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The importance of gas infrastructure in power systems with high wind power penetrations

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HIGHLIGHTS

- The first multi-vector gas and power system analysis for Ireland is performed.
- Power system security is vulnerable to outages on the gas network.
- Economic operation of the power system is negatively affected by gas network outages.
- Excessive power system reserve allocation can occur over a transmission constraint.
- Wind forecast error results in large utilisation swings for importing gas pipelines.

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ABSTRACT

Gas fired generation currently plays an integral support role ensuring security of supply in power systems with high wind power penetrations due to its technical and economic attributes. However, the increase in variable wind power has affected the gas generation output profile and is pushing the boundaries of the design and operating envelope of gas infrastructure. This paper investigates the mutual dependence and interaction between electricity generation and gas systems through the first comprehensive joined-up, multi-vector energy system analysis for Ireland. Key findings reveal the high vulnerability of the Irish power system to outages on the Irish gas system. It has been shown that the economic operation of the power system can be severely impacted by gas infrastructure outages, resulting in an average system marginal price of up to €167/MW h from €67/MW h in the base case. It has also been shown that gas infrastructure outages pose problems for the location of power system reserve provision, with a 150% increase in provision across a power system transmission bottleneck. Wind forecast error was shown to be a significant cause for concern, resulting in large swings in gas demand requiring key gas infrastructure to operate at close to 100% capacity. These findings are thought to increase in prominence as the installation of wind capacity increases towards 2020, placing further stress on both power and gas systems to maintain security of supply.

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1. Introduction

Due to the mass adoption of renewable energy, specifically wind in EU member states, the importance of gas fired generation is continually highlighted [1]. One of the driving factors behind large scale renewable integration is the pursuit of increased security of supply [2]. While the installation of renewables reduces reliance on imported fossil fuels in the long term, the high penetration of stochastic energy sources such as wind results in challenges for real time power system operation [3,4]. In markets with high penetrations of wind power, gas fired generation has been responsible for maintaining system supply and demand balance, accounting for the residual demand not fulfilled by wind and reacting to sudden changes in wind output. Wind power has been shown to gain fuel mix share at the expense of gas fired generation resulting in large decreases in gas unit capacity factors [5]. However, the resulting decline in capacity factor does not attribute less importance on gas plant, but signals a paradigm shift in electricity market operation [6].

The increasing support role fulfilled by gas and the uncertain supply profile required as a result of high penetrations of wind power are apparent in the flows of gas in pipeline infrastructure

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supplying gas units. It has been shown that variations in gas generator outputs are passed directly onto the existing gas infrastructure [7]. Uncertainty in the quantity of gas required to fuel a generator in order to participate in the electricity market poses a major problem for gas shippers by casting uncertainty over pipeline capacity nominations and re-nominations, as well as increasing their exposure to network balancing penalties [8]. Gas transmission system operators are also impacted, requiring to operate the system close to pressure margins in order to maintain adequate system pressure and ensure domestic customers are prioritised. Increased variability results in increased operational costs due to compressor usage in an effort to deliver gas where it is needed, since the transport time for gas in a pipeline is much longer than that of electricity over a transmission line [7].

In power systems with both high penetrations of gas fired generation and wind power, the importance of gas infrastructure (i.e. gas pipelines supplying power stations and compressor installations maintaining network pressure) for system security and operation is further heightened. This is especially true in the Single Electricity Market (SEM) of the Republic of Ireland (ROI) and Northern Ireland (NI). Analysis in [9] showed that gas supply interruptions to power generation on the island of Ireland ranging from 1 to 90 days could cost between 0.1 and 1 billion euro per day. Combined with domestic load losses, the cost of gas supply interruption was forecasted to be upwards of 80 billion euro.

While the interaction of flexible generation capacity in support of renewable energy has been well studied [10,11], research on the effects and role of gas infrastructure on power systems with high renewable penetrations has been relatively limited. A review of the recent research in the field shows that much of the work has focused on developing new integrated gas and electricity models and applying the optimisation to test networks. In [12], a security constrained unit commitment (SCUC) model incorporating gas transmission constraints was developed and applied to a six bus power system and a seven node gas system. Several scenarios were analysed, including the impacts of gas transmission constraints, gas pipeline outages and varying natural gas loads. Further analysis of the SCUC model was conducted using a 118 bus power system and a 14 node gas system to show the effectiveness of the proposed model. It was found that gas transmission constraints resulted in higher daily operating costs than the case with no gas transmission constraints. In addition, variations in gas load as well as gas pipeline infrastructure failures negatively impact system security and results in large levels of load shedding. A similar SCUC model was presented in [13] to assess the relationship between gas pipeline outages and power system security. It was found that implementing a suitable fuel switching strategy in affected zones prevented some unit shutdowns. However, the overall system load shedding was directly related to the number of gas units unable to receive fuel. A co-optimisation planning model considering the relationship between gas and power infrastructure was presented in [14], where the ability of gas infrastructure expansion to transport the required fuel to the power system was considered in the iterative planning approach.

A comprehensive overview of gas and power system security dependence is given in [15]. Again, a SCUC model is used to illustrate the importance of gas infrastructure on a test system containing renewable sources. However, this is the only work to consider the impact gas pipeline outages have on the locational marginal price, noting a large increase due to congestion in affected zones as a result of gas generators being forced off. A pumped storage plant placed in the zone with highest demand was found to be a suitable alternative to load shedding in times of gas pipeline outages.

A fully representative model of the Great Britain (GB) gas and power system was developed and presented in [16]. Combined optimisation of both networks was conducted for a winter month. Outages of key pieces of gas infrastructure such as terminals and storage and their effects on compressor use, network line pack, gas shedding and generation by fuel type were illustrated. Low pressure on the gas network was shown to negatively affect the ability of gas generators to contribute electricity supply. Large levels of gas shedding were apparent, accounting for the large increase in combined system operation costs. The work highlighted the importance of multiple supply routes and the ability of gas storage to compensate for supply failures by reducing load shedding. Further development of the above model in order to consider the impacts of high wind power penetration on the Great British gas network in 2020 was presented in [7]. Low and high wind scenarios were compared to the 2009 base case, which resulted in higher and lower total operational costs respectively. It was shown that when high gas demand and low wind occurred together, the gas network was placed under stress and saw a rapid depletion in line pack which impacted on the ability of gas generators to run. These variations require more compressor use and thus result in increased system operational cost. Gas storage was offered as a solution, as well as hourly instead of daily line pack balancing.

Reliability of the combined GB gas and power system during a winter week in 2020 was investigated in [17]. The gas and power co-optimisation model presented in [16] was coupled with a Monte Carlo simulation to determine the reliability of the combined networks. Uncertainties regarding supply, demand and infrastructure for both power and gas networks were considered. The multi-vector energy system approach to reliability assessment was shown to be a possible asset when considering future investment decisions. A £900 million decrease in expected energy unserved as a result of a doubling gas storage capacity was illustrated. The impact of various deterministic and stochastic unit commitment and economic dispatch strategies to deal with uncertainties in wind power forecasts were analysed in [18]. The test system consisted of the GB gas and electricity networks. Day ahead and within day dispatch instructions resulting from stochastic methods are shown to deal with the variation in wind power better than the deterministic method, achieving a saving of 1% in total gas and power system operational costs.

All of the above work has developed an integrated gas and power model and applied it to either a test system or the GB system. Power system operational impacts have not been fully investigated as a result of gas infrastructure outages, with the above research focusing mainly on gas consumption, load shedding, fuel mix changes and stochastic methods not currently used by the system operators in Ireland. Instead, this research focuses on the impact gas infrastructure outages have on system operational metrics such as the price of electricity, capacity utilisation and gas pipeline flows in a high wind power system where gas supplies are mainly imported and the use of gas storage is limited. This paper is presented as follows. Section 1 introduces the subject matter and establishes the state-of-the-art. Section 2 describes the choice of the test system, modelling methodology and key assumptions utilised in the analysis. Section 3 provides results and discussions regarding key results including power system marginal price, unit commitment impacts, gas infrastructure flows and the effect wind forecast error has on gas infrastructure operation. Section 4 concludes the paper.

2. Methodology

Due to the high penetrations of natural gas fuelled generating units and installed wind capacity, the SEM was chosen as the test system. A winter week in 2011 was used since the available data from both gas and power system operators enabled clear validation

to be performed. In 2011, gas fuelled generators contributed 56% of electricity demand throughout 2011 [19]. The importance of gas fired generation and therefore gas infrastructure is further compounded when the large installed capacities of renewable sources, particularly wind, is considered. Total installed wind capacity in the SEM in 2011 was 2278 MW.

Both gas and power models were built using Energy Exemplar's PLEXOS Integrated Energy Model Version 6.3 [20] and solved with the FICO Xpress Optimisation Suite solver [21]. PLEXOS minimises the objective function shown in Eq. (1) subject to the constraints in Eqs. (2)–(12) to deliver a dispatch instruction representative of the least cost solution for both power [22,23] and gas systems.

$$min\Sigma_{t\in T}\Sigma_{j\in J}\Sigma_{i\in I}\begin{pmatrix} SC_j\cdot US_{jt}+NLC_j\cdot UG_{jt} \\ +(VOM_j+UOS_j).P_{jt} \\ +PC_j\cdot P_{jt} \\ +PenLLE\cdot UEE_t+PenLLE\cdot RES_{jt} \\ +PDE\cdot ExE_t \\ +GPC_{it}+PenLLG\cdot UGD_t \end{pmatrix} \quad (1)$$

Subject to

$$\Sigma_{t\in T}\Sigma_{j\in J}(P_{jt}-Pload_{jt}+UEE_t)=ED_t \quad (2)$$
$$P_{jt}-P_{jt-1}-MRU_j\cdot UG_{jt}\leqslant 0 \quad (3)$$
$$P_{jt}-P_{jt-1}-MRD_j\cdot UG_{jt}\geqslant 0 \quad (4)$$
$$P_{jt}-Pmax_j\cdot UG_{jt}\leqslant 0 \quad (5)$$
$$P_{jt}-MSL_j\cdot UG_{jt}\geqslant 0 \quad (6)$$
$$\Sigma_{t\in T}\Sigma_{i\in I}(GProd_{it}+UGD_t)=GD_t \quad (7)$$
$$GFV_{it}_GFP_{it}\geqslant 0 \quad (8)$$
$$GPV_{kt}-MaxPV_{kt}\leqslant 0 \quad (9)$$
$$GPV_{kt}-MinPV_{kt}\geqslant 0 \quad (10)$$
$$GPF_{kt}-MaxPF_{kt}\leqslant 0 \quad (11)$$
$$GPF_{kt}-MinPF_{kt}\leqslant 0 \quad (12)$$

where t signifies the time period index from t to T, SC_j is the cost to start unit j subject to the binary multiplier determining if unit j has started in the current period. The no load cost of unit j is represented by NLC_j coupled with a binary value UG_{jt} determining if unit j is generating or not. Additional costs relating to unit j's short run marginal cost such as variable operation and maintenance charges, use of service charges, production costs and power output in period t are denoted by VOM_j, UOS_j, PC_j and P_{jt} respectively. Any unserved electrical energy in the system at time t, UEE_t, and reserve not met by unit j in period t, RES_{jt} is priced at the penalty for loss of electrical load, $PenLLE$. The penalty for dumped energy is represented by PDE and the quantity of excess energy in time t is ExE_t. Gas system production costs from field i at time t are represented by GPC_{it}. Unserved gas demand at time t, UGD_t, is priced at the penalty for loss of gas demand, $PenLLG$. Pump load performed by unit j at time t is given by $Pload_{jt}$ and electrical system demand is represented by ED_t. Upper boundaries on ramp up and down rates of unit j are denoted by MRU_j and MRD_j respectively. The maximum and minimum generation levels attributable to unit j are represented by $Pmax_j$ and MSL_j respectively. Gas production is symbolized by $GProd_{it}$, with GD_t representing total system gas demand at time t. Production from each gas field GFP_{it} must not violate the volume of gas in the field, GFV_{it}. Pipeline constraints representing the gas transportation algorithm are shown in (9)–(12). The volume and flow in pipeline k in each time period t are GPV_{kt} and GPF_{kt} respectively. These parameters are bounded by maximum and minimum volumes $MaxPV_{kt}$, $MinPV_{kt}$, and flow rates $MaxPF_{kt}$ $MinPF_{kt}$ respectively.

2.1. Single electricity market

The SEM in 2011 operated as a gross mandatory pool market, with generating units submitting bids corresponding to their short run marginal cost (SRMC) i.e. the cost corresponding to generating one additional MW [24]. The price of electricity in each 30 min period is set at the most expensive generator's SRMC which is dispatched to meet demand. This system marginal price (SMP) is determined on an unconstrained ex-post basis. For all dispatched generators with a SRMC lower than the SMP in each period, the difference is deemed infra-marginal rent and enables profit to be made, hence short run costs are used in the bidding process [25]. Constraint and capacity payments are made outside of the market, and are not considered in this analysis.

Total thermal capacity for the winter week was 8856 MW, and is shown by fuel type in Table 1 [26]. Average generating unit characteristics by fuel type are also shown in lieu of individual unit characteristics for the sake of brevity. Unit specific data is available publically via the verified regulator model available in [27]. A peak system demand of 4599 MW was experienced. All generators were assumed to be available for dispatch, with no forced or planned outages included in the analysis in an effort to attribute generation shortages as a function of gas pipeline availability. A single gas generator in the neighbouring GB electricity market was modelled, with a scaled level of installed wind in order to achieve the validated interconnector flows over the Moyle interconnector, linking both markets.

Average hourly power demand, wind forecast, wind generated and wind curtailment data for the week modelled are shown in Fig. 1.

2.2. Market modelling

In an effort to achieve a fully realistic representation of the SEM, the overall simulation is split into two main parts consisting of a market operator and a system operator. Both parts are run with a 24 h look ahead, a step size of one day and an interval length of one hour. An overview of the simulation is shown in Fig. 2.

Table 1
Installed thermal capacity.

Fuel	Installed capacity (MW)	Average maximum capacity (MW)	Average minimum stable level (MW)	Average ramp up (MW/min)
GAS ROI	3692	247	105	9
GAS NI	1518	152	72	3
COAL ROI	855	285	99	3
OIL ROI	804	115	27	1
COAL NI	476	238	93	6
PEAT ROI	345	115	51	1
DISTILLATE ROI	324	54	15	5
DISTILLATE NI	316	45	9	9
PUMPED STORAGE ROI	292	73	5	210
HYDRO ROI	216	14	5	5
WASTE ROI	17	17	3	

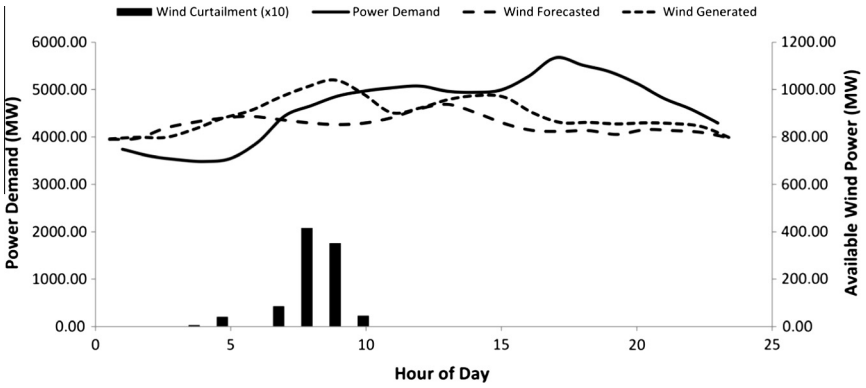

Fig. 1. Hourly average power and wind profiles.

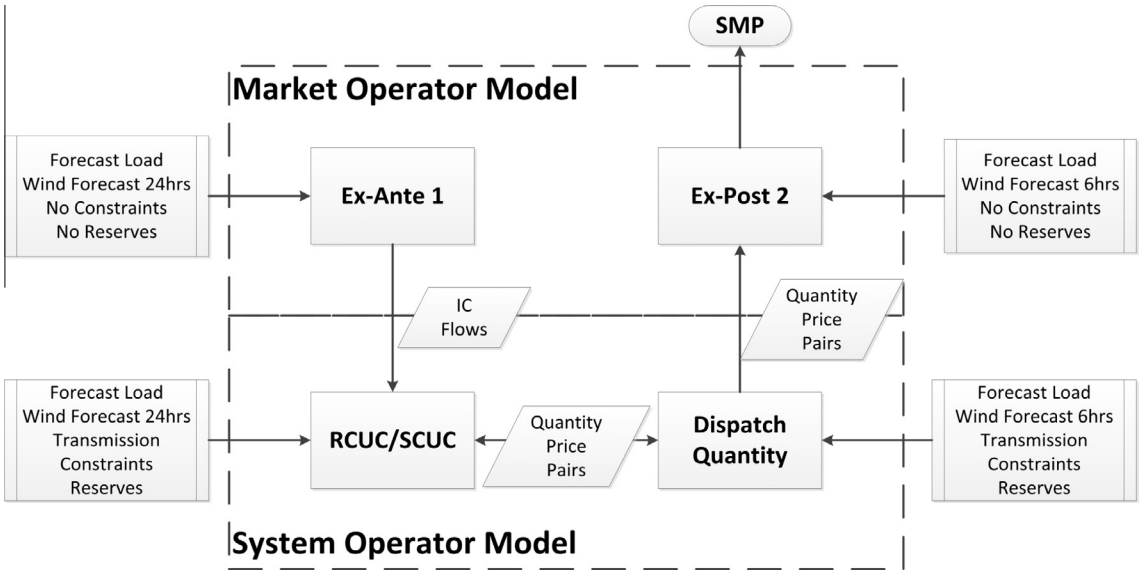

Fig. 2. Model schematic.

2.2.1. Market operator

The SEM market operator model manages the economic side of dispatch, forecasting and calculating the overall SMP. It does not consider system constraints. Within the market operator, two runs are carried out to model the SEM as a single node. The "Ex-Ante 1" model is run with a 24 h wind forecast, day ahead of real time with a 24 h look ahead. This serves to create an indicative SMP and unit schedule, as well as the scheduling of interconnector flows. The Ex-Ante 1 model in the simulation is formulated as a direct implementation of the SEM market scheduling and pricing software methodology set out in the trading and settlement code [24]. The second run for the market operator model is the "Ex-Post" model. The results from this run report the actual SMP for each trading period, and utilises the market schedule quantities from the system operator model, with no wind forecast applied. In this analysis, the overall economic conclusions due to gas infrastructure outages are arrived at using the Ex-Post model.

2.2.2. System operator

For the system operator part of the simulation, the model is run in interleaved mode. This results in both constituent models being ran at the same time, feeding generation quantities and prices back and forward for a more accurate solution. The system comprises of two nodes, NI and ROI. A single tie line connects both nodes, with a transfer capacity from North to South and South to North of 450 MW and 400 MW respectively. Both models ran in the system operator section are inclusive of transmission constraints and reserve requirements. A reserve and security constrained unit commitment model ("RCUC/SCUC") is the lead day ahead model utilising interconnector flows from the Ex-Ante 1 Model and a 24 h wind forecast. A wind forecast standard deviation of error corresponding to 13% [28] was applied to the actual wind generation data used in the dispatch quantity model run to create the day ahead wind profile. The dispatch quantity model ("DQ") uses all of the same scenarios as the RCUC/SCUC, but includes no wind forecast error which corresponds to actual available wind generation for each time step [29]. This ensures that an accurate market schedule quantity (MSQ) is created, with the quantities of generation being confined to the constraints of the actual transmission system from an operational and system security point of view. The results of the DQ model run are then used by the Ex-Post model for the completion of the simulation.

2.3. All Island gas network

Unlike the SEM, where the jurisdictions of NI and the ROI are operated as a single system, the gas network comprises 3 jurisdictions (NI, ROI, and GB) and has four separate transmission network codes in operation [30]. Both regulatory bodies on the island of Ireland, Utility Regulator in NI and the Commission for Energy

Regulation in ROI signed a Memorandum of Understanding in 2008 towards developing a single gas network with the aim of complying with the European Single Internal Energy market [31]. Work on the common arrangements for gas is still ongoing.

The gas transmission network modelled in this analysis is shown in Fig. 3, with major load centres and power stations highlighted [32]. In 2011, there were two entry points to the system. Indigenous production from the Kinsale gas fields off the coast of Cork enter the system through the Inch terminal, point 1 in Fig. 3. This is also the location of the only gas storage facility for the Irish system, using a depleted gas field to supplement seasonal demand [33]. The volumes experienced through the terminal at Inch are in decline due to the gas fields reaching their end of life. This location is thought to grow in prominence as a storage facility in future. Over 95% of All Island gas demand was met through imports from the Moffat entry point during 2011, point 2 in Fig. 3 [34]. Moffat supplies the ROI system via two subsea interconnectors, Interconnector 1 and Interconnector 2 (IC1 and IC2), whereas the entirety of NI's gas demand is supplied via the Scotland Northern Ireland Pipeline (SNIP) that connects to the onshore Scotland IC1 network at Twynholm and enters the NI system at Carrickfergus. It is possible for NI to receive gas from ROI and vice versa using the South North Pipeline (SNP). The North West Pipeline (NWP) supplies gas to the Coolkeeragh combined cycle turbine, and is able to receive gas from the SNP directly and the SNIP via the Belfast Gas Transmission Pipeline (BGTP). Key information regarding the importing pipelines used in the analysis is shown in Table 2, and maximum nodal entry and exit capacities are shown in Table 3 [35,36].

The gas model is integrated with the power system model via the gas fired generating units. A gas transportation algorithm is employed to supply demand at receiving nodes. Pressure and pipeline hydraulics are not modelled, resulting in an energy flow model optimised concurrently with a unit commitment and economic dispatch power model, the formulation of which is detailed in Section 2. Gas demand for the non-power sectors was obtained directly from Gas Networks Ireland, and located at the appropriate nodes. No compressors are modelled at above ground installations in the analysis.

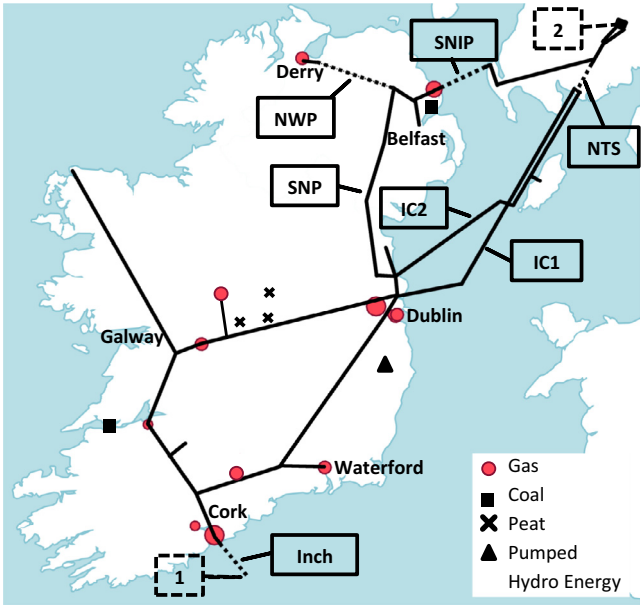

Fig. 3. Gas transmission network.

Table 2
Gas transmission design and operational parameters.

Pipeline	Diameter (D, mm)	Length (L, km)	Maximum pressure (kPa Gauge)	Minimum pressure (kPa Gauge)
IC1	600	204	14,800	5000
IC2	750	195	14,800	5000
SNP	450	156	8500	3000
SNIP	600	135	7500	5600
NWP	450	112	3500	2700
Inch	610	53	2950	1900

Table 3
Nodal constraints.

Node	Max flow (TJ/d)	Node type
Moffat	1231	Entry
Twynholm	321	Entry
Carrickfergus	107	Exit
Gormanstown	202	Exit
Inch	226	Entry

2.4. Line pack

Line pack is an important characteristic of gas transmission systems, enabling gas infrastructure to exhibit inherent storage capability and manage large fluctuations in demand. This is achieved by ensuring the pressure in the pipeline is above that of delivery pressure at exit nodes on the system [37]. Despite the gas transportation algorithm dealing in terms of energy flows, inclusion of line pack via maximum and minimum pipeline volumes serves as a proxy for pressure limitations in the model. Pipeline characteristics shown in Table 2 coupled with maximum and minimum pressure limits from [38,39,40] were used to calculate the line pack in each pipeline modelled.

Average pressure in each pipeline, accounting for differences in upstream and downstream pressures was calculated using Eq. (13) where P_1 and P_2 are the upstream and downstream pressures respectively.

$$P_{avg} = \frac{2}{3}\left(P_1 + P_2 - \frac{P_1 P_2}{P_1 + P_2}\right) \tag{13}$$

Line pack was then calculated via Eq. (14), assuming an average compressibility factor, Z_{avg} of 0.9 [41].

$$V_b = 7.855 \times 10^{-4}\left(\frac{T_b}{P_b}\right)\left(\frac{P_{avg}}{Z_{avg} T_{avg}}\right) D^2 L \tag{14}$$

where T_b, T_{avg} are base and average temperatures respectively. For the onshore Scotland Interconnector pipeline system, a 30 km section of the network is twinned. Therefore, an equivalent diameter for use in Eq. (14) was calculated using Eqs. (15) and (16) considering both pipe diameters and lengths, D_1, D_2, L_1, L_2 respectively.

$$D_{equivalent} = D_1\left[\frac{1 + Const}{Const}\right]^{\frac{2}{5}} \tag{15}$$

where:

$$Const = \sqrt{\left(\frac{D_1}{D_2}\right)^5 \left(\frac{L_2}{L_1}\right)} \tag{16}$$

2.5. Gas transmission tariffs

Gas transmission tariff arrangements in NI and the ROI operate on different charging regimes [42]. In NI, a "postalised" tariff policy on gas transmission is implemented. This policy results in a single

tariff payment regardless of the final destination of the transported gas on the NI portion of the system. The postalised tariff is comprised of a capacity charge regardless of utilisation to cover fixed infrastructure costs, and a commodity charge levied on the volume of gas transported to cover variable infrastructure costs. The capacity commodity split is 75/25 [43].

In the ROI system, an entry-exit tariff structure is employed for interconnection and offshore pipelines, with a postalised onshore tariff applied [42]. This enables booking of capacity at entry and exit points to be conducted independently. Additionally, different prices are applied at entry and exit points in order to signal system status and promote effective use of the network. The capacity commodity split on the ROI system is 90/10 [43]. Commodity charges from Moffat and Inch are priced differently in the analysis. It was decided to utilise the gas commodity transportation adders available in [44] to allocate tariffs on the modelled interconnection points. A similar approach is used for the SNIP pipeline. These transportation costs were deducted from the total price of gas input to the validated model. This is to ensure gas price parity between the validated model and the developed model used in this analysis. Capacity charges were not included, since generators participating in the SEM are prevented from bidding in any more than their short run costs [45]. All capacity utilised in the simulation is assumed to be long term purchased capacity on pipelines, the cost of which is not permitted to be recovered from short run costs. It was assumed nonetheless that the capacity commodity split was applied on a 50/50 basis between entry and exit, resulting in a single commodity charge applied on all relevant entry and exit points on the system.

2.6. Scenarios

In the main analysis, a base case and four gas outage scenarios (NTS, SNIP, NWP and Inch) are evaluated in order to determine the resiliency of the current gas infrastructure to supply power demand in times of unexpected outages. Therefore, key sections of pipeline were chosen to achieve this result. The NTS scenario corresponds to a failure of the single pipeline from Twynholm to Brighouse Bay compressor station in the onshore Scotland system. This then renders both subsea interconnectors (IC1 and IC2) down for the duration of the simulation. In the SNIP scenario, a failure on the subsea SNIP pipeline is assumed, forcing all of NI demand to be met by the South-North pipeline via IC2. Two further smaller impact scenarios were also modelled to assess the ability of the onshore Ireland system to respond to outages. The NWP scenario involved an outage on the section of pipeline towards Derry, cutting supplies to domestic demand in the city and requiring the 404 MW Coolkeeragh power station to remain offline. Finally, loss of the offshore pipeline connecting the Inch entry point is assumed in the Inch scenario. With the loss of this pipeline, the ability for storage utilisation is removed. The timeframe of one week was decided upon as it corresponds to a conservative estimate on the length of time required to repair a gas pipeline [46].

Additionally, the impact of wind forecast error is included as a sensitivity analysis for each of the outage scenarios. The inclusion of this sensitivity enables the measureable impact of wind power on the nomination requirements of shippers and in turn, the operation of gas transmission infrastructure to be achieved.

3. Results and discussion

3.1. Power system marginal price

The influence of the NTS pipeline on power system operation is the largest impact on system marginal price (SMP), and is shown in Fig. 4. Average SMP in the NTS scenario is above the base case in every hour. As expected, at peak times, the price of electricity rises extremely quickly as the increased load and constrained generation system struggles to keep the system secure. During the NTS scenario, a price cap of 1000 €/MW h corresponding to the value of lost load is reached six times, all around peak time reflecting the system's lack of next megawatt generation by online plants.

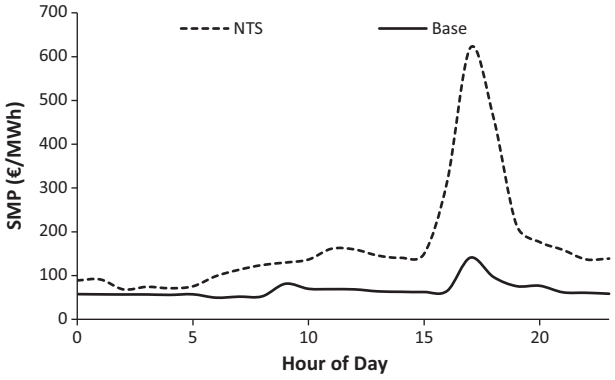

Fig. 4. Hourly SMP NTS scenario.

The average peak time fuel mix is shown in Fig. 5. The influence of expensive generating plants such as oil and distillate at peak time, combined with their overall increase in generation output are the reason for such high prices during the day, especially at peak time. This shows that by losing the IC system, consumers would be seriously negatively impacted due to having to pay very high prices.

The impacts each of the other scenarios have on SMP are shown in Fig. 6, with average SMP and operational costs shown in Table 4. It can be seen that the loss of the Inch pipeline does not have any

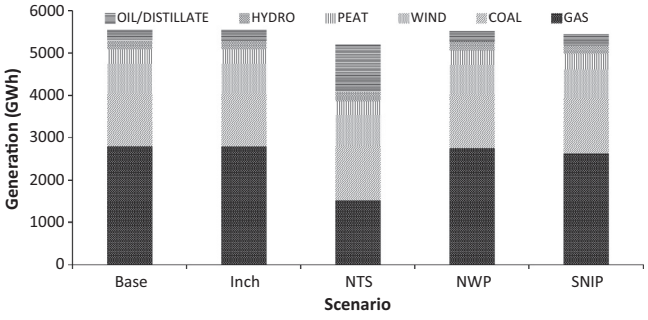

Fig. 5. Average peak time generation by fuel.

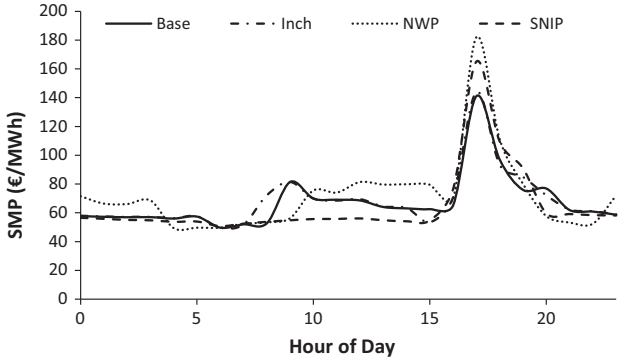

Fig. 6. All other scenario SMP impacts.

Table 4
Average SMP and combined operational costs.

Scenario	Average SMP (€/MW h)	Combined system operational costs (000's €)
Base	67.11	26,350
Inch	68.06	26,327
NTS	168.71	40,812
NWP	72.12	26,603
SNIP	64.56	29,625

significant effect on the SMP, tracking the base case SMP closely. However, by forcing all ROI gas flow through the cheaper IC system, a small decrease in operational cost is realised. It is envisaged that the saving in operational costs as a result of the Inch pipeline outage would not be achievable in the longer term, since the Inch node storage entry point is lost during the Inch outage. The ability to hedge against seasonal gas price variations in the GB gas market would therefore be lost, and the impact of this hedging would be captured over a longer simulation horizon, resulting in an anticipated increase in combined system operational costs for the Inch scenario.

The most interesting finding is due to the loss of the SNIP, which results in a lower average price experienced, despite a higher peak price at 17:00. This is due to the 2.2% increase in cheaper coal fired units output over the week at off peak times, and an increase in oil/distillate plant output at peak time. The increase in combined system operational cost is attributable to the use of oil and distillate plant at these peak times. The increase in coal unit output by inclusion in the merit order is due to the increased gas transportation costs to all gas fired units in NI. The increase in transportation cost is a result of gas flows via the IC and SNP rather than directly through the single postalised SNIP tariff, placing NI units further down the merit order, enabling increased coal NI generation.

The loss of the NWP results in a higher average price, higher peak price and higher total system operational cost than the base case although not as high as the SNIP case since only the Coolkeeragh unit is affected in the NWP scenario. This enables the other gas fired generating units in NI to contribute supply as they are fuelled by the SNIP and are not eliminated from the merit order due to increased gas transportation costs, reflecting the base scenario rather than the SNIP scenario. The increased output from gas units in NI over the timeframe delivers a larger SMP than the base and SNIP scenario. However, the NWP results in a similar total operational cost reported for the base case since the output of oil and distillate is much lower than that experienced in the SNIP scenario. Overall, excluding the NTS scenario, the peak time generation mix does not undergo significant change between scenarios, with small changes having noticeable effects on the SMP but less pronounced effects on system operational costs.

3.2. Unit commitment and reserve provision

Fig. 7 shows the difference in generation output by fuel type between each scenario and the base case. The total output from gas, coal and oil units in the system shows the largest variation over all scenarios studied.

As reserve provision is directly proportional to the availability and unit commitment status of the generating unit, the reserve provision is analysed concurrently with generation output. The percentage change in reserve provision by major fuel type per scenario is shown in Fig. 8.

When the NTS pipeline supplying both IC1 and IC2 is removed, gas generation in the ROI experiences a large decline in output from 1300 GW h to 360 GW h. This decline is countered by large increases in generation from gas and coal units in NI and ROI,

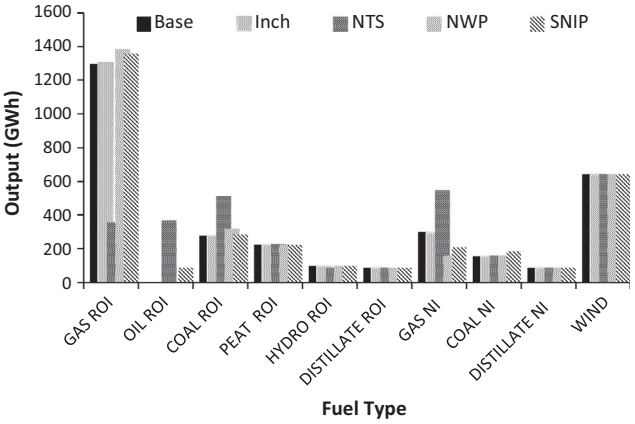

Fig. 7. Generation by fuel type.

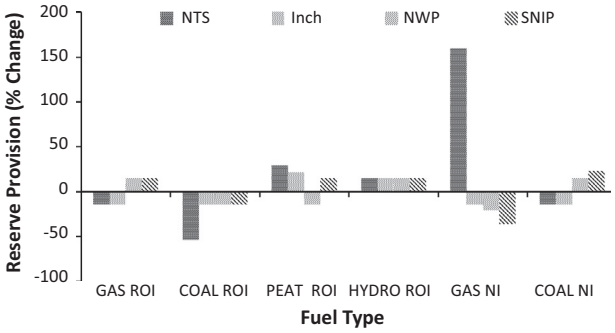

Fig. 8. Reserve provision changes.

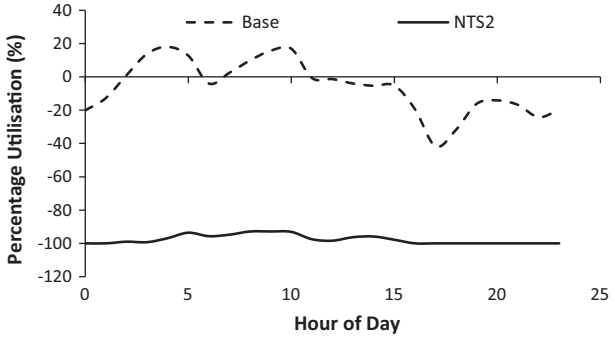

Fig. 9. Tie line flow.

respectively. Oil and Distillate ROI units also show increases in output, the only scenario in which this is the case. The shift in generation between ROI and NI during NTS outage is shown when considering the differences in flow over the North South tie line. The time averaged tie line utilisation percentage is shown in Fig. 9. It is evident that a dramatic change in the utilisation of the tie line occurs as a result of decreasing gas unit availability in ROI. The tie line is utilised at near to full capacity for the duration of the NTS scenario in the NI–ROI direction (negative values in Fig. 9), whereas the average transfer occurring in the base scenario does not achieve such high levels of tie line utilisation.

During the NTS scenario, the ability of the ROI gas units to contribute supply is severely limited. Therefore, their contribution to system reserves is similarly affected. This can be seen from Fig. 8, where ROI gas units reserve provision decreases by 12%. In an effort to maintain system security and satisfy demand, ROI coal

units are scheduled on to a higher level than in the base case. This results in a large decrease in the ability of coal units to provide reserve, as they are primarily dispatched for maintaining supply. Responsibility for reserve provision is transferred to units in NI, who show a large increase of over 150%. Although this is an acceptable solution from the viewpoint of the simulation, the ability of such an increase in reserve across the ROI/NI tie line is not necessarily an acceptable measure in real time system operation. The main reason for this concern is the transmission line constraint linking both jurisdictions. During 2011, the transfer capacity from North to South and South to North was 450 MW and 400 MW respectively. During the NTS scenario, the north south tie line was running at full capacity in the north south direction 95.2% of the hours studied. This placed 104 GW h of required reserve on the NI node where only approximately 25% of system demand is located. This would not be prudent system operation since if the reserve held in NI was required in the ROI, the capacity constraints on the ROI/NI tie line would not permit the required level of transmission to maintain system security. Other notable changes in reserve provision originated from peat generation, which saw an increase of 30% in the NTS scenario.

Loss of the Inch terminal has a limited effect on the running of gas units, surprisingly including those close to the reception facilities in the Cork area. Generation for these units actually increased from 428 GW h to 432 GW h on account of the cheaper gas available from the interconnector system as a result of the onshore postalised tariff. The loss of this pipeline also shows that storage withdrawal during winter is not a critical concern to gas system operation when other pipelines are in full operation. However, when considering the fact that over 95% of gas supplies are imported through Moffat, the lack of impact Inch terminal has on gas and power system operation is understandable. Reserve provision for the major load suppliers, gas and coal, are relatively unaffected. This is by and large due to the ability of lost supply being compensated by increased flows from Moffat. However, peat has again shown its ability to contribute reserve in times of disruption. Use of peat generation in this capacity is encouraging, since security of supply concerns area allayed due to indigenous fuel production.

The loss of the NWP pipeline leads to the loss of the 404 MW Coolkeeragh gas fuelled plant. As a result, it is more economical to dispatch large gas and coal units in the ROI that are already online, rather than starting the second of two coal plants in NI. The reluctance of the simulation to commit a further coal unit in NI due to the cost minimisation objective function employed is illustrated in Tables 5 and 6. It can be seen that despite the deficiency in generation output in NI, average unit commitment across the week for coal units remains unchanged, with a decrease in the quantity of online capacity not dispatched. However, it is clear that both gas and coal units located in ROI are utilised much more efficiently than the base case, given their similar average units committed, generation and undispatched capacity.

The loss of the SNIP had the largest cumulative effect on system reserve provision. A decrease in gas generation reserve provision actually resulted in a large increase in coal NI provision, which is the opposite of the NTS scenario. Coal NI exhibits more undispatched capacity due to an increase in average units committed, accounting for both the increased generation and increased reserve provision. Utilisation of the ROI gas units in the SNIP case is not as efficient as in the loss of NWP, since the units committed are the same, but undispatched capacity is increased despite relatively no change in reserve provision. The large decrease in gas NI generation is due to the increased costs associated with transporting gas over the IC system and through the SNP pipeline, with increases in gas ROI achieved due to the increased cost competitiveness.

Table 5
Unit commitment.

	Base	NWP	SNIP
Average units committed			
GAS ROI	0.62	0.65	0.65
COAL ROI	0.83	0.95	0.94
GAS NI	0.23	0.38	0.15
COAL NI	0.52	0.52	0.78

Table 6
Undispatched capacity.

	Base	NWP	SNIP
Average undispatched capacity (MW)			
GAS ROI	420	421	482
COAL ROI	211	221	239
GAS NI	85	93	46
COAL NI	38	34	42

The most interesting finding considering reserve and generation relates to the utilisation of peat units. Peat shows virtually no change across all scenarios with regards to generation. However, peat units are key providers of reserve for both NTS and Inch scenarios. This is attributable to their must run status due to their use of an indigenous fuel source. As can be seen from Table 7, peat units are almost committed in every time period across all scenarios, with variations in reserve attributable to the economic dispatch.

3.3. Gas interconnector flows

Since the scenarios utilised in this analysis involve forced outages on key pieces of gas infrastructure, it is beneficial to analyse the impacts each of the outage events has on the rest of the system. In order to maintain clarity, it was decided to present the scenarios in two distinct sub groups, one comparing NI pipeline outages with the base case and one comparing ROI outages. These can be seen in Figs. 10 and 11 respectively.

For NI pipeline outages, loss of the NWP and the large Coolkeeragh generator supplied does not significantly influence the total system line pack. Lower levels of line pack at 5 am and 6 am highlight the ability of the Coolkeeragh unit to contribute early morning generation due to being constrained on due to a system operational constraint with a high minimum stable level in the base case. However, when approaching peak demand, the levels of line pack in this scenario are close to those found in the base case. The most interesting finding of the line pack analysis is regarding the network situation on losing the SNIP pipeline. A large increase in line pack at 6 am and 3 pm occurs in anticipation of peak demand. The ability of line pack to reach such high levels is due to the large entry capacity of the IC system, accounting for the lack of imports through SNIP. However, when NTS is on outage, the smaller capacity SNIP coupled with the higher tariff for use results in gas line pack being significantly depleted and the change being made to run extra coal units in lieu of ROI gas units. This can be demonstrated by comparing the flow differences in each pipeline for each of the main system delivery scenarios, NTS, SNIP and Inch, shown in Fig. 12.

Table 7
Peat plant utilisation.

	Base	Inch	NTS	NWP	SNIP
Average undispatched capacity (MW)	9.37	10.45	10.41	8.84	10.01
Average unit commitment	1.00	1.00	1.00	0.99	0.99

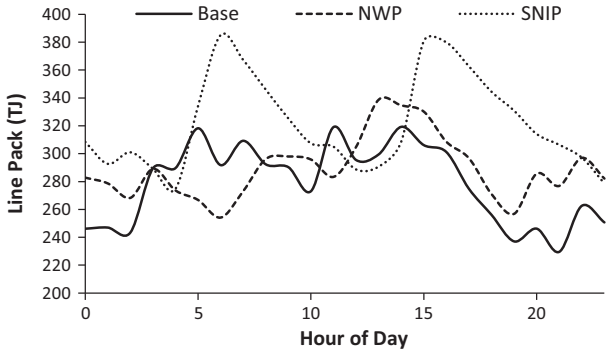

Fig. 10. NI pipeline line pack.

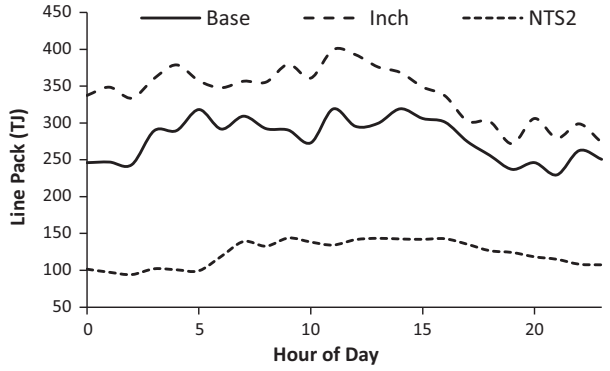

Fig. 11. ROI pipeline line pack.

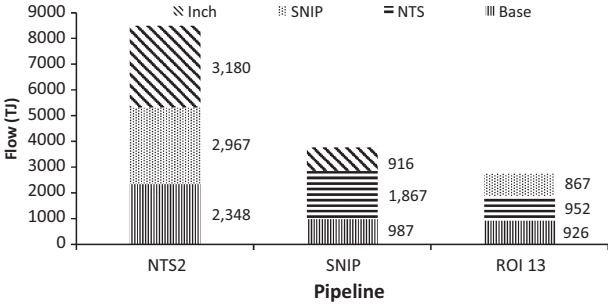

Fig. 12. Gas supply pipeline flows.

The peaks in line pack due to the outage on SNIP are directly attributable to the flows imported along the ROI subsea system via the NTS pipeline. Both Figs. 12 and 13 show that not only does overall volume across NTS increase in the SNIP scenario, but the time averaged flow across the IC system is also in strong agreement with the levels of line pack reported. With the loss of SNIP, system balancing is solely the responsibility of the NTS pipeline, showing an increase of 619 TJ across the week. A very small increase in supply from Kinsale is realised, the level of which does not contribute line pack or network balancing improvements since storage is withdrawing at or near its maximum capacity in all scenarios.

The line pack changes due to outages on the Inch pipeline do not show a great deal of variation from the base case. The loss of Inch results in slightly more total system line pack due to larger imports over the IC system in order to maintain system balance. As shown previously, gas generation does not alter significantly

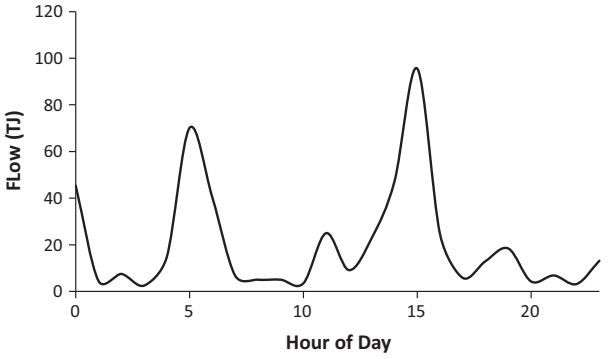

Fig. 13. NTS average hourly flow.

in this scenario, enabling larger levels of line pack to be achieved by forced import through a large capacity node. However, with the loss of the major IC subsea system, gas imports are focused primarily on maintaining domestic load, resulting in large decreases in gas generation. All imports in the NTS scenario are made through the smaller capacity SNIP entry therefore line pack levels are significantly depleted. The lowest levels of line pack found occur in this scenario, indicating the most stress applied to the gas system due to low pipeline pressures throughout the network.

Similarly, in the case of NTS outage, the level of imports across the SNIP IC show the most significant change in all IC scenarios studied. The smaller capacity SNIP shows a large increase in flows, from 51% utilisation in the base case to 97% as a result of NTS outage. However, this increase in utilisation is not enough to restore line pack to the levels seen in the base case, further highlighting the levels of stress on the gas network in an effort to maintain both gas and power system security. While the overall line pack situation in the outage of SNIP may seem acceptable and follow a well-defined daily profile, the utilisation of a single piece of infrastructure to near full capacity is a concern.

3.4. Wind forecast error

Fig. 14 shows the percentage difference in gas entry pipeline flows between the RCUC/SCUC and DQ models for each scenario. The only difference in each of these scenarios is the application of wind forecast error, which corresponds to 13% standard deviation of errors applied to the RCUC/SCUC model. In the base case, the only significant change occurs on the NTS pipeline, where the wind forecast error results in a 3.7% increase in flow for the DQ model which represents close to real time wind generation. In the Inch outage scenario, the 1.5% increase in flows required by lack of wind generation in NI via SNIP has accompanied a large swing in flow required in the IC system decreasing by over 5%.

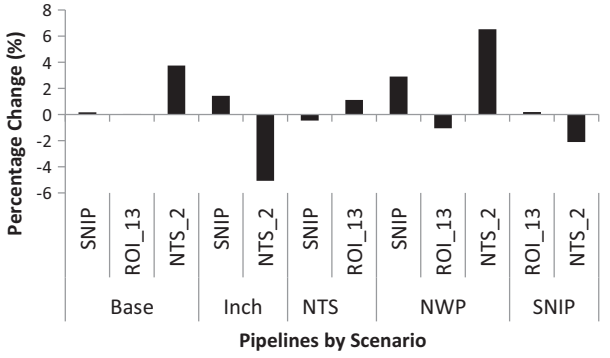

Fig. 14. Gas nomination changes due to wind forecast error.

The largest change in RCUC/SCUC and DQ flows due to wind generation occurs when the NWP pipeline is on outage. Both the SNIP and NTS lines experience increases of 3% and 6.5% respectively. The NWP pipeline effects a relatively small change in overall flows, representing a low stress gas system which is more susceptible to wind variability induced gas nomination changes. In contrast, during the NTS outage, the SNIP pipeline operates at near 100% capacity over 50% of the time periods analysed. Therefore, the ability of wind to effect change on this high utilised pipeline is minimised since the main stress of the pipeline is supplying demand regardless of wind. In a less stressed state, the necessity to supply demand is much less, presenting an opportunity for the effect of wind forecast error to be accentuated. This is also applicable in the Inch case. However, the ability of the SNIP pipeline in the Inch scenario to supply fast acting gas generation in the event of a significant drop in wind power is severely limited. This would present a significant problem for the system operators, as lack of flexibility on the system to respond to high ramp up in residual demand could lead to significant level of load shedding on the system. In addition, large swings in gas demand for power generation assets negatively impact the shippers involved in the purchase of gas unit fuel. Uncertainty around fuel requirements and lack of available well developed storage infrastructure on the island of Ireland increase the risk profile of gas unit operation. Large swings in wind generation ultimately increase the vulnerability of gas unit operators to the spot market instead of long term fuel contracts, directly impacting on the ability to operate the gas plant in the most economical fashion. As can be seen from the SMP results in Section 3.1, this uncertainty over gas flows and infrastructure operation is directly passed onto consumers.

4. Conclusions

In this paper, the ability of the natural gas transmission infrastructure to influence the operation of the power system has been well illustrated. Additionally, the resiliency of the gas transmission system to maintain supply in times of key infrastructure failures has also been demonstrated. The test system for this analysis was the all island gas and power system in Ireland. This case study proved interesting on three levels. Firstly, the high level of gas fired generation units enhanced the importance of gas infrastructure on power system security. Secondly, lack of indigenous production and well developed storage infrastructure implies that the overwhelming majority of gas supplies have to be imported from the GB system. Finally, the high penetration of wind power and the well understood wind/gas relationship further pressures the gas transmission system infrastructure to respond quickly to residual demand, placing the system in intermittent high stress operation. The influence of wind forecast error due to the high penetration of wind power was also investigated.

The key findings of the investigation all reveal the vulnerability of the Irish gas system due to the emphasis placed on power system security. The economic operation of the power system is severely impacted when the single pipeline supplying both of the ROI subsea interconnectors is on outage, resulting in an average SMP of € 169/MW h. The value of lost load in the SEM is hit over 50% of the periods analysed. This scenario also impacts on the power system's ability to respond to sudden changes in demand, wind related or otherwise, due to increasing the reserve provision in NI by over 150%. This reserve provision locates the system security across a power system transmission bottleneck, which causes serious concern as a result of possible gas pipeline outages.

Wind forecast error also has a significant impact on gas transmission infrastructure, requiring increased flexibility due to the operation of gas fired generation. Again, losing the key subsea system presents another significant issue to both gas and power system operators as the SNIP pipeline in NI operates at near 100%. Any further variability in wind generation or unexpected plant outage resulting in a rapid change in power system status would therefore not be served by gas fired generation further increasing the risk profile of the system. These risks are thought to be applicable to other systems with high fossil fuel import dependency and high gas and wind power penetrations. Future work will develop a fully representative GB and Ireland gas and power model. This will enable the interactions of combined systems and markets to be fully investigated.

Acknowledgements

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