developing Opex Modelling ... 80
8.3 FUTURE EVOLUTION OF THE TOOL ... 80
8.3.1 Increased Monitoring and Control ... 81
8.3.2 Innovation and Technology Development ... 81
8.3.3 Revolutionary Industry Changes ... 82

9 RECOMMENDATIONS FOR FURTHER WORK ... 83

9.1 DEVELOP UNDERSTANDING OF ENERGY NETWORK OPEX ... 83
9.2 DEVELOP OPEX MODELLING CAPABILITY ... 83
9.3 INDUSTRY DISCUSSION ON ENERGY NETWORK OPEX ... 84

APPENDIX 1: FLEXIBLE OPEX FOR AN UNCERTAIN FUTURE ... 85

FIGURES

Figure 1: Components of direct opex in electricity networks..13
Figure 2: Components of closely associated intirect opex in electricity networks, compared to direct opex..16
Figure 3: Mindmap showing the factors that affect the opex of electricity networks 20
Figure 4: Matrix describing the relationship between the components of electricity network opex and the opex factors. 23
Figure 5: Components of direct opex in gas distribution networks. 30
Figure 6: Closely associated indirect opex in gas distribution networks, compared to direct opex. 32
Figure 7: Mindmap showing the factors that affect the opex of gas networks.......................35
Figure 8: Matrix describing the relationship between the components of gas network opex and the opex factors. 38
Figure 9: The average annual opex of the Metropolitan Copenhagen Heating Transmission Company over 2012 and 2013. 45
Figure 10: Average annual expenditure on the direct and closely associated indirect opex components of the Metropolitan Copenhagen Heating Transmission Company. 47
Figure 11: Mindmap showing the factors that affect the opex of heat networks....................49
Figure 12: Matrix describing the relationship between the components of heat network opex and the opex factors. 52
Figure 13: Matrix describing the relationship between the components of hydrogen network opex and the opex factors. 61
Figure 14: An example of details of a component enered into the 2050 Infrastructure Tool . 74
Figure 15: The structure of the 2050 Infrastructure Tool, and the inputs that are used to determine the capex and opex of the projects. 75
Figure 16: The opex profiles used as default within the 2050 Infrastructure Tool.................76
Figure 17: The potential structure of the 2050 Infrastructure Tool, encorporating the factrs that have been identified as significantly imacting on network opex. 79

TABLES

Table 1: Factors that affect the opex of electricity networks..21
Table 2: Factors that affect the opex of gas networks 36
Table 3: Expenditure of the Metropolitan Copenhagen Heating Transmission Company. 45
Table 4: Heat and water losses of the Metropolitan Copenhagen Heating Transmission Company. 46
Table 5: Factors that affect the opex of heat networks 50
Table 6: Significant that affect the Network Related Opex of energy networks, in order of importance..76
Table 7: Significant factors that affect the Network Related Opex of energy networks, categorised by asset or project. 78

1 Introduction

1.1 Background and Scope

The Energy Technologies Institute (ETI) has engaged PPA Energy to provide consultancy support to gain insight into the operational expenditure (opex) of energy networks. This project builds on a previous project undertaken by PPA Energy, 'Opex Framework for Energy Infrastructure', in which an understanding of the opex costs associated with the energy infrastructure was developed. This understanding was then used to inform the 2050 Infrastructure Tool developed by Sweett Group for ETI.

The networks under consideration are:

- Electricity
- Gas
- Heat
- Hydrogen

The previous project identified that the opex of an energy network can be divided into the following categories:

- **Direct opex** represents operating costs which are directly incurred on or close to the network such as, for example, maintenance costs or tree and vegetation management for overhead lines.
- **Closely associated indirects** are those elements which are closely related to the network such as certain IT costs, training, drawing office, maintenance support etc.
- **Business support** costs are those costs that are more distant from the network itself but still need to be incurred. This would include, for example, finance, HR, and corporate costs.
- **Pass-through** or **uncontrollable** costs are those which are substantially outside of the control of the utility. Examples include regulatory licence fees and local government taxation (rates).
- Finally **depreciation** represents, of course, the non-cash charge to operating costs of previous capital expenditure.

The intention of this project is to understand the factors which affect, or may affect, the opex costs of an energy network, and to investigate how these might be modelled. Specifically, this project concentrates on the components of network opex that are directly related to the network assets themselves, such as direct opex and closely associated indirects and some elements of pass through costs. Business support costs will not be included, they are considered to be more dependent on business decisions of a network company than on the network itself. As there is no cash flow associated with depreciation, this will also be discounted. Within this report, the term 'Network Related Opex' means the sum of direct opex, closely associated indirect opex, and the components of pass through opex that are considered to be related to the network assets themselves, but does not include depreciation.

1.2 Approach

The project started with a Kick-Off Meeting, which was held on Friday the 18th July 2014 in the ETI offices in Loughborough. The meeting was attended by a number of representatives from the ETI, and an industry advisor from E.ON. Within this meeting, the 2050 Infrastructure Tool was described and a copy was issued to PPA Energy. The project programme and scope of work for this project was also developed. It was decided during this meeting that the concept of hybrid energy systems was not within scope, and that there was a focus on developing an understanding that could be implemented within an updated version of the Sweett model. This being said, PPA Energy also understands that the outputs of this project are to be used in a range of ways, not only for the 2050 Infrastructure Tool, and therefore a more general understanding about opex costs is valuable.

This project was carried out by undertaking the following steps:

- Identify and review the main factors that may affect opex costs (both now and into the future), known as 'Sources of Uncertainty';

- Gain an international perspective on the factors that impact opex costs of energy networks, which are more developed or significantly different to the UK. This is particularly relevant in the case of heat networks, which have been developed to a much greater scale in countries other than the UK;

- Identify and review the future potential developments within the energy systems that provide sources of flexibility, such as enhanced monitoring or load control; and

- Develop recommendations for the enhancement of the Sweett modelling of opex costs for energy networks.

This report summarises the resulting work which has been undertaken, which will be presented in a workshop, scheduled to take place on Friday 19th September 2014.

1.3 Structure of report

This report is structured as follows:

- Section 2 describes the methods used to identify the areas of uncertainty for each vector.

- Sections 3 to 6 discuss and identify the areas of uncertainty for each vector; electricity, gas, heat and hydrogen. These discussions include any international perspectives gained.

- Section 7 discusses the areas of flexibility for each vector, including future developments and possibilities, and international perspectives.

- Section 8 discusses potential developments to the 2050 Infrastructure Tool, including recommendations for further work.

2 Identify Areas of Uncertainty

One of the aims of this project is to identify the present factors that may affect the current levels of energy network opex. The approach used to achieve this was to first identify the current major contributors to opex costs within the energy networks, and then explore the major influencers on these costs. This method was used in order to ensure that only the most significant factors are identified. Each energy vector was assessed separately in order to make certain that both general and vector-specific elements were incorporated.

There are a number of ways in which the expenditure of network companies could be categorised. Two of these are by activity (for example, fault repairs and inspection) or by source (for example IT costs, labour costs and transport). Categorising by activity has the advantage of closely linking the expenditure to the purpose for which it is being spent and thus is useful in identifying costs drivers. Categorisation by source may provide an alternative insight into the scale and types of expenditure that are being made. Using both approaches in parallel will give a richer understanding of the overall costs. Within this project most of the analysis has concentrated on an activity categorisation as this data was more readily available. The exact content of some of these categories is dependent on the data sources, and so may not be completely consistent between the vectors. Further work would be required, potentially with network operators, in order to gain access to opex expenditure data that is categorised by source.

The opex of an energy network could be described as any ongoing cost. If the network is considered as a whole, this may be interpreted as anything from the fuel or source cost, the monitoring, maintenance and upkeep of the network, the supply and metering costs and the regulatory, compliance and tax costs that are associated with it. There will also be associated business costs of the organisation undertaking these activities.

As mentioned, this project focuses on the areas which are directly related to the network that is installed. Factors that are unrelated to the infrastructure itself, such as the way in which a business is run, are not included here as they are not considered to be relevant to the project aims and are likely to be relatively constant i.e. not to vary in line with the size, design or function of the network itself.

The characteristics of the industry of a particular energy vector will have a significant influence on the division of ongoing costs. For example, where the functions of supply and distribution are undertaken by separate organisations, as with the UK gas and electricity industry, ongoing costs may cover a different set of elements when compared to a vertically integrated industry where a single organisation is responsible for source, network operation, supply and all associated compliance requirements.

In order to support this task, a mixture of relevant in-house experience and knowledge, detailed research, and the consultation of industry and academic contacts, was called upon. The industry and academic contacts that contributed to this project were:

- Adam Bell – Senior Policy Advisor at Department of Energy & Climate Change (DECC), advising on gas policy, and gas, hydrogen, and heat strategy and future.

- Dr. Jianzhong Wu – Reader at the Centre for Integrated Renewable Energy Generation and Supply at Cardiff University, advising on electricity, gas heat and hydrogen opex, as well as multi vector systems.

- Muditha Abeysekera – Research Assistant at the Centre for Integrated Renewable Energy Generation and Supply at Cardiff University, advising on electricity, gas heat and hydrogen opex, as well as multi vector systems.

- Stewart Reid – Future Networks & Policy Manager at Scottish and Southern Energy, advising on electricity network opex and innovation in electricity, heat and hydrogen.

- Peter Lang – Senior Technology Transfer Engineer at UK Power Networks, advising on electricity network opex and innovation.

- Ray Eaton – Assistant Director at Department of Energy & Climate Change (DECC), advising on potential hydrogen network opex and policy.

Additionally there were a number of contacts that were approached for comment, but who could not make their contributions within the timeframe of the draft report.

The results of this activity are discussed in Sections 3 to 6 below. This was then extended to explore how the opex of energy networks might change in the future, which is discussed separately in Section 7 of this report.

3 Areas of Uncertainty – Electricity Networks

3.1 Introduction

This section discusses the factors that impact opex that are specific to electricity networks. Firstly, the major contributors to electricity network opex are identified. Following this, each contributor is explored in order to identify the major factors that affect the value of this cost.

In the GB electricity industry, the sourcing and supply of the energy is handled by the generation and supply companies respectively, which are separate entities to the electricity network companies, Distribution Network Operators, (DNOs, and Transmission Owners), who own and maintain the network itself. The implication of this is that the costs to the network companies do not include the costs related to electricity generation or purchasing, supply, and billing. The potential exception for this is customer metering, which has historically belonged to DNOs, but ownership is being transferred to suppliers. The discussions below will cover the metering that is currently owned by network companies. This also has an impact on the treatment of energy losses within the electricity network, as it is the supply companies that cover the financial costs of such losses, though network companies may be incentivised to reduce losses.

The discussions below cover the electricity Network Related Opex costs experienced by the network companies, and so will not directly cover generation costs, losses or supply costs, or any business costs which are distant from the network assets. The previous project undertaken by PPA Energy, 'Opex Framework for Energy Infrastructure', determined that the UK electricity distribution networks have a combined Network Related Opex of about £1.1bn, or about 0.8% of the network value (Modern Equivalent Asset (MEA) value). The electricity transmission networks have a Network Related Opex of about 0.5% to 1% of gross assets (MEA).

3.2 Direct Opex in Electricity Networks

Direct opex covers areas of opex that are incurred directly on or close to the network itself.

3.2.1 Electricity Distribution Costs

The data included in Ofgem's final proposals for the last regulatory distribution price control review (DPCR5) breaks down direct opex into four categories (note that the latest price control review, RIIO-ED1, is currently near to completion but it was considered inappropriate to use information from this until the process is fully concluded):

- Inspection and Maintenance
- Fault Repairs and Restoration

- Tree Cutting
- Other Network Costs

The chart below gives the relative proportion of each category.

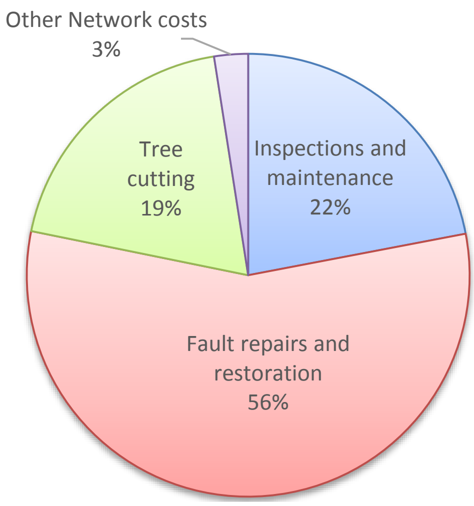

Figure 1: Components of direct opex in electricity networks

The data for Figure 1 is taken from Ofgem's final proposals for the last regulatory distribution price control review (DPCR5), and includes actual and forecast data for 2005 to 2015.

Inspections and Maintenance

Discussions with industry experts would suggest that the requirement to physically inspect networks is reducing as more modern equipment is being rolled out and monitoring is becoming more widespread. A similar affect is being felt in the area of maintenance, where assets are being installed with significantly longer required maintenance periods, a move to a more conditioned based approach and the installation of some assets that require no planned maintenance at all during their planned lifetime, for example, some new switchgear.

Fault Repairs

Fault repairs and recovery represent a significant proportion of the direct opex in an electricity network. This is because there is a significant time pressure to recover the network following faults, and it generally involves teams of people having to physically locate a fault, and then working to correct the issue. As this is entirely reactive, the personnel have to be ready to act on short notice.

Tree Cutting

Vegetation management, particularly tree cutting, is required close to overhead lines. This is necessary to prevent the trees causing faults by touching the lines, and to maintain distance around the live conductors, for example in case a person was to climb the tree. It is also necessary to be aware that trees may fall, for example in stormy weather or if damaged, and if they were to fall into an overhead line this would cause a fault. Technical Specification 43-8, 'Overhead Line Clearances'[1], sets out the current practice for the clearance distances for overhead lines. This is a carefully worked out requirement based on assumptions such as maximum conductor sag and, in the case of trees or vegetation, allows for the possibility that trees may be climbed, or may fall towards the line. This, therefore, requires continual inspection and management of vegetation near overhead lines, which is a particular issue in rural areas.

Other Network Costs

The other network costs may include activities such as monitoring, communications, physical and cyber security and wayleaves. This is a less significant proportion of the opex costs. However, there may be some portions worth considering. For example, from conversations with industry experts it was pointed out that wayleaves for lines and cables, and the leasing of spaces for substations can be significantly expensive if land owners wish to redevelop land or reclaim spaces. It was also highlighted that the extent to which network monitoring is used will rise as more information about the networks is needed.

3.2.2 Electricity Transmission Costs

As mentioned above, the scale of Network Related Opex of the transmission system is approximately comparable to that of the distribution networks, at 0.5% to 1% of network value (MEA). Whilst the broad categories of direct opex are the same for electricity transmission as they are for electricity distribution, there are some significant differences in the proportions of each component. This is summarised below, using indicative proportions:

- Network Inspection and Maintenance – 50%. This component is significantly higher than with DNOs. This may be because they have a higher proportion of assets that need maintenance, and there is a higher emphasis on maintenance due to the fact that faults within the transmission system can have significant implications on the supply of large areas of networks. This component will also include additional activities such as tower painting and maintenance.

- Fault repairs – 30%. The costs of fault repairs are proportionally lower, which may be because equipment is built to a higher specification, as the higher level of monitoring present at the transmission level and the comparatively low frequency of faults. This being said, the cost of faults, when they do occur, can be very high.

[1] Technical Specification 43-8, Overhead Line Clearances, published by the Energy Networks Association (ENA)

- Vegetation Management – 5%. This component is proportionally significantly lower than for distribution networks, as overhead lines are physically higher and beyond the reach of much vegetation.

- Other Network Costs – 15%. This component includes monitoring, which is presently significantly more prevalent at the transmission level compared to the distribution.

3.3 Closely Associated Indirect Costs in Electricity Networks

3.3.1 Electricity Distribution Costs

The data included in Ofgem's final proposals for DPCR5 for the indirect opex costs are broken down into three categories; Engineering Indirects, Network/Investment Support and Business Support. As mentioned, the scope of this project covers only those costs which are directly related to the network, and not those which are considered business costs or too distant to the network itself. Therefore only the Engineering Indirects and the Network/Investment Support costs will be considered. These include the following elements:

- Engineering Indirects
    - Network Design
    - Project Management
    - Engineering Management & Clerical Support
- Network/Investment Support
    - Control Centre
    - System Mapping
    - Network Policy
    - Call centre
    - Stores
    - Vehicles & Transport
    - Health & Safety and Operational Training

The charts below compare the proportions of the closely associated indirect costs and its components with the direct costs.

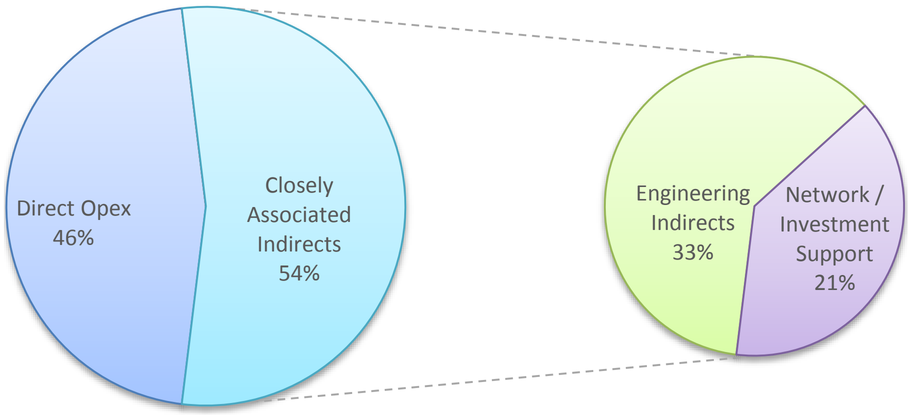

Figure 2: Components of closely associated intirect opex in electricity networks, compared to direct opex.

The data for Figure 2 is taken from Ofgem's final proposals for the last regulatory distribution price control review (DPCR5), and includes data for 2005 to 2015.

3.3.2 Electricity Transmission Costs

The closely associated indirect costs for the transmission networks are made up of the same categories as the distribution network, and at broadly the same proportions. For the purposes of this project, the differences in proportions of the categories are not significant.

3.4 Policy and Regulation Contributors to Electricity Network Opex

There are a number of areas where government policy and regulation significantly impact ongoing electricity network costs. However, it is the components that are directly associated with the networks and their assets which are relevant to this project. This section discusses and identifies the major external factors that are of interest to this project.

There are several UK government policies that directly impact on the energy industry, which generally aim to encourage change in the system through the uptake of low carbon or energy efficiency measures, rather than affecting opex of energy networks directly. The impact of changing energy networks on opex is explored further in Section 7.

There are requirements on the electricity network companies to maintain a high quality, secure and robust energy network, such as the 'Electricity Safety, Quality and Continuity Regulations'[2]. The most relevant requirements are listed below:

- Maintenance of the network: maintenance of any equipment in such a way as to maintain safety and continuity of supply, including preventing unauthorised access or vandalism of assets,

- Inspection of networks: inspect networks to ensure that any work can be done to comply with the regulations, and

- Overhead line clearance: ensure that overhead lines do not come close to any obstacles including buildings, structures and trees.

In each of these cases, the requirement is for these activities to be carried out, and there are no additional opex costs caused beyond the costs of completing these activities.

The RIIO (Revenue = Incentives + Innovation + Outputs) price control is a regulatory framework that is used to regulate gas and electricity networks. There are two relevant price control reviews for electricity networks, one each for distribution (RIIO-ED1) and transmission (RIIO-T1). These set out what the network companies are expected to deliver and the incentive mechanisms that will apply including the revenue that can be collected from network users.

RIIO-ED1 defines a range of outputs and incentives for the electricity distribution network operators (DNOs), covering the delivery of a network service to users including safety, environmental impact, customer satisfaction, social obligations, connections, reliability and availability. Some of these impact the opex costs of the network, most notably where interruptions to supply occur. In certain circumstances customers are entitled to direct payments if they experience interruptions in their supply, and the Interruption Incentive Scheme incentivises DNOs based on the number and duration of customer interruptions compared to a benchmark. Two fault related factors are incentivised by Ofgem; Customer Interruptions and Customer Minutes Lost. Interruptions may be associated with specific areas of the network or particular assets, so any costs associated with them are considered as Network Related Opex.

RIIO-T1 defines a range of outputs and incentives for the electricity and gas transmission networks, covering the delivery of a network service to users including system operator (SO) and transmission operator (TO) interactions, broad environmental output, visual amenity, electricity transmission losses, customer satisfaction, wider works secondary deliverable, and efficiency incentive rate. This also includes an

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[2] The Electricity Safety, Quality and Continuity Regulations 2002, which is available from: http://www.legislation.gov.uk/uksi/2002/2665/contents/made

incentive based on the reliability of the electricity network, based on the value of the lost load.

Within the RIIO price controls, there is a significant focus on innovation, and each network company has to demonstrate savings which they have achieved though innovation activities. This will include developments in efficient operation and other potential savings in the network opex.

As mentioned previously, electricity network companies do not pay for the electrical losses that occur in their system. However, the operation of the network will have an impact on the extent of these losses. Though measures have been attempted previously to incentivise network companies based on measured losses, this has experienced a number of problems due to the lack of sufficient and corrupted supplier data. RIIO-ED1 includes a mechanism aimed at reducing electricity losses in the networks, which includes a licence obligation to reduce losses and a requirement for DNOs to include in their business plans specific loss reduction activities and expenditure. DNOs will be obliged to report annually on the loss reduction activities. There will also be a reward for specific loss reduction activities. Similarly, RIIO-T1 mentions electrical loss reduction, but does not link this to any measured value of losses, and rather requires that companies publish strategies, activities and their progress.

This mechanism is aimed at reducing network technical losses, which is an aspect which is directly related to the network, and may encourage network companies to purchase different equipment, such as high efficiency transformers, and operate the network in such a way that minimises losses. However, because they are not currently based on measured losses on the network, it is noted that the cost or income associated with them are not directly related to the physical assets installed. However, incentives based on measured losses have been attempted in the past, and it is likely that this will be attempted again, as it is a significant topic within the industry. If this is the case, then is it probable that the lifetime opex of the assets that are being installed now may include an element of measured loss incentive in the future.

Network companies will pay a variety of taxes, some of which are directly related to the network assets, in particular, buildings tax and network rates. From a regulatory point of view, network rates are classed as ‘pass through’ costs, which means that the network companies can recover the costs in full from the customers. For the purposes of network rates, the valuation of property is based on the profit that they make on the property, calculated from income, expenditure, operation costs and depreciation. For electricity distribution, network rates are thought to be approximately £20 to 40 million per DNO licence holder per year, and for transmission, they range from £67 million for National Grid Electricity Transmission (NGET), to £12 million for Scottish Hydro Electricity Transmission (SHE Transmission). In both cases, this appears to amount to approximately 5% of Network Related Opex. The nature of these costs are not yet understood by the project team, and this could be subject for further work.

3.5 Factors that Affect Electricity Network Opex

There are several technical and environment factors that are relevant to the significant components of the opex within the electricity network that have been identified in the sections above. One way that these factors were identified was to explore, both through internal analysis and research, and with support from external experts, factors in certain areas, including:

- technical,
- location,
- conditions, and
- external factors.

The mindmap below shows the factors that were identified as being relevant to electricity network opex in each of the categories above.

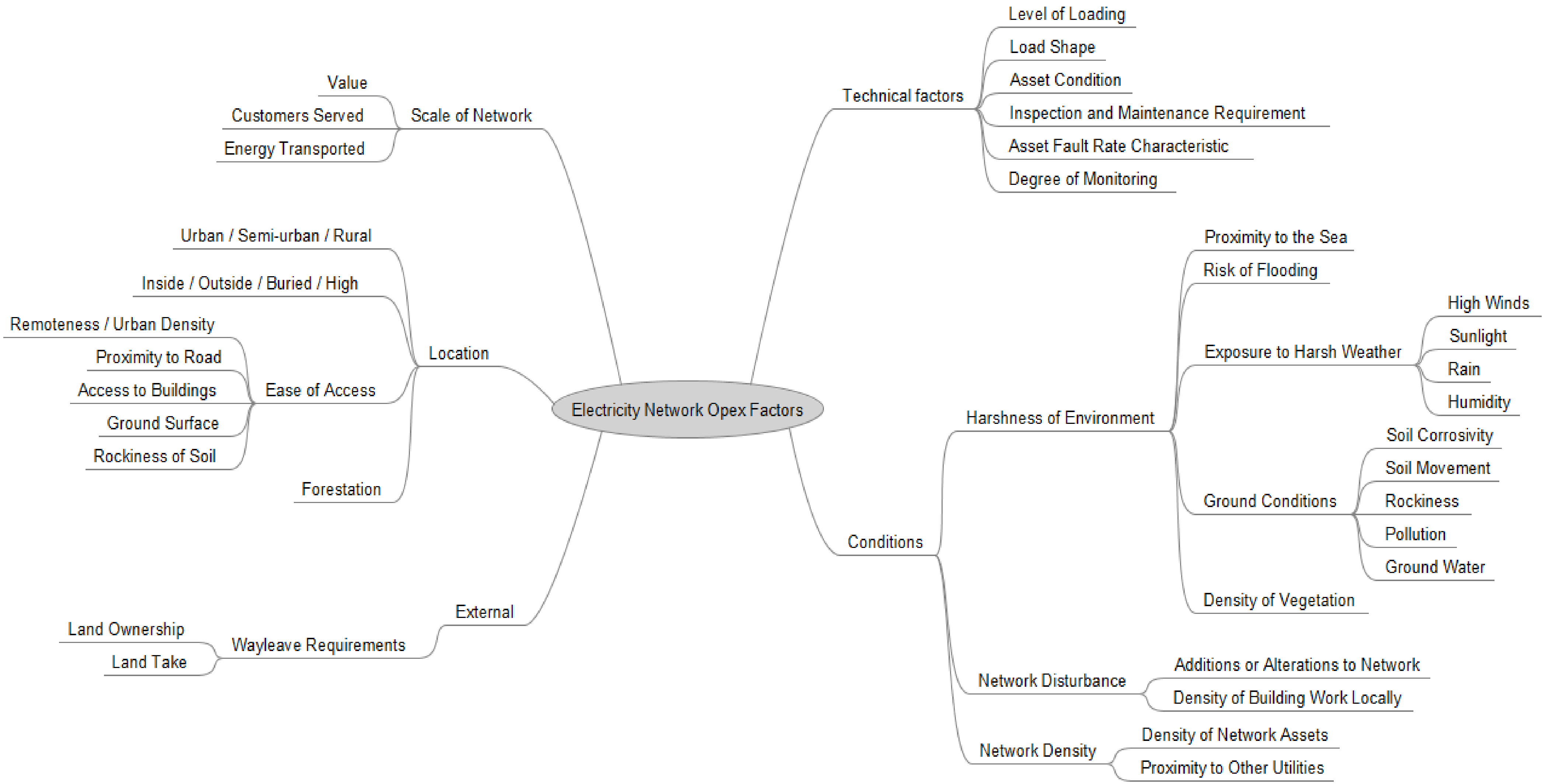

Figure 3: Mindmap showing the factors that affect the opex of electricity networks

The factors identified in the mindmap above are explained in more detail in Table 1 below. The factors relevant to the opex of electricity networks are very similar to those that affect the opex of gas, heat and hydrogen networks, though there are some key electricity network specific issues:

- Unlike with gas networks, the electricity load shape is considered to be a significant factor, as there is no inherent short term energy storage in the network, and therefore supply has to meet demand in real time.

- Vegetation management is a significant component of electricity network opex (unlike all of the other vectors). This is because there is a significant risk of fault resulting from contact between trees and over-head line conductors.

- There is some energy requirement within electricity network assets, for example ventilation, cooling and pumps. However, this is not a significant proportion of the Network Related Opex, which is in contrast to all of the other vectors where compressors or pumps have more significant energy requirements.

- As discussed previously, losses are not measured within electricity networks, and network companies are not expected to cover them. Therefore losses are not discussed in this chapter.

Table 1: Factors that affect the opex of electricity networks

FACTOR	COMMENT
Scale of the network	This factor refers to the scale of the parts of the network to be studied, in relation to the wider network. This is important as where an addition to a network is a more significant size compared to the network as a whole, then the increases in costs, for example staff and operations costs, will be much greater. Conversely, if the scale of an addition is relatively insignificant compared with that of the whole network, then additional support requirements are more likely to be able to be absorbed into existing systems and arrangements.
Level of loading	Where assets are more heavily loaded, they will age more quickly and would be more susceptible to increased faults.
Load shape	Where an asset experiences high peaks and low troughs in loading throughout a day or week, it may experience increased wear as they will experience corresponding temperature and magnetic field cycles.
Asset condition	Assets that are older, or in poor condition, may fail more often.
Inspection maintenance requirements	Different assets will have specific requirements for maintenance, and this may be significantly different from asset to asset.
Asset fault rate characteristics	Assets themselves have their own characteristics regarding failures and faults, and these may vary significantly from asset to asset.

Degree of monitoring	Greater levels of monitoring will add to opex costs as the monitoring systems and underlying IT systems will need to be operated and maintained. However, there are many advantages of increased monitoring including the opportunity for improved network operation and asset management. It is expected that monitoring and network visibility of the electricity network will tend to increase into the future, as discussed in Section 7.
Harshness of environment	Assets that are installed in certain environments, for example in close proximity to the sea, in areas with high humidity or prone to flooding, or areas exposed to high winds, may require increased maintenance. This includes harsher soil or ground conditions, such as corrosive or rocky soil, or areas with high soil movement or high levels of ground water. Areas that have high levels of vegetation may cause issues with root density and ground movement, as well as damage caused by fast growing plants and contact with trees.
Network density	Where there are very dense networks, and high proximity to other utilities, the location of buried cables can be more difficult, as multiple cables and other lines can be found within a single excavation. Proximity to other utilities may also increase the risk of other personnel making contact with the network cables and causing damage. Again, this is more likely in urban areas.
Network disturbance	Where a network has been subject to many additions or alterations to the network configurations, this might create weak points in the networks which may be more prone to faults. Additions may result in changing the use of existing network assets away from the existing or original designed purpose, which may cause additional issues.
Unban / semi-urban / rural	Remote rural areas may be difficult to get to, and the network may cross private land and not be accessible from the road. In urban networks, there are issues with road traffic and location of assets in a densely built up area. Costs may also be incurred associated with the New Roads and Street Works Act and the Traffic Management Act, including lane rental charges, and costs to perform work at only certain times to comply with restrictions.
Inside / outside / buried / high	Where assets are buried or installed up high, they become less easily accessible for maintenance. Assets that are outside are exposed to the weather, and this may result in additional faults, compared with those assets that are protected by being installed inside.
Ease of Access	Network assets may be situated in remote rural locations, or some distance from the nearest road. Alternatively, assets may be less accessible if they are installed in built up urban areas, or inside buildings being used for other purposes, such as the basements of offices or hospitals. Assets that are buried are less accessible, particularly if the ground surface is hard (such as a road or pavement), or the ground is rocky.
Forestation	The density of vegetation in the area is a significant factor for electricity network opex, as it will impact on the cost of tree cutting.
Wayleave Requirements	Where land for lines, cable routes and substations do not belong to the network company, a wayleave or land lease is required. From discussions with industry experts, it was clear that issues with wayleaves and land lease can become problematic, particularly where land owners wish to reclaim their land. In such cases, either an agreement is reached, which may be very expensive, or assets have to be relocated.

3.6 Factor Assessment

The factors that are identified within Section 3.5 affect the components of electricity network opex in very different ways. This is summarised within the indicative matrix below; where a darker blue signifies a more significant relationship between the factor and the opex component. The percentages in the matrix describe the approximate proportions of each component that make up the Network Related Opex for both transmission and distribution, which are based on the discussions above.

	Opex Components	Engineering Indirects	Fault Repairs and Restoration	Network Investment and Support	Inspection and Maintenance	Tree Cutting	Other Direct costs
	Distribution	33%	26%	21%	10%	9%	1%
Factors	Transmission	30%	15%	20%	25%	3%	7%
Scale	Scale of the Network						
Technical	Level of Loading						
	Load shape						
	Asset Condition						
	Inspection and maintenance req.						
	Asset Fault Rate Characteristics						
	Degree of Monitoring						
Conditions	Harshness of Environment						
	Network Disturbance						
	Network Density						
Location	Urban / Semi Urban / Rural						
	Inside / Outside / Buried / High						
	Ease of Access						
	Forestation						
External	Wayleave Requirements						

Figure 4: Matrix describing the relationship between the components of electricity network opex and the opex factors.

The assessment of the opex factors shown in the matrix above has been completed using a mixture of research, best judgement, and advice from the expert contacts. This is therefore not a definitive assessment, but is instead intended to indicate the current thinking of the project team, and further work would be required to validate this with academic and industry experts. It was also noted by the team that the opex of a network will change throughout its lifetime. For example, perhaps as the operators become more familiar with new network configurations, and equipment is 'bedded in', opex might fall, or conversely as assets age and the network becomes more congested or altered, faults might rise, increasing opex. This might also change the effect that each factor has on network opex, though it is considered that this is beyond the level of accuracy that this project has reached.

The assessment of each relationship is discussed below.

3.6.1 Engineering Indirects

Engineering indirects is the most significant proportion of electricity network opex, at around 33% of total opex for distribution, and around 30% for transmission. As explained above, for the electricity networks, engineering indirects includes activities such as network design, project management, engineering management and clerical support. As indicated in Figure 4, some of the identified factors would have an impact on this component, as discussed below:

- Network design activities will be impacted by the following factors:
    - Scale of the network,
    - Network density, and
    - Urban/semi-urban/rural.
- The opex related to engineering management and clerical support will be impacted by the level of work associated with inspection, maintenance and repair of the network. This, in turn, is impacted by the following factors (only significant impacts are included here, as this is only a proportion of engineering indirects):
    - Scale of the network,
    - Inspection and maintenance requirement,
    - Asset fault rate characteristic,
    - Urban/semi-urban/rural,
    - Inside/outside/buried/high, and
    - Ease of access.

3.6.2 Fault Repairs and Restoration

As indicated in Figure 4, some of the identified factors would have an impact on this component, as discussed below:

- It is likely that, in general, as the scale of the network increases, so will the frequency and cost of faults.
- The frequency of faults is impacted by the following factors:
    - Asset fault rate characteristics,

  - Level of loading (as heavily loaded assets are likely to wear more quickly),

  - Load shape (as where an asset experiences high peaks and low troughs in loading throughout a day or week, it may experience increased wear as they will experience corresponding temperature and magnetic field cycles),

  - Asset condition,

  - Harshness of environment,

  - Network disturbance (as where networks have been altered or changed, weak points may be created, and where there is building work near to network assets, the risk of accidental interference with the network becomes more likely),

  - Network density (as where the network assets are close to other network assets, or those of other utilities, then there is a possibility that the networks will interact or if maintenance or repair on one network may inadvertently risk faults on the other), and

  - Inside/outside/buried/high (as assets that are outside are exposed to the weather).

- The cost of repairing faults on the network are affected by the following factors:

  - Ease of access,

  - Network density (as accessing assets in a heavily dense network may be problematic, for example where a cable route is shared with many other cables or other utilities),

  - Urban/semi-urban/rural (as remote rural areas may be difficult to get to, and the network may cross private land and not be accessible from the road. In urban networks, there are issues with road traffic and location of assets in a densely built up area. Costs may also be incurred associated with the New Roads and Street Works Act and the Traffic Management Act, including lane rental charges, and costs to perform work at only certain times to comply with restrictions), and

  - Inside/outside/buried/high (as accessing buried or high assets will incur additional costs).

3.6.3 Network/Investment Support

As explained above, for the electricity networks, network and investment support includes activities such as control centres, call centres, stores, vehicles and transport and health and safety and operational training. Though a great deal of these costs are associated with the network, it is difficult to attribute them to particular assets. Figure

4 describes the minor relationships between the factors and the network and investment support costs. This is discussed below:

- All aspects of network and investment support will increase as the scale of network increases. For example, larger networks require larger or more control centres, more stores for spares and equipment and higher vehicle and transport costs to cover a greater area or higher numbers of assets.

- Control centre costs may be expected to rise as the frequency of faults rise. Call centre costs may also be affected by the frequency of faults, as customers are likely to contact network companies in the event of a fault for more information. As this effect is relatively minor, then only the factors with the most significant effect on fault rate are considered relevant:

    - Asset fault rate characteristics, and

    - Level of loading (as heavily loaded assets are likely to wear more quickly).

- Vehicle and transport costs will be effected by frequency and difficulty in visiting areas of the network, for example, for inspection, maintenance and repairs. This is affected by the following factors:

    - Asset fault rate characteristics,

    - Inspection and maintenance requirement,

    - Degree of monitoring (it may be that increased monitoring may result in decreased inspection requirements),

    - Harshness of environment (as this may increase the need for maintenance and the fault rate), and

    - Ease of Access.

3.6.4 Inspection and Maintenance

As indicated in Figure 4, some of the identified factors would have an impact on the costs of inspection and maintenance, as discussed below:

- Scale of the network,

- Inspection and maintenance requirement of the equipment installed,

- The requirement for maintenance may also be affected by:

    - Level of loading,

- Load shape,
- Asset condition,
- Degree of monitoring, and
- Harshness of environment.

- Accessibility of the assets may be affected by:
  - Ease of access,
  - Urban/semi-urban-rural, and
  - Inside/outside/buried/high.

3.6.5 Tree Cutting

As indicated in Figure 4, some of the identified factors would have an impact on the costs of tree cutting, as discussed below:

- Tree cutting is only relevant in networks with overhead lines. Therefore the factor Inside/outside/buried/high is relevant here.
- The requirement of tree cutting is directly related to the amount of forestation along the route of the overhead lines.
- The cost of tree cutting may also be related to the ease of access of the network.
- As with the other components, the cost of tree cutting will be related to the scale of the network.

3.6.6 Other Direct Costs

As described above, other network costs includes activities such as monitoring, communications, physical and cyber security, and wayleaves. The relevant factors to this component are indicated in Figure 4, and discussed below:

- These costs are closely related to the scale of the network.
- The following factors also have a significant effect:
  - Degree of monitoring, and
  - Wayleave requirements.

3.6.7 Identification of Key Factors

The factors that have been identified have very different effects on the overall opex of the network. The degree of their significance can be found through a combination of their effect on each individual component of opex, and the relative proportion that that component makes up of overall opex. For example, forestation has a significant effect on the cost of tree cutting, but this is a relatively small component of opex. However, asset fault rate characteristics has a significant effect on the cost of fault repairs and restoration, which is a much more significant component of direct opex for distribution networks.

Using this logic, and the following factors are identified as the most significant factors for the electricity Network Related Opex:

1. Scale of the Network

2. Ease of Access

3. Inspection and Maintenance Requirements

4. Asset Fault Rate Characteristics

5. Inside / Outside / Buried / High

6. Urban / Semi-Urban / Rural

7. Level of loading

4 Areas of Uncertainty – Gas Networks

4.1 Introduction

This section discusses the factors that impact opex which are specific to gas networks. As with the electricity network, the major contributors to gas network opex are identified, before each contributor is explored in order to identify the major factors that affect the value of this cost.

The gas industry within the UK is similar to the electricity industry, in that the sourcing and purchasing of gas is the responsibility of supply companies which are separate from gas network companies. Again, the implication of this is that the costs related to gas sourcing or purchasing, supply, and billing are not felt by the gas network companies, with the exception of any metering that belongs to the gas network companies.

However, there is a significant difference in the handling of gas network losses, or shrinkage, when compared with electrical losses. Gas network companies must purchase gas to cover all shrinkage, including 'own use' gas, and gas that is not accounted for such as that lost in leakage or theft.

The discussions below cover the gas Network Related Opex costs experienced by the network companies, and so will not directly cover extraction costs, losses or supply costs, or any business costs which are distant from the network assets. The previous project undertaken by PPA Energy, 'Opex Framework for Energy Infrastructure', determined that the UK gas distribution networks have a combined Network Related Opex of about £0.7bn, or about 1.3% of the network value (Modern Equivalent Asset value). The gas transmission networks have a Network Related Opex of about 1.1% of gross assets (MEA).

4.2 Direct Opex in Gas Networks

Direct opex covers areas of opex that are incurred directly on or close to the network itself. The chart below shows the costs associated with five categories of direct opex for gas distribution - emergency, repair, maintenance, shrinkage and other. The data is taken from information included in Ofgem's final proposals for the latest regulatory distribution price control review (RIIO-GD1).

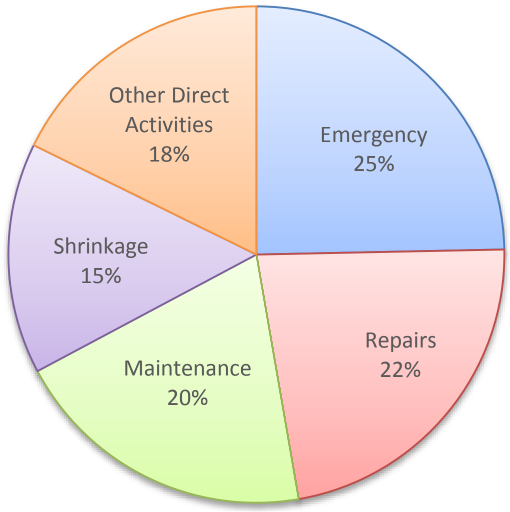

Figure 5: Components of direct opex in gas distribution networks.

The data for Figure 5 is taken from Ofgem's final proposals for the last regulatory distribution price control review (RIIO-GD1), and includes data for 2014 to 2021.

Within this chart-

- Emergency costs include the costs to respond to and repair any emergency on the gas network. Emergencies include a range of incidents including gas escape, appliance malfunctions, trapped birds or water ingress.

- Repair costs include items such as repair location, materials and labour costs, waste disposal costs, and costs incurred associated with the New Roads and Street Works Act and the Traffic Management Act.

- Maintenance activities are split into three categories: routine (where costs are predictable and regular), non-routine (where costs are not predictable or regular, but the requirement is known and has a material effect on opex) and exceptional items maintenance.

    - Routine Maintenance includes activities such as site maintenance, hedge maintenance, fencing repairs and site drainage, inspections and surveys, and any associated remedial work, alarm testing and resetting, calibration and maintenance of instrumentation, and gas quality maintenance.

    - Non Routine Maintenance includes activities such as repainting, inspections and maintenance of above ground exposed crossings and asbestos surveys.

    - Exceptional items are those activities that are not predictable in nature, and are not expected to be needed more than once in eight years.

- Other Direct Activities may include the addition of odorant, compensation payments, tools and Easement/wayleave costs.

- Shrinkage consists of: [3]

  - 95% Leakage;

  - 3% Unaccounted For gas, including theft and metering errors; and

  - 2% Own Use Gas; From conversations with experts, it was ascertained that own use gas is likely to be gas used in compressors, many of which are being replaced with more efficient electric pumps, with a high demand for electricity.

The data available to cover gas transmission opex costs is not provided at the same level of detail as that for distribution. It is expected that all of the elements mentioned so far will be relevant for transmission, though there may be differences in the specific proportion of opex that is made up from these elements. However, the aim of this task is to identify significant factors, and it is considered likely that the breakdown of transmission opex is sufficiently similar to that of distribution to assume that the same elements are considered 'significant'.

4.3 Closely Associated Indirect Costs within Gas Networks

Within the data included in Ofgem's final proposals for the latest regulatory distribution price control review (RIIO-GD1), the category of 'Work Management' covers the closely associated indirect costs. This includes:

- Asset Management, which includes monitoring,

- Customer Management (both customer services and commercial / contract management),

- Operations Management, which includes activities such as the direct management of field staff, HSE compliance and policy, and operations support such as plant protection, dispatch, work scheduling, and support costs in depots, and

- System Control, which aims to ensure that the system is running safely and well, and consists mainly of control room costs.

The sum of these costs are compared to the total direct opex costs in the chart below:

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[3] Shrinkage and Leakage Model Review No 1, Consultation on Northern Gas Networks Shrinkage and Leakage Model Review 2013/14, Northern Gas Networks, November 2014.

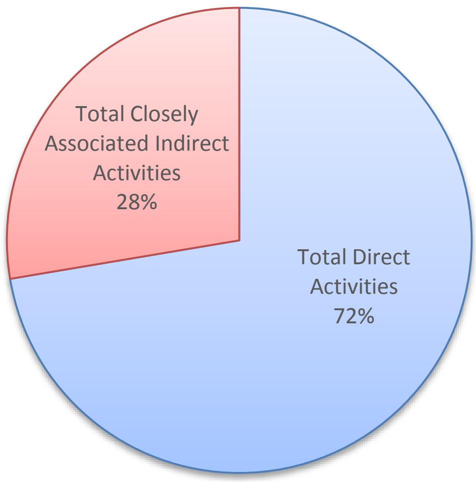

Figure 6: Closely associated indirect opex in gas distribution networks, compared to direct opex.

The data for Figure 6 is taken from Ofgem's final proposals for the current regulatory distribution price control review (RIIO-GD1), and includes data for 2014 to 2021

Again, the data available to cover gas transmission closely associated indirect opex is not provided at the same level of detail as that for distribution. As with direct opex, it is expected that the breakdown will be broadly similar, which is considered to be sufficient for the purposes of this project.

4.4 Policy and Regulation Contributors to Gas Network Opex

There are a number of areas where government policy and regulation contribute significantly to ongoing gas network costs. However, it is the components that are directly associated with the networks and their assets which are relevant to this project. This section discusses and identifies the major external factors that are of interest to this project.

As mentioned, there are several UK government policies that directly impact on the energy industry, which generally aim to encourage change in the system through the uptake of low carbon or energy efficiency measures, rather than affecting opex of energy networks directly. The impact of changing energy networks on opex is explored further in Section 7.

The Gas Act 1986 is the main piece of onshore gas market legislation, which includes the licencing regime for gas industry players including suppliers, and includes provisions that networks should be maintained in such a way that it is both economical and efficient. However, it does not impose any further costs on the network beyond the cost of maintenance.

The RIIO (Revenue = Incentives + Innovation + Outputs) price control is a regulatory framework that is used to regulate gas and electricity networks. There are two relevant price control reviews for gas networks, one each for distribution (RIIO-GD1) and transmission (RIIO-T1). These set out what the network companies are expected to deliver and the incentives that they will receive.

RIIO-GD1 defines a range of outputs and incentives for the Gas Distribution Network companies (GDNs), covering the delivery of a network service to users including safety, environmental impact, social, customer satisfaction and connection standards. Though these will make up a significant proportion of the ongoing costs to a GDN, these are not directly attributable to a specific piece of network, and are generally more to do with overall network and business performance.

RIIO-GD1 targets 15 to 20% reduction in gas transport losses, or ‘shrinkage’, which makes up about 95% of the carbon footprint of a GDN. This is enforced by an Environmental Emissions Incentive (EEI) and a shrinkage allowance mechanism. This incentive is based on shrinkage performance compared to a baseline. Shrinkage is not directly measured in the system, but is estimated using a shrinkage model which is validated using available data. Specific network assets will contribute to shrinkage, and so the ongoing costs associated with the network will include this incentive, as well as the costs of the lost gas itself.

RIIO-T1 was discussed previously in reference to the electricity transmission networks. However, this same scheme is applicable to gas transmission. Though RIIO-T1 includes outputs and incentives regarding the delivery of a network service to users including system operator/transmission operator interactions, environmental output, visual amenity, customer satisfaction, and efficiency, these are generally not attributable to specific sections of the network and are instead related to general performance.

There are other government acts and regulations that will affect the opex of the network, such as the Traffic Management Act 2004, which aims to reduce congestion on the roads (for Scotland, the Transport (Scotland) Act 2005 is in place instead). This allows local authorities to implement a permit scheme for works in the street, and they may impose constraints and conditions on the work. The costs associated with this are included in the direct opex costs.

As with electricity, gas network companies will pay a variety of taxes, some of which are directly related to the network assets, in particular, buildings tax and network rates. From a regulatory point of view, network rates are classed as ‘pass through’ costs, which means that the network companies can recover the costs in full from the customers. For the purposes of network rates, the valuation of property is based on the profit that they make on the property, calculated from income, expenditure, operation costs and depreciation. For gas networks companies, network rates may make a significant contribution to Network Related Opex, potentially as much as 25%. The nature of these costs are not yet understood by the project team, and this could be subject for further work.

4.5 Factors that Affect Gas Network Opex

There are several technical and environmental factors that are relevant to the significant components of opex within the gas network that have been identified in the sections above. One way that these factors were identified was to explore, both through internal analysis and research, and with support from external experts, factors in certain areas, including:

- technical,
- location,
- condition, and
- external factors.

The mindmap below shows the factors that were identified as being relevant to gas network opex in each of the categories above.

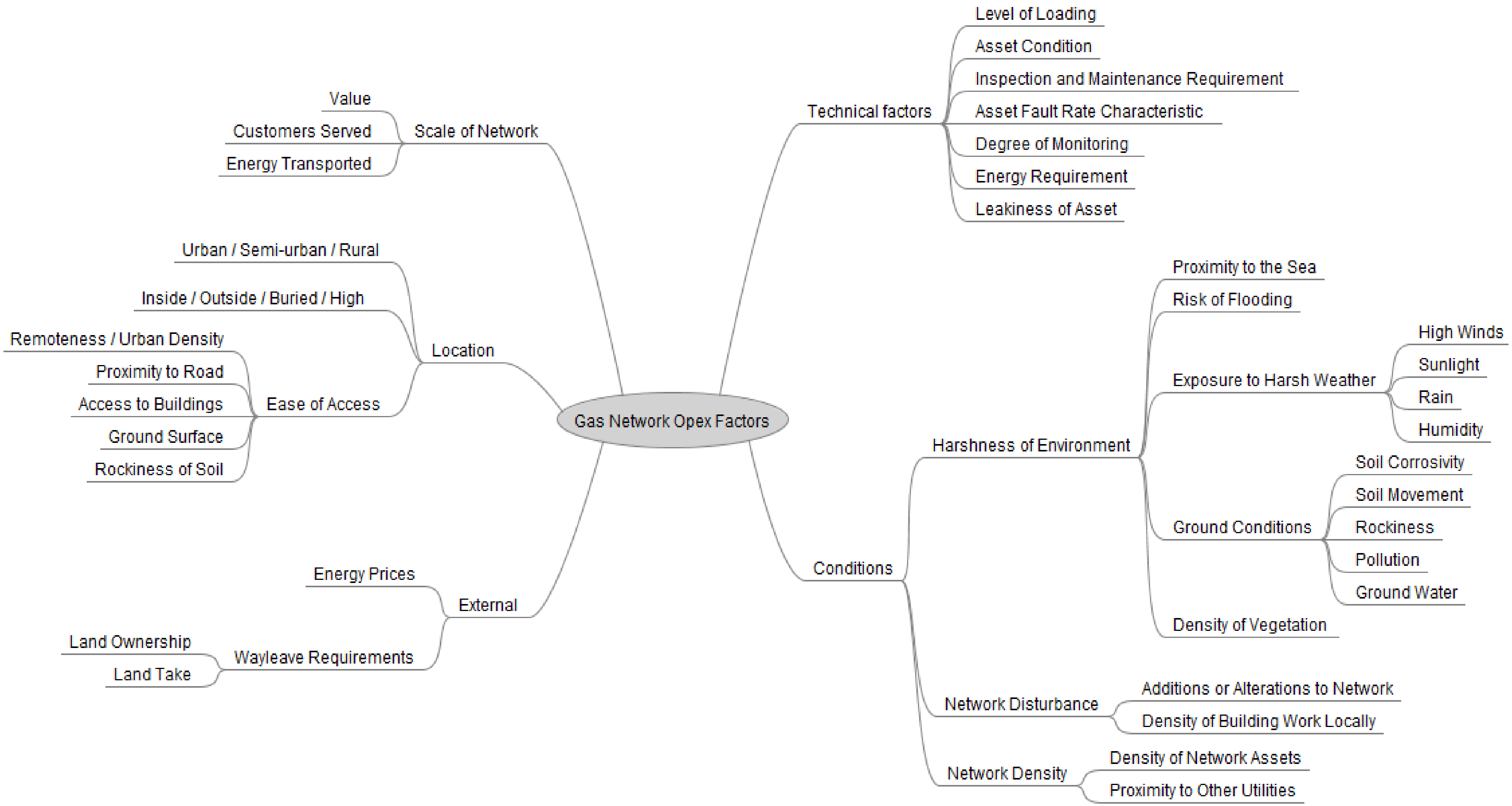

Figure 7: Mindmap showing the factors that affect the opex of gas networks

The factors identified in the mindmap above are explained in more detail in Table 2 below. The factors that affect gas network opex are similar to those that affect electricity and other energy vector networks, with the following differences:

- In contrast to the electricity network factors, gas network load shape is not considered to be a significant factor. This is due to the ability of the network to ‘line pack’, which involves using the network pipe capacity itself as short term storage. This will have the effect of decoupling compression requirements with the network load fluctuations.

- Vegetation management is not a significant component of gas network opex. This is because there is no significant risk of fault due to contact with trees, and pipe lines tend to be buried.

- Gas compression will have an inherent energy requirement that will need to be covered by the network company.

- Gas networks also have to cover the gas which escapes through leaks within the network, which makes characteristics such as leakiness relevant.

Table 2: Factors that affect the opex of gas networks

FACTOR	COMMENT
Scale of the network	This factor refers to the scale of the parts of the network to be studied, in relation to the wider network. This is important as where an addition to a network is a more significant size compared to the network as a whole, then the increases in costs, for example staff and operations costs, will be much greater. Conversely, if the scale of an addition is relatively insignificant compared with that of the whole network, then additional support requirements are more likely to be able to be absorbed into existing systems and arrangements.
Level of loading	Where assets are more heavily loaded, they will age more quickly and would be more susceptible to increased faults.
Asset condition	Assets that are older, or in poor condition, may fail more often.
Inspection maintenance requirements	Different assets will have specific requirements for maintenance, and this may be significantly different from asset to asset.
Asset fault rate characteristics	Assets themselves have their own characteristics regarding failures and faults, and these may vary significantly from asset to asset.
Degree of monitoring	Greater levels of monitoring will add to opex costs as the monitoring systems and underlying IT systems will need to be operated and maintained. However, there are many advantages of increased monitoring including the opportunity for improved network operation and asset management. It is expected that monitoring and network visibility of the gas network will tend to increase into the future, as discussed in Section 7.
Energy requirement	The energy required by assets, for example compressors, may be taken from the gas network, or may be electricity based. This requirement will vary from asset to asset.

Leakiness	Different assets may have different characteristics with respect to their leakiness.
Harshness of environment	Assets that are installed in certain environments, for example in close proximity to the sea, in areas with high humidity or prone to flooding, or areas exposed to high winds, may require increased maintenance. This includes harsher soil or ground conditions, such as corrosive or rocky soil, or areas with high soil movement or high levels of ground water. Areas that have high levels of vegetation may cause issues with root density and ground movement, as well as damage caused by fast growing plants and contact with trees.
Network disturbance	Where a network has been subject to many additions or alterations to the network configurations, this might create weak points in the networks which may be more prone to faults. Additions may result in changing the use of existing network assets away from the existing or original designed purpose, which may cause additional issues.
Network density	Where there are very dense networks, and high proximity to other utilities, the location of buried pipes can be more difficult, as multiple pipes, cables and other lines can be found within a single excavation. Proximity to other utilities may also increase the risk of other personnel making contact with the network pipes and other equipment, and causing damage.
Unban / semi-urban / rural	Remote rural areas may be difficult to get to, and the network may cross private land and not be accessible from the road. In urban networks, there are issues with road traffic and location of assets in a densely built up area. Costs may also be incurred associated with the New Roads and Street Works Act and the Traffic Management Act, including lane rental charges, and costs to perform work at only certain times to comply with restrictions.
Inside / outside / buried	Where assets are buried, they become less easily accessible for maintenance. Assets that are outside are exposed to the weather, and this may result in additional faults, compared with those assets that are protected by being installed inside.
Ease of Access	Network assets may be situated in remote rural locations, or some distance from the nearest road. Alternatively, assets may be less accessible if they are installed in built up urban areas, or inside buildings being used for other purposes, such as the basements of offices or hospitals. Assets that are buried are less accessible, particularly if the ground surface is hard (such as a road or pavement), or the ground is rocky.
Energy prices	This will affect the costs associated with the energy that is consumed in assets such as compressors.
Wayleave Requirements	Where land for pipelines and equipment does not belong to the network company, a wayleave or land lease is required. From discussions with industry experts, it was clear that issues with wayleaves and land lease can become problematic, particularly where land owners wish to reclaim their land. In such cases, either an agreement is reached, which may be very expensive, or assets have to be relocated.

4.6 Factor Assessment

The factors that are identified within Section 4.5 affect the components of gas network opex in very different ways. This is summarised within the matrix below; where a darker blue signifies a more significant relationship between the factor and the opex component. The percentages included in the matrix represent the proportions of the components that make up distribution Network Related Opex. As mentioned above, there is not sufficient data to provide a similar breakdown for transmission networks.

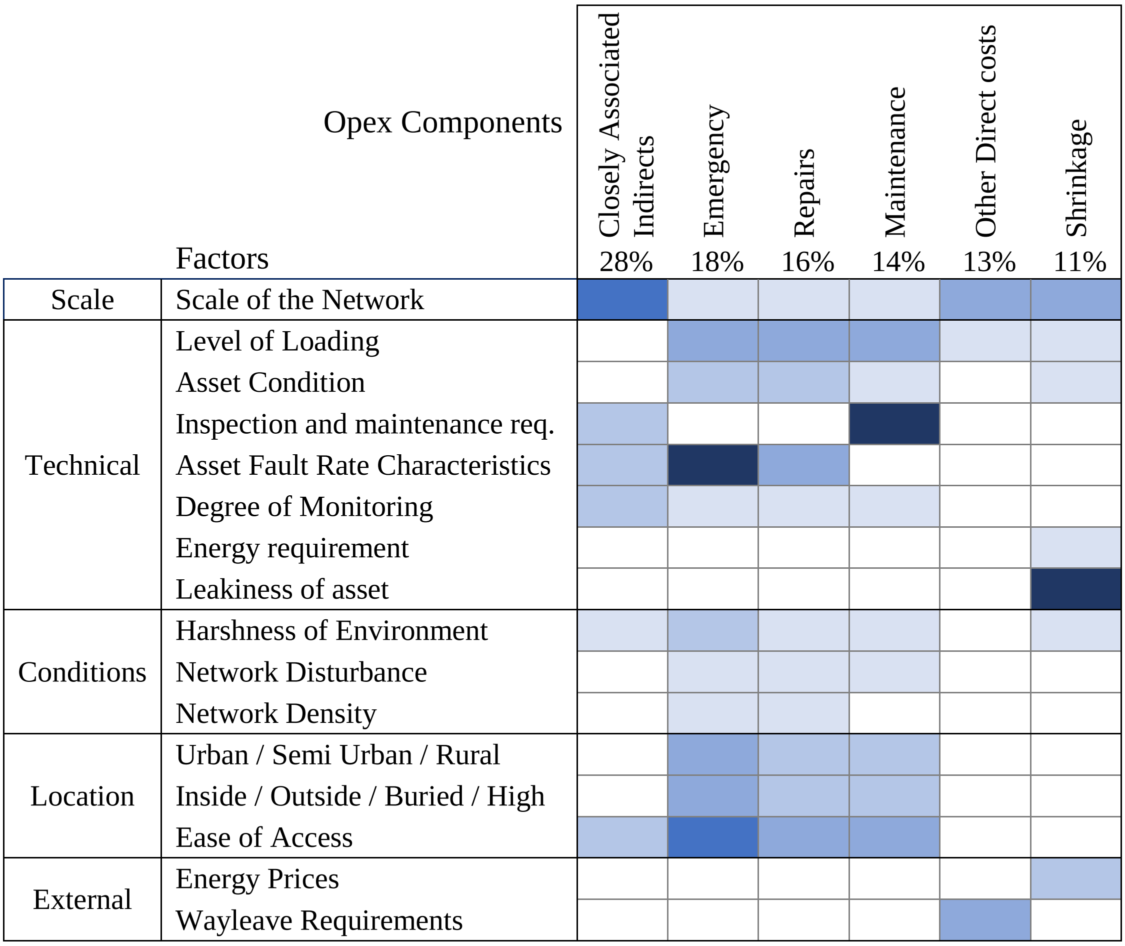

Figure 8: Matrix describing the relationship between the components of gas network opex and the opex factors.

The assessment of the opex factors shown in the matrix above has been completed using a mixture of research, best judgement, and advice from the expert contacts. Thus, as with electricity, this is therefore not a definitive assessment, but is instead intended to indicate the current thinking of the project team. It was also noted by the team that the opex of a network will change throughout its lifetime.

The assessment of each relationship is discussed below.

4.6.1 Closely Associated Indirects

The Closely Associated Indirect opex costs are the largest component of network related gas network opex, at about 28%. As discussed above, this component includes activities such as asset management and monitoring, customer management, operations management and system control. A number of factors affect this component, as discussed below:

- Many of the costs included in closely associated indirects are closely related to network scale.

- Increased fault rate is likely to increase the closely associated indirect costs, including the control room costs, customer management costs and the operations management costs. The factors that are most relevant for this are:

  - Asset fault rate, and

  - Harshness of environment.

- Operations management costs are related to the degree of work associated with inspection, maintenance and repairs, which is affected by the following factors:

  - Asset fault rate,

  - Inspection and maintenance requirement,

  - Degree of monitoring (for example, increased monitoring may decrease the requirement to inspect),

  - Ease of access, and

  - Harshness of environment.

4.6.2 Emergency and Repairs

As shown in Figure 8, a number of factors affect the costs to respond to and repair emergencies on the network. These are very similar to the factors that affect the cost of non-emergency repairs. These are discussed below:

- The frequency of faults may be affected by the following factors:

  - Asset fault rate characteristics,

  - Level of loading,

  - Asset condition,

  - Harshness of environment,

    - Network disturbance,
    - Network density,
    - Inside/outside/buried/high, and
    - Urban/semi-urban/rural.
- The cost of repairing faults is effected by access to the assets. This includes the associated costs related to digging up roads and highways. This is affected by:
    - Ease of access,
    - Inside/outside/buried/high, and
    - Urban/semi-urban/rural.
- These costs are also affected by the scale of the network, as, generally, the larger the network is, the more faults there will be.

4.6.3 Maintenance

As shown in Figure 8, a number of factors affect the costs to maintain the network. These are discussed below:

- The level of maintenance required on an asset is affected by:
    - Inspection and maintenance requirement
    - Level of loading
    - Asset condition
    - Harshness of environment
    - Network disturbance
    - Network density
    - Inside/outside/buried/high, and
    - Urban/semi-urban/rural.
- The cost of maintenance will depend on the ease of access to the asset:
    - Ease of access,
    - Inside/outside/buried/high, and

    - Urban/semi-urban/rural.

- These costs are also affected by the scale of the network, as, generally, the larger the network is, the higher the maintenance requirements will be.

4.6.4 Other Direct Costs

Other Direct costs may include activities such as the addition of odorant, compensation payments, tools and Easement/wayleave costs. This is affected by the following factors:

- The scale of the network (as aspects such as addition of odorant and purchase of tools is closely related to network scale),

- Level of loading (as it is directly related to addition of odorant), and

- Wayleave requirements.

4.6.5 Shrinkage

As mentioned above, the vast majority of shrinkage costs (about 95%) are attributable to leakage. The other components are own use (the energy requirements of the network assets themselves) and other unaccounted for gas (due to, for example, theft or metering errors). Therefore the factors that affect leakage are considered much more significant that those that affect the other components of shrinkage. These factors are:

- Leakage:
    - Scale of the network,
    - Leakiness of asset,
    - Asset loading,
    - Asset condition, and
    - Harshness of environment.

- Other components of shrinkage:
    - Energy requirement, and
    - Energy prices.

4.6.6 Identification of Key Factors

The factors that have been identified have very different effects on the overall opex of the network. The degree of their significance can be found through a combination of their effect on each individual component of opex, and the relative proportion that that component makes up of overall opex. For example, leakiness of asset has a significant effect on the cost of shrinkage, but this is a relatively small component of opex. However, asset fault rate characteristics has a significant effect on the cost of emergencies, which is a much more significant component of direct opex.

Using this logic, the following factors are identified as the most significant factors for gas Network Related Opex. These are the same factors as those that have been identified for electricity networks, though the order of significance is different in some cases:

1. Scale of the network

2. Ease of Access

3. Asset Fault Rate Characteristics

4. Level of Loading

5. Inspection and Maintenance Requirement

6. Urban / Semi-Urban / Rural

7. Inside / Outside / Buried / High

5 Areas of Uncertainty – Heat Networks

5.1 Introduction

This section discusses the factors that impact Network Related Opex that are specific to heat networks.

The system model that is generally adopted by heat networks is significantly different to the UK gas and electricity industries. Often, especially for smaller systems, the heat network is designed with specific heat sources and customers in mind, and it is installed and maintained as one complete system. Another model that is often used, for example in Copenhagen in Denmark, is that a network of heat pipes is established with a number of heat sources, and additional heat sources connect as they are developed. Over time this network is then grown and developed to include more heat sources and supply more customers.

In both of these cases, a single entity is responsible for generating or purchasing the heat, developing and maintaining the network, and supplying customers, as well as meeting any policy and compliance requirements. However, in the discussions of electricity and gas networks above, the fuel costs and the supply costs are not included as they are not the responsibility of the energy network companies. In order to keep the discussions as comparable as possible, these aspects will not be included in detail within this report.

The assumption within this project is that we are referring to hot water systems, where heat sources are used to heat the water, and loads are fed through heat exchangers. It is also assumed that the scale of heat networks, even when adopted fully, is likely to be smaller (compared to gas and electricity), and individual cities and towns may have their own local network as opposed to joining a country-wide network.

As there is limited UK experience in heat networks, compared with gas and electricity networks, an international case study is presented.

5.2 Case Study – The Main District Heating Network in Copenhagen[4]

The development of district heating within Denmark has been influenced significantly by heat supply legislation, which aimed to 'promote the most socio-economical use of energy for supplying buildings with heat and hot water' whilst reducing the dependence on oil. Environmental considerations also have had increasing importance, and developers are encouraged to combine production of heat and electricity.

The main district heating network in Copenhagen uses heat from waste incineration plants, and combined heat and power plants, backed up by peak load plants (which run

[4]The Main District Heating Network in Copenhagen, Metropolitan Copenhagen Heating Transmission Company (CTR), http://freshaireva.us/wp-content/uploads/2012/04/Copenhagen-District-Heating.pdf

on oil and gas), to supply 275,000 households with heat in the form of hot water. The infrastructure of the network includes 54km of pipework, 26 heat exchanger stations and 3 booster pump stations, as well as centralised control, monitoring and regulation.

The system is divided into three areas – production, transmission and distribution. The transmission network is maintained at a temperature of about 90 - 115°C, and a pressure of about 16 – 24 bar. There is a main transmission ring, which allows the system to be fed by the most economic and efficient source available at any time, as well as providing robustness in supply, in the event of a rupture in the network. The network is also interconnected with another network within the greater Copenhagen area, which ensures further robustness, and allows balancing across a wider network.

The network consists of steel piping of 250 to 800mm in diameter. The significant majority of network pipes were buried on a bed of drained aggregate. The vast majority of the piping consists of pre-insulated pipes with plastic sheaths. Where the pipes were laid in wet conditions, or where the pipes run above ground, then steel sheathed pipes were used. Where the installation was complicated, typically because multiple pipes exist within the same route, pipes were installed within concrete channels. The pipe insulation incorporates moisture sensors that alert the control room if the insulation material is compromised. This is important, as this would cause damage to the pipe lines.

Other components, including heat exchangers, booster pumps, minor control, monitoring and regulation stations are often installed in the heat exchanger stations, which are usually underground, protected from the elements.

The Metropolitan Copenhagen Heating Transmission Company, 'Centralkommunernes transmissionsselskab I/S' (CTR) releases accounts annually. Table 3 below shows opex for the years 2012 and 2013. This data is then illustrated in Figure 9 below, which compares the levels of expenditure, and shows that the heating purchase costs are the overwhelming majority of ongoing costs.

	2012	**2013**	**2012**	**2013**
Heating purchases	1,946,520,000kr	2,087,763,000kr	£ 207,849,406	£ 222,931,333
Electricity for pumps	54,695,000kr	54,550,000kr	£ 5,840,332	£ 5,824,849
Depreciation	39,138,000kr	50,073,000kr	£ 4,179,156	£ 5,346,795
Preventive maintenance	33,949,000kr	35,307,000kr	£ 3,625,074	£ 3,770,081
Remedial maintenance	29,548,000kr	24,589,000kr	£ 3,155,135	£ 2,625,613
Storage & antenna rental	2,478,000kr	5,586,000kr	£ 264,601	£ 596,473

Operations	2,361,000kr	2,943,000kr	£ 252,108	£ 314,254
Staff costs	16,472,000kr	19,104,000kr	£ 1,758,880	£ 2,039,925
Third-party services	9,619,000kr	8,952,000kr	£ 1,027,117	£ 955,895
Sundry administrative costs	4,655,000kr	5,791,000kr	£ 497,061	£ 618,363
Loan interest	26,514,000kr	29,535,000kr	£ 2,831,165	£ 3,153,747
Other financial costs	1,592,000kr	281,000kr	£ 169,994	£ 30,005
Interest on liquid assets, etc.	2,578,000kr	970,000kr	£ 275,279	£ 103,577

Table 3: Expenditure of the Metropolitan Copenhagen Heating Transmission Company.

The data in Table 3 is taken from the Metropolitan Copenhagen Heating Transmission Company's 2013 Annual Report. [5]

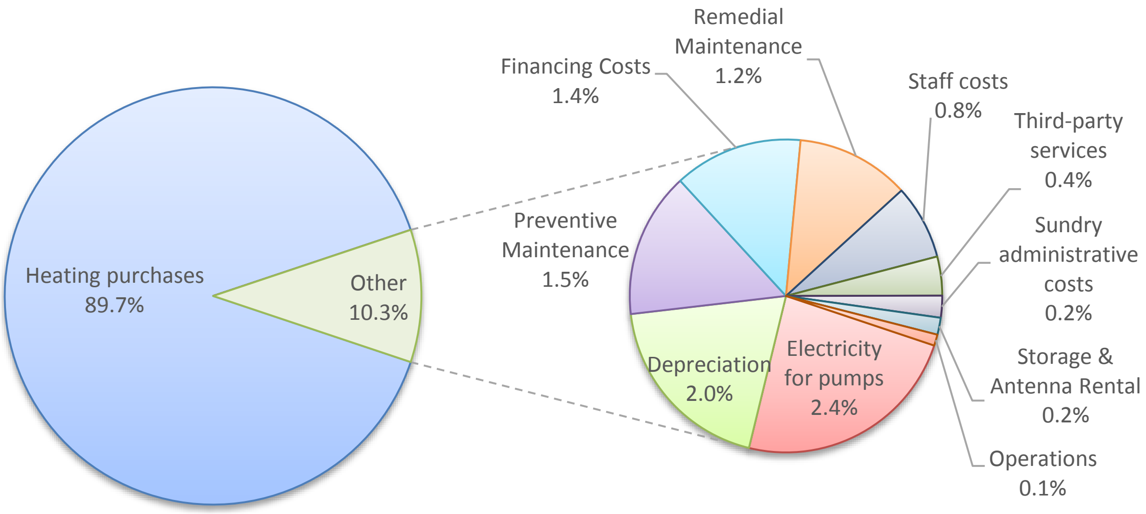

Figure 9: The average annual opex of the Metropolitan Copenhagen Heating Transmission Company over 2012 and 2013.

Again, the data for Figure 9 is taken from the 2013 Annual Report of the Metropolitan Copenhagen Heating Transmission Company.

[5] Financial Statements & Annual Report 2013, CTR Centralkommunernes Transmissionsselskab I/S, http://www.ctr.dk/Images/%C3%85rsberetninger/Aarsberetning%202013_%20Engelsk.pdf

The losses experienced in a heat network come in two forms; heat loss and water loss. The Table 4 below shows the water and heat loss data for the Metropolitan Copenhagen Heating Transmission Company for 2012 and 2013. The cost of heat loss has been calculated based on the average cost of the heat over these two years. This shows that heat loss is also a significant ongoing cost. Water loss will also incur costs, as water will have to be replaced within the system, which will require water treatment. Water leaking from the system may also cause damage to surrounding items and buildings. It is possible that the cost of replacing and repairing damage from accidental water leaks is covered in the 'remedial maintenance' component of opex, though this is not explicitly stated in the report. In this case, the costs are included in the Table 3 above, potentially within the operations or maintenance sections.

	2012	2013
Heat loss (tj)	127	82
Cost of heat loss (kr)	13,892,535kr	8,969,983kr
Cost of heat loss (£)	£ 1,483,445	£ 957,815
Water loss (m^3)	42,935	40,249

Table 4: Heat and water losses of the Metropolitan Copenhagen Heating Transmission Company.

The data in Table 4 is taken from the company's 2013 Annual Report. Costs are calculated based on the average cost of heat over 2012 and 2013.

5.3 Direct and Closely Associated Indirect Opex in Heat Networks

It is considered that the opex for heat networks will be similar to that of gas networks, as both are based on a network of pipes containing fluid to be moved around. However there are many differences, for example, whereas gas is compressed, hot water in heat networks is pumped. Heat networks also include heat exchangers where the heat energy is received by and delivered from the network.

While the UK gas and electricity networks are on a national scale, existing heat networks can vary from a single heat source feeding just a few loads, to a small network with multiple sources and many loads. The scale of the network has an impact on the relative proportion of the components of opex; as there are some costs that will not rise linearly with network scale. For example, even a small network will need an operations and control room team. However, a network may be able to grow up to a point without any significant impact on the staff and operations costs.

The case study of the Main District Heating Network in Copenhagen provides a benchmark for the opex costs within a heat network. It is noted that, as only costs that are directly attributable to the network are considered relevant for this project, depreciation, financing costs and third party and sundry administration costs are not considered here. Additionally, as explained previously, the cost of the heat supply itself will be excluded, as they are not specific network costs. The chart below shows all the remaining costs from the Copenhagen case study. From this, the major direct and closely associated indirect opex components that will be considered are:

- Electricity Costs for Pumps
- Preventative Maintenance
- Remedial Maintenance (interpreted as work to correct faults and issues)
- Staff Costs
- Heat Losses
- Water Losses (Unknown amount)

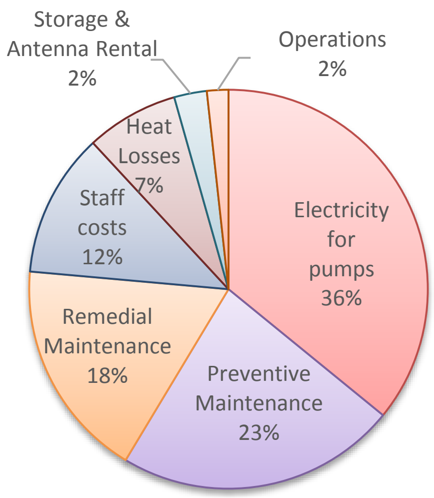

Figure 10: Average annual expenditure on the direct and closely associated indirect opex components of the Metropolitan Copenhagen Heating Transmission Company.

Again the information in Figure 10 is extracted from the 2013 Annual Report of the company.

5.4 Policy and Regulation Contributors to Heat Network Opex

Heat networks are not currently covered by any specific UK regulations, and there is therefore no formal customer protection other than the specific contractual agreements that they may have in place. It is likely that any contractual arrangements may include quality of supply terms, and compensation payments if these are not met.

It is likely that if heat networks are to become more widespread in the UK, there will need to be similar policy and regulation in place as there is for electricity and gas networks, including similar taxing arrangements.

One of the next steps identified in the DECC paper, “The Future of Heating: Meeting the challenge”, was to establish a Heat Networks Delivery Unit. The unit has been established to offer support to Local Authorities, in terms of financial support and expertise. The Heat Networks Delivery Unit (HNDU) was approached for an interview, but has not responded in time to contribute to this report.

5.5 Factors that Affect Heat Network Opex

There are several technical and environmental factors that are relevant to the significant components of the opex within a heat network that have been identified in the sections above. One way that these factors were identified was to explore, both through internal analysis and research, and with support from external experts, factors in certain areas, including:

- technical,
- location,
- condition, and
- external factors.

The mindmap below shows the factors that were identified as being relevant to heat network opex in each of the categories above.

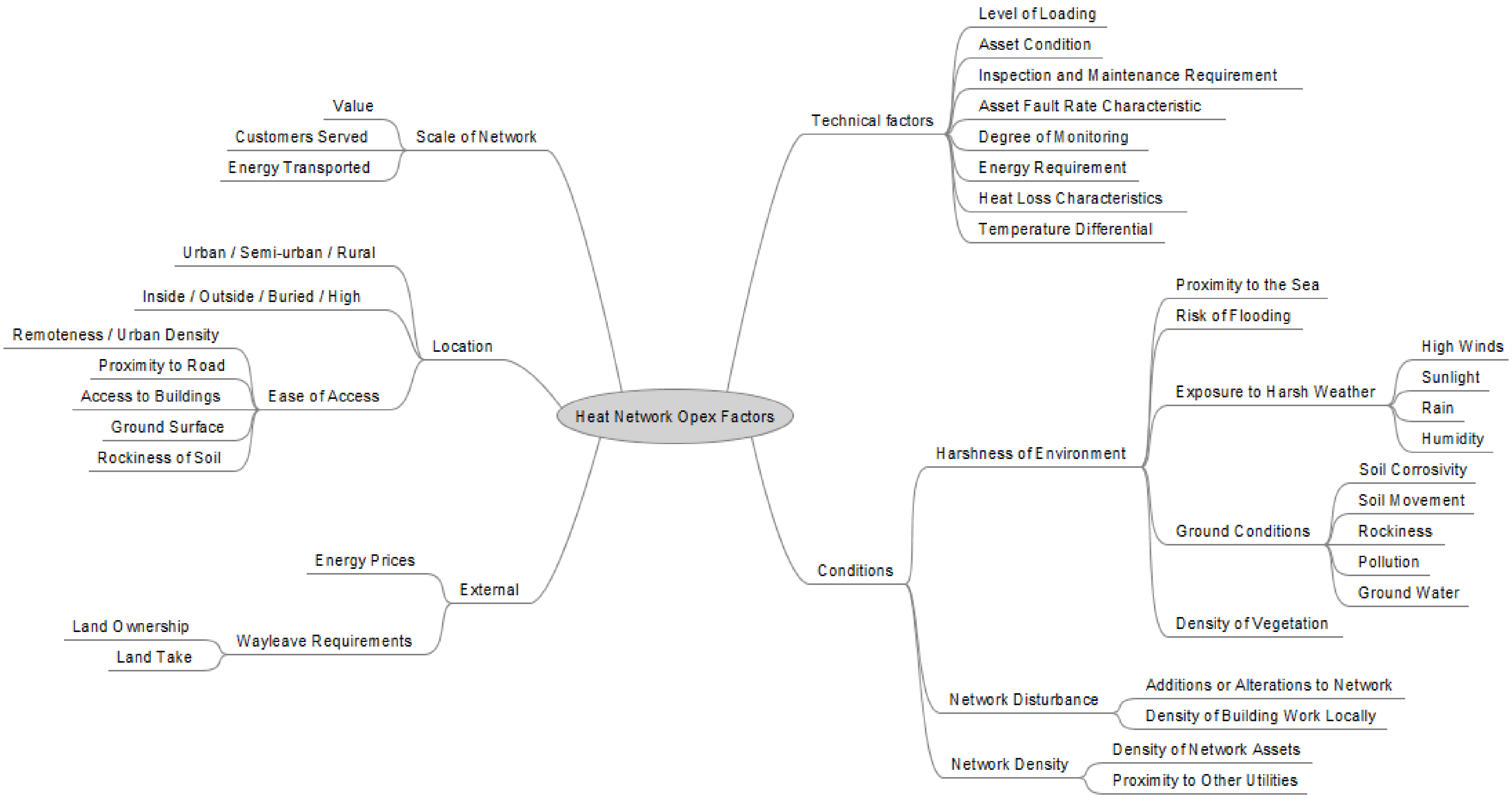

Figure 11: Mindmap showing the factors that affect the opex of heat networks

The factors identified in the mindmap above are explained in more detail in Table 5 below. This is similar to the factors that affect the other vectors, though there are some key heat specific issues:

- In contrast to the electricity network, the heat load profile is not considered to be a significant factor, because there is a certain amount of inherent thermal storage within the system, and the system temperature will not change instantaneously. The addition of distributed heat storage is also possible to improve the utilisation of capital assets such as pipes, though this would potentially add to opex costs and energy losses.

- As with the gas network, vegetation management is not a significant component of heat network opex, as there is no significant risk of fault due to contact with trees.

- There is an inherent energy requirement within assets such as pumps within heat networks, and the cost of this energy will need to be covered by the network company. This is likely to be a more significant component than with gas.

- Heat networks will have heat and water losses which will both need to be covered by the network companies. This makes factors such as heat loss characteristics and temperature differential more relevant.

Table 5: Factors that affect the opex of heat networks

FACTOR	COMMENT
Scale of the network	This factor refers to the scale of the parts of the network to be studied, in relation to the wider network. This is important as where an addition to a network is a more significant size compared to the network as a whole, then the increases in costs, for example staff and operations costs, will be much greater. Conversely, if the scale of an addition is relatively insignificant compared with that of the whole network, then additional support requirements are more likely to be able to be absorbed into existing systems and arrangements.
Level of loading	Where assets are more heavily loaded, they will age more quickly and would be more susceptible to increased faults.
Asset condition	Assets that are older, or in poor condition, may fail more often.
Inspection maintenance requirements	Different assets will have specific requirements for maintenance, and this may be significantly different from asset to asset.
Asset Fault Rate Characteristics	Assets themselves have their own characteristics regarding failures and faults, and these may vary significantly from asset to asset.
Degree of monitoring	Greater levels of monitoring will add to opex costs as the monitoring systems and underlying IT systems will need to be operated and maintained. However, there are many advantages of increased monitoring including the opportunity for improved network operation and asset management.
Energy requirement	The energy required by assets, for example pumps, will most likely be provided by electricity. The requirements will vary from asset to asset.

Heat loss characteristics	Assets may vary significantly in their heat loss characteristics, which may be due to material characteristics or insulation.
Temperature differential	The key driver for heat loss will be the difference in temperature between the hot water and the air or ground outside. Where this differential is higher, then greater losses are experienced.
Harshness of environment	Assets that are installed in certain environments, for example in close proximity to the sea, in areas with high humidity or prone to flooding, or areas exposed to high winds, may require increased maintenance. This includes harsher soil or ground conditions, such as corrosive or rocky soil, or areas with high soil movement or high levels of ground water. Areas that have high levels of vegetation may cause issues with root density and ground movement, as well as damage caused by fast growing plants and contact with trees.
Network disturbance	Where there has been many additions or alterations to a network configuration, weak points may be created in the networks which may be more prone to faults. Additions may result in changing the use of existing network assets away from the existing or original designed purpose, which may cause additional issues.
Network density	Where there are very dense networks, and high proximity to other utilities, the location of buried heat pipes can be more difficult, as multiple cables and other lines can be found within a single excavation. Proximity to other utilities may also increase the risk of other personnel making contact with the network pipes and causing damage. Again, this is more likely in urban areas.
Unban / semi-urban / rural	Remote rural areas may be difficult to get to, and the network may cross private land and not be accessible from the road. In urban networks, there are issues with road traffic and location of assets in a densely built up area. Costs may also be incurred associated with the New Roads and Street Works Act and the Traffic Management Act, including lane rental charges, and costs to perform work at only certain times to comply with restrictions.
Inside / outside / buried / high	Where assets are buried or installed up high, they become less easily accessible for maintenance. Assets that are outside are exposed to the weather, and this may result in additional faults, compared with those assets that are protected by being installed inside.
Ease of Access	Network assets may be situated in remote rural locations, or some distance from the nearest road. Alternatively, assets may be less accessible if they are installed in built up urban areas, or inside buildings being used by other purposes, such as the basements of offices or hospitals. Assets that are buried are less accessible, particularly if the ground surface is hard (such as a road or pavement), or the ground is rocky.
Energy prices	This will affect the costs associated with the energy that is consumed in assets such as compressors.
Wayleave / rental requirements	Where land for pipelines and equipment do not belong to the network company, a wayleave or land lease is required. From discussions with industry experts, it was clear that issues with wayleaves and land lease can become problematic, particularly where land owners wish to reclaim their land. In such a case, either an agreement is reached, which may be very expensive, or assets have to be relocated.

5.6 Factor Assessment

The factors that are identified within Section 5.5 affect the components of heat network opex in very different ways. This is summarised within the matrix below; where a darker blue signifies a more significant relationship between the factor and the opex component.

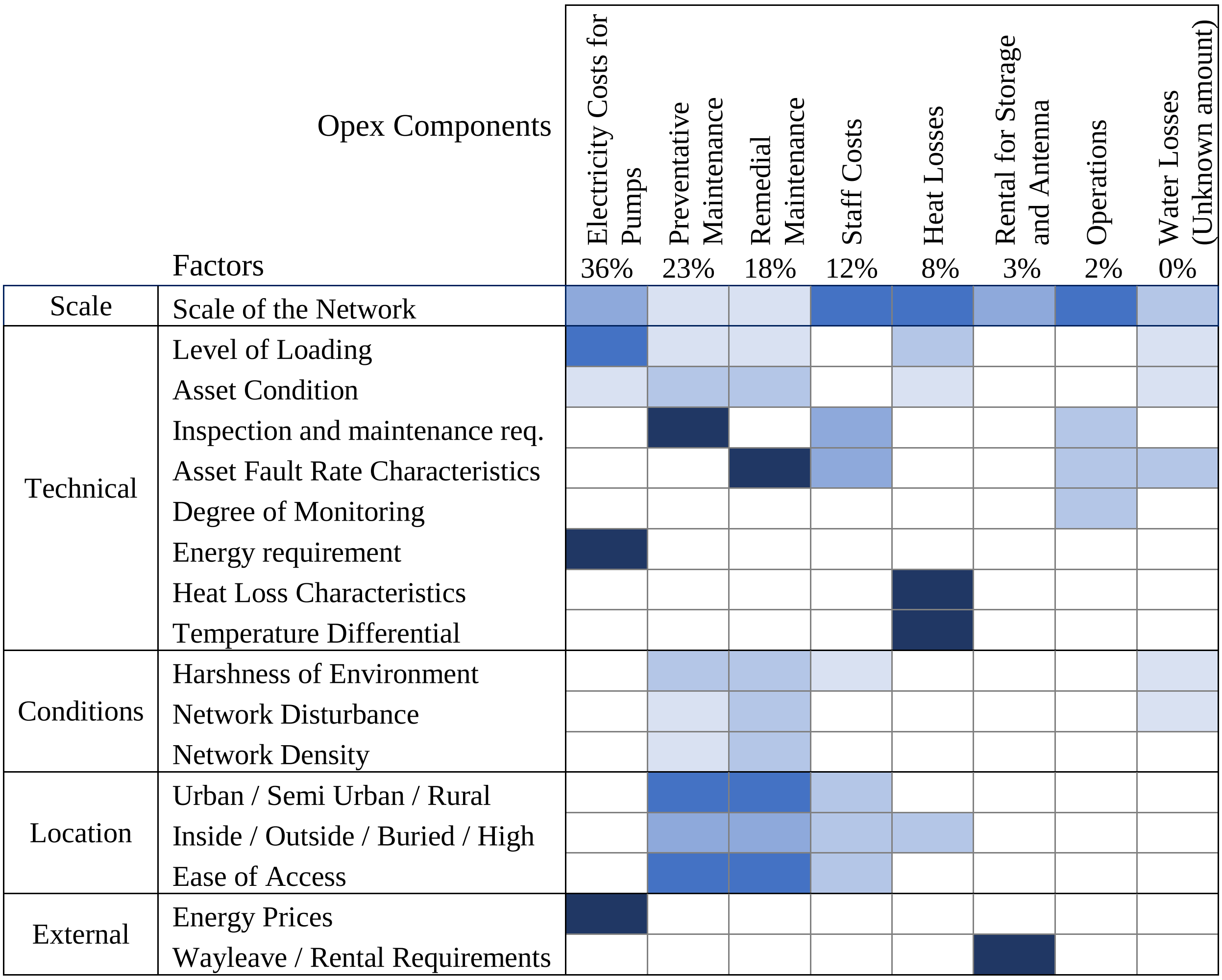

Figure 12: Matrix describing the relationship between the components of heat network opex and the opex factors.

The assessment of the opex factors shown in the matrix above have been completed using a mixture of research, best judgement, and advice from the expert contacts. This – as previously – is therefore not a definitive assessment, but is instead made to indicate the current thinking of the project team. As previously noted in Section 3.6, the opex of a network is likely to change throughout its lifetime, and the effect of these factors may also change over time.

The assessment of each relationship is discussed below.

5.6.1 Electricity costs for pumps

The electricity costs for pumps is a significant proportion of the network related opex of heat networks (about 35%). The factors that are related to this are:

- Asset energy requirements,
- Energy prices,
- Scale of the network (as larger networks will have greater pumping requirements),
- Level of loading (as heavily loaded networks will have greater pumping requirements), and
- Asset condition (as assets that are worn or in poor condition may be less efficient).

5.6.2 Preventative and Remedial Maintenance

As shown in Figure 12, a number of factors affect the costs to maintain the network including both preventative maintenance, and maintenance in reaction to events and faults). These are discussed below:

- The level of maintenance required on an asset is affected by:
    - Inspection and maintenance requirement,
    - Asset fault rate characteristic,
    - Level of loading,
    - Asset condition,
    - Harshness if environment,
    - Network Disturbance,
    - Network density,
    - Inside/outside/buried/high, and
    - Urban/semi-urban/rural.
- The cost of maintenance will depend on the ease of access to the asset, including the need to dig up roads and highways. The factors that are related here are:
    - Ease of access,

    - Inside/outside/buried/high, and
    - Urban/semi-urban/rural.

- These costs are also affected by the scale of the network, as, generally, the larger the network is, the higher the maintenance requirements will be.

5.6.3 Staff Costs

A significant component of the opex of a heat network is staff costs. It is considered likely that a larger network requires additional staff, and increased faults and issues on the network may increase the requirements to employ ad-hoc staff. The relevant factors are:

- Scale of the network,
- Inspection and maintenance requirement,
- Asset fault rate characteristics,
- Degree of monitoring,
- Ease of access,
- Inside/outside/buried/high, and
- Urban/semi-urban/rural.

5.6.4 Heat Losses

Though the costs associated with heat generation are not included in this analysis, the cost of heat losses within the network are. The factors that are relevant are:

- Scale of the network,
- Heat loss characteristics of the assets,
- Thermal differential between the external temperature and the hot water,
- Level of loading, as a more heavily loaded network is more likely to have higher heat losses,
- Asset condition (for example, if lagging and insulation is in poor condition, then heat losses will be higher), and

- Inside/outside/buried/high (as the asset situation may have significant effects on the heat loss, for example where pipes are buried, they may have very different heat loss characteristics compared to above ground networks).

5.6.5 Rental for Storage and Antenna

The factors relevant for this component are:

- Wayleave / rental requirements, which includes the land requirements and the ownership of that land, and

- Scale of the network.

5.6.6 Operations

The opex associated with operations will increase with the size and scale of the network, and may increase as faults and maintenance requirements increase. Therefore, the most relevant factors are:

- Scale of the network,

- Inspection and maintenance requirement,

- Asset fault rate characteristics, and

- Degree of monitoring (as increased monitoring may increase the capability of the operations team to, for example, enable advanced asset management regimes).

5.6.7 Water Losses

It is assumed that water loss will be as a result in leaks that are caused by assets failing or damage due to external personnel or factors (i.e. there is no inherent water leakage from the network, and therefore all leaks are a result of a fault). The cost of water losses includes the cost of the water itself, the loss of the associated heat energy, and also any associated water treatment necessary to maintain water quality within the system. The relevant factors are:

- Asset fault rate characteristic,

- Asset condition,

- Harshness of environment,

- Network density,

- Network disturbance, and

- Level of loading.

5.6.8 Identification of Key Factors

The factors that have been identified have very different effects on the overall opex of the network. The degree of their significance can be found through a combination of their effect on each individual component of opex, and the relative proportion that that component makes up of overall opex (in this case, these proportions are based on the Copenhagen case study). For example, heat loss characteristics of an asset have a significant effect on the cost of heat loss, but this is a relatively small component of opex. However, energy requirement has a significant effect on the cost of energy for pumping, which is the most significant component of direct opex.

Using this logic, certain factors are identified as the most significant factors for heat Network Related Opex. It is noted that the same factors that have been identified as significant for electricity and gas are recognised as being significant for heat networks. However, due to the relatively high proportion of opex associated with the electricity costs for pumping, the key opex factors for heat network include asset energy requirement and energy price.

1. Scale of the network
2. Level of loading
3. Ease of access
4. Urban / Semi-Urban / Rural
5. Energy requirement
6. Energy prices
7. Inside / Outside / Buried / High
8. Inspection and maintenance requirements
9. Asset fault rate characteristics

6 Areas of Uncertainty – Hydrogen Networks

6.1 Introduction

This section discusses the factors that impact Network Related Opex that are specific to hydrogen networks. For the purposes of this discussion, a hydrogen network is a network of pipes delivering pure hydrogen (as distinct from a hydrogen-natural gas mixture) to energy loads such as homes, industrial loads or refuelling stations for hydrogen powered transport. This vector is the least developed that is being addressed by this project, and so there is less direct experience to base conclusions upon.

6.2 UK Experience in Hydrogen Networks

This project has found no case study data of hydrogen energy networks (as opposed to hydrogen pipelines that are used to transport hydrogen for purposes other than energy, e.g. chemical processes) within the UK. It is recognised that some experience exists for transporting hydrogen for other purposes, for example, there is a large hydrogen plant which supplies Hudson's materials production facilities at Teesside[6]. This system consists of a large hydrogen plant supplying up to 32,000 tonnes of hydrogen per annum, alongside a supply of steam, through pipe lines to two industrial production facilities.

There are a number of additional areas of experience that can be drawn upon when developing this technology.

6.2.1 UK Research and Development

In the UK, the Technology Strategy Board (TSB) is supporting and planning to support a number of projects that develop the capability necessary to develop hydrogen networks, and has recently held a competition called 'Unlocking the Hydrogen Energy Market'. The projects that succeeded in gaining funding were announced in February 2014, and are as follows:[7]

- Quality control for the hydrogen supply chain
- Opening solid hydrogen storage markets through civil marine unmanned aerial system UAS

[6] Information from article 'BOC brings North Tees, UK hydrogen plant onstream', 4th February 2002, available at http://www.icis.com/resources/news/2002/02/04/156246/boc-brings-north-tees-uk-hydrogen-plant-onstream/

[7] Technology Strategy Board, Results of competition: Unlocking the Hydrogen Energy Market – Collaborative R&D, available from: https://www.innovateuk.org/documents/1524978/1866952/Unlocking+the+hydrogen+energy+market+-+Competition+results/93ed3207-4ffe-44b8-9c97-5ae845e9b747

- Innovation in services for off-grid hydrogen energy
- Hydrogen - Optimisation of Storage and Transfer (HOST)
- Continuous Monitoring system for fuel tank safety assurance on Hydrogen powered Vehicles (COMSAFE HV)

The 'London Hydrogen Network Expansion', part funded by the TSB, is a project that aims to develop a network of hydrogen fuelling stations for fuel cell powered vehicles in London. All of these are at the early stages, though their existence is evidence that the hydrogen energy industry may grow in the UK[8].

6.2.2 UK Town Gas

Before the widespread use of natural gas, the UK produced combustible gas from coal. Coal Gas, which was commonly known as Town Gas, is made up of approximately 50% hydrogen, as well as other combustible fuels such as methane and carbon monoxide, and a small amount of non-combustible gasses. The carbon monoxide component made Town Gas poisonous, which led to a number of accidental deaths.

There are some differences between the natural gas that is used in the UK today, and the Town Gas that was used before the 1970s:

- Town Gas has a calorific value of about half that of natural gas, meaning that much more gas was required to deliver the same amount of energy.
- Appliances that run on Town Gas use a burner jet that does not aerate the gas on delivery, whereas natural gas requires a specialised pre-mixing burner jet.

After natural gas was discovered in the North Sea in 1965, the British government encouraged the growth of its use across the country. This was due to the fact that natural gas is purer, with a higher calorific value, and could be sourced from within the UK with far less pre-processing than is required for Town Gas. Additional new transmission pipelines were installed to carry the natural gas across the country, but existing Town Gas distribution pipe lines were repurposed for carrying natural gas. Appliances were converted by the fitting of new burner jets to provide the correct mixture of gas and air. By 1987, there was no Town Gas production in the UK.

The fact that Town Gas has such a high proportion of hydrogen, and that the networks used for Town Gas were very similar to those currently in use to transport natural gas, suggests that any hydrogen network may be similar to the current UK gas network. The

[8] Information from Hydrogen London: http://www.hydrogenlondon.org/projects/london-hydrogen-network-expansion/

differences will be dictated by the physical and chemical differences between natural gas and hydrogen.

6.3 Hydrogen Networks – Comparison to Gas

As there is not statistically significant data available from operational hydrogen energy networks which can be used to gain direct insight into hydrogen network opex costs, a comparison to gas networks will be used. This is likely to be a relevant comparison, as in both cases, a combustible gas is being introduced into a network of pipes, which transports it to a load where it is extracted and used (often burned). The elements of the system are likely to be very similar; a network of pipes, including compressor stations and potentially storage of the gas.

The main potential differences between natural gas networks and a hydrogen network are likely to come about due to the physical differences between the gasses. Through discussions with the contributing experts, four major differences were discussed:

- Hydrogen has a significantly lower volumetric energy density, and therefore a higher volume needs to be delivered to meet a given energy load. This is likely to bring about increased pumping or compression requirements, or a proportionally higher capacity network.

- Hydrogen is a much smaller molecule than is present in natural gas, and therefore it is more prone to leaking through walls of pipes and storage. This may result in additional losses, though this could be mitigated by the development of specialist materials designed to prevent this. It is possible that any specialist material may have different maintenance requirements.

- Hydrogen is known to cause ‘embrittlement’, most importantly to high strength steels. This results in the metal becoming brittle and fracturing. Susceptible materials would need to be protected, or the maintenance requirements will increase.

- The safety considerations for hydrogen are different than with natural gas, and therefore any system would have to be designed carefully to ensure that it operates safely. The properties of hydrogen are well understood, and there is significant experience with its use within industry, with associated safety standards being established. However, the specific issues around the use of hydrogen as a consumer fuel to be used in homes and businesses is less understood. Issues such as understanding risks of hydrogen accumulating in confined areas and methods of detection will have to be considered. Odorants suitable for hydrogen would have to be developed, or else alternatives for detection would be needed. The detection of hydrogen flames would also have to be considered, as pure hydrogen flames are almost invisible.

6.4 Direct Opex and Closely Associated Indirect Costs in Hydrogen Networks

It is assumed that the major components of direct and closely associated indirect opex will remain similar to those of gas:

- Emergency costs: as the technology is first installed, it is likely that there will be a relatively high number of issues or perceived issues due to the lack of understanding. This may then settle down as learning is taken on.

- Inspection, Maintenance and Repair costs: these are likely to change as different materials will need to be used within the network.

- Leakage or Shrinkage: this is likely to include greater levels of leakage, though this might be mitigated by the use of specialist materials. It is likely that there will not be any 'own use hydrogen', and equipment such as compressors will be electricity driven.

- Asset Management: these are likely to be affected by the difference in material compared to natural gas networks. There may also be an increased need for monitoring while the technology is not as well understood, to ensure the system is being operated safely.

- Customer Management: while the technology is relatively unknown, customer management is likely to be increased.

- Operations and System Control: this, too, may be affected by the immaturity of the technology, as control room costs increase to ensure that the system is running safely and well.

- Activities such as the addition of odorant, compensation payments, and Easement/wayleave costs are as relevant with hydrogen networks as with natural gas networks.

6.5 Policy and Regulation Contributors to Hydrogen Network Opex

There is, of course, no current policy or legislation specifically regarding hydrogen energy networks as they are not yet established in the UK. If the UK government decides that hydrogen networks are to play a part in the future energy system within the UK, it is likely that policy will have to be developed. This would provide incentives and support to industry in the development of these technologies.

It is likely that if hydrogen networks are to become more widespread in the UK, it is likely that they will be covered by similar policy and regulation as there is for electricity and gas networks, including similar taxing arrangements.

6.6 Factors that Affect Hydrogen Network Opex

As discussed, it is not possible to gain understand the opex of a hydrogen energy network directly as there are no identified case studies with available data that could be analysed. In this report, gas networks are being used as a representative example. Therefore the factors that were assumed to be relevant for hydrogen network opex costs are very similar to those for modern gas networks.

6.7 Factor Assessment

Due to the differences in hydrogen and gas that are discussed in Section 6.3, it is considered that there are some differences in the proportions of each of the components of opex of hydrogen networks. Therefore, though the factors to be assessed are the same as those for gas, the assessment has been carried out separately. This is summarised within the matrix below; where a darker blue signifies a more significant relationship between the factor and the opex component.

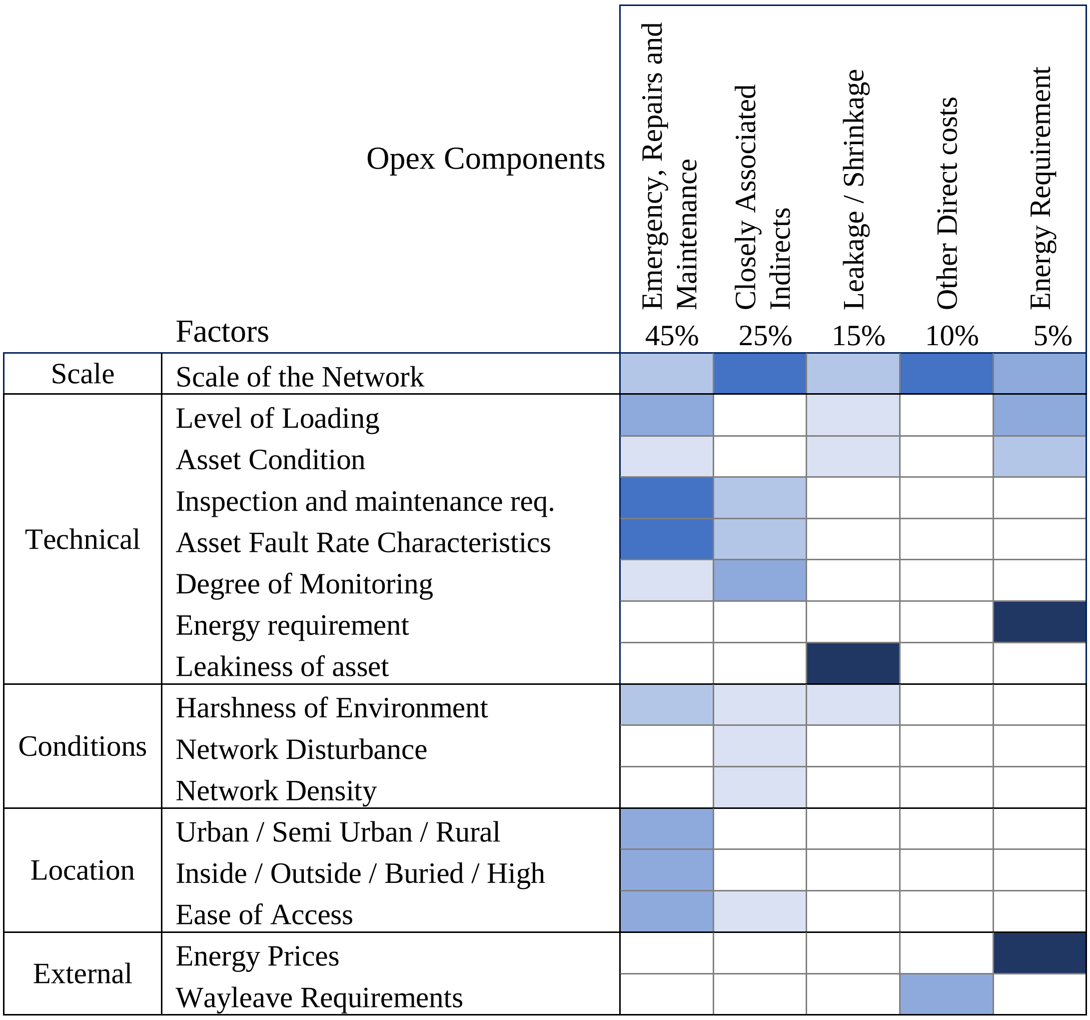

Figure 13: Matrix describing the relationship between the components of hydrogen network opex and the opex factors.

As with the factor assessments for electricity, gas and heat, the assessment of the hydrogen network opex factors shown in the matrix above reflect the current thinking of the project team, informed by research and input from external experts. This is therefore not a definitive assessment, and further work may include validation of this assessment by relevant experts. Again, it is also noted that the effect of the factors on opex may vary throughout the lifetime of the network, which is not explicitly included in this assessment.

6.7.1 Emergency, Repairs and Maintenance

According to the analysis in this project, responding to emergencies, repairs and network maintenance is the most significant proportion of the hydrogen network opex at 45% of total network related opex costs. The factors that are relevant are:

- Factors that increase the frequency of faults or the requirement for maintenance, including:
    - Inspection and maintenance requirement,
    - Asset fault rate characteristic,
    - Scale of the network,
    - Level of loading (as more heavily loaded equipment is expected to age more quickly and require a greater amount of repair),
    - Asset condition,
    - Degree of monitoring (for example, networks with more monitoring may require less frequent inspections, or may enable asset management regimes which make them less likely to fail), and
    - Harshness of environment.
- Factors that affect the cost of responding to faults, and of repairs and maintenance, including:
    - Ease of access,
    - Urban/semi-urban/rural, and
    - Inside/outside/buried/high.

6.7.2 Closely Associated Indirects

The closely associated indirect costs include activities such as asset management and monitoring, customer management, operations management and system control. The relevant factors to this component include:

- Many of the costs included in closely associated indirects are closely related to network scale.

- Increased fault rate is likely to increase the closely associated indirect costs, including the control room costs, customer management costs and the operations management costs. The factors that are most relevant for this are:

    - Asset fault rate, and

    - Harshness of environment.

- Operations management costs are related to the degree of work associated with inspection, maintenance and repairs, which is affected by the following factors:

    - Asset fault rate,

    - Inspection and maintenance requirement,

    - Degree of monitoring (for example, increased monitoring may decrease the requirement to inspect),

    - Ease of access, and

    - Harshness of environment.

6.7.3 Leakage / Shrinkage

As discussed above, the leakage of a hydrogen network is likely to be higher than that from a gas network. It will be related to the material properties of the assets themselves, as well as the fault rate (as faults may be a source of leaks). The relevant factors are:

- Leakiness of the asset,

- Scale of the network,

- Level of loading, and

- Harshness of environment.

6.7.4 Other Direct Costs

Other direct activities may include compensation payments, purchasing and maintaining tools and easement/wayleave costs. The relevant factors include:

- Scale of the network, and

- Wayleave requirements.

6.7.5 Energy Requirement

As discussed above, it is expected that the energy requirement of the network will be higher than that of an equivalent gas network, due to the lower energy density of hydrogen compared to natural gas. Therefore more gas will have to be transported to deliver the same amount of energy. The factors that are relevant for this component of opex are:

- Energy Requirement,
- Energy prices,
- Scale of the network,
- Level of loading, and
- Asset condition.

6.7.6 Identification of Key Factors

The factors that have been identified have very different effects on the overall opex of the network. The degree of their significance can be found through a combination of their effect on each individual component of opex, and the relative proportion that that component makes up of overall opex. In order to carry out this assessment, an assumption has been made about the proportions that each component contributes to the opex amount, which is based on the opex of gas networks, altered in accordance with research findings and discussions with experts.

Using this logic, the following factors are identified as the most significant factors for hydrogen networks. These are the same factors as those that have been identified for the gas network, which is due to the fact that the gas network opex was used as a basis for the hydrogen network analysis. However, there are differences in the relative significance of each factor, which has resulted in a slightly different order of factors when compared to the gas opex factors.

1. Scale of the network
2. Asset Fault Rate Characteristics
3. Inspection and Maintenance Requirement
4. Level of loading
5. Ease of Access
6. Urban / Semi-Urban / Rural
7. Inside / Outside / Buried / High

7 Areas of Flexibility

7.1 Sources of Flexibility

As well as identifying and discussing the areas of uncertainty in opex costs for energy networks, this project also aims to identify potential ways in which the networks may become more flexible and able to meet future challenges. This might include the ability to be operated in different, more optimised ways. In this project, these are referred to as sources of flexibility and are discussed below. Whilst the concept of multi-vector energy systems and the transfer between vectors is relevant to many of the areas of flexibility, this was removed from the scope of this project and so has not been explicitly dealt with here.

7.2 Electricity Networks – Sources of Flexibility

Many of the means of addressing future uncertainty in electricity networks form part of the "Smart Grid". There remains a continuing debate about the definition of the term but the Smart Grid Forum's vision for the smart grid is as follows:

"A smart electricity grid that develops to support an efficient, timely transition to a low carbon economy to help the UK meet its carbon reduction targets, ensure energy security and wider energy goals while minimising costs to consumers. In modernising our energy system, the smart grid will underpin flexible, efficient networks and create jobs, innovation and growth to 2020 and beyond. It will empower and incentivise consumers to manage their demand, adopt new technologies and minimise costs to their benefit and that of the electricity system as a whole."

This must be considered within the context of legacy assets, their condition and performance, as much of the network that is currently operational will continue to operate for decades into the future. This brings about significant questions, such as the real time asset and risk management, refurbishment and upgrading of existing assets for life extension high capacity.

Elements of the Smart Grid at the distribution level include:[9]

- The capability to handle two-way power flows,
- Smart meters,
- Demand side management,
- More automation and intelligence,

[9] IET briefing document; What is a Smart Grid

- Power electronics devices, and
- Local energy storage.

Developments at the transmission level are likely to include:

- Increased interconnection,
- Large scale energy storage (where technically feasible and economically viable),
- Use of DC connections (e.g. "bootstraps" in GB), and
- Time of Use Tariffs.

In general the capital costs of these items are understood, although subject to change in the future depending on levels of uptake and subsequent volume manufacturing, and reduced costs associated with learning and developing products. However, the benefits case and opex costs associated with elements of the Smart Grid are the subject of innovation project trials. For example, Ofgem's Low Carbon Network's Fund projects include:

- Smarter Network Storage, a project that aims to develop a commercial framework to understand and quantify benefits from distribution level storage through offering a variety of services, and
- Flexible Urban Networks – Low Voltage, which aims to trial power electronics devices at the low voltage distribution level, and understand more fully the business case for such devices, including the impact on opex. This is likely to be complex, as it will need to take account of increased opex costs (device maintenance, associated communications, devices losses) with potential reductions in opex costs (reduced network losses through improved utilisation and balance of network equipment).

There are many other examples of both Low Carbon Network Fund projects and those funded by other means that will be relevant to the evolution of Smart Grids.

The interaction between capex and opex is expected to change as Smart Grids develop. For example, where Smart Grid techniques such as condition monitoring and real time asset management are deployed, asset lifetimes could be extended thus reducing capex, but associated opex costs might increase, such as costs associated with communications systems, the need to train staff in new technologies, etc. In order to ensure that opex-capex trade-offs are captured in their assessments, Ofgem is utilising "totex" (total expenditure – both capital and opex) benchmarking and modelling in the RIIO price controls.

7.3 Gas Networks – Sources of flexibility

Similarly to electricity networks, gas networks require improved operational capability in order to deal with changing flow patterns. Flow patterns are expected to change as gas sources move from a small number of predictable sources (e.g. North Sea gas) to an increasing number of distributed gas sources, including LNG. One of the expert interviewers noted that the potential take up of fracking may add to this trend, introducing additional, geographically dispersed gas input points into the network (depending on the requirement for and location of gas treatment). This is likely to result in the need for increased direct monitoring in order to understand the gas flows within the network, and to manage the network effectively.

The impact that increased monitoring and network visibility has on the network opex is relatively complex. The opex costs of the monitoring systems themselves, including maintenance of equipment and the operation of associated IT systems, will add to the opex costs of the overall network. However, the increased visibility may enable network operators to develop more active operation or asset management techniques with the aim of increasing efficiency or decreasing issues and faults on the network. Remote monitoring may also enable a reduction of physical inspections.

Unlike electricity networks, storage is already a feature of gas networks, both in terms of physical storage connected to the network, and storage capabilities within the network, known as pipeline or line packing. However, the gas network is likely to be subject to greater fluctuations in load, particularly with the take up of intermittent renewable energy sources, as gas powered electricity generation will potentially be used to compensate for this intermittence. One of the key conclusions of a European Commission Expert Gas Group report was that: [10]

"*…smart gas grids cannot be developed in isolation but should be linked to future electricity smart grids and should facilitate smart energy utilisation, e.g. in cogeneration (CHP), heating and cooling*"

For example, the potential for gas networks to provide storage facilities to manage the electricity network is noted. Where the cost of electricity is dependent on time of use, line packing can also be used to store gas when the electricity costs are low and therefore compression is cheap, so that less energy is used when electricity costs are high.

There are other functionalities that may be required to deal with uncertainties and challenges in future gas networks, and associated tools required to facilitate these, including the following:

[10] EG4 report

- Flexible grids, e.g. through monitoring operations in real time and optimising pressure flows.

- Acceptance of non-conventional gasses, which may require additional gas quality monitoring, improved network analysis and capacity planning.

- Unconventional gas utilisation, including gas-fired heat pumps, micro CHP, natural gas vehicles and gas-fired cooling systems.

- Smarter grid operation, to maintain safety and continuity of supply in light of the future challenges.

Innovation incentives for gas networks in GB include Ofgem's Network Innovation Allowance (NIA) and Network Innovation Competition (NIC). National Grid Gas Transmission has an extensive portfolio of NIA projects, covering a wide range of areas including gas demand forecasting tools, mitigating pipe work vibrations, and investigating flow physics in the gas pipe network.

As with electricity networks, the impact of more innovative technologies on opex-capex interactions in gas networks are not likely to be well understood at present, due to the early stages of development.

7.4 Heat Networks – Sources of Flexibility

Compared to gas and electricity networks, there are relatively few heat networks in the UK; heat networks currently supply around 2% of domestic, public sector and commercial heat demand in the UK.[11] There is uncertainty over how many more heat networks will be deployed, due to significant external factors such as expected planning and coordination challenges associated with large scale infrastructure projects, and the uptake of small-scale heat pumps. However, there are policies and incentives, such as the Renewable Heat Incentive, which may encourage take-up of heat networks, and the UK Renewable Roadmap Update 2012, which is produced by the Department of Energy and Climate Change (DECC) states that:[12]

"Over time, heat for buildings is likely to move away from gas to a mix of building-level heat technologies such as heat pumps and, particularly in our cities, low carbon heat delivered through heat networks."

Increased take-up is likely to result in innovations within the sector, which may lead to some of the barriers and challenges being addressed.

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[11] DECC; The Future of Heating: Meeting Heat Demand; March 2013

[12] UK Renewable Energy Roadmap Update 2012, Department of Energy and Climate Change, 27 December 2012

Although not widely deployed in the UK, heat networks have a higher penetration in other countries, and could be considered a mature technology (in terms of the pipe products). However, it is considered that there is still potential for cost reductions in a number of areas, including areas that might impact opex:[13]

- Optimisation of operating temperatures and pressures to minimise losses, and
- Other operation and maintenance improvements, primarily through "learning by doing".

Heat networks can be made more economic by the use of heat storage, which can help to balance heat supply and demand, and help to manage peaks on the network. Innovation projects are being undertaken that explore this concept of electricity to water storage, such as Northern Isles New Energy Solutions (NINES), supported by Ofgem.

There is scope for innovation in some forms of heat storage; while water heat storage is well understood, there is considered to be significant potential for innovation in "advanced" forms of heat storage, such as those making use of phase changing materials and chemical reactions. In terms of multi-energy vectors, heat storage also has potential to support other energy networks, such as electricity.

As with other energy networks, there is considered to be potential scope for the use of smart metering in heat networks. It is noted that, should heat networks develop, they will not have the "legacy" issues that electricity and gas networks have, and that "smart" functionality can be built into the networks as they are designed and installed.

7.5 Hydrogen Networks – Sources of Flexibility

As hydrogen energy networks are not yet in general use, and their future is very uncertain, it is not possible to assess potential areas of flexibility in detail.

Within this report, it is assumed that a hydrogen network is a network of pipes delivering pure hydrogen (as distinct from a hydrogen-natural gas mixture) to energy loads. However, there are a number of other potential routes for hydrogen networks.

7.5.1 Hydrogen for Transport

Hydrogen can be used as a fuel for vehicles such as cars and busses, either directly through use in an internal combustion engine, or through a hydrogen fuel cell to produce the electricity to power electric motors. There are examples of hydrogen energy

[13] Low Carbon Innovation Group; Technology Innovation Needs Assessment (TINA): Heat Summary Report; September 2012

systems being developed to allow this, including the Clean Energy Partnership in Germany and the Japan Hydrogen and Fuel Cell Demonstration Project (JHFC).

In both of these cases, hydrogen is produced (either through electrolysis or from reforming natural gas or other sources), stored, and then used to fill vehicles in refilling stations. If the gas is not produced onsite, then it is usually transported via tankers.

The Clean Energy Partnership, Germany

The Clean Energy Partnership is a project that aims to demonstrate hydrogen energy for emission-free mobility, based in Germany. This project is currently in the third phase, and has so far involved[14]:

- Phase 1 (2002 to 2008): Testing of a variety of hydrogen technologies and applications, including onsite and centralised production (both using hydrolysis of water, and the reforming of natural gas or LPG), the storage and delivery of hydrogen filling stations, and the use of it within fuel cell powered vehicles as well as internal combustion engines. The first hydrogen filling station was opened in 2004.

- Phase 2 (2008 to 2010): Developing the required technologies, and proving that they are capable of becoming more widespread. This phase included the installation of improved refuelling stations.

- Phase 3 (2011 to 2016): Focuses on the widespread operation and use of the technologies in order to gather learning with which to improve the system.

This project seems to be focussed on production, storage and refuelling, and uses tanker vehicles to transport hydrogen from place to place. Whilst this is very distinct from the idea of using networks of pipes to deliver hydrogen to homes, such a project will produce significant learnings that would certainly support the development of hydrogen networks.

Japan Hydrogen and Fuel Cell Demonstration Project (JHFC), Japan[15]

The JHFC was a research and development project that aimed to study and demonstrate a hydrogen fuel cell system, including both the vehicles themselves and the infrastructure around it. It ran from 2002 to 2012, and consisted of two parts:

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[14] Clean Energy Partnership, http://www.cleanenergypartnership.de/en/project-phases/

[15] http://www.jari.or.jp/portals/0/jhfc/e/jhfc/index.html

- JHFC 1 (2002 to 2005): studied the 'well to wheel' process of a fuel cell system, including original energy source, production of hydrogen, transport, fuelling and driving the vehicles.

- JHFC 2 (2006 to 2010): further demonstration collected data and learnings in order to establish suitability of technologies, verify predicted performance and benefits, and to develop regulations, codes and standards.

Since this project, further stations have been planned to extend the hydrogen industry in Japan, with the support of the Japanese government.

7.5.2 Conversion of UK Gas Network to Deliver Hydrogen[16]

One possibility to establish a hydrogen network in the UK would be to convert the existing gas network. This would result in the decarbonisation of a significant energy system in a relatively short time. However, the conversion would require a significant amount of work and planning.

- All gas appliances and metering would have to be converted or changed, and hydrogen specific technologies may need developing if there is not suitable equipment in the market.

- It is possible that the gas transmission network would need replacing, as the process of embrittlement is more severe at higher pressures, and the current transmission network is generally made up of high strength steel which is susceptible to this effect.

- Pre-1970s gas distribution network is also made from materials that are susceptible to embrittlement, but the reduced pressures may be sufficient to prevent the need to replace these immediately. Modern polyethylene pipes are not susceptible, though are more porous and will experience increased losses, though this is not expected to be a significant proportion of the transported gas.

- There could potentially be significant issues with increased leakage, for example existing joints between pipework may be a source of leaks, even if they have been proven suitable for natural gas. Leaks could lead to the build-up of hydrogen in existing ducts and pits, which may cause a safety concern, as well as causing knock-on issues with the other utilities that share the network routes.

- Flow rates are likely to be higher after a conversion to hydrogen, to counteract the lower volumetric energy density. It is likely that this would result in significant extra strain on compressors and decompressors.

[16] Dodds PE, Demoullin S, Conversion of the UK gas system to transport hydrogen, International Journal of Hydrogen Energy (2013), http://dx.doi.org/10.1016/j.ijhydene.2013.03.070

Even at the much higher flow rate, the energy carrying capacity of the network would probably still be significantly less than that of the current natural gas network; perhaps 20 to 30% less. Additionally, the line packing capacity, where gas is stored in the pipeline and used to supply short term fluctuating demand, of the hydrogen network will be significantly lower than that of the natural gas network.

With consideration of these issues, conversion of the gas network is considered possible, however this would be a significant undertaking. Conversion of the UK supply from Town Gas to natural gas (discussed in Section 6.2.2) took about 10 years, and gas networks now are significantly more interconnected and cover a much larger number of loads. It is, however, noted that when compared with the development of a national scale purpose built hydrogen system, the effort involved in converting the natural gas network may be significantly smaller.

Another possibility for establishing a hydrogen industry would be to inject and mix hydrogen into the existing gas network, therefore resulting in a mix of natural gas and hydrogen[17]. It is thought that this is possible in very small quantities without making any significant changes to the network as it stands. It may be possible to transport higher proportions of hydrogen via the existing gas network, and then use membrane filters to extract it again at the point of use. This would allow the gas being delivered to existing gas loads to be suitable for use in existing appliances and equipment.

Issues such as leakage, embrittlement and lower volumetric energy density will increase with the concentration of hydrogen, and safety issues will have to be considered as well.

[17] Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues, M. W. Melaina, O. Antonia, and M. Penev, National Renewable Energy Laboratory, March 2013, http://www.nrel.gov/docs/fy13osti/51995.pdf

8 Modelling Opex Costs

This section refers to the 2050 Infrastructure Tool, and discusses potential areas that could be developed in order to improve the opex modelling features.

8.1 Review of 2050 Infrastructure Tool

In the 2050 Infrastructure Tool, capex of a network is calculated through a bottom-up approach. The method is to set a baseline cost for each component, and then the expected cost trends are set by selecting from a predefined list including 'high increase,', 'low increase' and 'flat line', or trends can be user defined. There is also the capability to add a technology cost curve, which allows for the maturity of the technology to be installed.

To establish how the cost is affected by a variety of site, component or trend conditions, certain Rate Modifiers are set for each component. These describe how the cost of a component will vary compared to the baseline costs under certain conditions. The conditions included are:

- Site context: Urban (greater than 60 dwellings per hectare), semi-urban (between 30 and 60 dwellings per hectare), or rural (less than 30 dwellings per hectare) locality.

- Capacity: A scale is set for low, baseline and high capacity, and then modifiers placed against each of these. Note that few components use this functionality as it is often preferred to simply add an additional component with its own set of details for each capacity level.

- Scale: For some components, if a large number (or long length) is being installed, then the cost per unit may be reduced due to the economies of scale. Again, the scale of a small, baseline and large installation is set, and then rate modifiers are assigned to each of these.

- Ground conditions: it is clear than only some components will be affected by ground conditions, for example those that are buried. Rate modifiers are set for high, mid and low levels of rockiness; ground contamination and ground water.

For example, if a component's Rate Modifier is 90% for rural locations, this implies that the capex of the component is only 90% of the full base cost when installed in a rural location (perhaps due to decreased traffic disruption costs during installation, or the reduced likelihood that the ground will be covered with a hard surface such as road or pavement). Where a component is not affected by a condition, then the rate modifier can be set at 100%.

The Figure 14 below shows an example of the details of a component.

Cost Build-Up	Baseline cost	Upper limit	Baseline cost	Lower limit
Material costs / Nr	£ 1,030.00	110%	100%	90%
Labour costs / Nr	£ 800.00	110%	100%	90%
Plant costs / Nr	£ 170.00	105%	100%	95%
Cost per / Nr	£ 2,000.00			

Cost Trends	Future cost trend
Material costs	Flat Price
Labour costs	Flat Price
Plant costs	Flat Price
Technology Cost Curve	Flat

Context	Impact of context on the baseline cost	Rural	Semi-urban	Urban
		100%	115%	130%
Capacity	Capacity unit	Low capacity	Baseline	High capacity
	kVA	20	20	20
	Impact of the line capacity on the baseline cost	Low capacity	Baseline	High capacity
		100%	100%	100%
Scale	Unit of installation scale	Small scale limit	Baseline scale	Large scale limit
	nr	1	1	50
	Impact of the scale of installation on the	Small scale	Baseline scale	Large scale
		100%	100%	95%
Ground conditions	Impact of ground conditions on the baseline cost	Ground is soft and clean. No rock or hard material	Intermittent rock / hard material (20% by volume)	Prolific rock / hard material (75% by volume)
		100%	110%	120%
		Ground is clean and inert	Ground is mildly contaminated	Ground is heavily
		100%	120%	130%
		Little or no ground water	Intermittent dewatering required	Continuous dewatering required
		100%	105%	110%

Figure 14: An example of details of a component enered into the 2050 Infrastructure Tool .

Once the components are defined, then they can be grouped into assemblies, and assemblies are then used to make up projects. Site, component and rate parameters are set at either the assembly or project set up, and the tool uses the component Rate Modifiers in order to establish the relevant modified capex for each component, and the entire project. This is illustrated in the diagram below.

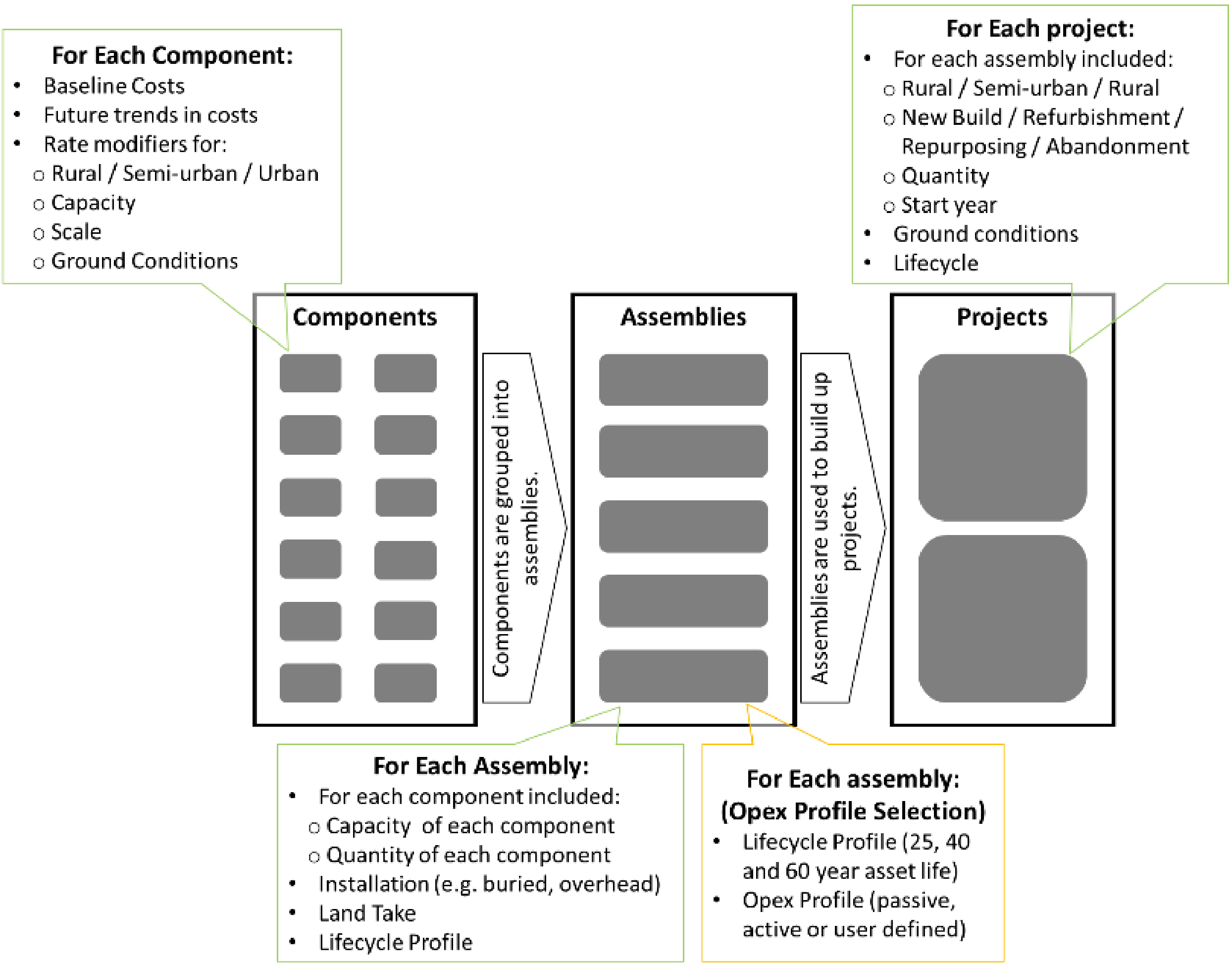

Figure 15: The structure of the 2050 Infrastructure Tool, and the inputs that are used to determine the capex and opex of the projects.

The method for calculating opex implemented within the 2050 Infrastructure Tool is significantly simpler than the approach for capex is, as it was considered that the data is not available to use the same bottom-up approach. The tool uses a set of pre-defined curves to determine the Opex throughout project life. Though the curves can be user-defined, by default the selection of the curves is dependant only on whether the component assemblies are considered to be ‘active’ or ‘passive’, and on the asset lifetime, which are defined at the assembly level. Additionally, there seems to be functionality to implement regional variations in opex although this is not currently in use. The curves used as the default opex profiles within the tool are shown in the Figure 16 below:

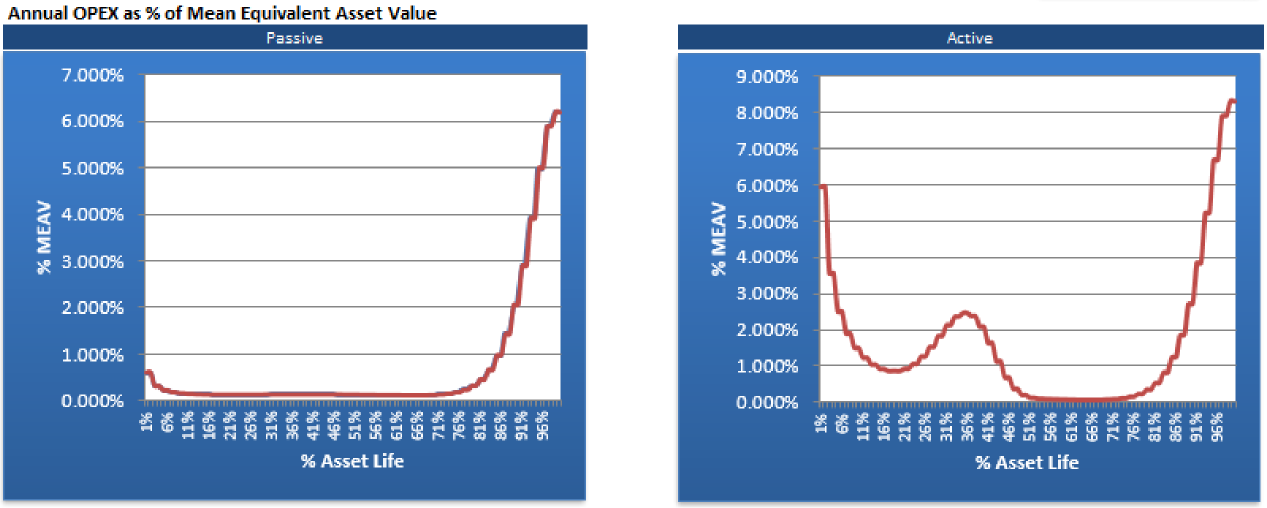

Figure 16: The opex profiles used as default within the 2050 Infrastructure Tool.

8.2 Options for Developing Opex Modelling

Within this report, the opex of energy systems is discussed, and this has resulted in the identification of the major factors that impact on these costs. This is a mixture of asset characteristics, location, conditions and external factors, and they vary between vectors. The factors that are considered significant at this stage, in order of importance, are:

Electricity networks	Gas networks	Heat networks	Hydrogen networks
1. Scale of the network 2. Ease of access 3. Inspection and maintenance requirements 4. Asset fault rate characteristics 5. Inside / outside / buried / high 6. Urban / semi-urban / rural 7. Level of loading	1. Scale of the network 2. Ease of access 3. Asset fault rate characteristics 4. Level of loading 5. Inspection and Maintenance Requirement 6. Urban / semi-urban / rural 7. Inside / outside / buried / high	1. Scale of the network 2. Level of loading 3. Ease of access 4. Urban / Semi-Urban / Rural 5. Energy requirement 6. Energy prices 7. Inside / Outside / Buried / High 8. Inspection and maintenance requirements 9. Asset fault rate characteristics	1. Scale of the network 2. Asset fault rate characteristics 3. Inspection and maintenance requirement 4. Level of loading 5. Ease of Access 6. Urban / semi-Urban / rural 7. Inside / outside / buried / high

Table 6: Significant that affect the Network Related Opex of energy networks, in order of importance.

It can be seen that most of the factors are considered relevant for all four energy vectors. However, there are an additional two factors that have been identified as significant to heat networks. This is because the network energy requirement is a more significant component of network related opex for a heat network, when compared with the other vectors. This means that the energy requirement of the network, and the energy prices, are both significant factors.

Though these factors have been identified and discussed in this report, there is little data currently available to effectively assess their true impact on opex throughout the asset lifecycle. It would be possible to explore the potential for further work in order to quantify the impact of these factors on network opex.

In addition to these factors, it is noted that the whole life opex cost of a network will be affected by the general market trends, for example, in the cost of labour and materials. This information is already captured by the 2050 Infrastructure Tool, and could be applied to the lifetime opex profile. In order to do this, it will be necessary to categorise the opex costs in terms of source, as opposed to activity as it is discussed in this report. As mentioned in Section 2, this data is not readily available in the public domain.

The impact of the opex factors could be included into the 2050 Infrastructure Tool in a number of ways, though it seems sensible to select a method that is in line with the current structure of the tool (discussed in Section 8.1).

A number of potential options are discussed below, in order of increasing complexity.

8.2.1 Use Existing Inputs to Revise Existing Opex Profiles

It is noted that some of the factors that impact on network opex are already captured within the 2050 Infrastructure Tool, namely situation (urban / semi-urban / rural), and to some extent, environment (as it is captured if an asset is buried, overhead etc.). The simplest option to develop the opex calculations within the tool would be to utilise this information. In this case, the existing opex profiles could be revised according to the information that the user inputs. The exact nature of the effect that each factor has would be the subject of further work as previously mentioned above. This could take the form of a flat percentage increase or decrease, or a more complex shape of effects over the lifetime opex profile of the network.

This option has the advantage of requiring minimal change to the tool, and having no additional user inputs on setup of a component, assembly or project. However, there are very few of the identified factors that are currently being captured in the tool, and these are not always the most significant factors. Therefore this is not seen as the most appropriate option.

8.2.2 Add Inputs for All Significant Opex Factors

An alternative option would be to capture all of the most significant factors listed in Table 6, and then these values could be used to determine a whole life opex profile, perhaps based on the existing profiles for active and passive assets.

There are a number of ways that the additional inputs might be included into the tool. For example, the factors can be divided into two categories;

- asset-based factors, which depend on the characteristics of the components themselves, such as the fault rate characteristics of assets and the inspection and maintenance requirements, and

- project based factors; which are those that will apply at a project level, such as location and conditions factors, and include external factors such as the cost of energy.

In each case, it seems inappropriate to ask the user for exact data such as, for example, an exact figure for network loading, as the user is not likely to have that information available to them, and this seems beyond the accuracy of the tool. Therefore, a more qualitative assessment could be asked for. Table 7 below organises the factors into the categories of asset based, project based and external factors, and suggests qualitative user input options for each factor.

	FACTOR	EXAMPLE USER INPUTS
ASSET BASED	Asset Fault Rate Characteristics	High / Medium / Low
	Inside / Outside / Buried / High	Inside / Outside / Buried / High
	Energy Requirement	High / Medium / Low
	Inspection and Maintenance Requirement	High / Medium / Low
PROJECT BASED	Urban / Semi-urban / Rural	Urban / Semi-urban / Rural
	Level of Loading	Heavily Loaded / Moderately Loaded / Lightly Loaded
	Ease of Access	Easily Accessible / Moderately Accessible / Access is Difficult
	Scale of the Network	Capex value, geographical size etc.
	Energy Price	Select a Profile

Table 7: Significant factors that affect the Network Related Opex of energy networks, categorised by asset or project.

The asset based factors may be included at either the component or assembly stage, as the assemblies that are included in the tool are limited to small assemblies with a specific purpose, such as substations and pipelines. The project based components may be set at project level, and therefore apply to all assemblies and components within a project. This is illustrated in Figure 17 below.

Again, the existing opex profiles could be revised according to the information that the user inputs about each factor. Asset factors would be dealt with by calculating a compound effect from the different individual impacts of the separate asset settings.

These revisions could be as simple as a percentage increase, or a more complex shape of effects over the opex profile of the network. Again, the exact nature of the effect that each factor has would be the subject of further work.

This option has the advantage of including all of the significant factors identified within this report, therefore creating an opex profile which is relevant to the project characteristics. It will result in a more complex tool, and additional inputs from the user.

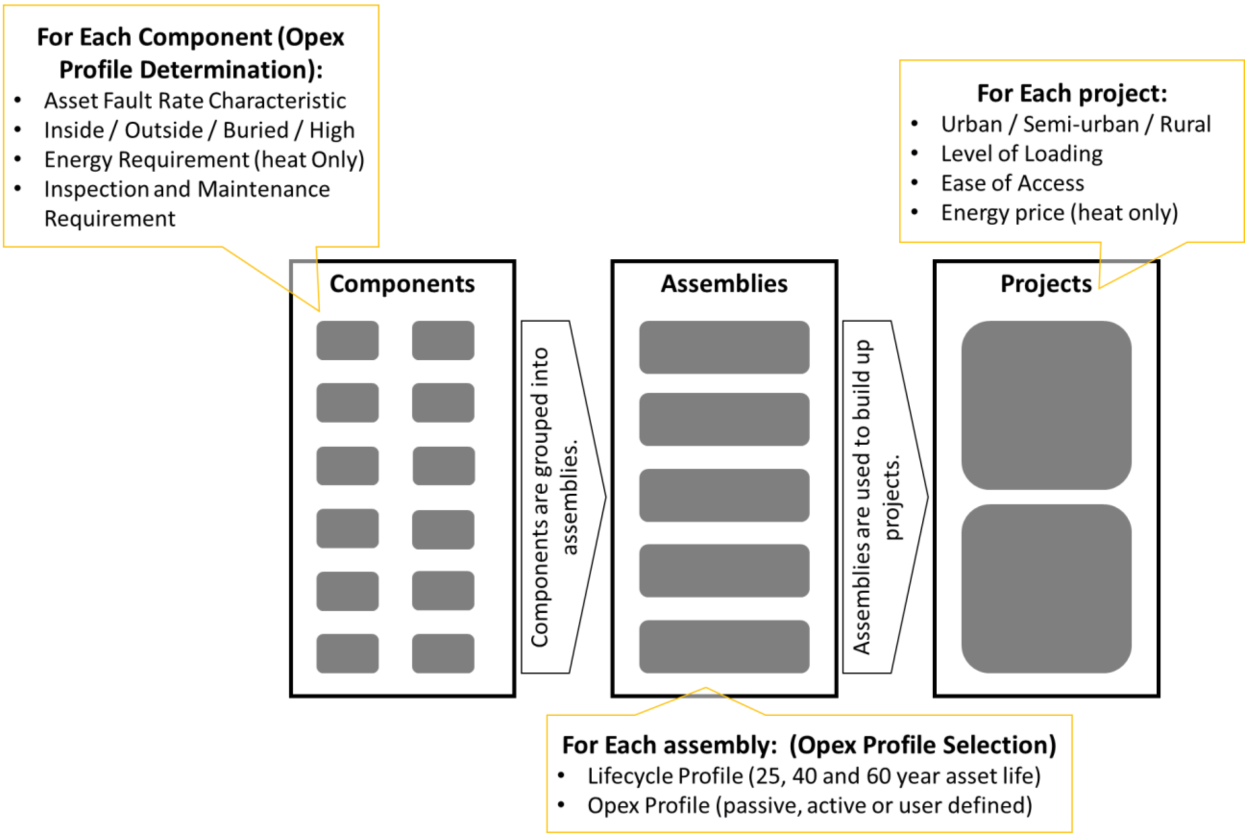

Figure 17: The potential structure of the 2050 Infrastructure Tool, encorporating the factrs that have been identified as significantly imacting on network opex.

8.2.3 Implement Rate Modifiers for Opex Factors

As discussed in Section 8.1, the 2050 Infrastructure Tool uses a bottom-up approach in calculating project capex, including the setting of rate modifiers. This allows the effect of the project characteristics to be set and controlled in relative detail by the user. It may be possible to use a similar format for some or all of the significant opex factors.

This is perhaps easiest to envisage when it comes to the project based factors; for example loading. The effect of heavily or lightly loading of an asset could be described using rate modifiers, and these would be used to determine the shape of the opex curve using the project network loading input set at project level. Rate modifiers could also be set for asset based factors at asset level, using a single user input modifier relevant to the asset characteristic.

It may also be possible to allow the tool to take into account the effects of changing the factors over the lifetime of a network. For example, it is possible that in general a heavily loaded network will have a higher fault rate compared to a lightly loaded one, but it is also possible that that effect changes within the lifetime of a network; heavily loading a new asset may have little effect on fault rate, but if the asset is aged and worn then heavily loading it may have a significant effect on it. Factors such as loading may also affect the lifetime of a network. One possibility would be to allow users to select the shape of the effect on opex of each factor, though this adds significantly to the complexity of the tool.

The main difference that this option has is that the effect of the opex factors can be tailored and controlled by the user. This is an advantage as the tool becomes more flexible to information as it becomes available. However, the user may not have the information and knowledge required to make these assessments manually. Therefore it is recommended that if this option is implemented, then there should be default settings that provide a sensible starting point.

This option would result in significantly increasing the complexity of the opex evaluation within the tool. It could be considered whether the advantages of this option justifies this increased complexity.

8.2.4 Recommendations for Developing Opex Modelling

Section 8.2 above discusses three options to develop the opex evaluations in the 2050 Infrastructure Tool:

1. Use the existing inputs to the tool to revise the existing opex profiles
2. Add new inputs for each of the significant opex factors in order to revise the existing opex profiles
3. Implement Rate Modifiers for the significant opex factors, which can be used to revise the existing opex profiles

It is the view of the project team that the second option, adding new inputs for each of the significant opex factors, is the most appropriate at this time. This is because this seems to bring the most benefits from the inclusion all of the significant factors identified within this report, therefore creating an opex profile which is relevant to the project characteristics. It is considered that the third option, which effectively implements the ‘rate modifiers’ method currently used for calculating capex, adds a significant amount of complexity and the required data may not be available. However, it is recommended that these and any other options are explored further in order to make an informed assessment.

8.3 Future Evolution of the Tool

As discussed in section 7, there is a great deal of uncertainty for all four of the energy vectors into the future. There are several aspects of the sources of flexibility that should be considered for the modelling of network opex:

- The increase in monitoring and control (for example 'smart grid' electricity networks)

- Innovation and technology development

- Revolutionary industry changes (such as new technologies, new legislation or a change in the structure of the industry)

8.3.1 Increased Monitoring and Control

The trend towards greater amounts of monitoring, control and network visualisation is one that is mirrored across electricity and gas, and as other energy vectors are developed, it is reasonable to assume that they will be designed to reflect the cutting edge attitudes within the existing vectors, where there is a business case to do so. This has implications on the opex of energy networks, as the monitoring and underlying IT systems will contribute towards these costs. In addition, increased visualisation could bring about new practises in asset management and network operations, which could have significant impacts for opex, though the exact effects in terms of either reducing or increasing opex are not yet fully understood. As such capability can be used in a variety of ways, and can significantly influence the opex/capex trade-off, the actual effect of increased monitoring, visualisation and control is likely to be affected significantly by the motivations of the network companies themselves.

It is also probable that the monitoring and other aspects of a network will be upgraded and altered during its lifetime. This is because the lifetime of a network may span several decades, and it becomes necessary to retrofit or alter networks in order to bring them in line with new processes and systems.

In order to include these aspects within an opex model, the options discussed in section 8.3 could be extended to include an additional factor, which would describe the 'smartness' of the network being studied, including the level of monitoring, visualisation and control on the network. This would include the upgrade of 'smartness' within the lifetime of the network. The user input for this factor would be set at the project level, and would be used to influence the shape of the opex profile over the lifetime of the network. However, as discussed, determining the nature of this affect is not straight forward, and would require further work. This may need to be refined as more data about the development of smart networks becomes available.

8.3.2 Innovation and Technology Development

Innovations and new technologies are constantly being developed, and there are a number of funds and mechanisms to encourage this in the energy networks industry. This may take the form of a new component or asset that can be installed within the network, or new techniques and methods, for example for operations or maintenance.

In the case of new components, it is important that they can be used within any modelling tool in order to understand their advantages and give the users relevant and up to date information. In this case, an opex modelling tool can account for this by including a new component or assembly, or a modified or upgraded one, with inherent characteristics which will be accounted for in any project that it is included in. There may need to be a review to understand if the opex modelling methods that are implemented are relevant for any new component, though it will still be possible for an opex profile to be user defined.

Where the new development is in network operation or management techniques, such as a new method of maintaining particular existing assets, then the effect on opex may be studied separately, and the opex profiles of individual projects may be changed. If such techniques are taken on widely, then it would be appropriate to review the shape of the opex profile used within the tool, so that every project analysis is conducted using up-to-date assumptions.

8.3.3 Revolutionary Industry Changes

The development of new, industry changing technologies (i.e. revolutionary changes rather than evolutionary changes) is something that is always a possibility, and may have a significant impact on the opex of a network. For example, if a significant new storage component is adopted on a large scale, then the utilisation of existing assets may be considerably improved, and the need for additional capital investment may be avoided or deferred. However, the assets may have significant operational or maintenance costs associated with it.

It is possible that new legislation and standards may have a significant effect on opex, for example if new standards of flood protection are established after a significant flood event, IT systems need adaption to counter cyber-attack or assets protected against terrorism actual or threatened.

These aspects are not easy to predict, and will need to be considered as they arise. It is therefore recognised that if the 2050 Infrastructure Tool is to be consistently maintained to be up to date, then it should be reviewed regularly for the latest development in technology and legislation, and to update the current thinking on future trends. It may also be beneficial to validate the opex assumptions with any new data that becomes available, such as the new Ofgem price control reviews for the electricity and gas networks.

9 Recommendations for Further Work

The purpose of this project was to gain insight into the operational expenditure of energy networks, in order to scope a further piece of work to develop opex modelling capability. It is recommended that this future work includes furthering the understanding of network opex, in order to develop opex modelling capability. This work would be supported by the initiation and involvement in a wider industry discussion about the development of knowledge and understanding of the opex of energy networks.

9.1 Develop Understanding of Energy Network Opex

A more complete understanding of network opex may be possible with the use of additional data sources. It is proposed that the further work includes a review of the data requirements and the sources identified to date, followed by the identification of additional data sources where available. It is noted that some of the data required may not exist, and where it does, it may be considered commercially sensitive and would not be made available to us.

Contributions from external experts proved to be a valuable source of understanding within this project. It is proposed that this be used to further validate the conclusions gained from data analysis, as well as providing additional qualitative understanding of network opex in general.

There may be certain areas of interest that have been identified that could be included within this analysis. In particular, energy network losses may be understood further, including the losses within the electricity network which was not covered by this project. This will be with a view to developing methods of modelling network losses as a component of opex.

It is also noted that heat transmission systems, where large heat sources are used to feed load centres that are geographically separated from them (comparable to centralised power stations feeding city load centres via the electricity transmission system) may be of interest for further study. This analysis may follow a similar methodology to the analysis used within this report, though data sources will have to be identified.

9.2 Develop Opex Modelling Capability

It is noted that the development of opex modelling capability is a central aim of the further work. Therefore the work detailed above in section 9.1 should be undertaken within this context.

Potential methods to develop the existing 2050 Infrastructure Tool has been briefly described within this report. It is proposed that this is developed further, with an understanding of the relative advantages of each method. In order for these methods to be implemented, there will have to be data available to be used in the tool. This can be gained through quantifying the findings within this report, and the additional understanding developed through the use of new data sources and research.

The intention is to support the development of a specification for an upgraded version of the 2050 Infrastructure tool.

It is noted that it is the intention of ETI to develop opex modelling capability beyond the 2050 Infrastructure Tool. It is therefore the intention to investigate and understand potential methodology for modelling opex within a stand-alone model, which will be considered separately to the existing tool. It will be necessary to fully understand the requirements and purpose of such a model, and as above, the data to be used within the model will have to be developed.

The work above should be considered within the context of the interaction between capex and opex, as this has been identified as a potential area of interest. This relationship is complex, as decisions taken about opex choices, such as condition monitoring and real time asset management, can affect asset lifetimes which, in turn, affects the timing of the need for capital investment in the future. Methods for including this within the modelling methodologies would be considered.

9.3 Industry Discussion on Energy Network Opex

It is understood that the subject of energy network opex is not widely researched or understood. This presents a significant problem when attempting to understand and model the opex costs as a whole.

Opening this conversation up to an industry wide, potentially international, audience could be achieved through open events and workshops attended by key industry and academic personnel. Such events could be part of an existing conference or forum that has a relevant subject matter and will be attended by suitable policy, industry and academic players. The first step towards achieving this would be to understand the existing opportunities and events that could form a suitable platform to achieve this.

It would also be possible to organise and run dedicated events in order to disseminate and discuss this subject. As a first step, it would be possible to organise a relatively small scale UK event inviting existing contacts before opening out to international participants. For example, initially the contributors to this project would be invited to attend, alongside additional personnel identified through existing contacts or further research.

The aim with these activities would be to initiate a wider debate, research and collaboration which would then lead to a more developed understanding of energy network opex in the future.

Appendix 1: Flexible Opex for an Uncertain Future

Kick Off Meeting Friday 18th July

Minutes

Attendees:

PPA Energy: Olivia Carpenter, Claire Newton, Cliff Walton

ETI: Gareth Haines, Suzie Kistruck, Liam Lidstone, Phil Proctor, Natalie Lowery (dial in)

E.ON: Richard Hair

Apologies:

PPA Energy: Tony Woods

Purpose

Kick-off meeting to further increase the understanding of ETI objectives and issues to be studied within the project.

Discussion Points

The meeting began with a brief introduction about PPA Energy. There was then a presentation of the background of the project, including the previous project completed by PPA Energy, and the expected scope of this project as presented in the proposal. There was some discussion around this:

1. It was highlighted that the Sweet model does not currently deal with hybrid energy systems, and it was suggested that the focus of the Flexible Opex project should focus on the opex of individual energy vectors.
    a. It was agreed to de-emphasise the review of hybrid energy systems and to concentrate on individual energy vectors: electricity, gas, heat and hydrogen (and within that focus, to bear in mind that this is more about relative, rather than absolute, costs).
    b. However, it was also pointed out that it is the eventual aim that the model should be developed to cope with hybrid systems, so any information that it discovered should be recorded.
2. It was noted that there has been validation of the model data, but that has focused on the Capex data. There has been no significant validation of the current Opex results from the model.
3. The model is currently undergoing a 6 month review period, due to end in late August. It is then intended to scope and develop another version of the model.

4. The review has included collecting comments from users. There have been very few Opex-related comments. The only one is that the current Opex calculation does not take asset usage levels into account.
    a. The model does not include any asset loading data, and there is no facility to include this kind of information, as it is simply asset based.
    b. It was also discussed that Opex is heavily dependent on the environment in which the assets sit (e.g. direct buried cables, ducted cables, indoor and outdoor substations).
    c. It was mentioned that the model is meant as a first look, not a detailed study, and that we should not get too bogged down in the detail. It is PPA Energy's intention to identify and focus on the most important factors that affect Opex.
5. The model is currently not generally available. Users would include industry players (suppliers, network operators…), and potentially policy makers.
6. A question was asked about whether the Opex modelling can be a bottom-up calculation, as for the approach to Capex build up.
    a. The issue is that data is not available to a sufficient level of detail for this. However, the model could be future-proofed for when such data does become available.
    b. It was suggested that it might be possible to have the Opex based on more than just Passive/Active categorisation.

Areas of Uncertainty and Areas of Flexibility that have already been identified in the proposal were discussed, and generally agreed. There were a few discussion points here:

1. Some of the areas of Uncertainty have not been included so far in the model. It was noted that including them may not be straight forward, and therefore if they are investigated, then a method for their inclusion should also be looked into.
2. It was suggested that this project should focus only on factors that can be included into the model, as this project will feed into the scoping of the next version of the model. It will be important to document any processes for arriving at outcomes / numbers, so that results can be interpreted.
3. It was also highlighted that, particularly within the policy/standards area, the focus should be on policy that is currently in the UK pipeline, and on international examples (i.e. this piece of work is not about scenario forecasting). This ensures that it will be as evidence-based as possible.

Actions

- [ ] Organise a teleconference a couple of weeks into the project to discuss approach to investigating areas of uncertainty and areas of flexibility (PPA and ETI)
- [ ] Organise a weekly teleconference catch up for the project (PPA and ETI)
- [ ] Secure a provisional date for the final project workshop (PPA and ETI)
- [ ] Review 2050 Infrastructure Tool and prepare for next steps (PPA)