Techno-Economic and Business Cases Assessment of Low Carbon Technologies in Distributed Multi-Energy Systems

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Abstract

Increasing focus on energy affordability and environmental impact is drawing interest towards the potential value of low carbon technology (LCT) interventions in buildings and district energy systems. Relevant interventions may include improvements of the insulation levels and installation of low carbon and renewable generation technologies (e.g., combined heat and power, photovoltaics, heat pumps). These LCT interventions for both electricity and heat supply can, in principle, reduce energy costs and CO₂ emissions for final energy consumers. This can be achieved by coupling, and possibly optimising, multiple energy vectors from traditionally independent systems (e.g., electricity, heat and gas). However, this transition to distributed *multi-energy* systems introduces complex physical and commercial interactions between the different energy vectors. Further, these interactions can be fundamentally different at different aggregation levels (e.g., premises, district, and commercial level). This makes the assessment of business cases for LCT interventions in a multi-energy context a grand challenge, and given the potentially disruptive commercial impact of many such novel technologies, such complexity might result in a barrier to their development. In light of this, this paper proposes a techno-economic framework for the assessment of business cases of LCTs, which systematically models the physical and commercial multi-energy flows at the premises, grid connection point, and commercial levels. This is particularly important given the commonly asymmetrical nature of various energy price components, which can have significant effects on the business cases of LCTs and associated actors (e.g., retailers and energy service companies). The proposed framework is demonstrated through a series of case studies that highlight the value of various LCT interventions and of aggregation, in terms of energy, emission and operational cash flow metrics. The relevance and importance of the framework to developing business cases for various energy system actors, including policy makers and regulators, is discussed, with the final aim of facilitating the uptake of low carbon multi-energy technologies.

Key words: multi-energy systems, low carbon technologies, business cases, integrated energy systems, renewable energy

Nomenclature

Acronyms

ASHP	Air Source Heat Pump	GDuoS	Gas Distribution Use of System
BSUoS	Balancing Services Use of System	GTNO	Gas Transmission Network Operator
CHP	Combined Heat and Power	GTUoS	Gas Transmission Use of System
COP	Coefficient of Performance	LCI	Low Carbon Incentive

DHW	Domestic Hot Water	LCT	Low Carbon Technology
ECO	Energy Company Obligation	PV	Photovoltaic
EDUoS	Electricity Distribution Use of System	ROC	Renewable Obligation Certificate
EHP	Electric Heat Pump	RHI	Renewable Heat Incentive
ESO	Environmental and Social Obligation	SMI	Supply Market Indicator
ESCo	Energy Service Company	SO	System Operator
ETNO	Electricity Transmission Network Operator	UoS	Use of System
ETUoS	Electricity Transmission Use of System	VAT	Value Added Tax
FiT	Feed-in-Tariff	WHD	Warm Homes Directive
GCP	Grid Connection Point		

37 Notation

38 Indices

c	Commercial entities, 1 to N_c	p	Premises, 1 to N_p
j	GCPs, 1 to N_j	t	Low carbon electricity generators, $\in T$
i	Time steps, 1 to N_i	u	Low carbon heat generators, $\in U$

39 Parameters

γ_i^{comm}	Commercial level gas prices, £/kWh	π	Gas emission rate, kgCO ₂ /kWh
γ_i^{GCP}	GCP level gas prices, £/kWh	$\theta_i^{-,comm}$	Commercial level electricity import prices, £/kWh
γ_i^{pre}	Premises level gas prices, £/kWh	$\theta_i^{+,comm}$	Commercial level electricity export prices, £/kWh
λ_t	Low carbon electricity incentive, £/kWh	$\theta_i^{-,GCP}$	GCP level electricity import prices, £/kWh
μ_u	Low carbon heat incentive, £/kWh	$\theta_i^{-,pre}$	Premises level electricity import prices, £/kWh
ϕ_i	Grid electricity emission rate, kgCO ₂ /kWh		

40 Variables

$e_{i,c}^{-,comm}$	Electricity import, commercial level, kWh	$g_{i,c}^{comm}$	Gas import, commercial level, kWh
$e_{i,c}^{+,comm}$	Electricity export, commercial level, kWh	$g_{i,j}^{GCP}$	Gas import, GCP level, kWh
$e_{i,j}^{-,GCP}$	Electricity import, GCP level, kWh	$g_{i,p}^{pre}$	Gas import, premises level, kWh
$e_{i,p}^{-,pre}$	Electricity export, premises level, kWh	$h_{i,p,u}^{pre}$	Low carbon heat generation, kWh
$f_{i,p,t}^{pre}$	Low carbon electricity generation, kWh		

41 1 Introduction

42 The increasing pressures of energy affordability and environmental sustainability are encouraging
 43 the emergence of improved energy efficiency and new low carbon technologies (LCTs) [1,2]. These
 44 new solutions include insulation improvements and installation of combined heat and power (CHP),
 45 photovoltaic (PV) and electric heat pump (EHP) LCTs in buildings, among others. Installation of LCTs
 46 can be particularly interesting as they can provide systems with flexibility to couple, and even jointly
 47 optimise, different energy vectors (e.g., electricity, heat and gas). This paves the way for a wide roll
 48 out of distributed multi-energy systems [3]. In this multi-energy context, traditionally independent
 49 systems (e.g., electricity, gas and heat) become physically and commercially coupled. The physical

and commercial interdependency that this coupling introduces greatly increases the complexity of the techno-economic system. This complexity makes assessment of LCT-related business cases, for various energy actors (e.g., retailers and energy service companies - ESCos) far from trivial. In particular, assessment of the impact of such interventions on operational cash flows is difficult, given the complexity of energy systems. Hence, such assessment may be considered a grand challenge. Even more importantly, as many such novel technologies can be disruptive, in the current commercial environment, for many actors in the value chain, this challenge might result in a barrier to the development of low carbon energy solutions.

Existing literature recognises the multi-vector (or multi-carrier) nature of emerging energy systems. In particular, given the complexity of the interplay between technical and economic factors, emphasis is put on techno-economic models. For example, several techno-economic models have been proposed for the assessment of low carbon interventions. At a disaggregated level, models for insulation upgrades [4–6], placement of heating options (e.g., considering various technologies and emitters [7–9]), and installation of electricity generation and electro-thermal alternatives (e.g., PV and CHP [10–12]) have been proposed. Considering the benefits of aggregation, models of district heating networks [13,14] and private-wire/microgrid arrangements [15–18] have also been advanced. Further, it is becoming more and more evident how there is a need for explicitly modelling physical characteristics of the buildings and heating system elements (e.g. building fabric, hot water storage, heat emitters) [19] as a basis for accurate assessment. Various papers are also addressing the economic and environmental attractiveness of LCT interventions (e.g., [1,20,21]).

While the reviewed works represent an initial step for the assessment of relevant business cases for LCTs, no systematic framework has, so far, been developed for techno-economic analysis of complex distributed multi-energy systems, with different LCTs. Further, given the potential impact of pricing and commercial arrangements (e.g., aggregation [18,22,23]) on business cases, there is not a sufficient level of detail on these operational aspects. Meanwhile, investment related costs are relatively well understood. Therefore, further research is needed on more realistic, representative physical (technical) models, and disaggregated pricing schemes, that capture the operational economic and environmental value of LCTs. Understanding the effects of such business cases in increasingly complex energy systems can be aided by mapping methodologies, which specify the relationships between various parties [24–26]. In this regard, also, further research is required, as existing mapping approaches focus on single energy vectors and lack disaggregation of energy flows by level (e.g., premises, GCP, commercial). This, as described, is critical for the assessment of LCT interventions in the emerging multi-energy context.

In light of the above, this paper proposes a new techno-economic framework for the assessment of business cases, particularly in terms of operational elements, for LCTs and associated network interventions, in economic and environmental terms. The framework is modular, and generalizable to any context. More specifically, the proposed framework improves current research in the area by:

- Explicitly coupling the physical and economic models of the electricity, heat and gas networks, to properly model the complex interdependences of the different energy vectors in a multi-energy context.
- Systematically enabling capture of the dynamic nature of energy (e.g., prices and carbon intensities) and disaggregated components of prices, to assess the attractiveness of different LCT alternatives in operational economic, energy and environmental terms.
- Defining separate premises, GCP and commercial level energy flows to represent current commercial arrangements where different energy price components are charged based on net consumption at the premises, GCP, and commercial level, as appropriate.

The rest of the paper is structured as follows. Section 2 introduces the proposed framework for the assessment of the operational elements of LCT business cases based on detailed physical,

aggregation and economic models of the relevant distributed multi-energy system. In Section 3, the properties of the framework are illustrated with a series of case studies in a UK context, which represent realistic applications of LCTs and associated interventions, with also assessment of specific operational economic and environmental metrics. Finally, the main findings and conclusions of this study are summarized in Section 4.

2 Techno-economic modelling framework

2.1 Generalities

The modelling framework proposed in this paper is comprised of a physical, an aggregation and an economic model (see Figure 1). These models are combined to facilitate the explicit modelling of premises, GCP and commercial level multi-energy (electricity/gas) import/export¹ profiles. These are critical for the assessment of the business cases of different LCTs under various aggregation levels.

Figure 1: Distributed multi-energy modelling framework

The framework is designed to be modular, so that the various component models may be substituted if required. This may be especially relevant for the physical model, if incorporation of additional energy resources (e.g., electric vehicles, batteries) is required.

2.2 Physical modelling

The physical model has been formulated to capture the multi-energy physical behaviour of a group of premises, and associated technologies. Two types of infrastructure are considered at the premises level. Firstly, buildings are modelled. Secondly, non-building district electricity/heat generators are considered (to serve the buildings through a heat network, in case).

The first constituent of the physical model is a multi-energy building energy demand model [19]. This model is comprised of space heating, domestic hot water (DHW), cooking, and electrical appliances and lighting sub-models. All the sub-models are based on the physical characteristics of buildings and informed by expected occupancy and activity levels. This facilitates modelling of relevant elements of (thermal) storage in each building. Also, it enables the creation of realistic diversity and coincidence in the relevant energy service determinants. The physical model is extended in this work to include capability for generation of realistic PV generation profiles (consistent with building solar insolation profiles). This is based on PV arrays designed with the modules described in [27]. All employed models are implemented with one-minute resolution. This facilitates a detailed and

¹ The separation of profiles into import and export profiles is a crucial feature of the proposed framework, as many consumer energy price components are typically directional (i.e. they are applied asymmetrically to consumption and generation; typically to consumption rather than generation).

realistic quantification of consequences, such as generation from back-up heat generation, which is typically neglected. As detailed in [19], the used building physical model has been validated against UK electricity, gas and DHW usage figures².

The second constituent of the physical model is an optional district heat model. This is employed if the considered premises include a district heat generator. The employed district heat network model is derived from [13]. The network comprises a central heat generator, pipes for heat transportation (through hot water), hydraulic pumps to pump the water through the network, and substations for heat exchange between the main network and the dwellings. Both thermal losses (from pipes to soil, and from heat exchanger substations to the air) and hydraulic losses (compensated by the electrically driven network pumps) are captured within the model. It is important to note that similar detailed models of the electricity network can be included for the assessment of the business case of LCTs. This may be relevant for emerging situations, such as networks subject to active reconfiguration operations and microgrids. This is beyond the scope of the current study, although it is being considered for future studies.

2.3 Aggregation modelling

Given the premises level multi-energy import and export profiles, the aggregation model, dependent on the user selection, may aggregate physical/commercial electricity and gas import/export profiles.

2.3.1 Physical aggregation

Physical aggregation is modelled through mapping of energy profiles from many premises to one GCP (see Figure 2). This allows electricity generators to serve loads which are behind the same GCP. Such an arrangement is somewhat common with respect to electricity (e.g., in microgrid literature [18,22,23]), but less so for gas. The results of this process are GCP level profiles, which are particularly relevant for the calculation of UoS charges.

Figure 2: Premises to GCP mapping

2.3.2 Commercial aggregation

Commercial aggregation is modelled through mapping of GCP energy profiles to one commercial agent (see Figure 3). This type of aggregation can provide significant benefits in terms of uncertainty reductions. This is achieved through increased gas and electricity load and generation diversity, which reduces the risk associated with energy purchase.

² It is however worth pointing out that in general any other physical model could be used in the context of the general techno-economic and business case operational assessment framework proposed here.

Figure 3: GCP to commercial agent mapping

2.4 Economic modelling

The economic model utilises the aggregated multi-energy profiles (at the various levels), and the profiles of low carbon generation, to calculate relevant revenue and CO₂ emission profiles. The revenue and costs are determined by the economic model. These are based on the different energy price components and, if applicable, low-carbon incentives (LCI) for low-carbon generation. Carbon emissions are estimated based on energy emission rates (which are variable for grid electricity), and relevant aggregated multi-energy (gas and electricity) flows.

2.4.1 Cash flow calculation

As illustrated in Figure 4, under current commercial frameworks, the energy retailer protects the customers from all risks associated with variable prices for consumption (and in some cases generation) of energy (e.g., price spikes, balancing responsibilities). This is done by producing flat tariffs for the customers (which include retailer costs and a profit margin). More detail on the various price components shown in Figure 4 is given in Table 1.

Figure 4: Mapping of consumer energy price components

Table 1: Energy price components

Level	Energy vector	Price component	Applicability	Description
Premises	Electricity/gas	VAT	Import	Value added tax (VAT) is a general consumption tax typically applied to consumption of a good.
	Electricity/gas	ESO	Import	Environmental and social obligations (ESOs) may be

				applied to energy consumption to pay for various government social and environmental programs.
	Electricity/heat	LCI	Generation	Low carbon electricity/heat generation may be eligible for LCIs, which are designed to support such socially desirable forms of generation
	Electricity/heat	Retailer costs	Import	Energy retailers need to recoup costs of operation and, if privately owned, an operating margin.
GCP	Electricity/gas	(E/G)TUoS	Import	Electricity/gas transmission/transportation use of system (ETUoS/GTUoS) fees are charged by electricity/gas transmission/transportation network operators (ETNO/GTNO) to recoup the costs of network operation, maintenance and expansion.
	Electricity/gas	(E/G)DUoS	Import	Electricity/gas transmission/transportation use of system (EDUoS/GDUoS) fees are charged by electricity and gas distribution network operators (EDNO/GDNO) to recoup the costs of network operation, maintenance and expansion.
	Electricity	BSUoS	Import	Balancing services use of system (BSUoS) fees are charged by the electricity system operators (SO) to recoup the costs of balancing the electricity system.
Commercial	Electricity/gas	Commodity	Import/export	The commodity price is the price the retailer pays to electricity producers and gas shippers for wholesale electricity/gas.

To calculate economic value, relevant prices must be applied to the corresponding energy import/export/generation flows. Equation (1) calculates the total aggregated gas related cash flow. Commercial, GCP and premises gas prices (γ_i^{comm} , γ_i^{GCP} and γ_i^{pre}) are constituted of the components described in Table 1. These are applied, to the relevant commercial agent ($c = 1$ to N_c), GCP ($j = 1$ to N_j) and premises ($p = 1$ to N_p), gas consumption. Equations (2) and (3) calculate the total aggregated electricity import and export related cash flows. Commercial, GCP and premises electricity import prices ($\theta_i^{-,comm}/\theta_i^{+,comm}$, $\theta_i^{-,GCP}$ and $\theta_i^{-,pre}$) are, again, constituted of the components described in Table 1. These are applied to the net electricity import/export at the relevant level. Equation (4) calculates the total aggregated incentive related cash flows.

$$Cash^{gas} = \sum_{i=1}^{N_i} \left(\sum_{c=1}^{N_c} \gamma_i^{comm} g_{i,c}^{comm} + \sum_{j=1}^{N_j} \gamma_i^{GCP} g_{i,j}^{GCP} + \sum_{p=1}^{N_p} \gamma_i^{pre} g_{i,p}^{pre} \right) \quad (1)$$

$$Cash^{elec-} = \sum_{i=1}^{N_i} \left(\sum_{c=1}^{N_c} \theta_i^{-,comm} e_{i,c}^{-,comm} + \sum_{j=1}^j \theta_i^{-,GCP} e_{i,j}^{-,GCP} + \sum_{p=1}^{N_p} \theta_i^{-,loc} e_{i,p}^{-,pre} \right) \quad (2)$$

$$Cash^{elec+} = \sum_{i=1}^{N_i} \left(\sum_{c=1}^{N_c} \theta_i^{+,comm} e_{i,c}^{+,comm} \right) \quad (3)$$

$$Cash^{inc} = \sum_{i=1}^{N_i} \sum_{p=1}^{N_p} \left(\sum_{t \in T} \lambda_t f_{i,p,t}^{pre} + \sum_{u \in U} \mu_u h_{i,p,u}^{pre} \right) \quad (4)$$

where T is the set of low-carbon electricity generators, and U is the set of low-carbon heat generators.

2.4.2 Emissions calculation

The aggregated CO₂ emissions are calculated based on the use of gas (5) and electricity (6). For this purpose, a fixed CO₂ emission rate (π) is applied to the aggregated gas flows. A dynamic rate (ϕ_i)

representing the variable carbon intensity of the electricity generation mix is applied to the net electricity flows. The application of a common rate for both import and export is valid as, just as import increases grid emissions, export reduces grid emissions, by displacing grid electricity.

$$Emission^{gas} = \pi \sum_{i=1}^{N_i} \sum_{c=1}^{N_c} g_{i,c}^{comm} \quad (5)$$

$$Emission^{elec} = \sum_{i=1}^{N_i} \phi_i \sum_{c=1}^{N_c} (e_{i,c}^{-,comm} - e_{i,c}^{+,comm}) \quad (6)$$

3 Case studies

This section illustrates the power of the methodology by showing how the described technoeconomic modelling framework can be applied to assess the business cases of particular LCT interventions, in terms of energy costs and incentive revenue, and emissions reduction. The studies highlight the attractive capabilities of the framework to accurately identify and quantify changes in gas and electricity flows (i.e., multi-energy flows), and hence emission and cash flows. As the utilised physical models operate at one-minute resolution, energy, emission and cash flows can be calculated at that resolution. Given space restrictions, and the interest in annual flows for business case analysis, all flows are aggregated to annual resolution.

The proposed framework was used to model each test case for seven representative days. This enables an estimation of the premises' behaviour and energy/emissions cost for a year. The representative days were selected to capture the effect of differing weather (which varies strongly across seasons) and occupancy (which varies strongly by day of week), as these are key drivers of energy demand. The year split is shown in Table 2. Note that that framework is general enough so that any alternative definition of seasons may be implemented.

Table 2: Season definition

Season	Number of days
Summer weekday	66
Summer weekend	26
Shoulder weekday	131
Shoulder weekend	52
Winter weekday	49
Winter weekend	26
Peak	15

3.1 Case study context

3.1.1 Energy prices and incentives

The case study energy prices and incentives considered in this study are based on relevant prices and incentives from the UK context. However, it should be noted that the modular design of the model makes the approach generalizable to any system. Electricity commodity prices are based on UK average wholesale market prices [28], BSUoS fees are taken from [29] and the VAT rate from [30]. ESOs are taken from the supply market indicator (SMI) [31], which provide an estimation of the contribution of various ESOs to retail energy prices, in the UK. These include the energy company obligation (ECO), renewable obligation certificates (ROCs) and the warm house directive (WHD). The contributions are estimated by dividing the total scheme costs' (domestic costs only, in the case of feed in tariffs – FiTs) by the total number of domestic customers. The cost of each type of ESO per kWh is shown in Table 3.

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Table 3: Domestic electricity ESO costs, p/kWh, 2014

ROCs	ECO	FiTs	WHD
1.02	0.42	0.27	0.16

ETUoS fees are modelled as the average UK transmission price in 2014 [32] (the prices vary per region), spread amongst the 15 hourly periods with the highest annual demand. This approach is in line with current UK practices. Typically 15 hourly triad warnings are issued per year as the actual triads (three peak settlement periods) are only known at the end of the season. EDUoS fees were taken from the charging statement of the electricity distribution company responsible for the north west England region [33]. For retailer costs an estimate of 3.45p/kWh is used.

For gas, gas commodity prices are based on the UK system average price [34]. The VAT rate was taken from [30]. The GDUoS fees are again based on charges applicable in the north west England region [35]. With respect to gas ESO, ECO (0.11p/kWh) and WHD (0.04p/kWh) are relevant [31]. GTUoS fees, although varying in practice, are modelled as a flat fee (from the average rate [31]), due to unavailability of the relevant data. For retailer costs an estimate of 1.3p/kWh is used.

It is assumed that the retailer simply transfers the various price components that it faces, so that the aggregation is directly exposed to the various variable prices. Electricity costs are calculated based on half-hourly prices under the assumption that each building is half-hourly metered. Gas costs are calculated based on daily prices (i.e., assuming daily metering) as, due to the storage inherent in gas networks (commonly known as "linepack"), gas is balanced on a daily basis.

The gas and electricity prices used in this study are shown in Figure 5 and Figure 6 respectively.

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Figure 5: Gas price components, by season

Also relevant are the available low carbon incentives, e.g., for air source heat pump (ASHP), CHP and PV. In the UK domestic ASHPs can attract the renewable heat incentive (RHI) at the rate of 7.3 p/kWh_{thermal} for heat production, whilst commercial ASHP attracts a rate of 2.5 p/kWh_{thermal} [36]. Domestic micro-CHP can attract a FiT of 13.24p/kWh_{elec} for electricity production, if the unit has electrical capacity of less than 2kW_{elec} [37]. Commercial CHP does not attract an incentive. The FiT for solar PV attached to buildings varies dependent on the size of the installation, as shown in Table 4 [38].

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Table 4: PV FiT rates

Threshold	kW	0	4	10	50	100	150	250
Incentive	p/kWh	13.24	13.03	12.13	10.71	10.71	10.25	6.61

3.1.2 CO₂ emissions

Based on the electricity and gas profiles produced by the proposed physical district model (described in section 2.1), the relevant district CO₂ emissions can be calculated through application of gas and electricity CO₂ emission intensity factors. The gas CO₂ emission rate is assumed to be 0.19kgCO₂/kWh_{gas}. The electricity CO₂ emission rate is set, in this study, based on the split of grid electricity generation by type, the lifecycle CO₂ emission rate of each generator [39] and considering transmission and distribution losses of 11%. Accordingly, and based on UK data for 2013 [40] the grid electricity CO₂ emission profiles shown in Figure 7 are considered in this work.

Figure 6: Electricity price components, by season

Figure 7: Grid electricity CO₂ emission rate, by season

3.2 Case study description

3.2.1 Aggregation description

The case study is conducted for two comparative groups of buildings. The first group is composed of 100 detached dwellings situated in a suburban area, on the gas network, with average annual heat load of 18,750 kWh_{thermal}/dwelling. The second group is composed of 100 flat dwellings, in an urban area, with no gas connection (an all-electric system), with average annual heat load of 8,900 kWh_{thermal}/dwelling. The dwellings are parameterised in the physical model as described in [41]. Each dwelling was modelled considering a set temperature of 21°C during times of active occupancy (there is no set temperature at other times) and a 145 litre DHW tank. Occupancy, DHW and base electrical profiles were generated for each dwelling following a pseudo-random process based on activity profiles (from the UK context), as described in [42]. All dwellings have their own GCP and are separate commercial entities. All dwellings are assumed to have half-hourly meters, enabling settlement of time-variable energy cost components (see 3.1.1).

The proposed methodology is general enough to handle a wide variety of LCT interventions. However, for the sake of clarity only six sets of combinations of LCT interventions are considered in this work. The six case studies represent typical sets of interventions normally considered in the UK, to reduce the energy costs and emissions of buildings. These include, in studies 5 and 6, the benefits of thermal and electrical network-related interventions. The studied interventions are undertaken incrementally. Therefore the results for each study are presented incrementally to the previous presented study. To make the presented studies realistic, the interventions are in the order in which they can reasonably be expected to be undertaken; starting with simpler/cheaper interventions, and progressing towards more complex/expensive ones.

3.2.2 Study 1: Baseline

The first study is designed as a baseline, in which the buildings are relatively inefficient and costly to heat. Both groups of dwellings are insulated to a poor standard (reflecting the standard of unimproved “old”, pre 1944 dwellings [42]). The detached dwellings are heated by a 30kW gas boiler (75% efficient) with radiator emitters. The flats are heated by a 12kW electric boiler (90% efficient), also with radiator emitters. Further, the GCPs are located at the premises level and there are no private networks. Hence, the benefits from physical or commercial aggregation cannot be realised.

3.2.3 Study 2: Insulation upgrade

In the second study, the effect of upgrading dwelling insulation, often considered the most cost-effective improvement, is modelled. In both groups of dwellings the insulation is upgraded to a good standard (reflecting the standard of “new”, post 1984 dwellings [42]). This intervention can be expected to lower energy consumption and hence energy costs and emissions.

3.2.4 Study 3: PV installation

In the third study, the effect of installing PV generation is modelled. For flat dwellings 12.8m² (1.76kW) of PV was installed per dwelling. For detached dwellings the equivalent figures are 22.8m² (3.14kW). This intervention can be expected to reduce grid electricity consumption and, dependent on the case, result in some electricity export. This export can displace grid generation, reducing energy costs and grid-related emissions.

3.2.5 Study 4: Heating technology upgrade

In the fourth study, the effect of installing new low carbon heat generators, to replace the existing heaters is considered. For detached dwellings gas boilers were replaced with heat-load following micro-CHP units. For flat dwellings, replacement of electric boilers by ASHP was considered. The micro-CHP and ASHP units were sized to provide adequate heating at design conditions [43,44]. The micro-CHP thermal/electrical efficiency is assumed to be 78/13%. The ASHP coefficient of performance (COP) is considered to be 1.97/3.51 at 0/20°C external temperature. The micro-CHPs are coupled to gas boiler back-ups, sized at the difference between 30kW and the micro-CHP size, and the ASHPs are coupled to 3kW electric boiler back-ups. In addition to the change in heating unit, the flat dwellings are also converted to under-floor heating.

3.2.6 Study 5: District heating network adoption

In the fifth study, the effect of replacing individual dwelling heating units with a district heat network was modelled. In each case the heat network was constructed of the single “series 1” steel pipe described in [45–47]. For the dwellings, the heat network is supplied by a central heat-load following CHP. The delivery temperature of large-scale CHP is set to 85 °C, which is medium temperature level setting in [13]. The electrical and thermal efficiencies are set to 41% and 46%, which fit to the configuration of ENER-G 770 described in [48]. For the flats, the heat network is supplied by a central ASHP. The delivery temperature is set to 65 °C. The difference between flow and return temperature is set to 30 °C, as in [13]. The principle of COP modelling is same as the one used for domestic ASHP modelling described in [19]. However, considering that large-scale ASHP commonly have better technical performance, the COP is boosted by 0.5 relative to the smaller ASHP in the previous study. In both networks the efficiency of hydraulic pumps is set to 75%.

3.2.7 Study 6: Private wire adoption

In the sixth study, the effect of adopting a private wire arrangement within the group is modelled. Following the methodology detailed in Section 2.3.1, this is modelled by mapping all energy import/export at the premises level to one GCP. This may produce a cost benefit from reduced UoS fees, as premises with excess generation supply electricity to other premises, behind the GCP. Accordingly, this study assumes full aggregation to the GCP level.

3.3 Results and discussion

3.3.1 Study 1: Baseline

For the baseline study, Figure 8 shows the premises level annual gas/electrical energy and CO₂ flows for the considered groups of detached and flat dwellings. The slightly higher carbon intensity of the electricity consumption of flats (0.538kgCO₂/MWh versus 0.529kgCO₂/MWh) indicates that heating related electricity consumption tends to occur at times of high carbon intensity, see Figure 7. With regards to premises level energy costs, Figure 9 shows that, despite the lesser heat load and energy

consumption, flats experience higher annual energy costs. This is due to the generally greater cost of electricity compared with gas.

Figure 8: Group premises level energy flows, and CO₂ flows, study 1

Figure 9: Group cash flows, study 1

3.3.2 Study 2: Insulation upgrade

Figure 10 shows the change in the premises level energy flows due to insulation upgrades. Reduced heat demand results in a reduction in gas costs. There is also a marginal reduction in electricity consumption, as improved insulation results in reduced heating system operation, which reduces heating system pump electricity consumption. For the group of flats, reduced heat demand results in a reduction in electricity consumption. Also shown is the associated reduction in local and grid emissions. Figure 11 shows the associated changes in cash flows, by price component.

Figure 10: Change in group premises level energy flows, and CO₂ flows, study 2 compared to study 1

Figure 11: Change in group cash flows, study 2 compared to study 1

3.3.3 Study 3: PV installation

Figure 12 shows the change in energy and emission flows, on study 2, due to installation of PV panels. For the detached dwellings, the introduction of PV reduces imports of electricity, as electricity consumption is self-served by generation. For the group of detached dwellings 45% of PV electricity generation is self-consumed. At the same time electricity export is increased, as electricity generated in excess of consumption is sold. For the group of flats a lesser share (30%) of PV generation is self-consumed. This is because of the greater disparity between increased evening, winter electricity consumption and the predominantly day-time, summer PV generation. This reduction of electricity imports and increase in electricity exports results in significant reduction in grid emissions for both groups of dwellings. Figure 13 shows the cash flow effect of PV adoption, compared to study 2. For both groups of dwellings, it is noticeable that the change in cost of the electricity commodity is much greater than the change is UoS costs. This is true of the percentage change as well as the absolute change, and occurs for two reasons. Firstly, UoS fees are only reduced when electricity consumption is reduced, and much of the generated electricity is exported; conversely electricity commodity cost/revenue reduces/increases equally due to electricity import/export. Secondly, PV generation occurs mostly at times when UoS fees are markedly low,

meaning that avoided consumption is, with respect to UoS fees, worth little. However, the electricity commodity price during these periods is only somewhat low (compared with the average). Therefore the impact on electricity commodity costs is comparatively greater than the impact on UoS costs.

Figure 12: Change in group premises level energy flows, and CO₂ flows, study 3 compared to study 2

Figure 13: Change in group cash flows, study 3 compared to study 2

3.3.4 Study 4: Heating technology upgrade

Figure 14 shows the change (compared with study 3) in premises level energy and emission flows given upgrade to low-carbon heating technology. For the group of detached dwellings, premises level electricity imports are reduced, and electricity exports are increased as CHP electricity generation self-serves electricity load, and exports surplus. The upgrade to CHP enables the detached dwellings to increase the percentage of electricity self-served (by CHP and PV) to 74%. Gas imports are reduced slightly, as the micro-CHP thermal efficiency (78%) is slightly higher than that of the gas boiler (75%) it is replacing. For the group of flats, the ASHP option reduces electricity import, as the ASHP produces heat more effectively than the electric boiler. Figure 15 shows the change in revenue due to the adoption of low-carbon heating technology, on study 3. The increases are substantial, and result in both groups having net positive revenue, over the year.

Figure 14: Change in group premises level energy flows, and CO₂ flows, study 4 compared to study 3

Figure 15: Change in group cash flows, study 4 compared to study 3

3.3.5 Study 5: District heating network adoption

Figure 16 shows the effect on energy and emission flows of adoption of a district heat network, compared to study 4. The increase in gas import for the detached dwellings group is partly due to increased heat generation (up 21%) associated with the thermal losses of the network, and partly due to the reduced thermal efficiency of the central CHP (46%) compared with the distributed micro-CHP (78%). This reduced thermal efficiency is due to an increased electrical efficiency (41% compared to 13%), which results in a ten-fold increase in premises level electricity export. Overall, for the detached dwellings group, this intervention produces a net CO₂ reduction, demonstrating the CO₂ benefits of local generation. For the flats, heat demand is also increased by the increased thermal losses in the heat network. However, this is counteracted by the increased COP of the central ASHP, compared with the distributed version. The result is only a slight increase in electricity imports. As a result of increased gas imports, and the removed CHP LCI (as LCIs are not applicable to commercial scale CHP, see 3.1.1), revenue for the detached dwellings group reduces significantly, despite the increased revenue from the additional electricity export. The group of flats experiences a more modest decrease in revenue, largely due to the decrease in ASHP LCI rate (due to change in type from domestic to commercial, see 3.1.1).

Figure 16: Change in group premises level energy flows, and CO₂ flows, study 5 compared to study 4

Figure 17: Change in group cash flows, study 5 compared to study 4

3.3.6 Study 6: Private wire adoption

Adopting a private wire arrangement within the neighbourhood (i.e., situating all premises behind a common GCP), naturally, does not affect premises level energy profiles. However, from the point of view of the grid, electricity imports and exports are reduced by 246 MWh/year (compared to study 5) for the group of detached dwellings, and 93MWh/year for the group of flats. Note that this is not due to any change in consumption/generation of the premises, but due to a change in the point at which grid import/export is assessed. This change means that electricity generated at one premises can serve load at another, without any impact on the grid, altering the import and export experienced by the grid, as described. For the dwellings this means that electricity imports are practically eliminated at the GCP level, whilst for the flats it is reduced by 18%. As the adoption of the private wire arrangement does not affect premises level profiles or local generation, CO₂ emissions are unchanged. However, as shown in Figure 18, electricity UoS costs are reduced. For the group of detached dwellings UoS costs are practically eliminated, whilst for the group of flats they are reduced by 9%. The limited reduction in the flats' UoS costs is due to the timing of local (PV) generation, which occurs around the middle of the day. At this time UoS fees are comparatively low; higher UoS fees exist in the early evening (see Figure 6).

Figure 18: Change in group cash flows, study 6 compared to study 5

3.4 Discussion

The demonstrated studies have shown how a detailed, highly resolved physical model, can be effectively employed to calculate premises level annual multi-energy flows. Whilst the specific results, in terms of effects of the different interventions, are of interest *per se*, the primary contribution of this work is in the power of the presented modelling framework to reveal the implications of dwelling behaviour. For example, in study 2 (Insulation upgrade) the model is able to demonstrate and quantify the effect of reduced heating system operation on electricity consumption (through reduced circulation pump operation). This is possible due to the detailed modelling of the heating system in the dwelling physical model. In study 3 (PV installation), the disaggregation of energy prices into components enables the revelation and quantification of the discrepancy between electricity commodity and UoS costs. In both study 3 and 4 (Heating technology upgrade), the high resolution of the physical modelling enables the change in the percentage of electricity load self-served to be calculated. In study 5 (District heating network adoption), the use of a detailed district heating network enables quantification of the thermal losses, which result in increased heat generation. In study 6 (Private wire adoption), the relevance of the illustrated aggregation model is demonstrated, in that the conceptual separation of premises from GCPs enables the effect on operational (UoS) cash flows to be systematically calculated. Further, the ability to the framework to split cash flows by component is of significant interest to those parties in receipt of the various components. This is particularly true where the effect on certain components is markedly different to the effect on the total cash flow, as in studies 3 and 6.

Based on the case study results, the power and importance of the proposed assessment framework clearly emerges. In particular, this framework will be useful to many energy system actors, for the estimation of operational cash flows to inform business case assessment for LCT in multi-energy systems. For example, for an EScO the detailed assessment of the savings available from various interventions may be appealing, as such an actor may wish to fund such interventions³. The detailed cash flow analysis can ameliorate the risk of such investments, lowering the cost of interventions. Policymakers may find the detailed assessment of policy-relevant metrics, such as grid/local emissions and energy self-sufficiency, appealing (e.g., to enable design of incentive schemes to

³ In this case, the outputs of the proposed model would be contrasted with the investment costs associated with the placement of relevant infrastructure using a cost benefit analysis framework.

address particular policy objectives). Within the energy system, electricity producers and grid operators may find the framework of particular use, given the effect of LCT interventions to reduce reliance on the electricity grid and centralised electricity production. In particular, the less obvious outcomes, such as demonstrated in study 3 and 6, which result in reduced electricity UoS costs, will be of particular relevance to electricity grid operators. For government and regulators, impacts such as this are significant, as they may motivate grid operators to increase fees. In particular, the distribution of the impact will be of interest, given that, without changes to fee structures, the impact is likely to be greater on non-LCT adopting consumers. In the future, consumers or their agents (i.e., third-party intermediaries such as ESCOs or aggregators) may find the presented modelling framework useful if such parties assume balance responsibility. This transfer of risk to smaller aggregations may spur interest in commercial aggregation (see 2.3.2), to ameliorate volume risk through load diversity.

4 Conclusion

This paper presents a modular and generalizable techno-economic framework for assessment of the operational elements of LCT and associated network intervention business cases. The framework is made up of three constituent models. The physical (heating system, building and heat network) model enables capture of the results of complex multi-energy interactions. The high-resolution is particularly useful as it enables quantification of disaggregated energy flow at the settlement period level, allowing the effect of asymmetric price components (e.g. UoS fees and taxes) to be captured [22]. The aggregation model enables the impact of physical aggregation (particularly important for UoS costs, as demonstrated), and commercial aggregation to be captured. Importantly, the form of the framework allows such effects to be captured in a systematic, elegant way, offering a clear contribution above existing literature [18,22,23]. The final part of the framework is the economic model. Here the capability to split prices down by component, and the multi-energy, multi-aggregation level nature of the framework is a clear contribution above the state of the art [24–26]. In general, these modular features enable the proposed framework to be generalized to any given setting; this is a major strength and contribution of this work.

Generally, the ability of the framework to enumerate the effects of interventions on energy costs and revenues for various parties, and on grid and local CO₂ emissions, will be useful for directly affected parties such as energy retailers, network operators and ESCOs. In addition, for regulators and policy-makers, who may utilise the framework for design of policy and the various tools of policy implementation (e.g., taxes, incentives, caps, standards and so forth), may find it useful. Utilisation of the framework to explore such possible applications is a possible direction for future work. Exploration of possible models for district heat network charging (including investments in relevant infrastructure and ownership), so that cash flows for the various parties within any considered group may be more completely considered, is another future direction. Investigation on the uncertainty of consumer multi-energy demands, and of distributed generation, during which the full benefit of the proposed method for commercial aggregation can be explored, could be a future application of the framework. Finally, utilisation of the operational cash flow results in this study to perform a full cost benefit analysis will be interesting, and is the object of work in progress.

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