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Benefits of demand-side response in combined gas and electricity networks

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HIGHLIGHTS

- Availability and cost of gas are crucial factors in power system planning.
- CGEN+ was developed to analyse expansion of combined gas and electricity systems.
- The model was enhanced significantly to take into account electricity DSR.
- The benefits of electricity DSR to GB gas and electricity networks were quantified.

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ABSTRACT

Active demand side response (DSR) will provide a significant opportunity to enhance the power system flexibility in the Great Britain (GB). Although electricity peak shaving has a clear reduction on required investments in the power system, the benefits on the gas supply network have not been examined. Using a Combined Gas and Electricity Networks expansion model (CGEN+), the impact of DSR on the electricity and gas supply systems in GB was investigated for the time horizon from 2010 to 2050s. The results showed a significant reduction in the capacity of new gas-fired power plants, caused by electricity peak shaving. The reduction of gas-fired power plants achieved through DSR consequently reduced the requirements for gas import capacity up to 90 million cubic meter per day by 2050. The cost savings resulted from the deployment of DSR over a 50-year time horizon from 2010 was estimated to be around £60 billion for the GB power system. Although, the cost saving achieved in the gas network was not significant, it was shown that the DSR will have a crucial role to play in the improvement of security of gas supply.

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1. Introduction

The power system is increasingly integrating generation from renewable energy sources in order to reduce the reliance on import fossil fuels and to mitigate the Green House Gas (GHG) emissions. Electrification of heat and transport in the Great Britain (GB) is expected to have a substantial contribution to the reduction of the total GHG emissions [1]. However, these changes in generation mix and electricity demand will lead to an increasing peak demand and consequently network congestions which challenge the system security. Therefore, more capacity of peaking generation plants such as the fast start and flexible gas-fired generation is required. It is estimated in [2] that, around 1 MW of new peaking plant is required for every 8 MW of wind generation installed.

As expected in the GB Gone Green Scenario [3], the gas-fired generation capacity will increase from 27.5 GW in 2009/10 to 34.6 GW in 2020/21. The increases in the gas-fired generation capacity will cause increasing gas consumption in the GB. As illustrated by the GB system operator, National Grid, the percentage of GB import gas will rise to 62–83% by 2020 [4]. However, reliance on imports is usually expensive and may cause concerns over the security of energy supply.

An alternative solution to mitigate the pressure of peak demand on future GB electricity and gas supply networks is the implementation of Demand-Side Response (DSR) [5]. DSR is a set of measures that uses loads, local generation and storage to support network operations and also to enhance the quality of power supply. DSR encourages customers financially to lower or shift their electricity use at peak times. This will help manage the load and voltage profiles on the electricity network [6]. DSR is also able to manage the power consumption of demand in response to supply conditions.

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Nomenclature

Superscripts

y	type of power generating technology (e.g. nuclear, wind, CCGT)
l	location
t	planning time step
n	new infrastructure
d	decommissioned infrastructure

Variables

$\overline{C}$	capacity of infrastructure
$\overline{P}$	capacity of power generation

Parameters

A	winter availability of power plants
ACS	average cold spell electricity peak demand
τ^{peak}	number of hours representing peak period (2 h)
$\tau^{off-peak}$	number of hours representing off-peak period (11 h)
δ^{-}	average power shaving during peak hours (GW)
δ^{+}	average power increase in off-peak demand, shifted from peak hours (GW)

Abbreviations

CCS	Carbon Capture and Storage
CCGT	Combined Cycle Gas Turbine
DSR	Demand-side response
OCGT	Open Cycle Gas Turbine
Capex	Capital expenditures
Opex	Operating expenditures

Research and projects have been undertaken to develop different DSR mechanisms. At present, DSR mainly from the large-size industrial loads, is able to provide ancillary services at the transmission level, for instance, frequency response services [7] and operating reserves [8]. The employment of DSR will reduce the reliance on partly-loaded fossil-fueled generators to provide spinning reserve for the maintenance of the balance between supply and demand. National Grid has started to turn DSR into actions through the 'Power Responsive Campaign' [9] across the GB power system. It is admitted that DSR is able to reduce the conventional generation capacity, to maximize the low carbon generation, to contribute to short-term system balancing and to defer the network reinforcements [10]. By 2014, DSR has provided approximately 1.6 GW of reserve services to the GB power system [11]. Carbon savings will also be obtained through DSR. In [12], the carbon savings were quantified by applying DSR for different balancing services in the GB power system including the Short Term Operating Reserve, Triad and Fast Reserve.

The roll-out of smart meters will provide the opportunity to introduce time varying price schemes such as Time-of-use price to customers [13]. It is therefore expected that customers will change their power consumption as a result of the financial savings offered by the time varying price schemes. This will contribute to the reduction of peak demand. Different optimization problems were established in [14–19] to shave the system peak and therefore alleviate the distribution network congestions. The rescheduling of demand minimizes not only the total system costs but also reduces the user payments. As discussed in [20], using smart meter with the price-responsive demand response programs will make long term electricity markets more competitive and will enhance the system reliability. Refs. [21,22] integrate the residential demand response, which is a real-time control of shiftable appliances such as the electric water heaters, Heating, Ventilating and Air Conditioning (HVAC) loads, with locational marginal price in a distribution energy market. It is shown that the distribution network congestions and the GHG emissions were alleviated while the customers achieve cost savings in using electricity. Although there are certain regulatory barriers in applying DSR at the distribution level in terms of network tariffs, DSO remuneration, consumer protection, etc. that slow down the involvement in DSR especially from the small consumers in the distribution network as discussed in [23], the benefits of implementing DSR are still worth to be investigated in order to facilitate the transition to a low-carbon power system.

The impact of DSR in the operation of combined electricity and gas network was briefly discussed in [24,25]. These studies show that DSR is an effective way in improving the operational efficiency of the integrated networks, and can reduce the network congestions during the peak demand period. The benefits of DSR to gas supply networks in terms of long-term planning have not been investigated in the literature.

In this study, an integrated approach based on the Combined Gas and Electricity Networks expansion model (CGEN+) [31] was adopted to investigate the long-term value of electricity DSR to the GB power and gas supply systems. The dynamic coevolution of gas and electricity systems up to 2050s was taken into account to quantify the value of electricity DSR in terms of capital costs, operating costs and security of gas supply.

2. Potential flexible demand for DSR

Flexible demand for DSR refers to the loads varying the energy consumption in response to system needs with minimal disruption to load owners. Fig. 1 depicts the electrical demand sectors across the GB power system [26]. The domestic sector represents the sin-

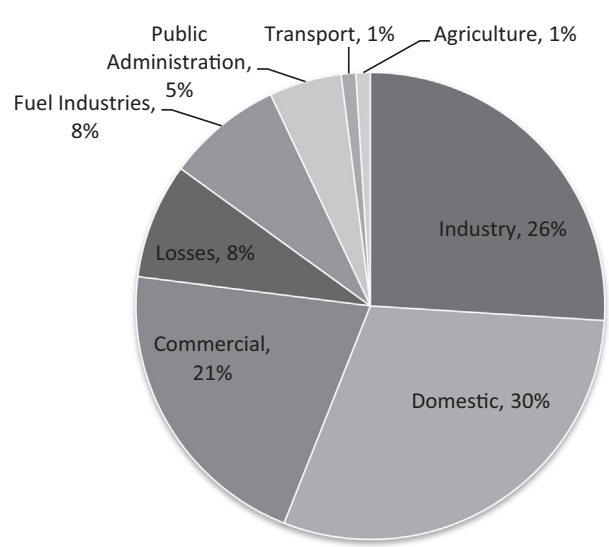

Fig. 1. Electricity demand of GB power system by sectors in 2012 [26].

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gle largest consumer of electricity in the GB power system. Flexible domestic demand includes mainly the cold appliances such as refrigerators, wet appliances such as washing machines, and electric space and water heating (ESWH). Cold appliances are able to modify their running time at power system peak, wet appliances are able to delay wash and dry and to modify cycling time, and ESWHs are able to shift the power consumption to off-peak period of a day, e.g. start to heat up the water at midnight. The potential amount of flexible domestic demand in 2030 was investigated in [27]. The percentage of flexible domestic demand is theoretically 26% at the peak time of a winter day and 10.8% at the peak time of a summer day.

For the non-domestic sectors, the potential peak shaving of flexible demand in winter days was estimated in [28]. Conservatively, the peak shaving is estimated to be 1.2 GW. A moderate prediction gives the peak shaving of 2.5 GW. A relatively stretch and ambitious estimation is up to 4.4 GW.

The amount of flexible demand in all sectors was investigated in [29] for 2025 and the results were referenced by National Grid. Two scenarios were studied. Business as usual (BAU) is a conservative scenario while the greenest scenario is a more optimistic prediction. The results are summarized in Table 1. Therefore, in order to study the potential impacts of DSR on the GB gas and electricity networks, different percentages (10%, 20% and 30%) of flexible demand were considered conservatively in the CGEN+ model.

3. Modelling methodology

The Combined Gas and Electricity Networks expansion planning model (CGEN+) is an optimization tool for long term infrastructure planning of interdependent gas and electricity networks in an integrated approach. The first version of the model was developed by Chaudry et al. [30] and continually has been improved through several research (e.g. [31]). For this study, CGEN+ was enhanced significantly to incorporate the electricity demand side response capability, and to quantify its benefits to both electricity and gas transmission networks.

Table 1
Potential flexible demand for DSR in 2025 [29].

		BAU	Greenest
Total demand (GW)	Winter	67	58
	Summer	45	37
Flexible demand (GW)	Winter	23	20
	Summer	13	19
Flexible demand percentage (%)	Winter	34.3	34.5
	Summer	28.9	51.4

The main components of both gas and electricity supply infrastructure are considered in the model (see Fig. 2). The main linkage between gas and electricity networks is gas-fired plants. The model simultaneously minimizes the discounted costs associated with expansion and operation of the both networks over the whole planning horizon (2010–2059), subjecting to meet energy demand, technical constraints (e.g. gas flow equations) and energy policy targets (e.g. renewable and emission targets). The structure of the model is shown by Fig. 3.

The temporal granularity considered in CGEN+ is depicted by Fig. 4. The planning time horizon is comprised of a number of planning time steps (every 10 years). At each planning time step, CGEN + performs expansion of the gas and electricity infrastructure by Eq. (1). Each planning time step was assumed to consist of 10 similar years, and each year in turn was divided into three seasons to capture seasonal variations of energy demand and renewable energy sources. It is worth noting that the number of cold and warm days in future are uncertain and will be affected by climate change. In this study it was assumed that the number of days in each season will remain constant throughout the planning horizon. Energy demand profile for each typical day of a season is represented by a peak of 2 h, off-peak period of 11 h and an intermediate period of 11 h [32]. These are the three prevailing levels of the demand, from which the peak value drives the capacity expansion, and their shares affect the operating cost of the system. Although using more segments to represent within a day energy demand profile increases the accuracy of the model (e.g. to calculate the operating cost), it enlarges the optimization problem and increases the computational time.

The DSR was modelled by allowing CGEN+ to shave up to a certain level of flexible electricity demand during peak hours, and shift and re-distribute it over the following off-peak hours as shown in Eq. (2).

Detailed description and formulations of the fundamental CGEN + model is reported in [30,31]. A security constraint was imple-

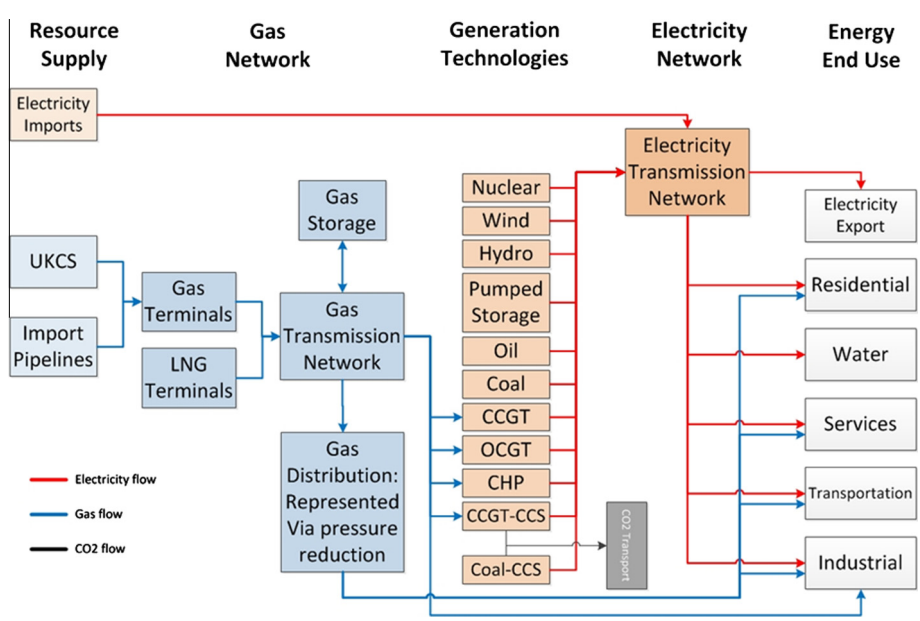

Fig. 2. Components of electricity and gas networks considered in the CGEN+ model.

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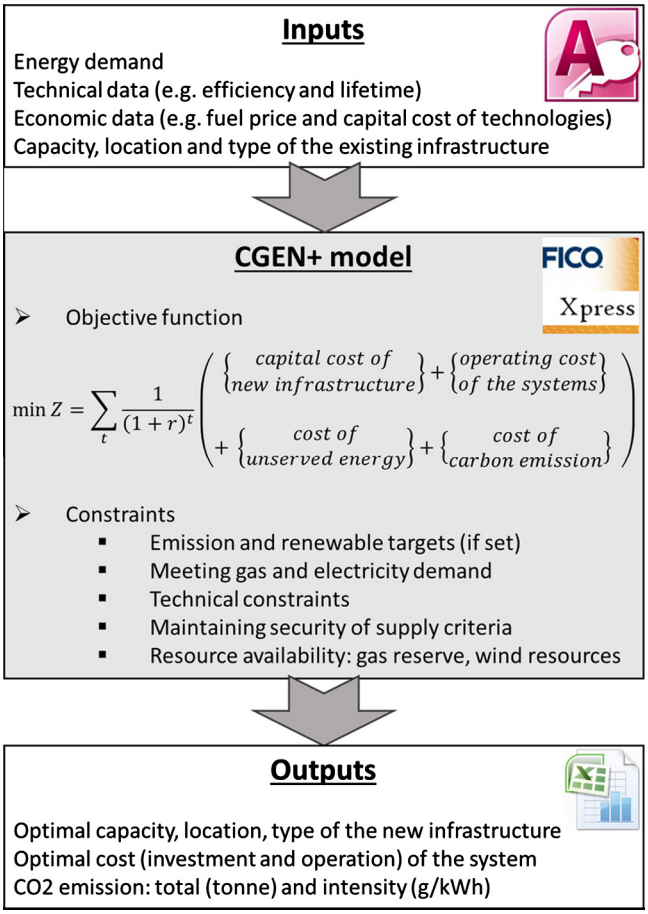

Fig. 3. The structure of the CGEN+ model.

mented to ensure that total generation capacity that can contribute to the peak demand is equal or greater than the Average Cold Spell[1] (ACS) electricity peak Eq. (3).

$$\overline{C}_{y,l,t} = \overline{C}_{y,l,t-1} + \overline{C}^{n}_{y,l,t} - \overline{C}^{d}_{y,l,t} \tag{1}$$

$$\delta^{-} \times \tau^{peak} = \delta^{+} \times \tau^{off-peak} \tag{2}$$

$$\sum_{y,l} (\overline{P}_{y,l,t} \times A_y) \geqslant ACS_t - \delta^{-}_{t} \tag{3}$$

The abbreviations and symbols used in Eqs. (1)–(3) are in the Nomenclature.

4. Case studies

Energy demand data used in this study were taken from [32]. Annual and peak demand for electricity and gas in different planning time steps from 2010 to 2050 are shown by Figs. 5 and 6. The increase in annual and peak electricity demand in Fig. 5 reflects the growing trend in electrification of heat and transport sectors. On the other hand, declination in the annual and peak gas demand in Fig. 6 is due to energy efficiency improvements as well as the partial electrification of the heat sector. It is worth noting that the gas demand given to the model as inputs excludes the gas demand for power generation. The gas demand for power generation is determined within the model by simultaneously optimizing the expansion and operation of the electricity and gas

[1] Peak demand adjusted for average weather conditions.

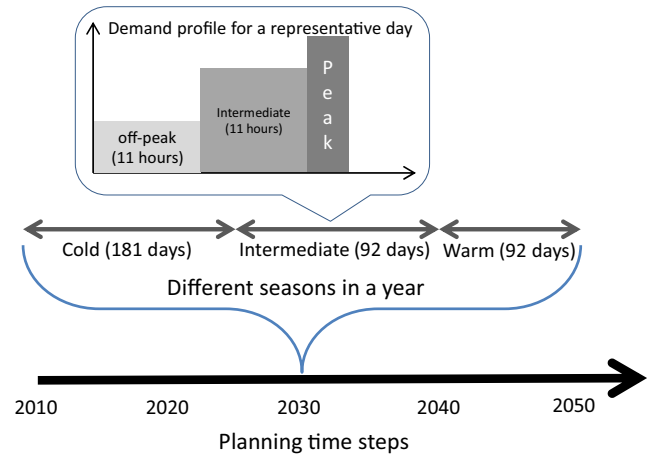

Fig. 4. Temporal characteristics of the CGEN+ [31].

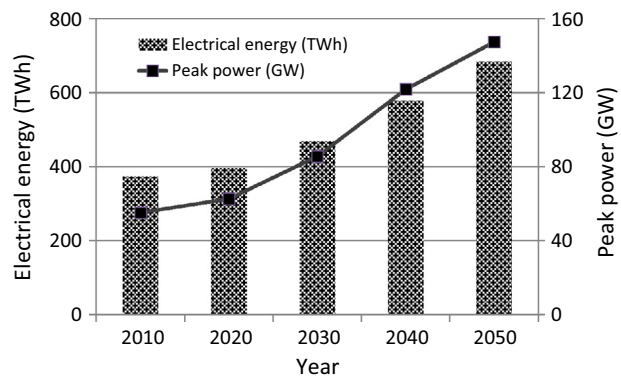

Fig. 5. Annual and peak electricity demand.

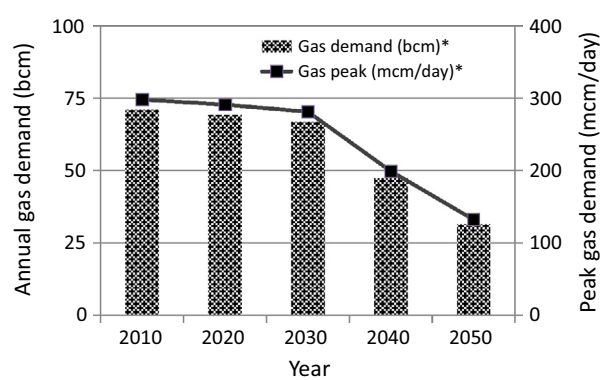

Fig. 6. Annual and peak gas demand.

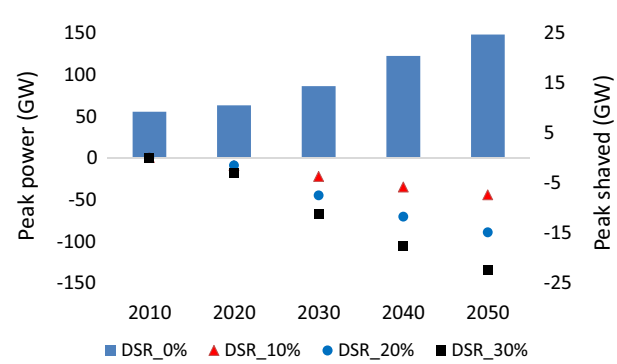

Fig. 7. Peak power in the reference cases (DSR_0%), and level of peak shaving achieved by different demand-side response scenarios.

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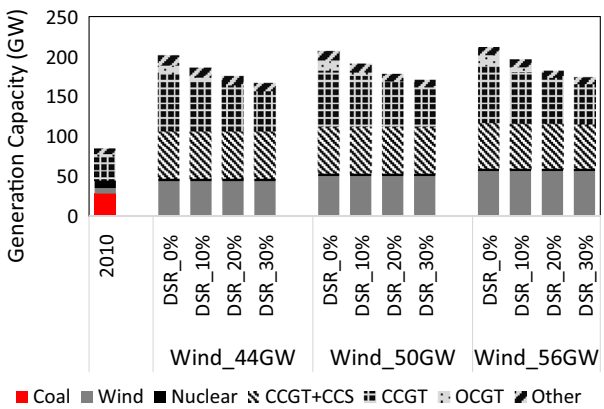

Fig. 8. Power generation capacity mix for different case studies in 2050 versus the generation mix in 2010.

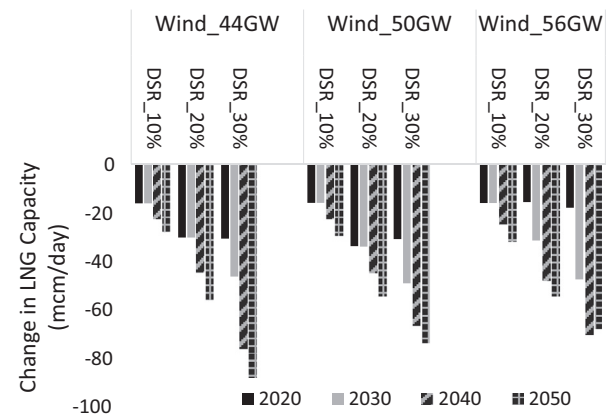

Fig. 11. Change in the new LNG capacity for different case studies compared to the reference case.

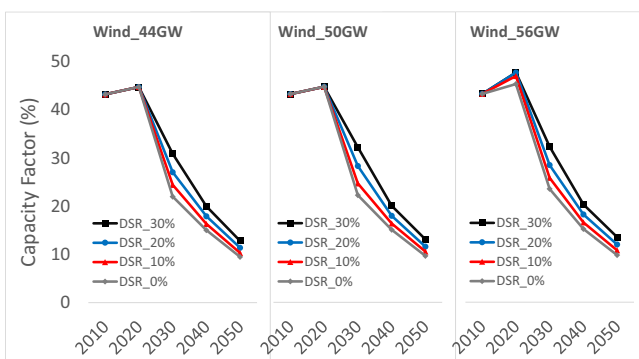

Fig. 9. Capacity factor for CCGT plants in different case studies.

networks. Detailed descriptions of methodology and assumptions for producing gas and electricity demand data are provided in [32]. The electricity and gas networks modelled in this study are shown in Figs. 13 and 14 in Appendix A. Costs data and emission intensity for different generation technologies are shown in Table 3 in Appendix A.

In order to assess the value of DSR in the GB gas and electricity supply system, a number of case studies were undertaken. The case studies represent different levels of peak electricity demand that potentially can be shifted, in combination with different capacity for wind generation. This is to analyze how sensitive the value of DSR is in respect to the different share of variable wind generation.

The future capacity of wind generation in the case studies was determined based on combined onshore and offshore wind generation capacity reported by National Grid's Gone Green Scenarios [1] with two variants of ±6 GW of the capacity. The three levels of wind generation capacity in 2030 and beyond are therefore 44 GW, 50 GW and 56 GW, which cover a range of plausible scenarios for wind in a low carbon energy system in GB. The three levels of maximum peak shifting potential (10%, 20% and 30% of the residential electricity peak demand) were also assumed for DSR based on the conservative analysis ('BAU') shown in Table 1 [29]. Table 2 shows the different combinations of wind generation capacity and maximum peak shifting potential in each case study. The DSR_0% refers to the cases in which there is no active demand participation in power system.

5. Results

5.1. Peak electricity demand

The peak electricity demand at different years from 2010 to 2050 is shown by the bar charts in Fig. 7 (left axis). The case with 'DSR_0%' is the reference case representing the peak demand with

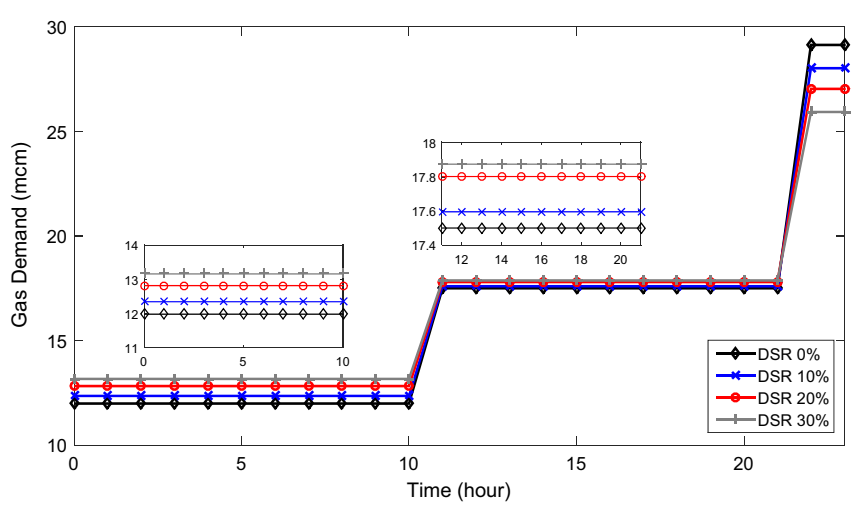

Fig. 10. Hourly gas demand in a typical winter day in 2050 for the Wind_50GW cases.

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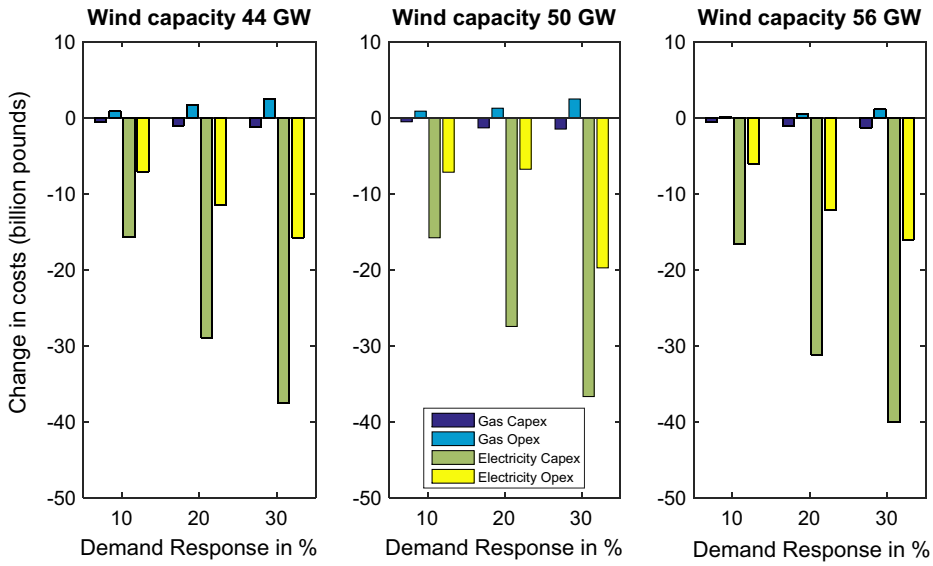

Fig. 12. Changes in the capital and operating costs for gas and electricity networks.

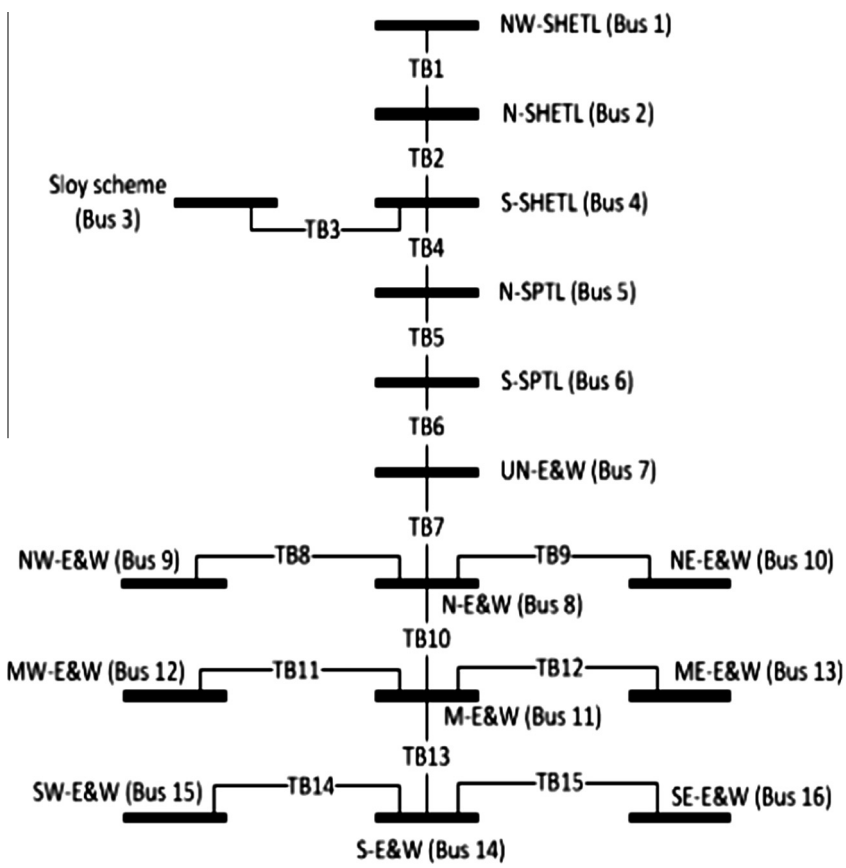

Fig. 13. GB electricity network representation [33].

0% of peak demand shaved. The growing trend in the peak electricity demand reflects the increasing electrification of the heat and transport sectors in the GB. The maximum amounts of flexible electricity demand from the residential sector during peak hours that can be shifted and re-distributed over the off-peak periods in each year are also shown in Fig. 7 (right axis). Different marks represent different percentage of peak demand shaved.

5.2. Generation capacity mix

CGEN+ determined the generation mix (see Fig. 8) as part of the co-optimization of the whole electricity and gas transmission networks. The capacity of wind generation in different case studies was imposed as inputs to the model. Capacity of different types of generation technologies for various case studies is shown and

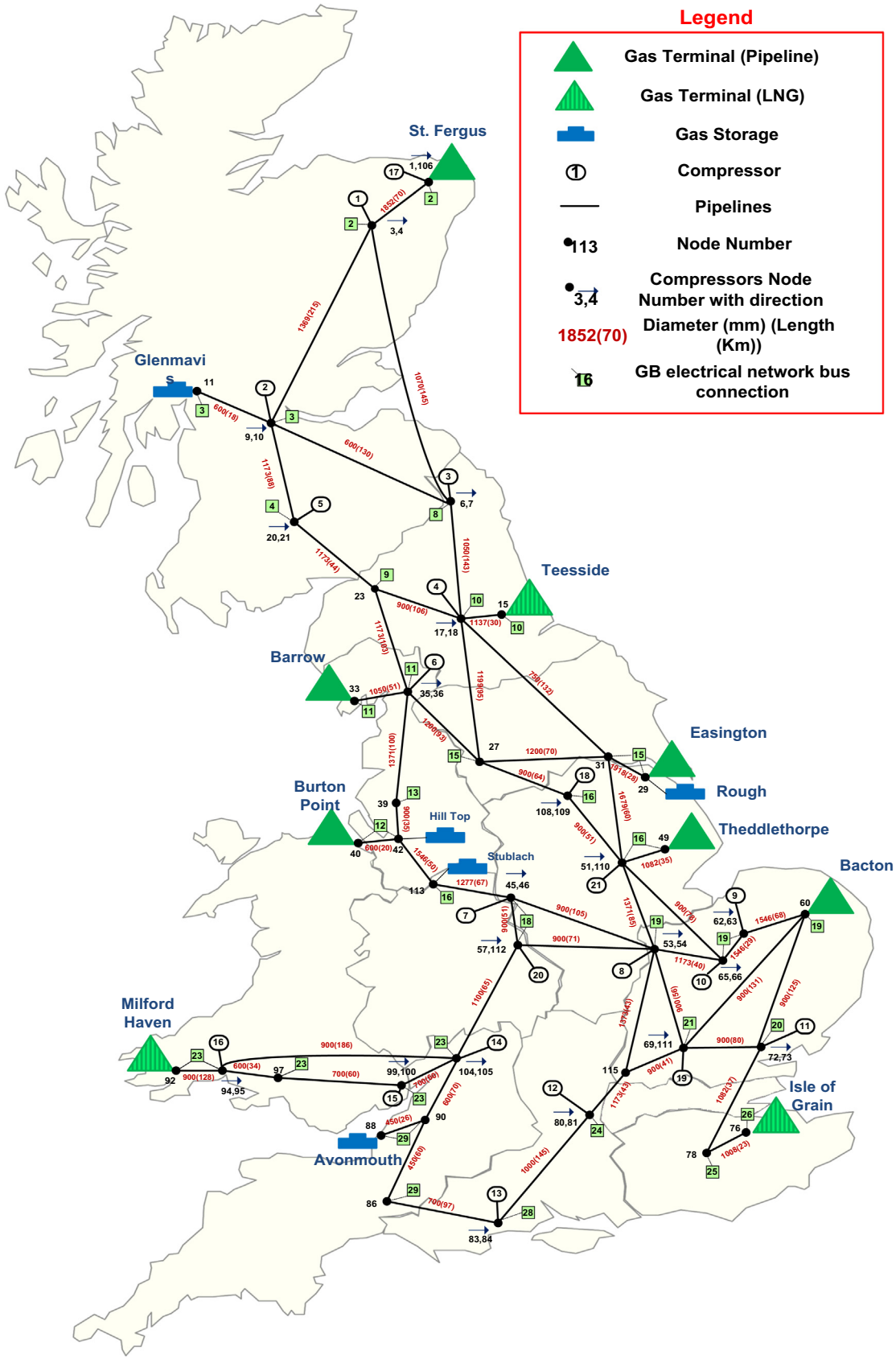

Fig. 14. GB gas network representation [33].

Table 2
Characteristics of case studies.

	Capacity of wind generation (GW)	Maximum peak shaving (% of peak)
Wind_44GW_DSR_0%	44	0%
Wind_44GW_DSR_10%		10%
Wind_44GW_DSR_20%		20%
Wind_44GW_DSR_30%		30%
Wind_50GW_DSR_0%	50	0%
Wind_50GW_DSR_10%		10%
Wind_50GW_DSR_20%		20%
Wind_50GW_DSR_30%		30%
Wind_56GW_DSR_0%	56	0%
Wind_56GW_DSR_10%		10%
Wind_56GW_DSR_20%		20%
Wind_56GW_DSR_30%		30%

Table 3
Characteristics of generation technologies.

Generation technology	Capital cost (£million/MW) [34]	Variable operating and fuel cost (£/MW h) [35]	Fixed operating cost (£/MW year) [34]	Emission intensity (kg/MW h)
Nuclear	4.6	19.7	77,449	0
CCGT	0.6	31.5	30,788	360
CCGT + CCS	1.2	34	36,774	36
Coal + CCS	2.8	26.2	79,850	68
Offshore wind	3.6	0	114,000	0
Onshore wind	1.5	0	37,537	0

compared with 2010. The coal-fired power plants will disappear from the generation mix after 2020 as required by the Large Combustion Plants Directive [2].

The large increase in electricity peak demand along with low capacity credit[2] of wind generation to contribute to supplying the peak demand, results in significantly larger total capacity in 2050 compared to the base year (2010).

In all the scenarios, CCGT plants with and without CCS play a crucial role in supplying electricity. CCGT with CCS (CCGT + CCS) is the main low carbon generation technology contributing to reducing the power system carbon emission intensity to 50 g/kW h by 2050. However, the maximum capacity of CCGT + CCS is restricted by the annual built rate of 2 GW per year [3]. CCGT plants without CCS also constitute a large fraction of the generation mix. Their low capital cost makes CCGTs a suitable option as backup and peaking plants.

When comparing amongst the cases with a same level of wind capacity, the deployment of DSR has the largest impact on the capacity of CCGTs. As it reduces the peak electricity demand, less capacity of peaking marginal plants is required. The capacity of OCGTs in 2050 in the absence of DSR is around 10 GW. In the cases that the deployment of DSR reaches 20% and above, the OCGTs are completely removed from the generation mix.

Capacity of nuclear power plants in all the scenarios decreased to 3.6 GW by 2030. This reflects the capacity of Hinckley Point C which was imposed in the model as a minimum level of nuclear power generation capacity. The model does not suggest additional nuclear power plants to be built in the GB power system following the Hinckley point C. This is mainly because of very large capital cost of nuclear plants in addition to the issues of decommissioning and waste management, making nuclear less competitive against other low carbon generation technologies.

[2] The capacity credit of wind power expresses how much peak demand can be supplied by wind power.

5.3. Capacity factor for CCGT plants

The gradual increase in the capacity of wind generation from 2010 to 2050 necessitates more CCGT plants. However, the capacity factor of CCGTs decreases with larger integration of wind farms. This is because of the new role of these plants to provide backup and reserves to compensate for the variations in the wind power generation. Therefore, despite the large capacity of CCGT plants, the annual electricity generation is not significant after 2020. This leads to the declining capacity factor shown in Fig. 9 ('*DSR_0%*'). Only slight differences were observed by comparison between CCGT capacity factor for case studies with different levels of wind generation. This is because of the small variants of 6 GW between the wind generation capacities in different cases.

For the case studies with the same capacity of wind generation, it is illustrated that the employment of DSR not only will reduce required capacity of CCGT plants, but also will increase the capacity factor of the installed plants.

5.4. Impacts of DSR on LNG import capacity

The reduced contribution of gas-fired plants to supply peak electricity demand caused by DSR results in lower peak for gas demand in generation sector, which consequently led to less gas supply capacity to be required. Fig. 10 illustrates hourly gas demand in a typical winter day in 2050 for the *Wind_50GW* case. A reduction of 16% in the maximum hourly gas demand was achieved in the *Wind_50GW_DSR_30%* case.

Depending on the level of wind generation and maximum potential of peak shaving in different case studies, compared to the reference case, between 28 mcm/day and 88 mcm/day lower LNG import capacity will be required by 2050 as shown in Fig. 11. The cases with lower wind capacity are more reliant on gas-fired plants to generate electricity. Therefore, the increasing integration of demand response will cause more significant reduction in the LNG capacity.

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5.5. Impacts of DSR on the costs of electricity and gas networks

The impacts of DSR on the costs of gas and electricity networks for different cases are presented in Fig. 12. Significant reductions in both capital and operating costs of the electricity networks were achieved through the deployment of DSR. This is due to the decrease in the capital costs required for installation of sufficient capacity of peaking plants (CCGT and OCGT), and the reduction in the contribution of expensive marginal plants in supplying electricity during peak hours.

The operational cost of the electricity network has a reduction of between roughly £7bn in DSR_10% cases to £19bn in DSR_30% cases, compared to the reference cases. The level of wind generation capacity does not make significant differences in the operational cost of the electricity network. The saving in capital cost of electricity networks resulted from DSR is even more substantial ranging from £15.7bn in *Wind_44GW_DSR_10%* to £40bn in *Wind_56GW_DSR_30%*. The DSR-related savings achieved in capital cost is proportional to the capacity of wind generation.

The analysis showed that depending on the maximum level of electricity peak shaving achieved through DSR, between £0.5bn and £1.5bn less investment is required for expansion of gas import capacity to ensure the peak demand for gas will be met (reduction in capacity of LNG import is shown in Fig. 11). Although DSR reduced the gas supply capacity and capital cost of the gas network, the operational cost of the gas network slightly increased. This is due to more electricity at non-peak hours are generated through gas-fired power plants. A fraction of shifted electricity from peak hours that used to be met via more expensive options (such as interconnectors) in the absence of DSR, is generated through gas-fired power plants at off-peak hours because there are adequate gas generation and gas supply capacity. This resulted in a larger total gas demand which increased the operating cost of gas networks.

The simultaneous decrease in the maximum gas supply capacity with the increase in the total gas flow through the gas network means a higher utilization factor of the gas network. Therefore, deployment of DSR not only offers obvious benefits to the power system, but also addresses the long-term debate on the issue regarding the low utilization factor of gas network which make the future investments unfavorable.

6. Conclusion

The CGEN+ model which is an optimization tool for combined gas and electricity networks expansion planning was significantly enhanced and used to investigate and quantify value of electricity demand side response (DSR) on both the electricity and gas supply infrastructure.

Shifting the flexible electricity demand from peak hours and redistributing it over the following off-peak hours greatly reduced the capacity of gas-fired power plants which act as peaking marginal generation technology. This resulted in substantial saving of capital cost in power generation sector.

The reduction in the power output from marginal gas-fired plants caused by the implementation of DSR, consequently will lead to decrease in the maximum gas demand. This will in turn lead to up to 80 mcm/day less LNG import capacity by 2050 (equivalent to the expected capacity of Isle of Grain LNG terminal).

By shifting the flexible electricity demand from peak hours to off-peak, the total capacity of CCGT plants will be reduced, but on the other hand, the capacity factor of the plants will be increased by up to 8%. Similarly, the utilization factor of the gas network will increase. The increase in utilization factors of CCGT plants and gas network make investments on the infrastructure more favorable.

In this study, the uncertainties associated with future energy demand and fuel prices as well as the impact of climate change on the energy demand and renewable energy resources have not been taken into account.

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Appendix A

Electricity and gas networks for GB are shown in Figs. 13 and 14.

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