Investing in flexibility in an integrated planning of natural gas and power systems

Hossein Ameli1, Meysam Qadrdan2, Goran Strbac1, Mohammad Taghi Ameli3

1 Control and Power group, Imperial College London, SW7 2AZ, UK
2 Institute of Energy, Cardiff University, CF24 3AA, UK
3 EE Department, Shahid Beheshti University, Tehran, Iran
E-mail: h.ameli14@imperial.ac.uk

Abstract: The growing interdependencies between natural gas and power systems, driven by gas-fired generators and gas compressors supplied by electricity, necessitates detailed investigation of the interactions between these vectors, particularly in the context of growing penetration of renewable energy sources. In this research, an expansion planning model for integrated natural gas and power systems is proposed. The model investigates optimal investment in flexibility options such as battery storage, demand-side response, and gas-fired generators. The value of these flexibility options is quantified for gas and electricity systems in Great Britain in 2030. The results indicate that the flexibility options could play an important role in meeting the emission targets in the future. However, the investment costs of these options highly impact the future generation mix as well as the type of reinforcements in the natural gas system infrastructure. Through the deployment of the flexibility options up to £24.2 billion annual cost savings in planning and operation of natural gas and power systems could be achieved, compared to the case that no flexibility option is considered.

Nomenclature
Parameters & variables

C: cost, £
CR: compressor ratio
D: diameter of the pipe, mm
e: produced greenhouse gas emissions, tonnes
E: energy level of electricity storage, MWh
E: maximum energy level of electricity storage at busbar h, MWh
E: energy level of electricity storage, MWh
E: maximum available capacity of electricity storage, which could be installed in the system, MWh
h: Sensitivity coefficient of flow on line l with respect to power injection of supply point i (based on DC load flow model)
L: length of a gas pipeline, km
n: economic lifetime of the technology or asset
F: power flow of line, MW
p: pressure, bar
P: power output, MW
P: maximum available capacity of electricity demand, which could be shifted, MW
P: maximum available capacity of flexible demand, MW
P: maximum available capacity of flexible combined cycle gas turbines, which could be installed in the system, MW
Q: gas flow, mcm/h
r: provided reserve, MW
ur: unreserved reserve, MW
Y: capacity of a generation unit, MW
Z: cost in the objective function, £
a: the weighted average cost of capital of each technology or asset
β: polytropic exponent (4.70)
η: efficiency, %
γ: carbon emission target of the system, grCO2/kWh
λ: decision variable on the presence of generator in the generation mix (1/0)

Ω: proportion of wind for reserve requirements
ω: number of installed compressor units
ψ: fraction of electricity demand that is flexible
Ψ: maximum ramp up/down power of a generation unit, MW/h
ε: amount of gas tapped by a compressor

Superscripts
ACAPEX: annualised capital cost expenditure
Avail: available
avg: average
cap: capacity
CAPEX: capital cost expenditure
comp: compressor
cur: curtailment
dis: discharge
dsr: demand-side response
d: decreased demand
d+: increased demand
ecomp: electrical-driven compressor
elec: electricity
eload: electricity demand
emission: emission
estor: electricity storage
eshed: electrical load shedding
eq: equivalent
ex: existing
dem: demand
flex: flexibility
flexGP: flexible gas-fired plant
FOPEX: annualised fixed operational cost expenditure
gen: generator
gshed: gas load shedding
gstor: gas storage
inv: injection
max: maximum
min: minimum
new: new installed
optimisation in enhancing the security and economic efficacy of subproblems were iteratively solved devising column and gas and electricity system is quantified. In [8], the authors demonstrated how making the gas infrastructure more flexible (FlexGP) in an integrated operation of wind farms' output power. In this model, the electricity and gas power generation [4], making it difficult to operate the natural gas network to meet the future network condition changes. It is demonstrated that the shortest total length is not necessary the optimal layout for the system, and cost saving is achieved in the used optimised layout in this research. Furthermore, it is concluded that the optimal pressure of a supply node is the maximum available pressure if the supply node is at the starting point of each pipeline connected to the supply node. From the other side, the optimum pressure for the demand node is the minimum required pressure if the demand node is at the end-point of each pipeline connected to that node. In [15], an optimisation model was introduced for expansion of natural gas fields, processing, and transport system. In this study, related decisions to model expansion were continuously proposed, which reduces solving time of the problem considerably.

The lack of these studies is in not taking into account the whole-system (e.g. electricity) constraints, since in the future the interaction of different energy vectors will increase significantly. Chaudry et al. [16] developed a planning strategy for the infrastructures based on the combined gas and electricity network model. Two possible scenarios including base and low-carbon have been investigated. It was shown that this model is able to allocate timely and efficiently the required resources across the energy system. In addition, different aspects of planning and expansion of natural gas and power systems have been presented in [17–24]. In [17], a mixed-integer linear programming optimisation problem is formulated to minimise costs of expansion planning of natural gas and power systems as well as limited resources capacity. Furthermore, finding optimal pathways to meet the future emission targets according to such as the Paris agreement on climate change [12] is of great importance. A coordinated expansion and planning for gas and electricity infrastructure facilitate a cost-effective transition to a low carbon and secure energy system. In a planning strategy, economic, environmental as well as security of supply aspects should be considered.

1 Introduction

Many countries are committed to increasing their share of renewable sources to reduce their greenhouse gas emissions by at least 80% until 2050 (compared to 1990) [1]. For example, in order to achieve these targets, in United Kingdom (UK) the projection is that the renewable sources should provide 27% of the total energy consumption by 2030 [2]. Given the abundant wind resources across UK, wind generation could play a significant role in the future generation mix to meet the renewable and emission reduction targets [3].

Although the volume of gas is decreasing due to the presence of renewables, the value of gas as the main compensation source to produce electricity in the lack of renewables is increasing. Therefore, the interdependency of the natural gas and power systems is increasing, which means more interaction between the gas and electricity system operators in supporting the balancing of electricity supply and demand. Utilising gas-fired plants to compensate for wind variability leads to variable gas demand for power generation [4], making it difficult to operate the natural gas system.

The interaction of these systems can be seen from operation and planning perspectives. From an operation point of view, many research studies such as [5–11], investigate the interaction of natural gas and power systems in terms of aspects such as security of supply, market, demand constraints, resiliency, and flexibility participation.

Owing to the interdependency of gas and electricity networks, some studies investigated the operation of these networks in an integrated manner. For instance, in [5], a robust optimisation model for scheduling natural gas and electricity networks was proposed taking into consideration uncertainties in electricity demand and wind farms’ output power. In this model, the electricity and gas subproblems were iteratively solved devising column and constraint generation (CCG) and outer approximation, respectively. The obtained results indicated the capability of gas-fired units to reduce wind curtailment in co-optimisation of these networks. In [6], a coordinated operation of natural gas and electricity infrastructures model was presented, in which different cases from non-integrated to fully-integrated optimisation were investigated. The results demonstrated the benefits of fully-integrated optimisation in enhancing the security and economic efficacy of these infrastructures. In [7], the value of different flexibility options including power-to-gas (P2G), electricity storage (EStor), and more flexible gas plants (FlexGP) in an integrated operation of gas and electricity system is quantified. In [8], the authors demonstrated how making the gas infrastructure more flexible through multi-directional compressors can improve the operation of gas and electricity systems and prevent gas load shedding in contingency condition. In [9], to optimise coordinated operation of gas and electricity networks, a hybrid approach was introduced, including a game-theoretic approach and multi-objective optimisation. The aim of this game was to reflect the relationship between the amount and price of energy that distributed energy stations purchased from a utility network. After that, a multi-objective model was solved, which minimises the conflicting cost of gas and electricity networks. In [10], it is demonstrated how provision of flexibility in gas and electricity systems decrease the value of interdependency of these systems. In [11], a robust model was introduced to enhance the resiliency of integrated gas and electricity systems against probable outages, which are caused by natural disasters. In this approach, an algorithm was also devised to solve the model consisting of Benders decomposition CCG.

Owing to the electrification of a segment of heat and transport sectors in the future, the electricity peak demand would be increased significantly. Therefore, the efficiency of the current natural gas and power systems as well as limited resources capacity highlights the need for optimal expansion of these systems. Furthermore, finding optimal pathways to meet the future emission targets according to such as the Paris agreement on climate change [12] is of great importance. A coordinated expansion and planning for gas and electricity infrastructure facilitate a cost-effective transition to a low carbon and secure energy system. In a planning strategy, economic, environmental as well as security of supply aspects should be considered.

In the following studies [13–15], the planning and operation optimisation for gas transmission networks are studied. In these research studies, investments on compressors and gas pipelines are proposed as the options to reinforce the gas system infrastructure to improve the operation of the natural gas system. In [13], a cost-based mixed-integer non-linear programming (MINLP) optimisation model is implemented to design a new or expand pipeline network to meet the future network condition changes. It is shown how this can help the policy-makers about the location and capacity of the pipelines and compressors. In [14], a genetic algorithm-based optimisation has been derived for the design of the natural gas system transmission network. It is demonstrated that the shortest total length is not necessary the optimal layout for the system, and cost saving is achieved in the used optimised layout in this research. Furthermore, it is concluded that the optimal pressure of a supply node is the maximum available pressure if the supply node is at the starting point of each pipeline connected to the supply node. From the other side, the optimum pressure for the demand node is the minimum required pressure if the demand node is at the end-point of each pipeline connected to that node. In [15], an optimisation model was introduced for expansion of natural gas fields, processing, and transport system. In this study, related decisions to model expansion were continuously proposed, which reduces solving time of the problem considerably.

This is an open access article published by the IET and Tianjin University under the Creative Commons Attribution License (http://creativecommons.org/licenses/by/3.0/)
was applied to optimise the cost of planning new gas-fired power plants, gas pipelines, and other flexibility options (e.g. energy storages and compressors) to ensure to meet gas and electricity demand under uncertainty. The obtained results indicated the role of storage systems in dealing with short time uncertainties. In another study [20], a two-stage co-planning model for optimal decision making on generating units, transmission lines, and gas pipelines was introduced for the context of gas-fired power plants. It is obvious that due to the constraints on gas transportation in the pipelines to the gas-fired plants, the scheduling planning in electricity system can be affected significantly. In [21], multi-stage stochastic programming was devised to cope with uncertainty of renewable energies in optimising expansion of natural gas and electricity networks. The obtained results demonstrated the enhancement of feasibility robustness in the case of multi-stage decision making. In [22], a decentralised stochastic model was introduced for co-expansion of gas and electricity systems. In this model, uncertainties in output power of renewable energies, demand growth, and interest rate were taken into consideration. Moreover, the role of renewable energy expansion and demand response programmes in preventing extra capacity investment was investigated. Alternating direction method of multipliers was also developed to solve the mathematic model of this study. In [23], a multi-attribute decision making method for expansion planning of gas and electricity networks was introduced taking into account the privacy of gas and electricity parties. In the proposed model, minimum of maximum regret and $\beta$-robustness approaches were also applied to deal with uncertainties and find a more stable plan. Finally, the Pareto optimal approach was devised to show the accuracy of the approach. In [24], an energy hub planning model consisting of different energy carriers (i.e. electricity, heat, and gas) is presented. The role of combined heat and power in providing the link between heat and electricity in the energy system is highlighted. Furthermore, it is illustrated that the coupled modelling of these energy vectors can provide more flexibility for the energy supply, as the whole system constraints are considered.

Flexibility options such as demand-side response (DSR), flexible combined cycle gas turbines (CCGTs), EStor, and interconnection could participate in real-time system balancing requirements and the need to effectively maintain security of supply [25]. Employment of different mitigation techniques in future is highly dependent on costs, technical, and social characteristics. As an example, DSR (especially from domestic households) has several non-technical barriers to be available at scale as well as to be at low cost. The barriers are but not limited to: (a) driving behavioural change in consumers, (b) contract design, (c) incentive structures to encourage adoption, and (d) efficient business processes to manage interactions with large numbers of customers. Contract design, incentive structures to encourage adoption and efficient business processes to manage interactions with large numbers of customers [25]. Each flexibility option only becomes economically attractive when the benefits are more than the associated costs of these options. Otherwise, actions such as using conventional generation capacity to provide backup or curtailing renewable instead of storing is chosen, alternatively. Another advantage of investment on flexibility is it can also provide ‘option value’. Option value means that small investments in flexibility could postpone decision-making on larger investments such as reinforcement of natural gas and power system infrastructure to whenever better information is available [25].

Considering flexibility options in expansion planning of integrated gas and electricity system is limited in the literature (e.g. role of DSR [22]), hence, this study investigates an integrated planning strategy based on the operational model presented in [10], for the natural gas and power systems, considering detailed modelling of the mentioned flexibility options. The optimisation problem of expansion planning of integrated natural gas and power systems is a MINLP (i.e. due to binary variables representing decision making on investment in new generating units and decommissioning of existing units as well as non-linear equations in natural gas system operation). The successive linear programming (SLP) is employed to solve this optimisation problem. The model minimizes annual costs related to integrated operation and planning of the natural gas and power systems whilst meeting demand requirements over a year. In the power system, decision on decommissioning the existing plants (e.g. coal plants), investment on installing power plants of onshore wind, off-shore wind, solar, nuclear, CCGTs, and CCGT-based carbon capture and storage (CCS) in terms of location and capacity is determined optimally. In the natural gas system, reinforcement on physical assets of the gas system infrastructure, namely, gas pipelines and compressor units are decision variables in the investment modelling. Additionally, optimal allocation and capacity of the aforementioned flexibility options to meet the emission targets in the future is determined. The model is quantified on a Great Britain (GB) natural gas and power system in the year of 2030. Owing to uncertainty associated with the capital cost of the flexibility options in the future, case studies are derived by considering different investment assumptions. It is demonstrated how the mentioned flexibility options in the power system can decrease the investments on the natural gas system infrastructure.

2 Modelling methodology

2.1 Natural gas and power systems operation

In the modelling of the operation of natural gas system constraints for (a) power consumption by the compressors, (b) gas flow along a pipe, (c) changes in the gas system line pack, (d) pipeline pressure limits, and (e) nodal gas balance are taken into account. In the power system operational model, the general formulation of the power flow model (based on the DC power flow model [26]) is applied to represent the power system (1)–(3). Hourly system demand–supply balance constraints (1) and the hourly network lines’ capacity constraint (2). The power flow through the transmission line is calculated through (3). Furthermore, following constraints are considered; (a) minimum and maximum power generation limits for generators (4), (b) operational characteristics of the thermal generators including ramp up/down limits of generators (5), the maximum limit for power generation and provision of the reserve by thermal generators (6), (b) generated wind absorbed by the grid (7), (c) minimum reserve requirement [10] (8), and (d) electricity demand–supply balance (9) (detailed operational modelling of natural gas and power systems is presented in [7–10]). It is worth mentioning that to reduce the complexity of the model, the unit commitment problem is not considered in this model.

\[
\forall t \in \mathcal{T}: \sum_{i \in N} p_{\text{load},i,t} + \sum_{j \in K} p_{\text{dem},j,t} = 0 \tag{1}
\]

\[
\forall t \in \mathcal{T}, \forall i \in \mathcal{I}: F_{i,t} \leq P_{\text{max},i,t} \tag{2}
\]

\[
F_{i,t} = \sum_{k \in h_{i}} p_{\text{wind},i,t} - \sum_{j \in h_{i}} p_{\text{dem},j,t} + P_{\text{pump},i,t} \tag{3}
\]

\[
\forall i \in \mathcal{I}, \forall t \in \mathcal{T}: P_{\text{min},i,t} \leq P_{i,t} \leq P_{\text{max},i,t} \tag{4}
\]

\[
\forall i \in \mathcal{I}, \forall t \in \mathcal{T}: P_{i,t} + r_{i,t} \leq P_{\text{nom},i,t} \tag{5}
\]

\[
\forall b \in \mathcal{B}, \forall t \in \mathcal{T}: P_{\text{wind},b,t} = P_{\text{wind},b,t} + P_{\text{wind},b,t} \tag{7}
\]

\[
\forall b \in \mathcal{B}, \forall t \in \mathcal{T}: P_{\text{load},b,t} + P_{\text{wind},b,t} \geq \max_{i \in \mathcal{I}} (P_{i,t}) + \Omega \tag{8}
\]

\[
\forall t \in \mathcal{T}: \sum_{b \in \mathcal{B}} P_{b,t} + \sum_{i \in \mathcal{I}} (P_{i,t} - P_{\text{wind},b,t}) \geq \sum_{b \in \mathcal{B}} (P_{\text{load},b,t} - P_{\text{load},b,t} + P_{\text{comb},b,t}) \tag{9}
\]
2. Power system planning

In this study, for sake of simplicity, two assumptions are considered. Firstly, the lifetime of the existing units, which could be retired in the future due to the number of installed years, is not considered. This means decommissioning of the existing generation units is decided according to the minimisation of planning and operation costs of natural gas and power systems along with meeting the carbon emission targets. Secondly, expansion planning on power transmission lines is not taken into account and the capacity of the lines is provided as input to the model. The model is implemented for a year. Therefore, based on weighted average cost of capital (WACC) and economic lifetime of different technologies and assets, capital costs are annualised [27] through the following expression (10):

\[
C_{\text{CAPEX}}^{\text{eq}} = C_{\text{CAPEX}} \cdot \frac{\alpha}{1 - (1 + \delta)^{-n}}
\]

In the generation expansion modelling, investment decisions on the following technologies are made: (a) renewables (offshore wind, onshore wind, and solar), (b) nuclear, (c) CCGTs, and (d) gas-based CCS.

2.2.1 Generation expansion planning: To model the future generation portfolio, binary decision variables on all of the generation units are considered. In other words, if the binary variable is 1, for an existing unit, it means that it is needed to be still connected to the system in the future generation mix. If the binary variable is 0, it means that the unit needs to be decommissioned to reduce the total energy system costs and/or emissions. For new generation units, if the binary variable is 1, the unit is required to be installed in the system. The power generation limits in the investment modelling for non-thermal and thermal units are expressed by (11) and (12), respectively

\[
\forall i \in (\mathbb{G} \setminus \mathbb{K}) + (\mathbb{K}_{\text{new}} - \mathbb{K}_{\text{new}}), r \in \mathbb{T}, t \in \mathbb{T}_d: P_{i,r,t} \leq P_{i,\text{max}}^{\text{gen}} \cdot \pi_{i,\text{gen}}
\]

\[
\forall i \in \mathbb{K} + \mathbb{K}_{\text{new}}, r \in \mathbb{T}, t \in \mathbb{T}_d: P_{i,r,t} + r_{i,r,t} \leq P_{i,\text{max}}^{\text{gen}} \cdot \pi_{i,\text{gen}}
\]

2.2.2 Planning and operational costs of power system: Costs of power system expansion consist of power generation and emission penalties of the existing and new generators, annualised fixed cost of the existing generators, electrical load shedding penalties (see (13)) and the annualised investment cost of new installed generators (14)

\[
Z_{\text{inv, elec}} = \sum_{i \in \mathbb{K}_{\text{new}}} (C_{i}^{\text{CAPEX}} + C_{i}^{\text{FOPEX}}) \cdot \eta_{i}^{\text{new gen}} \cdot \pi_{i}^{\text{gen}}
\]

2.3 Natural gas system infrastructure expansion

In the natural gas system planning model, expansion of the gas pipelines and compressor units are considered. Pipelines' expansion is based on installing new pipes parallel to the existing pipelines. In compressor investment, installing new compressors in series with the existing one is considered [28].

2.3.1 Natural gas pipes transmission system expansion: As mentioned, new pipelines are installed parallel to the existing pipelines. This means that total gas flow is summation of the gas flow in the existing and new pipelines. Therefore, the length of the new pipelines is assumed to be the same as existing parallel pipelines. The Panhandle A equation for high-pressure networks [29] for gas flow (15) and (16) is implemented

\[
\forall i \in \mathbb{L}_p, r \in \mathbb{S}, t \in \mathbb{T}_d: K_i = \frac{(Q_{\text{pipe}})^2}{18.43 \cdot L_i^{2/5}}
\]

\[
Q_{i,r,t}^{\text{avg}} = \left(K_i \cdot \left(\frac{p_{\text{in},i}^{\text{out},i}}{p_{\text{out},i}^{\text{in},i}} \cdot D_i^{4.854/1.854}\right) - Y_{\text{pipeline}}ight)
\]

\[
\Rightarrow D_i^{\text{avg}} = \left(D_i^{4.854/1.854} + D_i^{4.854/1.854}\right)
\]

From modelling point of view, to reduce the non-linear equations, by combining gas flow of the existing and new pipelines, an equivalent pipe with the same length and new diameter is replaced (Fig. 1).

In (17) and (18), the diameter of the equivalent pipe is calculated. In light of this, in the gas flow equations, a combination of the existing pipeline (i.e. given as input), and new pipelines (i.e. decision variable), are taken into account.

2.3.2 Gas compressor facilities expansion: To enhance the compression ratio, installing new compressors in series with the existing units is considered. As presented in [30], in the simplified version of NTS of natural gas, an equivalent compressor, represents the compressor units in the station yard. Hence, it is assumed at each compressor station, an equivalent compressor is installed. Here, in a specific compressor station, the type of the new compressor unit is the same as the existing compressor unit in the station yard. Compressor modelling is presented in (19)–(21). Each compressor is subjected to maximum flow rate, power consumption, and pressure constraints [8]. The tapped gas is calculated through (21)

\[
\forall c \in \mathbb{C}, r \in \mathbb{T}, t \in \mathbb{T}_d:
\frac{P_{c,r,t}^{\text{dis}}}{P_{c,r,t}^{\text{in}}} = \left(\beta \cdot \frac{Q_{c,r,t}^{\text{comp}}}{Q_{c,r,t}^{\text{comp}} - 1}\right) + 1
\]
The conversion of two compressors in series into an equivalent compressor is presented in Fig. 2. Discharge node of the first compressor is the same as suction node of the second compressor. Therefore, through product of the pressure ratio of the first compressor and the second compressor, the pressure ratio of $p_{c,1}^{\text{dis}}/p_{c,1}^{\text{suc}}$ is calculated (22)

$$p_{c,2}^{\text{dis}} = \frac{p_{c,2}^{\text{dis}}}{p_{c,2}^{\text{suc}}} \Rightarrow \frac{p_{c,1}^{\text{dis}}}{p_{c,1}^{\text{suc}}} = \frac{p_{c,2}^{\text{dis}}}{p_{c,2}^{\text{suc}}} \cdot \frac{p_{c,1}^{\text{suc}}}{p_{c,1}^{\text{dis}}}. \tag{22}$$

As a result, these compressors in series are replaced with an equivalent compressor unit. This procedure is expanded for all compressors in series. The general formula of the power consumption of the equivalent compressor with $\omega_c$ number of compressor units in series is presented in (23)–(25)

$$p_{\text{comp}}^{\text{suc}, c, r, t} = \frac{\beta \cdot Q_{\text{comp}}^{\text{suc}, c, r, t}}{Q_{\text{comp}}^{\text{p}, c, r, t}} \left(\frac{p_{c,1}^{\text{dis}}}{p_{c,1}^{\text{suc}}} \cdot \frac{p_{c,1}^{\text{suc}}}{p_{c,1}^{\text{dis}}} - 1\right) \tag{23}$$

$$CR_{\text{max}}^{\text{eq}} = (CR_{\text{max}})_{\omega_c} \tag{24}$$

$$1 \leq \frac{p_{\text{dis},c, r, t}}{p_{\text{suc},c, r, t}} \leq CR_{\text{max}}^{\text{eq}}. \tag{25}$$

### 2.3.3 Planning and operational costs of the natural gas system:

Costs of the natural gas system expansion consist of the operational cost of the natural gas system and investments on new physical assets in the infrastructure. The cost of gas supply, cost of gas storage, and gas load shedding penalties are considered in the operation of the natural gas system (26)

$$Z_{\text{op}, \text{gas}} = \sum_{r \in \mathcal{R}} \sum_{t \in \mathcal{T}} \left( \sum_{j \in \mathcal{J}} C_{\text{gas}, j, r, t} \cdot Q_{\text{inj}, j, r, t}^{\text{gas}} \right)_{\text{Gas supply}} + \sum_{i \in \mathcal{I}} C_{\text{gas}, i, r, t}^{\text{inj}} \cdot \left( Q_{\text{inj}, i, r, t}^{\text{gas}} - Q_{\text{inj}, i, r, t}^{\text{outj}} \right)_{\text{Gas storage}} - \sum_{i \in \mathcal{I}} C_{\text{gas}, i, r, t}^{\text{shed}} \cdot Q_{\text{shed}, i, r, t}^{\text{gas}}_{\text{Gas load shedding}} \tag{26}$$

In the investment part, annualised capital and fixed costs of reinforcement in new pipelines and compressor units are taken into account (27)

$$Z_{\text{inv}, \text{gas}} = \sum_{i \in \mathcal{I}} \left( C_{\text{ACAPEX}, i} + C_{\text{OPEX}}^{\text{CAPEX}, i} \right) \cdot L_i \cdot D_i^{\text{new}} + \sum_{i \in \mathcal{I}} \left( C_{\text{ACAPEX}, i} + C_{\text{OPEX}, i} \right) \cdot \omega_i. \tag{27}$$

In (27), decision variables of $D_i^{\text{new}}$ as the diameter of the new pipeline, and $\omega_i$, as the number of new compressors that are required to be installed, are optimised.

### 2.4 Investments on flexibility options in the power system

Flexibility options can improve the system operability to meet the carbon emission targets. Flexibility options including increased flexible generation, DSR, electrical storage, and enhanced transmission regional interconnections is considered in this study. The P2G option is not studied, since the overall efficiency of this technology is still low and it is not economically competitive to other flexibility options.

The investment and operational modelling of flexibility options are presented in (28)–(39). Contrary to the operational model of EStor [7] and DSR [31], in the investment model, the terms $E_{b}^{\text{max}}$ and $y$ in (33) and (37) are not model input and these terms are decision variables. Equation (38) illustrates the limitation on the installed capacity of DSR in the system. Through (39), the installed capacity of flexible CCGTs is constrained. Compared to the conventional CCGTs, for the flexible CCGTs, higher ramping up/down, higher efficiency and lower emission production are assumed

$$\forall b \in \mathcal{B}, r \in \mathcal{R}, t \in \mathcal{T} : \begin{array}{c}
P_{\text{Estor}, b, r, t} = E_{b, r, t}^{\text{Estor}} + (Q_{\text{Estor}, b, r, t}^{\text{inj}} - P_{\text{Estor}, b, r, t}) \cdot ts \tag{28} \\\phantom{\vdots} \\\phantom{\vdots} P_{\text{Estor}, b, r, t}^{\text{inj}} \leq P_{\text{b, r, t}}^{\text{inj}, \text{max}} \tag{29} \\\phantom{\vdots} P_{\text{Estor}, b, r, t} \leq P_{\text{b, r, t}}^{\text{with, max}} \tag{30} \\\phantom{\vdots} E_{b, r, t}^{\text{Estor}} \leq E_{b}^{\text{max}} \tag{31} \\\phantom{\vdots} P_{\text{Estor}, b, r, t}^{\text{inj}} \cdot ts + P_{\text{Estor}, b, r, t} \leq E_{b, r, t}^{\text{Estor}} \tag{32} \\\phantom{\vdots} \sum_{b \in \mathcal{B}} E_{b, r, t}^{\text{Estor}} \leq E_{\text{Estor, limit}} \tag{33} \\\phantom{\vdots} P_{\text{b, r, t}}^{\text{inj}} \leq P_{\text{b, r, t}}^{\text{inj}, \text{load}} \tag{34} \\\phantom{\vdots} P_{\text{b, r, t}}^{\text{inj}} = P_{\text{b, r, t}}^{\text{load}} - P_{\text{b, r, t}}^{\text{prev}} + P_{\text{b, r, t}}^{\text{ini}} \tag{35} \\\phantom{\vdots} \sum_{i \in \mathcal{I}} P_{\text{b, r, t}}^{\text{ini}} \leq P_{\text{b, r, t}}^{\text{ini}, \text{load}} \tag{36} \\\phantom{\vdots} P_{\text{b, r, t}}^{\text{cap, max}} = \max_{i \in \mathcal{I}} \left\{ \frac{1}{1 - \sum_{b \in \mathcal{B}} P_{\text{b, r, t}}^{\text{load}} / P_{\text{b, r, t}}^{\text{prev}} \right\} \tag{37} \\\phantom{\vdots} P_{\text{b, r, t}}^{\text{cap, max}} \leq P_{\text{b, r, t}}^{\text{cap, max}} \tag{38} \end{array}$$

The capital cost, economic lifetime, and variable operational cost of the flexibility options are considered (40) and (41). In (40), the operational costs of DSR are assumed to be zero, and the costs of flexible CCGTs are included in (13). Through the model, optimal placement and capacity for the mentioned flexibility options are determined. Furthermore, the model proposes a replacement for current inflexible CCGTs with flexible units

$$Z_{\text{op, flex}} = \sum_{r \in \mathcal{R}} \sum_{t \in \mathcal{T}} \sum_{b \in \mathcal{B}} C_{\text{b, r, t}}^{\text{flex, GP}} \cdot E_{\text{b, r, t}}^{\text{Estor}} \tag{40}$$

This is an open access article published by the IET and Tianjin University under the Creative Commons Attribution License (http://creativecommons.org/licenses/by/3.0/).
2.5 Objective function

The objective function of the integrated expansion planning of natural gas and power systems is to minimise the total costs of operation and investment of natural gas and power systems considering flexibility options (42). In addition, carbon emission targets are taken into account in the optimisation problem (43). It is worth mentioning that, operational constraints such as power balance, generation characteristics of the thermal power plants, reserve requirements, and gas nodal balance [7, 8] are considered in the optimisation model

\[
Z_{\text{plan}} = Z_{\text{op, elec}} + Z_{\text{op, gas}} + Z_{\text{op, flex}} + Z_{\text{inv, elec}} + Z_{\text{inv, gas}} + Z_{\text{inv, flex}}
\]

(42)

\[
\sum_{r=1}^{T} \sum_{t=1}^{T} \sum_{i \in K} \varepsilon_{i, r, t} \leq \gamma_{e, t} \cdot 10^3 \cdot \left( \sum_{r=1}^{T} \sum_{t=1}^{T} \sum_{i \in K} \sum_{b \in \mathbb{B}} P_{i, r, t} \right)
\]

(43)

3 Case study: GB natural gas and power systems

An expansion planning model for a GB natural gas and power systems is proposed to investigate cost-effective strategies for meeting the carbon emission target in 2030. In Table 1, the current installed capacity of each technology based on [32] is presented. A simplified representation of the GB power transmission system is shown in Fig. 3. It is worth mentioning that planned high-voltage DCs are considered in the GB power transmission system [33, 34]. According to the large combustion plant directive (LCPD) report [35], after 2025 coal power stations are planned to be decommissioned. However, in this research, the decommissioning of coal power stations due to LCPD is not implemented in the optimisation model as a constraint (i.e. \( \sum_{i=1}^{m} \xi_{i} = 0 \)), but an emission target is set and the capacity of various types of power station in 2030 is endogenous.

The expansion planning optimisation problem is for the year 2030. To make the optimal expansion planning decision for the year in a single problem, due to the complexity of the model (i.e. MINLP), an annual time horizon with an hourly time step (i.e. 8760 h) optimisation may not be feasible. In light of this, in the literature [36], the day is divided into three time steps including off-peak, intermediate, and peak. In this research, as the role of the flexibilities is considered, the representation of the day should be more accurate since by carrying out three time steps for a day, the dynamics of the demand profile during 24 h is not considered, notably. For example, the off-peak hours after the peak hours cannot be seen in this approach, which can have a negative impact especially on the value of DSR and EStor. Thus, in this case study, to model the dynamics of the system more precisely, a day is divided into six time steps; morning off-peak, morning intermediate, noon intermediate, afternoon intermediate, evening peak, and evening off-peak. As an advantage of this modelling, this division represents a dynamic behaviour of the demand during the day. In Fig. 4, the quasi-dynamic electricity demand profile against the real electricity demand is presented. It is shown that the dynamic electricity demand is an appropriate approximation of the real electricity demand. Furthermore, the entire year is represented by 12 days by applying a demand clustering method. In summary, in this research, the integrated expansion planning model of natural gas and power systems for the entire year is modelled through 72 time steps.

The impacts of power system flexibility options including DSR, EStor, and flexible CCGTs on the future expansion of natural gas and power systems infrastructure to meet the emission target of 100 grCO₂/kWh [25, 37] is investigated. The capacity of DSR, EStor, and FlexGP is uncertain in the future, which is imposed by technical, economical, political barriers, and uncertainties. In light of this the data from [25] is used, which is stated that the maximum technical potential capacity of DSR varies between 13 and 20 GW for different demand scenarios. Hence, in this study, 15 GW is

| Table 1 GB current generation mix (based on [32]) |
|-----------------------------------------------|
| Generation technology | Capacity, GW |
|-----------------------|-------------|
| coal                  | 12.7        |
| biomass               | 3.8         |
| hydro                 | 1.1         |
| other                 | 1.2         |
| wind                  | 14.7        |
| solar                 | 12.2        |
| gas                   | 30.8        |
| interconnection       | 14.1        |
| nuclear               | 9.7         |
| pumped storage        | 4.8         |
| coal                  | 12.7        |
| biomass               | 3.8         |
| hydro                 | 1.1         |
| other                 | 1.2         |
assumed as the maximum technical potential capacity for demand, which could be shifted. Consequently, to realise a comparison between different flexibility options, 15 GW is also assumed as the maximum capacity that can be installed in the system for EStor and FlexGP. As mentioned in Section 2.4, the actual installed capacity of DSR (as a proportion of demand), storage (installed capacity), and more flexible CCGTs (installed capacity) are variables and is determined in the optimisation problem. Therefore, to evaluate the impacts of each flexibility options on the future generation mix and natural gas system reinforcements, the following case studies are defined:

- **Reference (Ref):** In this case, none of the flexibility options are employed.
- **DSR:** A maximum of 15 GW of demand can be flexible.
- **EStor:** Maximum rated power of 15 GW of EStor with duration time of six hours [27] and 81% efficiency can be installed in the power system.
- **FlexGP:** A fraction of the existing gas plants can be operated more flexible (15 GW maximum capacity).
- **Fully flexible (Full Flex):** In this case, all aforementioned flexibility options are considered. This case is to compare the role of different flexibility options in the future paradigm.

For each of the above-mentioned case studies, due to uncertainty associated with the capital costs of the flexibility options in the future, two different options are considered (i.e. low capital cost (LC), and high capital cost (HC)), which are presented in detail in the Appendix. Furthermore, it is assumed that the capacity of current renewable energy sources (RES) and nuclear is maintained and none of these generation units are decommissioned for the year of 2030. It is worth mentioning that constructing new interconnectors can provide more flexibility to the system. However, as this requires an online monitoring of the supply--demand balance in the other part of interconnection (e.g. France), this option is not compared to the other flexibilities, and it is investigated separately.

A computer with a 3.20 GHz Intel(R) Xeon(R) processor and 16 GB RAM was used to solve the optimisation problem. To solve the MINLP problem of integrated planning of gas and electricity systems, the SLP algorithm of Xpress solver [38] has been employed. The SLP is a first-order, iterative-based approach, which can be employed for solving non-linear models. This method solves a sequence of linear programming problems. The Xpress SLP method is scalable and efficient for large problems [38]. This method has the following steps:

- **Step 1:** Solving linear approximation of the original problem at the current points.
- **Step 2:** Examining the distance of the output with the selected points.
- **Step 3:** Checking if the output is sufficiently close to the selected point. If yes terminate, otherwise return to step 1.

### 4 Results and discussions

#### 4.1 New capacity of generation technologies

The newly added generation capacities in GB in 2030 are presented in Figs. 5 and 6 (except for gas-fired power stations, which is presented separately) for different capital investment assumptions of flexibilities. Newly installed capacities of RES and nuclear, shown in Figs. 5 and 6, is added to the current capacity of these plants (Table 1), to build the generation mix in 2030.

In both LC and HC modelling assumptions of flexibility options, to meet the emission targets, the majority of coal plants are decommissioned (i.e. negative values). On the other hand, installation of RES including offshore wind, onshore wind, and solar are increased.

In **Ref** and **FlexGP** cases, 3 GW new nuclear plants are built. In other cases, due to the ability to store energy or shift the energy demand, no investment on new nuclear power plants is required. The largest level of integration of RES is observed in EStor cases, where storing the excess energy and withdrawing energy when required is possible. Moreover, the lowest decommissioning of coal plants as base load generation units has happened.

In the **DSR** case, if the investment costs of this flexibility is low, lower capacity of RES is installed (Fig. 5) compared to the case that the DSR costs are high (Fig. 6). This is due to the fact that low costs in DSR, enables more energy demand shifting within a day (17.14% of the demand across all the busbars), and in particular, to meet the peak-demand, lower installed capacity of RES is needed (Fig. 5). In high capital costs of DSR, the fraction of flexible demand is 13.9%, which leads to an increase in the installed capacity of RES (Fig. 6). This indicates that the costs of DSR play an important role in the future generation portfolio.

In **FlexGP** cases, it is demonstrated that although using these technologies, leads to less investment in new RES, new base load plants (i.e. nuclear plants) is installed. This is mostly due to the fact that in **FlexGP** cases, the conventional CCGT plants units are replaced by flexible units and additional generation capacity is not added to the system.

The capacity of gas-fired power stations, including existing CCGTs, new CCGTs, and CCGTs with CCS in the presence of different flexibility options are presented in Figs. 7 and 8. In the presence of flexibility options, ~1 GW less capacity of gas-fired power stations is required. In addition, when flexibility is provided, more CCGTs with CCS technologies are installed instead of the existing units.

In **Full Flex**, **EStor**, and **DSR** cases, new CCGTs are installed, which can be due to the change in the amount of available energy...
4.2 Location of new installed renewable energy sources

Based on the renewable energy targets [2], it is assumed that a minimum capacity of 12 GW for offshore and 2 GW for onshore wind generation should be installed in the system. In Fig. 9, the newly installed RES, in different case studies considering low and high investment costs of the flexibility options in different locations of the electricity transmission system is presented.

As can be seen in Fig. 9, the most accommodation of RESs is realised through the employment of energy storage facilities. It is demonstrated that when flexible CCGTs are installed instead of the conventional CCGTs, the capacity of new RES in both LC and HC are equal, as flexible CCGTs will mainly influence investments on gas-fired generation plants. It is shown that throughout the case studies, regardless of the capital cost of the flexibility options, new RESs are mainly installed in the south (bus 20, 27, and 29), where the majority of gas and electricity demands are located (in buses 20–29 around 50% of the demand is located).

4.3 Location of flexibility options

In Tables 2 and 3, the location of the ES tore in ES tore case (with more than 50 MW rated power capacity), and the flexible CCGTs in FlexGP case is presented, respectively. In both cases, the main installed capacity of ES tore and flexible CCGTs are in South England, where the majority of the demand is located. It is worth mentioning that it is assumed that there is no limitation on the ES tore capacity at each busbar.

It is demonstrated that when the costs of flexibility are low, more ES tore (4.6 GW compared to 4.2 GW) and flexible CCGTs (13.7 GW compared to 3.8 GW) are installed in the power system. As expected, the proposed model optimally determines the location of the flexibility options to be mainly close to the RES. This is due to the fact that, the flexibility options facilitate the accommodation of RES, while by-passing the power transmission congestions. It is worth mentioning that since a fixed pre-development cost for ES tore and flexible CCGTs is considered, hence in HC investment assumptions, fewer locations are chosen to install these units.

As mentioned previously, the DSR option is determined as a proportion of the electricity demand.

4.4 Expansion planning of natural gas system infrastructure

In Tables 4 and 5, the infrastructure reinforcements in the natural gas system are presented. In DSR cases, although the capacity of new CCGTs is about 5 GW, however, due to the role of DSR in shifting the energy consumption, less reinforcement in the natural gas system infrastructure is required. In the ES tore case, when the investment costs of ES tore facilities are low, 38.4 GW of gas-fired generation plants including 6 GW of new CCGTs (Fig. 7) are installed, therefore two new gas pipelines and compressors are decreased, compared to all other case studies. In this study, the pre-development (e.g. digging) costs for installing the new pipelines is not considered.

As a result, providing flexibility in the power system decreases the need for reinforcement in the natural gas system. Moreover, investment costs of the flexibility options play a significant role in expansion planning decisions on the natural gas system.
infrastructure. It is demonstrated that low investment costs of the flexibility options, leads to a higher installed capacity of the flexibility options, which makes lower reinforcements in the natural gas system infrastructures.

**4.5 Planning and operational costs of natural gas and power systems**

The total investment and operational costs of the natural gas and power systems in 2030 for low and high costs of flexibility options are presented in Fig. 10. Through the employment of each of the flexibility options, total costs are reduced. In the DSR case, since the energy demand shifts optimally within a day, up to £24.13 billion is saved in the entire year. As expected the most cost-saving is achieved when all flexibility options are considered in the future portfolio (Full Flex case). In this case, the model is employing 14.8 GW flexible CCGTs and 17.19% DSRs. As presented in Fig. 11, especially in the South of England, the conventional CCGTs are required to be replaced by more flexible CCGTs.

**4.6 Role of interconnection**

Importing electricity from interconnections can increase the flexibility of the system. To model the interconnectors accurately, the supply–demand balance of another side of the interconnector must be monitored, simultaneously. As an example, assume it is required to meet the peak demand in the evening hours (18:00–19:00). At some periods, importing electricity can help to increase flexibility and prevents investing in additional generation units. On the other hand, since in this period, there could be peak time in western European countries such as France and Netherlands as well, exporting electricity from these countries may not be possible. Therefore, in this modelling, an optimistic scenario is considered, in which it is assumed that annual imported electricity to GB is equal to the annual exported electricity from GB and the intra-day interaction between the sides of the interconnection is not taken into account. In the Appendix, the investment modelling assumptions for interconnectors are presented.

In Fig. 12, it is shown how interconnection can change the generation mix in the future. It is demonstrated that interconnectors can facilitate accommodation of renewable energy sources and decommissioning of the coal plants. In Table 6, the location of new interconnectors is provided.

**5 Conclusions**

An investment modelling of different flexibility options in an integrated expansion modelling of natural gas and power systems, to identify an optimal portfolio of the future energy system for achieving carbon targets at minimum whole-system costs was presented. In this model, decisions on decommissioning the existing plants (such as coal), and investment in installing new power plants including renewables, gas-fired power plants, and nuclear is optimally determined. In the natural gas system, reinforcements on the natural gas system infrastructure, including gas pipelines and gas compressors were taken into account.

To validate the investment model, the model was implemented on a GB natural gas and power system in 2030. It was demonstrated that flexibility options including DSR, flexible CCGTs, and EStor can save additional investment costs of natural gas and power systems. CCGTs continue to play a significant role in providing flexibility to the system in 2030, irrespective of the cost of flexibility options. The cost of DSR affects the future generation portfolio, notably. If the DSR costs are low, less investment on new renewable technologies is required. Furthermore, system-wide unbalanced supply and demand was handled, by optimal allocation of EStor through storing the excess of renewable and injecting it to the grid, when it was required. As was expected, the least investment and operational costs of natural gas and power system was achieved, when all of the mentioned flexibility options are included in the investment model. In this case, it was shown that employment of flexible CCGTs and DSRs is the most cost-effective pathway for meeting the emission targets in 2030 GB system.

It was demonstrated that an integrated analysis of national infrastructures was important for considering alternative evolution pathways of the natural gas and power system infrastructures. Furthermore, any change in the capital costs of the flexibility and prevents investing in additional generation units. On the other hand, since in this period, there could be peak time in western European countries such as France and Netherlands as well, exporting electricity from these countries may not be possible. Therefore, in this modelling, an optimistic scenario is considered, in which it is assumed that annual imported electricity to GB is equal to the annual exported electricity from GB and the intra-day interaction between the sides of the interconnection is not taken into account. In the Appendix, the investment modelling assumptions for interconnectors are presented.

To validate the investment model, the model was implemented on a GB natural gas and power system in 2030. It was demonstrated that flexibility options including DSR, flexible CCGTs, and EStor can save additional investment costs of natural gas and power systems. CCGTs continue to play a significant role in providing flexibility to the system in 2030, irrespective of the cost of flexibility options. The cost of DSR affects the future generation portfolio, notably. If the DSR costs are low, less investment on new renewable technologies is required. Furthermore, system-wide unbalanced supply and demand was handled, by optimal allocation of EStor through storing the excess of renewable and injecting it to the grid, when it was required. As was expected, the least investment and operational costs of natural gas and power system was achieved, when all of the mentioned flexibility options are included in the investment model. In this case, it was shown that employment of flexible CCGTs and DSRs is the most cost-effective pathway for meeting the emission targets in 2030 GB system.

It was demonstrated that an integrated analysis of national infrastructures was important for considering alternative evolution pathways of the natural gas and power system infrastructures. Furthermore, any change in the capital costs of the flexibility options can highly impact the future paradigm in both natural gas and power systems.

As the future work of this research, the multi-year expansion planning of integrated natural gas and power systems should be considered. This is due to the fact that since the emission targets are changing in the future after 2030 as well as some assets should be retired, hence the investments could be different for 2030 to see the longer-term investments. Furthermore, to realise a full coordination of the multi-vector energy systems, the role of natural gas system flexibility options (e.g. multi-directional compressors) in supporting the decrease in investment of electricity system needs further investigation.

**Table 6 Location of interconnections in GW**

| Bus Nr. | Country       | LC  | HC  |
|---------|---------------|-----|-----|
| 5       | Northern Ireland | 4.63 | 3.88 |
| 12      | Ireland Republic | 3.90 | 3.97 |
| 16      | Denmark       | 0.69 | 0.19 |
| 27      | France        | 1.19 | —   |
|         | Sum, GW       | 10.42 | 8.04 |
6 Acknowledgment
The authors gratefully acknowledge the ‘Sustainable gas pathways for Brazil; from microcosm to macrocosm’ project for providing funding for this work under NERC grant NE/N018656/1.

7 References
[1] European Commission: ‘A roadmap for moving to a competitive low carbon economy in 2050’, Brussels, Belgium, 2011
[2] European Commission: ‘2030 framework for climate and energy policies’, Brussels, Belgium, 2014
[3] Department of Energy & Climate Change: ‘UK renewable energy roadmap update 2013’, London, UK, November 2013. Available at http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_energy/re_roadmap/re_roadmap.aspx
[4] Oswald, J., Raine, M., Ashraf Ball, H.: ‘Will British weather provide reliable electricity?’, Energy Policy, 2008, 36, (8), pp. 3212–3225
[5] He, C., Wu, L., Liu, T., et al.: ‘Robust co-optimization scheduling of energy systems via ADMM’, IEEE Trans. Sustain. Energy, 2017, 8, (2), pp. 658–670
[6] Zlotnik, A., Roald, L., Backhaus, S., et al.: ‘Coordinated scheduling for interdependent electricity and natural gas infrastructures’, IEEE Trans. Power Syst., 2016, 31, (2), pp. 99–110
[7] Qadrdan, M., Ameli, H., Strbac, G., et al.: ‘Efficacy of options to address balancing challenges: integrated gas and electricity perspectives’, Appl. Energy, 2017, 190, pp. 181–190
[8] Ameli, H., Qadrdan, M., Strbac, G.: ‘Value of natural gas network infrastructure flexibility in supporting cost effective operation of power systems’, Appl. Energy, 2017, 202, pp. 571–580
[9] Wu, Q.H., Qin, Y.J., Wu, L.L., et al.: ‘Optimal operation of integrated energy systems subject to the coupled constraints of demand reliability and natural gas’, CSEE J. Power Energy Syst., 2019, 13, (1), pp. 1–14. DOI: 10.17775/CSEEJIPES.2018.00640
[10] Ameli, H., Qadrdan, M., Strbac, G.: ‘Coordinated operation strategies for natural gas and power systems in presence of gas-related flexibilities’, IET Energy Syst. Integr., 2019, 1, pp. 3–12
[11] Van, M., He, Y., Shahidehpour, M., et al.: ‘Coordinated regional-district operation of integrated energy systems for resilience enhancement in natural disasters’, IEEE Trans. Power Syst., 2019, 10, pp. 4881–4892
[12] United Nations: ‘Paris agreement’, Le Bourget, France, 2015. Available at: https://unfccc.int/sites/default/files/en/es_paris_agreement.pdf
[13] Uster, H., Dilaveroglu, S.: ‘Optimization for design and operation of natural gas transmission networks’, Appl. Energy, 2014, 133, pp. 56–69
[14] Sanaye, S., Mahmoudzadeh, M.: ‘Optimal design of a natural gas transmission network layout’, Chem. Eng. Res. Des., 2013, 91, (12), pp. 2465–2476
[15] Trovik, K., Fodstad, M., Hellemo, L.: ‘Optimization model to analyse optimal development of natural gas fields and infrastructure’, Energy Prog., 2015, 64, (1876), pp. 111–119
[16] Chaudry, M., Jenkins, N., Qadrdan, M., et al.: ‘Combined gas and electricity network expansion planning’, Appl. Energy, 2014, 113, pp. 1171–1187
[17] Unshuayu Vila, C., Marangon Lima, J.W., de Souza, A.C.Z., et al.: ‘A model to long-term, multiarea, multistage, and integrated expansion planning of electricity and natural gas systems’, IEEE Trans. Power Syst., 2010, 25, (2), pp. 1154–1168
[18] Qiu, J., Dong, Z.Y., Zhao, J.H., et al.: ‘Multi-stage flexible expansion co-planning under uncertainties in a combined electricity and gas market’, IEEE Trans. Power Syst., 2015, 30, (4), pp. 2119–2129
[19] Odetayo, B., Kazemi, M., MacCormack, J., et al.: ‘A chance constrained programming approach to the integrated planning of electric power generation, natural gas network and storage’, IEEE Trans. Power Syst., 2018, 33, (6), pp. 6883–6893
[20] Zhang, X., Shahidehpour, M., Alabuluwah, A.S., et al.: ‘Security-constrained co-optimization planning of electricity and natural gas transportation infrastructures’, IEEE Trans. Power Syst., 2015, 30, (6), pp. 2984–2993
[21] Nunes, J.B., Mahmoudi, N., Saha, T.K., et al.: ‘Multi-stage co-planning framework for electricity and natural gas under high reliable energy penetration’, IET Gener. Transm. Distrib., 2018, 12, (19), pp. 4284–4291
[22] Khaligh, V., Anvari Moghaddam, A.: ‘Stochastic expansion planning of gas and electricity networks: a decentralized-based approach’, Energy, 2019, 166, pp. 115889. Available at: http://www.sciencedirect.com/science/article/pii/S0360544219315610
[23] Khaligh, V., Auegi, M.O., Anvari Moghaddam, A., et al.: ‘A multiattribute expansion planning model for integrated gas-electricity system’, Energies, 2018, 11, (10), pp. 2573
[24] Zhang, X., Shahidehpour, M., Alabuluwah, A., et al.: ‘Optimal expansion planning of energy hub with multiple energy infrastructures’, IEEE Trans. Smart Grid, 2015, 6, (5), pp. 2302–2311
[25] Strbac, G., Auegi, M., Padjianto, D., et al.: ‘An analysis of electricity system flexibility for Great Britain’, November 2016
[26] Wood, A.J., Wolberg, B.F.: ‘Power generation, operation, and control’ (Wiley, New York, USA, 1996)
[27] Strbac, G., Auegi, M., Padjianto, D., et al.: ‘Strategic assessment of the role and value of energy storage systems in the UK low carbon energy future’, June 2012, Available at http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_energy/re_roadmap/re_roadmap.aspx
[28] Menes, S.: ‘Gas pipeline hydraulics’ (CRC Press, Boca Raton, FL, United States, 2005)
[29] Osiadacz, A.: ‘Simulation and analysis of gas networks’ (Gulf Publishing Company, Houston, United States, 1987)
[30] Qadrdan, M., Chaudry, M., Wu, J., et al.: ‘Impact of a large penetration of wind generation on the GB gas network’, Energy Policy, 2010, 38, (10), pp. 5684–5695
[31] Pujianto, D., Auegi, M., Djapic, P., et al.: ‘Whole-systems assessment of the value of energy storage in low-carbon electricity systems’, IEEE Trans. Smart Grid, 2014, 5, (2), pp. 1098–1109
[32] National Grid plc.: ‘Future energy scenarios; system operator’, UK, July 2018
[33] Sinclair Knight Merz (SKM): ‘Independent review of funding request for western HVDC link’, 2011. Available at https://www.ofgem.gov.uk/ofgem-publications/52716/westernhvcclink&stage=review&report=finalpublication
[34] Electricity Networks Strategy Group: ‘Our electricity transmission network: a vision for 2020’, February 2012
[35] UK Government: ‘Special feature – large combustion plant directive’, UK, September 2015
[36] Qadrdan, M., Cheng, M., Wu, J., et al.: ‘Benefits of demand-side response in combined gas and electricity networks’, Appl. Energy, 2017, 192, pp. 360–369
[37] Ameli, H., Qadrdan, M., Strbac, G.: ‘Techno-economic assessment of battery storage and power-to-gas: a whole-systems approach’, Energy Proc., 2017, 142, pp. 841–848. Proceedings of the 9th International Conference on Applied Energy
[38] [Online], Available at: http://www.maths.ed.ac.uk/hall/Xpress/FICO_Docs/mosel/mosel_lang_dhtml/moselref.html
[39] Auegi, M., Kountouriotsi, P.A., Calderon, J.E.O., et al.: ‘Economic and environmental benefits of dynamic demand in providing frequency regulation’, IEEE Trans. Smart Grid, 2013, 4, (4), pp. 2036–2048

8 Appendix: modelling assumptions

8.1 Investment assumptions in modelling of natural gas and power systems

For all cases, two different investment modelling assumptions based on the research in [25] including LC and HC of the flexibility options are considered. Furthermore, the investment modelling assumptions of different generation technologies were considered based on [25, 27, 36, 39].

The investment costs of gas network infrastructure including pipelines and compressors are presented in Tables 7 and 8 based on [16]. As mentioned in the previous section, in this modelling, it is assumed that the new gas pipelines can be installed parallel to the existing pipes. In addition, the new compressors are installed in series with other existing equivalent units in the station yard.

8.2 Investment assumptions in modelling of flexibility options

In Tables 9–12, low and high investment modelling assumptions for DSR, EStor, flexible CCGTs, and interconnection are presented, respectively [25].

Table 7 Gas pipeline investment modelling assumptions

| Component | Unit | Value |
|-----------|------|-------|
| CAPEX     | £    | 77,500 |
| 25 mm, km |     |       |
| WACC [16] | %   | 3.5   |
| lifetime [16] | years | 35 |

Table 8 Gas compressors investment modelling assumptions [36]

| Component | Unit | Value |
|-----------|------|-------|
| CAPEX     | £/unit | 15    |
| WACC      | %     | 3.5   |
| lifetime  | years | 25    |
### Table 9  EStor investment modelling assumptions [25]

|                             | Unit | Value |
|-----------------------------|------|-------|
| CAPEX (high)                | £/kW | 1879  |
| CAPEX (low)                 | £/kW | 673   |
| WACC                        | %    | 10    |
| fixed OPEX                  | £/kW/year | 6.1   |
| variable OPEX               | £/MWh | 0.7   |
| cycle efficiency            | %    | 81    |
| duration                    | hours | 6     |
| lifetime                    | years | 20    |
| maximum capacity            | GW   | 15    |

OPEX, operational cost expenditure.

### Table 10  Flexible CCGTs investment modelling assumptions [25]

|                             | Unit | Value |
|-----------------------------|------|-------|
| CAPEX (high)                | £/kW | 888   |
| CAPEX (low)                 | £/kW | 444   |
| WACC                        | %    | 10    |
| fixed OPEX                  | £/kW/year | 16    |
| variable OPEX               | £/MWh | 1.4   |
| ramp up/down                | MW/h | 350   |
| lifetime                    | years | 25    |
| maximum capacity            | GW   | 15    |

### Table 11  DSR investment modelling assumptions [25]

|                             | Unit | Value |
|-----------------------------|------|-------|
| costs (high)                | £/kW | 692   |
| costs (low)                 | £/kW | 121.5 |
| WACC                        | %    | 10    |
| lifetime                    | years | 10    |
| maximum technical potential | GW   | 15    |

### Table 12  Interconnection investment modelling assumptions

|                             | Unit | Value |
|-----------------------------|------|-------|
| costs (high) [25]           | £/kW | 1700  |
| costs (low) [25]            | £/kW | 300   |
| WACC                        | %    | 10    |
| lifetime                    | years | 40    |