Applied Energy 193 (2017) 479–490

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

An integrated gas and electricity model of the EU energy system to examine supply interruptions

J.P. Deane *, M. Ó Ciaráin, B.P. Ó Gallachóir

MaREI, Environmental Research Institute, University College Cork, Ireland

HIGHLIGHTS

- High temporal resolution analysis of a 28 country European power & gas systems.
- Identifies concerns for weak points and "bottlenecks" in the network.
- Publically available power and gas model of Europe.
- Impacts of several gas supply interruption scenarios on the power system described.

ARTICLE INFO

Article history:
Received 11 November 2016
Received in revised form 25 January 2017
Accepted 13 February 2017

Keywords:
Energy systems modelling
Integrated systems modelling
Energy security
Europe
Gas systems modelling

ABSTRACT

The EU dependence on imported gas is increasing, rising to 67% in the year 2014 with 30% of total gas consumption used for electricity generation that year. With such a dependence on imported gas, gas supply interruptions can have significant impacts on the EU energy system and economy. This points to the need for integrated electricity and gas modelling tools to fully explore the potential impacts of gas supply interruptions. This paper builds and applies a detailed publically available integrated electricity and gas model for the EU-28. We use this model to examine a number of hypothetical scenarios where gas supply routes are interrupted for yearly periods and the impacts on power system operation and gas flow in Europe observed. Model results show that interruption of Russian gas supply to the EU could lead to a rise in average gas prices of 28% and 12% in electricity prices. When supply from North Africa was removed all Southern European states were affected heavily, Spain in particular saw large increases of 30% in gas prices with a corresponding rise of 18% in electricity prices as a result. In addition to supply interruptions, all gas storages were removed from the model to examine the importance of gas storage infrastructure. This resulted in an average increase in power prices of 6% across Europe. These additional insights offer an increased understanding of the interplay between the gas and power systems and identify challenges which may arise when seeking to understand energy systems as a whole.

1. Introduction

The current global energy system is almost entirely dependent on hydrocarbons [5,33,56]. In the coming decades, global energy markets will face many challenges, such as emission restrictions, infrastructure restructuring and supporting renewable technologies in addition to maintaining reliability and security of supply [25]. The planned deployment of renewable electricity generation represents a significant change in electricity system operation. The impact of variable renewables on the electrical power system is well documented and researched [8,14,34,53,54]. The output from variable renewables such as wind, wave, and solar PV are variable with associated uncertainty in forecasting. While variability and uncertainty in electricity systems are not a recent phenomenon, their impact on the associated gas infrastructure is generally not well examined. The inherent variability of a renewable resource like wind requires a power system to be sufficiently flexible to cope with the changes in production. Both Open Cycle and Closed Cycle gas plants (CCGT and OCGT) have to cycle on and off and may have to ramp sharply over various timescales to accommodate this variability [32]. Depending on the specific power system portfolio this variability can be passed to the gas system and its associated infrastructure i.e. electric-driven compressors.

It is important to understand and quantify these associated impacts on the gas system in order to assess its resilience. Most gas infrastructure was built and deployed in times with low levels of variable renewables and will need to be expanded to deal with

* Corresponding author.
E-mail address: jp.deane@ucc.ie (J.P. Deane).

http://dx.doi.org/10.1016/j.apenergy.2017.02.039
0306-2619/

large temporal fluctuations in demand/generation [26]. While this has issue has been raised in the existing literature [16,40], the model presented here aims to analysis the impact of supply shortages on a large scale system with high levels of renewables. The work presented here provides a platform to analyse the interaction between gas and power across the EU for the year 2030 under a variety of scenarios effecting the gas system. The model has been constructed to highlight the interplay between the power and gas systems and examine the added value of such an approach. The model determines gas and power prices endogenously as well as the least cost generation and production mix to meet exogenous power and gas demands. The model developed is for the snapshot year of 2030 and results are not intended to be forecasts or predictions but instead are used to gauge the value of an integrated approach.

Following a summary of the relevant literature on this topic the methodology used is detailed, as well as the key findings from various scenarios that were applied to the model. In all scenarios, only the gas portion of the model was altered and the impact on the power sector studied, each variation highlighting the cascading effect that the operation of the gas network has on the power system in terms of cost, fuel mix, and operational flexibility.

The model, associated data and select hourly results have been made freely available for academic research and are online at link https://www.dropbox.com/sh/sfbc2tde6xi3cwe/AAA5KSTAcmGmTIvCHT2cCoTQa?dl=0.

2. Existing literature

Interest in integrated modelling has been growing over time with the challenges associated with a non-integrated approach being highlighted in literature [37,38]. From a research perspective, the interplay between the power and gas systems is important so as to understand how operational limitations on one system affects the other. Natural gas and electricity systems have certain similarities in terms of their topology, as both systems have transmission and distribution networks. Both networks are subject to physical laws that can limit the energy transmitted (electrical current or gas flows) and cause losses (electrical losses or pressure decreases). The systems, however, are very different in term of timeframes; power systems dynamics after a fault can travel much faster through the electrical system while disturbances are generally much slower in the gas system. The ability to store gas in linepack or conventional gas storages is also a major difference and in general, the gas system is thought to be a more 'forgiving' system in terms of balancing.

The paper addresses a gap in the literature on the issue of integrated gas and electricity modelling at EU level and presents an applied methodology and model to examine natural gas supply interruptions and consequential impact on electricity impacts. Previous EU wide studies such as [30] use probabilistic Monte Carlo techniques to examine supply interruption from North Africa but do not examine the power system or associated impact on electricity prices. Similarly at EU wide level [51], examine the impact of disruption scenarios of Russian natural gas to Europe however the study is limited to the gas system impacts. Integrated power and gas models exist across the literature that look at different aspects of the European energy system. Abrell and Weigt [1] present an integrated mixed complementarity problem (MCP) model of the European region in 2005. This model is used to show how upstream loss of gas supply from Russia could propagate throughout Europe leading to higher electricity prices. Indeed the loss of supply from Russia has become a highly topical issue with many articles discussing its likelihood as well as its potential impact [29,36,46]. In a detailed report by Dickel et al. [18] an overview of the problem is presented with projections for those countries highly dependent on Russian gas, mainly Central & Eastern Europe, becoming even more so. This is compounded when considering projections for indigenous European supply [18,27].

From a European perspective, the importance of the gas system to the stability of the power system is a topic found frequently in literature [1,4,42]. For example, in [39,40] a least cost optimisation model of the European power and gas networks was built using PLEXOS. The PLEXOS software package allows for both gas and power objects within its framework. The model was then used to analyse the robustness of the European system for the base year 2013, with that system being stressed by an increasing share of variable renewables. Similarly, Ahern et al. [2] use another PLEXOS model to investigate the possible role of power to gas systems in the context of Ireland.

On an individual member state level, there are several models which consider in greater analytical detail the interplay between the gas & power networks. While the more regional issues of security of supply mentioned are still important, these models instead look at a more local picture with the specific topologies and characteristics dominating the analysis. A model of the UK power and gas system developed and presented by Chaudry et al. [7] considers the local importance of gas storages and their usage to maintain system pressure. The findings point to certain gas generation plants that depend on the injection from stores to operate. This demonstrates the importance of storages in the context of whole system stability and local linepack management. A similar approach was taken by Devlin et al. to investigate the impact of stochastic renewables on the Irish power and gas system [16]. Here the Irish Single Electricity Market (SEM) was modelled with a detailed representation of the gas network i.e. regional transmission lines and real geographic placement of power stations. Again, this methodology allows for analysis of localized linepack management under normal and stressed operation and allowed Devlin et al. to demonstrate the high dependency of the power system on gas supply to maintain prices.

This aforementioned model by Chaudry et al. is adapted [48] to determine the impact of large-scale renewables on the UK power system. As the UK government attempts to generate more of its electricity from renewable sources, the contribution of wind, both onshore and offshore, is going to increase if the mandatory target of 31% electricity from renewables [13] is to be met (see [12]. With both pressure and linepack being considered, this model was well suited to analysing this problem and indeed showed how curtailment of CCGT plants could occur due to lack of sufficient pressure in certain lines due to external stresses. In an extension of their previous work Devlin et al. include the UK and develop a larger context for the Irish systems findings [15]. The integrated power and gas model of the UK and Ireland presented by Devlin et al. points to an increase of 40% to the short run costs of generators during periods of congestion and further demonstrated the interplay of gas and power systems by showing that gas storages can mitigate the total generation cost increases by 14%.

A number of models reviewed have been developed for specific purposes such as wheeling charges. In [41] different approaches were used to include wheeling charges in an integrated gas and electricity model of Brazil. This detailed study examines options for modelling wheeling charges based on data availability and shows the impact each has when looking at the best location of a new gas generator. In [52] a model for the USA is introduced where different technical, economic and policy scenarios are presented. One of the case studies undertaken using the proposed model is the impact of gas prices on CCGT competitiveness. A result of the sensitivity analysis carried out was the susceptibility of CCGT plants to gas price volatility, even with such high efficiency. In [35] similar conclusions are drawn when examining the Chinese systems.

Several of the models reviewed had the physical equations for model components (i.e. gas flows) embedded within the model to allow for detailed studies of the physical impact one system can have on the other. For example in [24] both the physics of the voltages across AC lines and the pressure drops along gas pipelines are included. A study was conducted on a fictional network topology with random faults introduced to determine the significance of their propagation from one system to the other. This level of detail is not usually modelled due to complexity as is the case in [48]. In the model proposed by Qadrdan et al. the simplifying assumption is made that by accounting for the changes in average pressure across a pipe the can be calculated. This is then used to locally determine supply and access shortage caused by large CCGT plants ramping up in response to falling wind generation. In the future scenario proposed the UK's power demand is met primarily by wind and CCGT plants, with the base load provided by coal and nuclear. An interesting outcome of this analysis is the stresses that low levels of wind put on the gas network. This scenario is a particularly interesting case as Europe moves towards generating more of its power from variable generation sources. Some model developments take a more stylised approach to modelling the real gas flows, either simplifying the governing equations or omitting them. In [57] the argument is made that from a system operator's perspective ignoring these physical realities can lead to significant errors. Damavandi et al. gas velocities and distances travelled are considered, giving a sub-hourly view of the system and its associated dynamics, leading to a highly divergent scenario to the static model used.

Qadrdan et al. [47] use a combined gas and electricity network model (CGEN) of the Great Britain 2030 system to investigate the impact of integrating a large capacity of wind generation on the combined system. It was found that the deployment of grid-scale electricity storage achieved the highest reduction in the operational cost of the integrated system. Qadrdan et al. [49] again used the CGEN model to quantify the combined benefits of demand side response in a future UK energy system. Diagoupis et al. [17] present a planning approach to the combined natural gas and electricity system in the Greek system which considers failures on the gas network. The study also presents a methodology for the location of natural gas storages. An interval gas flow analysis is presented in Qiao et al. [50] in a system with high levels of wind power production. The study highlighted the importance of a combined gas and electricity approach and demonstrated the significant of wind power production uncertainty on the impact on the steady-state operation of natural gas systems. The injection of hydrogen into the natural gas network is analysed in [31] and impact in terms of composition, flow rate and pressure profiles with comparison to the reference natural gas case are presented. The analysis presented in this paper does not include hydrogen and instead presents an applied methodology to explore the EU wide system and examine gas supply interruptions with a focus on associated impacts for electricity prices and emissions.

The model presented in this work adopts many of the techniques and methodologies detailed earlier to build a full simulation model of the European gas and power systems. This is then tested under extreme conditions to give a robust analysis of how the system might behave under low risk, high impact scenarios.

3. Methodology

The model was constructed using power plant portfolio and existing gas infrastructure data. The software used to develop the model is PLEXOS[1] which is a commercial modelling software that is provided free of charge by Energy Exemplar for academic non-commercial research purposes. The model and associated model data are available for download. This integrated gas/electricity model is not intended to perform the function of a gas pipeline flow model. Rather, it uses a transportation algorithm to model gas flows.

The software co-optimises gas delivery, hydro production, thermal generation and renewable production using mixed integer linear programming that aims to minimise an objective function subject to the expected cost of the system and a number of constraints. The model was constructed following the methodology presented in [11,9] and populated with data, power plant portfolios and prices from the EU PRIMES energy system model [20]. This scenario known as the EU Reference Scenario is consistent with European energy and climate policy but should not be seen as a forecast.

The objective function of the model (detailed below with further equation in [10]) is a sum of the various costs of the power and gas systems. Start costs, production costs, emissions costs and any possible penalties are combined with any wheeling charges to account for generation costs. For the gas portion of the model production costs, transport (i.e. pipeline) costs, any penalties for a loss of supply and the cost of using gas storages are added together. These two totals are balanced and minimised together to provide a least cost supply to the *integrated* system.

$$\left(\underbrace{\begin{bmatrix} SC_j.US_{jt} \\ +(PC_j + EC_j).P_{jt} \\ +WC.IF_{it} \\ +PenLoL.UE_t \end{bmatrix}}_{Power\ System\ Costs} + \underbrace{\begin{bmatrix} GPC_{lt} + GTC_{kt} + GSC_{st} \\ +PenLoS.UD_t \end{bmatrix}}_{Gas\ System\ Costs} \right)$$

The power system costs are comprised of start-up costs (SC_j) scaled by the unit commitment state (US_{jt}) of each plant j at time t and production costs (PC_j) plus emissions costs (EC_j) scaled by the amount of output (P_{jt}). Wheeling charges (WC) are also added for the amount of power flowing through an interconnector (IF_t). A penalty for any loss of load ($PenLol$) is imposed for every period with unserved energy (UE_t). The gas system costs consider the production costs (GPC_{lt}) at each gas field and LNG terminal l, the transport costs (GTC_{kt}) for each pipeline k and the storage costs (GSC_{st}) for each storage facility s. A penalty is incurred if the system is unable to supply gas ($PenLoS$) for each time period with unserved demand (UD_t).

In chronological mode the software solves for each period and maintains consistency across the full problem horizon. Temporal resolutions settings in relation to solving are flexible and in this study we use hourly resolution. To avoid issues with intertemporal constraints at the simulation step boundaries a 'look ahead' period is used similar to [10]. Look ahead means that the optimiser is given information about what happens ahead of the period of optimisation and solves for this full period (i.e. simulation period + look ahead period) however only results for the simulation period are kept. At simulation run time PLEXOS dynamically constructs the linear equations for the problem using AMMO software and uses a solver to solve the equation. In this work a duality gap set to 0.5% is used. These setting were chosen based on previous PLEXOS simulations on large systems. All simulations were checked for correct completion.

A separate gas and electricity node was used to represent each country within the EU with non-EU gas suppliers seen only as gas nodes. Each node has an electrical and gas demand profile with electrical generation and gas production capacity and their associated infrastructure. Both systems interact solely through gas generators that can draw gas from the country-specific node and create a demand (see Fig 1). It should be noted here that while

[1] http://energyexemplar.com/

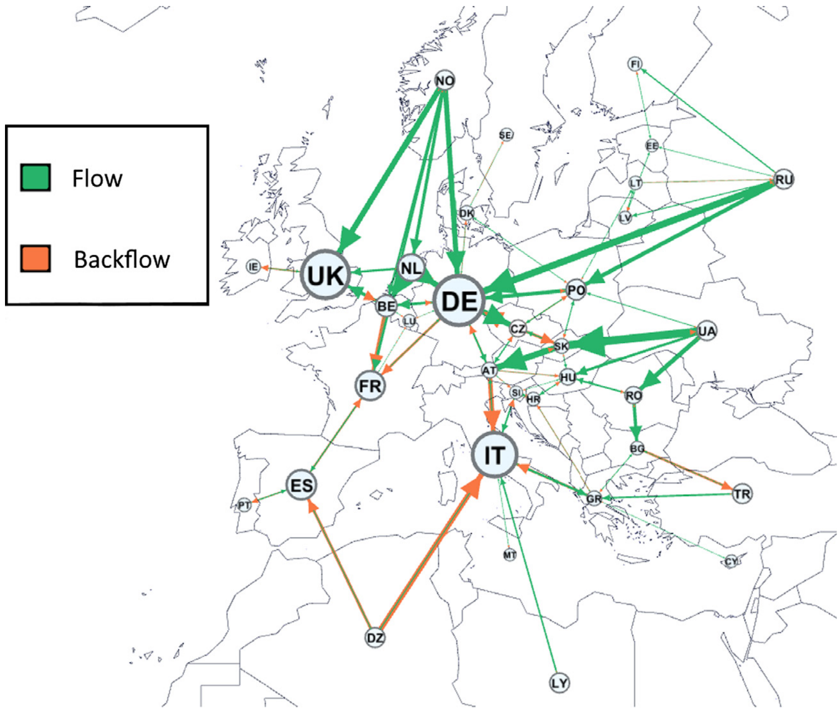

Fig. 1. Pipeline capacity map (Node size is proportional to total annual gas demand figures).

there is a fixed gas demand to capture non-generation uses, the amount demanded by generators is also determined within the model.

3.1. Power sector

The methodology used to develop the gas and electricity model draws on techniques developed in [9] which harnessed information from energy systems models (in this work EU PRIMES) to build a power system model. Generation aggregate capacities for the target year are obtained from the energy system model for all fuels types, (wind, solar, hydro, biomass, natural gas fired, coal fired etc). To disaggregate these single capacity figures for any one mode of generation (except for natural gas fired generation of which 10% was assumed to be OCGT and the rest CCGT), nominal plants for each mode were created by populating the model with "standard" generators, and each mode of generation having its own characteristics (ramp times, min/max capacities, start costs, minimum stability levels etc.). To account for outages a randomly generated profile was created for each mode of conventional generation with the same profile applied to every scenario for comparison. By using nominal plants as opposed to some countries where operational data was available any resultant bias was avoided. The only characteristics that were defined by member state were the heat rates which originated from the PRIMES figures.

Interconnectors between EU member states are aggregated resulting in single interconnectors between countries. Current net transfer capacity figures were taken from ENTSO-E and projected to 2030 using ENTSO-E's 10 Year Development Plan [21]. The data taken from the PRIMES reference scenario gives overall electrical demand at a yearly resolution and had to be broken down to hourly values for this model. This was done by setting 2012 as a base year and obtaining demand profiles from ENTSO-E for member states and scaling these to the 2030 figures.

Each member state with hydro generation is modelled using monthly targets imposed via generation profiles from ENTSO-E. These targets act as constraints on the model and are decomposed to hourly targets. For each country with solar capacity, the hourly generation profiles were established using NREL's PVWatts® Calculator [44]. PVWatts determined the generation of solar PV panels under in a customizable manner for each location [19]. The hourly profiles generated are then normalized and scaled to match the annual figures from PRIMES. All member states with wind generation capacity were issued hourly wind profiles to decompose the annual figure from PRIMES. The assumption was taken that all turbines had a hub height of 80 m the multi-turbine layout detailed by Norgaard and Holttinen [43]. Using these details data was taken from MERRA data [55].

During simulations all fuels are maintained at fixed prices with a carbon price of €40 per tonne was used, the one exception was natural gas which has its price determined endogenously. The price of natural gas varies from state to state depending on the supply mix (indigenous production, imports, LNG or storages) allocated.

The power system model integrates and interacts with the gas system model at country level. Each country is represented as a separate node with the model and the optimisation is undertaken across all nodes together.

3.2. Gas sector

The exogenous gas demands and indigenous production capacities of each EU member state were built using annual figures taken from the same EU reference scenario as the power system. As with the power system, it was necessary to decompose annual figures to hourly values where appropriate. The gas infrastructure was modelled using data taken from the ENTSO-G 2015 development plan [22], specifically, Annex D [23] which listed yearly capacities for all major projects in Europe to 2035 under 3 scenarios, High, PCI (Projects of Common Interest) and Low. Of these 3 scenarios PCI was used. This scenario contains existing projects, projects that have achieved FID (Financial Investment Decision) status and those projects which are deemed to be projects of common interest by the European Commission [28].

Total gas demand was disaggregated into 5 sectors, Residential, Services, Agriculture, Industrial and Transport. The gas demand for each sector in the year 2030 from the EU Reference Scenario is a yearly figure but for this model, it is necessary to disaggregate this by sector to daily and hourly resolutions. The method used depended on the data available for that sector and its inherent characteristics. For the transport sector, it was assumed that 75% of the demand would occur between 8 am and 8 pm every day. The industrial, commercial & agricultural sectors were given flat profiles as data was unavailable.

For the residential sector, hourly gas demand data was obtained for Ireland from a study completed by the Commission for Energy Regulation (CER) from 2010 to 2012 [6] and an initial Fourier analysis was performed on the time series so as to identify what trends were present. From this data, an average *hourly* consumption profile was established. From the amount of daily HDD's (Heating Degree Days) a linear trend was extrapolated and used to estimate *daily* gas demand (90% correlation). Using this trend a profile for *daily* gas demand was created and scaled to meet the annual EU Reference Scenario figures. Each *daily* value is then decomposed over the day according to the aforementioned *hourly* gas demand profile with the total *daily* value maintained. Due to the large variability in residential load, it was decided that the Irish scaling would be applied across the EU to capture the variation. By coupling the aforementioned relationship with daily degree day data for each capital city, hourly demand profiles were generated for each country and scaled by the EU Reference Scenario yearly figure to estimate the demand in 2030. Each set of degree day data was specific to one meteorological station in the capital city of each country and assumed to be indicative of the entire country.

Data on minimum and maximum flow constraints were taken from ENTSO-G 2015 development plan [22]. All pipelines in these documents are given in terms of where they enter the European Union first rather than the source or destination country. This led to pipelines being relabelled as coming from the supply country as opposed to the first country of contact with the EU to avoid confusion in the results. For example, the YAMAL-Europe pipeline connects to the EU at Kondratki on the border of Poland and Belarus but it provides gas to Germany from Russia's Yamal peninsula in western Siberia. All the pipelines between countries were aggregated to give a single representative line between each country node with a single maximum daily value for flow and backflow.

Note: For simplicity, all pipeline capacity from Western Asia was aggregated due to a lack of clarity in upstream supply and allocated to Turkey.

Gas is produced in 3 areas within the integrated model; indigenous EU production, non-EU production, and the LNG terminals. Non-EU countries and LNG terminals are assumed to have infinite reserves but are constrained by interconnector flow limits and the aforementioned operating characteristics. Indigenous EU production is based on the yearly figures from the EU Reference Scenario. For each country allocated production capacity, the supply is constrained by a maximum daily production limit otherwise the model is free to allocate as an endogenous variable. LNG send-out capacities were taken from the PCI scenario from ENTSO-G's 2035 Network Development Plan.

Gas Storages were aggregated by member state resulting in a single storage operating with the combined characteristics of all units. The gas storages start half full and follow an endogenous profile based on the real aggregated storage levels of the respective storages obtained from ENTSO-G. This profile enforces weekly targets that must be reached. This is done to capture the seasonality of gas storages which tend to be filled during the summer and emptied during the winter strategically based on gas prices. From the literature, the importance of adding wheeling charges, even under a simple scheme, was clear and a fixed charge was placed on each line.

3.3. Further additions and considerations

3.3.1. Note on linepack

Linepack refers to the gas stored in the pipeline network and is an important component for the short term pressure management of the network. While data on linepack levels is reported by some TSOs, it is not reported by all and was not included so as to not bias the model. From studying the existing literature it is clear that linepack would allow for a more detailed and accurate study of the dynamic response of pipelines, showing possible inadequacies within the system. Adding linepack into the model may also lead to a "smoothing" of imports to any one country as they use the linepack gas as a pseudo gas storage.

3.3.2. Note on dynamics

Within the model, both gas and power are transferred instantly from one node to another without accounting for the actual physics of the flows. With the power system this simplification is more easily justified but for the gas network on a European level, the reality of actual gas flows may be significant. As detailed above Yazdani et al. presents a comparison of static (not considering the real physics) and dynamic (accounting for the physics) models and demonstrates the problems that can't be seen with a static model. These arise from the pressure limitation of the pipelines involved and highlight the importance of storages in the system to equalize the pressure locally. By constructing a pan-European model dynamically time-lags would be introduced into a spatially consistent representation of the gas system. Even at the aggregation of one node per member state, a far more detailed image would emerge and further emphasise how crucial gas storages are for the stability of a large gas network.

3.3.3. Note on resolution

For the model presented here an hourly step size was used due to data and computational limits. With additional resources, a greater resolution could be achieved and it could be expected to add further value the results detailed below. A key feature of the interactions between gas-fired plant and renewables that was highlighted in the review of existing literature, is the sharp ramping of generation induced by the stochastic output of renewables. It should be noted however that the costs associated with ramping are not estimated nor is the potential extent to which plants are forced to ramp up and down due to the hourly step size.

3.3.4. Note on uncertainty

Like any forward looking exercise, careful consideration must be given to the model assumptions and associated uncertainty. Gas markets in Europe are influenced by many factors such as geopolitics, investments decisions, weather and national and European legislation. This paper makes no attempt to quantify or assess these uncertainties. Results are presented for one set of deterministic scenarios, however we do presents a methodology and available model data that may be used by different stakeholder to explore these uncertainties. A historical overview of development in Europe can be seen in [3] or potential developments in future markets such as [45].

4. Scenarios & results

In total 5 scenarios were applied to the model including the reference scenario with normal operation to gain insight into the interactions between the power system and gas system. The integrated model was then tested by removing the gas storages and stopping supply from North Africa, Western Asia, and Russia in turn. In all scenarios, only the gas system was perturbed and the resulting effects on both the power and gas sectors were analysed. Below, Table 1 details top level results across all scenarios. Indigenous supply is utilised to the full extent in every scenario as this is assumed to be the cheapest method for producing gas and meeting the almost constant level of gas demand (~25% endogenous for power generation & the remaining for the exogenous gas demand). Note that even with these annual averages there is a relationship between gas and power prices.

Given the size of the model and regions covered, it is difficult to present a discussion on all results. Detailed hourly results are available in excel format as supplementary material. Annual summary results are available for each Member State in Appendix A in Tables 4–7.

4.1. Reference case scenario

As one would expect the lowest average wholesale electricity market prices are seen in the reference scenario with just over 27% of total gas demand going to power generation. Table 2 details the contribution of gas to electricity generation, the wholesale electricity price, gas prices and resultant power sector emissions for each EU-28 member state. The wholesale costs of electricity is defined as the shadow price of the electricity supply demand constraint and an uplift component is added to the Shadow Price to recover no-load cost and start up costs. Wholesale electricity costs therefore do not capture elements such as capacity payments, ancillary services, taxes etc. Wholesale electricity prices are strongly influenced by gas prices and efficiency of gas plant rather than gas volumes, as gas is often the marginal fuel across regions. The highest wholesale electricity prices are seen in Spain and Portugal as both these countries in particular have to import LNG at times during the year when the demand for gas exceeds the import capacity from North Africa and limited import capacity from France is saturated. This is also reflected in the high gas price for these regions. Power sector emissions are determined by each member states portfolio and fuel type with larger member states

Table 1
Annual gas supply, demand & average power and gas prices.

		Reference scenario	No gas storages	No supply from:		
				North African	Western Asia	Russia
Indigenous production	% Change vs reference	–	0%	0%	0%	1%
	% Share of supply	31%	31%	32%	31%	32%
LNG	% Change vs reference		−22%	−1884%	3%	−244%
Imports	% Share of supply	0.27%	0.33%	5.32%	0.26%	0.92%
Non-EU Pipeline Imports	% Change vs reference		0%	8%	0%	2%
	% Share of supply	69%	69%	63%	69%	67%
Exogenous Demand	% Change vs reference		−2%	−2%	0%	−3%
	% of Total demand	*72.29%*	*73.42%*	*73.42%*	*72.38%*	*74.37%*
Endogenous Demand (For Generation)	% Change vs reference		4.08%	4.09%	0.34%	7.52%
	% of Total demand	*27.71%*	*26.58%*	*26.58%*	*27.62%*	*25.63%*
Average Gas Prices	$/GJ	12.95	13.50	13.99	13.18	16.61
Average power prices	**$/MW h**	*95.05*	*100.74*	*100.19*	*95.90*	*106.04*

Table 2
Annual summary results for reference scenario for each member state.

	Annual electricity generation (%) from natural gas	Annual whole sale prices (€/MW h)	Annual gas prices (€/GJ)	Annual power sector emissions (Mt)
Austria	7%	89.98	13.06	3.86
Belgium	61%	102.51	12.77	20.03
Bulgaria	8%	84.94	12.53	21.37
Croatia	44%	95.38	13.24	4.58
Cyprus	61%	98.17	11.13	2.15
Czech Republic	0%	86.80	13.13	34.01
Denmark	4%	82.00	11.42	8.08
Estonia	2%	77.87	11.77	8.49
Finland	0%	79.70	12.13	14.61
France	2%	93.79	13.54	5.20
Germany	16%	93.92	12.38	255.12
Greece	40%	97.58	12.54	18.33
Hungary	2%	97.34	12.54	1.64
Ireland	56%	84.27	13.51	10.10
Italy	32%	112.71	12.89	93.75
Lithuania	3%	83.41	12.22	0.15
Latvia	19%	83.08	11.22	0.49
Luxembourg	1%	90.66	13.38	0.00
Malta	50%	105.89	13.89	0.76
Netherlands	26%	92.99	11.84	47.10
Poland	3%	91.38	12.33	138.65
Portugal	6%	128.08	18.30	6.36
Romania	4%	89.47	12.06	23.57
Slovakia	2%	89.62	12.74	1.69
Slovenia	8%	93.19	13.38	5.07
Spain	20%	139.37	17.80	93.47
Sweden	0%	86.06	12.42	3.14
United Kingdom	34%	111.27	12.51	73.31

and member states with coal generation (Germany and Poland) having the highest emissions profiles.

4.2. No storages scenario

With all gas storages removed for the whole year, average gas demand for the power sector fell by 4% and average gas prices rose by 4% relative to the reference scenario. Across Europe, electricity prices rose by 6% on average and the yearly capacity factor of CCGT plants fell by 16% on average owing to the higher cost of gas. The largest increases in gas prices (see Appendix A for full table) were seen by those member states with higher percentages of gas-fired generation in their total generation capacity, for example, the UK and increases are also seen in the Baltic Member state of Latvia which utilises storage capacity in the reference scenario. The absence of storage in Latvia has a consequential impact also in Lithuania which imports more gas from Russia in this scenario. Gas demand fell and prices rose in this scenario because there were no storages to supply gas at peak times and the model was forced to draw on LNG imports to supply CCGT plants at critical moments during the year to maintain system stability. In Fig. 2 it can be seen how CCGT generation is used to match peak loads in Spain. This is common among all countries in the model. Without high levels of renewable generation (primarily onshore wind in Spain) so many CCGT plants are used that all pipelines into a single country become congested at peak times and the model must use LNG to meet the demand and gas prices rise sharply as a result.

Relative to the reference scenario, the total volume of gas transported within the EU fell by 3% but levels of congestion (as measured in days) were reduced by 50% on internal European lines. The effect was less pronounced on the large pipelines from non-EU supplier states which experienced a reduction of 20% in congestion levels as compared to the reference scenario. Noting that there is no shortage of gas within this scenario, the relatively small change in total gas transported is expected due to the enforced profiles starting the storages at 50% of total capacity and returning them to approximately the same by the end of the simulation. Gas storages act to store additional gas at off-peak times and release during peak times. This extra layer of demand is removed in this scenario and we see the hours of congestion fall as a result since the model doesn't have to maximise pipelines more frequently to maintain storage levels. The more substantial fall in congestion internally coupled with the fact that the countries forced to use LNG imports (Ireland, the UK, France and Spain) are furthest from a range of large non-EU gas sources shows that gas was imported to the EU at peak times and used by those member states where it first entered and not allowed to propagate through.

4.3. No North African supply

Within the model, it is assumed that only 2 North African countries supply gas to Europe, Libya, and Algeria. Of these Algeria provides the vast majority, supplying levels similar to Russia in the reference scenario. When the supply of gas from these countries is interrupted there are very large effects on the Iberian Peninsula (Spain and Portugal) and other changes to the integrated systems of the other Mediterranean states (see Table 3).

Portugal is impacted to a greater extent than Spain because it is at the end of a supply line running from central Europe through France to Spain. The vast majority (97%) of the gas flowing from France is used by Spain with only the remaining 3% passing to Portugal. Imports of LNG into the regions also increased significantly with LNG supplying 5% of all gas used in this scenario. This was due almost entirely to LNG imports to Spain and Portugal where LNG provided 70% of Spain's full gas demand and 85% of Portugal's gas demand. Both Spain and Portugal experienced high levels of unserved energy in the power system over 3 days between 7 and 11 pm (peak demand) which account entirely for the annual totals of unserved energy (35 GW h &17 GW h respectively) during this scenario. These periods of unserved energy occurred on days where a mix of generator outages and minimum down time constraints acted to limit dispatchable capacity. These factors had a greater influence than other scenarios since due to the high gas prices, conventional generation was being utilised to meet demand as

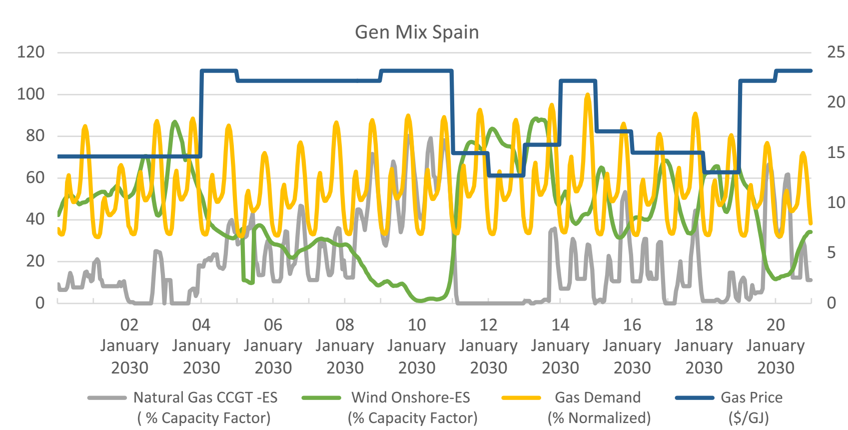

Fig. 2. Generation and gas prices for Spain over 3 weeks.

Table 3
% Changes relative to the reference scenario.

	Portugal	Spain	Italy	Greece	EU average
Gas price	26	30	17	13	8
Power price	13	18	14	10	5
Total generation costs	22	8	−9	9	4

opposed to CCGT plants. This meant that those plants switched off during the lull in demand between 2 pm and 7 pm were unable to come online when needed later the same day.

Flows on the gas pipelines between France and Spain that was fully utilised for the entire year apart from 6 days in the middle of the summer when French gas demand rose to its peak to fill its gas storages. This demand was so severe that it was the sole time during this simulation that France was forced to use its own LNG terminal.

It should be noted in the above table that the total generation costs for Italy fall during this scenario when all the costs for all other countries rose. Italy, during this scenario, reduced its total generation by 9% relative to the reference scenario which resulted in import levels of 18% of its electrical demand. These imports effectively achieve what the CCGT plants in other member states provide i.e. peak and upper-mid loads. Accounting for these imports we see that the true cost of supplying Italy's power demand rose by 13% versus the same metric in the reference scenario.

4.4. No Western Asia supply

This loss of supply had relatively little impact on Europe. Russia and the North African states increase their production to account for this loss and overall supply drops only marginally. Average electricity prices rose by ~1% and gas prices rose by 2% across Europe with the Eastern Balkans seeing the sharpest rises. Both Bulgaria and Romania saw electricity prices rise by approximately 10% with gas prices rising by 10% & 6% respectively. Greece also saw a large increase, where the price of a MW h rose by 10% relative to the reference scenario and gas prices rose by 14%. The higher prices in the Eastern Balkans lead to a fall in generation and an increase in imports and the generation of neighbouring states to account for the shortfall. Power generation fell by between 1% and 4% in this region and increased in Slovakia, Slovenia, and Hungary by 1–2%. The impact of this scenario was felt most keenly by Greece (see Fig. 3) due to the high percentage of gas generation in the Greek generation capacity (38% while Romania and Bulgaria had 6% and 5% respectively). This was compounded by the low electrical interconnection to surrounding countries with only 10% of peak demand available through imports (the EU average was 65%). This low level of interconnection was also visible in the number of hours of congestion which rose by 30% in this scenario relative to the reference.

4.5. No Russian supply

For this scenario, no gas flowed from Russia or Ukraine for the target year. Average gas price increased 28% with the Baltic countries and Finland seeing dramatic increases of over 50%. Countries at the edge of Western and Southern Europe (Ireland, Spain, Italy etc.) also saw increases in electrical prices above the mean demonstrating the consequences of long term supply interruption from European main supplier to gas. While countries on the periphery of European may not import gas directly from Russia, the interconnected gas and power systems response by increasing exports of power when available (for example Ireland increases coal generation and increases exports to the UK). In this scenario nearly all countries with LNG capacity utilised their LNG terminals to some degree, however, LNG still did not provide even 1% of the total supply of natural gas. This was responsible for most of the price increases but there were also much larger levels of gas moved through pipelines which increased costs due to the additional wheeling charges incurred. The average electricity price across the EU rose by 12% with some countries seeing a much sharper rise. Looking at countries containing a high percentage of CCGT plants (Germany, the UK, the Netherlands) the increases in the electricity price were over 20%. Gas demand for power generation fell by 10% with the balance made up by coal generation which had an increase of 5% of capacity utilisation on average when compared to the reference scenario. This, coupled with a rise in the amount of oil-fired generation, led to the average increase of 2% in emissions intensities.

5. Discussion and conclusion

For each scenario where supply was removed, the severity of the impact was proportional to % supply each region provided in the reference scenario. Loss of Russian supply saw the greatest increases in total systems costs, emissions and electricity and gas prices. However, it wasn't the larger share of solids-fired generation that prompted a price increase in the electricity market of 12% on average across Europe. Even when gas became much more expensive countries still needed to run CCGT plants to match fluctuating renewables and this was the primary cause of price increases across both systems. This is clear when comparing all scenarios and noting how endogenous gas demand remained relatively constant at ~26% of total demand.

Natural gas was able to flow freely within Europe and total system costs increased most during the loss of supply scenarios as opposed to the no storage case. This points to the extensive transport infrastructure that allows gas to flow easily within the model. It should be noted that across all scenarios there was never any gas shortages within the model for the exogenously prescribed demands. While gas flows freely and instantaneously between nodes the model doesn't take pressure based considerations into account but rather looks at the long-term ability of the predicted system to meet predicted demand.

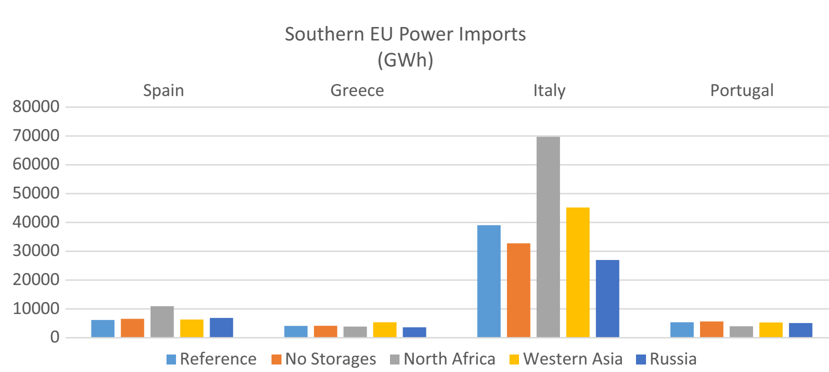

Fig. 3. Power imports to Spain, Greece, Italy and Portugal by Scenario.

When looking across all results several trends begin to become clear. Across all the scenarios the importance of Norway to the European energy system emerged with Norway consistently provided 30–40% of the natural gas supply to Europe. In all scenarios, gas-fired generation acted to balance the variability of renewable generation and this was done regardless of prices. The only other method to offset sudden falls in renewable generation was to import power from neighbouring countries but this led to those secondary countries increasing their CCGT generation and exporting it and was further limited by interconnector capacity. By this

Table 4
Annual summary results for 'No Storage Scenario' each member state.

	No storage scenario Electricity generation (%) from natural gas	No storage scenario Whole sale prices (€/MW h)	No storage scenario Gas prices (€/GJ)	No storage scenario Power sector emissions (Mt)
Austria	2%	97.64	13.57	2.81
Belgium	62%	106.50	13.20	21.57
Bulgaria	7%	93.79	12.96	21.97
Croatia	41%	105.58	14.04	4.22
Cyprus	61%	100.95	11.12	2.15
Czech Republic	0%	93.44	13.87	36.40
Denmark	3%	88.24	11.96	7.94
Estonia	2%	84.22	12.56	8.55
Finland	1%	87.05	12.56	14.43
France	2%	95.57	14.05	4.47
Germany	14%	100.08	12.90	255.28
Greece	40%	106.76	13.15	18.33
Hungary	1%	104.49	13.55	1.38
Ireland	54%	86.70	14.09	9.69
Italy	33%	118.11	13.07	97.31
Lithuania	1%	88.70	13.56	0.05
Latvia	3%	87.25	12.56	0.07
Luxembourg	1%	97.48	13.94	0.01
Malta	50%	107.19	14.07	0.76
Netherlands	26%	99.15	12.17	47.78
Poland	2%	100.09	12.96	142.53
Portugal	5%	131.53	18.39	6.22
Romania	4%	97.96	12.64	23.69
Slovakia	0%	95.29	13.63	0.90
Slovenia	4%	100.92	13.80	4.84
Spain	19%	137.49	17.54	93.80
Sweden	0%	91.47	12.96	3.20
United Kingdom	33%	117.13	13.11	72.55

Table 5
Annual summary results for 'No Western Asia Supply Scenario' each member state.

	No Western Asia Supply Electricity generation (%) from natural gas	No Western Asia Supply Whole sale prices (€/MW h)	No Western Asia Supply Gas prices (€/GJ)	No Western Asia Supply Power sector emissions (Mt)
Austria	7%	97.64	13.13	3.93
Belgium	61%	106.50	12.82	20.39
Bulgaria	6%	93.79	13.74	21.78
Croatia	43%	105.58	13.64	4.40
Cyprus	61%	100.95	11.13	2.16
Czech Republic	0%	93.44	13.17	33.84
Denmark	5%	88.24	11.51	8.12
Estonia	2%	84.22	11.79	8.49
Finland	0%	87.05	12.14	14.75
France	2%	95.57	13.55	5.56
Germany	16%	100.08	12.43	256.01
Greece	38%	106.76	14.33	17.80
Hungary	2%	104.49	12.64	1.79
Ireland	56%	86.70	13.58	10.12
Italy	31%	118.11	13.35	91.63
Lithuania	3%	88.70	12.23	0.14
Latvia	18%	87.25	11.23	0.46
Luxembourg	1%	97.48	13.44	0.01
Malta	50%	107.19	14.35	0.76
Netherlands	26%	99.15	11.89	47.20
Poland	3%	100.09	12.43	138.88
Portugal	6%	131.53	18.36	6.33
Romania	5%	97.96	12.76	23.67
Slovakia	2%	95.29	12.79	1.94
Slovenia	11%	100.92	13.57	5.31
Spain	19%	137.49	17.84	93.51
Sweden	0%	91.47	12.51	3.22
United Kingdom	34%	117.13	12.58	73.43

method, the model minimised total system costs but it implies perfect cooperation between member states. Interconnection and cooperation minimise the impact of peak demand and supply shortages but without these, a much more severe picture would likely emerge for specific countries.

The integrated approach adopted here highlights the importance of the gas system for the stability of the power sector. Each scenario, whether the removal of gas storages or a specific supply region, had a substantial effect on the behaviour of the power sector and added real value to the overall analysis. In response to

Table 6
Annual summary results for 'No North African Supply Scenario' each member state.

	No North African Supply Electricity generation (%) from natural gas	No North African Supply Whole sale prices (€/MW h)	No North African Supply Gas prices (€/GJ)	No North African Supply Power sector emissions (Mt)
Austria	4%	96.43	14.13	3.46
Belgium	61%	106.60	13.26	20.18
Bulgaria	8%	87.35	13.30	21.58
Croatia	44%	99.67	14.13	4.57
Cyprus	61%	98.04	11.13	2.15
Czech Republic	1%	89.83	13.88	35.73
Denmark	3%	84.02	12.13	8.09
Estonia	2%	78.57	12.19	8.62
Finland	1%	81.58	12.50	15.51
France	3%	99.35	14.18	7.54
Germany	16%	97.07	13.05	258.52
Greece	40%	107.63	14.20	18.36
Hungary	3%	101.77	13.12	2.23
Ireland	56%	89.06	13.58	10.21
Italy	24%	128.60	15.12	83.17
Lithuania	4%	85.28	12.63	0.19
Latvia	19%	84.17	11.63	0.51
Luxembourg	0%	93.67	14.05	0.00
Malta	49%	114.59	16.12	0.76
Netherlands	26%	96.89	12.28	47.24
Poland	3%	93.26	13.04	140.54
Portugal	4%	144.82	23.03	7.46
Romania	5%	91.43	12.54	23.86
Slovakia	2%	92.04	13.26	2.41
Slovenia	14%	98.68	14.51	5.54
Spain	15%	164.65	23.16	95.96
Sweden	1%	85.82	13.13	3.70
United Kingdom	35%	114.39	12.58	76.11

Table 7
Annual summary results for 'No Russian Supply Scenario' each member state.

	No Russian Supply Scenario Electricity generation (%) from natural gas	No Russian Supply Scenario Whole sale prices (€/MW h)	No Russian Supply Scenario Gas prices (€/GJ)	No Russian Supply Scenario Power sector emissions (Mt)
Austria	3%	103.04	16.91	3.42
Belgium	53%	117.52	16.47	18.32
Bulgaria	9%	89.20	13.90	21.80
Croatia	44%	105.94	15.48	4.61
Cyprus	61%	97.72	11.13	2.15
Czech Republic	0%	96.61	17.22	37.18
Denmark	2%	94.74	15.96	8.12
Estonia	1%	86.12	19.20	8.83
Finland	0%	87.29	19.76	17.87
France	3%	107.41	17.25	7.75
Germany	10%	112.12	16.36	249.75
Greece	40%	110.15	14.63	18.44
Hungary	3%	108.09	15.57	2.46
Ireland	55%	97.35	16.61	10.42
Italy	33%	126.92	15.41	98.35
Lithuania	2%	92.48	18.14	0.08
Latvia	7%	91.51	18.57	0.21
Luxembourg	2%	107.61	17.25	0.01
Malta	49%	114.47	16.41	0.76
Netherlands	17%	111.94	15.55	44.51
Poland	2%	100.55	17.13	143.27
Portugal	5%	136.22	20.26	6.63
Romania	3%	93.52	13.97	23.75
Slovakia	2%	96.95	17.48	3.04
Slovenia	10%	103.76	16.15	5.25
Spain	19%	151.67	19.71	94.58
Sweden	0%	97.09	16.96	3.62
United Kingdom	33%	131.03	15.68	73.80

these scenarios the European interconnected grid, if looked at holistically, responds to local problems in gas supply by altering the entire electrical system to mitigate the impact. Alterations to the gas network caused fuel switching, changed electrical and gas flow patterns, unserved energy, and shifts in how gas was procured. Another key insight was the interplay between renewable generation and CCGT plants and how their inherent characteristics complement each other. Overall these insights and effects would not have been possible with a stand-alone power systems model and demonstrate the possibilities and value of such an approach.

Appendix A

Note full model, model data and detailed results are available from link (see Tables 4–7).

Appendix B. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2017.02.039.

References

[1] Abrell J, Weigt H. Combining energy networks. Netw Spat Econ 2012;12:377–401. http://dx.doi.org/10.1007/s11067-011-9160-0.

[2] Ahern EP, Deane P, Persson T, Ó Gallachóir B, Murphy JD. A perspective on the potential role of renewable gas in a smart energy island system. Renew Energy 2015;78:648–56. http://dx.doi.org/10.1016/j.renene.2015.01.048.

[3] Arentsen MJ, Künneke RW. Chapter 4 – National Models in the Emerging European Gas Market. In: National Reforms in European Gas. Oxford: Elsevier Science; 2003. p. 45–61.

[4] Bilgin M. Geopolitics of European natural gas demand: Supplies from Russia, Caspian and the Middle East. Energy Pol 2009;37:4482–92. http://dx.doi.org/10.1016/j.enpol.2009.05.070.

[5] BP, 2014. BP Statistical Review of World Energy–June 2014.

[6] CER. Home, Irish Social Science Data Archive [WWW Document]. Ir. Soc. Sci. Data Arch; 2012. URL http://www.ucd.ie/issda/data/commissionforenergyregulationcer/ [accessed 11.25.15].

[7] Chaudry M, Jenkins N, Strbac G. Multi-time period combined gas and electricity network optimisation. Electr Power Syst Res 2008;78:1265–79. http://dx.doi.org/10.1016/j.epsr.2007.11.002.

[8] Cochran J, Bird L, Heeter J, J. Arent D. Integrating variable renewable energy in electric power markets: best practices from international experience. Summary Policymakers 2012.

[9] Deane JP, Chiodi A, Gargiulo M, Ó Gallachóir BP. Soft-linking of a power systems model to an energy systems model. Energy 2012;42:303–12. http://dx.doi.org/10.1016/j.energy.2012.03.052.

[10] Deane JP, Drayton G, Ó Gallachóir BP. The impact of sub-hourly modelling in power systems with significant levels of renewable generation. Appl Energy 2014;113:152–8. http://dx.doi.org/10.1016/j.apenergy.2013.07.027.

[11] Deane JP, Gracceva F, Chiodi A, Gargiulo M, Gallachóir BPÓ. Assessing power system security. A framework and a multi model approach. Int J Electr Power Energy Syst 2015;73:283–97. http://dx.doi.org/10.1016/j.ijepes.2015.04.020.

[12] DECC. UK Renewable Energy Roadmap Update 2013; 2013.

[13] DECC. National Renewable Energy Action Plan for the United Kingdom; 2009.

[14] Denholm P, Hand M. Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. Energy Pol 2011;39:1817–30. http://dx.doi.org/10.1016/j.enpol.2011.01.019.

[15] Devlin J, Li K, Higgins P, Foley A. A multi vector energy analysis for interconnected power and gas systems. Appl Energy 2016. http://dx.doi.org/10.1016/j.apenergy.2016.08.040.

[16] Devlin J, Li K, Higgins P, Foley A. The importance of gas infrastructure in power systems with high wind power penetrations. Appl Energy 2015. http://dx.doi.org/10.1016/j.apenergy.2015.10.150.

[17] Diagoupis TD, Andrianesis PE, Dialynas EN. A planning approach for reducing the impact of natural gas network on electricity markets. Appl Energy 2016;175:189–98. http://dx.doi.org/10.1016/j.apenergy.2016.05.006.

[18] Dickel R, Hassanzadeh E, Henderson J, El-Katiri L, Rogers H, Yafimava K et al. Reducing European dependence on Russian gas; 2014.

[19] Dobos AP. PVWatts version 1 technical reference. Contract 2013.

[20] E3MLab/ICCS. The PRIMES Model 2013-2014; 2014.

[21] ENTSO-E. 10 Year Network Development Plan [WWW Document]; 2016. URL <http://tyndp.entsoe.eu/> [accessed 9.7.16].

[22] ENTSO-G. Ten Year Network Develoment Plan 2015. Avenue de Cortenbergh 100 1000 Brussels, Belgium; 2015a.

[23] ENTSO-G. Ten Year Network Develoment Plan 2015 – Annex D; 2015b.

[24] Erdener BC, Pambour KA, Lavin RB, Dengiz B. An integrated simulation model for analysing electricity and gas systems. Int J Electr Power Energy Syst 2014;61:410–20. http://dx.doi.org/10.1016/j.ijepes.2014.03.052.

[25] EU Commission. ENERGY UNION PACKAGE – A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy. Brussels; 2015.

[26] EU Commission. Energy Roadmap 2050. EUROPEAN COMMISSION, Brussels; 2011.

[27] Eurogas. Eurogas Long Term Outlook 2007–2030; 2010.

[28] European Commission. Projects of common interest – Energy [WWW Document]. Energy; 2016. URL https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest [accessed 1.22.16].

[29] Finon D, Locatelli C. Russian and European gas interdependence: could contractual trade channel geopolitics? Energy Pol 2008;36:423–42. http://dx.doi.org/10.1016/j.enpol.2007.08.038.

[30] Flouri M, Karakosta C, Kladouchou C, Psarras J. How does a natural gas supply interruption affect the EU gas security? A Monte Carlo simulation. Renew Sustain Energy Rev 2015;44:785–96. http://dx.doi.org/10.1016/j.rser.2014.12.029.

[31] Guandalini G, Colbertaldo P, Campanari S. Dynamic modeling of natural gas quality within transport pipelines in presence of hydrogen injections. Clean Effic Afford Energy Sustain Future 2017;185(Part 2):1712–23. http://dx.doi.org/10.1016/j.apenergy.2016.03.006.

[32] Hart EK, Jacobson MZ. A Monte Carlo approach to generator portfolio planning and carbon emissions assessments of systems with large penetrations of variable renewables. Renew Energy 2011;36:2278–86. http://dx.doi.org/10.1016/j.renene.2011.01.015.

[33] IEA. IEA Key World Statistics; 2014.

[34] IEA. Empowering Variable Renewables (Options for Flexible Electricity Systems). IEA Publications. 75739 Paris Cedex 15; 2008.

[35] Jun D, Xu Z, Xue J, Xiaolin X, Yuxi T. Economic Analysis and Policy Suggestions on Gas Power Generation Projects Considering Carbon Emission Reduction. Procedia Environ. Sci., 2011 2nd International Conference on Challenges in Environmental Science and Computer Engineering (CESCE 2011) 11(Part B);2011:1029–1038. http://dx.doi.org/10.1016/j.proenv.2011.12.157.

[36] Kropatcheva E. He who has the pipeline calls the tune? Russia's energy power against the background of the shale "revolutions". Energy Policy 2014;66:1–10. http://dx.doi.org/10.1016/j.enpol.2013.10.058.

[37] Lienert M, Lochner S. The importance of market interdependencies in modeling energy systems – the case of the European electricity generation market. Int J Electr Power Energy Syst 2012;34:99–113. http://dx.doi.org/10.1016/j.ijepes.2011.09.010.

[38] Lukens J. Pricing an integrated energy transmission grid: are FERC's natural gas and electric power transmission pricing policies on a collision course? Electr J 2000;13:34–40. http://dx.doi.org/10.1016/S1040-6190(00)00083-X.

[39] Montoya Cardona, J. Impact of Renewable Energy Sources in the European Gas Network; 2014.

[40] Montoya Cardona Juliana. Impact of Renewable Energy Sources in the European Gas System. Hanze University of Applied Sciences; 2014.

[41] Morais MS, Marangon Lima JW. Combined natural gas and electricity network pricing. Electr Power Syst Res 2007;77:712–9. http://dx.doi.org/10.1016/j.epsr.2006.05.005.

[42] Möst D, Perlwitz H. Prospects of gas supply until 2020 in Europe and its relevance for the power sector in the context of emission trading. In: Energy. 11th Conference on Process Integration, Modelling and Optimisation for Energy Saving and Pollution Reduction, 34. p. 1510–22. http://dx.doi.org/10.1016/j.energy.2009.06.045.

[43] Norgaard P, Holttinen H. A multi-turbine power curve approach, Nordic Wind Power Conference. Nord. Wind Power Conf; 2004.

[44] NREL. PVWatts Calculator [WWW Document]; 2016. URL <http://pvwatts.nrel.gov/> [accessed 9.7.16].

[45] Orlov A. The strategic implications of the second Russia-China gas deal on the European gas market. Energy Strategy Rev 2016;13–14:1–10. http://dx.doi.org/10.1016/j.esr.2016.05.003.

[46] Paltsev S. Scenarios for Russia's natural gas exports to 2050. Energy Econ 2014;42:262–70. http://dx.doi.org/10.1016/j.eneco.2014.01.005.

[47] Qadrdan M, Ameli H, Strbac G, Jenkins N. Efficacy of options to address balancing challenges: integrated gas and electricity perspectives. Appl Energy 2017;190:181–90. http://dx.doi.org/10.1016/j.apenergy.2016.11.119.

[48] Qadrdan M, Chaudry M, Wu J, Jenkins N, Ekanayake J. Impact of a large penetration of wind generation on the GB gas network. Energy Policy, The socio-economic transition towards a hydrogen economy – findings from European research, with regular papers 38;2010:5684–5695. http://dx.doi.org/10.1016/j.enpol.2010.05.016.

[49] Qadrdan M, Cheng M, Wu J, Jenkins N. Benefits of demand-side response in combined gas and electricity networks. Appl Energy; n.d. http://dx.doi.org/10.1016/j.apenergy.2016.10.047.

[50] Qiao Z, Guo Q, Sun H, Pan Z, Liu Y, Xiong W. An interval gas flow analysis in natural gas and electricity coupled networks considering the uncertainty of wind power. Appl Energy; n.d. http://dx.doi.org/10.1016/j.apenergy.2016.12.020.

[51] Richter PM, Holz F. All quiet on the eastern front? Disruption scenarios of Russian natural gas supply to Europe. Energy Pol 2015;80:177–89. http://dx.doi.org/10.1016/j.enpol.2015.01.024.

[52] Shahidehpour M, Fu Y, Wiedman T. Impact of natural gas infrastructure on electric power systems. Proc IEEE 2005;93:1042–56. http://dx.doi.org/10.1109/JPROC.2005.847253.
[53] Skjølberg K. Power System Impacts of variable renewable Energy Sources towards 2050: With special emphasis on wind and solar utilisation and grid costs; 2014.
[54] Smith JC, Beuning S, Durrwachter H, Ela E, Hawkins D, Kirby B, et al. Impact of Variable Renewable Energy on US Electricity Markets; 2010.
[55] Suarez MJ, Gelaro R, Todling R, Bacmeister J, Liu E, Bosilovich MG, et al. MERRA: NASA's modern-era retrospective analysis for research and applications. J Clim 2011;24:3624–48. http://dx.doi.org/10.1175/JCLI-D-11-00015.1.
[56] World Energy Council. World Energy Resources: 2013 Survey. London: World Energy Council; 2013.
[57] Yazdani Damavandi M, Kiaei I, Sheikh-El-Eslami MK, Seifi H. New approach to gas network modeling in unit commitment. Energy 2011;36:6243–50. http://dx.doi.org/10.1016/j.energy.2011.07.034.