Proceedings of BS2013:
13th Conference of International Building Performance Simulation Association, Chambéry, France, August 26-28

THE IMPACT OF DISTRICT HEATING NETWORK ADOPTION ON ACHIEVING ZERO CARBON TARGETS

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ABSTRACT

This study formulates a mixed integer linear programming (MILP) model to examine the impact of district heating networks on the delivery of on-site carbon reduction targets for new mixed-use, multi-phase urban development projects over their entire construction cycle. The model is formulated to design district energy systems, e.g. technology selection, unit sizing, and distribution network configuration, with the objective of minimising economic cost. A number of fuel and network configuration scenarios are developed, and their relative cost-effectiveness for achieving zero carbon emissions is assessed. Further analysis is carried out to determine if off-site interventions, i.e. allowable solutions, can be employed to meet emission reduction shortfalls.

INTRODUCTION

There is an on-going paradigm shift in urban energy systems, from centralised energy generation and long-range transmission, towards decentralised generation and the implementation of district energy systems and local distribution networks. These local systems can increase the efficiency and flexibility of energy delivery by minimising transmission and distribution losses, reusing waste energy (e.g. combined heat and power systems), or utilising local sources of renewable fuel. However, the widespread adoption of local energy systems also increases the complexity of energy provision at the district level. To make them effective, it is essential that the structure and operation of district systems are determined in a rigorous manner that takes into account the temporal and spatial variations in energy demand, in addition to the drivers (i.e. cost, climate change mitigation, air quality, etc.) that influence the energy-planning decision-making framework.

A number of optimisation tools including MARKAL (Seebregts et al, 2001), MODEST (Henning et al, 2006), and DER-CAM (Siddiqui et al, 2003) have been developed using the mixed integer linear programming (MILP) approach to determine the optimal configuration of district energy systems at various spatial and temporal scales. More recently, Keirstead et al (2012), Mehleri et al (2011, 2012), and Webber and Shah (2011) have developed MILP models to determine not only the structure and operation of a district energy system, but also the configuration of the distribution networks.

The Distributed Energy Network Optimisation (DENO) model, presented in this study, builds upon this on-going work. The primary aim of DENO is to determine the optimal design and operation of a district energy system. It does so by selecting the optimal combination of electricity and thermal generation technologies to install, while also determining when to install them during a multi-phase development schedule, where to locate each technology, and how best to distribute the generated energy among the buildings through the design of the district heating and cooling network.

Within the model formulation, nodes define the locations of energy generation and consumption. Arcs, which link the nodes, represent the possible distribution of energy between generation and consumption nodes via the distribution network. The model is formulated to minimize operational cost by identifying the set of generation nodes and their characteristics (i.e. technologies installed, unit sizes, hourly operation, etc.), as well as the set of active arcs and the amount of energy that they distribute during each time-interval. DENO's default time-interval is 1 hour, twenty-four of which are aggregated to form a single day. Four of these days, one for each season, define one design year, and each construction phase is represented by one typical design year.

Large urban developments are typically constructed in multiple phases, leading to significant variations in the magnitude and location of energy demand between the phases of construction. This has an impact on the optimal location of generation technologies, and on the ideal schedule for technology installation and unit sizing. Including construction phases within the model allows for the intermediate installation of technologies at the start of each phase. This means that energy systems are not designed solely for the development's full build energy demand, which can lead to units that are underutilised until development's construction reaches completion. Instead, the systems are designed to expand modularly, in parallel with building construction and the growth in energy demand.

Full details of the model formulation are described in (Omu et al, 2013), which demonstrates the application of DENO on an urban development project in South East England by examining how energy subsidies, such as the Feed in Tarrifs and Renewable Heat Incentive, influence technology selection for district energy systems.

Another interesting application of the DENO model is an assessment of how development-level decisions about district heating network structure and fuel use can influence the ability for buildings to meet future zero carbon emissions targets in new mixed-use, multi-phase urban development projects.

Case Study: Queen Elizabeth Olympic Park

In 2012, construction of the Olympic Park was completed in Stratford, East London, in order to host the 2012 Olympic Games. The development area was subdivided into a number of districts called planning delivery zones (PDZs). Currently, the only buildings that are standing on the park are the Olympic venues (main stadium, aquatic centre, velodrome, indoor arena, etc.), the Media Press Centre, the International Broadcasting Centre, the Athlete's Village, and the energy centre. The rest of the land will be developed into residential and commercial neighbourhoods over the next 18 years.

Using energy efficient design, efficient energy supply, and on-site renewables, the Olympic Delivery Agency (ODA) set a target to reduce the park's immediate legacy (until 2013) emissions by 50% against a 2006 baseline; with 20% of this reduction to be from efficient energy supply and 20% from the use of on-site renewable generation (ODA, 2011). To achieve these targets an energy strategy was developed by the ODA, in collaboration with Buro Happold, and an energy centre was constructed at the Kings Yard site in PDZ 4. The energy centre houses a 3.3 MW_e natural gas fired combined heat and power plant (CHP), a 4 MW LiBr absorption chiller, three 7 MW ammonia chillers, a 3 MW_{th} biomass boiler, and two 20 MW_{th} natural gas boilers that meet the energy demands of the site by distributing energy through a district heating network (OPLC, 2012). The CHP presently provides 57% of the heat in the network, with the biomass and natural gas boilers providing the remaining 20% and 23%, respectively (OPLC, 2012). Additionally there are 7 small helical wind turbines and 107 PV panels mounted around the park. The entire Olympic Park energy system results in a park-wide emissions reduction of 20% due to energy efficiency of the CCHP, but only 9.3% from renewables, around 1000 tonnes/year short of the original 20% renewables emissions reduction target. This shortfall has been covered through the investment in off-site energy efficient retrofit projects in the surrounding boroughs, so called "allowable solutions" (ODA, 2011).

The heating network infrastructure is already installed for all PDZs except for PDZ 8 and PDZ 12, with a plan to expand the network to these areas in the future. If the district heating network is installed in a PDZ, then all buildings in that area are contractually required to connect to the network; and are unable to install renewable building scale heating technologies such as solar thermal collectors or ground source heat pumps (OPLC, 2012).

From 2013, the entire Olympic Park site will be transformed into its legacy form, the Queen Elizabeth Olympic Park, which will be mixed-use (about 70% residential overall) development that will be constructed from 2014 to 2031 (OPLC, 2012). Each PDZ contains mixes of different building uses including residential, office, retail, culture, and leisure. Table 1 summarises the floor areas and building use mixes for each planning delivery zone, and highlights any notable buildings.

Table 1: Characteristics of each Planning Delivery Zone

PDZ	Total Floor Area (m^2)			Residential (%)	Notable Buildings
	Current	Phase 1	Full Build		
1	22,910	119,687	186,938	65%	Aquatic Centre
2	0	0	86,181	70%	
3	62,300	62,300	62,300	0%	Olympic Stadium
4	0	50,945	72,778	76%	King's Yard Energy Centre
5	208,200	255,807	327,219	25%	Indoor Arena
6	0	146,761	146,761	69%	Velodrome
8	0	0	152,073	63%	
9	300,000	300,000	300,000	99%	Athlete's Village
12	0	0	58,563	52%	

The aim of the energy plan for the legacy development is to utilise the energy system that was installed for the 2012 Olympics while transitioning and expanding the system to meet the growing energy demands of the legacy development. Furthermore, as buildings will be constructed over an 18 year time period, the energy system that is put in place must adhere to increasingly stringent carbon reduction targets, including a zero carbon policy that will likely be introduced in 2016, for domestic building, and 2019, for non-domestic buildings (OPLC, 2012).

In order to assess the long-term implications of the Olympic Park's district heating network, the DENO model is employed to design the expansion of the current district energy system over the course of the two construction phases. The model aims to not only determine the optimal technology and fuel selection, but also to decide how best to increase generation capacity as demand grows.

As this analysis is carried out against a backdrop of progressively more stringent CO_2 emissions legislation, two key questions are assessed using a series of scenario analyses. Firstly, what is the impact of different district heating network fuel mixes? In other words, can a natural gas or biomass-fuelled system achieve the zero carbon standards, or is a move towards biogas required? Secondly, what is the overall impact of not expanding the district heating network to PDZ 8 and PDZ 12? Not expanding the network would allow buildings in these PDZ to install building scale renewables, which may influence the cost-effectiveness of the carbon emissions reduction measures.

The outputs (i.e. annual cost and annual CO_2 emissions reductions) of each scenario are compared to determine the degree to which future buildings on the site will be able to meet long-term emission reduction targets set by the Building Regulations and Zero Carbon Policy. This study also highlights the comparative annual cost-effectiveness (£/tonne CO_2 reduced) of each scenario, and determines the additional cost of meeting any emissions reduction shortfalls through "allowable solutions".

MODEL FORMULATION

The DENO model contains three integer decision variables, the number of units of technology i purchased at node n during phase h ($U_{n,i,h}$), the number of units of technology i operating at node n during period p of season s of phase h ($O_{p,s,h,n,i}$), and the active/inactive status of the arc between nodes n and n' for each energy end use u ($L_{n,n',u}$).

The continuous variables in the model are the amount of end use energy u generated by technology i at node n during period p of season s of phase h ($G_{p,s,h,n,i,u}$), the quantity of end use energy u distributed from node n to node n' during period p of season s of phase h ($D_{p,s,h,n,n',u}$), and the electricity that each node n purchases during period p of season s of phase h ($EP_{p,s,h,n}$).

There are three energy end uses, heating (heat), which includes both space heating and hot water, cooling (cool), and electricity (elec), each PDZ is defined as a node (n), and the model phases (h) are defined by the two development construction phases (OPLC, 2012):

- Phase 1 (2015-2021): Construction of up to 308,050 m^2 of floor space. (40% of entire site)
- Phase 2 (2022-2031): Construction of up to 460,585 m^2 of floor space.

Objective Function

The objective of the model is to minimise economic cost of the energy system, which is the sum of the electricity and fuel costs (C_{elec} and C_{fuel}), operational and maintenance costs (C_{om}), technological capital and installation costs ($C_{capital}$), and amortised network cost ($C_{network}$).

$$\mathbf{min}\ C_{fuel} + C_{elec} + C_{om} + C_{capital} + C_{network} \tag{1}$$

The fuel cost for the DER system is expressed as the annual energy generation of each purchased technology divided by the technology's efficiency, multiplied by the price of the appropriate fuel, summed over the entire time horizon.

$$C_{fuel} = \sum_n \sum_h \sum_s \sum_p \sum_i \sum_u \frac{N_h \cdot N_s \cdot Price_f \cdot G_{p,s,h,n,i,u}}{\eta_i} \tag{2}$$

The electricity cost is equal to the sum of the amount of electricity purchased multiplied by the electricity tariff.

$$C_{elec} = \sum_n \sum_h \sum_s \sum_p N_h \cdot N_s \cdot EPrice_p \cdot EP_{p,s,h,n} \tag{3}$$

The operation and maintenance cost is made up of a fixed cost, which is a function of the capacity of the unit, and a variable cost, which is a function of the annual generation of the unit.

$$C_{om} = \sum_n \sum_i \left(O_i^F \cdot MaxCap_i \cdot U_{n,i,h} + \sum_s \sum_p \sum_h N_h \cdot N_s \cdot O_i^V \cdot G_{p,s,h,,n,i,u} \right) \tag{4}$$

The capital cost is determined by multiplying the number of units of a technology that are purchased by the capacity of the technology and the unit cost of the technology.

$$C_{capital} = \sum_n \sum_i \sum_h MaxCap_i \cdot U_{n,i,h} \cdot CapC_{\ i} \tag{5}$$

The network cost expresses the cost of constructing the optimal distribution networks. This cost is calculated by multiplying the active arcs by the distance between the connected buildings and the unit cost of the network pipe or wiring, then amortising over the lifetime of the network components, and summing over the entire time horizon.

$$C_{network} = \sum_h \sum_u \sum_n \sum_{n'} N_h \cdot Dist_{n,n'} \cdot L_{n.n,u} \cdot PCost_u \cdot AnP_u \tag{6}$$

$$AnP_u = \frac{IR}{1 - \frac{1}{(1+IR)^{life_u}}} \tag{7}$$

Main Constraints

The following constraints limit the hourly energy generation of each unit. For all non-solar technologies, the hourly energy generation of each unit must be between the unit's maximum and minimum capacities. The maximum capacity of each unit is determined by the number of units of a given technology that are operational during each time interval ($O_{p,s,h,n,i}$) and the rated power of each of technology (*MaxCap$_i$*), while the minimum capacity is set by each technology's minimum allowable apart load (*MinLoad$_i$*).

$$O_{p,s,\hbar,n,i} \cdot MaxCap_i \cdot MinLoad_i \leq G_{p,s,\hbar,n,i,u} \leq O_{p,s,\hbar,n,i} \cdot MaxCap_i \qquad \forall\ p,d,s,n,i,u \tag{8}$$

For solar technologies, the hourly energy generation depends on the amount of available solar radiation, the surface area of the solar panels, and their orientation and modular efficiencies. The roof space at each node limits the maximum panel area.

$$G_{p,s,\hbar,n,i,u} \leq O_{p,s,\hbar,n,i} \cdot Area_i \cdot Solar_{p,s,\hbar} \cdot Orientation_n \cdot \eta_i \cdot \eta_{temp} \cdot \eta_{cabling} \cdot \eta_{inverter} \tag{9}$$

$$U_{n,i,\hbar} \cdot Area_i \leq MaxRoof_n \tag{10}$$

The next set of constraints ensure that the supply and demand of energy is balanced at every consumption node. Firstly, the electricity demand at every node, including any additional loads from DER technologies that consume electricity (e.g. heat pumps, electric chillers), must be satisfied by electricity that is generated by that node, distributed from other nodes, or purchased from the national grid.

$$\sum_n D_{p,s,\hbar,n,n',u} + EP_{p,s,\hbar,n'} \geq Dem_{p,s,\hbar,u,n'} + \sum_{i\in\{ASHP,GSHP\}} \frac{G_{p,s,\hbar,n',i,\{\hbar eat\}}}{COP_i * Corr_s} + \sum_{i\in\{EC\}} \frac{G_{p,s,\hbar,n',i,\{cool\}}}{COP_i} + \sum_{i\in\{ST\}} G_{p,s,\hbar,n',i,\{\hbar eat\}} \cdot Pump_{ST} \qquad \forall p,s,\hbar,n,n,u\{elec\} \tag{11}$$

Similarly, the heating and cooling demands at every node must be satisfied by energy that is generated internally or distributed from other nodes.

$$\sum_n D_{p,s,\hbar,n,n,u} \geq Dem_{p,s,\hbar,u,n} + \sum_{i\in\{AC\}} \frac{G_{p,s,\hbar,n',i,\{cool\}}}{COP_i} \qquad \forall p,s,n,n,u\{\hbar eat\} \tag{12}$$

$$\sum_n D_{p,s,\hbar,n,n,u} \geq Dem_{p,s,\hbar,u,n} \qquad \forall p,s,n,n,u\{cool\} \tag{13}$$

Heat generation from CHP units is in the form of heat recovered from the generation of electricity by the CHP. Therefore, the heat recovered from CHP units ($G_{p,s,\hbar,n,i,u\in\{\hbar eat\}}$), plus any heat that is dumped ($Q_{waste_{p,s,n}}$), must equal the electricity generation of the unit ($G_{p,s,\hbar,n,i,u\in\{elec\}}$) multiplied by the unit's heat to power ratio (λ).

$$G_{p,s,\hbar,n,i,u\in\{\hbar eat\}} + Q_{waste_{p,s,n}} = \lambda_i \cdot G_{p,s,\hbar,n,i,u\in\{elec\}} \qquad \forall p,s,n,i \in \{RE,BCHP,SCHP\} \tag{14}$$

There are a number of constraints that manage the way in which energy is distributed between nodes. For all energy end uses, energy that is distributed from a node to all connected nodes during every time interval must equal to the amount of energy that is generated at that node, divided by a distribution loss factor that indicates the percentage of the energy that is lost during energy distribution.

$$\sum_n D_{p,s,\hbar,n,n,u} = \frac{\sum_i G_{p,s,\hbar,n,i,u}}{DLoss_u} \qquad \forall p,s,\hbar,n,n,u \tag{15}$$

Finally, nodes can only be connected if they are part of the pre-determined set of allowable connections (*Net$_{n,n',u}$*) which is a binary matrix. For a fully flexible distribution problem, all the values in this matrix can be set to 1. This would allow all nodes to distribute energy to each other, as long as all other constraints are satisfied. Alternatively, certain entries in this matrix can be set to 0 in order to limit the number of locations where DER installation is allowed.

$$L_{n,n,u} \leq Net_{n,n,u} \qquad \forall n,n,u \tag{16}$$

Solution Algorithm

The MILP model is solved using the IBM ILOG CPLEX Optimisation Studio, which is an optimisation software program that uses the CPLEX solver. CPLEX employs a branch and cut algorithm to solve the MILP model (IBM, 2012).

Energy Demands

The electricity, heating, and cooling demands where calculated using the methodology that is outlined in Legacy Communities Scheme Revised Energy Statement (OPLC, 2012), which is based on the use of energy consumption benchmarks (CIBSE TM46, ECON 19, etc.). A summary of the annual electricity, heating, and cooling demands for each PDZ, presented in Figure 2, shows that the energy demand of the entire development is dominated by PDZs 1, 5, 6, 8, and 9. Additionally, in all PDZs the heat demand is higher than the electricity demand, which means that additional CHP units may be a viable option. Finally, PDZ 5 is the only area that has a significant demand for cooling, so cooling units will not need to be expanded beyond current capacity.

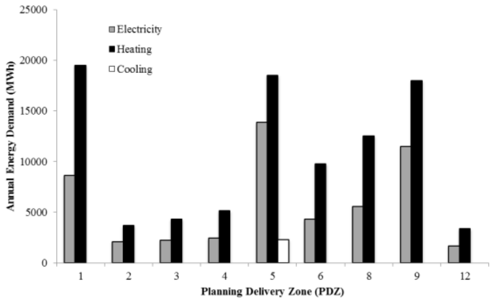

Figure 2: Annual Energy Demands for each PDZ

The annual end use energy demands where then applied to reference profiles for each building use in order to generate hourly energy demand profiles for every building use in each PDZ. The hourly energy demands of all the building uses in each PDZ where then aggregated to give the overall hourly energy demand profile for each PDZ, which were used as the energy demand profile for each consumption node for each season. Figure 3 shows the total seasonal electricity and heating demands segmented by planning delivery zone. As expected, while electricity demand is relatively constant throughout the seasons, the heating demand is lowest in the summer and highest in the winter.

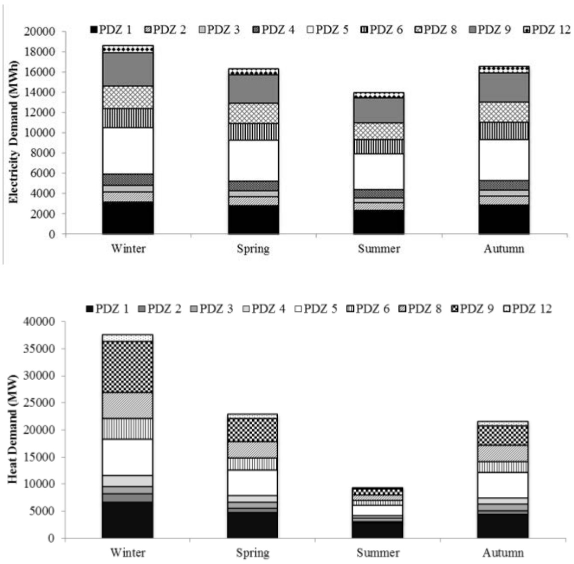

Figure 3: Seasonal heating demand broken down by PDZ.

Technology Set

A summary of the technology performance characteristics is given in Table 2 (NERA, 2009; POYRY, 2009; OPLC, 2012).

Table 2: Summary of DER Technology Set

Technology	Capacity (kW)	Capital Cost (£/kW)	Efficiency/COP	Heat to Power Ratio
Natural Gas Boiler	1000	45	86%	NA
Natural Gas CHP	1100	657	37.7%	0.95
Solar Thermal	2	1600	34%	NA
Photovoltaic	8	648	14%	NA
Biomass CHP	1500	4000	25%	2.0
Biogas CHP	1000	7745	39.7%	1.13
Biomass Boiler	1000	368	86%	NA
Ground Source Heat Pump	100	1410	3.3	NA
Air Source Heat Pump	100	619	2.6	NA
Absorption Chiller	1000	400	80%	NA
Electric Chiller	1000	200	2.0	NA

Electricity and Fuel Tariffs

Standard UK electricity and fuel tariff rates are employed in this analysis. The price of electricity bought from the grid is 0.11 £/kWh, while natural gas, biomass price, and biogas price are 0.038 £/kWh, 0.03 £/kWh, 0.04 £/kWh respectively (EST, 2012; DECC, 2012).

Legislative Targets

From 2016 all new homes will be zero carbon, and from 2019 all new non-domestic buildings will be zero carbon, which is defined as 100% reduction in regulated emissions. Regulated emissions are CO_2 emissions that result from energy uses that are currently regulated by Part L1A of L2A of Building Regulations. These include emissions that result from space heating, space cooling, water heating, fixed lighting, and auxiliary energy for pumps and fans. They do not include emissions that result from domestic appliances, decorative lighting, or equipment (OPLC, 2012).

Validation

In the Legacy Communities Energy Statement, the Olympic Park Legacy Committee (OPLC) calculate the annual regulated CO_2 for a number of scenarios including, 1) 2010 Baseline, 2) Only demand reduction measures, 3) Installation of Only Gas CHPs, and 4) Installation of only biomass boilers. Scenarios 3 and 4 include the installation of back up natural gas boilers. A comparison of the DENO modelled output emissions with the OPLC calculations, presented in Figure 4, shows that the model is able to output emission values that are consistent with the OPLC calculations.

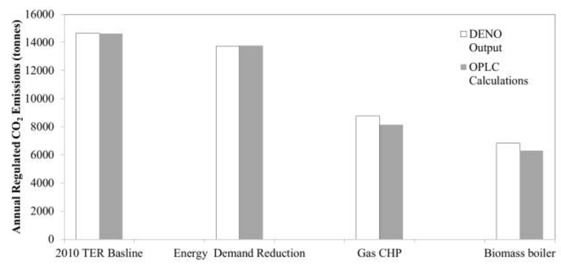

Figure 4: Comparison of emissions outputs from DENO model with OPLC calculated values.

Scenarios

In this study DENO is used to analyse how decisions made at the development-wide scale influence the ability for building level CO_2 emissions targets to be achieved. To do so, two questions are addressed. Firstly, what is the impact of the district heating fuel mix? To understand the extent of this influence, three scenarios are formulated in which different fuels, natural gas, biomass, and biogas, are available for combustion. For this analysis it is assumed that all buildings, including those in PDZ 8 and PDZ 12, will be forced to connect to the district heating network.

- **BAU:** All current and future demand is met by the district heating network with no change in fuel mix
- **Biomass**: All current and future demand is met by the district heating network with the utilisation of more biomass in the future through the installation of a biomass CHP
- **Biogas**: All current and future demand is met by the district heating network with the utilisation of biogas in the future through the installation of a biogas CHP

The second question revolves the impact of not expanding the district heating network to the two PDZs that are currently not connected, thus allowing for the installation of building scale renewable heat technologies. To understand this trade-off the following scenarios are compared:

- **BAU**: All current and future demand is met by the district heating network with no change in fuel mix
- **No Expansion**: The district heating network meets all current demand, but the network is not extended to PDZ 8 and PDZ 12. Additionally, there is no limitation on the combustion fuel.

DISCUSSION AND RESULTS

District Heating Network Fuel Analysis

It should be noted that in all scenarios studied the units that are currently installed at Kings Yard (i.e. 3.3 MW_e gas CHP, 4 MW absorption chiller, 21 MW of ammonia chillers, 3 MW_{th} biomass boiler, and 40 MW_{th} of natural gas boilers) are retained. Any additional capacity beyond this indicates the units that need to be installed in the future.

Table 3 outlines the technology and district heating network (DHN) fuel mix outputs for the three fuel scenarios. As the district system moves towards biomass and biogas, the share of energy provided by the gas CHP reduces, which should lead to less carbon intensive heat for the buildings on the site.

Table 3: Installed technology capacities and DHN fuel mix

Scenario	Final Installed Capacity [*Installed Capacity at end of Phase 1*]	District Heating Network Fuel Mix
BAU	Gas Boilers: 40 MW *[40 MW]* Biomass Boilers: 6 MW *[6 MW]* Gas CHP: 9.9 MW *[7.7 MW]* Absorption Chiller: 4 MW *[4 MW]* Ammonia Chiller: 21 MW *[21 MW]* PV : 68,940 m^2 *[40,565 m^2]*	56% Gas CHP 19% Gas Boiler 25% Biomass Boiler
Biomass	Gas Boilers: 40 MW *[40 MW]* Biomass Boilers: 6 MW *[6 MW]* Gas CHP: 8.8 MW *[6.6 MW]* Biogas CHP: 1.5 MW *[1.5 MW]* Absorption Chillers: 4 MW *[4 MW]* Ammonia Chillers: 21 MW *[21 MW]* PV : 68,940 m^2 *[40,565 m^2]*	24% Biomass CHP 39% Gas CHP 23% Biomass Boiler 14% Gas Boiler
Biogas	Gas Boilers: 40 MW *[40 MW]* Biomass Boilers: 6 MW *[6 MW]* Gas CHP: 3.3 MW *[3.3 MW]* Biogas CHP: 9 MW *[0 MW]* Absorption Chillers: 4 MW *[4 MW]* Ammonia Chillers: 21 MW *[21 MW]* PV : 68,940 m^2 *[40,565 m^2]*	59% Biogas CHP 23% Biomass Boiler 11% Gas Boiler 7% Gas CHP

Analysing the economic and emissions outputs in Table 4, the Biogas scenario is the only scenario that can reach the 100% reduction in regulated emissions through on-site generation. The original proposal was for an advanced thermal treatment facility at the nearby Fish Island site, with a gas distribution network between Fish Island and Kings Yard energy centre (OPLC, 2012). However, after an additional feasibility assessment, the preferred site was found to be prohibitively expensive, therefore biogas fuelled CHP is not a viable option for this development (OPLC, 2012). Consequently, the zero carbon policy cannot be met through on-site emissions reductions alone.

Table 4: Economic and emissions outputs of fuel change analysis

Scenario	Capital Cost (£million)	Annual CO_2 Emissions Reduction (tonnes)	Regulated Emissions Reduction	Annual Cost Effectiveness (£/tonnes CO2 saved)
BAU	£99.4	8,570	65%	2,240
Biomass	£106	12,500	92%	1,590
Biogas	£164	20,800	148%	1,670

District Heating Network Expansion Analysis

The main benefit of not expanding the district network to PDZ 8 and PDZ 12 is that the houses in those areas are able to install building renewable scale technologies, such as heat pumps and solar thermal. Looking at the technology outputs, given in Table 4, this is shown to be the case for PDZ 12 in which 200 kW of GSHP is installed. Whereas PDZ 8 would require its own small energy centre with a 1.1 MW gas CHP, a 2 MW gas boiler, and a 2 MW biomass boiler.

Table 4: Installed capacities for expansion scenarios

Scenario	Final Installed Capacity *[Installed Capacity at end of Phase 1]*
BAU	Gas Boilers: 40 MW *[40 MW]* Biomass Boilers: 6 MW *[6 MW]* Gas CHP: 9.9 MW *[7.7 MW]* Absorption Chillers: 4 MW *[4 MW]* Ammonia Chillers: 21 MW *[21 MW]* PV : 68,940 m^2 *[40,565 m^2]*
No Expansion	**DHN:** Gas Boilers: 40 MW *[40 MW]* Biomass Boilers: 6 MW *[6 MW]* Gas CHP: 7.7 MW *[6.6 MW]* Biomass CHP: 1.5 MW *[1.5 MW]* Absorption Chiller: 4 MW *[4 MW]* Ammonia Chiller: 21 MW *[21 MW]* PV (PDZ 1-7,9) : 48,000 m^2 *[40,565 m^2]* **PDZ 8:** 2 MW Gas Boiler *[0 MW]* 2 MW Biomass Boiler *[0 MW]* 1.1 MW Gas CHP *[0 MW]* PV: 14,924 m^2 *[0 m^2]* **PDZ 12:** 1 MW Gas Boiler *[0 MW]* 1 MW Biomass Boiler *[0 MW]* 200 kW GSHP *[0 MW]* PV : 6,014 m^2 *[0 m^2]*

Examining the economic and emissions outputs in Table 5, the capital cost of the No Expansion case is about 2% higher than the BAU case, however the annual emissions reduction is 50% higher, resulting in a lower cost effectiveness value of £1,500 per tonnes of CO_2 saved.

Table 5: Economic and emissions outputs for the expansion analysis

Scenario	Capital Cost (£mill)	Annual CO_2 Emissions Reduction (tonnes)	Regulated Emissions Reduction	Annual Cost Effectiveness (£/tonnes CO_2 saved)
BAU	£99.4	8,570	65%	2,240
No Expansion	£103	12,800	94%	1,500

Allowable Solutions

Allowable solutions are investments in off-site carbon emissions reductions that can be used to meet emissions reduction targets. They cost around £1,380/tonne CO_2 saved (OPLC, 2012). When the carbon shortfall, i.e. residual CO_2 emission reduction needed to reach zero carbon targets, is calculated, the cost of satisfying that excess through allowable solutions can also be determined.

Table 6 shows that although the Biogas scenario was the only scenario in which the zero carbon target was achieved through on-site reductions, it is the most expensive solution once allowable solutions are taken into account. In fact, the No Expansion scenario is actually the better option because the annual cost is relatively low, and the emissions shortfall is small, so the cost of allowable solutions needed to fill the gap is small, resulting in the lowest total annual cost.

Table 6: Annual costs including allowable solutions

Scenario	Annual Cost (£million)	Emission reduction shortfall (tonnes)	Allowable Solutions (£million)	Total Annual Cost Including Allowable Solutions (£million)
BAU	£19.2	5180	£ 7.1	£ 26.3
Biomass	£19.9	1220	£ 1.7	£ 21.6
Biogas	£34.8	0	0	£34.8
No Expansion	£19.3	927	£ 1.3	£ 20.6

A key result here is that the scenario that meets the on-site emissions reductions target is not necessarily always the best solution, especially when it is possible to offset any emission shortfalls through the investment in off-site emissions reductions.

CONCLUSION

In this study, the Distributed Energy Network Optimisation (DENO) model was employed to determine how top-level decision about district heating network structure and fuel can influence the ability for zero carbon emissions targets to be achieved at the building level. The analysis determined that due to the installation of the district heating network and the contractual obligation of future buildings to connect to the network, it is not possible for these buildings to be zero carbon through on-site measures alone, unless the main fuel used in the energy centre is biogas. As biogas was found to be infeasible for the site, the developers will need to invest in off-site carbon reduction measures (i.e. allowable solutions) in order to achieve their target emissions reductions.

In fact, the calculation of the emission shortfalls and the required allowable solutions shows that it is actually more cost-effective for developers to not attempt to meet the emissions targets solely through on-site measures. Instead, a biomass based district heating network (with the installation of one 1.5 MW biomass CHP), coupled with allowable solutions leads to the least expensive option for scenarios in which the district heating network is expanded to include all planning delivery zones (PDZs).

When the structure of the district heating network is considered, not expanding into PDZ 8 and PDZ 12 can lead to a marginally cheaper and more cost-effective solution as it allows for the installation of a small amount of GSHP in PDZ 12. In this case as well, a biomass based district heating network for the rest of the site is also required.

ACKNOWLEDGEMENTS

The main author is indebted to staff at Buro Happold Consulting Engineers for discussing the content of the energy strategies for both the Olympic Park and Olympic Legacy masterplan, as well as explaining how the energy strategies were developed.

NOMENCLATURE

f	=Fuel
h	=Phase
i	=Technologies
n	=Generation node
n'	=Demand node
p	=Period of the day
s	=Season
u	=Energy end use
y	=Year
AnP	=Annuity of the distribution network pipes
Area	=Solar panel surface area (M2)
CapC	=Capital cost (£/kW)
COP	=Coefficient of performance
Corr	=COP seasonal correction factor
Dem	=Energy Demand (kW)
Dist	=Distance between nodes (M)
DLoss	=Energy lost in distribution (%)
Eprice	=Price of electricity (£ per kWh)
IR	=Interest Rate for investment (8%)
KW_p	=Peak power output (kW)
Life	=Distribution network lifetime (years)
MaxCap	=Maximum unit capacity (kW)
MaxRoof	=Maximum available roof area (m2)
MinLoad	=Minimum load of technology
Net	=Allowable network Connections
N_p	=Years in each phase
N_s	=Days in each Season
OF	=Fixed O&M cost (£/kW)
Orientation	=Orientation efficiency factor (%)
OV	=Variable O&M cost ((£/kW)
PCost	=Price of network connection (£ per m)
P_p	=Hours in each time Period
$Price_f$	=Price of fuel (£/kWh)
Pump	=Pumping electricity Demand (kWh)
Qwaste	=Waste heat from CHP (kWh)
Solar	=Solar Irradiation (kW)
η	=Efficiency
λ	=Heat to power ratio

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