Abstract: A detailed investigation of interaction between natural gas and power systems is necessary, due to the increasing interdependency of these vectors, especially in the context of renewable generations integration growth into the grid. In this paper, an outer approximation with equality relaxation decomposition method is proposed to solve a mixed-integer non-linear problem representing the operation of coupled natural gas and power systems. The proposed coupled modeling of natural gas and power systems resulted in about 7% operational cost savings. In addition, the value of gas-related flexibility options, including flexible gas compressors, flexible gas generation plants, and gas interconnections, to the operation of natural gas and power systems is quantified for a 2030 GB energy system. It is shown that if the natural gas and power systems are flexible enough, operation of the gas and electricity as a coupled system resulted in about 7% operational cost savings. In addition, the value of gas-related flexibility options, including flexible gas compressors, flexible gas generation plants, and gas interconnections, to the operation of natural gas and power systems is compared to a decoupled operational modeling. It is demonstrated that operating gas and electricity as a coupled system resulted in about 7% operational cost savings. In addition, the value of gas-related flexibility options, including flexible gas compressors, flexible gas generation plants, and gas interconnections, to the operation of natural gas and power systems is quantified for a 2030 GB energy system. It is shown that if the natural gas and power systems are flexible enough, operation of the systems in the decoupled approach is almost the same as the coupled model and therefore there is no need to reform the current energy market framework to make the systems fully coupled.

Nomenclature

Parameters & Variables

- $A$: cross-sectional area of the pipe ($m^2$)
- $C$: cost (£)
- $C_R^{max}$: compressor pressure ratio
- $D$: diameter of the pipe (mm)
- $e$: emissions (tonnes)
- $f$: friction factor
- $L$: linepack ($m^3$)
- $L_e$: length of pipe (m)
- $M$: matrix
- $p$: pressure (Pascal)
- $p^{std}$: pressure at standard condition ($\approx$ 1 bar)
- $P$: power output (MW)
- $r$: reserve provided through a generation unit (MW)
- $R$: gas constant for natural gas (518 J/kgK)
- $Re$: Reynolds number
- $t$: time step
- $T_a$: gas temperature (K)
- $T_a^{std}$: gas temperature at standard condition (288 K)
- $Q$: gas flow rate ($m^3/h$)
- $v$: velocity of gas along the pipe ($m/s$)
- $V$: volume of gas ($m^3$)
- $w^{std}$: shut-down cost function ($£$)
- $w^{sta}$: start-up cost function ($£$)
- $X$: objective function ($£$)
- $Z$: compressibility factor (0.95)
- $\beta$: polytropic exponent of a gas compressor (4.70 MJ/m$^3$)
- $\eta^{comp}$: efficiency of compressor units (60%)
- $\eta^{pmp}$: pipe efficiency factor (92%)
- $\gamma$: On/Off state of generation units (1/0)
- $\mu$: gas turbine fuel rate coefficient of a compressor (0.084 m$^3$/MJ)
- $\nu_g$: dynamic viscosity of gas (poise)
- $\partial L$: changes in linepack ($m^3$)

- $\Phi$: maximum ramp up/down power of a generation unit (MW/h)
- $\omega$: proportion of wind for reserve requirements
- $\rho$: density of gas (kg/m$^3$)
- $\Theta$: minimum up time of a generation unit (h)
- $\delta e_c,t$: amount of gas tapped by a compressor at node $c$ and time $t$ ($m^3/h$)

Superscripts

- avg: average
- comp: compressor
- cop: coupled
- dis: discharge
- ecomp: electrically-driven compressor
- em: emissions
- elead: electrical load
- gshed: electrical load shedding
- gload: gas load
- gshd: gas load shedding
- gstor: gas storage facility
- inj: injection
- min: minimum
- max: maximum
- std: standard
- suc: suction
- supp: supply
- ur: unserved reserve
- with: withdraw
- var: variable

Sets

- $B$: set of busbars
- $C$: set of compressor nodes
- $C_p$: set of electrically-driven compressors

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1 Introduction

1.1 Interaction between natural gas and power systems

In GB, natural gas supplies a substantial amount of energy used for heating (278 TWh in 2014) and power generation (218 TWh in 2014) [1]. Despite the increasing share of renewable and low carbon energy sources of power and heat production, it is expected that natural gas will continue to be an important part of the energy mix to 2030 [2].

Gas demand for power generation will be affected by the increase in wind and Photovoltaic (PV) generation. Owing to their flexible operating characteristics, gas-fired generating units will play a crucial role in compensating for the variability of renewable energy sources. Consequently, variations of wind and solar generation will be transferred to the gas demand [3], which makes the operation of these systems more interdependent. As a result, investigating a coordinated operation of these systems is of a great importance.

The interactions of natural gas and power systems are studied in the literature in detail [4–11]. A Security- Constrained Unit Commitment (SCUC) model considering natural gas transmission constraints is proposed in [4] and [5]. In this model, the scheduling problem of gas and electricity systems is solved using an iterative approach, i.e. the power system optimal dispatch problem was solved first and then gas demand for electricity generation was used in the gas network model for a feasibility check. In [7], a coupled model of natural gas and power systems is presented to account for the adequacy of gas as a fuel to power stations in the power system reliability assessment. In [8], the efficiency of coordinated operation of natural gas and power systems in presence of microgrid aggregators is quantified. In [10], two different coupling methodologies for gas and electricity markets based on a) maximizing the profit of electricity market, and b) minimizing the operational cost of the natural gas system are presented. It was shown that if the modeling is accurate, the difference between these two methodologies may be negligible. Authors in [22] proposed an iterative operation of natural gas and power systems without UC constraints to investigate the benefits of storing renewable electricity in the form of hydrogen and methane.

1.2 Solution algorithms for coupled operation of natural gas and power systems

The optimization problem for the coordinated operation of coupled natural gas and power systems is a Mixed Integer Non-Linear Programming (MINLP), due to binary variables in the UC constraints of generating units and non-linear equations in natural gas system dynamics.

MINLP problem is a complicated and challenging class from theoretical, algorithmic and computational perspectives [14, 15]. To simplify the complexity of solving the MINLP problem, several algorithms such as Generalized Benders Decomposition (GBD), Outer Approximation (OA), feasibility approach, Outer Approximation with Equality Relaxation (OA/ER), generalized outer approximation, and generalized cross decomposition are developed [14]. A number of previous works have applied deterministic and meta-heuristic solution techniques to solve MINLP problems [12–25]. Deterministic methods such as Priority List (PL) [16], Branch and Bound (BB) [17], Lagrangian relaxation (LR) [18], and Benders Decomposition (BD) [22] have been applied to solve MINLP problems. BB method is suitable for problems with small number of variables. LR method is an appropriate method for large-scale systems. However, due to non-zero duality gap, the solution obtained from dual problem could be infeasible [20]. In power systems, there are several studies that applied BD such as [23] in the UC problem. To solve the UC problems, heuristic methods such as evolutionary algorithm [23] and particle swarm optimization [24] have been implemented. In these methods, the optimal solution can be achieved if at each iteration the optimality is obtained. However, due to the stochastic nature of the search algorithms, the weakness of these methods is that mostly optimality of the solution cannot be guaranteed and consequently evaluating a solution is difficult. In addition, there are studies that linearize the non-linear constraints to make the problem MILP [26]. The OA approach is applied in few studies for solving the UC problem [27, 28].

In the context of coordination of gas and electricity systems, in [29], optimal operation of natural gas and power systems in presence of a large capacity of wind was assessed through a Combined Gas and Electricity Networks (CGEN) model. In this model, to avoid computational complexity, UC constraints were not taken into account. The CGEN model was further improved in [30] by taking into account the unit commitment constraints of thermal generating units. In [7], in the coupled model of natural gas and power systems, non-linear equations are linearized, and therefore the model is formulated as a mixed-integer linear programming (MILP). In [11] static and dynamic gas flow modelings are considered for the gas system operation. The results indicate the security and economic efficiency enhancement of the dynamic model. In the proposed model, the unit commitments constraints for thermal generating units are neglected in order to reduce the complexity of the optimization problem. Authors in [31] formulated a MILP problem to analyze gas supply interruption cases in an integrated electricity and gas system. In another study [32], a co-optimization scheduling of natural gas and power systems is proposed. A decomposition method is implemented to solve separately the gas network sub-problem and electricity network sub-problem.

1.3 Key contributions of this work

For operation of natural gas and power systems, two different strategies are compared, (a) decoupled approach in which these systems are operated in an iterative manner, and (b) coordinated operation of coupled natural gas and power systems. The value of a coupled modeling is quantified through comparing with the decoupled approach. Due to the nature of the non-linear equations in the natural gas system, the MINLP problem of coordinated operation of coupled natural gas and power systems is non-convex, which implies the potential existence of local optima. Therefore, one of the contributions of this research is to propose an efficient solution algorithm for the optimisation problem representing the coupled operation of natural gas and power systems. To the best of our knowledge, for the first time, an OA/ER decomposition method is implemented to solve the optimisation problem of integrated gas and electricity systems operation. Moreover, as the second contribution of this research, the role of gas-related flexibility options including, (a) multi-directional compressors, (b) flexible gas plants, and (c) gas interconnections, in the interaction between these systems is investigated. Set of case studies are analyzed on a 2030 GB gas and electricity transmission system to compare the proposed modelling approaches, and to quantify the value of gas-related flexibility options in interdependency of natural gas and power systems in presence of renewables.

2 Operational Models for Natural Gas and Power Systems

Operation of the natural gas and power systems is optimized using a day-ahead rolling strategy. A complete set of equations used in the model is provided.
2.1 Operation of Natural Gas System

2.1.1 Gas Flow along a Pipe: In the gas flow model, it is assumed that gas flows in one dimension, as the variations of gas properties along the radius is much slower than variations in the pipeline direction. In light of this, the following conditions are assumed: a) pipe is horizontal, b) along the pipe the velocity and temperature are constant, c) pipe’s diameter is small compared to the radius of curvature, and d) change of cross-sectional area along the path of gas stream is negligible [6].

The gas flow along a pipe (Fig. 1) is calculated through the Continuity (1) and Momentum (2) equations [33]. The volumetric flow rate of gas is governed by (3).

\[
\frac{\partial Q}{\partial x} = -\frac{A}{\rho ZRT} \frac{\partial p}{\partial t} \tag{1}
\]

\[
\frac{\partial p}{\partial t} = -\frac{Q}{\rho D} \frac{\partial^2 v}{\partial x^2} - 2\mu D \frac{v}{D} \tag{2}
\]

\[Q = \rho \cdot A \tag{3}\]

Through neglecting terms of \(\frac{\partial p}{\partial t}\) and \(\frac{\partial^2 v}{\partial x^2}\) due to the gas flow slow changes and large time steps (hourly compared to seconds) [6], in combination with (3), and mass flow rate (4), the transient flow of gas through a horizontal pipe is described in (5).

\[
M = \rho \cdot Q = \rho^{\text{std}} \cdot Q^{\text{std}} \tag{4}
\]

\[
\frac{\partial Q}{\partial t} = \frac{2f(\rho v^2)ZRT_{\text{avg}}Q^{\text{std}}}{\frac{\partial p}{\partial t}} \tag{5}
\]

where

\begin{align*}
M & \quad \text{mass flow rate (kg/s)} \\
\rho^{\text{std}} & \quad \text{density of gas in standard condition (0.713 m}^3\text{/s)} \\
Q^{\text{std}} & \quad \text{volumetric flow rate in standard condition (m}^3\text{/s)} \\
\end{align*}

In order to represent the derivatives of (1) and (5), a finite difference approach is applied [6]. Figure 2, illustrates the time-position plane of a pipeline element. In this figure, \(l\) is a length of the pipeline and \(\tau\) is time step of the modeling. The steady-state average pressure of a pipeline as well as the average gas flow in a pipeline are formulated in (6)-(7).

\[
p_{\text{avg},l}^{\text{std}} = \frac{1}{2} (p_{\text{in}}^{\text{std}} + p_{\text{out}}^{\text{std}}) \tag{6}
\]

\[
Q_{\text{avg},l}^{\text{std}} = \frac{1}{2} (Q_{\text{in}}^{\text{std}} + Q_{\text{out}}^{\text{std}}) \tag{7}
\]

By applying (6)-(7) and the gas equation of state (8) [33], (1) and (5) are converted to ordinary differential equations used for calculating gas flow through a pipe (9) and (10).

![Fig. 2: Finite difference cell.](image)

\[
Z \cdot R = \frac{\rho}{\mu} \frac{Q^{\text{std}}}{T_{\text{avg}}} = \frac{\rho^{\text{std}}ZRT_{\text{avg}}}{\rho^{\text{std}}ZRT_{\text{avg}}} = \frac{A}{\Delta x} \left[ \rho^{\text{std}}ZRT_{\text{avg}} \right] \tag{8}
\]

\[
\frac{\partial Q}{\partial t} = \frac{2f(\rho v^2)ZRT_{\text{avg}}Q^{\text{std}}}{\frac{\partial p}{\partial t}} \tag{9}
\]

In this research, the Panhandle A approach for high-pressure networks [33] for gas flow is implemented. Therefore, the friction factor is defined as (11) [33]:

\[
\sqrt{\frac{1}{T}} = 6.872 \cdot (Re)^{0.073} \cdot \rho^{\text{pipe}} \tag{11}
\]

\[
Re = \frac{\rho \cdot v \cdot D}{\mu} \tag{12}
\]

On the other side the gas flow could be calculated as follow (13):

\[
Q = A \cdot v = \frac{\pi D^2}{2} \cdot v \Rightarrow v = \frac{4Qp}{\pi D^2} \tag{13}
\]

By substituting (13) into (12), (15) is obtained, and by assuming the physical parameters of gas are constant, (16) is achieved.

\[
Re = \frac{4Qp}{\mu \cdot D} \tag{15}
\]

\[
Re = \frac{Qp}{D} \tag{16}
\]

where \(B\) is constant. Thus, through combining (16) to (11), the friction factor is simplified (17):

\[
\sqrt{\frac{1}{T}} = 6.872 \cdot C^{0.073} \cdot \frac{Q^{\text{pipe}}}{D^{0.073}} \tag{17}
\]

In a natural gas network, (10) can be written as (18):

\[
\forall t \in T \in \mathcal{L}_{\text{fg}}, \quad \frac{Q_{\text{in}}^{\text{std}} - Q_{\text{out}}^{\text{std}}}{L_{\text{gt}}} = \frac{2f(\rho v^2)ZRT_{\text{avg}}Q^{\text{std}}}{\frac{\partial p}{\partial t}} \left[ \frac{1}{2} (p_{\text{in}}^{\text{std}} + p_{\text{out}}^{\text{std}}) \right] \tag{18}
\]

Finally, by substituting (17) into (18) and simplification, (19) would be achieved.
\[ \forall l \in L_p, t \in T : h_{l,t}^{flow} = \frac{\left(p_{in,l,t}^{\text{min}}\right)^2 - \left(p_{in,l,t}^{\text{max}}\right)^2}{2 \cdot 18.43 \cdot L_e \cdot D_{l,t}^{8.554}} \] (19)

2.1.2 Gas Compressors: In order to enhance the lost pressure caused by friction in the pipelines, installation of compressor units is considered. Required power of the prime mover for the compressor is calculated by (20) [6]. The ratio of discharge pressure to suction pressure is limited to (21). Each compressor is subjected to pressure constraints [34]. The tapped gas is calculated from (22).

\[ \forall c \in C, l \in L_p, t \in T : P_{c,l,t}^{\text{comp}} = \frac{\beta \cdot Q_{c,l,t}^{\text{comp}}}{\eta_{c,l,t}} \left( \frac{p_{in,l,t}}{p_{out,l,t}} \right)^{1/\beta} - 1 \] (20)

\[ 1 \leq \frac{p_{in,l,t}}{p_{out,l,t}} \leq \frac{C_l}{\beta} \] (21)

(22)

2.1.3 Linepack: Due to the fact that supplying gas from sources take time to reach demand centers (typically hours), linepack [34] is used to meet the rapid changes in the network. The linepack \( L \) within a pipe, calculated through combining (8), (23), (24), and considering parameter \( K \) as in (25), is shown in (26):

\[ V = p^{-1} \] (23)

\[ \frac{\partial V}{\partial p} = -V^2 \] (24)

\[ K = \frac{V}{\rho R T_p^{\gamma-1}} = \frac{A \cdot L_e}{\rho R T_p^{\gamma-1}} \] (25)

\[ L = V^{\text{std}} = K \cdot p^{\text{std}}. \] (26)

In the dynamic state, gas flow oscillates when supply or demand changes. Change of total gas volume due to the mass conservation law is equal to the difference between flow into and out of the pipeline (27).\n
\[ \forall l \in L_p, t \in T : L_{l,t} = L_{l,t-1} + \int_{t-1}^{t} (Q_{l,t-1} - Q_{l,t}) \, dt. \] (27)

To deal with the integration as a non-linear function in (27), the changes in the gas flow is replaced with the changes in pressure through using (5), and therefore (27) can be approximated to (28):

\[ \forall l \in L_p, t \in T : h_{l,t}^{\text{linepack}} = L_{l,t} = L_{l,t-1} + K(l) \left( p_{l,t}^{\text{avg}} - p_{l,t-1}^{\text{avg}} \right). \] (28)

2.1.4 Natural Gas System Constraints: Pressure limits (29) and the gas flow balance (30) (i.e., gas inflows are balanced with gas outflows) are imposed to each system node.

\[ \forall x \in M, l \in L_p, t \in T : p_{l,t}^{\text{min}} \leq p_{l,t} \leq p_{l,t}^{\text{max}} \] (29)

\[ Q_{\text{comp}}^{\text{flow}} + \Delta Q_{\text{outlet}} + \sum_{i \in K} M_{\text{flow}}^{\text{out}} - Q_{l,t}^{\text{out}} + \sum_{i \in C} M_{\text{comp}}^{\text{out}} - Q_{l,t}^{\text{comp}} = Q_{l,t}^{\text{inflow}} + Q_{\text{std}}^{\text{out}} - Q_{\text{std}}^{\text{inflow}} - \sum_{i \in C \in C-\gamma} M_{\text{comp}}^{\text{in}} - Q_{l,t}. \] (30)

2.2 Power System Modeling

The general formulation of the power flow model (based on DC power flow model [35]) is applied to represent the power system (31)(33). Hourly system demand-supply balance constraints (31) and the hourly network lines' capacity constraint (32). The power flow through the transmission line is calculated through (33).

\[ \forall l \in T : \sum_{i \in G} s_{i,t} - \sum_{j \in K} d_{j,t} = 0 \] (31)

\[ \forall l \in L_e, t \in T : F_{l,t} \leq \left| P_{l,t}^{\text{cap}} \right| \] (32)

\[ F_{l,t} = \sum_{i \in C} h_{l,i,t} - \sum_{j \in N} h_{l,j,t} + d_{l,t}, \] (33)

where \[ L_e \] set of electricity transmission lines
\[ N_e \] set of supply points
\[ N_d \] set of demand points
\[ s_{i,t} \] power supply at location \( i \) and time \( t \)
\[ d_{j,t} \] power demand at location \( j \) and time \( t \)
\[ P_{l,t}^{\text{cap}} \] maximum capacity of line \( l \) (MW)
\[ h_{l,i,t} \] power flow of line \( l \) and time \( t \) (MW)

\[ h_{l,j,t} \] Sensitivity coefficient of flow on line \( l \) with respect to power injection of supply point \( i \) (based on DC load flow model)

\[ h_{l,j,t} \] Sensitivity coefficient of flow on line \( l \) with respect to power demand at location \( j \) (based on DC load flow model)

The generation technologies characteristics including, physical limitations (34), state of the unit (On/Off) (35), reserve provision (36), minimum up/down time (37) and (38) [36], ramp up/down limits (39), start-up cost (40) and shut-down cost (41), spinning reserve, and power flow balance at each time step (43) is considered in the modeling of the power system.

\[ P_{l,t} + r_{l,t} \leq \gamma_{l,t} \cdot P_{l,t}^{\text{min}} \] (34)

\[ P_{l,t} \leq \gamma_{l,t} \cdot P_{l,t}^{\text{max}} \] (35)

\[ P_{l,t} + r_{l,t} \leq \gamma_{l,t} \cdot P_{l,t}^{\text{min}} \] (36)

\[ \gamma_{l,t} = \gamma_{l,t-1} ; \quad \left| t - \left\lfloor t_{l,j} \right\rfloor \right| \leq 1 \] (37)

\[ \gamma_{l,t-1} = \gamma_{l,t-1} \leq \gamma_{l,t-1} ; \quad \left| t - \left\lfloor t_{l,j} \right\rfloor \right| \leq 1 \] (38)

\[ [P_{l,t} - P_{l,t-1}] \leq \Psi_i \] (39)

\[ w_{l,t}^{\text{cap}} = \text{max}(\gamma_{l,t-1}, 0) \] (40)

\[ w_{l,t}^{\text{cap}} = \text{max}(\gamma_{l,t-1}, 0) \] (41)

\[ \sum_{i \in B} \sum_{p \in P_{l,t}} w_{l,t}^{\text{cap}} \geq \text{max} \left( \sum_{i \in K} w_{l,t}^{\text{cap}} \right) + \omega \sum_{i \in K} w_{l,t}^{\text{cap}} + \omega \sum_{i \in K} w_{l,t}^{\text{cap}} \] (42)

\[ \sum_{i \in B} \sum_{p \in P_{l,t}} w_{l,t}^{\text{cap}} \geq \text{max} \left( \sum_{i \in K} w_{l,t}^{\text{cap}} \right) + \omega \sum_{i \in K} w_{l,t}^{\text{cap}} \] (43)

3 Operational Strategies for Natural Gas and Power Systems

The model has perfect foresight on gas and electricity demand as well as available wind power within the same say. Each optimisation is conducted for a time horizon of 32 hours, but the results
for the first 24 hours are only used. This is to avoid the ‘end-of-optimization’ effect and model operation of energy storages and unit commitment of the thermal generators more realistically. After solving the optimization problem for each iteration (i.e., 32-hours), state of the system, e.g. linepack, storage, On/Off state of thermal generating units for first 24-hours of the iteration is stored. Afterwards, the latter data is used in time-dependent constraints when running the model for the next 32-hours. At each iteration, the first 24-hours are taken as the solutions.

Two operation strategies are presented. The first strategy is a decoupled approach with an iterative process, in which operation of the power system is modeled irrespective to the natural gas system. Then, using the results from the optimization of the power system, operation of the natural gas system is optimized. The second strategy is an integrated approach, which takes into account every constraint of the natural gas and power systems, simultaneously.

### 3.1 Decoupled Modeling

In the Decoupled mode, operation of power system (including UC/economic dispatch and power flow) is optimized, hence gas demand for power generation is calculated. This method has been used in different manners in the literature such as in [34] and [37].

In this approach, gas demand for power generation is provided as an input to the natural gas system operation model. In this modeling, operational costs of the power system is minimized, followed by minimization of the operational costs of the natural gas system. In the power system operational model, costs of power generation, electrical load shedding, and Greenhouse Gas (GHG) emission penalties are taken into account in the objective function (44). For the natural gas system, costs of gas supplies, storage facilities, changes of the linepack, and gas load shedding are considered (45).

\[
X_{\text{dec}} = \sum_{t=1}^{T} \sum_{g \in G} \left( C_{\text{cost}} \cdot w_{g,t} + C_{\text{inst}} \cdot \left( R_{\text{gas}} \cdot s \cdot t + \sum_{i \in K} C_{\text{var}} \cdot e_{i,t} \right) \right)
\]

\[= \sum_{t=1}^{T} \sum_{g \in G} \left( C_{\text{cost}} \cdot w_{g,t} + C_{\text{inst}} \cdot \left( R_{\text{gas}} \cdot s \cdot t + \sum_{i \in K} C_{\text{var}} \cdot e_{i,t} \right) \right)
\]

The delivered gas for power generation as well as the power consumption of electrically-driven compressors are inputs of the operational model of the power system. If the total required gas for power generation cannot be delivered, re-dispatch of power is necessary to complement lack of power generated by the gas plants. For this purpose, in the next iteration, a constraint is imposed to limit the maximum power generation from gas plants. This procedure is carried out to avoid infeasibility in the operation of the gas system.

The algorithm of the Decoupled modeling is demonstrated in Fig. 3. The green (dashed) lines indicate links of the natural gas and power systems. The Decoupled approach does not consider gas-supply constraints simultaneously when optimizing the operation of the power system. Hence, a key disadvantage of this model is that potential interruptions of gas supply does not affect dispatch of gas-fired plants for the power system in initial decision-making stage. Therefore, after providing status of the delivered gas for power generation to the power system, it may be required to use more expensive options (e.g., interconnectors) or generating electricity from plants characterized with high emissions (e.g., coal plants), to keep energy balance in the power system.

### 3.2 Coupled Modeling

In Coupled mode, the natural gas and power systems constraints are considered simultaneously (Figure 4). The Coupled model minimizes total operational cost of the natural gas and power systems (46).

\[
X_{\text{cop}} = X_{\text{dec}} + X_{\text{gas}}, \quad \text{(46)}
\]

where \(X_{\text{cop}}\) is the cost of coupled operation of natural gas and power systems.

The corresponding optimization problem of Coupled model is solved through the proposed OA/ER decomposition method. The main reason for using the decomposition method is to improve the computational performance of the optimization (compared to successive linear programming solver for MINLP problems in Xpress-IVE [38]). Moreover, the rolling approach has been implemented to reduce size of the optimization problem at each step. Based on output of the steady state optimization for the time period, initial values are given to all decision variables. In addition, the decision variables are scaled, therefore order of magnitude values do not vary significantly. The latter procedures are used to achieve convergence and stability in the optimization process.

In general, a in a Decoupled approach model, since in an iterative process the systems are optimized, if the systems are linked properly, the results of this method should be very close to optimizing the systems fully coupled. However, to obtain this accuracy, many iterations should be carried out, which makes the model computationally expensive. In this research, based on the criteria (gas load curtailment), the number of iterations can be up to two iterations. This means if gas load curtailment is not happened, after one iteration the optimization will terminate, although the results are not necessary close to the Coupled model.
In this research, a solution algorithm is developed based on the OA/ER approach [14] considering penalties for solving the MINLP problem of the operation of coupled natural gas and power systems. The OA/ER handles with non-linear inequalities, and similar to GBD creates sequences of upper and lower bounds. As a difference between these methods, the GBD method uses dual information, while OA/ER is based on primal information. Compared to the GBD method, the advantage of OA/ER is that in problems with large number of binary variables, less iterations is required to reach the convergence. However, due to the number of constraints added per iteration in the master problem, computational time for solving the MINLP problem in OA/ER is more than that of GBD [39].

### 4 Solution Algorithm for Coupled Operation of Natural Gas and Power System

In this research, a solution algorithm is developed based on the OA/ER approach [14] considering penalties for solving the MINLP problem of the operation of coupled natural gas and power systems. The OA/ER handles with non-linear inequalities, and similar to GBD creates sequences of upper and lower bounds. As a difference between these methods, the GBD method uses dual information, while OA/ER is based on primal information. Compared to the GBD method, the advantage of OA/ER is that in problems with large number of binary variables, less iterations is required to reach the convergence. However, due to the number of constraints added per iteration in the master problem, computational time for solving the MINLP problem in OA/ER is more than that of GBD [39].

#### 4.1 Basic theory

In OA/ER, to solve the MINLP problem, for every iteration, an upper bound and a lower bound of the objective value is generated. In Fig. 5, the structure of the OA/ER method is shown. Upper bound is obtained from the primal problem, while lower bound is obtained from the master problem. In the primal problem, binary variables are fixed. The Lagrangian multipliers associated with the non-linear equality constraints and the upper bound are supplied from the primal to solve the master problem. In the master problem, the non-linear equalities are relaxed into linear inequalities using the Lagrangian multipliers provided from the primal problem. Solution of the master problem provides information for the lower bound, and the fixed binary variables carried out in next iteration of the primal problem. As the iterations proceed, it is shown that upper bounds and lower bounds sequences converge in a finite number of iterations.

![Fig. 5: Structure of the OA/ER decomposition method.](image)

For better understanding, an example of a geometrical interpretation of the master problem in OA with a convex objective function and the convex feasible region is presented in Fig. 6. As it is presented, the convex objective function is being underestimated, and through these linearizations, the convex feasible region is overestimated (Further details can be found in [14] and [39]).

![Fig. 6: Geometrical interpretation of linearization in master problem.](image)

#### 4.2 Objective function

The objective function for the problem is the operation cost of coupled natural gas and power systems (46), which can be formulated as (47), where:

- \( \mathbf{P} \) set of \( P_{l,t} \) at time \( t \), \( l \in \mathcal{G} \)
- \( \mathbf{P}^{\text{inflex}} \) is set of \( P_{l,t}^{\text{inflex}} \) at time \( t \), \( b \in \mathcal{B} \)
- \( \mathbf{e} \) set of \( e_{i,t} \) at time \( t \), \( i \in \mathcal{I} \)
- \( \mathbf{Q}^{\text{supp}} \) set of \( Q_{y,t}^{\text{supp}} \) at time \( t \), \( y \in \mathcal{Y} \)
- \( \mathbf{Q}^{\text{inj}} \) set of \( Q_{y,t}^{\text{inj}} \) at time \( t \), \( s \in \mathcal{S}_p \)
4.3 Primal problem

As mentioned previously, in the primal problem, binary variables are fixed. Therefore, binary variables of \( w_{i,t}^{\text{comp}} \) and \( w_{i,t}^{\text{linepack}} \) functions in (47) are fixed, converting the problem to Non-Linear Programming (NLP) solving. \( X_{\text{primal}}(\rho) \) is the objective function of the primal problem at iteration \( \rho \). The \( \langle \cdot \rangle_{\text{primal}} \) in the equations represents a provided fixed value of the variables (i.e., initial value or output of one iteration of OA/ER).

\[
X_{\text{primal}}(\rho) = X_{\text{cont}} + \sum_{t=1}^{T} \left( \sum_{i \in K} (w_{i,t}^{\text{comp}}(\rho) + w_{i,t}^{\text{linepack}}(\rho)) \right).
\] (49)

For the first iteration, initial values based on the Decoupled approach, is fed as an input to the primal problem (\( \langle w_{i,t}^{\text{comp}} \rangle \) and \( \langle w_{i,t}^{\text{linepack}} \rangle \)). For next iteration of the primal problem, information on binary variables is provided subsequently by the master problem.

4.3.1 Feasible Primal Problem: If at iteration \( \rho \), the primal problem is feasible, then the solution of continuous variables in the natural gas and power systems as well as Lagrangian multipliers associated with non-linear equalities would be provided for the master problem.

4.3.2 Infeasible Primal Problem: If at iteration \( \rho \), the primal problem is infeasible, a penalty function associated to the binary variables is added to the objective function (50). A feasible solution exists when the penalty function is zero.

\[
X_{\text{primal}} = X_{\text{primal}} + \kappa \cdot \alpha \cdot \tau.
\] (50)

Information on continuous variables in the power system \( f \left( P_{\text{flow}}(\rho), P_{\text{linepack}}(\rho), e_{\text{sup}}, \lambda_{\text{cont}}(\rho), \mu_{\text{tid}}(\rho) \right) \) and in the natural gas system \( g \left( \Phi_{\text{flow}}(\rho), \Phi_{\text{linepack}}(\rho), \Phi_{\text{sup}}, \Phi_{\text{comp}}(\rho), \Phi_{\text{tid}}(\rho) \right) \) as well as the Lagrangian multipliers associated with natural gas system non-linear equations \( X_{\text{flow}}(\rho), X_{\text{comp}}(\rho), \), and \( X_{\text{tid}}(\rho) \) are found from solving of primal problem. Subsequently, the elements of \( \Phi_{\text{flow}}(\rho), \Phi_{\text{linepack}}(\rho), \Phi_{\text{sup}}, \Phi_{\text{comp}}(\rho), \Phi_{\text{tid}}(\rho) \) are calculated as follows (51)-(53). These elements are inputs to the master problem for converting the non-linear equalities to linear inequalities.

\[\Phi_{\text{flow}}(\rho) = \begin{cases} 1 & \text{if} \ X_{\text{flow}}(\rho) < 0 \\ +1 & \text{if} \ X_{\text{flow}}(\rho) > 0 \\ 0 & \text{if} \ X_{\text{flow}}(\rho) = 0 \end{cases} \] (51)

\[\Phi_{\text{linepack}}(\rho) = \begin{cases} 1 & \text{if} \ X_{\text{linepack}}(\rho) < 0 \\ +1 & \text{if} \ X_{\text{linepack}}(\rho) > 0 \\ 0 & \text{if} \ X_{\text{linepack}}(\rho) = 0 \end{cases} \] (52)

\[\Phi_{\text{sup}}(\rho) = \begin{cases} 1 & \text{if} \ X_{\text{sup}}(\rho) < 0 \\ +1 & \text{if} \ X_{\text{sup}}(\rho) > 0 \\ 0 & \text{if} \ X_{\text{sup}}(\rho) = 0 \end{cases} \] (53)

4.4 Master problem

The master problem is expressed by equations (54)-(60) (Equations (55)-(58) are presented at the top of the next page). The objective function of the problem is to minimize \( X_{\text{master}}(\rho) \). Variable \( \xi \) is constrained through the linearized objective function of the primal at solution points of continuous variables in the power system \( f \left( P_{\text{flow}}(\rho), P_{\text{linepack}}(\rho), e_{\text{sup}}, \lambda_{\text{cont}}(\rho), \mu_{\text{tid}}(\rho) \right) \) and in the natural gas system \( g \left( \Phi_{\text{flow}}(\rho), \Phi_{\text{linepack}}(\rho), \Phi_{\text{sup}}, \Phi_{\text{comp}}(\rho), \Phi_{\text{tid}}(\rho) \right) \) (55).

\[X_{\text{master}} = \sum_{t=1}^{T} \left( \sum_{i \in K} (w_{i,t}^{\text{comp}} + w_{i,t}^{\text{linepack}}) \right) + \xi.
\] (54)

The non-linear equalities of gas flow equation (19), compressor power consumption (20), and hourly linepack (27) are relaxed to inequalities of (56), (57), and (58), respectively, where: As the master problem is a MILP problem, it can be solved using standard BB algorithms. The integer cuts are in the form of (59). These integer cuts eliminate the already found binary variables. Therefore, in this method all 0-1 combinations of the problem are taken into account.

\[
\forall \rho \in F, i \in K, t \in T : \sum_{i \in K} \gamma_{i,t}(\rho) - \sum_{i \in K} \gamma_{i,t}(\rho) \leq |R(\rho)| - 1,
\] (59)

where \( |R(\rho)| \) is the cardinality of \( R(\rho) \) and:

\[
R(\rho) = \{ \sigma : \gamma_{i,t}(\rho) = 1 \}.
\]

\[
NR(\rho) = \{ \sigma : \gamma_{i,t}(\rho) = 0 \}.
\]

In each iteration, the objective function of the master problem must be within the current objective function of the primal and previous objective value of the master to proceed to convergence (60). The optimization is terminated when the criterion (61) is satisfied or the master problem is infeasible. Parameter \( \epsilon \) is the convergence bound of the OA/ER approach.

\[
\forall \rho \in F, X_{\text{master}}(\rho) - X_{\text{master}}(\rho) \leq X_{\text{primal}} - X_{\text{primal}} \leq \epsilon.
\] (60)
∀ρ ∈ F : \[ ξ ≥ \sum_{t=1}^{T} \left( \sum_{i} f(P_{i}^{\text{base}}(\rho), P_{i}^{\text{shed}}(\rho), e_{i}(\rho), ur_{i}(\rho)) + g^{*}(Q_{i}^{\text{sup}}(\rho), Q_{i}^{\text{shed-inj}}(\rho), Q_{i}^{\text{wrd}}(\rho), CL_{i}(\rho), Q_{i}^{\text{inj}}(\rho) \right) \]

\[ + \left[ \nabla f^{*}(P_{i}^{\text{base}}(\rho), P_{i}^{\text{shed}}(\rho), e_{i}(\rho), ur_{i}(\rho)) \right]^T \left[ P_{i} - P_{i}^{\text{base}}(\rho), P_{i}^{\text{shed}}(\rho), e_{i}(\rho), ur_{i}(\rho) \right] \]

\[ + \left[ \nabla g^{*}(Q_{i}^{\text{sup}}(\rho), Q_{i}^{\text{shed-inj}}(\rho), Q_{i}^{\text{wrd}}(\rho), CL_{i}(\rho), Q_{i}^{\text{inj}}(\rho)) \right]^T \left[ Q_{i}^{\text{sup}}(\rho) - Q_{i}^{\text{sup}}(\rho), Q_{i}^{\text{shed-inj}}(\rho) - Q_{i}^{\text{shed-inj}}(\rho), Q_{i}^{\text{wrd}}(\rho) - Q_{i}^{\text{wrd}}(\rho), CL_{i}(\rho) - CL_{i}(\rho), Q_{i}^{\text{inj}}(\rho) - Q_{i}^{\text{inj}}(\rho) \right] \leq 0 \]

∀ρ ∈ F, l ∈ L_{\rho}, t ∈ T : \[ h_{l,t}^{\text{flow}} + h_{l,t}^{\text{comp}}(Q_{l,t}^{\text{comp}}(\rho), Q_{l,t}^{\text{inj}}(\rho), Q_{l,t}^{\text{out}}(\rho)) + h_{l,t}^{\text{stack}}(Q_{l,t}^{\text{stack}}(\rho), Q_{l,t}^{\text{inj}}(\rho), Q_{l,t}^{\text{out}}(\rho)) + h_{l,t}^{\text{linpack}}(Q_{l,t}^{\text{linpack}}(\rho), Q_{l,t}^{\text{inj}}(\rho), Q_{l,t}^{\text{out}}(\rho)) \leq 0 \]

4.5 Algorithmic development

The procedure of OA/ER can be described as follows:

- **Step 1:** Setting initial points for \( w_{\text{in}}^{(1)} \) and \( w_{\text{in}}^{(1)} \)
- **Step 2:** Solving the primal problem (NLP) and taking the information of \( g^{\text{comp}}(\rho), Q_{l,t}^{\text{wrd}}(\rho), CL_{i}(\rho), Q_{l,t}^{\text{inj}}(\rho), f(P_{i}^{\text{base}}(\rho), P_{i}^{\text{shed}}(\rho), e_{i}(\rho), ur_{i}(\rho)) \), \( h_{l,t}^{\text{flow}}(\rho), h_{l,t}^{\text{comp}}(\rho), h_{l,t}^{\text{stack}}(\rho), h_{l,t}^{\text{linpack}}(\rho) \).
- **Step 3:** Calculating \( h_{l,t}^{\text{flow}}(\rho), h_{l,t}^{\text{comp}}(\rho), h_{l,t}^{\text{stack}}(\rho) \), and \( h_{l,t}^{\text{linpack}}(\rho) \).
- **Step 4:** Calculating the required terms for equations (55)-(58).
- **Step 5:** Solving the relaxed master problem (MILP). If the master problem is feasible then take the information of \( w_{\text{in}}^{(2)}(\rho) \) and \( w_{\text{in}}^{(2)}(\rho) \) for the next iteration of primal.
- **Step 6:** If equation (60) is satisfied or the master problem is infeasible then terminate. Otherwise, return to step 1.

5 Case Studies

The operation of a GB natural gas and power systems is modeled for a winter week considering high electricity demand and variabilities in wind generation in 2030. The interaction between natural gas and power systems is quantified through using a coupled and decoupled operation strategies for these systems. Afterwards, the role of natural gas system related flexibilities in the interaction between natural gas and power systems is evaluated. In this study, options of (a) more flexible gas-fired plants [30]; (b) multi-directional compressors [34], where the one-directional compressors are replaced with multi-directional ones, and (c) increasing the gas imports to the gas system are taken into account.

5.1 GB natural gas and power systems

The demand and available wind for a winter week is presented in Fig. 7. The historical hourly electricity demand is obtained from National Grid and scaled up to represent 2030. Due to projection of electrification of heat and transport sectors [40], the peak demand is assumed.
to be 85 GW. Real Hourly wind generation data observed in GB during 15/04/2013–22/04/2013 [41] is scaled up to represent the wind generation in 2030 [30].

In this study, a period of sudden drop in wind and increase in electricity demand is considered as well to evaluate how the system deals with a dramatic increase in net demand (98-118 hours). Additionally, partial unavailability of gas terminals throughout the week due to maintenance is assumed in this study. The model is implemented on a natural gas system and 29-busbar power transmission system presented in [34]. The power generation mix is derived from [40]. In Fig. 8, it is shown that around 50% of the power is provided by the renewable technologies.

5.2 Description of case studies

To investigate the role of the mentioned flexibility options in interaction of natural gas and power systems, following case studies are considered:

- **Base**: In the base case no significant means of flexibility are introduced to the system.
- **Flexible Gas-fired Plants (FlexGP)**: It is assumed that 30% of gas-fired generation capacity is operationally more flexible [30].
- **Flexible Compressors (Multi)**: Compressors are able to boost the pressure in multiple directions [34].
- **Gas imports (Int-5% and Int-10%)**: Increasing the gas supply through importing 5% and 10% more gas from outside GB.
- **All flexible (Flex-5% and Flex-10%)**: In these cases, all above-mentioned flexibility options with 5% and 10% increased gas imports is considered.

These cases are derived to see how different flexibility options related to the natural gas system, including flexibilities provided to the natural gas system infrastructure and more flexible gas-fired plants can smooth the interaction between natural gas and power systems.

6 Key Findings of the Proposed Models

6.1 Computational performance

The corresponding optimization problem of operation of natural gas for the entire week contains around 260k variables including 20k integer variables. Due to the rolling approach, the model is broken down into seven smaller optimization problems. As mentioned previously, 32 hours are optimized in each of these optimization problems. Therefore, at each step around 50k variables including 4k integer variables are optimized.

Fig. 7: (a) available wind and electricity demand, (b) gas demand

From modeling perspectives, in both Coupled and Decoupled models, MILP and NLP problems are optimized. However, since in the Decoupled model, the natural gas and power systems are optimized separately, the number of variables in each problem is less than the Coupled model and hence the convergence should be faster. For example, in the base case, the computation time of the first iteration is 88.9 minutes. However, according to Fig. 3, in case of gas load shedding the model should be run for the next iteration. Hence, overall the computation time of the Decoupled model is more than the Coupled model. The computational performance of the Coupled and Decoupled models in different case studies for the entire week is provided in Table 1. As presented, the Coupled model (Two iterations) is performing from 86% to 101% faster than the Decoupled (up to two iterations) model through different case studies.

Table 1: Approximated computational performance in minutes

| Modeling  | Base Multi Int | Int-5% FlexGP Flex-5% Flex-10% Flex-15% |
|-----------|----------------|-----------------------------------------|
| Coupled   | 130 114 117    | 90 101 98 115                           |
| Decoupled | 245 232 261    | 235 240 238 254                         |

To demonstrate the value of the flexibility options in the interaction of natural gas and power system, the presence of these options in Coupled and Decoupled modeling of operation of natural gas and power systems are quantified. In this section key numerical results are presented.

6.2 Power system analysis

In Fig. 9-a, gas plants generation scheduling in the Base case for both operation strategies is presented. It is shown that especially in 98-118 hours, in the Coupled approach, more power is produced by the gas plants. The reason is that since in this model, all the security of supply constraints are considered simultaneously, the gas plants are scheduled so that to compensate for the lack of wind more appropriately. On the other hand, in the Decoupled approach, due to the partial unavailability of gas supply terminals along with the fact that the gas transmission in the grid is relatively slow, the gas could not be delivered to some of the gas plants. Consequently, as shown in Fig. 9-b, to keep the supply-demand balance, more electricity is imported (i.e., more expensive option).

If the systems become more flexible, this leads to better operation in the Decoupled mode. As it can be illustrated from Fig. 10, if there is enough flexibility in the systems, including flexible gas plants, multi-directional compressors, and more flexible gas interconnectors, the gas plants scheduling in both operational strategies are relatively close to each other. This is due to the fact that, in the natural gas system, the gas transportation system is improved, and therefore the gas could be delivered to the gas plants as required. In the power system, thanks to the provided flexibility in the gas plants, the flexibility of the natural gas system is reflected to the power system, and as result re-dispatching of these plants in the Decoupled mode is done properly.
the linepack will deal with dynamics of the system. In case of increase in electricity and gas demand, the linepack will help to deliver the gas to the gas plants for electricity generation as well as non-electric gas demands. Furthermore, in case of demand decrease, more gas is stored in the pipelines to deal with the next rapid change in the system.

In Table 3, it is presented that if the flexibility of the energy system is increased, more linepack is available throughout the day. This enables the gas system operator to deal more properly with the rapid changes in the system. However, it is demonstrated that in the Coupled model, since the whole-system constraints are taken into account, the flexibility provided by the gas system is more used compared to the same case in Decoupled model.

To highlight the operation of the natural gas system, the gas supply-demand balance criteria is presented. In Table 4, it is demonstrated that in the Decoupled approach, due to the operational limitations in the gas delivery in the transmission grid, the gas could not be delivered to some of the gas demands. It is shown that if the systems become more flexible, the gas delivery is improved and finally, in the most flexible case that is considered in this study (Flex-10% case), there is no need to shed any gas demands. In Coupled modeling, since all the constraints of the systems are taken into account at the same time, gas demand curtailment is not happened.

6.4 Operational cost of natural gas and power systems

In Fig. 12, the operational cost difference of natural gas and power systems in Decoupled approach in respect to Coupled approach is shown. It can be concluded if there is no flexibility provided in the system, the proposed decomposition method for solving effectively the Coupled strategy results in up to 7% cost saving (Operational cost of the Base case in Coupled mode is £1081m). On the other hand, once the systems become more flexible, the cost differences are becoming smaller. Finally, if there is enough flexibility in natural gas and power systems, the systems are operated in Decoupled model, very close to the Coupled approach.

6.3 Natural gas system analysis

In Fig. 11, the aggregated linepack in the pipelines for the time period where significant changes in electricity net demand and gas demand happens (i.e., 87-106 hours), is presented. It is shown how
In order to solve efficiently the MINLP problem of the coordinated operation of coupled natural gas and power systems, to the best of our knowledge, for the first time an outer approximation with equality relaxation decomposition method was applied to the model. The value of the proposed coupled operational modeling of natural gas and power systems was quantified through comparing with the decoupled modeling. It was shown that if the systems are flexible enough, a decoupled modeling was decreased, since in the decoupled approach the operation of natural gas and power systems was improved.

Finally, if we have all the mentioned options in the systems, the operational cost difference of the RES in order to meet the supply-demand balance will be decreased (i.e., 7% cost saving). This indicates that the coupled modeling could enhance the flexibility of the system and enables control of natural gas and power systems more efficiently to deal with the variabilities of the RES in order to meet the supply-demand balance.

The options of flexible compressors, flexible gas plants, and gas interconnections were employed in the system, to make the natural gas and power systems more flexible. It was demonstrated that by making the systems more flexible, the value of the coupled modeling was decreased, since in the decoupled approach the operation of natural gas and power systems was improved. Finally, if we have all the mentioned options in the systems, the operation of the natural gas and power systems were almost the same as the coupled operation of these systems. As a result, it could be concluded that if the systems are flexible enough, a decoupled modeling of these systems can meet the required constraints.

This becomes important, since for a coupled operation of these systems, reforming the current regulatory and market framework to coordinate the operation of natural gas and power systems is required, which this needs revisions in high-level energy policies in different countries. On the other hand, to have these options in the system, the investment costs should also be taken into account. Therefore capital cost of the flexibility options will play an important role in the future decision-making of the energy systems.

7 Conclusion

In order to solve efficiently the MINLP problem of the coordinated operation of coupled natural gas and power systems, to the best of our knowledge, for the first time an outer approximation with equality relaxation decomposition method was applied to the model. The value of the proposed coupled operational modeling of natural gas and power systems was quantified through comparing with the decoupled modeling of these systems. It was shown that in the coupled approach the systems were operating more cost-effectively (i.e., ~7% cost saving). This indicates that the coupled modeling could enhance the flexibility of the system and enables control of natural gas and power systems more efficiently to deal with the variabilities of the RES in order to meet the supply-demand balance.

Afterwards, the options of flexible compressors, flexible gas plants, and gas interconnections were employed in the system, to make the natural gas and power systems more flexible. It was demonstrated that by making the systems more flexible, the value of the coupled modeling was decreased, since in the decoupled approach the operation of natural gas and power systems was improved. Finally, if we have all the mentioned options in the systems, the operation of the natural gas and power systems were almost the same as the coupled operation of these systems. As a result, it could be concluded that if the systems are flexible enough, a decoupled modeling of these systems can meet the required constraints.

This becomes important, since for a coupled operation of these systems, reforming the current regulatory and market framework to coordinate the operation of natural gas and power systems is required, which this needs revisions in high-level energy policies in different countries. On the other hand, to have these options in the system, the investment costs should also be taken into account. Therefore capital cost of the flexibility options will play an important role in the future decision-making of the energy systems.

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**Fig. 11**: Available linepack in the pipelines in different cases for the Coupled mode

**Fig. 12**: Natural gas and power systems operational cost difference of Decoupled mode in respect to Coupled mode
