Value of gas network infrastructure flexibility in supporting cost effective operation of power systems

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HIGHLIGHTS

- Integration of renewable energies causes operational challenges in power systems.
- Value of operational practices for gas and electricity networks were quantified.
- Role of gas network flexibility to address the challenges were evaluated.
- Less gas load curtailment when the gas network is more flexible.
- Cost savings when integrated approach and gas network flexibility were considered.

ABSTRACT

The electricity system balancing is becoming increasingly challenging due to the integration of Renewable Energy Sources (RES). At the same time, the dependency of electricity network on gas supply system is expected to increase, as a result of employing flexible gas generators to support the electricity system balancing. Therefore the capability of the gas supply system to deliver gas to generators under a range of supply and demand scenarios is of a great importance. As potential solutions to improve security of gas and electricity supply, this paper investigates benefits of employing flexible multi-directional compressor stations as well as adopting a fully integrated approach to operate gas and electricity networks. A set of case studies for a GB gas and electricity networks in 2030 have been defined to quantify the value of an integrated operation paradigm versus sequential operation of gas and electricity networks. The results indicate there are significant overall system benefits (up to 65% in extreme cases) to be gained from integrated optimization of gas and electricity systems, emphasizing the important role of gas network infrastructure flexibility in efficiently accommodating the expected expansion of intermittent RES in future power systems.

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1. Introduction

The share of Renewable Energy Resources (RES) is projected to increase significantly across the Great Britain (GB) network to meet the de-carbonization target in the future [1]. The installed capacity of wind power generation is expected to be between 52 GW [1] and 64 GW [2] in 2030 GB power system. This increase in wind generation share leads to balancing challenges due to the variable nature of the wind. In this context, flexible gas-fired generation with fast ramping rates is expected to facilitate cost effective integration of wind generation to meet the balancing challenges of supply and demand. The interdependency of the gas and electricity networks is increasing because of the role of gas-fired plants as the main linkage of these networks. Thus, the wind variability is reflected as intermittency in the gas demand as well. Based on higher inertia of gas, delivery time from supply sources (terminals and storage facilities) to demands in the gas network is much higher than electricity transmission. Hence, the Gas System Operator (GSO) maintains minimum volumes of gas, called Linepack, within the pipelines to meet rapid changes in the network. The variability of gas demand for power generation, consequently influences the linepack and makes its management more difficult. Real operational data from National Grid indicates that the linepack of the GB high pressure gas network in 2012 fluctuated with larger magnitude compared to year 2002 [3].
Several studies have examined the role of flexibility options in addressing the balancing challenges driven by RES in power systems [4–8]. Flexibility is described as the ability of the system to deal with uncertainty and variability in the network, while keeping an acceptable level of reliability, from time scales of seconds to hours [4]. In [5] a framework considering generation flexibility requirements and environmental constraints for the Unit Commitment (UC) process is proposed. It was concluded, through utilizing flexible plants the occurrences of supply and demand imbalances caused by the wind forecast errors was decreased. In [7] it is shown that through using multi-mode operation of Combined Cycle Gas Turbines (CCGTs) the system security was increased. The multi-mode operation of CCGTs is related to the units which incorporate a steam bypass stack. These units are capable also to operate in open-cycle mode, which increase the flexibility of these gas plants in order to deal with large integration of wind into the system. Although less efficiency was achieved when operating in open-cycle mode, however it was shown that in overall the emissions high emissions is decreased. 

The focus of these studies was mainly on the impact of the flexibility options in power systems operation, while the integrated energy systems value (gas and electricity) of flexibility has not been taken into account. Although, the interaction of gas and electricity networks have been studied from security of supply perspectives [9], wind forecasting and uncertainty [10,11], energy adequacy [12], coordinated scheduling [13,14], market coupling [15], and also planning strategy [16], however comprehensive analysis of large penetration of RES on the gas network operation has been reported by couple of studies [12,17–20]. The value of an integrated operation practice of the gas and electricity networks in comparison to sequential operation of these networks, has not been evaluated in these studies. Furthermore, in the literature, electricity side flexibility options are discussed and to the best of our knowledge the value of gas network flexibility has not been investigated. In a few studies, including [21–23] the planning and operation optimization of the gas transmission networks from different aspects are studied. Additional pipelines and compressor stations are the main reinforcement components in the planning mode of these studies. In [24], an assessment on the role of gas network infrastructure in providing energy security has been studied. But, none of these studies considered the role of multi-directional compressor units in operation of the gas network. Although the role of multi-directional compressor as a mean of providing flexibility to the gas network is discussed in [25], however the research was focused on the gas network infrastructures and the value of this flexibility option was not quantified.

As mentioned above, the future growth of wind generation capacity will increase the complexity of gas network management. One of the solutions to deal with these challenges is to make the gas network infrastructures flexible. Gas storage facilities and flexible multi-directional compressor stations are potential candidates to cope with the growing variabilities in the gas network. The interest of the GB system operator to invest in more flexible stations able to compress gas in different directions is reported in [26]. For example, if the available gas in North Sea could not be delivered to the network, one-directional compressor stations are not able to compensate for the lack of gas supply to meet the demand. Thus, redirecting the gas flow through the compressors could help to avoid additional reinforcement in the network.

In this paper, potential solutions for improving capability of gas and electricity supply system to meet the demands were investigated. The solutions are (a) changing the operation practice through adopting an integrated approach to operate gas and electricity networks, (b) employing flexible multi-directional...
compressor stations in the gas transmission network, and (c) the first two solutions combined. In the operation of gas and electricity networks, the multi-directional compressors are modeled so that the gas flow could be redirected to ensure that the gas demand is met while minimizing the operational cost of the gas and electricity networks. The value of multi-directional compressors were especially highlighted, when large variations in the gas network was happened (e.g., post-contingency conditions). Therefore, a set of gas supply interruption scenarios for a GB gas and electricity network in 2030 were defined. The efficacy of the above solutions to mitigate the impacts of the gas supply interruptions on the operation of gas and electricity networks were quantified. In these scenarios as a contingency was happened in the gas supply system, difficulties in the operation of the gas network was occurred. Due to the fact that location of majority of the gas plants were not very close to the gas supply points, gas might not be delivered in time due to limitations in speed in transporting gas through gas transmission grid. In order to compensate for limited electricity production by gas plant, more expensive options were required to produce more and imports from interconnection were increased. On the other hand, as the flexibility in the gas network was enhanced through multi-directional gas compressors, gas delivery to the gas plants was possible. Consequently, the overall emission and the total operational costs of the networks were reduced.

2. Modeling methodology

2.1. Integrated gas and electricity networks

The enhanced version of the Combined Gas and Electricity Networks (CGEN) operation model [18] was used in order to represent a detailed model of flexible multi-directional compressor stations. This model was employed to examine the role of the gas network infrastructure flexibility in supporting future power systems with significant penetration of wind generation. The model is able to optimize the operation of the gas and electricity networks, simultaneously. Constraints of the power system modeled including characteristics of thermal generating units (i.e. ramp up/down, minimum up/down time, minimum stable generation of thermal units) and spinning reserve requirements, and energy balance (1) were considered. In the supply side of the energy balance, generation of the units, net energy of pump storage, absorbed wind by the grid are taken into account. On the other side (i.e., demand), electricity demand and electricity required for electrically-driven compressors are considered. The electrical load shedding term prevents the model from infeasibility, which shows the Value of Lost Electricity Load (VoEL) in the electricity network. Eq. (1), indicates that at each time step (i.e., hourly) the supply and demand has to be balanced.

\[
\forall t \in T : \sum_{b \in B_t} P_{g, b, t} \cdot \tau + \sum_{b \in B_t} (P_{pump, b, t} + P_{pump, b, t}^{wt}) \cdot \tau + \sum_{b \in B_t} P_{wind, b, t} \cdot \tau
\]

\[
= \sum_{b \in B_t} (P_{load, b, t} - P_{shed, b, t} \cdot \tau + P_{comp, b, t} \cdot \tau) \quad (1)
\]

Fig. 1. A simplified structure of a flexible multi-directional compressor station.

In the gas network modeling, constraints such as gas supply limits for terminals and storages, lineup changes, pressure limits, and gas compressor operation limits, and gas flow balance (2) were taken into account. The gas flow balance should be satisfied at each node and each time step. Gas provided through terminals, gas available in the pipelines, net gas from the storage facilities, and gas from the compressors excluding the gas consumed by gas-driven compressors are the key terms in the supply side. Two type of demands are considered; (a) required gas for the plants for power generation, and (b) gas for other uses. Same as the electric-
was calculated through \((11)\). Of different junctions in the station yards. The blue (dashed) line indicate the ability of modifying the gas flow direction in the network. Multi-junctions (i.e., pipelines, valves, and regulators) to control the flow of gas in the National Transmission System (NTS). Multi-junctions can be located close to compressor stations, and therefore this make the gas compression in different directions possible. Reinforce the existing compressor units with additional piping so that the order magnitude of the values do not vary significantly. Each compressor was subjected to maximum flow rate, power consumption, and capacity constraints \((7)\)–\((10)\). In the gas network the operational costs of the gas network were minimized \((12)\) and afterwards the operational costs of the gas network were minimized \((13)\). The algorithm of the Sequential modeling using a rolling planning approach is presented in Fig. 2. The red (dashed) line indicates the sequential link of the electricity and gas networks.

The Sequential approach does not consider the gas supply constraints while optimizing operation of the power system. Hence, a key disadvantage of this modeling is that potential interruptions in the gas supply do not influence the dispatch of gas-fired plants in the electricity network, as the modeling of electricity system is carried out before the gas network.

2.2. Integrated modeling

Unlike the Sequential mode, in the Integrated modeling the gas and electricity network constraints were considered synchronously. Fig. 3 illustrates the algorithm of the Integrated modeling. The Integrated model minimizes the total operational cost of the gas and electricity networks, simultaneously \((14)\).

The corresponding optimization problem of Integrated model was solved through Mixed Integer Non-Linear Programming (MINLP) approach in Xpress-IVE (i.e., mmnlp module) \((29)\). The total number of variables for the week is about 260 k variables including about 20 k integer variables. However, as mentioned previously, a rolling approach has been implemented and the optimization is divided into seven smaller optimization problems. The main reason of using a rolling approach is that due to the non-linearity as well as integer space of the model, by increasing the number of variables, the computational time would be increased exponentially. In order to get more accuracy for modeling each day, four hours of the next day is also considered. As a result, at each step of the rolling approach around 43 k variables including around 3500 integer variables has been optimized. A branch and bound strategy has been used to find the solution of the binary variables. The search has been stopped when the absolute tolerance of the best solution’s objective function and the current best solution bound is less than a set value which is presented in \((15)\).

\[
F^{\text{int}} = F^{\text{elec}} + F^{\text{gas}} \quad (14)
\]

In Integrated approach, in order to avoid twice calculation of gas plants generation cost, \(C^{\text{fuel}}\) of gas power plants are zero, as the gas consumption of these plants were considered as a type of demand in the gas network operation.

2.2.1. Sequential strategy

In the Sequential mode, the operation of electricity network (including UC/Economic Dispatch and power flow) was optimized and the gas demand for power generation was then calculated. In this approach, the gas demand for power generation was provided as an input to the gas network operation model. In this modeling, the operational costs of the electricity network were minimized \((12)\) and afterwards the operational costs of the gas network were minimized \((13)\). The algorithm of the Sequential modeling using a rolling planning approach is presented in Fig. 2. The red (dashed) line indicates the sequential link of the electricity and gas networks.

2.2.2. Integrated modeling

The model was performed on a 3.20 GHz Intel(R) Xeon(R) processor and 16 GB of RAM system. The simulation time for different case studies was between 93 and 118 min. Initial values based on output of the optimization for a single time step were given to all decision variables. In addition, the decision variables were scaled so that the order magnitude of the values do not vary significantly. These two procedures aided to obtain convergence and stability of the optimization process.
3. Case studies

3.1. Descriptions of the cases

As it was mentioned previously, three solutions were suggested in this paper. Changing the operation practice (i.e., integrated approach of gas and electricity modeling), reinforcing the physical assets of the gas network (i.e., flexible multi-directional compressor stations), and combination of these two. To evaluate the capability of the solutions in improving the security of supply, following cases for the GB electricity and gas networks were examined:

- **Base (Case 1)**: In this case the *Sequential* modeling of gas and electricity networks (see Fig. 2) was considered. Direction of gas flow through compressors (i.e. suction and discharge nodes of compressors) were pre-set.

- **Flexible multi-directional compressor stations (Case 2)**: The compressors were assumed to have the capability to change the direction of gas flow (see Fig. 1). The suction and discharge nodes of each compressor were decision variables that were determined as part of the optimization problem of the gas network operation.

- **Integrated operational practice (Case 3)**: In this case the operation of gas and electricity networks were optimized simultaneously (see Fig. 3). The directions of gas flow through compressors were pre-set.

- **Fully flexible (Case 4)**: Both solutions presented in Case 2 and Case 3 were combined in this case study.

Impacts of partial and complete outage of Bacton gas terminal, the largest gas terminal in GB, on the operation of the gas and electricity networks were investigated for different cases. Two outage scenarios were defined: (a) interruption of gas import from Bacton to Bacton Line (BBL) and Interconnectors UK (IUK) and (b) interruption of gas supply from whole Bacton terminal (see, Fig. 4). These studies were to assess how *Integrated* approach along with flexible multi-directional compressor stations could mitigate the adverse effect of an incident in the gas network.

![Fig. 2. Sequential mode algorithm.](image)

![Fig. 3. Integrated mode algorithm.](image)

![Fig. 4. Bacton supply sources.](image)
3.2. GB gas and electricity 2030 networks

A GB electricity transmission network including 29 busbars, 47 transmission lines and 148 generators based on [26] was implemented in this research (Fig. 5). An updated version of the simplified NTS network (63 nodes, 54 gas pipelines, 9 terminals, and 5 storages), introduced in [17] based on [3] was applied in the model (Fig. 6).

3.3. Input data

The GB gas and electricity networks were modeled over a typical winter week in 2030. Table 1 presents the power generation mix in this study (see Fig. 7).

In the National Grid outlook in 2030, 52 GW wind generation is projected to be installed across GB [1]. The hourly wind generation, electricity demand data as well as non-electric gas demand data in 2030 were taken from [20]. It is worth noting that in the model wind generation data was defined as available wind power. The available wind power could be absorbed by the electricity system or had to be curtailed due to the excess of wind generation (16).

\[
\forall b \in B, t \in T : \quad P_{\text{avail}}^{b,t} = P_{\text{wind}}^{b,t} + P_{\text{pcur}}^{b,t}
\]  

Fig. 5. GB 29-Busbar electricity transmission network.

Fig. 6. GB simplified NTS gas network.

Table 1

| Technology       | Capacity (GW) |
|------------------|---------------|
| Wind             | 52            |
| Gas              | 33            |
| Interconnector   | 11.5          |
| Nuclear          | 9             |
| Coal with CCS    | 4.5           |
| Pumped storage   | 2.7           |
| Hydro            | 1.1           |
| Other            | 1.2           |

Fig. 7. Hourly available wind power, gas demand, and electricity demand [20].
4. Results and discussion

4.1. Partial outage of Bacton gas terminal

4.1.1. Generation mix

The operation of the electricity network in the Sequential cases (Case 1 and Case 2) were the same, as it was optimized irrespective to the operation of the gas network. In Integrated Cases (Case 3 and Case 4) the constraints of gas supply were taken into account. Changes in electricity generation by different technologies in Integrated cases compared to Sequential cases are presented in Fig. 8. The generation of nuclear and hydro did not vary considerably as these are lowest cost generation technologies [17]. Moreover, hydro capacity was relatively small (see Table 1), so these plants did not make significant contribution to meeting electricity demand. Total generation of gas plants over the week in Integrated cases was less than Sequential cases. The reason is that in the Integrated modeling the gas and electricity networks operation were optimized simultaneously, therefore gas supply constraints were considered in the economic dispatch of power generation. As a result, roughly 18,000 and 7,000 tonnes of CO2 production were reduced in Case 3 and Case 4 (compared to Sequential cases), respectively. Due to the flexible multi-directional compressor stations option, gas flow was redirected in different time steps in order to deliver gas from different supply points. Therefore, because of the provided flexibility in the gas network the gas plants in Case 4 generated about 40 (GWh) more than Case 3 over the time horizon. In Case 3 in order to meet the energy balance, about 35 (GWh) electrical energy was imported through interconnectors. Whereas, in Case 4, the power flow through interconnectors has been decreased.

In Fig. 9-a, the role of gas plants as an economical option [17] able to complement the lack of wind generation during low-wind, high-demand period (105–118 h) is presented. In Sequential cases, the gas supply constraints were not considered in operation of the electricity network. Therefore, as the electricity network operation was modeled first (see Fig. 2), it was preferred operating gas plants rather to importing energy via interconnection to keep the energy balance in the network, as this minimizes the operation costs. On the other side in Integrated cases as gas supply interruption at Bacton terminal was taken into account in the operation of power system, the generation through gas plants was reduced compared to the Sequential cases. This was mostly due to the fact that less gas was available close to Bacton terminal, which has affected especially the gas plants in busbars 20 and 26. In Case 4, thanks to the gas flow redirection option, delivering gas to the aforementioned plants could be managed cost effectively. The reduced generation from gas plants in Case 3 and Case 4 were compensated with interconnectors. Fig. 9-b presents the contribution of interconnectors in providing the energy balance in low-wind, high-demand period. It is worth noting that although the price of importing energy via interconnectors was assumed to be higher than gas plants [17], the interconnection prevented gas load shedding in the gas network. Whereas, in the Sequential cases the model selected seemingly lower cost option based on using gas plants rather interconnector, as the real-time gas availability was not considered.

4.1.2. Gas supply and linepack

Total gas supply through terminals and gas storage facilities are presented in Table 2. Changing the operational practice as well as the provided flexibility improved the gas delivery to the demand centers by reducing the gas transmission congestion.

Fig. 10 shows the linepack in the pipelines during the simulation horizon. The linepack on a particular day of the week changes based on the demand pattern for power generation on that day. The linepack fluctuations was related to the fact that in off-peak times (e.g. in the mornings before 06:00) the gas demand was low, and therefore linepack was increasing. In the peak-times
(e.g. 17:00–20:00) the stored gas in the pipelines was used and the linepack has been reduced. The analysis of the amount of the linepack indicates more availability in the within-pipeline storage capability of the gas network in multi-directional cases (Case 2 and Case 4). This enables the gas network operators to manage rapid changes in the gas demand in short term.

The gas load shedding in different cases is shown in Table 3. In Case 1 the total amount of gas load shedding throughout the week was about 35 million cubic meter (mcm) due to the low flexibility of the network. As explained before, in the Sequential cases, first the electricity network was modeled, and different states of the gas network were not considered. This means that the electricity network requested gas for generation without any constraints on gas supply. On the other side, as an outage occurred, the gas could not be delivered to the demands.

In Case 2 there was flexibility in the gas network physical assets but the requested gas for power generation was still more than supply. Hence, in the modeling’s point of view about 0.85 (mcm) and 2.27 (mcm) of the gas for power generation and non-electric gas demand had to be curtailed, respectively. In Integrated modeling the above mentioned problem was obviated as the gas supply constraints were considered and so it was not required to shed any gas demand. A comparison between Case 1 and Case 3 indicates the importance of considering gas and electricity constraints synchronized as through proper scheduling of the gas plants there was no need to curtail gas demands. In the Sequential modeling, gas for power generation and other uses have the same value, and therefore there was no priority in curtailing different type of demands.

4.1.3. Compressor direction modification
The proposed model was capable of changing the direction of the compressors. Mostly the compressors close to the Bacton gas terminal operated in reverse direction than the pre-set direction.

In Figs. 11 and 12 it is shown that how flexible multi-directional compressor stations could provide flexibility to manage better the balancing issues. A positive power consumption means that the compressor was operating in the pre-set direction, whereas a negative value of power consumption indicates that the gas flow was redirected.

In normal condition, the direction of the gas through compressors close to the gas terminals was same as the injected gas through terminals. Thus, when an incident in the gas terminals happened, compressor units close to the terminal stations had to modify the direction of the gas flow in order to meet the gas demand in areas close to the terminals and keep the gas pressure in the acceptable range as much as it was feasible.

As an example, compressor station number nine (located in node 62, 63) mostly operated in the reverse direction. In addition, the power consumption by the compressors in Case 4 was less than Case 2 which means the gas network operation was managed better as it was less need to compress the pressure.

4.1.4. Gas and electricity networks costs
Operational cost of the networks for various case studies over the typical winter week in partial outage of Bacton gas terminal are presented in Table 4. It is noteworthy that the penalty price of gas load shedding was assumed to be 11.1 £M/mcm [27].

The cost savings in different case studies are presented in Fig. 13. It is demonstrated that through operating simultaneously the gas and electricity networks and employing flexible multi-directional compressor stations, the lack of gas supply was completely compensated and about 30% cost saving in comparison to Case 1 was achieved.

| Case study | Electrical network | Gas network | Total |
|------------|--------------------|-------------|-------|
| Case 1     | 78.92              | 1190.66     | 1269.58|
| Case 2     | 78.92              | 834.49      | 913.41 |
| Case 3     | 92.90              | 808.18      | 901.08 |
| Case 4     | 80.21              | 810.39      | 890.60 |

Fig. 11. Compressors power consumption in Case 2.

Fig. 12. Compressors power consumption in Case 4.

Fig. 13. Cost savings in comparison to Case 1.

Fig. 14. Gas load shedding (Locations).
4.2. Outage of Bacton gas terminal

In this section, the complete outage of Bacton gas terminal was considered. This event would be triggered by the gas interruption through UK Continental Shelf (UKCS), BBL and IUK (see Fig. 4).

In Fig. 14 the gas load shedding over the week in the gas network is presented. Due to the inertia of gas, as it was expected, close to the Bacton gas terminal largest load shedding was happened.

In Table 5, it is shown that through integrated there was no need to shed any gas demand for power generation as the security supply constraints of the gas network were taken into account. In Case 3, the modeling was done simultaneously and therefore the dispatch of the power generation had been modified in order to reduce gas for power generation, but there was not enough gas infrastructure flexibility to deliver gas to the demand centers.

From Tables 4 and 6 it is concluded that value of gas infrastructure flexibility was increased with the severity of the contingency in the gas network. It is shown about 36% improvement in operational cost in Case 2 in respect to Case 3 in complete outage of Bacton gas terminal. Consequently, the contingency mode was more effectively managed in Case 2 rather to Case 3. As it was expected, the lowest operational cost was achieved in Case 2. In this mode, even in contingency conditions the gas and electricity networks were securely operating. The solutions helped to obviate the lack of gas supply with re-dispatching the generation mix in the power system and changing the gas flow direction in the gas network, which led to no gas demand curtailments.

Through comparing the operation of the gas and electricity networks in different case studies it could be concluded that by taking into account the gas network infrastructure flexibility, the coupling link and interdependency of gas and electricity networks was decreased. The impact of a gas network incident on the electricity network was reduced and vice versa. Consequently, the security of the energy systems was increased.

5. Conclusion

In order to improve the security of supply of gas and electricity networks, two solutions were presented. The first solution was to change the operation practice from sequential to an integrated approach to operate gas and electricity networks. The second solution was improving the flexibility of gas network infrastructure (multi-directional compressor stations). Through the modeled gas compressors, the gas flow could be redirected when it was required. Whereas, in one-directional compressor stations, the gas flow was dictated by the system operator. The system-wide performance of these two solutions in dealing with wind intermittency was evaluated.

It was shown that through an integrated operational practice significant amount of gas load shedding in contingency situations was avoided as the gas network security constraints were considered in the operation of the power system. In this research the contingency was related to partial and complete outage of the largest gas terminal in the GB gas network in 2030. Using flexible multi-directional compressor stations, reduced the total operational cost of the networks compared to one-directional compressor stations, due to the additional flexibility that was given to the network to deliver gas to the demand centers. When the severity of the gas network incident was increased the impact of gas network infrastructure flexibility was more noticeable. In another words, the coupling link between gas and electricity networks was decreased when flexibility was provided in the gas network infrastructure. The best operational management of the networks was achieved through combining the proposed solutions.

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