A multi vector energy analysis for interconnected power and gas systems

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HIGHLIGHTS

- The first multi vector energy system analysis for Britain and Ireland is performed.
- Extreme weather driven gas demands were utilised to increase gas system stress.
- GB gas system is capable of satisfying demand but restricts gas generator ramping.
- Irish gas system congestion causes a 40% increase in gas generator short run cost.
- Gas storage in Ireland relieved congestion reduced operational costs by 14%.

ARTICLE INFO

ABSTRACT

This paper presents the first multi vector energy analysis for the interconnected energy systems of Great Britain (GB) and Ireland. Both systems share a common high penetration of wind power, but significantly different security of supply outlooks. Ireland is heavily dependent on gas imports from GB, giving significance to the interconnected aspect of the methodology in addition to the gas and power interactions analysed. A fully realistic unit commitment and economic dispatch model coupled to an energy flow model of the gas supply network is developed. Extreme weather events driving increased domestic gas demand and low wind power output were utilised to increase gas supply network stress. Decreased wind profiles had a larger impact on system security than high domestic gas demand. However, the GB energy system was resilient during high demand periods but gas network stress limited the ramping capability of localised generating units. Additionally, gas system entry node congestion in the Irish system was shown to deliver a 40% increase in short run costs for generators. Gas storage was shown to reduce the impact of high demand driven congestion delivering a reduction in total generation costs of 14% in the period studied and reducing electricity imports from GB, significantly contributing to security of supply.

1. Introduction

Previously, the interactions between energy supply vectors such as power and gas were relatively unexplored [1]. The continual increase in renewable energy penetration requires a pressing need to understand the interaction between energy system supply networks. By 2030, installed wind and gas generation capacity in Irish and British power systems will be 78% [2] and 67% [3] respectively. The reliance on both generation technologies results in an implicit relationship between power and gas systems as fast ramping gas generators are frequently utilised in the supply of residual load, adding flexibility to the power system and facilitating the

adoption of renewable energy [4]. In the case of power systems with high penetrations of wind power and a reliance on gas fired generation, the stochastic nature of wind power is transmitted onto gas fired units and thus the gas transmission infrastructure.

The importance of considering the wider, multi vector energy system has been highlighted in [5] where the demand driven gas price had an impact on the ability of gas generators to be competitive in the power market. Significant work has been conducted regarding the ability of one energy system to cope with failures in another. The requirement of gas system operators to consider the impacts on power system operation when dealing with outages over a short time frame was highlighted in [6]. Both [7,8] show how power system security is negatively affected due to outages on the gas transmission network. As power systems continue to integrate high penetrations of renewable energy, the increased flexibility and variable output provided by gas units [9] will

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continue to couple the gas and power energy vectors closely. A modelling approach for system operators to co-ordinate demand response in both power and gas vectors considering wind power uncertainty was described in [10] and applied to an IEEE test system. The approach highlighted how supply companies could reduce system operating costs by incentivising demand response participation and optimising peak energy system loads. A model investigating the dynamic interaction between power and gas systems at the micro grid scale was developed in [11]. It was found that single shaft micro turbines insulate both power and gas systems from each other, whereas a split shaft turbine increases interaction between both vectors allowing faults to be distributed.

Unit commitment models relating to short term security constrained operation and long term planning of combined power and gas test systems were developed in [12,13] respectively. The long term model highlighted the ability of gas transmission constraints to impact combined system expansion planning schedules, due to the dependency of natural gas units on gas transmission infrastructure. However, short term operational impacts due to natural gas transmission constraints were shown to impact on gas generators ability to contribute flexible generation, overall generation volumes and ultimately total system generation costs [14]. Similar work regarding short term power and gas interaction was performed in [15]. Similarly, a combined network expansion planning methodology applied to both an IEEE test system and the real gas and power system of Hainan province, China was presented in [16]. It was shown in this analysis that planning gas and power networks together in addition to optimising investment and production costs delivered higher social welfare than planning of individual networks. However, it was shown that high levels of wind power have the potential to increase cost despite multi vector expansion planning.

The aforementioned work considers idealised test systems. The following references consider the Great Britain (GB) power and gas network utilising a DC load flow model for the power system and a representative hydraulic model for the gas network. The model is initially presented [17] and developed to consider the impacts large penetrations of wind have on the gas network [18], then utilised to investigate operating strategies to account for wind forecast error [19] and influence expansion planning respectively [20]. More recently, the work has been used to outline the benefits of power to gas technology with respect to wind curtailment and system operational costs, reducing both [21]. Similar work on the GB network has been conducted by [22], where changes in domestic heating technology are implemented to quantify the changes in flexibility afforded to the power system by the gas network. Work undertaken by [23] quantified the impacts gas system outage events had on power market prices in the Hellenic power and gas system. By installing gas storage, gas network failures are mitigated and result in only a small increase in system cost. The importance of combined energy system operation is further highlighted in [24], where an optimal control model of the Illinois power and gas system is developed. It was found that gas unit dispatch considering only the power system decreased the flexibility of the gas system. However, when both energy vectors were operated in tandem gas units were shown to offer demand response capability to gas pipeline operators and assisted to increase gas supply ability.

The above work, whilst focusing on the interaction between power and gas supply networks, is performed using either a test system or a representation of a real power system. The work conducted in this analysis utilises a fully realistic unit commitment and economic dispatch model (UCED) which considers the technical characteristics of every unit in the power system. An energy flow model of the gas network is included, respecting pressure constraints via line pack limitations and interfacing with the UCED model in a spatially accurate manner. Additionally, multiple

energy systems are considered. The integrated energy systems model is developed for GB and the island of Ireland, which to the author's knowledge is the first multi vector, multi-jurisdictional energy flow model for large scale interconnected power and gas systems. This facet of the analysis is extremely valuable since secure operation of the gas network in Ireland is almost exclusively dependant on imports from GB [25]. In turn, it has been shown that gas system operation is fundamentally important for the secure operation of the power system in Ireland. The methodology and analysis presented here is envisaged to contribute to high level understanding of the interactions between interconnected power and gas systems where one system is dependent on another, in line with EU progress towards a single European internal energy market [26].

2. Methodology

The overarching aim of the methodology employed in this work is to investigate the interaction between power and gas vectors when operation of both systems is co-optimised, rather than the separate operation which is historically the case. The work presented is an energy flow analysis, performed using a fully realistic unit commitment and economic dispatch model of the power systems of the UK and Ireland coupled with a representative gas model for each system. The objective function is shown in (1) and described in [27,28,7,29]. It is tasked with supplying both gas and power demands at least production cost, solved by Fico's Xpress Optimisation Suite [30] and built using Energy Exemplar's Plexos Integrated Energy Model 6.4 [31].

$$\min \ \Sigma_{t \in T} \Sigma_{j \in J} \Sigma_{i \in I} \Sigma_{k \in K}$$

$$\times \left(\underbrace{\begin{bmatrix} SC_j \cdot US_{jt} + NLC_j \cdot UG_{jt} \\ +(VOM_j + UoS_j) \cdot P_{jt} \\ +PC_j \cdot P_{jt} \\ +PenLLE \cdot UEE_t + PenLLE \cdot RES_{jt} \\ +PDE \cdot ExE_t \end{bmatrix}}_{\text{Power System Component}} \underbrace{+[GPC_{it} + GTC_{kt} + PenLLG \cdot UGD_t]}_{\text{Gas System Component}} \right)$$

$$(1)$$

where SC_j and NLC_j are start costs and no load costs of each generator j at each time step from t to T. US_{jt} and UG_{jt} belong to set 0 or 1 determining the unit commitment state of each unit, if started or generating respectively. Variable operation and maintenance charges, VOM_j and use of service charges UoS_j are variable with the level of output from each unit, P_{jt} as is total production cost PC_j. Unserved energy UEE_t and insufficient reserve provision RES_{jt} are penalised the cost of loss of electrical load $PenLLE$. Excess energy ExE_t is priced at the dumped energy price PDE which is an arbitrary high price to ensure generation does not exceed demand at each node. The base price of gas in the model is set at the production cost of the individual supply source field GPC_{it} located at gas node i. Gas pipeline transportation tariffs for pipeline k are represented by GTC_{kt}. Loss of gas load is handled similarly to the electrical load counterpart, with unserved gas demand UGD_t penalised at the loss of load price $PenLLG$.

This work builds on the models presented in [7,32]. The key part of the methodology is focused on the interaction between power and gas vectors and is achieved by gas generators. Gas generators are present in both UCED and gas models, thus enable the co-optimisation of both systems to occur. Gas generators attached to a gas node are fuelled by the gas model and produce electricity in the UCED model. These gas nodes all receive a shadow price which is the value the energy system places on the next unit of gas supply at that node. Any scarcity pricing due to congestion, linepack limitations (where the volume of gas in a pipeline reaches

upper or lower bounds) or more expensive supply routes are reflected in this shadow price. Each gas generator then utilises this gas node shadow price in the calculation of its short run marginal cost (SRMC) shown in (2) in order to bid into the UCED model. Therefore, constraints in the gas network model have a direct impact on gas generators in the UCED model.

$$SRMC_j = (SP_i * MHR_j) + VOM_j + UoS_j + P_c \qquad (2)$$

where $SRMC_j$ is the short run marginal cost of unit j, SP_i is the shadow price at gas node i, MHR_j is the marginal heat rate, VOM_j is the variable operation and maintenance charge per MWh of electricity production and UoS_j is the use of service charge to require to supply to the grid, for unit j. The market price of carbon was reflected in the fuel prices input to the model, but if not implicit, would also be included in determining the SRMC.

2.1. Unit commitment and economic dispatch model

A fully realistic unit commitment and economic dispatch model of the entire British Electricity Trading and Transmission Arrangement (BETTA) and Single Electricity Market of Northern Ireland (NI) and Republic of Ireland (ROI) (SEM) is utilised in this work. Additionally, a representative unit commitment model of northern Europe in order to achieve appropriate interconnector flows is included. The model is a direct implementation of the 2016 model presented in [28] and developed to 2030. A unit based modelling approach is utilised, whereby the technical characteristics of each generating unit (maximum capacities, minimum stable levels, ramp rates, minimum up and down times) are explicit inputs. Each unit has a short run marginal cost based on (2) which is submitted to form a merit order. This merit order considers the quantity of generation each unit is offering to the market based on current availability and level of reserve provision. The unit commitment problem is solved considering these specific generator technical constraints, energy and ancillary service bids and overall system security constraints in order to maintain supply and demand balance. The objective function is formulated as shown in (1) and is solved to achieve a solution with the least production cost required to meet demand.

The UCED modelling methodology takes a security and reserve constrained approach centred on the real time balancing market in an attempt to create a realistic system operational schedule for both the SEM and BETTA. The SEM consists of two nodes, ROI and NI. The BETTA is modelled using National Grid's system study zones, with all boundary interfaces and transfer capacities respected in order to achieve a realistic flow of energy in the UCED and gas models. The UCED model is the main component of this analysis, as it is the dynamic driver of gas system demand. Non power generator gas demand in the gas model is passive and exists purely to achieve realistic energy flows in the system. However, the gas system component due to its presence in the objective function and line pack limits discussed in Section 2.2 has the ability to influence unit commitment and gas generator dispatch. Installed capacity for each system is shown in Table 1 for 2030 and is extrapolated from data available in [2,3]. Installed wind capacity in the BETTA is based on National Grid's Gone Green projections in [3]. Wind capacity in the SEM is based on projections in [33]. The simulation was run for one year, with the results for a winter month presented, at a step size of one day and an interval length of one hour.

2.2. Gas system model

The multi vector dimension to this analysis is given by the inclusion of a representative model of the entire GB and Ireland

Table 1
SEM and BETTA installed capacities [3,2].

Fuel type	Installed capacity (MW)	
	SEM	BETTA
Gas	5791	32,207
Oil	–	445
CHP	–	1084
Coal	855	3218
Nuclear	–	9752
Pumped storage	292	3344
Hydro	216	2826
Offshore wind	600	38,197
Onshore wind	6368	13,150
Renewables	970	16,968
Biomass	101	4312
Peat	346	–
Distillate	640	–
Waste	151	–
Total	16,330	125,503

gas network. As previously outlined, the gas model interfaces with the UCED model at gas nodes where a gas generator is located and influences combined system optimisation via a gas shadow price. The gas model is an energy flow model, which does not directly incorporate hydraulic aspects of gas system operation such as pressure levels and compressor usage. It is clear that these modelling considerations do not give rise to detailed gas system operational results. However, the scope of this work is to investigate the interactions between power and gas vectors, thus the energy flow model of the gas component of the analysis is deemed acceptable. Whilst pressure limits are not directly implemented in the model, they are achieved using line pack limitations as a proxy. Gas system line pack was represented by pipeline volume constraints governing minimum and maximum volumes. These levels were based on an assumed system wide minimum operating pressure of 38 barg [34] and a maximum pressure of 70 barg [35]. Utilising these pressure limits and pipeline characteristics, (3) was used to determine the maximum and minimum pipeline volumes (V_b) [36].

$$V_b = 7.855 \times 10^{-4} \left(\frac{T_b}{P_b}\right)\left(\frac{P_{avg}}{Z_{avg}T_{avg}}\right)D^2L \qquad (3)$$

where the base temperature and pressure of the pipeline is T_b and P_b respectively. The average pressure and temperature are represented by P_{avg} and T_{avg}, with the average compressibility factor Z_{avg} set at 0.9 [36]. Pipeline equivalent diameter and length are represented by D and L respectively. By introducing this line pack constraint on all pipelines, the gas model gained a spatial dimension and a more realistic operating profile. Additionally, the gas network was balanced hourly in the simulation since the twice daily balancing in GB was not possible to add into the sub problem and daily balancing dramatically increased simulation time in order to solve without infeasibilities. This assumption is expected to overvalue the line pack limitations in the model, but results in a steady state gas network analysis. However, given the hourly interval granularity of the UCED model, the co-optimisation of both power and gas vectors at the same interval was assumed to be a necessary trade off since the UCED model is the driving component in this work.

2.2.1. Entry nodes

Unlike the power component of the energy system model, where import and exports from the SEM and BETTA with northern Europe are accounted for via a representative merit order in each interconnected country, the gas model operates under an import only methodology. This is a necessary simplification since this work is not concerned with modelling the macroeconomic

geopolitical landscape which determines global commodities prices. Both the UK and the island of Ireland are forecasted to be net importers of gas in 2030 [3,37]. This, in addition to the analysis being conducted for a winter month in which exports of gas from GB are envisaged to be low, are justification for the import only assumption. A simple merit order approach documented in [38] was applied to differentiate between entry points and import volumes in the gas model and is shown in Table 2.

Indigenous production for the UK and Ireland is achieved by output from the North Sea's United Kingdom Continental Shelf (UKCS) and the Corrib gas field respectively. Both of these fields are currently at different levels of maturity, with Corrib coming online in late 2015. However, both are set to decline production significantly by 2030. Fig. 1 shows the production from each field from 2015 to 2030. North Sea production data is obtained from [3] based on the gone green scenario, and Corrib data is extrapolated from 2025 levels reported in [37]. These production limits were added as a constraint in the simulation. Imports from Norway and contractual continental imports via interconnectors to Belgium and the Netherlands were also based on volumes reported in [3].

Supply flexibility in the system was achieved using the remaining capacity on the continental gas interconnectors, Interconnector UK from Zeebrugge (IUK) and Balgzand Bacton Line (BBL) that both connect at the Bacton entry node. Additional flexible supply routes, as decided by the model via least cost total energy system minimisation were achieved through liquefied natural gas (LNG) imports. The import capacity of each LNG terminal was reduced to 70% in order to account for the fact that continual regasification of LNG cargo is not characteristic of LNG terminal operation [39] due to the spot price responsiveness of such cargos. Minimum daily supply from LNG terminals was constrained to be 314 TJ/d due to boil off volumes in the GB system [3]. The location of each of these entry points based on the simplified system in [18].

The location of each gas generator modelled, gas transmission pipelines and the power system boundaries are shown in Fig. 2. Table 3 shows the import capacity of each entry node.

2.2.2. Gas storage

The total level of storage inventory was based on the National Grid's Winter Update for 2011 [40]. The distribution of this inventory was weighted by the size of each facility, resulting in long and

Table 2
Gas import merit order.

Supply	Position
Beach terminals	1
Continental contract	3
Rough	3
LNG	5
IC imports	4
All other storage	6
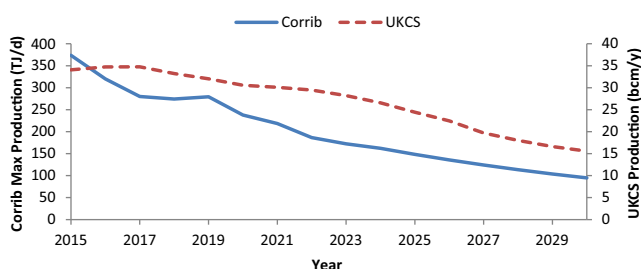
Fig. 1. Projected domestic gas production UK and Ireland.

medium range storage levels at 49.35% and 55.55% of full capacity respectively. Pricing of injection and withdrawal services was reflected by the position of each classification of storage in the merit order. Avonmouth is not included in the analysis and Horn Sea mothballing has been accounted for. The model was ran for a full year in order to determine the most optimal storage injection and withdrawal for summer and winter seasons, with the medium term levels decomposed to the short term via target values. The medium term simulation takes a longer view, incorporating weekly duration curves over a year. This is in contrast to the short term simulation which optimises a day at a time with a six hour look ahead. Executing the model in this manner avoids short term over utilisation of assets to satisfy demand, and delivers a more prudent supply profile. The medium term/short term interaction is also utilised for annual constraints in the supply sources discussed in Section 2.2.1 for UKCS and Corrib production. The operational data for each storage facility in GB was obtained from [41]. A sensitivity analysis of a planned storage device on the island of Ireland is performed in Section 5.

2.2.3. Gas system updates

The gas model utilised in this work is developed from the Irish only model in [7] and the combined GB and Irish model presented in [32]. No major changes to the GB model have been implemented, aside from the demand scenarios presented in Section 2.3. However, for the Irish model, the twinning of the South West Scotland Onshore System (SWOSS) which supplies all three subsea interconnectors to Ireland (SNIP, IC1, IC2) was included. This section of pipeline, whilst technically in GB, is considered part of the Irish network in this analysis. The SWOSS connects to the GB national transmission system at the Moffat entry point, which is the single source of non-indigenous supply for Ireland. The twinning of the SWOSS was undertaken as a European project of common interest (PCI) and is intended to be completed before the simulation horizon [37]. The representation of this network improvement is shown in Fig. 3.

2.3. Scenarios

The scenarios developed aimed to increase gas demand directly in the case of domestic demand and indirectly by dramatically reducing the level of wind power available in the SEM and BETTA. By putting stress on the gas system in this manner, the methodology aims to fully investigate the interaction of both power and gas vectors in the interconnected energy systems in GB and the island of Ireland.

2.3.1. Base case

Gas, power and wind data was obtained for the year 2011 and scaled by the appropriate factor in order to arrive at the projected 2030 demand and installed capacity as reported in [2,44]. Annual and peak demand for each jurisdiction in the analysis is shown in Table 4 Gas and Power Demand Inputs. Power demand in the SEM was applied at two nodes, ROI and NI. However, in the BETTA system, power demand was allocated with respect to National Grid's System Study Zones [45]. For the gas system, a similar nodal approach to demand was taken. Non-power data was obtained directly from Gas Network's Ireland and National Grid for each aggregate load point reported on in 2011 [44]. These load levels were input to the model at geographically accurate locations and scaled appropriately to achieve the total gas demand forecast for 2030, using the grey scenario for Irish demand [37] and the gone green scenario for GB gas demand [3]. Gas demand for NI was based on [46]. Demand forecasts for ROI and NI were only available to 2025 so a linear trend to 2030 was assumed. This is not thought to have any significant impact on the results as the demand
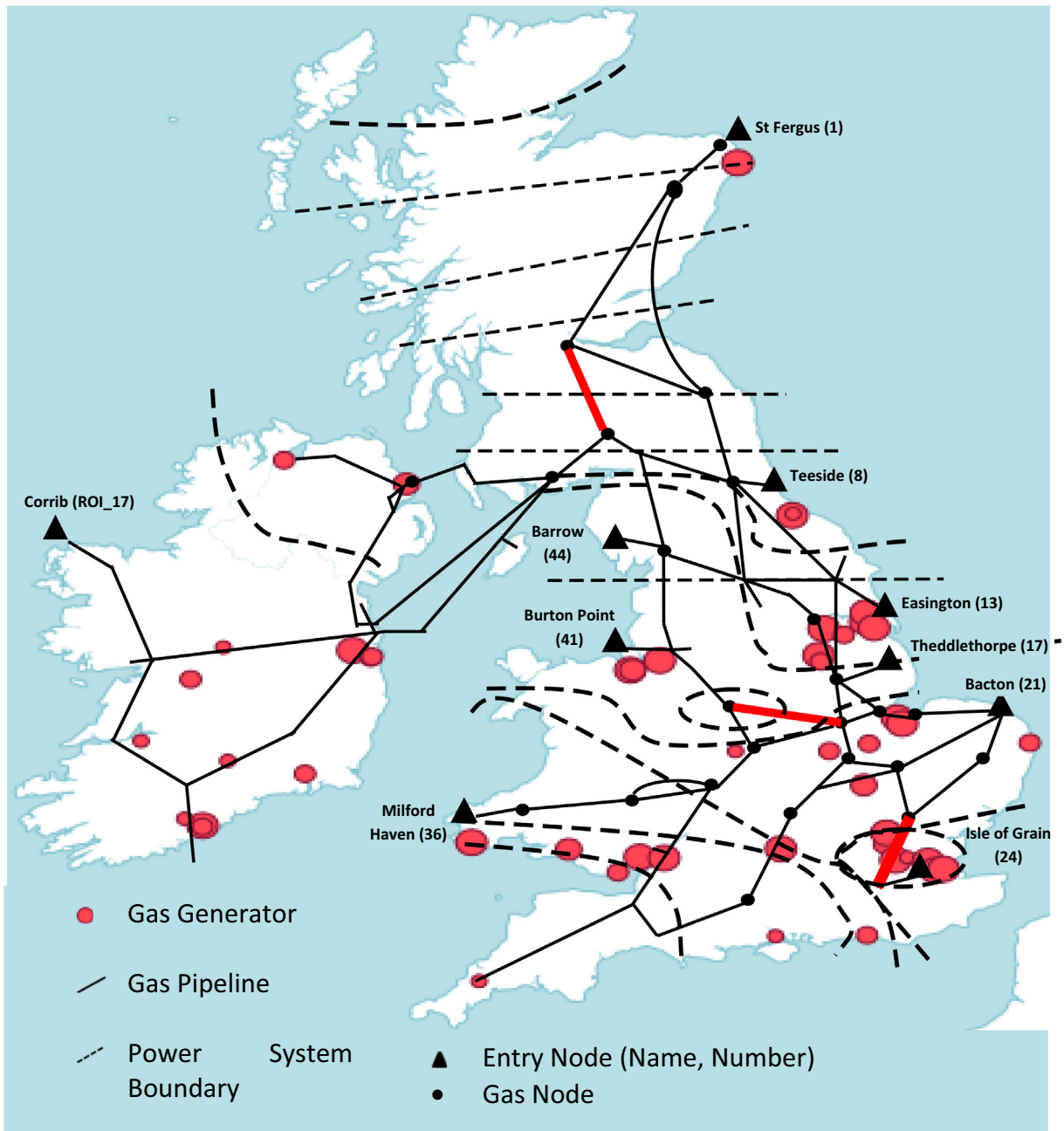
Fig. 2. GB and Irish power and gas network.

Table 3
Gas system entry nodes [42,43].

Entry point	Source type	Max capacity (TJ/d)
Bacton	Continent	6414
Teeside	LNG	1121
Isle of Grain	LNG	1761
Milford Haven	LNG	2392
Easington	Norway	5061
Theddlethorpe	UKCS	2196
Burton point	UK production	264
Barrow	UK production	1223
St Fergus	UKCS/Norway	6009

profiles utilised for both ROI and NI are envisaged to be relatively stagnant in the 2020's. Power sector gas demand is omitted from the inputs since the UCED model drives consumption.

2.3.2. Extreme weather gas

Both of the extreme weather scenarios analysed in this work are based on the weather events which occurred in the UK and Ireland during the winter of 2010. Both national weather services in the UK and Ireland reported severe weather with heavy snow fall and low temperatures [47,48]. The original load profile of 2011 utilised in the formation of the base case gas demand was modified to reflect the increase in demand realised during 2010 by comparing total demand reported in [3] before scaling to 2030 levels as conducted in the base case. This step was necessary since 2010 nodal demand from [44] was not available for the extreme weather event in question. A similar approach for the Irish system was conducted due to lack of granular data [49]. The scaling demand factor was applied uniformly for each gas demand node in the Irish system.
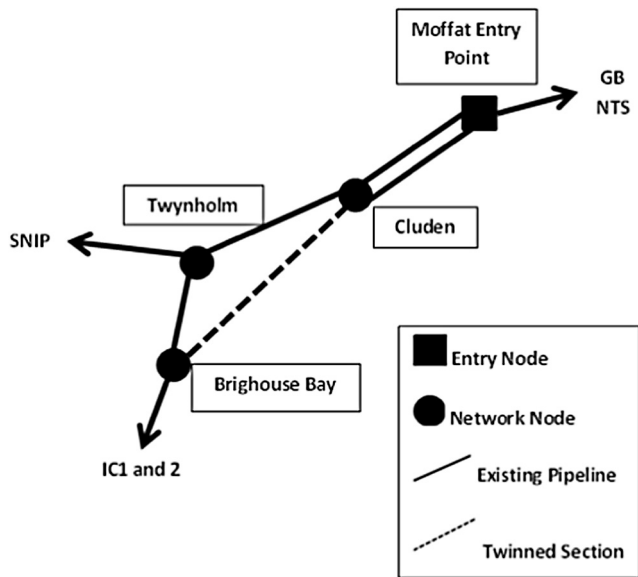
Fig. 3. SWOSS twining update.

Table 4
Gas and power demand inputs.

Energy vector	Demand	BETTA/GB	ROI	NI
Power	Annual (TWh)	345.00	32.36	10.20
	Peak (GW)	62.10	5.36	1.90
Gas	Annual (TWh)	378.87	21.00	739.00
	Peak (incl Power) (GW h)	3631.43	230.00	88.95

2.3.3. Extreme weather wind

Coupled with the decrease in temperatures, wind power generation also decreased significantly, with wind speeds in Ireland reaching minimum values over many locations [48]. By applying a dramatically reduced wind generation capacity factor for 2030 installed capacity in the SEM and BETTA the requirement for gas units to run would increase, since gas units would regain their position in the merit order. This in turn would put further stress on the gas transmission network in both systems and potentially highlight capacity or flexibility issues. Historic capacity factors by location in the BETTA and SEM for 2010 were obtained from [50] and [51]. These were then applied to the anticipated 2030 level of installed capacity. The adjustment of the wind profile as a result of the change in capacity factor was conducted by creating a load duration curve and scaling it by the appropriate factor (found by an iterative process) to achieve the desired decrease in wind output whilst maintaining time series accuracy [52].

2.3.4. Combined extreme weather gas and power

The individual energy vector adjustments were included in the analysis to identify the real drivers in system operational changes due to an extreme weather event where it is very likely that low wind and temperatures will occur together. By analysing together, the change in wind and gas demand profile represents the worst case scenario for gas system operation.

3. Extreme weather analysis

3.1. BETTA analysis

The addition of increased domestic demand in the EW Gas scenario had a negligible impact on all fuel types. The reduction in

wind power available for dispatch in the EW Wind case has resulted in the residual demand required by the objective function to be met with increased generation from thermal units and biomass. Fig. 4 shows the largest generation changes by fuel type. It is clear that gas generation from CCGT's accounts for the majority of the drop in wind, increasing generation from 12,113 GW h in the base case to 13,851 GW h (+14.3%) in the EW Wind scenario. Therefore, it can be concluded that the main driver of generation unit commitment change in the BETTA market as a result of the combined EW Wind Gas scenario is mainly due to the decreased wind profile. This is due to similar total generation volumes between the EW Wind and EW Wind Gas scenarios. The combined EW Wind and Gas scenario required the largest dispatch of gas units, increasing production by 14.7% from the base case.

Since gas fired generation was the fuel type most affected by the scenarios studied, the dispatch of this fuel type is analysed further. Due to the level of installed capacity in the BETTA test system, and the technical ramping ability of the CCGT technology, it is not surprising to find that gas generation has fulfilled over 74% of the reduction in wind generation in both EW scenarios with decreased wind generation. The difference in generation over a typical week in the simulation between the base case and the EW scenarios is more clearly illustrated in Fig. 5. It is clear that despite four scenarios analysed, there exits two dispatch profiles. The first is the base and EW Gas scenarios, which show little variation in the output profile in addition to similar total generation. Secondly, the output profiles of both EW Wind and EW Wind Gas, whilst showing more variation in output than the base and EW Gas, the overall output profile of both are very similar. This highlights that the total level of dispatch is unaffected by high demand on the gas network and gas generation. Furthermore, the similarity of total gas generation highlights the ability of the gas system in GB to withstand these peak demand situations.

Despite relatively minor deviations in total gas generation volumes between each scenario within each dispatch profile shown above, the effects of increased gas demand and low wind were investigated further. The ability of a thermal generator to change its output quickly from one time period to the next is defined as ramping. Ramping is a key flexibility requirement for maintaining security of supply, and increases in importance as the penetration of renewable energy continues to increase. Specifically, ramp up of generators is more important to system security than ramping down and for that reason is analysed further here. Total ramp up conducted by all dispatchable generating units on the system is shown in Table 5.

A change in gas profile via addition of high residential gas demand reduces total ramp up conducted throughout the system. The effects of changing gas demand have a bigger influence on the ramping performed in the system than the reduction of wind, which is an expected finding due to less wind on the system therefore less variability in the demand required to be fulfilled by gas. When compared, EW Gas reduces ramp up by 2.9% with the decrease in wind power reducing ramping up by 2.38%. When combined, the reduction in total ramp up rises to 4.52%. Therefore, it is clear that high residential demand has a significant effect on system operation rather than overall system output, similar to that of low wind with regards to ramping capability of online generators.

Considering each fuel type individually, gas units provide an average of 54% of ramp up requirement in the system across all scenarios and is shown alongside pumped storage and coal as the top three providers of ramp up in Table 5. However, unlike the system wide ramp up trend noticed above, gas unit ramp up actually increases as wind decreases. This increase is far outweighed by the decrease in ramp up conducted by coal in the face of reduced wind, highlighting how flexible generation via gas is
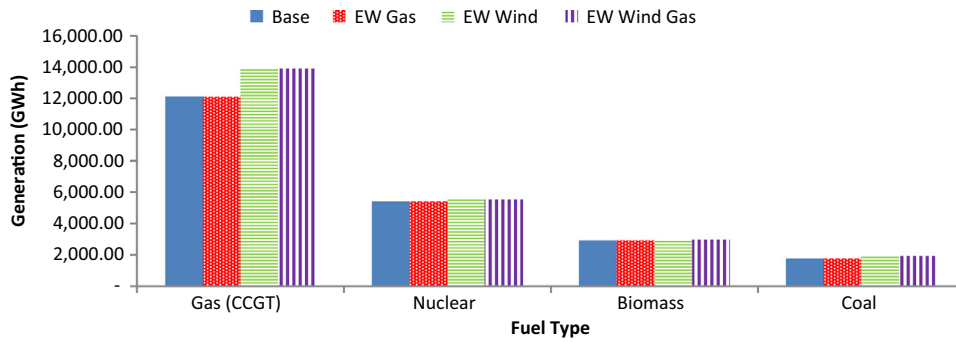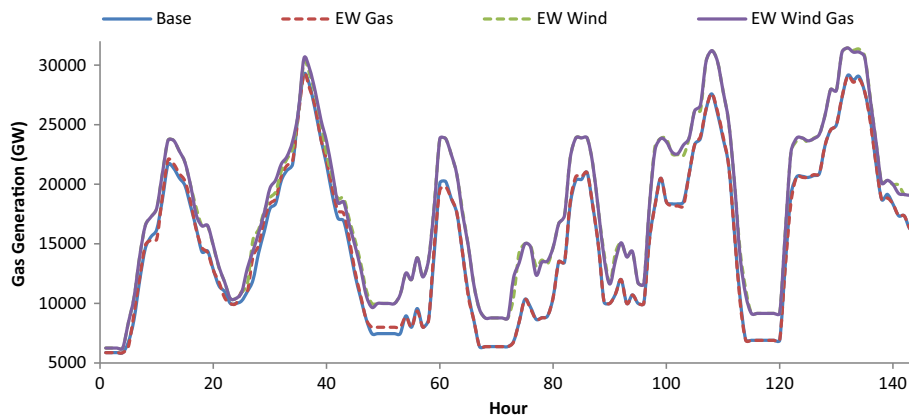
Fig. 4. Total generation change.

Fig. 5. Gas generation.

Table 5
System ramp up.

Ramp up (MW)	GG base case	GG base EW wind	GG base EW gas	GG base EW wind gas
System total	587661	570622	573670	561075
Gas (CCGT)	420525	425427	412886	415928
Pumped Storage	87916	91133	87206	92522
Coal	41842	25374	40725	22179

still important for system operation regardless of wind penetration levels. However, when considering a change in gas profile, the ramp up conducted by gas units decreases by an average of 2%. This suggests that increasing gas demand negatively impacts gas generators ability to provide the flexibility offered in the base case.

Investigating further, day four shows the both the largest ramp up required by gas generators on the system, and the largest difference between ramp up between EW Wind and EW Gas cases. Furthermore, the unit most affected by increased gas demand saw a 1305 MW decrease in ramp up conducted from the base case to the EW Wind Gas case. This unit is connected at gas node 22, mainly supplied via the NTS_34 pipeline. Analysis of the GB system imports during this day show that the entry terminal at GB_24 (Isle of Grain) provides a significant fraction of the extra demand required, rising from a capacity factor of 6.5% in the EW Wind case to 70% in the EW Wind Gas case. As a result of the increased demand on the system supplied from this terminal, the line pack on the NTS_34 line for the 4th day of the simulation reduces by 11%. This directly impacts the ability of the unit to respond directly to the ramp up requirements of the system and shows how increased gas demand has a direct impact on the operation of the power system. This is similar to findings in [14], where flows on the gas system reduced the quantity of ramping provided by gas generators. However, this decreased ramping capability does not automatically mean a reduction in system security. As can be seen from Fig. 6, the average ramp up conducted by all gas units for each scenario with increased gas demand does not show any significant deviation at both morning and peak times from the base case.

The largest deviation in ramp up from the base case occurs as a result of a change in wind profile where units are committed and ramped up to supply the morning peak. High ramping at peak times characteristic of the wind profile scenarios in this analysis are a larger concern for system security than increased domestic gas demand, due to risk of not meeting a large level of consumer demand during high power system stress time periods. The change in wind profile scenarios required a total peak time ramp up increase of 4.47% over the base case and EW Gas scenarios. The majority of the deviations from the base case as a result of increased gas demand occur as smaller changes made throughout the day due to unit commitment decisions. Therefore, it has been shown that increased gas demand has the ability to impact specific gas units, and the ramp up conducted system wide, but a reduction in overall system security due to high gas demand is not apparent. The BETTA system showed no instances of gas units failing to acquire gas to run, only a reduction in the variability of their output. This finding shows that when considering multi vector
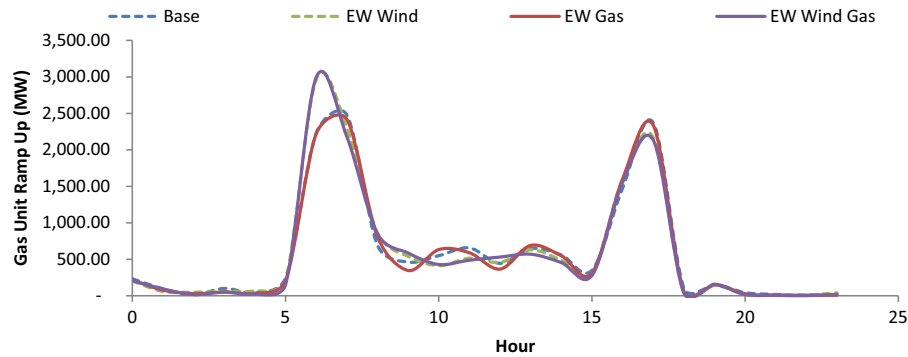
Fig. 6. Gas unit time averaged gas unit ramp up.

systems, aggregate generation data is not enough. This analysis highlights the importance of location and unit specific findings in order to deliver a full understanding of the interactions between power and gas vectors.

3.1.1. Generation costs and emissions production

Similarly for the total generation output and time averaged ramping analysis above, generation costs and emissions follow the same wind/gas profile split. Table 6 Total Generation Costs and Emissions Production shows the total generation costs for all units in the BETTA, the cost per unit generated (for all plant and thermal only) in addition to total emissions production. A change of gas profile had negligible impacts on all metrics shown in Table 6, showing the tolerance of the entire BETTA system to operate economically and securely due to high domestic gas demand. However, a large change in wind profile plays an increasing role in total system operation resulting in a 14% increase in total generation costs. This large increase in costs is also well reflected in the cost per MWh increase from €41.56 in the base case to €47.47 in the EW Wind case. Unsurprisingly the combined low wind and high gas demand in EW Wind Gas scenario results in the highest total generation cost and thus the highest unit cost of electricity. Furthermore, emissions production as a result of the decrease in wind power has produced 15% more CO_2 emissions than the base case. These results show that increased gas demand does not have a large impact on the economic operation of the BETTA in addition to the limited implications for system security. However, decreased wind power production delivers high unit costs and significant increases in CO_2 emissions, directly limiting progress towards a more sustainable power system. Both of these findings are driven by decreased wind power and are compounded with the occurrence of high domestic gas demand, not driven by it.

3.2. GB gas system analysis

The purpose of implementing an extreme weather event was to place increased demand on the gas network via increasing gas demand in the power system and in the domestic sector. Total gas demand for each of the scenarios is shown in Table 7. The impact on gas demand and therefore gas network stress is much larger in scenarios where domestic demand is increased to achieve the desired cold weather profile. It can be seen in Table 7 that the highest percentage of demand required by gas generators peaks at approximately 36% of total demand corresponding to an increase in total demand of 3.7%. Increasing the domestic demand profile in the EW Gas scenario resulted in a total increase of 12.9%. The largest increase in demand occurred in the combined EW Wind and Gas scenario, rising 16.7% when compared to the base case. This, coupled with the lack of unserved energy in all scenarios, shows that from an energy flow perspective, the ability of the GB gas network to successfully manage an extreme weather event is sufficient.

However, the dramatic change in demand required to be supplied by the network involves large changes in the spatial energy flow. Fig. 7 shows the supply sources for each extreme weather scenario. The increase in demand by each scenario over the base case is clearly illustrated. The response of low merit order gas from UKCS and Norway is limited due to production constraints on total annual volumes. Despite this, the model has allowed increased production from the base case in the combined EW scenario by 0.51%. Pricing imported LNG and non-contractual continental gas volumes at the same level enables the simulated gas network to determine the most optimal energy flows, utilising network constraints on entry nodes instead of global economic factors. As a result, the volumes imported from both continental and LNG
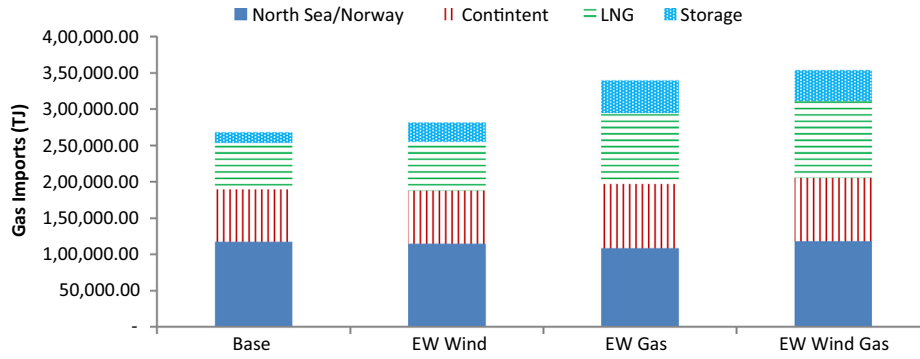
Table 6
Total generation costs and emissions production.

	GG base case	GG base EW gas	GG base EW wind	GG base EW wind gas
Total generation cost (000€'s)	1351961	1358820	1535668	1551039
Overall cost per unit (€/MWh)	41.56	41.76	47.47	47.84
Dispatchable cost per unit (€/MWh)	60.40	60.68	62.60	63.05
CO_2 production (tonnes)	6385450	6393028	7296094	7336908

Table 7
Gas demand by scenario.

Demand (TJ)	GG base case	GG base EW wind	GG base EW gas	GG base EW wind gas
GB domestic and industrial	245377	245377	287104	287104
Power generation	76970	88761	76941	89091
Power as a %	31.37	36.17	26.80	31.03

Fig. 7. Supply source by scenario.

terminals increased significantly in the extreme weather scenarios. LNG imports showed the most flexibility in response to the increased gas demand from the base case to the combined EW scenario, increasing supply by 67.32%. This also corresponded to a rise in capacity factor, from 38% to 65% respectively. This was followed by an increase of 21% in imports through the continental interconnectors, equating to an average utilisation increase of 12% for each pipeline.

Considering the rise in imports through LNG and continental entry nodes, nodal flow variations across all scenarios further illustrate the response of various supply locations to increases in demand. A simple metric to evaluate variability between scenarios is to compare the relationship between the range of imports for each entry node to the average of all imports across each scenario. Fig. 8 shows the results of this variability metric for each entry node in the GB system. Node 24, location of the Isle of Grain LNG import terminal shows the highest degree of variability over all four demand scenarios, with the LNG entry node showing the third most variability. This confirms the utilisation of LNG as a flexible supply source, and highlights the importance of such flexibility in ensuring security of both power and gas systems in times of simultaneous high stress events.

3.3. Locational flows

The above entry node analysis, due to its aggregate reporting does not fully capture the intraday flow changes and variability experienced by pipelines in the system. Therefore, an alternative method for analysing the changes in zonal flows was developed. Gas system supply zones exactly equivalent to the system study zones utilised in the UCED model were created. Coupled with flow magnitude, flow direction is an important aspect of the energy flow analysis and enables changing supply and demand dynamics to be identified. In an effort to capture the intrazonal energy flows in the gas system, the percentage of forward and reverse flow in each intrazonal pipeline was determined, with respect to total flows experienced in each of the pipelines for each scenario. Pipelines with the largest change in flow direction are shown in Fig. 9. Pipelines NTS_10, 34 and 55 consistently experience the largest changes in flow direction in the whole system for each scenario analysed and are highlighted in Fig. 2. It is interesting to note the locations of each of these lines. NTS_10 is one of the main transit pipelines for the transmission of gas entering at St Fergus and is representative of flows between Zones 5 and 6. NTS_34 is also a key piece of infrastructure for delivery of LNG via the Isle of Grain terminal and links Zones 12 and 14. NTS_55 is one of the few pipelines modelled that enables transverse gas flow from Zone 11 to 12, whereas the majority of other pipelines flow in the longitudinal direction.

The various demands placed on the gas system are shown to have a substantial impact on the direction of gas flow in the pipelines presented. Fig. 9 shows the percentage of total flow in each pipeline that is in the notional forward direction. In the case of NTS_34, the additional gas demand as a result of decreased wind generation and increased domestic gas demand has significantly
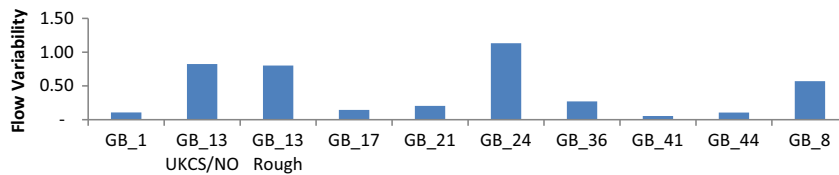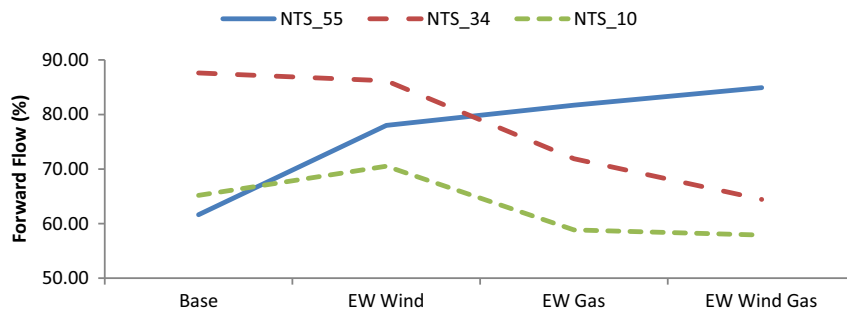

Fig. 8. Flow variability by entry node.

Fig. 9. Interzonal pipeline percentage forward flow.

reduced the volume of gas flowing from Node 22 to 23. Flows in this direction have dropped from 87.62% in the base case to 64.45% in the combined extreme wind and gas scenario, resulting in a corresponding rise in reverse flow (i.e. supplies flowing from the Isle of Grain LNG terminal) of 21.74%.

Similarly for the NTS_10 pipeline, the general trend is for flows in the forward direction to decline with increasing gas system demand. However, for the EW Wind scenario forward flow increased by approximately 5%. This increase was driven by high flows of gas through NTS_10 during a few isolated periods in the simulation horizon, of which are not reflective of the overall trend for the EW Wind scenario. Momentarily large increases in flows out of Zone 6 via NTS_10 and 11 were required in order to support the levels of line pack in the southern parts of the system during two main periods where large capacities of gas generation were required to ramp up significantly at peak time. The average peak time ramp up conducted in the EW Wind scenario was 1300 MW, whereas ramp up over the same period in the EW Wind Gas scenario was 1062 MW. The decision to increase the flows from this zone during these select periods was influenced by the look ahead functionality of the model. This instantaneous flow decision is not made in other scenarios due to the already high domestic gas demand increasing the capacity factor of pipelines in the system, changes in storage supply and small changes in unit commitment across all scenarios.

NTS_55 is the only pipeline in the system where a noticeable increase in forward flow has been experienced. It is worth noting that the flow directions utilised in the analysis are arbitrary, and have been considered when calculating the notional flows. As previously stated, this pipeline is also one of the few pipelines enabling transverse cross country flow. Similarly to the result for the NTS_34 pipeline, the increase in forward flow through NTS_55 is directly attributable to increased imports through the Dragon/South Hook LNG terminal. NTS_55 in the simulated network is an arterial supply route for these imports, enabling the high domestic and power generation demand in South East GB to be met. The rise in forward flow from 61.63 to 84.92% highlights the importance of resilient import and transmission infrastructure in satisfying unexpected weather driven demand events. The decrease in forward flows in NTS_10 shows how the decrease in supply from the UKCS puts further importance on the southern parts of the network. However, due to the historic investment in the gas infrastructure in Scotland, where transmission capacity was focused more on transmission of St Fergus imports rather than satisfying local demand, the resiliency is still important as was demonstrated in the EW Wind scenario.

The lack of any unserved demand in both the power and gas systems in the scenarios investigated has shown the inherent resiliency present in the GB energy system. However, this work has quantified the locational energy flow impacts a simulated extreme weather event driving increased gas demands in the power and domestic sectors has had on the multi-vector energy system. Changes in flow patterns and direction in these high demand situations are an issue for system operators due to the uncharacteristic operation required to ensure security of supply. The modelling conducted here is energy only, but it is assumed in a real world system requiring the use of compressors and more stringent pressure limits could further challenge safe, secure system operation in these times of unorthodox system operational envelopes.

4. Dependent system impacts

The analysis thus far has been mainly focused on the impacts extreme weather has on the power and gas systems in GB. Whilst novel in itself, the interaction between interconnected GB and Ireland multi vector energy systems delivers further originality. Similarly for the GB system, both power and gas systems on the island of Ireland do not experience any loss of load. However, impacts of the power and gas demand profiles for each scenario studied produced interesting results.

4.1. All island gas system

Domestic production in Ireland is assumed to be priced at the same level as GB production due to the proximity of the notional GB National Balancing Point (NBP), one of the most liquid trading hubs in Europe. Therefore, production from the Corrib field is by default cheaper than imports from GB since there are no interconnector charges associated with indigenous production. As a result, the model utilises Corrib supply at maximum capacity in all scenarios. This is expected since imports from GB are the marginal supply source. Fig. 10 shows the levels of imports delivered through the Moffat entry point. Additionally, Table 8 shows the total imports, capacity factor and number of constrained days experience at the entry point.

As expected, the base case scenario showed the lowest levels of import requirement for the overwhelming majority of days in the month, with a total import of 19,361 TJ. The first interesting result concerns both the EW Wind and EW Gas scenarios. Close correlation in the daily flows between both scenarios is apparent in Fig. 10 and Table 8 with total imports in each case also matching very closely at 21,455 TJ and 21,457 TJ respectively. This result was not expected, since the preceding analysis conducted for the GB system showed a higher gas demand experienced in the EW Gas than in the EW Wind scenario. The similarity in imported gas between the EW Wind and EW Gas shows that power driven gas demand and domestic driven gas demand can achieve the same impact on interconnector flows and therefore system security. This is in contrast to the GB system, where domestic demand has the ability to significantly change the operational requirements of the system. Smaller domestic demand levels and higher penetrations of wind power on the island of Ireland coupled with the increased requirement for fast acting gas plant supplying residual power demand have been shown to result in similar gas system operation.

With regards to the EW Wind and gas scenario, it can be seen that this profile results in the largest level of imports from GB as expected at 23,257 TJ. The timeframe of the analysis also shows a marked change in imports for each half of the month. The range between intramonth imports is greater due to less overall demand driven by higher wind power generation for the first half. Conversely, from the 16th day onwards, it can be seen that the entire import system is operating at a higher level across all scenarios, with import profiles operating within a much closer range. Moffat reaches its maximum daily capacity 9 times during the simulation horizon. This is compared to 4, 2 and 1 for each of the EW Gas, EW Wind and base cases respectively. Therefore, whilst all domestic demand is satisfied, it is clear that in times of both high domestic and power generation demand, the entry node capacity at Moffat cannot deliver all the required energy.

Furthermore, the EW Gas Wind scenario delivers the single largest change in intraday flows. A total change in flow of 318 TJ between the 16th and 17th day is the largest reported in the results. This large change was driven by a large increase in wind generation during days 15 and 16 thereby reducing the gas generation demand for each of these days. However, given the large domestic demand and increased gas generation required to satisfy power demand in the EW Wind Gas scenario, import flows increased significantly to accommodate 547 MW of ramping over a 7 h timeframe. Whilst this increase in generation was well within the system's capacity capability, it is clear that gas infrastructure is
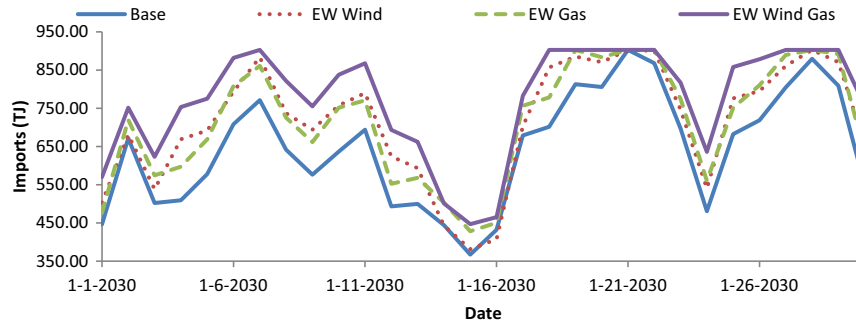
Fig. 10. Irish gas system imports.

Table 8
Flow conditions at moffat.

	GG base case	GG base EW wind	GG base EW gas	GG base EW wind gas
Total flow (TJ)	19362	21455	21458	23257
Capacity factor (%)	71.50	79.23	79.24	85.89
Number of days at maximum capacity	1	2	4	9

required to exhibit or accommodate the same degree of flexibility required of flexible gas generating units.

4.2. High gas demand unit commitment effects

As a result of a large reduction in wind generation, generation volume from all other fuel types shown in Fig. 11 increased from the base case to the EW Wind Gas scenario. The largest increase was delivered by gas fired units in ROI, as expected due to the role of gas in the SEM and the installed capacity in the aforementioned zone.

However, due to the congestion at the Moffat entry point, the ability of CCGT's to import gas in order to bid into the UCED model was limited in each instance of congestion. A characteristic period during the 28th day of the simulation highlights the restricted operating profile of gas units due to this gas import constraint. The shadow price, i.e. the price at which the next unit of gas is valued by the system, at Moffat during this timeframe increased significantly from 13.83 €/GJ in the base case to 19.60 €/GJ. This increase in shadow price had an even larger impact on the short run marginal cost (SRMC) of gas units in the system. Huntstown Unit 2, a 412 MW CCGT unit, with an output profile representative of the trend shown in Fig. 12, saw its SRMC increase from 84.70 €/MWh in the base case to 117.87 €/MWh in the EW Wind Gas case. This shows that any import constraint or restricted ability to source gas in response to extreme weather events has a significant impact on a gas unit's ability to successfully bid into the UCED model. As can be seen in Fig. 12, the peak output in the EW Wind Gas case (5147 MW) is significantly higher than that in the base case (4526 MW). However, for the gas units in the EW Wind Gas case to deliver this increased peak load at the time of considerable security of supply risk, output volumes are constrained during off
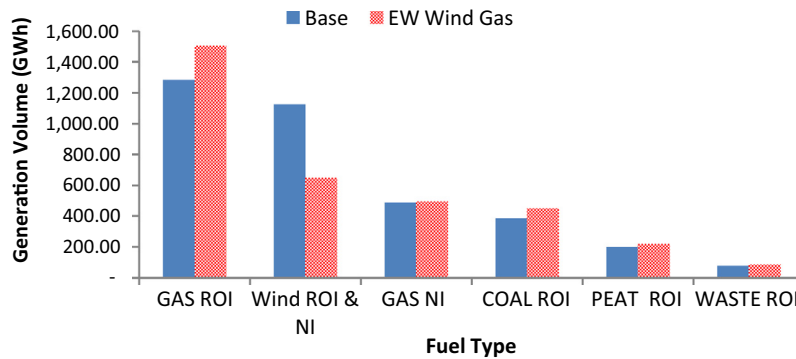

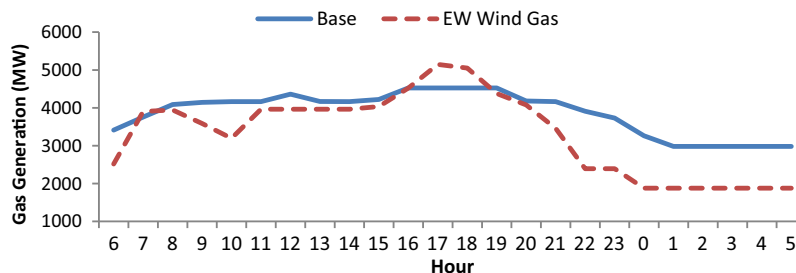**Fig. 11.** SEM generation volumes by fuel type.

Fig. 12. Gas generation output.

peak periods. This is characterised by the output profile from hours 0 to 5, where all online units are running at their minimum stable level, despite the system experiencing an increase in residual demand of 8.92% over the base case. The increased SRMC of gas units due to the high gas price places them further up the merit order, and results in minimal generation volumes being scheduled in an effort to maintain system security in the most economic fashion. Total generation cost for the day in the SEM increased from €11.7 million to €14.2 million in the EW Wind Gas scenario due to the Moffat constraint.

5. Sensitivity analysis

5.1. Gas storage in ireland

The SEM system is, despite having a level of domestic gas production, overwhelmingly dependent on the GB NTS system for supply security. The level of dependence regarding electricity interconnection is not as detrimental to energy security, but existing interconnection plays an important role in economic system operation. However, as demonstrated in the analysis, this dependant relationship has the possibility to limit the economic operation of the SEM in time of high gas demand and low wind generation. Therefore, the addition of a planned gas storage facility in Ireland has been investigated to determine how the connected market dependency changes during stress events. The characteristics of the storage facility are based on information obtained from Gas Infrastructure Europe (GIE) [53] and data obtained directly from Islandmagee Gas Storage Limited (IMSL). The EW Wind and Gas scenario coupled with the gas storage facility was included as the storage "IMSL" scenario. It the sensitivity analysis, it is assumed that the gas storage facility prices its injection and withdrawal services at the same level as Rough in GB, i.e. it operates as a long term facility. This assumption is deemed reasonable since if developed, the IMSL facility will be the only gas storage site on the island. Operation in a long term manner is envisaged to have the largest positive impact on consumers due to the reduced exposure to seasonal price spreads and is suitable for this sensitivity analysis.

From initial inspection of Table 9, over the month timeframe analysed, addition of gas storage reduced the number of days

Table 9
Moffat flow conditions storage.

	GG base case	GG base EW wind gas	Storage
Total flow (TJ)	19362	23257	21128
Capacity factor (%)	72	86	78
Number of days at maximum capacity	1	9	5
Total generation cost (€)	11,669,206	14,255,854	12,209,510

congestion occurred at the Moffat entry point, from 9 in the EW Wind and Gas case to 5 in the storage case. A 9.16% reduction in flows from Moffat have also been realised, resulting in large drop in capacity factor to 78%, which is more in line with base case utilisation. This result shows that storage in Ireland has the ability to significantly reduce real time reliance on imports from GB at times of high system stress due to weather driven demand.

However, the presence of storage did not relieve congestion during day 28, due to very high residual gas generation demand in addition to the high domestic load. Despite this congestion, the storage case enabled an increase in gas generation throughout the day shown in Fig. 13, delivering a gas node shadow price of 13.83 €/GJ. The off peak profile in the storage case is analogous to that in the base case, showing the unconstrained operation of CCGT plant with respect to fuel supply. This shadow price is the same as is reported in the base case, enabling gas units to continue to bid into the UCED model at their true marginal cost, i.e. not reflecting gas scarcity. As a result, system operational costs for the day in the storage scenario decreased by over 14% (€2.046 million).

Furthermore, the increase in gas generation during the storage scenario dramatically reduced the requirements for electricity interconnector imports. Net interchange between the SEM and BETTA is shown in Fig. 14, where positive values indicate exports from the SEM and negative values indicate imports to the SEM, over both interconnectors. Over the characteristic period of the 28th day in the base case, interconnectors from the SEM to the BETTA were exporting power for every hour of the day, with interconnectors at maximum capacity during morning and night off peak periods. However, during the extreme weather scenario a significant shift in interconnection utilisation occurs. The interchange profile is much more varied over the course of the day and maximum system import/export capacity is not reached. However, it is clear that the dependence on importing energy due to the gas generation constraint highlighted in Section 4.2 is much greater in the EW Wind Gas scenario. Imports to the SEM outnumbered exports from the SEM during this scenario, with an Import/Export ratio of 1.3. By utilising the gas storage facility, the effect of the gas import constraint on gas fired units was reduced, enabling minimal reliance on the BETTA for power imports. This highlights how intrinsic gas supply is to power system operation in Ireland and the increased security of supply of both power and gas systems brought by gas storage. The purpose of this work was to evaluate the interaction of interconnected multi vector energy systems. The ability of a gas storage facility to significantly contribute to power system security shows how important multi vector energy analysis is when evaluating any aspect of the total energy system. As power and gas systems become more intertwined with the growth of renewable energy, the benefits of understanding how actions in one system impact on the other have the potential to reduce inappropriate infrastructure investment costs and contribute to the overall social welfare of consumers.
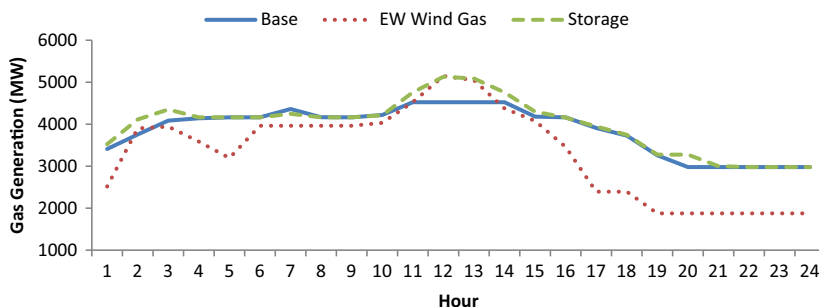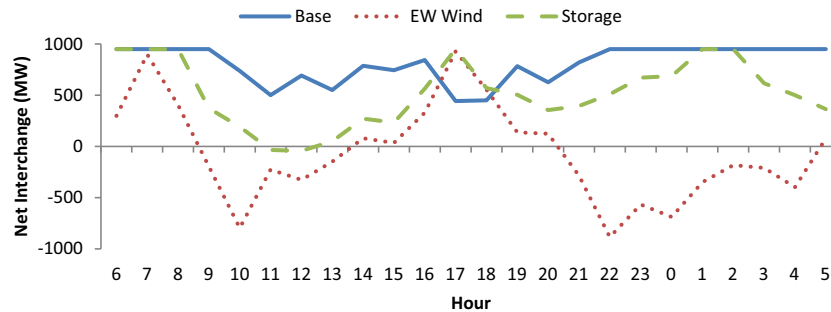

Fig. 13. Gas output profile storage.

Fig. 14. SEM net interchange (power).

6. Discussion and conclusion

This paper presented the first multi vector energy analysis for the interconnected energy systems of Great Britain and Ireland. A simulated extreme weather event resulting in high gas demand from both the power system and domestic gas consumers was simulated in order to understand the interactions between both energy vectors. From this analysis, it is clear that the energy supply network in GB has a much greater resilience to extreme weather demands placed on both power and gas systems than its Irish counterpart. Under the scenarios analysed, total BETTA gas generator output rose by 1638 GW h from the base case due to decreased wind. This coupled with the high domestic demand at spatially reflective locations in the gas model did not limit the ability of the gas network to supply the required demand. However, the extreme weather scenario resulted in a significant increase in transverse GB gas flows of 24%, with LNG supply contributing key flexibility for system security. A reduction in traditionally north south flows on the GB system of over 7% highlights the changing gas system operational challenge due to the reduction in UKCS production.

Under the same relative extreme weather conditions, the ability of gas units in the SEM to generate was severely constrained, resulting in an increase in operational costs of €2.6 million for the characteristic period analysed. Constraints at the Moffat entry point were the limiting factor, with gas shadow prices rising from 13.83 €/GJ in the base case to 19.60 €/GJ in the extreme wind and gas case. However, a sensitivity analysis with the inclusion of a planned gas storage facility prevented high gas prices in the model even during times of congestion at the Moffat entry point. The benefits of conducting multi-vector energy systems analysis were manifested in the significant decrease in power imports from the BETTA in extreme weather as a result of utilising gas storage.

Previous work in the field has identified the impacts of wind power on operation of the gas network in test systems and the GB system respectively [15,18]. The locational change in energy flows and ability of the gas network to limit ramping of gas generators found in this work is in agreement with [18]. This agreement validates the approach taken, relating to development of a realistic unit commitment and economic dispatch model of interconnected power systems coupled with an energy flow gas model. However, the results documented in this work have not only confirmed gas system operation has the potential to impact flexible dispatch of gas generating units via multi energy vector analysis in real power systems, but have shown the importance of considering the interactions between interconnected energy systems. The key strength of the work presented has been the ability to simultaneously conduct an energy flow analysis, involve additional infrastructure and investigate the changes in security of supply in the Irish system. The key finding of this work has shown that gas storage in an energy system heavily dependent on gas imports for power generation has the ability to significantly improve the economic operation of the power system. As the EU continues to not only pursue challenging renewable energy integration targets but also actively develops a single internal energy market, the analysis conducted in this work will continue to grow in significance. It is clear that a full understanding of the relationship between power, gas and interconnected energy systems in pursuit of these aims will be required to transition effectively to the energy system of the future. In conclusion, the methodology presented here delivers the required high level insight into multi vector, multi jurisdiction interconnected energy systems rooted in realistic unit commitment and economic dispatch modelling.

Acknowledgement

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