The Integrated Design of New Build Multi Vector Energy Supply Schemes

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DECLARATION

This work has not previously been accepted in substance for any degree and is not concurrently submitted in candidature for any degree.

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This thesis is being submitted in partial fulfilment of the requirements for the degree of PhD.

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Abstract

Future energy supply infrastructure schemes for the built environment are set to consist of a diverse mix of distributed generation technologies, increasingly stringent local emissions reduction targets, and potentially complex ownership structures. This thesis presents a new modelling method that integrates technical design, green house gas emissions analysis and financial analysis models for new build multi energy vector systems.

The model was used to compare and characterise several alternative heating technology options for the carbon constrained design of a generic UK market town residential development. Of the options examined, natural gas combined heat and power based district heating was shown to provide the least cost solution for projects built before 2020. Beyond 2025, electric heat pumps provided the cheapest option in response to the decarbonisation of the grid supplied electricity.

The integrated model was used as the basis of an optimised infrastructure design tool. This was applied to determine the least cost energy supply technology mix for a new build community redevelopment scheme at Ebbw Vale, South Wales. It was shown that both the optimal design and corresponding optimal cost is dependent upon the year of build completion for the project and the accounting methodology used for grid supplied electricity emissions.

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Nomenclature

Abbreviations

ADMD	After diversity maximum demand
ASHP	Air Source Heat Pump
BFI	Building Fabric Index
CCGT	Combined Cycle Gas Turbines
CCL	Climate Change Levy
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CEF	Carbon Emissions Factor
CHP	Combined Heat and Power
DNO	Distribution Network Operator
ESCO	Energy Service Company
FEE	Fabric energy efficiency
FiT	Feed in Tariff
GHG	Greenhouse gas
GSHP	Ground Source Heat Pump
LNG	Liquified Natural Gas
LV	Low Voltage
LP	Low Pressure
NG	Natural Gas
PRI	Pressure Reduction Installation
PV	Photovoltaic
RHI	Renewable Heat Incentive
ZCH	Zero Carbon Homes

Romans

A_{Bld}	Floor area per building within each cluster (m^2)
$A_{Cluster}$	Total area of cluster (m^2)
A_{PV}	Area of PV per building (m^2)
$C_{AnnESCo}$	Annualised Energy Services Company Capital expenditure (£/yr)
C_{BFI}	Total cost of building fabric improvement (£)
C_{Build}	Total cost of building level technologies (£)
C_{DHN}	Total cost of district heat network (£)
C_{DHNdev}	Heat network Capital expenditure incurred by developer (£)
C_{ECelec}	Annual revenue from Energy centre electricity generation (£/yr)
$C_{ElecNet}$	Total Electricity distribution network Capex (£)
C_{ESCo}	Capital expenditure carried by Energy Services Company (£)
C_{ESexp}	Annual energy services company expenditure (£/yr)
C_{ESopex}	Energy services Company operational expeenditure (£/yr)
C_{GasNet}	Total Gas distribution network Capex (£)
$C_{GenCost}$	Cost of generation at time step (£)
C_{Heat}	Total annual district heat revenue (£/yr)
C_{HTech}	Total cost of heating technologies (£)
C_{Infr}	Total infrastructure cost to developer (£)
C_{Opex}	Total Energy services company opex (£/yr)
C_{Plant}	Total cost of energy centre generation plant (£)
$C_{Premium}$	Total infrastructure build premium (£)
$C_{PrimSub}$	Cost of 33/11kV primary substation (£)
C_{PV}	Total cost of PV capacity (£)
C_{Store}	Total cost of heat accumulator (£)
c_{ASHP}	Cost of air source heat pump per building (£/building)
c_{BFI}	Cost of building fabric improvement per building(£/building)
c_{CCL}	Climate change levy (£/kWh)
$c_{DHNserv}$	Cost of district heat network service pipe (£/m)
c_{DHNmet}	Cost of district heat meter and heat user interface (£/connection)

c_{Fuel}	Cost of fuel (£/kWh)
$c_{GasPipe}$	Cost of gas pipe (£/m)
c_{GBoil}	Cost of gas boiler per building(£/building)
$c_{GasServ}$	Cost of gas service connection (£/m)
c_{GasMet}	Cost of gas meter (£/connection)
c_{GSHP}	Cost of ground source heat pump per building(£/building)
c_{Heat}	Average price of heat (£/kWh)
c_j	Cost of electricity cable j (£/m)
c_l	Cost of natural gas pipe of element l (£/m)
c_n	Cost of district heat pipe at element n (£/m)
c_{Plant}	Cost of energy centre generation plant (£/kW)
c_{Power}	Price of exported electricity power (£/kWh)
c_{PRI}	Cost of Pressure Reduction Installation at element l (£)
c_{PV}	Cost of PV (£/m^2)
c_{SS}	Cost of 11/0.4kV substation (£)
c_{Store}	Cost of heat accumulator (£/m^3)
CoP_{HP}	Heat pump coefficient of performance
CoP_{GSHP}	Ground source heat pump coefficient of performance
CoP_{ASHP}	Air source heat pump coefficient of performance
$D_{Min,NG}$	Minimum available natural gas pipe diameter
DR_{ESCo}	Energy Services Company discount rate
E_{HE}	Heat exchanger effectiveness
f_{ASHP}	Fraction of floorspace supplied by air source heat pumps
f_{DHN}	Fraction of floorspace supplied by district heating
f_{GCH}	Fraction of floorspace supplied by individual gas boilers
f_{GSHP}	Fraction of floorspace supplied by ground source heat pumps
F_{CHP}	Average fuel consumption of natural gas CHP (kWh$_{fuel}$/h)
F_{DmdNG}	Cluster natural gas network demand (kWh$_{fuel}$/h)
F_G	Fuel consumption of generator (kWh$_{fuel}$/h)
F_{GCH}	Average fuel consumption of individual gas boilers (kWh$_{fuel}$/h)

F_{PeakNG}	Peak cluster natural gas network demand (kJ/s)
$F_{PeakPRI}$	Peak flow rate across pressure reduction installation (kJ/s)
F_{Rated}	Rated fuel consumption of generator(kJ/s)
h	Head of pressureat district heat pump (Pa)
K_{Capex}	Fraction of ESCo Capex apportioned to developer
L_j	Length of electricity network element j (m)
L_j	Length of district heat network element n (m)
$L_{LVbranch}$	Length of cluster LV network branch section (m)
$L_{LVsubBranch}$	Length of cluster LV network sub branch section (m)
N_b	Number of building occupancy types
N_{Bld}	Number of buildings per cluster
N_c	Number of clusters
N_d	Number of representative days per annual profile.
$N_{Feeders}$	Number of feeders per 11/0.4kV substation
N_{floors}	Number of floors per building
N_g	Number of community generation plant
N_h	Number of electricity busbars
N_j	Number of electricity network elements
N_k	Number of gas network nodes
N_l	Number of gas network elements
N_m	Number of district heat network nodes
$N_{BldLVFeed}$	Number of consumers per LV feeder
N_n	Number of district heat network pipes
N_p	Number of time steps per representative day.
$N_{Project}$	Project duration (years)
$N_{PrTimeSt}$	Number of generation time steps per day
N_{Trans}	Number of 11/0.4kV transformers per cluster
P_{CHP}	Power output from natural gas CHP (kWh_{el}/h)
P_G	Power output from generator (kWh_{el}/h)
P_{HP}	Heat pump electricity consumption (kWh_{el}/h) or (kW)

P_{Rated}	Rated electricity output of generator (kW_{el})
p_{from}	Pressure at from node of gas or district heating arc (Pa)
p_{to}	Pressure at to node of gas or district heating arc (Pa)
PF	Penalty Factor
$\boldsymbol{S}_{AL}$	Annual appliance and lighting electricity demand profile
$S_{ADMD,\,AL}$	After diversity maximum residential appliance and lighting demand (kW_{el})
$S_{AnnualAL}$	Annual appliance and lighting demand (kWh/year)
S_{Dmd}	Cluster electricity demand (kWh/h)
S_{Import}	Electrical power imported from the grid (kWh/h)
S_{MinAL}	Minimum appliance and lighting demand (kW/m^2)
S_{MinDmd}	Minimum cluster electricity demand (kW)
S_{PeakAL}	Peak appliance and lighting demand for non residential dwellings (kW_{el})
$S_{PeakDmd}$	Peak cluster electricity demand (kW)
S_{PeakPV}	Peak electricity generation per installed area of photovoltaic panels (kW/m^2)
S_{PV}	Electricity generation per installed area of photovoltaic panels (kWh/m^2)
s_{AL}	Normalised average appliance and lighting demand ($kWh/m^2/kWh_{annum}$)
s_{PeakAL}	Peak appliance and lighting demand per floor space for non residential dwellings (kW_{el}/m^2)
SF_{SH}	Seasonality factor for space heating
SF_{PV}	Seasonality factor for photo voltaics
T_{air}	Temperature of outside air (°C)
T_{ground}	Temperature of ground (°C)
T_{sink}	Temperature of heat sink for heat pumps (°C)
w	Weighting

Greeks

$\Delta\Phi_{Step}$	Step length for generation cost gradient calculation (kW_{th})
δ_{OnOff}	Binary on off variable for generation plant
ϵ_{NG}	Carbon Emissions Factor for natural gas ($kgCO_2e/kWh$)
η_{Fconv}	Fuel to heat conversion efficiency of generation plant
η_{Elec}	Electricity generation efficiency of generation plant

$\eta_{Rated,Elec}$	Electrical generation efficiency at rated generation output.
$\xi_{Cluster}$	Total annual emissions from cluster fuel consumption ($kgCO_2e$)
ξ_{EC}	Total annual emissions from Energy Centre fuel consumption ($kgCO_2e$)
ξ_{EGrid}	Total annual emissions from grid supplied electricity ($kgCO_2e$)
$\xi_{Reduction}$	Reduction of annual regulated on site emissions($kgCO_2e$)
$\xi_{Regulated}$	Total annual regulated on site emissions($kgCO_2e$)
ξ_{Target}	Annual emissions target($kgCO_2e$)
ξ_{Total}	Total annual on site emissions($kgCO_2e$)
$\boldsymbol{\Phi}_{\boldsymbol{DHW}}$	Annual domestic hot water demand profile
$\boldsymbol{\Phi}_{\boldsymbol{SC}}$	Annual space cooling demand profile
$\boldsymbol{\Phi}_{\boldsymbol{SH}}$	Annual space heating demand profile
$\Phi_{ADMDDHW}$	After diversity maximum demand for domestic hot water (kW_{th})
$\Phi_{ADMDHeat}$	After diversity maximum total residential heat demand (kW_{th})
$\Phi_{AnnualCK}$	Annual Cooking demand(kWh/year)
$\Phi_{AnnualDHW}$	Annual domestic hot water consumption (kWh/year)
$\Phi_{AnnualHeat}$	Annual total building heat demand (kWh/year)
$\Phi_{AnnualSC}$	Annual space cooling demand (kWh/year)
$\Phi_{AnnualSH}$	Annual space heat hemand(kWh/year)
Φ_{CHP}	Heat output to heat network from natural gas CHP (kWh_{th}/h)
$\Phi_{DailyDH}$	Daily district heat network demand (kWh/day)
Φ_{DmdDH}	District heat network demand at time step (kWh/h)
Φ_{GCH}	Heat output from individual gas boilers (kWh_{th}/h)
Φ_{G}	Heat output from generator (kWh_{th}/h)
Φ_{HP}	Heat generation by heat pumps (kWh_{th}/h) or (kW_{th})
Φ_{MinDH}	Minimum cluster district heat network demand (kW_{th})
Φ_{PeakDH}	Peak cluster district heat network demand (kW_{th})
$\Phi_{PeakHeat}$	Peak heat demand for non residential dwellings (kW_{th})
Φ_{Rated}	Rated heat output from generation plant (kW_{th})
Φ_{SH}	Average space heating demand (kWh/h)
$\Phi_{SH,Ref}$	Reference average space heat demand (kWh/h)

$\Phi_{Storage}$	Heat stored within heat accumulator (kWh)
$\Phi_{StorCap}$	Storage capacity of heat accumulator (kWh)
ϕ_{DHW}	Normalised domestic hot water demand ($kWh/m^2/kWh_{annum}$)
$\phi_{PeakHeat}$	Peak heat demand per floor area of non residential dwellings (kW_{th}/m^2)
ϕ_{SC}	Normalised average space cooling demand ($kWh/m^2/kWh_{annum}$)
ϕ_{SH}	Normalised average space heat demand ($kWh/m^2/kWh_{annum}$)
τ	Length of timestep (h)

Superscripts

$X^{(b)}$	... of building of occupancy type b
$X^{(c)}$	... of building cluster c
$X^{(d)}$	... at representative day d
$X^{(g)}$	... of generation plant g
$X^{(p)}$	... at time step p

Chapter 1

Introduction

1.1 Background

The provision of energy to the built environment in the UK is undergoing significant change. The majority of buildings within urban environments are presently supplied via the national gas and electricity transmission and distribution infrastructure. In recent years the reliance upon fossil fuels has given rise to concerns over anthropological climate change, rising fuel prices and exposure to political volatility. In response, a series of mitigatory policies and measures have emerged aimed at reducing UK energy consumption and carbon emissions including those from buildings. The Climate Change Act (HM Gov 2008) has set a legally binding 80% reduction target for all UK green house gas emissions by 2050 compared to 1990 levels. The potential pathways to an intermediate target reduction of 32% by 2020 was set out by the Low Carbon Transition Plan (DECC 2009).

The energy consumption of buildings accounts for ~48% (29% residential, 19%

non-residential) of total UK emissions. The reduction of building energy emissions must therefore be central to the UK emissions reduction strategy. Emissions savings can be achieved within existing buildings by using more efficient lighting and appliances, by retrofitting building insulation materials, by replacing older inefficient boilers with more energy efficient heating methods or by retrofitting renewable electricity generation technologies (Hinnells 2008a). The ongoing (at time of writing) *The Future of Heating* consultation (DECC 2012c) aims to provide a strategic framework for existing a future policy measures aimed at heat provision. Policy measures to effect such changes at building level include the Carbon Emissions Reduction Target (CERT) scheme (DECC 2010a), and the Green Deal (DECC 2012b) which is due for implementation towards the end of 2012. To discourage wasteful consumer behaviour, efforts are under way to replace 53 million existing gas and electricity meters with smart meters in the UK (DECC 2011c).

For new build schemes carbon critical or carbon constrained design is emerging as an integral part of UK energy strategy to 2050 as discussed by Clarke (2010). This approach requires the developer to deliver a reduction of green house gas (GHG) emissions within the site boundary . The BedZed housing development was a pioneering example of a carbon constrained design paradigm by delivering a 90% emissions reduction using a mix of on site technologies (Chance 2009). In 2007 the *Building a Greener Future* policy statement (DCLG 2007) set out the requirement for all new build domestic dwellings to be “zero carbon” from 2016. The *Definition of Zero Carbon Homes* consultation in 2008 (HMGov 2008) detailed the framework and pathway to zero carbon implementation. This was formalised by the creation of the *Zero Carbon Hub* (ZCH) in 2009 which provides guidance and compliance standards for the zero carbon homes initiative.

In response industry concerns following the recent economic downturn, the definition of zero carbon has been relaxed to apply to regulated (i.e. space heating, cooling and lighting) rather than total emissions. In its present form the ZCH initiative mandates a 70% reduction of regulated emissions compared to the 2006 building standards using on-site solutions from 2016. The remaining 30% reduction must be met using “allowable off site solutions” (ZCH 2011). On-site solutions cover a diverse range of technologies. These include individual installations such as PV, solar thermal and micro CHP through to large scale community level solutions such as biomass gasification CHP district heating. Improved building fabrication standards are considered an integral component of the on-site solution and a minimum Fabrication Energy Efficiency Standard (FEES) applies (ZCH 2009).

1.2 Low Carbon Electricity Supply to Buildings

Micro electricity generation technologies are anticipated to provide a significant contribution to the future supply mix and required emissions reduction. The recently introduced Feed in Tarrif (FiT) scheme aims to stimulate the uptake of renewable micro-generation technologies such as photovoltaic panels, micro wind or micro hydro (DECC 2010b). The Green Energy Act (HM Gov 2009) defines micro-generation as installations producing up to $50kW_e$ or $300kW_{th}$. The 2011 micro generation strategy (DECC 2011a) sets out a number of actions to promote the uptake of micro-generation technologies without stipulating any particular targets for uptake.

The technical challenges of integrating of distributed electricity generation into distribution networks include the voltage rise, power quality and system protection. These are considered in detail by Strbac et al (2009) and a discussed in a generic sense within the review by Pecas-Lopes et al (2007).

The effect of embedding significant levels of generic micro generation upon local electricity networks has been modelled by Ingram et al (2003), who considers the penetration limits of small scale generation (up to 16A) with respect to network voltage beyond the 33kV substation. Thompson and Infield (2007) provide a simulation of the impact of very high levels of PV upon an existing UK 11kV distribution network feeder including all corresponding LV networks. Firestone et al (2006) modelled the optimised dispatch of domestic storage, and distributed generation with PV. Similar studies upon the implications of integrating micro wind has been performed by Behaj et al (2007), Peacock et al (2008) and James et al(2010).

The decarbonisation of the UK centralised generation mix will have a considerable indirect effect upon emissions from building electricity consumption. The Low Carbon Transition (DECC 2009) targets 40% of UK electricity generation using low carbon sources by 2020. This is to be achieved through the use of renewable technologies such as large scale wind, a shift towards cleaner and more efficient fossil fuel technologies such as CCGT, and the use of novel post processing technologies such as carbon capture and storage. The Renewables Obligation (Ofgem 2012) has provided a mandatory framework since 2002 for suppliers to generate using renewable resources (currently 10.4% rising to 15.4% by 2016). At the time of writing, a draft Electricity Market Reform Bill (DECC 2011e) was published which aims to ensure low carbon technologies can compete fairly within the marketplace.

1.3 Low Carbon Heat Supply to Buildings

Space and hot water heating in buildings accounts for approximately 35% of the total UK energy demand (540TWh out of 1668TWh in 2009, DECC 2012c). Several options are emerging to allow a shift away from gas boilers as the default supply technology. Lowe (2007) reviews the alternative heat supply options for the existing UK housing stock and suggests that a 60-70% carbon reduction may be achieved by re-engineering the energy supply using heat pumps, micro CHP or building fabric measures. A study by Monahan (2011) on the other hand considers the potential performance of various heat supply technologies for new homes. The Renewables Heat Incentive (RHI, DECC 2011d) is a fiscal measure introduced towards the end of 2011 as a replacement for the Low Carbon Buildings program. This aims to encourage the uptake of renewable sources such as heat pumps, biomass boilers and solar thermal panels.

1.3.1 Heat Pumps

Heat pumps use electrical power to displace thermal energy from a low temperature source to a higher temperature sink. The technical issues facing heat pump implementation within the UK was examined by Singh et al (2009) who concluded an improvement of long term viability with reversible operation to provide cooling during the summer. Jenkins et al (2009), identifies supply temperature as one of the main constraints for heat pump viability with improved prospects for new build dwellings applying lower temperature regimes. A UK field trial of air source heat pumps presented by Kelly and Cockroft (2011) showed a 12% carbon saving compared to gas boilers assuming a grid carbon intensity of 0.54kg/kWh and significantly higher savings would be expected with grid decarbonisation. The heat pump coefficient of performance (CoP, the ratio of heat generated to electricity consumed) range was found to vary between 2.55 and 3.1.

Heat pumps are presently a capital intensive technology and installation costs vary considerably according to the type of system. For ground source systems, the ground coil or bore hole used to collect heat can comprise up to half of the overall cost (Rawlings 2004). Significant cost savings may therefore be achieved with a reduction of capacity. By shifting the heat demand to electricity demand, opportunities may arise for more sophisticated modes of system operation. Hewitt (2012), for example, examines the potential for using heat pumps as part of a smart grid to balance excess wind energy production. This may lead to more favourable tariffs for participating heat pump units.

1.3.2 District Heat Networks

District heating (DH) is the distribution of thermal energy to a set of consumers using a network of insulated hot water pipes. Common heat sources include commercial scale gas boilers, biomass boilers and Combined Heat and Power (CHP) plant. Other potential sources include Industrial waste heat, solar thermal and geothermal energy. District heating has been deployed extensively Northern and Eastern European cities, with Denmark often cited as the leading example with 58% of households served by 50,000km of DH pipe (Danish Energy Authority 2005).

The case for DH as a vector for delivering sustainable and low carbon heat to buildings in the UK has received a resurgence of interest over the past decade. Such schemes offer the opportunity to utilise heat from a variety of sources local to the point of consumption. Examples of resources exploited within the UK include natural gas CHP (EST 2003), energy from waste (Kirkman et al 2010), biomass (Vital Energy 2008) and geothermal (SCC 2011). The exploitation of the industrial waste heat at Port Talbot Steelworks is currently under consideration (Upham & Jones 2012). The diversity of potential sources provides some protection against long term supply technology lock in so that new technologies or resources may be readily adopted should they become commercially viable. The flexibility to switch fuel sources may also protect against fuel poverty, particularly in the event of rising fossil fuel costs (Austin 2010).

The viability of retrofitting DH into UK households was examined by Woods et al (2005) and by Poyry (2009). These suggest that the high installation costs of pre-insulated pipe provides the biggest barrier to uptake compounded by a lack of industry wide standards, an undeveloped supply chain and the lack of a suitably skilled construction workforce. Schemes deemed suitable for DH were those with access to a low cost waste heat source, with a high demand density such as apartments and commercial premises, and dwellings currently using electric heating. A study by the EST (2008) examined the case for DH within new build schemes concluding that viability is dependent upon the extent of network cost reduction as the energy demand per dwelling decreases.

A number of researchers have considered the regulatory, financial and organisational changes required to improve the outlook for DH schemes. Hinnells (2008b) describes the lack of a heat market and regulatory framework as a key obstacle to the uptake of CHP based schemes. Lee et al (2010) focuses upon the use of CHP within completed UK district heating schemes, suggesting that high up front capital costs, a lack of long term contracts and a culture of short term profit as a sources of perceived but overstated risk to investors. A review of CHP-DH prospects by Kelly and Pollit (2010) identifies two key planning activities required to overcome barriers to uptake: Optimising or improving the engineering design principles and selecting the most appropriate organisational framework.

Several approaches have been examined for the cost reduction of DH networks. Bohm (2008) explored alternatives to the standard configuration for separate supply and return lines. Dual pipe systems, for example, were shown to reduce losses and material costs and are now widely adopted in Scandinavian countries. Koersman et al (2008) examined the use of plastic pipes within a district heating system. The use of plastic pipes for static pressures of up to 6bar and temperatures of 90-95°C offers significant potential material cost savings compared to stainless steel. The net cost savings were found to be small, however, due to the undeveloped supply chain for plastic products. Further cost savings can be achieved by optimising the network route and design. Jamsek et al (2010), for example, use a non linear simplex method to select the least cost subset of possible routes for a DH infrastructure.

1.3.3 Micro-CHP

Micro CHP is the small scale (<$50kW_e$) simultaneous generation of heat and electricity usually installed within the building being supplied. Newborough (2004) examined the cost benefits of residential units. A study by Peacock and Newborough (2008) examine the carbon savings for the existing housing stock. The effect of introducing large numbers of micro CHP into the local electricity network has been examined by Beddoes et al (2007), Sulka et al (2008) and by Thomson and Infield (2008).

1.4 Integration of Energy Vectors

The growing range of commercially available energy supply technologies increases the number of potential points of coupling between distribution networks. An understanding of this increased network interaction and interdependency may lead to reductions of cost, energy consumption and emissions. Benefits may include increased design flexibility and operational degrees of freedom, whilst disadvantages include potential cross network vulnerabilities as well as capacity issues for the existing infrastructure.

The point of coupling introduced by combined heat and power with district heating (CHP-DH) has been of extensive interest in recent years. Helseth & Holen (2009) modelled the structural vulnerabilities of the heat network and electricity interdependency. Sunberg & Karlsson (2000) and Carradore & Turri (2009) examine the optimal operation of urban CHP-DH schemes including heat and electricity interactions. Heat accumulators provide an option to improve performance and viability of the system by decoupling the output streams. The IEA (2005) developed a dynamic programming approach to the optimal cost design of heat accumulators for CHP systems. Fragaki et al (2008) showed that the return on investment could be doubled for a UK CHP-DH scheme with heat storage when operating in response to market electricity price. A similar study was performed by Strekiene et al (2009) for the German spot market. An interesting development from Denmark to increase large scale wind production by supplying excess generation to CHP-DH schemes with storage capacity (Lund & Munster 2006, Meibom et al 2007, Anderssen & Lund 2007).

Space cooling provides potential option for extending the annual duration of operation range for community generation schemes. Cardona & Piacentino (2003) examine the sizing methodology for a trigeneration (heating, cooling and power) unit incorporating an adsorption chiller within a hotel. Colonna & Gabrielli (2003) evaluated the design of an industrial based trigeneration system. The optimised design for an urban level district heating and cooling system was considered by Li et al (2006), Xu et al (2010), who suggests a 30% energy saving compared to the seperate provision of heating and cooling, and by Kavvadias (2010). Examples of operational analysis for urban level integrated cooling and trigeneration systems include Zhang et al (2007), who examine the case with seasonal storage, Lozano (2009), who provides a cost optimised operational model for a natural gas trigeneration system and Rentizelas et al (2009), who studied the viability of a Biomass trigeneration system.

A number of researchers have attempted to provide multi-energy vector models for infrastructure analysis. Integrated load flow models have been developed for gas and electricity distribution (Salvador & Hernandez-Aramburo 2008), gas and electricity transmission (An et al 2003, Seungwon et al 2003, Chaudry et al 2008) and for electricity and heat distribution (Rees et al 2010). A generalised approach to the modelling of systems with conversions and couplings between several supply streams has been developed by Geidl & Andersson (2005), using the energy hubs concept, and by Chicco & Mancerella (2008a) who define a multigeneration approach. Application examples can be found within Geidl and Andersson (2006, 2007), Hajimiragha et al (2007) and Chicco & Mancarella (2008b).

1.4.1 Planning and Design

The conventional approach to infrastructure development under the centralised supply structure is generally consisted of identifying the least cost extension of the existing gas and electricity networks. With legally binding emissions reduction targets and a shift towards sustainability, developers are now faced with the task of delivering infrastructure that provides on-site emissions savings at minimal additional construction cost. CISBE Guide F (2004) and King and Shaw (2011) detail examples of whole energy based methodology for project delivery aimed at building developers (Fig 1.1). Established approaches typically consist of a sequential treatment of system design, project cost and project life emissions and is often limited to the comparison of a few selected alternative options. As the range of commercially viable energy supply technologies increases, developers are seeking a more sophisticated design approach (CHPA 2011). For community level schemes, this may be compounded by a diverse mix of building types and infrastructure ownership structures.

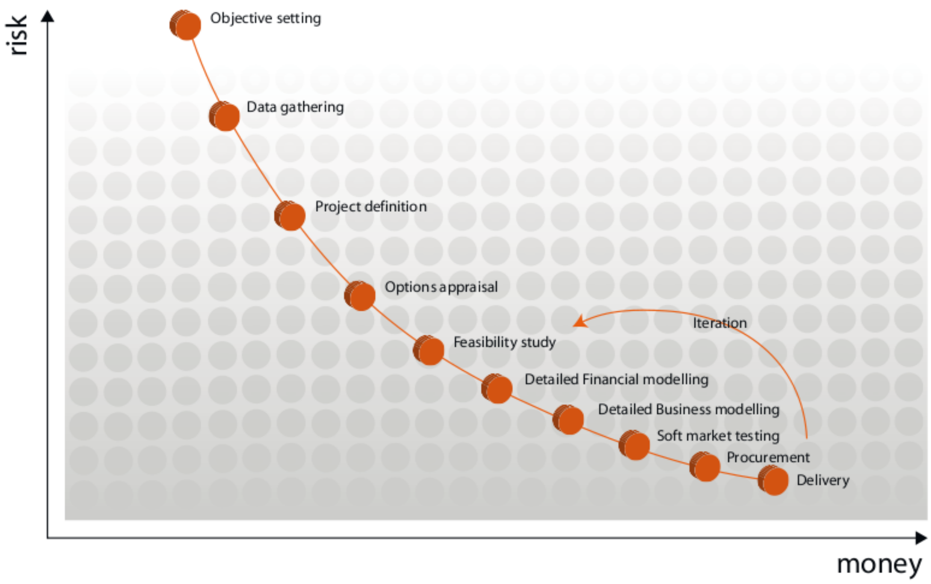


Figure 1.1: An illustrative project development process with the trade-off between project risk and project expenditure shown (King and Shaw 2011).

The need for a more integrated approach to energy network design and planning has been reflected by a growing research interest over recent years. The main aim has been to develop methodologies that allows consideration of the range of emerging technologies and the design requirements of increasingly complex distribution systems, particularly those involving district heating and combined heat and power. Earlier efforts tended to focus on cost and energy efficiency as design drivers. Examples include the linear programming model by Marchand et al (1983) for the optimal investment and operation of an urban coal fired steam turbine CHP-DH system with heat storage. Burdon (1998) presented a planning case study for an integrated natural gas based

CHP-DH scheme in Newcastle.

More recent models incorporate emissions and environmental impact as one of the main design criteria. Examples focusing specifically upon structural planning and design of integrated community heating include work by Soderman and Pettersson (2006,2007) who provide a MILP model for the structural and operational planning of a district heat and electricity distribution system by optimising the life cycle costs (including heat storage); by Vallios et al (2009) who present a whole system design of a Biomass district heating scheme with heat storage; and by Casisi et al (2009) who developed a mixed integer linear programming planning model for the optimal layout and operation of a CHP-DH network within a city centre with supply options including a centralised natural gas engine and a microturbine.

Several researchers have developed planning and design and design models that extend to a wider range of networks and technologies. These invariably demonstrate a tradeoff between the detail and the scope of the model. Sakawa et al (2001) examined the optimised cost planning of a district heating and cooling system; Sugihara et al (2004) examined the cost optimal design of a mixed use city scheme with heat pumps, fuel cell trigeneration, PV and solar thermal panels; Bakken and Skjelbred (2007) developed the use of a modular model called e-Transport for the optimal outline design of local multi-energy vector infrastructure (electricity, natural gas, district heat and hydrogen) with respect to cost and environmental impact; and Diaz et al (2010) presents a model for evaluating the integrated design and operation of a multiple plant CCHP system with an adsorption chiller and heat pumps.

The development of tools for the strategic planning of distribution networks with embedded generation has also been the focus of recent research. El-Khattam (2004, 2005), provides a heuristic approach to the investment planning of generic distributed sources using a distribution company model; a strategic design model by Mancerella et al (2009) used a fractal approach to evaluate the investment potential for electricity and district heat networks; Ren & Gao (2008, 2010) provided an optimised planning and evaluation study for a CHP integrated electricity, gas and heat system; and Mancerella et al (2011) details a design and evaluation model for the integration heat pumps and CHP into the LV network.

1.5 Research Objective and Thesis Structure

A growing number of tools are now available for the design of energy distribution systems, a comprehensive review of which was provided by Connolly et al (2010). A gap exists however for modelling methods that combine technical design with the flexible modelling approach to financial and emissions analysis required to cater for the growing number of possible organisational structures and local low carbon energy strategies. The contribution of the work within this thesis is therefore an integrated modelling method for the selection, design and evaluation of new build energy supply infrastructure schemes. The method integrates the following core features:

- An energy supply infrastructure model to represent the the layout of the scheme, the building energy demand of each building, all on-site generation plant and the local energy distribution infrastructure.

- A technical design model and operational model for the energy infrastructure.

- A flexible model for the analysis of on site energy supply related emissions.

- A flexible model for the financial analysis of each scheme.

Each feature was implemented using a software platform best suited to the analysis being performed. The financial and emissions analysis models, for example, were implemented using spreadsheets whilst the technical design modelling and operational modelling was conducted using a set of analysis modules written and compiled as Java programs. The analysis structure for the model is shown by Figure 1.2.

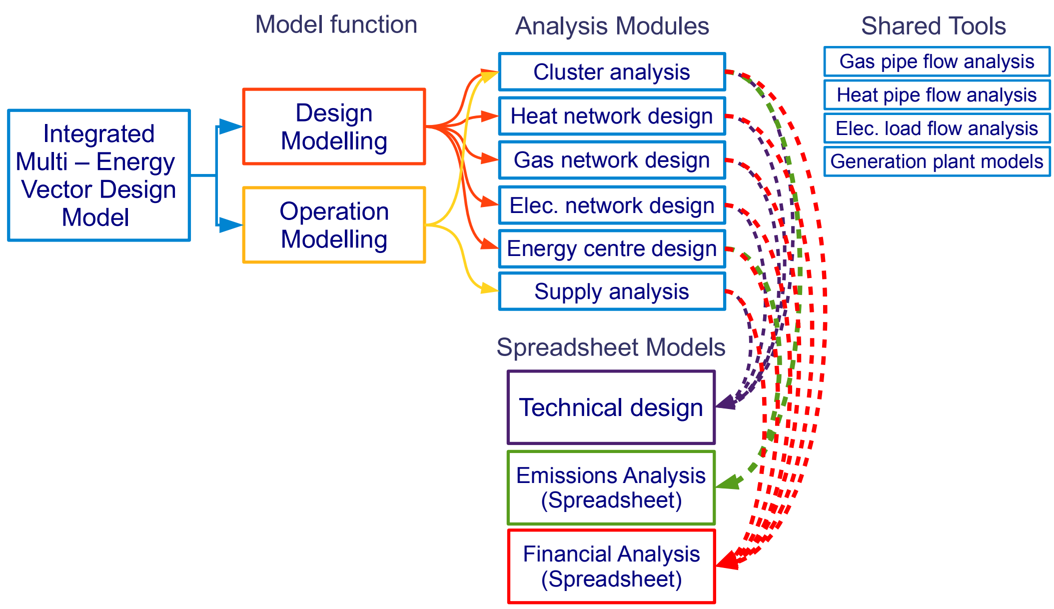


Figure 1.2: Analysis structure for the integrated design and analysis tool.

The structure of the thesis is shown by Figure 1.3. Chapter 2 details the infrastructure model used to represent building energy demand, energy supply technologies and energy distribution networks. Chapter 3 describes the technical design model and operational modelling for the scheme. Chapter 4 presents the carbon emissions analysis model used to determine the annual and project life on-site green house gas emissions for a community energy system. The model also provides an assessment of the adherence to specific emissions reduction target using the Zero Carbon Homes initiative as an example. Chapter 5 describes the financial analysis model used to evaluate the cost of a new build development. An example ownership structure involving an Energy Services Company for the community heating scheme is considered. Chapter 6 details the optimisation tool developed to select and design the energy supply infrastructure for new build community schemes. This tool uses the work described in the previous chapters and was applied to a case study based upon a mixed use community regeneration scheme at Ebbw Vale in South Wales, UK.

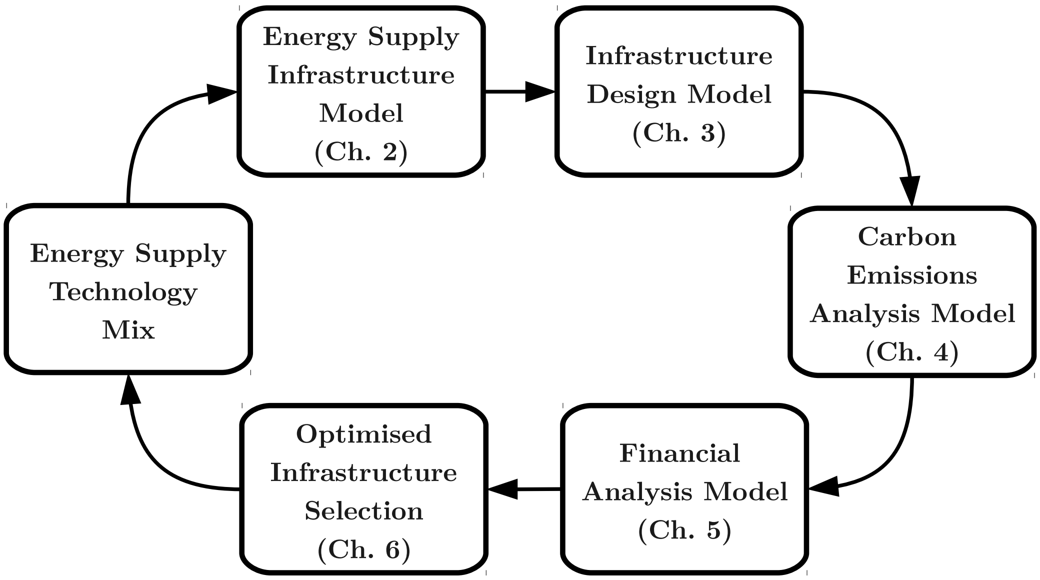


Figure 1.3: High level structure of integrated design and analysis model tool and outline of thesis.

Chapter 2

Community Energy Infrastructure Modelling

2.1 Introduction

This chapter describes the model used to represent the energy consumption characteristic for each building and the on-site supply infrastructure for each scheme. The model details the energy demand of each building, the energy supply technologies used on site, and the structure of the natural gas, district heat and electricity distribution networks. The model was used as the basis for the integrated analysis model detailed within subsequent chapters.

The energy supply infrastructure model is presented in three sections. The *energy demand model* defines the peak energy consumption and average energy consumption profiles for each building cluster. The *energy source* *models* were used to represent each heating and electricity generation technology used by each building and within the energy centre. The *network models* were used to represent the energy distribution networks within the site boundary. The structure and scope of the model is shown by Fig 2.1.

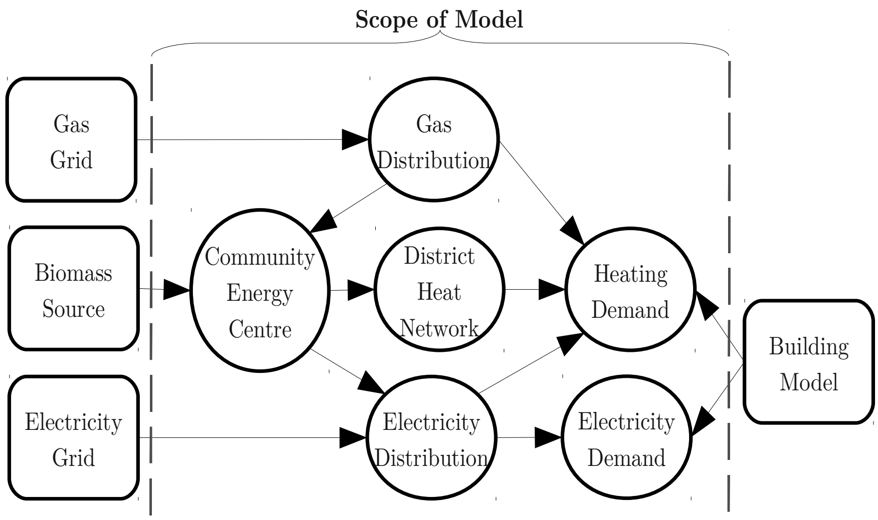


Figure 2.1: Scope and structure of Energy Supply Infrastructure model.

2.2 Energy Demand Modelling

Each scheme was modelled by grouping the buildings on site into a set of consumer clusters. A consumer cluster was defined as geographical area A_C containing a set of N_{Bld} buildings each of occupied floorspace A_{Bld} and of identical occupancy type b. The energy supply to each cluster was defined by the fraction f of total building floorspace ($= N_{bld}\, A_{Bld}$) supplied by each heating technology and the total installed area of photovoltaic panels, A_{PV}. The energy demand was defined by the annual demand and annual demand profile for each consumption type, the peak energy demand and a building fabrication index to model the insulation standard applied for each building.

2.2.1 Energy Demand Profiles

Space heating, hot water, appliance and lighting, space cooling and cooking annual consumption profiles were modelled for each building occupancy type. Each annual profile defined the average consumption per unit of occupied floor space using N_d daily profiles each with N_p time steps of length $\tau^{(p)}$. Each profile was constructed by first defining a daily profile shape for each occupancy type. A seasonality factor *SF* was then applied to scale the profile for each representative day. Finally, the annual profile was normalised so that the total annual demand = 1kWh/m^2. The annual demand profile was represented within the model in the following form:

$$\begin{aligned}
\boldsymbol{\Phi}_{\boldsymbol{SH}}^{(\boldsymbol{b})} &= \left\{ \left\{ \phi_{SH}^{(1)}, \ldots, \phi_{SH}^{(p)} \right\}^{(1)}, \ldots, \left\{ \phi_{SH}^{(1)}, \ldots, \phi_{SH}^{(p)} \right\}^{(b,d)} \right\} \\
\boldsymbol{\Phi}_{\boldsymbol{DHW}}^{(\boldsymbol{b})} &= \left\{ \left\{ \phi_{DHW}^{(1)}, \ldots, \phi_{DHW}^{(p)} \right\}^{(1)}, \ldots, \left\{ \phi_{DHW}^{(1)}, \ldots, \phi_{DHW}^{(p)} \right\}^{(b,d)} \right\} \\
\boldsymbol{S}_{\boldsymbol{AL}}^{(\boldsymbol{b})} &= \left\{ \left\{ s_{AL}^{(1)}, \ldots, s_{AL}^{(p)} \right\}^{(1)}, \ldots, \left\{ s_{AL}^{(1)}, \ldots, s_{AL}^{(p)} \right\}^{(b,d)} \right\} \\
\boldsymbol{S}_{\boldsymbol{SC}}^{(\boldsymbol{b})} &= \left\{ \left\{ s_{SC}^{(1)}, \ldots, s_{SC}^{(p)} \right\}^{(1)}, \ldots, \left\{ s_{SC}^{(1)}, \ldots, s_{SC}^{(p)} \right\}^{(b,d)} \right\}
\end{aligned} \tag{2.1}$$

such that, using space heating as an example:

$$\frac{\tau\, 365}{N_d} \sum_{1}^{N_p} \sum_{1}^{N_d} \phi_{SH}^{(p,d)} = 1 \tag{2.2}$$

The load profile per unit floor area for each building was therefore obtained by multiplying the normalised profile by the annual demand:

$$\Phi^{(c,b,p,d)} = \Phi_{Annual}^{(c)} \phi^{(b,p,d)} \tag{2.3}$$

2.2.2 Seasonal Variation of Energy Demand

The annual demand was modelled using a representative day for each month of the year. Table 2.1 shows the seasonality factors used for the space heating demand and the domestic appliance and lighting demand. The space heat consumption at each time step for each month was calculated using:

$$\frac{\Phi_{SH}^{(c,p,1)}}{SF_{SH}^{(1)}}=\frac{\Phi_{SH}^{(c,p,2)}}{SF_{SH}^{(2)}}=\ \dots\ =\frac{\Phi_{SH}^{(c,p,12)}}{SF_{SH}^{(12)}} \tag{2.4}$$

The average domestic hot water consumption profile and the domestic cooking profile was assumed to be unchanged over the year.

Month	**Space heating** (Oxford Uni 2011)	**Electric appliance / lighting** (Elexon 2006)	**Month**	**Space heating** (Oxford Uni 2011)	**Electric appliance / lighting** (Elexon 2006)
1 (January)	1	1	7 (July)	0	0.62
2 (February)	0.9	0.92	8 (August)	0	0.63
3 (March)	0.85	0.83	9 (September)	0	0.67
4 (April)	0.68	0.74	10 (October)	0.34	0.77
5 (May)	0.39	0.68	11 (November)	0.65	0.9
6 (June)	0	0.64	12 (December)	0.92	0.98

Table 2.1: Seasonality factors for space heating demand and electricity appliance and lighting demand.

2.2.3 Peak Energy Demand

The peak energy consumption of each building was modelled to determine the maximum cluster load upon each network and the installed capacity of each heat supply technology. The calculation of peak demand for non residential dwellings was based upon indicated values per unit floorspace provided by CIBSE guidance (see Appendix 1):

$$\Phi_{PeakHeat}^{(c,b)}=A_{Bld}^{(c)}N_{Bld}^{(c)}\phi_{PeakHeat}^{(b)} \tag{2.5}$$

And:

$$S_{PeakAL}^{(c,b)}=A_{Bld}^{(c)}N_{Bld}^{(c)}s_{PeakElec}^{(b)} \tag{2.6}$$

For residential buildings, the peak demand was considered in terms of the

After Diversity Maximum Demand (ADMD). This takes into account the coincidence probability of individual peak demands within a group of premises. The ADMD was considered for electrical appliance and lighting use, space heating with hot water use, and domestic hot water only. The space and hot water heating ADMD assumed a direct wet central heating system and was calculated using the empirical relationship provided by IGEM (2008):

$$\Phi^{(c)}_{AdmdHeat}=0.30484\,N^{(c)}_{Bld}(5.69+0.00109\,\Phi^{(c)}_{AnnualSH}+(19.25+0.00369\,\Phi^{(c)}_{AnnualSH})(N^{(c)}_{Bld})^{-0.5}) \tag{2.7}$$

The domestic hot water ADMD was given by:

$$\Phi^{(c)}_{AdmdDHW}=0.010398\,N^{(c)}_{Bld}(0.0505+0.18\,(N^{(c)}_{Bld})^{-0.5})\,\Phi^{(c)}_{AnnualDHW} \tag{2.8}$$

The appliance and lighting ADMD within a was calculated using the Central Networks design rule of thumb (2006):

$$S^{(c)}_{AdmdAL}=N^{(c)}_{Bld}(1.42289+8\,(N^{(c)}_{Bld})^{-0.9767}) \tag{2.9}$$

2.2.4 Building Fabrication Index.

A detailed model of the relationship between building fabric and space heating demand was beyond the scope of this work. However, a simple representation of building insulation was included by defining a Building Fabric Index (BFI). This defined the building insulation standard in terms of the fractional space heating reduction relative to a reference standard:

$$BFI^{(c)}=1-\frac{\sum \Phi^{(p,c)}_{SH}}{(\sum \Phi^{(p,b)}_{SH})_{Ref}} \tag{2.10}$$

2.3 Energy Supply Technology Modelling

Two classes of energy supply technology were modelled: those installed within or upon individual buildings and those used for community scale provision.

2.3.1 Gas heat only boilers

Domestic and large scale gas boilers were modelled as a simple fuel to heat conversion process. The fuel consumption required to supply a given heat demand Φ_{GCH} was determined using:

$$F_{GCH}=\Phi_{GCH}/\eta_{Fconv} \tag{2.11}$$

Where η_{Fconv} is the fuel to energy conversion efficiency for the boiler.

2.3.2 Combined Heat and Power (CHP)

For the purpose of this thesis the modelling of combined heat and power was limited to natural gas internal combustion engine units. Such units are widely applied for schemes up to ~8MW$_{th}$. The model consisted a fuel combustion stage, an energy conversion stage and a waste heat recovery stage, as shown by Fig 2.2.

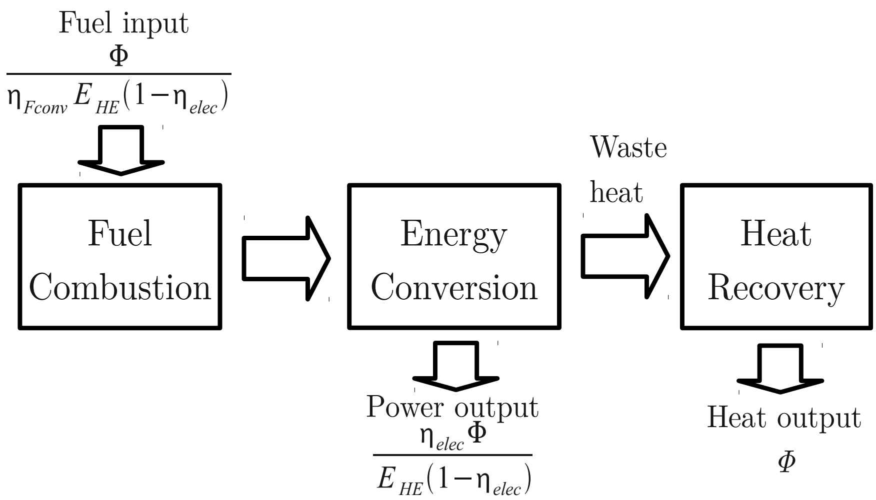


Figure 2.2: Simple model of an Internal Combustion Engine Combined Heat and Power Plant.

The electricity generation output P_{CHP} was defined in terms of the fuel consumption F_{CHP} using:

$$P_{CHP} = \eta_{Elec}\,\eta_{Fconv}\,F_{CHP} \tag{2.12}$$

Where η_{Fconv} is the fuel combustion efficiency and η_{Elec} is the electrical generation efficiency. The heat recovered for distribution to heat consumers, Φ_{CHP} was given by:

$$\Phi_{CHP} = K_{HE}(1-\eta_{Elec})\eta_{Fconv}F_{CHP} \tag{2.13}$$

where K_{HE} is the heat recovery factor of the heat exchanger. Within the integrated model, the heat generation from each plant was used as a known variable. The corresponding fuel consumption was thus determined by re-arranging Equation 2.13:

$$F_{CHP} = \frac{\Phi_{CHP}}{\eta_{Fconv}E_{HE}(1-\eta_{Elec})} \tag{2.14}$$

And the electrical power generation was obtained by substituting for F_{CHP} by Equation 2.12:

$$P_{CHP} = \frac{\eta_{Elec}\Phi_{CHP}}{E_{HE}(1-\eta_{Elec})} \tag{2.15}$$

The electrical efficiency η_{Elec} was defined as empirical functions of part load and rated plant output. From Figure 2.3. the rated efficiency was modelled as:

$$\eta_{Rated,Elec} = 0.024\ln(P_{Rated,CHP}) + 0.239 \tag{2.16}$$

The part load efficiency was obtained from Figure 2.4 such that:

$$\eta_{Elec} = \eta_{Rated,Elec}\left(0.09835\ln\left(\frac{P_{CHP}}{P_{Rated,CHP}}\right)+1\right) \tag{2.17}$$

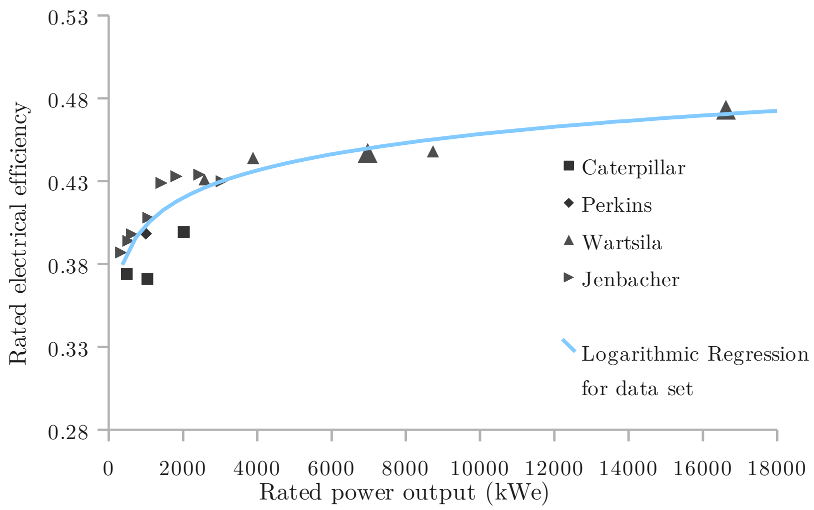


Figure 2.3: Rated electricity generation efficiency as a function of rated power output for commercially available natural gas internal combustion engine combined heat and power plant.

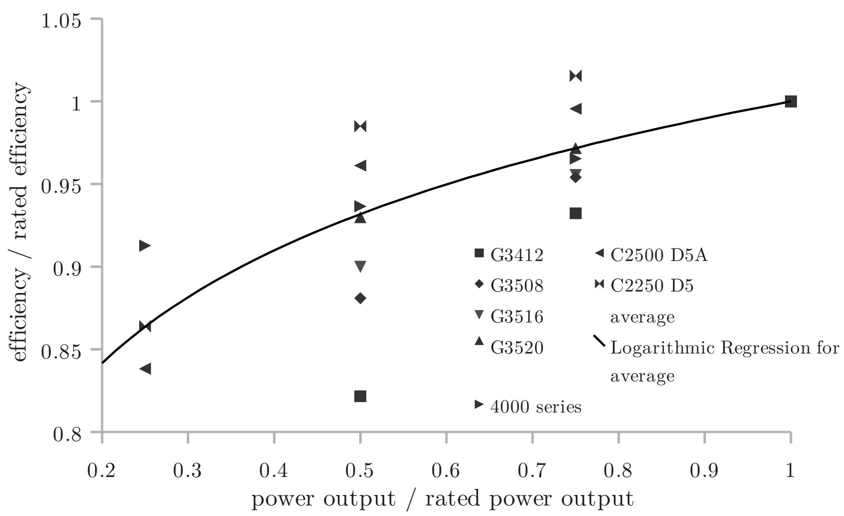


Figure 2.4: Electrical efficiency of commercially available natural gas Internal Combustion Engine Combined Heat and Power Plant as a function of plant downturn.

2.3.3 Heat Storage

The model of heat storage was limited to the hot water accumulators of the type described within (IEA 2005) and (Nielsen 2003). These are essentially large well insulated hot water tanks for the short term storage of thermal energy. Several heat accumulator designs are currently in use worldwide, with the variations primarily due to the measures employed to minimise the zone separating the hot and cold water sections of the tank. The cheapest and most common design is the simple cylindrical single vessel type stratified accumulator (IEA 2005) and is shown schematically by Fig. 2.5.

Each heat accumulator was assumed to be hydraulically separated at the charge / discharge points via heat exchangers. The tank was assumed to be cylindrical with a height/diameter ratio of 1.5 and a separation zone of 1m (IEA 2005). Each unit was characterised by the storage capacity (m^3), the volume of hot water stored at each time step (m^3), the temperature of the hot water zone (°C) and the temperature of the cold water zone(°C).

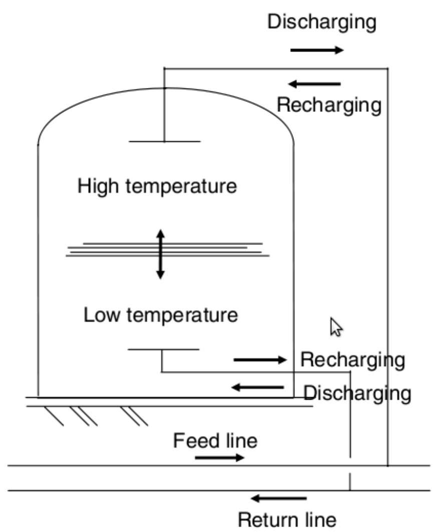


Figure 2.5: illustration of a stratification type hot water accumulation tank for district heating networks (Soderman and Petterson 2006).

2.3.4 Heat Pumps

Heat pumps use electrical power to move heat from a low temperature source to a higher temperature sink. The coefficient of performance (CoP) of a heat pump is the thermal energy supplied per unit of electricity consumed. The general form of the heat pump energy conversion process is given by:

$$P_{HP} = \Phi_{HP} / CoP_{HP} \tag{2.18}$$

Two types of heat pump were modelled. Ground source heat pumps (GSHP's) recover thermal energy using pipes buried horizontally at a depth of ~2m or into boreholes typically sunk to depths of 70m. Air source heat pumps (ASHP's) recover heat directly from the outside air. The heat pump CoP is dependent upon the temperature difference between the source and sink ΔT_{HP} . Fig 2.6 is a collation of stated manufacturers CoP data by Staffell (2009) for GSHP's as a function of ΔT_{HP} . Similar data was also presented for ASHP's. The following empirical relationships were derived:

$$\begin{aligned} CoP_{GSHP} &= -0.11 (T_{sink} - T_{ground}) + 8.51 \\ CoP_{ASHP} &= -0.07 (T_{sink} - T_{air}) + 5.83 \end{aligned} \tag{2.19}$$

The ground temperature was estimated by assuming an installation depth of 2m . Fig 2.7 illustrates the typical variation of UK ground temperature with depth (Staffell 2009). At depths below 2m the average ground temperature varies between 7°C and 13°C over the year and beyond 8m the ground temperature range converges to a year round average of 10°C.

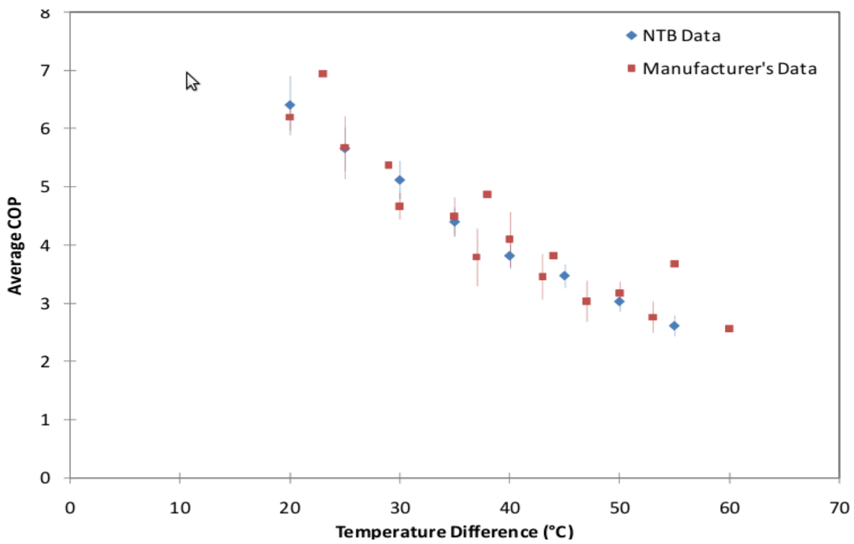


Figure 2.6: Collated data of Coefficient of Performance (CoP) against sink-source temperature difference for commercially available ground source heat pumps (Staffell 2009).

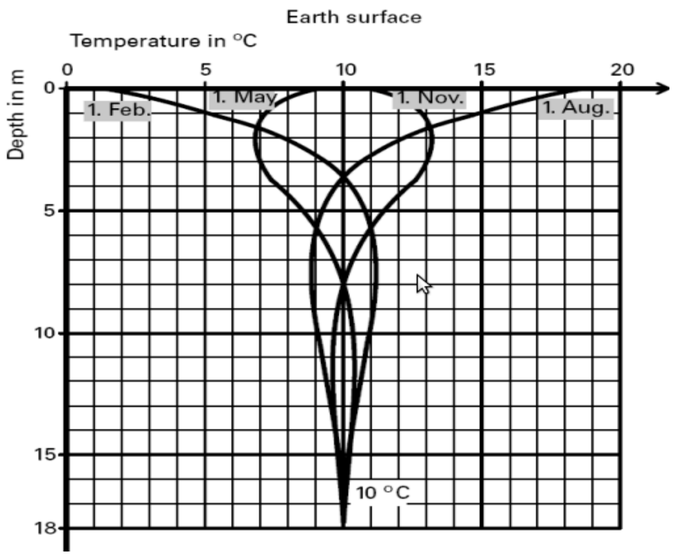


Figure 2.7: Variation of average UK ground temperature with depth.(Staffell 2009).

In contrast to the ground temperature, the UK air temperature is subject to significant daily and seasonal variation. Average daily temperature for Wales ranges from 1.1°C in February to 19.1°C in July. The minimum ground and air temperature determines the minimum CoP values for GSHP's and ASHP's respectively for peak electricity demand calculations where heat pumps are used. A minimum air temperature of -3°C (CIBSE 2002) and a minimum ground temperature of 5°C (Staffell 2009) was applied.

2.3.5 Photovoltaic Panels

PV panels were modelled in terms of the average power generation output profile at each time step per installed m^2. Fig 2.9 shows the profile for peak summer. A seasonality factor (SF_{PV}) was applied to determine the average generation per time step over the rest of the year. The monthly seasonality factors applied within this work are shown by Table 2.2. It was assumed that all excess PV electricity generation was exported to the local distribution network.

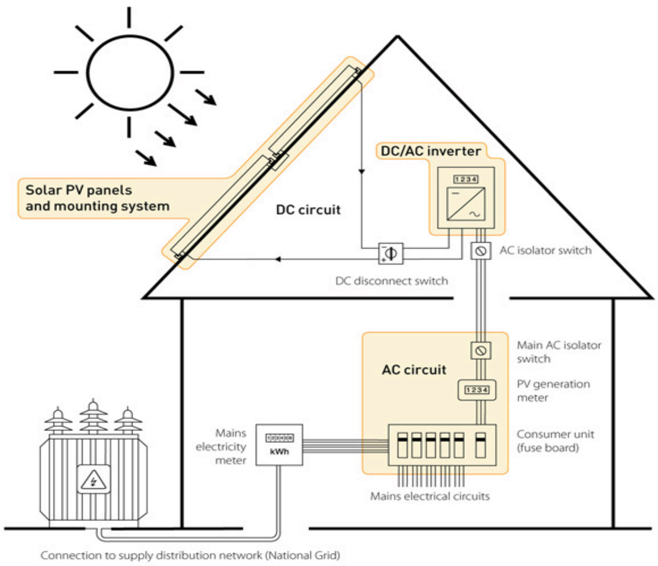


Figure 2.8: Schematic illustration of a residential photovoltaic installation (ohmicSolarPower 2011).

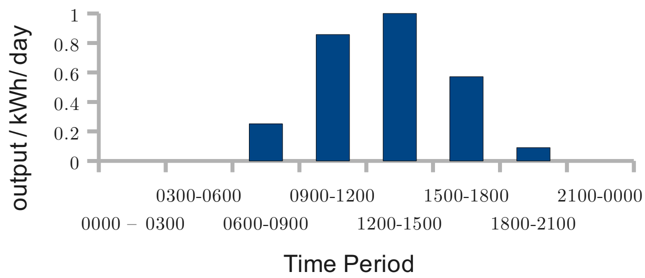


Figure 2.9: Normalised generation profile for solar generation installations(Suna 2006).

Month	Solar generation factor	Month	Solar generation factor
January	0.15	July	0.98
February	0.19	August	0.95
March	0.47	September	0.88
April	0.67	October	0.3
May	0.97	November	0.17
June	1	December	0.11

Table 2.2: Seasonality multiplication factors for solar generation outputs (Carbon Trust 2009).

	Annual Generation	Peak Generation
Solar Thermal	450 kWh_{th}/m^2 /yr	-
PV	117 kWh_{el}/m^2 /yr	$0.14kW_{el}/m^2$

Table 2.3: Peak and annual generation outputs used for solar technology modeling.

2.4 Energy Network Modelling

The electricity, natural gas and district heating distribution networks were modelled. Two levels of detail were considered for each: The *primary network* extends from the grid connection point to the boundary of each cluster. The *intra-cluster network*, defines the network from the cluster boundary to the meter of each building. A generalised approach to network modelling was applied whereby each network was considered as a graph. Thus, using graph theory terminology, each network consisted of a set of nodes interconnected by a set of edges.

2.4.1 Electricity Network

The electricity distribution network between the grid connection point and the metering at each building was modelled. A generic network configuration was used to model the variability of the network within each building cluster. This was then reduced to the required network configuration using the electricity network design modules described within Chapter 3. The generic network configuration and the parameters used to define the network are s shown within Fig. 2.10 and Table 2.4 respectively. Further detail of the network configurations considered by the model are found within Appendix 5.

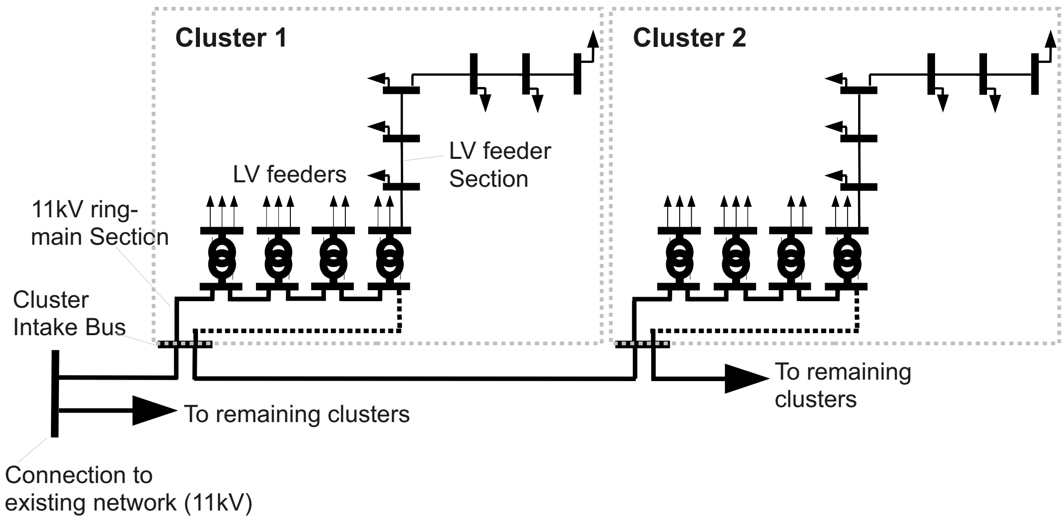


Figure 2.10: Schematic illustration of the electricity distribution network as considered within the model.

Edge Parameters:	Length, Impedance, rated current of cable, power rating of transformer, current at each time step.
Node Parameters:	Voltage, peak power demand, minimum power demand, power demand at each time step.

Table 2.4: Parameters used to define the nodes and edges within the electricity network.

2.4.2 Gas Distribution Network

The natural gas distribution network model comprises a set of N_k nodes interconnected by a set of N_l edges. Each edge represented either a gas distribution network pipe of length L_l, or a pressure reduction installation (PRI) of capacity F_{MaxPRI}. The scope of the natural gas distribution network model is shown schematically by Fig. 2.11.

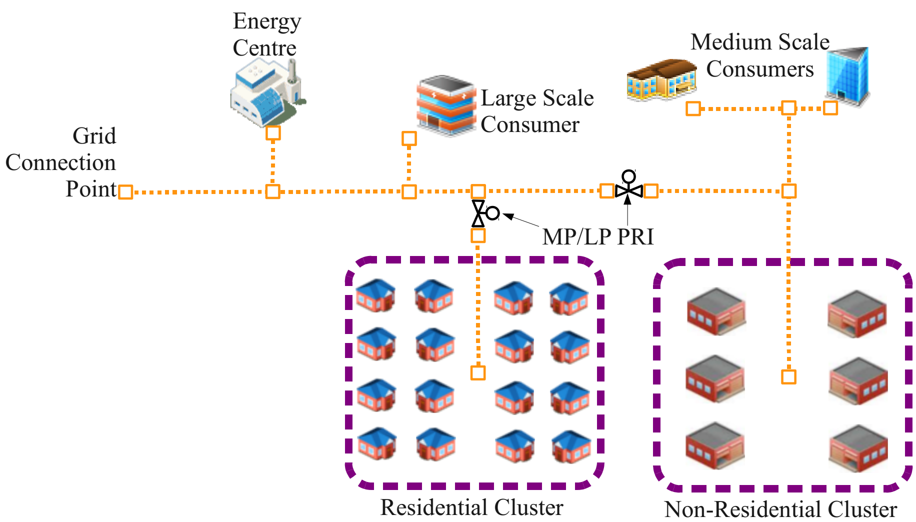


Figure 2.11: Schematic illustration of the gas distribution network as considered within the Energy Supply Infrastructure Model.

It was assumed that each pressure reduction installation was configured to reduce the network pressure from intermediate pressure (IP) or medium pressure (MP) regimes (4-7 bar and 0.5 – 2bar respectively) to 75mbar (Low Pressure). The presence and capacity of each PRI was determined by the pressure at the PRI *from* node as shown by Table 2.5.

p_{from}	p_{to}	$F_{l,PRI}$
>75mbar	75mbar	$F_{l,max}$
<75mbar	p_{from}	0 (not required)

Table 2.5: Rules used to determine the capacity of pressure reduction installations within the natural gas network

Arc Parameters:	Length, pipe diameter, pipe roughness, Pressure reduction installation capacity, flow rate, flow velocity
Node Parameters:	Pressure, peak gas demand

Table 2.6: Parameters used to define the nodes and edges of the gas network.

The network configuration used to model the intra-cluster gas is shown by Fig 2.12. The model assumes that buildings are evenly distributed within square grid of area $A^{(c)}_{Cluster}$. Figure 2.12 also shows the reduced arrangement used to within the analysis. The load along the represented branch and sub branch was assumed to be evenly distributed between 3 nodes along each.

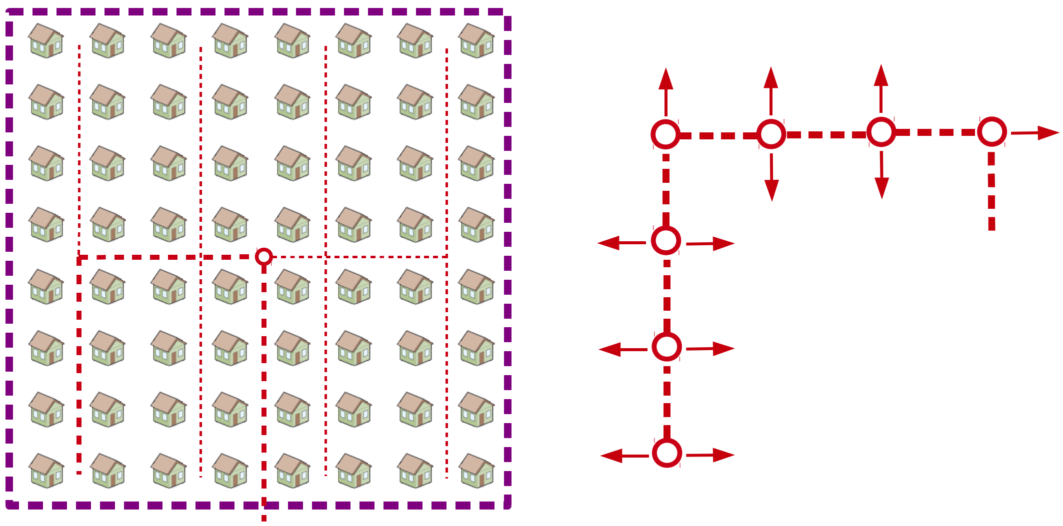


Figure 2.12: Simplified cluster topology used to model the intra-cluster district heating and gas distribution networks.

The length of each branch and sub branch section was defined, using the gas network as an example, as:

$$L_{GasBranch}^{(c)} = \frac{1}{2}\sqrt{A_{Cluster}^{(c)}} \tag{2.20}$$

The number of consumers along each sub branch section was defined as:

$$N_{GasSubBranch}^{(c)} = \frac{1}{3}\sqrt{N_{Bld}^{(c)}} \tag{2.21}$$

The number of consumers at each of the remaining branch nodes was therefore:

$$N_{GasBranchNode}^{(c)} = \frac{N_{Bld}^{(c)} - 4\sqrt{N_{Bld}^{(c)}}}{4} \tag{2.22}$$

A similar set of relationships was obtained for the district heat network.

2.4.3 District Heat Network

The district heat network model consisted a set of N_m nodes interconnected by N_n edges (supply and return pipes). A schematic illustration of the district heating model is shown by Fig. 2.13. The heat network was assumed as a continuous hydro-statically isolated dual pipe system connecting each consumer to the each energy centre. The intra-cluster district heat network was modelled using the same configuration and methodology as that used for the natural gas network (Fig 2.12), but this time with each section of network representing a supply and return pipe.

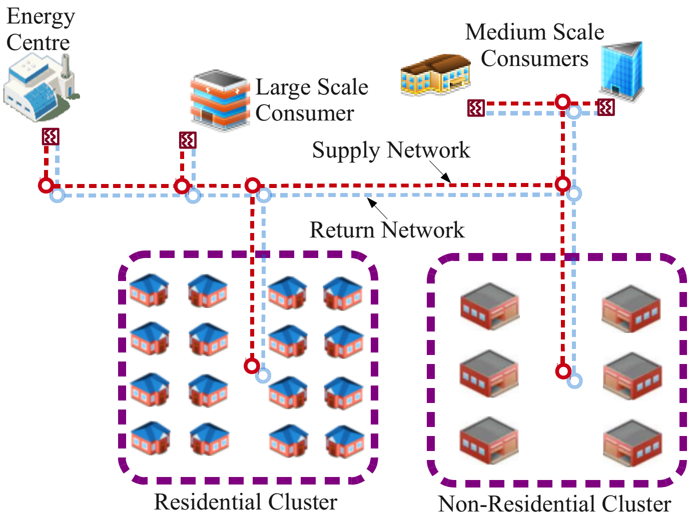


Figure 2.13: Schematic illustration of the district heat network as considered within the Energy Supply Infrastructure Model.

Edge Parameters:	Length, pipe diameter, pipe insulation thickness, pipe insulation thermal conductivity, pipe roughness, mass flow rate, flow velocity
Node Parameters:	Pressure, peak heat demand, heat supply, supply temperature, return temperature, ground temperature

Table 2.7: Parameters used to define the edges and nodes of the district heat network.

Chapter 3

Design of Multi Energy Vector Distribution Systems

3.1 Introduction

A set of technical design models, or modules, were developed for new build multi energy-vector distribution infrastructure. Each module was tasked with the design or analysis a particular aspect of the on-site energy distribution infrastructure. These were combined to provide a bottom up distribution infrastructure design for a given mix of on-site energy supply technologies. The technical design model was applied to a set of infrastructure options for a case study developed to represent a generic new build market town residential scheme in the UK. The Energy Supply Infrastructure model described within Chapter 2 was implemented in tabular form using a spreadsheet. Each design model was therefore implemented as a compatible add-in function. The structure of the model is illustrated by Fig. 3.1.

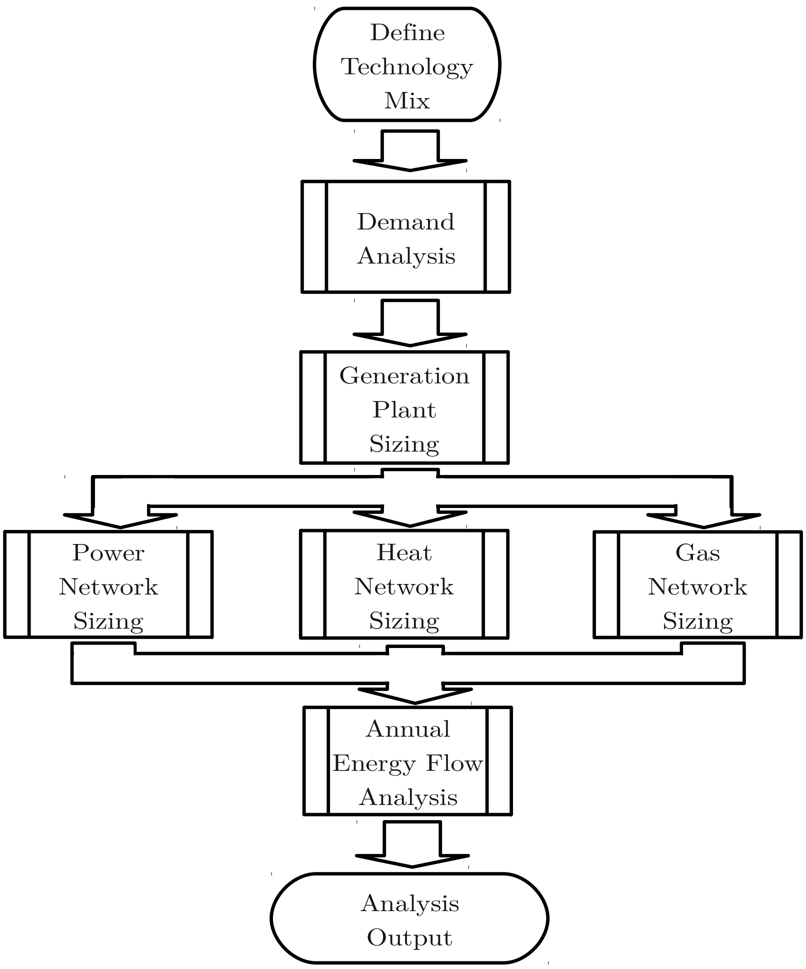


Figure 3.1: Data flow between the technical design models.

3.2 Technical Design Modules

3.2.1 Energy Demand Analysis

The energy demand analysis module was used to determine the average network load profile and peak network load for each cluster using the models described by Chapter 2. The structure of the module is described by Algorithm 1.

Algorithm 1: ConsumerLoadAnalysis

Inputs: No. of premises; Occupancy type; Occupied floor space; Cluster area; Building Fabric Index; PV capacity; heating technologies employed at each premise; reference consumption profiles; air and ground temperature profiles.

Begin
1 Look-up $\boldsymbol{\Phi_{SH}}, \boldsymbol{\Phi_{DHW}}, \boldsymbol{S_{AL}}, \boldsymbol{S_{SC}}$
2 **for** all time steps
3 Calculate CoP_{GSHP} *and* CoP_{ASHP}
4 Calculate $S_{Dmd}^{(c,p)}, \Phi_{DmdDH}^{(c,p)}, F_{DmdNG}^{(c,p)}$
5 **end**
6 Calculate $S_{Peak}^{(c,p)}, S_{Min}^{(c,p)}, \Phi_{PeakDH}^{(c,p)}, F_{PeakNG}^{(c,p)}$
End

Outputs: Peak cluster or building electricity, gas and district heat demand; Annual cluster or building electricity, gas and district heat demand profile.

The average cluster electricity demand at each time step was given by:

$$S_{Dmd}^{(c,p)} = N_{Bld}^{(c)} \left(A_{Bld}^{(c)} \left(S_{AL}^{(c,p)} + S_{SC}^{(c,p)} + \left(\frac{f_{GSHP}^{(c,p)}}{COP_{GSHP}^{(c,p)}} + \frac{f_{ASHP}^{(c)}}{COP_{ASHP}^{(c,p)}} \right) \left(\Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)} \right) \right) + A_{PV}^{(c)} S_{PV}^{(p)} \right) \tag{3.1}$$

The peak electricity demand using the of thumb recommended by Central Networks (2006) such that $S_{peak} = S_{peak,A\&L} + 0.5(maxSpaceHeating)$:

$$S_{Peak}^{(c)} = A_{Bld}^{(c)} N_{Bld}^{(c)} \left(S_{PeakAL}^{(c)} + 0.5 \left(\frac{f_{GSHP}^{(c)}}{(COP_{GSHP}^{(c)})_{min}} + \frac{f_{ASHP}^{(c)}}{(COP_{ASHP}^{(c)})_{min}} \right) \right) \Phi_{PeakHeat}^{(c)} \tag{3.2}$$

The installation of PV panels may result in significant reverse network power flows during summer months. A worst case minimum electricity demand (i.e. maximum negative demand) was modelled by assuming the maximum PV generation coincided with the minimum daytime demand.

$$S_{Min}^{(c)} = N_{Bld}^{(c)} \left(A_{Bld}^{(c)} S_{MinAL}^{(c)} + A_{PV}^{(c)} S_{peakPV} \right) \tag{3.3}$$

The load upon the natural gas network corresponds to the fuel consumption of the domestic gas boilers. If $f_{GCH}^{(c)}$ is the fraction of consumers or floorspace served by gas boilers, the total gas demand for consumer or cluster c at time step p was given by:

$$F_{DmdNG}^{(c,p)} = A_{Bld}^{(c)} N_{Bld}^{(c)} f_{GCH}^{(c)} \left(BFI^{(c)} \Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)} \right) / \eta_{Fconv} \tag{3.4}$$

The peak gas demand heat demand for residential clusters was obtained using the peak heat demand defined by Eq. 2.5 so that:

$$F_{PeakNG}^{(c)} = \frac{f_{GCH}^{(c)}}{\eta_{GCH}^{(c)}} \Phi_{PeakHeat}^{(c)} \tag{3.5}$$

The average district heat load for each cluster was defined by:

$$\Phi_{DmdDHN}^{(c,p)} = A_{Bld}^{(c)} N_{Bld}^{(c)} f_{DHN}^{(c)} \left(BFI^{(c)} \Phi_{SH}^{(c,p)} + \Phi_{DHW}^{(c,p)} \right) \tag{3.6}$$

The peak district heat demand for residential clusters was determined using:

$$\Phi_{PeakDHN}^{(c)} = f_{DHN}^{(c)} \Phi_{PeakHeat}^{(c)} \tag{3.7}$$

3.2.2 Energy Centre Generation Plant Design

The design parameters of each community heat generation plant were determined using the generation plant sizing module. The module structure including the plant sizing algorithm is shown by Algorithm 2. The algorithm contains an iterative loop to determine the electricity efficiency and peak electrical output for each CHP unit corresponding to a given rated heat output.

Generator 1 within the energy centre was designed to provide 100% back up capacity for the heat network. This plant was used to meet any supply shortfall during normal operation and to ensure reserve capacity to cover generator downtime. The rated heat output for the remaining units were entered as inputs to the algorithm. These were set either manually by the user or as the output of a selection process such as the optimisation algorithm described within Chapter 6.

Algorithm 2: GenerationPlantSizing

Inputs: Plant Type; Fuel Type; Plant rated heat output; Peak district heat demand;

Begin
look up E_{HE} and η_{Fconv}
if(plant Type = CHP)
  initial estimate: $\eta_{Rated,\,Elec}=0.4$
  while *error > 0.001*
    calculate $P^{(g)}_{Rated}$
    re-estimate efficiency $\eta^{(g)}_{Rated,\,Elec}$
    error = $|\eta^{(g)}_{Rated,\,Elec}-\eta^{(g)-}_{Rated,\,Elec}|$
  end
end
calculate $F^{(g)}_{Rated}$
End

Outputs: Rated heat output; Rated fuel consumption; Rated electrical efficiency; heat recovery factor; fuel conversion efficiency

3.2.3 Electricity Network Design

The design of the 11kV/0.4kV electricity distribution network was performed in two stages. A *clusterNetworkSizing* algorithm was used to determine the number of 11/0.4kV transformers required per cluster, the number of feeders required per transformer, the configuration of each 0.4kV feeder and the cable size required at each section of the 0.4kV feeder. A separate algorithm, *primaryPowerNetworkSizing*, was used to determine the configuration of the 11kV network within each building cluster and the cable size required at each section of the 11kV network across the scheme. Both algorithms use a radial steady state load flow algorithm *powerLoadFlow* which is detailed within Appendix 3. Each network was designed in adherence to mandatory voltage tolerances: 0.4kV+10/-6% and 11kV+/-6%.

The *clusterNetworkSizing* is shown by algorithm 3. An iterative procedure was used to determine the number of substations required at each cluster and to ensure that the diversified peak demand was less than or equla to the largest available transformer. The minimum number of feeders required per transformer was specified by the following criteria:

i. A maximum number of dwellings per LV circuit: $N_{BldLVfeed}^{(c)} = N_{Trans}^{(c)} / (N_{BldLVfeeder})_{max}$

ii. The maximum current per phase per feeder <= rating of the largest available cable.

A steady state load flow analysis determined the network currents and voltage drops at peak and minimum demand conditions. The methodology used to model the configuration of the 0.4kV feeder is detailed within Appendix 5.

The *primaryPowerNetworkSizing* algorithm is shown by Algorithm 4. A steady state power load flow was used to determine the cable sizes required within each section of the 11kV network. The methodology used to model the configuration of the 11kV network within each cluster is detailed within Appendix 5.

To account for the presence of micro-generation and community generation, the design cases defined within Table 3.1 were considered within each algorithm.

Case	Energy centre generation	Consumer demand
Case 1	zero	minimum
Case 2	zero	maximum
Case 3	maximum	minimum
Case 4	maximum	maximum

Table 3.1: Generation – demand combinations used to determine electricity cable sizes and transformer ratings.

Algorithm 3: clusterNetworkSizing

Inputs: number of premises; cluster area; peak cluster demand.

Begin

Estimate number of transformers : $N_{Trans} = ADMD\,/(transformer\ rating)_{max}$

Estimate number of feeders : $N^{(c)}_{Feeders} = max\{N^{(c)}/(N_{BldLVfeed})_{max}, S^{(c)}_{max}/3V_p N^{(c)} I_{rating,max}\}$

Calculate ADMD through each LV cable

Initiate cable sizes for all cables : cable rating = $(\text{cable rating})_{\min}$

run *powerLoadFlow*

while bus voltage is outside of tolerance

    upsize cable : voltage drop = $(\text{voltage drop})_{\max}$

        run *powerLoadFlow*

    upsize cable : cable current > cable rating

        run *powerLoadFlow*

    if ($cable\ rating = (cable\ rating)_{max}\ \forall\ cables$)

        $N^{(c)}_{Feeders} = N^{(c)}_{Feeders} + 1$

        recalculate feeder lengths and bus loads

        run *powerLoadFlow*

    end

end

End

Outputs: number of transformers; rating of each transformer; length and rating of additional 11kV cable; length and rating of each feeder cable.

Algorithm 4: primaryPowerNetworkSizing

Inputs: primary network topology and cable lengths; peak demand for each premise and cluster.

```
Begin
    Calculate ADMD at all busbars.
    Initiate cable sizes for all cables : cable rating = (cable rating)_min
    for all feasible open points
        run powerLoadFlow
        while bus voltage is outside of tolerance
            upsize cable : voltage drop = (voltage drop)_max
            run powerLoadFlow
            upsize cable : cable current > cable rating
            run powerLoadFlow
        end
    end
End
```

Outputs: Cable ratings; transformer ratings

3.2.4 Gas Network Design

The gas network sizing module (Algorithm 5) was used to determined the diameter of each gas pipe and rated capacity of each pressure reduction installation. A steady state load flow analysis *gasLoadFlow* was used to determine pipe sizes required at maximum demand conditions (see Appendix 3).

3.2.5 Heat Network Design

The district heating pipe diameters and pump ratings were determined by the heat network sizing module. Details of the steady state heat network load flow algorithm *heatLoadFlow* are presented within Appendix 3.

Algorithm 5: GasNetworkSizing

Inputs: gas network topology; pipe lengths; pressure reduction installation locations; gas grid connection pressure; peak gas demand for each premise / cluster; peak gas demand for each energy centre.

Begin
1 calculate pipe flowrates F_l
2 initiate diameters : $D_l = (D_{NG})_{min}$ *s.t. Gas velocity < (Gas velocity)$_{max}$*
3 **While** node pressure < (node pressure)$_{\min}$
4 **run** *gasLoadFlow*
5 identify pipe : pressure drop = (pressure drop)$_{\max}$
6 upgrade pipe to next largest diameter
7 **end**
End

Outputs: gas pipe diameters; PRI capacity.

Algorithm 6: District Heat network pipe sizing algorithm

Inputs: Heat network topology; heat network pipe lengths; supply temperature; return temperature; peak heat demand for each premise / cluster; Maximum heat generation from each energy centre.

Begin
1 initiate pipe diameters : pipe diameter = (pipe diameter)$_{\min}$
2 ***run*** *heatLoadFlow*
3 **While** pressure differential > (pressure differential)$_{\max}$
4 upsize pipe *: pressure loss = (pressure loss)$_{max}$*
5 ***run*** *heatLoadFlow*
6 **end**
End

Outputs: DHN pipe diameters; pump sizes

3.2.6 Energy Flow Analysis

It was assumed that the energy centre was operated to supply the heat network at minimum operational cost. Two generation scheduling models were used: the *stepDispatch* Algorithm modelled the case without heat storage capacity; the *storageDispatch* Algorithm modelled the case with heat storage operated on a daily cycle.

(i) stepDispatch (Generation Scheduling, No Storage)

The on-off status of each generation unit was modelled using a binary variable $\delta_{OnOff}^{(g,p)}$. The on/off configuration for the set of N_g generation units at each time step was modelled as a bit pattern B with bit 1 corresponding to $\delta_{OnOff}^{(1,p)}$ and so on. Each plant combination was analysed in turn starting from B = 0...01 and increasing B as a binary numeral by 1 until B = 1...11. The feasibility of each combination was first examined using the following tests:

Test 1: if $\sum \delta_{OnOff}^{(g,p)} \Phi_{Rated}^{(g)} < \sum \Phi_{DmdDH}^{(c,p)}$; Insufficient capacity to meet network demand.

Test 2: if $\sum \delta_{OnOff}^{(g,p)} (\Phi_{G}^{(g)})_{min} < \sum \Phi_{DmdDH}^{(c,p)}$; Plant downturn constraints do not permit supply at the required level.

An estimation of the least cost generation schedule for each feasible configuration was performed. For configurations with only one plant committed, i.e. $\sum \delta_{OnOff}^{(g,p)} = 1$, the generation output was simply assigned as $\sum \Phi_{DmdDH}^{(c,p)}$. For configurations where $\sum \delta_{OnOff}^{(g,p)} > 1$, the following algorithm was applied:

Set all generation plant with $\delta_{G}^{(g,p)} = 1$ to rated output:

$$\Phi_{G}^{(g)} = \Phi_{Rated}^{(g)} \tag{3.8}$$

The total operation cost for each plant at each time step was defined as:

$$C_{GenCost}=\sum\left(c_{Fuel}^{(g)}F_{G}^{(g)}-c_{Heat}^{(g)}\Phi_{G}^{(g)}-c_{Power}^{(g)}S_{G}^{(g)}\right) \tag{3.9}$$

The cost gradient for each plant is calculated using the backwards difference:

$$C'^{(g)}_{GenCost}=\frac{C(\Phi_{G}^{(g)})_{GenCost}-C(\Phi_{G}^{(g)}-\Delta\Phi_{step}^{(g)})_{GenCost}}{\Delta\Phi_{step}^{(g)}}+(1-\delta_{OnOff}^{(g)})PF \tag{3.10}$$

Where PF is a penalty factor used to assign an arbitrarily large cost reduction gradient to non committed plant. PF = -999999 was used within the analysis. The generation plant for which the highest cost reduction (or lowest cost increase) is identified and the output reduced. The calculation was repeated until the total excess reduction = 0. The backward difference step size was arbitrarily defined for each plant as $\Delta\Phi_{step}^{(g)}=-10\text{kW}_{th}$.

(ii) storageDispatch (Generation Scheduling With Storage)

The total daily production was initially estimated as:

$$\Phi_{DailyDH}=\sum\Phi_{DmdDH}+\sum\Phi_{Losses} \tag{3.11}$$

The number of production time steps is thus given by:

$$N_{prTimeSt}=\frac{\Phi_{DailyDH}}{\sum\Phi_{Rated}} \tag{3.12}$$

The average generation within the fractional time step was calculated by assuming rated plant output for that period. For the case where $N_{prTimeSt}>N_{p}$, the excess production is supplied using back up boilers. Each time step was ranked in order of decreasing electricity tariff. Beginning at the time step with rank 1, the heat output of the CHP unit was set to rated output until:

1. the daily heat demand was met

   or

2. all time steps were visited.

The relative heat stored within the heat accumulator was given by

$$\Phi_{storage}^{(p)} = \Phi_{storage}^{(p-1)} + \sum \Phi_{rated}^{(g,p)} - \sum \Phi^{(c,p)} \tag{3.13}$$

With $\Phi_{storage}^{(0)} = 0$. The capacity of the heat accumulator required on site was defined by:

$$\Phi_{storeCap} = max\left((\Phi_{storage})_{Max} - (\Phi_{storage})_{Min}\right) \tag{3.14}$$

Algorithm 7: EnergyFlowAnalysis

Inputs: heat network specifications; power network specifications; energy centre plant specifications; district heat and electricity demand profiles for each premise/cluster, fuel price, heat price, electricity price.

Begin
1 **if**(storageIndex = 0)
2 **for** all time periods
3 **run** *heatDispatch*
4 **else**
5 **for** all representative days
6 **run** *storageDispatch*
7 **end**
End

Outputs: Heat and power generation and fuel consumption schedule for each production plant; Heat accumulator charge/discharge schedule; Heat accumulator capacity; Heat network losses; power network losses; power flows across grid connection point.

3.3 Module Implementation

For the purpose of this thesis, the Energy Supply Infrastructure model was implemented as an OpenOffice Calc (v3.2.0) spreadsheet. Each technical design module was therefore written as a Java program and compiled as a Calc add-in function using the Netbeans Open Office development extension.

3.4 Design of Example Scheme.

The design tool was applied to evaluate on-site energy supply options for a representative UK new build residential development. Details of the scheme are provided by Appendix 4. The study was limited to the use of natural gas or electricity grid as off site sources of energy. Chapters 4 and 5 extend the results of the study to examine the capability and cost of each option to deliver on site emissions savings. Table 3.2 presents a summary of the technology mix considered by each option.

	Primary heating	**PV Capacity**	**BFI**	**Gas Network**	**DH network**	**Heat Storage**
Reference	NG boilers	0	0	domestic	none	none
Building Fabric	NG Boilers	0-18.7m^2	0-0.8	domestic	none	none
Electrification	GSHP/ASHP	0-18.7m^2	0-0.8	none	none	none
Community Co-generation	ICE-CHP	0-18.7m^2	0-0.8	Energy Centre	90/50^{o}C, 16bar	Daily cycle

Table 3.2: Options evaluated by example scheme study.

3.4.1 Reference case

The key results for the reference case infrastructure are shown within Table 3.3. The use of natural gas for cooking and heating results in an annual demand of 3,859MWh with a diversified peak gas demand of 1.86MW at the grid connection. The reference electricity usage was composed entirely of appliance and lighting with an annual demand of 1,572MWh and a diversified peak of 0.78MW at the transformer.

The gas and electricity networks required for the reference scheme are shown by Fig 3.2. The network design is dependent upon the grid connection pressure with 75mbar assumed for the case shown. The effect of reducing the grid connection pressure is shown by Fig 3.3. A reduced connection pressure results in a reduced density which increases the gas velocity and thus the pressure drop. The electricity network consists a 95cne extension of the existing ring-main system to a single 800kVA substation serving 5 LV feeders.

Annual electricity demand (kWh)	1,572,860
Annual imported electricity(kWh)	1,620,883
Peak Electricity demand(kW)	808.61
On site losses(kWh)	48,023
Total Losses	86,925
No. 11/0.4kV substations	1
transformer capacity (kVA)	800
No. of LV feeders per Transformer	5
Peak load per feeder (kW)	155.67
Peak current per phase per feeder(A)	200.19
Annual gas consumption (kWh)	3,859,472
Peak gas demand(kW)	1857.41

Table 3.3: Key design parameters and consumption data for reference case option.

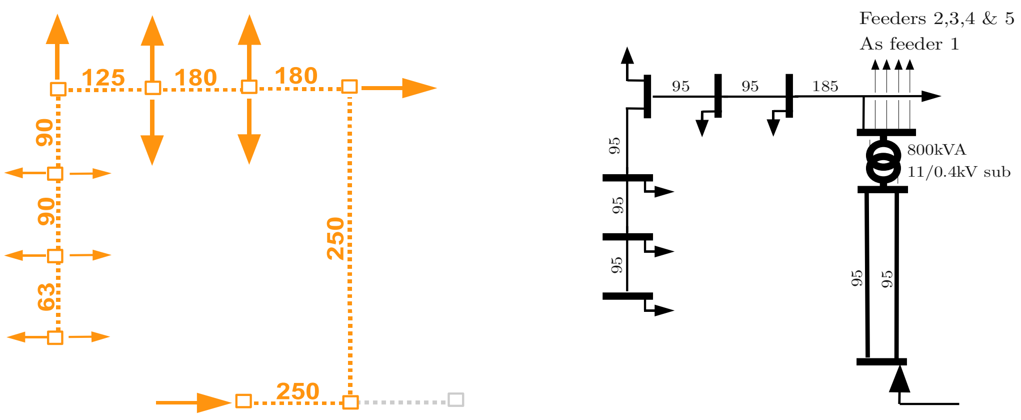


Figure 3.2: Schematic of the gas network and electricity network designs for the reference option.

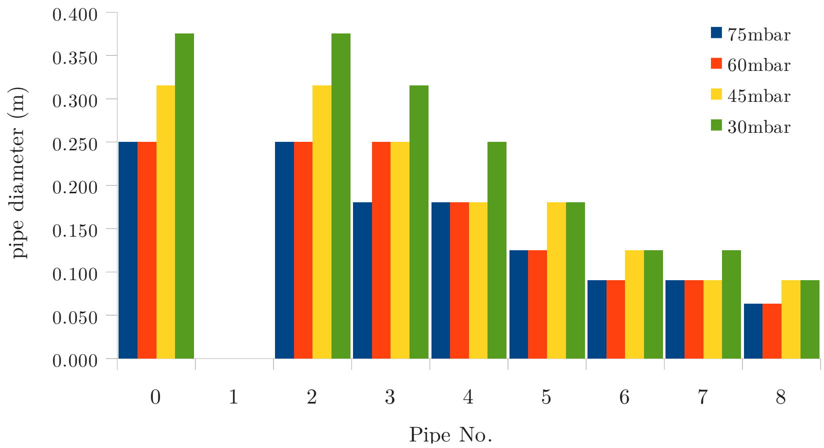


Figure 3.3: Effect of grid connection pressure upon pipe diameters for the reference option.

3.4.2 Building Fabric Option

The building fabric option models the use of improved building insulation to reduce the space heat demand combined with the use of PV to reduce the annual electricity consumption. The effect of increasing the level of domestic building insulation is shown by Table 3.4. The annual and peak gas consumption decrease proportionally to BFI. At BFI = 0.8, the annual demand is decreased by over 50% to 1.87MWh/year. The corresponding decrease of gas ADMD is less significant with a 37% reduction to 1.17MW. The parasitic electricity demand for the reference heating system and building fabric was assumed to be negligible. The annual and peak electricity demand are therefore independent of BFI for this option.

The impact of domestic PV capacity upon the reference electricity distribution system was examined. The key results are summarised by Table 3.5. Increasing the PV capacity per dwelling has a significant effect on the on-site demand, with a transition to a net annual export of 17MWh with 4kW$_e$ PV per dwelling. The impact of PV capacity upon network electricity losses was also examined. At 1kW per dwelling, the on site network losses were increased due to the reduction of on site demand. At 2kW and beyond, however, the network losses increase as the reverse flows from excess electricity production become increasingly significant. At 4kW, the total network losses account for approximately 6% of the total PV generation. The effect of PV capacity upon the electricity loss profile is shown by Fig. 3.4.

BFI	**0**	**0.2**	**0.4**	**0.6**	**0.8**
Annual electricity demand (kWh)	1,572,860	1,572,860	1,572,860	1,572,860	1,572,860
Annual imported electricity(kWh)	1,620,883	1,620,883	1,620,883	1,620,883	1,620,883
Peak Electricity demand(kW)	808.61	808.61	808.61	808.61	808.61
Annual gas consumption (kWh)	3,859,472	3,360,577	2,861,683	2,362,788	1,863,894
Peak gas demand(kW)	1857.41	1685.63	1513.85	1342.06	1170.28

Table 3.4: Effect of increased building fabric index upon peak and average energy consumption for the building fabric option.

PV Capacity (kW/dwelling)	**0**	**1**	**2**	**3**	**4**
Annual electricity demand (kWh)	1,572,860	1,572,860	1,572,860	1,572,860	1,572,860
Annual imported electricity(kWh)	1,620,883	1,169,219	733,237	321,964	-17,656
Peak Electricity demand(kW)	808.61	808.61	-954.51	-1,464.43	-1,954.96
On site losses(kWh)	48,023	36,612	40,883	69,846	170,496
Total Losses(kWh)	86,925	65,646	66,002	92,908	192,333
No. 11/0.4kV substations	1	1	1	2	3
transformer capacity (kVA)	1000	1000	1000	800	800
No. feeders per Transformer	5	5	5	3	3
Peak load (kW/feeder)	153.73	155.67	155.67	-269.87	-252.28
Peak current (A/phase/feeder)	200.19	200.19	200.19	374.82	350.38

Table 3.5: Effect of photovoltaic panel capacity upon the key design parameters and energy consumption for the building fabric option (BFI = 0).

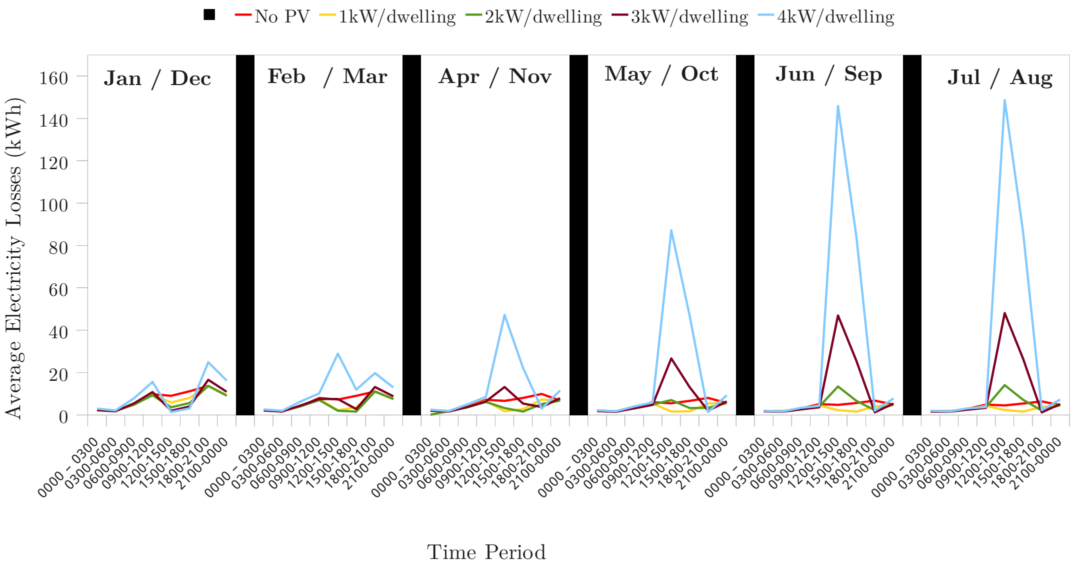


Figure 3.4: Electricity network loss profiles for each representative day at various average installed capacities of Photo Voltaic panels (for Building Fabric Index = 0).

The capacity of PV was shown to have a considerable effect upon the electricity network design. At 1kW/dwelling, the network is still designed to meet the winter appliance and lighting peak demand of 808kW_{el} as per the reference case. At capacities greater than 2kW_{e}/dwelling, the summer peak PV generation exceeds the winter peak demand and therefore dictates the network design. At 3kW PV per dwelling, the peak power exported from the site rises to 1,464kW, requiring 2 x 800kVA transformers with reverse power flow capability. At 4kW/dwelling the number of 11/0.4kV substations increases further to 3 x 800kVA units each with 3 feeders. This is illustrated by Fig. 3.5.

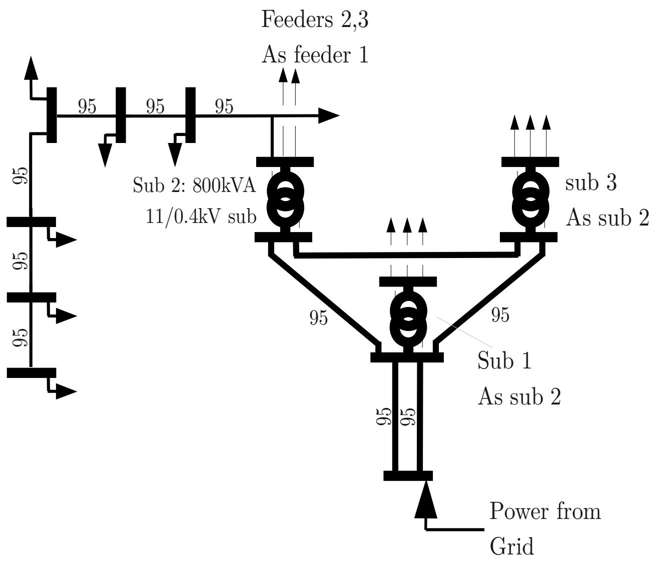


Figure 3.5: Schematic of electricity infrastructure for the building fabric option with 4kW of Photo Voltaic panels installed per dwelling (for Building Fabric Index = 0).

3.4.3 Electrification of heat

Table 3.6 shows the results of modelling the supply of space and domestic hot water to the example scheme using a mixture of ground source and air source heat pumps. This results in an increased diversified peak and annual electricity demand to 3,001MWh and 2MVA respectively at an assumed central heating temperature of 55°C.

The distribution network design for the heat pumps option at BFI = 0 is shown by by Fig 3.6. The increase of peak electricity demand increases the number of required substations to 2 1MVA units each with 4 feeders. Increasing BFI to 0.8 reduced the required transformer rating and the number off feeders required per transformer the infrastructure requirement is reduced to 2 x 800MVA transformers each with 3 feeders.

BFI	0	0.2	0.4	0.6	0.8
Annual electricity demand (kWh)	3,001,301	2,830,274	2,659,247	2,488,220	2,317,193
Annual imported electricity(kWh)	3,109,524	2,932,441	2,7346,280	2,572,931	2,404,620
Peak Electricity demand(kW)	2,001.83	1,996.51	1991.24	1,648.92	1,573.12
Onsite losses(kWh)	108,222	96,987	87,032	84,710	87,427
Total Losses	182,851	167,241	152,943	146,461	145,138
No. 11/0.4kV substations	2	2	2	2	2
transformer capacity (kVA)	1000	1000	1000	1000	800
No. feeders per Transformer	4	4	4	4	3
Peak load (kW/feeder)	250.23	234.93	219.81	206.11	262.19
Peak current (A/phase/feeder)	313.23	295.83	278.43	261.04	324.85

Table 3.6: Key design parameters and energy consumption data for the electrification option.

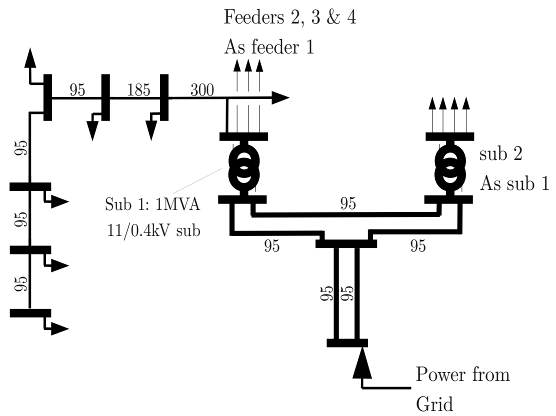


Figure 3.6: Schematic of the on site electricity distribution network for the electrification option (for Building Fabric Index = 0).

Total on site energy losses are increased from 86MWh for the reference case to 108MWh for heat pumps at BFI = 0, however this corresponds to a decrease to 3.5% of total demand. This is due to the shift to a low load factor winter peak demand profile as illustrated by Fig. 3.7 combined with the increased cable ratings and number of feeders used .

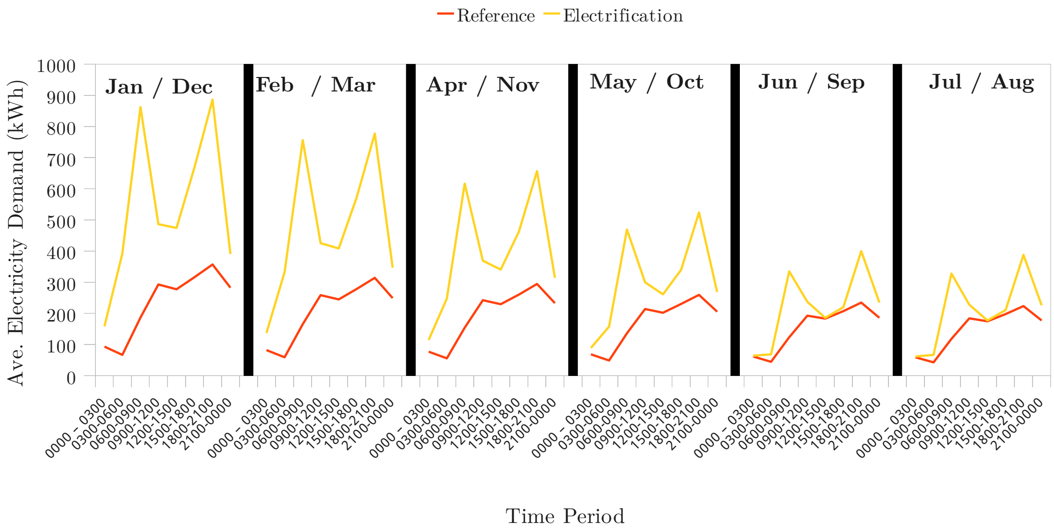


Figure 3.7: Average electricity demand profile for the reference option and heat electrification option for each representative day. (for Building Fabric Index = 0).

The dependence of CoP upon the central heating temperature effects the peak and annual electricity demand for the development. At BFI = 0, a 10°C rise of heating temperature to 65°C increases the electricity imported to the site to demand to 4,011.9MWh per year (a 28.8% increase) with peak demand of 2.37MVA. The use of heat pumps as an energy reduction measure therefore necessitates the use of as low a central heating temperature as is practically possible.

3.4.4 Community Co-generation Option

In the absence of heat storage capacity, the energy centre is required to operate in heat following mode, i.e. to meet the heat demand at each time step. In Fig. 3.8, the annual load duration curve for the district heat network is used to illustrate how the heat output of a CHP plant is constrained by the load profile for the heat following case. The bounded areas correspond to the annual heat production of each plant which in turn determines the annual electricity production.

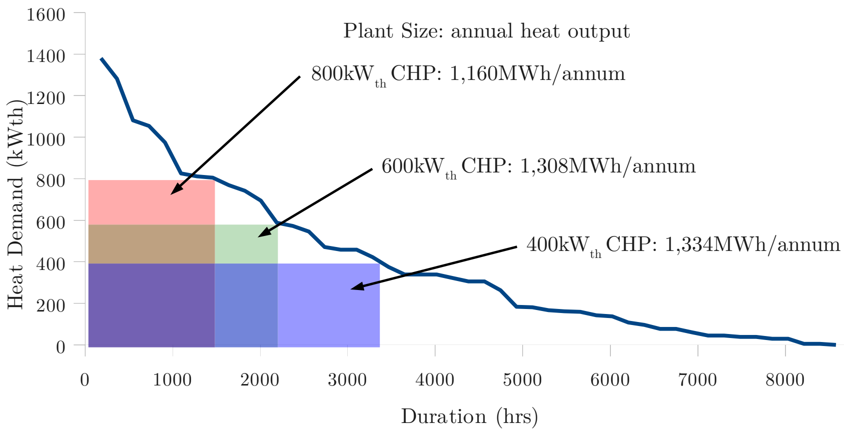


Figure 3.8: Influence of the heat network demand profile upon the heat generation output of CHP when operating in heat following mode.

The effect of this constraint upon the fuel consumption and electricity generation characteristics of the energy centre is shown by Fig. 3.9. The electric generation efficiency of the CHP plant increases with plant size as described by Equation 2.17. However, the constraint placed by the district heat load profile upon the duration of operation results in a plant size at which maximum annual electricity generation occurs. At BFI = 0 the maximum annual generation output occurs at a CHP plant size of ~1100kW$_{th}$. Increasing BFI to 0.6 impacts the DH demand profile such that the optimal plant size decreases to 700kW$_{th}$.

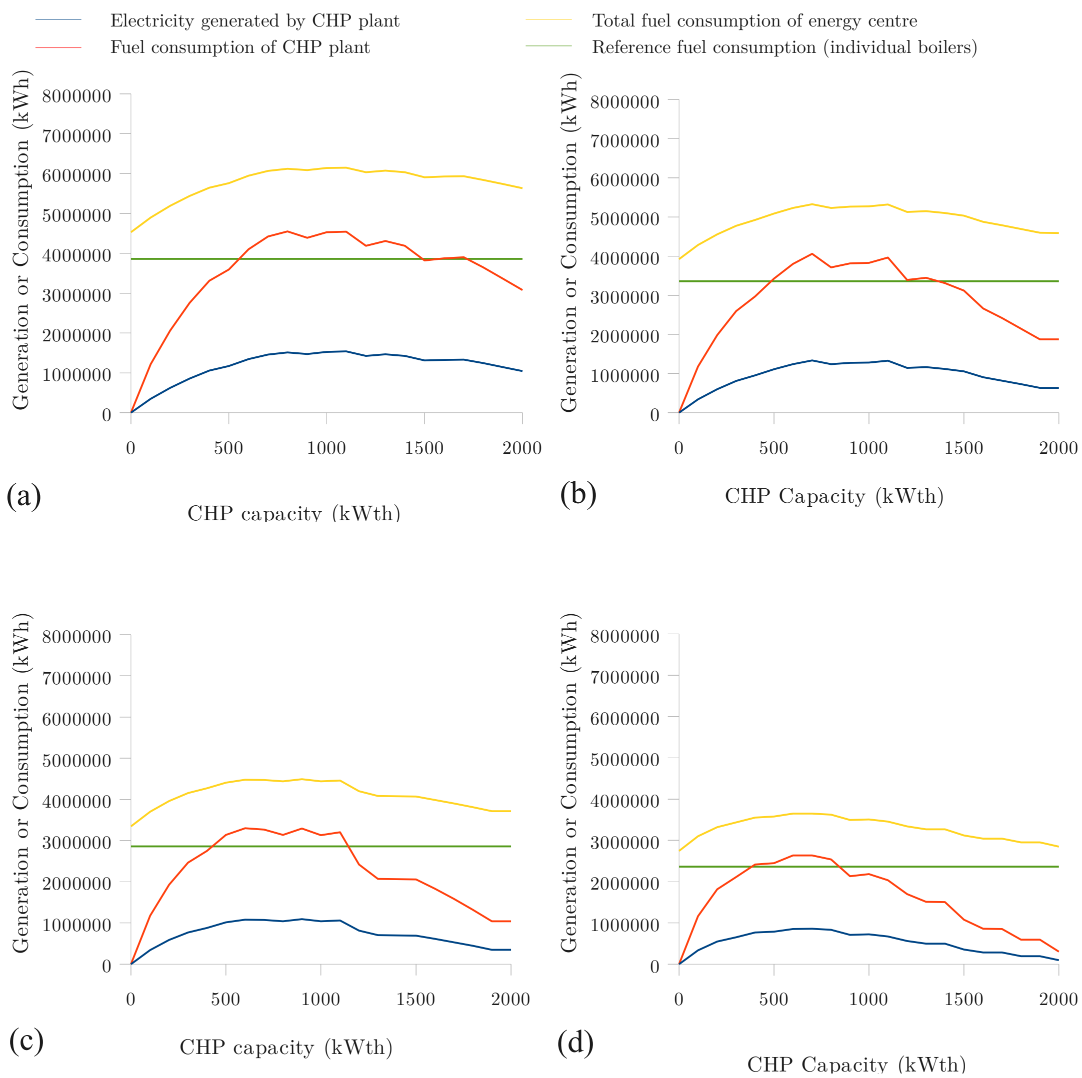


Figure 3.9: Variation of annual energy generation and consumption with combined heat and power plant size for the community co-generation option without storage: (a) Building Fabric Index = 0, (b) BFI = 0.2, (c) BFI = 0.4, (c) BFI = 0.6.

The net annual fuel consumption of the energy centre consists of the fuel consumed by the CHP unit and the fuel consumption of the back up heat only boiler. The community co-generation option with NG-CHP results in a significant increase of on site fuel consumption compared to the reference case with individual gas boilers, with a maximum value coinciding with maximum electricity production. At BFI = 0, the CHP-DH system with an 1100kW$_{th}$ ICE CHP unit consumed 6147MWh of natural gas per annum, a 59.3% increase relative to the reference case. Similar increases are observed at all values of BFI, with a 54.6% increase at BFI = 0.6.

The addition of a heat accumulator decouples the heat generation from the heat consumption allowing CHP operating strategies based upon electricity generation rather than heat generation. Fig 3.10 shows the result of modelling the generation schedule of a 500kW$_{th}$ CHP unit operating a daily heat accumulation cycle and with electricity generation focused at periods of peak electricity tariff.

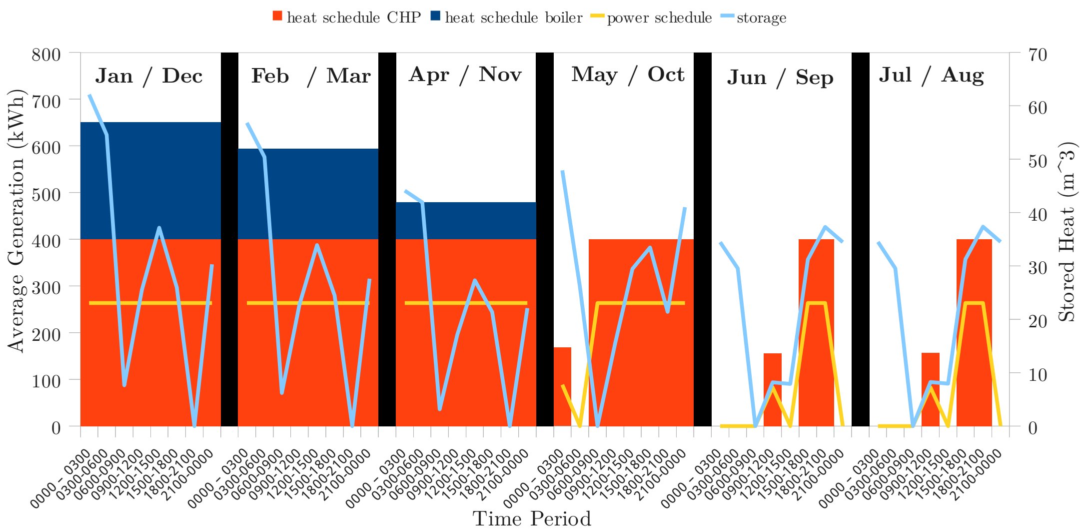


Figure 3.10: Heat generation profile and heat storage schedule for each representative day of the community co-generation option with a 500kW$_{th}$ Natural Gas Combined heat and Power plant and heat accumulator.

The effect of CHP plant size upon the annual electricity production and fuel consumption of the energy centre is shown by Fig 3.11. Increasing the plant capacity results in a corresponding increase of electrical output as the heat load served by the CHP unit is increased together with the plant efficiency. At 810kW$_{th}$, the CHP unit has sufficient capacity to supply the entire annual district heat demand. Any further plant size increase results in a much lower gain of electricity output corresponding efficiency increase only.

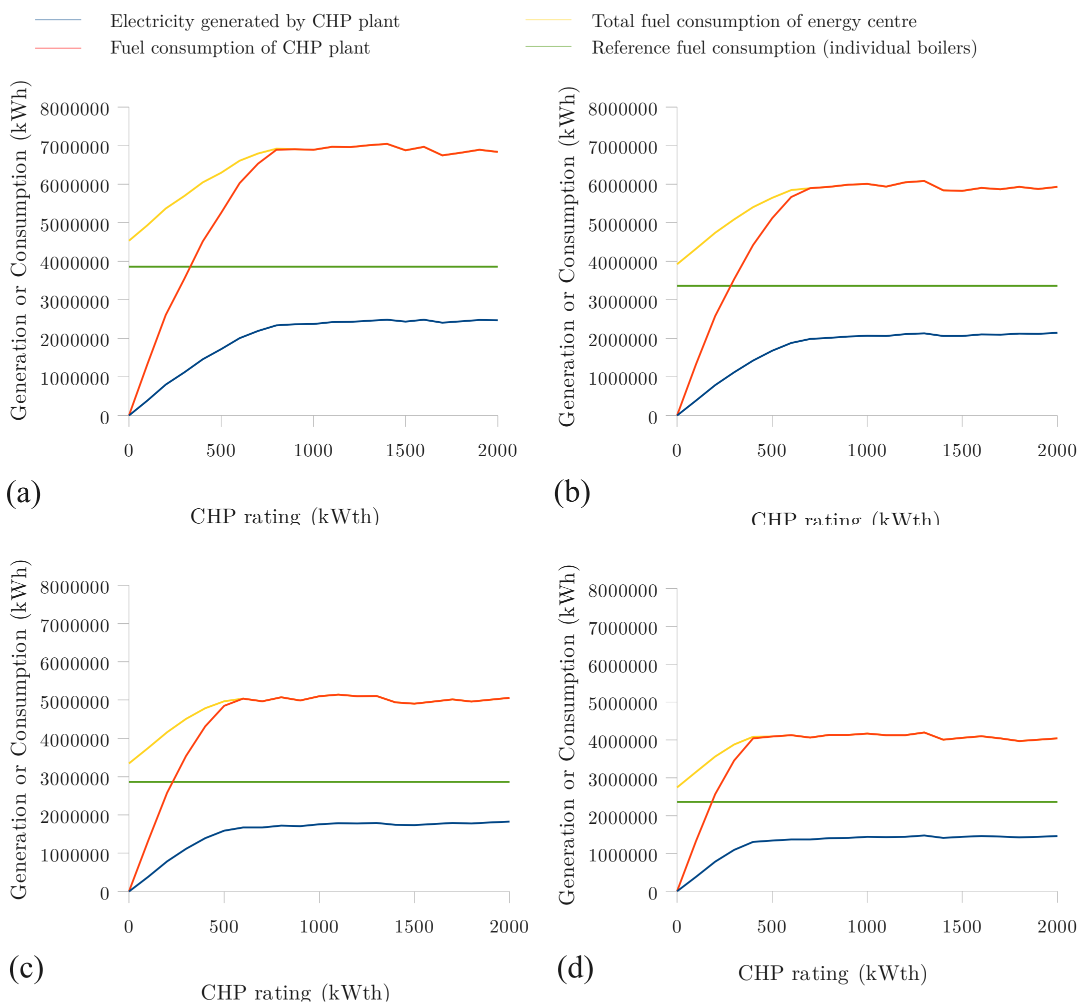


Figure 3.11: Variation of annual electricity production and fuel consumption with Combined heat and power plant size for the community co-generation option with heat storage. (a) Building Fabric Index = 0, (b) BFI = 0.2, (c) BFI = 0.4, (c) BFI = 0.6.

The increased electricity production results in a corresponding increase of total fuel consumption compared to the case without storage. At BFI = 0 and a CHP plant size of 1100kW$_{th}$ the total annual fuel consumption was 6,972MWh with the inclusion of a heat accumulator. This represents an 80.7% increase compared to the reference case.

The design and operational performance of the district heat network is dependent upon the operating temperature and allowable system pressure regime. An examination of the effect of these system parameters upon the design were not considered here. Fig 3.12 shows the distribution infrastructure that results for for a 90°C/ 50°C temperature regime and a maximum pressure differential of 0.6MPa.

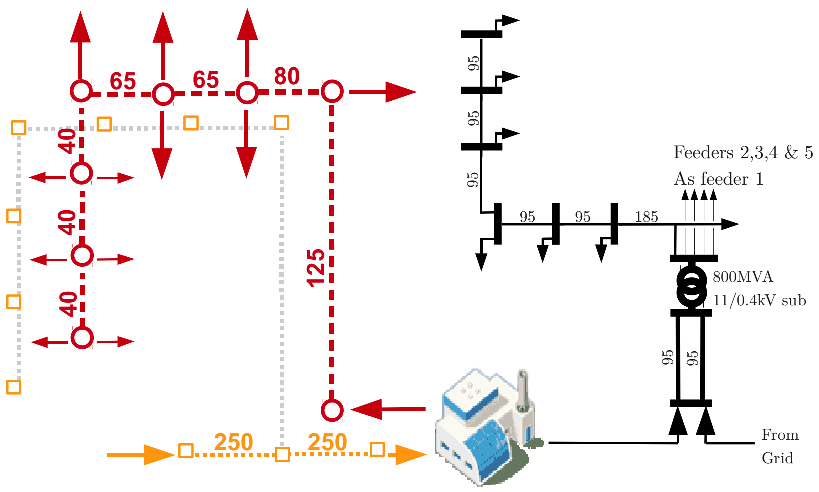


Figure 3.12: Schematic of the gas, district heat and electricity networks for the community co-generation option. (For Building Fabric Index = 0).

3.5 Conclusions

A modular design model was developed for multi-energy vector community distribution systems. This was used to determine the loads upon each network, the ratings of the required infrastructure and the annual energy balance of each network and generation plant. The model was successfully implemented using a spreadsheet user interface and a set of analysis add in functions implemented using Java.

The infrastructure design of a generic new build residential scheme was investigated. The model was shown to be capable of providing the design and performance of several infrastructure options based upon the extension of the existing natural gas infrastructure or the use of grid connected electricity:

Building fabric option: The effect of the building fabric index and gas source pressure upon the gas network design was examined. The capacity of photo voltaic panels installed per premise was shown to significantly effect network losses and the required network topology upon exceeding the peak electricity demand of each dwelling.

Electrification option: The use of heat pumps increased the number of transformers required for the development. Increasing the building fabric index decreased the required cable ratings and the number of feeders required per transformer. The total network losses were shown to be comparable to the reference case. This is attributable to the high peak heat demand which results in a low network load factor.

Community Co-generation option: The annual electricity production and fuel consumption for the combined heat and power unit is dependent upon the plant size and upon whether a heat storage unit was used. Without heat storage, the combined heat and power unit operates in heat led mode which restricts the electricity production and results in a maximum electricity production at 1100kW$_{th}$. The inclusion of heat storage decouples the heat production and heat demand and allows the plant to operate at rated output. At a building fabric index of 0, a combined heat and power unit of 810kW$_{th}$ generates 100% of the required on site heat demand.

Chapter 4

Carbon Emissions Analysis

4.1 Introduction

A carbon emissions analysis model was developed to evaluate the energy related greenhouse gas (GHG) emissions of new build infrastructure schemes. The scope of model was limited to greenhouse gas emissions resulting from fuel consumed within the site boundary and electricity supplied to the site from the grid. The model was used to determine the project life emissions for each option considered for the residential case study.

The structure of the GHG emissions model is shown by Figure 4.1. Three sources of emissions were considered: the electrical power supplied by the electricity grid; the fuel consumed within each individual building; and the fuel consumed by each generation plant within the energy centre. For the purpose of this thesis, the model was implemented as an OpenOffice Calc spreadsheet.

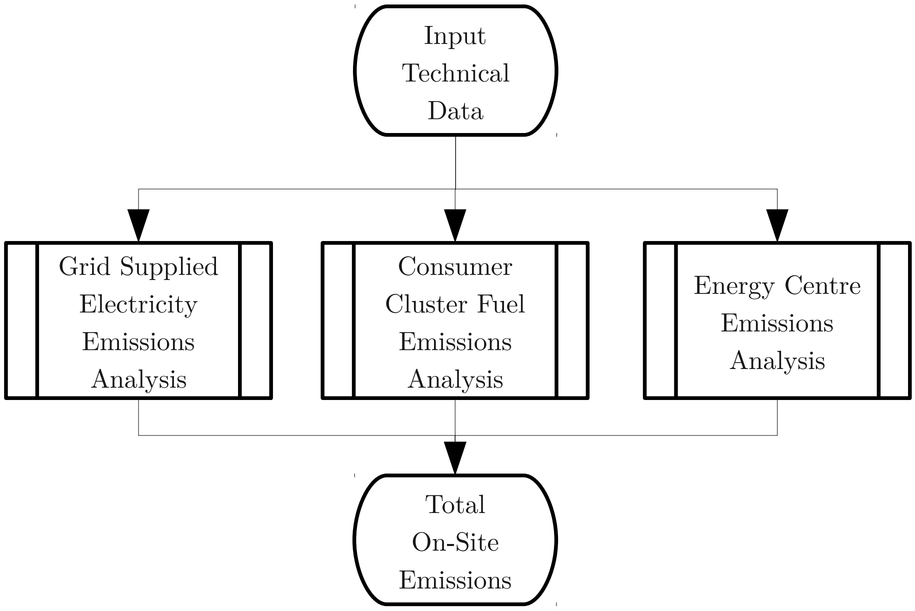


Figure 4.1: Structure of the carbon emissions analysis model.

4.2 Carbon Emissions Modelling

Initiatives such as *Zero Carbon Homes* aim to encourage low carbon infrastructure design by limiting the energy consumption related project life emissions. With the scope of such initiatives expected to widen and mandatory emissions reduction targets likely to increase over time in line with the decarbonisation strategy for the UK, the importance of conducting project life emission analysis within the project appraisal process is set to grow.

4.2.1 Grid Electricity Emissions: Literature Review

Several researchers have attempted to model the factors that govern the impact upon green house gas emissions due to small scale changes to the demand for grid supplied electricity (Hitchin and Pout 2002, Bettle et al 2006, Hawkes 2010). Each considers grid carbon emissions using the parameter referred to here as the *carbon emissions factor* (CEF). This defined the quantity of greenhouse gas emissions per unit of electricity as an equivalent mass of CO_2. The widely adopted approach is to consider two components of CEF referred to here as the *average* grid Carbon Emissions Factor (CEF_{Ave}) and the *marginal* Carbon Emissions Factor (CEF_{Margin}). CEF_{Ave} is used to evaluate the baseline emissions for the "business as usual" or do-nothing case. Any deviation from the baseline demand is determined by CEF_{Margin} (Hitchen and Pout 2002, Matsuo and Sato 2004, Levyveld 2010).

CEF_{Ave} is the average emissions intensity of the generation plant used to supply the grid over a specified period of time. The forecast of future CEF_{Ave} values is determined by the projected generation mix and is therefore subject to considerable uncertainty. The Department of Energy and Climate Change publish projections of annual CEF_{Ave}, currently to 2030 with ongoing yearly updates of the forecast generation mix (DECC 2011). Zheng and Li (2011) provide a methodology for deriving a projection of annual CEF_{Ave} to 2020 based upon forecasts of the decommissioning rates of existing plant and the build rates of new plant.

CEF_{Margin} is the average emissions intensity of plant used to increase or decrease generation in response to a change of demand. Hitchin and Pout (2002) consider the nature of CEF_{Margin} for England and Wales, identifying a distinction between the short term and long term effect of demand intervention. In the short term, CEF_{Margin} will result from the operation of existing plant that are committed or curtailed as part of the everyday operation of the grid. This is referred to as the *operational marginal* component of CEF_{Margin}. For long-term demand intervention a *build marginal* component of CEF_{Margin} was considered to account for the impact upon the choice and timing of building new generation capacity or upon the retirement rate of existing plant. This approach is recommended by the Clean Development Mechanism (CDM) Executive board of the UN Framework

Convention on Climate Change Committee (UNFCCC) for assessing projects within reporting schemes under the Kyoto protocol (Matsuo and Sato 2004). It is suggested that CEF_{Margin} is considered as a weighted average of the operational marginal and build marginal components for long term demand intervention (Eq. 4.1).

$$CEF_{Margin} = w_{OpMargin} CEF_{OpMargin} + w_{BldMargin} CEF_{BldMargin} \tag{4.1}$$

Several attempts have been made to model CEF_{Margin} projections for the UK. Bettle et al (2006) indicated that CEF_{Margin} may be up to 50% higher than CEF_{Ave}, but may be sensitive to the type of demand side intervention and also to any future changes to the electricity market structure. Hawkes (2011) provides a study that examines the daily and seasonal variation of CEF in addition to the that from year to year. For example, the average hourly CEF_{Margin} was found to vary from ~0.5kgCO_2/kWh to ~0.75kgCO_2/kWh. The study primarily focuses upon the operational marginal but also considers the build marginal citing the problem of predicting the influence of new plant upon future generation scheduling. A simplified approach was adopted by Levyveld (2010) for analysis of the proposed UK zero carbon homes initiative. This estimated CEF_{Margin} by assuming the operational and build marginals correspond to a single plant type at any given year within the projection. The operating marginal, for example, was assumed to be coal fired plant up to 2021. This however appears to be an overestimate compared to the other studies included herein.

It should be noted that none of the studies found in literature provide a conclusive treatment of the weighting that should be applied to the build and operational components of CEF_{Margin}. The CDM guidelines suggest a default weight of 1:1 but without justification. This weighting is also arbitrarily applied by Hitchen and Pout (2002), Bettle et al (2006) and Levyveld (2010).

4.2.2 Modelling of Grid Supplied Electricity Emissions

For consistency with methodologies described by the existing literature the following assumptions were applied in the emissions model:

1. The emissions factor of grid supplied electricity to the reference case was equal to CEF_{Ave}.

2. The emissions factor for any deviation from the reference case was equal to CEF_{Margin}.

3. A negative power flow at the site boundary was considered as power exported from the site to the grid.

The net annual emissions resulting from grid supplied electricity was therefore determined using:

$$\xi_{EGrid} = \sum_{1}^{Np} \sum_{1}^{Nd} \left(CEF_{Ave} (S_{import}^{(p,d)})_{reference} - CEF_{Margin} ((S_{import}^{(p,d)})_{reference} - S_{import}^{(p,d)}) \right) \tag{4.2}$$

Where S_{import} is the electrical power flow across the site grid connection point.

4.2.3 Consumer Cluster Fuel Emissions

The fuel consumption of each building resulted from the use of natural gas boilers, micro CHP and gas cookers. The total building emissions were given by:

$$\xi_{cluster} = \sum_{1}^{Np} \sum_{1}^{Nc} \epsilon_{NG} F_{NG}^{(c,p)} \tag{4.3}$$

Regulated emissions were defined as those resulting from the supply of space heating, space cooling, domestic hot water and lighting (HMGov 2008). The reduction of emissions for a development are usually defined as a percentage of regulated emissions for a reference case (ZCH 2011, WAG 2009a). For a reference case consisting individual natural gas boilers with grid supplied electricity the regulated emissions are given by:

$$\xi_{regulated} = \frac{365\,\tau}{N_d} \sum_{1}^{Np} \sum_{1}^{Nd} \sum_{1}^{Nc} N_c^{(c)} (\epsilon_{NG} (\Phi_{SH}^{(c,p,d)} + \Phi_{DHW}^{(c,p,d)}) + CEF_{Average} (\Phi_{SC}^{(c,p,d)} + S_{lighting}^{(c,p,d)}) \tag{4.4}$$

4.2.4 Energy Centre Emissions

The GHG emissions directly attributable to the energy centre were determined by the sum of the fuel emissions for each installed plant:

$$\xi_{EC} = \sum_{1}^{Np} \sum_{1}^{Nd} \sum_{1}^{Ng} \epsilon_{fuel}^{(g)} F_G^{(g,p,d)} \tag{4.5}$$

4.2.5 Net Emissions Reduction

The total on-site annual GHG emissions were determined by the sum of the energy centre emissions, cluster emissions and grid electricity emissions:

$$\xi_{total} = \xi_{EC} + \xi_{cluster} + \xi_{EGrid} \tag{4.6}$$

The net emissions reduction relative to the reference case was given by:

$$\xi_{reduction} = (\xi_{total})_{reference} - \xi_{total} \tag{4.7}$$

4.3 Example Study

The emissions model was applied to determine the annual and project life emissions for each option of the example scheme (Table 3.2). The model was also used to determine the capability of each option to meet the proposed emissions reduction target of the UK Zero Carbon Homes initiative. The emissions reduction hierarchy for the Zero Carbon Homes initiative is illustrated by Figure 4.2. This scheme targets the elimination of regulated emissions from all new domestic premises built from 2016, with the 2006 Part L building standard used as a benchmark. 70% of this target must be met using on-site measures which includes a minimum housing construction standard referred to as the Fabric Energy Efficiency (FEE) standard. The proposed FEE at the time of writing corresponds to a building fabric index $BFI_{FEE} = 0.3$ (ZCH 2009).

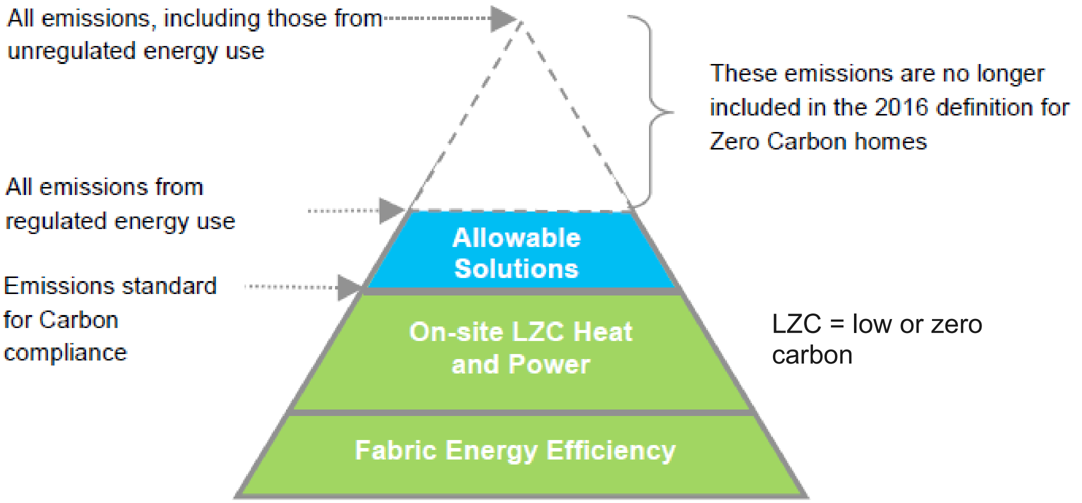


Figure 4.2: Emissions reduction hierarchy "pyramid" illustration for the zero carbon homes initiative [ZCH 2011].

4.3.1 Grid Electricity Emissions Modelling

The projection of grid supplied electricity emissions used to evaluate compliance with the zero carbon homes initiative were obtained from Levyveld (2010). This applied the IAG projection of CEF_{Ave} as shown by Fig. 4.3. A linear approximation of the projection was used with a constant a minimum of $CEF_{Ave} = 0.05kgCO_2e/kWh_e$ beyond 2039. Fig 4.4 shows the assumed projection of CEF_{Margin} together with its build marginal and operational marginal components. Coal fired plant were assumed to provide the operational marginal between 2011 and 2022 before switching to CCGT plant from 2023 to 2035. From 2035 a linear transition to coal fired carbon capture and storage (CCS) plant was assumed with the marginal at 2050 = $0.05kgCO_2e/kWh_e$. The build marginal between 2011 and 2025 was assumed to be new build CCGT with LNG natural gas. Beyond 2025 the build marginal was assumed to be a mix of low carbon plant including nuclear, large scale renewables and fossil fuel plant with carbon capture and storage. A 1:1 weighting between the build and operating marginal components was assumed.

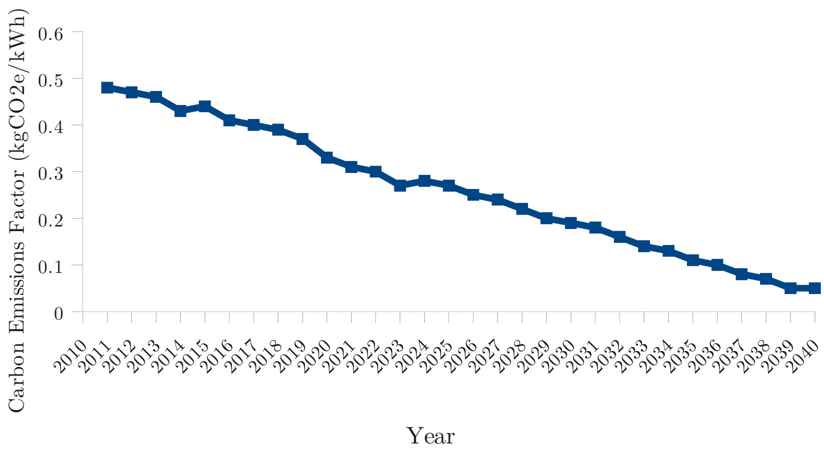


Figure 4.3: Projection of the average carbon emissions factor ($CEF_{Average}$) for grid supplied electricity in the UK (IAG 2011).

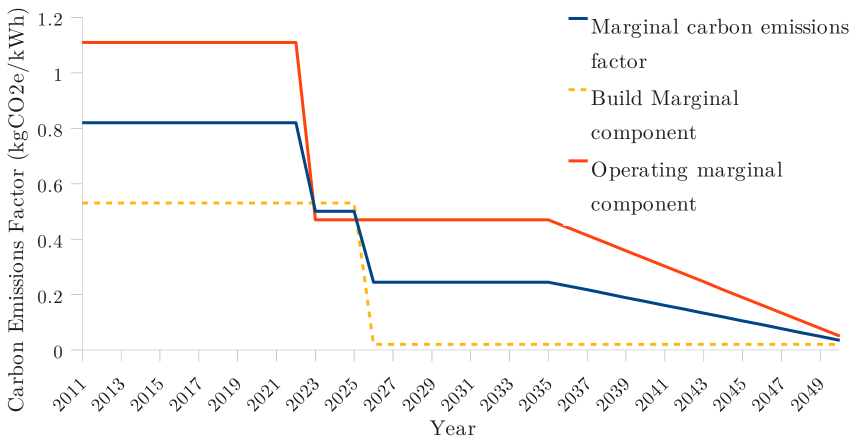


Figure 4.4: Marginal grid electricity carbon emissions factor projection applied within carbon emissions analysis model (Levyveld 2010)

4.3.2 Reference Case.

The reference case defined the benchmark project life GHG emissions for the zero carbon homes target. The variation of total and regulated emissions with CEF_{Ave} is shown by Fig 4.5.

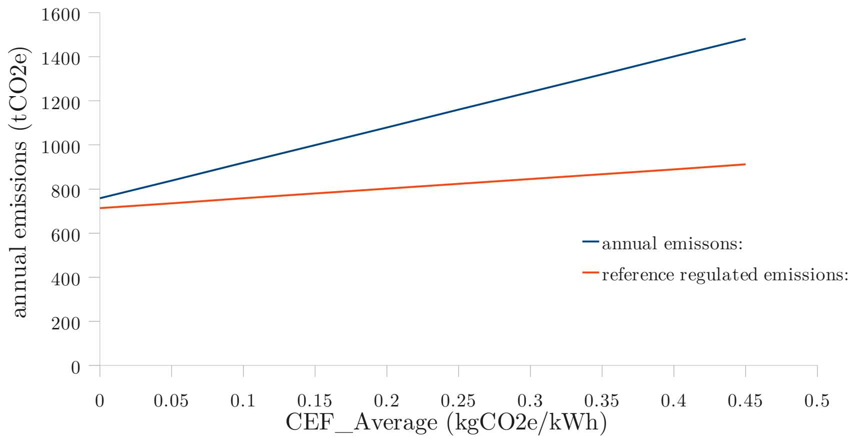


Figure 4.5: Total and regulated on site emissions for the reference option.

Fig 4.6a shows the annual total emissions for the reference case and zero carbon homes target. Each trajectory is governed by the projection of CEF_{Ave}. The variation of 20 year project life emissions against build completion date is shown by Fig 4.6b. The zero carbon homes target is shown to decrease against build completion year but increase as a percentage of total emissions.

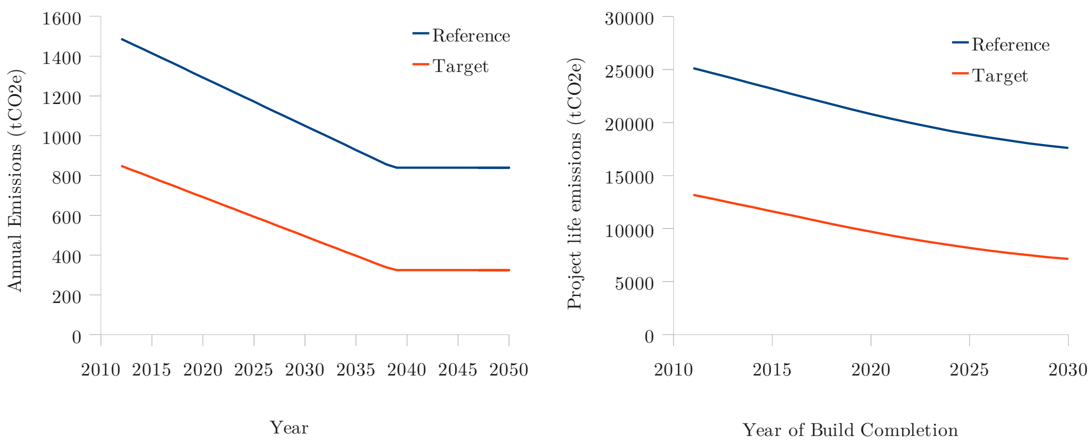


Figure 4.6: (a) Annual and (b) Project Life of the reference reference option and Zero Carbon Homes emissions target.

4.3.3 Building Fabric Option

Increasing the building fabric index to reduce the space heat demand will correspondingly decrease the building emissions. The extent of the reduction depends upon the type of heat supply technology used in each dwelling. For the reference case with domestic gas boilers installed at all premises the emissions reduction is proportional to the carbon intensity of natural gas and independent of grid electricity carbon intensity. This is illustrated by Fig 4.7 which shows a constant reduction over time for various values of BFI.

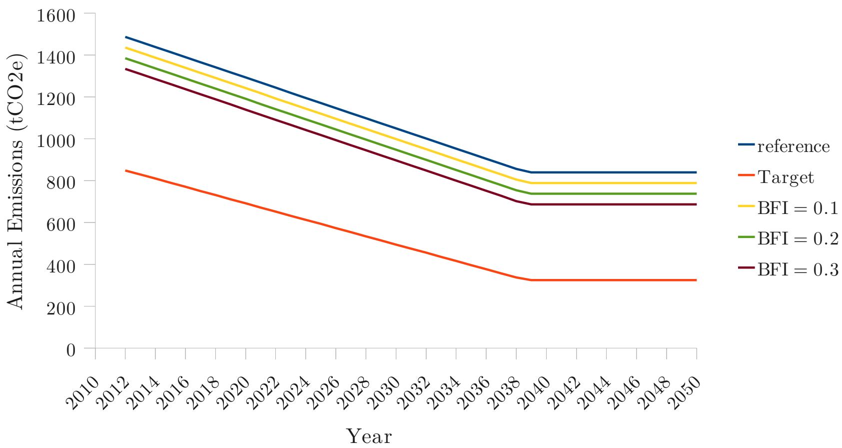


Figure 4.7: Effect over time of Building Fabric Index upon annual on-site emissions.

The effect of using photovoltaics to reduce on site emissions is illustrated by Fig. 4.8. The addition of PV results in a decreased consumption of grid supplied electricity relative to the reference case without PV. The corresponding change to the annual on site carbon emissions is therefore determined by the marginal carbon emissions factor of grid supplied electricity given by Fig. 4.4. A given capacity of PV thus results in a constant emissions reduction until 2023 at which point a step decrease of CEF_{Margin} occurs from 0.82kgCO_2e/kWh$_e$ to 0.5kgCO_2e/kWh$_e$. This results in a corresponding step decrease of the emissions reduction obtained relative to the reference case. A Further step change is observed as CEF_{Margin} decreases from

$0.5kgCO_2e/kWh_e$ to $0.25kgCO_2e/kWh_e$ in 2026. The accumulative effect is that the emissions reduction obtained from PV or any similar micro renewable generation technology diminishes over time. This is shown by Fig. 4.8b.

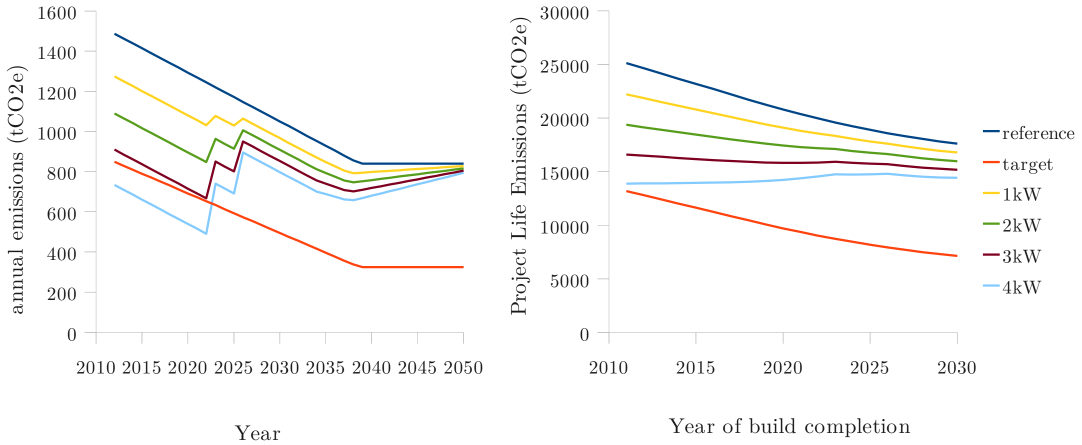


Figure 4.8: Effect of installed Photo Voltaic capacity per dwelling upon (a) annual emissions and (b) project life emissions for the building fabric option.

The effect of the decreased emissions reduction with CEF_{Margin} when using PV is shown by Fig 4.9. This shows that the capacity of PV required to meet the zero carbon target with increases with year of build completion. The maximum capacity of PV per dwelling is constrained by the total area of roof space directly exposed to the sun (for the UK, this corresponds to the roof space facing the arc of direction from south east to south west). It was assumed that an equal proportion of houses face each direction so that 25% of the available roof space was deemed suitable for PV. For the market town property mix, the average available roof space is $19.4m^2$/dwelling which corresponds to a maximum generation capacity of 2.7kW/dwelling. For new build dwellings built beyond 2017/2018 the range of allowable BFI values for adherence to the zero carbon homes target is therefore restricted. Projects starting 2022, for example, require an average BFI value greater than 0.4 to meet the zero carbon homes target when using gas boilers with PV.

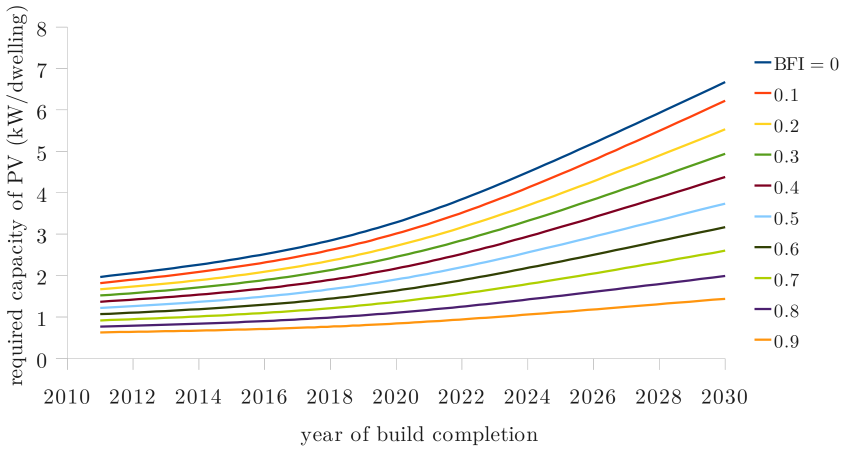


Figure 4.9: Installed capacity of Photo Voltaic panels required per dwelling to meet the zero carbon homes target for the building fabric option.

4.3.4 Electrification of heat.

Heat pumps increase the electricity demand relative to the reference case by shifting the burden of domestic heating to the electricity network. The increase of emissions is therefore governed by the emissions intensity of the marginal centralised generation plant, CEF_{Margin}. The extent of the emissions change depends upon the heat pump CoP and the emissions factor of the reference fuel. Fig. 4.10 shows the modelled emissions intensity of the heat pumps per unit heat generation for a range of typical CoP values.

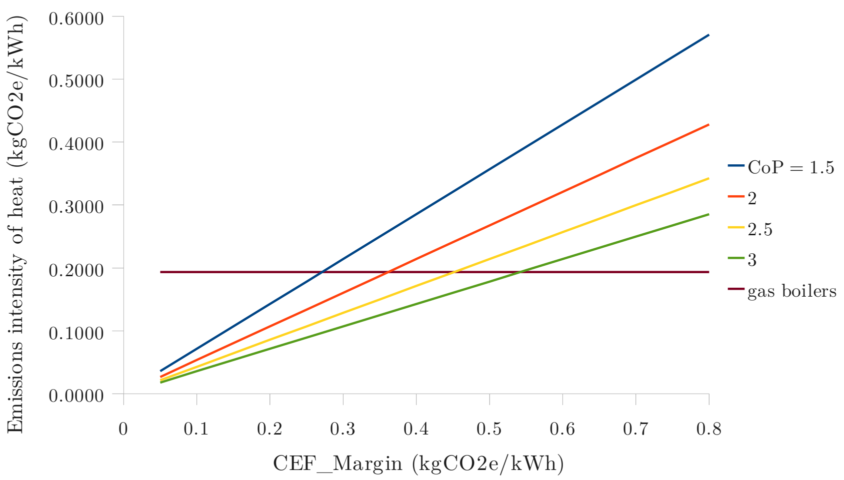


Figure 4.10: Green house gas emissions factor for heat delivered using heat pumps heat against marginal emissions factor of grid supplied electricity.

The average CoP for the electrification option varied from 2.75 during winter to 3.0 during the summer months. On site emissions savings are therefore obtained by using heat pumps instead of gas boilers at CEF_{Margin} values below ~0.45kgCO_2e/kWh$_e$. The effect upon the example scheme emissions is shown by Fig 4.11a for BFI = 0 and assuming a central heating temperature = 55°C. The annual on-site emissions exceed those of reference case prior to 2025 with CEF_{Margin} > 0.5kgCO_2e/kWh$_e$. Emissions savings are only observed beyond 2025 with CEF_{Margin} dropping to 0.25kgCO_2e/kWh$_e$.

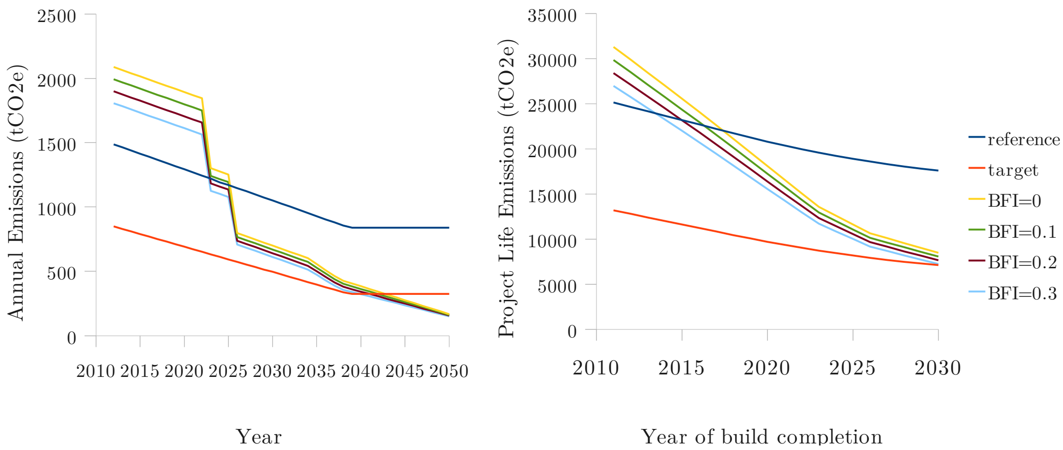


Figure 4.11: (a) annual emissions and (b) 20 year project life emissions for the electrification option.

Fig 4.11b describes the variation of project life emissions against year of build completion. At BFI = 0, the project life emissions for the electrification option exceeds the reference case for projects completed prior to 2017 . This is brought forward to 2013 when BFI is increased to 0.3. By 2030, the electrification option achieves zero carbon homes emissions target using heat pumps without PV capacity when BFI > 0.6. The effect upon the required capacity of PV is shown by Fig. 4.12.

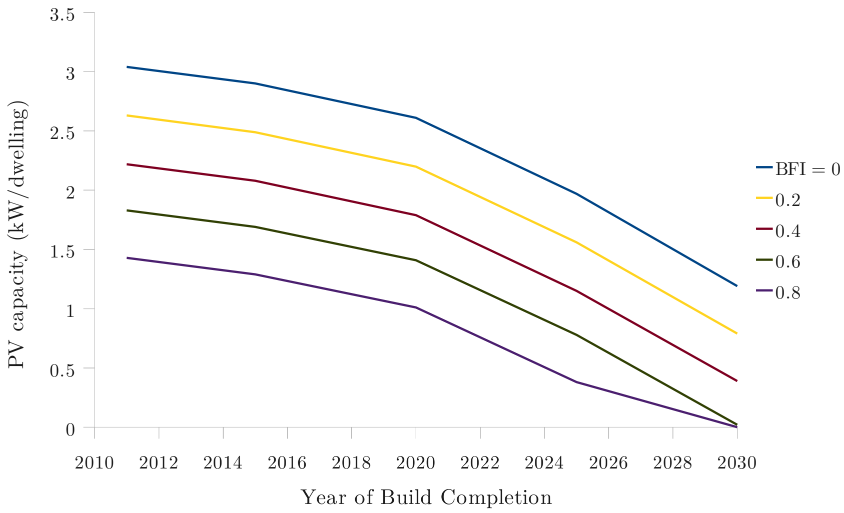


Figure 4.12: Installed capacity of Photovoltaic panels required to meet zero carbon homes emissions target for the electrification option.

4.3.5 Community Co-generation

The effect of CHP plant size upon energy centre fuel consumption and electricity production was examined in chapter 3. The change of on-site emissions relative to the reference case is dependent upon the emissions intensity of each fuel used and the avoided grid supplied electricity emissions determined by CEF_{Margin}. Figure 4.13 describes the effect of CHP plant size upon annual on-site emissions relative to the reference case for the community cogeneration option without storage. For $CEF_{Margin} > 0.5kgCO_2e/kWh_e$, the emissions reduction from the avoided grid supplied electricity exceeds the additional emissions from fuel consumption at plant sizes greater than $100kW_{th}$. At $0.25kgCO_2e/kWh_e$ and below, the displaced grid electricity emissions are exceeded by the additional fuel and the community cogeneration option becomes a net contributor to emissions relative to the reference case.

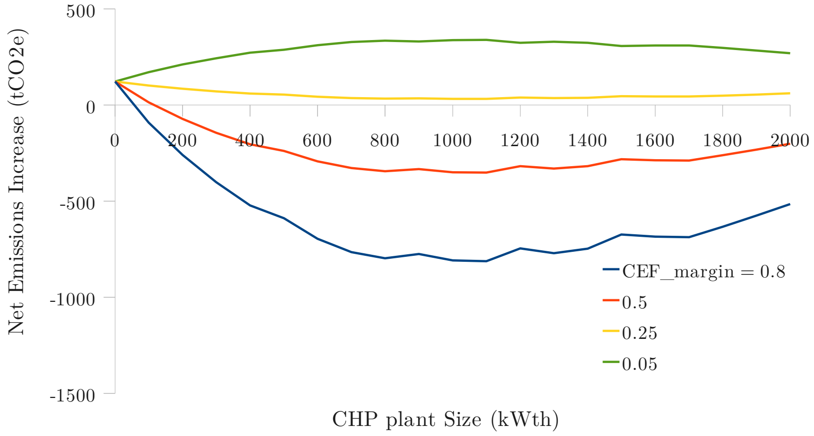


Figure 4.13: Variation of the net annual emissions increase against combined heat and power plant size for the community cogeneration option, no heat storage.

The effect of introducing heat storage to the energy centre is shown by Fig. 4.14. The increased electricity production results in an decrease of emissions compared to the case without storage when $CEF_{Margin} > 0.25kgCO_2e/kWh$. Figure 4.15 shows that the minimum CEF_{Margin} at which emissions savings are observed is reduced with the use of heat storage. At $1100kW_{th}$, for example, the addition of storage decreases the minimum CEF_{Margin} required for emissions savings from $0.27kgCO_2e/kWh_e$ to $0.23kgCO_2e/kWh_e$.

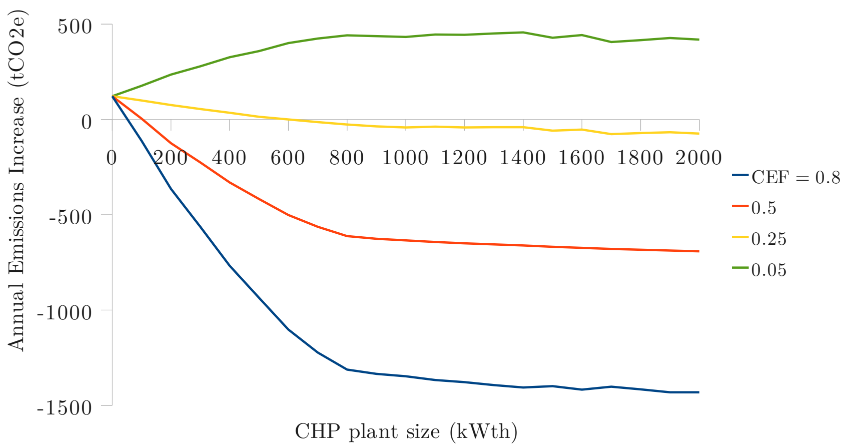


Figure 4.14: Variation of the net annual emissions increase against combined heat and power plant size for the community cogeneration option with heat storage.

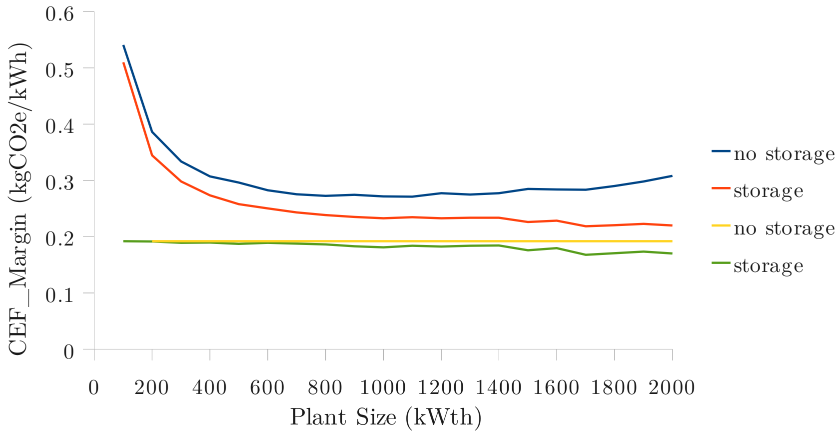


Figure 4.15: Variation of minimum CEF_{Margin} required to provide emissions savings against combined heat and power plant size for community generation option.

Figure 4.16 compares the annual and project life emissions for the community co-generation option (at BFI = 0) using a 1100kW_{th} CHP plant both without and without heat storage. Fig. 4.16a shows that the bulk of emissions savings occur during the period at which coal fired plant and CCGT are assumed as the operational and build marginal respectively. This suggests a window of opportunity to deliver zero carbon homes targets using natural gas CHP. Natural gas-CHP is however unsuitable as a long term solution as the marginal plant transition to renewable generation technologies.

Figure 4.16b illustrates the period and extent to which natural gas CHP may be applied to deliver a reduction of emissions. Without storage, a net emissions reduction is achieved until 2023. A build completion beyond this point will deliver a net increase of emissions relative to the reference case. The use of heat storage has a significant effect upon the shortfall against 20 year target and results in a period (to 2017) for which no supplementary capacity of PV is required to meet the zero carbon homes target. The effect upon the year at which NG-CHP results in a net contribution of emissions is limited however, with a delay of 1 year to 2024.

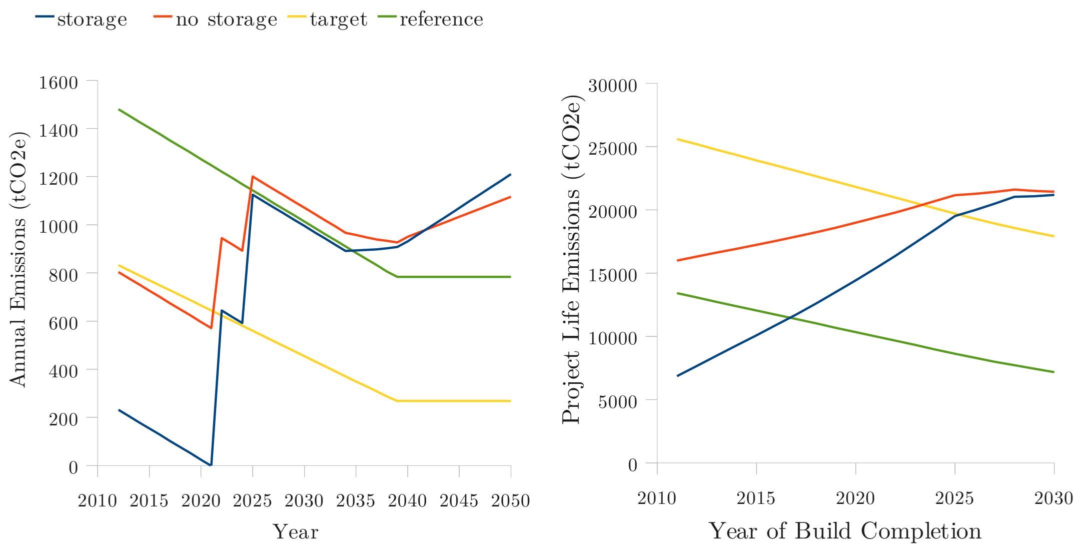


Figure 4.16: (a) Annual emissions and (b) project life emissions for the community co-generation option with a 1100kW$_{th}$ combined heat and power plant. (Building Fabric Index = 0).

Fig. 4.17 shows the PV capacity required to deliver the zero carbon homes target. The restriction of PV capacity to 2.7kW/dwelling constrains the period for which NG-CHP can be applied for any given BFI.

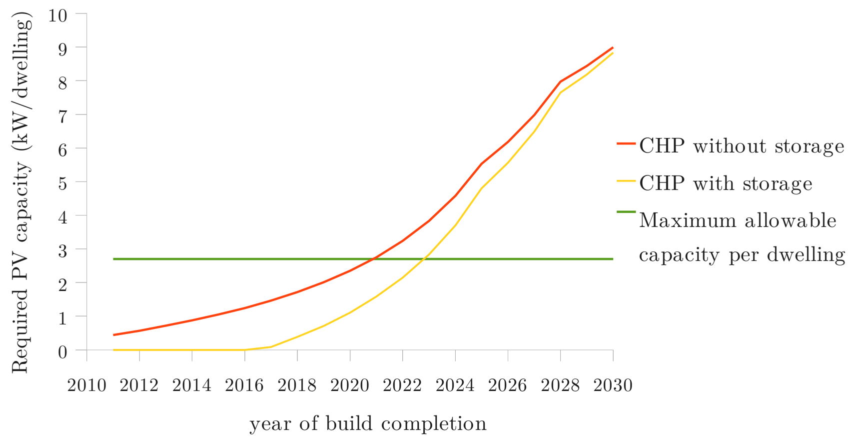


Figure 4.17: Installed capacity of Photovoltaic panels required to deliver the zero carbon homes emossions target for the community co-generation option with an 1100kW$_{th}$ combined heat andd power plant. (Building fabric Index = 0).

4.4 Conclusions

The carbon emissions analysis model was developed to evaluate the green house gas emissions resulting from on site energy usage. This determined the annual and project life emissions for the on site fuel consumption, on site electricity generation and grid supplied electricity for a community development scheme. The model was used to evaluate the emissions reduction obtained for each option within the example residential case study. This included an examination of the capability to meet the 70% target reduction of regulated emissions stipulated by the zero carbon homes initiative.

Building fabric option: Improving the building insulation standard results in a constant reduction of carbon emissions when using gas boilers as the space heating technology. The effectiveness of PV to reduce carbon emissions decreases proportionally with $\mathrm{CEF}_{\mathrm{Margin}}$. This resulted in a increase of required PV capacity for a given shortfall against the specified target.

Electrification option: When using heat pumps the total energy demand for each dwelling was proportional to the grid carbon emissions factor. The emissions reduction relative to the gas boilers reference case was proportional to CEF_{Margin}. An emissions reduction was observed at CEF_{Margin} $<0.25kgCo_2e/kWh$ at which the additional emissions from grid supplied electricity exceeds that of the natural gas displaced. At CEF_{Margin} $>0.5kgCO_2e/kWh$, a net contribution to emissions was observed relative to the gas boilers reference. Project life emissions were shown to be significantly sensitive to the year of build completion. For a building fabric index off 0.3, the electrification option transitions from providing a net emissions contribution in 2013 to meeting the 70% target without supplementary PV in 2028.

Community generation option: The emissions reduction achieved from the use of natural gas CHP- district heating results from the balance between the additional fuel consumed and the emissions factor of the avoided grid electricity supply. The net annual emissions reduction decreases over time with natural gas CHP eventually acting as a net contributor to on site emissions. The addition of storage can significantly increase the emissions reduction performance at high values of CEF_{Margin} by increasing the quantity of electricity produced per unit of heat production. The diminishing performance of CHP-DH over time results in a correspondingly increasing PV capacity required to deliver the on site target.

Chapter 5

Financial Analysis for Community Energy Infrastructure

5.1 Introduction

A financial analysis model was developed for new build energy distribution infrastructure. A simplified organisational structure of an energy services company for the ownership and operation of the district heating scheme and energy centre was considered. The financial model was implemented as a spreadsheet using OpenOffice Calc and was used to determine the build premium for each option considered within the residential new build example study.

5.2 Energy Services Companies

An Energy Services Company (ESCo) is an entity created specifically for activities or services relating to energy provision. These may be public or privately owned and may take one of several forms including a cooperative, an industrial society, a trust or an incorporated body (LEP 2007). Local area energy schemes can be subject to significant investment risk and operational learning curves. The BedZed development is one example where the lack of an ESCo has been cited as a hindrance to the successful operation of the community energy system(UtilityWeek 2007). A review by Kelly and Pollit (2010) observes that ESCo's are now set up in almost all public – private partnerships for energy energy infrastructure developments. One example is the Thamesway development by Woking borough council for which a joint public / private ESCo was set up in 1999 for the operation and management of a private wire electricity network and a district heating scheme(see Fig. 5.1).

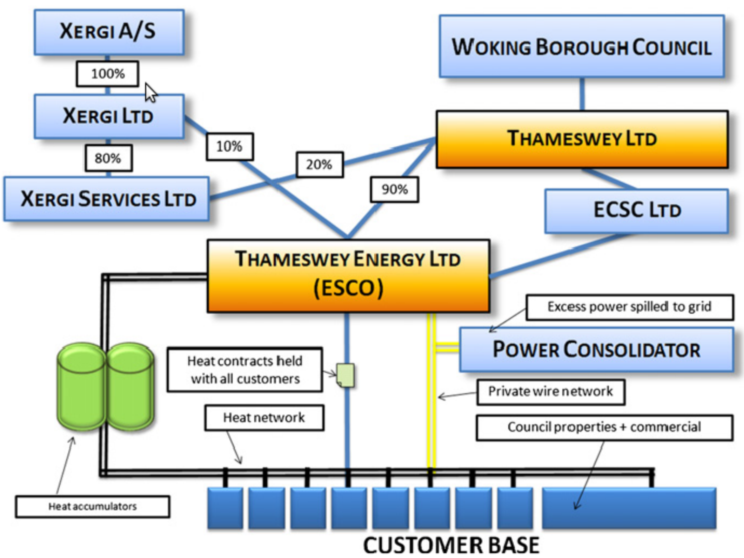


Figure 5.1: Structure of the joint public-private energy services company for the Woking Borough private wire and districct heating scheme (Kelly and Pollit 2010).

The level of public or private sector investment desired for an ESCo will depend upon the objectives and priorities of each specific project. Public ESCo's are not bound to profit and may have access to lower interest rates, but may also have less direct access to capital and expertise (EACOM 2009). Examples of successfully implemented public sector led ESCo`s include the 1000 dwelling CHP-DH scheme with a not for profit ESCo in Aberdeen and the Southwark Council ESCo responsible for a number of community heating schemes in its borough (PAS 2009). Private ESCo ownership on the other hand has the advantage of transferred risk and access to private capital but at the expense of a loss of project and strategic control. The Southampton District Energy Scheme is an example of a private sector led ESCo with a profit share allocated to the city council.

5.3 Financial Analysis Model

The organisational structure used to illustrate the financial analysis of new build energy distribution infrastructure is shown by Fig. 5.2.

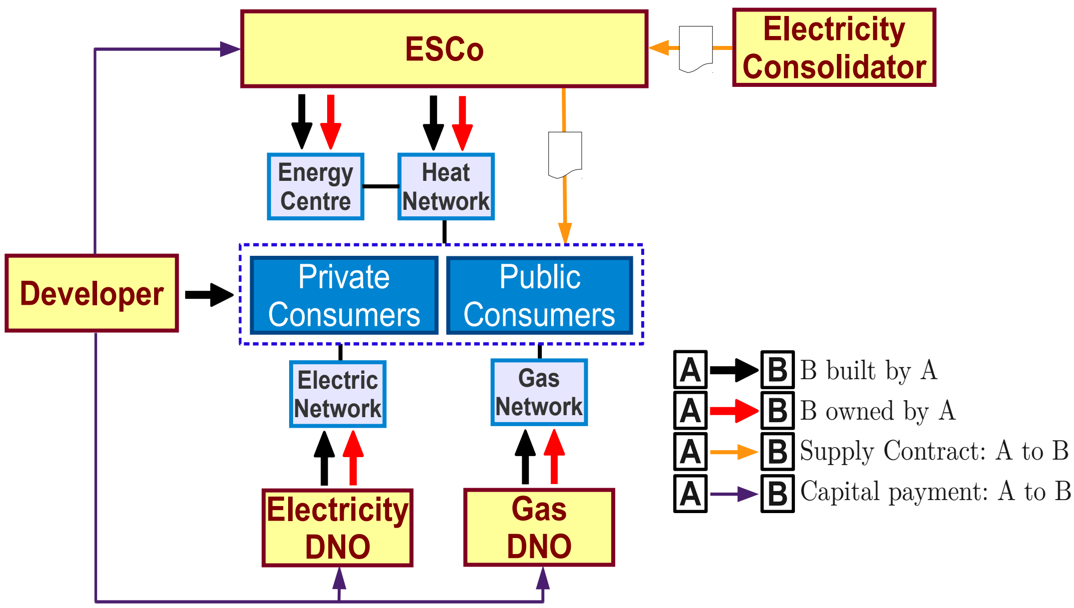


Figure 5.2: Structure of the asset ownership and financial model applied to the example study.

The model applied the following simplifying assumptions:

- The district heating network, energy centre and all dwellings were constructed by a single actor referred to as the *Developer*.

- An *Energy Services Company* (or ESCo) was formed to own, manage and operate the energy centre and district heat network.

- Building level supply technologies were assumed to be property of the house owner.

- The electricity and gas distribution networks were constructed and owned by the DNO. All of the associated capital expenditure was passed to the developer.

- All infrastructure was laid and installed within utility service trenches prepared by the developer. Street works and excavation costs were therefore ignored.

5.3.1 Gas and Electricity Network Capex

The cost passed from the DNO to the developer for a new build scheme depends upon: the revenue received from use of system charges; the extent and complexity of any specialist engineering and construction works; the extent of any reinforcement to the existing infrastructure; and the charging policy of any contractors responsible for any contestable works. The total cost can therefore vary considerably from one similar project to the next.

For clarity, the model was limited to the installed cost of the on-site infrastructure and the apportioned cost of the local 33/11kV primary substation. The electricity network capex was defined by:

$$C_{ElecNET} = \sum_{1}^{Nj} (c_j L_j + c_{SS,j}) + C_{PrimSub} \tag{5.1}$$

The length of cluster LV branches and sub branches defined using:

$$\begin{aligned} &if\ j = LVbranch, && L_j = N^{(c)}_{Feeder} N^{(c)}_{Trans} L^{(c)}_{LVbranch,j} \\ &if\ j = LVsubBranch, && L_j = 6\, N^{(c)}_{Feeder} N^{(c)}_{Trans} L^{(c)}_{LVsubBranch,j} \end{aligned} \tag{5.2}$$

Similarly for the gas network:

$$C_{GasNET} = \sum c_l L_l + c_{PRI,l} + \sum_{1}^{N_c} N^{(c)}_{Bld} (10\, c^{(c)}_{GasServ} + c^{(c)}_{GasMet}) \tag{5.3}$$

With cluster branch lengths defined by

$$\begin{aligned} &if\ L = GasBranch, && L_l = 2\, L^{(c)}_{GasBranch,l} \\ &if\ L = GasSubBranch, && L_l = 12\, L^{(c)}_{GasSubBranch,l} \end{aligned} \tag{5.4}$$

5.3.2 Building Capex

The building capex was composed of the cost of the building fabric, the cost of each individual heating installation and the cost of the installed capacity of PV. The building fabric premium is the additional cost of insulation required to achieve a given value of BFI. For the example scheme, this was defined using the 2006 Part L building standard as the reference. The zero carbon hub provides indicative costs for various levels of building improvements for a range of domestic dwelling types (ZCH 2009b). These were used to define an empirical relationship between BFI and fabric premium (Fig. 5.3):

$$\begin{aligned} &c^{(c)}_{BFI} = 9110.72\,(BFI^{(c)})^{1.55} + 6496(BFI^{(c)})^{3.02} \\ &C^{(c)}_{BFI} = \sum_{1}^{Nc} N^{(c)}_{Bld}\, c^{(c)}_{BFI} \end{aligned} \tag{5.5}$$

A similar treatment was not conducted for non residential clusters due to the lack of a suitable data set.

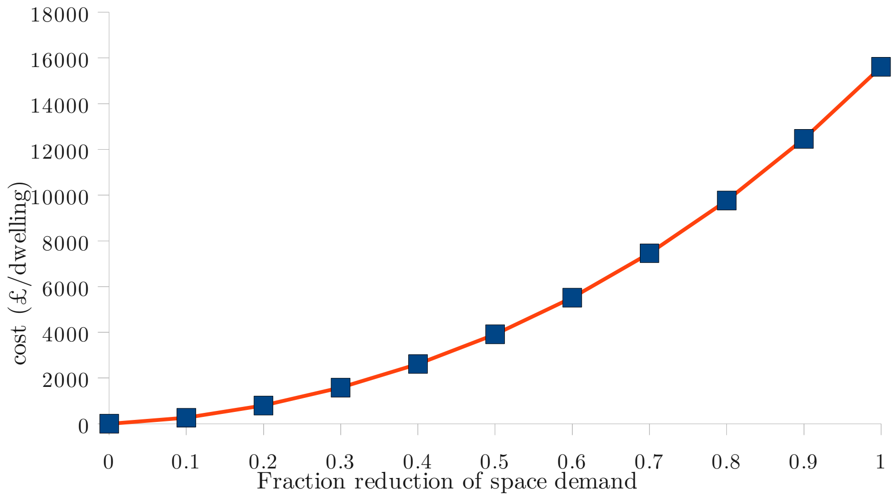


Figure 5.3: Plot of average build premium per dwelling against Building Fabric Index for a market town residential mix (ZCH 2009b).

The cost of the building level heating technologies was given by:

$$C_{HTech} = \sum_{1}^{Nc} N_{Bld}^{(c)} \left(f_{GSHP}^{(c)} c_{GSHP}^{(c)} + f_{ASHP}^{(c)} c_{ASHP}^{(c)} + f_{GCH}^{(c)} c_{GCH}^{(c)} \right) \tag{5.6}$$

The cost of the PV capacity installed within each premise was given by:

$$C_{PV} = c_{PV} \sum_{1}^{Nc} N_{Bld}^{(c)} A_{PV}^{(c)} \tag{5.7}$$

The total building capital expenditure is therefore given by:

$$C_{Build} = C_{BFI} + C_{HTech} + C_{PV} \tag{5.8}$$

5.3.3 Energy Services Company

The ESCo capital expenditure consists of the cost of the energy centre generation plant and the installed cost of the district heat network :

$$C_{Plant}^{(g)} = \sum c_{Plant}^{(g)} \Phi_{Rated}^{(g)} \tag{5.9}$$

$$C_{DHN} = 2\sum_{1}^{Nn} c_n L_n + \sum_{1}^{Nc} N_{Bld}^{(c)} (20\, c_{DHNserv}^{(c)} + c_{DHNmet}^{(c)}) \tag{5.10}$$

The energy centre operational expenditure consists of the cost of fuel consumed and the cost of running and maintaining each generation unit. The fuel cost includes a Climate Change Levy (CCL) is a tax payable for specific energy products such as fuels used for lighting, heating and power (HMRC 2011). Fuel used for CHP may qualify for CCL exemption if classified as *good quality CHP* under the CHP quality assurance scheme (Defra 2007). The total expenditure is given by:

$$C_{ESexp} = C_{ESopex} + \sum_{1}^{Np} \sum_{1}^{Ng} F_G^{(g,p)} (c_{Fuel}^{(g)} + c_{CCL}^{(g)}) \tag{5.11}$$

The electricity revenue generated by the energy centre was given by:

$$C_{ECelec} = \sum_{1}^{Np} \sum_{1}^{Ng} (c_{Power}^{(g,p)} S_G^{(g,p)}) \tag{5.12}$$

The heat revenue was calculated using:

$$C_{Heat} = \sum_{1}^{Np} \sum_{1}^{Nc} (c_{Heat} \Phi_{DHdem}^{(c,p)}) \tag{5.13}$$

The total ESCo capex was considered as an annualised expenditure:

$$C_{AnnESCo} = \frac{(1+DR_{ESCo})(C_{ESCo})}{1-(1+DR_{ESCo})^{-N_{Project}}} \tag{5.14}$$

Where DR is the annual discount rate applied to the scheme. The maximum annualised ESCo capex, $C_{AnnESCo}$, was calculated based upon the assumption that the annual income was equal to the annual expenditure:

$$C_{AnnESCo}+C_{ESexp}-C_{ECelec}-C_{Heat}=0 \tag{5.15}$$

The total ESCo capex was therefore determined by:

$$C_{ESCo}=(C_{ECelec}+C_{Heat}+C_{ESexp})\frac{1-(1+DR_{ESCo})^{-N_{Project}}}{DR_{ESCo}} \tag{5.16}$$

It was assumed that any surplus capital expenditure was passed to the developer as a contribution C_{DHNdev} to the build premium given by:

$$C_{DHNdev}=C_{Plant}+C_{DHN}-C_{ESCo} \tag{5.17}$$

5.3.4 Infrastructure Build Premium

The financial viability of the energy distribution infrastructure option was considered in terms of the overall build premium which the cost relative to that of a chosen reference case. This overall infrastructure cost was determined using:

$$C_{Infr}=C_{Build}+C_{ElecNET}+C_{GasNET}+C_{DHNdev} \tag{5.18}$$

The build premium was therefore defined as:

$$C_{Premium}=C_{Infr}-(C_{Infr})_{Ref} \tag{5.19}$$

For residential developments, it is more useful to consider the infrastructure cost in terms of build premium per dwelling:

$$C_{Premium}=\frac{C_{Infr}-(C_{Infr})_{Ref}}{\sum N_{Bld}^{(c)}} \tag{5.20}$$

5.4 Example Scheme Analysis

The financial model was used to determine the build premium for meeting the zero carbon homes emissions target of each example scheme option. The energy price assumptions are shown by table 5.1. The cost data applied for the evaluation of infrastructure capex is provided by Appendix 2.

Electricity domestic retail price	12.9p/kWh (DECC 2009)
Electricity commercial retail price	11.46p/kWh (DECC 2009)
Electricity wholesale price	5p/kWh (APX Power 2011)
Electricity export price	4p/kWh (assumed ~ 80% of wholesale)
Electricity climate change levy	0.485p/kWh (HMRC 2011)
Gas domestic retail	3.74p/kWh (DECC 2010)
Gas commercial retail price	3.32p/kWh(DECC 2010)
Gas Industrial price (<1,500 MWh/annum)	2.79p/kWh (DECC 2011)
Gas Industrial price (>1,500 MWh/annum)	2.24p/kWh (DECC 2011)
Gas climate change levy	0.169p/kWh (HMRC 2011)

Table 5.1: Price and cost assumptions for financial model

5.4.1 Reference Case

The cost breakdown for the reference case is shown by Table. 4.2. This defines the benchmark used to calculating the build premium of each infrastructure option.

Electricity Network	£746,295
Gas Network	£351,556
Gas Boilers	£1,250,000
Building fabric cost	£0 (benchmark)
Total	£2,347,851

Table 5.2: Breakdown of infrastructure costs for the reference case

5.4.2 Building Fabric Option

The trade-off between BFI and the capacity of PV required to obtain the zero carbon homes emissions reduction target was examined in chapter 4. Fig. 5.4 shows the resulting cost of the gas and electricity networks. At a build completion year of 2012, the PV capacity has little impact upon the electricity infrastructure design and cost. Due to the decreasing reduction of emissions obtained by PV, the infrastructure cost increases with build completion year for a given BFI. By 2025 for example, the additional electricity network premium is £422 per dwelling at BFI = 0 and £194 per dwelling at BFI = 0.3.

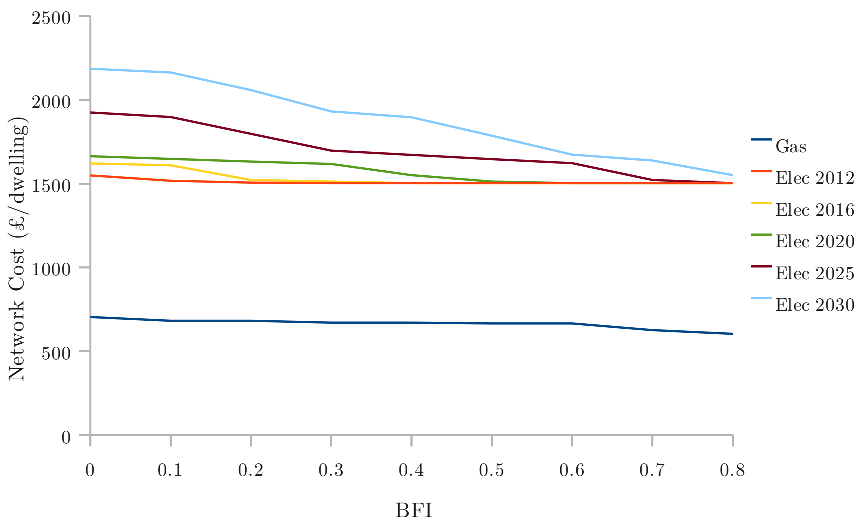


Figure 5.4: Cost variation of gas and electricity distribution networks against Building Fabric Index for various year of build completion.

The total build premium is a trade-off between the fabric premium, the cost of PV and the cost of the energy distribution infrastructure. Fig. 5.5 shows the variation of build premium with BFI at a build completion date of 2012 with a minimum of £9,156 per dwelling observed at BFI = 0.3. At 2020 (not shown) the increase of required PV capacity increases the minimum cost to £12,745 at BFI = 0.4.

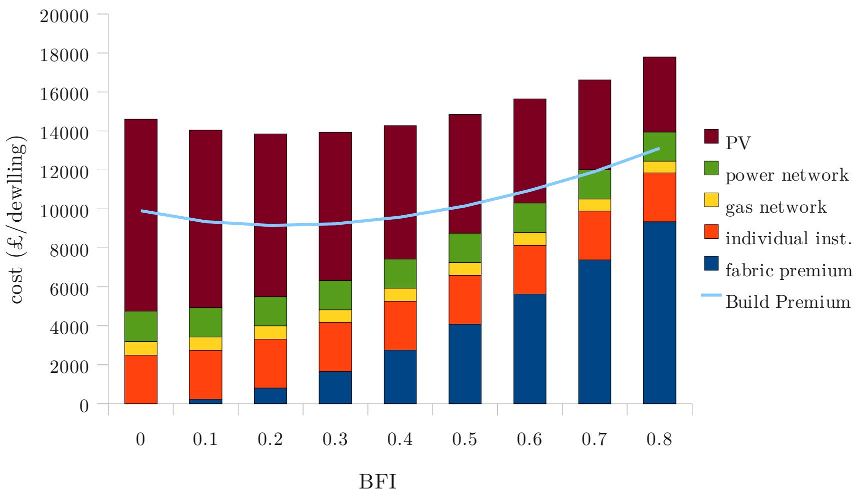


Figure 5.5: Variation of cost breakdown and build premium with Building Fabric Index for the building fabric option (build completion date = 2012)

Figure 5.6 illustrates the variation of the build premium curve with year of build completion. The minimum build premium and the corresponding BFI both increase due to the increasing PV capacity required to meet the zero carbon homes target. At 2020, the minimum cost (£12,745) occurs at BFI = 0.4 and at 2025 further increases to £16,824 at BFI = 0.8. The building fabric option therefore favours a shift towards higher insulation standards over time.

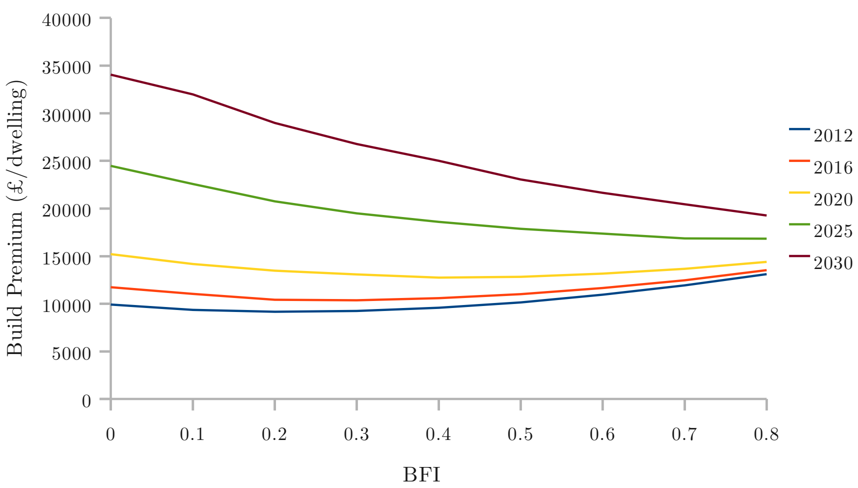


Figure 5.6: Variation of average build premium per dwelling with Building Fabric Index for the building fabric option at various years of build completion.

5.4.3 Electrification of Heat

The breakdown of build premium for the electrification option is shown by Fig. 5.7. The capacity of PV required to meet the zero carbon target, the installed cost of heat pumps, and the cost of the electricity infrastructure all decrease as BFI increases. At a project completion of 2012, the minimum build premium (£19,321) per dwelling occurs at BFI = 0.3. This option is thus considerably more expensive than the building fabric option.

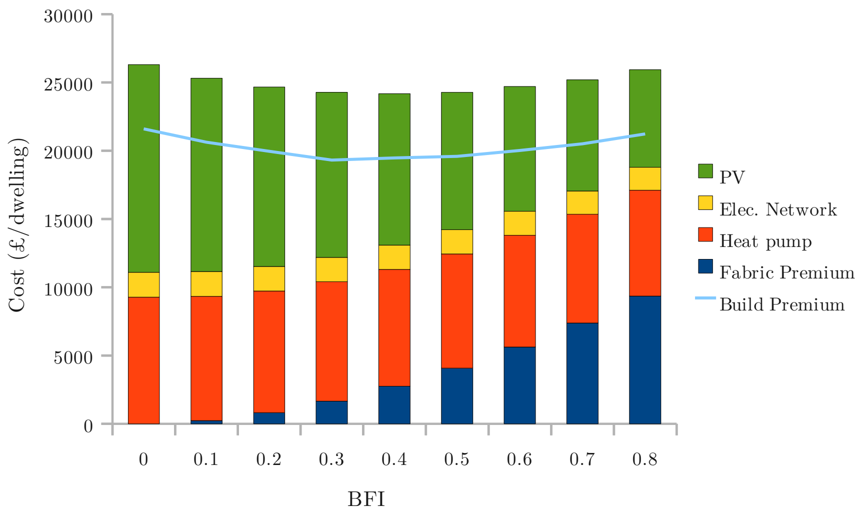


Figure 5.7: Variation of cost breakdown and build premium with Building Fabric Index for the electrification option (build completion date = 2012)

Analysis within chapter 4 showed that the capacity of PV required to meet the zero carbon target for the electrification option decreased with grid decarbonisation. Figure 5.8 shows the corresponding effect upon build premium. At 2020, the minimum build premium is reduced to £17,361 at BFI = 0.4 and at 2025 is further reduced to £14,163 at BFI = 0.4, which is below that of the building fabric option.

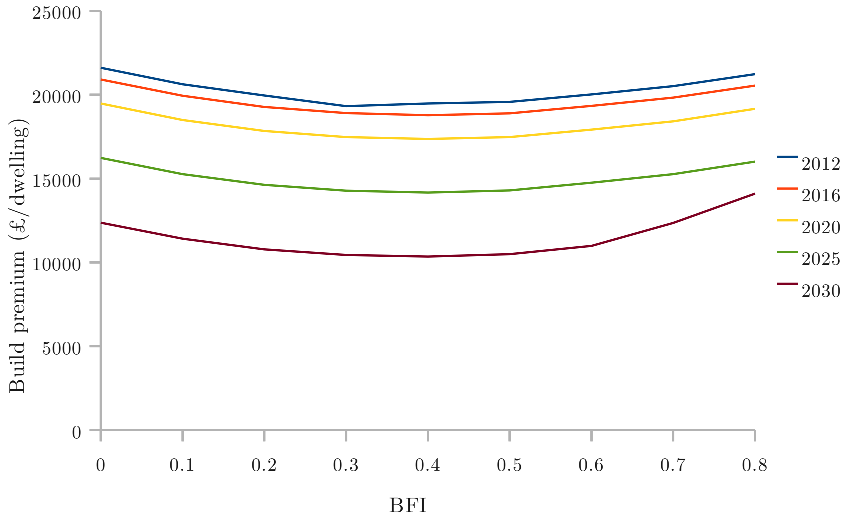


Figure 5.8: Variation of average build premium per dwelling with Building Fabric Index for the electrification option at various years of build completion.

5.4.4 Community Cogeneration

The build premium of the community cogeneration option consisted primarily of the energy centre and heat network capex apportioned from the ESCo, the fabric premium and the capacity of PV required to meet the zero carbon homes target. The ESCo was assumed to operate the heat network with the objective of delivering heat at or below the average price of domestic gas (taken as 3.74p/kWh). This places a constraint upon the maximum ESCo capital expenditure. The remaining Capex was apportioned to the developer build premium.

The annual financial breakdown for the ESCo at BFI = 0 is shown by Fig. 5.9. Without heat storage, the maximum income occurs at a CHP plant size of 1100kW$_{th}$, corresponding to the plant size for maximum electricity generation. The cost of fuel and plant opex reduces the plant size for maximum annual net revenue (£44,814) to 700kW$_{th}$. The use of heat storage removes the electricity production peak and results in a 67% increase of maximum net energy centre revenue (£74,962) at 1100kW$_{th}$. The capital expenditure of the community heating system increases with CHP plant size. This suppresses the plant size at which the annual net revenue occurs. This occurs at 400kW$_{th}$ without storage capacity and at 700kW$_{th}$ when storage is used.

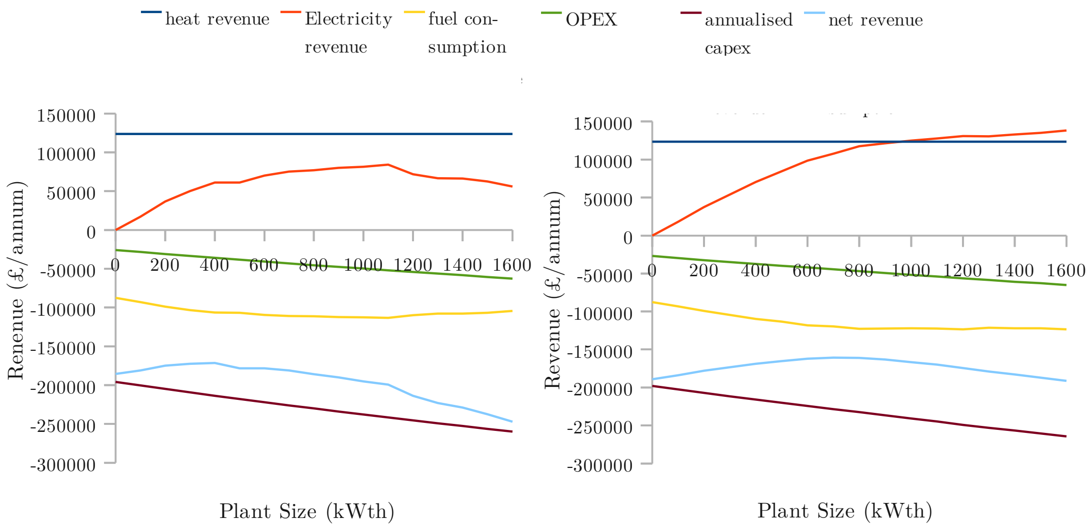


Figure 5.9: Variation of ESCo revenue and expenditure with combined heat and power plant size for the community cogeneration option: (a) no heat storage, (b) with storage. (BFI = 0, 6% discount rate, heat price = 3.74p/kWh)

The capital cost apportioned to the developer was determined by assuming that the minimum net annualised ESCO revenue is zero. Thus, any deficit of net annualised revenue determines the annualised capex incurred by the developer. The total developer capex for an assumed discount rate of 6% is shown by Fig. 5.10. The least cost DH-CHP option is shown to be dependent upon the building fabric index. For the case without storage, an increase of BFI to 0.6 decreases the least cost plant to 300kW$_{th}$ whilst increasing the scheme cost to £2,013,412. A similar trend is observed for the option with storage with the same increase of BFI resulting in a reduced plant size to 400kW$_{th}$ and an increased cost to £1,942,242.

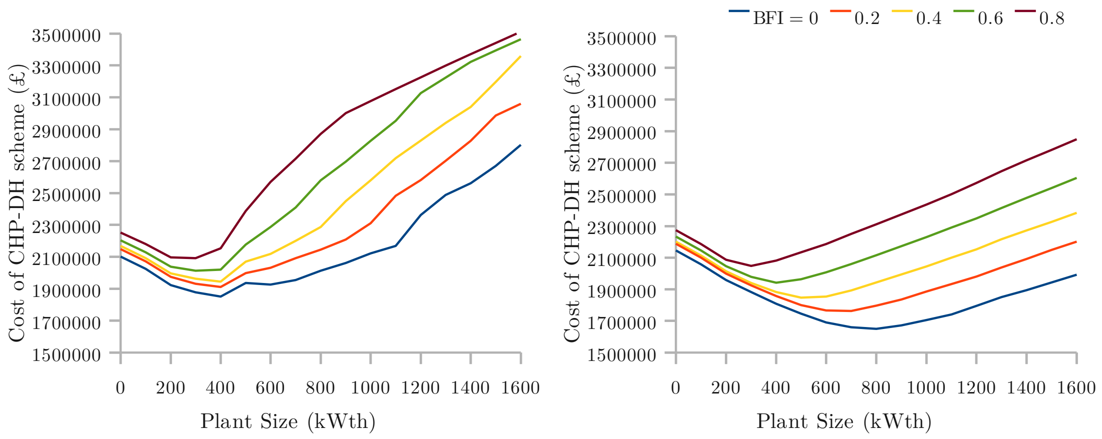


Figure 5.10: Variation with combined heat and power plant size of capex passed to developer from ESCo for the community cogeneration option: (a) without heat storage and (b) with storage. (Discount rate = 6%, heat price = 3.74p/kWh).

The energy centre capex comprises the cost of the CHP plant, peak load boiler (determined by peak district heat demand and thus BFI), and storage capacity. Fig. 5.11 illustrates the effect of increasing and using heat storage upon the energy centre capex.

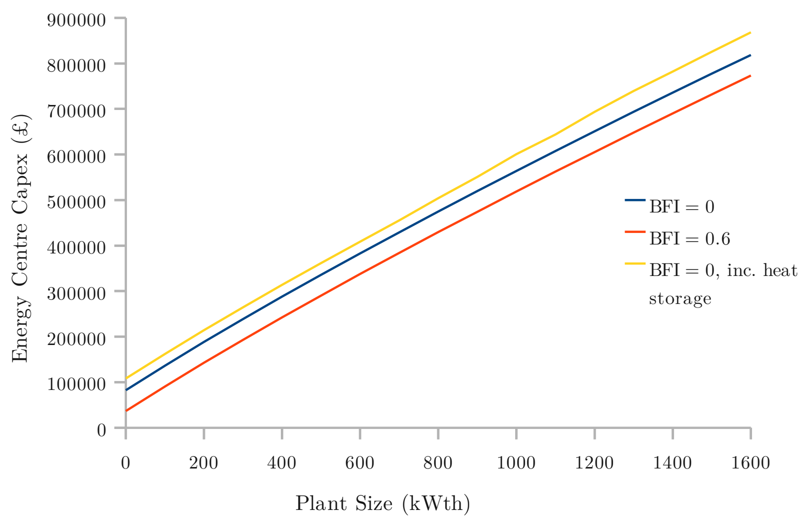


Figure 5.11: Variation of energy centre generation plant capex with Combined Heat and Power plant size for the community cogeneration option.

The district heating network capex is dependent upon the peak heat demand and therefore BFI. Fig. 5.12 shows the variation of heat network capex with

BFI with an assumed maximum network pressure differential of 14bar. For a development of this scale we would anticipate a limited influence of BFI upon variation of heat network cost, and the total cost decrease of increasing BFI from 0 to 0.9 is 2.5%

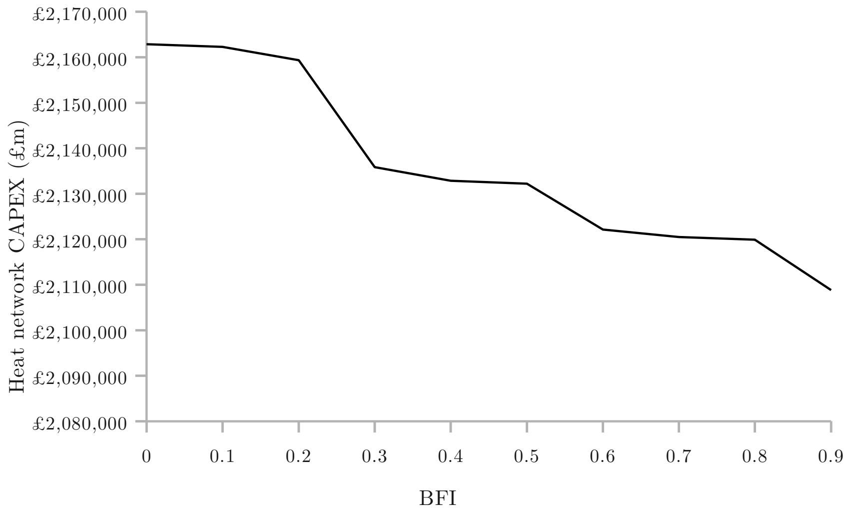


Figure 5.12: Effect of building fabric index upon the district heat network capex for the community cogeneration option (design pressure = 14 bar).

The total build premium for the community cogeneration option consists the cost of the PV capacity required to meet the shortfall against the zero carbon homes emissions target. In Chapter 4 it was shown that the minimum emissions (and thus minimum required PV capacity) occur for the plant with the highest electricity output. The high capital cost of PV therefore shifts the optimal CHP plant size to this point. This is illustrated by Fig. 5.13 which shows the net build premium per dwelling at a 2012 build completion. Without capacity, the minimum build premium of £7,311 occurs at BFI = 0 with a CHP plant size of 1000kW$_{th}$. Using heat storage, the minimum build premium is reduced to £5,524 at BFI = 0 with a CHP plant size at 700kW$_{th}$.

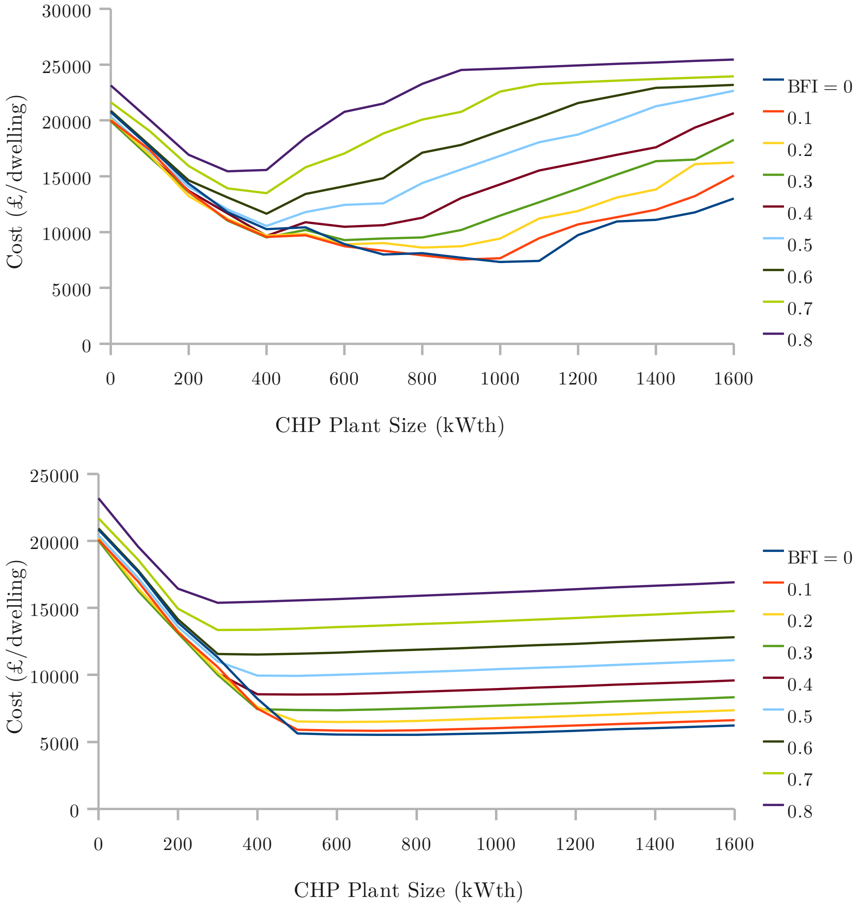
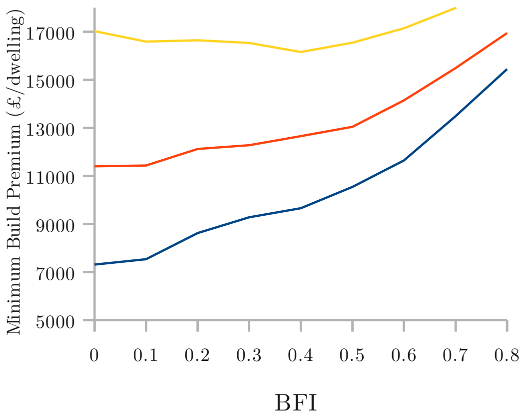


Figure 5.13: Variation of average build premium per dwelling with combined heat and power plant size for the community cogeneration option (a) without heat storage and (b) with heat storage. (Build completion 2012, discount rate 6%, heat price 3.8p/kWh)

The effect of grid decarbonisation and BFI upon the minimum build premium for the community cogeneration option is illustrated by Fig 5.14. The proposed minimum insulation standard for zero carbon homes corresponds to a BFI ~ 0.3. This results in a increased of minimum build premium from £11,405 per dwelling to £12,279 without storage and from £5,527 per dwelling to £7,360 per dwelling when storage is included. By 2020, the increase of required PV capacity results in a significant increase of build premium for the case without and with storage to £16,530 per dwelling and £11,506 per dwelling respectively at BFI = 0.3.



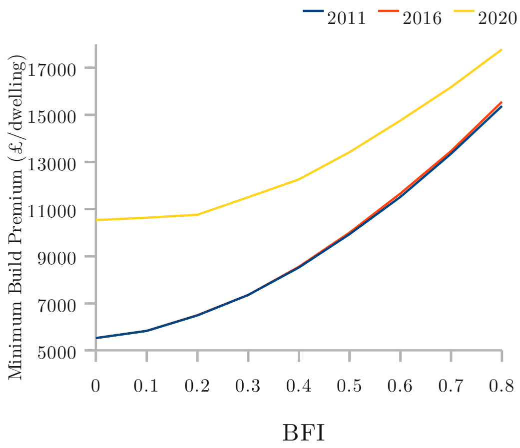


Figure 5.14: Variation of minumum build premium with Building Fabric Index for the community cogeneration option: (a) without storage, (b) with storage.

5.5 Conclusions

An financial analysis model for community energy distribution systems was developed. The model was used to provide an indicative evaluation of build premium for each infrastructure option within the example study under a 70% regulated emission reduction design criteria. A summary of the findings based upon the assumed financial structure and energy prices are as follows:

Building fabric option: The total cost of the building fabric option was characterised by a trade-off between the cost of the required PV capacity and the cost of implementing building fabric improvement. A minimum cost was observed for which the corresponding building fabric index increases with year of build completion due to the diminishing contribution of PV to on site emission reduction.

Electrification option: The electrification option was also characterised by the trade-off between PV capacity and fabric cost. This was exacerbated by the high installation cost of heat pumps which drives the minimum cost solution towards a higher building fabric index. The electrification option relies on electricity grid decarbonisation for its carbon reduction capability which decreases the installed cost of PV and thus total cost with build completion date. The electrification option was found to be the most expensive option at present.

Community Co-generation option: The cost of the natural gas district heating option was found to depend upon the interaction between plant size, annual heat demand, annual electricity generation and the required capacity of PV. The inclusion of heat storage capacity was shown to significantly reduce the associated build premium for the option and for a project completion of 2012 was found to be the least cost option of those examined. The extent to which natural gas engine combined heat and power is able to contribute to emissions savings is dependent upon the carbon intensity of the grid imported electricity. It was found that the diminished contribution of both PV and natural gas engine combined heat and power over time results in a significant increase of the net development cost with year of build completion. This implies a narrow window of opportunity to use natural gas engine combined heat and power alone as a low carbon technology for new build community schemes.

Chapter 6

Optimised Design of Ebbw Vale Community Redevelopment

6.1 Introduction

A heuristic optimisation algorithm was applied within the integrated design and analysis model described within chapters 2 to 5. This was used to determine the least cost mix of energy supply technologies subject to the technical, emissions and financial constraints of the scheme. The integrated optimisation model was applied to a case study based upon a community redevelopment scheme at Ebbw Vale in the South Wales Valleys, UK.

6.2 Integrated Optimisation Model

6.2.1 Structure of Integrated Optimised Model

The *Solver For Non-linear Programming* is an open source extension for the OpenOffice Calc spreadsheet. The solver was thus incorporated into the spreadsheet of the integrated design and analysis model. The structure of the integrated optimisation model is shown by Fig. 6.1.

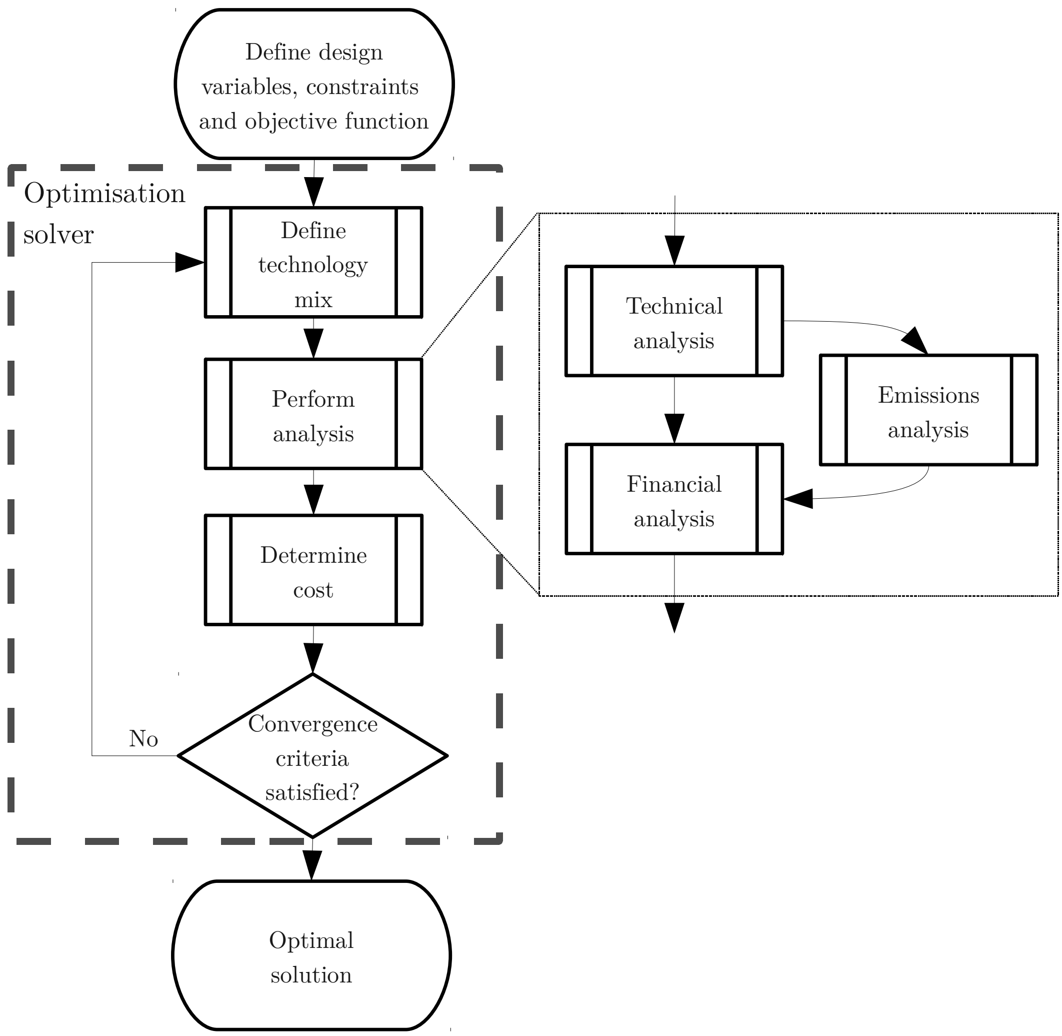


Figure 6.1: Structure of the integrated optimisation model.

The solver implements one of three optimisation algorithms: Differential Evolution Optimisation (DE); Particle Swarm Optimisation(PSO); Social Cognitive Optimisation(SCO). A hybrid Differential Evolution – Particle Swarm algorithm was also available as a fourth option. Each algorithm applies a heuristic search methodology to identify the optimal (in this case minimum cost) location within a defined solution space. Through trial and error, the

SCO algorithm was found to display the fastest convergence to an optimal solution for the problem described within this chapter and was applied exclusively.

6.2.2 Social Cognitive Optimisation

Social Cognitive Optimisation is an evolutionary algorithm developed by Xie et al (2002). The method was developed as a progression from methods based upon biological selection (such as genetic algorithms) and swarm intelligence by modelling human observation and learning traits into the search process(Fig 6.2).

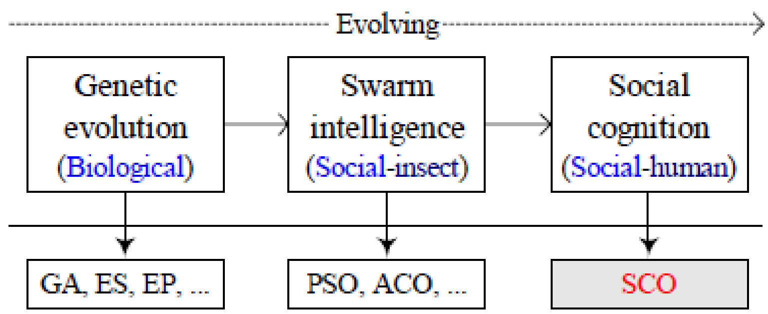


Figure 6.2: "Evolution" of heuristic algorithms (Xie 2002)

SCO selects a *library* of feasible *knowledge points* from the solution space each defined by its location and fitness (i.e. objective function value). A set of *learning agents* perform the optimisation search with each holding a single knowledge point. Each agent performs a search for an improved point based upon a comparative operation between its current knowledge point and two or more neighbouring points within the library. A flow chart summarising the method is given by Fig 6.3.

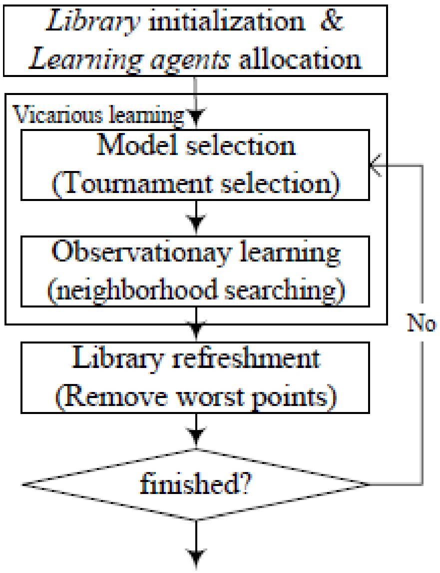


Figure 6.3: Illustrative flow chart for Social Cognitive Optimisation angorithm (Xie 2002)

6.3 The Works Ebbw Vale Scheme

The Works Ebbw Vale is a £350m publicly funded community regeneration scheme for the redevelopment of a disused steelworks at Ebbw Vale in South Wales, UK. The project is a joint venture between Blaenau Gwent Council and the Welsh Assembly Government to build 720 new homes, a local general hospital, primary and secondary schools, an adult education centre, an arts centre, business units, a leisure centre and council offices and is due for completion by 2016. Sustainable development forms one of the key objectives of the scheme that includes (WAG 2009a):

- Maximising the economic benefit to the local area and Blaenau Gwent region.
- Maximising the social benefit to the local community by strengthening communities, health and well being, local culture and improved housing.
- The stewardship and enhancement of the natural, built and historic

environment.

- The efficient use of local and global resources and minimise the environmental footprint

The sustainable energy strategy for the development was based upon three fundamental principles: (i) to minimise the demand for energy; (ii) to supply energy efficiently and (iii) to use renewable energy (WAG 2009a). The mission statement for the sustainable energy strategy states that:

"*The project will be an exemplar for the sustainable use of energy and will contribute to Wales's sustainable development. It will demonstrate how projects can move towards being carbon neutral over time.*" (WAG 2009b).

The development strategy also considers the use of a local Energy Centre to utilise local energy resources and to distribute heat to the area using district heating. The high level concept is illustrated by Fig 6.4.

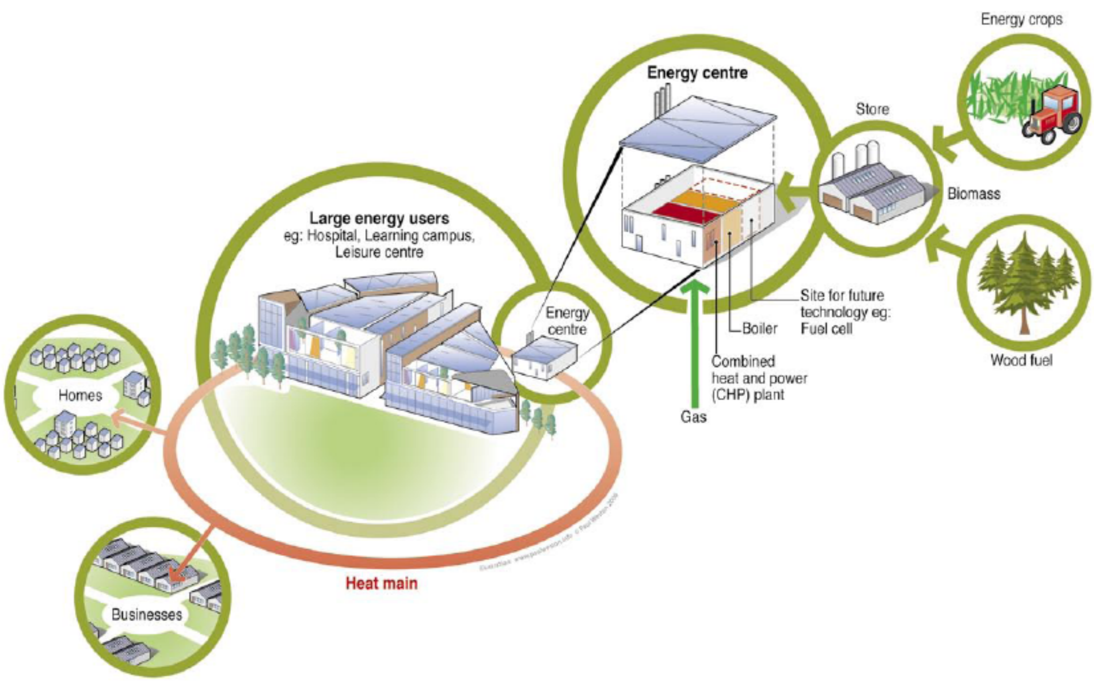


Figure 6.4: Community energy provision concept for *The Works Ebbw Vale* development (WAG 2009b).

6.3.1 Scheme Model

Table 6.1 details the building clusters used to model the scheme. The demand profiles used to model each occupancy type can be found within Appendix A1.

Cluster ID	Consumer	No. of Buildings	Occupancy Type	Occupied floor space (m^2)	No. floors	Cluster Area (m^2)
1	General Offices	1	Office	3,940	3	5,000
2	Learning Centre	1	Education	13,000	4	8,000
3	Arts Centre	1	Education	5,200	2	10,400
4	Comprehensive School	1	Education	9,500	2	19,000
5	Leisure Centre	1	Leisure Centre	9,500	2	9,500
6	Residential	245	Residential	77.6	2	110,250
7	Residential	255	Residential	77.6	2	114,750
8	Business Park	10	Offices	450	1	12,225
9	Business Park	30	Offices	450	1	68,270
10	Hospital	1	Hospital	10,695	2	53,475
11	Business Park	30	Offices	450	1	42,069
12	Primary School	1	Education	7,400	2	32,718
13	Residential	160	Residential	77.6	2	72,000
14	Business Park	15	Offices	450	1	31,912
15	Residential	60	Residential	77.6	2	27,000

Table 6.1: Building clusters modelled within *The Works Ebbw Vale* case study.

The layout and utility routes for the development are shown by Fig 6.5. Figures 6.6 to 6.8 show the proposed network layout for each energy vector required to serve all clusters on site from which a sub set was selected (see Appendix 4 for data tables). The development was divided by a railway line with the *main site* located to the West and the *Lower Sidings* to the East. The electricity network was therefore modelled as two separate 11kV ring-main systems each connected to the grid via an existing 11kV system. The proposed gas distribution network was modelled as a radial configuration connected to the existing natural gas infrastructure via a single 2bar connection at the site boundary. The proposed district heating network was as a radial dual pipe system with a supply/return regime of 90°C/50°C during the heating season (October to May) dropping to 80°C/50°C during the summer period.

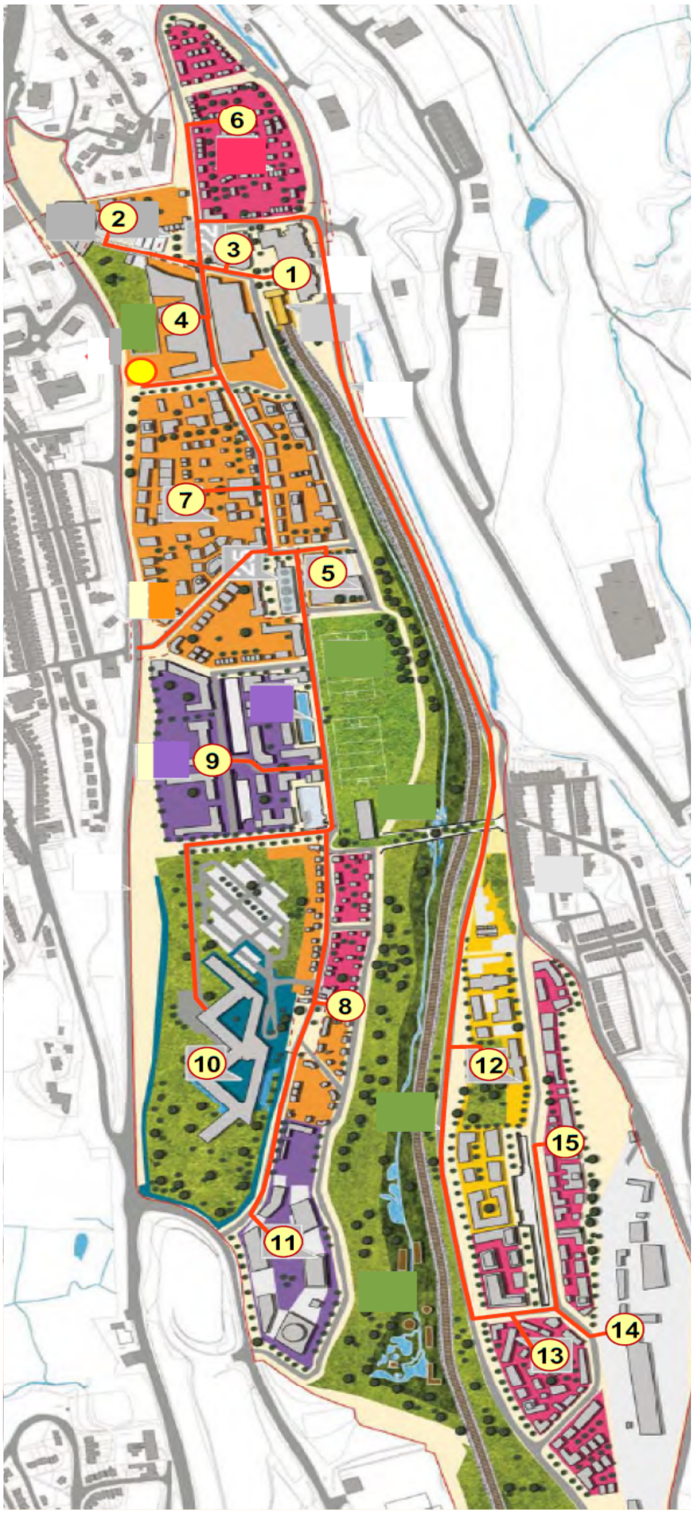


Figure 6.5: Proposed development layout (WAG 2009c).

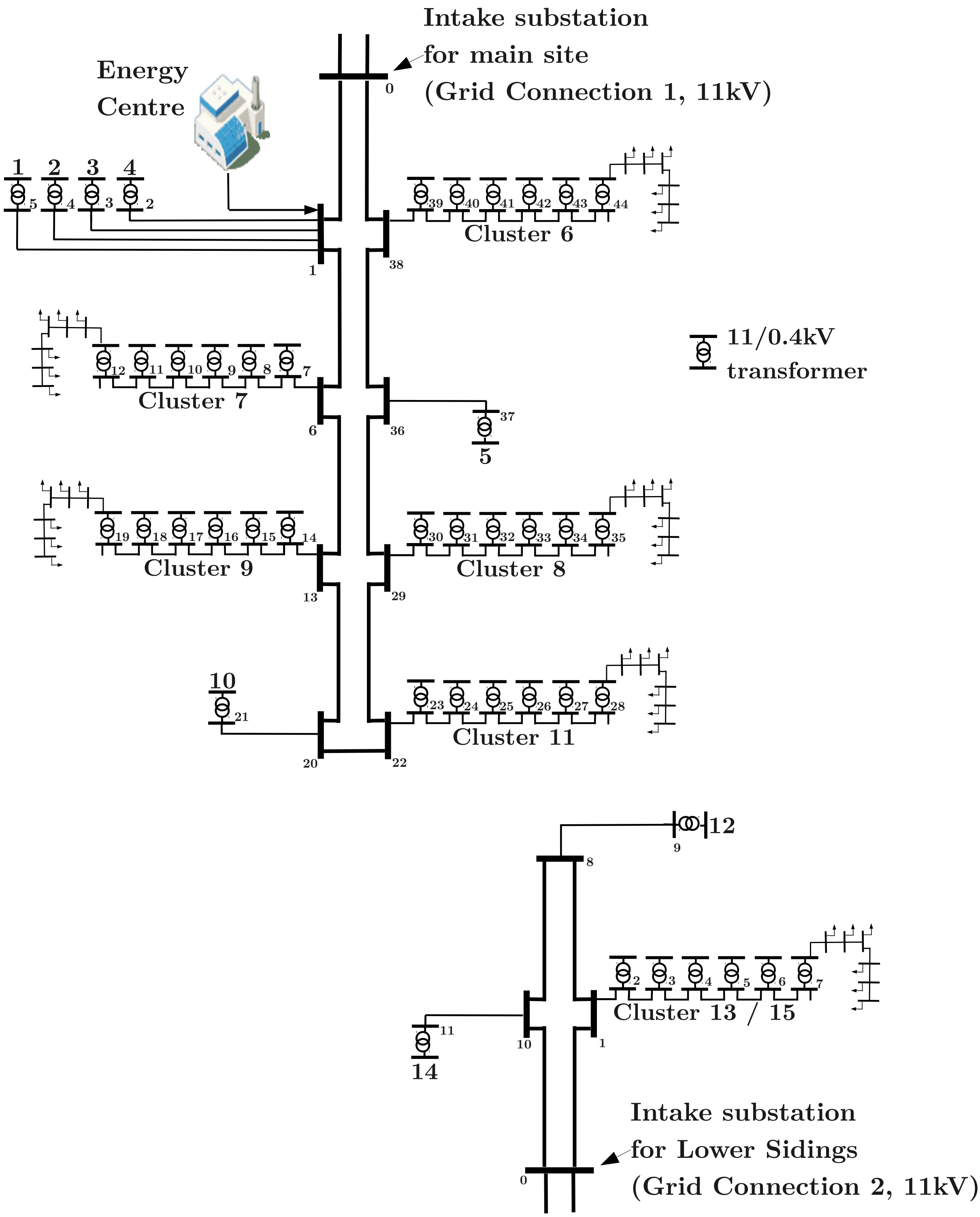


Figure 6.6: Electricity Network Superstructure for *The Works Ebbw Vale* case study.

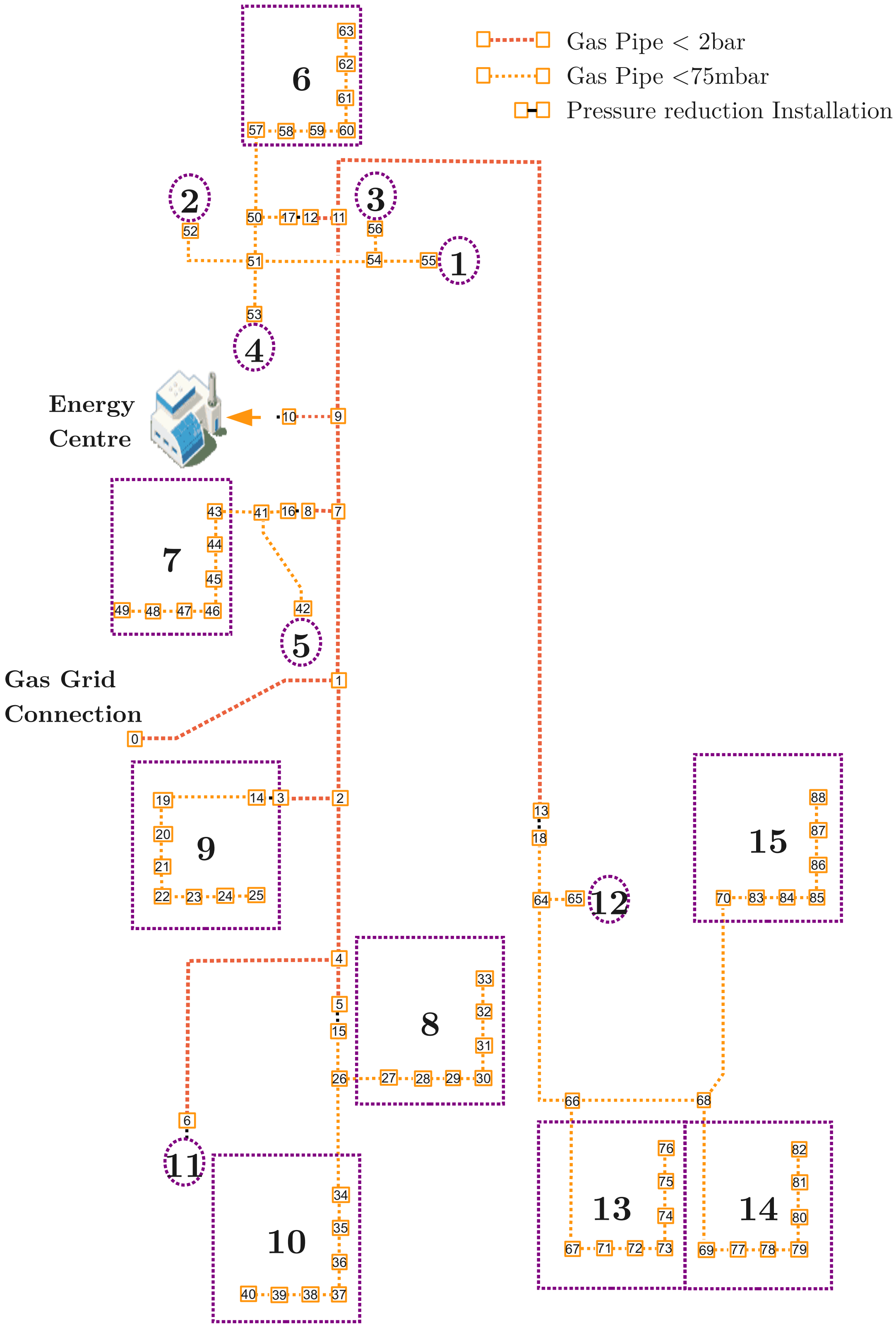


Figure 6.7: Gas Network Superstructure for *The Works Ebbw Vale* case study.

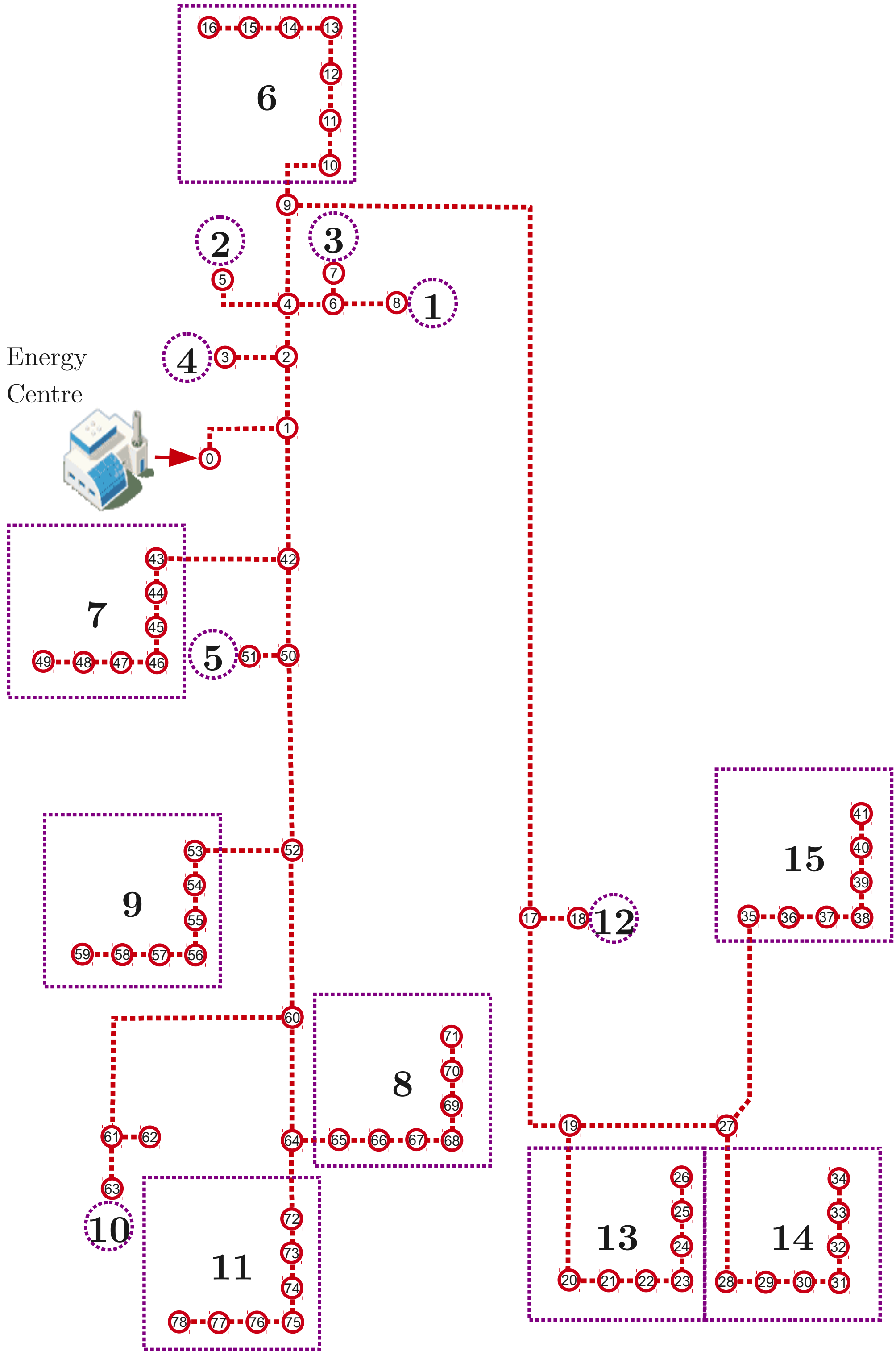


Figure 6.8: District Heat Network Superstructure for *The Works Ebbw Vale* case study.

The construction of the buildings and infrastructure was carried out in stages over the development period. For the purpose of this study, however, it was assumed that the construction was completed at a single year with full building occupancy from the following year.

6.3.2 Financial Model

The financial structure described by Fig. 6.9 was assumed to apply to the scheme. The *Developer* was responsible for the construction of each premise, the installation and commissioning all building level supply technologies and all on site civil engineering works. The gas and electricity distribution networks were assumed to be installed, owned and operated by the regional *gas DNO* and *electricity DNO* respectively. It was assumed that the total capital expenditure incurred for each was passed to the developer. An independent not for profit *ESCo* was set up to build, operate and maintain the energy centre and the district heating network, and manage the heat contracts with all connected premises.

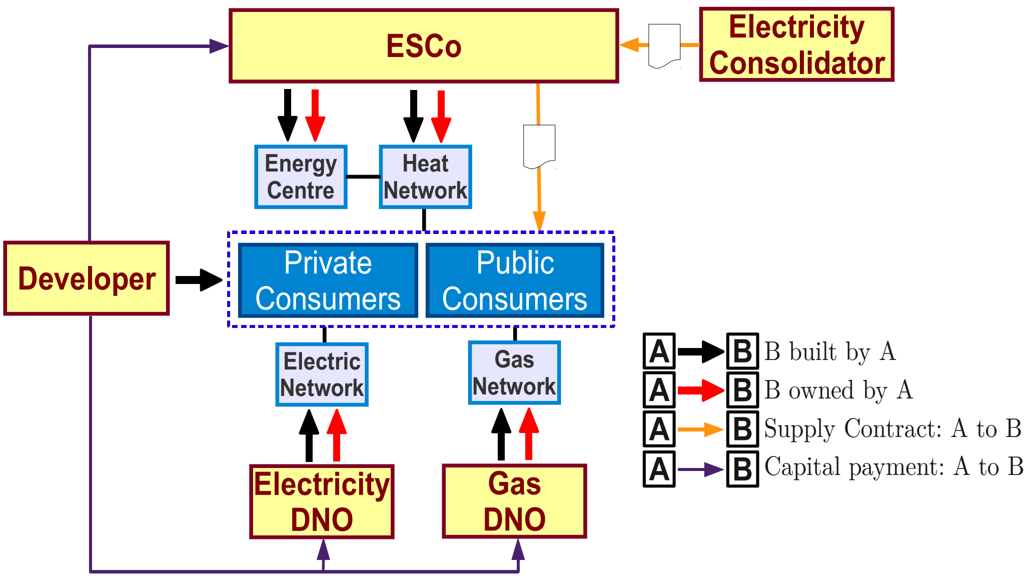


Figure 6.9: Illustration of financial structure modelled within *The Works Ebbw Vale* case study

A simplified supply arrangement was considered for public sector buildings using building level supply technologies connected to a DNO owned system (gas boilers, heat pumps, PV). This assumed that the associated revenues obtained by the ESCo (FiT, RHI, electricity exported from PV, electricity and gas revenue from public sector) were equal to the expenditure from plant maintenance and payment to the gas and electricity suppliers. A detailed financial treatment for these technologies was therefore not considered.

6.3.3 Design Objectives

A 60% reduction of regulated emissions relative to 2006 building standards was specified as part of the energy strategy for the scheme. The objective of the optimisation study was to identify the energy infrastructure that delivers the emissions target at minimum cost to the developer assuming construction at the anticipated build completion date of 2016. The study then examined the effect of build completion date upon the optimal infrastructure design by considering an early build completion date of 2012 and late build completion date of 2020 for the project. Finally, the effect of applying alternative electricity grid carbon emissions intensity projections was examined.

The study investigated the delivery of an on-site carbon reduction target without developing new energy or fuel supply chains such as biomass, municipal waste or industrial waste. The model was thus constrained to the use of domestic building fabric improvement, individual natural gas boilers, PV, ground sourced heat pumps, air sourced heat pumps as building integrated options, and natural gas boilers or CHP as options for the energy centre supply. A non-domestic building fabric index was not considered due to the lack of available data to model a relationship between space heating demand and building fabric cost.

6.4 Optimisation Problem

6.4.1 Reference Case

A reference case was defined with all buildings constructed to 2006 Part L building standards. The peak and annual energy consumption for each building type is shown in Table 6.2. Space heating and hot water was assumed to be provided using gas boilers at all premises. The remaining energy demand was met using grid supplied electricity.

Consumer type	Space heat (kWh/m^2/yr)	Hot water (kWh/m^2/yr)	Space cooling (kWh/m^2/yr)	Appliance & lighting (kWh/m^2/yr)	Peak Heat demand[3] (W/m^2)	Peak Electricity demand (W/m^2)
Education[1]	51.5	30.9	0	74.5	110[3]	30[4]
Hospital[1]	87.6	46.4	0	234.9	90[3]	35[4]
Offices[1]	103.9	15.5	13.9	116.3	90[3]	60[4]
Leisure Centre[1]	0	159.8	69.8	118.7	110[3]	90[4]
Residential[2]	65.1	25.0	0	40.5	-	-

1. Annual values adapted from HM Gov(2008)
2. ZCH 2009
3. CIBSE Guide F (2005)
4. CIBSE Guide K (2005)

Table 6.2: Average annual and peak energy consumption rates for buildings constructed to 2006 Part L standards.

6.4.2 ESCo Model

The ESCo cost model described within chapter 5 was modified for use within the optimisation tool. The variable K_{capex} as used to represent the fraction of total heat network capex passed on to the developer. The cost apportioned between the developer and the ESCo was therefore given by:

$$C_{Dev} = K_{capex}(C_{DHN} + C_{plant}) \tag{6.1}$$

$$C_{ESCo} = (1 - K_{capex})(C_{DHN} + C_{plant}) \tag{6.2}$$

The annualised ESCo capex was determined using:

$$C_{AnnESCo} = \frac{(1 - K_{capex})(1 + DR_{ESCo})(C_{DHN} + C_{plant})}{1 - (1 + DR_{ESCo})^{N_{Project}}} \tag{6.3}$$

The average heat price was determined using:

$$c_{heat} = \frac{C_{AnnESCo} + C_{ESexp} - C_{ESincome}}{\sum_{1}^{Nc} \Phi_{DHN}^{(c)}} \tag{6.4}$$

6.4.3 Grid Electricity Emissions Model

The DECC projection (DECC 2011) of the average carbon emissions factor (CEF_{AVE}) was used throughout the study. Three alternative projections for the marginal carbon emissions factor of grid supplied electricity were considered within the study. These are shown within Fig. 6.10. The first projection is the marginal carbon emissions factor published by DECC (DECC 2011). This was assumed to be the projection used by default for the analysis of the Ebbw Vale scheme. The second projection is that recommended for use within the Zero Carbon Homes initiative by the Zero Carbon Hub (Levyveld 2010). The final projection follows the assumption that the marginal and average carbon emissions factors are equal as applied within various studies (e.g. AEA 2008, Carbon Trust 2009, Poyry 2009).

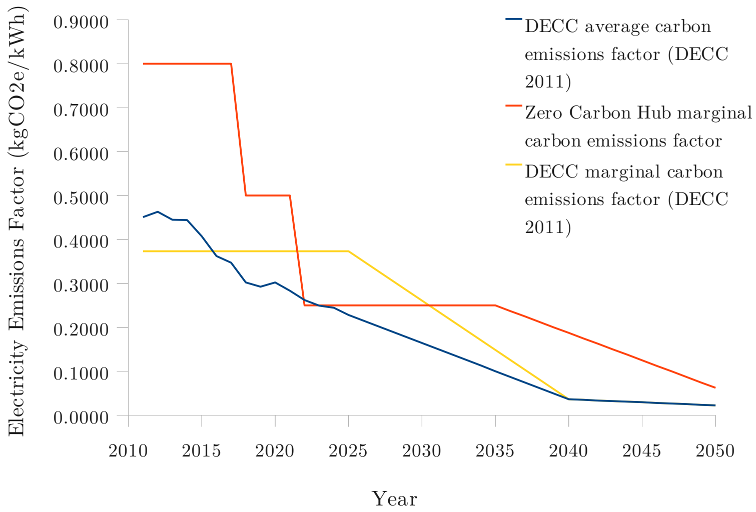


Figure 6.10: The projections of marginal carbon emissons factor for grid supplied electricity used within *The Works Ebbw Vale* case study.

6.4.4 Optimisation Design Variables

A summary of the optimisation variables is provided by Table 6.3. The fraction of penetration for heat pumps and district heating (f_{HP}, f_{DHN}) were applied as binary design variables for each cluster. Gas boilers were assumed to be the default building level supply technology within each cluster so that $f_{GCH} = 1 - f_{HP} - f_{DHN}$. The Building Fabric Index was applied as a continuous variable for all residential clusters. A Building Fabric Index was was not considered for non-domestic dwellings due to the lack of available data, so that $BFI_{NonRes} = 0$. The installed area of PV within each cluster was defined as a continuous optimisation variable. The rated heat output of each generation plant was applied as a continuous optimisation variable for the energy centre.

Heating technology penetration	*(f_{HP}, $f_{microCHP}$, f_{DHN})*
Domestic building fabric index	BFI
Installed PV capacity (m^2)	A_{PV}
CHP plant size (kW_{th})	$\Phi_{CHP,max}$ (kW_{th})
Apportioned ESCo cost	K

Table 6.3: Design variables applied within *The Works Ebbw Vale* optimisation study

6.4.5 Design Constraints

The optimisation constraints are summarised by Table 6.4. The model limited the allocation of building level heating technologies to one per cluster. The heat technology penetration was therefore considered as a binary variable so that $\sum f_{HP}^{(c)} + f_{GCH}^{(c)} + f_{DH}^{(c)} = 1$ and $f_{HP}^{(c)}, f_{GCH}^{(c)}, f_{DH}^{(c)} \in \{0,1\}$. Adherence to the residential Fabric Energy Efficiency Standard described within Chapter 5 was assumed so that $BFI_{Res} \geqslant 0.3$. The PV capacity for each building was limited by the available roof space so that $(A_{PV})_{Res}^{(c)} \leqslant 18.6\mathrm{m}^2 / dwelling$ for residential dwellings and $(A_{PV})_{NonRes}^{(c)} \leqslant (A_{Bld}^{(c)} / 2N_{floors}^{(c)})$ for non domestic builidngs. The design of the district heat network was constrained by the maximum allowable head of pressure at the energy centre. The working pressure limit of the steel district heating pipes was assumed to be 16bar. The system was pressurised to 2bar to avoid boiling and cavitation. The design head pressure constraint of $h_{max} \leqslant 14\mathrm{bar}$ was therefore applied.

The emissions reduction target was defined as $\xi_{target} = (\xi_{Total} - 0.6\xi_{regulated})_{ref}$. This was implemented within the optimisation model as a penalty function rather than a hard constraint which aids the solver by expanding the feasible solution space to include cases where the emissions target is exceeded. A penalty factor of £5,000/tCO_2e was selected as an arbitrarily high cost of exceeding the emissions target. The emissions function was therefore defined as:

$$PF_{emissions} = \begin{cases} 5000(\xi_{Total} - \xi_{reference}) & if\,\xi_{Total} > \xi_{target} \\ 0 & if\,\xi_{Total} \leqslant \xi_{target} \end{cases} \tag{6.5}$$

The maximum price of heat served by the district heating system was assumed to be equal to the price of natural gas that would otherwise be consumed by the use of gas boilers:

$$(c_{Heat})_{max} = \frac{c_{NG,Res}(\Phi_{DmdDHN,Res}/\eta_{GCH,Res}) + c_{NG,Com}(\Phi_{DmdDHN,Com}/\eta_{GCH,Com})}{\sum \Phi_{DmdDH}} \tag{6.6}$$

Constraint	Feasible range
Heating technology capacity	$f_{HP}, f_{DHN} \in \{0,1\}$
	$f_{HP} + f_{DHN} \leqslant 1$
PV capacity	$(A_{PV})_{Res}^{(c)} \leqslant 18.6\mathrm{m}^2/\,dwelling$
	$(A_{PV})_{public}^{(c)} \leqslant (A_{Bld}^{(c)}/2\,N_{floors}^{(c)})$
Building Fabric Index	$0.3 \leqslant BFI_{Res} \leqslant 1$
CHP plant size (kW_{th})	$\Phi_{Rated} \leqslant \sum \Phi_{PeakDH}$
Average heat price (£/kWh)	$c_{Heat} \leqslant (c_{Heat})_{Max}$
Maximum DHN pressure head	$h_{max} \leqslant 14\mathrm{bar}$
Total project life emissions (tCO_2e)	$\xi_{Total} = (\xi_{Total} - 0.6\,\xi_{regulated})_{ref}$

Table 6.4: Summary of design constraints applied within *The Works Ebbw Vale* case study.

6.4.6 Objective Function

The objective function was defined as the sum of the infrastructure cost and the penalty function. The optimisation objective was therefore:

$$minimise\, y = C_{total} + \sum PF \tag{6.7}$$

6.5 Results

6.5.1 Reference Case

A breakdown of the infrastructure cost for the reference case is shown by Table 6.5. This was used within the optimisation tool as the benchmark cost to the developer and consisted of the capital expenditure for the gas network, electricity network and gas boilers. It was assumed that each building was constructed to 2006 Part L standards and thus defined the baseline building fabric cost. The infrastructure design for the on-site natural gas and electricity networks is shown by Fig. 6.11.

Annual Electricity Consumption	14,508,134kWh/yr
Annual regulated electricity consumed	6,139,345kWh/yr
Peak Electricity Consumption	5,691kW
Annual Gas consumption	15,699,808kWh/yr
Annual regulated gas consumption	15,380,848kWh/yr
Peak Gas consumption	13,673kW
Electricity network Capex	£1,921,625
Gas Network Capex	£931,190
Gas Boilers Capex	£2,841,500
Building fabric cost	£0 (baseline)
Total Capex	**£5,694,315**

Table 6.5: Key consumption and cost parameters for *The Works Ebbw Vale* reference case infrastructure.

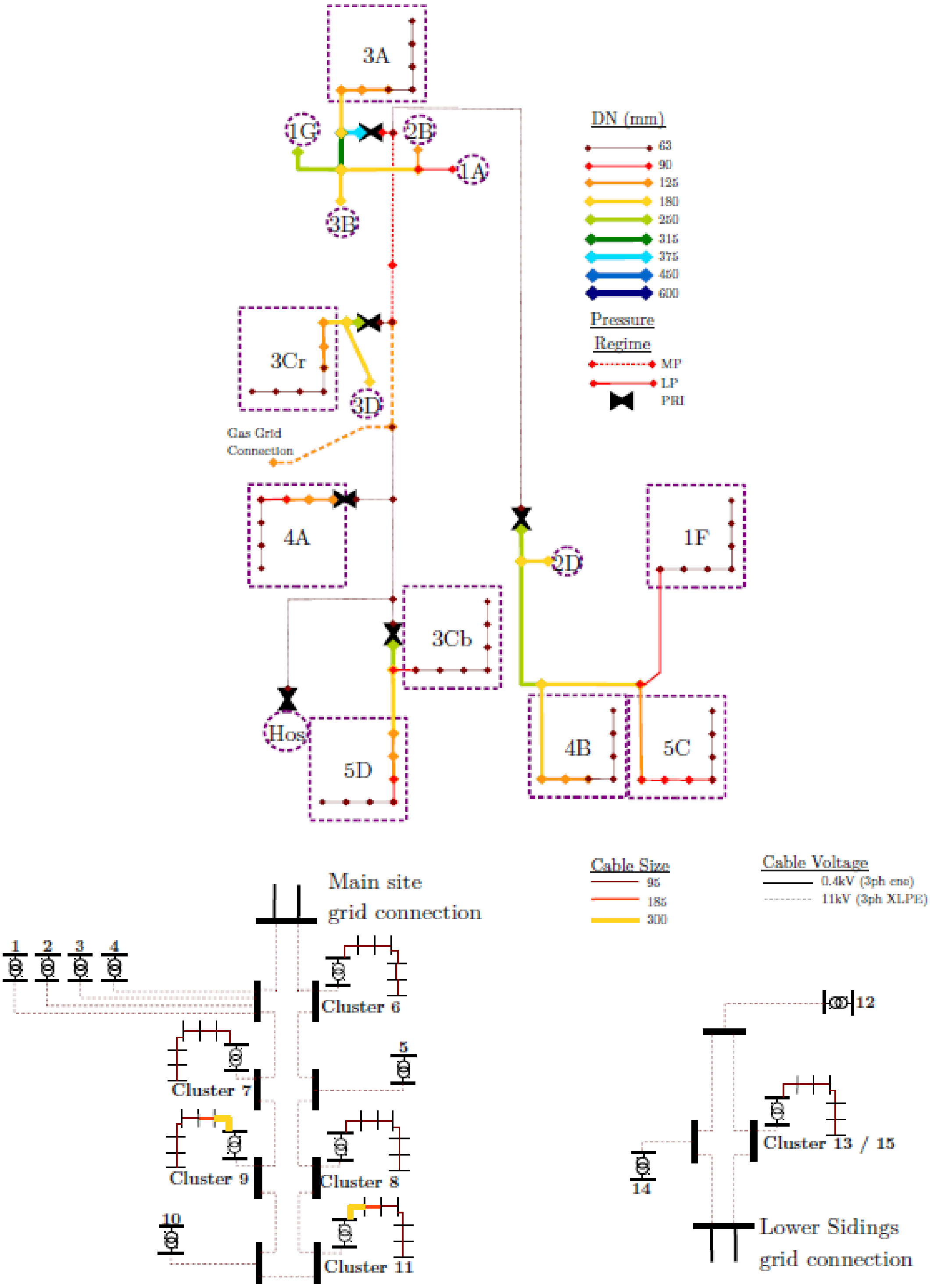


Figure 6.11: Energy distribution infrastructure design for reference case

6.5.2 Optimal Infrastructure Design

Table 6.6 provides a summary of the key design parameters for the optimal infrastructure design determined by the integrated optimisation model.

Cluster ID	2016		
	Heating Type	PV capacity	BFI
1	DH	83.2	0
2	DH	137.3	0
3	GB	54.9	0
4	DH	100.3	0
5	DH	300.1	0
6	DH	0.11	0.3
7	DH	0.11	0.3
8	DH	51.6	0
9	DH	288.4	0
10	DH	94.1	0
11	DH	296.1	0
12	DH	78.1	0
13	DH	0.11	0.3
14	DH	144.9	0
15	GB	0.11	0.3
ESCo Capex	£8,847,779		
Capex Passed to Developer	**£7,277,853**		
Electicity Network	**£1,855,886**		
Gas Network	**£114,055**		
Intra-Building Capex	**£9,744,600**		
Additional infrastructure cost	**£13,267,253**		

GB – Gas Boilers DH – district heating

Table 6.6: Optimal infrastructure design results for *The Works Ebbw Vale* case study (Build completion = 2016; ESCo discount rate = 3.5%).

The optimal design consists a district heating network extending to all clusters with the exception of clusters 3 and 15 where gas boilers are fitted into each domestic dwelling. The heat network is supplied by a 4,075kW$_{el}$ natural gas combined heat and power unit with 11.8MW$_{th}$ of back up boilers and a 714m^3 heat storage tank. A total of 1,630kW of PV was allocated to non domestic premises and an average of 0.11kW per domestic dwelling. A schematic of the optimal infrastructure design is shown by Fig. 6.12.

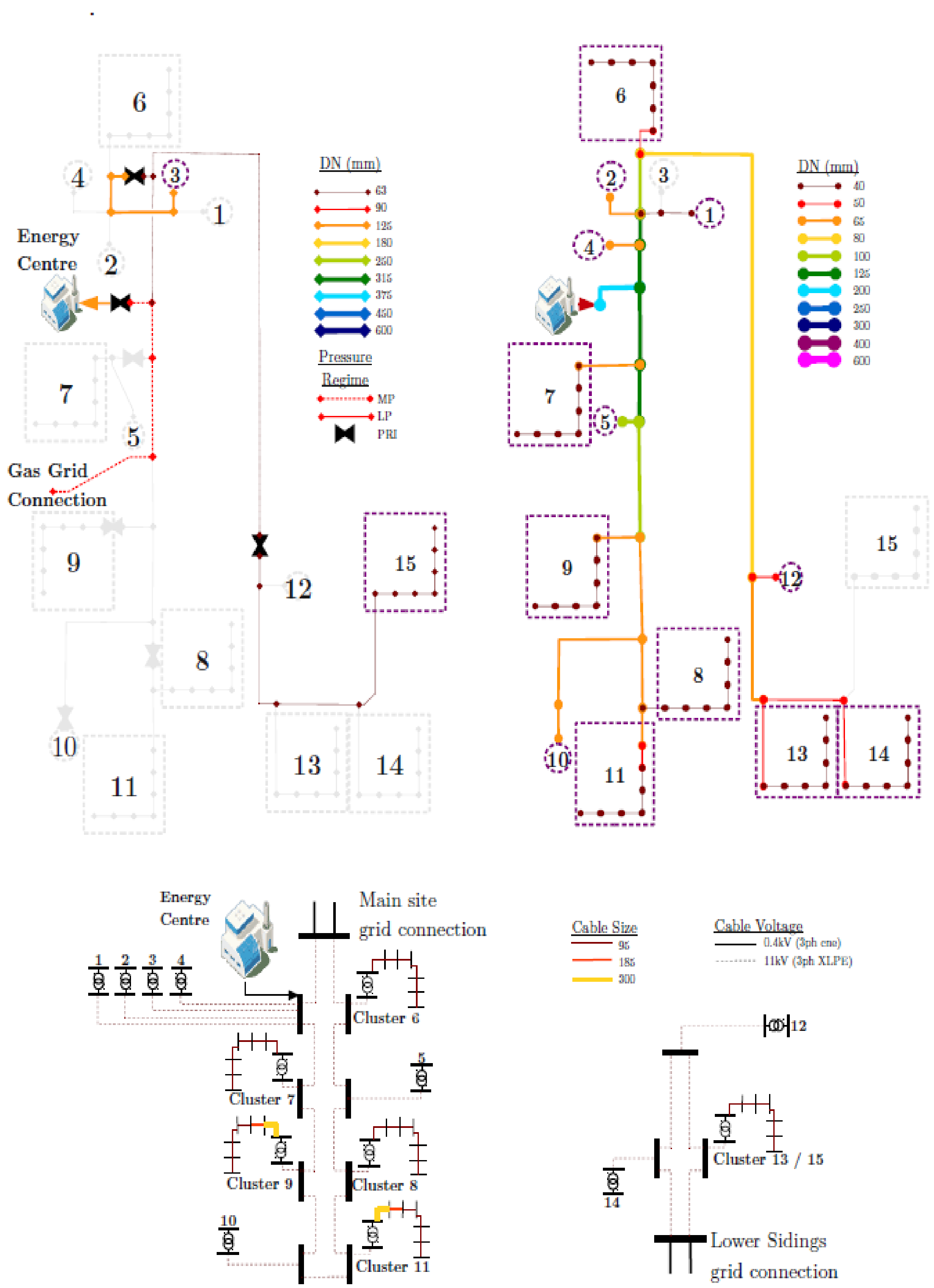


Figure 6.12: Optimal Infrastructure design for *The Works Ebbw Vale* with a build completion date of 2016.

6.5.3 Effect of Build Completion Date

It was shown within chapter 4 that the starting year for the project analysis period has a significant effect upon the performance of each energy supply technology. This was due to the decrease of the grid supplied electricity emissions factor over time. The effect of a change of build completion year upon the optimal design for the Ebbw Vale development was examined. This considered an early completion of 2012 and a late completion of 2020. The emissions targets, assumed building standards and cost parameters were unchanged. The key results of the study are summarised by Table 6.7.

Cluster ID	2012			2016			2020		
	Heating Type	PV	BFI	Heating Type	PV	BFI	Heating Type	PV	BFI
1	DH	0	0	DH	83.2	0	DH	102.8	0
2	DH	0	0	DH	137.3	0	DH	169.5	0
3	GB	0	0	GB	54.9	0	DH	67.8	0
4	DH	0	0	DH	100.3	0	DH	123.9	0
5	DH	0	0	DH	300.1	0	ASHP	750.2	0
6	DH	0	0.3	DH	0.11	0.3	HP	1.53	0.53
7	DH	0	0.3	DH	0.11	0.3	GB	1.53	0.53
8	DH	0	0	DH	51.6	0	GSHP	95.6	0
9	DH	0	0	DH	288.4	0	GSHP	534.2	0
10	DH	0	0	DH	94.1	0	GSHP	255.7	0
11	DH	0	0	DH	296.1	0	GSHP	548.6	0
12	DH	0	0	DH	78.1	0	GSHP	214.5	0
13	GB	0	0.3	DH	0.11	0.3	GB	1.53	0.53
14	DH	0	0	DH	144.9	0	GSHP	268.4	0
15	GB	0	0.3	GB	0.11	0.3	GB	1.53	0.53
ESCo Capex	£6,990,132			£8,847,779			£782,091		
Capex Passed to Developer	**£5,508,745**			**£7,277,853**			**£736,727**		
Electicity Network	**£1,855,866**			**£1,855,886**			**£2,152,570**		
Gas Network	**£285,333**			**£114,055**			**£436,869**		
Intra-Building Capex	**£1,224,363**			**£9,744,600**			**£32,159,297**		
Additional Developer Cost	**£3,149,184**			**£13,267,253**			**£29,760,320**		

DH = district heating ASHP = Air source heat pumps GSHP = ground source heat pumps HP =50% GSHP + 50% ASHP
GB = gas boilers

Table 6.7: Optimal infrastructure design results for *The Works Ebbw Vale* case study (ESCo discount rate = 3.5%).

Early build completion of 2012: In this case the optimal design consists primarily of a district heating system but without the requirement for any supplementary PV capacity. The increased emissions reduction obtained by the natural gas CHP plant also reduces the extent of the required district heat network with gas boilers specified at residential clusters 13 and 15 and at the arts centre (cluster 3). The energy centre was specified with a 2390MW_{el} natural gas CHP unit, 10.9MW_{th} of gas boilers and 430m^3 of storage capacity. The cost of the optimal infrastructure to the developer was was decreased significantly by £15,773,212 to £3,149,184.

Build completion delayed to 2020: In this case the infrastructure design determined by the integrated optimisation model is a mix of district heating and heat pumps. This solution balances the lower cost of provision for the district heating system and the higher emissions reduction capability of ground sourced heat pumps. The heat network was limited to clusters 1,2,3 and 4 with a 415kW_{el} natural gas CHP plant and 95m^3. Residential clusters 7,13 and 15 were supplied using domestic boilers with the remaining clusters supplied by ground sourced heat pumps. The insulation standard for domestic dwellings was increased to a corresponding BFI of 0.53 as part of the solution. The optimal design also relies upon a larger capacity of PV to meet the on site target than the 2016 case (3137kW on public buildings, 1.53kW per residential dwelling). This together with the use of heat pumps results in a significant increase of optimal cost to £29,760,320.

The reason for the technology mix results from a balance between the cost of provision and the capability of each technology to deliver on site emissions savings. The heat network is a cost effective means for supplying heat to the site at ~£0.45/kWh/year compared to ground source heat pumps at ~£0.8/kWh/year. Heat pumps are however a more cost effective means for delivering carbon savings at this carbon projection at $0.187kgCO_2e/kWh_{Served}/year$ compared to $0.096kgCO_2e/kWh_{Served}/year$ for district heating. The emissions reduction contribution from each supply technology is illustrated by Figure 6.13.

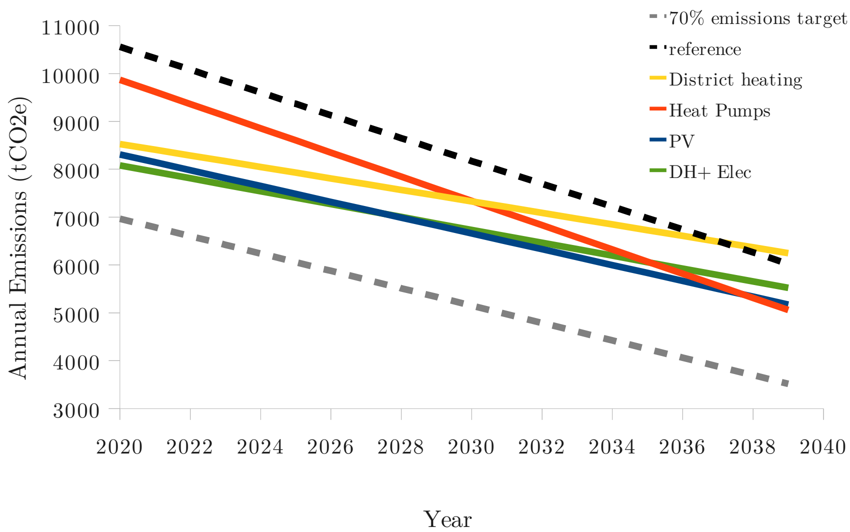


Figure 6.13: Emissions reduction contribution of PV, district heating and heat pumps for projection 3 optimal solution with 2012 build completion.

6.5.4 Effect of Emissions Projection

It was also shown in chapter 4 that the method and assumptions used to calculate the grid supplied electricity emissions can significantly effect the performance of energy supply options for new build schemes. The effect upon the optimal design for the Ebbw Vale scheme was investigated by considering two alternative projections. The first considers the projection of CEF_{MARGIN} (see section 4.3.1) recommended by the *Zero Carbon Hub*. The second applies the assumption that the average grid electricity emissions factor was used for account for all grid electricity supplied by and to the grid.

Cluster ID	DECC projection			ZCH projection			Average emissions factor		
	Heating Type	PV	BFI	Heating Type	PV	BFI	Heating Type	PV	BFI
1	DH	83.2	0	GB	0	0	ASHP	30.8	0
2	DH	137.3	0	DH	0	0	ASHP	91.6	0
3	GB	54.9	0	DH	0	0	ASHP	36.6	0
4	DH	100.3	0	DH	0	0	GSHP	36.6	0
5	DH	300.1	0	DH	0	0	ASHP	99.9	0
6	DH	0.11	0.3	DH	0	0.3	HP	2.25	0.38
7	DH	0.11	0.3	DH	0	0.3	HP	2.25	0.38
8	DH	51.6	0	DH	0	0	GSHP	12.7	0
9	DH	288.4	0	DH	0	0	GSHP	71.2	0
10	DH	94.1	0	DH	0	0	GSHP	34.1	0
11	DH	296.1	0	DH	0	0	GSHP	73.1	0
12	DH	78.1	0	DH	0	0	GSHP	28.6	0
13	DH	0.11	0.3	GB	0	0.3	HP	2.25	0.38
14	DH	144.9	0	DH	0	0	GSHP	35.6	0
15	GB	0.11	0.3	GB	0	0.3	HP	2.25	0.38
ESCo Capex	£8,847,779			£6,626,846			£0		
Capex Passed to Developer	**£7,277,853**			**£5,193,842**			**£0**		
Electicity Network	**£1,855,886**			**£1,885,886**			**£2,397,482**		
Gas Network	**£114,055**			**£266,108**			**£0**		
Intra-Building Capex	**£9,744,600**			**£1,219,244**			**£27,013,291**		
Additional Developer Cost	**£13,267,253**			**£2,809,939**			**£23,685,631**		

DH = district heating; GB = gas boilers; ASHP = Air source heat pumps; GSHP = ground source heat pumps; HP = 50% GSHP + 50% ASHP

Table 6.8: Optimal infrastructure design results for *The Works Ebbw Vale* case study under alternative emissions projections (Build completion = 2016; ESCo discount rate = 3.5%).

Zero Carbon Homes Projection: optimal infrastructure design in this case was comprised of a district heating scheme to serve the majority of consumer clusters for the main development using a 1600kW$_{el}$ natural gas CHP unit with 270m^3 of storage capacity. The general office, residential cluster 7 and the lower sidings (clusters 12-15) were supplied using gas boilers. The increase of MEF$_{MARGIN}$ relative to the DECC projection eliminates the requirement for PV on site. The result is a decrease of the optimal cost to the developer relative to the reference case by £10,387,314 to £2,809,939.

Average Emissions Factor: For this case the design determined by the integrated optimisation model selects heat pumps as the heating technology at all clusters. At the lower marginal emissions factor for grid imported electricity compared to the DECC projection natural gas CHP becomes a net contributor to on site emissions so that any cost benefit is off set by the additional required capacity of PV. Ground source heat pumps, however, provide a high and accelerating emissions reduction rate such that by 2033 the annual emissions reduction exceeds the target as illustrated by Fig. 6.14. The infrastructure cost primarily consists the installations costs of the heat pumps (£13,652,750) and PV (£9,393,477). This results in an increase of the optimal infrastructure cost relative to the reference case by £10,418,378 to £23,685,631.

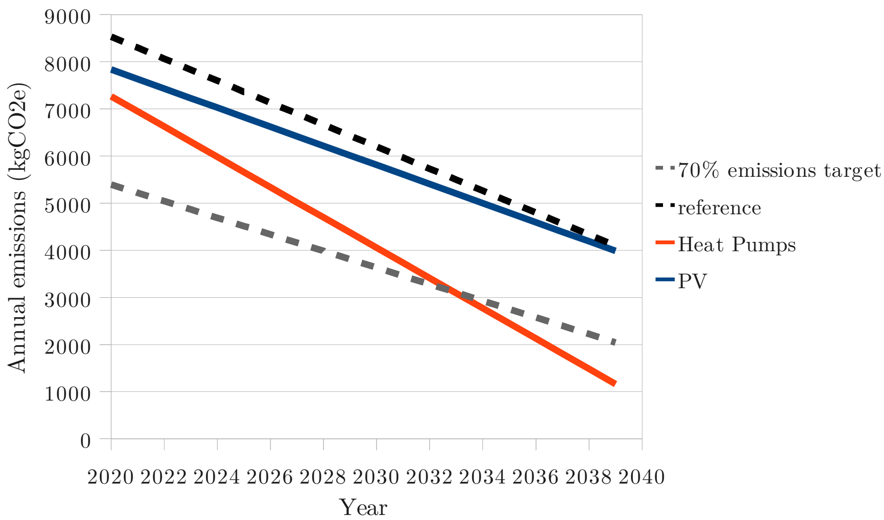


Figure 6.14: Emissions reduction contribution of PV and heatpumps for projection 3 optimal solution with 2020 build completion.

6.6 Conclusions

An integrated optimisation model for new build energy infrastructure schemes was successfully implemented using OpenOffice Calc. The tool applied the design and evaluation models presented within previous chapters to determine the least cost energy supply infrastructure for a community redevelopment case study in at Ebbw Vale in South Wales. An optimal design was determined for an anticipated build completion date of 2016 with a 60% reduction of regulated emissions and an additional cost to the developer of £13,267,253 relative to the reference solution of gas boilers at all premises.

The optimal infrastructure design and corresponding cost was shown to be strongly dependent upon the year of build completion. At an early completion date of 2012, the requirement for PV was removed and the cost relative to the reference case reduced to £3,149,184. A delayed completion date resulted in an optimal solution requiring heat pumps and an increased use of PV. This increased the optimal cost to £29,760,320.

A similar dependency was shown for the choice of emissions accounting method and projection for grid supplied electricity. Using a marginal emissions factor approach with the projection recommended by the Zero Carbon Hub, a solution based on natural gas district heating without PV was identified with a cost of £2,809,939 relative to the reference. Using the average grid carbon intensity to account for the electricity imported to and exported from the site resulted in an optimal solution based entirely on heat pumps and PV. The additional cost to the developer was correspondingly increased to £23,685,631.

Chapter 7

Conclusions

7.1 Conclusions

A new modelling method for the design and analysis of multi-energy vector distribution systems was demonstrated. The method provides an integrated framework for the technical design, carbon emissions analysis and financial analysis modelling of new build schemes. The model was also shown to be capable of capturing the interactions between the infrastructure design drivers for different energy supply technologies. The integrated model consists of the following key components:

- An *Energy Supply Infrastructure Model* to represent the layout and composition of each scheme;
- A *Technical Design Model* to provide the infrastructure design and the energy flow analysis inclusive of the interactions between technologies and networks.

- A *Carbon Emissions Analysis Model* to evaluate the energy consumption related greenhouse gas emissions;
- A *Financial Analysis Model* to evaluate the cost of the scheme and the performance of each actor within the ownership structure;
- An *Integrated Optimisation Model* to determine the least cost carbon constrained design of the energy supply infrastructure.

Two case studies were used to demonstrate the capability of the modelling method. A generic residential case study was devised to represent a typical new build market town residential development in the UK. This was used to examine the underlying design and performance drivers behind four competing on site infrastructure options:

- A reference case, which was defined with all buildings built to 2006 standards and heated using natural gas boilers.
- A building fabric option, which examined the use of improved insulation standards alone.
- An electrification of heat option, which used a mixture of ground source and air source heat pumps to supply space and hot water heating.
- A community heating option, using natural gas combined heat and power to supply all dwellings via a district heat network.

A second real life case study was used to demonstrate the capability of the model as a fully integrated optimised infrastructure design tool. This was based upon The Works, Ebbw Vale community regeneration scheme in South Wales. This scheme is scheduled for build completion by 2016 with a mandatory 60% target reduction of regulated emissions compared to 2006 building standards with gas boilers.

7.1.1 Energy Supply Infrastructure Model

Future energy systems are set to consist of a diverse mix of heat and electricity supply technologies implemented at building or community level. There is therefore a growing requirement for a whole system approach to infrastructure modelling within planning and design activities. This was achieved within the integrated framework by the use of an infrastructure model which consisted of:

- The grouping of buildings into clusters to model building level technologies and building energy consumption characteristics.
- Models of the energy distribution networks required to serve the entire site.
- An energy centre model containing community generation and heat storage units.

This modelling approach allowed the simultaneous consideration of all energy distribution networks and energy supply technologies on site including any interactions between them. For the purpose of this research the model was implemented successfully by using Open Office Calc. This software platform provided the necessary analytical functionality, but also demonstrated the modular form of the model. This suggests that the model is suitable for future development using database platforms such as Geographical Information System software.

7.1.2 Technical Design Modelling

The mix of energy supply technologies chosen for each scheme may significantly effect the peak energy demand and energy flow variation over time for each network. A technical design and operational model of the energy supply infrastructure was therefore required to capture the performance of each technology option and the interactions between them. A modular technical design modelling approach was applied that used a set of analysis algorithms which consisted of:

- A cluster analysis algorithm to determine the peak demand and network demand variation over time.
- Network design algorithms to specify the electricity, gas and district heat network components required on site.
- An energy centre design algorithm for the generation and heat storage installed within the energy centre.
- Operation modelling algorithms to determine the generation schedule of plant within the energy centre and the load flow variation over time for each distribution network.

Each analysis algorithm was successfully integrated into the Energy Supply Infrastructure Model. This was achieved by compiling a set of Java programs as add-in functions for direct use within OpenOffice Calc. The capability of the technical design model was demonstrated by evaluating the design of each option within the residential case study. It was able to show that:

- The increased peak electricity demand when using heat pumps can effect the design of the electricity distribution network by increasing the number of distribution substations and number of feeders required per transformer.
- Increasing the building fabric standard decreases the peak and annual electricity consumption when using heat pumps. The effect of heat pumps upon the design of the electricity network is therefore decreased.
- Using co-generation district heating without storage results in a heat

led mode of operation constrained by the shape of the demand profile. This results in an optimal combined heat and power plant size with regards to electricity generation.

- Using heat storage with natural gas engine community generation results in a decoupling of heat generation and the heat demand curve. This allows the gas engine combined heat and power plant to operate at rated heat generation output and for longer periods, and therefore increases the corresponding annual electricity production.
- Increasing the building fabric standard decreases the peak and annual heat demand but also reduces the corresponding electricity output when using natural gas engine co-generation district heating. The quantity of electricity imported annually from the grid is therefore increased.
- Increasing the capacity of PV results in an increase of peak electricity network flow during the summer months. This can significantly effect the design of the electricity network by increasing the number of transformers and the number of feeders required.
- The capacity of PV that may be accommodated without effecting the design of the electricity network is increased when used in conjunction with heat pumps.

7.1.3 Carbon Emissions Modelling

Building developments are set to become increasingly subject to mandatory emissions reduction targets through initiatives such as the Zero Carbon Homes. A detailed model of the annual and project life energy related carbon emissions for new build schemes is therefore an increasingly important part of the planning and design process.

A carbon emissions analysis model was implemented within the integrated framework. It was found that the contribution of four sources of energy related emissions were required for the analysis of each scheme: the fuel consumed within each cluster; the fuel consumed by the energy centre; the electricity imported from the grid; and the electricity exported to the grid. To determine the adherence to the emissions reduction targets, the model was required to evaluate both regulated and total emissions for each scheme.

The emissions model was shown to be suitable for integration with the Energy Supply Infrastructure model using the output data from the Technical Design models. The scope and capability of the model was demonstrated by examining the mechanism and extent of the emissions reduction obtained for each option within the residential case study. It was able to show that:

- For the electrification of heat using heat pumps the on-site emissions decrease proportionally with the emissions factor of the grid supplied electricity.
- At marginal grid carbon emissions intensities above ~0.5kgCO_2e/kWh a net emissions increase occurs when using heat pumps instead of individual natural gas boilers.
- At marginal grid carbon emissions intensities below ~0.2kgCO_2e/kWh, heat pumps are capable of delivering the emissions saving alone. The accumulative zero carbon homes emissions reduction target over a 20 year period may therefore be met by only using heat pumps from 2030.
- There is a synergistic relationship between the use of heat pumps and building fabric improvement with regards to achieving a reduction of on site emissions.
- For the community co-generation option, the emissions reduction results from the trade-off between the increased fuel consumption of the combined heat and power plant and the avoided grid imported

electricity.

- At the high marginal grid carbon emissions intensity of 0.8kgCO_2e/kWh assumed within the zero carbon homes initiative for the current generation mix, the emissions reduction using the natural gas engine community co-generation with heat storage option exceeds that required by the annual zero carbon homes emissions target. The aggregated project life emissions target over a 20 year period is therefore met without using supplementary technologies for projects completed before 2018.
- At marginal grid carbon emissions intensities <0.25kgCO_2e/kWh, the community generation option results in a net increase of annual emissions compared to individual gas boilers. Beyond 2025 therefore, this option was shown to provide a net contribution to emissions over a 20 year project period compared to individual gas boilers.
- As the marginal grid carbon emissions factor decreases, the emissions reduction obtained from electricity generated on site using photovoltaic panels is also decreased. The capacity of PV required per unit reduction of emissions therefore increases with year of build completion. This suggests that initiatives such as the Zero Carbon Homes may not be conducive to the uptake of PV in the long term.

7.1.4 Financial Modelling

The use of community level generation technologies and district heating schemes gives rise to potentially complex organisational and ownership structures. These may include a diverse mix of actors that may also vary considerably from scheme to scheme. Typical actors may include the building construction contractors, distribution network operators and local energy services companies. A flexible approach to financial analysis was therefore required by the integrated model for an adequate consideration of such schemes.

An example financial analysis model was devised to reflect a mix of actors typically involved with community developments. The total cost of the scheme was considered in terms of the additional total scheme cost per dwelling relative to the reference case. The model was integrated into the OpenOffice Calc framework developed for this thesis. The generic residential scheme was used to demonstrate the capability of the model which was able to show that:

- At a build completion of 2012, the minimum additional cost for the community co-generation option was £7,360 per dwelling. This was a consequence of PV not being required together with the revenues obtained from electricity generation. This compared to £9,156 for the building fabric option and £19,321 for the electrification of heat.
- At 2020, the cost of the community generation option was increased to £11,506 due to an increasing reliance upon PV. A similar increase to £12,745 was shown for the building fabric option due to the diminishing performance of PV. The electrification of heat remains the most expensive option, but with a reduced cost of £17,361 due to a reduced reliance upon PV.
- At 2025 and beyond, the electrification option incurs the lowest additional cost of those options considered at £14,163 per dwelling.

The results suggest that a window of opportunity exists for the use of natural gas community generation as the solution for new build schemes under the zero carbon homes initiative. This may therefore provide a short term transitional technology for the development of district heating schemes. In the long term, heat pumps can take advantage of any significant measures to de-carbonise the grid. However the high installation costs still present a significant obstacle to developers.

7.1.5 Integrated Optimal Infrastructure Design

The ability to identify the least cost energy supply infrastructure for new build schemes has always been a fundamental requirement of the planning and design process. With the growing number of energy technology options and increasingly stringent environmental constraints, this is becoming an increasingly challenging task beyond the capability of existing design tools.

The modular structure of the modelling approach developed within this thesis was not suited for use with gradient based optimisation methods. The search for an optimal solution instead required the use of non derivative based search algorithms. For the purpose of this thesis, a Social Cognitive Optimisation Solver extension for OpenOffice Calc was successfully implemented within the modelling framework and applied to the The Works, Ebbw Vale case study.

The optimal energy supply infrastructure was determined for the scheme at a build completion date of 2016 using the DECC projection for grid supplied electricity emissions. The optimal solution primarily consisted of a district heat network supplied using a 4,075kW natural gas combined heat and power with heat storage. Individual natural gas boilers were specified for 60 residential dwellings and 1.6MW of PV was required on site. The corresponding additional cost to the developer was ~£13.2m compared to the reference case with individual gas boilers at all premises.

The effect of build completion year upon the optimal design was examined. An early completion of 2012 reduced the extent of the required heat network and eliminated the requirement for any photovoltaic panels. This was due to the higher emissions factor of the marginal grid electricity production replaced by local CHP. By avoiding the use of PV to meet the emissions target, a significant reduction of the optimal cost by ~£10m to £3.15m was obtained. A delayed completion to 2020 reduces the emissions factor of the marginal grid electricity generators. This increases the capacity of PV required for natural gas combined heat and power and decreases that required for heat pumps. The resultant optimal solution was thus a mix of district heating, heat pumps, individual natural gas boilers and PV. The corresponding optimal cost was increased by more than £16m to £29.7m reflecting the high capital cost of heat pumps and the reduced emissions reduction capacity of natural gas combined heat and power.

The high sensitivity of optimal cost to the emissions factor of grid supplied electricity emissions was also shown to manifest within the choice effect of emissions factor projection. By using the average emissions intensity for all grid supplied electricity, an optimal solution is obtained that specifies only heat pumps and PV with a cost increase >£10m to £23.7m. Applying the Zero Carbon Hub methodology on the other hand was shown to eliminate the need for PV and reduce the required extent of the heat network. The corresponding optimal cost was reduced to £2.8m.

7.2 Summary of Contributions

- A new integrated modelling framework was demonstrated which combines the technical design, emissions analysis and financial analysis of new build energy supply infrastructure schemes.
- The use of a new Energy Supply Infrastructure model for new building schemes was demonstrated.
- The drivers underlying the carbon constrained design of new build residential developments were studied. The interactions between different technology options were shown. Natural gas combined heat and power district heating was shown to be viable in the near term,

whilst the viability of heat pumps requires a significant level of decarbonisation of grid supplied electricity.

- The use of the model as an optimal infrastructure design tool was shown for a real mixed use community redevelopment scheme in South Wales.
- The sensitivity of the optimal infrastructure solution and corresponding cost to year of build completion was shown, reflecting the different responses of competing technologies to the grid carbon emissions projection.
- The high sensitivity of the optimal infrastructure solution and cost to the choice of emissions projection was shown, illustrating the potential impact of applying an incorrect emissions accounting methodology.

7.3 Future Work

7.3.1 Framework development

It is anticipated that the modular structure of the model will be suitable for application within other platforms used for infrastructure planning and design including propriety geographical information systems such as ArcGIS. Further work may therefore examine the requirements for implementing the framework of the model within a wider range of platforms.

7.3.2 Modelling

The scope and detail of the model has been limited for the purpose of this thesis. Several areas of improvement have however been recognised. The cluster approach to modelling the built environment may be improved by including:

- An extended treatment of solar based technologies including solar thermal heating. This may include more sophisticated models of generation output verses penetration levels.

- A model of building insulation improvements for commercial premises and an inclusion of other building efficiency measures such as lighting.
- A model of the effect of electric vehicle penetration within schemes.
- A consideration of the effect of smart metering and distribution level control schemes.
- The modelling of a local micro-grid as a building cluster.

The models used for the energy centre and distribution networks may be extended by:

- The inclusion of district cooling, adsorption chillers and tri-generation for schemes with a significant space cooling demand.
- An extension of the model to include biomass conversion technologies such as biomass boilers, integrated biomass gasification combined heat and power, integrated anaerobic digestion combined heat and power, gas grid integrated anaerobic digestion and energy from waste. These models could be used to examine the use of sustainable local resources for meeting energy emissions reduction targets.

The emissions analysis model was limited to those directly resulting from on site energy consumption and generation. Further work may extend the model to evaluate the full life-cycle emissions for each infrastructure component. The financial model was limited to new build schemes with all construction complete at the start of year 1. Further development may therefore include:

- A multi-time period analysis for schemes developed in phases and to consider the replacement / upgrade of generation units.
- Consideration of the cost of retrofit schemes including construction

costs etc.

- An expansion of the cost model to include DNO costs and charges, end user costs and private wire ownership structures.

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Appendix A1

Energy Demand Data

A1.1 Daily Demand Profiles

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	0.2	0.2	1	1	1	1	0.4	0.4
Hot Water	0	0	1	1	1	1	1	1
Appliance	0.25	0.25	0.93	0.93	1	1	0.81	0.81
Cooling	0	0	0	0.25	1	1	0.5	0.25

Table A1.1: Daily profile shape for Offices

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	1	1	1	1	1	1	1	1
Hot Water	0	0	1	1	1	1	1	1
Appliance	0.74	0.74	0.93	0.93	1	1	0.74	0.74
Cooling	0	0	0	0	0	0	0	0

Table A1.2: Daily profile shape for Small Education

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	1	1	1	1	1	1	1	1
Hot Water	0	0	1	1	1	1	1	1
Appliance	0.74	0.74	0.93	0.93	1	1	1	1
Cooling	0	0	0	0	0	0	0	0

Table A1.3: Daily profile shape for Large Education

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	1	1	1	1	1	1	1	1
Hot Water	1	1	1	1	1	1	1	1
Appliance	0.53	0.53	0.74	0.74	1	1	0.74	0.74
Cooling	0	0	0	0	0	0	0	0

Table A1.4: Daily profile shape for Health

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	1	1	1	1	1	1	1	1
Hot Water	0	0	0	0	0	0	0	0
Appliance	0.2	0.2	1	1	1	1	0.65	0.65
Cooling	0	0	0	0.25	1	1	0.5	0.25

Table A1.5: Daily profile shape for Retail

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	0	0	0	0	0	0	0	0
Hot Water	0	0	1	1	1	1	1	1
Appliance	0.43	0.43	0.78	0.78	0.95	0.95	1	1
Cooling	0	0	0	0.25	1	1	0.5	0.25

Table A1.6: Daily profile shape for Leisure

	0000 - 0300	0300-0600	0600-0900	0900-1200	1200-1500	1500-1800	1800-2100	2100-0000
Space Heat	0.16	0.74	1	0.36	0.49	0.84	0.81	0.14
Hot Water	0	0	1	1	1	1	1	1
Appliance	0.26	0.19	0.53	0.82	0.78	0.89	1	0.79
Cooling	0	0	0	0	0	0	0	0
Cooking	0	0	1	0.5	0	0.5	1	0

Table A1.7: Daily profile shape for Domestic

A1.2 Annual Demand

Building Usage Type	Space heating (kWh/m^2)	Hot Water (kWh/m^2)	Appliance and lighting			Space Cooling (kWh/m^2)
			Auxilliary (kWh/m^2)	Lighting (kWh/m^2)	Equipt. (kWh/m^2)	
Office	103.9	15.5	9.3	46.5	60.5	13.9
Education	51.5	30.9	4.7	34.9	34.9	0
Health	87.6	46.4	27.9	62.8	144.2	0
Retail	56.7	0	18.6	158.2	30.2	113.9
Leisure	0	159.8	34.9	51.2	32.6	69.8

Table A1.8: Annual demand for non domestic premises (2006 building standards, HMGov 2008)

Building Usage Type	Dwelling Size (m^2)	Space heating (kWh/m^2)	Hot Water (kWh/m^2)	Cooling (kWh/m^2)	Appliance and lighting: Appliance (kWh/m^2)	Appliance and lighting: Lighting (kWh/m^2)
Apartment	43	49.6	35.4	4.9	48.5	9.3
Terrace	76	72.8	26.5	3.5	32.9	7.6
Semi detached	76	72.8	26.5	3.5	32.6	8.7
detached	118	61.5	19.1	2.7	24.4	9.3
Market Town	**77.6**	**65.1**	**25.0**	**3.5**	**31.7**	**8.8**

Table A1.9: Annual demand for domestic premises (2006 building standards) (derived DCLG 2008).

A1.3 Peak Demand

Building Usage Type	Peak Heat Demand (W/m^2)	Peak Electricity Demand (W/m^2)
Office	90[1]	60[2]
Small Education	90[1]	60[3]
Large Education	110[1]	60[3]
Health	110[1]	40
Retail	110[1]	60[2]
Leisure	110[1]	90[3]

Table A1.10: Estimated Peak demand for non-domestic premises (1, CIBSE Guide F; 2, CIBSE Guide K; 3, DECC CHP Plant Sizer).

A1.4 Seasonality factors

Month	Space heat[1]	Electric appliance / lighting[2]	Space cooling[1]	Solar[3]
January	1.00	1.00	0	0.11
February	0.90	0.92	0	0.19
March	0.85	0.83	0	0.47
April	0.68	0.74	0.04	0.67
May	0.39	0.68	0.78	0.97
June	0	0.64	1	1
July	0	0.62	0.83	0.98
August	0	0.63	0.69	0.95
September	0	0.67	0.29	0.88
October	0.34	0.77	0.05	0.3
November	0.65	0.90	0	0.17
December	0.92	0.98	0	0.1

Table A1.11: Seasonality factors for building energy demand. (1, Oxford Uni 2011; 2, Elexon 2006; 3, Carbon Trust 2009).

Appendix A2

Technical and Cost Data

A2.1 Electricity Network Data

Rating (A)	Size (mm^2)	R(Ω/km)[1]	X(Ω/km)[1]	Cost (£/m)[2]
233	95 XLPE	0.32	0.119	50
337	185 XLPE	0.164	0.108	55
442	300 XLPE	0.1	0.101	60

Table A2.1: 11kV cable parameters. All cables assumed to be aluminium XLPE Triplex (1, Central Networks 2006; 2, Green 1999 (adjusted for inflation)).

Rating (A)	Size (mm^2)	R(Ω/km)[1]	X(Ω/km)[1]	Cost (£/m)[2]
201	95 Wavecon	0.32	0.075	50
292	185 Wavecon	0.164	0.074	55
382	300 Wavecon	0.1	0.073	60

Table A2.2: 0.4kV cable parameters (1, Central Networks 2006; 2, Green 1999 (adjusted for inflation)).

Capacity (kVA)	Type	R(Ω)[1]	X(Ω)[1]	Cost (£)[2]
7500	33/11kV	-	-	383,160
15000	33/11kV	-	-	494,760
315	11/0.4kV	0.009	0.0268	26,784
500	11/0.4kV	0.0051	0.0171	27,404
800	11/0.4kV	0.0029	0.0107	29,140
1000	11/0.4kV	0.0022	0.0086	30,504

Table A2.3: Electricity transformer parameters. Impedances are refered to the low voltage side of the transformer (1, Central Networks 2006; 2, Green 1999 (adjusted for inflation)).

A2.2 Gas Network Data

Pipe Diameter (mm)	Roughness	Installed Cost (£/m)
32	0.08	5.83
63	0.08	7.33
90	0.08	13.66
125	0.08	26.21
180	0.08	62.25
250	0.08	100.6
315	0.08	138.56
375	0.08	173.9
450	0.08	216.65
600	0.08	302.15

Table A2.4: PE Gas pipe parameters (www.pipestock.com)

Component	Cost (£)
Grid Connection	10,000
PRI	7,500
Domestic service connection	590 (/dwelling)
commercial service connection	10 (/kW)

Table A2.5: Miscellaneous Gas network costs

A2.3 Heat Network Data

Pipe diameter (m)	Roughness	Insulation Thickness (mm)	Insulation Thermal Conductivity (W/m/K)	Installed Cost (£/m)
0.032	0.08	0.1	0.028	134
0.040	0.08	0.1	0.028	140
0.050	0.08	0.1	0.028	146
0.065	0.08	0.1	0.028	151
0.080	0.08	0.1	0.028	161
0.100	0.08	0.1	0.028	182
0.125	0.08	0.1	0.028	209
0.150	0.08	0.1	0.028	259
0.200	0.08	0.1	0.028	325
0.250	0.08	0.1	0.028	488
0.300	0.08	0.1	0.028	626
0.400	0.08	0.1	0.028	765
0.600	0.08	0.1	0.028	1040

Table A2.6: Data for polyurathane insulated steel district heat pipes (http://www.hevac.ie/calpex-pipe.php).

A2.4 Building Level installation Costs

Installation type	Cost
Gas Boilers (Domestic)[1]	£2500/dwelling
Gas Boilers (Commercial)[1]	£45/kW
Ground Source Heat Pumps (Domestic)[2]	$2560\Phi^{0.6}$ £/dwelling
Ground Source Heat Pumps (Commercial)[1]	£1000/kW
Air Source Heat Pumps (Domestic)[1]	£600/kW
Air Source Heat Pumps (Commercial)[1]	£600/kW
District Heating (Domestic)[1]	£4820/dwelling
District heating (Commercial)[1]	£20/kW
PV[3]	£725/m^2

Table A2.7: Building level supply costs (1, Poyry 2010; 2, derived from Rawlings 2004; 3, data obtained from http://info.cat.org.uk/solarcalculator)

A2.5 Energy Centre Plant

Plant Type	Fuel conversion efficiency	Heat recovery factor	Maximum Downturn
NG Boiler	0.94[1]	0.8[2]	0.2[1]
NG-ICE-CHP	0.94[2]	0.8[2]	0.5[2]

Table A2.8: Energy Centre Plant Parameters (1, HVAC 2012; 2, NREL 2003 (adjusted for inflation))

The data set used to model the relationship between large scale natural gas boiler cost and rated plant output is shown by Fig. A2.1. The corresponding empirical relationship was determined as:

$$C_{NGB}=7{,}171\left(\frac{\Phi_{Rated}}{1{,}000}\right)^{0.93}+3{,}365 \tag{A2.1}$$

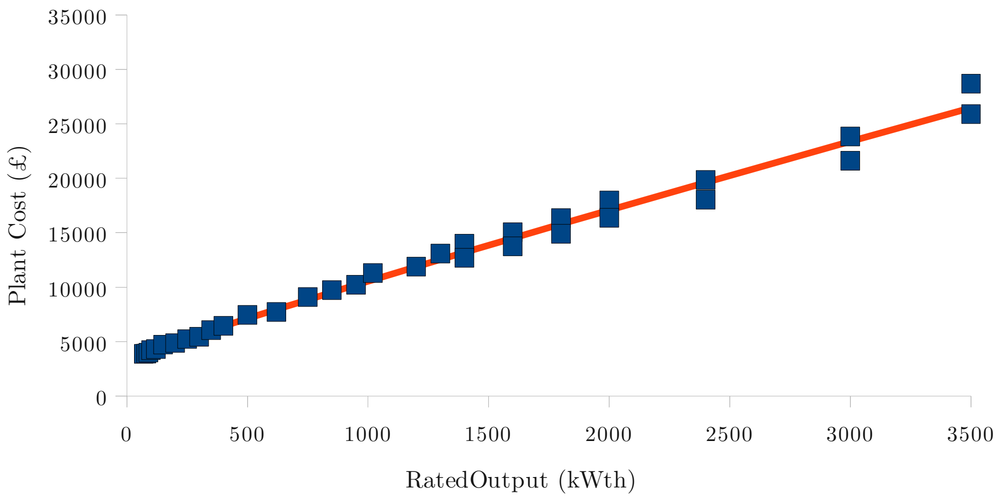

Figure A2.1: Variation of cost against plant size for large scale heat only gas boilers. (From Hevac 2012)

Figure A2.2 Shows typical cost data for natural gas CHP. The corresponding empirical equation is:

$$c_{CHP}=1{,}712\,P_{Rated}^{-0.11} \tag{A2.2}$$

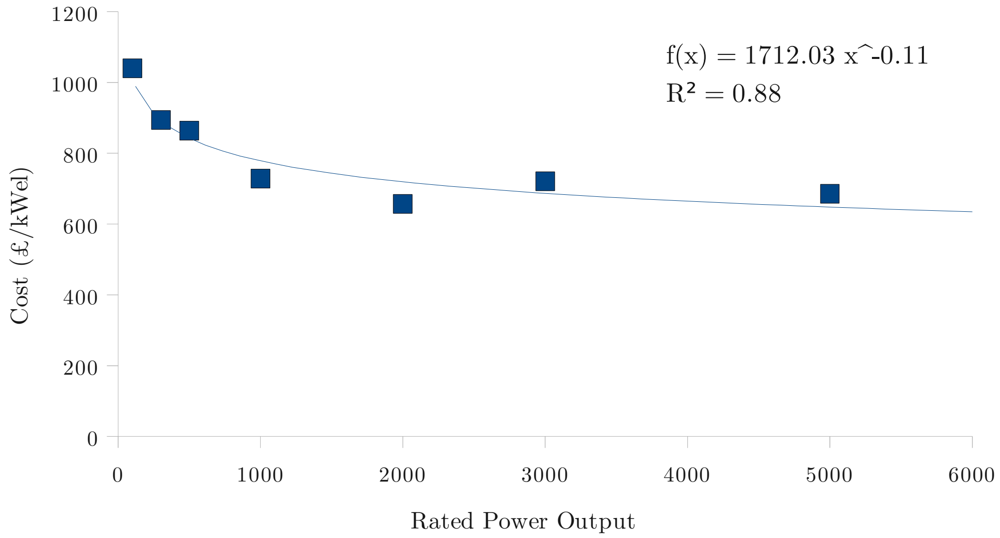

Figure A2.2: Variation of plant cost with rated power output for natural gas internal combustion engine combined heat and power plant (Data obtained from: 1, NREL 2003; 2, Poyry 2010).

The pump cost was determined using the following empirical relationship obtained from Vallios et al (2009):

$$C_{Pump} = 4{,}000\left(\frac{P_{rated}}{36}\right)^{0.21} \quad \text{(A2.3)}$$

A2.6 Building Fabric costs

This section presents the data used to model fabric costs. This was obtained from (ZCH 2009).

Building Standard	Ventillation Type	Annual space heat demand (kWh/yr)	Fraction reduction	Build Premium (£/dwelling)
Base	NV	2,132	0.00	0
A	NV	1,125	0.47	675
B	NV	880	0.59	1,417
B	MVHR	424	0.80	3,117
C	NV	532	0.75	4,100
C	MVHR	72	0.97	5,800
D	MVHR	81	0.96	6,159

Table A2.9: Building fabrication cost data for Small Apartments (occupied floor space = $43m^2$)

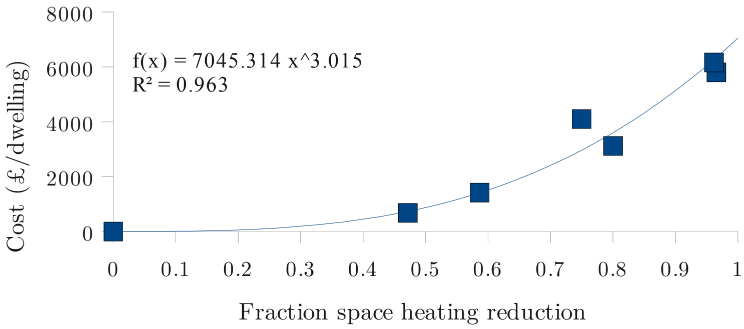

Figure A2.3: Variation of cost with fraction reduction of space heating for appartments.

Building Standard	Ventillation Type	Annual space heat demand (kWh/yr)	Fraction reduction	Build Premium (£/dwelling)
Base	NV	5,532	0.00	0
A	NV	2,780	0.50	675
B	NV	2,271	0.59	1,417
B	MVHR	1,336	0.76	3,117
C	NV	1,610	0.71	4,100
C	MVHR	493	0.91	5,800
D	MVHR	197	0.96	6,159

Table A2.10: Building fabrication cost data for mid terraced houses (occupied floor space=76m^2).

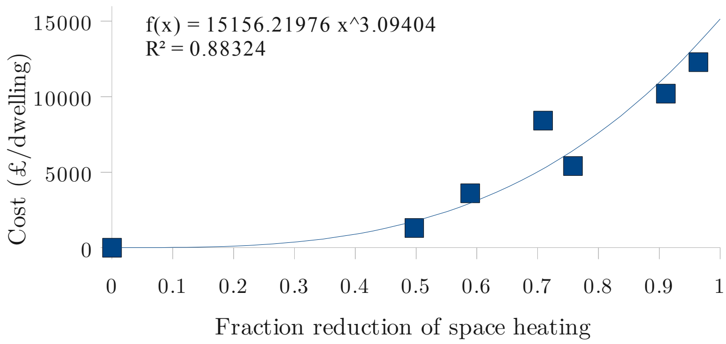

Figure A2.4: Variation of cost with fraction reduction of space heating for mid terrace houses.

Building Standard	Ventillation Type	Annual space heat demand (kWh/yr)	Fraction reduction	Build Premium (£/dwelling)
Base	NV	5,320	0.00	0
A	NV	3,724	0.30	1,297
B	NV	2,736	0.49	3,602
B	MVHR	1,900	0.64	5,402
C	NV	2,627	0.51	8,410
C	MVHR	828	0.84	10,210
D	MVHR	296	0.94	12,284

Table A2.11: Building fabrication cost data for semi detached houses (occupied floor space = 76m^2).

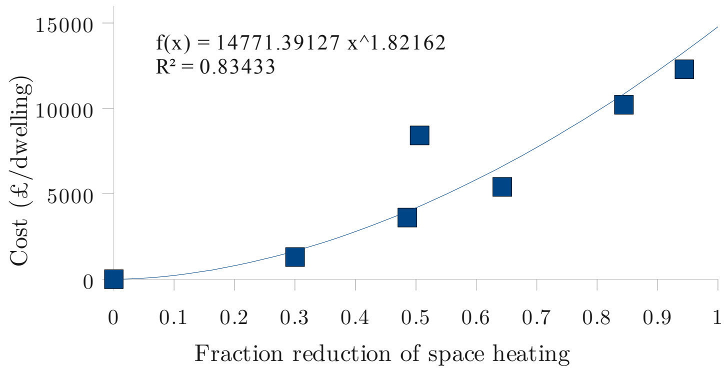

Figure A2.5: Variation of cost with fraction reduction of space heating for semi detached houses.

Building Standard	Ventillation Type	Annual space heat demand (kWh/yr)	Fraction reduction	Build Premium (£/dwelling)
Base	NV	7,257	0.00	0
A	NV	5,865	0.19	1,946
B	NV	4,803	0.34	5,851
B	MVHR	3,599	0.50	8,051
C	NV	3,563	0.51	13,380
C	MVHR	1,864	0.74	15,580
D	MVHR	849	0.88	19,541

Table A2.12: Building fabrication cost data for detached houses (occupied floor space = 118m^2)

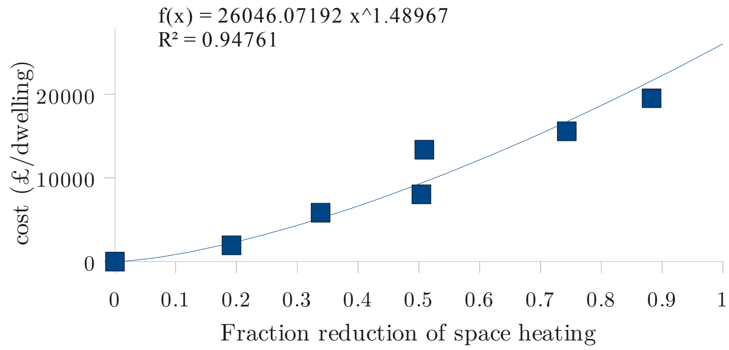

Figure A2.6: Variation of cost with fraction reduction of space heating for sdetached houses.

The market town residential mix was defined as a development scenario by the Department for Communities and Local Governments as 25% Detached houses, 27% terraced houses, 21% semi detached and 27% Apartments. This weighting was applied to each of the derived curves to obtain the following data set and empirical relationship:

Fraction reduction	Cost
0	0
0.1	263
0.2	801
0.3	1579
0.4	2608
0.5	3912
0.6	5517
0.7	7455
0.8	9759
0.9	12464
1	15607

Table A2.13: Weighted build premium for Market town residential mix

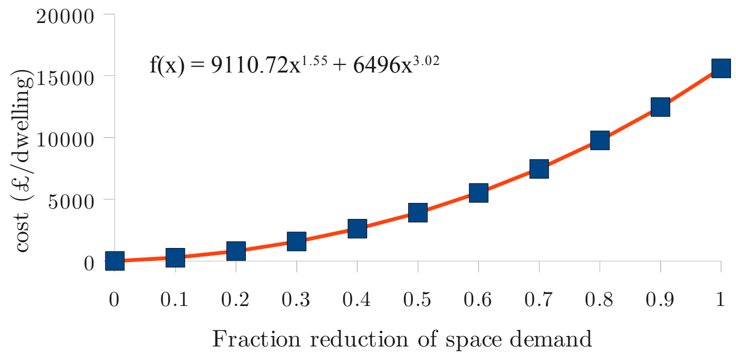

Figure A2.7: Variation of cost with fraction reduction of space heating for market town property mix.

A2.7 Energy price data

Fig. A2.8 shows the daily variation of electricity tariff used to model the participation of a CHP plant with the electricity market via an aggregator. This was obtained by assuming that the price varied proportionally with the variation of daily electricity demand. The percentage range of variation from the daily average price was taken to be that used by Fragaki et al (2008).

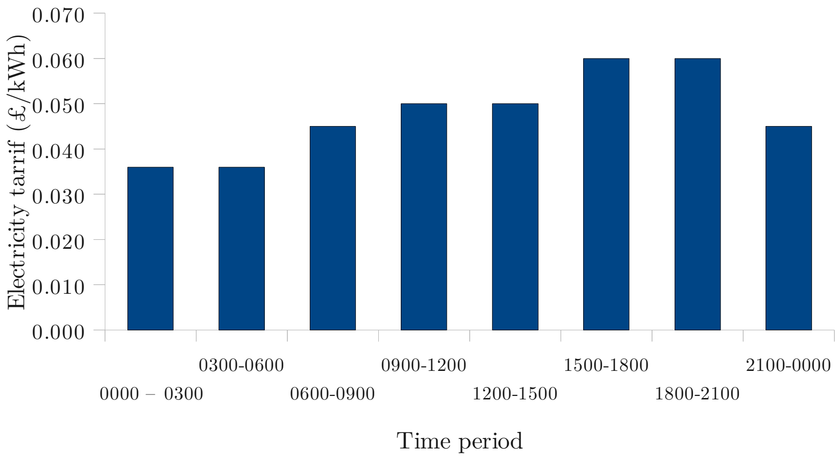

Figure A2.8: Variation of electricity tarrif for electricity exported to the grid by community scale combined heat and power.

Appendix A3

A3.1 Electricity network Load flow analysis

A backwards – forwards sweep method was employed for the analysis of the electricity distribution networks.

The selected algorithm was a two-step iterative process consisting a backward sweep to determine the line currents from the currents injected from each bus and a forwards sweep to update the voltages at each bus.

1. Backwards Sweep:

The current per phase corresponding to a balanced three phase power consumption S at bus j is given by:

$$I_{phase} = \frac{S^*}{3V^*} \tag{A3.1}$$

By kirchoffs current law, the injected into each bus is given by:

$$I_{in,j} = \sum I_{out,j} + \sum I_{load,j} \tag{A3.2}$$

This summation is repeated for all busbars traced back to the root bus (slack).

2. Forwards Sweep:

The forwards sweep uses the line currents to determine the voltage drop along each line from the root bus to each of the terminal busbars. For each line, the voltage drop along each phase is given by:

$$\Delta V_{phase} = I_{phase} Z_{phase} \tag{A3.3}$$

The updated voltage at each bus is therefore:

$$V_{phase,to} = V_{phase,from} - \Delta V_{phase} \quad \text{(A3.4)}$$

The backwards sweep is then repeated using the updated voltages to recalculate the bus load currents.

A3.2 Gas Network Load Analysis

A radial pipe flow algorithm was used to analyse the natural gas network. This involved a backwards sweep from the points of consumption to the grid connection point followed by a single forwards sweep to determine the flow velocity and the pressure drop within each pipe.

Consider a gas pipe of length L *(m)* and diameter D (m) connecting a demand node *node 2* with a supply node *node1*. The demand at *node2* is F_{node2} (kJ/s). If the Gross Calorific Value of the gas = GCV_{gas} (kJ/mol), then the molar flow rate F_{mol} (mol/s) of the gas through the pipe is given by:

$$F_{mol} = \frac{F_{node2}}{GCV_{gas}} \quad \text{(A3.5)}$$

The gas volumetric flow rate $\dot{V}$ (m^3/s) was estimated using the ideal gas equation by assuming a negligible pressure drop across the pipe:

$$\dot{V} = \frac{F_{mol} R T}{p_{node1}} \quad \text{(A3.6)}$$

Where R is the gas constant, T is the absolute temperature (K), and p_{node1} is the pressure at the source node *node1*. The flow velocity u (m s^{-1}) of the gas through the pipe was thus given by:

$$u = \frac{4\dot{V}}{\pi D} \quad \text{(A3.7)}$$

The density of the gas ρ (kg/m^3) within the pipe is given by

$$\rho = \frac{p_{node1} M_{gas}}{R T} \tag{A3.8}$$

Where M_{NG} is the molecular mass of natural has (kg/mol). The pressure drop due to friction Δp_l was calculated using the Darcy equation:

$$\Delta p_{friction} = \frac{f_D L}{D} \frac{\rho u^2}{2} \tag{A3.9}$$

Where f_D is the dimensionless Darcy friction factor for the pipe.

A3.3 District heat network Load flow

A radial pipe network flow and heat loss analysis was employed within district heat network analysis algorithm. This performed the network analysis in three stages. The first stage determines the fluid flow rate along each pipe. The second stage calculates the temperature drop. An iteration between stages 1 and 2 are performed until convergence. The third stage determines the pressure drop along each pipe due to friction.

Stage 1:

The flow rate through each pipe within a hydraulically isolated radial district heat network is obtained from:

$$\boldsymbol{A}\dot{\boldsymbol{m}} = \boldsymbol{q} \tag{A3.10}$$

Where $\boldsymbol{A}$ is the network incidence matrix, $\dot{\boldsymbol{m}}$ is the vector of pipe mass flows, and $\boldsymbol{q}$ is vector of flows entering and leaving the network at each node. The flow at each demand node is given by:

$$\dot{m}_{Dmd} = \frac{\Phi_{Dmd}}{c_p (T_s - T_r)} \tag{A3.11}$$

Where Φ is the heat demand (kW) T_s is the supply temperature (°C), T_r is the return temperature (°C), and c_p is the specific heat of water (kJ kg^{-1} K^{-1}). The flows entering the point of supply are calculated such that:

$$\sum \dot{m}_{sup} = \sum \dot{m}_{dem} \tag{A3.12}$$

Stage 2:

The second stage is a forward sweep to determine the temperature drop across the network. For each pipe this is given by:

$$T_{endNode} = (T_{startNode} - T_{amb}) e^{-\frac{(h \pi D L)}{(4 \dot{m})}} + T_{amb} \tag{A3.13}$$

Where k is the overall heat transfer coefficient for the pipe (W/m^2 K). This is calculated from the thermal conductivity k (W/mK) of the pipe insulation using:

$$h = \frac{2k}{D_{inner} \ln (D_{outer} / D_{inner})} \tag{A3.14}$$

By assuming perfect mixing, the temperature of water leaving any given node is given by:

$$T_{out} = \frac{\sum T_{in} \dot{m}_{in}}{\sum \dot{m}_{out}} \tag{A3.15}$$

Having obtained the updated node temperatures of the supply and return lines, stage 1 is repeated to obtain new estimates of the flows at consumers.

Stage 3:

After a convergence of nodal temperatures, the pressure loss across the network is calculated using the mass flow form of the Darcy equation:

$$\Delta p_{friction} = \frac{f_D L}{D^5} \frac{8 \dot{m}^2}{\pi^2 \rho} \tag{A3.16}$$

A3.4 Calculation of the Darcy friction factor.

The friction factor for a pipe transporting a fluid is a function of the Reynolds number *Re.* For circular pipes this is given by:

$$Re=\frac{\rho u D}{\mu} \tag{A3.17}$$

Where ρ is the fluid density, u is the fluid velocity (ms^{-1}), D is the pipe diameter (m) and μ is the dynamic viscosity of the fluid ($kg\ m^{-1}\ s^{-1}$).

For Re <2000 (Laminar flow):

$$f_D=\frac{64}{Re} \tag{A3.18}$$

For Re > 4000 (turbulent flow):

$$\frac{1}{\sqrt{f_D}}=-2\log_{10}\left(\frac{e}{3.7D}+\frac{2.51}{Re\sqrt{f_D}}\right) \tag{A3.19}$$

Where e is the pipe roughness.

Appendix A4

Case Study data

A4.1 Residential Case Study

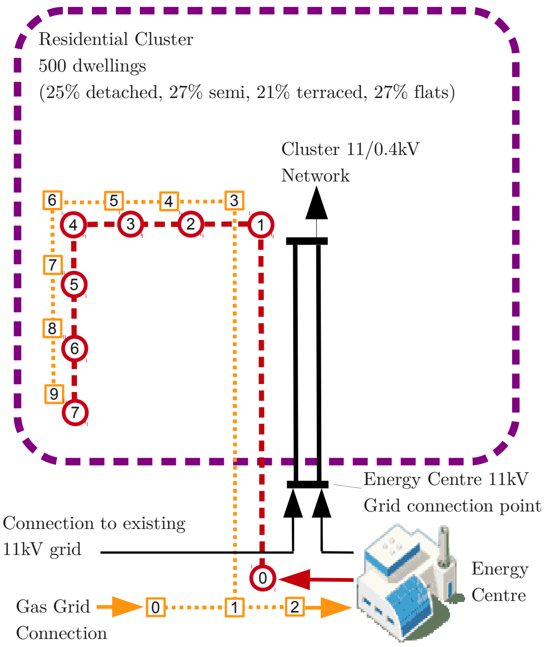

Figure A4.1: Schematic of example scheme.

Cluster Area:	225000 m^2
Number of dwellings:	500
Annual Space heat demand:	4490kWh/dwelling
Annual domestic hot water demand:	2014kWh/dwelling
Annual appliance and lighting demand:	3145kWh/dwelling
Annual cooking demand:	443kWh/dwelling

Table A4.1: Residential cluster properties

Line	Type	from	To	length
0	XLPE cable	0	1	
1	XLPE cable	1	2	
2	XLPE cable	2	3	
3	XLPE cable	3	4	
4	XLPE cable	4	5	
5	XLPE cable	5	6	
6	XLPE cable	6	7	
7	11/0.4kV sub	7	8	
8	XLPE cable	7	1	
9	XLPE cable	1	0	

Table A4.2: 11kV Electricity network

Arc Number	Arc type	from	To	Length
0	PE Pipe	0	1	50
1	PE Pipe	1	2	50
2	PE Pipe	1	3	240
3	PE Pipe	3	4	80
4	PE Pipe	4	5	80
5	PE Pipe	5	6	80
6	PE Pipe	6	7	80
7	PE Pipe	7	8	80
8	PE Pipe	8	9	80
Grid connection pressure: 65mbar (Low Pressure)				

Table A4.3: Gas network

Pipe	from	To	Length
0	0	1	240
1	1	2	80
2	2	3	80
3	3	4	80
4	4	5	80
5	5	6	80
6	6	7	80
Supply temperature: 90°C			
Return temperature: 50°C			
Maximum head of pressure: 14bar			

Table A4.4: Heat Network

A4.2 Ebbw Vale Case Study Data

Cluster	Arc No.	From	To	Length	Cluster	Arc No.	From	To	Length
	0	0	1	200	3Cr	43	43	44	57
	1	1	2	250	3Cr	44	44	45	57
	2	2	3	80	3Cr	45	45	46	57
	3	2	4	100	3Cr	46	46	47	57
	4	4	5	150	3Cr	47	47	48	57
Hospital	5	5	6	400	3Cr	48	48	49	57
	6	1	7	150		49	12	50	50
	7	7	8	90		50	50	51	50
	8	7	9	130	1G	51	51	52	150
Energy C.	9	9	10	150	3B	52	51	53	100
	10	9	11	200		53	51	54	100
	11	11	12	75	1A	54	54	55	100
	12	11	13	1500	2B	55	54	56	100
PRI	13	3	14	-		56	50	57	250
PRI	14	5	15	-	3A	57	57	58	56
PRI	15	8	16	-	3A	58	58	59	56
PRI	16	12	17	-	3A	59	59	60	56
PRI	17	13	18	-	3A	60	60	61	56
	18	14	19	200	3A	61	61	62	56
4A	19	19	20	45	3A	62	62	63	56
4A	20	20	21	45		63	13	64	100
4A	21	21	22	45	2D	64	64	65	50
4A	22	22	23	45		65	64	66	400
4A	23	23	24	45	4B	66	66	67	100
4A	24	24	25	45		67	66	68	200
	25	15	26	200	5C	68	68	69	80
	26	26	27	70	1F	69	68	70	300
3Cb	27	27	28	20	4B	70	67	71	45
3Cb	28	28	29	20	4B	71	71	72	45
3Cb	29	29	30	20	4B	72	72	73	45
3Cb	30	30	31	20	4B	73	73	74	45
3Cb	31	31	32	20	4B	74	74	75	45
3Cb	32	32	33	20	4B	75	75	76	45
	33	26	34	250	5C	76	69	77	30
5D	34	34	35	35	5C	77	77	78	30
5D	35	35	36	35	5C	78	78	79	30
5D	36	36	37	35	5C	79	79	80	30
5D	37	37	38	35	5C	80	80	81	30
5D	38	38	39	35	5C	81	81	82	30
5D	39	39	40	35	1F	82	70	83	30
	40	8	41	50	1F	83	83	84	30
3D	41	41	42	75	1F	84	84	85	30
	42	41	43	100	1F	85	85	86	30
					1F	86	86	87	30
					1F	87	87	88	30

Grid connection Pressure	2bar
PRI outlet pressure	75mbar

Table A4.5: The Works Gas Network topology and arc lengths

Cluster	Arc No.	From	To	Length	Cluster	Arc No.	From	To	Length
Energy C.	0	0	1	80		41	1	42	190
	1	1	2	70		42	42	43	100
	2	2	3	15	3Cr	43	43	44	57
	3	2	4	50	3Cr	44	44	45	57
	4	4	5	120	3Cr	45	45	46	57
	5	4	6	30	3Cr	46	46	47	57
	6	6	7	15	3Cr	47	47	48	57
	7	6	8	70	3Cr	48	48	49	57
	8	4	9	60		49	42	50	80
	9	9	10	150		50	50	51	50
Cluster 3A	10	10	11	56	3D	51	50	52	270
3A	11	11	12	56		52	52	53	110
3A	12	12	13	56	4A	53	53	54	44
3A	13	13	14	56	4A	54	54	55	44
3A	14	14	15	56	4A	55	55	56	44
3A	15	15	16	56	4A	56	56	57	44
	16	9	17	1500	4A	57	57	58	44
	17	17	18	60	4A	58	58	59	44
2D	18	17	19	400		59	59	60	160
	19	19	20	80		60	60	61	270
4B	20	20	21	45		61	61	62	15
4B	21	21	22	45		62	61	63	60
4B	22	22	23	45	Hospital	63	60	64	200
4B	23	23	24	45		64	64	65	70
4B	24	24	25	45	3Cb	65	65	66	19
4B	25	25	26	45	3Cb	66	66	67	19
	26	19	27	60	3Cb	67	67	68	19
5C	27	27	28	80	3Cb	68	68	69	19
5C	28	35	36	30	3Cb	69	69	70	19
5C	29	36	37	30	3Cb	70	70	71	19
5C	30	37	38	30		71	64	72	300
5C	31	38	39	30	5D	72	72	73	35
5C	32	39	40	30	5D	73	73	74	35
	33	40	41	30	5D	74	74	75	35
1F	34	27	35	210	5D	75	75	76	35
1F	35	35	36	30	5D	76	76	77	35
1F	36	36	37	30	5D	77	77	78	35
1F	37	37	38	30					
1F	38	38	39	30					
1F	39	39	40	30					
	40	40	41	30					

Supply temperature: 90°C
Return temperature: 50°C
Maximum head of pressure: 14bar

Table A4.6: The Works district heat network topology and arc lengths

Appendix A5

Electricity Distribution Network modelling

This section describes the methodology used to model the configuration of the electricity distribution network within a new building scheme. The modelling methodology was devised to accommodate the use of the parameters that govern the network topology as design variables. A generic network configuration was defined and applied to each cluster within the scheme as illustrated by Fig. A5.1. This generic configuration was then reduced to the configuration required for the scheme.

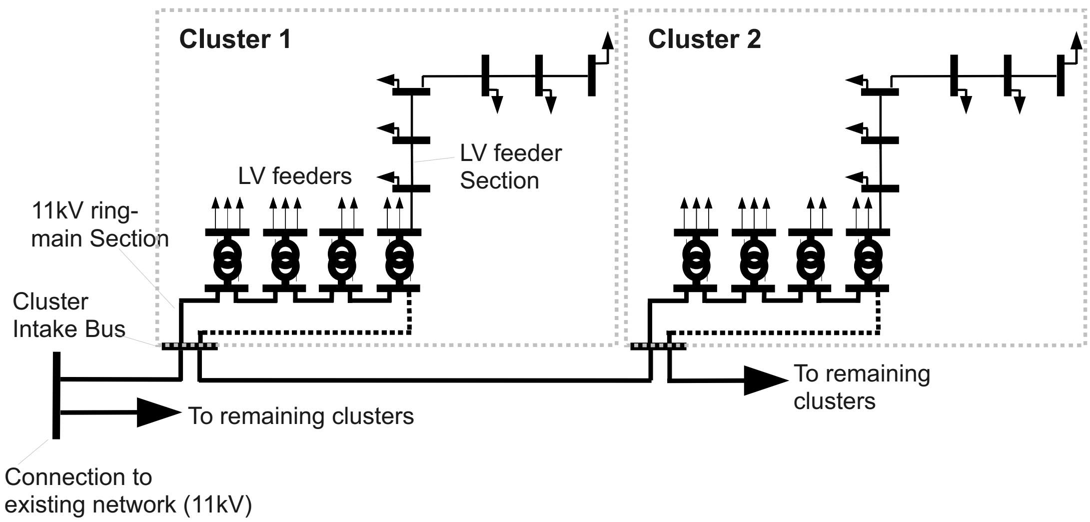

Figure A5.1: Illustration of the generic network configuration applied to initiate the design of electricity distribution network.

A5.1 Configuration of 0.4kV feeders

The configuration used to model each 0.4kV feeder was dependent upon the number of transformers required per cluster, N_{Trans}, and the number of feeders required per transformers N_{feeder}. These parameters were determined by the *clusterNetworkSizing* algorithm (see Chapter 3). A rule base system was then used to collapse the generic 0.4kV feeder configuration to the configuration required. This is detailed within Tables A5.1 and A5.2 and illustrated by Fig. A5.2.

Table A5.1: Rule system used to determine the lengths of each 0.4kV feeder section:

N_B / N_{ss}/ $N_{Feeders}$	$L_{Section1}$	$L_{Section2}$	$L_{Section3}$	$L_{Section4}$	$L_{Section5}$	$L_{Section6}$
≤ 1	$\sqrt{A_{feeder}}/2$	0	0	0	0	0
≤ 2	$\sqrt{A_{feeder}}/2$	$\sqrt{A_{feeder}}/4$	0	0	0	0
≤ 3	$\sqrt{A_{feeder}}/2$	$\sqrt{A_{feeder}}/4$	0	0	0	0
≤ 4	$\sqrt{A_{feeder}}/4$	$\sqrt{A_{feeder}}/2$	$\sqrt{A_{feeder}}/4$	0	0	0
≤ 5	$\sqrt{A_{feeder}}/4$	$\sqrt{A_{feeder}}/4$	$\sqrt{A_{feeder}}/4$	0	0	0
≤ 11	$\sqrt{A_{feeder}}/3$	$\sqrt{A_{feeder}}/3$	$\sqrt{A_{feeder}}/3$	$\sqrt{A_{feeder}}/4$	0	0
≤ 17	$\sqrt{A_{feeder}}/3$	$\sqrt{A_{feeder}}/3$	$\sqrt{A_{feeder}}/3$	$\sqrt{A_{feeder}}/6$	$\sqrt{A_{feeder}}/6$	0
≥ 18	$\sqrt{A_{Feeder}}/3$	$\sqrt{A_{Feeder}}/3$	$\sqrt{A_{Feeder}}/3$	$\sqrt{A_{Feeder}}/8$	$\sqrt{A_{Feeder}}/8$	$\sqrt{A_{Feeder}}/8$

Table A5.2: Rule system used to determine loads at each 0.4kV feeder busbar:

N_B / N_{ss}/ $N_{Feeders}$	P_{bus1}	P_{bus2}	P_{bus3}	P_{bus4}	P_{bus5}	P_{bus6}
≤ 1	$P_c/N_{ss}/\ N_{feed}$	0	0	0	0	0
≤ 2	$P_c/N_{ss}/\ N_{feed}/2$	$P_c/N_{ss}/\ N_{feed}/2$	0	0	0	0
≤ 3	$2P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/3$	0	0	0	0
≤ 4	$P_c/N_{ss}/\ N_{feed}/2$	$P_c/N_{ss}/\ N_{feed}/4$	$P_c/N_{ss}/\ N_{feed}/4$	0	0	0
≤ 5	$2P_c/N_{ss}/\ N_{feed}/5$	$2P_c/N_{ss}/\ N_{feed}/5$	$P_c/N_{ss}/\ N_{feed}/5$	0	0	0
≤ 11	$P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/6$	$P_c/N_{ss}/\ N_{feed}/6$	0	0
≤ 17	$P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/6$	$P_c/N_{ss}/\ N_{feed}/12$	$P_c/N_{ss}/\ N_{feed}/12$	0
≥ 18	$P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/3$	$P_c/N_{ss}/\ N_{feed}/6$	$P_c/N_{ss}/\ N_{feed}/18$	$P_c/N_{ss}/\ N_{feed}/18$	$P_c/N_{ss}/\ N_{feed}/18$

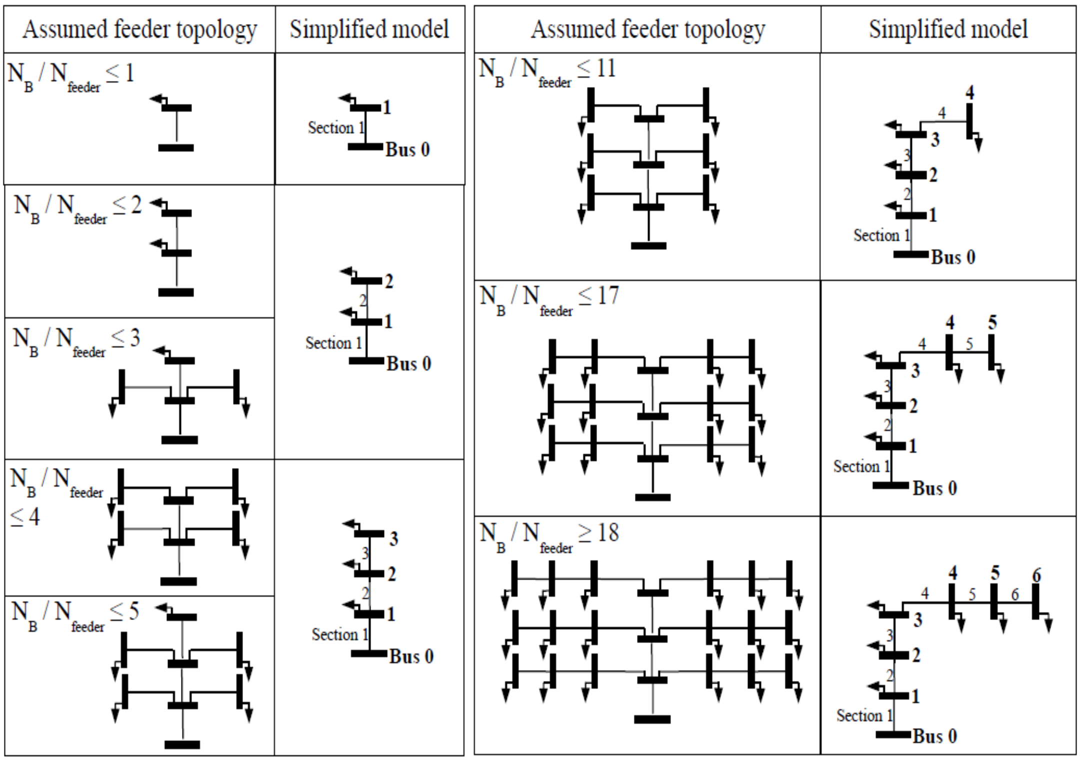

Figure A5.2: Possible 0.4kV feeder configurations modelled by generic feeder configuration.

A5.2 Configuration of 11kV distribution network

It was assumed that the route of the 11kV ring-mains interlinking the grid connection point to the N_c building clusters was known. Within each building cluster, the configuration of the 11kV network was dependent upon the number of 11/0.4kV transformers required, N_{Trans}. This was determined by the *clusterNetworkSizing* algorithm. The configuration of the 11kV network within each cluster was determined within the *primaryPowerNetworkSizing* algorthm (Chapter 3) using the rule system described by Table A5.3. The possible 11kV configurations obtained from the generic configuration within the model are illustrated by Fig. A5.3.

Table A5.3: Rule system used to determine 11kV network:

Cable of generic network:	Rule:
1	If $N_{ss} > 3$ then $L_{cable1} = \sqrt{A_C}/2$, else $L_{cable1} = 0$.
2	If $N_{ss} > 2$ then $L_{cable2} = \sqrt{A_C}/2$, else $L_{cable2} = 0$.
3	If $N_{ss} > 1$ then $L_{cable3} = \sqrt{A_C}/2$, else $L_{cable3} = 0$.
4	If $N_{ss} > 1$ then $L_{cable4} = \sqrt{A_C}/2$, else $L_{cable4} = 0$.

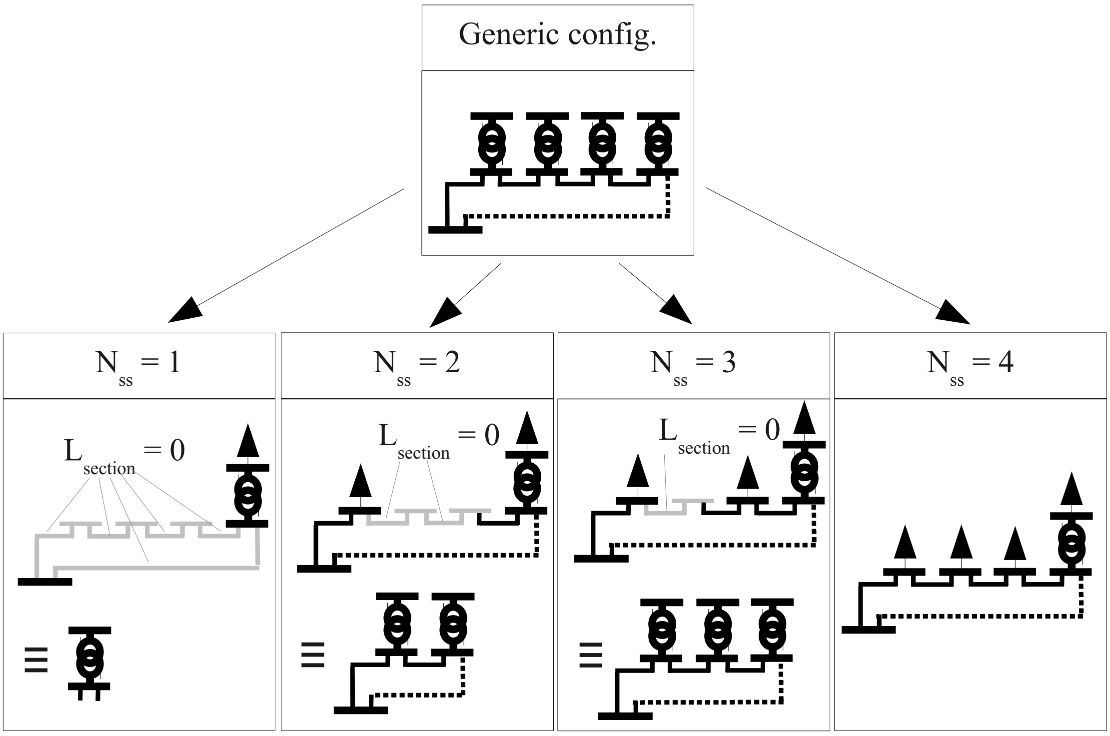

Figure A5.3: Possible 11kV network configurations modelled for each building cluster.