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Integrated Electricity-Heat-Gas Modelling and Assessment, with Applications to the Great Britain System. Part II: Transmission Network Analysis and Low Carbon Technology and Resilience Case Studies

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Abstract

With the increasing interactions between the heat, electricity and gas sectors due to the introduction of low carbon heating technologies, there is a need for models to assess the inter-sector interactions at a network level. This paper presents a novel integrated electricity-heat-gas transmission network model that considers electrical and gas network flows coupled with the fuel requirements for the heating sector. The latter is modelled at a nodal network level and on a half-hourly basis, building upon the high-resolution temporal and spatial heat demand model presented in Part I. In particular, here the modelling is developed further to include an integrated heat-electricity-gas optimization to assess the operation of different heating technologies, and particularly hybrid ones. More specifically, DC power flow modelling is coupled with steady-state gas network energy and transportation cost optimisation to assess gas-electricity price interactions, and with transient gas flow modelling for gas network operational studies. Numerical case studies are performed on the GB energy system, considering the evolution towards a low carbon future, the operation of hybrid dual-fuel electric heat pump/gas boiler technologies, and the ability to alleviate gas network constraints. Resilience case studies considering nodal gas price implications under gas network supply shocks are also considered. The results show how pathways to electrify heating and decarbonise the power sector can lead to a 75% reduction in carbon emissions of the heat and electricity sectors and that using hybrid heating technologies can reduce conventional generation peaks by 24%. Additionally, it is shown that exploiting gas demand response can provide an additional resilience option to the gas network.

Key words:

Gas networks, multi-energy systems, hybrid heating technologies, network resilience, integrated energy systems, gas demand response.

1 Introduction

In the companion paper [1], modelling was presented into the heat demand assessment of an energy system as part of an integrated heat-gas-electricity system analysis which includes the regional assessment of the heat demand requirements and heat technology operation at half-hourly intervals. In this paper, the developed models have been integrated into gas and electrical network modelling and applied to a number of case studies assessing network and system implications of changes to the heating sector and extreme weather scenarios.

Often a country's heating sector is intimately linked to either its power system, its gas system or both systems as these networks are used to transport the fuel used by the heating technologies. It is not uncommon for the heating demand to form a large constituent of the overall energy consumption and also have a large carbon footprint [2]. It has therefore been the subject of focus as a means to reduce the carbon impact of an energy system. Technology changes in the heating sector can impact the gas and electricity sectors and specific tools are required to fully assess their implication [3]. This work builds upon preliminary work into the interactions between the heating sector and the gas and electricity networks presented by the authors in [4] [5] [6] where the impact of the system-wide heating demand was considered. In this work, this has been extended to consider regional heat demands, the implications of adopting different heating technologies, including hybrid ones, and the impacts on electricity and gas prices. More specifically, in Part I a novel high-resolution model to evaluate the heat demand was presented which captures both its regional aspects and its demand peaks as it is evaluated at half-hourly intervals. In this paper, that model is applied to form a novel integrated electricity-heat-gas-transmission network model with the appropriate spatio-temporal resolution for network studies. In particular, the heat demand modelling is integrated with electrical transmission network modelling consisting of a DC power flow with consideration of the meeting of the regional heat and electrical demands. This is further incorporated into an integrated electricity-heat-gas optimization which can capture the operation of hybrid heating technologies and the variation on gas and electricity prices at a system and nodal level. The gas prices are assessed with consideration of the gas price at supply points and novel, nodal gas demand response modelling using steady-state gas flow analysis, whilst integrated intraday gas network modelling congestion relief is evaluated using transient gas flow analysis.

A number of case studies and applications of the developed modelling are presented. These focus on the Great Britain energy system and consider the introduction of low-carbon electrical generation and heat technologies. A number of key results are presented into the utilization levels of various technologies as the integrated electricity-heat-gas model is applied to the transitional energy system. Additionally, studies are performed into hybrid heating technologies showing how they can be beneficial to the gas and power system through the reduction in conventional generation peaks and it is shown how hybrid combined heat-and-power (CHP) with auxiliary boiler may be used to alleviate gas network constraints.

Finally, resilience case studies are performed into extreme weather modelling of the British system. Although the British gas network is resilient to extreme weather, should shortfalls in the gas supply manifest, then these are likely to lead to limitations in the gas required to meet all consumer's requirements. Additionally, gas network analysis on such days shows

how the increased use of more expensive gas from alternative sources leads to changes in the network flows around the network. Finally, the impact of industrial gas demand response on the gas and electricity prices is also evaluated.

The rest of Part II is organized as follows. Section 2 describes the integrated electricity-heat-gas transmission networks modelling including the optimization formulations and gas network modelling. Section 3 describes the case studies into the utilization and operation of the developing energy system, the operation of hybrid technologies and the resilience of the gas network. Finally, Section 4 gives conclusions.

2 Integrated heat, gas and electrical transmission network modelling

The developed nodal heat model has been integrated into gas and electrical transmission network models for application in assessing network implications. This integrated electricity-heat-gas transmission network model uses the nodal heat demand model, electrical power flow modelling and gas flow modelling to assess these inter-sector network interactions.

2.1 Integrated modelling overview

This integrated modelling is achieved by applying the iterative procedure outlined in Figure 1. The process begins by assessing the nodal heat demands based on historical outside temperatures as described in [1]. In this manner, each heat node n has a half-hourly heat demand profile $HD_{U,T,n}(t)$ associated to each sector U (domestic, commercial and industrial) and daily temperature T . This heat demand is fulfilled by the available heat technologies which are described by their level of penetration. If $\mathbf{B}$ is the collection of base heat technologies, then the heat met by the base fulfilling heat technologies is $\sum_{\tau \in \mathbf{B}} \eta_{\tau} \cdot \overline{D_{U,n,\tau}}$ where η_{τ} is the technology's thermal efficiency (or coefficient of performance in the case of a heat pumps) and $\overline{D_{U,n,\tau}}$ is its capacity. This is subtracted from $HD_{U,T,n}(t)$ so that the heat demand fulfilled by heat-driven technologies is given by $HD_{U,T,n}^d(t) = HD_{U,T,n}(t) - \sum_{\tau \in \mathbf{B}} \eta_{\tau} \cdot \overline{D_{U,n,\tau}}$. The combined electrical and heat-fulfillment optimization, as will be described in Section 2.2, is conducted to analyze the power system generation and heat technology operation to meet the heat and electrical demands. This defines the gas utilization levels for the power and heat sectors (two of the principal end-uses of gas demand) which is combined with that for other uses to perform gas network assessments using the gas network modelling and price evaluation described in Section 2.3. This gas price goes on to be used in the consequent iterations in determining the fuel requirements for meeting the heat and electrical demand (where it is used as a proxy for the wholesale fuel prices). Upon each iteration, the change in wholesale gas price is compared and, although there is no mathematical guarantee of convergence, in practice, the values begin to stabilize to a 2% tolerance within a few iterations.

Figure 1. Overall integrated electricity-heat-gas modelling methodology for assessment of impacts of changes to heat, electricity and gas sectors

2.2 Electrical transmission network model and interaction with heat

The gas and electrical requirements for the heating sector and the gas requirements for electrical generation are assessed through an optimization which extends the ‘DC’ OPF [7] to consider the heating sector interactions. This optimization, conducted for 30 min snapshots, has objective function

$$f(\mathbf{P}, \mathbf{D}^g) = \sum_G c_G P_G(t) + \sum_{U,n,\tau} c_g D_{U,n,\tau}^g(t) + \sum_{U,n} c_g D_{U,n,CHP}^g(t) \quad (1)$$

where $\mathbf{P}$ is the vector of real power outputs P_G for each generator G (excluding CHPs), with cost c_G while $\mathbf{D}^g$ is the vector of gas demands $D_{U,n,\tau}^g$ providing the heat demand at each heat node n , sector U , and heat technology τ (including the combined heat-and-power units CHP) at a cost of c_g . It is assumed that all fossil-fuel users, including the heating sector, incur costs for the carbon released and so the costs presented consist of a fuel as well as carbon costs.

The operation of generators at a given time is impacted by the marginal cost of generation. For conventional generators, this cost is primarily related to the cost of fuel and the cost of carbon emissions. On the other hand for intermittent generators such as wind, there is a low marginal cost and, when there is sufficient wind, and subject to the power system requirements and constraints, the wind turbine will generate. With respect to the cost of generation, each generator G depends on the electrical generation efficiency of the unit η_G^{gen} , its emissions rate E_G and the fuel and the carbon cost. For gas, this depends on the cost c_{gas} of natural gas on that day while for the other fuel types is fixed. The cost of the generation is then given by $c_G = c_{fuel}/\eta_G^{gen} + c_{carbon} \cdot E_G$, where c_{fuel} is the fuel cost and c_{carbon} is the carbon cost.

Suppose that at each node n , for the sector U , $\phi_{n,U,\tau}$ is the fraction of heat fulfilled by technology τ . (If τ is a hybrid heating system, then τ may be a collection $\tau_1, \tau_2, \dots$ of different types). The gas and electrical fuel requirements ($D_{U,n,\tau}^g$ and $D_{U,n,\tau}^e$) to meet the heat demand are then described by

$$\sum_{\tau} (\eta_{TO(t),\tau}^e(t) \cdot D_{U,n,\tau}^e + \eta_{\tau}^g D_{U,n,\tau}^g) + \sum_{CHP} \eta_{CHP}^g D_{U,n,CHP}^g(t) = \phi_{n,U,\tau} \cdot HD_{U,T,n}^d(t) \quad (2)$$

where $\eta_{TO(t),\tau}^e$ (resp. η_{τ}^g) is the ratio of heat production to electricity (resp. gas) consumption by technology τ (which, for EHPs, depends on the outside temperature $TO(t)$). The net power injection P_z at each electrical network bus z is then described by

$$P_z = \sum_{CHP} \eta_{CHP}^{\text{gen}} D_{U,n,CHP}^g(t) + \sum_G P_G(t) - ED_z - \sum_{\substack{U,\tau \\ n \text{ supplied by } z}} D_{U,n,\tau}^e \quad (3)$$

where η_{CHP}^{gen} is the electrical efficiency of the CHP unit and ED_z is the non-heat electrical demand at z .

The intermittent renewable generation (wind and solar in the case studies here) are modelled with a marginal cost of zero. The generation capability of these renewable sources has been modelled using historical meteorological data. In order to model the requirements of the gas generators in providing system reserve in a power system with an increased level of variable generation, the optimisation considers reserve requirements accounting for wind and load forecast errors and generation outages. This reserve is assumed to be fulfilled by conventional generators, modelled with 30 minute ramp rate and minimal stable generating level constraints [4].

If the optimisation indicates that each gas generation G has dispatch level P_G then the gas demand for the generator is given by $P_G / \eta_G^{\text{gen}}$. This, along with the level of gas demand for heat is transformed into the volumetric gas demand by $VD_G^{\text{gen}} = P_G / (\eta_G^{\text{gen}} \cdot LHV)$ and $VD_{U,n,\tau}^{\text{heat}} = D_{U,n,\tau}^g / LHV$ where LHV is the lower heating value of natural gas.

2.3 Gas transmission network model

Natural gas is transported from supply points to the location of consumption via high-pressure transmission network pipes. The main use for the gas is as a low-grade fuel in the heating sector or in power generation. The gas flow in the pipes is the consequence of a pressure difference in the pipeline. To study the effects of the heating sector on the gas network, a gas flow computation is conducted from which the flows and pressures within the gas network are determined. The gas demand for heavy industry and other uses (e.g., cooking) as well the interconnector demand is modelled as constant throughout the day and when this is combined with the demand for the heating sector it determines the total gas demand at each network node. In the modelling of the gas network, each network node must preserve the conservation of mass. To each node g is associated a volumetric gas demand VD_g which is determined by the sum of the gas required for generation, the gas demand for heating and the gas demand for other uses which includes industrial gas use and gas exports.

While demand side response in gas network operations is rare, it may occur under extreme conditions. Moreover, demand response may be considered as more likely in future gas systems as an economic alternative to gas network expansion. Industrial facilities who use large amounts of gas are some of the prime candidates to reduce their consumption. This can arise through a reduction in production. Additionally, some industrial facilities have

onsite distillate meaning they can, for short periods, use alternative fuel while maintaining operation. In the network modelling, gas demand response has thus also been included. In particular, it is assumed that it would act to reduce the gas demand at a given node in response to both network transportation as well as network supply limitations. Each gas demand response capability DR is associated with an opportunity cost OC_{DR} , a gas node DR_g , a maximum reduction volume per day $\overline{V_{DR}}$, and the employed volumetric demand reduction $V_{DR,g}$.

The operation of the gas network may be assessed using gas flow analysis where the system's pressures and flows are evaluated. Such analysis can be categorized into two classes: steady-state and transient. Transient analysis is required for the assessment of pressures and flows at any instant within the day, while steady-state gas flows may be used for assessing gas network capability and pressure drops for daily gas flows and may be used as a day-ahead analysis tool for the operation of the gas network.

The gas network operational characteristics (e.g., pressures and flows) and cost are assessed by considering that the gas network infrastructure is used to meet the demand at minimum cost. The model is formulated as a mathematical programme with consideration of the supply costs from each supply point and the provision of gas demand response. Each gas supply point S at node g is associated with a marginal cost function $\pi(\cdot)$ which is a function of the supply rate VS_g at that point and in the case studies is derived from historical data associated with the gas price and supply rate. The objective function is given by

$$\min \sum_g \pi(VS_g) + \sum_{DR} OC_{DR} \cdot V_{DR,g} \quad (4)$$

The formulation considers as constraints the network limitations including the pressure limits, compressor station fuel requirements and limitations, and the conservation of mass at each network node.

In steady-state conditions, under the common assumption of a horizontal gas pipe q , then the rate of flow Q_q (m^3/s) is related to the pressures at either end of the pipe, p_{g_1} and p_{g_2} (Pa) by

$$|Q_q|^{\alpha-1} Q_q = K_q (p_{g_1}^2 - p_{g_2}^2) \quad (5)$$

where K_q is a constant which depends on the pipe's length, diameter and efficiency as well as characteristics of the gas including its composition and temperature [8].

Following (5), each pipe's pressure limits can impact its flow capability. To each pipe q are therefore associated pressure limits. The pipe's upper limits are based on the technical characteristics of the pipe (which, for the British case, can vary across the transmission network) while the lower bounds may be limited by regulatory constraints on the pressure at offtakes. These minimum pressures ensure that pressures in the distribution networks can be maintained. If p_{g_1} and p_{g_2} are the pressures related to either end of the pipe q , then it is required that

$$\underline{p}_q \leq p_{g_1}, p_{g_2} \leq \overline{p}_q \quad (6)$$

To gas supply point nodes are associated a supply flow rate VS_g , which is assessed with consideration of the gas supplies necessary to meet the gas demand for each day. With the pressure drops resulting from gas flow, compressor stations may be utilized to maintain the network's minimum offtake pressures. If the node g has an adjacent compression facility,

then there is an associated compression inlet flow CI_g or outlet flow CO_g . Additionally, if the compressor is gas-driven, then its fuel source is the gas in the gas network. Therefore, when required, the fuel consumption CF_g is also included with the gas balance relation at each node. This fuel consumption is given by

$$CF_g = \frac{p_{CP,in} \cdot CI_g \cdot Z}{\eta_{CP} \cdot LHV} \cdot \frac{\gamma}{\gamma - 1} \left(\left(\frac{p_{CP,out}}{p_{CP,in}} \right)^{(\gamma-1)/\gamma} - 1 \right) \quad (7)$$

where Z , γ and LHV are the gas' compressibility factor, polytropic exponent and lower heating value, η_{CP} is the efficiency of compressor CP , and $p_{CP,in}$ and $p_{CP,out}$ are the compressor station's respective inlet and outlet pressures.

If for a given gas node g the set of neighbouring nodes is $N(g)$ and for each $g' \in N(g)$ the pipe $q_{g',g}$ from gas node g' to node g has flow rate $Q_{g',g}$, then the conservation of mass at the node is described by

$$CM(g): VD_g - VS_g - V_{DR,g} + \sum_{g' \in N(g)} Q_{g',g} + CI_g - CO_g + CF_g = 0 \quad (8)$$

Each supply point's maximum supply flow rate is limited by its technical characteristics so that

$$VS_g \leq \overline{VS_g} \quad (9)$$

Each volumetric demand response is also limited by

$$0 \leq V_{DR,g} \leq \overline{V_{DR,g}} \quad (10)$$

An interior point solver [9] is used to assess the supply flows, gas demand side response, and compressor fuel for the gas system operation described by (4)–(10). The feasibility of the obtained solution is checked by comparing the pressures and flows with flow analysis based on the solution's supply point flows and compressor station parameters.

The dual $CM(g)^*$ to the conservation of mass relation (8) at each network node $CM(g)$ provides the nodal gas marginal price π_g at each gas node g . For systems, such as that of Britain, which implement zonal gas pricing, the gas price for a given zone Ξ defined by a collection of gas nodes has been modelled by the weighted mean with respect to the net demand at each node, i.e., the zonal marginal price is given by π_Ξ

$$\pi_\Xi = \sum_{g \in \Xi} \pi_g \cdot (VD_g - V_{DR,g} + CF_g) / \left(\sum_{g \in \Xi} (VD_g - V_{DR,g} + CF_g) \right) \quad (11)$$

While, for the system, similarly, the marginal price π_S has been modelled by

$$\pi_S = \sum_g \pi_g \cdot (VD_g - V_{DR,g} + CF_g) / \left(\sum_g (VD_g - V_{DR,g} + CF_g) \right) \quad (12)$$

where the summation is over all system nodes.

The transient gas flow in a pipeline, in contrast, has time dependent relations. Under the common assumption of isothermal gas flow, then these are expressed by the equation of motion, the continuity relations and the equation of state which are represented by (13), (14) and (15), respectively.

$$\frac{\partial p}{\partial x} + \frac{\rho_n}{A} \frac{\partial Q}{\partial t} + \frac{r\alpha^2\rho_n^2}{2dA^2} \frac{Q}{p} = 0 \quad (13)$$

$$\frac{\alpha^2\rho_n}{A} \frac{\partial Q}{\partial x} + \frac{\partial p}{\partial x} = 0 \quad (14)$$

$$\frac{p}{\rho} = ZR_s\theta \quad (15)$$

Where p and Q are, again, the pressure and flows, while ρ_n (kg/m³) and ρ (kg/m³) are the gas's density in the pipe and at normal temperature and pressure, x (m) is the distance along the pipe, α (m/s) is the speed of sound in gas, d (m) and A (m²) are the pipe's diameter and cross-sectional area, r is the Darcy friction factor, Z is the compressibility factor, R_s is the specific gas constant (J·kg/K) and θ is the temperature of the gas (K). Relations (7), (8), (13), (14) and (15) are solved to find flows and pressures around the network using an implicit finite difference scheme [10].

In the following, the steady-state modelling with energy and transportation cost optimization will be applied for the assessment of the daily gas prices, flows and demand response in the resilience study, while the transient modelling will be used for an evaluation of within-day peak-time alleviation of gas constraints using hybrid heating technologies.

3 Case studies

3.1 Gas and electrical transmission networks

As mentioned above, the cases studied have been performed on the British system. Before presenting results of the case studies, some background on the networks and technologies will be presented. In [1], the half-hourly nodal heat demands in the British heat model have been associated to a given electrical bus and gas network node of the GB gas and electrical transmission networks depicted in Figure 2(a) and (b), respectively.

Figure 2. GB gas (a) and electrical (b) transmission network model and localities of wind farms (c) and solar irradiance (d) from which historical wind and solar generation profiles are derived.

3.2 Intermittent generation modelling

The primary sources of intermittent generation in the UK is wind and solar generation. Each has been modelled at a regional basis using half-hourly historical profiles. Wind speeds from 2004-05 for 39 localities of wind farms (Figure 2(c)), both onshore and offshore, across GB have been recorded. These are translated to wind generation capacity using the technical characteristics of wind turbines. For solar generation, historical solar irradiance and cloud cover have been collated from a number of UK positions (Figure 2(d)). This is translated to the irradiance of solar panels with consideration of the solar position and the direct, diffused and reflected irradiance incident to each panel. The solar generation capability is then evaluated. These historical profiles are consequently mapped against the increase in generation in a future generation portfolio. Figure 3 presents the system generation time series for wind and solar considered in the 2020/21 scenario.

Figure 3. Wind and solar generation capacity for the 2030/31 scenario

3.3 Gas price and supply assessment

All the gas prices are considered relative to the summer gas price. This summer gas price is indicative of the cheapest gas available to the network for a given year.

The evaluation of the gas price at each supply point is derived using historical daily gas prices and historical supply flows as follows. The historical daily volumetric supplies for each supply point are partitioned into intervals according to their minimum historical flow and maximum flow capability (without network limitations). For a supply point S and a given interval of supply flow rates $[V_S^i, \bar{V}_S^i]$, between V_S^i and $\bar{V}_S^i$ the set of historical flows V_S^i is considered. To each volumetric daily supply $V_S \in V_S^i$ is associated the gas price for the day (scaled so that it is expressed as relative to the summer gas price for that sample year). If Π_S^i is the set of gas prices associated to V_S^i , then the marginal price π_S^i associated with the supply point S supplying gas at a flow rate between $[V_S^i, \bar{V}_S^i]$, is given by the lower q -quantile of Π_S^i . The intervals are ordered so that for $j > i$, $V_S^i < \bar{V}_S^i \leq V_S^j < \bar{V}_S^j$ and if $j = i + 1$, $V_S^j = \bar{V}_S^i$, then to ensure that the marginal prices are monotonically increasing with an increase in flow rate, π_S^i is set to $\min(\{\pi_S^j \mid j \geq i\})$.

Based on historical flow rates, each supply point is, additionally, associated with a minimum flow rate.

3.4 Heat technologies

Technologies that are considered in this work are based on those presented in [11] and [12], and are summarized in Table 1. The thermal efficiency is used to describe the ratio of heat production to fuel consumption while for gas and electric heat pumps this ratio is described by their coefficient of performance. For combined heat-and-power units, the electrical efficiency of power generation is also considered. For emerging technologies, such as gas heat pumps, the coefficients of performance and thermal efficiencies considered are based on those presented in [11] and the associated workbooks.

326

Table 1 Heat technologies

Technology	Thermal efficiency or coefficient of performance	Electrical efficiency
Gas boiler	76–91%	-
Resistive heating	100%	-
Oil-fired boiler	97%	-
Solid-fuel boiler	87%	-
Micro-CHP	45–63%	23%–45%
Air-source heat pump	Function of air/ground temperature	-
Ground-source heat pump		
Geothermal with district heating	85%	-
Community-scale gas CHP	38%	38%
Community-scale solid-fuel CHP	57%	17%
District heating from power stations	90%	-
Gas heat pump	150%	-
Hybrid technology	Depends on operation	-

327

328 As discussed in Part I, the heat technologies have been categorized into those which are
 329 community-based and supply a base-load and those which are heat driven. With
 330 consideration of the technologies available, the *base-load heat* generating units are assumed
 331 to be the community-scale CHPs and heating from power stations, while all other
 332 technologies are heat-driven.

333 The hybrid heating technologies considered are the air-source electric heat pump with boiler
 334 and the CHP with boiler.

335 3.5 Evaluation of impact of low-carbon heating and electricity sector 336 technologies

337 The UK government has proposed changes to the heat and electricity sectors as a means to
 338 reduce the carbon impact of the energy system. The electrification of the heating sector is
 339 key to many of the proposed changes and the development of the heat, electricity and gas
 340 sectors on such a pathway has been investigated. The study takes as an input the
 341 development of the heat and electricity sectors and up until 2035. The heating sector
 342 pathway considered is presented in Figure 4 and is based on a program to decarbonise the
 343 heating sector through the displacement of existing technologies, in particular gas boilers,
 344 with electric heating technologies primarily ground-source and air-source electric heat-
 345 pumps. Accompanying the change in the heating sector is a program to decarbonise the
 346 electricity sector. In the transitioning years, this is achieved through large increases of the
 347 penetration of renewable energy sources, primarily wind generation which increases by 70%
 348 between 2025/26 and 2030/31. Coal without carbon capture and storage (CCS) generation is
 349 phased out and, beyond 2025, there is an increase in the installed capacity of nuclear
 350 generating units. The considered evolution of the electricity sector is presented in Figure 5.
 351 The operation of the electricity and gas sectors as well as, through hybrid heating
 352 technologies, the heating sector, is also impacted by changes to the carbon, gas and coal
 353 prices (Figure 6). The electricity sector follows the 'Gone Green' scenario of [12] while the
 354 heating technologies have been elaborated from those put forward in the UK's Department
 355 of Energy and Climate Change (DECC) 2050 pathways, [11] from which the future heat
 356 generation technologies in 2035 have been assessed using the methodology of [4]. The
 357 efficiencies, minimum stable generation (MSG) and ramp rates of the conventional
 358 generators are presented in Table 2.

359

360

Table 2 Conventional generator properties

Generator	Electrical efficiency	MSG (%)	30 min ramp rate (%)
Coal power station	33%	50	25
Combined-cycle gas turbine	50%	50	25
Open-cycle gas turbine	32%	10	50

Figure 4. Installed generation capacities in future scenarios [12]

Figure 5. Fraction of heat fulfilled through given technologies in future scenarios [11]

Figure 6. Carbon price and coal and annual mean gas costs in future scenarios [12].

In addition to the historical wind speeds and solar irradiance time series as discussed in Section 3.2, historical annual temperatures are included with historical electrical demands as inputs. By simulating the power system for 30 min snapshots over a yearly timeframe using the methodology presented in Section 2.1, the change to the utilization of the different generators has been evaluated along with the operating cost and carbon emissions.

The resulting gas demand for the heating sector and power generation is shown in Figure 7 where it can be seen how, from 2015/16 to 2020/21, there is an increase in the annual gas utilization for generation. This is caused by the increased carbon cost leading to a greater increase in the cost of coal generation which is displaced by cleaner gas generation. The annual gas generation begins to decrease after 2025 with an increase in nuclear and the further increases to the installed capacity of wind. The level of utilization of the gas turbines can be assessed through the duration curves which are presented in Figure 8. Again, the increase of gas generation from 2015/16 to 2020/21 can be observed, then beyond 2020/21, the gas turbines have reduced generation though have increased generation peaks (Table 3) which are required to meet the increased peak electrical demand (Figure 9) at times of reduced generation from renewable sources.

Figure 7. Annual gas demand for electricity and heating sector

Figure 8. Duration curves of gas demand for electrical generation

Table 3 Peak gas demand for generation

Year	Peak gas generation (GW)
2015/16	15
2020/21	28
2025/26	31
2030/31	34
2035/36	36

Figure 9. Resulting peak system electrical demand (based on historical temperature estimates from 2013/14) for future scenarios

The electricity and heat pathways have been developed as part of scenarios for a low-carbon 2050 energy system for Britain. Figure 10 presents the rate of the reduction of the carbon emissions of the two sectors which in 2035/36 is 24.8% that of the 2015/16 level.

Figure 10. Carbon impact of power and heating sectors (exc. heat demand fulfilled through electricity)

With the assumption of a correspondence between the gas demand and the natural gas price then there can be day-to-day variations in the gas price. The resulting gas price for each day is presented in Figure 11 where for each future scenario there continues to be seasonal price variations. The range between the minimum and maximum daily gas prices are presented in Table 4 where it can be seen that, until 2030/31, the range in gas prices remains within 3.7–3.9 £/MWh. These variations in the gas price highlight that the British system can still benefit from gas storage in the gas infrastructure. As the heating sector turns from gas to electric then there will be a shift of fuel costs to the electricity sector. The annual cost of meeting the heat and power sectors demand are shown in shown Figure 12 where the power sector costs have been broken down into that for fossil fuel and carbon costs, and that for other costs which includes the levelised generation costs from [13]. Despite the rise in fuel costs, the reduction in fossil fuels used in the heating sector leads to a reduction in the cost of meeting the supply as its fuel source is transferred to the power sector. There is an increase in the annual power system fossil fuel and carbon costs into 2025/26 driven by an increase in the wholesale prices, however, beyond this, the cost of utilizing the newly introduced, more expensive, technologies (in particular carbon capture and storage (CCS) and nuclear), exceeds the reduction in overall cost from fossil fuels and carbon and leads to an increase in the overall power system costs.

Figure 11. Annual variation in daily gas prices evaluated for each future scenario

428

Table 4 Range in gas price

Year	Annual range in gas price (£/MWh)
2015/16	3.7
2020/21	3.8
2025/26	3.9
2030/31	3.9
2035/36	3.0

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Figure 12. Power sector fossil fuel and carbon costs, power sector other fuel and levelised costs and heating sector costs for future scenarios. (Electric heating included with power sector costs)

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3.6 Hybrid heating technologies

A potential benefit of hybrid heating technologies is to mitigate against the need for a change in the generation portfolio. The case studies considering the operation of the hybrid technologies are based on the 2035/36 scenarios of Section 3.3. However, the generation portfolio, which is presented in Table 5 has been adapted to meet the heating sector needs by reducing the installed capacity to 121GW.

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Table 5 Installed generation capacity

Generator	Installed capacity
Nuclear	8.5%
Coal (inc. CCS)	12.0%
Gas (inc. CCS)	17.2%
Other conventional dispatchable sources (inc. interconnectors)	18.1%
Other renewables (inc. biomass, marine, hydro)	8.4%
Solar PV	4.4%
Wind	31.4%

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The case studies compare the benefits of using alternative hybrid heating technologies. The level of penetration of the heat technologies is again derived from [11] and is presented in

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Table 6 where the level of penetration is described in terms of the fraction of heat met by a given technology. The scenarios considered are:

- 'ASHP and boiler' produces 29.1% heat using an air-source heat pump and boiler.
- 'CHP and boiler' where technology consists of a hybrid CHP with auxiliary boiler.

Each of these has been compared against a respective base case without hybrid technologies though with the same generation portfolio. The 'ASHP and boiler' scenario is compared against 'ASHP' for which the heating technologies are those of 2035/36 in Section 3.2 while 'CHP and boiler' is compared against 'CHP' where all the heat which was previously met by a hybrid technology is now met using a micro-CHP.

In a commonly applied configuration, homes fitted with a hybrid CHP and auxiliary boiler use the boiler to meet the heat demand above that which may be supplied by the CHP. The dimensioning of the CHPs, i.e., its installed capacity in comparison to the heat demand, has been evaluated through the maximum rectangle method [14] and is sized so as to meet the heat demand for, on average, 6412 hours per year.

The operation of each hybrid technology and power system at a given time is determined using the electricity-heat optimization of Section 2.2. This is conducted for a weekly simulation period based on historical temperatures from 30 Jan–5 Feb 2013 and wind and solar generation based on data from 2004. This is presented in Figure 13 along with the actual wind generation in each scenario.

Table 6 Heat technology scenarios

Technology	Demand sector	2011	Pathway based on potential DECC heating scenario at 2035	
			ASHP and boiler	CHP and boiler
Gas boiler (old)	Domestic	43%	18%	18.2%
	Commercial	52%	21%	20.6%
Gas boiler (new)	Domestic	39%	16%	16.5%
	Commercial	19%	7.3%	7.4%
Resistive heating	Domestic	8%	3.6%	3.6%
	Commercial	19%	10%	10.0%
Oil-fired boiler	Domestic	5%	2.3%	2.3%
	Commercial	10%	4.9%	4.9%
Solid-fuel boiler	Domestic	5%	2.3%	2.3%
	Commercial	-	-	-
Stirling engine micro-CHP	Domestic	-	-	6.1%
	Commercial	-	-	7.2%
Fuel-cell micro-CHP	Domestic	-	-	12.3%
	Commercial	-	-	14.3%
Ground-source EHP	Domestic	-	5.7%	4.3%
	Commercial	-	5.7%	5.0%
Air-source EHP	Domestic	-	17.1%	3.7%
	Commercial	-	17.1%	4.3%
Community scale gas CHP	Domestic	-	-	10.1%
	Commercial	-	-	11.8%
District heating from power stations	Domestic	-	-	4.3%
	Commercial	-	-	5.0%
Gas heat pump	Domestic	-	-	6.8%
	Commercial	-	-	-
ASHP and boiler	Domestic	-	29.1%	-
	Commercial	-	29.1%	-
CHP and boiler	Domestic	-	-	9.5%
	Commercial	-	-	9.5%

Figures 14 and 15 exemplify the operation of the hybrid technologies and show the means by which the heat is produced in the 'ASHP and boiler' and 'CHP and boiler' scenarios. Comparing Figures 13 and 14, it can be seen how, as the wind generation levels drop towards the middle of the week, the 'ASHP and boiler' hybrid technologies begin to use gas at peak times thereby avoiding an increase in conventional generation. However, as transmission line constraints on the British north-south transmission lines limit the quantity of wind generation that can be transported to the demand sources in the south, for most of the week, there remains wind curtailment. On the other hand, comparing Figures 13 and 15, there is greater generation from the 'CHP and boiler' hybrid technologies when there is a reduction in wind generation corresponding to the increase in electricity prices. On the other hand, when there is excess wind towards the beginning of the week, it is often more efficient to meet the heat demand using gas boilers even though the CHP has a greater overall efficiency (when considering the sum of heat and power generation). The level to which this technology utilizes its boiler or CHP to meet the heat demand can provide insights into regions where they can be most beneficial. Such regional variations in the utilization can arise due to the regionality of wind generation and limitations in the network's transportation capability due to line constraints. Figure 16 presents the regional breakdown of the utilization of the hybrid CHP and auxiliary boiler. There is greater CHP generation levels in the south of England where there is a higher locational marginal electricity price; on the other hand, in Scotland, where there are large quantities of wind generation, gas boiler is often preferred for heat generation. This leads to a 20.0% difference in the CHP utilization level across different GB regions thereby highlighting the need for the consideration of the regional heat demand studies in an evaluation of power system operation.

With the consideration of the introduction of hybrid heating technologies, the results in Table 7 show the minimum and maximum output of the conventional generators. Considering the 'ASHP and boiler' scenario then at times of reduced renewable generation the operation can switch to use gas as the fuel source thereby reducing the need for more expensive peaking plants, this is highlighted in Table 7 by a 24% reduction in the peak conventional generation. On the other hand, with the increase in household micro-CHPs then on cold days, the morning heat demand peak precedes the electrical peak and leads to reductions in the demand net the CHP generation. This reduced system level demand can lead to stability issues as there are less conventional generating units online. There are benefits to the power system in the 'CHP and boiler' as there is an increase in the minimum conventional generation level above that for the CHP as more expensive generation supplying system reserve is no longer required to be online.

Figure 13. Solar generation and available wind and its actual output for various hybrid heating technology scenarios

Figure 14. Fuel for hybrid heating in the 'Gas and ASHP' Scenario

Figure 15. Fuel for hybrid heating in the 'CHP and boiler' Scenario

Figure 16. Regional breakdown of technology utilisation levels of hybrid combined heat-and-power with auxiliary boiler heating

Table 7 Peak conventional generation

Scenario	Peak conventional generation	Minimum conventional generation
'ASHP'	88GW	29GW
'ASHP and boiler'	67GW	29GW
'CHP and boiler'	38GW	19GW
'CHP'	35GW	17GW

3.7 Hybrid CHP and auxiliary boiler as demand side intervention to relieve gas transmission constraints

With the introduction of hybrid heating technologies, there is the potential of switching technology as a demand side means to alleviate gas transmission constraints. It is proposed that, in this scenario, which uses the generation and heat technology portfolios of the 'CHP and boiler' scenario, compressor outages reduce the capacity of certain gas network pipelines. In particular, it is proposed the compressor facilities C_1 , C_2 and C_3 of Figure 2 are out of service. Compressor station C_4 must run to maintain pressures at N_2 which leads to reduced pressures at node N_1 . However, based on the heat demands derived from the temperatures on 24 November 2013, at N_1 , there is 13GWh of heat demand fulfilled by the hybrid CHP with auxiliary boiler. The breakdown of the technology's form of heat generation is presented in Figure 17.

Figure 17. Operation of CHP with auxiliary boiler at N_1

In the study here, it is proposed, so as to alleviate the gas network constraints, that between the hours 1900–0000 all of the heat demand which was previously met using the CHP is now met through the gas boiler. The impact of swapping the technology in this manner has been assessed by comparing the pressures at node N_1 using a transient gas flow analysis (Section 2.3).

Figure 18. Pressures at N_1 with and without gas demand response using hybrid CHP and boiler

Figure 18 shows how, if the opportunity exists substitute the heat technology, then there is an ability to raise the system pressures. In the study here, the minimum pressure at N_1 was raised from 42.8bar to 43.9bar. The cost to the energy system for implementing the gas demand reduction at this node may be assessed by considering the change in fuel costs.

When the gas demand for the heating sector is reduced in this manner, then the total fuel costs for the power and heat sectors on this day increases by £36,500.

3.8 Extreme weather and supply constraints resilience assessment

The developed modelling has been applied in a study into the resilience of the British system. As noted in [15] [16], under normal operating conditions, the British system can accommodate 1-in-50 demand conditions. However, with the majority of gas sourced internationally [12], then other factors can impact the operation of the network. We consider a scenario where there has been a large interruption to a number of supply sources. Following [17], a scenario is considered where there is a reduction in the gas which is able to be imported from Continental Europe. Additionally, the British gas network has historically relied on the storage provided by the Rough storage facility to meet the demand on cold days. In the study here two cases have been considered.

Case (A) The following three conditions are imposed:

- i) External factors lead to a $89 \times 10^6 \text{ m}^3/\text{day}$ reduction in supplies from Continental Europe and a $58 \times 10^6 \text{ m}^3/\text{day}$ increase in exports to Zeebrugge.
- ii) Decommissioning of the Rough gas storage facility leading to a reduction in system supply of $41 \times 10^6 \text{ m}^3/\text{day}$.
- iii) Mothballing of 33% of the Hornsea storage facility.

Case (B) In addition to imposing all three of the conditions of Case (A) the following additional condition is considered:

- iv) Limited LNG availability due to tanker delivery scheduling [5].

Under these circumstances, the gas system may have to rely on demand response to maintain a daily energy supply/demand balance. As discussed in Section 2.3, associated to a given response volume is an opportunity cost. Following [18], the potential gas demand response volumes and opportunity costs are presented in Figure 19. The maximum system demand response is $35 \times 10^3 \text{ m}^3/\text{day}$ which is approximately 384 GWh/day.

Figure 19. Industrial demand response opportunities

In this scenario, the mean annual gas price is £19/MWh as predicted in base case for 2020/21 in [12].

The case study has considered the system heat and generation characteristics from the 2020/21 scenario from Section 3.3. At this time, there remains a large gas demand for the heating sector and an increase in the gas demand for generation. Furthermore, a historical winter's day where there is little wind generation is considered. Figure 20 presents the potential wind and solar generation derived from historical wind speeds and cloud cover data of 14 February 2003 which is then projected against the 2020/21 installed wind capacity of 21.6GW and solar capacity of 9.2GW. The heat demand is based upon that of a peak winter's day and results in 3.2TWh/day in gas demand for the heating sector. This is combined with other distribution level demand (including gas for cooking and industrial use), the transmission level industrial offtakes, interconnector export demand and, finally, the gas demand for generation which results from the power-heat modelling presented in Section 2.2. Figure 21 shows how, in Case A, the system can operate without the need for demand response.

Concerning the implications on the network's ability to meet the flow requirements, with over 30% of the gas now sourced from storage, there will be changes to the conventional supply routes of the network's gas. To assess the network adequacy of these scenarios, the steady-state gas flow optimisation modelling of Section 2.3 is performed. The breakdown of supply sources for Case A to different regions of Britain is presented in Figure 22. Although there remains a regional diversity to the supply sources, over 30% of the gas demand is now sourced from the eastern side of Britain and there is an east-to-west flow with, for example, 468GWh/day flows across boundary B_1 (Figure 22(a)). Furthermore, all the pipes between Milford Haven and the exporting Bacton flow east-to-west (Figure 22(a)). Each of the pipes q_1 and q_2 which B crosses are single pipelines in the full network also. Their maximum flow rates have been calculated by considering the maximum and minimum pressures (i.e., ignoring the requirement of these pipes to provide any gas network flexibility or pressure variation) giving each pipe a transportation capacity of 452GWh/day and 583GWh/day, respectively. Therefore, should one of these pipes become compromised, then the system operation may become effected.

As the gas network nears its technical capability, network limitations and the compressor fuel required to transport gas around the network mean that there are large variations in the nodal gas price, with the cheapest being near the terminals and the more expensive at the network extremities. In Case A, the lowest nodal gas price is £16.6/MWh at C (Figure 22(b)), while the highest is £26.4/MWh at D (Figure 22(b)).

Figure 20. Wind and solar generation based on wind speeds and cloud cover data from 14 February 2003

Figure 21. Breakdown of gas supply and demand for alternative scenarios

Figure 22. (a) Supply sources of network's gas in Case A and (b) localities of demand response

In Case B, supply limitations mean that the system operator has to employ 116 GWh/day of gas demand side response. Figure 22(b) presents its distribution around the network where it is focused on areas of gas intensive industry, in particular in the north of England. However, both the gas and electrical network remain able to meet their firm demand highlighting how gas demand response may be considered as an important alternative to replacing aging storage infrastructure while maintaining the ability to meet peak day demands. In this case, the use of gas demand response leads to a rise in the system marginal cost to £302/MWh, while, again, there are wide regional variations due the cost of gas transportation with nodal marginal gas prices of £255/MWh at C and of £503/MWh at D.

The large regional gas price variations in both Case A and Case B highlight how, on peak days, the network's capability can lead a large imbalance of prices around the network. The results highlight therefore that the current policy of a national balancing point (i.e., a single gas price for the system) can lead to a disincentive for the regional consideration of alternative pathways for heating technologies, further highlighting the requirement to consider regional analysis for future scenarios.

4 Conclusions

A novel integrated power-heat-gas model has been presented which allows for the assessment of the interdependences between different energy sectors at a nodal level and at half-hourly intervals. In Part I [1], a half-hourly nodal heat demand model was developed allowing for a comprehensive understanding of the temporal and regional of the heating sector and its fuel requirements. In this paper, Part II, the heat demand modelling has been coupled with gas and electrical networks to form an integrated assessment as to how changes in the heating impact the respective networks. The power system modelling considers an integrated heat-power optimization with DC power flow while the gas network flows, pressures and prices are evaluated using a steady-state gas flow optimization and transient modelling. Case studies show the development of the energy system as each of the heat, power and gas sectors develop towards a low-carbon future. The results show how hybrid heating technologies can be used as an additional flexibility option reducing the peak generation requirements of the conventional generating units, while allowing for gas demand switching to meet gas transmission capacity limitations. Finally, using extreme historical wind and solar data and heat demand, the ability of the gas network to support the heat and power system under supply limitations has been conducted, thus assessing the resilience level of the integrated energy system. It is shown how, under these limitations, gas consumers are constrained and that network limitations lead to large gas price spikes at network extremities. However, the use of industrial demand response can provide an additional option to maintaining the resilience of both the electricity and gas sectors.

The modelling framework with the modular nature of the heat demand evaluation allows it to be applied to alternative network studies. In particular, its high spatial resolution means that it is readily applicable to distribution network regions within the British system and can also be adapted to assess city-wide energy demands [19]. Alternatively, other countries planning pathways to decarbonize systems with comparable gas-based heating demand may integrate the models with alternative gas and electrical transmission networks to assess the impact of a shift in network demands.

Ongoing work is utilizing the developed modelling in designing possible pathways to a future low-carbon energy system and in assessing the possibilities of using thermal storage as a means of offering integrated system flexibility.

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