Efficacy of Options to Address Balancing Challenges: Integrated Gas and Electricity Perspectives

Meysam Qadrdan[1*], Hossein Ameli[2], Goran Strbac[2] and Nicholas Jenkins[1]

[1] Institute of Energy, Cardiff University, CF24 3AA, UK
[2] Electrical and Electronic Engineering Department, Imperial College London, SW7 2AZ, UK
[*] qadrdanm@cardiff.ac.uk

Abstract: Integration of a large capacity of wind generation in the Great Britain (GB) electricity network is expected to pose a number of operational challenges. The variable nature of wind generation necessitates introduction of technologies that can provide flexibility to generation portfolios and therefore compensate for intermittency of wind generation. In this paper, the efficacy of three options to address electricity balancing challenges was evaluated: flexible gas-fired plants, electricity storage and Power-to-Gas system. The combined gas and electricity network model (CGEN) was enhanced and through adopting a rolling optimisation approach the model aims at minimising the operational cost of an integrated gas and electricity networks that represents a GB system in 2030. The potential impacts of employing each of the flexibility options on the operation of the integrated electricity and gas networks were investigated. The analysis showed that amongst all the flexibility options, the deployment of grid-scale electricity storage will achieve the highest reduction in the operational cost of the integrated system (£12 million reduction in a typical winter week, and £3 million reduction in a typical summer week). The results of this study provide insights on the system-wide benefits offered by each of the flexibility options and role of the gas network in the energy system with large capacity of wind generation.

Keywords – Energy Storage; Flexibility; Gas network; Power-to-Gas; Power system

Nomenclature

Superscripts

ι	Gas injection into a storage facility
ω	Gas withdrawal from a storage facility
ue	Unserved electricity
ug	Unserved gas
su	Start-up
sd	Shut-down
f	Fuel cost of power generation
var	Variable cost of power generation
av	Average
$ecom$	Electrically-driven compressors
dem	Demand
$supp$	Supply
inj	Injection of electricity into storage
$avail$	This superscript indicates available wind power
abs	This superscript indicates the wind power absorbed by the electricity grid
cur	This superscript indicates the wind power curtailed

Subscripts

t	Time
s	Gas storage facility
b	Electrical busbar
i	Power generating unit

k	Thermal generating unit
n	Gas node
g	Gas terminal
q	Gas pipe
c	Gas compressor
l	Transmission line
e	Electrolyser

Parameters & Variables

C	Cost (£)
P	Electrical power (MW)
Q	Volumetric gas flow rate in standard temperature and pressure (m^3/h)
$Ramp$	Ramp rate (MW/h)
ρ	Density of gas in standard temperature and pressure (0.8 Kg/m^3)
p	Gas pressure (bar)
$\overline{P}$	Power generation capacity (MW)
$\underline{P}$	Minimum stable generation (MW)
T	Standard temperature (288 K)
Z	Gas compressibility (0.95)
$\overline{p}$	Upper pressure bound (bar)
$\underline{p}$	Lower pressure bound (bar)
v	ON and OFF state of a thermal generating unit (1/0)
UT	Minimum up time for a thermal generating unit (h)
DT	Minimum down time for a thermal generating unit (h)
r	Spinning reserve (MW)
V	Volume of a pipe (m^3)
η	Efficiency (%)
LP	Linepack (m^3)
α	Polytropic exponent (1.27)
CPR	Compressor pressure ratio
τ	Amount of gas trapped by a compressor (m^3/s)
β	Gas turbine fuel rate coefficient of a compressor
E	Level of energy storage (MWh)
D	Diameter of a pipe (m)
L	Length of a pipe (m)
R	Gas constant (518.3 J/Kg K^o)
H	The constant to convert energy content of hydrogen to its equivalent natural gas volume (90.9 m^3/MWh)
ts	Length of time step (1 h)
$WindP$	Wind power (MW)

1. Introduction

UK is committed to increase the share of renewable sources in the total energy consumption to 15% by 2020 [1] and 27% by 2030 [2], in order to achieve a longer term CO_2 reduction target of 80% in 2050 (to 1990 level). Given the significant wind energy resources across UK, wind generation will play a crucial role in achieving the renewable and emission reduction targets [3]. According to a number of low carbon scenarios studied by academics, industries and governmental bodies, capacity of wind generation in 2030 is expected to span between 52 GW and 65 GW [1].

Due to the variable nature of wind generation, increasing trend of wind farms integration into the GB power grid is expected to make the balancing of electricity supply and demand even more challenging [4-6]. Consequently, gas-fired generation will play increasingly important role in supporting balancing of demand and supply given that nuclear generation is inherently inflexible [4].

Gas-fired generation links gas and electricity networks. In the gas network, a gas-fired plant can be seen as a gas load, and in the electricity network this plant is an electricity supplier. Thus, utilising gas-fired plants to compensate for wind variability leads to variable gas demand for power generation [4].

Unlike electrical power, gas takes time to travel from supply sources (terminals and storage facilities) to demand centres. Linepack which is within-pipe storage capability of gas network is therefore a key factor that enables gas network to deal with rapid changes of the gas demand locally. Gas network operators tend to maintain a certain level of linepack, for example National Grid balances linepack of the GB National Transmission System (NTS) every 24 hours.

Growing variability and unpredictability of gas demand for power generation, caused by increased penetration of intermittent wind and inflexible nuclear generation will adversely affect linepack and make its management more difficult. Real operational data from National Grid shows that the within-day linepack of the GB NTS in 2012 fluctuated with larger magnitude compared to 2002 (Fig. 1). This is due to increased wind generation capacity and also partly as a result of closure of several gas holders in gas distribution networks [7].

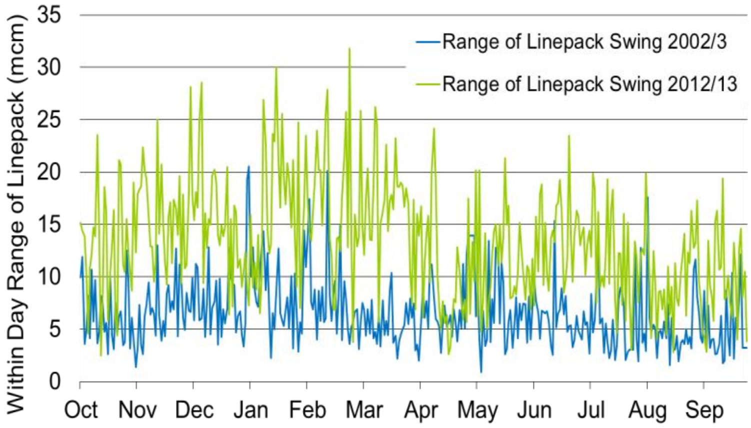

Fig. 1 *Comparison of within day Max-Min range of NTS linepack (mcm)*

In addition to flexible gas-fired plants, there are other flexibility options that can be employed for addressing balancing challenges such as demand-side response, electricity storage and power-to-gas system. Electricity storage can facilitate integration of wind to the grid and also affect the operation of gas network through smoothing variation of power output from gas-fired plants. Power-to-gas concept is to utilise electrolysers to convert electricity to hydrogen and then inject it into the gas network. Power-to-gas system can enhance the ability of system to integrate variable wind generation and reduce its curtailment through converting the excess wind and nuclear power to hydrogen, and affect the gas network operation by introducing new sources of gas in the network [8].

Several studies have investigated the role of flexibility options in addressing the balancing challenges. Reference [9] studied and quantified key parameters of thermal power plants that influence their flexibility in future power systems with a large capacity of variable renewable generation. It was shown although the flexible plants will have a crucial role in balancing electricity supply and demand in future, significant changes in the current market design needs to be made in order to encourage investments in flexible plants. In [10], the effectiveness of demand side response to deal with adverse impacts of the large integration of wind generation into power systems was investigated. Using real option analysis, authors in [11] evaluated optimal investments in hydrogen storage for storing excess wind power generation in a wind park. In [12], the effectiveness of power-to-gas systems in increasing the integration of renewable and reducing power losses in transmission networks was investigated. The value of electrical storage in a GB electricity system in 2030 which includes large capacity of variable renewable generation is studied in [13] using a whole electricity system investment model (WeSIM). The proposed model optimises the total investment and operational costs of the electricity system while considering the system security. The study highlights how different capacity of electrical storage installed in different part of the power system (transmission vs. distribution level) can contribute to providing reserve and manage distribution and transmission network congestion.

The focus of previous studies was on the role of flexibility options in operating power system, while the system-wide (gas and electricity) value of flexibility has not been considered. Although, interactions between gas and electricity networks have been investigated from security of supply perspectives [14], detailed analysis of impacts of wind generation on the gas network operation has been investigated by a very few studies [15], [16], [17]. In [15], optimal operation of combined gas and electricity networks in presence of large capacity of wind was assessed without taking into account the unit commitment constraints, in order to avoid computational complexity, as the optimisation problem would otherwise become a mixed integer nonlinear problem (MINLP). In [16], detailed unit commitments constraints were considered, however to deal with the computational complexity gas and electricity networks were decoupled and optimal operation of the networks were calculated in an iterative manner, i.e. operation of electricity system was optimised and then gas demand for power generation was calculated and given to the gas network as an input, and finally operation of gas network was optimised. Authors in [17] investigated benefits of storing renewable electricity in the gas network through convert the electricity into hydrogen and methane. In [17], unit commitment constraints were not considered.

In this paper, in order to analyse the whole system performance of flexibility options and explore interactions between gas and electricity networks in detail, capabilities of the Combined Gas and Electricity Networks (CGEN) model reported by [15] and [16] was significantly enhanced, so that the operation of gas and electricity networks can be simultaneously optimised through a rolling planning approach, taking into account detailed unit commitment constraints. Using the enhanced model, performance of three options to address balancing challenges was studied and compared from an integrated electricity and gas network perspective. These options include flexible gas plants, electrical storage and power-to-Gas system.

2. Modelling Methodology

CGEN model ([15], [16] and [18]) is an optimisation tool for detailed analysis of operation of interdependent gas and electricity networks. For this study, the CGEN model was significantly enhanced to investigate the system-wide (gas and electricity) impacts of employing various flexibility options. The model is capable of capturing hour-by-hour dynamics of the integrated system.

2.1. Objective Function

The objective function of the CGEN model is to minimise the total operational cost of both networks including electricity generation cost (fuel and variable operation and maintenance costs), cost of gas supply and cost of unserved energy (1).

$$Z = \min \sum_{t} \left\{ \begin{array}{c} \underbrace{\sum_{i} (C_i^f + C_i^{\text{var}}).P_{i,t} + \sum_{k} C_{k,t}^{su} + \sum_{k} C_{k,t}^{sd} +}_{Costs\ of\ Electricity\ Generation} \\ \underbrace{\sum_{\mathrm{g}} C_{\mathrm{g}}^{gas}.Q_{\mathrm{g},t} + \sum_{\mathrm{s}} (C_s^t.Q_{s,t}^t + C_s^{\omega}.Q_{s,t}^{\omega}) +}_{Costs\ of\ gas\ supply} \\ \underbrace{\sum_{b} C_g^{ue}.P_{b,t}^{ue} + \sum_{n} C^{ug}.Q_{n,t}^{ug}}_{Costs\ of\ Unserved\ Energy} \end{array} \right\} \tag{1}$$

2.2. Electricity Network Operation Modelling

In the modelled power system, power flow balance at each electrical busbar should be satisfied (2). The arrows underneath the sigma signs represent the connections of the components (e.g. electrolysers and compressors) to busbars.

$$\sum_{i \to b} P_{i.t} + \sum_{l \to b} P_{l.t} + WindP_{b,t}^{abs} = \sum_{e \to b} P_{e.t}^{elec} + P_{b.t}^{dem} + \sum_{c \to b} P_{c.t}^{ecom} - P_{b.t}^{ue} \tag{2}$$

The generation unit characteristics including power generation limit (3), minimum stable generation limit (4), generation ramp up/down limit (5), minimum up/down time limit for thermal generating units (6) are taken into account.

$$P_{i.t} \leq \overline{P_i} \tag{3}$$

$$\underline{P}_k\, \nu_{k.t} \leq P_{k.t} \leq \overline{P}_k \nu_{k.t} \tag{4}$$

$$|P_{i.t} - P_{i.t-1}| \leq Ramp_i \tag{5}$$

$$\nu_{k.\acute{t}} - \nu_{k.\acute{t}-1} \leq \nu_{k.t} \qquad \acute{t} = [t - UT_k + 1.\, t - 1] \tag{6.a}$$

$$\nu_{k.\acute{t}-1} - \nu_{k.\acute{t}} \leq 1 - \nu_{k.t} \qquad \acute{t} = [t - DT_k + 1.\, t - 1] \tag{6.b}$$

The available spinning reserve (7) is assumed to be equal or greater than the largest thermal generator connected to the grid in addition to reserve driven by uncertainty in wind power production.

$$r_{k.t} = \nu_{k.t} \times (\overline{P_k} - P_{k.t}) \tag{7}$$

The available wind power which could be absorbed by the grid or at some hours has to be curtailed, is presented in (8). In addition, the power transfer along the lines is limited by maximum capacity of the transmission lines (9).

$$WindP_t^{avail} = WindP_t^{abs} + WindP_t^{cur} \tag{8}$$
$$-\overline{P_l} \leq P_{l.t} \leq \overline{P_l} \tag{9}$$

2.3. Gas Network Operation Modelling

The operation of the gas network is constrained to the gas flow balance at each node (10). The arrows underneath the sigma signs represent the connections of the components (e.g. pipes and storage) to gas nodes.

$$\sum_{\mathbf{g}\to n} Q_{\mathbf{g}.t}^{supp} + \sum_{s\to n} Q_{s.t} + \sum_{q\to n} Q_{q.t} + \sum_{e\to n} Q_{e.t}^{elec} = \sum_{c\to n} \tau_{c.t} + Q_{n.t}^{dem} - Q_{n.t}^{ug} \tag{10}$$

Limitations on upper/lower pressure of the gas flow in the pipelines (11), gas supply capacity for terminals and storage facilities, and gas compressor operation are considered (12.a) to (12.c).

$$\underline{p} \leq p_{n.t} \leq \overline{p} \tag{11}$$
$$P_{c.t} = \frac{Q_{c.t}\alpha}{\eta_c(\alpha - 1)}\left[\left(\frac{p_{c.t}^{\mathrm{out}}}{p_{c.t}^{\mathrm{in}}}\right)^{\frac{(\alpha-1)}{\alpha}} - 1\right] \tag{12.a}$$
$$1 \leq \frac{p_{c.t}^{\mathrm{out}}}{p_{c.t}^{\mathrm{in}}} \leq \mathrm{CPR}^{\mathrm{max}} \tag{12.b}$$
$$\tau_{c.t} = \beta P_{c.t} \tag{12.c}$$

Panhandle 'A' equation is used to model gas flow along a pipe (13).

$$p_{in}^2 - p_{out}^2 = 18.43\frac{L}{\eta^2 D^{4.854}}Q^{1.854} \tag{13}$$

The linepack of a pipe is proportional to volume of the pipe and average pressure along the pipe (14.a). The linepack at each time step is equal to the linepack at the previous time step in addition to any gas accumulation from the previous time step (14.b).

$$\mathrm{LP}_{q.0} = \frac{p_{q.t}^{\mathrm{av}} V_q}{\rho Z R \mathrm{T}} \tag{14.a}$$
$$\mathrm{LP}_{q.t} = \mathrm{LP}_{q.t-1} + (Q_{q.t-1}^{\mathrm{in}} - Q_{q.t-1}^{\mathrm{out}}) \tag{14.b}$$

The option of producing hydrogen from electricity, and injection of the hydrogen into the gas network (Power-to-Gas) is also modelled in CGEN. The energy content of hydrogen from electrolyser is converted to volume of natural gas with the same energy content (15). Due to the small fraction of hydrogen in the mixture with natural gas, the impact of hydrogen injection on pressure and flow within the pipes are neglected.

$$Q_{e.t}^{electrolyzer} = \eta_e \, H \, P_{e.t} \tag{15}$$

The electricity storage units were modelled via their storage level (16) and maximum power output (17).

$$E_t = E_{t-1} + (\eta \times P_t^{inj} - P_t) \times ts \tag{16}$$
$$P_t \times ts \le \min(\overline{P} \times ts. E_t) \tag{17}$$

Constraints of both networks have to be met simultaneously. More details about the formulation of gas and electricity networks operation is presented in [15], [16] and [18].

The main linkage between gas and electricity networks is gas-fired plants, however in this study it was extended to take into account the interaction driven by electrically driven gas compressors and hydrogen electrolysers.

Operation of the combined gas and electricity system was optimised using a rolling planning approach presented in Fig. 2. Day-ahead optimal decision for operation of the combined system is made over typical winter and summer weeks. When optimising the system operation for a day, the model has perfect foresight on the gas and electricity demand as well as the available wind power within that day (no uncertainty is associated with the forecasts). However, although the data for the whole week is available before running the model, the model is blind to the data beyond the current day. After solving the optimisation problem for a day, the state of the system e.g. linepack, storage, ON/OFF state of the thermal generating units, are saved and then will be used in time-dependant constraints when running the model for the next day.

The main reasons for using the rolling planning approach are to a) avoid perfect foresight for wind out-turn beyond a day in order to more realistically model the operation of energy storage b) improve the computational performance by splitting a large optimisation problem (the optimisation problem of minimising the operational costs of gas and electricity networks over a week) into a number of smaller problems (seven optimisation problems of minimising day-ahead operational costs of gas and electricity networks).

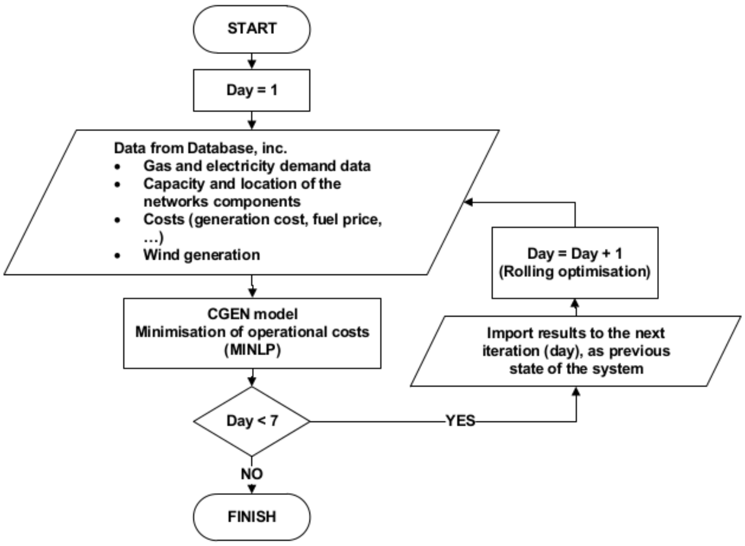

Fig. 2 *Solution structure of the model*

The model was developed using Xpress-Mosel, which is a modelling and a programming language and solved by Xpress-NonLinear solver [19].

3. Case Studies

Operation of a GB integrated gas and electricity system with large capacity of wind generation (Table 1) was modelled over typical winter and typical summer weeks in 2030.

Efficacy of the three options, including more flexible gas-fired plants, electricity storage and Power-to-Gas, to address electricity balancing challenges was evaluated and compared against a reference case in which no particular measure was considered to mitigate adverse consequence of integration of large capacity of wind generation into the grid.

Table 1 Electric power supply mix and cost of electricity generation [1]

Generation technology	Capacity (GW)	Cost of electricity (£/MWh)
Nuclear	9	7
Coal with CCS	4.5	22
Gas	33	2.3* + locational gas price
Wind	52	0
Pumped storage	2.7	Variables**
Interconnector	11.5	100

* £2.3/MWh is variable operating cost for gas-fired generating plants

** Depends on marginal cost of electricity used for pumping water, and overall efficiency of the plants

3.1. Descriptions of the cases

Reference case (Ref): In the Reference case no significant means of flexibility are introduced to the system.

Flexible Gas-fired Plants (FlexGP): It was assumed that a fraction of gas-fired generators that will be operating in 2030 are operationally more flexible, i.e. faster ramping, lower minimum stable generation limit, shorter minimum up and down time, and lower start up and shut down costs [20] (see Table 2). As shown in Table I, total capacity of gas-fired plants in 2030 is 33 GW from which it was assumed 10 GW are flexible plants that are uniformly distributed across the electricity network.

Electricity Storage (Estor): In this case it was assumed that electricity storage with rated power output capacity of 6 GW (aggregate) and total storing capacity of 24 GWh [21] with round trip efficiency of 80% will be integrated into the GB system by 2030.

Power-to-Gas (P2G): Possibility of injecting hydrogen produced from electricity into the GB gas network was considered. Total capacity of electrolysers was assumed to be 6 GW with efficiency of 70% [22] for converting electricity to hydrogen. All the busbars in the electricity network (and the gas nodes connected to them) are potential locations to install electrolysers. No limit was set for capacity of the electrolysers at each busbars. Taking into account wind generation and electricity demand, the CGEN model determines the optimal quantity of hydrogen production at each busbars and at each time step. Hydrogen storage was not considered as part of the Power-to-Gas system. The hydrogen produced using electricity via electrolysers was assumed to be injected directly into the gas networks.

Table 2 Gas-fired plants parameters

Type	η (%)	MUT /MDT (h)	$Ramp$ (MW/h)	$\underline{P}$ (% of capacity)	Start-up/ Shut-down cost (£)
Inflexible	60	4	250	40	2000
Flexible	60	1	350	30	1000

3.2. Wind generation, gas and electricity demand data

Real hourly electricity demand data for a typical winter week and a typical summer week were taken from National Grid and scaled up to represent the demands in 2030. Electricity demand was increased to represent 62 GW peak load in winter, which is expected due to electrification of segments of heat and transport sectors [1]. Non electric gas demand (i.e. total gas demand excluding gas for power generation) of 280 mcm/day for winter days and 120 mcm/day for summer days are used [23]. Gas demand within each day is at its maximum during 07:00am to 09:00am and also 18:00 to 20:00. Hourly wind generation data observed in GB during 15/04/2013 - 22/04/2013 [24] is scaled up to mimic

52 GW wind that is projected to be installed by 2030 [1]. Wind generation data shown in Fig. 3 is provided to the model as inputs, and interpreted by the model as potentially available wind power (not wind power absorbed by the grid). In the studies carried out winter and summer wind generation patterns are similar, with average capacity factors of 40% and 30% respectively.

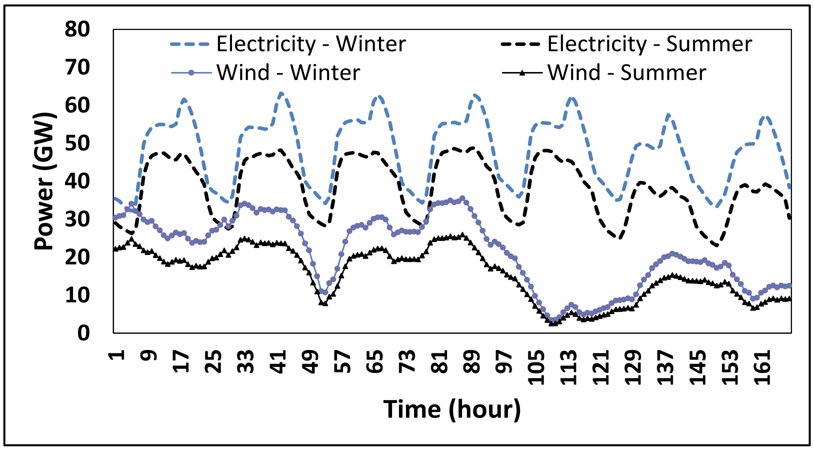

Fig. 3 *Hourly available wind power and electricity demand.*

3.3. Gas and electricity networks

Future GB electricity and gas networks were represented using Fig. 4 and Fig. 5. The figures illustrate the topologies and spatial granularities of gas and electricity networks.

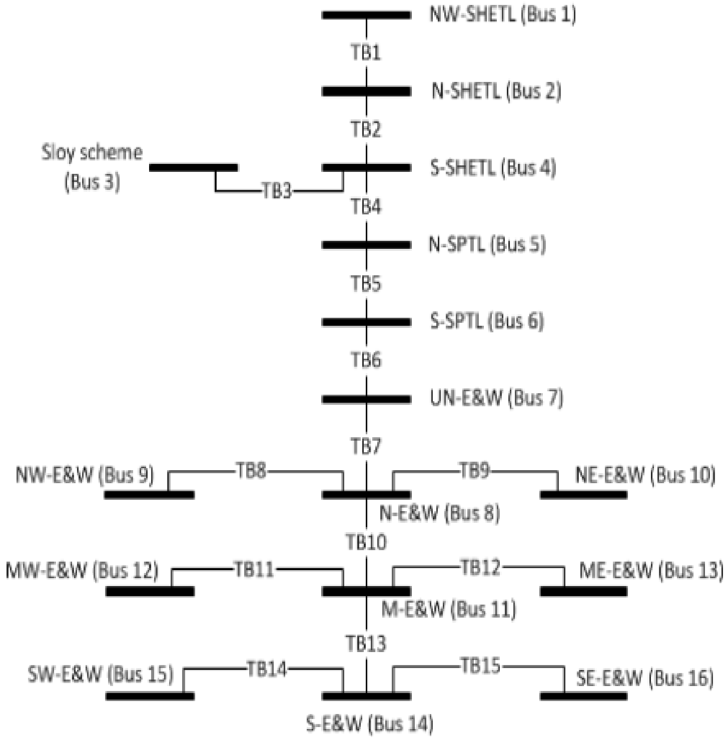

Fig. 4 *GB electricity network representation*

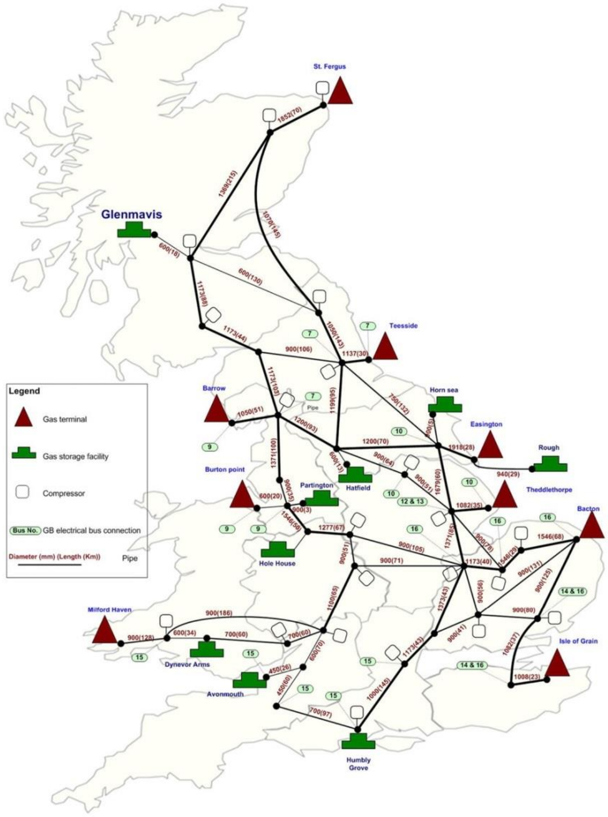

Fig. 5 *GB gas network representation [15]*

4. Efficacy of Flexibility Options in 2030

4.1. *ON/OFF cycle for thermal generating units*

Most of the coal units equipped with Carbon Capture and Storage (CCS) technologies operate throughout the time horizon, due to lower generation costs [25] when compared with gas-fired units. In addition, CCS-equipped coal units are less flexible compared to gas in providing backup for wind variation. In contrast to coal units, total number of committed gas-fired units varies frequently and significantly in both winter and summer weeks, due to variability in wind generation. Aggregate number of committed gas-fired units in the winter and summer weeks for the *Ref* case are shown in Fig. 6.

For instance, as shown in Fig. 3 in the winter week, before hour 110 when electricity demand increases and concurrently wind generation drops, roughly 60 additional gas generating units (with average capacity of 300MW) become online in 4 hours to ensure meeting electricity demand and reserve requirement. In the same low wind-high demand situation in the summer week, almost 80 gas-fired generating units start up.

The general pattern of committed units are similar, however, in the case in which storage is used, the magnitude of fluctuation is lower, as electrical storage absorb electricity in high wind period and contribute to the electricity supply when wind drops.

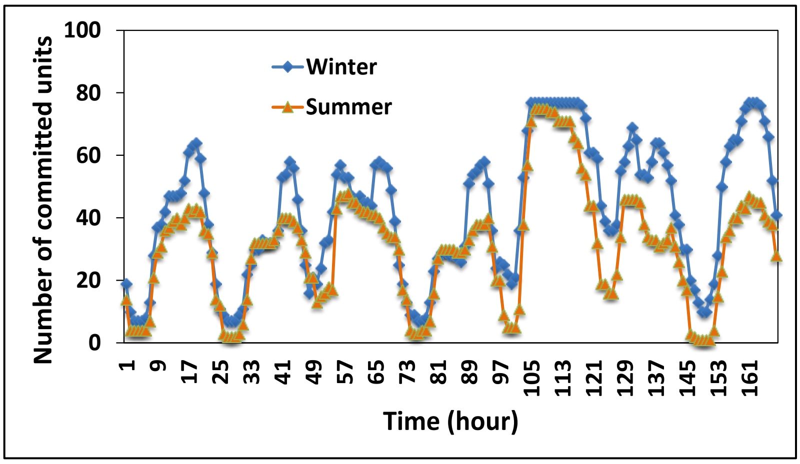

Fig. 6 *Number of committed gas generating units for Ref case*

4.2. Power generation mix

Contribution of different generation technologies to supplying electricity in the winter and summer weeks are shown in Fig. 7 and Fig. 8 for the *Ref* case. Given the inflexible operation characteristics of nuclear generation, power output from these plants does not vary over time to complement variability and uncertainty in wind generation.

A limited flexibility is offered through coal power plants equipped with CCS technology. These plants are all committed throughout the modelling periods, however their power output fluctuates within their minimum stable generation limit and their total capacity. Gas-fired plants (in the figures as CCGT) are the main resource of flexibility for management of wind variability. In the fifth day of the summer and winter weeks very low wind power period coincides with peak electricity demand which resulted in substantial increase in outputs of gas-fired plants to balance supply and demand, i.e. in the fifth day of winter week from 4.1GW to 32.3GW, and in the fifth day of summer week from 0.8GW to 29.6GW. In this study price of electricity supplied by interconnectors was assumed to be higher than the generation cost of the other technologies.

Consequently, as presented in Fig. 7, power supplied by interconnectors fills the gap between supply and demand during peak hours of the fifth day in the winter week when wind generation is very low and all the other plants are operating at their maximum capacity.

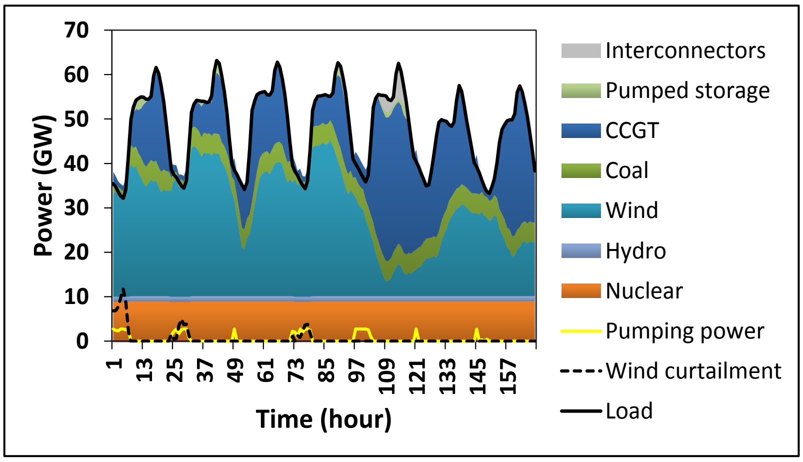

Fig. 7 *Generation mix and wind curtailment for Ref case (winter week).*

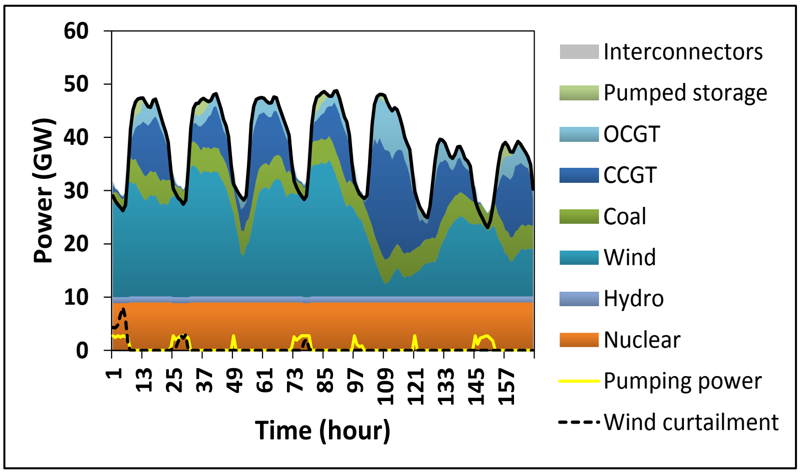

Fig. 8 *Generation mix and wind curtailment for Ref case (summer week).*

Changes in the electricity generated by various types of technologies (over both winter and summer weeks) in respect to the *Ref* case are shown by Fig. 9. Electricity generation by nuclear plants undergoes no changes. In *FlexGP* case, introduction of flexible gas-fired plants which could provide more reserve due to their lower minimum stable generation limit and faster ramp rates, resulted in higher absorption of available wind by the grid. However, these flexible generators, with total capacity of 10GW, only produce 16GWh more electricity compared to the same capacity of less flexible gas-fired plants.

In the *Estor* case, more wind generation is possible to integrated (less curtailment occurs) which reduces the output from gas-fired plants (75 GWh) and interconnectors (27GWh). Energy production by coal CCS also increased because of the energy storage not only supports balancing of the supply and demand, but also provides reserve, and therefore less flexible and lower cost coal CCS (compared to the gas-fired plants) operate with higher load factors.

Introduction of Power-to-Gas (P2G) system boosts the amount of wind absorbed to its maximum compared to the other case studies. As it can be seen from Fig. 9, there is very small decrease in the output of other generating technologies. The reason for this is that the increased electricity supply from wind is used to produce hydrogen and therefore cannot contribute to meeting electricity demand.

In all the cases in which new flexibility options are introduced, the contribution from non-dispatchable (wind) and inflexible (coal with CCS) in supplying electricity increased. On the other hand, electricity generation from gas-fired plants is reduced (*FlexGP* and *Estor* cases) or slightly increased (*P2G* case).

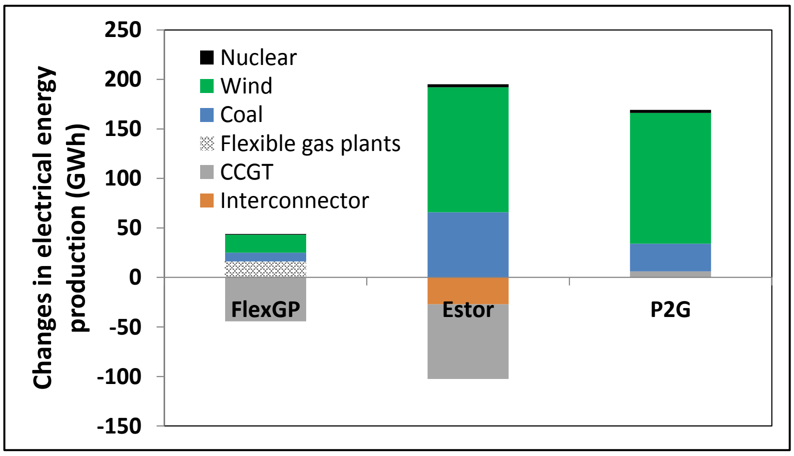

Fig. 9 *Changes in electricity generation from various type of technologies over both winter and summer weeks compared to Ref cases.*

4.3. Wind Curtailment

Wind curtailment during the winter and summer weeks for different cases are shown in Fig. 10. Employment of flexibility options led to reduction in wind curtailment. Utilising more flexible gas-fired plants in *FlexGP* case reduced the wind curtailment almost by 20% compare to the *Ref* case. This is due to higher ramp rates and shorter up/down time periods of this type of power plants, which enhances the ability of the plant to manage wind variability. However, in some periods total electricity generated via wind and must run technologies is higher than demand and because of limited capacity to store electricity (e.g. pumped storage), yet a significant fraction of electricity from wind has to be curtailed.

In the *Estor* case, roughly 10 GWh wind was curtailed during off-peak hours in the first two days of the winter week when large amount of wind energy is generated. During these periods electricity is injected to the storage at their maximum capacity.

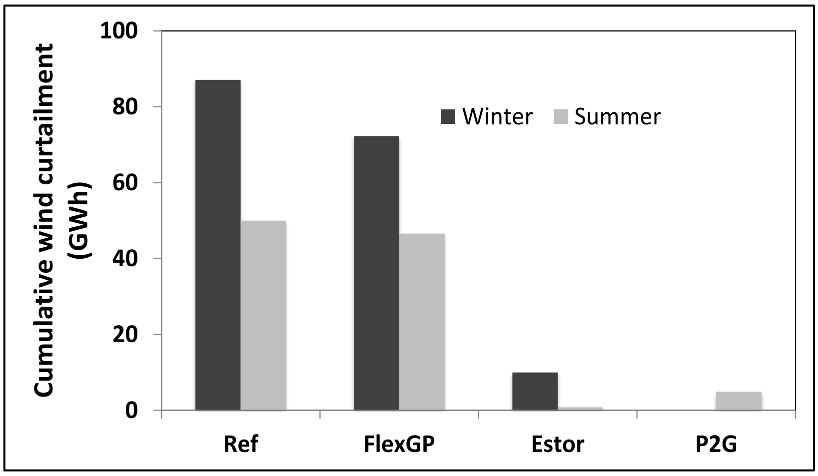

Fig. 10 *Cumulative wind curtailment in different case studies*

In the *P2G* case, using electrolysers to convert electricity to hydrogen and then injecting the hydrogen to the gas network eliminate wind curtailment in the winter week, as the volume of hydrogen that can be injected to the grid (and therefore the electricity demand for electrolysers) can be significant. In contrast, due to lower gas demand in the summer week which reduces the maximum limit for hydrogen injection, roughly 5 GWh wind energy cannot be converted to hydrogen and as such is curtailed.

Although, higher level of flexibility in *Estor* and *P2G* cases prevented wind curtailment to a large extent, the losses of wind energy due to round-trip efficiency of electricity storage (80%) in *Estor* and efficiency of converting electricity to hydrogen (70%) and then regeneration of electricity via CCGTs (60%) in *P2G* are still significant (Fig. 11). In particular, in *P2G* the overall efficiency is around 42% which resulted in higher energy losses compared to storage.

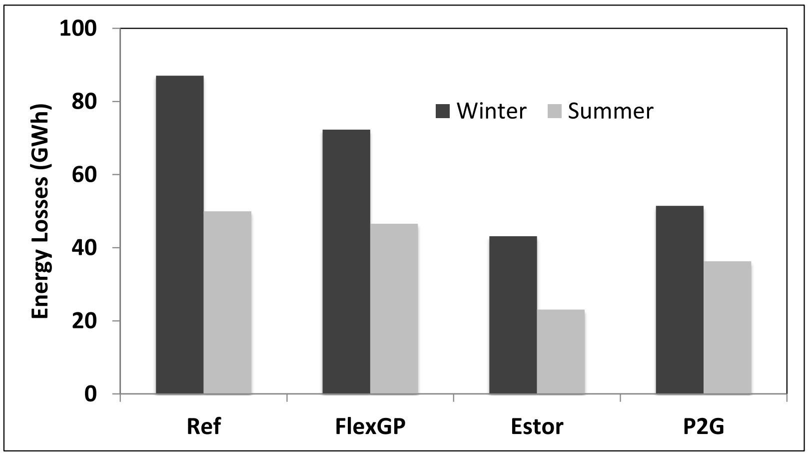

Fig. 11 *Cumulative energy loss in different case studies*

4.4. Gas network operation

Compressor power consumption for the winter and summer weeks of the *Ref* case is shown by Fig. 12 and Fig. 13. In terms of fuel use, there are two types of compressors operating in NTS: electrically driven and gas-fired compressors. Electrically driven compressors are operating in Scotland and north England to maintain gas flow to the demand centres in the south. In general, compressor power consumption increases by rise of total gas demand in order to maintain gas flow to demand centres and keep the gas pressure and linepack within the acceptable range.

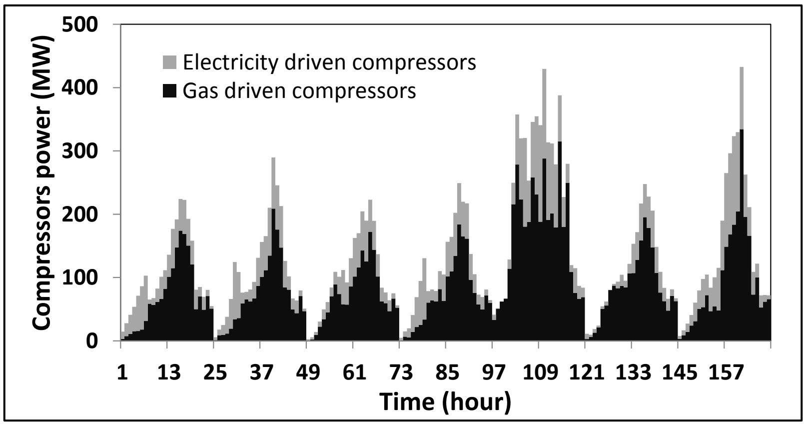

Fig. 12 *Compressor power for Ref case (winter week)*

In the winter week, during high wind days contribution of electrically driven compressors is increased to make the best use of low cost electricity and therefore contribute to lowering the total operational cost of the system.

In day 5 of the winter week, low wind generation resulted in less electricity consumption by electrically driven compressors so that balancing electricity supply and demand to be less challenging (Fig. 14). In the summer week, due to lower gas demand, gas compressors on average consume 70% less power compared to the winter week, with minimal share from electricity. Employing both gas and electricity driven compressors in the gas network provides higher flexibility to the system.

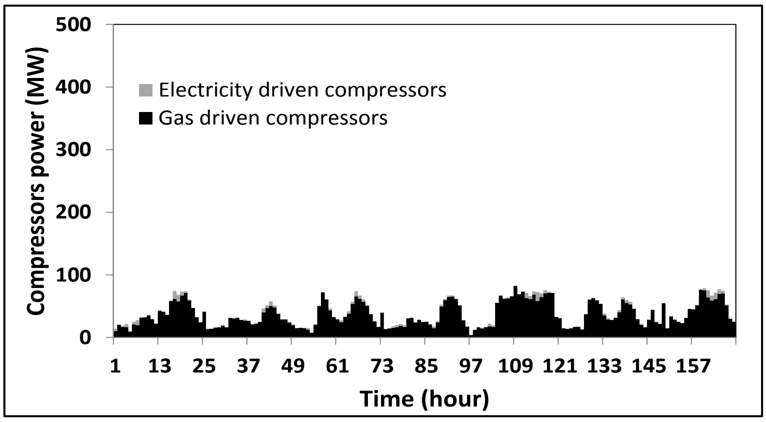

Fig. 13 *Compressor power for Ref case (summer week)*

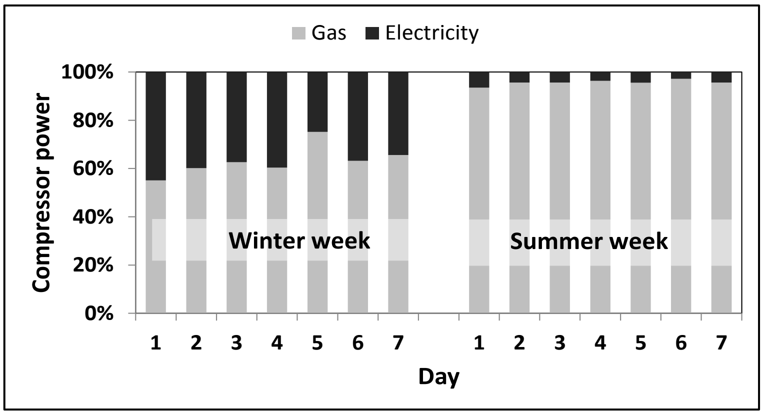

Fig. 14 *Electrically driven and gas compressor power for Ref case*

In the *FlexGP* case, the maximum power consumed by compressors is higher compared to the other cases, due to larger share of gas-fired plants in the power supply when wind speed drops (Fig. 15). It can be concluded that using more flexible gas-fired plants, will not have significant impact on the total gas demand, however, the maximum gas flow capacity required will increase.

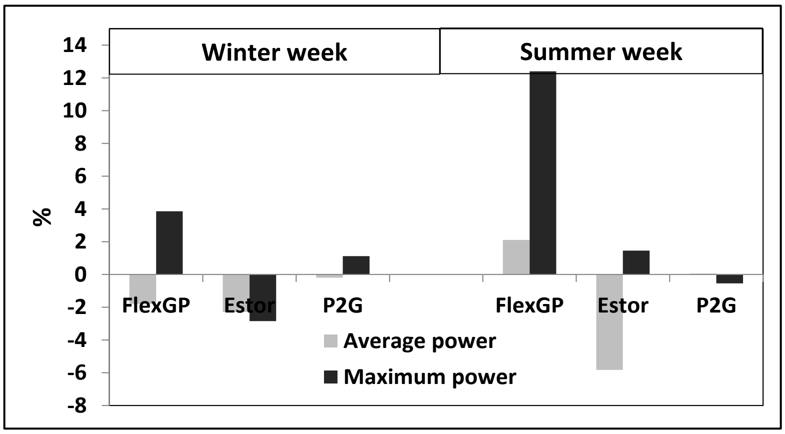

Fig. 15 Changes of average and maximum compressor power compared to the Ref case

4.5. Operational Cost

Operational cost of the combined gas and electricity network over the typical winter and summer weeks for various case studies are shown by Fig. 16. Various measures for provision of flexibility have a role to play in terms of reducing the operational costs of the system. The lowest operational cost was achieved in the *Estor* case. In *P2G* case as the overall efficiency of converting electricity to hydrogen and then using the produced hydrogen to generate electricity is relatively low, the total operational costs of the system is higher compared to *Estor*, yet lower than *Ref* and *FlexGP* cases.

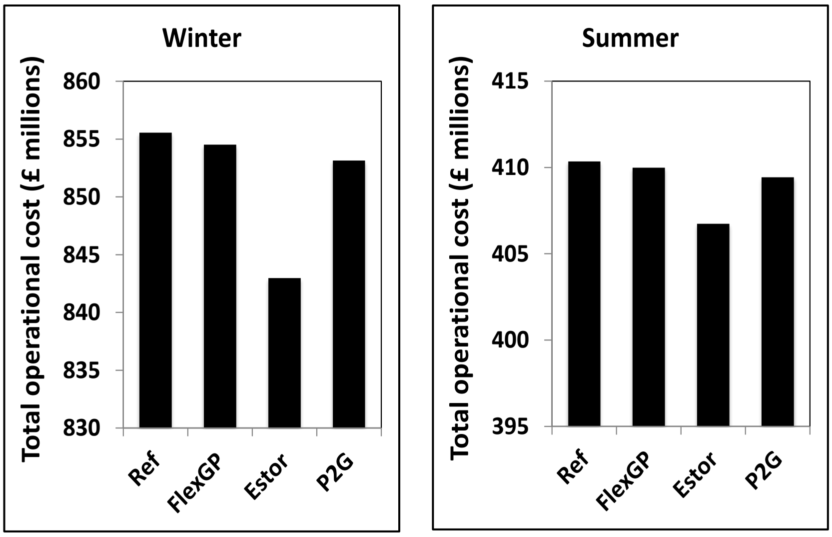

Fig. 16 *Total operational cost of the combined gas and electricity network over the optimisation time horizon (one week) in winter and summer*

5. Conclusion

In this paper a detailed optimisation model for operation of an integrated gas and electricity system was developed to investigate the system-wide value of various options to address balancing challenges. Efficacy of employing more flexible gas-fired plants, electrical energy storage and Power-to-Gas system in dealing with wind variation is analysed, including the impacts on the GB gas network.

All the flexibility options were demonstrated to have a role in facilitating cost effective integration of variable renewable generation through reducing wind curtailment and operating costs of the integrated gas and electricity system.

It was shown that the employment of more flexible gas-fired plants although contributes to lowering operational cost of the electricity network, it results in lower utilisation factor for these generators. The flexible gas-fired plants mainly provide reserves and therefore less flexible plants can operate with higher load factors. Furthermore, the use of more flexible gas-fired plants increases the difference between maximum and average power consumption by compressors in the gas network. This is primarily due to the increased magnitude of fluctuations in gas demand for the flexible gas-fired plants.

The lowest operational cost was achieved through using electrical energy storage. The use of electrical storage reduces the magnitude of fluctuations in power output from gas-fired plants and consequently reduces variations of compressors power consumption and linepack.

The Power-to-Gas system introduces a large energy storage capacity (in the form of gas) which results in complete absorption of wind power. One of the advantages of the Power-to-Gas system is that excess electricity can be converted to hydrogen and then transported via gas network to the demand centres, which helps to bypass power transmission congestion.

As this work focused on quantifying the benefits of alterative technology options in operating integrated gas and electricity networks, future work needs to include development of the business case for the options considered taking into account investment cost implications and the overall system emissions performance. Furthermore, it will be important to examine the suitability of the present market arrangements and their ability to reward flexibility services provided by the options considered. As demonstrated, investment in flexible gas generation would reduce their load factors, while increasing load factors of less flexible plant, and it is not clear if the present market provides sufficient rewards for benefits delivered.

Acknowledgments

The authors gratefully acknowledge the Whole Systems Energy Modelling Consortium (wholeSEM) for providing funding for this work under EPSRC grant EP/K039326/1.

References

[1] "UK Future Energy Scenarios," National Grid, Jul. 2014.

[2] European Council, "2030 framework for climate and energy policies," European Council, Brussels, 2014.

[3] "UK Renewable Energy Roadmap Update," Department of Energy and Climate Change (DECC), 2013.

[4] Oswald, J., Raine, M., Ashraf-Ball, A., "Will british weather provide reliable electricity?," Energy Policy 36, pp. 3212-3225, 2008.
[5] Touretzky, C.R., McGuffin, D.L., Ziesmer, J.C., Baldea, M., "The effect of distributed electricity generation using natural gas on the electric and natural gas grids," Applied Energy, Vol. 177, pp. 500-514, Sep. 2016.
[6] Kubik, M.L., Coker, P.J., Barlow, J.F., "Increasing thermal plant flexibility in a high renewables power system," Applied Energy, Vol. 154, pp. 102-111, Sep. 2015.
[7] "GB Ten Year Statement," National Grid, 2008a.
[8] ITM Power, "Power-to-Gas: A UK feasibility study," 2014.
[9] Brouwer, A., S., Broek, M., Seebregts, A., Faaija, A., "Operational flexibility and economics of power plants in future low-carbon power systems", Applied Energy, Vol. 156, pp. 107-128, 2015.
[10] Finn, P., O'Connel, M., Fitzpatrick, C., "Demand side management of a domestic dishwasher: Wind energy gains, financial savings and peak-time load reduction", Applied Energy, Vol. 101, pp. 678-685, 2013.
[11] Kroniger, D., Madlener, R., "Hydrogen storage for wind parks: A real options evaluation for an optimal investment in more flexibility", Applied Energy, Vol. 136, pp. 931-946, 2014.
[12] Zeng, Q., Fang, J., Li, J., Chen, Z., " Steady-state analysis of the integrated natural gas and electric power system with bi-directional energy conversion", Applied Energy, 2016, doi:10.1016/j.apenergy.2016.05.060
[13] Pudjianto, D., Aunedi, M., Djapic, P., Strbac, G., "Whole-Systems Assessment of the Value of Energy Storage in Low-Carbon Electricity Systems," IEEE Transaction on Smart Grid, vol. 5, no. 2, pp. 1098-1109, Mar. 2014.
[14] Li, T., Eremia, M., Shahidehpour, M., "Interdependency of Natural Gas Network and Power System Security," IEEE Transaction on Power Systems, vol. 24, no. 4, pp. 1817-1824, Nov. 2008.
[15] Qadrdan, M., Chaudry, M., Wu, J., Jenkins, N., Ekanayake, J., "Impact of a large penetration of wind generation on the GB gas network," Energy Policy 38, pp. 5684-5695, 2010.
[16] Qadrdan, M., Wu, J., Jenkins, N., Ekanayake, J., "Operating Strategies for a GB Integrated Gas and Electricity Network Considering the Uncertainty in Wind Power Forecasts," IEEE Transaction on Sustainable Energy, Vol. 5, no. 1, pp. 128-138, Jan. 2014.
[17] Clegg, S., Mancarella, P.," Storing renewables in the gas network: modelling of power-to-gas seasonal storage flexibility in low-carbon power systems," in IET Generation, Transmission & Distribution, Vol. 10, Iss. 3, pp. 566-575, 2016.

[18] Chaudry, M., Jenkins, N., Strbac, G., "Multi-time period combined gas and electricity network optimisation," Electric Power Systems Research 78, pp. 1265-1279, 2008.
[19] [Online].Available: http://www.maths.ed.ac.uk/hall/Xpress/FICO_Docs/mosel/mosel_lang/dhtml/moselref.html
[20] Schroder, A., Kunz, F., Meiss, J., Mendelevitch, R., and Hirschhausen, C. V., "Current and Prospective Costs of Electricity Generation until 2050," 2013.
[21] Strbac, G., et al, "Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future," Energy Futures Lab, Imperial College London, Jun. 2012.
[22] "Report and Financial Statements," ITM Power, 2013.
[23] "National infrastructure assessment: Analysis of Options for Infrastructure provision in Great Britain," UK Infrastructure Transitions Research Consortium (ITRC), Jan. 2014.
[24] Elexon, [Online]. Available: www.Elexon.co.uk. [Accessed 2013].
[25] Ummels B.C., Pelgrum, E., Kling, W.L., "Integration of large-scale wind power and use of energy storage in the Netherlands electricity supply," in IET Renewable Power Generation, Vol. 2, No. 1, pp. 34-4, 2008.