Innovation Funding Incentive (IFI)

Management of electricity distribution network losses

Appendices

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Appendices

Appendix 1:

Distribution network modelling and analysis

1 Representative networks

Many of the findings of this project are based upon the outcome of modelling and analysis completed by Imperial using their network evaluation tools.

The overall approach is illustrated in Figure 1. Scenarios of network demand and generation are applied to representative network models. Losses are assessed for each network under the chosen scenarios.

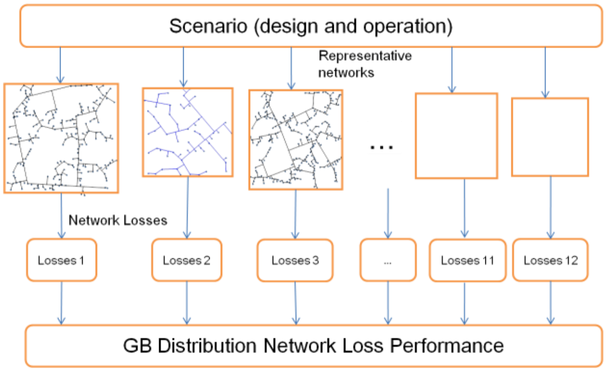

Figure 1: Schematic Network model for assessing loss performance

Two forms of network representation have been used, the fractal model for LV and HV networks, and Imperial's GDS tool for EHV networks.

2 Fractal model

LV and HV networks have been assessed using Imperial College's fractal calibrated network models which reproduce realistic network topologies and network lengths. In order to evaluate losses for the whole of GB, 12 representative networks have been developed to characterise distribution networks of different types. The models represent two urban networks, two semi-urban, four semi-rural and four rural networks.

These representative networks are presented illustratively in Figure 2 to Figure 13. LV network topologies and demand profiles are shown for each representative network. Such networks capture the statistics of typical network topologies that range from high-load density city/town networks to low-density rural networks. The design parameters of the representative networks should closely match those of real distribution networks of similar topologies.

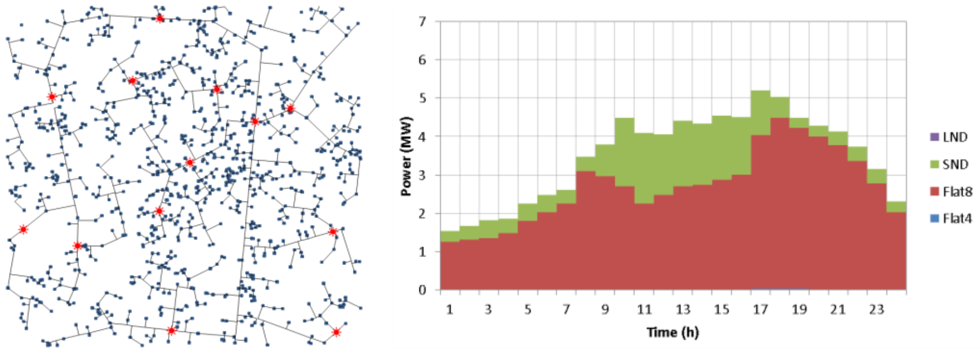

Figure 2: Urban 1 network: 13500 consumers per km^2, 32.5 distribution substations per km^2, 13 MW/km^2

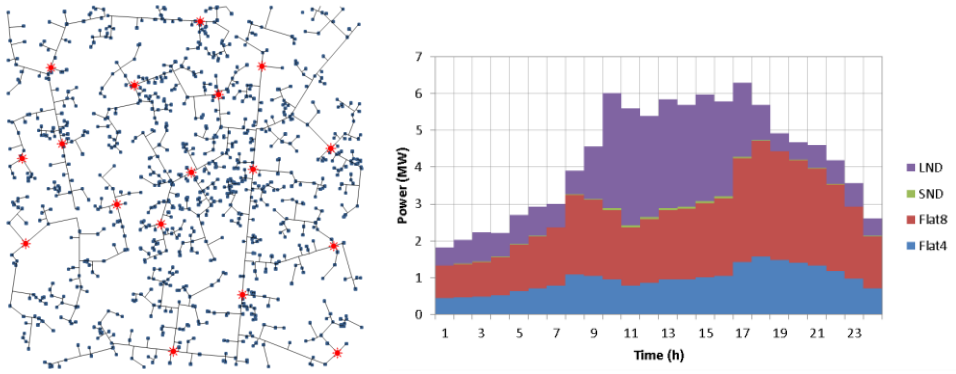

Figure 3: Urban 2 network: 13500 consumers per km^2, 45 distribution substations per km^2, 15.5 MW/km^2

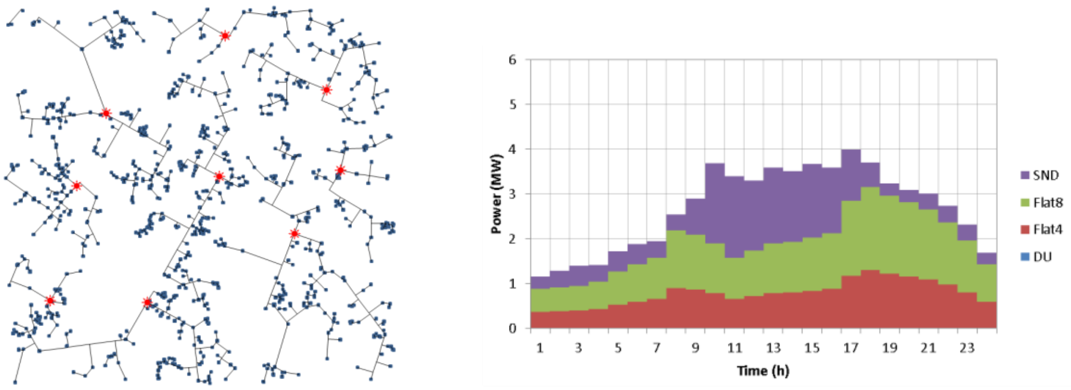

Figure 4: Semi-urban 1 network: 3150 consumers per km^2, 7.3 distribution substations per km^2, 3 MW/km^2

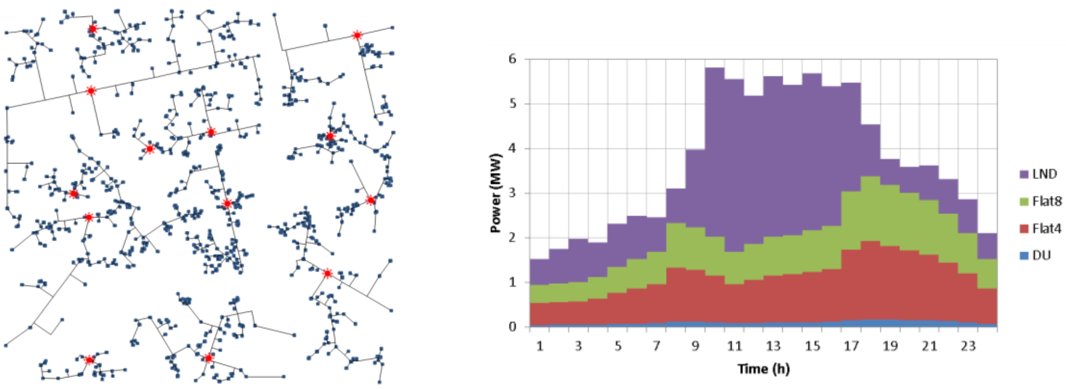

Figure 5: Semi-urban 2 network: 3150 consumers per km^2, 10.5 distribution substations per km^2, 4.5 MW/km^2

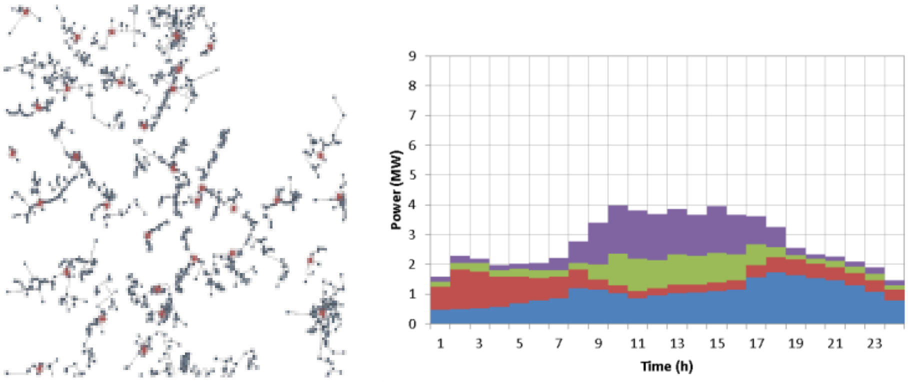

Figure 6: Semi-rural 1 network: 350 consumers per km^2, 5.3 distribution substations per km^2, 0.6 MW/km^2

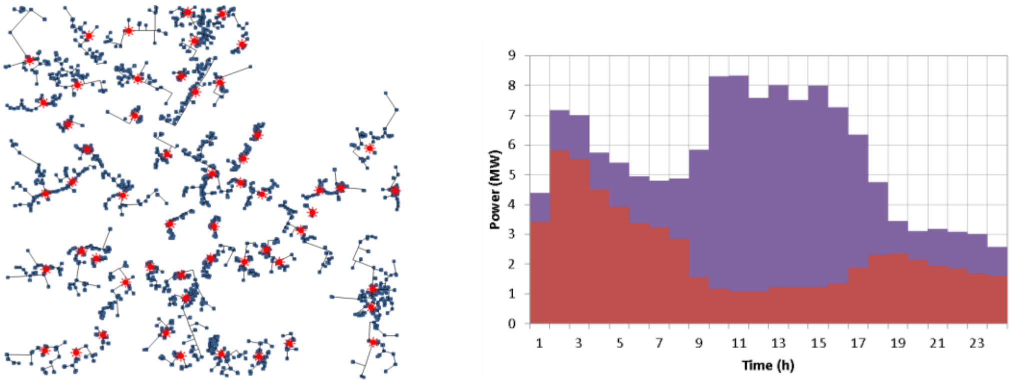

Figure 7: Semi-rural 2 network: 350 consumers per km^2, 7.9 distribution substations per km^2, 1.2 MW/km^2

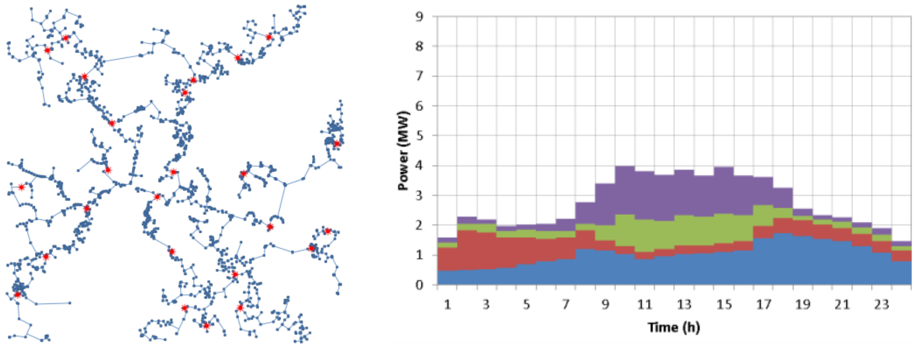

Figure 8: Semi-rural 3: 350 consumers per km^2, 3.6 distribution substations per km^2, 0.6 MW/km^2

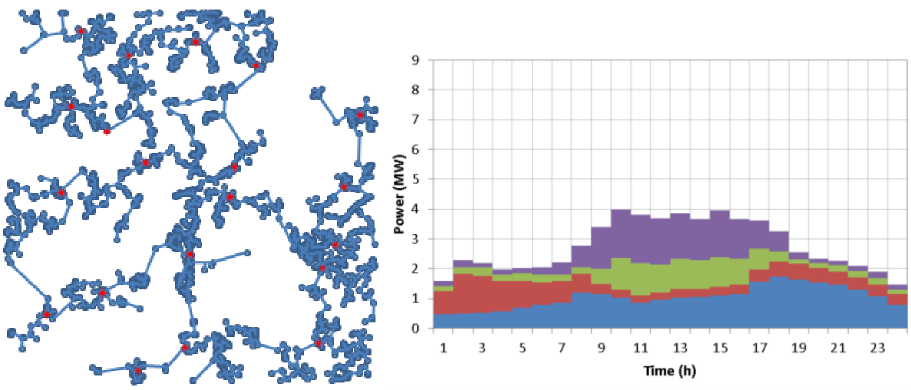

Figure 9: Semi-rural 4: 350 consumers per km^2, 2.9 distribution substations per km^2, 0.6 MW/km^2

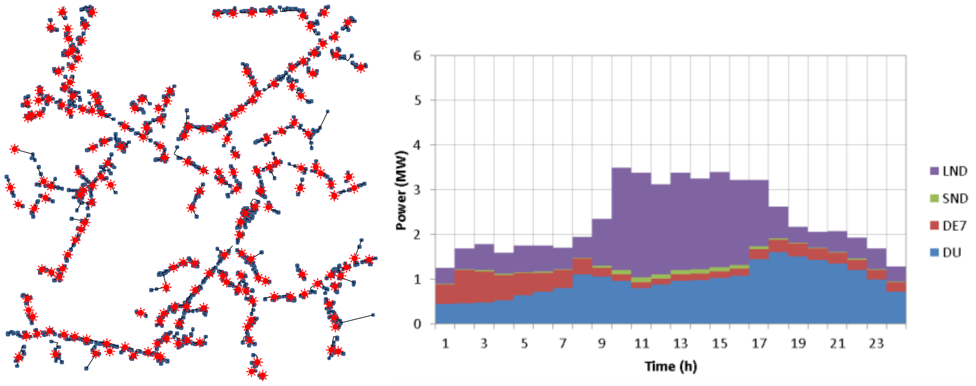

Figure 10: Rural 1 network: 100 consumers per km^2, 10.2 transformers per km^2, 0.18 MW/km^2

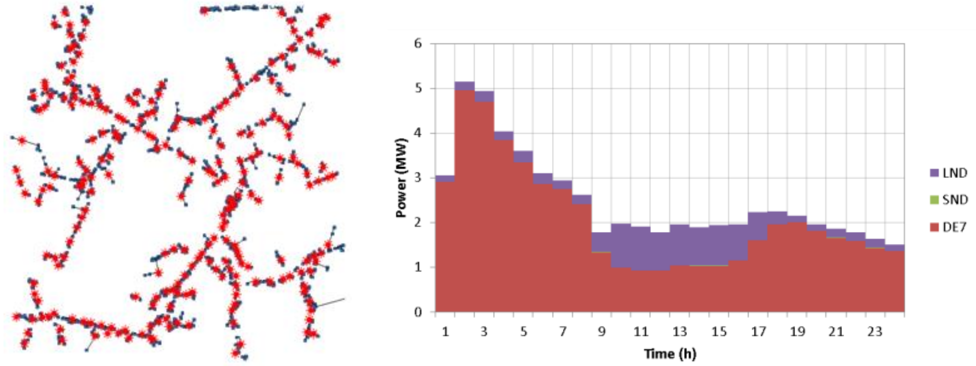

Figure 11: Rural 2 network: 100 consumers per km^2, 12.7 transformers per km^2, 0.25 MW/km^2

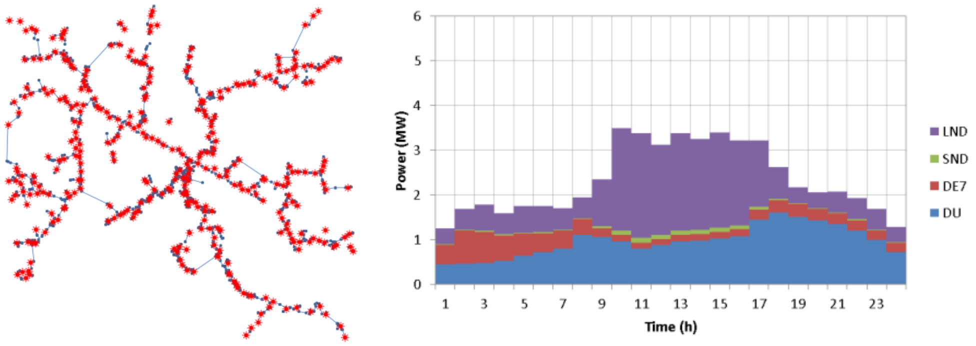

Figure 12: Rural 3: 100 consumers per km^2, 17.8 transformers per km^2, 0.18 MW/km^2

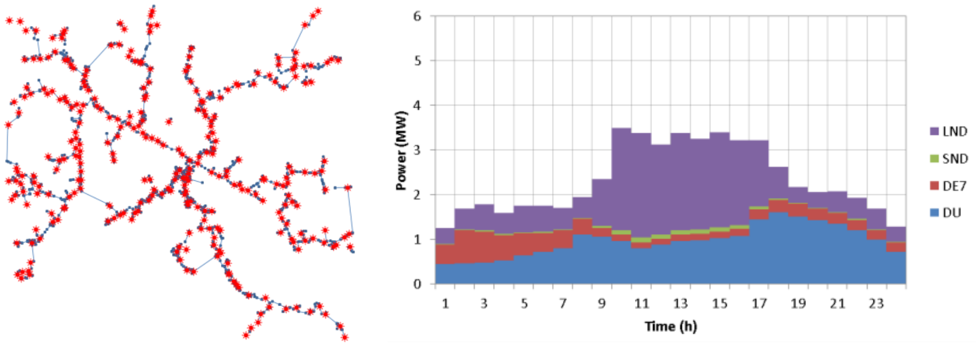

Figure 13: Rural 4: 50 consumers per km^2, 7.5 transformers per km^2, 0.09 MW/km^2

The mapping of the representative networks into a GB wide distribution system is tested against a number of parameters characteristic for the GB distribution networks. Table 1 shows the total number of consumers and the GB aggregate values and the discrepancies between the two. It is considered that the representative networks closely map GB aggregate values.

Table 1: Comparison of modelling parameters and GB distribution networks

Parameter	GB Value	Representative Network Value	Discrepancies (%)
Number of connected consumers	29,416,113	29,410,374	-0.02%
Overhead LV network length (km)	64,929	64,905	-0.04%
Underground LV network length (km)	327,609	327,822	0.07%
Number of pole mounted transformers (PMT)	343,857	343,848	-0.00%
Number of ground mounted transformers (GMT)	230,465	230,323	-0.06%
Overhead LV network length per PMT (m)	189	189	-0.03%
Underground LV network length per GMT (m)	1,422	1,423	0.13%

3 GDS tool

EHV networks are represented through typical Generic Distribution Networks. The Imperial Generic Distribution System (GDS) tool has been enhanced and calibrated for the analysis of operation, losses and constraints on typical GB distribution networks using Generic Grid Supply Point (GSP) models as shown in Figure 14.

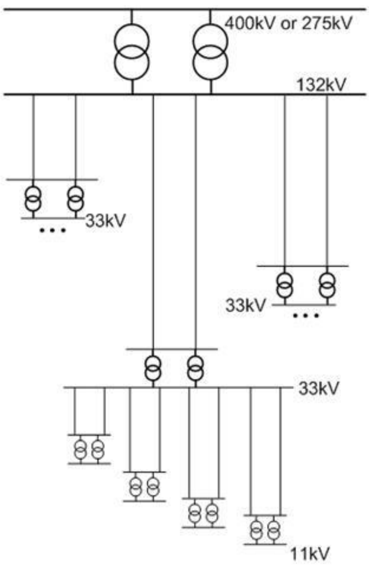

Figure 14: Schematic of a Generic GSP model

In order to design a GSP model of a real network, the following is required:

- For transformers: capacity, impedance, no load and load losses,
- For feeders: number of feeders, feeder size, lengths, type,
- For demand and distributed generation: demand and DG levels, types, load distribution along feeder, power factor and
- GSP: connection arrangement and rationale of the low voltage modules.

The GDS tool then uses characteristic demand and generation profiles in order to perform annual analyses of the network performance. The profiles cover:

- three seasons - winter, summer and autumn/spring, and
- three types of day, namely weekdays, Saturdays and Sundays.

Six GSP models have been created and these are calibrated against typical real networks. Parameters of the final six GSP models are given in Table 2.

Table 2: Parameters for Generic GSP models

Model Name	No of EHV/HV transformers	EHV network length (km)	No of 132/EHV transformers	132 kV network length (km)
Rural 1	120	9,931	103	17,526
Rural 2	129	17,035	111	5,678
Rural 3	519	28,483	65	11,289
Urban 1	705	1,089	128	58,442
Urban 2	44	131	44	3,655
Urban 3	187	2,467	156	3,310

The EHV losses are calculated for real networks and for their equivalent GSP networks. The result of comparison, as shown in Figure 15, demonstrates that the GSP models are representative of typical distribution networks in particular with respect to the assessment of energy losses.

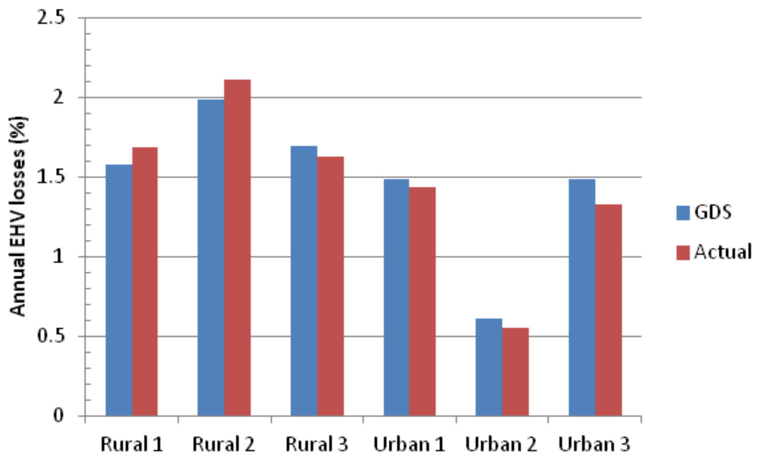

Figure 15: Comparison of actual and estimated losses for GSP models

The correlation between DNOs' views of network losses and the calculated values from Imperial's models provides assurance that the modelling techniques are a valid approach to further network loss analysis.

Appendix 2:

Consumers Load Data

Nine typical days are adopted to represent annual variation in load as shown in Figure 16 to Figure 19 for domestic unrestricted, domestic economy 7, commercial and industrial consumer types, respectively. For this exercise we have chosen three temperature seasons (winter, summer and spring/autumn) with each of them represented with the three typical days (working day, Saturday and Sunday). Holidays are classified as Saturdays or Sundays.

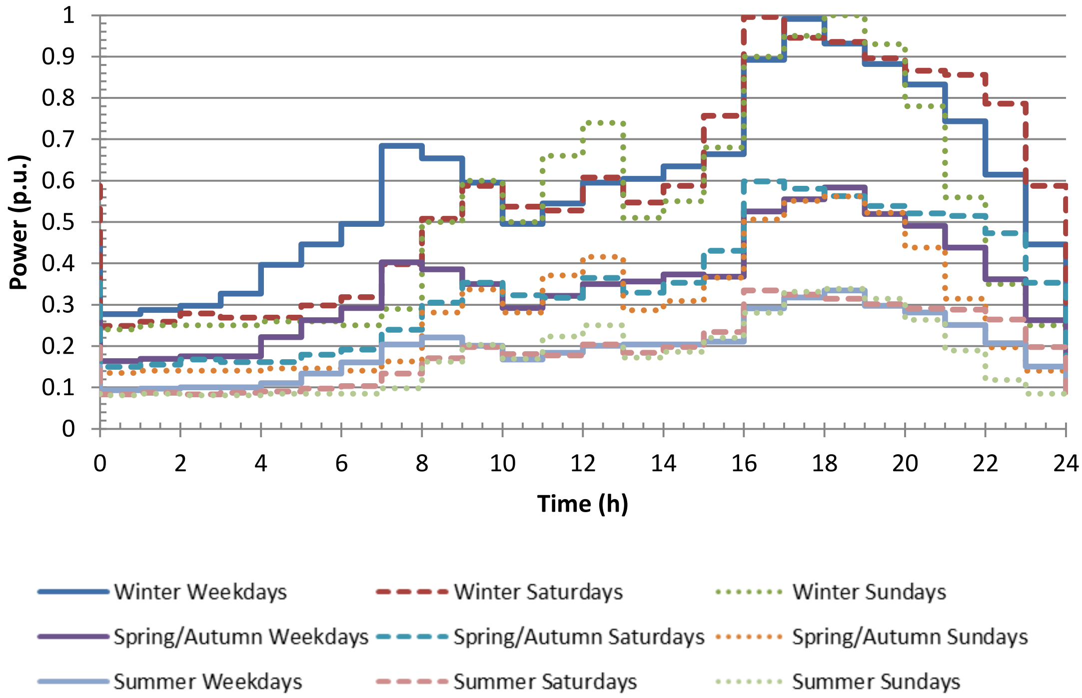

Figure 16: Nine characteristic normalised daily profiles for unrestricted domestic consumer type

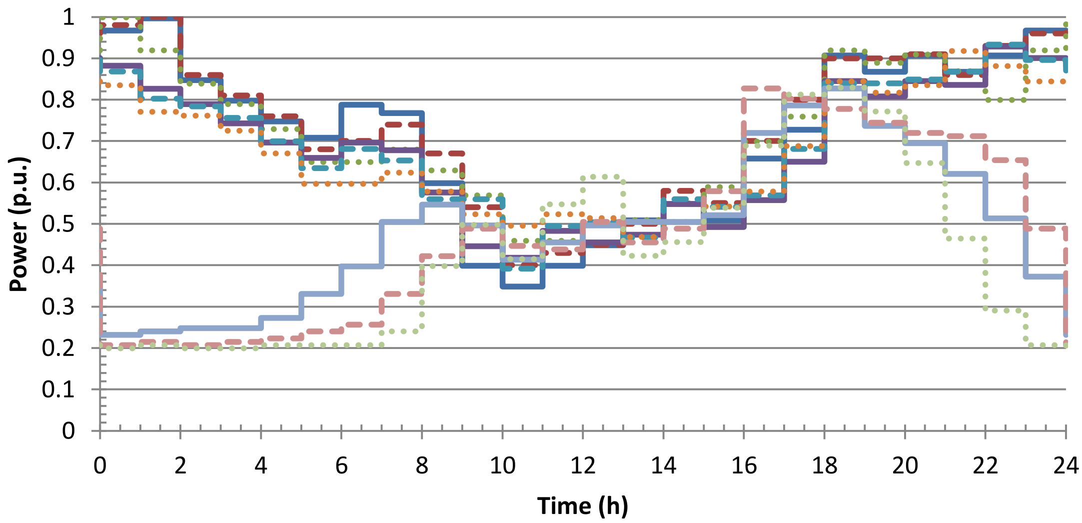

Figure 17: Nine characteristic normalised daily profiles for domestic economy 7 consumer type; Legend is shown in Figure 16

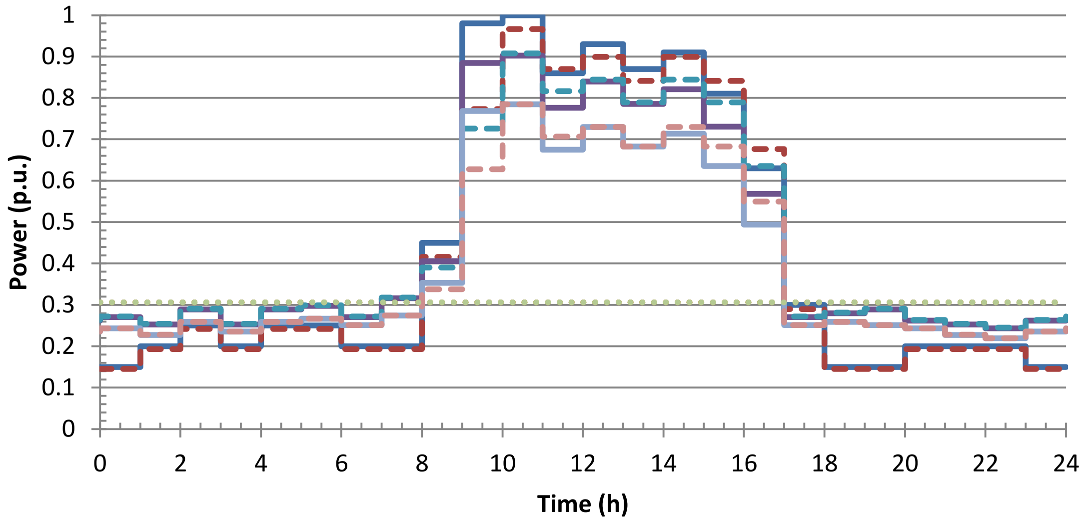

Figure 18: Nine characteristic normalised daily profiles for commercial consumer type; Legend is shown in Figure 16

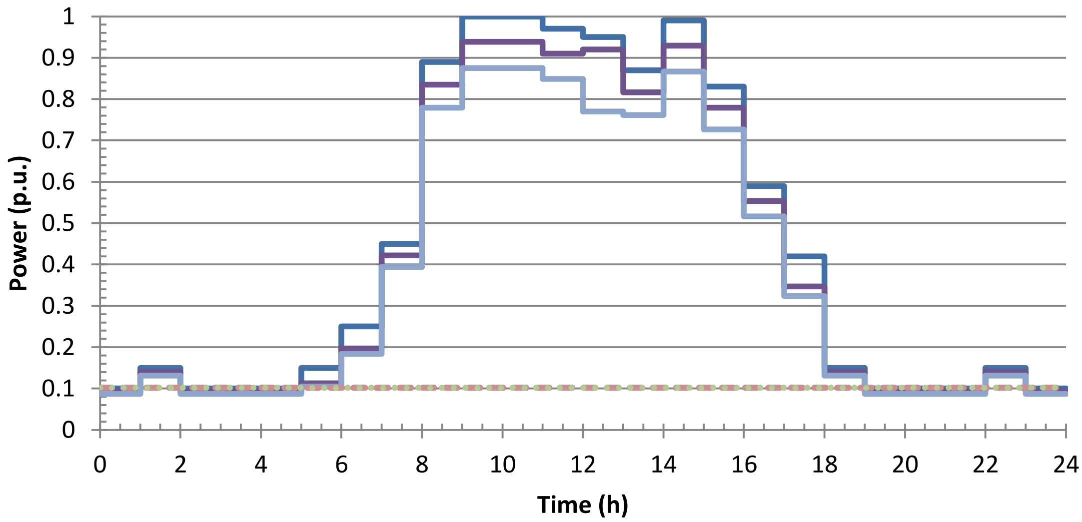

Figure 19: Nine characteristic normalised daily profiles for industrial consumer type; Legend is shown in Figure 16

Appendix 3:

New materials

1 An overview of attempts to reduce losses

Main efforts to reduce losses can be summarized as attempts to use either a different geometry and/or a different material or to improve optimisation procedures to reduce the total loss in the system. Examples below are typical for the vast amount of the literature devoted to the problem. Note that, whilst some of these refer to rotating machinery which is not directly relevant to distribution network equipment, they indicate the effort which is going into reducing losses in electricity utilisation, which is indirectly relevant to network losses.

Various references[1,2,3,4] indicate for example, that the efficiency in industrial three-phase induction motors can be improved, making use of a die cast copper rotor cage and premium electrical steel.

Cougo *et al*[5] have argued that the orientation used to wind a transformer is important in power transformers. Analysis of copper losses due to skin and proximity effects is performed in order to choose the best configuration of the turns inside the winding area when conductors are carrying non-sinusoidal current. Initially results are a direct application of Dowell's formula for the fundamental component and the harmonics of the current flowing through the winding. Later, FEA simulations confirm the relationship between current frequency, insulation thickness, winding window width and winding position.

Al-Badi *et al*[6] have examined the problem of losses in distribution transformers and the authors attempt to optimize the performance for different loading conditions.

2 Copper and aluminium

Various reference sources have been studied[7, 8].

Variable losses may be reduced by using ultra high purity material but such developments are uneconomic due to the high cost of purer materials. The general view is that it is unlikely that copper (Cu) wire standards will increase beyond the current minimum value of 101% IACS. Although 6-nines

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[1] D.T. Peters, E.F. Brush, Jr., J.L. Kirtley, Jr., Die-cast copper rotors as strategy for improving induction motor efficiency, Electrical Insulation Conference and Electrical Manufacturing Expo, 2007 , pp..322-327, 22-24 Oct. 2007.

[2] J.L. Kirtley Jr., J.G. Cowie, E.F. Brush, Jr., D. T. Peters, and R. Kimmich, Improving induction motor Efficiency with die-cast copper rotor cages, Power Engineering Society General Meeting, 2007. IEEE, pp.1-6, 24-28 June 2007

[3] F. Parasiliti and M. Villani, Design of high efficiency induction motors with die-casting copper rotors in Energy Efficiency in Motor Driven Systems, Eds: F. Parasiliti, P. Bertoldi, Springer, 2003, pp 144-1

[4] F. Parasiliti, M. Villani, C. Paris, O. Walti, G. Songini, A. Novello, T. Rossi, Three-phase induction motor efficiency improvements with die-cast copper rotor cage and premium steel, International Symposium on Power Electronics, Electrical Drives, Automation and Motion SPEEDAM 2004, pp.338-346, 16-18 June 2004

[5] B. Cougo, T. Meynard, F. Forest, and E. Laboure, Winding position in power transformers to reduce copper losses: non-sinusoidal currents, IEEE Energy Conversion Congress and Exposition, 20-24 September, 2009, pp. 3959-3965, 2009

[6] A.H. Al-Badi, A. Elmoudi, I. Metwally, A. Al-Wahaibi, H. Al-Ajmi and M. Al Bulushi, Losses reduction in distribution transformers, Proc. Int. MultiConf. Engineers and Computer Scientists, IMECS 2011, 16-18 March 2011, pp.1-5

[7]

[8] Various sources: http://www.icf.at/en/5762/material_substitution.html, http://www.bloomberg.com/news/2012-02-07/aluminum-over-copper-for-cables-helps-rusal-alcoa-commodities.html, London Metal Exchange forward prices

copper has been produced in small quantities, it is extremely expensive. Conductivity of 6-nines and 4-nines Cu is nearly the same at ambient temperature, similarly with aluminium (Al) 4-nines and higher purity 6-nines.

Whilst copper is about 65% more effective as a conductor than aluminium, it is more expensive and about twice the weight. Consequently, aluminium continues to be used as a conductor in preference to copper unless there are specific space constraints. The ratio of the price of copper to aluminium has increased from unity in 1987 to about four in 2012. This high differential is likely to continue as the aluminium market has oversupply but, until very recently, copper is short supply.

For the same electrical resistance aluminium is almost 8 times cheaper than copper as shown in Figure 20.

	Copper	Aluminum	Ratio Δ
Length (m)	1.000	1.000	-
Resistance (Ω)	1,72E-01	1,71E-01	-
Section (mm²)	100	164	0,61
Weight (kg)	0,890	0,443	2,01
Price (€/ton) – June 2012	5.930,46	1.505,32	3,94
Price Ratio			7.91

Approximate equivalent cable sizes

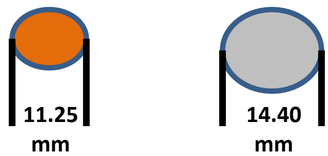

Figure 20: Comparison of Cu and Al conductors[9]

3 Amorphous core transformers

Amorphous core material has been in existence for more than 35 years. Amorphous steel is a non-crystal substance created by rapidly freezing liquid steel from high temperature. The hysteresis loss is low as there is “no rule of atomic arrangement”. The eddy current loss is decreased as the thickness of around 0.03 mm is about 1/10 compared with silicon steel. No-load loss (eddy current loss and hysteresis loss) can be reduced to about 20% of the no-load losses of transformers using silicon steel.[10]

Hitachi Metals is the main global supplier of amorphous material. While Hitachi Metals is based in Japan, it also has a facility in the United States where amorphous metal is produced. The U.S. facility currently has three production lines, and can produce approximately 41,000 tons of amorphous steel per year. The Hitachi facility in Japan has two production lines, and can produce 30,000 tons per

[9] EC Transformer EcoDesign Impact Assessment

1 [10] http://www.wilsonpowersolutions.co.uk/products/wilson-e2/what-are-amorphous-metal-core-transformersSuper low loss amorphous distribution transformers - Wilson e2

year. However, Hitachi is upgrading its Japanese facility to add two additional production lines, which will bring its capacity to 100,000 metric tons per year.

In addition to Hitachi Metals, one other supplier is known to be producing amorphous metal commercially - a company based in China called Advanced Technology & Materials (AT&M) which has production capacity of 40,000 tons per year. However, this company is not considered a global supplier, because it is not known to supply amorphous metal outside the Chinese market. Several other companies have attempted to produce amorphous metal in recent years such as Posco in Korea which has recently started to manufacture amorphous metals.

The use of amorphous steel in transformers is now fairly common in Japan, the US and parts of the GB private sector. These are most advantageous in operating conditions of periods of high load combined with long periods of low load, such as in factories or offices when the load is much reduced overnight. Although the capital cost is only slightly higher, transformers with amorphous cores are heavier and noisier than standard laminated cores which may become an issue when replacing existing units.

4 Superconductors

High-temperature superconductors (HTSs)

The discovery of High-temperature superconductors (HTSs) has renewed the interest in practical applications of superconductivity including power transmission lines. For example, Zanella et al[11] explore ac power losses in HTS samples. It is shown that the power dissipation due to irreversible flux motion might represent the main heat load and must be assessed for practical considerations. 50 Hz current-dependent loss measurements were carried out at 4.2^0K on short straight samples of $Bi_2Sr_2Ca_1Cu_{2O8+x}$/Ag wires having high critical current densities of up to $1.5x10^4 A/cm^2$ at 26T. The AC power losses vary proportionally to the square of the transport current which is not consistent with the simple Bean model[12]. On the other hand the losses depend linearly on the frequency of the alternating current which would be compatible with hysteresis as the dominant loss mechanism. Loss values are found to be rather high and are not strongly influenced by bias magnetic fields up to 1T. It is argued that several effects may contribute to the loss enhancement and its current dependence. Loss mechanisms were further studied by A. Sultan[13] .

The demand to transport large quantities of renewable energy from wind, solar, or hydro projects in remote locations to population load centres is increasing worldwide. The improved efficiency and greater power capacity that superconducting cables provide in this application continue to attract interest. In the United States, the Tres Amigas interconnector project, which reportedly will eventually use DC superconductors, is, in part, motivated by the need to transport wind power from west to east. Interest in DC superconducting cables for long--distance transfer of bulk renewable power or for special applications such as power flow control continues to grow internationally, with continuing activities in Germany, Russia, China, Japan, and Korea.

In addition to long distance transports, urban complexes face a combination of issues that continue to make the retrofitting of existing underground AC transmission cables with superconducting AC cables an attractive proposition. In dense urban areas electricity distribution planners face the challenges of increasing power density, the soaring cost of real estate and a lack of space for high

[11] S. Zannella, J. Tenbrink, K. Heine, V. Ottoboni, A. Ricca, and G. Ripamonti 50 Hz current-dependent losses of $Bi_2Sr_2Ca_1Cu_{2O8+x}$/Ag wires, Appl. Phys. Lett. 57, 192-194 (1990)

[12] Ch.P. Bean, Magnetization of high-field superconductors, Rev. Mod. Phys. 36, 31–39 (1964)

[13] A. Sultan, A contribution to the ac losses of technical low temperature multifilament superconducting wires. PhD thesis, Swiss Federal Institute of Technology, 1995.

voltage substations. Superconducting cables can help by bringing power into urban centres at lower voltages, eliminating the need for high--voltage substations. Combined with fault current limiters, they can also interconnect urban substations on the distribution side of transformers, leading to a more robust power system.

Appendix 4:

Potential for extracting heat from distribution network losses

1 Introduction

This Appendix describes in more detail the research and analysis conducted to evaluate the potential for using the heat generated by network electrical losses. It is a companion document to the report "Management of electricity distribution network losses", which is being published concurrently, in which we describe the work on understanding the electrical losses of distribution networks and the potential for better management through loss-inclusive network design. The key objective of this Appendix is to present the methodology applied to assess the benefits of harvesting heat generated by distribution network losses, as well as provide an overview of recent projects that implemented heat recovery.

If it is technically and practically feasible to capture and use the heat generated by network losses, the overall energy efficiency of electricity distribution can be improved and this may also be economically viable in some cases. Whilst much technical and economic analysis is focussed on achieving the economic level of losses in network design and operation, there are opportunities in some locations to consider the additional benefits from using any heat which has a commercial value. This may be implemented as a retrofit solution, or may be engineered into the overall network design when new equipment is required.

Technologically, there are simple solutions to reducing losses by installing larger conductors and specifying lower-loss transformers. In the future, new materials and equipment designs will be available to take loss reduction even further. However, there are limits to what may be achieved in reducing electrical losses as such activity will be limited by the economic justification[14] and level of affordability of loss-reducing investments. Also, the network will not be "converted" to lower loss levels in a short timeframe and full replacement of networks will take many years to complete at the present rate and proposed future rates of network investment.

Therefore it may be concluded that electrical losses, some of which will be higher than the economic level in some parts of the network, will exist for many years. Whatever the level of loss on the network, be it economic or uneconomic, there is opportunity to improve energy efficiency by recovering and using the heat generated by electrical losses.

Losses are mainly generated from transformers, overhead lines and underground cables; those that are generated by other components of the network, such as switchgear and busbars, are negligible for practical considerations. However, it is obvious that harvesting heat generated on overhead lines is unlikely to be technically or practically feasible, nor economically viable, and in some cases heating of overhead cables is desirable to reduce ice formation. The study has therefore been limited to transformers and underground cables.

Even though most electrical losses occur in the low voltage networks, they are widely dispersed. Greater concentrations of losses are found, for example, in 132/33 kV or 33/11 kV transformers and the more likely success in economically harvesting heat lies within these higher voltage networks, which is where we have focussed our attention. Also, the heat generated from the network is general fairly low grade (<50 °C) and it is uneconomic to transport it across large distances. Heat recovered from cables and transformers is therefore most likely to be useful for adjacent or near-by buildings.

As with many cases of heat recovery, there is usually a mismatch between the temporal variations of heat generation and demand, reducing the overall effectiveness. This will especially be the case if the recovered heat is only used for building heating and/or cooling rather than for hot water. To some extent this mismatch may or may not be mitigated by heat storage and this is also considered as part of our investigation.

[14] For example, cryogenic techniques where extremely low or zero resistance can be achieved, are unlikely to be economically feasible.

Theoretically, in commercial properties it may be possible to use the heat for heating in winter and cooling in summer although this adds complexity. We would advocate demonstrating heating applications before tackling cooling solutions.

Ground Source Heat Pumps (GSHP) can also be employed to utilise the low grade heat recovered to increase temperatures and improve operational efficiency, although there is a need to better understand optimal operating temperatures which is outside the scope of this report. GSHP are currently most likely to be useful within a local heat recovery scheme due to the characteristics of commercially available products.

This Appendix is organised as follows. Details of current applications where heat is being harvested are given in Section 2. Section 3 discusses the potential for recovering heat from power transformers. The methodology for the assessment of the value of the heat recovered from distribution transformers is given in Section 4, along with the results of the economic analysis of various heating system designs. A study of the potential for extracting heat from cables is described in Section 5, while Section 6 examines the opportunities for heat storage.

2 Overview of current applications of heat recovery from distribution networks

The investigations described below have revealed a greater level of interest worldwide in heat extraction from electricity networks than we had been expecting although there are few projects that have been operating for longer than one or two years. The research into previous work has included over 35 telephone conversations with representatives of active participants in this field and relevant trade associations. Many of the conversations have been followed-up with emails and subsequent calls to build the evidence base.

The information on ongoing projects is presented for GB and non-GB based projects separately. We also present a case study for one of the most significant UK developments to date (RegenairHeat©) where we have been able to obtain some data.

2.1 Projects in Great Britain

2.1.1 Tate Modern project

The Tate Modern at Bankside in London is developing a low energy Extension which will use heat recovery and GSHPs.[15] This scheme will use recovered heat from the adjacent UK Power Network transformers in the old Switch House.

There are 6 transformers reducing the voltage from 132 kV to 20 kV and 11 kV for distribution to the local network. Approximately, 1 MW of heat at 55 °C (Flow) and 45 °C (Return) is being recovered to provide heating in the new Extension scheduled for completion in 2015. The hot water is initially used directly for heating which is supplemented by heat from a Heat Pump using the low temperature return water as a source. The scheme also has air cooled heat exchangers when the Tate heat demand is insufficient to provide complete cooling - all of which requires a complex pipework system.

Main partners are Bartlett School of Architecture and Arup Group along with Max Fordham as engineering consultants. The capital cost of the heat recovery system has been provided by UKPN as part of the Innovation Funding Initiative and the initial estimates of the heat recovered[16] (7,000 MWh/annum) will give a 4 year payback for the installation.

[15] http://www.maxfordham.com/projects/transforming-tate-modern/

[16] EDF IFI/RPZ Annual Report 2010

2.1.2 Islington Council project

Islington Council is currently planning Phase 2 of their Bunhill[17] Energy Centre project and aim to include heat recovery from the City Road substation owned by UK Power Networks. The expectation is that it will be partially funded through the EU "Smart Cities" programme as part of a consortium that includes the GLA, Gothenburg Energia and UK Power Networks. Technical details have not yet been agreed although an initial study funded through the Low Carbon London initiative indicated that the heat recovery would be commercially viable.

2.1.3 Rook Services "Regenair" heat system with National Grid Transmission (NGET)

This is a non-intrusive heat recovery system which has been developed over the last few years by Rook Services Ltd. Rook Services[18] have installed their RegenairHeat© system at NGET Hurst 400/132 kV substation with a further four projects under development and the potential to roll out installations for all of NGET's substation offices subject to successful feasibility surveys. Rook Services is also in dialogue with the social housing and water utility sectors to provide heat recovered from electrical systems.

At the Hurst substation site, the RegenairHeat© system provides space heating for the office space. The non-intrusive system extracts the heat from two brick built transformer noise enclosures via two dry air coolers, using a brine[19] circuit (to avoid potential freezing in the winter). The brine is fed into a heat pump which upgrades the operating temperature and supplies low pressure hot water to the office radiators, replacing electric panel heaters. Similar systems could also provide domestic hot water for kitchens and toilets etc.

Results so far demonstrate that the system is outperforming estimates which were provided by a carbon management company, Carbon Low[20], prior to the installation of the system. Also, initial analysis of the heat pump data indicates that the recovery temperatures are exceeding the original design projections with a greater amount of useful heat being available than expected. This "heat bonus" beyond what was expected appears to be the heat recovered from the cables in the shared cable troughs.

Capital costs for the Hurst installation and other NGET survey estimates indicate 'typical' installation costs of £125k for future projects resulting in a payback of just over seven years on energy costs alone. Considerable additional savings will also be delivered following the implementation of the CRC Energy Efficiency Scheme[21] which (along with refinements to the RegenairHeat© system) are projected to bring down payback periods to between four and six years (subject to detailed assessment and verification). A detailed case study of this project is provided towards the end of this chapter.

2.2 Non-GB projects

Table 3 summarises various projects in which heat from electrical losses has been recovered and used. The Table includes a project in Ireland which reached an advanced stage of development but was cancelled due to the recession.

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[17] http://www.islington.gov.uk/services/parks-environment/sustainability/sus_energy/Pages/decentralisedenergy.aspx
http://www.burohappold.com/fileadmin/uploads/bh/Documents/PDFs/Heat%20Networks%20-%20Islington%20Perspective.pdf
http://www.vitalenergi.co.uk/CaseStudy_Bunhill.html

[18] Source: Jason Garside, Commercial Manager, Rook Services Ltd, http://rookservices.co.uk

[19] Brine is the generic term for any anti-freeze mixture. The use of ethylene or propylene glycol is typical for GSHPs.

[20] http://www.carbonlow.co.uk/

[21] https://www.gov.uk/crc-energy-efficiency-scheme

Table 3: Summary of non-GB transformer heat recovery projects

Project	Summary	Comment
Brietfield local municipality "Stadtwerke", Switzerland	Utilises water heated by transformer losses to provide heat to adjoining building.	Unable to obtain performance information. Project driven by sustainability aspirations rather than commercially.
Carrickmines, ESB, Ireland	Proposed transformer heat recovery system for the first zero carbon commercial building in Ireland.	Project was cancelled due to economic recession.
E.ON, Sweden	Vattenfall believe that E.On may also be considering substation heat recovery systems in Sweden.	Unfortunately we have been unable to verify this with E.ON.
Helsinki Harbour, Finland	Separate feedback indicated that there is a transformer heat recovery installation operating in Helsinki. This is believed to be at Helsinki Harbour (Helsingen Satama) and was installed by RITTAL/RentraTek[22].	Unfortunately we have been unable to obtain further details from RITTAL.
RITTAL Vantaa office, Helsinki	RITTAL/RentraTek heat pump system recovering heat from 1000A transformer operating for 1.5 years.	Unfortunately we have been unable to obtain further details from RITTAL.
Vattenfall substation office heating installations, Sweden	Air heat exchanger/heat pump systems being installed in all Vattenfall's new substations where they have office buildings except in the north where it is too cold to achieve efficient performance. Typically Vattenfall install/replace around 10 substations each year and have been installing this system for some 5 years so potentially up to 50 installations.	Vattenfall prefer this simple non-intrusive approach, which apparently works well although performance data is not publicly available. Clearly Vattenfall would not be adopting this approach as standard if the technology did not perform well.
Vattenfall, six to eight projects commercially supplying heat to third party premises, Sweden	Supplies heat from new 130kV transformer installations via oil-oil transfer. One project utilises a heat pump.	No publicly available performance data. Some problems with oil leaks. No further installations planned as plant was being run to maximise heat output which resulted in sub-optimal transformer operation that had transformer maintenance/lifetime and electricity network performance impacts.

Further details of these development projects and references to published data are provided in the following paragraphs.

2.2.1 Stadtwerkes, Switzerland

At Wuelfingen, in the city of Winterthur, Switzerland, a semi-underground 110 kV substation has been built in a bespoke design adapted to the environment. The substation is built using Siemens' GIS technology[23] and the use of extracted heat has been a relatively small value-added feature of the total project. The substation is embedded between a school playground and a highway which is 4

[22] RentraTek and RITTAL, two Finnish companies, have developed a patented packaged transformer product (rEMCi) that allows heat recovery although the design of this was initially driven by the aim of improving magnetic field protection.

[23] Bert Strassburger, Peter Glaubitz Siemens AG, Energy Sector, Germany http://www.energy.siemens.com/hq/pool/hq/energy-topics/pdfs/en/gas-turbines-power-plants/Modern-Subterranean-Substationsin-GIS-Technology.pdf

metres above the playground. The substation building is used to compensate the height difference and muffle the noise from traffic. To improve the energy balance, the heat dissipated from the transformers is used for heating the substation building.

Two substations have been identified in Switzerland, in Zurich and Brietfield, which use water heated by transformer losses to provide heat to adjoining buildings. These were in substations designed by the local municipality (“Stadtwerke”) where the decision to use these systems was driven by sustainability aspirations. Brietfield heating adjoining buildings[24].

2.2.2 Vattenfall, Sweden

Vattenfall[25] have 6-8 (130 kV) projects in Sweden. These use an oil to oil heat exchanger feeding into a heat pump, although one system just employs a heat exchanger without a heat pump.

Heat is supplied to local buildings including one school from transformers between 4-120 MVA. All are new transformer installations rather than retrofit. In our discussions with Vattenfall we understand that there have been some mechanical problems relating to the oil/oil systems and they have concluded that the more practical solution is to recover heat with housed transformer and air cooling/transfer as with the Rook RegenairHeat system. This work has not been publicly reported.

2.2.3 Helsinki Harbour, Finland

From discussions with Vattenfall, a substation heat recovery installation is believed to have been installed in Helsinki Harbour, Finland by RITTAL. Unfortunately we have been unable to obtain details of this.

2.2.4 Carrickmines, ESB, Ireland

The global recession curtailed the proposed ESB system at Carrickmines substation[26]. Carrickmines sub-station comprises 2x220 kV/110 kV transformers, 2x110 kV/38 kV transformers and 2x38 kV MV transformers which required refurbishments for load and SCL reasons including rebuild of 110 kV busbars and installation of an additional 2x 220/110kV transformers. There was also an opportunity to utilise space at Carrickmines for offices and rationalise ESB Network’s Dublin Head Quarters. A proposal for the first zero carbon commercial building in Ireland was developed that included a transformer heat recovery system. However, due to the financial crisis in Ireland, the project did not proceed. Up to 5,000 MWh was projected to be available from the two proposed new transformers (equivalent to 2,800-3,000 tonnes CO_2 per annum). Key issues identified included cost, the heat exchange medium, ability to cool transformers without a heat requirement from the building, security of water (if water cooled) and LV supplies.

ESB also has one Dublin 110/MV substation where transformers had to be size restricted and water-cooling was used with a heat exchanger dumping on the roof. Theoretically the collected heat could have been utilised for space heating. Water cooling was only used due to the particular location of the substation within the network that provided sufficient back-up in the event of water cooling failure.

2.2.5 Other transformer heat projects

Other systems[27] that collect heat from transformers for cooling purposes with the collected heat being dumped e.g. SF6-cooled underground transformers have also been identified. For example in

[24] Source: Anthony Walsh, ESB Specifications Manager, Procurement Asset Management
[25] Vattenfall Source: Mikael Sollén, Vattenfall.
[26] Source: Anthony Walsh, ESB, Specifications Manager, Procurement Asset Management.
[27] Bert Strassburger, Peter Glaubitz Siemens AG, Energy Sector, Germany.
http://www.energy.siemens.com/hq/pool/hq/energy-topics/pdfs/en/gas-turbines-power-plants/Modern-Subterranean-Substationsin-GIS-Technology.pdf

Australia (Haymarket), America, Japan[28] and Singapore where either space and/or land value is at a premium.

Haymarket Substation forms an integral part of the electricity supply to the city of Sydney. It is an underground substation supplied by cable at 330 kV with some fourteen outgoing 132 kV circuits. All of the high voltage plant in the substation is insulated using SF6 gas. The three Toshiba transformers each rated at 400 MVA are among the largest SF6 insulated transformers in the world and are located in the Sydney CBD adjacent to the Darling Harbour entertainment precinct and with a basement some five metres below sea level.

Park Station, City of Anaheim, USA (underground design). Hidden within view – the underground Park Substation built for the power supplier "City of Anaheim" comprises a 69-kV GIS with 8 bays, two 56-MVA transformers and a 12-kV medium voltage system with 18 panels, all housed in a basement building under Roosevelt Park in Anaheim, California.

In residential Tokyo, the Sanban-cho substation is slipped under a school gymnasium, while another substation sits beneath three tiers of sub-surface parking, an at-grade commercial facility, and twenty-two residential floors above. An unusual substation stacking by Chubu Electric beneath a parking lot near the seventeenth century Nagoya landmark, Meijo Castle – where an above-grade ornamental fountain added to help cool electrical equipment also serves to cancel its mechanical noise. Towards 'Multiplex' or Next Generation Infrastructure, Hillary Brown, Associate Professor, Bernard & Anne Spitzer School of Architecture, The City College of New York.

Systems that remove heat from transformers sited at underground train stations are also found, for example at Leicester Square, London.

2.3 Ground based heat storage projects

2.3.1 GI Energy schemes at Sainsburys, Carlisle[29]

In 2012, as part of an on-going partnership with Sainsbury's, GI Energy completed a packaged heating solution for the new Carlisle store with 6,000 m^2 of retail space. The installation is also designed to minimise refrigeration running costs, which are typically up to 40% of total energy use in a conventional store. The installation is projected to deliver a 30% reduction in CO_2 emissions and deliver 1,200 MWh of heat annually.

The 700 kW ground source heat pump scheme utilises a compact vertical closed-loop design, using twin 40 mm loops in a total of 26 boreholes to a depth of 65 m. The ground loop also takes advantage of significant heat recovery from the in store refrigeration units, further reducing the bore hole requirement, whilst improving the performance of the refrigeration units. Surplus heat, including any produced by the chillers is re-directed back into the ground and stored there until required during colder weather, when it can be extracted by the GSHP and used to heat the building. This dramatically increases the efficiency of the system.

A packaged plant solution, where the complete plant room and control system was assembled off site, allowed the complete Energy Centre to be delivered and installed in a single day.

The energy services package allows Sainsbury's to cut the carbon footprint of the store and reduce costs from year one with no capital outlay and is underpinned with a 20 year performance warranty and maintenance package. GI Energy is also working in partnership with a provider of CHP systems, Cogenco, to offer an integrated CHP/thermal recovery system.

GI Energy[30] is also considering the installation of a potential CHP heat recovery project for a university in 2013.

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[28] http://www.utrc2.org/sites/default/files/pubs/Final-HBrown1.pdf
[29] http://www.gienergy.net/gi-energy-in-your-sector/case-study-sainsburys/

2.3.2 Helsinki Data Centre[31]

A partnership between the IT company Academica of Helsinki, Finland and Helsinki Energia resulted in the compatible co-location of a new 2 MW data server centre sited underneath the nineteenth century Eastern Orthodox Uspenski Cathedral.

The waste heat from the computers is transferred by heat pump into the district heating network developed by the municipality back in the 1950's which provides heating for approximately 500 detached homes. At the same time, district cooling produced by heat pumps from thermal energy, seawater or the City's energy generation, provides cooling to the data centre. Reduction of the centre's cooling energy use by nearly 80% has saved Academica nearly $200,000 annually, shrinking its carbon footprint by 1,600 tons.

2.3.3 Lötschberg Base Tunnel, Switzerland

The Lötschberg Base Tunnel is a 21 mile long railway tunnel accommodating both passenger and freight rail bisecting the Swiss Alps. The tunnel's high potential for geothermal energy has been exploited by extracting heat for the nearby Tropenhaus Frutigen, a tropical greenhouse and aquaculture facility turning out tropical fruit, as well as sturgeon and caviar. This scheme uses excess groundwater at 20°C to heat the greenhouses and aquaculture facilities[32].

2.3.4 Utilisation of summer heat from road surfaces for snow-melting and de-icing of bridges and roadbeds[33]

A good example of infrastructural spatial integration that incorporates heat-exchange functionality is geothermal snow-melting and de-icing of bridges and roadbeds.

Icy surfaces, especially treacherous black-ice, can more rapidly form on exposed bridge road surfaces, causing delays and accidents. Piloted first in Switzerland in the 1990's to equalize the temperature of bridges with adjacent road beds, the SERSO system collects summertime heat from road surfaces and stores it in a rock-pile surround within a field of contiguous geothermal piles.

Heat for use on the roadbed is extracted in winter using an electric pumping system to achieve a constant bridge temperature just above freezing. Used in reverse, the water that is chilled during winter is used in summer to keep the pavement cool, reducing wear.

2.4 Case study on loss-generated heat recovery: RegenairHeat

This section is a copy of the Case Study of a development by Rook Services Ltd in conjunction with National Grid Electricity Transmission. It describes the installation of heat recovery at Grid substations.

2.4.1 Introduction

RegenairHeat is the name of a unique heating system developed by Rook Services Ltd to recover waste heat from substation transformers and use this for heating adjacent offices. The Hurst substation is the first installation for National Grid Electricity Transmission (NGET) of the unique

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[30] Source: Mind Paugas and Chris Davidson, GI Energy.

[31] Source: Towards 'Multiplex' or Next Generation Infrastructure, Hillary Brown, Associate Professor, Bernard & Anne Spitzer School of Architecture, The City College of New York, February 20, 2011.
http://www.utrc2.org/sites/default/files/pubs/Final-HBrown1.pdf
http://www.computerworlduk.com/news/it-business/17804/green-data-centre-recycles-waste-heat/ and
http://perspectives.mvdirona.com/content/binary/Hel_En_Eco-efficient_computer_hall.pdf

[32] Ochsenbein, Gaby. "Alpine caviar and papayas come to Switzerland, January 1, 2009.
http://www.swissinfo.org/eng/front/Alpine_caviar_and_papayas_come_to_Switzerland.html?siteSect=107&sid=10149999

[33] European Geothermal Energy Council. "Geothermal Snow-melting and De-icing."
http://www.egec.org/target/Brochure%20Snow%20Melting%20&%20De%20Icing.pdf

RegenairHeat system which uses a standard Ground Source Heat Pump (GSHP) to provide Low Pressure Hot water (LPHW) to radiators in place of the original electric panel heating system. The GSHP is installed and monitored by Rook Services' technology partner, Vaillant, as part of an on-going product development agreement to improve RegenairHeat. The system has been operating since June 2012 and has just completed its first operating year with better than expected performance.

NGET has reported that the transformer cooling banks are now apparently running 'a lot more efficiently' thereby also improving transformer performance[34].

Rook Services has been developing a further four projects for NGET with the potential to roll out installations for all of its substation offices across its 241 sites that cover 337 substations, subject to successful feasibility surveys. Rook Services is also progressing installations at a further five sites with other clients. The technology has the economic potential to be installed at DNO and privately-owned substations with an adjacent suitable heat demand.

Rook Services is an independent multi-disciplined civil engineering and utility contractor that embraces new technologies and develops innovative solutions. Significant clients include NGET, AMEC, Skanska and Morrison Utilities.

We are indebted to Rook Services for their time spent in assisting us in compiling this case study and for their willingness to provide installation and performance data.

2.4.2 Design and installation approach

Rook Services use a four stage design and installation approach, which typically takes between 10-12 weeks, to deliver the RegenairHeat system as detailed below:

<u>Stage 1 - Feasibility survey</u>

This is undertaken by an in-house[35] certified EPC surveyor to assess the heat demand based on the building fabric, floor area, heating system, energy and occupancy data, including feedback from the substation manager. The substation heat availability is also assessed from temperatures recorded by data loggers during the heating season. The demand / supply measurement is used to produce an initial assessment of the commercial viability and an approximate cost for the RegenairHeat system along with the expected capital efficiency savings.

<u>Stage 2 - Design and technical outputs</u>

A detailed report is produced in from this stage that includes detailed technical calculations, system design, project costings, payback periods and timescales. CAD building designs are used by in-house hydraulics engineers to design the heating system, including the route of the delivery pipework from the heat source.

<u>Stage 3 - Project delivery</u>

Installation of the RegenairHeat system typically takes between 4 and 6 weeks dependent on the system size, with a three-week lead time from the date of order. This is undertaken by an in-house installation team, including Vaillant engineers, closely liaising with the substation manager. In the case of NGET, all members of the team are fully certified to work on NGET sites. The team typically comprises of:

- 2 No. Plumbers;
- 3 No. External pipework and mechanical installers;
- 1 No. Electrician;

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[34] Potentially this would allow transformers to gain some additional capacity headroom but this would need to be demonstrated through pre and post installation monitoring.

[35] An independent company, Carbon Low, undertook the Hurst substation survey.

- 2 No General operatives; plus
- 1 No. Independent Commissioning Engineer.

Stage 4 - Commissioning and system handover

Following full installation and testing, the independent commissioning engineer then signs off the system and provides the system warranty. A half day hand over demonstration is provided together with full user manual, service booklet and warranty information.

2.4.3 Overview of the Hurst installation

The RegenairHeat system provides space heating for the office space at the Hurst substation site. It is a non-intrusive system that extracts the waste heat from two transformer noise enclosures via two dry air coolers, using a brine circuit (to avoid potential freezing in the winter) feeding into a heat pump which upgrades the operating temperature and supplies LPHW to the office radiators. Some similar systems can also provide domestic hot water for kitchens and toilets.

Hurst feasibility study

The feasibility study for the Hurst offices illustrated that a substantial heat demand up to a maximum of 68 kW would exist for up to 10 hours/day during the heating season. The average heat production for each of the two Hurst transformers was estimated at 17.7 kW and 21.2 kW respectively. Allowing for the anticipated Coefficient of Performance of the heat pump this could provide 46 kW of heat with a projected total of approximately 36 MWh per month and 427 MWh of heat per annum. The estimated monthly heat demands depicted in Figure 21 thereby remained significantly below the monthly thermal output figures, although additional direct electric heaters would be needed to meet the potential maximum demand.

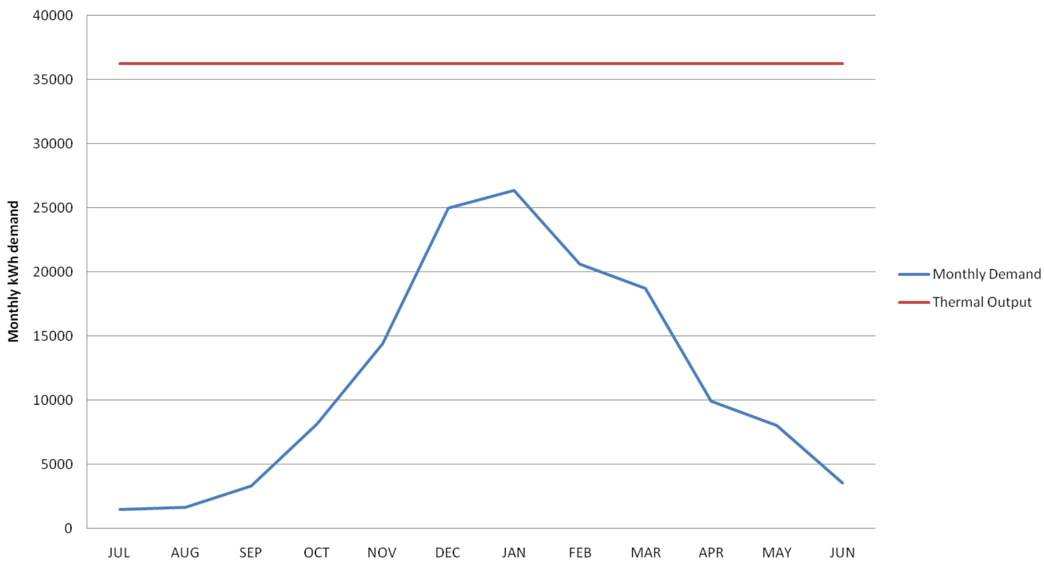

Figure 21: Potential thermal output of GSHP vs. annual office heat demand at Hurst substation

Waste heat is recovered from the transformers and the cables in the troughs where the pipework is installed. The air collecting units used to recover the waste heat from the transformer noise enclosures are best located at high level, where typical temperatures are higher as shown in the temperature logging chart in Figure 22.

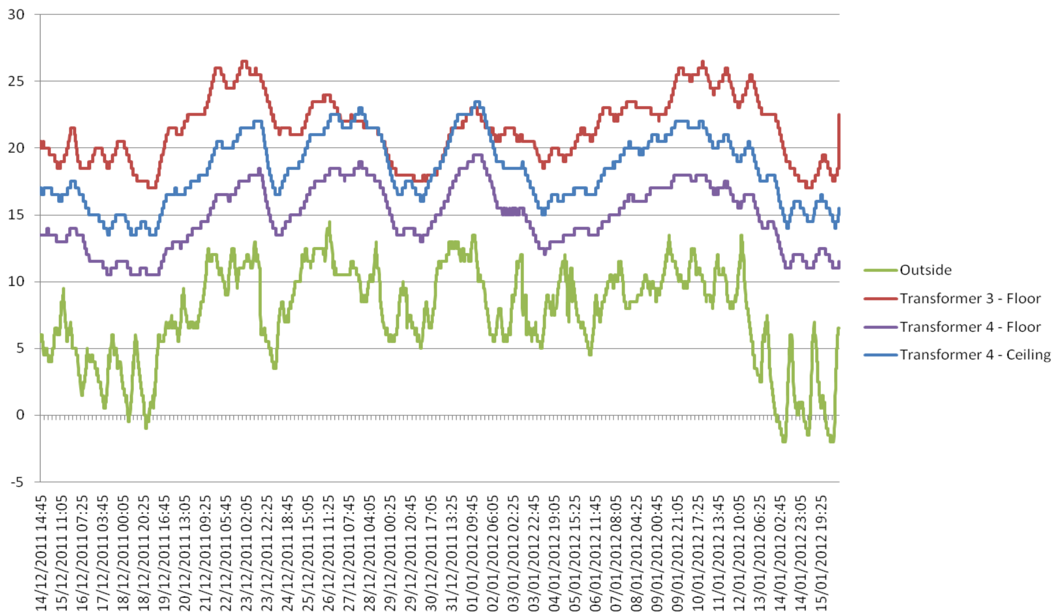

Figure 22: Temperature profiles recorded at Hurst substation

Whilst this approach will not extract the maximum amount of available heat from the transformers, it is an efficient and inexpensive solution. The non-intrusive approach is clearly attractive as it removes the risk of interfering with the operation of the transformers. Normally the heat from the transformers would escape through the natural air gaps in the noise enclosures consequently this serves as the default cooling system when there is no heating demand from the offices.

The brine circuit

The design of the brine circuit, which transports the recovered heat from the transformer enclosures to the heat pump, is a critical factor. The circuit installed at Hurst, where the two transformer enclosures are approximately 80 metres and 215 metres from the heat pump, consisted of a combination of four separate 63 mm MDPE plastic pipes, which are insulated with 19 mm thick Armaflex closed cell insulation.

Installation of the pipework system at Hurst was difficult and time consuming. The initial feasibility study calculated that 40 mm MDPE pipes could be utilised but during the detailed design process the pipe routing had to be amended resulting in an increase in the number of bends and length of system. This increased the resistance for the brine pump and so the size of the pipework was increased to 63mm to meet the parameters of the brine pump. 63 mm MDPE was difficult to handle on site due to the properties of the product and the jointing technique. In addition installing the Armaflex insulation after the pipes were jointed meant that the timescales for installation were longer than expected. This has been resolved by the use of a single flexible coil removing the need for multiple joints between the evaporator and the plant room.

Pre-insulated 63 mm MDPE pipe is readily available and can also be delivered in 100 m lengths with longer lengths of triple insulated pipework available subject to longer lead times. The experience at Hurst has demonstrated that utilisation of coils and pre-insulated pipe in the design and procurement stage could reduce installation time on site by up to 75% against a standard product with separate insulation. Furthermore, with pre-insulated pipe advancements, the thermal properties of the pre-insulated pipe show greater efficiencies and provide better damage protection from site activities compared to Armaflex insulation.

Clearly the distance between the heat pump and the transformer enclosures will impact on the cost of the installation. Current thinking is that distances of up to 750 metres would be feasible, although this would depend on a number of factors, most notably the amount of available heat and the type of insulated pipework specified. In the case of Hurst, operating performance has demonstrated that a lower level of pipework insulation would have been possible; as heat recovery from the transformer enclosure is better than expected.

The heat pump system

A Vaillant Geotherm 46 kW[36] brine-water heat pump provides heat for the office heating circuit. The heat pump uses the R 407 C refrigerant with an average 45/40°C design temperature for the flow/return to the radiators. The principle of heat pump operation[37] is presented in Figure 23 (note that the Hurst heat pump is not used to supply hot water).

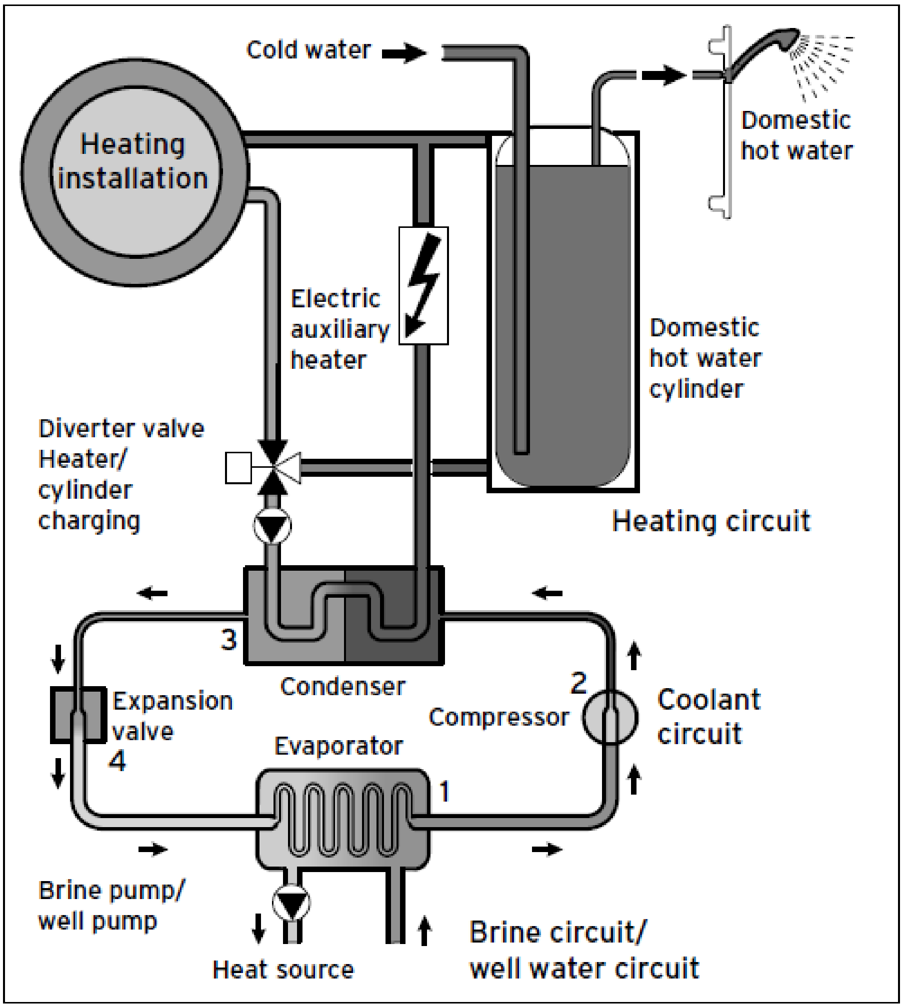

Figure 23: Principle of heat pump operation

Office heating system

The office heating system utilises 'smart-radiators'[38], which increase efficiency giving an estimated extra saving of between 10% and 17% when compared to standard steel radiators. When coupled with the optimal level of insulated pipework, it is envisaged the running costs can be reduced to around a fifth of what is normally achieved from previously installed electric panel heating systems.

36 http://www.vaillant.co.uk/stepone2/data/downloads/10/44/00/geotherm-22-46-kw-operating-manual.pdf
37 Source: Vaillant manual.
38 Smart radiators use a compact, high efficiency heat exchanger and intelligently controlled fan to assist convection and heat delivery. Despite lower water temperatures, smart radiators are significantly more powerful and as a result can be 3½ times smaller than a conventional steel convector radiator with the same level of output (source: Dimplex).

2.4.4 Actual technical performance data

Vaillant records the heat pump performance data via the VRNET Dilog system, located at the front of the heat pump. This also allows remote monitoring of the heat pump for maintenance purposes. This system has also been extended to include monitoring the performance of the air collectors. The data is extracted through a GSM SIM card, which logs the performance of the heat pump over a period of time and is summarised on a monthly basis in Table 4 below.

Table 4: Heat pump performance data

Month	Heat extracted from the transformers by dry air coolers (kWh)
June 2012	2,149
July 2012	1,670
August 2012	1,636
September 2012	1,574
October 2012	3,003
November 2012	4,667
December 2012	6,865
January 2013	8,283
February 2013	7,632
March 2013	8,311
April 2013	5,041
May 2013	3,184
June 2013 (up to 4th June)	316
Total	**54,331**

The dry air coolers have extracted 54,331 kWh of energy from the transformers whilst 73,066 kWh of useful heat has been supplied by the heat pump in the same period. It is calculated that 18,735 kWh of electricity has been used by the heat pump to produce this heat indicating that the heat pump has operated with an average COP of 3.9 at 45/40°C flow/return.

We hope to receive time profiles of the flow and return temperatures of the coolant fluid and the associated coolant fluid flow rates and ambient air temperatures from Rook Services following verification of the full year data along with the time profile of the transformer loading. This can then be used to establish the excess heat available.

The 18 kW backup electric immersion elements have only started four times and have been on for one hour, using 18 kWh in total, despite the relatively cold and prolonged winter. This is extremely encouraging as it demonstrates that the heat pump is easily covering the full heating demand at Hurst thereby providing an extremely sustainable heating system with low carbon emissions.

The two dry air coolers each contain a 0.75 kW fan motor and have the potential to have used up to around 5,460 kWh electricity for the full year based on the office heating requirements of ten hours/day and seven days per week. The performance of the coolers, including electricity usage, is currently being monitored and is expected to be considerably lower. Of particular interest is the performance of the fan motors in the atmospheric conditions of the transformer enclosures and the potential impacts on lifetimes.

Results so far demonstrate that the system is outperforming estimates provided by Carbon Low prior to the installation of the system. Initial analysis of the heat pump data indicates that performance is exceeding the original design projections with a greater amount of useful heat, for example from the cables in the shared troughs, being available than expected. At times this has resulted in the glycol being sufficiently warm enough to provide heat without actually requiring the heat pump to run.

2.4.5 Financial performance

Actual full year running costs

Total electricity requirements = 18,735 + 18 + 5,460[39] = **24,213 kWh**

Total electricity cost = **£1,874** (at the advised electricity price of 7.74p/kWh)

Carbon emissions were initially independently estimated to be around 24 tCO_2, but these should be treated with a degree of caution at this stage due to the number of variables and complexity of calculation. Based on previous estimates annual carbon emissions are indicatively assessed at just over 10 tonnes CO_2. Actual emissions are currently being assessed and will be independently verified.

Comparison of expected and actual costs of running the heat pump

Expected and actual values of various parameters relevant for heat pump operating cost are presented in Table 5.

Table 5: Expected and actual heat pump operating costs

Item	Expected	Actual
System operation	Full year with 45/40 system flow temperatures at an estimated COP of 4.5 and larger sized radiators as installed at Hurst	Full year results at an initial COP of 3.9 with heat pump not always being required to run
Total heat demand from previous year	141,168 kWh	142,000 kWh
Assumed / actual heat delivered by heat pump	115,578 kWh (nominal 82% of demand)	73,066 kWh
Heat Pump COP	4.5	3.9
Electrical input into heat pump	25,724 kWh	18,735 kWh
Assumed/actual electrical top-up for peak periods	25,410 kWh (nominal 18% of demand)	36 kWh
Maximum usage for dry air coolers	5,460 kWh	5,460 kWh
Total electrical input	56,594 kWh	24,213 kWh
Total electricity cost	£4,380 at 7.74p/kWh	£1,874 at 7.74p/kWh
Total carbon footprint	23.91 tonnes of CO_2	10.23 tonnes of CO_2

2.4.6 Capital cost projections for a typical installation

Given the uniqueness of the installation, detailed capital costs are clearly commercially sensitive information, however indicative costs for typical installations have been provided by Rook Services.

Capital costs for the Hurst installation and other NGET survey estimates indicate 'typical' installation costs of £125k for future projects, including the costs of the initial Stage 1 and 2 project assessment work. The approximate split between the costs of the heat collection party of the system and the heat distribution part of the system, including the heat pump is approximately 40:60.

Costs are expected to reduce through economies of scale as a result of multiple installations, design and installation improvements.

Table 6 shows the financial savings projected for a typical installation from the actual deliverable figures from Hurst substation, which directly align with the figures calculated and expected to be

[39] This is the maximum possible usage and current monitoring is expected to show that this is lower.

delivered on NGET's Melksham substation. It is expected that the CRC Energy Efficiency Savings will be indexed to RPI but are shown below based on the 2014/15 expected cost. The current estimates will be refined, once the carbon emissions for Hurst substation have been verified.

Table 6: Projected financial savings from a typical heat recovery installation

Energy savings payback	
Installation cost	£125,000
Cost saving on electric per year	£14,230
Cost saving on electric over 20 years (assuming 5% increase/year)	£287,918
Payback period on energy savings only	7.6 years
Additional CRC Energy Efficiency Scheme Savings (subject to detailed assessment and verification)	
Estimated pre-installation carbon production for electric heating	92 tCO_2/year
Actual post-installation carbon production (subject to full verification)	10.23 tCO_2/year
Projected Carbon savings delivered	81.77 tCO_2 /year (89%)
CRC Energy Efficiency Scheme rate[40]	£16 /tCO_2
CRC Energy Efficiency Scheme saving	£ 1,308/year
Total CRC Energy Efficiency Scheme saving over 20 years	£26,160 ignoring RPI increases

With future improvements to RegenairHeat, Rook Services aims to achieve an improved system performance equivalent to COPs of around 6. When taking account of the glycol being warm enough at times without requiring the heat pump to operate. Combined with the expected rise in carbon tax are expected to reduce payback periods to between 4 and 6 years for a typical installation.

2.4.7 Procurement, contractual and maintenance arrangements

Rook Services have entered a technology partnership agreement with Vaillant for the RegenairHeat system. This will facilitate technology improvements to the system installed at Hurst substation for future projects. Vaillant is providing a 20 year lifetime guarantee for the heat pump, backed up by remote monitoring and an annual service, as part of this agreement. The dry air coolers are also subject to annual maintenance.

Rook Services is currently developing a warranty package for the RegenairHeat system and to meet NGET's needs, which will be underpinned by individual manufacturers' guarantees for example Dimplex smartrads. This will take account of lifetime expectancies of the fan motors if impacted on by the operating conditions.

The lifetime of the RegenairHeat system is expected to be around 20 years, although in reality this can be extended by replacing technical components as and when the need arises.

2.4.8 Potential technical improvements

Over time it is expected that the performance of the RegenairHeat system will be improved compared to the pilot installation at Hurst substation, for example by improving the specification of insulated pipework as discussed above. Future installations will also include a control cable between the heat pump and the dry air coolers to limit the operation of the fans to match the operation of the brine pump on the heat pump.

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[40] In December 2012, Government announced that the price of CRC allowances will be £12/tCO2 in 2013-14; £16/tCO2 in 2014-15; and from 2015-16 onwards, the price will increase in line with the Retail Prices Index.

In new build situations, the RegenairHeat system will benefit from lower installation costs and is likely to perform better than the current retrofit approach. Obviously, this will depend on the amount of available waste heat, which is likely to be less if low-loss transformers are employed. New build installations would allow more efficient heating solutions such as underfloor heating, plinth heating and air curtains to be implemented through the use of lower flow temperatures, which will increase the COP as illustrated in Table 7 below (based on Hurst flow temperatures and Vaillant performance specification). For future installations COP values closer to 5.5 are expected.

Table 7: Projected financial savings from a typical heat recovery installation

Hurst Flow Temperature (°C)	COP
55	3.9
45	4.5
35	5.5

Similarly, savings will be vastly improved if a longer heating period and/or hot water demand was found nearby, for instance at a sports centre or retirement home. However, savings will be lower when compared to conventional gas heating systems as opposed to electric plate systems, although this is less likely to be relevant for substation offices as they are unlikely to use gas.

Improving the GSHP refrigerant

The Hurst installation uses a GSHP where the refrigerant has a boiling point at 20°C. Once the refrigerant is a gas it cannot be compressed so when the brine circuit has a flow temperature of 20°C, the heat pump will automatically shut down. At Hurst the outside temperature would have to be around 25°C for this issue to occur. This can easily be resolved by programming the heat pump to come on at 05.00 in order to prime the large buffer tank when the ambient temperature is low before sending the heating water around the heating circuit. This also allows the heating cycle to maximise its efficiency for space heating.

The RegenairHeat system can be improved by changing the refrigerant within the GSHP to that which is used in Air Source Heat Pumps (ASHPs). ASHPs work at outside temperatures up to 45°C as the boiling point of the refrigerant gas is much higher than that used in GSHPs and would allow the GSHP to work at higher incoming brine temperatures throughout the year. This would allow the heat pump to be used to provide hot water during the summer, which is not part of the system at Hurst presently.

Further research, being undertaken with Vaillant, may demonstrate that ASHPs could be directly employed to reduce plant cost and installation costs whilst improving operational efficiency.

2.4.9 Key risks

Due to the non-intrusive nature of the RegenairHeat system there is no additional risk to transformer performance. Indeed, indications are that the improved cooling will improve transformer performance. The use of simple, proven technologies combined with the staged design process, minimises the risk of the non-performance of the heating system.

2.4.10 Summary

Initial monitoring of the Hurst installation demonstrates that the RegenairHeat system can economically recover heat from enclosed transformers. Simple and cost-effective improvements will be implemented in future projects as the system continues to be refined thereby further improving performance. Further technological improvements and the expansion of the system to provide water heating are also possible.

It would appear that the RegenairHeat system can be readily applied to suitable transformers on the distribution network and in the private sector with a nearby heat demand. We understand that Rook Services is keen to demonstrate the RegenairHeat system in these sectors.

2.4.11 Financial Support

Sustainable Development Capital Limited (SDCL) and the Building Research Establishment (BRE) launched a new programme in July 2013 to provide capital investment for non-domestic energy efficiency retrofit projects in the UK.

The new programme is now open for applications and has up to £100 million available to invest in buildings' retrofit projects and energy infrastructure projects where clear energy and carbon emissions savings will result.

2.4.12 Future developments

In addition to the potential technical improvements and economies of scale mentioned above, Rook Services are exploring a number of other related products including:

- The extraction of waste heat from underground HV cables via a cooling circuit laid along cables with a single point draw off to a heat pump, which can then be used to heat buildings. This could be attractive for new installations, where cooling is required for operational purposes and it could increase capacity without impacting on maintenance/operating life where there are potential hot spot/joint integrity issues.
- The development of a directional air-vortex heat collection system, which will take the maximum waste energy from any apparatus situated in an open space without interfering with any type of mechanical process.
- The use of 'energy harvesting' where excess heat can be stored underground in brine tanks and extracted via heat pumps when required.

2.5 Potential support mechanisms for heat recovery

Heat recovered from transformers and utilised instead of fossil fuel sources will benefit from avoiding carbon taxes such as the Climate Change Levy[41] (CCL), the European Union's Emissions Trading System[42,43] and the new carbon price floor mechanism[44]. Avoidance of the latter is likely to prove particularly attractive if it is implemented as planned.

In addition it is possible that waste heat recovery from transformers could benefit from enhanced capital allowances in future if the technology was deemed eligible. This scheme allows businesses to claim 100% first year allowances on their investment in designated energy-saving plant and

[41] The CCL is a tax on the taxable supply of electricity, natural gas supplied by a gas utility, liquid petroleum gas (LPG) and other gaseous hydrocarbons in a liquid state, coal and lignite, coke, semi-coke and petroleum coke when used for lighting, heating and power, by business consumers in industry, commerce, agriculture, public administration and other services. The CCL does not apply to taxable commodities supplied for use by domestic consumers or to charities for non-business use.
http://customs.hmrc.gov.uk/channelsPortalWebApp/channelsPortalWebApp.portal?_nfpb=true&_pageLabel=pageExcise_InfoGuides&propertyType=document&id=HMCE_CL_001174#P4_44

[42] http://ec.europa.eu/clima/policies/ets/index_en.htm

[43] https://www.gov.uk/government/policies/reducing-the-uk-s-greenhouse-gas-emissions-by-80-by-2050/supporting-pages/eu-emissions-trading-system-eu-ets

[44] The carbon price floor is a tax on fossil fuels used in the generation of electricity which came into effect on 1 April 2013. It includes the setting up of new carbon price support (CPS) rates of the CCL.
http://www.hmrc.gov.uk/climate-change-levy/carbon-pf.htm

machinery against the taxable profits of the period of investment. Qualifying technologies and products such as existing GSHP models are specified in the Energy Technology List[45].

Heat pumps systems that combine heat recovery from transformers with naturally occurring heat extracted from the ground or the air might also benefit from the Renewable Heat Incentive (RHI) in future.

The RHI provides a 20-year financial incentive to increase the uptake of renewable heat by eligible, non-domestic renewable heat generators and producers of bio-methane. This includes community and district heating projects where one boiler serves multiple homes. Ofgem[46] is responsible for implementing and administering the scheme on behalf of the DECC[47] including the accreditation of installations. Although the RHI currently only supports non-domestic installations, DECC intends to extend the RHI to the domestic sector and to increase the number of technologies and fuels which are eligible.

The use of a non-natural heat source, such as heat from a transformer, disqualifies a heat pump system from the RHI subsidy under current legislation. However DECC are currently considering arguments for the proportion of naturally occurring heat extracted from the ground or the air, which is defined as renewable, to be eligible in future provided that the overall system met required technical standards. Heat pumps that produce heat from renewable sources and supplemented by heat recovered from transformers may or may not be eligible for incentives for the renewable element of the system in the future.

2.6 Summary

Vattenfall appears to be the market leader in recovering heat from transformers and is rolling out heat recovery solutions at its substations as a matter of course. Otherwise the projects that we have identified have so far been one-off installations, although Rook Services is in discussions to roll out additional projects for NGET and is exploring other opportunities.

Some projects appear to have been driven more by sustainability aspirations rather than by economic drivers, although clearly Vattenfall believe heat harvesting from transformers is economic for heating its substation offices. We have not identified any projects that have demonstrated economic viability as commercial solutions but this does not mean that such projects are uneconomic and more detailed examination of Vattenfall's installations is likely to prove helpful.

We have not been able to obtain detailed performance data from any existing installations that have been operating for any length of time and to date no examples of completed heat-recovery projects which have become enduring solutions.

It does not appear that detailed monitoring and performance data is being recorded or analysed for existing projects. Certainly such data is not available in the public domain.

[45] https://etl.decc.gov.uk/etl/site.html
[46] http://www.ofgem.gov.uk/e-serve/RHI/Pages/RHI.aspx
[47] https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/renewable-heat-incentive-rhi

3 Potential for recovering heat from transformers

3.1 Transformer cooling systems

There are a number of different transformer cooling systems currently in use. These systems vary in complexity and in their effectiveness of meeting the primary objective of cooling the transformer, as indicated in Table 8.

Table 8: Potential to extract useful heat from different transformer cooling systems

Cooling method	Potential	Comment
Oil Natural Air Natural (ONAN)	Low	This is the simplest type of cooling, used in many smaller transformers which are usually freestanding and from which it would be difficult to harvest heat. It is also used as the first stage of a typical sub-station transformer.
Oil Natural Air Forced (ONAF)	Medium	This type of cooling is normally used in a staged operation in conjunction with Oil Forced.
Oil Forced Air Forced (OFAF)	Medium	This is the final stage of a typical sub-station transformer which cascades from ONAN to OFAF as the cooling requirement increases. As the oil/air heat exchanger is in the open air, there is limited opportunity to harvest the heat except from within the transformer building.
Oil Forced Water Forced (OFWF)	High	This type of transformer currently offers the most opportunity for heat recovery and is used in several schemes. This system offers a high degree of control for heat recovery.
Oil Directed Air Forced (ODAF)	Medium	These are mainly used for high load industrial applications where minimising plant size is important and there is probably limited opportunity to harvest the heat in these situations.
Oil Directed Water Forced (ODWF)	High	

3.2 Recovery of heat from transformers

3.2.1 OFWF Cooling

The OFWF transformer cooling system (Figure 24) is the preferred starting-point for the implementation of heat recovery of losses in new transformers as most of the generated heat is captured by the cooling water of the oil-water cooler, and water is a good medium for transporting heat to a distant load. In addition, transformer size is reduced when OFWF cooling is used and this is particularly attractive in urban areas where space limitation is an important constraint when upgrading old or developing new substations. Additional advantages of OFWF transformers over natural circulation cooling for heat recovery include:

- Water can be pumped to a tank and/or used;
- Water can be reheated with boilers, heat pumps or electric heaters;
- Better heat recovery control is possible.

Forced cooling systems are likely to provide a larger quantity of heat at higher temperatures but will require some form of back-up system to cool transformers in the event of system component failure, e.g. the water pump.

Figure 24: OFWF transformer at Tate Modern substation

It is this form of cooling system which has been modelled and analysed in some detail later in this Appendix.

3.2.2 Non-intrusive techniques

Non-intrusive techniques for heat recovery are potentially attractive as they may be engineered to not compromise network operation nor affect security of supply or transformer lifetime. Non-intrusive systems may also be more attractive for retro-fit solutions as demonstrated by the recent installations for National Grid by Rook Services.

It may prove possible to exchange heat directly from transformer insulating oil to a heat pump although this would bring additional risks of contamination in case of a heat exchanger leak and more complex control systems.

Although the non-intrusive systems have lower risk and are likely to be cost-effective for existing transformers with an adjacent heating load, they also have a reduced capability for heat recovery and often will require the use of a GSHP to provide sufficient heating capacity to be operationally useful. Conversely, the forced water cooling systems can have a higher risk but be engineered to provide back-up capability and recovery of heat in sufficient quantities and at a high enough temperature to be used directly for space heating but are likely to be only cost-effective for new installations.

3.3 Potential heat availability

There are several differences between the value potential for heat recovery from new transformers compared to retrofit systems such as:

- New build heat recovery will benefit from lower installation costs and is likely to perform better than retrofit solutions through an integrated design approach;
- New installations will allow solutions that optimise heat recovery from associated cabling;
- New transformers are likely to be more efficient so quantity of heat that can be recovered will be lower.

The economic potential will depend on whether the transformer is enclosed in a building or in an open environment where the heat from the transformer casing escapes to the atmosphere. The construction of enclosures around open transformers combined with air collectors would enable the collection of waste heat from the majority of substations. Materials such as PVC panels can be easily and cheaply used to enable the heat capture, whilst reducing the noise impact on the environment. Of course, the addition of an enclosure and recovery pipework will have a cost implication but this will be small compared to the total project cost.

More expensive "rubber bladder" systems could be used as the next best alternative, where the construction of an enclosure is not feasible. The rubber bladder system would capture heat from the radiator fins of the transformer coolers through direct contact on the fins giving more efficient heat transfer although a drainage system would be required to maintain cooling in case of heat pump failure.

Utilising recovered heat for new buildings from new transformer installations will result in the most economic schemes as the entire system can be developed at the design stage, especially where a developer or occupier is keen on innovation. Such opportunities will be less common than potential retrofit opportunities.

DNOs would need to be proactive in developing projects and the impacts of various issues are summarised below:

Positive impacts

- Local authorities (and possibly housing associations) with fuel poverty focus might be more interested.
- Heat recovery could be attractive where space attracts a premium at urban sites and underground SF6 transformers may provide niche opportunities where land is at a premium although there are few SF6 transformers in GB.
- Horticultural applications might be of interest but this introduces commercial risk for growers.

Negative impacts

- Opportunities for heat recovery from new transformers will be reduced by the Regulations for reduced losses under the Ecodesign Directive and the general adoption of lower loss transformers. This will typically reduce losses by between 10% and 30% (depending on utilisation) increasing the project payback by a corresponding amount.[48]
- Other transformer cooling alternatives will be required if there is no heat demand, although heat can just be vented as normal from transformer enclosures if non-intrusive solutions are adopted.
- Waste heat is likely to be too low grade and in insufficient quantity to be valuable for larger heating schemes and industrial processes.

There is clearly an opportunity for a LCNF Tier 2 demonstration project to prove the potential for heat recovery from transformers and associated cabling. This could take several forms depending on whether the project is:

- A new transformer or retrofit solution;
- An intrusive or non-intrusive systems;

[48] Eurelectric response to implementation of Directive 2009/125/EC

- Transformer only or combined harvesting system;
- Includes a heat pump;
- Includes thermal storage;
- Provides heating and/or hot water;
- Supplies substation offices or third party property.
- Supplies a new build heat demand source

Rook Services appears to be the UK market leader in the installation of non-intrusive systems and would be interested in working on a DNO project.

3.4 Methodology for modelling of heat recovery from transformers

The modelling presented in this section focuses on the process of recovering heat from electrical losses of medium-sized power transformers equipped with OFWF cooling. Our modelling also included the characterisation of other components of the heat recovery system, i.e. the associated oil-water coolers, oil and water pumps, heat pumps and radiators. According to currently available transformer designs, the quantity of heat generated by losses, which can be potentially recovered from transformer sizes of 15 MVA to 90 MVA, varies between 54 kW and 197 kW.

Using a set of computer models, we have developed the methodology for assessing the feasibility and potential benefits of the use of recovered heat from transformer losses in combination with the use of heat pump technology.

Evaluation of the potential benefits of recovering heat from transformer losses was carried out using the detailed component models, and the approach presented in Figure 25. By calculating transformer losses for a given loading level, it is possible to calculate the transformer oil temperatures and use the oil-water cooler model to compute the outlet water temperature. This allows for the COP of the heat pump to be calculated. In addition to the results of the energy consumption and heat transfer calculations, the investment and operating costs are further used as inputs for the Cost-Benefit Analysis (CBA), the results of which include Payback Times and NPV of Capital Expenditure (CAPEX) and Operational Expenditure (OPEX). Doing this for all heating system design options eventually suggests the least-cost solution.

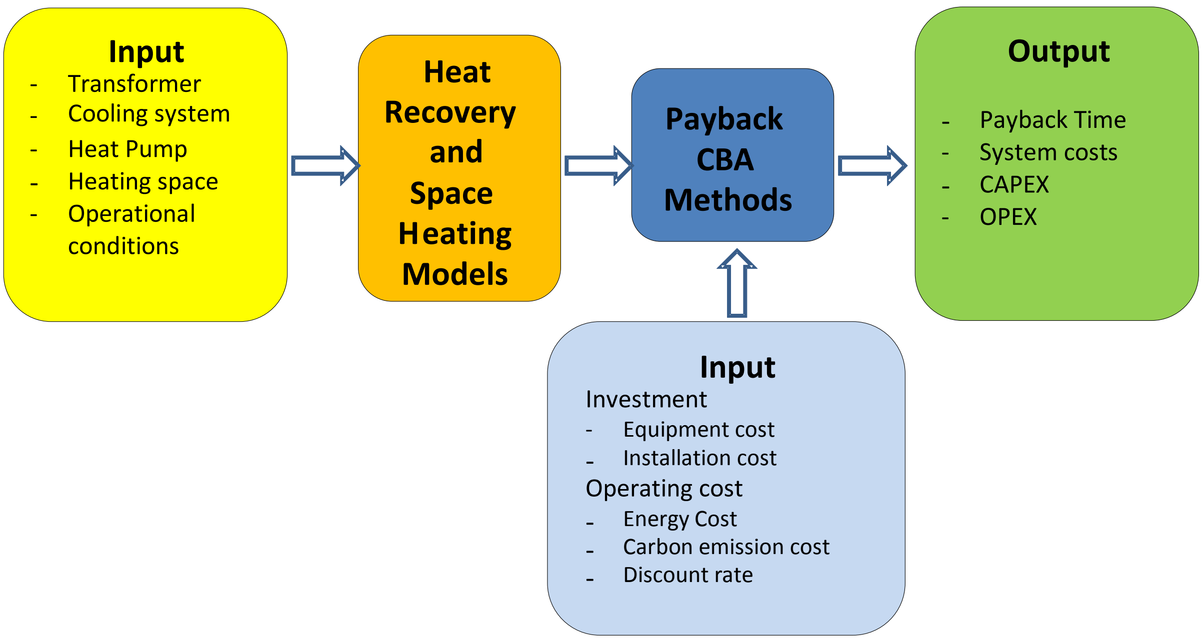

Figure 25: Modelling methodology

The concept of the transformer heat recovery system is illustrated in Figure 26. This system includes several key components: transformer, oil-water cooler, oil and water pumps, heat pump and heat diffusers (radiators) which are installed in the heated space. Heat generated by losses in the transformer is conducted from the oil circuit into the water circuit, and is used to improve the performance (COP) of the heat pump. The heat supplied through the heat pump is finally transferred to the heated space via a Low Pressure Hot Water (LPHW) radiator system.

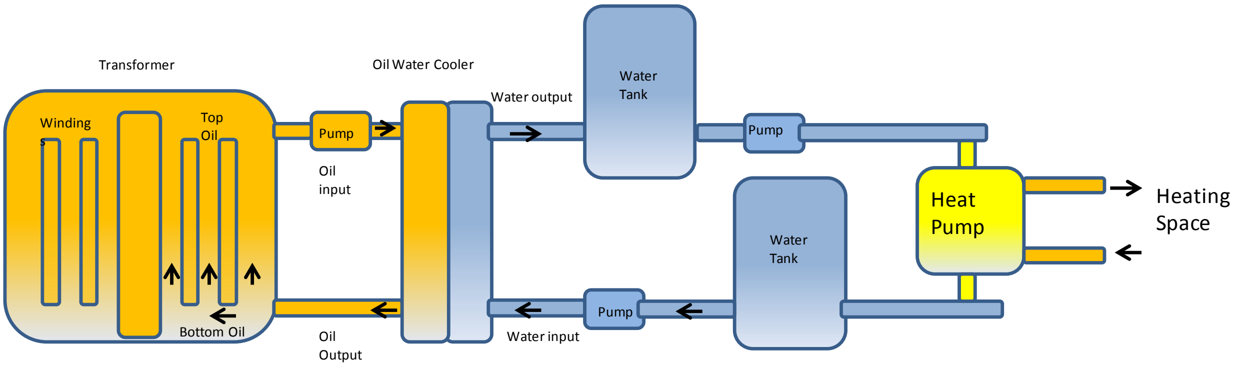

Figure 26: Concept of heat recovery from distribution power transformers

The economic assessment methodology presented in this report is demonstrated on an example of an OFWF-cooled transformer rated at 15 MVA with an average loading of 70%. The capacity of the heating system was determined as the level of losses occurring at the loading of 70% of the nominal rating, with 80% of the heat generated by the losses being successfully recovered (the remainder being lost to the ambient). The baseline assumption for the heat pump cycle efficiency was 60% (i.e. that its COP is 60% of the maximum theoretical value for a given temperature difference), while the inlet water temperature has been assumed at 7.7 °C, which corresponds to average winter temperature.

3.4.1 Economic performance assessment

The assessment of the economic performance of heat recovery has been carried out by comparing alternative space heating designs under different scenarios. The economic feasibility of various heating options is quantified using two key metrics:

- *Payback Time*, quantified with respect to the two conventional benchmark heating systems: (a) electric heater, and (b) gas boiler. Payback times are calculated by finding the number of years needed to recoup the additional investment into equipment and installation through savings in operating cost when compared against the benchmark technology.
- *Net Present Value (NPV)* of different cost components over the assumed equipment lifetime. The total cost of each option is disaggregated into equipment, installation, maintenance, energy (gas or electricity) and carbon cost, and expressed as NPV using the assumed discount rate.

<u>Discounted payback method</u>

Payback is one of the most simple and frequently used methods for evaluating the savings generated by investing into a project or a piece of equipment. This method determines the number of years that are necessary for recovering the initial capital investment. The simple payback period is calculated as follows:

$$Payback\ Period = \left(\frac{Investment}{yearly\ benefits - yearly\ costs} \right)$$

When evaluating the heat recovery system against the two benchmark systems, it is necessary to quantify the difference between the initially required investments, as well the difference in the annual operation and maintenance cost. Unlike the simple payback calculation, the discounted payback period[49] adopted in this study also takes into account the discount rate:

$$R = -\frac{\ln\left(1 - \frac{iC}{M}\right)}{\ln(1+i)}$$

Where:

R = break-even number of years

M = yearly net benefits

C = initial investment costs

i = discount rate

<u>Net present value of project cost</u>

The net present value (NPV) of annual operation and maintenance cost is evaluated along with the initial investment cost. The least-cost heating system design can then be found by comparing total NPVs (investment plus operation cost) for each case. The investment cost considers equipment such as the gas boiler, electric heater, heat pump, flow control and their installation costs. Operation costs comprise energy costs, carbon emission costs and maintenance. Figure 27 illustrates the trade-off between the investment cost and the cost of energy (operation cost), and quantifies how each of the two cost components depends on the maximum capability for heat recovery, which although saves energy, requires more equipment i.e. higher investment cost.

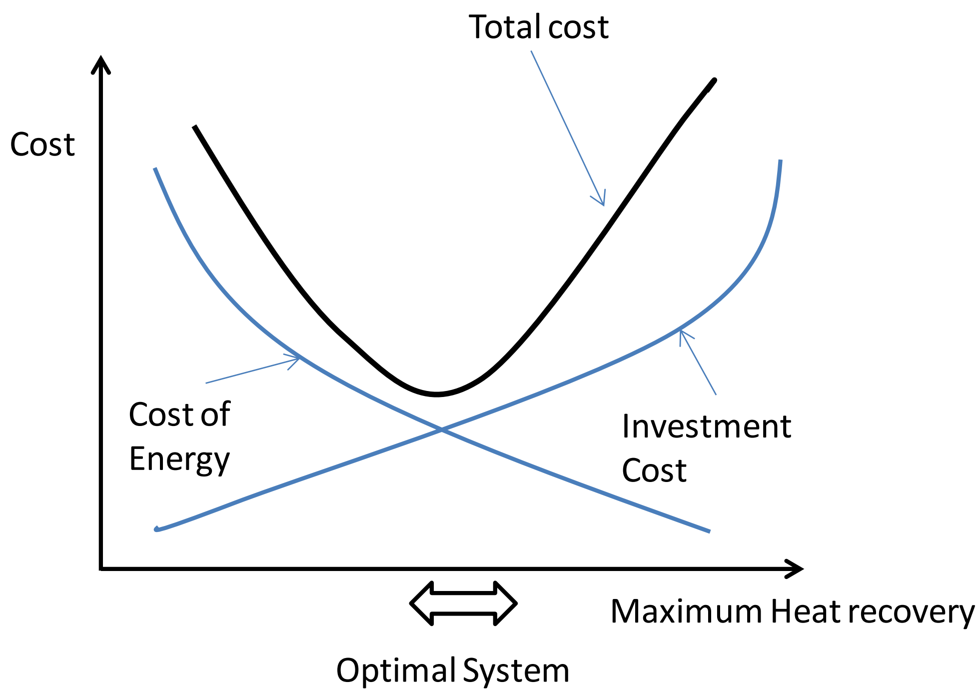

Figure 27: Cost-benefit analysis of heat recovery systems

[49] http://www.financeformulas.net/Discounted-Payback-Period.html.

3.4.2 Modelling of heat recovery systems

The model evaluation process starts with the computation of transformer losses which are associated to its size and loading. The total losses are used to determine the heat recovery potential and the internal transformer refrigerant temperatures. Then the temperatures produced through the refrigerant heat exchange in the transformer cooler are calculated according to the transformer cooling classification and technical characteristics.

The values of recovered heat, refrigerant temperatures and required water temperatures for heating spaces are then used to evaluate heat pump performance. This is essential because the fundamental idea of this heat recovery design is that the rise of the outlet water temperature of the transformer cooler can significantly enhance the heat pump COP. This improved heat pump system can provide hot water for heating spaces in residential or commercial buildings with positive economic and environmental impacts. The computational flowchart is illustrated in Figure 28.

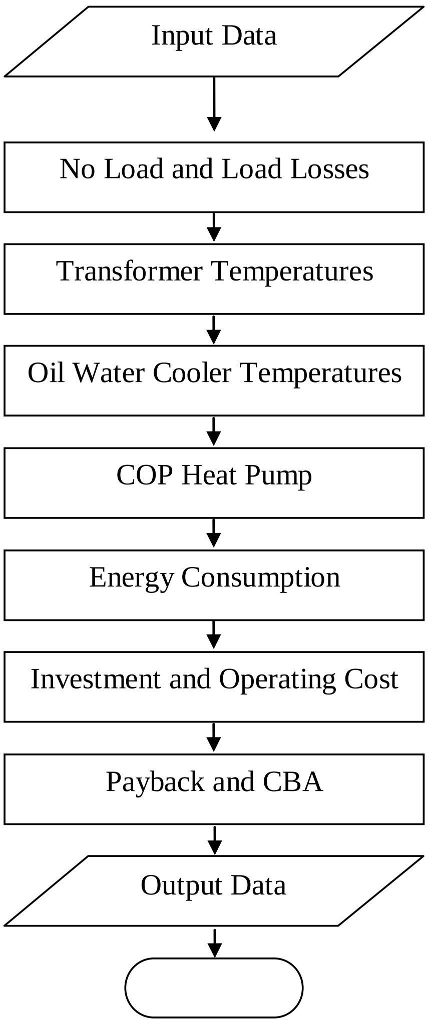

Figure 28: Methodology flowchart

3.4.3 Thermal behavior of transformers

The transformer data listed in Table 9 show the key inputs required for this analysis. Transformer nominal power is particularly relevant because the amount of recovered heat is nearly proportional to transformer capacity. Nominal load and no-load losses are not always available, but can be calculated using the polynomial functions derived from actual measurements. As already mentioned, this analysis has been carried out taking into account OFWF transformers only.

The ambient temperature is the same as the external refrigerant; air or water. In this analysis, the ambient temperature is assumed as the same as the inlet water temperature of the transformer cooler and is associated with the ground temperature at 1 metre depth. The remaining internal transformer temperatures (the bottom, top, and hotspot temperature rises) are then referenced to this.

The empirical exponents have been taken from the British Standard [BS IEC 60076-7:2005] and correspond to the transformer cooling specification.

Table 9: Transformer input data

No.	Parameter/Variable	Value	Units	Description
1	Transformer nominal power	15	Megavolt-amperes (MVA)	Selected
2	No load losses	P_{NLL}	Kilowatts (kW)	Calculated
3	Load losses	P_{LL}	Kilowatts (kW)	Calculated
4	Cooling	OFWF	(ODWF) or (OFWF)	Selected
5	Ambient temperature	10 +273.2	Kelvin (K)	Estimated
6	Bottom oil temperature rise	45	Kelvin (K)	Estimated
7	Top oil temperature rise	65	Kelvin (K)	Estimated
8	Hotspot temperature rise	15	Kelvin (K)	Estimated
9	Empirical exponent m	1	NA	ODWF/OFWF
10	Empirical exponent n	1	NA	ODWF/OFWF

Technical characteristics of the oil-water cooler are essential for determining the effectiveness of the heat exchange. The oil and water temperatures, flow rates and pressures can then be used to determine the effect of flow control in the process. Table 10 shows the characteristics of a 15 MVA transformer manufactured according to the British Standard [BS EN 50216-9:2009].

Table 10: Oil-water cooler input data

No.	Parameter/Variable	Value	Units	Source
1	Nominal capacity	100	kW	Manufacturer
2	Oil flow	26.2	m^3/h	Manufacturer
3	Water flow	7.5	m^3/h	Manufacturer
4	Pressure loss from A/B oil	0.3	Bar	Manufacturer
5	Pressure loss from A/B water	0.18	Bar	Manufacturer
6	Inlet temperature oil	70	°C	Manufacturer
7	Inlet temperature water	30	°C	Manufacturer
8	Outlet temperature oil	62	°C	Manufacturer
9	Outlet temperature water	41.8	°C	Manufacturer

The COP of the heat pump is dependent on the difference between the inlet water and evaporator temperatures, and outlet water temperature of the condenser. The heat demand of an indoor heated space is typically around 80 W/m^2 with standard radiators requiring water temperatures of 55^oC. This temperature requirement can be decreased to 45^oC when low-temperature radiators are used. In cases where domestic hot water is added, the water temperature requirement will be 65^oC.

The percentage loading of a transformer will vary during the day and throughout the year. Location, hour of the day and season will all influence the electricity demand and consequently the transformer loading. Furthermore, the water which is used in the oil-water cooler has a different temperature during the year. Table 11 shows the assumed inlet water temperatures, equal to the ground temperatures at 1 m depth.

Table 11: Seasonal data

Season	Loading percentage (%)	Inlet Water Temperature (°C)
Winter	80%	7.7
Spring	70%	9.3
Summer	60%	15.4
Autumn	70%	13.1
Annual	70%	11.4

Transformer thermal characteristics

Transformer losses can be classified as no-load or load losses. The former are constant for all transformer operating points and are related to core losses whilst the latter are proportional to transformer loadings and are associated with winding losses. The transformer losses are normally given in its nameplate data for nominal operation and vary for each transformer according to its size, manufacturer and specific characteristics. However for an approximate calculation of losses, a simple rule of thumb for power transformers is that nominal losses are around 0.5% of nominal transformer capacity. A better method is to use statistical data from actual transformers to build polynomial approximations which use the transformer nominal capacity as input data only. This is the approach that has been adopted for this analysis.

We denote with S_T the transformer capacity in MVA and with *a*, *b*, *c*, *d*, *e*, and *f* the polynomial parameters of the function that gives the values of losses in kW per MVA. The no-load losses (kW/MVA) are then calculated as follows:

$$f_{NLL}(S_T) = \mathrm{a}S_T^2 - \mathrm{b}S_T + \mathrm{c}$$
$$\mathrm{a} = 6.216 \times 10^{-5}$$
$$\mathrm{b} = 0.01219$$
$$\mathrm{c} = 1.523$$

Load losses (kW/MVA) on the other hand are calculated as follows:

$$f_{LL}(S_T) = \mathrm{d}S_T^2 - \mathrm{e}S_T + \mathrm{f}$$
$$\mathrm{d} = 0.0002657$$
$$\mathrm{e} = 0.0524$$
$$\mathrm{f} = 4.969$$

When operation temperatures differ, the following equation can be used for adjusting the load loss calculation to the new temperature in the conductor:

$$P_{CU\_Tr} = P_{CU\_Tm} \frac{T_k + T_r}{T_k + T_m}$$
$$T_k = 234.5 \text{ for copper}$$
$$\mathrm{T}_r = \text{New temperature}$$
$$\mathrm{T}_m = \text{Manufacturer temperature}$$

Transformer losses are converted into heat which is dissipated in the transformer refrigerant. Refrigerants can be liquid such as synthetic liquid, mineral or vegetable oil; or gas such as SF6. Heat dissipation through refrigerant is relevant because temperatures can rise above operation limits. The key criterion which limits the transformer loading is the hottest-spot temperature, as it can cause degradation of the winding insulation, increasing the potential of transformer failure.

In addition to the transformer refrigerant, the cooling system will drop the refrigerant temperature by exchanging its heat to another refrigerant. With the appropriate cooling system and under certain operating conditions, a transformer may be safely loaded beyond its nameplate rating. Because oil filled transformers are the most frequently used, the analysis focuses on this transformer type.

The specification of transformer cooling is based on both the internal cooling medium and circulation mechanism and the external cooling medium and its circulation mechanism. This specification can be found in British Standard [BS EN 60076-2:2011].

First letter: Internal cooling medium:

- O: mineral oil or synthetic insulating liquid with fire point ≤ 300 °C;
- K: insulating liquid with fire point > 300 °C;
- L: insulating liquid with no measurable fire point.

Second letter: Circulation mechanism for internal cooling medium:

- N: natural thermosiphon flow through cooling equipment and in windings;
- F: forced circulation through cooling equipment, thermosiphon flow in windings;
- D: forced circulation through cooling equipment, directed from the cooling equipment into at least the main windings.

Third letter: External cooling medium:

- A: air;
- W: water.

Fourth letter: Circulation mechanism for external cooling medium:

- N: natural convection;
- F: forced circulation (fans, pumps).

Table 12 shows the transformer cooling specification and their availability for the implementation of heat recovery process. The water cooled systems OFWF and ODWF have a high potential for heat recovery implementation.

Table 12: Transformer cooling specification

Sub-method	ID	Low	Medium	High	Comments
Oil Natural Air Natural	ONAN	√			Low control in heat recovery
Oil Natural Air Forced	ONAF		√		Medium control in heat recovery
Oil Forced Air Forced	OFAF		√		Medium control in heat recovery
Oil Forced Water Forced	OFWF			√	High control in heat recovery
Oil Directed Air Forced	ODAF		√		Medium control in heat recovery
Oil Directed Water Forced	ODWF			√	High control in Heat recovery

Transformer losses produce heat which drives the rise of transformer temperatures and consequently have an impact on ageing. Simple and complex thermal models have been developed to understand the link between them.

An accurate and detailed analysis can be carried out using the Finite Element Method (FEM), but reduced thermal models are more frequently used for practical reasons. These can be found in standards such as [BS IEC 60076-7:2005], and use a lumped capacitance method with thermal electrical analogy for the transformer thermal analysis. This approach has been adopted in this work, focusing on steady-state analysis.

Steady state of hotspot and top oil temperatures are calculated using the following equations:

$$\Delta T_H = \Delta T_{Hnom} K^{2m}$$

$\Delta T_H =$ Hotspot temperature rise
K= load ratio
R= load loss to no load loss ratio
m= empirical exponent

$$\Delta T_{TO} = \Delta T_{TOnom} \left[\frac{K^2 R + 1}{R + 1} \right]^n$$

$\Delta T_{TO} =$ Top oil temperature rise
K= load ratio
R= load loss to no load loss ratio
n= empirical exponent

The bottom oil temperature is calculated following a similar procedure:

$$\Delta T_{BO} = \Delta T_{BOnom} \left[\frac{K^2 R + 1}{R + 1} \right]^n$$

$\Delta T_{BO} =$ Bottom oil temperature rise
K= load ratio
R= load loss to no load loss ratio
n= empirical exponent

Oil forced water forced (OFWF) transformer

The concept of the OFWF cooling system is quite simple; the top oil which has the highest temperature is pumped from the transformer to the oil-water cooler where the heat is exchanged in the oil-water cooler and the cooled oil is returned to the transformer. The water takes the heat in the oil-water cooler and increases its temperature.

The OFWF transformer type is a good choice for implementation of the heat recovery process of transformer losses because almost the entire heat is captured by the cooling water of the oil-water cooler, and water is a good medium to transport heat. In addition, transformer size is reduced when OFWF is used which is an excellent feature for installing this type in urban areas where space limitation is an important restriction for upgrading old or developing new substations. After raising its temperature by taking the heat from the oil, the cooling water can be pumped to a tank and/or sent directly to other equipment with minor heat losses and can be reheated with boilers, heat pumps or electric heaters; or it can operate as a continuous heat source. Additional features such as variable flow control can be implemented to enhance the heat recovery.

Figure 29 and Figure 30 show an OFWF transformer and the principal components of the heat recovery system.

Figure 29: OFWF transformer

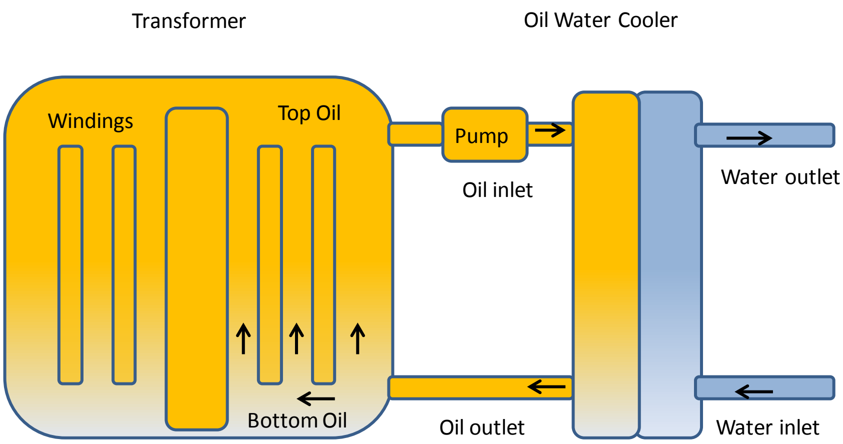

Figure 30: OFWF transformer components

The top oil of the transformer is pumped to the oil-water cooler, which is a heat exchanger, where the heat is transferred from the oil to the cooling water. The outlet temperatures of water and oil are dependent on the inlet water and oil temperatures and their respective mass flow.

However, not all heat can be recovered and there is a certain level of heat loss in this process. The heat exchanger effectiveness can be around 80% i.e. with around 20% of heat loss in the exchange. Further information about oil-water cooler and heat exchangers can be found in British Standards [BS EN 50216-9:2009] and [BS EN 305:1997].

The following equation is used to calculate the heat exchanged and the respective temperatures for a typical oil/water cooler shown in Figure 31, with the assumptions that the heat loss in the tank and cooler are 20%, T_{oil_inlet} is equal to bottom oil temperature and T_{oil_outlet} is equal to top oil temperature.

$$Q = \dot{m}_{oil}\, C_{p\_oil} \left(T_{oil\_inlet} - T_{oil\_outlet} \right) + Q_{loss}$$

$$Q = \dot{m}_{water}\, C_{p\_water} \left(T_{water\_inlet} - T_{water\_outlet} \right) + Q_{loss}$$

Q = Heat of transformer losses (in kW)

m=mass flow rate (in kg/s)

C_p =specific heat at constant pressure (kJ.kg.K);

T= Temperature (K)

Q_{loss}= heat loss to or the heat gained from enviroment (kW).

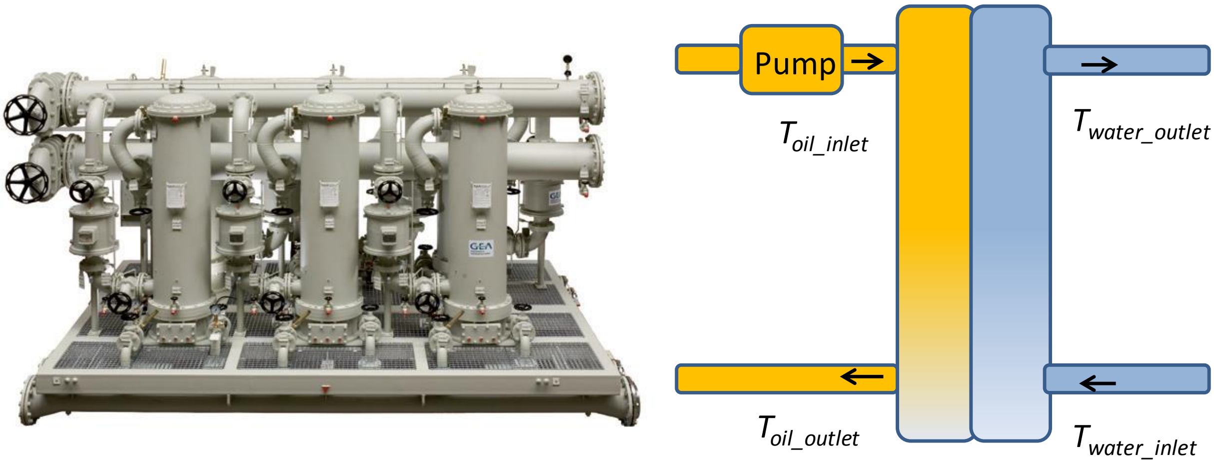

Figure 31: Oil-water cooler

3.4.4 Heat pump characteristics

In general, heat pumps transfer heat based on the vapour compression cycle known as the Carnot cycle. Figure 32 shows the four stages of this cycle; compression, condensation, expansion and evaporation. Evaporation can be described as the stage where the heat is extracted from the outlet water of transformer cooler and condensation as the stage where the heat is delivered by increasing the water temperature which is distributed for space heating.

The compression stage requires external work and this is provided by means of a mechanical compressor normally driven by an electric motor. In general the COP is defined as the ratio of the heat delivered by the heat pump to the electricity supplied to the compressor.[50] However, for an ideal heat pump the COP can be calculated as the ratio of condenser temperature to the temperature lift which is defined as the difference of condenser and evaporator temperatures, as described in the following equation:

$$COP_{Ideal} = \frac{T_{Condenser}}{T_{Condenser} - T_{Evaporator}}$$

[50] R. Rawlings, "Ground Source Pumps – A technology review", Building Services Research and Information Association BSRIA, July 1999.

The ratio of the actual COP to the ideal one is defined as the Carnot efficiency cycle ηC. This equation is adequate for real systems using a cycle efficiency factor, which varies between 30% for inefficient systems to 70% for very efficient ones.[51]

$$COP_{Real} = \eta C\left(COP_{ideal}\right) = \eta C\left(\frac{T_{Condenser}}{T_{Condenser} - T_{Evaporator}}\right)$$

This equation suggests that lower temperature lift will result in higher efficiency and this characteristic is the reason why outlet water temperatures of the transformer cooler help to increase heat pump efficiency.

A general assumption is to use the heat pump inlet and outlet water temperatures as evaporator and condenser temperature, respectively, but this approach will deliver misleadingly high COP values. A conservative assumption is to use a fixed or variable temperature difference between the inlet and evaporator, as well as between condenser and outlet water.

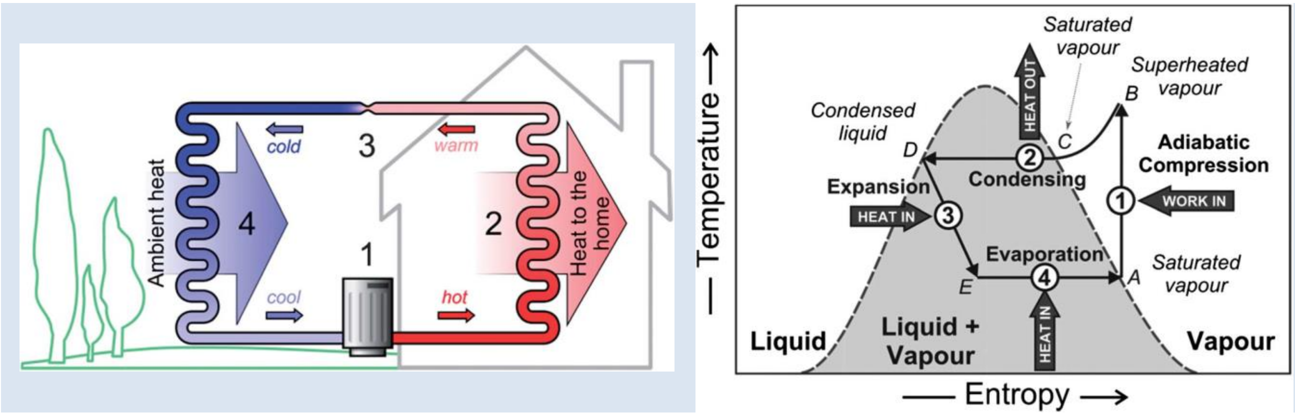

Figure 32: Vapour–compression refrigeration cycle used by heat pumps[52]

The heat which is produced by the heat pump can be distributed by different kind of systems inside the building. The heat that is required by an average house is around 60 W/m^2 whilst a commercial building requires between 70 and 100 W/m^2.[53] Independently of heat requirements for the heating space, there are temperature requirements for the operation of heat diffusers.

This work evaluates the impact of temperature requirements of two types of heat diffusers; conventional radiators and low temperature radiators, which have 55°C and 45°C of temperature requirements respectively. The selection of the radiator type will directly affect the heat pump temperature lift and consequently the COP.

3.4.5 Thermal performance of heat recovery systems

Transformer losses can be calculated for the full operation range using transformer nominal values given by the manufacturer, or using the polynomial functions presented earlier. An example for the specific case of a 15 MVA transformer is shown Figure 33, where the curves of load losses, no-load losses and the sum of both are depicted. It can be observed that the total transformer losses increase with higher loading percentage. Nominal losses occurring at 1 pu loading are slightly above 80 kW.

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[51] R. Brown, “Heat Pumps – A guidance document for designers”, Building Services Research and Information Association BSRIA, October 2009.
[52] I. Staffell, D. Brett, N. Brandon and A. Hawkes, “A review of domestic heat pumps”, Energy & Environmental Science, 2012, 5, 9291.
[53] “The BSRIA Blue book”, Building Services Research and Information Association BSRIA, December 2012.

It is important to calculate the losses for the full operating range because the transformer loading percentage varies according to the fluctuation of the demand, which can range between 50% and above 100% of nominal, resulting in loss levels of 40 to 80 kW.

It is necessary to have an estimate of the transformer loading throughout the year in order to correctly estimate of the amount of heat that can be recovered annually and to size the equipment accordingly.

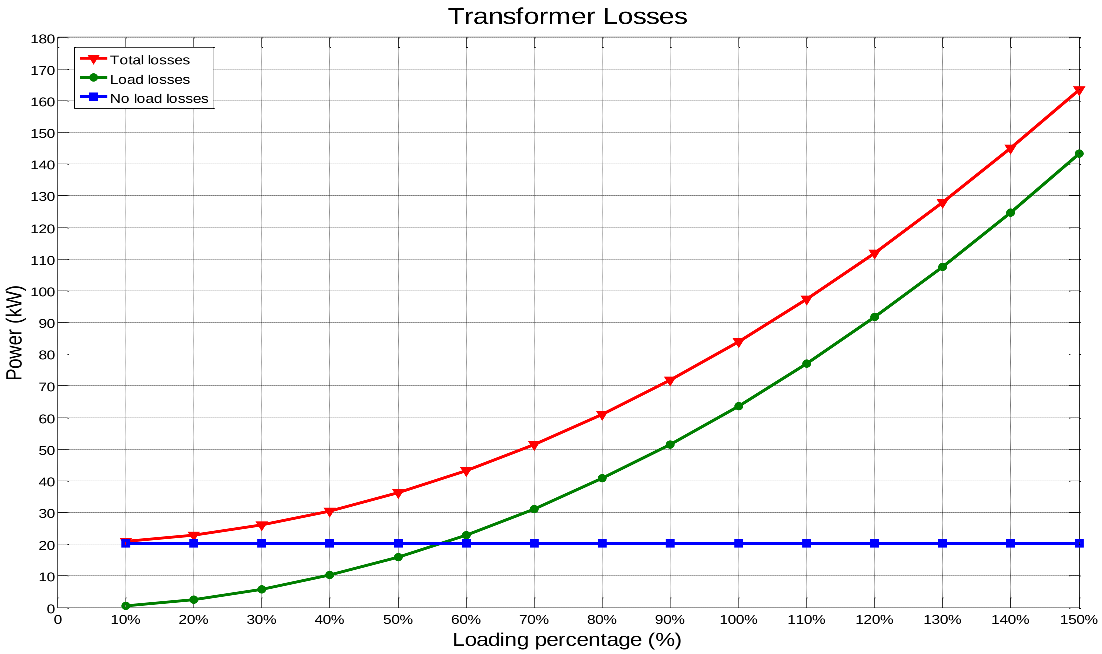

Figure 33: Losses of a 15 MVA transformer as function of loading

Because internal transformer temperatures are associated with the losses, the losses are computed for all possible transformer operating points. Using the example of a 15 MVA transformer, the relationship between losses and loading is depicted in Figure 34.

Steady-state temperatures are calculated from the nominal ones, considering their relation with the cooling water. The hot spot temperature is critical for transformer ageing and life. The top and bottom oil temperatures are the same as the inlet and outlet oil temperatures of the oil-water cooler, respectively. During transformer operation all these temperatures respond to changes in heat generation, cooling water temperatures, and refrigerant flows according to the system thermal mass. However, for long-term evaluation the steady-state temperature computation is adequate.

In the heat exchange which takes place in the oil-water cooler, the heat is taken away from the oil decreasing its temperature and raising the temperature of the water which takes this heat. An important element in this exchange is the time that that both liquids spend inside the cooler and this is defined by their mass flow. This flow can be modified by the use of a mechanical reducer or controlled by using a variable speed driver for the motors that are moving oil and water pumps. Figure 35 shows different outlet water temperature curves for different constant and variable flows for the entire range of possible transformer loading percentages.

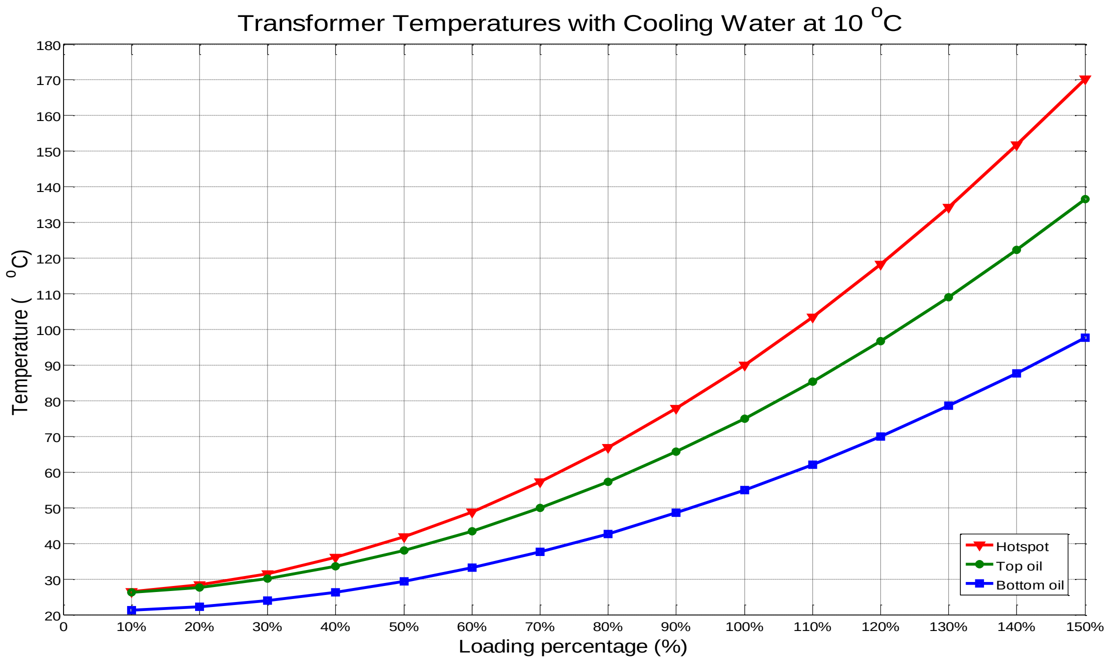

Figure 34: Transformer temperatures

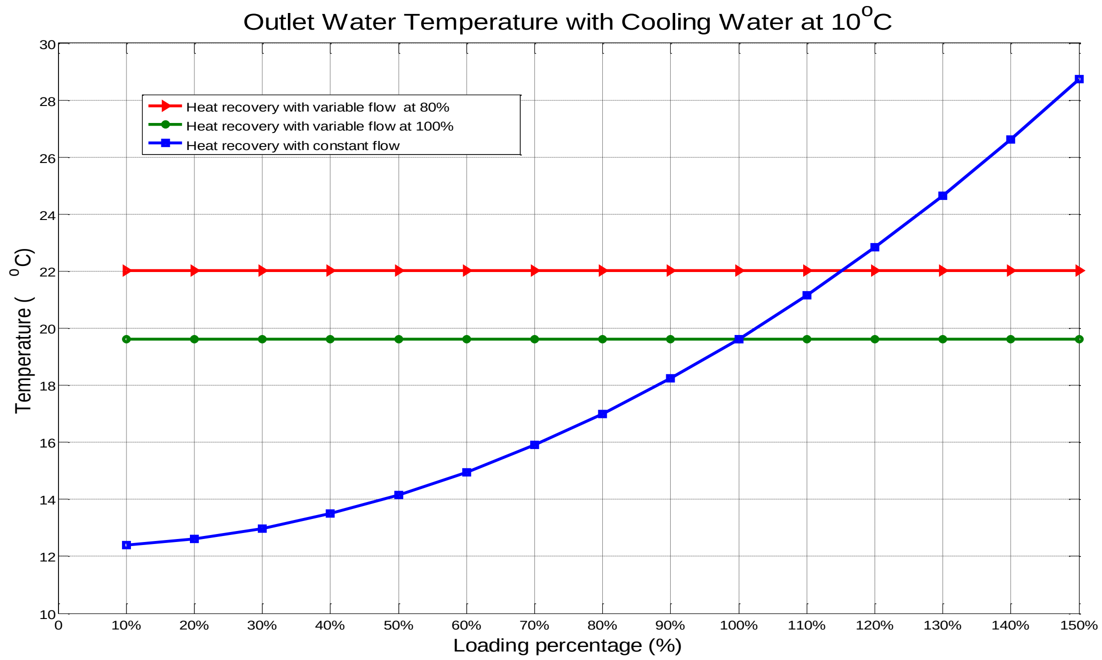

Figure 35: Outlet water temperature of the oil-water cooler

As described previously, the performance of a heat pump is related to the temperature lift between the evaporator temperature and the condenser. The first is highly influenced by the heat source which is the outlet water temperature and the second one by the water temperature which is used for heating space.

Figure 36 shows the effect of the transformer loading on the heat pump COP. The standard GSHP is unaffected although there is a possible degradation of the COP with long operating times. The COP in a heat recovery system increases with higher transformer loading. On the other hand, a constant COP can be achieved when variable control flow is used.

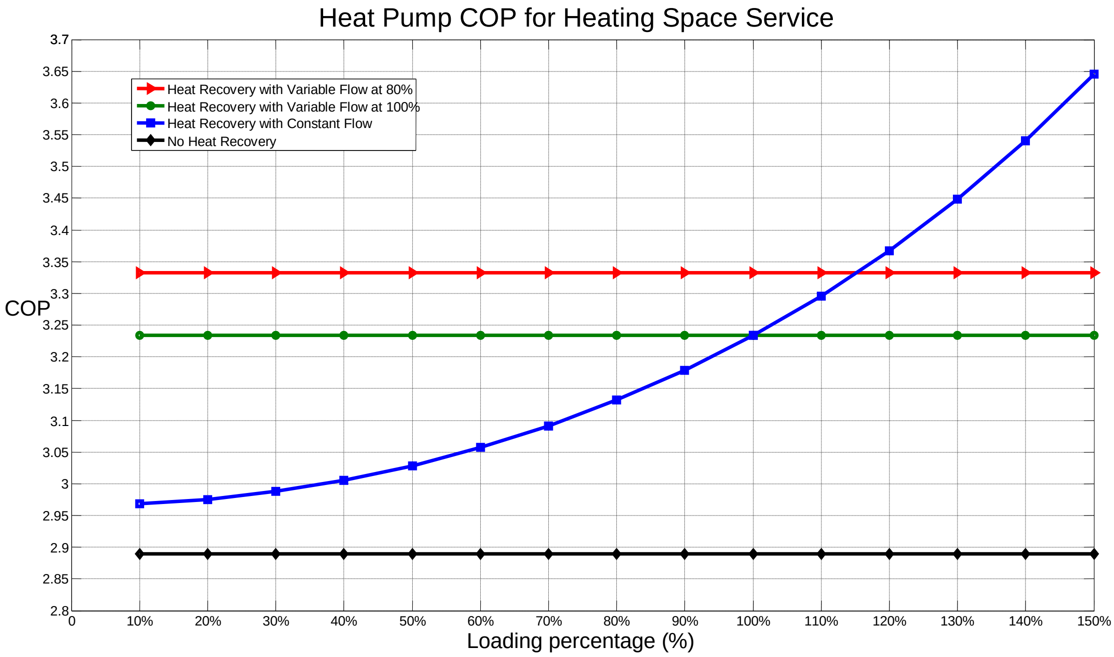

Figure 36: Heat pump COP

3.5 Scenarios and assumptions

The assessment has been carried out comparing different alternatives for providing space heating under different scenarios. Each scenario comprises a full space heating system using a gas boiler, an electric heater or a heat pump with or without heat recovery. The operation of gas boiler and electric heater is determined based on inlet water temperature requirements of standard radiators at 55 °C. Cases with heat pumps are evaluated with temperature requirements of both standard and low-temperature radiators at 55 °C and 45 °C, respectively.

3.5.1 Technical assumptions

Inlet water temperature of transformer oil-water cooler/heat-exchanger

The role of the oil-water heat exchanger is to reduce the transformer oil temperature, by transferring the heat released through losses during transformer operation to the water circuit. This improves the heat pump COP and consequently has a beneficial impact on the performance of the heating system.

Table 13: Technical drivers

Transformer Size (MVA)	15
Loading percentage (%)	70%
Inlet Water Temperature (°C)	7.7
Heat Pump Cycle Efficiency (%)	60%
Heat Recovery Percentage (%)	80%

Transformer rating and loading percentage

We have assumed a transformer rating of 15 MVA and an average loading at the level of 70% of this rating. Our assumptions may not match actual system transformer operating characteristics but they adequately reflect typical quantities of waste heat which may be collected and distributed to a water/space heating load located adjacent, or close to, the substation.

Naturally, a higher rated transformer operated at a lower load will generate similar levels of heat and further analysis would benefit from actual transformer and site loading data. This will be important for the sizing and design of adequate heat recovery systems, and for the calculation of actual scheme benefit/cost ratios and payback periods.

Heat pump cycle efficiency

The heat pump cycle efficiency is the ratio between the actual COP and the theoretically achievable COP. Typical cycle efficiency values vary from 30% to 70%. Cycle efficiency has a direct impact on energy consumption and the associated carbon emissions. We have selected a cycle efficiency of 60% in our studies.

Heating system operation time

If a heating system operates during a longer time within one year, there will be more opportunities for operating cost savings and the time to recover the investment will be reduced. Space heating requirements normally vary considerably throughout the year, and some recovered heat may be in excess to these requirements, so that additional water/air heat exchangers will be necessary to keep the transformer cool during these periods. In future, alternatives which can increase the operation time of the heat recovery system need to be investigated; examples include the provision of domestic hot water during summer times and inter-seasonal thermal storage.

3.5.2 Economic assumptions

Gas and electricity cost

There is clearly a direct effect of gas and electricity price on the operating cost and consequently the value of savings generated by heat recovery. Variation in energy prices can therefore either increase or diminish the payback time for an investment. Gas prices directly affect the operating cost of gas boilers whilst electricity prices determine the operating costs of electric heaters and heat pumps.

Carbon emission factors

In our analysis we attach carbon emission factors to the consumption of gas and electricity, expressed as the quantity of CO_2 released per kWh of either gas or electricity used for heating. The average carbon emission factor of the UK electricity generation mix is expected to continue to reduce in the future as the proportion of renewable energy continues to rise and more efficient components are introduced in the system. Carbon emissions will affect the operating costs and benefits depending on the assumed price of emission allowances. Our assumptions for the average emission factors of gas and electricity are given in Table 14.

Carbon emission cost

Higher carbon emission costs, as a result of Government decarbonisation policy, could be highly beneficial for increasing the penetration of low-carbon energy technologies such as heat pumps with and without heat recovery systems. The baseline assumptions used in our modelling are shown in Table 14.

Table 14: Baseline assumptions on operating costs, carbon emissions and discount rate

Gas price (£/kWh)	0.031
Electricity price (£/kWh)	0.087
Gas carbon emissions (kg/kWh)	0.185
Electricity carbon emissions (kg/kWh)	0.237
Carbon price (£/t)	14.74
Discount rate (%)	3%

3.5.3 *Equipment cost*

Heat pumps have significant higher cost than boilers and electric heaters, decreasing substantially their costs can make more attractive the investment of heat recovery systems.

Installation

Installation of ground source heat pumps can be more expensive than the cost of the equipment. When a transformer heat recovery system is implemented, the installation cost is substantially reduced because do not require boreholes or ground loops. Therefore, the full heat recovery system can have lower installation costs than traditional installations of ground source heat pumps.

Maintenance

Normally maintenance cost is proportional to the investment and affect directly to the benefits. This is the case when flow control systems are implemented; the savings can be notably reduced by its maintenance cost.

Discount rate

Higher discount rates reduce the present value of the benefits which are accumulated during the time, while having no effect on the investment costs involved in the project.

The assumed investment cost associated with a given option includes the cost of heating equipment and the respective installation cost, as shown in Table 15. Operating costs used for the economic evaluation include maintenance, energy and emission costs, as shown in Table 16. Sensitivity analysis was undertaken for the most important technical drivers such as transformer size, loading percentage, ambient temperature, percentage of heat recovery and heat pump cycle efficiency; as well as for non-technical ones such as energy, carbon emission cost and discount rate.

Table 15: Investment and maintenance cost assumptions

Equipment	**kW**	**Cost £/kW**	**Subtotal**
Gas Boiler	54	38.5	£2,079
Electric Heater	54	70	£3,780
Heat Pump	54	600	£32,400
Smart Radiators	54	100	£5,400
Flow Control System	54	50	£2,700
Installation and Commissioning			
Gas Boiler	54	20	£1,080
Electric Heater	54	20	£1,080
Standard Heat Pump (No Heat Recovery)	54	800	£43,200
Heat Pump with Transformer Heat Recovery	54	250	£13,500
Smart Radiators	54	100	£5,400
Flow Control System	54	50	£2,700
Annual Maintenance	**% Equipment**	**% Installation**	**Subtotal**
Gas Boiler	3.0%	3.0%	£95
Electric Heater	2.0%	2.0%	£97
Heat Pump No Heat Recovery	0.5%	0.5%	£378
Heat Pump Heat Recovery	0.5%	0.5%	£230
Smart Radiators	1.0%	1.0%	£108
Flow Control System	3.0%	3.0%	£162

Table 16: Operating cost and discount rate assumptions

Item	Cost
Gas energy cost (£/kWh)	0.031
Electricity energy cost (£/kWh)	0.087
Gas carbon emission (kg/kWh)	0.185
Electricity carbon emission (kg/kWh)	0.237
Carbon emission cost (£/tonne)	14.75
Discount rate	3%
Equipment life time (years)	20
Capitalisation factor[54]	15.88

3.6 Results of the economic valuation of heat recovery

3.6.1 Heat recovery scenarios

Table 17 summarises the heat recovery scenarios considered in our study. Each scenario comprises a full space heating system using a gas boiler, an electric heater or a heat pump. The operation of gas boilers and electric heaters is calculated based on the input water temperature requirements for standard radiators at 55 °C. Scenarios with heat pumps are evaluated based on the temperature requirements of both standard and low-temperature radiators at 55 °C and 45 °C, respectively.

Scenarios 2b and 3b are evaluated assuming a heat pump coupled with transformer heat recovery system using a constant water flow. The remaining four variations (2c, 2d, 3c, 3d) are heat pump scenarios that include heat recovery and flow control as follows:

- Variable flow at 100% means that the flow is adjusted down from the flow specified for the nominal loading of the transformer in proportion to the loading.
- Variable flow at 80% means that the flow is adjusted at 20% less than the flow in the first approach (variable flow at 100%) for each transformer loading point.

Reducing the flow in proportion to transformer loading results in higher and constant water temperatures at loading levels below 100%, and thus improves the COP of the heat pump due to smaller temperature lift requirements.

[54] Capitalisation factor represents the discounted (present) value of a constant stream of revenues or expenses in the amount of 1 monetary unit per year, incurred during the assumed equipment lifetime. In the example above, with the discount rate of 3% and the assumed equipment lifetime of 20 years, the annual operating cost of each heating design option is multiplied by 15.88 (rather than 20 if no discounting was applied) before it is added to the initial investment cost to determine the total present value of each alternative.

Table 17: Space heating scenarios

Scenario	Heating at 55 °C	Heating at 45 °C	Alternative system	No heat recovery	Heat recovery	Variable flow @ 80%	Variable flow @ 100%
1a	√		Gas Boiler	√			
1b	√		Electric Heater	√			
2a	√		Heat Pump	√			
2b	√		Heat Pump		√		
2c	√		Heat Pump		√	√	
2d	√		Heat Pump		√		√
3a		√	Heat Pump	√			
3b		√	Heat Pump		√		
3c		√	Heat Pump		√	√	
3d		√	Heat Pump		√		√

3.6.2 Economic performance of alternative heating options

The resulting payback times obtained for different heat recovery scenarios, and based on assumptions presented in Table 15 and Table 16, are shown in Figure 37. Payback times for investment into non-conventional heating systems rather than electric heaters or gas boilers are calculated by comparing the savings in operating cost with the additional investment cost needed for installing the heat pump and heat recovery equipment. Four different operating assumptions are made with respect to the time during which a heating system is used within a year: 25%, 50%, 75% and 100%.

It can be observed that if the heating system operates for 50% of the year, a simple GSHP without heat recovery (cases 2a and 3a) has a payback period of between 6 and 7 years when compared against an electric heater, while a heat pump-based heat recovery system offers a payback time of less than 4 years (Figure 37a). However, even when operating throughout the year (100% of time), the payback for a heat pump system with heat recovery against a gas boiler is more than 10 years; for 50% operation time the payback period increases to over 20 years. In both cases the longer payback time for a simple GSHP without heat recovery is due to the extra cost of installing the ground source heat exchangers.

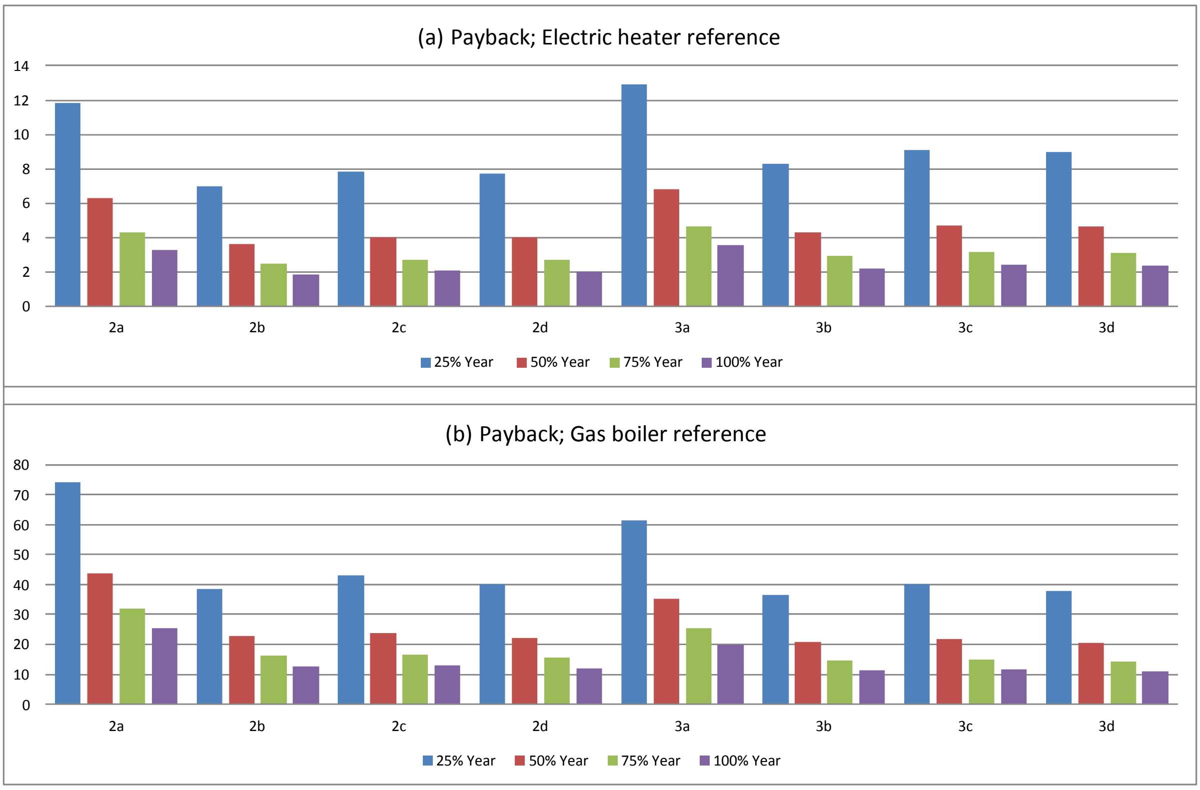

Figure 37: Payback times for different heat recovery scenarios

Figure 38 shows the results of NPV calculations for different heating system designs (electric heaters, gas boilers, GSHPs without heat recovery and heat pumps with heat recovery). Various categories of investment cost (equipment, installation) and operating cost (maintenance, energy, carbon) depicted in the figure have been discounted to the start of the assumed 20-year lifetime of heating systems to facilitate comparison between different designs. The results in parts (a) to (d) of Figure 38 correspond to operating times between 25% and 100%.

According to the results and our input assumptions, for operating times of 25% and 50% the least-cost option is the conventional gas boiler (case 1a), while the most expensive choice is the electrical heater (case 1b) followed by GSHPs without heat recovery (cases 2a and 3a). At 75% operating time the heat pumps with heat recovery (cases 2b to 2d and 3b to 3d) achieve a comparable cost to gas boilers, while at 100% operation they become the cheapest option (with only minor variations as the result of different flow control or radiator temperatures).

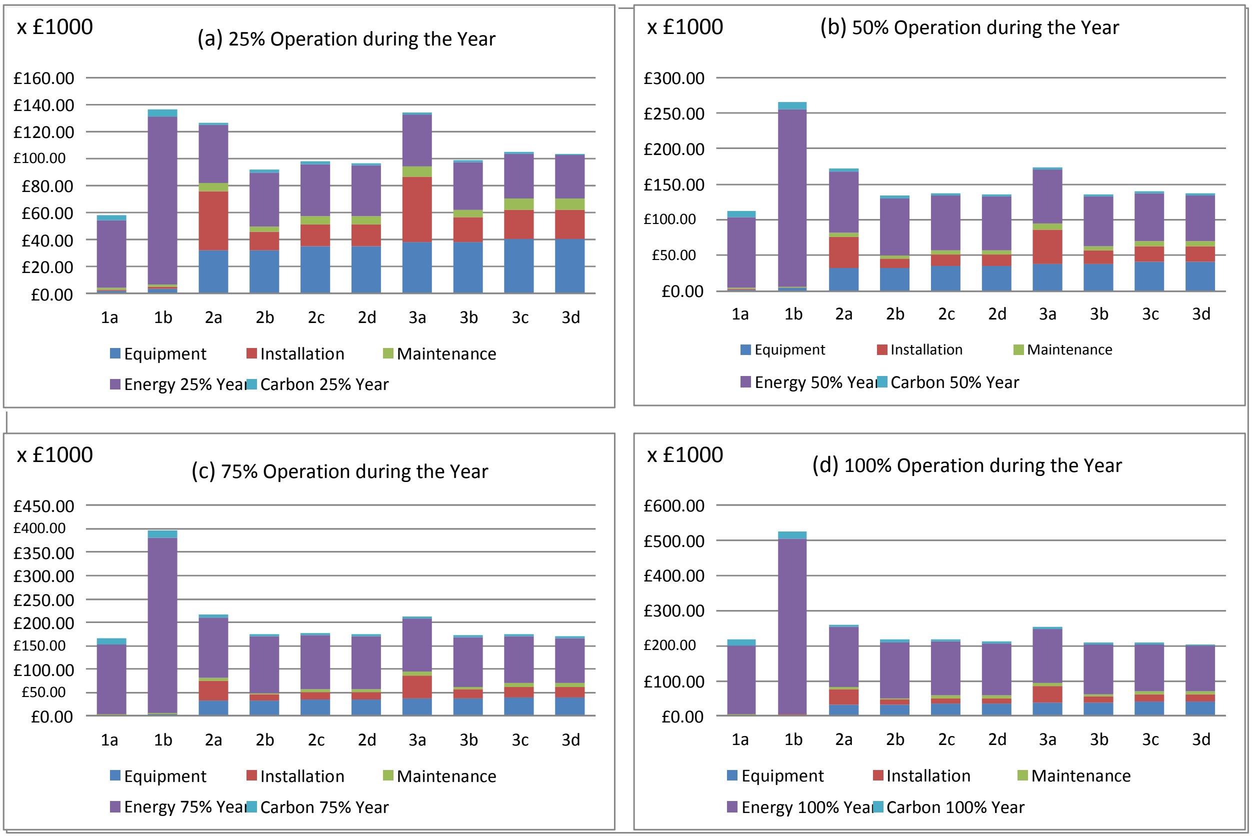

Figure 38: NPV of different heating system designs with varying operation times

3.6.3 Sensitivity Analysis

Sensitivity analysis of the economic performance of different heating systems has been carried out according to the list of drivers presented in Table 18. These include the variations in transformer loading, cooling water temperature, heat pump cycle efficiency, energy (gas and electricity) prices, carbon prices and discount rate. As in the main set of studies, we calculate the payback times for different heat recovery systems against electric heaters and gas boilers, as well as the NPV of life-cycle cost of each heating alternative.

Table 18: Sensitivity studies (parameters varied from default assumptions are shown in red)

Variation	Default	Load Ratio	Cooling water	HP efficiency	Optimal operation	Gas price	Electricity price	Carbon price	Discount rate
Loading percentage	70	**80**	70	70	**80**	70	70	70	70
Cooling water temp. (°C)	7.7	7.7	**11.4**	7.7	**11.4**	7.7	7.7	7.7	7.7
Heat pump cycle efficiency (%)	60	60	60	**70**	**70**	60	60	60	60
Gas price (£/kWh)	0.031	0.031	0.031	0.031	0.031	**0.062**	0.031	0.031	0.031
Electricity price (£/kWh)	0.087	0.087	0.087	0.087	0.087	0.087	**0.0435**	0.087	0.087

Variation	Default	Load Ratio	Cooling water	HP efficiency	Optimal operation	Gas price	Electricity price	Carbon price	Discount rate
Carbon price (£/tonne)	14.74	14.74	14.74	14.74	14.74	14.74	14.74	73.69	14.74
Discount rate (%)	3	3	3	3	3	3	3	3	9

Transformer loading

In this sensitivity study we assume a higher transformer loading than in the main set of studies. The assumed loading is increased to 80% from the default value of 70%, resulting in more heat being available for recovery. The results depicted in Figure 39 suggest that the quickest payback against an electric heater is achieved with heat pump-based recovery (case 2b), which drops to 6 years (previously 7 years). Payback times of heat recovery systems measured against a gas boiler are also reduced, dropping to below 20 years for 50% operation.

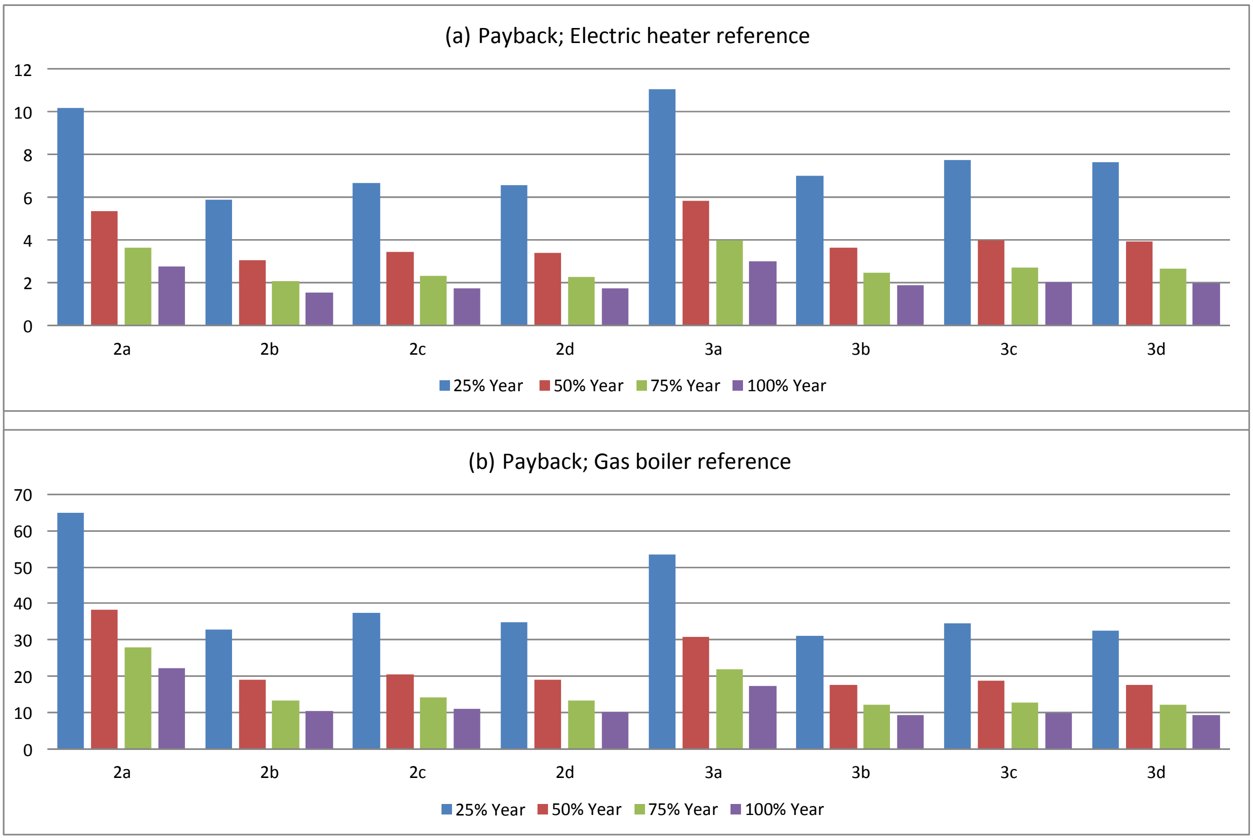

Figure 39: Payback times with increased transformer loading

Similarly, Figure 40 quantifies the reduction of NPV for all cases where heat pumps with heat recovery are involved, and any of these will be a more attractive investment than a gas boiler or electric heater with at least 75% operating time.

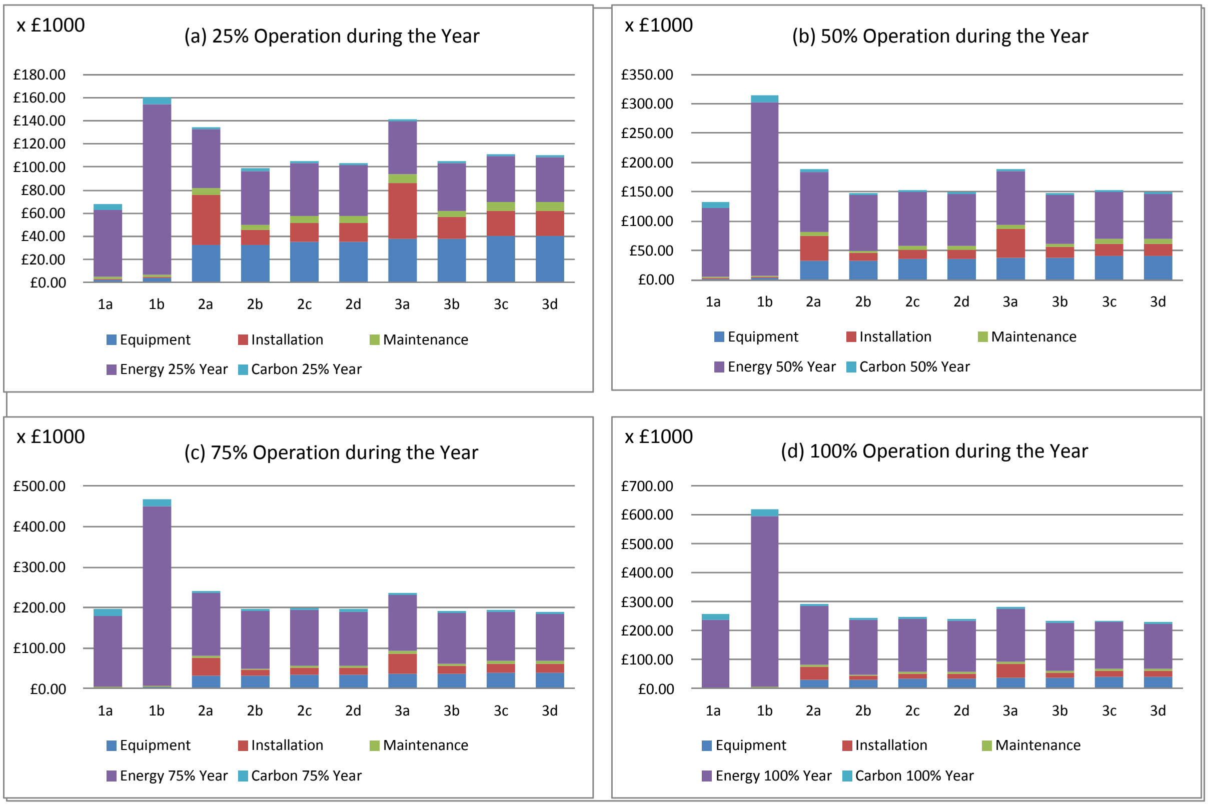

Figure 40: NPV of different heating system designs for increased transformer loading

Cooling water temperature

The impact of the inlet water temperature of the oil-water cooler was considered by increasing it from 7.7 °C in the default case to 11.4 °C, i.e. from a winter average to a year-round average.

The increased inlet temperature has beneficial effects for both the payback time and the NPV of heat recovery systems, as illustrated in Figure 41 and Figure 42, respectively. This demonstrates that the system will operate more efficiently during summer than winter. This suggests that hot water usage in summer, inter-seasonal heat storage and cooling systems may be attractive and potentially worthy of further research.

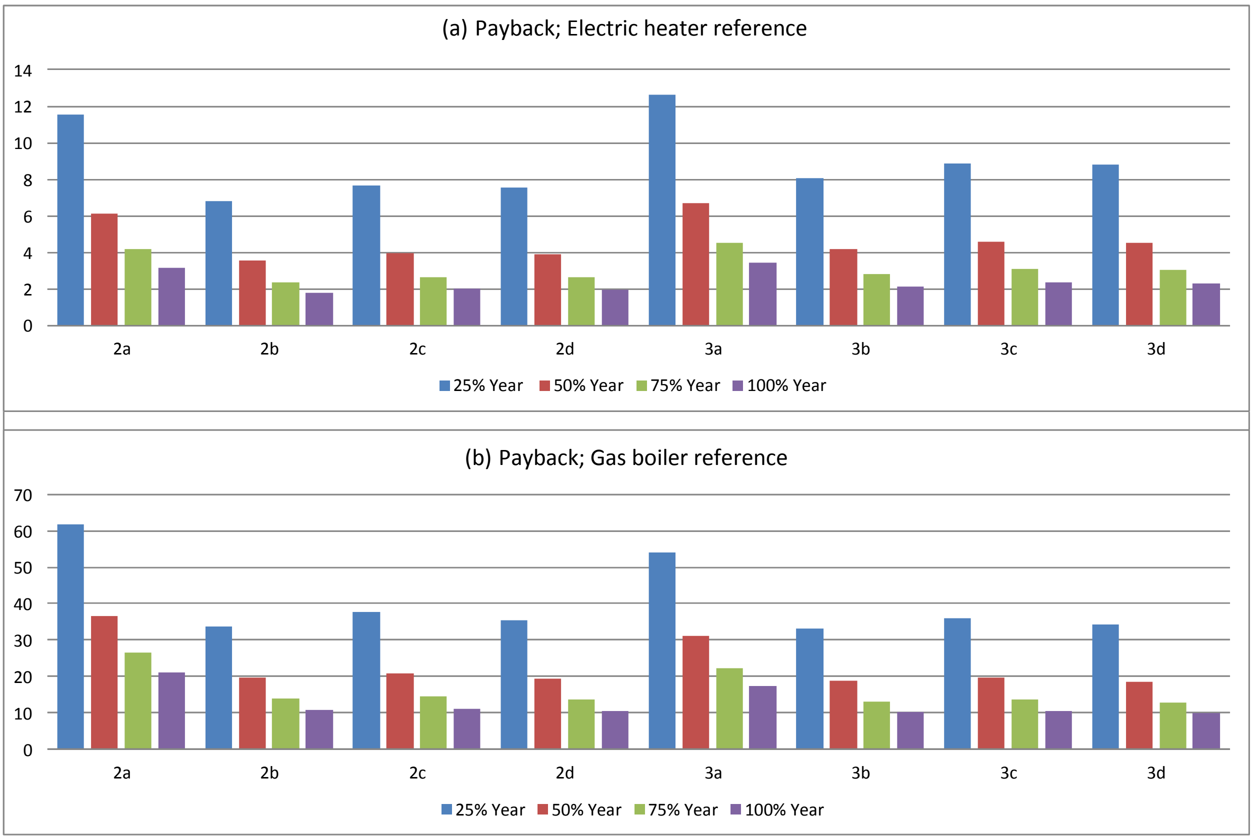

Figure 41: Payback times with increased inlet water temperature

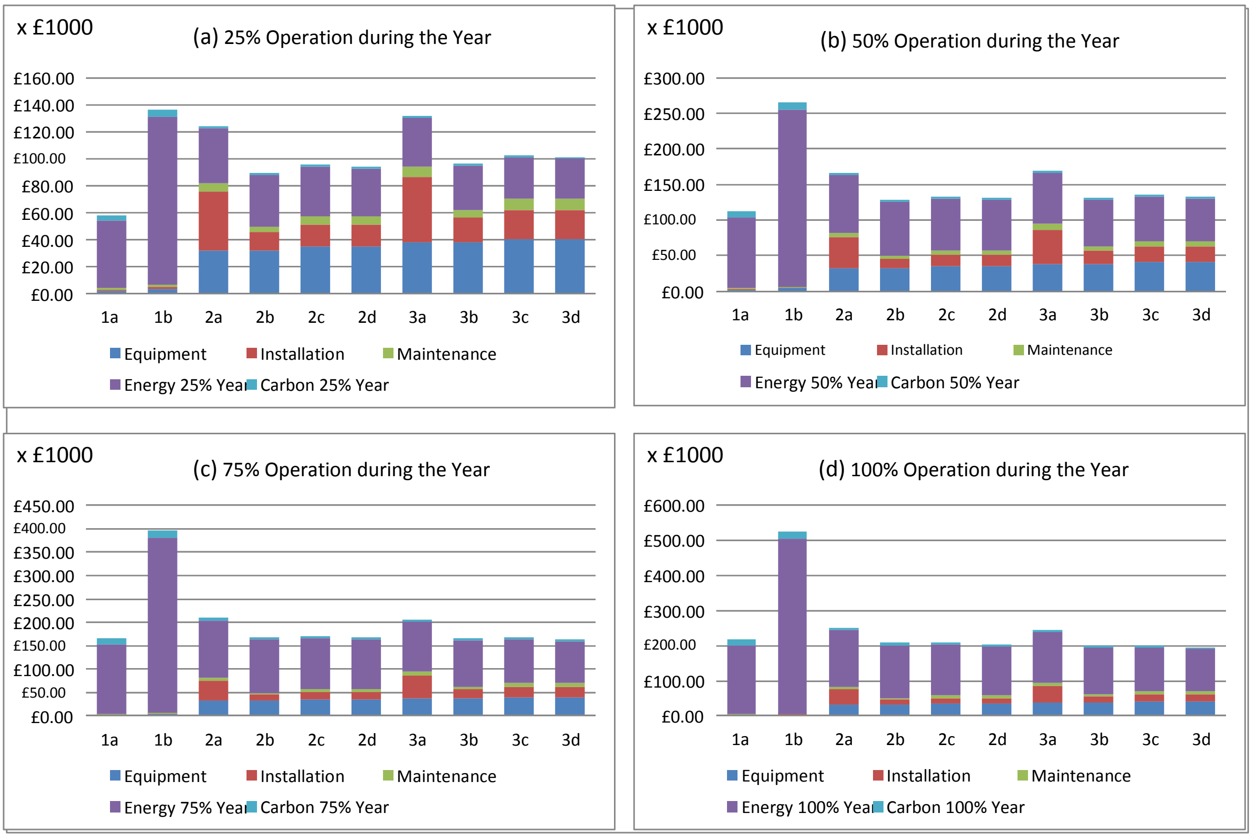

Figure 42: NPV of different heating system designs for increased inlet water temperature

<u>Heat pump cycle efficiency</u>

In order to assess the impact of the heat pump efficiency, we have increased the cycle efficiency of the heat pump from the default value of 60% to 70%.

The improved heat pump efficiency has a beneficial effect in terms of reducing the payback times (as shown in Figure 43) and reducing the NPV of heat pump systems so that at 50% operating time it is only marginally higher than the gas boiler, while at 75% and 100% it outperforms the gas boiler (Figure 44). This reduction in costs shows the importance of choosing the right equipment, given that a higher efficiency also allows for a smaller heat pump capacity.

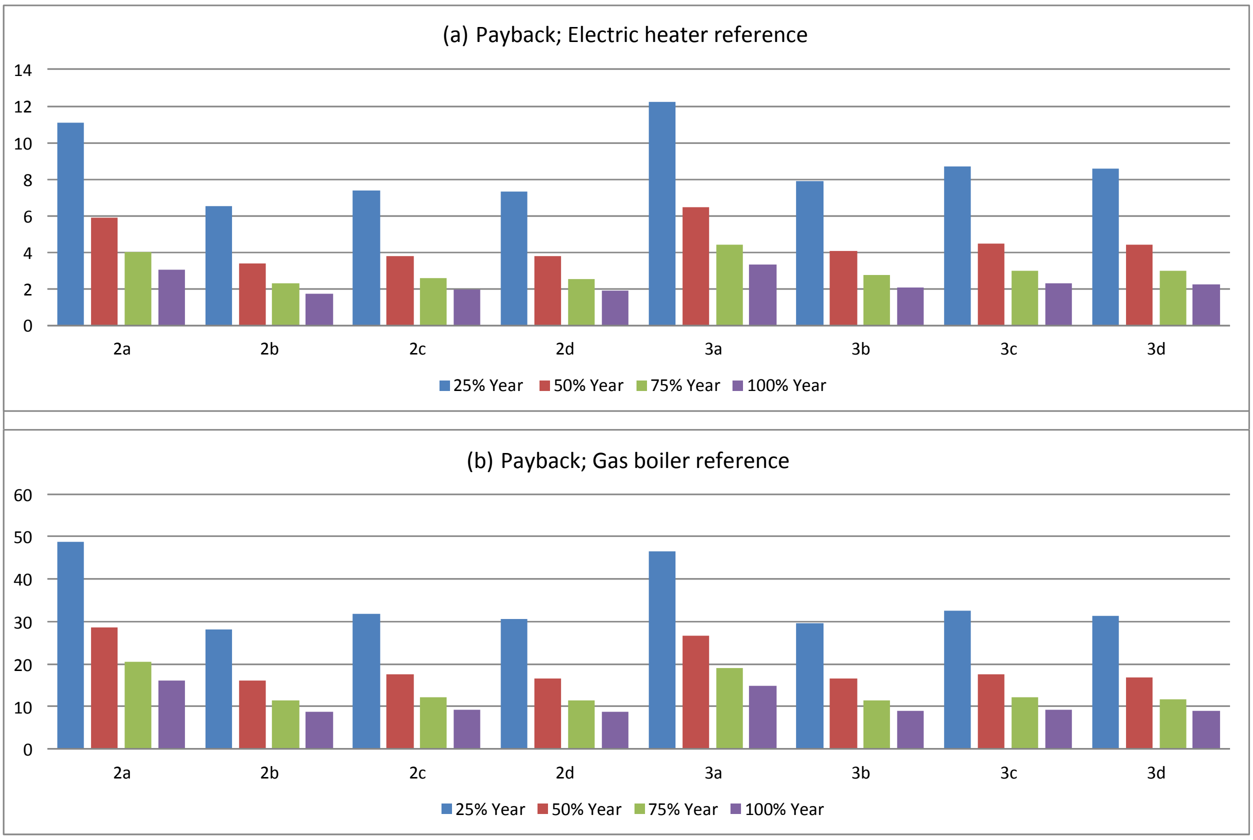

Figure 43: Payback times for increased heat pump cycle efficiency

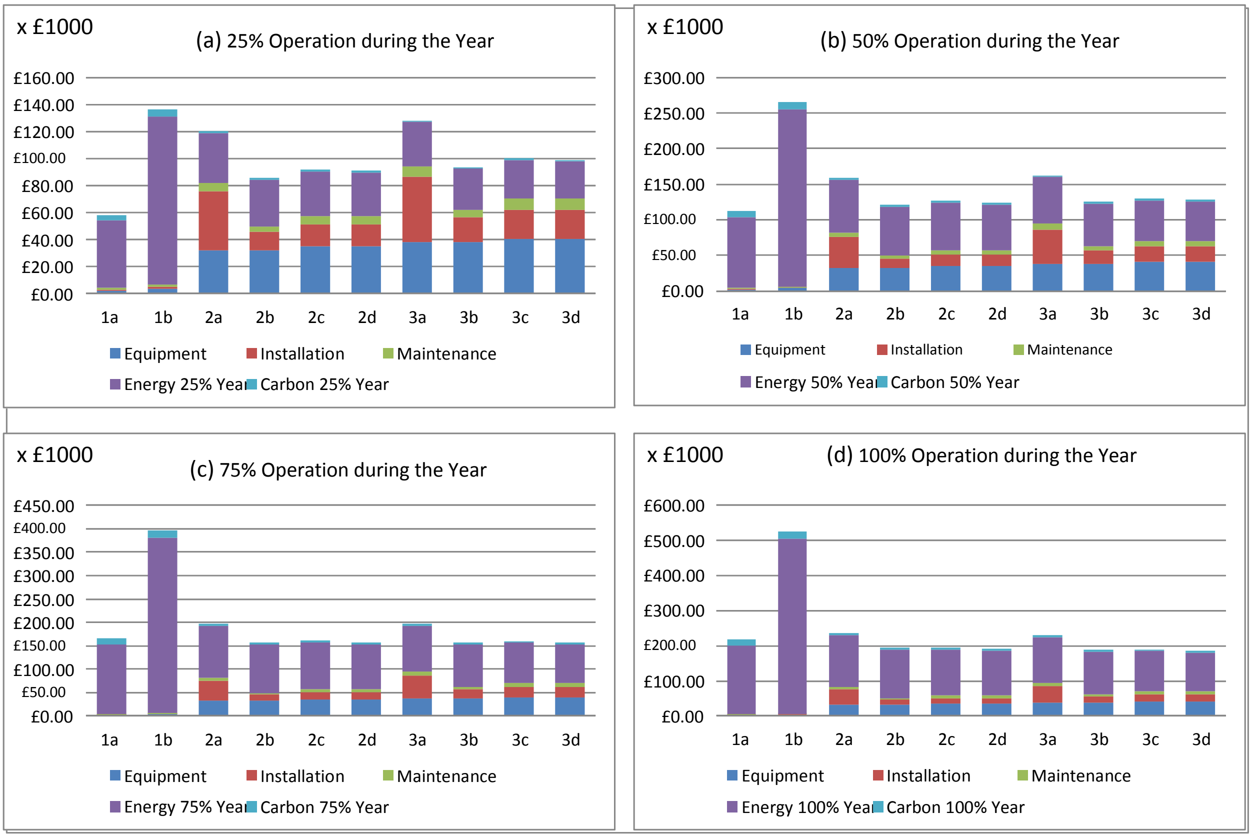

Figure 44: NPV of different heating system designs for increased heat pump cycle efficiency

Favourable scenario

In this sensitivity study the beneficial drivers analysed in Sensitivities B, C and D have been combined to simulate a beneficial scenario for heat pump-based heat recovery systems. It therefore includes an increased transformer loading (from 70% to 80%), increased inlet water temperature (from 7.7 °C to 11.4 °C) and increased heat pump efficiency (from 60% to 70%).

Favourable combination of parameters results in a significantly improved performance for the heat pump systems, as shown in Figure 45 where the payback time of heat recovery options compared against an electric heater has been considerably reduced (for instance, case 2b payback period reduces from 7 to 5 years at 50% operating time). When heat recovery systems are compared with gas boilers, the payback time for case 2b reduces from 37 to 22 years.

Figure 46 shows the corresponding effect on the NPV, where all heat recovery options have a comparable cost to a gas boiler for 50% operating time. The least-cost option in nearly all calculations is case 2b, i.e. a simple heat recovery system with no flow control and with standard radiators.

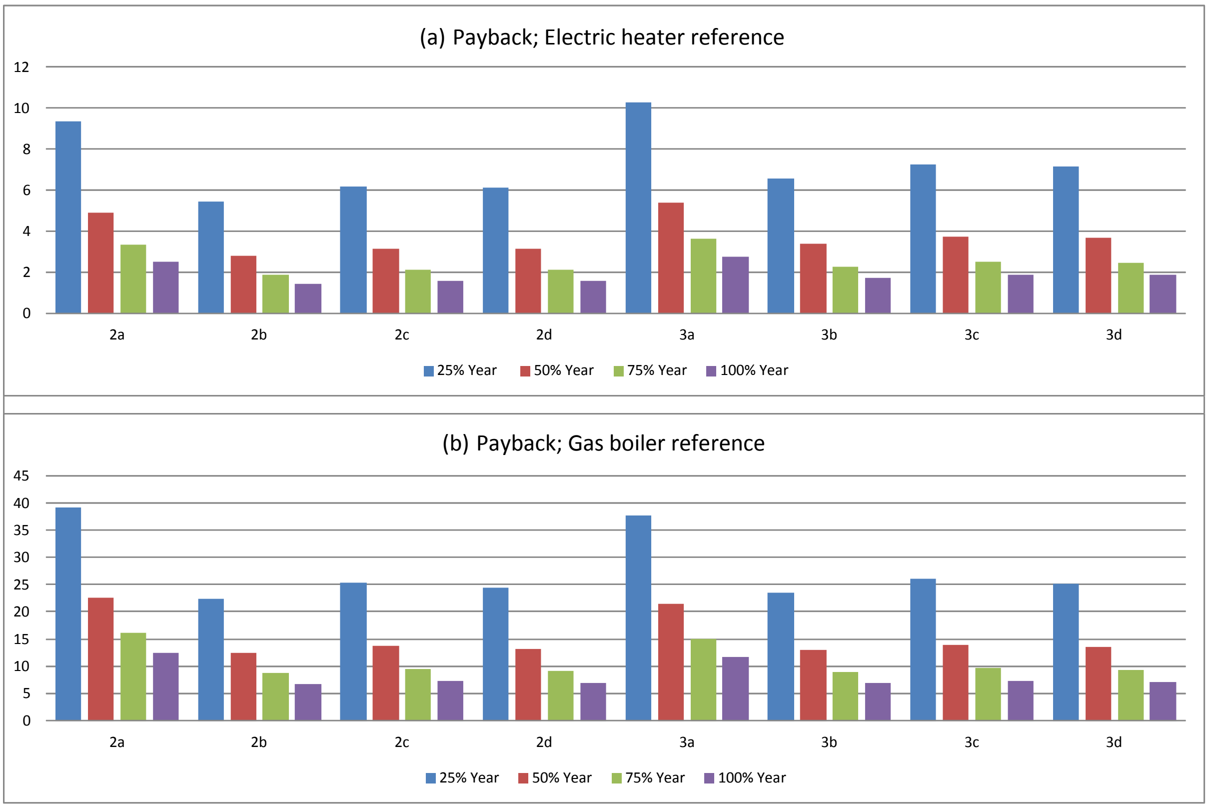

Figure 45: Payback times for optimal operation scenario

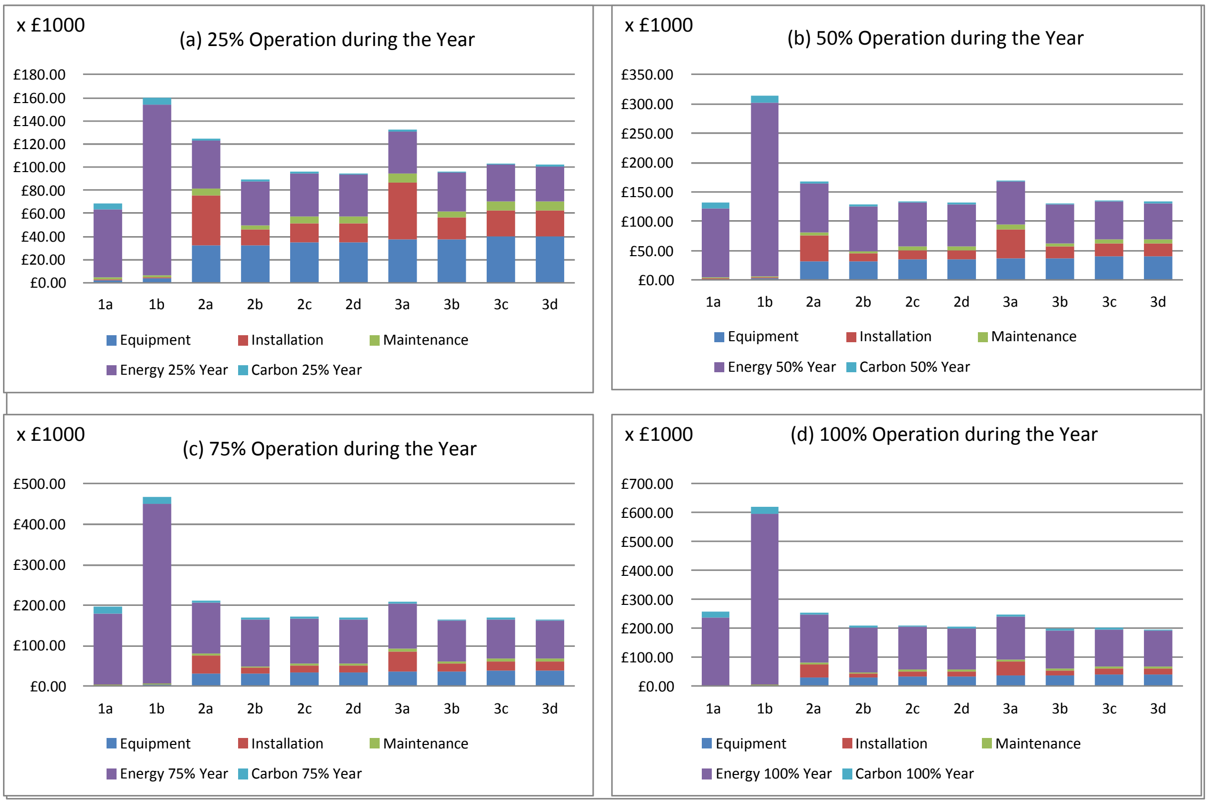

Figure 46: NPV of different heating system designs for optimal operation scenario

Gas price

In order to evaluate the impact of increased gas price, we ran the payback time and NPV calculations with the gas price of £0.062/kWh, which is double of the default assumption (£0.031). Higher gas price will obviously have a direct impact on the economics of the gas boiler option, without any effect on the electric heaters or the heat pump systems as these only require electricity as input.[55] Consequently, there is a considerable reduction in payback times compared with the gas boiler for all heat pump systems, and particularly for those that have heat recovery, as shown in graph (b) on Figure 47 (payback times against electric heaters do not change). Figure 48 shows that this impact is also observed in the NPV calculations, where all heat recovery options outperform a gas boiler already at 25% of operation time.

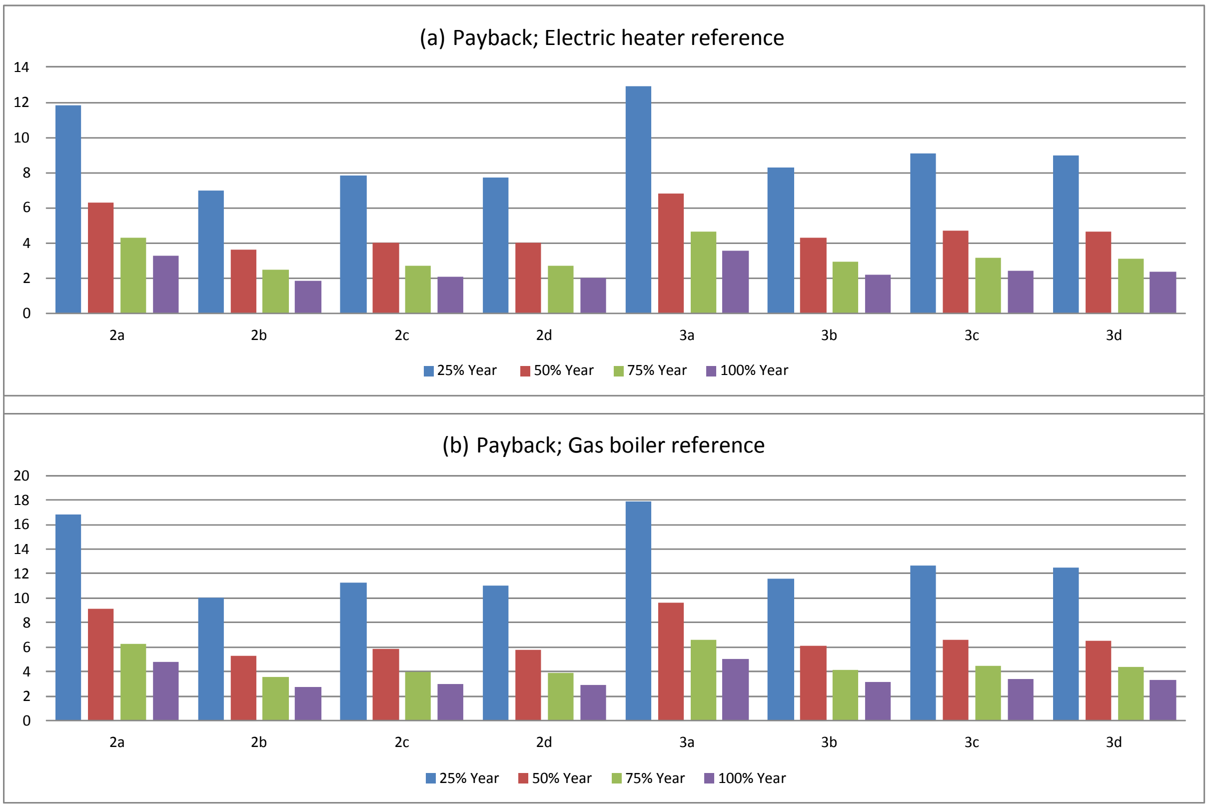

Figure 47: Payback times for increased gas price

[55] The impact of a higher gas price on the price of electricity has been ignored, i.e. the assumption for the price of electricity has been as in the default case (£0.087/kWh).

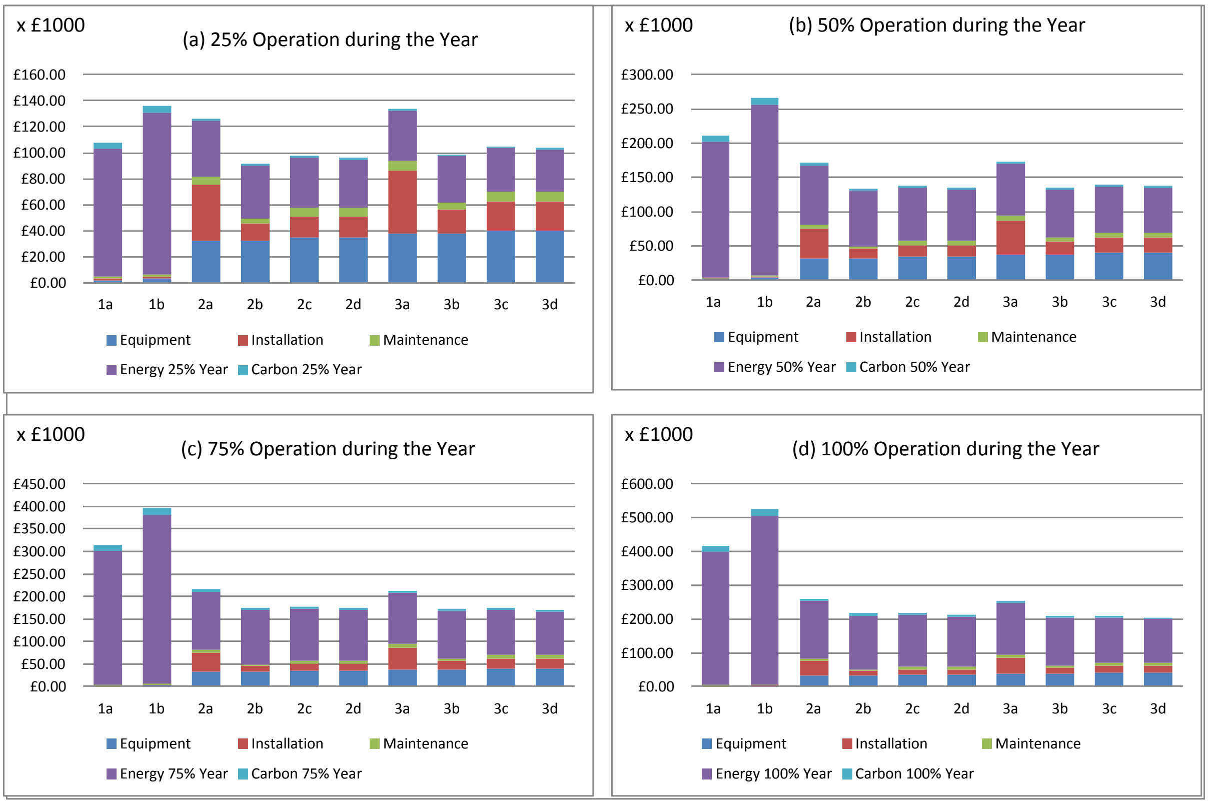

Figure 48: NPV of different heating system designs for increased gas price

Electricity price

The impact of a different electricity price has been assessed by reducing the electricity price by 50% from the default assumption, i.e. from £0.087/kWh to £0.0435/kWh.

When comparing against an electric heater, lower electricity price increases the payback times for heat pump systems (as the savings compared to the resistive heater are lower), as shown in Figure 49. On the other hand, payback times of heat pump systems compared to a gas boiler reduce, given that their operating cost becomes relatively lower.

The impact of a reduced electricity price on the NPV of different heating options is shown in Figure 50. Electric heaters have a significantly lower overall cost than in the previous studies, and are the most cost-efficient option when operating for 25% of the time. However, they become more costly as the operating time increases. On the other hand, reducing the electricity price makes heat pumps with heat recovery significantly more attractive than gas boilers, even for operating times as low as 25%.

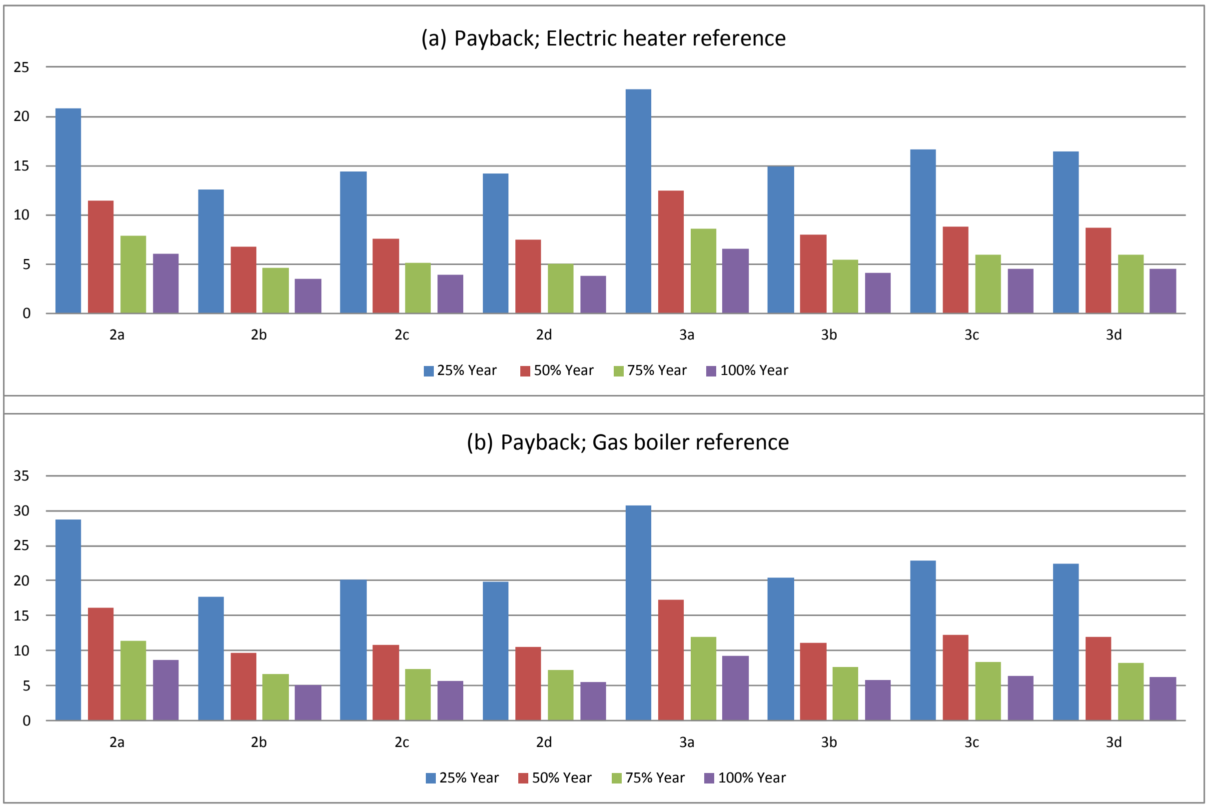

Figure 49: Payback times with lower electricity price

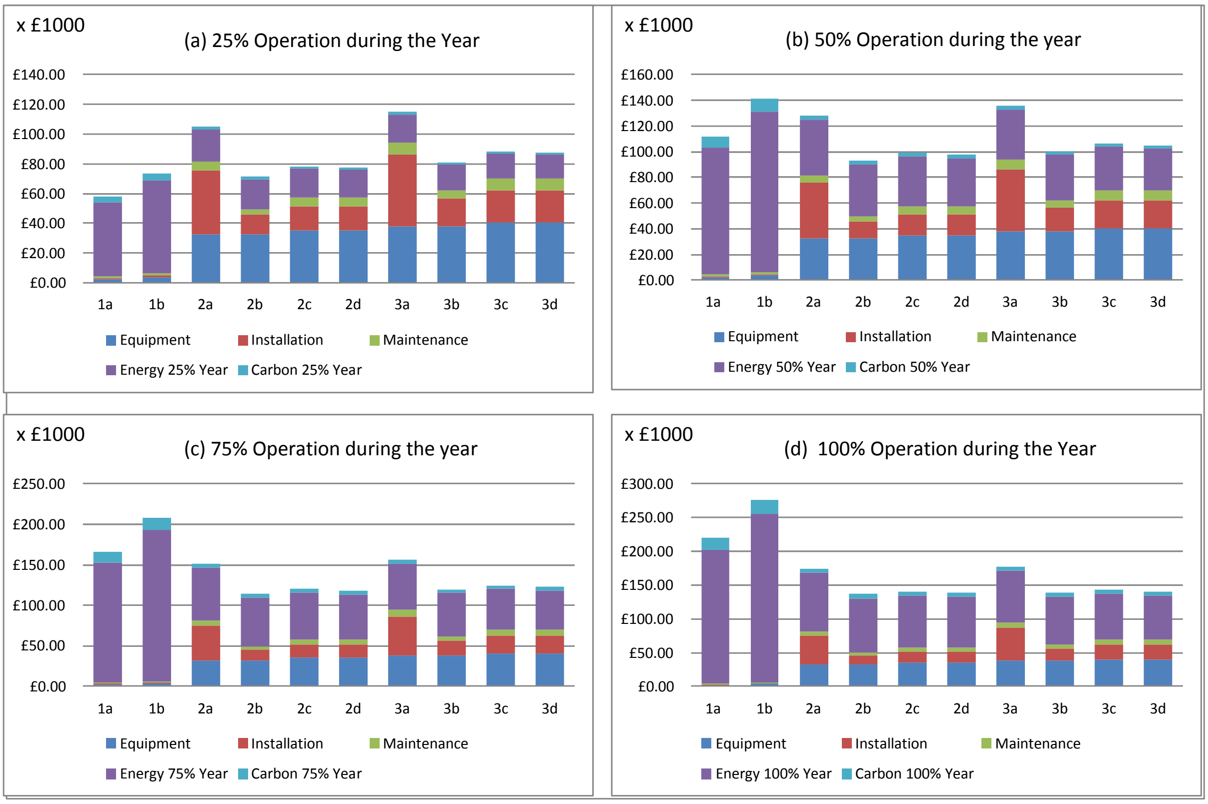

Figure 50: NPV of different heating system designs with lower electricity price

Carbon price

We have further assessed the impact of a change in carbon emission allowance price by increasing the carbon price fivefold – from £14.7/tonne in the base case to £ £73.7/tonne.

The effect of this increase in carbon price is reflected in reduced payback times in all cases, which can be observed when comparing Figure 51 with Figure 37. However, payback times are still excessive for most cases when compared to a gas boiler.

The NPV of heat pump systems (with or without heat recovery) systematically outperforms electric heaters. Systems with heat recovery start to be more attractive than gas boilers at 50% operation time, as shown in Figure 52 (the corresponding break-even operation time in the default case was 75%).

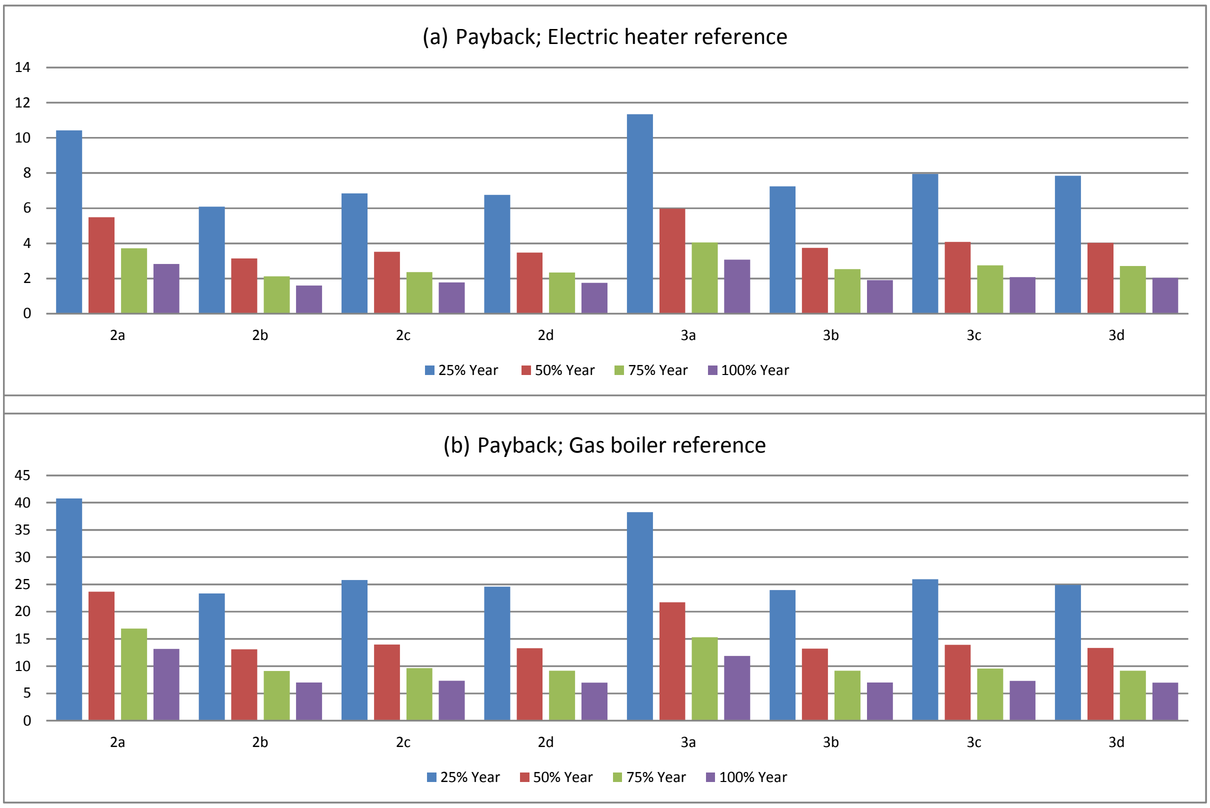

Figure 51: Payback times for increased carbon price

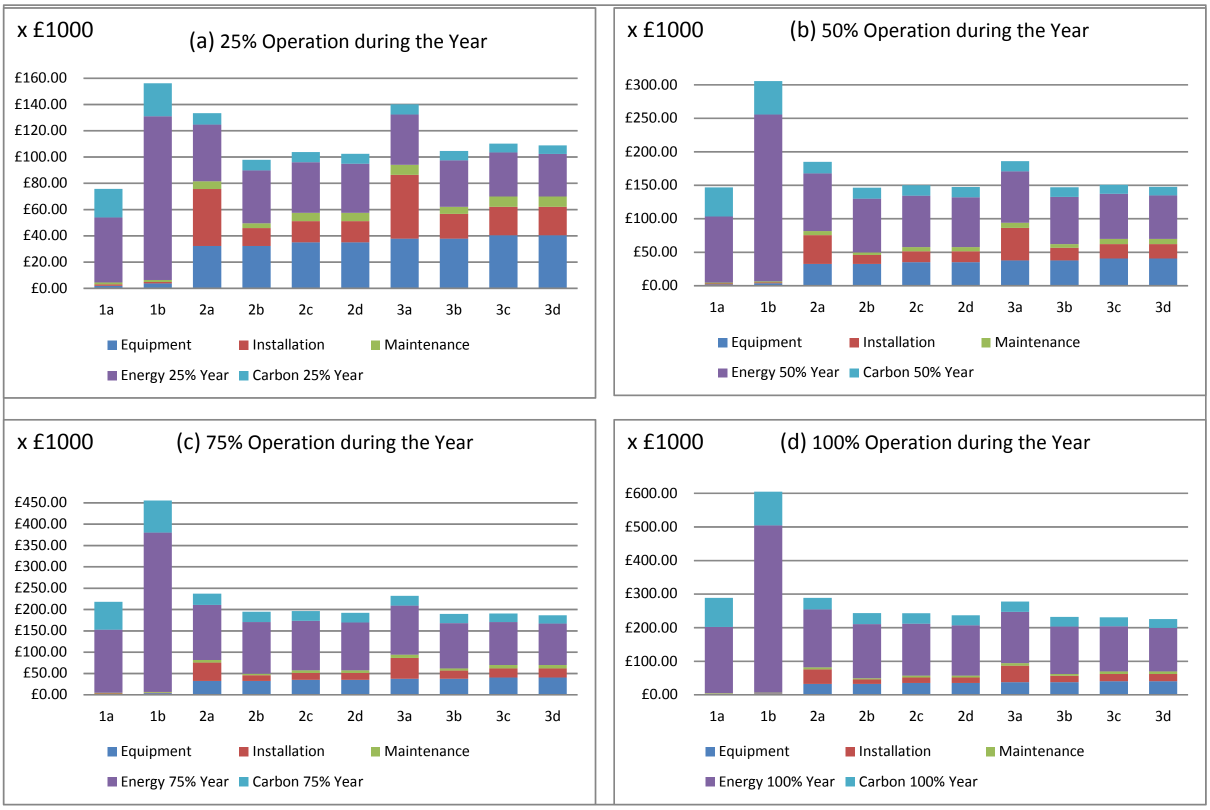

Figure 52: NPV of different heating system designs for increased carbon price

<u>Discount rate</u>

We have investigated the impact of an increase in discount rate by using a value three times that of the default scenario, i.e. 9% instead of 3%. This has the effect of decreasing the payback times[56] and the NPV of future savings, i.e. of favouring options with lower upfront capital cost but higher operating cost to those with opposite characteristics.

In comparison with both electric heaters and a gas boiler, the number of years to achieve payback reduces slightly compared to the main set of studies, as shown in Figure 53. Although its absolute value drops, the NPV of heat pump systems becomes less favourable in comparison to electric heaters and gas boilers given that the contribution of future operating costs to the NPV is reduced for all systems, as shown in Figure 54. Due to electric heaters and gas boilers having higher operating cost but lower investment cost than heat pump systems, their NPV experiences a larger drop in relative terms.

[56] As described earlier, the payback time calculation method used in this study takes into account the time value of money i.e. the discount rate, which is why payback times change with a different assumption on discount rate.

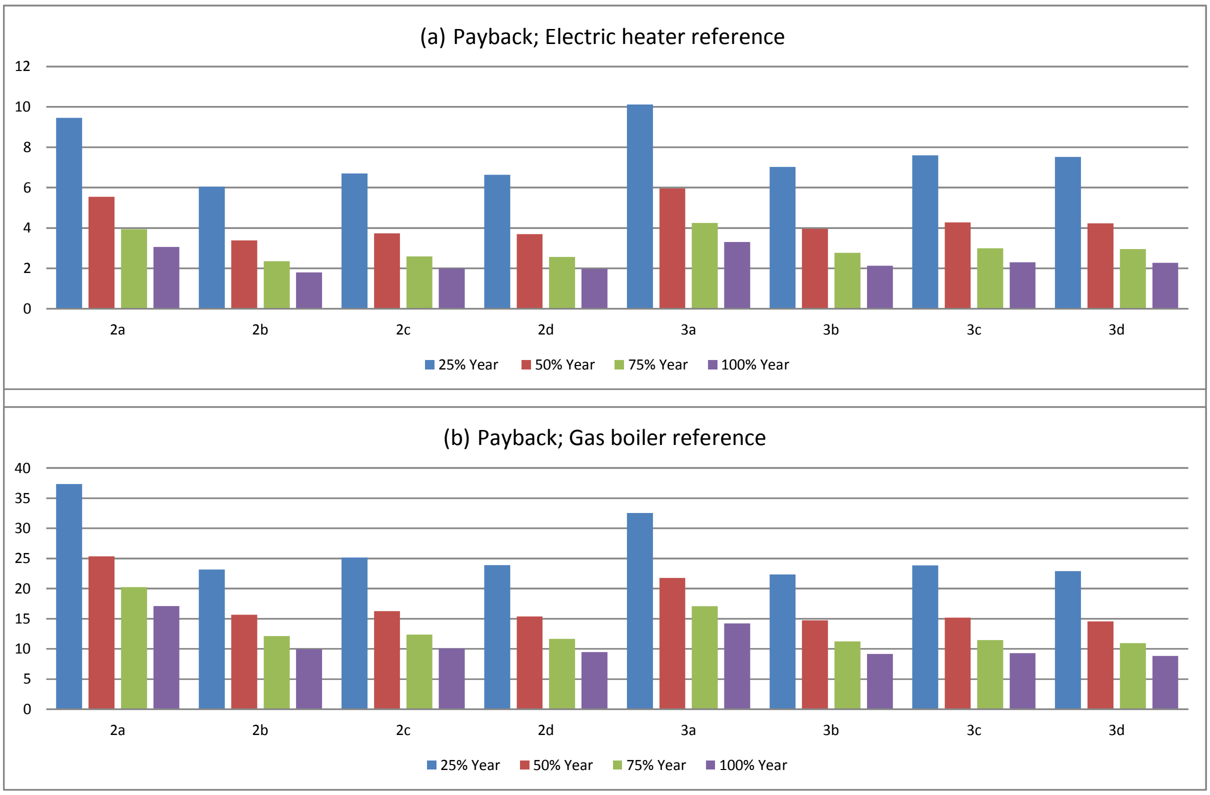

Figure 53: Payback times with increased discount rate

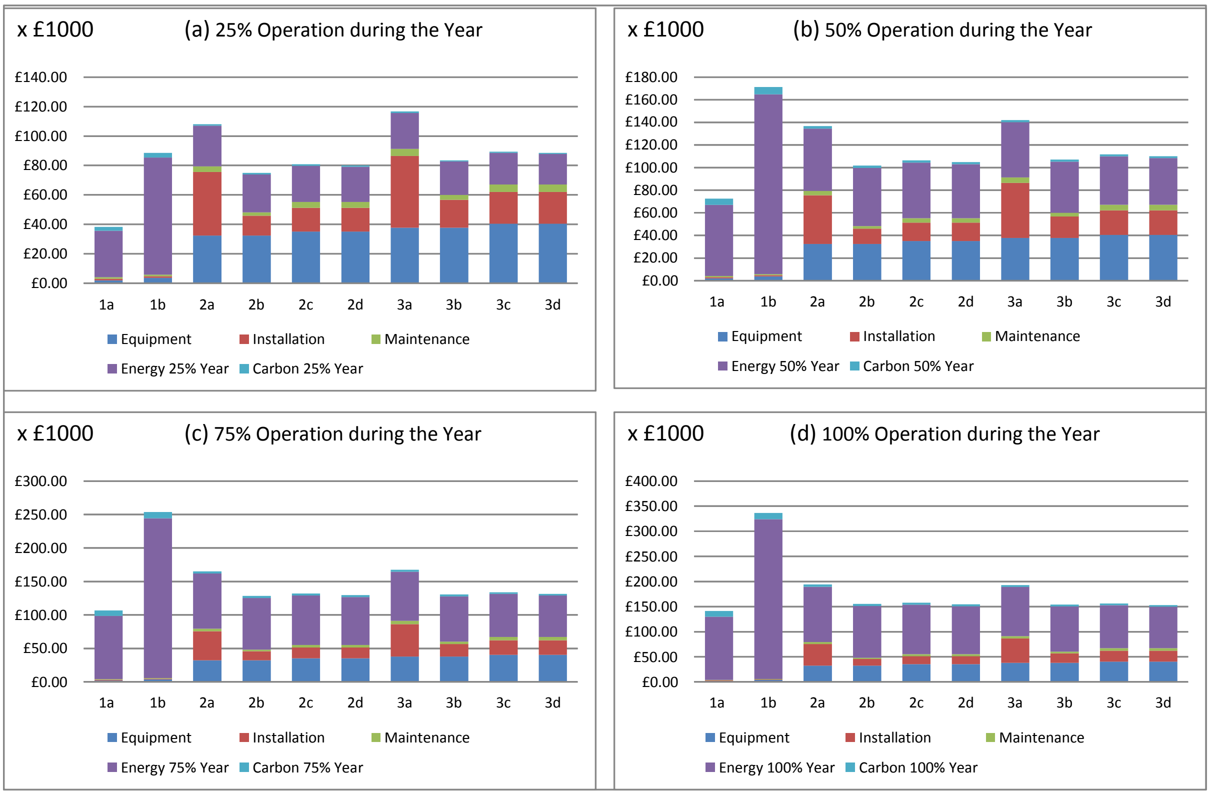

Figure 54: NPV of different heating system designs with increased discount rate

Unfavourable scenario

We finally conduct a sensitivity study for the worst operation scenario constructed by assuming a lower transformer loading of 60% and a lower heat pump cycle efficiency of 50%. Other parameters are kept at the same level as in the main set of studies.

Comparison between Figure 37 (baseline case) and Figure 55 shows that payback times increase for heat pump systems against both electric heaters and gas boilers. Compared to the latter, a simple GSHP has payback times that extend far beyond the life of the equipment (and are therefore not depicted in the figure).

Figure 56 shows that even when the heat recovery system operates 100% of time, the gas boiler will still be the least-cost option. On the other hand the NPV of heat pumps with heat recovery makes them more attractive than electric heaters. GSHPs without heat recovery are preferred to electric heaters when the operating time exceeds 25%.

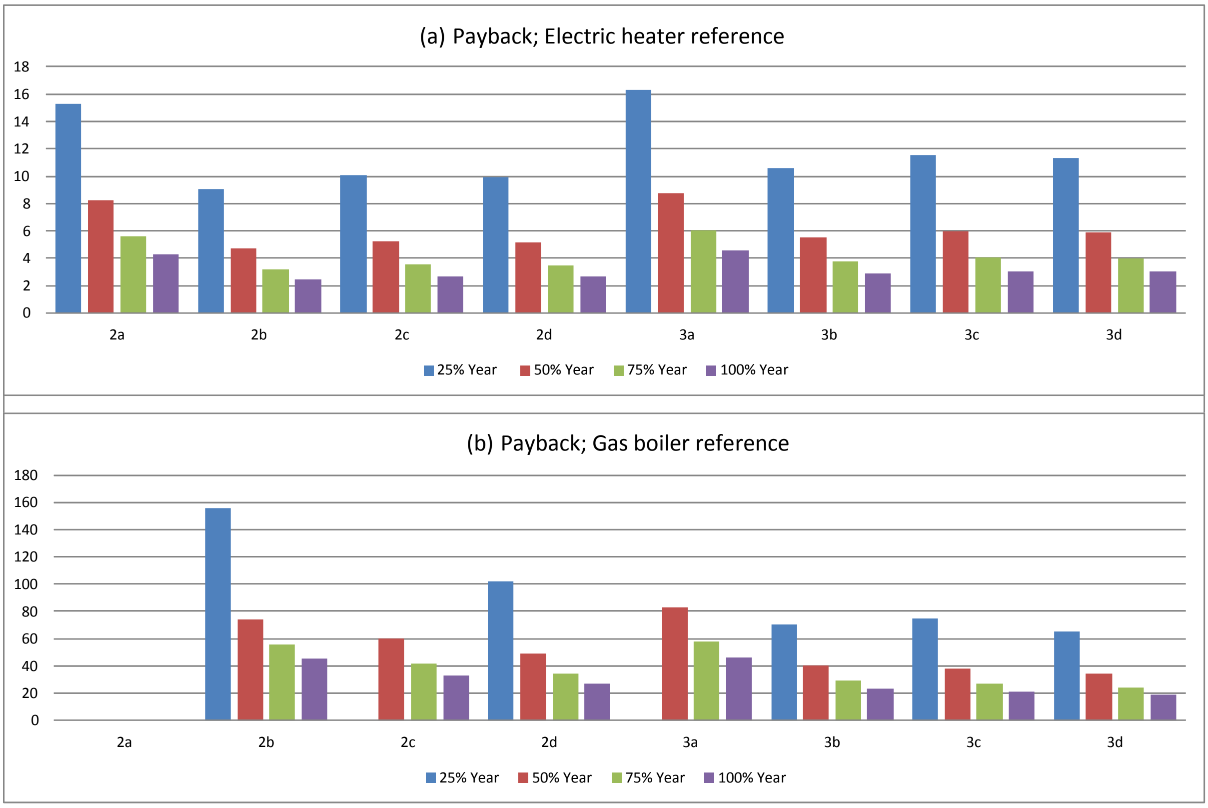

Figure 55: Payback times for the unfavourable scenario

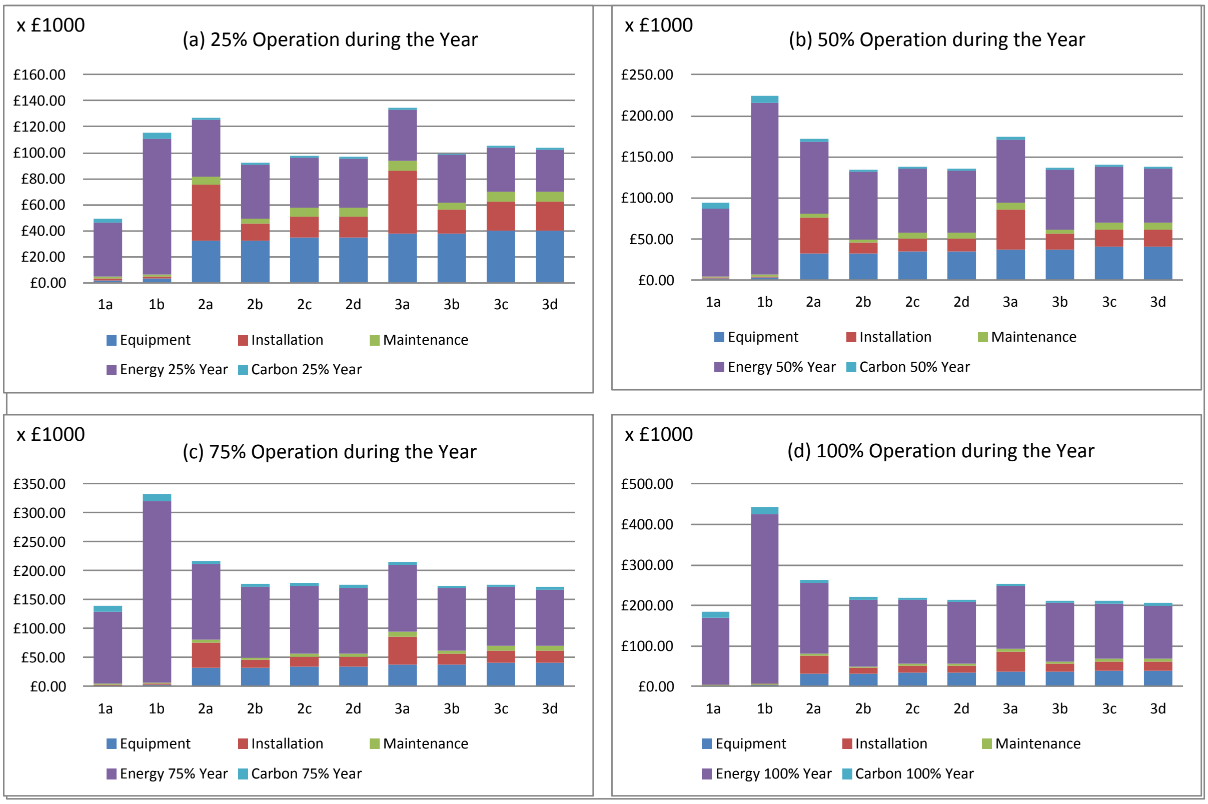

Figure 56: NPV of different heating system designs for the unfavourable scenario

3.6.4 Impact of present security of supply criteria, low-loss transformers and heat storage

In addition to the rating of transformers, its loading profile will impact the business case of heat recovery from electrical losses. This is because the volume and grade of heat (i.e. temperature at which heat is extracted) are directly related to the transformer loading. The loading will vary according to the fluctuations in electricity demand in the supplied area, and this information represents a starting point for identifying promising areas where the implementation of heat recovery may be viable. As an example of representative transformer loading profiles, we present measurements taken on four 15 MVA transformers in Merton substation during the month of January 2013.

Figure 57 shows the load diagrams for the four transformers for the week starting from Monday 14th and ending on Sunday, 20th of January 2013. We observe that the loading varies from about 40% to more than 100% (reaching 110% in one of the transformers). To provide additional insight, Figure 58 shows the relative frequencies for the loading of each transformer based on half-hourly measurements during January 2013, suggesting that neither transformer drops below 35% at any point during the observed month, while for two of them the maximum loading exceeds their nominal capacity. Average transformer loading levels observed during the same month are between 67% and 70%. This information suggests that if there is sufficient heat demand in the area, this substation could be a feasible location for implementing a heat recovery system.

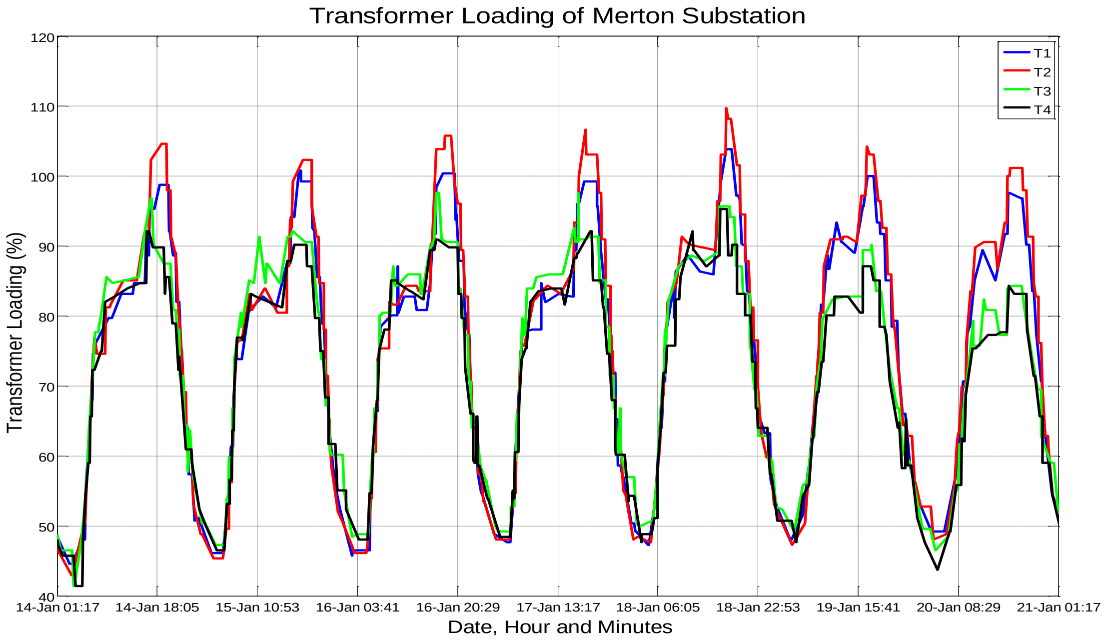

Figure 57 Weekly diagram of transformer loading at Merton Substation

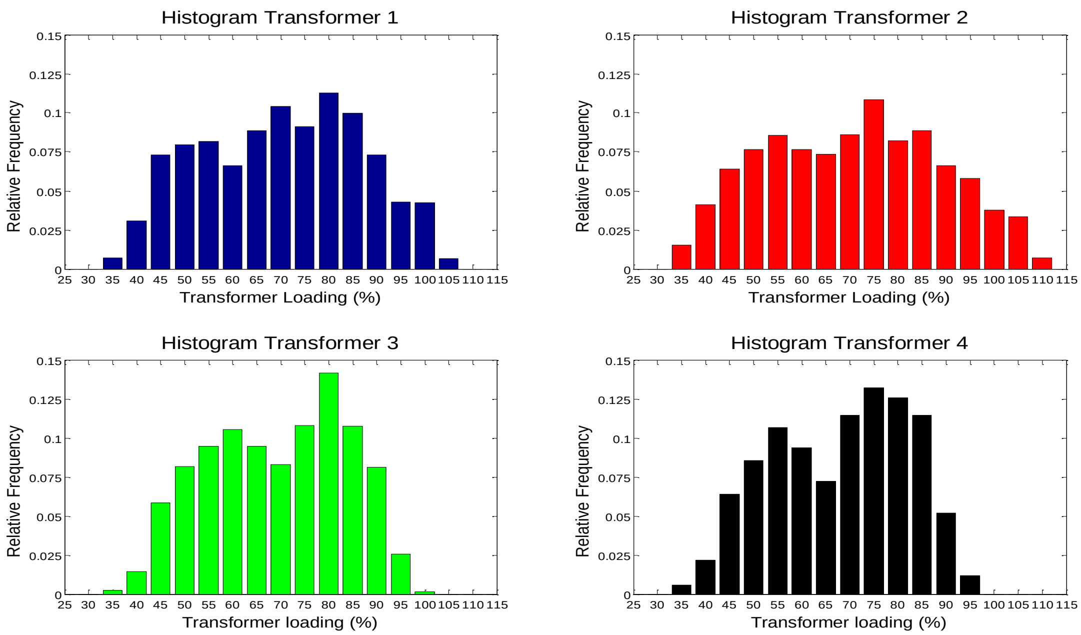

Figure 58 Histogram of transformer loading at Merton substation during January 2013

However, transformer loading may be lower in some locations due to the enforcement of security of present supply criteria such as N-1, and this section explores the impact of consequently lower loading levels. We further investigate in this section the impact of low-loss power transformers on the heat recovery process, and also study the possibility to install heat storage in the form of a water tank in order to bridge the potential gap between hourly variations in heat recovery and heat demand.

Security of Supply and Transformer Loading

In the context of present Engineering Recommendation P2/6, the maximum loading in normal operation (i.e. without transformer outages) can be expected to reach 75% when the substation is designed with four transformers, i.e. 50% with two transformers in parallel operation. On the other hand, it is important to bear in mind that the application of various smart grid technologies may significantly increase the pre-fault loading of transformers.

Lower transformer loading will result in less heat being generated, which should be considered when sizing the heat recovery equipment. For instance, a 15 MVA transformer operating at 70% can deliver around 46 kW of heat, while at 30% loading only 23 kW of heat will be generated. The additional effect of reduced transformer loading is that the recovered heat is of lower grade as it is delivered at a lower temperature. This will reduce the heat pump COP and consequently the efficiency of the heat recovery system. Under these conditions the alternative heat recovery approaches with variable flow seem to be particularly promising.

This is shown in Figure 59, where the payback times using a gas boiler as reference are slightly shorter for variable flow control than for the standard heat recovery scenario across all operating time percentages. Payback times for the electric heater reference on the other hand are slightly longer than in the constant flow case. Figure 60 shows that according to the NPV analysis, heat recovery alternatives become more attractive than gas boilers for operating times of 75% and above. We also note that beyond the 50% operating time the NPV values for variable flow and low-temperature radiators at 45°C are quite similar to the standard heat recovery with conventional radiators. We again find that for all operating times heat recovery systems are more attractive than electric heaters or standard heat pump systems.

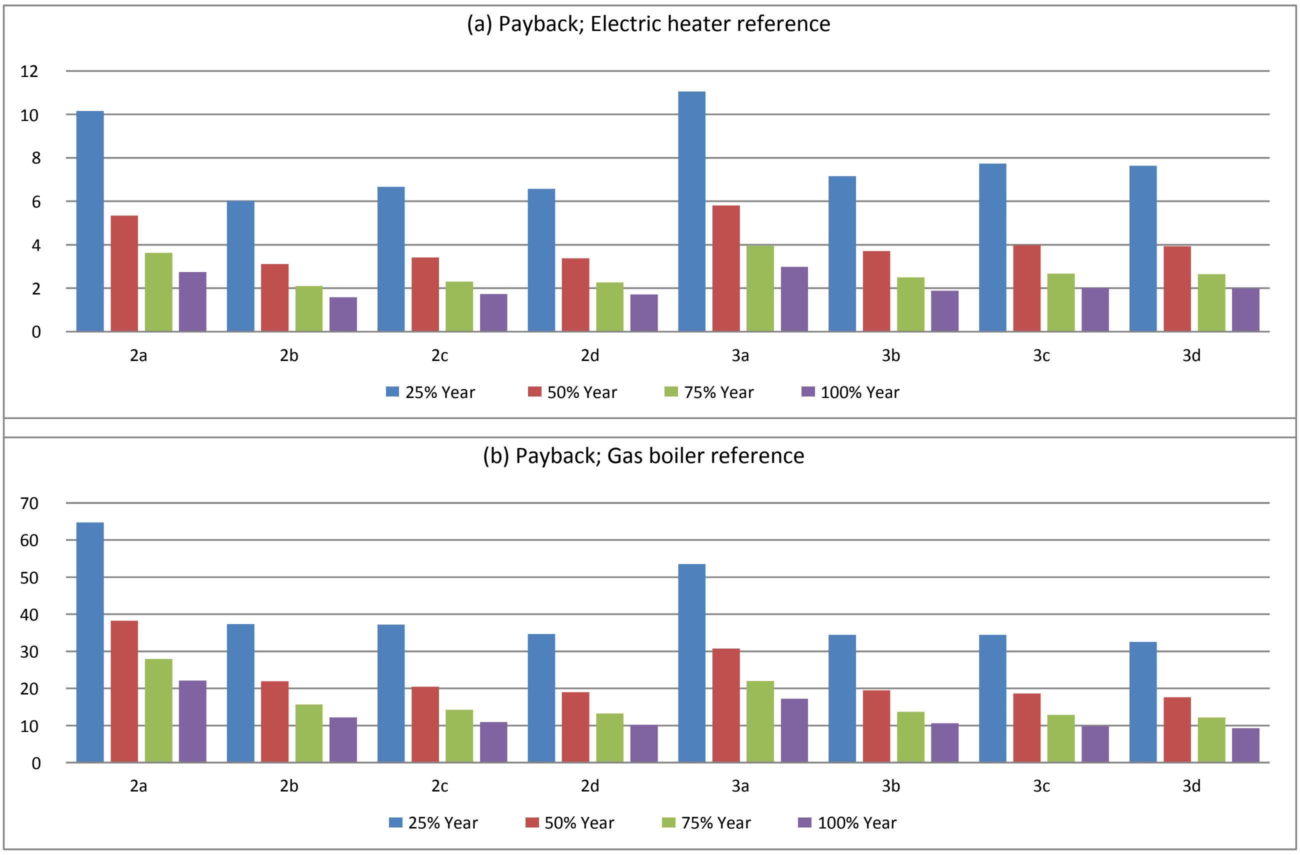

Figure 59 Payback times for decreased transformer loading (30%)

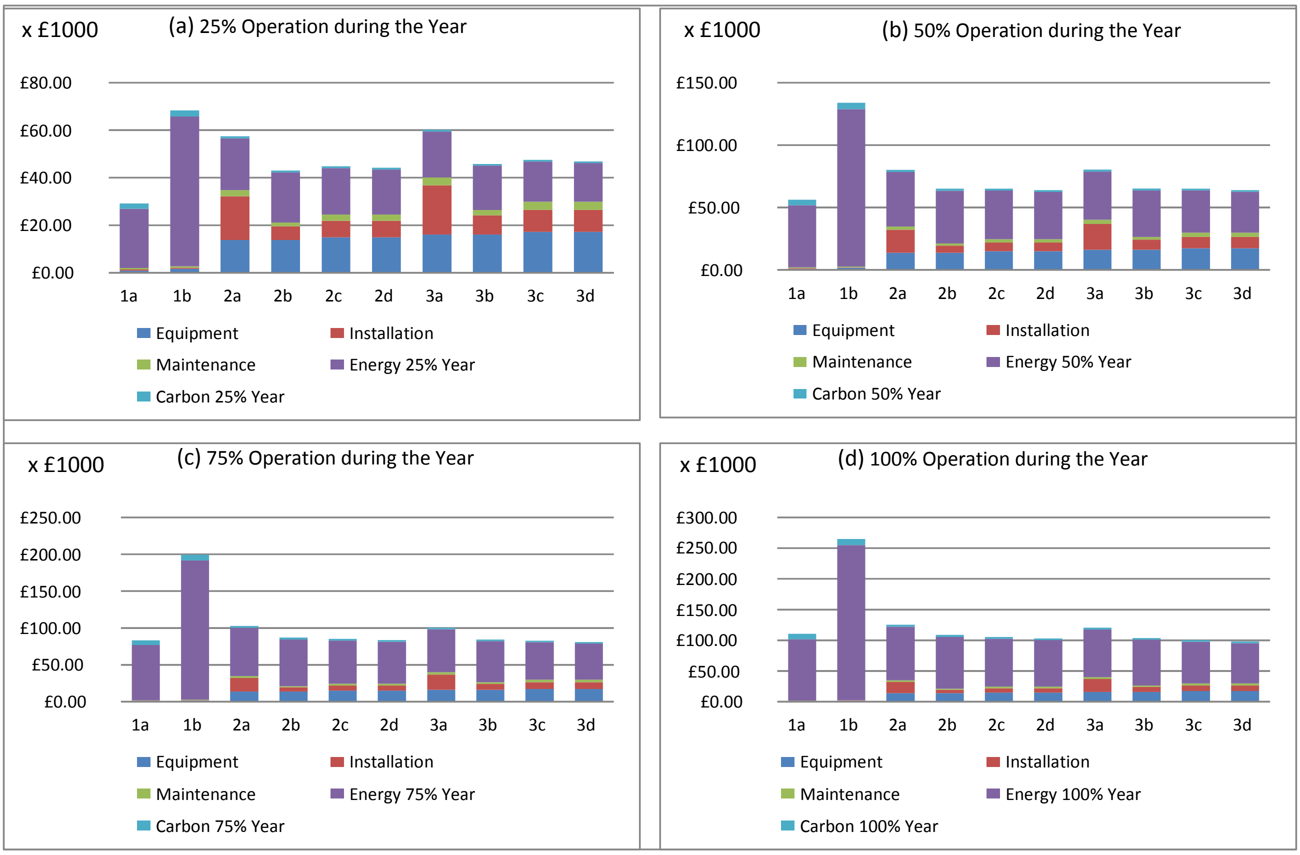

Figure 60 NPV of different heating system designs for decreased transformer loading (30%)

Low loss transformers and available heat

Under the new requirements of Directive 2009/125/EC of the European Parliament and of the Council with regard to small, medium and large power transformers the amount of power transformer losses will be reduced and consequently the amount of recoverable heat will be lower. Taking the assumption that the amount of losses will change but the internal temperatures will remain similar in low-loss as in standard transformers, the major impact will be that the heat recovery equipment size would need to be reduced accordingly. For instance, a 15 MVA low loss transformer with no-load and load losses lowered by 50% and an average loading of 30% will deliver 12 kW of heat compared to 23 kW obtained from the standard transformer. The generated heat of 12 kW is a relatively small quantity for space heating; however, in a common arrangement with four transformers per substation this would result in a total available heat of 48 kW.

Payback times for different heat recovery alternatives fitted to this low-loss transformer are shown in Figure 61. The payback period compared to an electric heater for all heat recovery systems is shorter than eight years with 25% of operating time. Payback times against gas boilers become viable for operating times of 50% and above. We note that heat recovery alternatives with variable flow and low temperature radiators at 45°C have slightly lower payback times than the standard heat recovery. Figure 62 shows the NPVs of different heat recovery alternatives and verifies that these become competitive to gas boilers at operating times above 50%. All heat recovery systems again outperform electric heaters and conventional heat pump systems.

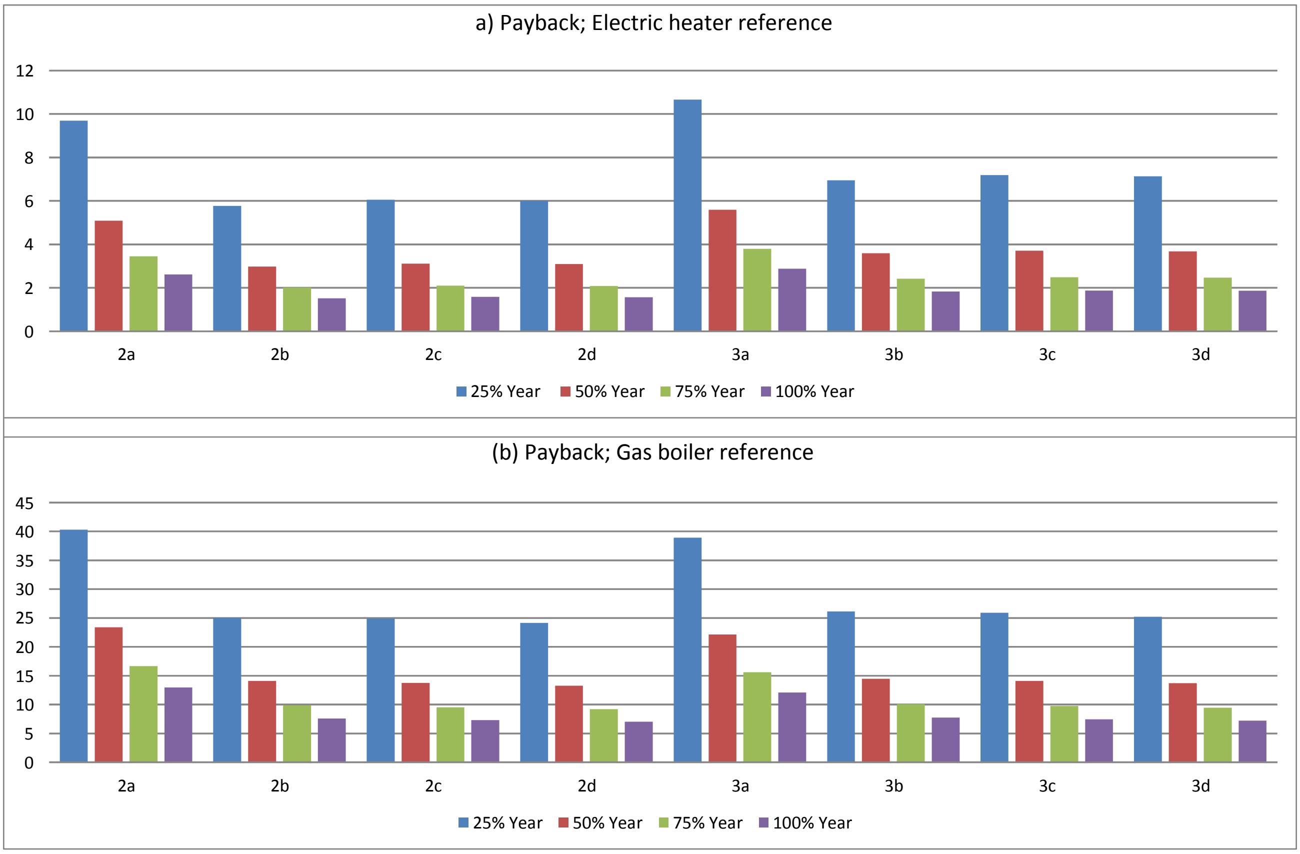

Figure 61 Payback times with low-loss transformer loaded at 30%

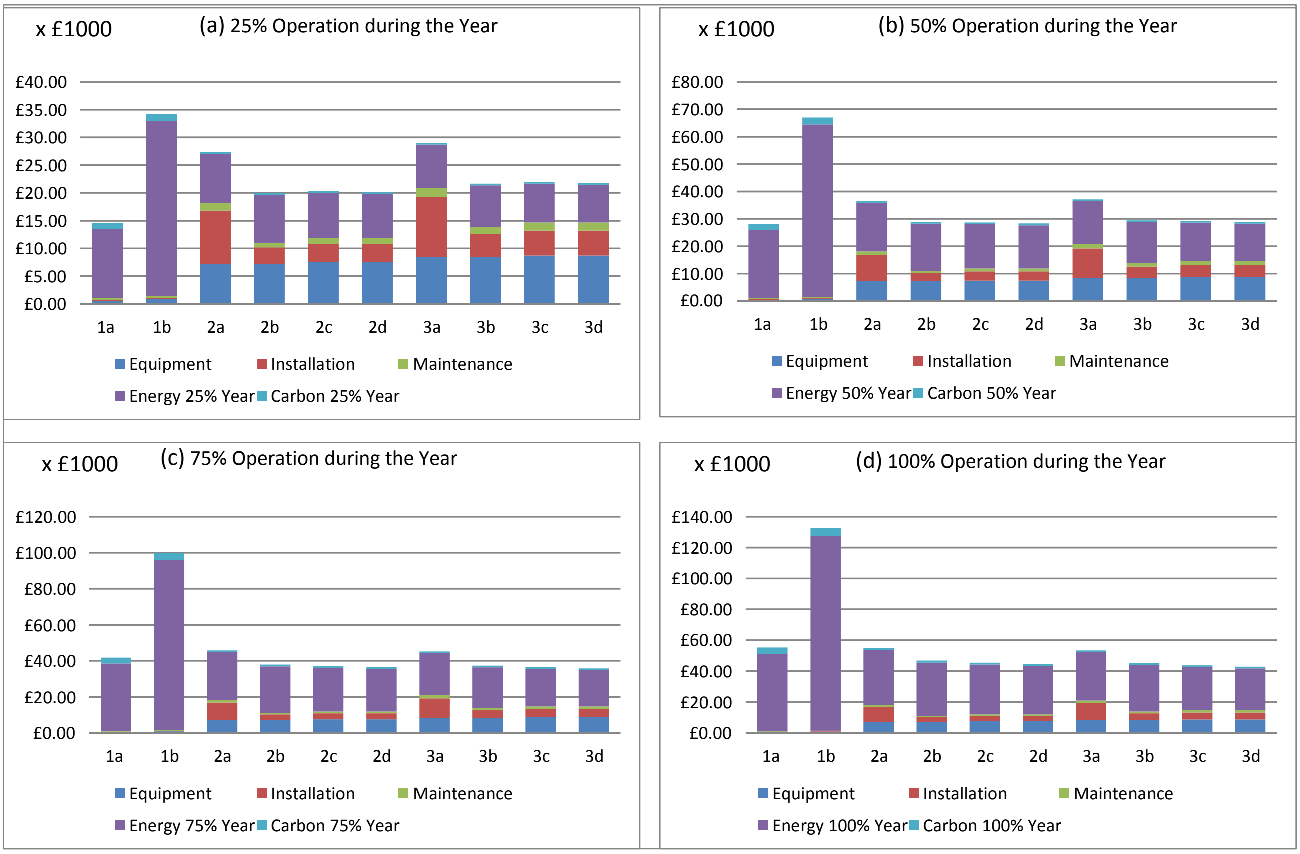

Figure 62 NPV of different heat recovery options with low-loss transformer loaded at 30%

Using heat storage to match temporal variations in heat generation and demand

The amount of heating energy required at a particular site may not only differ from the total volume of heat recoverable from transformer losses, but can also vary significantly during the day and across seasons. The difference between the amount of heat recovered in summer and winter is out the scope of this study; however a possible solution for seasonal variations can be to diversify the use of the recovered heat by supplying hot water to commercial or industrial premises, e.g. restaurant kitchens or laundry services.

The mismatch between the daily variations in heat demand and recovered heat can be managed using a water tank as heat storage to dampen these variations. An extreme scenario can be constructed assuming that the heat demand is only present during daylight, and requires additional heat which can only be supplied by using the stored heat that is not used during the night. The analysis of the transformer presented in Figure 59 and Figure 60 is used as the reference for this assessment. The investment cost of a water tank, and the installation and maintenance cost shown in Table 19 is added to all heat pump alternatives, but is not added to the gas boiler and electric heater. However, the ratings of these two alternatives are doubled in order to meet the peak daytime heat demand. The cost of reheating the stored water (due to storage heat losses) and the energy required for storing the water at higher temperatures (to prevent bacteria growth) are not considered in this analysis.

Table 19 Water tank cost

Item	m^3	Cost/m^3	Subtotal
Water Tank	4.7314	£1,000.00	£4,731.43
Installation and commissioning	4.7314	£500.00	£2,365.71
Annual maintenance	-	-	£141.94
Total			**£7239.08**

Figure 63 shows that the addition of heat storage in all heat pump alternatives slightly increases the payback times when the electric heater is used as reference. On the other hand, payback periods with gas boiler as reference increase by 20 to 30 percent in comparison with heat recovery systems without the water tank. Payback times shorter than 20 years (compared to a gas boiler) are only achieved when the operating time is above 75%. Slightly lower payback times are observed for heat recovery alternatives with variable flow and low-temperature radiators at 45 °C.

Figure 64 shows the NPV with the cost of heat storage included. The water tank investment renders heat recovery alternatives attractive when compared against electric heaters and conventional heat pump systems regardless of the operating time. In contrast, it is only beyond the 75% operation that heat recovery becomes preferred to a gas boiler.

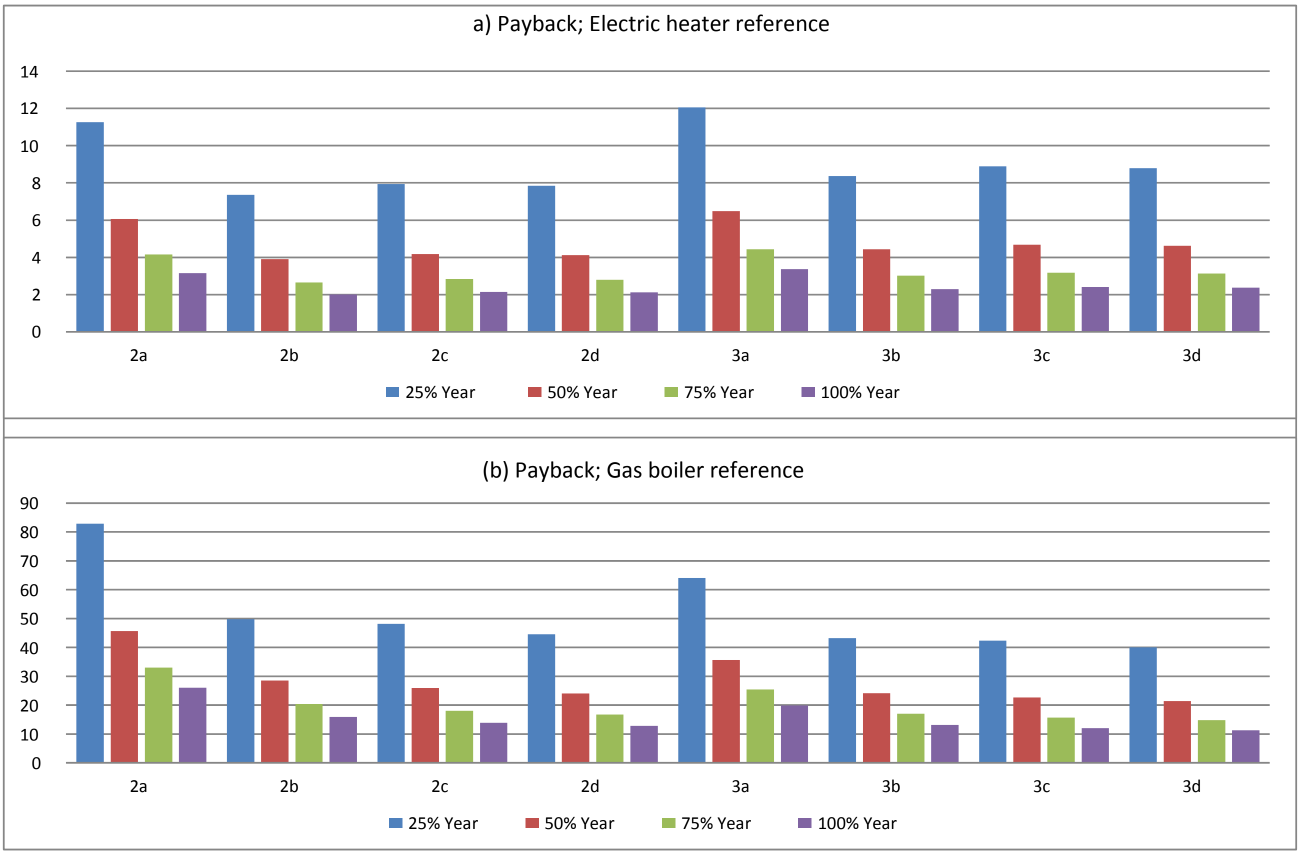

Figure 63 Payback time with water tank

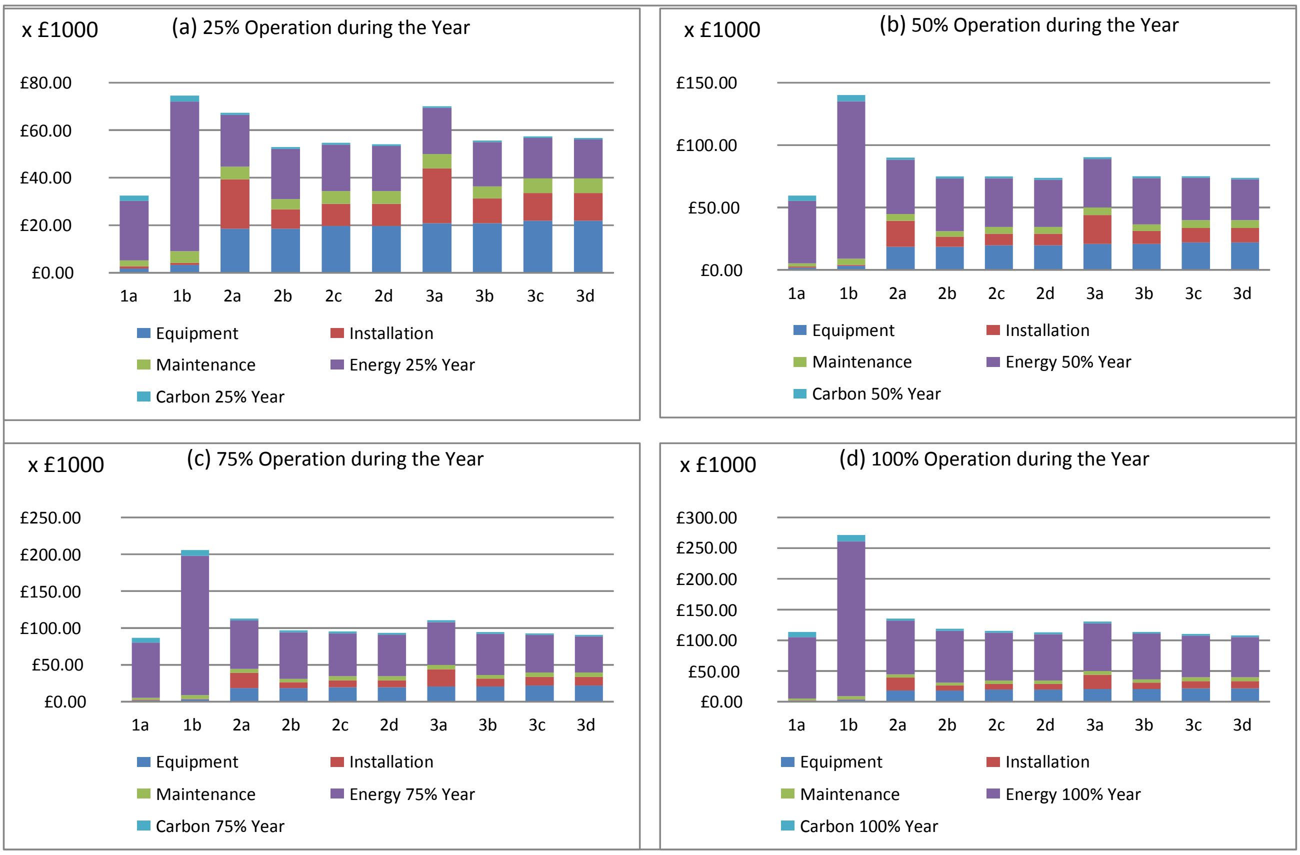

Figure 64 NPV with water tank

3.7 Summary

In this section we have presented the methodology for assessing the economic performance of various options for recovering the heat generated by electrical losses in a power transformer. This required a detailed modelling of thermal behaviour of transformer cooling systems as well as the associated heat pump systems. It is important to highlight that the results of the valuation for a given situation are driven by a number of technical and economic factors such as transformer loading, inlet water temperature of the oil-water cooler, heat pump cycle efficiency, efficiency of heat recovery, and energy and carbon prices.

We have illustrated our methodology on an example of a 15 MVA distribution transformer. The results show that combining heat pump technology with heat recovery from transformers is a good investment option when compared with conventional installations of GSHP. It is estimated that with heat recovery the installation cost is reduced by at least 50% because it is no longer necessary to drill boreholes or excavate for ground loops.

In general, the combination of heat pumps with simple heat recovery systems for heating space purposes may represent an attractive investment if it competes with electric heaters. Our analysis suggests that the payback time can take from five to ten years with 25% to 50% of time spent in operation during the year. This indicates a promising potential for applications where it is not possible to connect to the gas network.

When a heat pump system with heat recovery is compared to a conventional gas boiler, the payback time can take between 12 and 30 years, which can be significantly longer than the estimated equipment life of 20 years. The prospects for these systems start to be attractive when they operate for at least 50% of the year, although this may be substantially reduced if gas and carbon prices increase as widely expected. In particular, incorporating hot water systems into the heat recovery scheme will increase the attractiveness of projects competing with mains gas solutions as the operating time is extended and the water inlet temperatures are higher in the summer.

The results of our sensitivity analysis show that payback times are significantly reduced as a result of increased transformer loading and increased gas and carbon prices. Marginally better payback times are obtained for higher cooling water temperatures, increased heat pump efficiency (although there is a significant reduction in capital cost) and an increased discount rate (with total costs being reduced by nearly 50%). The impact of a 100% increase in gas price is that the heat pump system with heat recovery becomes more attractive than a gas boiler, reducing the payback times at 50% operation from 35 years to 6 years. The impact of a 50% reduction in electricity price is that the heat pump option with heat recovery is much less attractive compared to conventional (resistive) electric heating, increasing the payback at 50% operation from 4 to over 6 years.

4 Cable cooling systems

Cable capacity is reduced at high temperatures as the properties of the insulation can break down, consequently cables are either increased in diameter (reduces heating effect and gives a higher surface area for cooling) or force cooled.

There are a number of different forced cable cooling systems that could form the basis for heat recovery, including:

- Those which control the environmental conditions in which the cables are laid i.e. irrigation of the backfill or separate-pipe cooling;
- Those which directly cool the cable surface i.e. trough and weir water cooling, forced air cooling or integral-pipe cooling;
- Those which cool the cable from within i.e. internal water or oil cooling;
- Those which alter the characteristics of the conductor material using cryogenic techniques i.e. cryoresistive or superconductive cables.

One of the main issues with cable cooling is the lateral nature of the cooling flow, leading to increased temperatures of the cooling medium (and loss of cooling capability) as it flows along the cable. This puts a limit on the length of cable which can be cooled without "refreshing" the cooling medium, e.g. by venting air to the atmosphere.

Consequently, at present, most cable cooling is carried out in discrete locations where there are risks of high temperatures, such as within cable ducts.

Table 20: Summary of cable cooling methods

Cooling method	Sub-method	Potential	Comment
Controlling environmental conditions	Irrigation of backfill	Low	Not easy to control circulation and hence recover heat.
	Separate pipe cooling	High	Can be feasible but relatively small quantities and temperatures.
Directly cooling the cable surface	Trough and weir water cooling	Low	Difficult to control temperatures and water flow rate.
	Forced air cooling	Medium	Relatively low temperatures of air (and large volumes) mean that direct heat use is more feasible
	Integral pipe cooling	High	Can be feasible but relatively small quantities and temperatures.
Cooling the cable from within	Internal water	High	Used by National Grid for HV cables in ducts. These are usually some distance from suitable heat locations and the heat is dumped.
	Oil cooling	High	
Cryogenic	Cryoresistive cables	V Low	Currently not commercially viable.

techniques	Superconductors	V Low	

Clearly sites with concentrations of cables are likely to have the greatest potential for heat recovery as are sites where cooling might be an issue as these provide an additional incentive to collect and remove heat. However, to be commercially attractive, a nearby heat demand would be required, thereby reducing potential opportunities.

In addition, harvesting heat from cables is likely to prove most attractive for new build installations as retrofit is unlikely to be economic due to the costs of exposing cables, laying heat recovery loops and re-laying cables, etc. Existing cooling systems are mainly used for HV cables in less densely populated areas reducing the opportunity for use of the recovered heat.

Rook Services[57] is extracting heat from cable troughs at Hurst transformer station and believe this is why the installation is performing better than expected.

A Project would be required to demonstrate the technical feasibility and economics of harvesting heat from cables and this would require proactive DNO engagement. However, with appropriate instrumentation, this could also be explored as part of transformer heat recovery project to minimise costs.

Previous work

We have been unable to identify any stand-alone cable heat recovery projects.

GI Energy[58] did propose a GSHP heat recovery installation from HV underground cables as part of a Skanska-led bid for a project in Slough but this did not proceed.

There are difficulties and cost implications in capturing heat over the cable runs for new build but potential solutions using single point extracts to a heat pump appear technically feasible e.g. by laying coiling coils looped across cables.

Potential value

We have modelled the indicative available heat from typical DNO cables using first principles and cable data from one of the principal DNO suppliers[59].

Table 21: Cable components for heat assessment

Cable component	Details of component			
Voltage	33kV			
Cable materials	Aluminium conductors			
Cable location	Direct buried			
Conductor shape & type	Circular stranded wire			
Conductor size	300 sq mm			
Max current carrying capacity	475 A			
Maximum power capacity per circuit	27.14 MVA			
Operating capacity	25%	50%	75%	100%
Conductor temperature	40°C	60°C	75°C	90°C
AC Resistance (Ω\km) [60]	0.113	0.119	0.125	0.130
Estimated loss (kW/km)	9.6	40	95	176
Annual heat loss for typical 50% loading (MWh/km)	350			

[57] Source: Jason Garside, Commercial Manager, Rook Services Ltd, http://rookservices.co.uk
[58] Source: Mind Paugas and Chris Davidson, GI Energy.
[59] http://www.nexans.co.uk/eservice/UK-en_GB/navigate_183507/BS7870_4_10_19_33kv_Single_Core_Un_armoured.html#doc_and_info
[60] Temperature effect from: http://www.openelectrical.org/wiki/index.php?title=AC_Resistance

This assessment indicates that it is unlikely that heat recovery from buried cables will be cost effective unless there is also a need for cable cooling. Cable cooling is standard practice in some cable tunnels but this is usually achieved through air circulation which has a low value for heat recovery and is simply vented to atmosphere.

Combined transformer and forced cable cooling systems

We have found no projects where the recovery of heat from cables and transformers together has been engineered from the outset. In most cases the cable heat recovery has been an additional bonus to the main transformer heat source, e.g. Birmingham Market project by Central Networks.

Rook Services recovers the heat from cables leading to/from the transformers in the cable troughs through running its pipework alongside the existing cables to improve the performance of its Hurst installation (see Appendix 3). At times this provides sufficient heat for the substation offices without the need to operate the heat pump. This has provided an unexpected benefit to system performance.

Integrating heat recovery from "transformer cables" at the design stage is likely to prove attractive although there is no detailed monitoring data available to illustrate this. Further research is required to establish whether natural, such as Rook Services' Hurst installation, or forced systems prove most attractive.

5 Potential support mechanisms for heat storage

Heat recovered from transformers and utilised instead of fossil fuel sources will benefit from avoiding carbon taxes such as the Climate Change Levy[61] (CCL), the European Union's Emissions Trading System[62,63] and the new carbon price floor mechanism[64]. Avoidance of the latter is likely to prove particularly attractive if it is implemented as planned.

In addition it is possible that waste heat recovery from transformers could benefit from enhanced capital allowances in future if the technology was deemed eligible. This scheme allows businesses to claim 100% first year allowances on their investment in designated energy-saving plant and machinery against the taxable profits of the period of investment. Qualifying technologies and products such as existing GSHP models are specified in the Energy Technology List[65].

Heat pumps systems that combine heat recovery from transformers with naturally occurring heat extracted from the ground or the air might also benefit from the Renewable Heat Incentive (RHI) in future.

[61] The CCL is a tax on the taxable supply of electricity, natural gas supplied by a gas utility, liquid petroleum gas (LPG) and other gaseous hydrocarbons in a liquid state, coal and lignite, coke, semi-coke and petroleum coke when used for lighting, heating and power, by business consumers in industry, commerce, agriculture, public administration and other services. The CCL does not apply to taxable commodities supplied for use by domestic consumers or to charities for non-business use.
http://customs.hmrc.gov.uk/channelsPortalWebApp/channelsPortalWebApp.portal?_nfpb=true&_pageLabel=pageExcise_InfoGuides&propertyType=document&id=HMCE_CL_001174#P4_44

[62] http://ec.europa.eu/clima/policies/ets/index_en.htm

[63] https://www.gov.uk/government/policies/reducing-the-uk-s-greenhouse-gas-emissions-by-80-by-2050/supporting-pages/eu-emissions-trading-system-eu-ets

[64] The carbon price floor is a tax on fossil fuels used in the generation of electricity which came into effect on 1 April 2013. It includes the setting up of new carbon price support (CPS) rates of the CCL.
http://www.hmrc.gov.uk/climate-change-levy/carbon-pf.htm

[65] https://etl.decc.gov.uk/etl/site.html

The RHI provides a 20-year financial incentive to increase the uptake of renewable heat by eligible, non-domestic renewable heat generators and producers of bio-methane. This includes community and district heating projects where one boiler serves multiple homes. Ofgem[66] is responsible for implementing and administering the scheme on behalf of the DECC[67] including the accreditation of installations. Although the RHI currently only supports non-domestic installations, DECC intends to extend the RHI to the domestic sector and to increase the number of technologies and fuels which are eligible.

The use of a non-natural heat source, such as heat from a transformer, disqualifies a heat pump system from the RHI subsidy under current legislation. However DECC are currently considering arguments for the proportion of naturally occurring heat extracted from the ground or the air, which is defined as renewable, to be eligible in future provided that the overall system met required technical standards. Heat pumps that produce heat from renewable sources and supplemented by heat recovered from transformers may or may not be eligible for incentives for the renewable element of the system in the future.

There are essentially three common types of heat storage: Ground heat/cool for long term storage with heat pumps, large volume insulated tanks holding water and smaller Phase Change modules.

GSHP have traditionally used bore holes to extract heat in the winter and dump heat (in reverse cycle) in the summer for cooling. The UK heat/cool cycle is such that there is a greater demand for heat than cooling so there has to be "natural" heat flow into the bore holes to maintain the equilibrium. This could be supplemented by electrical system heat recovery in the summer but this would add additional complexity to systems which are already marginally cost effective.

Water tanks have been used for heat storage in a number of applications for some time; often referred to as "buffer" tanks these take the excess heat generated in a boiler or combined heat and power plant at times of low heat demand (which enables the plant to run at optimum efficiency) and then feeds the heat back to the primary circuit at times of high demand, avoiding the infrequent use of additional plant capacity. Due to volume limitations, this heat storage is fairly short term with a maximum "swing" between input and output of 24 hours – a diurnal store.

The use of Phase Change modules rely on the physical characteristics of some materials to change from a solid to a liquid state at high temperatures (compared with the well known ice-box packs working at freezer temperatures). Heat is absorbed by the material as it liquefies and then released if it is allowed to cool. A Phase Change Material (PCM) system occupies about half the space of a water tank but is about five times more costly and hence can only be justified in locations where space is at a premium. These systems are often used in underfloor heat exchangers to provide peak cooling for air conditioned offices where there are space constraints on chiller plant (as used in the K2 building at CEREB[68]).

It is suggested by one supplier that a PCM[69] system could recover 55% of the heat created in a Distribution transformer whilst maintaining a constant oil temperature independent of load or ambient conditions using a small heat pump integrated into the oil cooling system.

Both water and PCM heat storage systems would be capable of operating on a diurnal basis but it is unlikely that sufficient capacity could be created for inter-seasonal storage. The only successful long term storage is based on ground source heat pump units using the ground capacity as a long term store as described below.

Ground based heat storage approaches are increasing, mainly driven by the need to cool spaces:

[66] http://www.ofgem.gov.uk/e-serve/RHI/Pages/RHI.aspx

[67] https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/renewable-heat-incentive-rhi

[68] CEREB at South Bank University http://www.cereb.org.uk/technologies/.

[69] PCM Products Ltd http://www.pcmproducts.net/.

- GI Energy schemes at Sainsburys, Carlisle and for Crossrail.
- Helsinki data centre cooling (Helsingin Energia) helps heat 500 homes[70,71].
- Vienna Metro Line U2 has four substations where heat recovered from cooling is used to heat office space[72].
- The Swiss Lötschberg Base Tunnel uses excess groundwater to heat greenhouses and aquaculture facilities[73].
- Summer heat from road surfaces is utilised for snow-melting and de-icing of bridges and roadbeds in Switzerland[74].

The ground thermal storage concept is readily transferable to transformers and cables. It would be easier to implement compared to the Sainsbury's scheme as it does not have control system complications associated with the refrigeration part of the system.

Heat removal for summer cooling purposes (e.g. London Underground network) without heat being utilised is more common and long term heat storage could be attractive if the overall scheme efficiencies can be increased.

[70] Source: Towards 'Multiplex' or Next Generation Infrastructure, Hillary Brown, Associate Professor, Bernard & Anne Spitzer School of Architecture, The City College of New York, February 20, 2011.
http://www.utrc2.org/sites/default/files/pubs/Final-HBrown1.pdf

[71] http://www.computerworlduk.com/news/it-business/17804/green-data-centre-recycles-waste-heat/ and http://perspectives.mvdirona.com/content/binary/Hel_En_Eco-efficient_computer_hall.pdf

[72] Untergerger, W., Hofinger, H., & Grünstäudl, T. "Utilization of Tunnels as Sources of Ground Heat and Cooling – Practical Applications in Austria." iC Group of Companies website.
http://www.ic-group.at/upload/publications/TunnelsGroundHeat_en.pdf

[73] http://www.swissinfo.org/eng/front/Alpine_caviar_and_papayas_come_to_Switzerland.html?siteSect=107&sid=10149999

[74] http://www.egec.org/target/Brochure%20Snow%20Melting%20&%20De%20Icing.pdf

Appendix 5:

GB regulation and losses

1 History of loss incentives

The development of the loss incentive within the Distribution Price Controls is summarised in Table 22.

Table 22: History of loss reduction mechanisms within GB Distribution Price Controls

Price control	Period	Loss reduction mechanism	Incentive value per MWh (pre-tax)
DPCR1	1990-1995	None	
DPCR2	1995-2000	Output based incentive, including secondary benefit through volume driver (100%)	£40
DPCR3	2000-2005	Output based incentive, including secondary benefit though volume driver (50%)	£40
DPCR4	2005-2010	Output-based incentive	£48
DPCR5	2010-2015	Output-based incentive	£60
RIIO-ED1	2015-2023	Obligations and a small award mechanism	N/A

DPCR1 was first the GB Distribution Price Control (1990 -1995) at the time of Privatisation of the GB electricity sector. This was a relatively simple mechanism based upon the RPI-X form of incentive regulation, with the single objective of generating improvements in operational and capital efficiency.

The losses incentive was first introduced in DPCR2 (1995-2000) and this was retained for DPCR3 (2000-2005). The introduction of the incentive did focus some attention on what may be done to reduce technical losses. However, there was a greater incentive to examine non-technical losses such as theft since additional revenues could be gained by registering the additional “lost” units as units distributed. This yielded additional allowed revenue through the volume driver which also existed in the price controls at that time.

DPCR2 and DPCR3 were set during periods when there were significant changes to energy settlements arrangements, with the introduction of profiling arrangements for full supply competition (1998), separation of supply and distribution businesses (progressively from 1998 to full separation in 2001) and further changes with the introduction of New Electricity Trading Arrangements (NETA) in 2001. There was also considerable activity in changes of ownership of networks companies during this period. A consequence of these changes was increasing uncertainty in the measurement and reporting of losses.

DPCR4 (2005-2010) and the present control DPCR5 (2010 to 2015), were developed amidst increasing concerns relating to loss measurement, recording and reporting. Fundamentally, uncertainties relating to non-technical losses are compromising any meaningful assessment of technical losses as may be derived from the settlements and associated data systems.

OFGEM reported a number of problems with the current incentive, revolving around the difficulty in getting an accurate measure of losses and the difference in the techniques the DNOs use in calculating and reporting losses. OFGEM chose to address these problems so that customers only pay for and DNOs are only rewarded for real improvements.

After public consultation, and considerable discussions with DNOs and other stakeholders through the Losses Working Group[75], Ofgem has taken the decision to suspend the incentive in the next price

[75] The RIIO-ED1 development programme includes working groups. In 2012 there were several meetings of the Losses Working Group with many relevant papers which are accessible at: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/working-groups/Pages/index.aspx

control, RIIO-ED1 (2015-2023). An alternative loss reduction mechanism, largely based upon a set of obligations, has been proposed in RIIO-ED1.

From 2023 onwards, the loss-reduction mechanism may revert to the form of a financial incentive, assuming that losses will be assessed more accurately than has been practically possible to date.

On the 19th February 2013, Ofgem presented an informed view of energy supply in GB[76], expressing real risks relating to security of supply in the next ten years and beyond. In this context, a reduction in losses could present a valuable contribution to reducing demand, thus contributing to the mitigation of supply-side risk.

2 RIIO- ED1 strategy on losses

The overall "package" of features of the loss reduction mechanism within the RIIO-ED1 has been very clearly described in the various Ofgem Decision documents published on the 4th March 2013. The mechanism is summarised in Table 23, with key values as shown in Table 24.

Table 23: The RIIO-ED1 Loss Reduction Mechanism

Component	Summary of detail taken from Ofgem's 4th March strategy document
Licence obligation	DNOs required to design and operate their networks to ensure that losses are as low as reasonably practicable. This will sit alongside the DNOs' overarching obligation to develop and maintain an efficient, co-ordinated and economical distribution system.
Loss reduction expenditure in Business Plans	DNOs will be required to set out in their business plans their approach to losses reduction in support of their licence obligation. This strategy statement should demonstrate their overall approach, as well as set out specific projects or actions, with timescales and deliverables and an assessment of their impact on losses and the associated additional costs.
Annual reporting	DNOs will be required to report annually on their loss reduction activities undertaken in the year, setting out improvements achieved in the year and cumulatively, and actions planned for the following year. The reporting will be linked to the Cost Benefit Analysis of relevant actions.
Discretionary award	There will be a losses discretionary reward (DR) of up to £32m across all DNOs, awarded in three tranches over the eight years. The aim is to encourage DNOs to undertake additional loss reduction actions over and above those set out in their business plans.

Table 24: Ofgem's criteria for cost-benefit assessment of loss-reducing investments

Factor	Requirement
Cost benefit analysis	Simple discounted approach
Discounting	Applied to all costs and benefits
Treatment of capital costs	Convert to annual cost using pre-tax Weighted Average Cost of Capital (WACC)
Term of assessment	Assumed economic life of the asset up to 45 years
Test discount rate	3.5% for costs and benefits
Value of energy loss reduction	The average of wholesale prices over 2011/12. This is £48.42/MWh in 2012/13 prices.
Value of carbon abatement	DECC's latest valuation https://www.gov.uk/carbon-valuation. For the power sector a linear carbon regression is applied from the present value to 10g/kWh in 2050 in order to reflect decarbonisation policy.

[76]Presentation by Alistair Buchanan, Ofgem CEO
http://www.ofgem.gov.uk/Media/keyspeeches/Documents1/LECTURE%20%2019TH%20FEBRUARY%202013.pdf

Over a 45 year asset life and with a 3.5% test discount rate, Ofgem's valuation method for loss reduction under their stated rules of Cost Benefit Analysis, delivers a net present value of £1,451/MWh.

3 Impact of Ofgem's requirements on Distribution Network Operators

Ofgem considers that a financial incentive arrangement will be a more effective mechanism for loss reduction and will expect DNOs to make progress in more accurate assessments of technical losses during the RIIO-ED1 period, in order that an incentive mechanism may be re-introduced in RIIO-ED2 for 2023 onwards.

Nevertheless, it is our considered view that the proposed loss mechanism in RIIO-ED1 will be effective in making progress with lower losses between now and 2023. The final versions of the DNOs' Business Plans[77] indicate a significant change in approach to addressing losses from those developed five years' ago under the previous price control regime.

Ofgem have indicated their expectation that strategies for loss reduction should be updated during the course of RIIO-ED1. This will allow best practices across the DNOs to be developed further. At present there is a wide variation in approach from the DNOs. For example, some DNOs refer to "opportunist" loss investments by using lower-loss equipment when some change is required to the network for reasons of load, reliability, new connection or safety. Other DNOs refer to more interventionist strategies, in which investments may be driven by no other reason than to reduce losses.

[77] The DNOs' Business Plans have been published on the individual companies' websites. A list of websites is available here: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIO_ED1_BP_publication_seeking_views.pdf

Appendix 6:

Standards and losses

1 Europe: EN Standard 50464-1 for HV/LV transformers

New EU legislation has been adopted for transformer efficiencies. Previously there were no mandatory standards for transformer losses in Europe. However, for some time there has been a standard loss classification for HV/LV (or as referred to in Europe, MV/LV) transformers. There are five levels of iron loss, classified from A_0 to E_0 and four load loss levels classified from A_k to D_k with typical values for losses of a 400kVA transformer shown in Table 25.

Table 25: European Standard for distribution transformer losses

No-Load (Iron) Losses		Load (Copper) losses	
Level	Gains over Eo	Level	Gains over Dk
A_0: 430W	54%	$A_{k:}$ 3,250W	46%
B_0 520W	44%	$B_{k:}$ 3,850W	36%
C_0: 610W	34%	$C_{k:}$ 4,600W	23%
D_0: 750W	19%	D_k: 6,000W	-
E_0: 930W	-	-	-

2 Europe: application of standards

The majority of EU countries already use transformer specifications which typically require a 30% reduction on no-load loss and a 10% or more improvement in load loss at full load compared with standard GB values. This may become the standard specification for Eco-design products from 2014 with a further 10% reduction in full load loss required from 2019.

The standard design for German distribution companies (according to Siemens) is A_0B_k, i.e. For a 400 kVA transformer, No-load Loss of 430W, Load Loss of 3,850W.

A paper from the European Copper Institute[78] also states "Despite the fact that there are no mandatory standards in Europe, there are some procurement procedures (internal standards of electricity distribution companies) which are highly demanding in Benelux, Germany, Austria, Switzerland and Scandinavia. Most of the electricity distribution companies in these countries buy transformers at C1 [C' minus 30%] (HD 428[79]) or A_oB_k (new 50464) standards. ENDESA in Spain purchases HD 428 CC' for 400 kVA units. EdF has introduced a purchasing policy which specifies no load losses between C_o and E_o and load losses between D_k and B_k. The mix of losses is focused on low no-load losses for small ratings and low load losses for higher ratings. Also tolerance of losses has changed recently. More often utilities reduce the tolerance of losses to, e.g., 0% instead of 15%."

3 United States

In April 2013, the U.S. Department of Energy issued new energy efficiency standards for distribution transformers[80], to take effect from 2016. For liquid-immersed transformers sold over the next thirty years, savings based upon government assessment will reach about 130TWh and net savings for utility owners and their customers will reach about $3 billion. Whilst these are large figures, the standards have not met universal approval as the minimum requirements can be achieved with conventional steel cores, without developing towards amorphous steel cores which could provide

[78] http://www.copperinfo.co.uk/transformers/downloads/seedt-guide.pdf
[79] HD428-S1 Standard for Three phase oil immersed distribution transformers 50 Hz, Cenelec 1992
[80] http://www1.eere.energy.gov/buildings/appliance_standards/pdfs/dt_final_rule.pdf

further savings. Some stakeholders argue that losses should be reduced further by requiring amorphous cores.

4 GB standards

The most basic and fundamental standard relating to GB network design is Engineering Recommendation P2/6. This standard, which is made obligatory through Network Operators' Licences, relates only to network reliability. There is no reference in this document to the efficient development and design of network in relation to losses.

The most useful standard relating to management of network losses is the suite of Engineering Documents under the generic heading of Engineering Recommendation G81. Each DNO has produced an Annex for G81 providing company-specific detail of network specifications. These are summarised in Table 26.

Table 26: Comparison of DNOs' Appendices for Engineering Recommendation G81

Requirement	ENWL	NPG	SPEN	SSEPD	UKPN	WPD
3-Core XPLE 11kV cable size direct laid	95mm^2 to 245A or 300mm^2 to 461A		95mm^2 only for transformer feed. 95mm^2 to 235A, 185mm^2 to 335A, 300mm^2 to 435A	Preferred sizes of 11kV cable: 70mm^2, 150mm^2 & 240mm^2	Specified in ENA Recommendation P17	Winter (sustained): 95mm^2 to 250A, 185mm^2 to 360A, 300mm^2 to 475A
Primary transformers (33/11 kV or 33/6.6 kV)	Comply with ES322 from Schneider MDS range	Ratings calculated in accordance with BS7735 to NPS/003/011	Ratings calculated from IEC 60076 and comply with ENATS 35-2 & SPPS T20	Comply with ENA TS 35-1, losses are comparable to Low-Loss units (see below). Suitable sizing to minimise losses. Normal loads to 80% of nameplate with cyclic loads <6 hours up to 30% above nameplate.	Approved units listed in EA 00-0004 Comply with ENA TS 35-1 and IEC 60076	Comply with ENA TS 35-1 with max losses comparable to standard units (see below).
Distribution Transformers (11kV/433V or 6.6kV/433V)	Comply with ES322 and of low-loss design	Ratings calculated in accordance with BS7735 to NPS/003/011	Ratings calculated from IEC 60076 and comply with ENATS 35-1 & SPPS T21. Normal loads to 80% of nameplate with cyclic loads <6 hours up to 30% above nameplate.		EAS 04-0023 lists Al wound transformers from CG Power Systems EAS 04-0024 lists Al wound transformers from Efacec	
3-core Waveform LV Cables direct laid	95mm^2 to 235A, 185mm^2 to 335A, 300mm^2 to 435A	300mm^2 except for I&C services (185mm^2) & short spurs with <120A/phase (95mm^2)	Cables for >75 consumers or backfeed >185mm^2. 95mm2 to 235A & max 328m, 185mm^2 to 335A & max 728m, 300mm^2 to 435A & max 710m	Summer: 95mm2 to 237A, 185mm^2 to 336A, 300mm^2 to 435A Winter (cyclic): 95mm^2 to 300A, 185mm^2 to 425A, 300mm^2 to 550A	Summer cyclic (assumed to be max): 95mm^2 to 281A, 185mm^2 to 411A, 300mm^2 to 544A	Specified in ST:SD8B Winter (cyclic): 95mm^2 to 275A, 185mm^2 to 400A, 300mm^2 to 525A
LV Voltage Drop on Network	<7% from LV busbars, with max 2% for service connection	Urban network <7%, Rural network <5%, max 1% for service	<8.5% with max 5.5% from LV busbars to furthest service joint.	<7% from LV busbars, with max 2% for service connection		<8% from LV busbars with max 2% for service connection.
LV Service size	3 core, 25mm^2 Al		3 core, 25mm^2 or 35mm^2, max 25m	3 core, 25mm^2 or 35mm^2, max 25m more detailed table for heating loads	35mm^2 for domestic, max length 43m, Direct laid max rating = 163A	

Requirement	ENWL	NPG	SPEN	SSEPD	UKPN	WPD
Loss Evaluation Criteria	Kept to a minumum	£200/MWh of average annual losses		Suggest use of EATL "Debut" software	Suggest use of EATL "Debut" software	£2.034/W at nameplate rating Max values specified in EE SPEC:5
Buried cable criteria		Soil resistivity = 1.2°Cm/W. Ambient Temp = 15 °C Max duct length w/o de-rating = 20m	Soil resistivity = 1.2°Cm/W. Ambient Temp = 15 °C Max duct length w/o de-rating = 25m	Soil resistivity = 1.2°Cm/W. Ambient Temp = 15 °C Max duct length w/o de-rating = 15m		Soil resistivity = 1.2°Cm/W. Ambient Temp = 15 °C Max duct length w/o de-rating = 15m

Where transformer specifications have been made readily-available they are shown in Table 27 across three DNOs and in comparison to the loss standard applied in Germany (A_0B_k). It is also interesting to note the performance level compared with amorphous core transformers provided by one manufacturer. The quoted losses show significant reduction for no load losses (which apply throughout the life of a transformer) although load losses at full capacity are similar to current low loss specifications, giving an overall lower loss at a significantly higher cost.

Table 27: Comparison of Transformer Losses

Rated Power (kVA)		Transformer Specification (watts)				
		WPD	UKPN	SSEPD	A_0B_k	Amorphous Core
315	No load	609	420	540	360	160
	Load loss	4,364	4,200	2,880	3,250	3,650
500	No load	765	472	680	510	250
	Load loss	6,236	5,250	4,420	4,600	4,700
800	No load	1,130	840	1,000	650	325
	Load loss	9,091	8,400	6,410	7,000	6,200
1000	No load	1,304	1,050	1,080	770	500
	Load loss	10,727	9,450	7,110	9,000	6,530

5 The EU End User Product Directive

In future GB network development, it may be envisaged that network companies will specify more energy efficient products, through their own economic assessment of what is viable as determined in discussions with Ofgem. The stimulus for more energy efficient network developments will also be driven by regulations relating to product specification. A prime example of this is the European Union (EU) framework for the setting of eco-design requirements for energy-related products[81] which was adopted by the Regulatory Committee on the 13th December 2013 and is discussed further in the context of loss reduction techniques. The full title for this development is: *"Directive 2009/125/EC of the European Parliament and of the Council establishing a framework for the setting of ecodesign requirements for energy-related products"*

This is a significant development as the Regulation will establish minimum standards of energy efficiency of transformers. It will require the deployment of existing designs of lower-loss transformers from 2015 onwards and will stimulate the development of new lower loss materials

[81] http://ec.europa.eu/enterprise/policies/sustainable-business/documents/eco-design/legislation/framework-directive/#h2-1 21 October 2009

and transformer designs to meet standards of lower losses by 2020. It is also intended that the EU standards will be subject to a review in 2018.

5.1 The framework for the setting of eco-design requirements for energy-related products applied to electricity transformers

Under Directive 2009/125/EC the European Union (EU) has developed a framework for the setting of eco-design requirements for energy-related products82. This framework is now being used to implement minimum standards of energy efficiency for new transformers through a legally-binding EU Regulation.

The framework for introducing eco-design requirements across the EU is a consultative process. Each product group is called a "Lot". The official name for this Lot is "ENTR[83] Lot 2: Distribution and power transformers." The scope of this Lot includes small, medium and large power transformers with a minimum power rating of 1 kVA used in 50Hz electricity transmission and distribution.

An extensive product study was undertaken for each Lot, which examines market data, technological status and provided recommendations to the European Commission prior to the release of a draft proposal. This was completed in February 2012[84] and followed by a Consultation Forum on 20 April 2012 with experts and stakeholders met at.

A Technical Subgroup was set up to investigate options for defining mandatory minimum peak efficiency requirements for large power transformers. It was concluded that minimum efficiency requirements taking into account no-load and load losses is technically possible to specify and proposals were produced. The draft proposal was then discussed at a Consultation Forum on 9 November 2012.

A further meeting of the Technical Subgroup of the Consultation Forum took place 12 April 2013, which recommended several changes to the original draft proposal including the calculation methodology.

A revised draft was the released for inter-service consultation across the European Commission, then submitted to the World Trade Organisation for further consultation.

The final proposal was sent for voting in the Regulatory Committee on the 13th December 2013 where it was adopted. The Regulation will enter into force on the 20th day following its publication in the Official Journal of the European Union.

The Regulation will require the deployment of existing designs of lower-loss transformers from 1st July 2015 onwards and will stimulate the development of new lower loss materials and transformer designs to meet standards of lower losses by 1st July 2021. It is also intended that the EU standards will be subject to a review by 1st July 2018.

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5.2 Summary of the Regulation

[82] http://ec.europa.eu/enterprise/policies/sustainable-business/documents/eco-design/legislation/framework-directive/#h2-1 21 October 2009

[83] The Directorate-General for Enterprise and Industry, which is the European Commission Directorate leading on this Lot.

[84] http://www.eceee.org/Eco_design/products/distribution_power_transformers/Final_report_Feb2011

The Regulation[85] includes:

- Defined maximum load and no load losses and minimum peak energy efficiency requirements for medium transformers (<3150kVA),
- Further sub-categories depending on winding size and type, for example liquid-immersed and dry,
- Separate standards for maximum load and no load losses for pole-mounted transformers,
- Minimum peak energy efficiency requirements for large transformers (>36kV),
- Product information requirements from 1 July 2015,
- Introducing initial standards, known as "Tier 1" from 1 July 2015 and tightened in "Tier 2" from 1 July 2021 " and
- A review of the Regulation by 1st July 2018.

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When comparing Table 27 data with the Regulation for maximum load and no-load losses for three-phase liquid-immersed medium power transformers with the high-voltage winding rated ≤ 24 kV and the other winding rated ≤1.1kV, we see that:

- WPD's current specification is above the 2015 Maximum load losses standard for each of the sample four sizes whilst all the other specifications are lower, other than UKPN's 315kVA specification, which is also higher.
- The Maximum no load losses standard for 2015 matches the current German standard, with all three DNOs current specifications higher than these levels other than UKPN's 500kVA specification, which is lower.
- Only SSEPD's current specifications for 500 and 1,000kVA transformers are lower than the Regulation's 2021 standards for Maximum load losses.
- None of the current Maximum no load losses specifications are close to the 2021 standards.
- It is worth noting that whilst the amorphous transformer specification included in the table complies with the 2021 Regulation for Maximum no load losses, only the 1,000kVA transformer meets the Maximum load losses standard.

This implies that the current EU Regulation will in general improve GB specifications and therefore reduce losses. This is especially the case for maximum no load losses from 2021, although this might change following the 2018 review. The maximum no load standard would appear to be the most challenging, even though it has been reduced from earlier proposals.

Both the modelling work and SSEPD's current maximum load loss specification for some transformers, indicates a business case for going beyond the standards specified in the Regulation.

[85] http://www.eceee.org/Eco_design/products/distribution_power_transformers/WD%20ENTR%20Lot%202%20Ecodesign%20Tranformers%20-%20Final%20draft%20for%20CF%209-Nov-2012.pdf

Appendix 7:

Present knowledge of losses

1 Assessment of overall technical losses

Network managers' approach to understanding losses is usually through network analysis and modelling of the specific sections of the network under consideration.

There is value for networks companies and other stakeholders in being able to assess and report overall figures for losses on distribution systems at regional or national level. This is usually in percentage terms of total energy flowing in the distribution network. Such figures are used to assess the network operators' performance in managing losses. The overall loss assessment may be used for benchmarking between network operators within countries, or for international comparisons between countries. Distribution network managers, executives and regulators also wish to have an overall assessment of losses in order to set targets and track progress against any targets which may be set. Network operators and designers may wish to have an overall loss figure in order to assess trends in network efficiency and to provide feedback that management policies for loss management are having an impact.

The assessment of overall technical losses is notoriously difficult. Energy entering the network is measured every half hour and aggregation of input energy is reasonably assessed. However losses are assessed as the difference between energy entering the system and energy leaving the system, i.e. energy consumed, is not measured to the same quality leading to a degree of uncertainty in the derived value.

An objective in assessing the overall level of technical losses is to achieve an acceptable accuracy and confidence in the assessment in relation to the use that is to be made of the information. The regulatory and management requirement for the overall loss information is to ensure that the right management actions are taken to ensure that losses are at, or moving towards, the most economically efficient level which may be practically achieved. These actions will include the use of overall loss figures for setting targets, monitoring changes and making comparisons between network companies and with other countries.

2 Reported GB technical losses

2.1 Disaggregating non-technical losses

A detailed assessment of non-technical losses is outside the scope of this project. However, In order to provide a meaningful assessment of technical losses, a view has to be taken of the non-technical losses because they exist within the overall loss figures derived from the GB electricity settlements system. Inherently, loss assessment requires the calculation of differences between two large numbers, namely input energy and consumption. With limited knowledge of network loadings (especially on the low-voltage systems) technical losses cannot be calculated accurately enough to subtract them from the overall loss assessment derived through the energy settlements system. Conversely, non-technical losses such as theft cannot be assessed sufficiently well (e.g. theft is unknown unless detected and assessed) in order to deduct them from the overall loss figure.

Non-technical losses in the UK are generally low. There is comprehensive metering across networks and consumers with regular settlements as part of the arrangements for cost allocation between suppliers. The value of 0.3% is the government estimate as published by DECC in chapter 5 of the annual Directory of UK Energy Statistics (DUKES)[86].

[86] DUKES 2012 https://www.gov.uk/government/organisations/department-of-energy-climate-change/series/digest-of-uk-energy-statistics-dukes

However, there remains considerable uncertainty on this figure, as recognised by Ofgem in their decision not to use loss reduction incentives in DPCR5 or the forthcoming RIIO-ED1 price control 2015 to 2023[87].

Sohn Associates identified the major sources of non-technical losses in a report to Ofgem in March 2009[88]. This included an estimate of their influence on overall loss assessment, as summarised in Table 28.

Table 28: Non-technical loss estimates (Sohn Associates 2009)

Factor	Underlying Cause	Estimated error as Proportion of DNO supply
Theft		Overstatement of up to 0.3%
Idle Service Energisation	Quality of Records / Action by Supplier	Losses understated by 0.04%
Services incorrectly labelled De-Energised	Quality of Records / Action by Supplier	Losses overstated by 0.04%
GSP Correction Factor variations	Inaccurate Settlement data	Reduction of losses by 1.1% between first estimate and Post Final Settlement Run
Unmetered Supplies	Inaccurate inventories and mismatches	Variation from +0.05% overstatement to -0.04% understatement
Erroneous AA / EAC factors	Meter reading and recording errors by suppliers	Up to 0.05% understatement of losses (after adjustment)
Meter accuracy for older meters	Aging meters tend to under-record	Up to 0.03% overstatement of losses
Embedded generation	Metering errors and incorrect loss factors	Growing issue, BSC Audit identified inconsistency between DNOs
Calculation of losses by DNOs	Different methodologies and data sources	Up to 0.9% understatement of losses (based on step change in DNO values for 2007/8)
Adjustment of published loss factors	Inconsistency between DNOs	
TOTAL		Overstatement of 0.48% to 1.4% on initial estimate

2.2 Disaggregating transmission losses

Most GB information on transmission losses is reported separately from distribution losses. The nature of GB markets and energy settlements is such that transmission, being fully-unbundled from distribution, is separately measured. Distribution network input is readily identifiable from Grid Supply Point (GSP) metering, after adjustment for embedded generation and the energy flowing through interconnectors between GSPs.

Factors affecting losses on transmission lines are very different from those on the distribution network. GB Transmission Operators' programmes for maintenance and refurbishment of overhead lines are planned for times of lower demand on the networks but with circuits out of commission abnormal running conditions invariably mean higher losses on the remaining circuits. Similarly, generating stations may be totally out of commission for periods of time, requiring less-than optimal running conditions and invariably having an adverse impact on losses.

[87] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=755&refer=Networks/ElecDist/Policy/losses-incentive-mechanism
[88] Electricity Distribution Systems Losses – A non-technical overview
http://www.ofgem.gov.uk/Networks/ElecDist/Documents1/Sohn%20Overview%20of%20Losses%20FINAL%20Internet%20version.pdf

In contrast the main factor affecting losses on distribution networks is demand, which in turn is diurnal and seasonal.

Recent annual data taken from data published by Elexon as “Half-hourly Transmission Loss Multipliers (TLM) for Off-take and Delivery” indicates an average annual level of transmission loss of between 1.6% and 2.0%. This value is derived from the simple average (ie un-weighted for demand) of the day’s half-hourly values. It shows distinct daily and seasonal variations since April 2011 which may be primarily due to changing location of sources of generation[89].

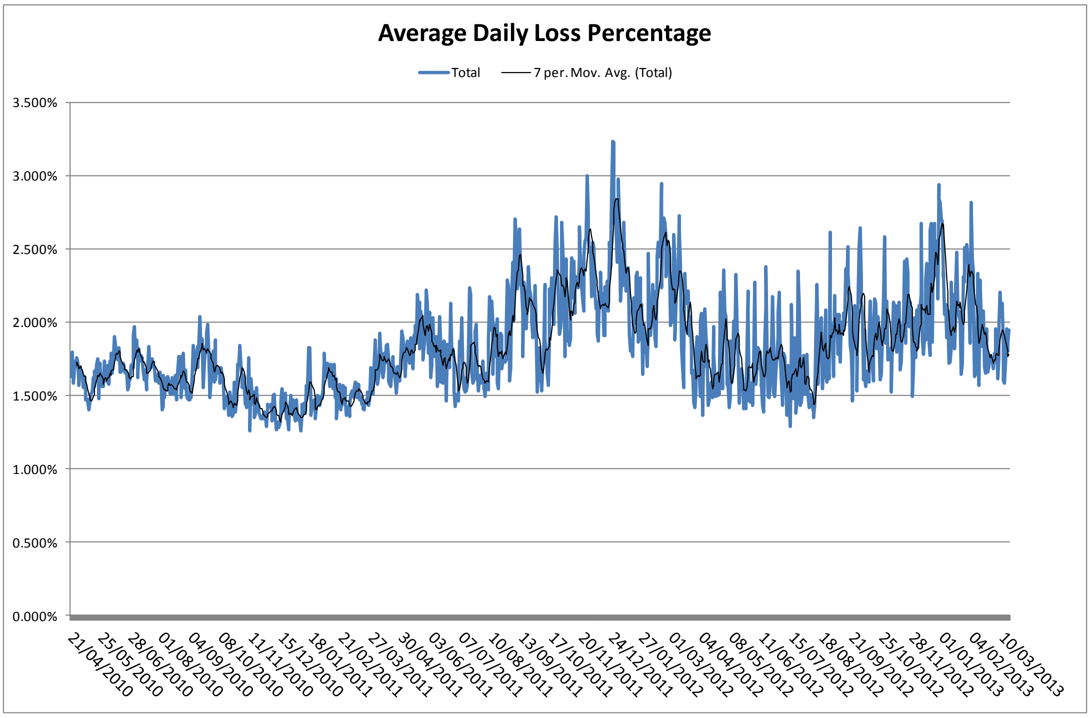

Figure 65: Annual GB transmission loss

3 Losses data published by Ofgem and Government

For the purposes of this project, our key sources of information relating to GB losses have been Ofgem’s reports in various Consultation and Decision documents, and the information provided in the Digest of UK Energy Statistics Reports (DUKES), provided by the Department of Energy and Climate Change (DECC)[90]

At the time of the Sohn Associates’ paper in 2009, reported losses published by Ofgem had reduced from 6.1% to 5.3% compared to a fairly steady value of 6.2% reported in DUKES. The DUKES reported values are an aggregation of monthly settlement data values which are not corrected as more accurate consumption data becomes available following later Settlements Runs, leading to a potential overstatement of the losses.

In contrast, DNOs have applied corrections to data and have used the latest values from Settlements for Regulatory reporting. This has produced more meaningful figures relating more closely to true technical loss, but has required a delay in the provision of final data to Ofgem for up to 28 months after the financial year end before the “Final Settlement” runs have been completed by Elexon.

[89] NGET Report on impact of Hinkley Point shutdown.
[90] Chapter 5 of DUKES 2012 and the Historical Electricity Data in Energy Trends https://www.gov.uk/government/statistical-data-sets/historical-electricity-data-1920-to-2011

Ofgem has published a summary of losses as reported over the period 1st April 2000 to 31st March 2010. As shown in Figure 66, during this period there are very significant variations in losses between the DNOs' networks, and significant variations from one year to the next. The large variations are technically unrealistic as it is impossible to make that much difference in the network within one year. They are driven by data adjustments.

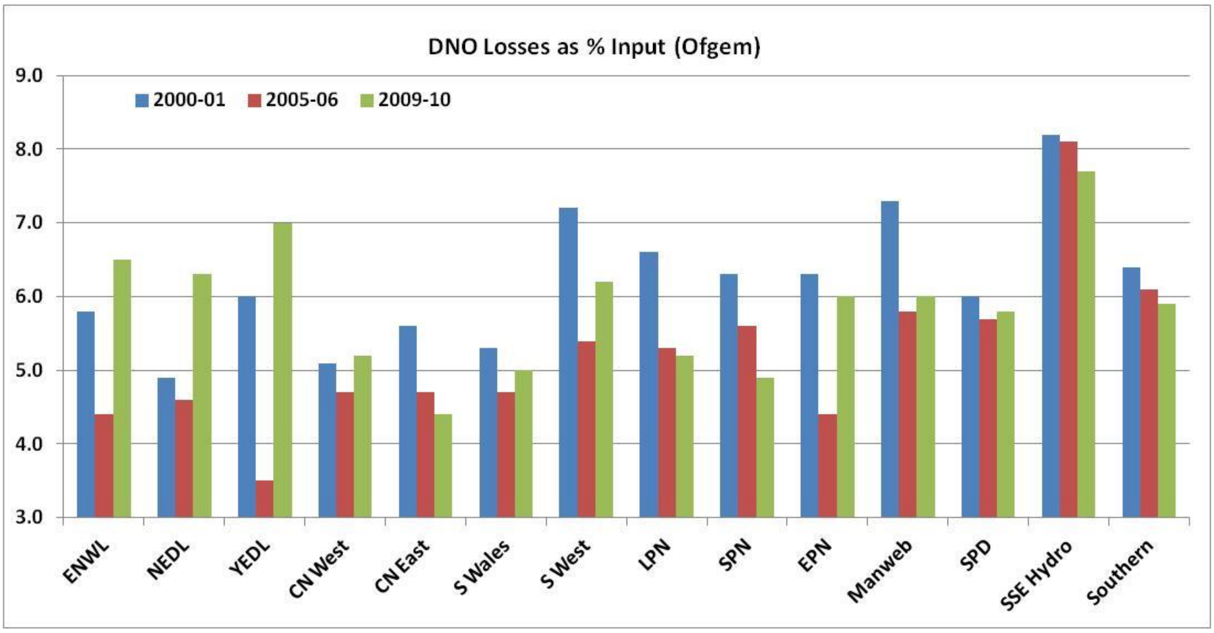

Figure 66: Variation in GB Distribution losses, 2000 – 2010

DUKES data relating to GB distribution losses is as shown in Figure 67 and directly compared against the reported Ofgem data.

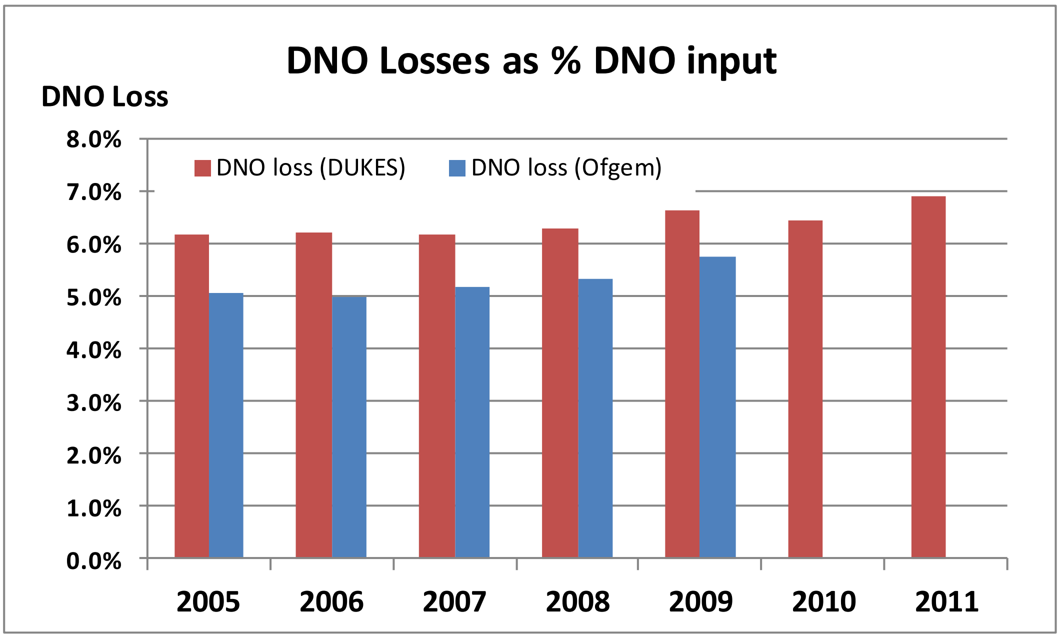

Figure 67: DNO Losses comparison of DUKES and Ofgem data

In considering the above, it is our view that there should be a thorough review by DECC of the data they are presenting into public domain, in order to ensure that there is clarity of purpose in publishing the data and an understanding of the uncertainties and variables within the published figures.

4 Relevance of GB overall loss statistics

According to the extensive investigations by Ofgem into the nature of reporting[91] there are variations in reported losses due to the various adjustments made by DNOs in their best interpretation and reporting of settlement data. Despite best endeavours, and with adjustment for non-technical losses, technical losses cannot be really assessed other than as being between 5% and 6% of units distributed.

Unless and until this problem is resolved, little significance can be ascribed to any year on year comparison of losses. Solving this problem will require a systematic and structured analysis of data in conjunction with Elexon, the organisation responsible for GB settlements issues. A good test of success in better reporting will be when better correlation is identified between loss results and the management actions affecting losses, and when correlation can be identified between changes in units distributed and losses. Presently neither correlation can be identified, and greater focus of attention will be required to achieve this throughout the RIIO-ED1 period.

5 GB network loss distribution

Each DNO has a view on its own level of network losses. Historically, there has been a general similarity in network design and operation across the UK and there is a reasonably typical breakdown of losses across the network as shown in Figure 68.

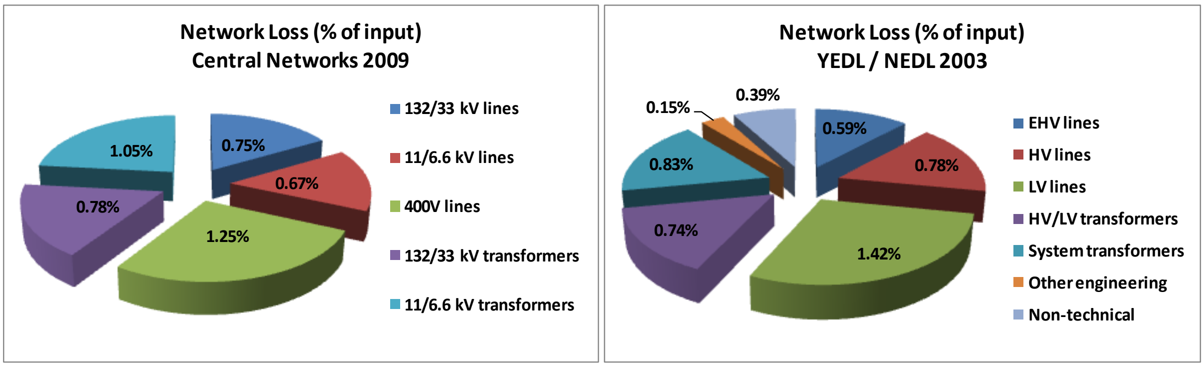

Figure 68: Typical breakdown of DNOs' losses

Clearly, the LV network is where the greatest losses occur and will therefore justify the greatest attention for loss management. It is also the least-measured part of the network. However, as there are now many initiatives under DNOs' various innovation schemes for improved knowledge of the LV network, there is high potential for improvements in this area in the next few years. Some of the initiatives identified as part of the review of DNO Innovation projects are as follows:

[91] Decision not to activate the Losses Incentive Mechanism in the Fifth Distribution Price Control: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=755&refer=Networks/ElecDist/Policy/losses-incentive-mechanism

- “Understanding networks with high penetration of Distributed Generation” (Central Networks, now WPD). The 2nd phase of this project aims to obtain measurement of micro-generation and loads in a small LV network for comparison with modelled parameters;
- “Network Technical Loss Reduction programme” (EdF, now UKPN). This project aims to identify the before and after impacts of operational changes on a specific LV network;
- “LV Network Modelling and Analysis Environment” (SSE) – this project will use an existing GIS to build a model of an LV network with existing network data and profiles, enabling an analysis to identify the “best fit” of data gathering for networks and customers;
- Smart Network trial (WPD) – This project has identified the LV substation loads for every substation fed from a primary HV station in the Pontypool area and aims to build up to the measurement of loads across the Rassau Supergrid group using consumer data from Smart Meters; and
- WPD’s LV Network Templates project on measuring impact of low carbon technologies on LV networks.

Appendix 8:

International comparison of technical losses

1 Factors affecting the quality of comparison

Whilst it is a very challenging exercise to establish a reasonably accurate overall figure for technical losses in GB at both DNO level and nationally, the comparison with losses of other countries is even more prone to error due to different bases for assessment.

There are several factors affecting the validity of comparison:

1. **Definition of "Distribution".** There is a diversity of operating voltages across Europe and the distinction between Transmission and Distribution is drawn at different voltages, e.g. "distribution" in England and Wales includes 132kV but not in Scotland;
2. **Transmission losses.** Some countries' reported losses do not disaggregate transmission from distribution loss;
3. **Input v output.** Some countries record their losses as % of network input and some as % of network output, requiring adjustment in making direct comparisons;
4. **Non-technical losses.** The simple difference between input and output also includes non-technical losses which include metering errors, theft and data errors, all of which are difficult to determine (e.g. theft cannot be assessed unless it is detected);
5. **Nature of company.** The sizes of the distribution companies vary, with some countries having a single company and others have multiple companies of different sizes and customer types (e.g. urban networks compared with rural networks);
6. **Embedded generation.** Some countries' reports do not take account of the impact on loss calculations of embedded generation.

2 European comparison

Despite the differences in loss reporting already highlighted, network loss management in Europe provides an important yardstick against which to compare GB loss performance. We anticipate the start of a significant debate on the energy efficiency of electricity networks across Europe as the Directive on Energy Using Products[92] is implemented in the electricity supply industry.

Recent surveys of use of electricity such as "National Energy Policies"[93] by Enerdata for ABB and the "Energy Statistics Yearbook"[94] from the IEA include an estimate of the total Transmission and Distribution losses for each country. This data indicates a large difference between the best (Luxembourg) and the worst (Romania). These surveys show the GB losses as 8% (Enerdata) and 7.1% (IEA) compared to a European average of 6.7%. The GB values are higher than comparable EU countries with the same GDP such as Germany and France as shown in Figure 69 below.

[92] Directive 2009/125/EC: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0125:EN:NOT
[93] http://www.abb.com/cawp/db0003db002698/6cc1f7ff2eff1660c12579ba004b64ef.aspx
[94] http://data.worldbank.org/indicator/EG.ELC.LOSS.ZS/countries/1W?display=default

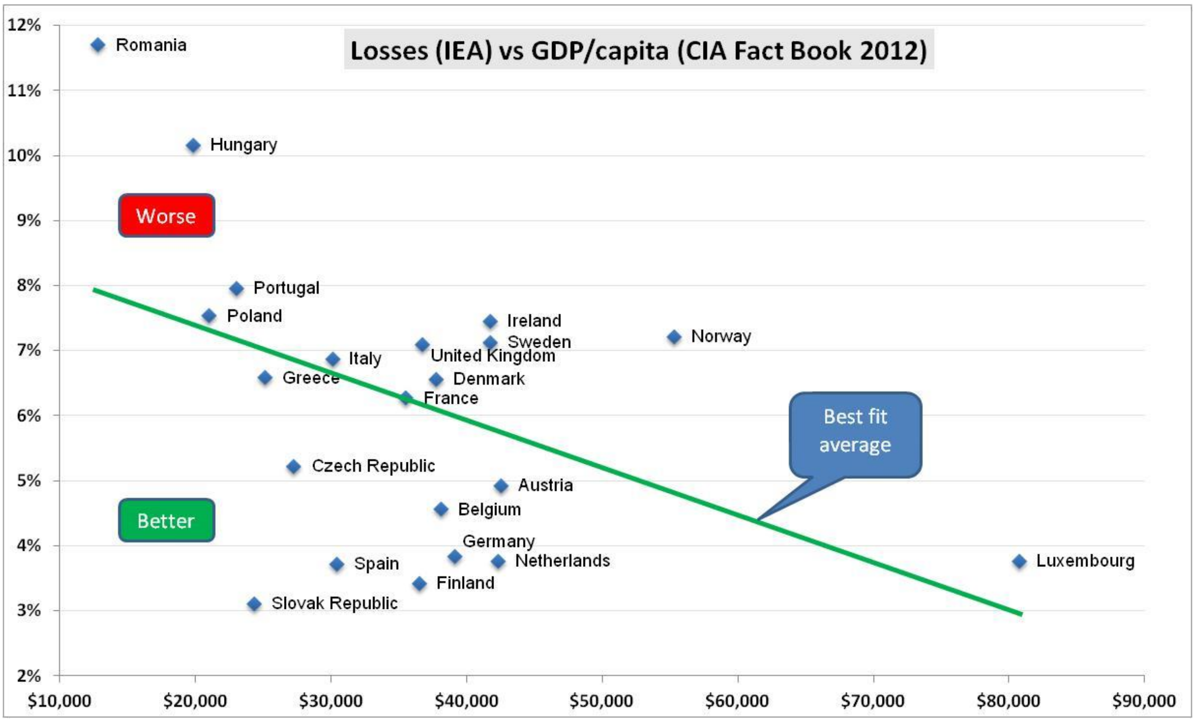

Figure 69: EU Country losses relative to EU average

3 Global comparisons

The abatement of carbon dioxide emissions is a key driver of loss reducing measures and such emissions are by their very nature a global issue. In comparison with many countries of the world, especially developing nations, loss management in GB is very healthy, with relatively good understanding of losses, relatively low technical losses and very low non-technical losses. From such a good starting base in GB the challenge to reduce losses further is much greater than in less well-developed countries within Asia, Africa and South America.

In some less-developed countries, total Distribution losses have been reduced dramatically in recent years especially when privatisation programmes have been introduced, bringing new management and new incentives to deal with underlying problems such as poor management, under-investment, high levels of theft, corruption and unbilled consumption. Data from private sources is shown in Figure 70 for a number of recent privatisation schemes.

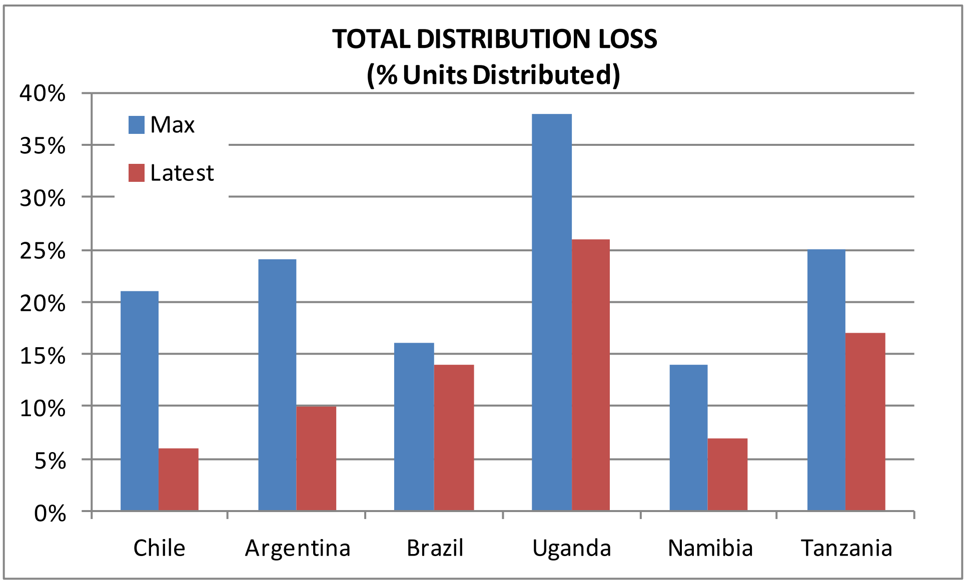

Figure 70: Losses in developing countries

Comparisons of losses data from the IEA, ABB, ERGEG[95] and JEA[96] show a high variation in values, for some countries, which is mainly due to the methodologies employed and the data adjustments made before publishing.

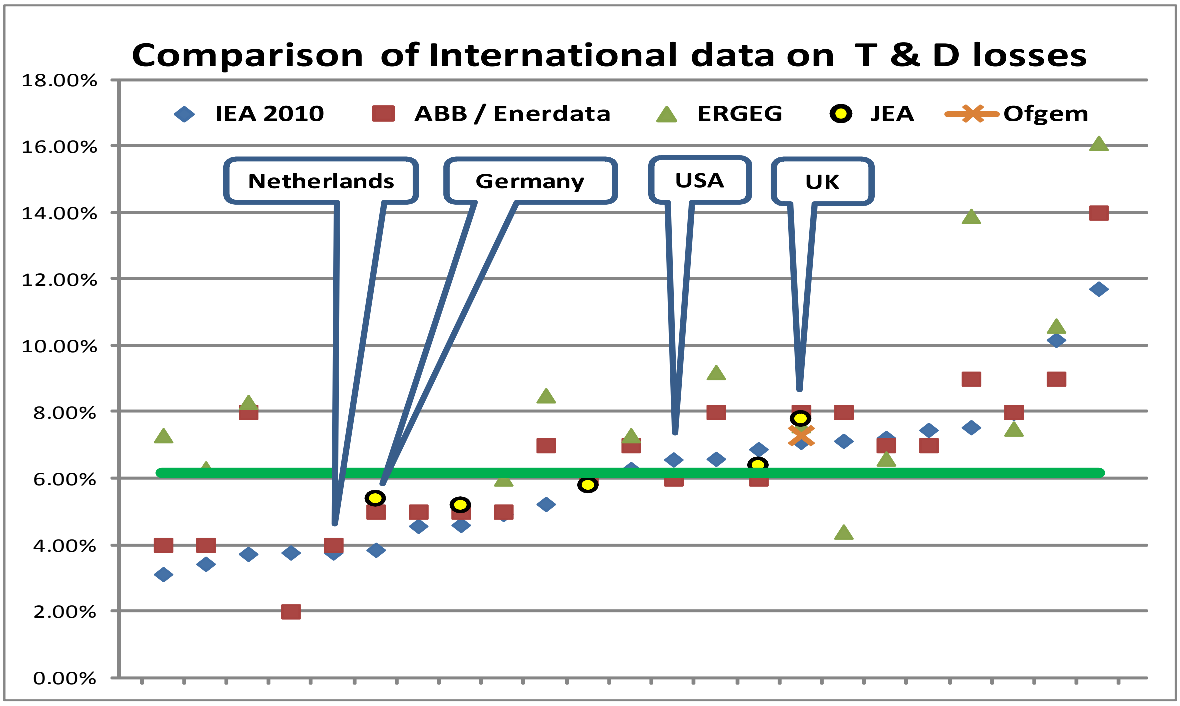

Figure 71: International loss data

[95] http://www.energyregulators.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Treatment%20of%20Losses/CD/E08-ENM-04-03_Treatment-of-Losses_PC_2008-07-15.pdf

[96] http://www.jepic.or.jp/en/data/EPIJ2012Japan%20data.pdf

From our consideration of both European and global loss comparisons, we conclude that much more work would be required to develop meaningful comparisons. In view of the importance attached to overall loss figures some further work is justified, but a more pragmatic approach will be to ensure that readers of comparative loss reports understand the inaccuracies in and inconsistencies between countries' or network companies' estimates. DNOs may play their part here by ensuring that interested parties (regulators, governments, NGOs etc.), are aware of the limitations in the accuracy of overall loss estimates.