

Economic impacts of wind generation variability on gas network operation

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Abstract—Large capacity of wind generation is expected to be installed across Great Britain by 2020. Wind generation is variable, therefore fast ramping generation plants will be required to balance electricity demand. Gas-fired generation plants will most likely be used to compensate for wind generation variability because of their ramping capability and large installed generation capacity. This will cause comparable gas demand swings in the gas network as wind varies.

A combined gas and electricity network optimisation model (CGEN) is used to quantify impacts of wind variability on gas network operation. Analysis is performed on mitigation measures such as greater dual fuel capable gas-fired power plants and gas storage capacity in order to reduce gas network constraints and provide alleviation against wind generation variability.

NOMENCLATURE

Q^{supp}	Gas flow from terminals (mcm/h)
Q	Gas flow rate in a pipe (mcm/h)
Q_c	Flow rate through a compressor (mcm/h)
τ_c	Amount of gas tapped by a compressor (mcm/h)
Q_s	Gas storage flow rate (mcm/h)
$Q^{Gas\ dem}$	Gas demand (mcm/h)
$Q^{Gas\ shed}$	Gas load shedding (mcm/h)
p^{min}	Lower pressure bound (bar)
p^{max}	Upper pressure bound (bar)
V_s	Volume of gas assuming standard conditions (m^3)
p_{AV}	Average pressure in a pipe (Pa)
V	Volume of a pipe (m^3)
ρ_s	Density of gas (kg/m^3)
Z	Compressibility of gas
R	Gas constant ($J/kg\ K$)
T_s	Temperature of gas (K)
LP_0	Initial gas stored in the pipe (mcm)
G	Number of generators
Dd	Number of buses
$P_{i,t}^{Gen}$	Power output of the i^{th} generation plant (MW)
$P_{j,t}^{Demand}$	Power demand of the j^{th} load bus (MW)
$P_{j,t}^{Elec\ shed}$	Electrical load shedding of the j^{th} load bus (MW)
t	Time step
P^{Gen}	Power output of a generation plant (MW)
φ	Thermal efficiency of the gas turbine
Q_e	Gas flow into a gas-fired power plant (m^3/s)
H_g	Gas heating value ($39\ MJ/m^3$)

I. INTRODUCTION

Wind generation is expected to contribute the bulk of new renewable generation capacity at around 30 GW by 2020 which is roughly 30% of the total generation capacity in GB [1].

Wind is an intermittent source of energy hence the amount of electricity generated by wind farms is variable. Variability of wind requires other generators to ramp up and down to balance the electricity demand. Due to ramping constraints, rapid electric power swings incurred by wind cannot be compensated for by base load generation plants. Hydro and pumped storage power plants are capable of rapid ramping up/down, but the total capacity of these technologies is small in GB (around 3.7 GW). The capacity of coal-fired power generation on the GB system is also expected to decline due to the Large Combustion Plant Directive (LCPD) [2]. Combined Cycle Gas Turbines (CCGT) with their large generating capacity in GB are potential candidates to compensate for wind variability. However, this would lead to large flow variations in the gas network as CCGT plants ramp up and down.

The volume of gas stored in a pipe is known as linepack and is a key factor that affects the ability to supply gas to demand nodes. During low wind periods, when CCGTs are operating close to their maximum capacity to meet peak electricity demand, large amount of gas is delivered which increases the risk of linepack depletion. A gas network with low linepack is not capable of meeting abrupt demand changes since it typically takes hours for gas to reach demand nodes from a terminal.

General information about CGEN including the objective of the optimisation problem as well as formulation of gas and electricity networks models is represented in section II. In section III wind generation data is explained. Sections IV and V contain case studies and their results, respectively.

II. COMBINED GAS AND ELECTRICITY NETWORK (CGEN) MODEL [3], [4]

CGEN is a modelling and optimisation tool for the gas and electricity infrastructure [3]. It minimises the total operational cost of the combined gas and electricity networks (1) over the entire time horizon while meeting demand.

Objective Function =

$$\min \sum^{Horizon} \text{cost of} \left\{ \begin{array}{l} \text{gas supplies} \\ + \text{linepack changes} \\ + \text{gas storage operation} \\ + \text{electricity generation} \\ + \text{electricity load shedding} \\ + \text{gas load shedding} \end{array} \right\} \quad (1)$$

Technical limitations and characteristics of both networks are considered as constraints of the optimisation problem.

In this study, a time horizon of two days with a time step of two hours was used for optimisation of the operation of the GB gas and electricity network. At this level of granularity the model is able to capture sudden changes in wind output and its impact on linepack and its depletion.

A. Gas Network

The main components of a gas network are modelled in CGEN including pipelines, compressors, storage facilities, and gas terminals. The 'Panhandle A' equation [5] is used to calculate gas flows through pipelines (assuming that all pipes are horizontal). At each node in the gas network, gas flow balance (2) and pressure constraints (3) are applied. For each time step, gas in-flows at each node (gas supply, gas storage withdrawal) are balanced with gas outflows (gas demand, compressor fuel usage, gas storage injection).

$$Q^{supp} + Q + Q_c - \tau_c + Q_s = Q^{Gas\ dem} - Q^{Gas\ shed} \quad (2)$$

$$p^{min} \leq p \leq p^{max} \quad (3)$$

The linepack (LP) of a pipe is calculated by (4):

$$LP = V_s = \frac{p_{AV} V}{\rho_s Z R T_s} \quad (4)$$

This equation is suitable for calculating the volume of gas in a pipe when the gas flow is in steady state. Equation (4) illustrates that the pipe linepack is proportional to the average pressure in the pipe section, therefore, increasing the average pressure of the pipe will increase the linepack and vice versa.

The gas flow into and out of a pipe fluctuates with changing supply and demand. According to the law of conservation of mass, the change of total gas volume is equal to the difference between the flow into and out of the pipe. Hence, (4) changes into (5):

$$LP(t) = LP_0 + \int_0^t (Q_n - Q_{n,X}) dt \quad (5)$$

A simplified GB gas network used in this study is shown in Fig. 1.

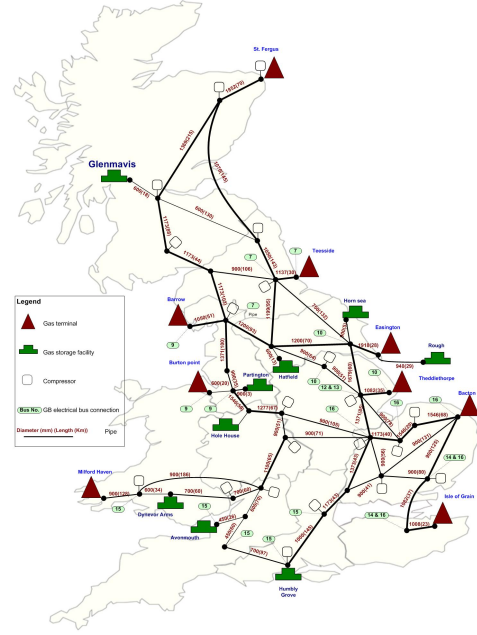


Fig. 1: Great Britain simplified gas network

B. Electricity Network

A 'dc' power flow model [6] was used to represent the electricity network. The power balance equations are satisfied such that total generation is equal to total demand minus load shedding at each time step.

$$\sum_i^G P_{i,t}^{Gen} = \sum_j^{Dd} P_{j,t}^{Demand} - \sum_j^{Dd} P_{j,t}^{Elec\ shed} \quad (6)$$

Gas turbine generators provide the linkage between the gas and electricity networks. The relationship between the gas fuel flow and the real electrical power generation is expressed as:

$$P^{Gen} = \varphi Q_e H_g \quad (7)$$

III. WIND GENERATION IN GB

Oswald, et al. [7] used hourly wind speed data in January 2005 and modelled the aggregate electricity output of 25 GW wind farms which could be installed across GB by 2020. The wind generation was subtracted from electricity demand for the same period to calculate the residual electricity demand which must be met by other generation plants. As shown in Fig. 2, residual electricity demand varied between 5.5 and 56 GW over the month, and there are many power cycles with larger fluctuations than is currently seen in the GB network. The residual electricity demand that represents relatively low wind generation levels from Oswald et al. [7] was used in this paper to define a case study in 2020.

IV. CASE STUDIES

Two case studies were defined. The Base case represents the existing GB network (2009), and the other represents the GB network in 2020 with low level of wind generation.

The impact of gas prices are neglected in this study (a constant price of $\text{£}0.15/\text{m}^3$ is assumed for all terminals). Due to low operating costs, nuclear and wind are considered as must run plants in all the cases.

The annual increase rate of total gas demand is forecast to be 1.5% over the next decade which is mostly due to electrical gas demand [8]. Hence, non-electrical gas demand (residential, commercial, and industrial) in 2009 and 2020 was assumed to remain constant. Non-electrical gas demand at each time step is shown in Fig. 3.

A. Base Case - Existing network

The Base case is represented by the GB gas and electricity network (and generation capacity mix) in 2009. Electricity demand for this case is shown in Fig. 4 which is derived from the actual data of two typical winter days (8th and 9th January 2009) [9].

The wind generation capacity in 2009 is fairly low (the capacity is 2.4 GW, around 3% of the total generation capacity) and its fluctuation does not have any noticeable effect on network operation. Therefore in the Base case a capacity factor of 40% [1] and constant injection of wind power over the two days are assumed.

B. Low Wind Case - 2020

Part of the residual electricity demand acquired from Oswald et al.'s paper [7] was used in this case, after applying an annual increase rate of 0.7% [10]. The escalated residual electricity demand for Low Wind case is shown in Fig. 5.

For this case study the CGEN model uses nuclear as must run plants, and determines the optimal amounts of electricity generation from other technologies (excluding wind) to satisfy the difference between the residual electricity demand and electricity generation of the must run plants. Non-electrical gas demand for this case is same as the Base case (3).

V. RESULTS

A. Impacts on Electricity Generation

As shown in Fig. 6, in the Base case coal-fired plants generate the bulk of electricity. Power generation by CCGTs varies considerably from the Base to Low Wind cases. In the Low Wind case, CCGTs are the major contributor to electricity production over the entire time horizon.

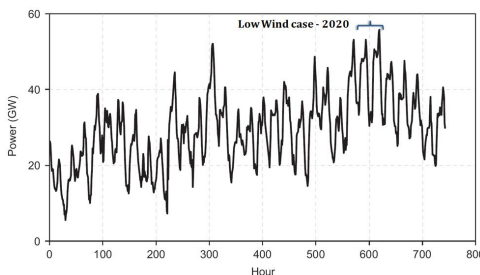


Fig. 2: Residual electricity demand [7]

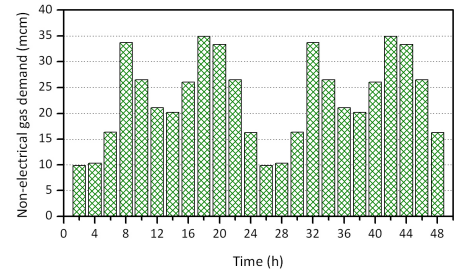


Fig. 3: Non-electrical gas demand for the case studies

At hours 18-20 and 42-44 in the Low Wind case, peak residual electricity demand coincides with peak non-electrical gas demand and leads to rapid and large increase of total gas consumption. Given this situation, the gas network cannot fully supply gas to CCGTs. Consequently, power output from CCGTs decreases by 3.1 GW at hours 42-44 (compared to maximum power output) and more expensive electricity supply from the GB-France interconnector is used to avoid electricity load shedding.

B. Impacts on the Gas Network Operation

The amounts of gas supplied from various sources (Domestic, LNG and Interconnector) at each time step for the two cases are shown in Fig. 7. In the low Wind case, due to higher electrical gas demand, total gas supplies from terminals increase. This increase mainly takes place at LNG terminals (Milford Haven and Isle of Grain). The changing share of gas sources from 2009 to 2020 is due to rapid decline of UKCS (United Kingdom Continental Shelf) gas resources.

As a result of higher total gas demand in the Low Wind case, gas supply and total compressors power in this case are higher in comparison to the Base case.

Figure 8 shows the aggregate gas network linepack for the different cases. In the Low Wind case, despite high compressor power during hours 42-44, the network linepack abruptly decreases by 10 mcm. This is due to peak non-electrical and electrical gas demand occurring at roughly the same time. The resulting pressure drop in the gas network limits its ability to meet rapid changes in gas demand and causes interruption of gas supplies to CCGTs at peak hours.

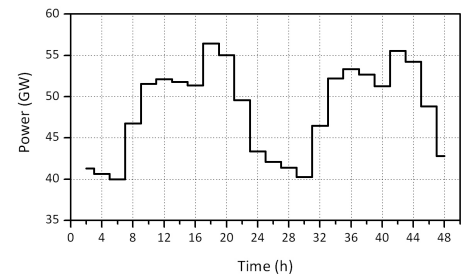


Fig. 4: Electricity demand for the Base case

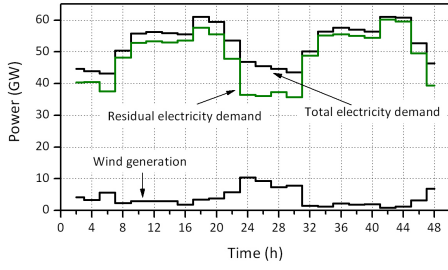


Fig. 5: Residual electricity demand for the Low Wind case

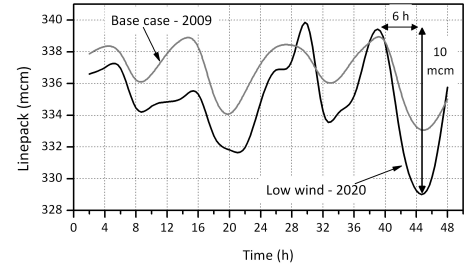


Fig. 8: Aggregate gas network linepack for the case studies

C. Analysis of mitigation measures

The impact of greater gas storage capacity and dual-fuel capable CCGT plants on the ability of the gas network to support delivery of energy to both gas and electricity customers are investigated. Examination of the power output of individual CCGTs shows the plants close to Burton point gas terminal generate far less than their maximum capacity during

peak hours. This is due to the limited gas supply capacity of Burton point terminal as well as low network linepack.

Table I shows that dual-fuel capable plant around Burton point gas terminal would help to relieve gas network constraints and at the same time increase the participation of these plants for power generation during peak hours (Table I).

TABLE I: Comparison of power output from CCGTs close to Burton Point gas terminal in Low Wind case, with and without dual-fuel capability.

Hours	CCGT output (MW)			
	18	20	42	44
Without dual-fired capability	606	166	650	573
With dual-fired capability	2100	2100	2100	2100

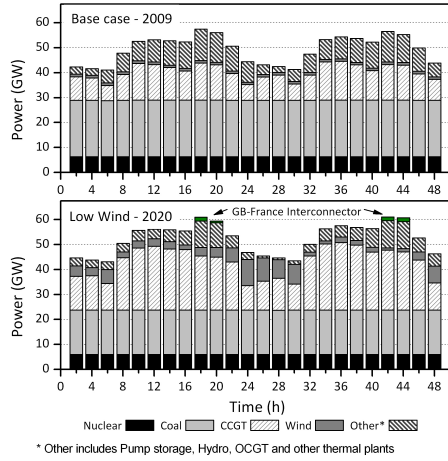


Fig. 6: Generation mix for both case studies

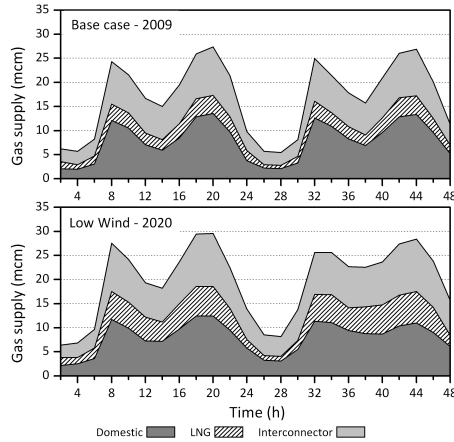


Fig. 7: Share of different sources for gas supply

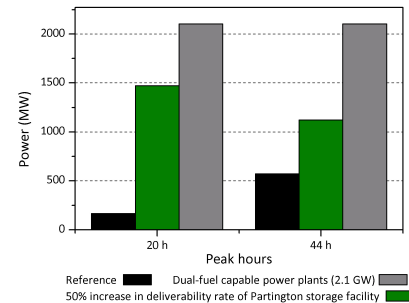


Fig. 9: Power generation of CCGT plants around Burton Point (Low wind case)

TABLE II: Impact of mitigation measures (£Millions)

	Mitigation measures	
	Dual fuel CCGT plants (2.1GW)	Gas storage (50% increase in deliverability rate of Partington gas storage facility)
Change of operational costs when compared with no mitigation	-146	-443

VI. CONCLUSION

Given the large amount of wind generation and low coal fired generation capacity anticipated in GB by 2020, CCGTs will be used to compensate for wind power variability due to their fast ramping rates and sizable generation capacity. However, this could lead to significant power swings on the gas network as CCGT plants ramp up and down. The simulation results show that the simultaneous occurrence of low wind generation and peak electricity demand in 2020 will result in rapid and large increases in gas consumption, mainly due to the demand from gas-fired generation. The insufficiency of local linepack in the gas network will constrain gas supply to some CCGTs. Consequently these plants will operate with reduced capacity and more expensive sources of electricity such as the GB-France interconnector will be employed to meet shortfalls in generation. The use of backup fuel for CCGT operation and greater gas storage capacity was shown to reduce gas network constraints and increase the contribution to power generation during peak hours.

Designing policy for encouraging investment in dual fuel power plants is simpler than for gas storage. Policy dictating that all new gas fired plants should have dual firing capability could be implemented although issues with regards to equipping (limited space and retrofitting costs) existing CCGTs plants persist. Policies for gas storage investment could take the form of capacity payments. This could encourage the increase in gas storage capacity, but such capacity payments could result in an over build of storage capacity resulting in marginally used assets and as with any policy instrument costs will be borne by energy users.

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