Title	Liquefied natural gas and gas storage valuation: Lessons from the integrated Irish and UK markets
Authors(s)	Devine, Mel T., Russo, Marianna
Publication date	2019-03-15
Publication information	Devine, Mel T., and Marianna Russo. “Liquefied Natural Gas and Gas Storage Valuation: Lessons from the Integrated Irish and UK Markets.” Elsevier, March 15, 2019. https://doi.org/10.1016/j.apenergy.2019.01.157.
Publisher	Elsevier
Item record/more information	http://hdl.handle.net/10197/10967
Publisher's statement	This is the author’s version of a work that was accepted for publication in Applied Energy. Changes resulting from the publishing process, such as peer review, editing, corrections, structural formatting, and other quality control mechanisms may not be reflected in this document. Changes may have been made to this work since it was submitted for publication. A definitive version was subsequently published in Applied Energy (238, (2019)) https://doi.org/10.1016/j.apenergy.2019.01.157
Publisher's version (DOI)	10.1016/j.apenergy.2019.01.157

Liquefied natural gas and gas storage valuation: Lessons from the integrated Irish and UK markets

Mel T. Devine[a,b,c,*], Marianna Russo[b,c]

[a]Energy Institute, School of Electrical and Electronic Engineering, University College Dublin, Ireland
[b]Economic and Social Research Institute, Dublin, Ireland
[c]Department of Economics, Trinity College Dublin, Ireland

Abstract

To guarantee European countries greater access to competitive energy sources, the European Union has identified new infrastructures as Projects of Common Interest (PCIs). This paper aims to evaluate the implications for consumers of new investments in liquefied natural gas (LNG) import capacity and gas storage capacity. We utilise a stochastic mixed complementarity problem model with daily timesteps, incorporating stochastic natural gas supply cost and demand scenarios. Therefore, we assess the expected benefits for consumers of a diversified natural gas supply, and their sensitivity to changing market conditions. We use the integrated UK-Ireland gas system, which represents an ideal framework to evaluate new energy routes. We underscore the complementary of LNG and gas storage investments to manage short-term peak loads and long-term seasonal loads, and reduce energy bills. This study has implications for decision- and policy-makers when addressing new gas infrastructure development and the flexibility of energy systems.

Keywords: Natural gas markets, Liquefied Natural Gas, Gas storage, Stochastic Mixed Complementarity Problem.

---

1. Introduction

Securing affordable natural gas supply, ensuring supplier diversification and building infrastructure in a timely way are becoming important challenges for policy-makers worldwide [1]. Due to its versatility and environmental advantages relative to the other more polluting fossil fuels (coal and oil) [2], natural gas contributes towards policy objectives that target environment quality and sustainable development. However, infrastructure availability is a major potential

---

[*]Corresponding author
Email address: `mel.devine@ucd.ie` (Mel T. Devine[a,b,])

constraint to the growth of natural gas markets. Consequently, the future role of natural gas, and its transition from a niche fuel to the mainstream fuel, will depend on infrastructure development, likewise on a liquid and competitive liquefied natural gas (LNG) market [1].

The European Union (EU) is the world's biggest importer of natural gas and continued declines in domestic production mean that reliance on imports is set to increase. Diversification of supply sources is therefore paramount to ensure energy security and competitiveness. Several academic [3, 4] and policy studies [5] have underscored the need for more interconnected European natural gas network to enhance supply security. To reduce its dependence on a single supplier and address the difficulties of implementing projects with wider benefits, the European Commission (EC) has identified new natural gas routes as Projects of Common Interest (PCIs), with the aim to guarantee European countries with greater access to international energy markets and diversified supply sources [1]. Among these projects, 53 are new natural gas infrastructures across 24 EU and 7 non-EU countries. Of these new infrastructures, 6 are LNG import terminals (in Cyprus, Croatia, Greece, Ireland, Poland and Sweden) and 8 are gas storage facilities (in Bulgaria, Estonia, Greece, Ireland, Latvia, Lithuania, Romania, the UK).

Like all natural gases, LNG is cleaner than coal and oil, and offers an opportunity to diversify energy supply [2]. Especially, when there is insufficient storage capacity to balance seasonality, as in some European and most emerging Asian countries, LNG import capacity is an option to manage seasonal natural gas and electricity demand variations, thus providing higher flexibility to the energy system [1]. Furthermore, LNG can be used combined with liquid-air energy storage systems to improve the thermodynamic of micro-grids and distributed storage, and to increase the economic efficiencies of generation systems with high penetration of variable renewable-sources (vRES) [6]. Combined with technologies for energy recovery during the regasification process, LNG import capacity can be also effectively used as thermal energy storage [7].

Gas storage can be considered as a flexibility tool as well, since it enables the optimisation of natural gas transmission and ensures continuity of the service [8, 9]. Together, LNG import capacity and gas storage have strategic and speculative functions. The strategic function is linked to the opportunity of transportation and storage to optimise the natural gas value chain [10]. Consequently, it is relevant for decision-makers in gas companies and policy-makers, when designing new natural gas routes and distribution networks, while minimising investment and

---

[1] Available at `https://ec.europa.eu/energy/sites/ener/files/documents/memberstatespci_list_2017.pdf`. Updated on April 2018, as available at `https://ec.europa.eu/energy/sites/ener/files/technical_document_3rd_list_with_subheadings.pdf`. Access on 12 September 2018.

operating costs [11, 12, 13]. The speculative function refers to the possibility offered by LNG and storage capacity to exploit inter-temporal price differentials, and arbitrage opportunities in spot markets, with the potential to create more globally integrated and competitive natural gas markets [14, 15, 16].

The PCIs list suggests the importance and complementarity of LNG and natural gas storage facilities to guarantee secure, affordable and diversified energy supply in the EU. However, there are questions about the expected benefits associated with these projects, as raised by the European Agency for the Cooperation of Energy Regulators [17]. Storage can deteriorate welfare in imperfectly competitive markets, since it can give incentives to vertically integrated firms (supply and distribution) to use it strategically to adjust prices. In contrast, vertical integration between storage and distribution can reduce these incentives, thus improving social welfare [18]. Moreover, social welfare is maximised when storage is combined with spot markets [9]. In this context, the availability of LNG import capacity becomes crucial to optimise inter-temporal and arbitrage opportunities across international markets, since it provides the flexibility to respond to changing market conditions.

Previous studies have examined the implications of natural gas infrastructure development worldwide. Gabriel et al. [19] [20] considered the potential extent of market power in the North American natural gas market to address decision- and policy-makers' concerns on adequate investment in production and transportation capacity. In a similar vein, but in the context of European markets, [21] focused on the international trade of natural gas, including LNG, to address supply security concerns. In particular, they underscored, among others, the contribution of a liquid global LNG spot market in providing flexibility for countries with significant LNG import capacity. A similar European natural gas market investment model was used by [22] to find that Cournot competition was best placed to model the European market as a whole. However, they also noted how perfect competition was best placed to model the UK market.

Egging et al. [23] extended these previous studies to develop the World Gas Model (WGM). Following this study, the WGM was used to analyse the influence of the Pananma Canal on the international gas trade [24] and to examine the effects of US LNG exports on natural gas markets worldwide [25]. However, these studies do not allow for stochasticity in the market players' problem, thus neglecting to reflect market uncertainty. More recently, the WGM was extended to incorporate stochasticity [26]. The authors investigated the impact of different risks - from both supply and demand sides - on investment decisions and natural gas flow, especially LNG. Their findings imply that investment in LNG capacity is mostly affected by demand-side risks. Furthermore, they support an enhancement of reverse (i.e. bidirectional) flow pipeline network capacity, in line with the EC energy policy agenda. However, these results mainly focus on Eastern Europe. Risk-aversion was explicitly incorporated into a natural gas market modelling framework in [27], which found that risk-aversion alters the investment behaviour of gas suppliers. Further studies addressing future investment in the natural gas production sector and potential export capacity worldwide include [28, 29, 30, 31].

Recent studies have investigated the adequacy of infrastructure to satisfy the increasing demand for natural gas in the future, and the implications of new investments worldwide. Some of these studies mainly focused on pipeline capacity to address persistence of congestion and bottlenecks across the network, and their impacts on supply security in the U.S. [32, 33] and Europe [34]. Following earlier work in [35], Feijoo et al. [36] underscored the implications of socio-economic conditions for the future development of natural gas infrastructure in the U.S. in an integrated perspective. Specifically, they argued that the geographical distribution of investments depends on international markets and global economy conditions, as well as constraints due to existing infrastructure access. Based on current expectations on the Chinese natural gas demand growth, [37] evaluated the impact of uncertain import and domestic supply costs on natural gas supply in China, and the future development of LNG import capacity. Shi and Variam [38] assessed the impact of low oil prices on investments in natural gas in the East Asian region. Holz et al. [4] underlined the role of LNG as a bridging technology for the achievement of a diversified and sustainable supply in Europe but they do not account for uncertainties in natural gas markets and only rely on deterministic scenarios.

By investigating the interplay between natural gas and power sector, [39] assessed the impacts of natural gas supply interruptions on natural gas and electricity prices across Europe. They underlined the importance of gas storage for the stability of energy systems. Qiao et al. [40] assessed investments in gas storage capacity for gas-fired power plants using the EU as a representative model. They evaluated the day-ahead gas storage schedule matching short-term peak loads and long-term seasonal loads and prices, thus providing information about transmission management operations and network investments in the European gas system. Despite the extra costs, they argued that gas storage avoids power generation limitations resulting from natural gas supply shortages and ensures power system reliability. Furthermore, it has implications when considering the maximum absorption capacity of vRES and their uncertainty. A lack of gas storage capacity increases the risk profile of electricity generation, and in turn generation costs. In contrast, gas storage can reduce generation costs up to 40%. Potential under-investment in natural gas infrastructures can therefore influence power sector functioning, especially with a high penetration of wind generation. Wind uncertainty exacerbates the exposure of gas generators to spot price volatility, thus affecting their ability to economically operate gas-fired plants [41]. Lynch et al. [42] suggested that it will become beneficial for electricity systems to invest in power-to-gas electrolysis. Such investments would have a significant impact, e.g. on natural gas supply and demand in Ireland. Further studies focusing on the implications of developing natural gas infrastructures for the reliability of electricity and gas systems include [43, 44, 45, 46, 47, 48, 49, 50, 51].

Kiss et al. [52] focused on assessing different infrastructure projects in Central and South Eastern Europe from the proposed PCIs and concluded that different baseline assumptions favour different project combinations. Overall, these studies underscore the relevance of adequate LNG and gas storage capacity to achieve a diversified and affordable energy supply, and to allow for the effective integration of vRES. However, they do not provide an evaluation of costs-benefits associated with different projects, which also accounts for the impact on domestic natural gas prices and final consumers. The contributions of this paper are clarified below.

First, we contribute to the literature by considering the expected economic benefits for consumers of LNG and gas storage infrastructures in the context of the EU PCIs. We assess the effects of new LNG capacity on gas system prices, as well as the interplay of LNG and gas storage capacity. That is, we evaluate the impact of both LNG and integrated LNG-storage facilities on the consumers' energy bill. To our best, little research has been done to assess the implications of PCIs on consumers and on how they complement each other. Therefore, we address concerns raised by European regulators on the impact of PCIs on social welfare [17]. We use the integrated Irish-UK natural gas market as a reference model. This because the Irish market is only connected to the European energy system through the UK. In the absence of further natural gas routes, any bottleneck in the UK natural gas market can have critical impacts on Ireland, thus compromising the achievement of a single EU-wide energy market, as mandated by the European Union.

Second, we use a stochastic Mixed Complementarity Problem (MCP) to model the integrated Irish-UK natural gas markets on a daily basis. The model also incorporates the Moffat pipeline which connects these two markets. Therefore, we contribute to the literature by assessing the economic benefits for consumers of reverse flow pipeline network capacity. MCPs allow optimisation problems of multiple individual players to be solved simultaneously and in equilibrium by combining the Karush-Khun-Tucker (KKT) conditions for optimality of each of the players and connecting them via market clearing conditions. In addition, MCPs allow both primal variables (e.g., sales) and dual variables (e.g., prices) to be constrained together [53]. In this work, the MCP considers a number of probabilistic scenarios which represent different demand curve and supply cost possibilities for 2025.

MCPs have been used to model natural gas markets in many of the previous works in the literature mentioned above [4, 19, 20, 21, 22, 23, 24, 25, 26, 27, 35, 36]. However, each of these consider large-scale natural gas markets. Consequently, they do not consider detailed timescales, i.e., they only model timesteps at a seasonal or monthly scale. While the present work only focuses on the Irish and UK markets, this allows us to consider daily timesteps. This finer granularity is in contrast to each of the MCPs considered previously and represents a significant contribution to the literature since it allows us to account for short-term peak loads and long-term seasonal loads while assessing their effects on consumers' cost. The closest work to current study can be found in [54], which does consider daily timesteps. However, this work uses a linear programming approach over a MCP approach and focuses on modelling one single market with not interconnections.

The remainder of this paper is structured as follows: in Section 2 we provide a background of the Irish natural gas market. In Section 3 we describe the MCP methodological framework while in Section 4 we introduce the data used to parametrise the model. In Section 5 we present the results, which are discussed in Section 6. Section 7 concludes the paper.

2. Background

We perform our analysis in the context of the Ireland-UK integrated natural gas market due to its peculiarities. First, Ireland is the only EU country without LNG and storage facilities. Second, the UK serves as transit country for natural gas (and electricity) flowing into Ireland. Therefore, the UK also represents the only transit route to connect Ireland's energy market to European and global energy markets. Finally, the achievement of the EU 2020 and 2030 renewable energy targets is expected to set Ireland as a leader in the penetrations of vRES in the power sector worldwide [55]. Yet, according to the most recent analysis by the International Energy Agency [56], system integration of vRES remains a major challenge. The development of new infrastructures, including natural gas infrastructure, is thus paramount to facilitate the integration of larger volumes of vRES across integrated energy markets. Therefore, the Ireland-UK gas system provides an ideal framework to evaluate the contributions of new investments in natural gas infrastructures to the achievement of sustainable development, security of supply and competitiveness, along with the costs-benefits for consumers.

Similar to other European countries, natural gas plays a pivotal role in the energy mix and economic development of Ireland. In 2016, it met 29% of the total energy demand of Ireland compared to 23% of the EU-28[2]. The flexibility and efficiency of gas-fired power plants have supported the increase of vRES in the power sector. On average, natural gas accounted for 49% of the fuel used for electricity generation in the period 2012-16 [57].

Ireland's natural gas comes from both indigenous production and imports. The indigenous production is mostly satisfied by the Corrib gas field. Production at Corrib started in December 2015 and amounted to 54% of 2016 gas demand. In low demand days, during the summer months, it amounted to 100% of the Irish gas demand. The balance on Ireland's natural gas requirement is imported from the UK through the Scotland-Ireland Interconnector Moffat. In 2016, 40% of the Irish gas demand was satisfied through import from the UK, thus making Ireland highly dependent on a single supply source. Nevertheless, Corrib production is expected to decline quickly and deplete by 2025 [57]. The declining indigenous production in Ireland is of particular concern among policy-makers, in particular when considering that the island's only energy link to the EU will disappear in March 2019, after Brexit [3]. Ireland currently has no LNG terminal. Ensuring gas supply security in Ireland, in particular following Brexit, is therefore paramount for the achievement of EU's objective [58] [59]. Ireland and the UK have intergovernmental agreements on sharing gas supplies that will exist beyond Brexit. However, Brexit uncertainty may represent a risk for gas supply to Ireland [58].

The PCIs envisage the development of alternative sources of supply and supply routes to Ireland [60]. The Shannon Liquefied Natural Gas (LNG) import terminal, which was granted planning permission in 2008, is listed on the EU PCIs. While construction for this project has yet to begin, it would allow Ireland to import gas from the Atlantic Basin (incl. US) and Middle East, thus bypassing the UK and providing Ireland with diversified gas supplies. The development of the Islandmagee Underground Gas Storage (UGS) facility in Northern Ireland, which is expected by 2021, would further improve the security of supply and the flexibility of the gas market in Ireland. The Islandmagee storage facility is a salt cavern facility. Its proposed location is close (<6 Km) to the existing gas-powered electricity station Ballylumford

---

[2] `https://ec.europa.eu/info/news/eu-energy-statistics-latest-data-now-available-2018-oct-04_en`

[3] *EU closer to genuine Energy Union as MEPs support gas supply solidarity*, Euractiv 12 September 2017. Available at `https://www.euractiv.com/section/energy/news/eu-closer-to-genuine-energy-union-as-meps-support-gas-supply-solidarity/`. Access on 17/10/2018

and, hence, to the national gas grid[4].

The implications of Irish LNG and gas storage facility for consumers have not been not addressed. Developing a LNG import terminal would provide access to the increasingly competitive international gas market, making the Irish gas market more competitive. The development of a storage facility would allow the management of seasonal loads, thus reducing gas price volatility and the risks of supply shortage. In the following section, we investigate what is the optimal and most competitive option for Irish consumers in 2025, i.e. when the Corrib field is expected to be depleted and when LNG and storage facilities should be operational.

3. Model Formulation

In this section, we describe the formulation of the stochastic mixed complementarity problem (MCP) approach. The MCP allows both primal variables (demand and supply) and dual variables (prices) to be constrained together [53]. It models a natural gas system with $|M|$ nodes/markets and $|K|$ suppliers. Suppliers buy and sell gas, subject to constraints, in order to maximise their profits. Each of the $|K|$ suppliers has separate optimisation problems that are connected through market clearing conditions. The stochastic MCP is made up of these market clearing conditions along with the Karush-Kuhn-Tucker (KKT) conditions for optimality from each of the suppliers. Thus, the MCP solves $|K|$ optimisation problems simultaneously and in equilibrium. All players are modelled as price-takers. In this work, the MCP considers different stochastic scenarios $|S|$, which represent different demand and supply curves in 2025. Each scenario has a probability ($PROB^s$) associated with it. Tables A.5 - A.8 describe the sets, variables and parameters used in the model. The following conventions are used: lower-case Roman letters indicate indices or variables, upper-case Roman letters represent parameters (i.e., data, functions), while Greek letters indicate endogenous prices. The variables in parentheses alongside each constraint are the Lagrange multipliers associated with those constraints.

3.1. Supplier k's problem

Supplier k maximizes expected profit (revenues less cost) by deciding how much gas to sell ($sales^s_{kmt}$), to buy ($supply^s_{kmt}$), inject to storage (inj^s_{kmt}) and extract from storage (xtr^s_{kmt}), in each scenario s. In addition, it also decides how much gas to flow ($flows^s_{kat}$) through $|A|$

---

[4] Further details on Islandmagee can be found at `http://www.islandmageestorage.com/index.php?option=com_content&task=view&id=67&Itemid=101`

pipelines to other nodes/markets explicitly modelled, e.g., the Irish and UK markets in this work. Furthermore, each supply source k may have a storage facility associated with it.

The marginal price suppliers in node m at time t receive is π^s_{mt}. The marginal cost values associated with supply, injection to storage, extraction from storage and flowing gas through pipelines are $C^{supply,*}_{mtr}$, C^{inj}_{mt}, C^{xtr}_{mt} and C^{pipe}_{at}, respectively. Supplier k's optimisation is given below with the associated KKT conditions shown in the Supplementary Appendix. Suppliers k's optimisation problem is

$$\begin{aligned}\max_{\substack{sales^s_{kmt},\\ supply^s_{kmt},\\ flows^s_{kat},\\ inj_{kmt},\\ xtr^s_{kmt}}} \sum_{t,m} DAYS_t \Bigg\{ \sum_s PROB^s \Bigg[& \pi^s_{mt} sales^s_{kmt} - C^{supply,s}_{mt} supply^s_{kmt} \\ & - C^{inj}_{mt} inj^s_{kmt} - C^{xtr}_{mt} xtr^s_{kmt} - \sum_{a \in A(m)} C^{pipe}_{at} flows^s_{kat} \Bigg] \Bigg\},\end{aligned} \tag{1}$$

subject to:

$$\begin{aligned} supply^s_{kmt} + xtr^s_{kmt} \quad &+ \sum_{a \in a^{in}(m)} (1 - LOSS_a) flows^s_{kat} \\ = sales^s_{kmt} \quad &+ \sum_{a \in a^{out}(m)} flows^s_{kat} + inj^s_{kmt},\ \ \forall s, m, t,\ (\lambda^{s,k1}_{kmt}), \end{aligned} \tag{2a}$$

$$\sum_t DAYS_t supply^s_{kmt} \quad \leq \quad TP^{\max}_{km},\ \forall s, m,\ (\lambda^{s,k2}_{km}), \tag{2b}$$

$$supply^s_{kmt} \quad \geq \quad DP^{\min}_{km},\ \forall s, m, t,\ (\lambda^{s,k3}_{kmt}), \tag{2c}$$

$$supply^s_{kmt} \quad \leq \quad DP^{\max}_{km},\ \forall s, m, t,\ (\lambda^{s,k4}_{kmt}), \tag{2d}$$

$$inj^s_{kmt} \quad \leq \quad DI^{\max}_{km},\ \forall s, m, t,\ (\lambda^{s,k5}_{kmt}), \tag{2e}$$

$$xtr^s_{kmt} \quad \leq \quad DX^{\max}_{km},\ \forall s, m, t,\ (\lambda^{s,k6}_{kmt}), \tag{2f}$$

$$MINSTOR_{km} \quad \leq \quad INITSTOR_{km} + \tag{2g}$$

$$+ \quad \sum_{e=1}^{t} DAYS_e[(1 - LOSS_m) inj^s_{kme} - xtr^s_{kme}], \forall s, m, t,\ (\lambda^{s,k7}_{kmt}), \tag{2h}$$

$$INITSTOR_{km} + \sum_{e=1}^{t} DAYS_e[(1 - LOSS_m) inj^s_{kme} - xtr^s_{kme}] \leq MAXSTOR_{km}, \forall s, m, t,\ (\lambda^{s,k8}_{kmt}), \tag{2i}$$

where $DAYS_t$ represent the number of days in timestep t and and $PROB^s$ represents the probability associated with scenario s. Supplier k's objective function (1) maximizes their expected profit in all time periods. We assume that there is one day in each time period ($DAYS_t = 1\ \forall t$) and 365 time periods in total. The first time period represents the 1st January 2025.

The expected profit of suppliers is the money they receive from sales less the cost of supply, less the cost associated with flowing gas through pipelines and less the cost of injections and extractions to and from storage. Constraint (2a) ensures that the amount of gas supplier k has entering market m equals the amount of gas they have exiting that market, where $LOSS_a$ represents the percentage losses associated with pipeline a. An upper bound for the total amount of gas supplier k sources from source p in market m, across all time steps, is provided by constraints (2b). Constraints (2c) and (2d) give minimum and maximum supply rates for source p, respectively, while constraints (2e) - (2f) give maximum injection and extractions rates to and from storage. Lower and upper bounds for the amount of gas supplier k can have in storage, for source p, at time t is provided by constraints (2h) and (2i) respectively, where $LOSS_m$ represents the percentage losses associated with storage facilities in market m.

Finally, all primal variables in supplier k's problem, except $sales^s_{kmt}$, are constrained to be non-negative. When supplier k purchases more than it sells, $sales^s_{kmt}$ takes a negative value. This situation may only occur when suppliers k injects gas to storage. For clarity, in Figure 1 an overview of all gas flows in the model is depicted.

3.2. Market-Clearing Conditions

The $|K|$ optimisation problems are connected via the following market clearing conditions:

$$\sum_k DAYS_t sales^s_{kmt} = Z^s_{mt} - B_{mt} \times \pi^s_{mt},\ \ \forall m, s, t,\ \ (\pi^s_{mt} \text{ free}), \tag{3a}$$

$$\sum_k flows^s_{kat} \leq DA^{\max}_a,\ \ \forall a, s, t,\ \ (\tau^s_{at}). \tag{3b}$$

Equation (3a) states, for each timestep and scenario, that the total amount of gas sold by the suppliers in market m equals a linear demand curve, where Z^s_{mt} and B^s_{mt} are the demand curve intercept and slope respectively. Demand curves allow consumers to adjust their demand, depending on the price of gas, and thus represent natural gas market more accurately than fixed demand levels that are unresponsive to price. While linear demand curves have been used in each of the previous MCPs mentioned in Section 1, future work will also consider non-linear

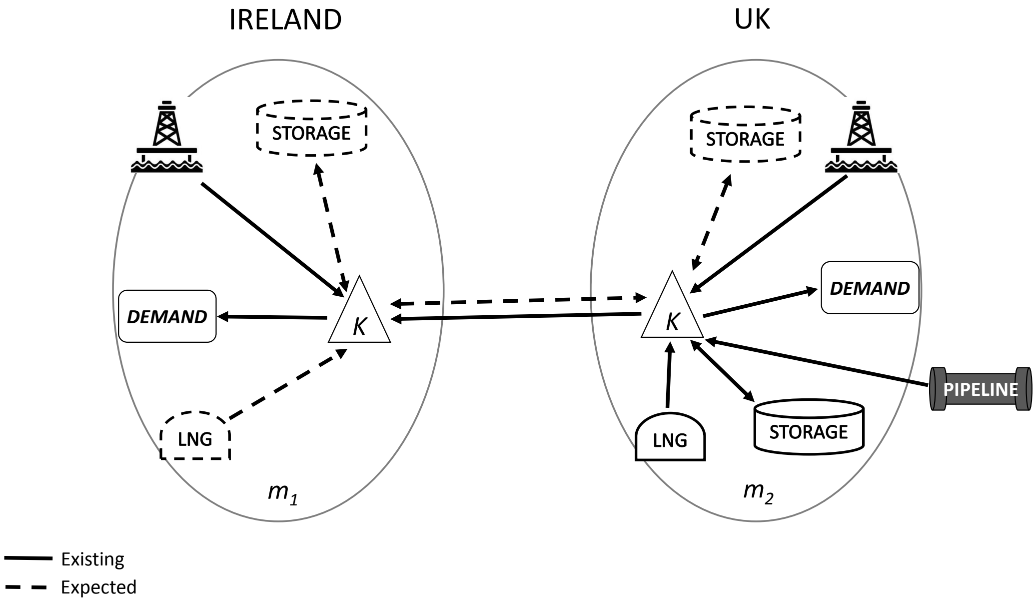


Figure 1: Overview of gas flows

demand curves. Condition (3b) constrains the total amount of gas that can flow through pipeline a in each timestep and scenario.

The Karush-Kuhn-Tucker (KKT) conditions for suppliers are presented in the Supplementary Appendix. As supplier k's problem is linear, these conditions are both necessary and sufficient for optimally for all players. The MCP model consists of these KKT conditions in addition to the market clearing conditions (3).

4. Data

In this section, we describe the data used in the MCP model. Section 4.1 focuses on the supply side in 2025; Section 4.2 presents data on demand.

4.1. Supply side capacity data

Firstly, we assume there are $|M|$=2 nodes, representing the Irish and UK gas markets. Secondly, we assume that there are $|K|$=10 supply sources in total, three Irish and seven from the UK. These supply sources are listed in Table 1, where their projected daily maximum capacities in 2025 are reported. The three Irish sources represent the Corrib gas field, the

Supply sources (k)	Ireland ($m = 1$)	UK ($m = 2$)
Corrib	55.22	0.00
Irish LNG	311.08	0.00
UKCS	0.00	699.93
Norway	0.00	1722.05
BBL	0.00	588.83
IUK	0.00	822.14
UK LNG	0.00	1622.06

Table 1: Daily maximum capacities ($DP_{km}^{\max}$, GW h/day).

proposed Shannon LNG import terminal (Irish LNG)[5] and a potential gas storage facility. The seven UK sources include the UK Continental Shelf (UKCS), imports from Norway, the Netherlands (via the BBL pipeline) and Belgium (via the IUK inter-connector). A long-range (LRS) and a medium-range (MRS) storage facility are also included, along with a UK LNG import facility. The long-range capacity represents the Rough storage facility; the medium-range storage capacity represents the sum of all medium-range facilities projected to be in the UK in 2025 [61]. Regarding UK LNG, today there are three operational LNG import terminals located in Wales and England (South Hook, Dragon and Grain). However, we assume these terminals import gas at the same price, thus implying they work as one combined LNG import facility. The depicted values of the Irish supply sources were obtained from [62] while the UK numbers were obtained from [63] and [61].

Using the daily maximum flow rates in Table 1, the corresponding minimum capacities were computed. For Corrib, UKCS and Norway they were set at 34%, 46% and 21% of the daily maximum capacities from Table 1, respectively. These percentages reflect long-term contracts and were calculated by examining the actual minimum flow rates and maximum capacities at 2015 and 2016, as recorded by Gas Networks Ireland[6] and the UK National Grid[7]. For all other sources of supply, the daily minimum capacities were set to zero.

Table 2 displays the total yearly maximum capacities. Values for the UKCS and Norway were obtained from [63]. The remaining yearly values were calculated by multiplying the daily

---

[5] http://www.shannonlng.ie/

[6] https://www.gasnetworks.ie/corporate/gas-regulation/transparency-and-publicat/

[7] http://mip-prod-web.azurewebsites.net/DataItemExplorer/Index

Supply sources (k)	Ireland ($m = 1$)	UK ($m = 2$)
Corrib	15776.20	0.00
Irish LNG	79480.94	0.00
UKCS	0.00	199980.00
Norway	0.00	333300.00
BBL	0.00	214922.95
IUK	0.00	300081.10
UK LNG	0.00	414436.33

Table 2: Yearly maximum capacities ($TP^{\max}_{km}$, GW h).

	Irish LNG Storage	Irish Independent Storage	UK LRS	UK MRS
$MAXSTOR_{km}$ (GW h)	8.89	8888.00	36663.00	15998.40
$MINSTOR_{km}$ (GW h)	0.00	0.00	957.00	3719.00
$INITSTOR_{km}$ (GW h)	0.00	4266.24	12625.00	12438.00
$DI^{\max}_{km}$ (GW h /day)	2.93	222.20	455.51	1422.08
$DX^{\max}_{km}$ (GW h /day)	2.93	222.20	455.51	1422.08

Table 3: Storage parameters.

values in Table 1 by 365. For both the Irish and UK LNG sources, the yearly values where discounted by a factor of 0.7. This factor is in accordance with the UK National Grid [63] and [54] and accounts for the actual LNG operating hours (a factor of 1 would imply the LNG facility operates at 100% of its capacity, thus injecting gas into the network without interruption during 1-year period). Consequently, the total yearly maximum capacities of Irish LNG and UK LNG in Table 2 were obtained as $TP^{\max}_{km} = 0.7 \times 365 \times DP^{\max}_{km}$. Storage facilities can allow for the injection or withdraw of gas, but not its production. In contrast, LNG terminals are associated with tanks that permit to stockpile gas. Therefore, Irish LNG is assumed to operate as a source of gas supply, likewise as a storage facility.

The parameters associated with the different storage facilities are displayed in Table 3. As Shannon LNG import terminal also consists of four storage tanks, each with a capacity of 200,000 cubic meters (cm), an Irish LNG storage capacity of 8.89 GW h is assumed. Following [21], we consider a storage loss factor of $LOSS_m = 0.015\ \forall m$, which corresponds to a minimum amount of gas required to maintain a pressure level in the storage facility for normal operations. A

	Summer	Winter
C_{pmt}^{inj}	7.315	255.64
C_{pmt}^{xtr}	255.64	7.315

Table 4: Storage marginal costs (€/GW h)

potential independent Irish storage facility with a maximum capacity of 8888 GW h (800 mcm) is also considered in the model. We assume that this storage facility is initially 48% full.

For the UK facilities (LRS and MRS), the maximum capacities and maximum daily rates were obtained from [61]. The minimum values correspond to the actual minimum values for these facilities across 2015 and 2016 while the initial values were taken from the actual values from the 1st January 2018.

The storage marginal costs (Table 4) are the same for each facility but vary depending on the season: In the summer (March - September, inclusive), injection costs are lower than in the winter, and *vice versa*. These costs were obtained from [64].

Finally, we consider $|A|$=1 pipeline interconnecting the Irish and UK markets. This pipeline represents the Moffat interconnector, which has a maximum daily capacity of 344.41 GW h/day [62] [61]. Following [21], we consider a pipeline loss factor of 0.22% per 100Km. As Moffat is 258.88 Km in length, this corresponds to a loss factor of $LOSS_{a=1} = 0.0063$. For the marginal cost of the pipelines, we assume a value of $C_{a=1,t}^{pipe} = 442$ (€/GW h) $\forall t$, a number determined from Gas Networks Ireland [65].

4.1.1. Supply side cost data

The marginal supply cost values ($C_{mt}^{supply,s}$) for $|S|$=10 scenarios were set as follows. The UKCS production costs were based on operating costs recovered from the UK Oil & Gas Economic Report 2017 [66]. In accordance with the outlook in [66], in the period 2017-25 we assumed different trends in these costs to account for the depleting path underlying UKCS production and the uncertainty in its recovery costs. These trends were set by assuming costs linearly increasing/decresing at progressively higher annual rates, such as to achieve UKCS production costs for 2025 in the range of ± 20% compared to the 2016 level. Corrib production costs were assumed to be the same as the UKCS costs.

Pipeline and LNG import costs for 2017 were retrieved from Thomson Reuters Eikon. For LNG, we considered separate import costs scenarios for Qatar and Trinidad & Tobago, since these countries are the two most important LNG suppliers in the UK, and accounted on average for 90% and 3% of the total LNG supply during the period 2013-17, respectively[8]. LNG price scenarios can be found in Appendix B. The expected import cost profiles over the period 2018-25 where set based on the forward curves as follow: Pipeline import costs from Norway were assumed to follow the forward price curve at the UK National Balancing Point (NBP) gas trading hub [67]; Expected pipeline import costs through IUK (from Belgium) and BBL (from the Netherlands) were assumed to mimic the forward curves of TTF[9] and Zeebrugge[10], respectively; LNG import costs were assumed to proceed along with the NBP forward curves. The natural gas forward curves were recovered from Thomson Reuters Eikon as published on 19 April 2018.

To account for the unpredictability of the natural gas prices and changing market conditions, a Monte Carlo exercise was set to design different scenarios for each supply source. Brownian motions were simulated with increasing levels of volatility. We assumed greater variability in the winter than in the summer, thus in accordance with empirical evidence in the natural gas markets [68] [69]. The Brownian motions were therefore added to the price series above in a proportional way and accounting for seasonalities in the series, so that all import costs show the same amount of uncertainty under each scenario. We chose the first ten Monte-Carlo simulations to populate the $|S| = 10$ scenarios for each supply source, that is the parameter $C_{mt}^{supply,s}$. Consequently, we assumed each scenario had an equal probability, i.e., $PROB^s = \frac{1}{10}$, $\forall s$.

Ideally, we would like to include infinitely many scenarios. However we chose ten scenarios following the most previous works in the literature where eight and nine scenarios where chosen, in [26] and [27], respectively.

4.2. Demand side data

In order to obtain the parameters associated with the linear stochastic demand curves in 2025, we assume different demand profiles. For the UK, the demand profiles were set such as to reflect the 2017 energy and emissions projections published by the UK Department for Business, Energy and Industrial Strategy [70]. These projections are based on different assumptions of

---

[8] `https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/736148/DUKES_2018.pdf`

[9] Natural gas price at the Title Transfer Facility (TTF) Virtual Trading Point, operated by Gasunie Transport Services (GTS), the transmission system operator in the Netherlands

[10] Natural gas price at the Zeebrugge Trading Point (ZTP), operated by Fluxys Belgium SA, the transmission system operator in Belgium

economic growth and fossil fuel prices. We consider the BEIS reference case, which reflects the economy forecast published in the UK Office for Budget Responsibility (OBR) January 2017 Fiscal Sustainability Report [71]. Our demand profiles consider the BEIS low and high economic growth cases as well, which reflect the OBR's alternative economic trends. These trends embody the UK's exit from the EU (low case) and the assumption of no-Brexit (high case). The two alternative economic trends are broadly symmetric around the central reference case.

Similar to the UK, demand profiles in Ireland were designed to reflect a broad range of likely economic outcomes, depending upon external and internal factors. These profiles are in accordance with the low, median and high gas demand forecasts published by Gas Network Ireland (GNI) in the Network Development Plan 2017 [72].

To explore the impact of uncertainty and changing markets conditions, in each scenario the same Brownian motions simulated for the supply costs were added to the demand profiles in a proportional way. This ensured that the same amount of uncertainty was added to demand and supply costs in each scenario. We chose the first four Monte-Carlo simulations based off the reference case, the first three based off the low case and the first three based off the high case. In total, this gives us $|S| = 10$ scenarios for the demand curve intercepts (Z^s_{mt}). For the slope of the demand curves (B_{mt}), we assumed values of 0.005 and 0.051 for Ireland and the UK, respectively. These values are scenario independent and were calculated using the following formula:

$$B_{mt} = \text{elasticity} \times \frac{\hat{Q}}{\hat{P}}, \tag{4}$$

where $\hat{Q}$ and $\hat{P}$ represent the average quantities and price of gas, respectively, and were calculated based on the 2016 values. Moreover, for the Irish market we chose an elasticity of -0.347 [73] while for the UK we used a value of of -0.3 [74].

5. Results

5.1. PCIs: The Impacts of an LNG facility on consumers' energy bill

5.1.1. Low LNG prices

In order to determine the impact of PCIs on the consumers' energy bill in Ireland, we run the MCP model twice, once with the Irish LNG project operational and once without it. The 10 scenarios for the marginal LNG prices are based on projections for Qatari LNG prices. In the figures that follow, we display expected values. However, we also use error bars to show the maximum and minimum values observed across the 10 scenarios considered and hence demonstrate the robustness of the model's results.

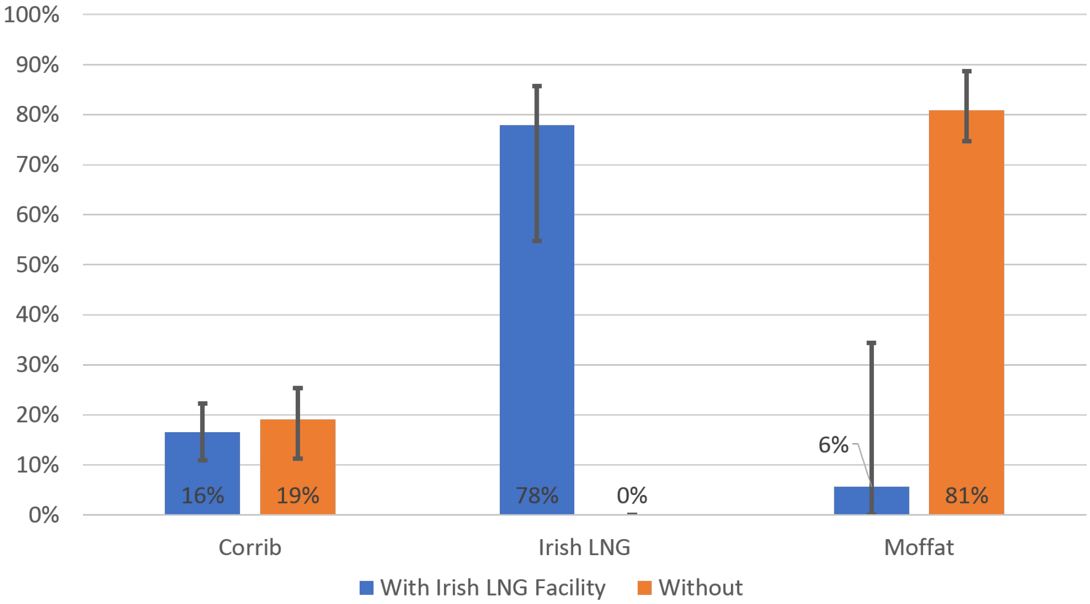


Figure 2: Sources of supply in Irish gas market (Qatar LNG prices and no Irish storage)

As summarised in Figure 2, the expected dependency of Ireland on gas imported from the UK (through the Moffat pipeline) reduces from 81% to 6% with the Irish LNG import facility. Even in the most stressed scenario, the dependency reduces from 88% to 34%. In contrast to Figure 2, the composition of UK supplies is relatively unchanged following the introduction of the Irish LNG facility, as depicted in Figure 3. However, when Irish LNG is present, the UK does receive some supplies via the Moffat pipeline.

Figure 4 displays the expected consumer savings when an Irish LNG is introduced into the market. Expected consumer cost are calculated using the following formula

$$\sum_{s} PROB^{s} \sum_{k,t} \pi^{s}_{mt} DAYS_{t} sales^{s}_{kmt}. \tag{5}$$

Figure 4a shows that total expected consumer costs in Ireland decrease by €125M in 2025, which represents an average annual saving of 8.9% with maximum savings reaching 23.2%. The minimum savings observed was 1.2%, suggesting the Irish LNG facility reduces consumer cot regardless of the cost/demand scenario considered. These savings occur despite the fact that gas supply costs in the UK and Ireland are driven by the same LNG import prices (Qatar). The cost reduction tallies with evidence in Figure 5, which depicts the expected net flow of gas into Ireland from the UK via the Moffat pipeline. Net flows for the individual scenarios can be found in Appendix C. Without an LNG import facility, gas flows from the UK to Ireland through

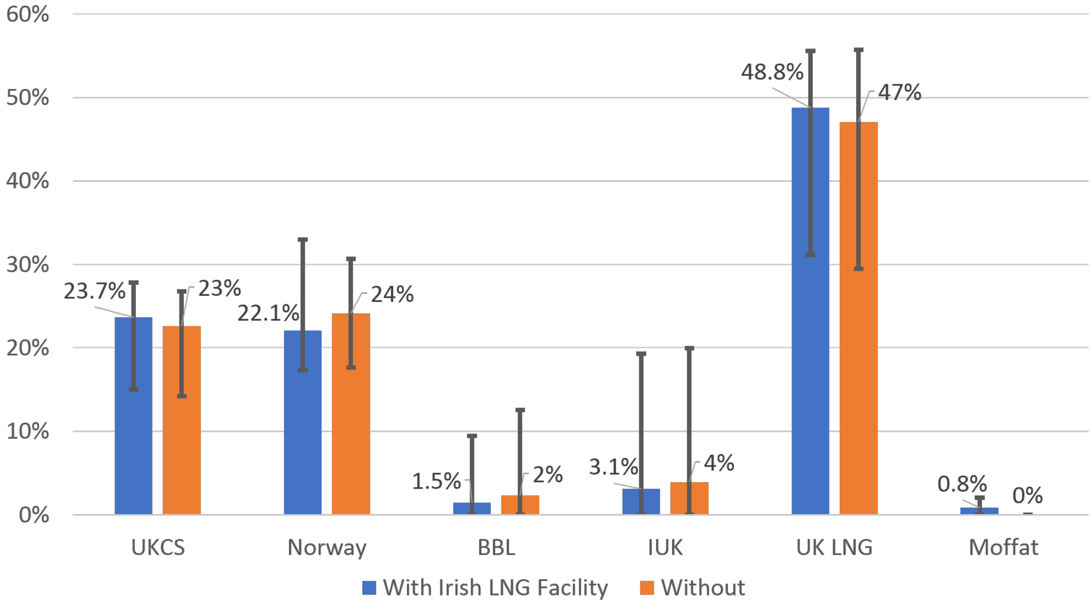
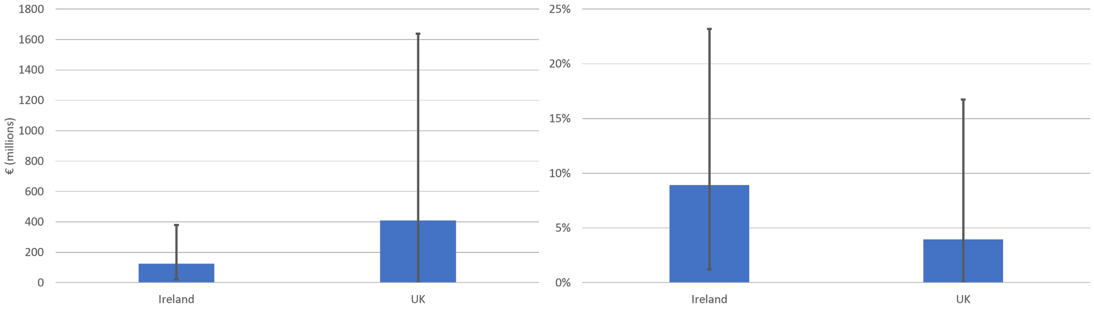


Figure 3: Sources of supply in UK gas market (Qatar LNG prices and no Irish storage)



(a) Absolute savings

(b) Percentage savings

Figure 4: Expected consumer savings (Qatar LNG prices and no Irish storage)

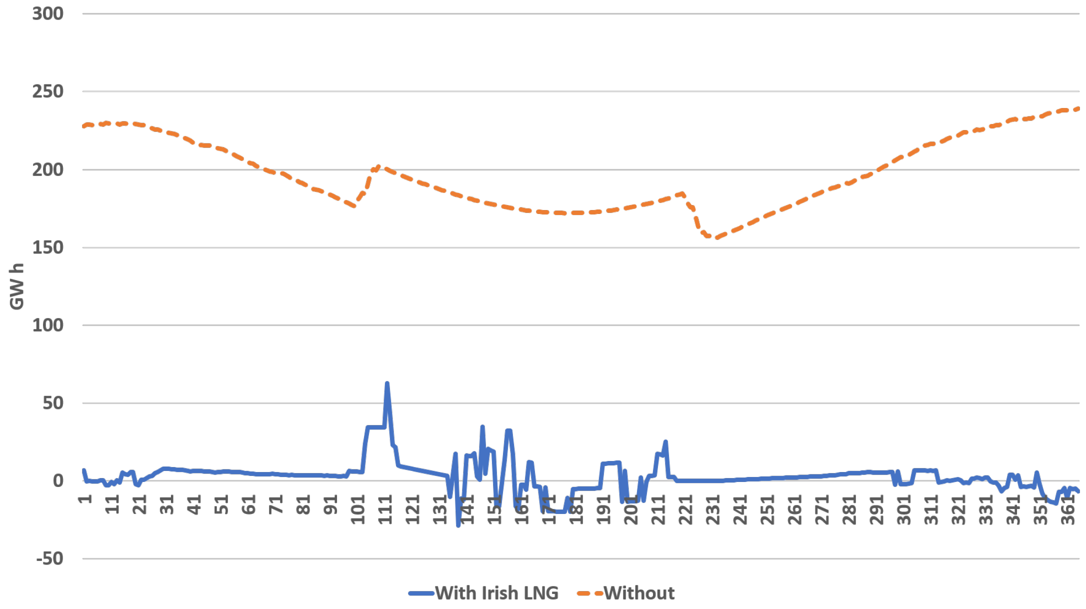


Figure 5: Net flows into Ireland via Moffat (Qatar LNG prices and no Irish storage)

Moffat everyday. Consequently, the cost of using Moffat is added to the Irish marginal cost of gas. When Ireland has its own LNG facility, these flows are significantly lower. Furthermore, in some days, during the summer, gas flows in reversed direction, that is from Ireland to the UK. During these days, the Moffat cost is paid by consumers in the UK, thus representing a saving for consumers in Ireland.

Figure 4 implies that, following the introduction of an LNG facility in Ireland, total expected consumer costs in the UK reduce by €410M (4.0%), with these savings potentially reaching a high of 16.7% and a low of 0.02%, depending on the scenario. Currently, Ireland can only import gas through the UK. In order to satisfy Irish gas demand, the UK needs to increase its own gas import. The observed lower consumer costs in the UK can be regarded thus as a consequence of the lower volumes of gas that, with an Irish LNG import terminal, the UK needs to import from international markets to satisfy the gas demand of Ireland.

Finally, as a further robustness check, we re-ran the tests of this section with thirty scenarios included in the model instead of ten. The resulting figures can be found in Appendix C. While the expected production, flow and cost saving values vary slightly, the qualitative results of this section remain unchanged, suggesting that the model is robust to the number of scenarios chosen.

5.1.2. High LNG price

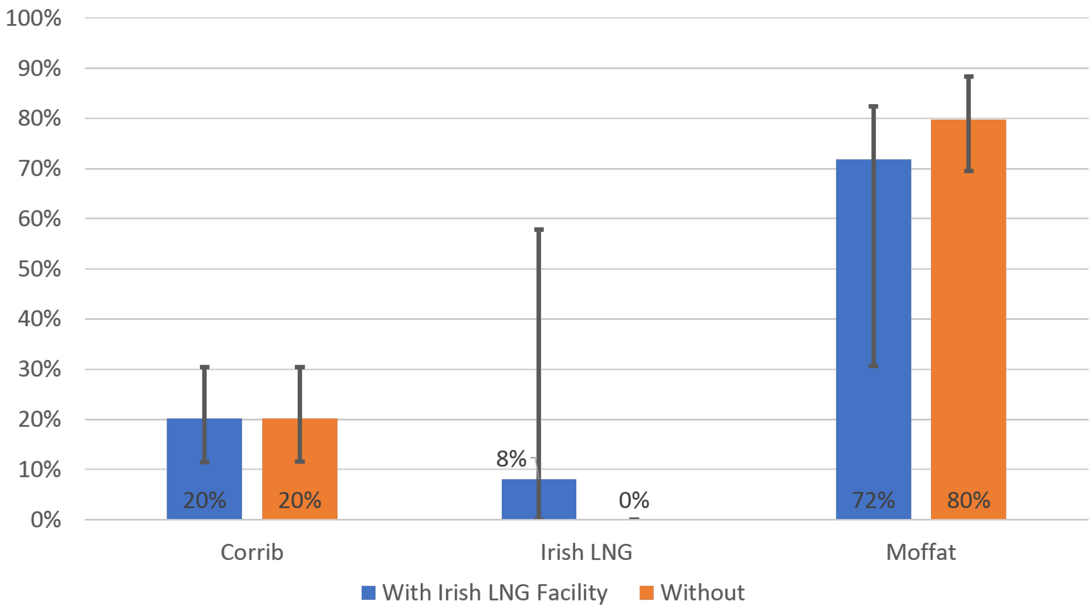


Figure 6: Sources of supply in Irish gas market (Trinidad & Tobago LNG prices and no Irish storage).

In this section, the impact of an Irish LNG facility on consumers' energy bill is assessed by assuming Trinidad and Tobago LNG import prices, which are higher than the Qatari LNG prices, considered in the previous section. Based on 10 different scenarios for the gas demand and supply costs, results in Figure 6 show that with a LNG import facility, Ireland's dependency on gas import from the UK reduces from 80% to 72%. This reduction is lower when compared with that observed in Figure 2 and suggests that, because of the higher LNG prices, there are many days when it is cheaper to import gas through the UK than from the international LNG markets. Figure 7 implies that the composition of the UK supplies is largely unaffected by an Irish LNG facility. Yet, when compared to Figure 3, evidence in Figure 7 suggests that the proportion of LNG supply in the UK reduces from 47% to 2.2%. That is, with high LNG import costs it is more convenient for the UK to import gas from Norway and continental Europe.

Figure 8 suggests that total expected consumer costs reduce in both Ireland and the UK as a result of the Irish LNG facility. In contrast to results in Figure 4, this reduction is limited (0.6% and 0.2% respectively). However, depending on the scenario, the savings may reach 4.2% in Ireland and 1.6% in the UK. These result provides a measure of the sensitivity of the consumers' cost saving, resulting from the presence of a LNG facility, to changing market conditions.

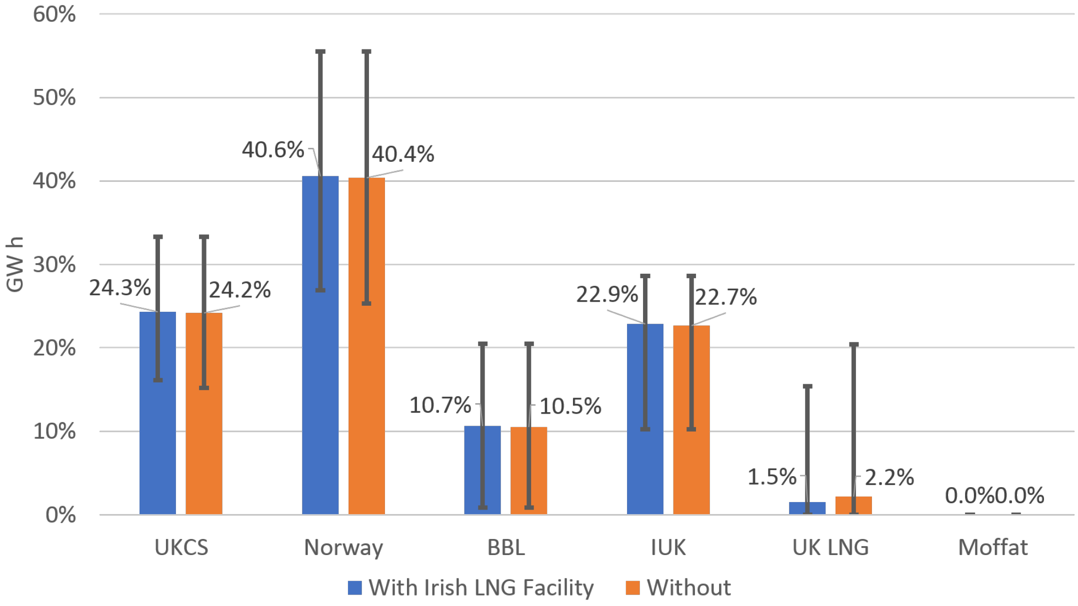
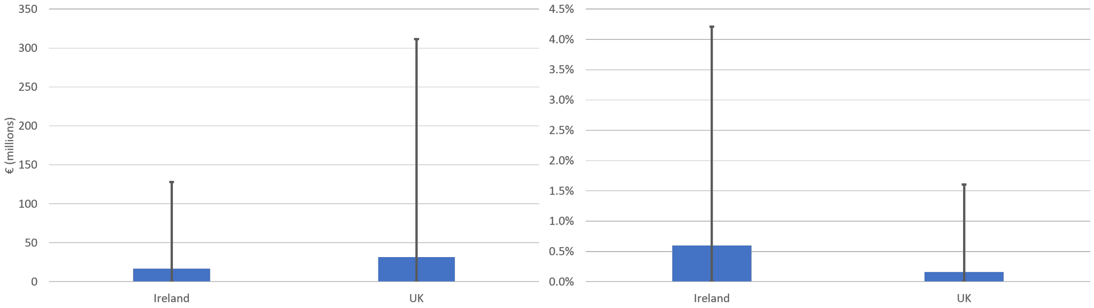


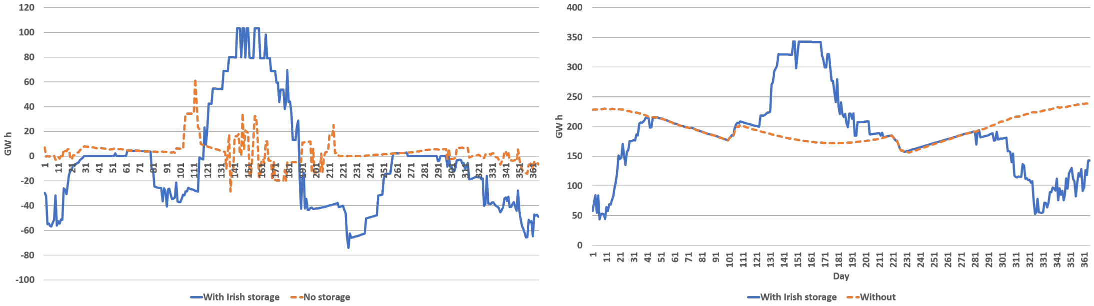
Figure 7: Sources of supply in UK gas market (Trinidad & Tobago LNG prices and no Irish storage).



(a) Absolute

(b) Percentage

Figure 8: Expected consumer savings (Trinidad & Tobago LNG prices and no Irish storage)



(a) With Irish LNG facility (b) Without

Figure 9: Net flows into Ireland via Moffat (Qatar LNG prices and with Irish storage)

5.2. Impacts of Irish storage facility

The results from the sensitivity analysis on the impact of a 800 mcm independent storage facility in Ireland (with and without an Irish LNG facility) are presented in this section. In this analysis, we assumed that LNG import cost scenarios are based on Qatari LNG prices. With a storage facility in Ireland, gas import increases both in Ireland and the UK, regardless of the presence of an Irish LNG facility (Figure 9). Yet, results show that gas import is greater with an Irish LNG import terminal. That is, the Irish storage facility allows for higher volumes of gas to be imported into Ireland during the summer, when gas prices are lower compared to winter. These volumes mostly come to Ireland through the UK. During winter, i.e. when gas demand is higher, the storage facility allows the gas to flow back to the UK via the Moffat pipeline. Therefore, an Irish storage facility would enable arbitrage opportunities in the gas markets to be exploited by allowing the gas to be imported (and stored) into Ireland from the UK in the summer at lower costs, and to be reexported to the UK in the winter, at higher costs.

Overall, evidence in Figures 10 and 11 implies that an Irish storage facility would reduce total expected consumer costs. The cost reduction amounts to €9.61M (0.7%) in 2025 with an LNG facility and to €30.31M (2%) without, with these savings potentiality rising to 1.3% and 9.1% respectively. Compared to results in Section 5.1.1, results in this section can be explained by the different use of the Moffat pipeline, in both direct (from the UK to Ireland) and reversed (from Ireland to the UK) flow. The reversed flow implies that consumers in the UK pay for the pipeline marginal cost in some days of the year, during the winter. This cost represents a saving for Irish consumers. Total expected consumer costs in the UK are also reduced with an Irish storage facility, although is limited to 0.3%.

Consequently, results in Figure 10 suggest that LNG and storage facilities represent comple-

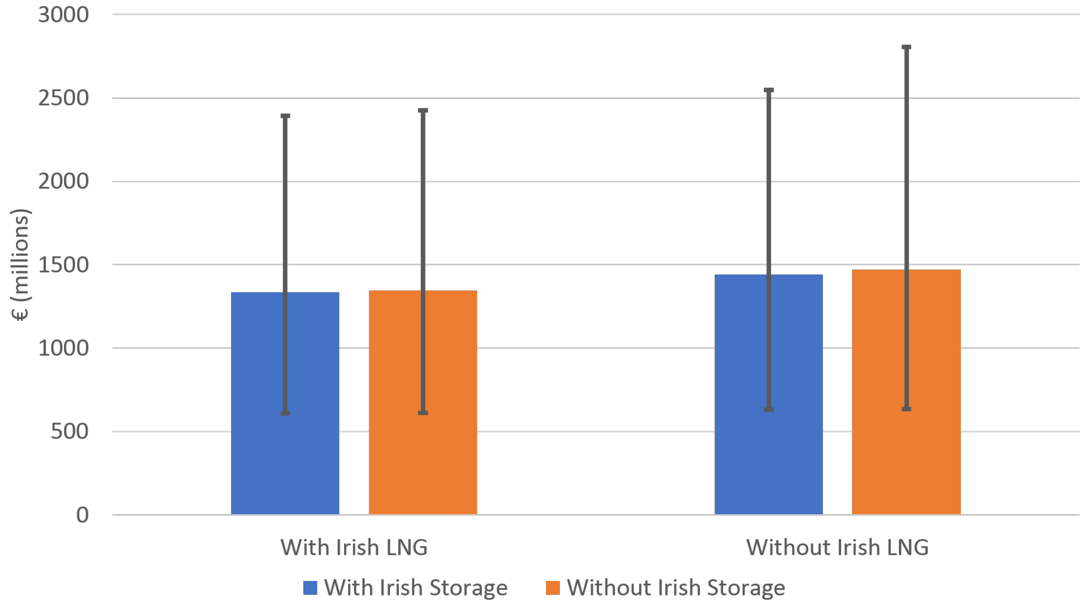


Figure 10: Expected consumer cost (Qatar LNG prices and with Irish storage)

mentary technologies and both contribute to reduce consumers' energy bill.

5.3. Impact of a storage facility in the UK

In the previous sections, we have accounted for the closure of the UK Rough storage facility. [11]. Therefore, it has not been included in the model runs as operational. In this section, we consider the hypothesis of a refurbishment of Rough, which is based on the UK Competition and Markets Authority (CMA) review. According to this review, a reinstatement of Rough becomes economically valuable when assuming high gas demand and price volatility[12]

Figure 12 and Figure 13 show the percentage decrease in expected Irish and UK consumer costs due to a re-introduction of the Rough facility for each of the cases considered in Section 5.1 and Section 5.2. These percentages imply a saving for consumers in both the UK and Ireland. Similar to the Irish storage facility above, the Rough facility allows gas to be stored during the

---

[11] https://www.ft.com/content/564a1ec0-8288-11e7-a4ce-15b2513cb3ff

[12] In October 2017, the UK Competition and Markets Authority announced the appointment of a Group to undertake a review of the Rough decision based on changes in market conditions. Conclusions from this review imply the economic infeasibility of such a refurbishment, based on the current forward projections of summer/winter gas spread. `https://assets.publishing.service.gov.uk/media/5a30ff94ed915d2cf25281ac/rough-final-decision.pdf`.

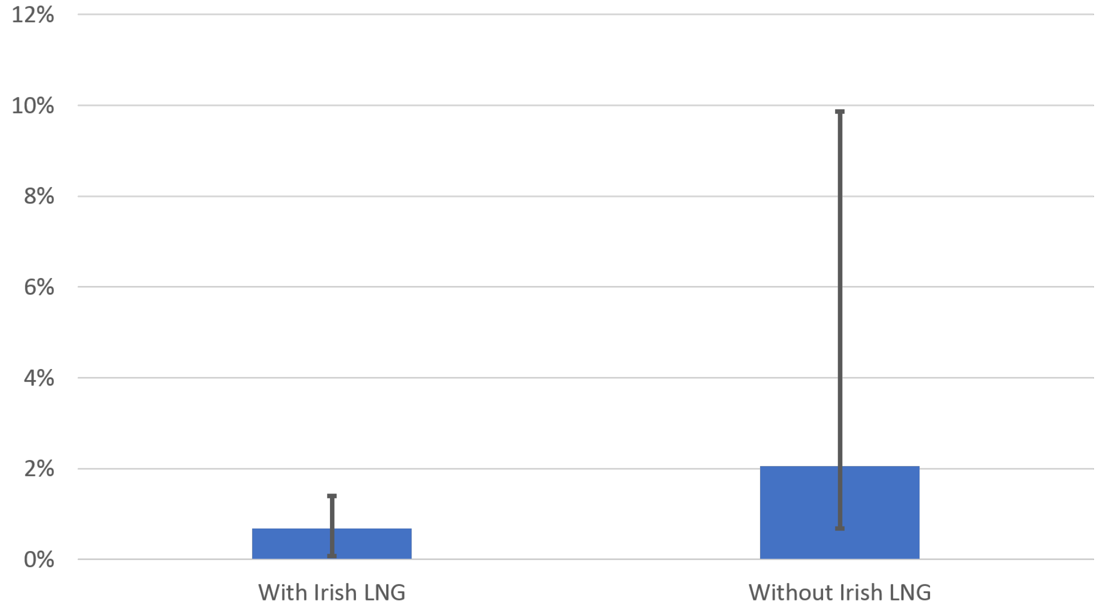


Figure 11: Expected consumer savings (Qatar LNG prices and with Irish storage)

summer, when prices are relatively cheap, and to use it in the winter, when demand and prices are higher. Therefore, Rough allows arbitrage opportunities between summer/winter gas prices to be exploited to the benefit of UK consumers. Given Ireland's connection with the UK market, the benefit is also passed to Irish consumers in the form of lower expected gas costs. The saving is greater when LNG prices are relatively low (i.e. Qatar prices) but modest when LNG prices are higher (Trinidad & Tobago). This implies that summer/winter arbitrage opportunities are more economically exploitable in a context of low LNG import prices and with an operational Irish LNG facility. In this latter case, the expected percentage saving of UK consumers is above 1.1% when compared to the case without Rough (Figure 13); for Irish consumers, the saving is 0.8%. When there is no Irish storage facility, UK cost savings can be high as 3.54%. The presence of an Irish storage reduces the benefit of refurbishing the Rough storage facility.

Interestingly, both Figure 12 and 13 show that, in one scenario, the re-introduction of the Rough storage facility may actually increase consumer costs, albeit slightly (0.14% for Ireland and 0.08% for the UK). This occurs in the high demand and high LNG cost scenario where increased injections into the Rough storage facility cause increased demand and prices in the summer but winter withdrawals do not significantly decrease prices as winter demand is so high.

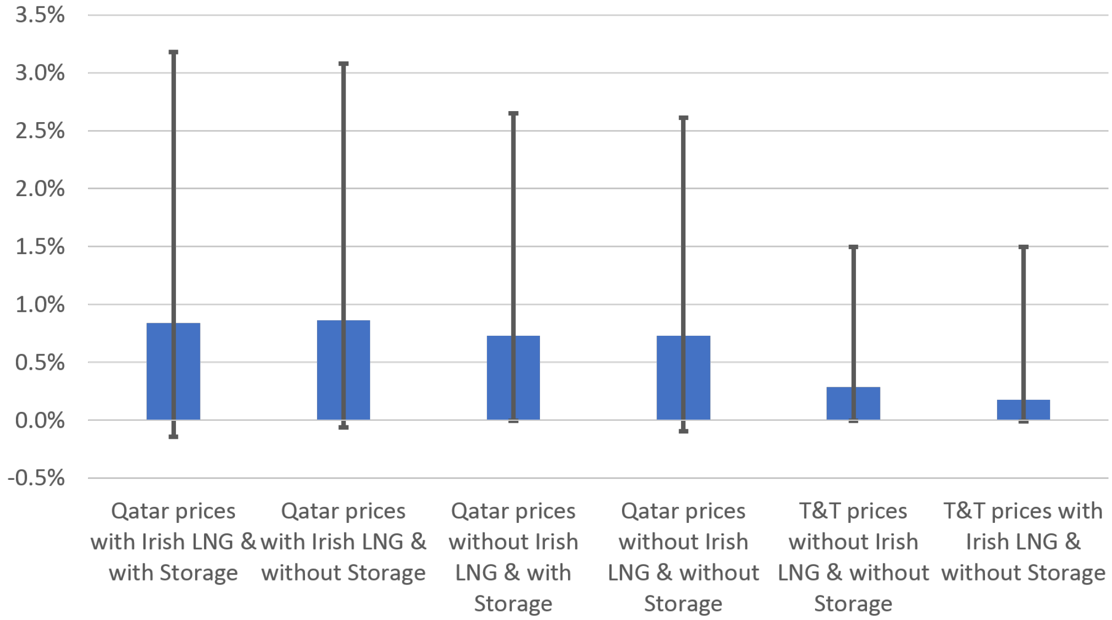


Figure 12: Percentage decrease in expected Irish consumer costs as a result of re-introduction of the Rough facility.

6. Discussion

In this work, we use a stochastic Mixed Complementarity Problem (MCP) approach and daily timesteps to assess the sensitivity of natural gas supply mix and consumer saving to future developments of different natural gas facilities, as prescribed by the EU Projects of Common Interest (PCIs). In the last two decades, the EU has focused on accomplishing the objective of a European single market, thus encouraging the creation of single markets for electricity and natural gas, in line with EU targets for energy and climate. PCIs are infrastructure projects that are considered pivotal for the European energy policy and hence eligible for financial support through the Connecting Europe Facility EU's funding [13]. Natural gas projects are of particular interest since they are aimed to improve EU's supply security through diversified gas sources, especially in the context of expected more competitive LNG markets [75]. In the energy system of Ireland (Republic of Ireland and Northern Ireland), PCIs have further political implications since their development can affect the achievement of a single market.

We evaluate the potential of PCIs to increase supply diversification and reduce consumers' energy bill. The model developed in this study includes a detailed representation of the UK

---

[13] https://ec.europa.eu/inea/connecting-europe-facility/cef-energy

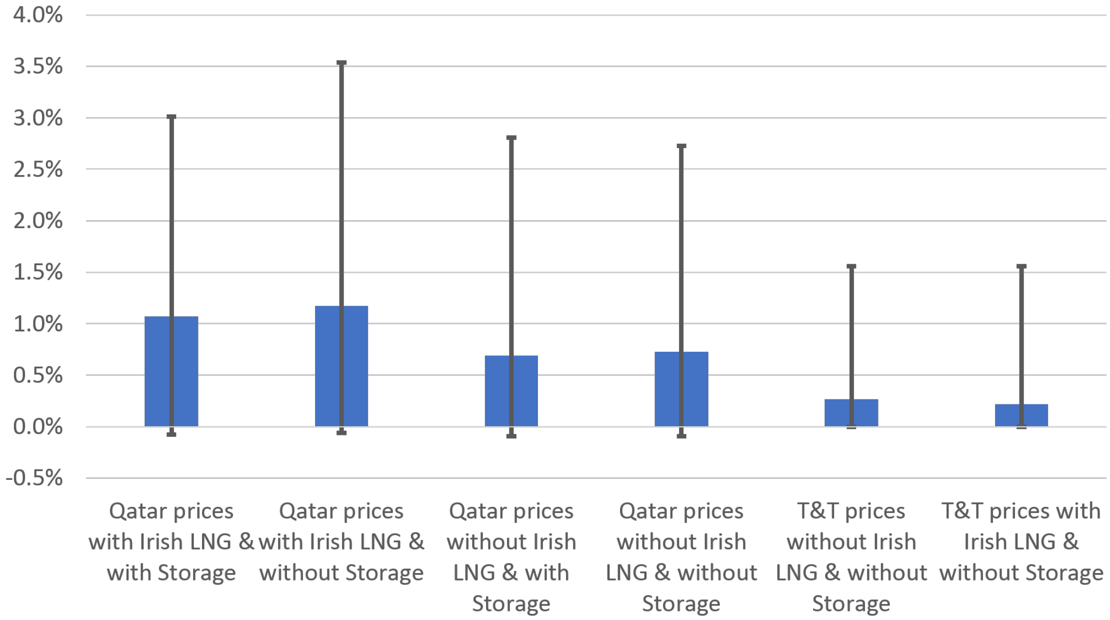


Figure 13: Percentage decrease in expected UK consumer costs as a result of re-introduction of the Rough facility.

and Ireland gas markets on a daily basis. This permits to assess the complementary of LNG and gas storage investments to manage short-term peak loads and long-term seasonal loads. It also permits to capture changes of interconnectedness between the two markets, and their benefits for consumers. The stochastic MCP incorporates ten different demand and supply cost scenarios with equal probability. This allows for an evaluation of expected natural gas supply costs. Specifically, depending upon the volatility of LNG prices in international markets and the uncertainty about future demand, our study provides a quantification of the expected economic benefits for consumers associated with PCIs for 2025.

Our findings underscore the importance of ensuring long-term natural gas supply to overcome vulnerability to gas shortages, as in [8]. The importance of supply diversification is well documented in our paper, which contributes to some previous studies on European gas markets, e.g. [21, 34]. We assess the impact of LNG for diversification and observe that a LNG import facility in Ireland can reduce Irish gas dependence from UK from 81% to 6% when LNG prices are based on Qatari prices. However, compared to previous research, we consider the impact of such a diversification on consumers. Our results show that with the introduction of an Irish LNG facility, total annualised expected costs for consumers reduce both in Ireland and the UK. The results also show the extent to which the competitiveness of the global LNG market, relative to pipeline import costs, can affect these costs. These findings are of interest when considering the impact of market conditions on investments in natural gas in other regions, for instance East Asia [38].

Pipeline import costs mostly reflect NBP and continental Europe hub prices. When LNG prices are more competitive than European prices, as in the case of the LNG imported from Qatar, expected consumer costs can fall by 8.9% in Ireland and 4% in the UK. This corresponds to annual savings on the gas bill in Ireland of around 63 million of Euro in the residential sector and 67 million of Euro in the industrial sector [14]. When global LNG prices are less competitive, as in the case of LNG imported from Trinidad & Tobago, an Irish LNG import facility can bring annual savings of 0.6% in Ireland and 0.2% in the UK. Furthermore, the Irish LNG facility would allow the UK-Ireland pipeline, Moffat, to be used in reverse flow, i.e. not only to import gas from the UK but also to export it into the UK. This significantly enhances supply diversification in both markets. Also, reverse flow implies that transportation tariffs are allocated between the two markets, based on the import/export flow. In the case of Ireland, since on-land transmission and distribution costs constitute about 40% of the final gas price, a reverse flow can have significant positive impacts on consumers' energy bill. These findings are of interest to decision- and policy-makers when designing gas new routes, and contribute to previous studies on the economic rational for adding reverse flow investments in gas markets [26].

Our results underline the role of gas storage to improve market flexibility, in accordance with [9, 8, 10]. Compared to these previous studies, results in this study show that a storage facility can reduce annualised consumer costs by 1 - 2%, depending upon the presence or not of a LNG import facility. The main driver behind this saving is the potential for reverse flow. This flow is mostly driven by the presence of arbitrage opportunities between the two markets. Therefore, our study contributes to previous literature on the speculative function of storage capacity and its implications for market competitiveness [14, 15, 16]. Our model implies that gas is injected into storage in Ireland during the summer, when prices are lower, and withdrawn to be exported to the UK in the winter, at higher prices. The cost of this reverse flow is borne by consumers in UK while consumers in Ireland benefit from more competitive supply sources.

---

[14] Energy saving based on the average Irish gas demand and prices of the residential and industrial sectors in 2015-16, as published by Eurostat and available at `https://ec.europa.eu/eurostat/data/database`. In the residential sector, an average gas demand of 11,000 kWh per annum has been assumed, in accordance with the Commission for Energy Regulation survey available at `https://www.cru.ie/wp-content/uploads/2017/07/CER17042-Review-of-Typical-Consumption-Figures-Decision-Paper-1.pdf`).

Yet, this arbitrage opportunity led by the winter-summer gas price spread can also bring a cost-reduction for consumers in the UK (0.3%). With the increasing importance of gas storage in Europe [76], the results of our model imply that developing a storage facility can permit to effectively manage supply risk and seasonal supply-demand imbalances. This is mainly evident when considering the effects for consumers of re-introducing the Rough facility in the UK. In this case, the expected consumers' energy bill decreases in Ireland are in the range of 0.2% - 0.85%, depending upon LNG import prices, and the presence of a LNG and/or storage facility. For consumers in the UK, cost decreases vary, on average, between 0.25% and 1.2%.

Despite the importance of gas storage to guarantee supply diversification, we find that the expected cost reduction associated with a storage facility is lower than the cost reduction led by a LNG import facility. A link between trade volumes, forward curves and profitability of storage assets has been observed in literature, e.g. [77, 41, 78]. In particular, [77] argued that under normal market conditions, storage capacity is efficiently used and available at relatively low costs. However, in the long-term and in the presence of unexpected conditions, (e.g. shocks to the demand, high price volatility, high winter-summer spread), there may be a shortage of storage in the system, which reduces its flexibility and increases storage value. In this study, we document the value of storage for consumers when considering the impact of re-introducing the UK storage facility Rough (see Figures 12 and 13).

Following the liberalisation of European energy markets, players are able to pursue storage operational decisions based on a combination of available flexible sources and market prices. This leads to a more efficient use of storage capacity for the market as a whole. In our study, the implications of storage operational decisions can be inferred by comparing market dynamics with low and high LNG prices. With low LNG prices (based on Qatar prices in our study), LNG imports increase and natural gas markets become more exposed to price volatility, and winter-summer spread in international LNG markets. In such a context, the flexibility brought by a storage facility in the system is higher, likewise the economic value of gas storage for consumers. In contrast, when LNG prices are high (based on Trinidad & Tobago prices), LNG becomes less competitive compared to more traditional pipeline imports from Norway and continental Europe. Pipeline imports are subject to lower price volatility and winter-summer spread, which implies lower economic value for storage, and in turn for consumers. This reasoning is in line with consumer cost evaluations in Figures 12 and 13, and in accordance with [77]. Therefore, our study is relevant for decision-makers when assessing the speculative function offered by LNG and gas storage facilities, and has implications when considering power systems highly reliant on vRES [41, 40, 42].

Overall, findings in this study contribute towards an understanding of LNG and gas storage facilities as complementary investments to guarantee supply security and market competitiveness to the benefit of consumers. Furthermore, they are pivotal in supporting the increasing integration between gas and power markets.

7. Conclusions

In this paper, we utilise a stochastic Mixed Complementarity Problem (MCP) on daily timesteps to provide an evaluation of the EU PCIs natural gas infrastructures and their implications for gas market interconnectedness and supply diversification. We contribute to the literature by proposing a model that considers both LNG and storage infrastructures, and their interaction in managing short- and long-term gas flows. Based on seasonal fluctuations of gas loads and prices at daily resolution, our model assesses not only annualised expect cost reductions for consumers but also their sensitivity to changing market conditions. Our results are of interest when considering consumers' benefits of EU energy policies and legislation goals. Furthermore, they are of interest to decision- and policy-makers worldwide when designing and evaluating new infrastructure developments in integrated energy systems.

Results in our study suggest that LNG import capacity contributes towards lower energy costs for consumers. In contrast, gas storage capacity enhances natural gas and power system flexibility. While the methodological approach in this paper provides useful insights, there are limitations to the analysis undertaken. When analysing the impact of LNG and storage facilities, only benefits of these investment options are considered. The initial investment cost of building the facilities are not available to the authors. Thus, while the consumer-cost savings are clear, this paper does not quantify the net benefit of such options.

In our model specification, we only consider integrated gas markets, and not their integration with power systems. Consequently, electricity demand is determined exogenously (albeit multiple demand scenarios are assumed). With higher target-driven penetrations of variable renewable-energy sources expected, interactions between natural gas and electricity systems will increase. These interactions are of interest to decision- and policy-makers, in particular in the context of integrated and global energy markets, and represent an avenue for future research.

Acknowledgements

The authors wish to thank the Editors, Prof. Jinyue Yan and Prof. Bin Chen, and three anonymous referees, who have substantially contributed to improve this paper. We are grateful to John Curtis and Kieran McQuinn for comments and suggestions. We acknowledge financial support from the ESRI's Energy Policy Research Center. Mel Devine also acknowledges funding from Science Foundation Ireland (SFI) under the SFI Strategic Partnership Programme Grant number SFI/15/SPP/E3125. Marianna Russo also acknowledges funding from Science Foundation Ireland (SFI) under the SFI Strategic Partnership Programme Grant number No. 09/SRC/E1780. The opinions, findings and conclusions or recommendations expressed in this material are those of the authors and do not necessarily reflect the views of the Energy Policy Research Center and Science Foundation Ireland. All omissions and errors are our own.

Appendix A. Tables

$a \in A$	Arcs (gas pipelines).
$k \in K$	Suppliers.
$t \in T$	Time steps.
$m \in M$	Gas node/market m.
$a \in A(m)$	Arcs connected to market m.
$a^{in}(m)$	Arcs inward to market/node m.
$a^{out}(m)$	Arcs outward from node m.
$e \in \{1, .., t\}$	Dummy time index for storage constraint that represent timesteps from 1 to t.

Table A.5: Sets

$DAYS_t$	Number of days in time period t.
$DP^{\max}_{km}$	Maximum supply capacity for source p at node m (GW h/day).
$DI^{\max}_{km}$	Maximum storage injection rate of supply source p at node m (GW h/day).
$DX^{\max}_{km}$	Maximum storage extraction rate of supply source p at market/node m (GW h/day).
$DA^{\max}_{a}$	Maximum arc capacity for arc a (GW h/day).
$TP^{\max}_{km}$	Total production capacity from source p at node m over the whole time horizon for (GW h).
$MP^{\max}_{km}$	Minimum production capacity from source p at node m over the whole time horizon (GW h).
$MINSTOR_{km}$	Minimum amount of supply source p in market m must have (GW h).
$INITSTOR_{km}$	Initial amount of supply source p in market m has(GW h).
$MAXSTOR_{km}$	Maximum amount of supply source p in market m can have (GW h).
$LOSS_m$	Injection to storage loss factor for node m (%).
$LOSS_a$	Arc a loss factor (%).
Z^s_{mt}	Demand curve intercept at market/node m for timestep t and scenario s (GW h).
B_{mt}	Demand curve slope at market/node m for timestep t(€/GW h).
$PROB^s$	probability associated with scenario s.

$C^{supply,s}_{pmt}$	Marginal supply cost for source p at node m at time t and scenario s (€/GW h).
C^{xtr}_{mt}	Marginal cost of extraction from storage at node m at time t (€/GW h).
C^{inj}_{mt}	Marginal cost of injection to storage at node m at time t (€/GW h).
C^{pipe}_{at}	Marginal supply cost for flowing gas through pipeline a at time t (€/GW h).

Table A.6: Model parameters.

$sales^{s}_{kmt}$	Amount supply source p, at node m, sells at time t and scenario s (GW h/day).
$supply^{s}_{kmt}$	Amount supply source p,at node m, buys from source p at time t and scenario s. (GW h/day).
inj^{s}_{kmt}	Amount injected into supply source p's, at node m at time t and scenario s (GW h/day).
xtr^{s}_{kmt}	Amount extracted from supply source p's, at node m at time t and scenario s (GW h/day).
$flows^{s}_{kat}$	Supplier k's flows through arc a at time t and scenario s (GW h/day).

Table A.7: Primal variables: each of the primal variables have two superscripts.

π^{s}_{mt}	Market-clearing price of gas for node m, time t and scenario s (€/GW h).
$\lambda^{*,k\#}_{\cdot}$	Lagrange multiplier associated with constraint # in supplier's problem (unit depends on the constraint).
τ^{s}_{at}	Lagrange multiplier associated with maximum capacity of arc a at time t at scenario s (€/GW h).

Table A.8: Dual variables.

Appendix B. Additional Data

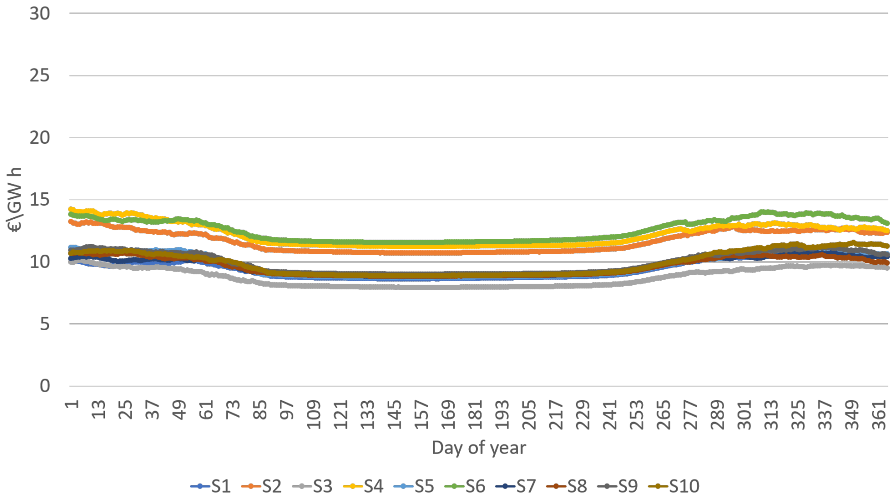


Figure B.14: Qatari LNG price scenarios

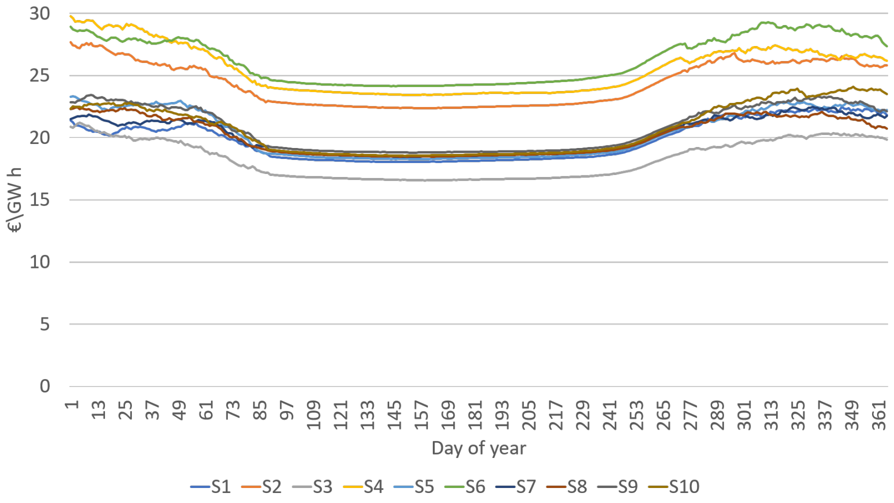


Figure B.15: Trinidad and Tobago LNG price scenarios

Appendix C. Additional Results

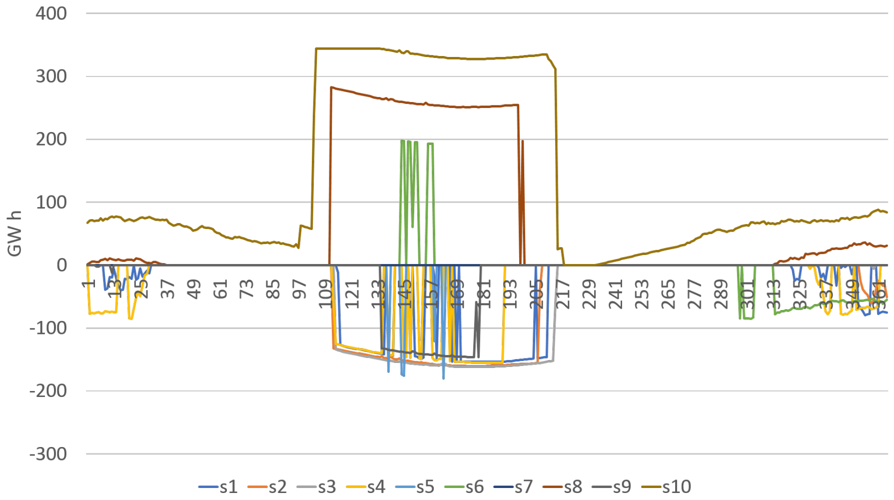


Figure C.16: Net flows into Ireland via Moffat (Qatar LNG prices, Irish LNG present but no Irish storage)

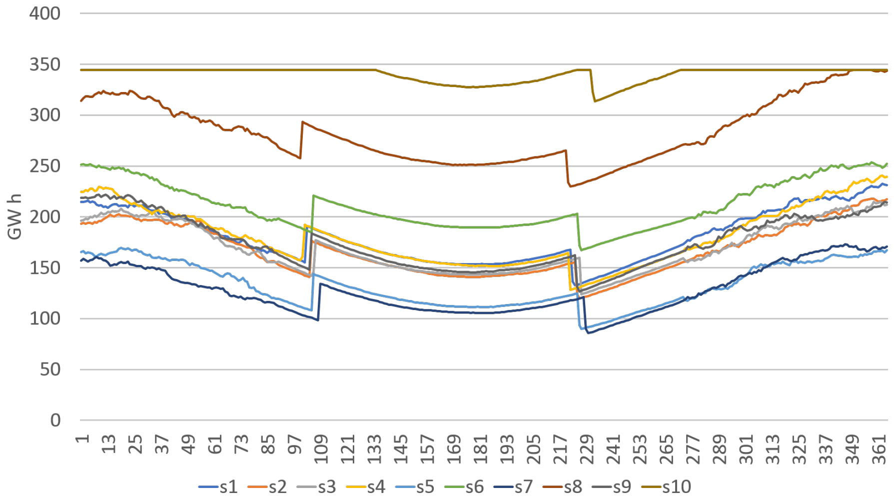


Figure C.17: Net flows into Ireland via Moffat (Qatar LNG prices, no Irish LNG present and no Irish storage)

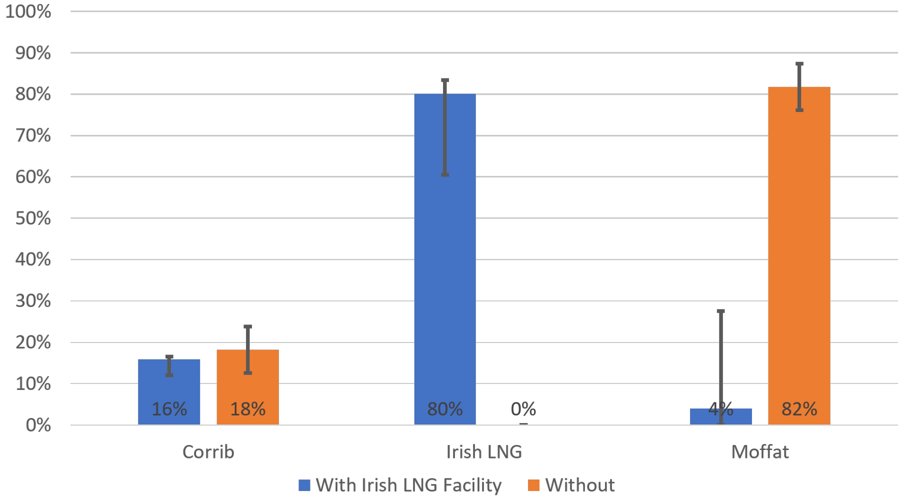


Figure C.18: Sources of supply in Irish gas market (Qatar LNG prices and no Irish storage and 30 scenarios)

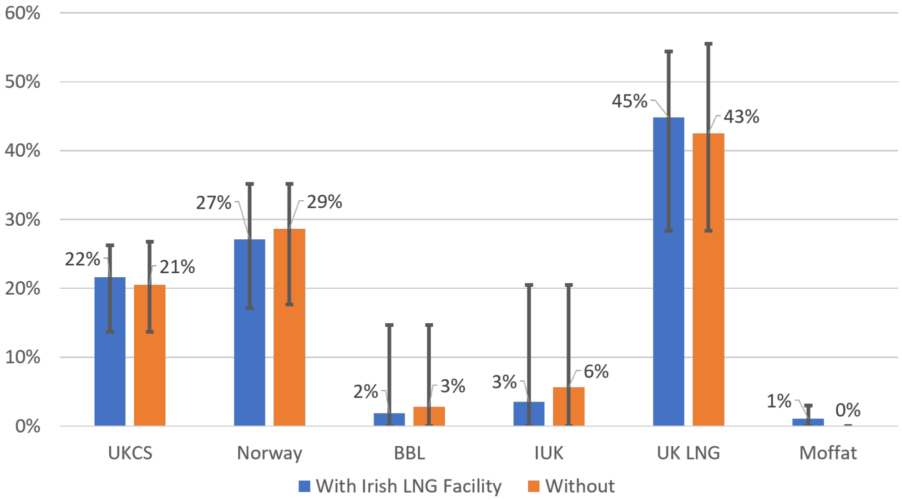
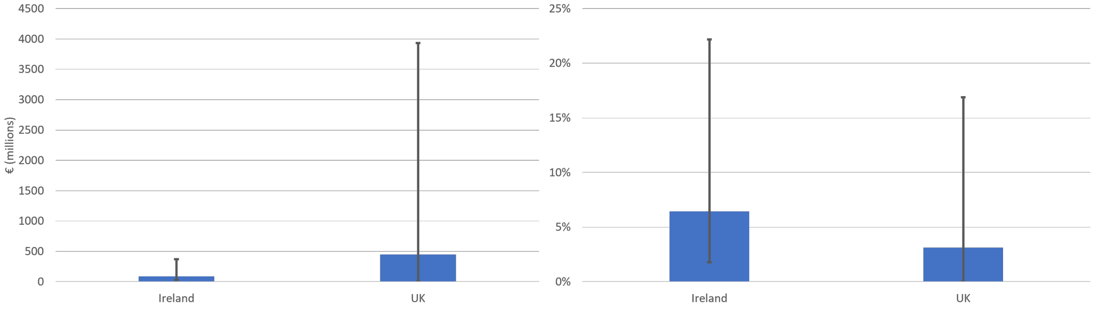


Figure C.19: Sources of supply in UK gas market (Qatar LNG prices and no Irish storage and 30 scenarios)



(a) Absolute savings (b) Percentage savings

Figure C.20: Expected consumer savings (Qatar LNG prices and no Irish storage and 30 scenarios)

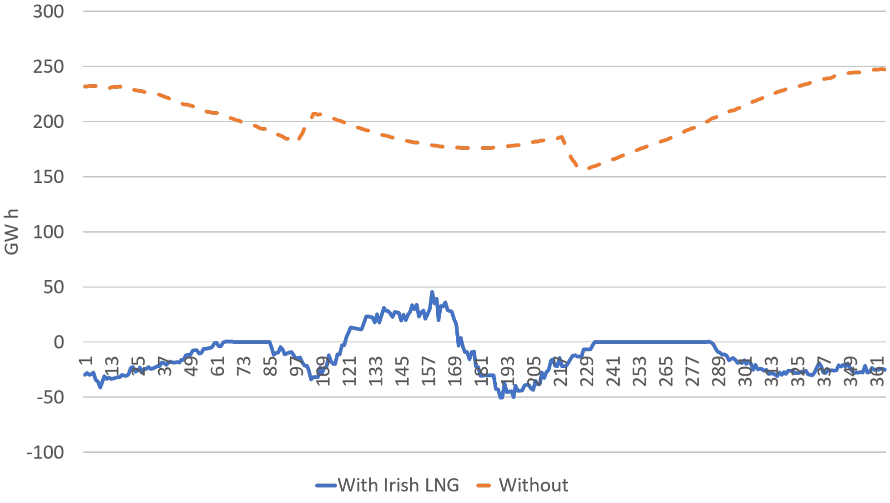


Figure C.21: Net flows into Ireland via Moffat (Qatar LNG prices and no Irish storage and 30 scenarios)

References

[1] International Energy Agency, World Energy Outlook 2018 (2018).

[2] S. Kumar, H.-T. Kwon, K.-H. Choi, W. Lim, J. H. Cho, K. Tak, I. Moon, LNG: An eco-friendly cryogenic fuel for sustainable development, Applied Energy 88 (12) (2011) 4264–4273.

[3] W. Lise, B. F. Hobbs, Future evolution of the liberalised European gas market: Simulation results with a dynamic model, Energy 33 (7) (2008) 989–1004.

[4] F. Holz, P. M. Richter, R. Egging, The role of natural gas in a low-carbon Europe: Infrastructure and supply security, The Energy Journal 37 (Sustainable Infrastructure Development and Cross-Border Coordination) (2016) 33–59.

[5] European Commission, European Energy Security Strategy, COM(2014) 330 final, available at `https://www.eesc.europa.eu/resources/docs/european-energy-security-strategy.pdf` (2014).

[6] J. Kim, Y. Noh, D. Chang, Storage system for distributed-energy generation using liquid air combined with liquefied natural gas, Applied Energy 212 (2018) 1417–1432.

[7] J. Pospíšil, P. Charvát, O. Arsenyeva, L. Klimeš, M. Špiláček, J. J. Klemeš, Energy demand of liquefaction and regasification of natural gas and the potential of LNG for operative thermal energy storage, Renewable and Sustainable Energy Reviews 99 (2019) 1–15.

[8] E. Leahy, C. Devitt, S. Lyons, R. S. J. Tol, The cost of natural gas shortages in Ireland, Energy Policy 46 (2012) 153–169.

[9] E. Baranes, F. Mirabel, J.-C. Poudou, Access to natural gas storage facilities: Strategic and regulation issues, Energy Economics 41 (2014) 19–32.

[10] A. Tomasgard, F. Rømo, M. Fodstad, K. Midthun, Optimization models for the natural gas value chain, in: Geometric modelling, numerical simulation, and optimization, Springer, 2007, pp. 521–558.

[11] S. Poddar, D. Sasaki, The strategic benefit from advance production, European Journal of Political Economy 18 (3) (2002) 579–595.

[12] E. Sönmez, S. Kekre, A. Scheller-Wolf, N. Secomandi, Strategic analysis of technology and capacity investments in the liquefied natural gas industry, European Journal of Operational Research 226 (1) (2013) 100–114.

[13] H. Üster, Ş. Dilaveroğlu, Optimization for design and operation of natural gas transmission networks, Applied Energy 133 (2014) 56–69.

[14] A. Neumann, Linking natural gas markets–is LNG doing its job?, The Energy Journal (2009) 187–199.

[15] A. Cavaliere, V. Giust, M. Maggi, Efficient mechanisms for access to storage when competition in gas markets is imperfect, Energy Economics 36 (2013) 481–490.

[16] R. Li, R. Joyeux, R. D. Ripple, International natural gas market integration, The Energy Journal (2014) 159–179.

[17] ACER, Consolidated Report on the progress of electricity and gas Projects of Common Interest for the year 2017, available at https://www.acer.europa.eu (2018).

[18] E. Baranes, F. Mirabel, J.-C. Poudou, Storage and competition in gas market, Economics Bulletin 12 (19) (2005) 1–9.

[19] S. A. Gabriel, J. Zhuang, S. Kiet, A large-scale linear complementarity model of the North American natural gas market, Energy Economics 27 (4) (2005) 639–665.

[20] S. A. Gabriel, S. Kiet, J. Zhuang, A mixed complementarity-based equilibrium model of natural gas markets, Operations Research 53 (5) (2005) 799–818.

[21] R. Egging, S. A. Gabriel, F. Holz, J. Zhuang, A complementarity model for the European natural gas market, Energy Policy 36 (7) (2008) 2385–2414.

[22] F. Holz, C. Von Hirschhausen, C. Kemfert, A strategic model of European gas supply (GASMOD), Energy Economics 30 (3) (2008) 766–788.

[23] R. Egging, F. Holz, S. A. Gabriel, The World Gas Model: A multi-period mixed complementarity model for the global natural gas market, Energy 35 (10) (2010) 4016–4029.

[24] S. Moryadee, S. A. Gabriel, F. Rehulka, The influence of the Panama Canal on global gas trade, Journal of Natural Gas Science and Engineering 20 (2014) 161–174.

[25] S. Moryadee, S. A. Gabriel, H. G. Avetisyan, Investigating the potential effects of US LNG exports on global natural gas markets, Energy Strategy Reviews 2 (3-4) (2014) 273–288.

[26] R. Egging, F. Holz, Risks in global natural gas markets: investment, hedging and trade, Energy Policy 94 (2016) 468–479.

[27] R. Egging, A. Pichler, Ø. Kalvø, T. M. Walle-Hansen, Risk aversion in imperfect natural gas markets, European Journal of Operational Research 259 (1) (2017) 367–383.

[28] M. F. Chávez-Rodríguez, L. Dias, S. Simoes, J. Seixas, A. Hawkes, A. Szklo, A. F. P. Lucena, Modelling the natural gas dynamics in the Southern Cone of Latin America, Applied Energy 201 (2017) 219–239.

[29] S. H. Tan, P. I. Barton, Optimal shale oil and gas investments in the united states, Energy 141 (2017) 398–422.

[30] J. Cooper, L. Stamford, A. Azapagic, Economic viability of UK shale gas and potential impacts on the energy market up to 2030, Applied Energy 215 (2018) 577–590.

[31] D. J. G. Crow, S. Giarola, A. D. Hawkes, A dynamic model of global natural gas supply, Applied Energy 218 (2018) 452–469.

[32] M. E. Oliver, C. F. Mason, D. Finnoff, Pipeline congestion and basis differentials, Journal of Regulatory Economics 46 (3) (2014) 261–291.

[33] M. E. Oliver, Economies of scale and scope in expansion of the US natural gas pipeline network, Energy Economics 52 (2015) 265–276.

[34] C. Dieckhöner, S. Lochner, D. Lindenberger, European natural gas infrastructure: the impact of market developments on gas flows and physical market integration, Applied Energy 102 (2013) 994–1003.

[35] F. Feijoo, D. Huppmann, L. Sakiyama, S. Siddiqui, North American natural gas model: Impact of cross-border trade with Mexico, Energy 112 (2016) 1084–1095.

[36] F. Feijoo, G. C. Iyer, C. Avraam, S. A. Siddiqui, L. E. Clarke, S. Sankaranarayanan, M. Binsted, P. L. Patel, N. C. Prates, E. Torres-Alfaro, M. A. Wise, The future of natural gas infrastructure development in the United States, Applied Energy 228 (2018) 149–166.

[37] Q. Zhang, Z. Li, G. Wang, H. Li, Study on the impacts of natural gas supply cost on gas flow and infrastructure deployment in china, Applied Energy 162 (2016) 1385–1398.

[38] X. Shi, H. M. P. Variam, East Asias gas-market failure and distinctive economicsA case study of low oil prices, Applied Energy 195 (2017) 800–809.

[39] J. P. Deane, M. Ó. Ciaráin, B. P. Ó. Gallachóir, An integrated gas and electricity model of the eu energy system to examine supply interruptions, Applied Energy 193 (2017) 479–490.

[40] Z. Qiao, Q. Guo, H. Sun, T. Sheng, Multi-time period optimized configuration and scheduling of gas storage in gas-fired power plants, Applied Energy 226 (2018) 924–934.

[41] J. Devlin, K. Li, P. Higgins, A. Foley, The importance of gas infrastructure in power systems with high wind power penetrations, Applied Energy 167 (2016) 294–304.

[42] M. Á. Lynch, M. T. Devine, V. Bertsch, The role of power-to-gas in the future energy system: how much is needed and who wants to invest?, ESRI Working Paper. Available at `https://www.esri.ie/pubs/WP590.pdf`, year = 2018.

[43] R. Avalos, T. Fitzgerald, R. R. Rucker, Measuring the effects of natural gas pipeline constraints on regional pricing and market integration, Energy Economics 60 (2016) 217–231.

[44] K. Amirnekooei, M. M. Ardehali, A. Sadri, Optimal energy pricing for integrated natural gas and electric power network with considerations for techno-economic constraints, Energy 123 (2017) 693–709.

[45] Chávez-Rodríguez, M., and Varela, D., and Rodrigues, F., and Salvagno, J. B., and Köberle, A. C., and Vasquez-Arroyo, E., and Raineri, R., and Rabinovich, G., The role of LNG and unconventional gas in the future natural gas markets of Argentina and Chile, Journal of Natural Gas Science and Engineering 45 (2017) 584–598.

[46] M. Mikolajková, C. Haikarainen, H. Saxén, F. Pettersson, Optimization of a natural gas distribution network with potential future extensions, Energy 125 (2017) 848–859.

[47] Z. Qiao, Q. Guo, H. Sun, Z. Pan, Y. Liu, W. Xiong, An interval gas flow analysis in natural gas and electricity coupled networks considering the uncertainty of wind power, Applied Energy 201 (2017) 343–353.

[48] J. R. U. C. Almeida, E. L. F. De Almeida, E. A. Torres, F. G. M. Freires, Economic value of underground natural gas storage for the Brazilian power sector, Energy Policy 121 (2018) 488–497.

[49] P. Hauser, H. U. Heinrichs, B. Gillessen, T. Müller, Implications of diversification strategies in the European natural gas market for the German energy system, Energy 151 (2018) 442–454.

[50] Z. Zhen, L. Lou, L. Tian, Q. Gao, Investment optimization path of NG power generation in China based on carbon value realization and market linkage, Applied Energy 210 (2018) 241–255.

[51] C. Saldarriaga-Cortés, H. Salazar, R. Moreno, G. Jiménez-Estévez, Stochastic planning of electricity and gas networks: An asynchronous column generation approach, Applied Energy 233 (2019) 1065–1077.

[52] A. Kiss, A. Selei, B. T. Tóth, A top-down approach to evaluating cross-border natural gas infrastructure projects in Europe, The Energy Journal 37 (Sustainable Infrastructure Development and Cross-Border Coordination) (2016) 61–79.

[53] S. A. Gabriel, A. J. Conejo, J. D. Fuller, B. F. Hobbs, C. Ruiz, Optimality and Complementarity, Springer, 2013.

[54] M. T. Devine, J. P. Gleeson, J. Kinsella, D. M. Ramsey, A rolling optimisation model of the UK natural gas market, Networks and Spatial Economics 14 (2) (2014) 209–244.

[55] Sustainable Energy Authority of Ireland, Irelands Energy Targets, available at `https://www.seai.ie/resources/publications/Ireland___s-Energy-Targets-Progress-Ambition-and-Impacts.pdf` (2016).

[56] International Energy Agency, Renewables 2018 - Analysis and Forecasts to 2023 (2018).

[57] Gas Network Ireland, A Look at the Irish Gas Market, available at `https://www.gasnetworks.ie/corporate/company/our-network/irish-gas-market-overview/A-Look-at-the-Irish-Gas-Market.pdf` (2017).

[58] M. Á. Lynch, Re-evaluating Irish energy policy in light of Brexit, ESRI Workin Paper. Available at: `http://www.esri.ie/pubs/RN20170201.pdf` (2017).

[59] Department of Communications Climate Action and Environment, National Renewable Energy Action Plan (NREAP), available at: `https://www.dccae.gov.ie/documents/NREAP%20Fourth%20Progress%20Report.pdf` (2018).

[60] Irish Academy of Engineering, Natural gas: Essential fro Ireland's Future Energy Security, available at `https://www.europeangashub.com/wp-content/uploads/2018/08/IAE_Natural_Gas_Energy_Security.pdf` (2018).

[61] Department of Energy and Climate Change, Digest of United Kingdom energy statistics (DUKES), available at: `https://www.gov.uk/government/statistics/digest-of-uk-energy-statistics-dukes-2017-main-report` (2017).

[62] Gas Networks Ireland, Gas Networks Ireland Network Development Plan 2016, available at: `https://www.gasnetworks.ie/corporate/company/our-network/GNI_NetworkDevPlan_2016.pdf` (2016).

[63] National Grid, UK National Grid's Gas Ten Year Statement 2016, available at: `https://www.nationalgrid.com/uk/publications/gas-ten-year-statement-gtys` (2016).

[64] Oxford Institute for Energy Studies, Gas storage in Great Britian, available at: `https://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/01/NG-72.pdf` (2013).

[65] Gas Networks Ireland, Gas Networks Ireland Transmission Tariffs, available at: `https://www.gasnetworks.ie/corporate/gas-regulation/tariffs/transmission-tariffs/`.

[66] Oil & Gas UK, Economic Report 2017, available at `https://oilandgasuk.co.uk/wp-content/uploads/2017/09/Economic-Report-2017-Oil-Gas-UK.pdf` (2017).

[67] P. Heather, The evolution of European traded gas hubs, Oxford Institute for Energy Studies Oxford, 2015.

[68] R. S. Pindyck, Volatility in natural gas and oil markets, Journal of Energy and Development 30 (2004) 1–19.

[69] X. Mu, Weather, storage, and natural gas price dynamics: fundamentals and volatility, Energy Economics 29 (2007) 46–63.

[70] Department for Business Energy and Industrial Strategy. UK , Updated energy and emissions projections: 2017, available at `https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/671187/Updated_energy_and_emissions_projections_2017.pdf` (2017).

[71] Office for Budget Responsibility. UK , January 2017 Fiscal Sustainability Report, available at `http://cdn.obr.uk/FSR_Jan17.pdf` (2017).

[72] Gas Networks Ireland, Network Development Plan 2017, available at: `https://www.gasnetworks.ie/corporate/gas-regulation/system-operator/publications/GNI-Network-Development-Plan-2017.pdf`.

[73] V. Di Cosmo, M. Hyland, Carbon tax scenarios and their effects on the Irish energy sector, Energy Policy 59 (2013) 404–414.

[74] Centre for Climate Change Economics and Policy, Energy use policies and carbon pricing in the UK, available at: `https://www.ifs.org.uk/comms/r84.pdf` (2013).

[75] I. Ruble, European Union energy supply security: The benefits of natural gas imports from the Eastern Mediterranean, Energy Policy 105 (2017) 341–353.

[76] M. Cummins, G. Kiely, B. Murphy, Gas storage valuation under Lévy processes using the fast Fourier transform, Journal of Energy Markets 10 (4) (2017) 43–86.

[77] C. De Jong, Gas storage valuation and optimization, Journal of Natural Gas Science and Engineering 24 (2015) 365–378.

[78] M. Cummins, G. Kiely, B. Murphy, Gas storage valuation under multifactor Lévy processes, Journal of Banking & Finance 95 (2018) 167–184.