Storing renewables in the gas network: Modelling of power-to-gas (P2G) seasonal storage flexibility in low carbon power systems

Stephen Clegg^{1*}, Pierluigi Mancarella¹

¹School of Electrical and Electronic Engineering, Electrical Energy and Power Systems Group, The University of Manchester, Manchester, M13 9PL, UK

*stephen.clegg@postgrad.manchester.ac.uk

Abstract: The power-to-gas (P2G) process, whereby excess renewable electrical energy is used to form hydrogen and/or synthetic natural gas that are injected, transported and stored in the gas network, has the prospect to become an important flexibility option for the seasonal storage of low-carbon electricity. This paper is the first to model and assess the potential of P2G when combined with gas seasonal storage operation accounting for the two networks' characteristics and constraints (including the amount of hydrogen that can be blended with natural gas under different gas network conditions). Power system operation with P2G is analysed via a two-stage optimisation based on DC power flow in order to assess the gas production from otherwise curtailed renewables, also considering impact of P2G on short-term and long-term gas prices. Additionally, impact of P2G on gas network operation and its potentially required re-dispatch are evaluated with a steady-state gas flow model. Case studies conducted on the Great Britain gas and electrical transmission networks quantify benefits and limitations of the integrated usage of P2G with seasonal gas storage under different scenarios. The proposed model thus sets the fundamentals for further development of this emerging technology as a seasonal storage option in low-carbon power systems.

1. Introduction

Many countries have energy demand profiles that exhibit high seasonal variations. For example, in the UK, where the heating sector is a prominent consumer of energy, heating requirements lead to much greater energy consumption in winter compared to summer months [1]. In accommodating these variations in demand, seasonal storage has the opportunity to reduce operating costs and, indeed, many energy systems have existing seasonal energy storage in the form of long-term gas storage installations which are used in this manner. With increasing interactions between different energy sectors, there is the possibility of additional benefits when utilising alternative forms of energy storage in an integrated manner within the context of multi-energy system analysis [2]. In this respect, the development of power-to-gas (P2G) technologies creates potential interactions between the electrical and gas sectors which could lead to new options for seasonal storage. More specifically, in the P2G process electrical energy is used to form hydrogen or synthetic natural gas (SNG) which can then be injected, transported, stored and used at a later time in the gas network for heating or electrical generation. Therefore, the coupling of P2G with seasonal storage offers the possibility of integrating an additional form of energy storage with seasonal characteristics for low-carbon energy from renewable generation, thus helping reduce further the carbon impact of both electricity and heating sector.

A few previous studies have considered the possible effects and benefits of P2G. For instance, reference [3] shows how P2G can impact the gas, electrical and carbon prices, while the results in [4] show that the impact of P2G on gas seasonal storage utilisation is slight. The economic feasibility of installing P2G units is assessed in [5] and [6], with [5] giving indications as to the optimal size and location for the facilities and with [6] investigating the optimal operational strategy under wind uncertainty. However, none of these consider gas network analysis and the resulting implications and constraints in supporting P2G. Implications of the gas network have been considered in the modelling of [7] where results show short-term system benefits of P2G; however, there is no consideration for seasonal storage, effect on gas prices, and operational restrictions imposed by hydrogen content limits. On the other hand, several other models developed to study the interactions between the gas and electrical networks (e.g., [8] [9] [10]) do not consider P2G.

This paper builds upon the authors' work in [11], where integrated gas and electrical network modelling is used to assess the technical feasibility and benefits of P2G over shorter (daily) timescales. In particular, the work here is the first to model P2G with seasonal storage with an integrated gas and electrical transmission network model. The modelling considers a yearly time frame to assess the seasonal variations in generation, demand, storage levels, and gas prices. The evaluation of electrical power supplying the P2G facilities and gas consumption at electrical generators is determined by a two-stage iterative integrated DC power flow and power-to-gas operational optimisation which accounts for the electrical network constraints and changes in power flows due to the introduction of P2G facilities. Each iteration is conducted with half-hourly snapshots over a year to capture variations in the wind and solar generation, which are modelled with the use of historical regional meteorological data. The results from the two-stage optimisation are used in assessing the gas network operation including seasonal storage injection/withdrawal, the effects on short-term (daily) and long-term (seasonal) gas prices, and potential constraints arising in the gas network operation. Implications on the gas network flows are modelled using a steady-state gas flow which determines the seasonal changes in flow direction. This also accounts for the changes in gas characteristics due to the P2G process and their effect on gas demands, pressure drops and the operational characteristics of storage facilities including their capacity and input/output flow rates. In terms of numerical studies, quantifications of the level of energy content of the hydrogen that may be safely blended with natural gas (NG) for alternative levels of gas demand are presented. The benefit of P2G and the effects on the level of utilisation of the seasonal storage are also quantified. Finally, the ability of the Great Britain (GB) gas network to accommodate P2G with seasonal storage under different scenarios is discussed.

The paper is organised as follows. Section 2 describes the P2G process, its modelling (including the power system simulation based on the iterative two-stage optimisation), and its implementation with seasonal storage. Section 3 describes the gas network modelling. These methods are applied in Section 4 in case studies based on GB gas and electrical transmission network models with consideration of the existing seasonal storage infrastructure. Section 5 gives conclusions.

2. Power-to-gas modelling

2.1. The power-to-gas overall process

Power-to-gas is the process of using electrical energy to form hydrogen or SNG which can then be stored, transported and used at a later date. The process of electrolysis, described by $2\text{H}_2\text{O} \longrightarrow 2\text{H}_2 + \text{O}_2$, converts electrical power into hydrogen. Because of limits to the quantity of hydrogen which may be introduced into the gas network, and transported to the storage locations, further SNG production facilities may be considered for a large-scale P2G gas injection program. The SNG production process (methanation) is achieved by the combining of hydrogen with carbon dioxide: $2\text{CO}_2 + 4\text{H}_2 \longrightarrow \text{CH}_4 + 2\text{H}_2\text{O}$. In the modelling, each of the processes (hydrogen production and methanation) is considered as distinct with an associated efficiency [12].

2.2. Overall modelling

The modelling is based on an iterative procedure which assesses half-hourly gas generation, power-to-gas utilisation, and daily gas storage and gas network operation, and then updates the daily gas prices and gas and electrical network constraints for each day.

Each iteration takes as input gas prices for each day of the year. A two-stage optimisation is used to determine the generation levels of the gas turbines and the level of power supplied to the P2G facilities at a given time. The resulting energy for the P2G process is then transformed into gas which is introduced into the NG network. The storage injection/withdrawal rate is assessed with consideration of the gas price on this day. A steady-state gas flow analysis is conducted to assess the gas network's ability to fulfil the operational requirements of a given day. If necessary, alternative gas network operation is attempted to find a successful daily operation for a given demand. If constraints remain, then limitations are imposed on the gas generators. The resulting gas demand including storage injection, net the gas which is displaced by gas produced via the power-to-gas process, is then used to determine the gas price for the consequent

iteration. The procedure is rerun with updated gas prices and constraints on the power-to-gas operation imposed by the gas network's storage capacity. The overall methodology is outlined in Fig. 1.

Fig. 1. Overall integrated electricity and gas network modelling methodology with evaluation of gas prices, gas network re-dispatch and constraint circumvention.

2.3. The two-stage optimisation

The two-stage optimisation process begins with a DC Optimal Power Flow (OPF) that assesses the levels of gas demand for generation and the level of renewable generation curtailed. Each non-gas conventional generating unit CG_i is modelled with a fixed marginal cost c_{CG_i} while each gas generating unit GG_j has marginal cost equal to $c_{gas}(d)/\eta_{GG_j}$ where η_{GG_j} is the generator's efficiency and $c_{gas}(d)$ the price of NG on day d . Must-run generating units are modelled with zero cost. Each variable renewable generating unit RG_k is also modelled with a marginal cost c_{RG_k} equal to zero. The OPF aims to minimise the cost of generation; thereby, if at time t the real power output of the non-gas and gas conventional generators is $P_{CG_i}(t)$ and $P_{GG_j}(t)$, respectively, and the real power output of the renewable generators is $P_{RG_k}(t)$, then the objective function g_1 of the first-stage optimisation is given by

$$g_1(\mathbf{P}) = \sum_{CG_i} c_{CG_i} \cdot P_{CG_i}(t) + \sum_{GG_j} c_{GG_j}(d) \cdot P_{GG_j}(t) + \sum_{RG_k} c_{RG_k} \cdot P_{RG_k}(t) \quad (1)$$

where $\mathbf{P}$ is the vector of real power outputs indexed by the generators and the cost of the gas generators at time t is defined by the gas price on the corresponding day d . The generating capability $\overline{P_{RG_k}(t)}$ of the renewable units at t is modelled with consideration of the prevailing meteorological conditions, while $P_{RG_k}(t)$ indicates actual production after curtailment in the OPF. The formulation has the electrical network modelled by the DC power flow approximation and accounts for line constraints and system reserve requirements. This reserve, which at any particular time accounts for the largest conventional generation loss and uncertainty in wind and load predictions, is fulfilled by conventional generating units considering their 30 minute ramp rates and minimal stable generation (MSG) levels [13].

The results of the OPF yield the real power dispatch P_{GG_j} of each gas generator GG_j . Then, the system gas demand required for power generation is assessed. This is combined with the non-generation gas demand, including that for storage injection and for heating requirements. This, in turn, allows the determination of the supply rate at each gas terminal to meet the demand. The energy content of the hydrogen which may be blended with the gas entering the network depends on the flows (higher terminal throughput allows for a greater amount of hydrogen to be blended). If, at a terminal T_l , there is a hydrogen production facility $P2G_{T_l,H_2}$ of installed capacity $\overline{P_{P2G_{T_l,H_2}}}$, and the gas energy throughput at a given time is $E_{T_l}(t)$, then the power to the hydrogen producing facility will be modelled by

$$\overline{P_{P2G_{T_l,H_2}}}(t) = \min(\overline{P_{P2G_{T_l,H_2}}}, \bar{L}_{H_2} \cdot E_{T_l}(t)/\eta_{H_2}) \quad (2)$$

where $\bar{L}_{H_2}$ is the limit of hydrogen (in terms of energy) which is permissible in the gas network and η_{H_2} is the efficiency of the hydrogen producing process.

The second stage of the two-stage optimisation has an objective function which aims to maximise the system benefit of P2G. More specifically, the hydrogen producing P2G units $P2G_{T_l,H_2}$ and the SNG producing facilities $P2G_z$ are modelled with costs of $c_{P2G_{T_l,H_2}}(d) = -c_{gas}(d)/\eta_{H_2}$ and $c_{P2G_z}(d) = -c_{gas}(d)/\eta_{SNG}$ where η_{SNG} is the SNG production process efficiency. The second stage optimisation has objective function g_2 described by

$$g_2(\mathbf{P}_{P2G}) = \sum_{P2G_{T_l,H_2}} c_{P2G_{T_l,H_2}}(d) \cdot P_{P2G_{T_l,H_2}}(t) + \sum_{P2G_z} c_{P2G_z}(d) \cdot P_{P2G_z}(t) \quad (3)$$

where $\mathbf{P}_{P2G}$ is the vector of powers to the P2G facilities and, again, the costs at t are defined by the corresponding day d . The greater efficiency of the hydrogen process will prioritise hydrogen production

over that of SNG. Each conventional generator has its generation fixed at the dispatch levels given by the results of the first-stage OPF. If the renewable generator RG_k has, at t , the generation capability $\overline{P_{RG_k}}(t)$ and the results of the first-stage OPF indicate that $P_{RG_k}(t)$ is the actual production, then the remaining (otherwise curtailed) power which may be used for the P2G process is limited by $\overline{\Delta P_{RG_k}}(t) = \overline{P_{RG_k}}(t) - P_{RG_k}(t)$, so that

$$0 \leq P_{RG_k^1}(t) \leq \overline{\Delta P_{RG_k}}(t) \quad (4)$$

where $P_{RG_k^1}(t)$ is the power from the generator RG_k which is used in the P2G process. The hydrogen and SNG producing facilities are modelled by the constraints

$$0 \leq P_{P2GT_{l,H2}}(t) \leq \overline{P_{P2GT_{l,H2}}}(t) \quad (5)$$

$$0 \leq P_{P2G_z}(t) \leq \overline{P_{P2G_z}} \quad (6)$$

where $P_{P2G_z}(t)$ is the power at t to the SNG facilities $P2G_z$, with rating $\overline{P_{P2G_z}}$ and $P_{P2GT_{l,H2}}(t)$ is the power to the hydrogen production facility $P2GT_{l,H2}$. This optimisation continues to include bounds due to the power system's line constraints accounting for changes in the power flows due to the inclusion of the P2G facilities.

The gas network analysis is conducted for 24 hour snapshots. It is assumed that all the power to the P2G facilities is used in the production of gas. Hence, if at gas node n there is a hydrogen producing facility $P2GT_{l,H2}$ and/or SNG producing facility $P2G_z$, the energy content of the gas introduced into the gas network at node n from the P2G process for the day d is given by

$$E_{P2G,n} = \sum_t [\eta_{H2} \cdot P_{P2GT_{l,H2}}(t) + \eta_{SNG} \cdot P_{P2G_z}(t)] \quad (7)$$

where the summation is over the time periods (48 in the analysis conducted here) within a day.

2.4. Determination of gas storage operation

A seasonal storage facility S with capacity $\bar{S}$ is considered. Based on actual operation of existing long-term gas storage facilities, the operation of S is such that, throughout a day, it operates to either inject or withdraw gas. Moreover, the injection/withdrawal rate is limited by the volume of gas in the facility at that time. I.e., if on a given day d the energy content of the gas in storage is S_d , then the limits to the injection (resp. withdrawal) rates (in m^3/day) are described by $\bar{I}_S(d) = j_I(S_d/HHV_{net})$ (resp. $\bar{W}_S(d) = j_W(S_d/HHV_{net})$) where HHV_{net} is the higher heating value (HHV) of the network's gas and j_I (resp. j_W) are functions which are based on the operational characteristics of the facility including its size and

operating pressure. In the case studies of Section 4, j_I and j_W are based on characteristics of existing storage installations. In terms of the storage facility operation, during the season of reduced gas demand, cheaper gas is injected; while at times of higher marginal cost, gas is withdrawn to contribute to meeting the gas demand. The injection or withdrawal rates are modelled with consideration of the difference between the gas price on a given day and the predicted gas price for the consequent summer, following [14]. More specifically, if $c_{gas,s}$ is the predicted cost of NG for the summer, and then the resulting storage level is modelled by

$$S_{d+1} = S_d + \begin{cases} \min(h(c_{gas}(d) - c_{gas,s}), \bar{S} - S_d, HHV_{net} \cdot \bar{I}_S(d)) & \text{if } h(c_{gas}(d) - c_{gas,s}) \geq 0 \\ \max(h(c_{gas}(d) - c_{gas,s}), -S_d, -HHV_{net} \cdot \bar{W}_S(d)) & \text{if } h(c_{gas}(d) - c_{gas,s}) < 0 \end{cases} \quad (8)$$

where h is a function relating the difference in gas price to the potential injection/withdrawal rate. This function h may be derived from the historical operational characteristics of the storage facility and, in the case studies, is described by a piecewise linear function derived from historical gas price and injection/withdrawal rate data.

2.5. Assessment of the daily gas price

The gas price has been modelled considering the demand level on a given day d . Let us assume that, on a given day, E_D is the expected gas energy demand [GWh/day], $E_S = S_{d+1} - S_d$ is the storage injection/withdrawal [GWh/day], and the total power-to-gas injection is $E_{P2G} = \sum_n E_{P2G,n}$ where, from (7), $E_{P2G,n}$ is the energy content of the power-to-gas injected at each node n and the summation is over all gas network nodes. The gas prices have been modelled by a piecewise linear function π relating the gas demands with the gas price [£/MWh] so that

$$c_{gas}(d) = \pi(E_D + E_S - E_{P2G}) \quad (9)$$

In the case studies of Section 4, π has been modelled by a piecewise linear function based on historical gas price and demand data as well as future gas price predictions.

Upon updating the gas price, the process is repeated recursively (Fig. 1) until the gas price converges to a given tolerance (practically within a 3% tolerance within a few iterations).

3. Gas flow analyses

3.1. Gas flow in a pipeline and impact of hydrogen

A steady-state gas analysis is a commonly employed tool to assess the network flow requirements on a given day, as the planning of the operation of a gas network is often conducted on a day-ahead basis. This analysis is conducted here to assess vulnerabilities in the gas network's ability to accommodate P2G with seasonal storage.

Gas flow in pipelines is due to the pressure difference between the two ends of the pipe. Bernoulli's equation for fluid flow describes how the flow rate is related to the pressure difference [15]. For a single pipe, under the assumption that it is horizontal, the flow between two points a and b with pressures p_a and p_b [Pa] is described by

$$F^2 = \frac{\pi^2}{64 \cdot \rho_n^2 \cdot R_s} \cdot \frac{D^5}{fL\Theta Z} (p_a^2 - p_b^2) \quad (10)$$

where ρ_n is density [kg m^{-3}] of gas at normal temperature and pressure (NTP), R_s is the specific gas constant [$\text{J kg}^{-1} \text{K}^{-1}$], D is the pipe diameter [m], L is the pipe length [m], Θ is the absolute temperature [K], Z is the compressibility factor of the gas in the pipe [dimensionless] and f is the friction factor [dimensionless]. The rate of flow F is measured with respect to volume of gas at NTP [m^3/s].

The friction factor f will be modelled using the Panhandle A approximation [15], described by

$$f = 0.085 \cdot (Re)^{0.147} \quad (11)$$

where Re is the Reynolds number [dimensionless].

Considering the higher heating value (HHV) as the measure of gases' energy content per unit volume, if hydrogen makes up ϕ_{H2} of the energy content of the gas in the network, then the HHV of the gas in the network is

$$HHV_{net} = \left(\frac{\phi_{H2}}{HHV_{H2}} + \frac{1 - \phi_{H2}}{HHV_{NG}} \right)^{-1} \quad (12)$$

where HHV_{H2} (resp. HHV_{NG}) is the HHV of hydrogen (resp. NG). Similarly, the specific gas constant for the gas in the network $R_{s,net}$ is given by

$$R_{s,net} = \left(\frac{\phi_{H2}}{HHV_{H2}} + \frac{1 - \phi_{H2}}{HHV_{NG}} \right) \cdot \left(\frac{\phi_{H2}}{HHV_{H2} \cdot R_{s,H2}} + \frac{(1 - \phi_{H2})}{HHV_{NG} \cdot R_{s,NG}} \right)^{-1} \quad (13)$$

where $R_{s,H2}$ (resp. $R_{s,NG}$) is the specific gas constant of hydrogen (resp. NG). The density $\rho_{n,net}$ of the network's gas at NTP is then given by $\rho_{n,net} = \rho_{n,NG} \cdot R_{s,NG} / R_{s,net}$ where $\rho_{n,NG}$ is the density of NG.

3.2. Gas network modelling

The gas network analysis is used to determine the flows and pressures in the network by using the Newton-node method. In the following, the models discussed in [15] are used.

For a given pipe A with start and end nodes a and b , then the volumetric flow rate F_A between the two ends of the pipe can be described by

$$(F_A)^\alpha = k \frac{(D_A)^\gamma}{L_A} ((p_a)^\beta - (p_b)^\beta) \quad (14)$$

Where p_a and p_b are the pressures at each end of the pipe, α , β and γ are positive numbers which are dependent on the gas flow model, D_A and L_A are the pipe's diameter and length, respectively, while k is a constant dependent on the gas model and which is defined by gas characteristics and the smoothness of the network's pipes.

For a network's demand and supply rates and compressor stations operation, a gas flow study is used to determine the pressure and flow rates for pipes in the network. Let us suppose that there are a number of supply and demand volumetric flows rates associated to each gas node n in the network, a daily terminal/storage facility injection/withdrawal V_T , daily injection of gas from the P2G process V_{P2G} , and daily demand V_n (all in m^3/s). Therefore, letting $\mathbf{Q}$ be the vector indexed by the gas nodes with entries $Q_n = V_n - V_T - V_{P2G}$, then the conservation of mass at each node is given by $\mathbf{A}\mathbf{F} = \mathbf{Q}$ where $\mathbf{F}$ the vector of pipe flows F_A and $\mathbf{A}$ is the signed pipe-node incidence matrix with rows indexed by the network nodes and columns indexed by the pipes. A fixed pressure (slack) node is considered at the terminal with the largest throughput.

For the solution method, it is beneficial to work with the “pressures with exponent” $U = p^\beta$. The operation of each compressor C_m is therefore modelled by a fixed outlet pressure p_C so that

$$\mathbf{U}_C = \mathbf{J}\mathbf{U} \quad (15)$$

Where $\mathbf{U}_C$ is the vector of outlet pressures with exponent, $\mathbf{U}$ is the vector of network pressures with exponent, and $\mathbf{J}$ is the compressor outlet matrix defined by

$$J(i, m) = \begin{cases} 1 & \text{if compressor } C_m \text{ has its outlet at node } i \\ 0 & \text{otherwise} \end{cases} \quad (16)$$

Let $\mathbf{c}$ be the vector of compressor flows and $\mathbf{K}$ the matrix describing the inlet/outlet nodes of the compressors, with entries

$$K(i, m) = \begin{cases} 1 & \text{if compressor } C_m \text{ has outlet at node } i \\ -1 & \text{if compressor } C_m \text{ has inlet at node } i \\ 0 & \text{otherwise} \end{cases} \quad (17)$$

The relation describing the conservation of mass at the nodes can then be expressed by

$$\mathbf{B}\mathbf{A}\mathbf{B}^t\mathbf{U} + \mathbf{K}\mathbf{c} = -\mathbf{Q} \quad (18)$$

where $\mathbf{B}$ is the signed pipe-node incidence matrix and $\mathbf{A}$ is a diagonal matrix indexed by the pipe A with each entry $\lambda = (L_A/(k(D_A)^\nu)) \cdot |F_A|^{\alpha-1}$.

The Newton-node method proceeds to solve relation (15) and (18) for $\mathbf{U}$ and $\mathbf{c}$ by successive iterations. At each iteration, with an approximate solution $\mathbf{U}$ and $\mathbf{c}$ the flow rates are determined by (14), from which the matrix $\mathbf{A}$ is determined. After setting the network's fixed pressure points as in (15), the next set of approximate solution to $\mathbf{U}$ and $\mathbf{c}$ are determined by solving (18). This is repeated until $\mathbf{U}$ and $\mathbf{c}$ are calculated to a given level of accuracy.

The gas demand on a given day is fulfilled by supply from a number of sources. A heuristic dispatch hierarchy (for instance based on historic shipper actions) is used to determine the level of supply through each entry point on a given day.

3.3. Gas network re-dispatch and constraint modelling

For given gas terminals' flows and given gas demands, the inability of the gas network to successfully operate is highlighted in the model by pressure violations at the extremities of the network. The gas network operator would then attempt to successfully meet the demand by using operational means including the use of more expensive gas from sources closer to the demand. To mimic the network operator's practises in gas re-dispatch, a heuristic methodology is presented for which pressure breaches are attempted to be resolved by changes in gas network supplies. This is done by increasing the terminal flows in the locality of the network vulnerability and is modelled as follows. The network is partitioned into zones so that each zone has a terminal. If a given zone N has pressure violations and its total gas demand is V_N , then the terminals' throughput is increased so that, if the maximum throughput capacity of the terminal and storage facilities in the zone is $\overline{V}_{T,N}$, then the rate of supply is increased to

$$V_{T,N} = \min(\overline{V}_{T,N}, V_N) \quad (19)$$

If there remain pressure violations within the zone, then constraints are introduced in the two-stage optimisation process. More specifically, if the closest gas generator to the system's minimum pressure is GG_j then, if $ON(GG_j)$ is the times of the day for which the generator is online and $t_m \in ON(GG_j)$ is the time for which the system electrical demand is minimum, then the additional constraint $P_{GG_j}(t_m) = 0$ is included in the OPF constraints. Upon re-evaluation of the network flows and possible limitations on the gas generation, these results are then used as inputs into the consequent iteration. The ability of the proposed gas network re-dispatch modelling to alleviate network constraints is exemplified in Section 4.9.

4. Case studies

Case studies are performed on scenarios put forward by National Grid in their Future Energy Scenarios [16] for the future of the GB electrical and gas transmission system requirements. Generation portfolios are considered with increased levels of wind and solar in order to assess the ability of the system to integrate additional renewables with the use of seasonal storage with P2G. Two scenarios are considered, namely, “Gone Green 2030” scenario, with generation portfolio based on those in [16], and “High Renewable Penetration” scenario, with increased renewables as well as changes to the gas and electrical demands caused by the electrification of the heating sector.

4.1. Electrical network data

The studies are performed on a 29 bus representation of the GB electrical transmission network (Fig. 2(a)). The installed generation capacity for the two scenarios are described in Table 1 along with the cost of the non-gas fuelled generators and the 30 minute ramp rates and MSG, each expressed as a percentage of the installed capacity. The cost of combined-cycle gas turbines and open-cycle gas turbines depend on their HHV-based efficiencies, taken as 50% and 32%, respectively. Electrical OPFs are conducted for 30 minute snapshots.

Fig. 2. 29 busbar electricity (elaborated from [17]) (a) and 79 node gas (b) models of the GB transmission networks, including zones for gas network operational dispatch.

Table 1 Generation technologies and their installed capacities, costs, MSG and 30-min ramp rates [13].

Technology		Installed capacity (GW)	Cost (£/MWh)	MSG	30 min ramp rate
Combined-cycle gas turbine		35	function of gas price	50%	25%
CHP		7	must-run	-	-
Coal (incl. CCS)		11	46	50%	25%
Marine		7.5	0	-	-
Nuclear		11	Must run	-	-
Open-cycle gas turbine		0.5	function of gas price	10%	50%
Other renewables		20	70	-	-
Solar	Gone Green 2030	20	0	-	-
	High Renewable Penetration	40	0	-	-
Wind	Gone Green 2030	52	0	-	-
	High Renewable Penetration	92	0	-	-

There are two primary sources of intermittent generation installed in the power system, namely, wind farms and photovoltaic (PV) generation. Historical regional meteorological data is combined with wind turbine and photovoltaic cell characteristics to assess the generation capability of each. For the Gone Green 2030 scenario, these are shown in Fig. 3

Fig. 3. System solar and wind generation capability, Gone Green 2030 scenario.

4.2. Electricity and heat demand data

As the heat demand plays a dominant role in the overall energy consumption levels, changes to the technologies by which the heat demand is fulfilled will have knock-on effects on the electrical and gas demand requirements. Modelling previously developed has been used to assess consequent changes to the gas and electrical demand due to changes in heat generation technologies, based on EnergyPlus software package for commercial and industrial buildings [18], the model developed in [19] for residential buildings, and the model in [20] for hot water demand. Combining this with statistics on building stock and lifestyle patterns, the heat demand for the system has been estimated at half-hourly intervals [21]. Historical temperature and gas demand data from 2012–13 are used to model the heat requirements. The impacts of changes of heat production technologies (Table 2) on the electrical and gas demands have been assessed as in [13]. The resulting electrical demands are shown in Fig. 4.

Table 2 Fraction of annual heat fulfilled by gas and electricity.

	Electrified heat	Gas-fuelled heat
Gone Green 2030	12%	62%
High Renewable Penetration	39%	50%

Fig. 4. System electrical demand.

4.3. Limits on hydrogen P2G utilisation

Restrictions to the levels of hydrogen which may be blended with the gas in the gas network vary widely with legislation. It is suggested that hydrogen up to 17% (mol.) is feasible without changes to existing technologies [22]. The GB gas network has historically set a comparatively low limit of 0.1% (mol.). A future P2G programme would benefit from a relaxation to this level and, indeed, industry is currently petitioning for this to be raised to 3%. Furthermore, the quantity of hydrogen that may be blended with NG has a seasonal nature. In particular, with lower gas demands in summer compared to winter, the energy content of the hydrogen which may be injected into the network is less. The mean power required for hydrogen facilities to meet the 3% and 17% blending limits is given by $\bar{L}_{H_2} \cdot B / \eta_{H_2}$, where B is the mean gas demand (GW). These are presented in Table 3 for alternative demand levels and hydrogen content.

Table 3 Hydrogen-based P2G mean powers to meet gas network hydrogen content limit per season.

<i>Limit to hydrogen content of gas in network (% mol.)</i>	3%	17%
Gone Green 2030: Average winter gas demand	1.5 GW _e	8.7 GW _e
Gone Green 2030: Average summer gas demand	0.6 GW _e	3.4 GW _e
High Renewable Penetration: Average summer gas demand	1.2 GW _e	6.7 GW _e
High Renewable Penetration: Average summer gas demand	0.6 GW _e	3.1 GW _e

4.4. Gas network data

Gas network flows have been computed on a simplified model of the GB Gas transmission network (Fig. 2(b)) for daily snapshots for the year. The supply source origin of the network's gas demand is highly dependent on the level of demand. In the UK, at times of low demand cheaper gas from the UK continental shelf (UKCS) and Norway are used to fulfil demand. The remaining NG is the more expensive gas imported either from Continental Europe or on LNG ships. Historical gas supplies from 2013 have been used to model entry flow rates and characteristics for different terminals and different sources of NG.

In addition to gas demand for the heating sector and for electrical generation, the remaining gas demand consists of large industrial and interconnector demands which are modelled as constant throughout the year at 187GWh/day and 120GWh/day [23]. The total system gas demand for the High Renewable Penetration scenario is shown in Fig. 6.

The slack node and compressor stations are modelled with a fixed outlet pressure of 65bar. For the process of re-dispatch of the terminal flows as described in Section 3.3, the zonal decomposition of Fig. 2(b) is considered. This allocation of the network's zones is based on partitions used by the Great Britain's gas transmission network as an operational tool. These zones are defined by the network's characteristics and consider the network's transportation capability within and between zones.

As discussed in Section 2.5, the relationship between the demand and the gas price (represented by π in (9)) has been estimated using historical gas price and gas demand data and future gas price predictions and has been modelled by a piecewise linear function (Fig. 5(a)).

Fig. 5. (a) Relationship between gas demand, including storage injection net power-to-gas, and the gas price. (b) Relationship between the cost of gas above the predicted summer gas cost and the potential injection (+)/withdrawal (-) rate. (c) Limits on the injection and withdrawal rates of storage facility, elaborated from [24]

4.5. Seasonal gas storage data

The existing long-term gas storage facility in the UK has been developed at the depleted Rough gas field (Fig. 2(b)). The storage operation has been modelled with the function h in (8) relating the difference between the gas price on a given day and the forecasted summer gas price to the potential injection/withdrawal rate. A piecewise linear function, derived from historical operation data of the Rough storage facility from the years 2010–2014 [23], has been used to describe the historical correspondence between the gas price and the Rough operation and for which the injection (positive) and withdrawal (negative) rates are bounded by the facilities operational characteristics (Fig 5(b)). This relationship has been extended linearly to accommodate the operation of storage facilities with additional injection/withdrawal capacity. The resulting relation which defines the function h is also shown in Fig. 5(b). As discussed in Section 2.4, the maximum injection/withdrawal rates are described as a function of the current storage levels. The injection/withdrawal limits for the Rough facility in 2015 are shown Fig 5(c) and its capacity is $3.2 \times 10^9 \text{ m}^3$ of gas [24].

4.6. Computational aspects

The model has been developed and implemented in MATLAB [25] with the aid of the Matpower package [26] for the electrical OPF modelling. Each electrical snapshot of 30 minutes consists of 161 free variables and 451 constraints leading to $161 \times 48 \times 365 \approx 2.8 \times 10^6$ free variables and $451 \times 48 \times 65 \approx 7.9 \times 10^6$ constraints for the two-stage optimisation. The computations are parallelised into 24 hour time frames each of which is processed independently. The processing of each the 365 parallelised components is performed using the high-throughput computing HTCondor environment on a shared computational pool of ~400 desktop computers. The timeframe for the completion of the 365 jobs is ~8 hours.

Each daily gas flow has 170 free variables and constraints. The evaluation of the gas flows for the year including assessment of network re-dispatch and electrical constraints has a computational time of approximately 15 minutes. For each case study, the gas price converged to a tolerance of 3% within three iterations.

4.7. System benefit from P2G with seasonal storage

Results are presented for alternative levels of installation of P2G facilities, heat and generation portfolios and levels of hydrogen permissible in the gas network as stated in Table 4.

Table 4 Scenarios considered for case studies

Installed P2G installations	Heat and generation portfolio	Limit to hydrogen content of gas network
Each of the nine terminals has 1GW hydrogen production facility; no SNG facilities installed*	Gone Green 2030	3%
		17%
	High Renewable Penetration	3%
		17%
Each of the nine terminals has 1GW hydrogen production facility and 5GW SNG facilities*	Gone Green 2030	3%
		17%
	High Renewable Penetration	3%
		17%

* Installed capacities based on the gas network and the powers presented in Table 3; efficiency of the hydrogen (resp. SNG) production process facilities is taken as 73% (resp. 64%) [11].

The benefit of power-to-gas with a gas network with seasonal storage infrastructure has been evaluated with the consideration of the annual cost of the natural gas required to meet the system's gas demand. This has been evaluated by considering, for each day d , the gas demand $E_D(d)$, the storage injection/withdrawal $E_S(d)$, the power-to-gas injection $E_{P2G}(d)$ and the gas cost (assumed to vary daily) $c_{gas}(d)$. For the simulation period of a year, the gas in storage at the start of the period S_{d_s} may not be equal to that at the end S_{d_e} ; therefore, to make a comparative study between alternative scenarios, the change in gas demand in storage is accounted for with consideration of the summer cost of gas $c_{gas,s}$. The annual cost of fulfilling the gas demand is then expressed by

$$ACG = \sum_d [(E_D(d) + E_S(d) - E_{P2G}(d)) \cdot c_{gas}(d)] + (S_{d_e} - S_{d_s}) \cdot c_{gas,s} \quad (20)$$

Tables 5 and 6 show the resulting levels of P2G production, seasonal storage utilisation, the effect on the seasonal gas spread (defined as the difference between the mean winter and summer gas prices), the cost of NG displaced by gas produced by P2G which has been evaluated using gas price on each given day and a reduction in the cost of meeting the annual gas demand. There is an increase in integration of generation from wind and solar while the results also show how the introduction of P2G leads to a decrease in the seasonal gas spread. Table 5 also shows the additional renewables integration which would accompany a relaxation in the limit to the hydrogen content permissible in the gas network when the P2G units only produce hydrogen.

Table 5 Benefits of the use of hydrogen production with seasonal storage.

	Gone Green 2030 [†]		High Renewable Penetration [‡]	
<i>Limit to hydrogen content of gas network (% mol.)</i>	3%	17%	3%	17%
Wind and solar generation (TWh _e /year)	103.8	114.3	158.1	172.4
Hydrogen formed from P2G process (TWh _{gas} /year)	3.2	10.9	3.4	13.8
Decreases in seasonal storage injection	1.9%	6.4%	2.7%	10.5%
Cost of natural gas displaced by P2G (£M/year)	73.2	245	73.0	297
Decrease in seasonal gas spread	-0.2%	1.5%	0.4%	1.7%
Annual cost of gas (£M/year)	17330	17130	12860	12610

[†] Without P2G in the Gone Green 2030 scenario the annual wind and solar generation is 99 TWh_e/year, the utilisation level of the gas seasonal storage is 27.6 TWh_{gas}/year and the annual natural gas costs are £17420M/year.

[‡] Without P2G in the High Renewable Penetration scenario the annual wind and solar generation is 154 TWh_e/year, the utilisation level of the gas seasonal storage is 28.6 TWh_{gas}/year and the annual natural gas costs are £12940M/year.

Table 6 Benefits of the use of hydrogen and SNG production with seasonal storage.

	Gone Green 2030		High Renewable Penetration	
<i>Limit to hydrogen content of gas network (% mol.)</i>	3%	17%	3%	17%
Wind and solar generation (TWh _e /year)	134.6	134.6	230.2	230.2
Gas formed from P2G process (TWh _{gas} /year)	23.0	23.9	49.4	50.7
Decrease in seasonal storage injection	2.6%	6.7%	8.4%	14.9%
Cost of natural gas displaced by P2G (£M/year)	510	531	1039	1065
Decrease in seasonal gas spread	4.0%	3.9%	15.6%	16.0%
Annual cost of gas (£M/year)	16810	16730	11710	11680

For the High Renewable Penetration scenario with the installation of both hydrogen and SNG facilitates and a gas network hydrogen content limit of 17%, the ability of the P2G process in reducing the GB gas network's reliance on gas from LNG and Continental Europe is highlighted in the seasonal gas dispatch example shown in Fig. 6.

Fig. 6. Example of fulfilment of system gas demand for High Renewable Penetration scenario with 17% limit to the hydrogen content in gas network and hydrogen and SNG production.

4.8. System benefit from increasing seasonal storage capacity

As a means of assessing the additional benefits of further seasonal storage capacity, the model has been applied to consider additional capacity in the existing facility. Following [24], the benefits of increasing the maximum operating pressure of the storage facility is 240 bar are considered below. Under these circumstances, the facilities' capacity increases to $4.7 \times 10^9 \text{ m}^3$ of gas, a 43% increase on the 2015 levels; while the increase in the limits to the injection/withdrawal capacity are shown in Fig. 5(c). Tables 7 and 8 present, for the case studies of Section 4.7, the impact of an increase in the storage facility's capacity on the annual cost of gas and the level of storage utilisation. In ease scenario considered, the results show benefits to such an increase in the system's storage capacity accompanied by an increase in the injection/withdrawal limits.

Table 7 Benefits of additional gas storage capacity with hydrogen production.

	Gone Green 2030		High Renewable Penetration	
<i>Limit to hydrogen content of gas network (% mol.)</i>	3%	17%	3%	17%
Reduction in cost to meet annual natural gas demand (£M/year)	6.7	25.5	7.7	13.9
Increase in storage injection	15.6%	18.7%	11.0%	16.0%

Table 8 Benefits of additional gas storage capacity with hydrogen and SNG production.

	Gone Green 2030		High Renewable Penetration	
<i>Limit to hydrogen content of gas network (% mol.)</i>	3%	17%	3%	17%
Reduction in cost to meet annual natural gas demand (£M/year)	14.3	20.2	15.3	19.6
Increase in storage injection	11.0%	16.0%	19.6%	15.6%

4.9. Gas network impact

As discussed in Section 3.1, the introduction of hydrogen will have an effect on the gas flows and will lead to greater pressure drops throughout the network. To demonstrate the model's capabilities, the effect of hydrogen on the system pressures has been considered for the Gone Green 2030 scenario. Fig. 7 compares, for the month of maximum demand, the minimum pressure for hydrogen content limit of 3% and 17% as well as with no power-to-gas facilities installed. The results show that with an increase in the levels of hydrogen content permissible in the network there are greater pressure drops and, in particular, for the scenario where the hydrogen content limit is 17% the minimum system pressures are up to 7% less than when there are no P2G facilities installed. These reductions in pressure highlight the reduction in flow capacity which accompanies an increase in the injection level of hydrogen into the gas network. This can lead to restriction in the dispatch options for the gas network shippers as localised gas sources are required

to meet a given region's demand. Gas network planners should therefore consider the utilisation levels of P2G facilities and the impact of the consequent hydrogen injection when assessing gas network requirements in fulfilling demand in a future energy system.

However, for the GB gas network with minimum offtake pressures of 38 bar, the results of our modelling do not highlight any pressure violations. In fact, the British gas transmission network in 2015 is able to successfully operate to meet gas supplies for the peak day with the loss of its single largest piece of infrastructure [16], and so with full network functionality gas constraints are unlikely. Should there be multiple network outages, however, then pressure violations may occur and, under these circumstances, the re-dispatch of gas flows at alternative terminals, as described in Section 3.3, could be used to alleviate gas network constraints. To illustrate this in practice, a scenario for which there are a number of network outages is considered. The pipe labelled Π in the reduced network in Fig. 2(b) in reality consists of a set of parallel pipes. It is therefore considered that a 24km section of 900mm pipes has become unavailable. In addition, it is assumed that the two compressor stations C_1 and C_2 in Fig. 2(b) are not functioning. Then, considering the day of maximum gas demand in the simulation year (12 November), in the 'Gone Green 2030' scenario there is a demand of $V_{N_1} = 74.8 \times 10^6 \text{ m}^3/\text{day}$ in Zone N_1 (Fig. 2(b)), and node A (Fig. 2(b)) has a pressure of 36.3bar: this configuration leads to pressure violations. The terminal, T_1 , in the same zone, the Isle of Grain LNG terminal (B of Fig. 2(b)) has a maximum capacity of $\overline{V_{T_1, N_1}} = 56 \times 10^6 \text{ m}^3/\text{day}$ [27]. However, as a more expensive source of natural gas on this day, without re-dispatch, only $19.7 \times 10^6 \text{ m}^3/\text{day}$ is supplied through this terminal. Following the methodology in Section 3.3, upon increase in the supply flows through this terminal to $V_{T_1, N_1} = 56 \times 10^6 \text{ m}^3/\text{day}$, then the pressure at node A increases to 54.5bar.

Fig. 7. Minimum system pressure for each alternative levels of permissible hydrogen content of the gas network.

5. Concluding remarks

This work, the first of its kind, has proposed an integrated electricity-gas transmission network model with P2G technology adopted for applications with long-term seasonal storage in the gas network. The P2G electricity from otherwise curtailed renewable sources and the level of gas production has been modelled using a specifically developed integrated electricity and gas network two-stage optimisation methodology, in which the electrical network modelling has been conducted with a DC OPF. The impact of the P2G process on the gas prices and utilisation of seasonal gas storage has been evaluated. Gas flows have been modelled with steady-state analysis, and limitations in the gas network's ability to meet demands have been implemented. Case studies based on a model of the GB gas and electrical networks and National Grid's future scenarios have illustrated the capability of the proposed model, including assessment of hydrogen-only and hydrogen and SNG P2G facilities. Numerical results indicate that for National Grid's 'Gone Green' scenario, P2G can lead to an *additional* integration of 35.6TWh/year of renewable generation and the production 23.9TWh_{gas}/year of gas. In addition, it is shown how the introduction of this low-cost gas from the P2G process into the gas network can lead to a 4% reduction in the annual cost of natural gas. Furthermore, the benefits which would accompany a relaxation of the level of hydrogen permissible in the gas network have been quantified. Finally, it has been shown how the increase in hydrogen content in the network can lead to a reduction in the flow capacity at the network extremities: for the GB gas network case study, a 17% hydrogen content limit for natural gas can lead to an increase in pressure drops of up to 7%. Therefore, for the widespread introduction of power-to-gas, the increase in pressure drops should be incorporated into the planning of the future gas network infrastructure requirements and the potential need for network reinforcement.

While this work has set the fundamentals for a sound technical assessment of seasonal P2G taking into account realistic network and system constraints, work in progress aims to develop a full techno-economic assessment of this solution under different conditions.

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