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The economics of global LNG trade: the case of Atlantic and Pacific inter-basin arbitrage in 2010-2014

EPRG Working Paper 1602

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Abstract We examine the economic and strategic implications for gas supply security and diversity of Europe's reliance on global LNG markets. In particular, we carry out a detailed assessment of LNG trade between Atlantic and Pacific basins in 2011-2014, focusing on why there was not as much LNG arbitrage as might have been expected given the large price differential between these two regions in that period. By explicitly modelling a counterfactual scenario, in which LNG can be diverted to follow price differentials between Europe and Asia, we found that: (a) it is not the demand shock in Asia (driven by the Fukushima incident) *per se* but the high oil price in that period, as well as decoupling of European spot prices from oil-linked contract prices that created the huge natural gas price differentials between Asia and Europe; (b) amongst the largest LNG suppliers who could arbitrage between the Atlantic and Pacific regions, Qatar would have received the highest net benefit from diverting cargoes to Asia, however, these benefits are highly sensitive to the possibility of contract price renegotiations with Asian buyers (similar to what happened to large pipeline gas suppliers in Europe in the recent past); (c) furthermore, diverting contractual volumes from Europe to Asia would have required lengthy negotiations with European buyers who, as our modelling results suggest, did not necessarily have compelling commercial interests in sending contractual cargoes to Asia after taking into account that the surplus of LNG created in North-West Europe allowed these buyers to reduce high oil-linked contract prices with traditional pipeline suppliers. Thus, contrary to the currently prevailing view that European importers have largely 'overinvested' in LNG import capacity, these investments should be seen as a strategic bargaining option that European importers have developed to counterbalance the otherwise potentially larger pricing power of pipeline suppliers. Thus, investment in LNG import capacity reduces the need to invest in *'strategic and special relationship'* with traditional suppliers to ensure against 'unfair' pricing practices.

Keywords: Liquefied natural gas, LNG, security of supply, natural gas, pipelines, long-term contracts, spot transactions, Asia, Qatar, Russia, gas pricing, arbitrage

JEL Classification: Q48, L140, L130, O13, Q47, Q410, P28

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EPRG WORKING PAPER

The economics of global LNG trade: the case of Atlantic and Pacific inter-basin arbitrage in 2010-2014[1]

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[1] Part of this paper is based on a chapter to appear in Silvia Colombo, Mohamed El Harrak and Nicolò Sartori (Eds.), *The Future of Natural Gas. Markets and Geopolitics*, Lenthe/European Energy Review, Hof van Twente, The Netherlands, 2016.
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1. Introduction

Amidst the geopolitical tension in Eurasia due to the conflict in the east of Ukraine, concerns over the security of gas supply from Russia have once again arisen in Europe (see, e.g., the recent communication from the EC on the Energy Union Package, EC (2015a) and the Mission Letter to Maroš Šefčovič, Vice-President for Energy Union, EC, (2014)). These concerns and strong political will from European politicians to diversify away from Russian gas is appreciated if one looks at Europe's rather limited gas supply options. The most 'secure' gas supply sources for Europe are indigenous sources, including Norway. However, they are either stagnating or have limited upside potential (Dickel et al., 2014), while the future of shale gas in Europe is rather gloomy from economic and, importantly, social and political feasibility perspectives (Chyong and Reiner, 2015). Looking further afield, the North Africa region is another political bet for Europe. However, this region faces many challenges in ramping up production due to political and military risks, a surge in domestic demand due to very low prices and a lack of investment in infrastructure[4]. Further, the Eastern Mediterranean region, and in particular Israel's and Cyprus' recently discovered offshore gas fields, are sparking Europe's interest but limited reserves coupled with surging demand and concerns over the regions' own energy security and geopolitical tensions mean that the potential for gas coming from that region is limited (Tippee, 2014). The Caspian and Caucasus regions, and in particular the southern gas corridor concept, another European flagship diversification project, are also expected to help Europe reduce its dependence on Russian gas. However, beyond Azerbaijan's gas, which is limited to roughly 10-20 bcm/year for Europe in the next decade (Agayev, 2010), the scope for further supplies from the region is limited – Turkmenistan's rich gas reserves have been secured by China while Iran and Iraq are faced with political and military risks as well as financial constraints, making these countries unable to ramp up gas production any time soon. Even if the sanctions are lifted, Iran faces both surging demand at home and, more seriously, a lack of infrastructure, and it would be at least another decade before Europe could see gas flowing out of Iran.

Thus, the potential for Europe to significantly diversify its gas imports based on the supply sources close to its vicinity seems to be rather limited. Hence, for European policy makers, the global liquefied natural gas (LNG) markets seem to be a viable, and perhaps the only, option for Europe to diversify gas imports in the short to medium term. Europe's LNG regasification capacity could, in theory, secure around a third of its annual gas demand – currently, the LNG import capacity stands at around 190 mn tpa with an additional 62 mn tpa under construction (Cotin, 2015). With this level of import capacity it is believed that LNG could in theory replace significant volumes of Russian gas (IEA, 2014 as cited by Cotin, 2015). Thus, to advance its policy objective of having secure gas supplies, the European Commission (EC) has proposed developing a comprehensive LNG strategy (Šefčovič, 2015) to further gas import diversification in its recently launched Energy Union paper (EC, 2015). However, what are implications of Europe increasingly relying on global markets to deliver more diversity and security? The question of diversification of European gas imports, and in particular the role of LNG in this quest, has been quite extensively

[4] For example, the European Commission has acknowledged the problems of 'chronic underinvestment' in gas production in Algeria and thus the commission is planning to launch an EU-Algeria business forum in 2016 to discuss the issues of unlocking the country's untapped gas reserves (Simon, 2015).

discussed (Stern, 2006; Poyry, 2010[5]; Dickel et al., 2014; Bordoff and Houser, 2014), as has the topic of international LNG trade and pricing more generally (see Jensen, 2003; Brito and Hartley, 2007; Barden et al., 2009; Aune et al. 2009; Rogers 2010, 2012; Kumar et al., 2011; Koenig, 2012; Kate et al., 2013; Corbeau et al., 2014; Hartley, 2015).

However, surprisingly, the economic and strategic perspectives on LNG trading between Europe and Asia and the implications of Europe's increasing reliance on global market dynamics have received rather limited attention. One exception is work by Rogers (2010), who studied LNG trade flows, particularly focusing on LNG cargo arbitrage in the Atlantic Basin and the arbitrage between LNG and pipeline gas in Continental Europe. Subsequently, Rogers (2012) carried out scenario analyses of the impact of the globalization of the gas trade on Europe, focusing on North American supply and Asian gas demand, and found significant potential for connectivity and regional price linkage in all analysed scenarios. Both these papers are important sources of detailed information on how the LNG markets function from an industry perspective. Apart from Rogers' (2010; 2012) work, there is economic research on the LNG trade, with particular focus on international trade patterns and price convergence, such as that by Siliverstovs et al. (2005), Barnes and Bosworth (2015), Neumann (2009), Brown and Yücel (2009), Rosendahl and Sagen (2009). It is worth noting the work by Ritz (2014), who elegantly showed that the market power of large LNG producers can explain the wide divergence between European and Asian prices, especially following the Fukushima incident in Japan. Ritz (2014) noted that purely looking at price differentials net of transport costs is not particularly helpful for understanding the strategic considerations of (large) LNG producers and hence could lead to an incomplete understanding of the nature of the global LNG trade and arbitrage.

Our paper contributes to the above literature with a detailed assessment of LNG trade patterns from 2011-2014, focusing in particular on: (i) assessing what could have happened to prices in Europe and Asia had the LNG trade patterns diverged from the historical pattern in that period, and (ii) on the economic reasons why LNG arbitrage between Asia and Europe did not happen as one would expect, given the large regional price differentials. To the best of our knowledge, this is the first empirical work which uses a huge amount of data on LNG trade and prices to explore the economic drivers behind LNG trading between Asia and Europe. The paper also contributes to the energy policy debate: in particular, we discuss the implications for Europe of increasing its reliance on the global LNG markets to deliver diversity and security. Also, to the best of our knowledge, this is the first study that comprehensively and quantitatively analyses the issue of LNG trading between Europe and Asia taking into account dynamics in oil and gas prices in both markets as well as differentiating between short-term and long-term trade and, importantly, taking the LNG shipping market into account.

[5] Based on rigorous quantitative research, the report outlines various policy options available for GB to improve its security position; however, the modelling work made some simplifying assumptions about LNG markets that this research intends to discuss in greater details. Particularly, Poyry modelling work assumes that all LNG cargoes can go from any liquefaction plant to any regasification terminal, and that cargoes are fully 'market determined'. We discuss implications of this and other assumptions on the economics of LNG trade in this paper.

Therefore, the contribution of the paper to energy economics literature is manifold: first, we model and explain the nature of spot LNG pricing in Asia – a hotly debated topic amongst energy experts, academics and policy makers (Kate et al., 2013; Corbeau et al., 2014; Rogers and Stern, 2014). Secondly, we provide a simple econometric model showing major drivers behind LNG shipping rates and, using these econometric models, we explain the economic rationale behind LNG trade patterns observed since mid-2010 and in particular the strategic rationale of LNG exporters and European LNG importers in not arbitraging away the observed huge price differential between Europe and Asia in 2011-2014.

The rest of the paper is structured as follows. In the next section we try to succinctly summarise major pricing differences in international trade in gas, the evolution of the LNG industry and the emergence of short-term and spot LNG trading. Following this section, we summarise the role of Europe in the global LNG trade to set the scene for our main research – Section 4 - in which we try to assess the impact on regional prices of LNG diversion from Europe to Asia in 2011-2014 and also explain the strategic rationale behind the observed LNG trading between Europe and Asia in that period. Lastly, we conclude with a discussion of Europe's increasing reliance on LNG to secure its gas flows in Section 5.

2. Internationalization of the Gas Trade

2.1. Evolution of trade and pricing

Traditionally, gas markets were regional in nature because of large-scale infrastructure investment requirements along the whole value chain, especially capital requirements to build transport pipeline networks to supply gas to end consumers. However, since the late-1960s and up to the mid-2000s there has been a general trend towards cost reduction due to technological improvements in the whole LNG value chain (Stern, 2006; Greaker and Sagen, 2008). This, coupled with demand uptake in remote consumption centres relative to production locations, allowed the LNG trade to emerge as one of the fastest growing internationally traded in the period late-1960 to 2012, during which annual growth in LNG exports averaged 14% (see Figure 1). Also, in that period, starting with Algeria – the first LNG exporter – there has been a proliferation in the number of LNG exporting countries. In 1975 there were only 4 exporters, whereas in 1995 this figure doubled to 8 and, as of 2012, we have 20 exporters (including re-exports from Europe), with Qatar emerging as the largest LNG producer and exporter globally, accounting for more than 30% of global LNG exports (Figure 1).

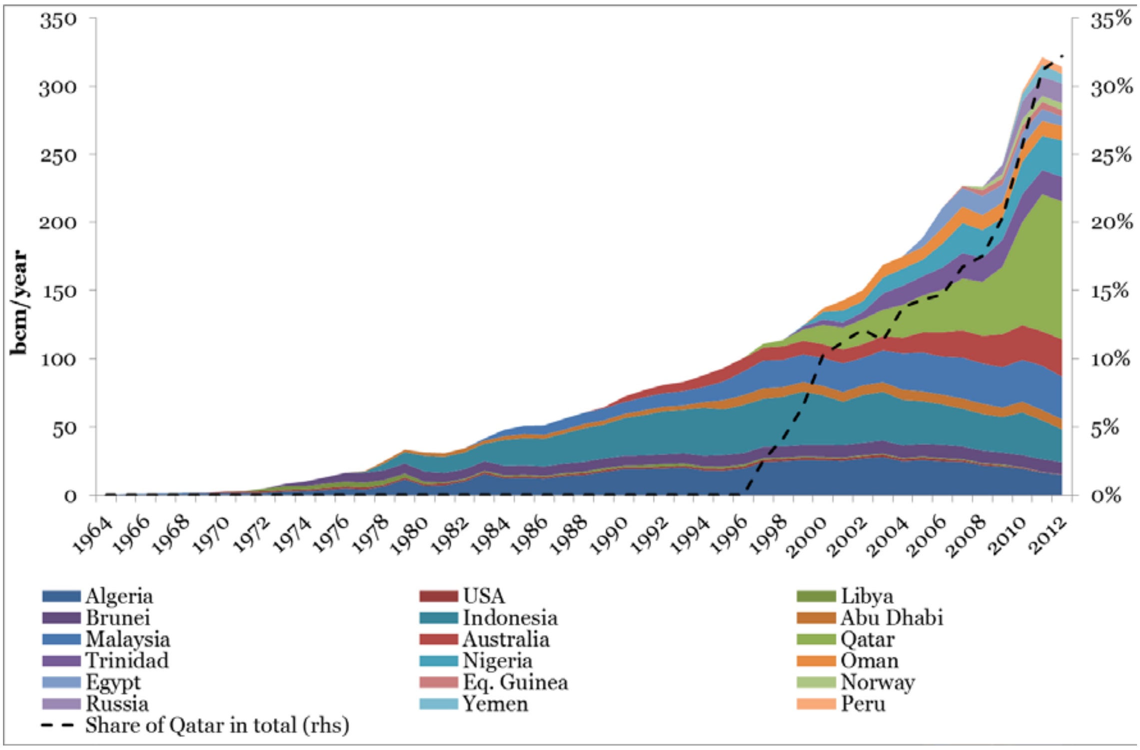

Figure 1: Global LNG Exports
Source: Poten and Partners via Bloomberg Terminal

In general, the economics of gas trading via seaborne LNG transport are more advantageous relative to pipeline trading if the transportation distance is more than 4000 km (Rogers, 2010; Jensen, 2002), which allows for shipping super-cooled gas across continents at a lower cost than if using pipelines. Thus, in 2000, pipeline gas accounted for 78% of total gas traded, whereas LNG was 22%[6]. However, in 2013 LNG trade accounted for 31% of the global gas trade[7].

On the import side, the LNG trade has been dominated by Asian countries, in particular Japan, South Korea, Taiwan (JKT) and, more recently, China and India (for other Asian countries, see Figure 2). Thus, in the late-1990s, JKT countries' LNG imports accounted for 78% of all trade but this figure has been reduced since then to below 60%, primarily due to the rise of other buyers such as China and India in Asia, the UK in Europe and Mexico, Argentina and Brazil in South America.

[6] Authors' calculations based on ENI (2014)
[7] Authors' calculations based on ENI (2014)

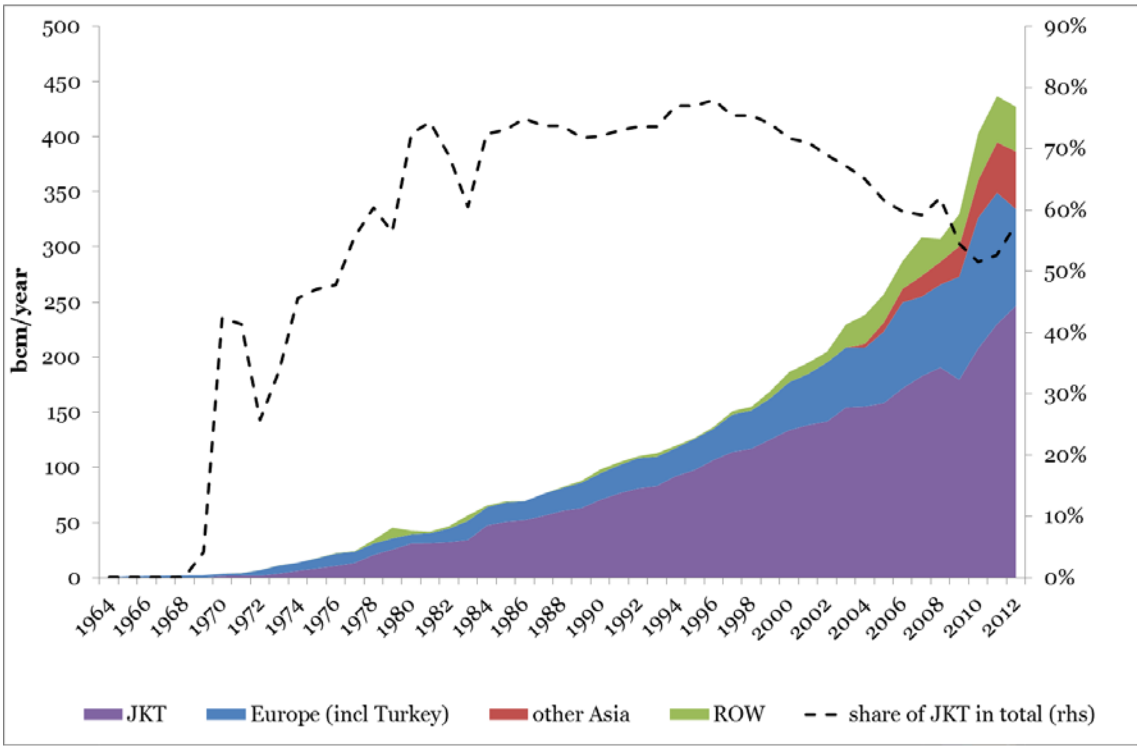

Figure 2: Global LNG Imports
Notes: JKT refers to Japan, South Korea and Taiwan and ROW to Rest of World
Source: Poten and Partners via Bloomberg Terminal

Figure 3 shows a snapshot of gas consumption and pricing in all regional markets. As noted earlier, international gas trading is still dominated by cross-border pipelines: in Europe, cross-border trading using pipelines accounts for about 43% of total consumption and only 6% is accounted for by LNG, while the rest is domestic production. The situation in Asia-Pacific (due to geography) is completely reversed – LNG accounts for 36% of total consumption while pipeline trading accounts for only 9% and the rest is accounted for by domestic production (primarily in China). Other regional markets are predominantly either self-sufficient or import gas using pipelines (North and South Americas).

Turning to pricing mechanisms for the international gas trade, gas is predominantly priced using two mechanisms (IGU, 2014): (i) oil price indexation, or oil price escalation, where the value of gas is determined based on the price dynamics of oil products, and (ii) hub-based pricing where gas prices are discovered through the interaction between gas supply and demand.

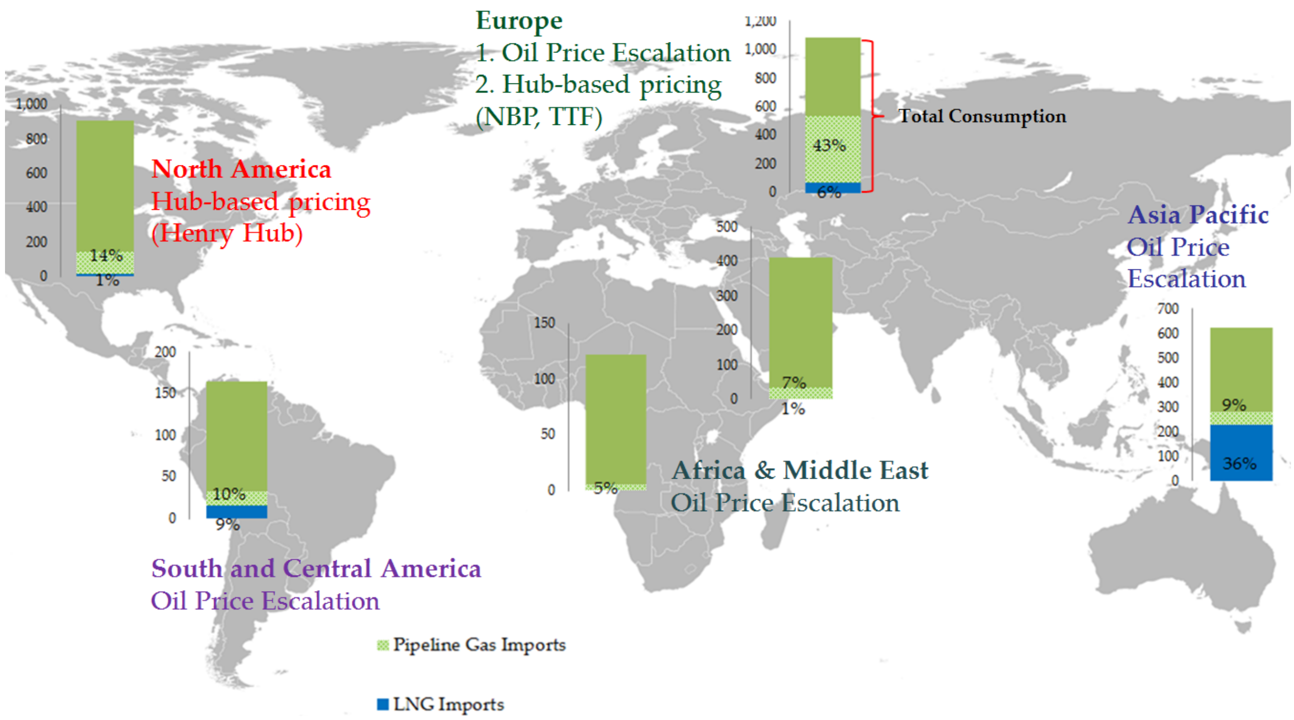

Figure 3: Gas pricing mechanisms in international trade
Notes: data on shares of pipeline and LNG trading is from 2012
Source: LNG and pipeline trade is based on BP (2013), pricing regimes are based on IGU report (IGU, 2014)

It is important to note that North America (USA and Canada) is currently the only market with gas trading based purely on supply and demand conditions, with the Henry Hub price as the dominant spot price index used in this market.

More recently, Europe has also begun to transition to hub-based pricing, and it is reported that more than 40% of the European gas supply in 2012 was linked to European regional hubs (such as NBP in the UK and TTF in the Netherlands) (Jensen, 2012). The rest of the international gas trade in Europe is still based on oil indexation; this is true in particular for gas coming from Russia, North Africa and Norway (marginally). Thus, Europe has emerged as a unique market place where two different pricing mechanisms exist – hub-based and oil-indexation pricing - with unclear prospects of moving to one pricing system or the other.

The Asia-Pacific gas market is dominated by an oil price indexation mechanism and the trade is supplemented by short-term and spot transactions to balance the positions of importers in those markets. The pricing of such short-term and spot transactions is assessed by price reporting agencies such as Platts (the spot index assessed by Platts is called the 'Japan Korea Marker', JKM) or ICIS Heren (called the 'East Asia Index', EAX). The world's first cleared LNG swap traded on 16 July 2012. The contract settled on the EAX for physical LNG. A small but growing derivatives market has emerged behind both indices and liquidity has been on increase.

We should note that although oil price escalation can be found both in Europe and Asia, the oil-indexation pricing mechanism differs for pipeline gas in Europe and for LNG in Asia. In Europe, traditionally, pipeline gas has been traded using long-term contracts (usually 20-25 years in length) with three main features:

(i) a minimum offtake level, or take-or-pay clause, is specified and importers are obliged to pay for that minimum level of gas even if they do not import at this level
(ii) a 'make-up' clause allowing buyers to 'delay' offtaking volumes to future periods, usually within a limited timeframe (e.g., 3 years)
(iii) the pricing mechanism is usually based on prices of oil products[8] (IGU, 2014) such as gasoil and heavy fuel oil with a smoothing effect (averaged prices of oil products for the previous 6-9 months) and a lag ranging from 1-9 months (Stern and Rogers 2014).

It should be noted that in recent years, due to a fall in demand and the rise of gas-to-gas as well as inter-fuel competition (e.g., coal and renewables in electricity generation), the majority of long-term oil-indexed contracts have been renegotiated to include some elements of indexation based on spot indices (e.g., TTF or NBP).

Concerning LNG imports in Asian markets, the LNG commodity is priced under similar long-term contracts with pricing linked to the average price of the so-called Japanese Customs' Cleared (JCC) – a basket of crude oil imports into Japan. It is important to note that industry experts consider that these long-term LNG contracts have similar take-or-pay clauses with specific minimum annual offtakes – this is not entirely true since LNG contracts allow for some flexibility for importers to 'delay' offtaking the cargoes in a particular year but the importer then should take these 'delayed' cargoes in other years within the contract's time horizon[9]. This is in contrast to pipeline contracts, where the take-or-pay clause would specify a minimum annual offtake level, say 80% of the agreed quantity, and a limited time period during which buyers can delay offtaking physical volumes.

The indexation would normally have a lag of three to six months of the JCC price, while in general the JCC price itself has a lag of one month from the Brent crude mark price[10]. However, the exact duration of a lag varies from contract to contract. Some contracts are based on average rolling crude prices over preceding year, while some include much longer periods, such as five years. This means that the price of a cargo is determined by calculating the price of crude on the basis of an agreed benchmark up to the day of physical delivery. The idea behind an average price is to protect both buyer and seller from any short-term spikes or drops on the volatile crude markets.

The pricing of LNG in long-term contracts would usually be specified as a percentage of the JCC price, called the 'slope', plus a small fixed component to reflect shipping and other costs. There is a more sophisticated pricing method applied to LNG imports, the S-curve method, which specifies ranges of low and high oil prices and in those ranges prices tend to be more flat, acting as a ceiling (when oil prices are high) and a floor (when oil prices are low) when the JCC increases/falls to a certain level. When market demand in Asia is very strong, LNG sellers, such as Qatar, could exert market power and demand that LNG be priced close to 'oil parity' or even above parity (see Section 4). This means that LNG prices

[8] In some German legacy contracts with Russia, gas is also pegged to coal prices (according to our conversation with major gas trading firms in Europe)
[9] Based on our conversation with LNG traders
[10] Based on our conversation with LNG traders

should be equal to those of crude oil based on the thermal values of the two commodities. Given all conversions, a slope of around 17% of the JCC price would produce an LNG price (measured in $/mmbtu) close to oil parity in terms of thermal content.

Summing up the discussion on pricing and gas trade in the major consumption regions – Europe, Asia and North America – the different pricing mechanisms coupled with market structure have produced a variety of price differentials in the last decade (Figure 4). These have been driven by supply and demand balancing, oil price dynamics and discontinuities in trade and the regulatory environment, as well as demand (e.g., the Fukushima accident in Japan) and supply (e.g., shale gas in the USA) shocks. For a comprehensive review of gas pricing and trade dynamics in Europe see (Stern, 2007, 2009; 2014; Stern and Rogers, 2011; Stern and Rogers, 2014; Melling, 2010; Franza 2014; Asche et al., 2013; Miriello and Polo, 2015) and Asia see (Kiani, 1991; Rogers and Stern, 2014).

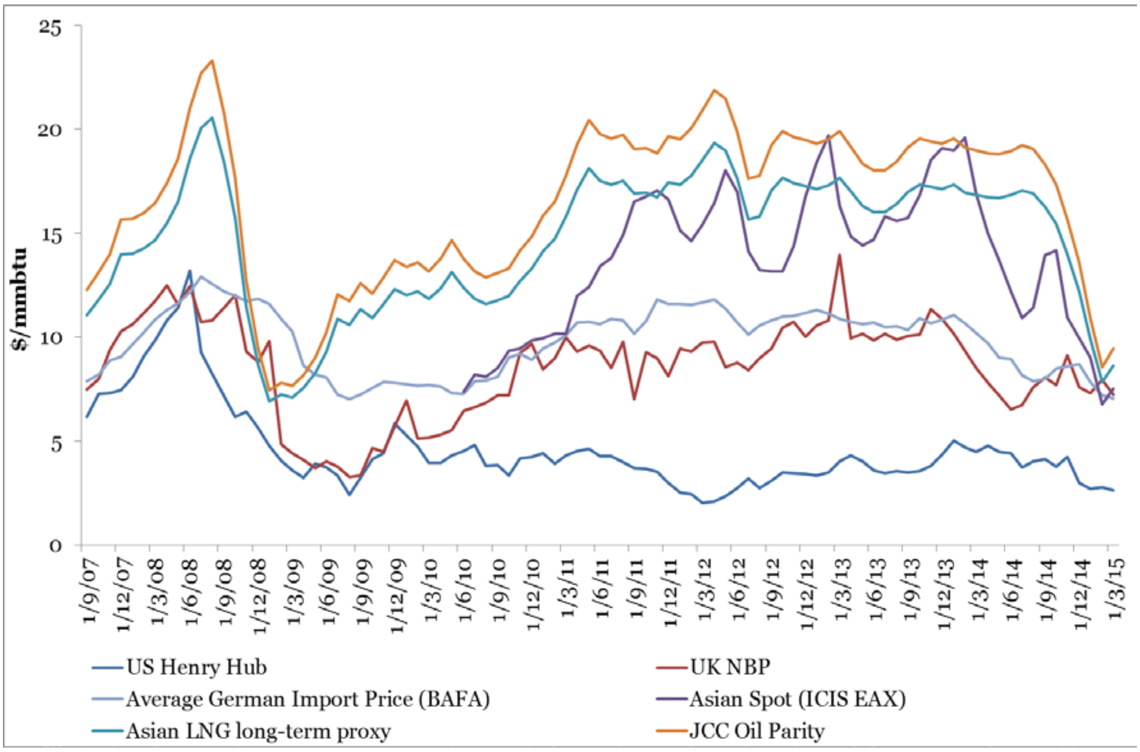

Figure 4: Evolution of regional gas prices
Note: Asian Long-term proxy is based on formula as in BG (2015)
Source: Bloomberg and ICIS

It is, however, worth mentioning major structural shifts that produced these price dynamics:

- In mid-2008 the US spot Henry Hub price traded in the range of $13/mmbtu and since then has fallen to an average of $3.75 (average over 2010-present); this 3.5 times slump in the US spot price was largely due to uptake in shale gas production.
- In the meantime, in Asia, starting from mid-2010, the price assessment for LNG spot cargoes was in the range of $7.4/mmbtu, which then peaked in Feb-13 at $19.7/mmbtu – 1% above oil parity. This was largely due to Japan's decision to take its entire nuclear power fleet offline following the Mar-11 Fukushima accident. However, since late-2014, the spot index has crashed to below $7/mmbtu, largely

due to a mild winter in Asia, a crash in oil prices and expectation of new LNG capacity being created in the coming years.

- In Europe, regulatory changes in gas markets coupled with a surplus of LNG created by the US shale gas revolution low gas demand due to the economic slowdown and increased inter-fuel competition (e.g., uptake of coal and renewables in electricity generation) have forced gas importers to renegotiate pricing mechanisms in their traditional contracts with suppliers. Thus, since about 2010, a pricing system has emerged in Europe which is based on long-term oil-indexed contracts as well as being based on hub trading (NBP in the UK and TTF in Continental Europe). It is believed that the pricing of Norwegian and Dutch gas volumes is now entirely based on hub prices, whereas for Russian gas the rebalancing consists of discounts from the base price plus rebates and spot indexation for marginal volumes (see Rogers and Stern 2014).

2.2. Short-term and spot LNG trading

In the formative stages of the LNG trade, spot or short-term trading was viewed as something of an outlier of the general pattern due to the overall low liquidity on the market. To present, there is no single accepted definition of what constitutes a spot LNG trade. Generally, however, it can be said that spot or flexible LNG volumes are those sold outside of long-term contracts for delivery within a calendar year. Spot volumes can be sold on a cargo per cargo basis or as several cargoes delivered over pre-defined period of time at an agreed upon schedule and pricing terms. Occasionally, the term incremental is also used for cargoes traded between a buyer and a seller that already have an existing long-term sales contract. Such volumes can be sold at the existing contractual price or at a price agreed upon at the time of transaction.

The mechanism for spot transactions could involve bilateral negotiations between a buyer and a seller, open or restricted tenders and the involvement of a broker. Given that the market for LNG is still less than 50 active participants, the commodity is not heavily brokered and most transactions are concluded on a bilateral basis. The short-term market is dominated by portfolio suppliers such as Anglo-Dutch oil and gas major Shell and UK-based BP, as well as several Japanese trading houses—Mitsubishi, Itochu, Marubeni and Mitsui—and commodity traders like Trafigura, Vitol and Gunvor. Large producers will typically also engage in spot trading but more as a way of optimising their existing supply positions than of focusing on short-term risks and profit opportunities. Due to high entry costs and associated financial risks, there have been several instances where companies have ceased LNG trading operations. The least successful and short-lived strata of commodity trading in LNG have been banks and financial traders.

On the buy side, the spot market has offered an opportunity to deal with short-term demand spikes, as well as allowing some buyers to take advantage of international pricing if domestic levels of gas or competitive fuels are deemed to be high. While very few buyers have relied exclusively on short-term volumes, there is a significant trend on the market towards allocating a portion of energy baskets to short-term deals. To date, Argentina, Brazil, Egypt, Israel and Pakistan have exclusively relied on short-term deals and buying tenders to secure supply. Notably, all of these importers also rely on floating storage and regasification units (FSRU) rather than a traditional on-land import terminal. Typically, such buyers either require LNG only during periods of peak demand or see the commodity as a temporary feature of their market before they begin production of their own domestic supplies.

The portion of spot trade according to its broad definition in overall global commercial flows has expanded significantly over the course of last fifteen years, largely due to new entrants on the market and increasing sources of LNG production. According to our estimates, LNG trading made up less than 5% of global trading around the year 2000, whereas currently it constitutes around 25% of the global trade (Figure 5). Around 4000 LNG cargoes were traded in 2014, which means that about 1000 were sold on a short-term or flexible basis. By the year 2020, the overall global production capacity is expected to reach 500mtpa, which would equate to around 5800 cargoes per annum or 1450 short-term or flexible cargoes. However, with expectations of flows from North American LNG projects on the basis of shale gas production, the percentage of short-term trading could increase significantly, as many facilities in the United States and Canada are marketing tolling arrangements rather than a traditional long-term contractual structure. It is also important to add that emergence of reload trading across terminals in Europe and Asia is also likely to add liquidity to the short-term market.

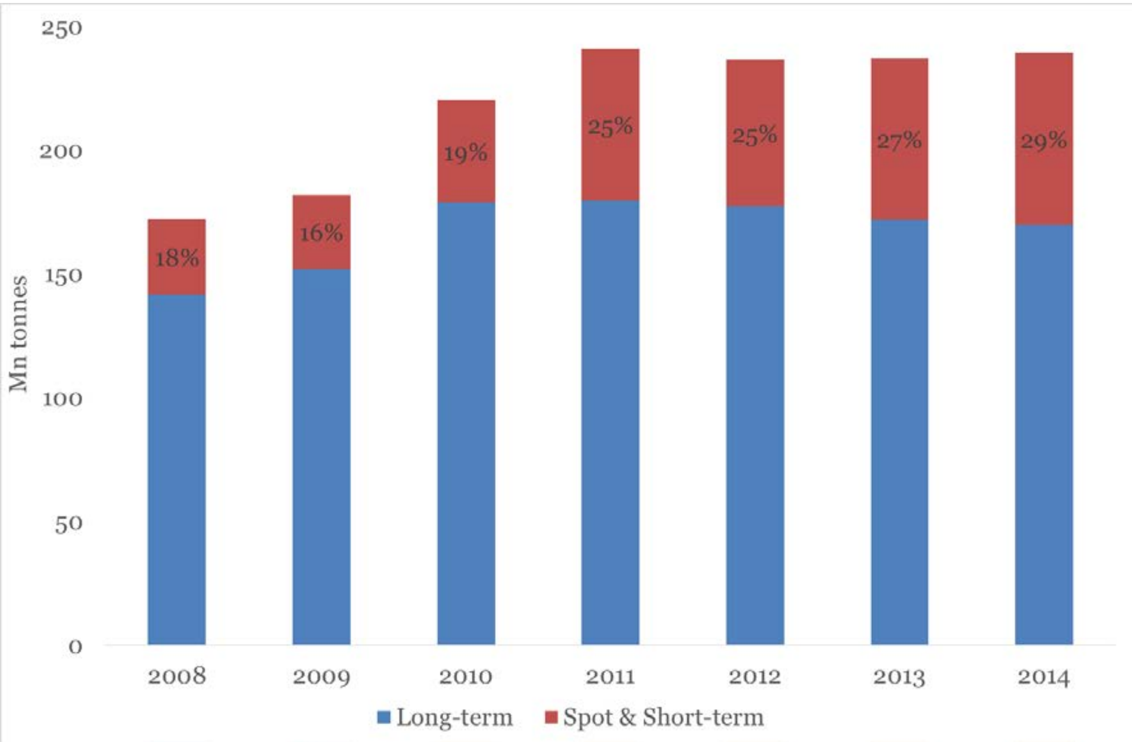

Figure 5: Long and short term LNG trading
Note: According to GIIGNL definition all contracts lasting less than 5 years are considered short-term contracts and spot trading
Source: GIIGNL[11] Annual Reports 2008-2014

There is no prevailing pricing mechanism for the short-term LNG market. Transactions have been structured on a fixed-price basis for prompt deals that involve delivery within 30 days or have been indexed to Brent or JCC crude benchmarks. Other indexation

[11] International Group of Liquefied Natural Gas Importers (GIIGNL) - http://www.giignl.org/

mechanisms used include the Nymex Henry Hub gas futures benchmark, UK's NBP gas benchmark and increasingly the Dutch TTF gas benchmark. The choice of price mechanism is influenced by several factors, which could include buyers' requirements and risk management strategies for sellers. Buyers working with competitive fuels, such as fuel oil, will typically procure spot LNG as the basis of crude oil price indexation. This, however, leaves the seller exposed to the volatility of crude markets, which can in turn be countered by reliance on various crude-based hedging tools and derivative products. The choice of pricing benchmark is mostly influenced by the pricing dynamics of the buyers' domestic market and how sensitive it is to crude fluctuations. For short-term deals, a 60 or 90-day average settlement of the Brent crude benchmark up to the date of delivery is preferred. This smoothes out any short-term violent fluctuations and tends to capture the overall pricing trend. As JCC is a monthly average price of crude imports into Japan, the benchmark will typically follow the moves on the Brent market. It should be added that no deep derivatives market exists for JCC-linked pricing, and proxy benchmarks that mimic the movements of the JCC curve are frequently used. Moreover, as JCC is a retrospective index, various mechanisms are imbedded in the contracts and typically require partial settlement until the price is released.

There have been several attempts by the price reporting agencies (PRAs) to issue credible benchmarks on the basis of in-house price assessments. Both the ICIS East Asia Spot LNG Index and Platts' Japan-Korea Marker are testaments to these efforts. Neither benchmark has gained significant traction, however, at this stage. The choice of benchmark is quite important as it will dictate the risk management strategies employed by sellers to limit their exposure. The depth of the swaps market on the basis of both EAX and JKM is very shallow at present, with the whole global churn on a monthly basis to hedge a single LNG cargo.

Over the last two years, the issue of short-term pricing has become an important commercial discussion. Several exchanges, including SGX in Singapore, TOCOM in Japan, ICE and CME, have released competitive products that attempt to create liquidity and attract business to their respective platforms. In the case of SGX and TOCOM, a proprietary price collection mechanism is used to derive the underlying price, whereas both ICE and CME base their products on the price assessments of ICIS, Platts or the Japanese price reporting agency RIM. To date, no trades have taken place on the basis of the SGX index, one trade was reported in August 2015 on the basis of TOCOM's index and only a handful of trades were reported on CME and ICE. It is important to note that the contract offered through an exchange represents only a small portion of a physical cargo. Thus, short-term derivatives trading on the basis of physical LNG is still extremely small. Over-the-counter (OTC) trading in LNG swaps has also emerged over the course of last five years, with three brokerages offering the product. However, the OTC trade has not been robust enough to meet even a small portion of the industry's risk management needs and, according to our research, no more than 10% of an LNG cargo can be hedged via existing OTC or exchange products based on a pure LNG price logic.

As with long-term volumes, short-term LNG trading is very much Asia-focused. More than 70% of spot LNG has found a home in the Pacific Basin so far in 2015, as shown by data from the ICIS LNGEdge platform. Key markets for spot LNG have emerged in Japan, South Korea, China and India. Important short-term markets have also sprung up in Egypt, Jordan, Argentina, Mexico and Pakistan. More countries are expected to start importing LNG over the course of next five years, including Bangladesh, the Philippines, Vietnam and Indonesia. With the growing availability of flexible import infrastructure, LNG can find a home with virtually any buyer with a coastline. Other than Lithuania, Europe has seen declining LNG imports, and the importance of this market has been shrinking. This is largely due to the fact that pipeline gas is much more competitive than LNG. Over the last five years, LNG has traded at a strong premium to all the European gas hubs, making the economics of spot importing very difficult to justify. Short-term LNG markets are growing in areas where domestic gas production is declining and there is no alternative source of pipeline gas available internationally. The Pacific Basin as a whole is set to remain the key area for both long-term and short-term LNG imports going forward.

2.3. The LNG shipping market – an overview

The midstream component of global LNG trading has evolved dramatically over the years. The general trend can be briefly described as an increase in both the size and number of vessels. Our research identified a total of 431 LNG tankers which are used for international trade. This number also includes floating storage and regasification units (FSRU) which, while they can be used as conventional tankers, are designed to act as floating LNG terminals. 142 vessels are on the order books with shipbuilders and expected to be added to the global fleet within the next five years.

Most LNG tonnage has been ordered to service specific production projects, and is commonly referred to as project tonnage. The cost of building an LNG carrier has varied dramatically due to fluctuations in global steel prices, technical specifications and carrying capacity. The cost of a new-build varies from $200-$250mn for a conventional vessel. Most LNG carriers are built in either South Korea or Japan. Due to the comparatively high cost of LNG ships, very few ship-owners have ordered vessels on a purely speculative basis. Of 142 tankers on the order books, only 18 are being built without a long-term commitment from a charterer. In terms of the existing global fleet, less than 5% of the existing fleet has been built on a speculative basis. Rather than servicing any particular production project, the owners of these vessels target mid-term, short-term and spot markets.

Tonnage built and designed to service specific LNG projects will typically have a long-term charter agreement signed between the owner of the tanker and the operator of the project. The charter agreement will stipulate, firstly, the charter rate, which is typically expressed in dollars per day ($/day), servicing agreements, conditions for sub-chartering the tanker and so on. The sub-charter market is an important part of LNG trading which aims to deal with imbalances on the global market. There are several scenarios under which the operator of a project may consider offering project tonnage on the sub-charter market. These could include prolonged production outages at an LNG plant, lower-than-expected production or force majeure conditions experienced by project offtakers.

Depending on the market conditions, a sub-charter rate may be lower or higher than the long-term charter rate. Since 2010, LNG shipping has gone from feast to famine on several occasions. While a long-term charter rate is typically locked for the period during which a vessel is expected to service the project, which normally ranges between ten and fifteen years, short-term or spot rates fluctuate with the movements of the market and are therefore indirectly exposed to the price of LNG. During strong seller market periods, such as the one following the aftermath of the Fukushima incident in Japan, spot charter rates have reached highs of $140,000/day, whereas when the market hits bottom due to oversupply the very same vessel could attract only $25,000/day. The periods of high charter rates normally coincide with arising arbitrage opportunities between the Atlantic and Pacific Basin. The longer the voyage between the buyer and the seller, the more strain it adds to the midstream component. This means that when available cargoes are mostly located in the Atlantic Basin and most demand is in the Pacific Basin, the pool of available vessels is greatly reduced as longer voyage times will on the whole absorb greater numbers of ships. The movement of cargoes between the Atlantic and Pacific basins typically coincides with bull seller markets. Thus, short-term charter rates will typically follow the direction of spot LNG prices.

It should be added that all LNG carriers face operational costs which range from $30,000-$40,000/day. These costs include items like crewing, insurance, technical servicing and finance re-payments. It is not uncommon during bear markets to see charter rates fall below operational costs as long-term charterers attempt to minimize their daily losses. In any scenario, idling an LNG carrier is an expensive exercise that costs about $1,000,000 per month. Hence, shipping optimization aims to minimize idling time.

On the short-term market, the employment of a vessel that is not on a long-term charter is primarily the responsibility of the owner. If the vessel is attached to an LNG production project via a long-term charter the financial burden falls on the charterer, who will seek alternative employment for the vessel if it is not utilized.

The carrying capacity of LNG tankers is a significant factor in terms of utilization. The short-term market requires vessels that are suitable for transporting spot volumes. While there is no standard size for a spot cargo, it tends to be between 135,000cbm and 142,000cbm. The carrying capacity of the modern LNG fleet ranges from 138,000cbm to 177,000cbm and represents a spectrum of tonnage suitable for short-term markets. While much has been said about the Q-flex and Q-max category tankers, which are used to transport volumes produced by Qatar's RasGas and Qatargas companies, these tankers are rarely used by third parties due to their large size. Q-flex category tankers, first introduced in 2007, have a carrying capacity of 210,000cbm and 216,000cbm. Q-max category carriers have a capacity of 266,000cbm. These vessels were specifically designed for Qatari projects and are used to service long-term contracts. The large size of such a vessel makes it impractical for carrying standard-sized cargoes produced by other projects. Q-flex and Q-max carriers require special modifications to be installed at the receiving terminal of the customer. Not all terminals in the world have the technical capacity to receive Q-flex and Q-max category tankers. As such, the infrastructure requires relatively heavy funding and the LNG buyers in the past have not typically installed infrastructure to accommodate carriers of this size without there being a long-term contract in place with either RasGas or Qatargas.

Another technical consideration which often determines a vessel's employment potential is the boil off rate. Once LNG is loaded onto a vessel, the cargo will sustain a loss during its transportation which is expressed as percentage of the cargo per day. The lower the boil off rate, the fewer losses the seller will incur as a result of transporting the cargo. Highly efficient vessels will typically sustain a boil off rate of around 0.05-0.06%/day, while older tonnage could have a boil off rate as high as 0.1-0.12% per day. On a voyage lasting thirty days or more, such losses can be quite substantial. The boil off rate is also calculated into the equation if a vessel is used as storage. Typically, boil off and the pressure of charter payments makes LNG carriers a poor option for storing LNG. While there have been cases of traders "floating" or storing a cargo on water for a period of three months or more, such moves have rarely paid off and have resulted in heavy losses. This factor should also be accounted for in any delays in discharging the cargo.

In operational terms, LNG terminals have restrictions in place in terms of what vessels they can accommodate. Vessels built before 1989, for example, rely on using low-grade bunker fuel, which is not compatible with environmental standards or the regulations of certain countries around Europe. Some production projects, such as Snohvit LNG in Norway and Sakhalin-2 in Russia's Far East, require "winterization" for vessels lifting volumes during certain times of the year. Thus, there is no global compatibility between all LNG ports and vessels. Of the current global fleet, we have identified just under 50 vessels that have sufficient flexibility in terms of technical features and size to service the short-term market. Of these 50, only around 20 are available for three month charters. Thus, it can be generally concluded that at present only about 5% of the total global LNG fleet can be dedicated to the spot trade. The proportion is likely to at least double by 2020 on the basis of the current order book. This would mean that 10% of the global LNG fleet could be dedicated to short-term or flexible trading by 2020 without taking into consideration any midstream lengths offered by production projects.

Due to the high costs and risks involved, transportation of LNG is very expensive in terms of the percentage figure of the overall cost of the commodity. The cost of shipping typically represents from 5-10% of the overall cost of a spot cargo. The percentage is typically much lower on long-term contractual volumes, and represents less than 5% of the cargo's overall cost.

3. Europe in the Global LNG Market

In the context of global LNG trading, Europe has taken a backstage role. Slow economic growth and an abundance of cheap pipeline gas from Russia, Norway, Algeria and Azerbaijan, in addition to domestic production, have made LNG uncompetitive in terms of price across the major hubs in the UK, Belgium, the Netherlands, Italy, Portugal, France and Spain. Thus, the import terminals have seen a significant reduction in LNG flows not only in terms of spot volumes but also in form of contractual volumes in 2014 and 2015[12]. The total volume of LNG imported into Europe in 2014 stood at around 29.85 million tonnes (mt), according to ICIS' estimates. Of this, less than five percent can be attributed to spot imports. This represents a decline of 2 mt year-on-year from 2013, and an approximately 50% decline compared with 2011. There are several explanations for these market dynamics. The growth of short-term demand from markets across Northeast Asia—Japan, South Korea, China and Taiwan—coupled with robust absorption from South

[12] LNG is occasionally imported on a spot basis in Greece and Turkey to deal with seasonal spikes in demand. In 2015, Europe has imported less than 30 spot cargoes as a whole, which is less than what Egypt has imported alone, to put it in context.

America's Brazil and Argentina have provided better profitability margins on a netback basis. Japan's LNG demand went from 70 mt per annum in 2010, to 78.5 in 2011 and to 87.2 mt in 2012. Demand has stabilised since then (Figure 2).

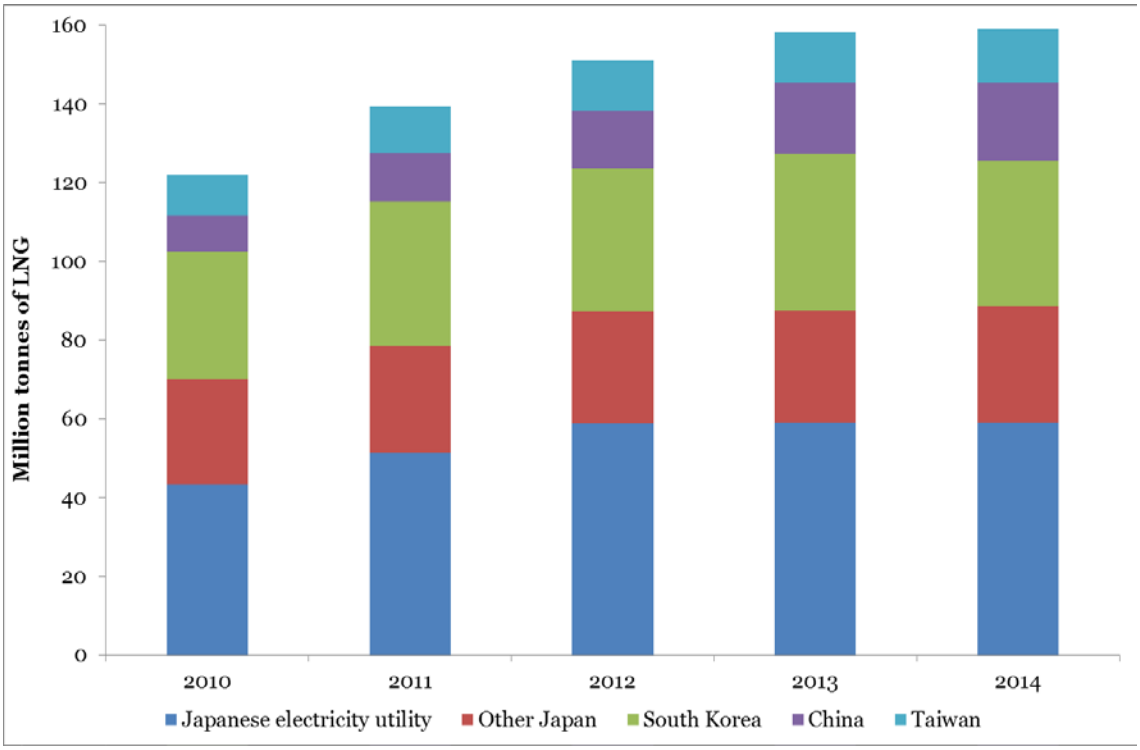

Figure 2: Japan, South Korea, China and Taiwan's LNG imports: 2010-14
Source: ICIS

Interestingly, Europe has emerged as a source of reload volumes sold on free on a board basis to traders that have in turn taken these volumes to consumers elsewhere. In countries where liquid trading hubs exist, spot volumes cannot exceed 98% of the hub's front month volume. The two percent is taken into account for regasification costs. The logic is very straightforward. In a competitive market, a gas buyer always has a choice to buy volumes on the hub. Hence, LNG must represent a discount from domestic hub prices in order to be competitive. Demand for LNG elsewhere in the world has kept prices at a premium to hubs and, therefore, made them prohibitively expensive for European buyers. As a matter of fact, strong pricing elsewhere has presented an opportunity for European LNG buyers to attempt to divert their long-term contractual volumes to better-priced markets. This trend has resulted in massive restructuring of trade flows, particularly involving volumes from Nigeria's LNG project.

Robust LNG trading has emerged at the Gate LNG terminal in the Netherlands, the Isle of Grain LNG in the UK and across several of Spain's terminals in Huelva, Bilbao and Barcelona. The reload trade allows traders to take advantage of the proximity of European terminals to key markets in the Middle East and South America. A reload operation takes place when the original long-term buyer with a downstream contract is able to cover his obligations on the downstream market by buying gas on the hub and keeping the LNG volumes in-tank for sale without regasifying them, then releasing them into the system. For the buyer of reload volumes, the price typically involves a premium of up to $0.30/MMBtu on the hub price as well as fixed reload costs. The cargo is then available for delivery elsewhere.

Thus, in 2014, Europe saw dramatic growth in the re-export trade, whereby LNG volumes were re-loaded at terminals in Spain, France, Belgium and the Netherlands and exported to other global buyers. About 5 mt was re-exported from the EU in 2014. The reload operations were carried out largely to take advantage of arbitrage opportunities from buyers in other geographies. The contractual volumes delivered to Europe could be replaced by cheaper pipeline volumes – instead of releasing LNG into the domestic grid, importers optimised profit opportunities by re-exporting volumes to markets that could offer a competitive price. The profit could still be found on markets in Asia and South America despite the additional reload cost, which averages $0.50-$0.70/MMBtu. Spain has emerged as the most liquid point for re-load operations due to technical capacity at its terminals in Huelva, Cartagena and Barcelona, as well as low domestic demand for natural gas and limited profit opportunities for importers working with the domestic gas market . Therefore, approximately 15% of the 29.85 mt of LNG imported by European buyers in 2014 has never been released into local gas grids.

The LNG import terminals in the United Kingdom, Belgium, France and the Netherlands, which represent the bulk of import liquidity into the EU, have an underlying connection with local gas hubs. This means that the cost of LNG imported on a short-term basis should fall below the prices on the local hubs in order for the buyers to dispose of volumes at a profit. A realistic target price level for prospective LNG buyers on these markets is actually a two to five percent discount from local hub prices in order to reflect regasification costs. The regasification costs are generally transparent across Europe and are estimated at between $0.30-$0.90/MMBtu.

There are exceptions to these theoretical price dynamics when a potential buyer requires a cargo for technical reasons (such as maintenance of a terminal) or when the volumes are to be injected into a country's storage system to take advantage of seasonality in the price curve. In countries where the local traded gas hub is underdeveloped, lacks the liquidity to be used as a trading mechanism or is absent altogether (Spain, Italy, Greece and Lithuania can be qualified as such) different price dynamics are used by local buyers. In all cases, however, LNG in Europe commercially competes against pipeline supplies. The interconnectivity in the European gas market means that some, such as Spain and Portugal, remain largely isolated. Thus, even if an arbitrage opportunity exists on one of the Northwest European gas hubs, the existing network does not allow for delivery of Spanish gas at significant flows. At present, LNG re-exports are the only economically feasible outlet for that market.

This, however, does not mean that LNG procured on a long-term basis will be discounted against pipeline volumes, as other considerations, such diversification of supply base and potential shortfalls in pipeline deliveries, are considered. Indeed, the proliferation of LNG import terminals across Europe is driven mainly by a long-term commercial strategy which is based on forecasts of gas demand growth in Europe beyond 2020, as well as political motivation for increased security of supply, which has been in part propelled by the frequency of Ukraine-Russia transit disputes and their attendant implications in terms of gas deliveries to European consumers. The availability of short-term volumes globally stood at 62mt in 2012 and 2013 and increased to about 70mt in 2014[13]. Availability is likely

[13] ICIS estimates

to increase with the onset of exports from eastern Australian projects: QCLNG, APLNG and GLNG. While LNG remains a viable alternative to Russian pipeline supplies, Europe has yet to see a scenario whereby flexible LNG imports are dramatically increased on a short-term basis in reaction to such shortfalls.

While the import dynamics in 2014 on the whole show lukewarm demand for the product in the region, the figures can be somewhat misleading. With the sharp declines on the global crude markets, which started in August 2014 with the Brent crude benchmark trading at above $100/bbl and increased in December 2014 when Brent fell below $50.00/bbl, Europe has once again begun to emerge as a relatively attractive destination for LNG volumes. Low crude prices, which often form the basis of long-term LNG and pipeline gas contracts, saw buyers anticipate a significant discount on contractual deliveries from January 2015 onwards. This was the case not only in Europe but also in Asia, where buyers typically use an alternative benchmark known as the JCC (Japanese Crude Cocktail). Moreover, a dramatic decrease in seasonal prices in Asia, where the LNG price curve switched from contango to backwardation, meant that Japan and South Korea no longer presented an arbitrage opportunity for LNG volumes originating from the Atlantic Basin. Demand in South Korea and Japan is typically highest between January and March, while April, May and October-November represent points of lowest annual demand commonly referred to as the shoulder months.

Northeast Asia has seen physical oversupply in 2015 on the back of new production in the Pacific Basin and increased crude imports from the utility buyers in Japan, South Korea and China. Fuel switching opportunities in Northeast Asia are limited, however, with many power utilities lacking extensive crude-fired power generation capacity. In some cases, LNG is not only the fuel of choice but also the only one that can be imported for power generation needs. The European hub-linked LNG prices held firm throughout the 2014-2015 winter procurement season with some markets, namely Greece and Turkey, taking advantage of short-term oversupply and attracting spot volumes. From the late autumn of 2014 until recently, the market has also seen several distressed sellers that have placed their bets on the seasonality of LNG markets and have failed to anticipate the slump seen between November 2014 and March 2015 (Kazmin, 2015a). This essentially means that they have secured cargoes at a higher price in September than they could sell the cargo for in January.

Without a doubt, the threat of interruptions to pipeline gas deliveries from Ukraine was factored into spot prices seen on the hub markets across Northwest Europe. The National Balancing Point (NBP) in the UK was particularly sensitive to any news of supply interruptions and reacted violently to signs of potential shortfalls in deliveries from Russian in 2014 and, so far, in 2015. The "Ukraine premium" on the hubs supported European LNG prices, which gradually reduced the attractiveness of diversions of long-term volumes from Europe to Asia. As the arbitrage window between Europe and Asia closed, the number of nominations for free-on-board (FOB) cargoes sold from the European terminals for re-exporting subsided as well. By April 2015, Northwest European markets were trading at a premium to Northeast Asia, resulting in a short-term reversal of Atlantic-to-Pacific directional flow. The window of opportunity for such trades closed fairly quickly and less than a handful of pure spot trades took place with production originating in the Pacific Basin outside of the Middle East.

The decrease in European LNG imports in 2014 coincided with dramatic increases in imports in other geographies, including Asia-Pacific, South America and the Middle East. However, the declining price of crude oil has reduced the attractiveness of long-term contractual volumes for buyers in Japan and South Korea, as spot prices have been seen below these levels. This means that a number of utility buyers in these two countries have reduced their nominations under annual delivery programmes (ADPs) for 2015. The producers, in turn, have been left with little option but to offer excess volumes into an already oversupplied market on a tender basis, which further depresses spot prices. The situation escalated to a degree that historic low were seen on the spot market in early 2015, and the April and May delivery months traded at around $7.00/MMBtu or at parity with the European hubs. While spot prices have rebounded slightly, with prices pushing toward $8.00/MMBtu by the end of March 2015, most forecasts for 2015 remain profoundly bearish as more supply is expected to enter the market in the short-term. The summer demand has been supported by the entry of Egypt's state-owned EGAS into the short-term market, as well as Jordan's power producer Nepco. Demand in the Middle East has prevented prices from collapsing. The September EAX stood at $8.20/MMBtu on 4 August, while the Northwest Europe Index remained fairly weak at $6.23/MMBtu. The ramping up of the BG Group-led QCLNG project in Gladstone, Australia, along with anticipation of two other major export projects – APLNG and GLNG – coming online this year, mean that buyers remain convinced that supply will dramatically outstrip demand in Northeast Asia.

However, new demand is seen on the market elsewhere. In Egypt, the state-owned gas company EGAS is likely to start absorbing volumes, beginning from April 2015. EGAS has secured an FSRU to serve as its temporary import terminal and the volumes from several trading entities for the facilities. The suppliers include Gazprom Marketing & Trading, Swiss-based energy traders Trafigura and Vitol and several other suppliers that have no access to their own production volumes. In total, Egypt is due to import just under 40 cargoes from 2015-2016. Egypt's demand is sufficient to absorb some spare capacity in the Atlantic Basin, as well as to rejuvenate the reload trade from Spain, given the proximity of its terminals and the attractiveness of this trade route on a netback basis. In South America, spot demand is likely to be supplemented by Argentina and Brazil. Both countries could import as many as 50 cargoes over the 2015-2016 period on a flexible basis.

The attractiveness of the European short-term and spot LNG markets will be capped by their hub prices. As previously seen, any signs of instability in terms of delivery of Russian long-term volumes to Europe have previously resulted in large but unsustained spikes on the short-term markets. The spikes do create an opportunity for some traders to lock in hub prices using derivative products with sufficient windows of opportunity to justify importing LNG cargoes. The derivative products are then used to lock in the physical price of the cargo. However, the profit margin on such deals tends to be relatively low and other geographies, namely Asia and South America, have been seen as markets of choice for short-term opportunities. The oversupply on the global markets, which is expected to last into 2016, could mean, however, that Europe as a whole will be an attractive destination for short-term volumes, particularly if seasonal demand in Northeast Asia mirrors the 2014-2015 procurement season.

The convergence of prices in Europe and Northeast Asia seen at the beginning of 2015 disappeared by the end of March. As of 4 August, the ICIS East Asian Index (EAX) was assessed at \$8.20/MMBtu compared with the \$6.23/MMBtu seen on the Northwest Europe LNG Index. The current spread between Europe and Asia is likely to limit the flow of volumes between the Atlantic and Pacific basins, as the cost of shipping is likely to obstruct inter-basin arbitrage opportunities. The emergence of robust markets in Egypt, Jordan and Pakistan, all of which are currently paying above \$8.00/MMBtu, also makes Asia a less attractive port of call for spot cargoes. It is not clear, however, if buyers in the Middle East will continue to influence spot prices at the present rate. With stabilisation of supply to both Egypt and Jordan, the pricing influence of the Middle East could fizzle out as quickly as it emerged in mid-2015. The spread, however, has narrowed significantly from the levels seen in 2014, when Asia's premium over Europe stood at \$5.00/MMBtu at times, presenting a clear arbitrage opportunity for sellers.

4. The Economics of LNG Arbitrage between Europe and Asia

4.1. LNG arbitrage in 2010-2014

Based on the above analyses of global LNG and European gas market dynamics we can conclude that flows of spot LNG into Europe are a function of price differentials between spot LNG price achieved in Asia, netted back – less transport costs – to the LNG production location (e.g., Qatar), plus transport costs from this production location to North-Western Europe (e.g., to the UK) and the European spot price (e.g., NBP), less the trading margin (2-5%) to allow a trader to lock in cargoes to Europe. Stating this formally:

$$\delta_i = p_e^S(1-\alpha) - R_{i,e} - (p_a^s - R_{i,a}) \qquad (1)$$

where δ_i is the price differential for an LNG producer i in month t (omitted in eq. (1) for brevity), p_e^S is the spot price in Europe, α is the trade margin (taken as 5%), $R_{i,e}$ is the shipping cost from producer i to e, Europe, $p_{a,t}^s$ is the spot price in Asia, and $R_{i,a}$ is the shipping cost from producer i to a, Asia. Thus, eq. (1) stipulates that if δ_i is positive then Europe is more competitive than the Asian spot market. In a competitive market setup, producer i will arbitrage away any price differentials net of transport costs resulting from imbalances in one of the markets, subject to infrastructure availability.

Using eq. (1) and monthly LNG flow data between all exporters and the two markets – Europe and Asia – we have assessed the LNG trade in European and Asian markets in the period from June 2010 until March 2015. Figure 3 below shows price differentials (x-axis) as defined by eq. (1) and monthly LNG flows to Europe (y-axis, positive numbers) and to Asia (y-axis, negative numbers).

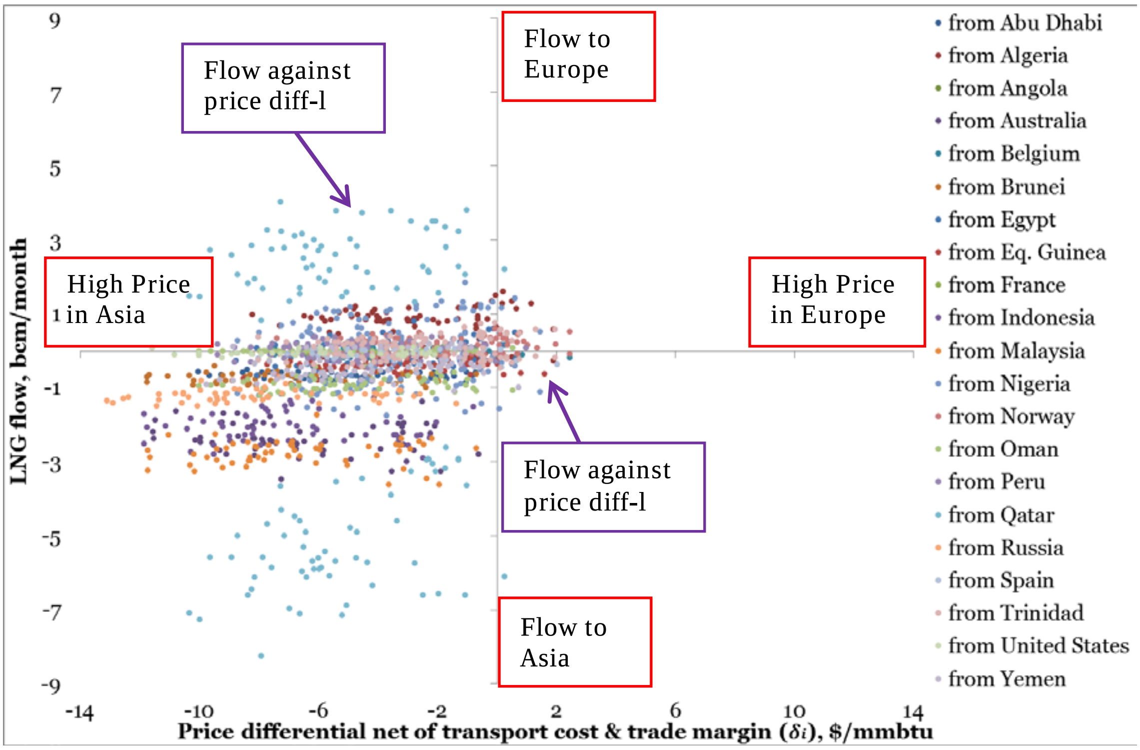

Figure 3: LNG flows and price differentials: Europe vs. Asia
Source: authors' calculations based on data from Bloomberg terminal

One can see that the LNG trade volume which was sent against the price differential was quite substantial, meaning that, taking into account both transport cost and the trade margin (α=5%[14]), one would expect LNG to flow to Asia (lower left part of Figure 3) rather than to Europe (upper left part of Figure 3). Rogers and Stern (2014) put forth two possible explanations for this rather counterintuitive trade pattern:

1) The first is what they called '*the discriminating monopolist hypothesis*', which argues that LNG exporters have ability to differentiate between markets and sell essentially the same product at different prices to different customers according to their willingness to pay.
2) Their second hypothesis – '*the inertia hypothesis*' – is to do with the actual LNG industry setup: contractual rigidities in LNG long-term Sales and Purchase Agreements (SPA) and what they call the 'diplomatic/political constraints' of European importers, as well as logistical challenges to organising LNG diversions.

Thus, an LNG export strategy which conforms to the first explanation is to send LNG cargoes to Europe, even though the prices there are comparably lower than in Asia, in order to support higher prices in Asia. Indeed, in a perfectly competitive market setting, one should not expect to see such inefficiencies in trade flows. Ritz (2014) explained that this 'irrational' flow could result from LNG exporters having market power, or the ability to discriminate and differentiate between markets, and hence refrain from sending some of their cargoes to the high priced market (Asia) and instead forward these cargoes to the low priced market (Europe) in order to support the prices in the high priced markets. A rather closely related trade phenomenon is often observed in the electricity markets (see, e.g.,

[14] Based on conversations with gas traders

Newbery et al., 2014) and the pipeline gas trade (see, e.g., the UK energy regulator's call for evidence regarding gas trading between the UK and Continental Europe, see OFGEM (2012)), and this is sometimes called 'flow against the price differentials' or FAPD.

Thus, one can see (Figure 4) that such a strategy has been employed by those exporters, namely Qatar, Nigeria and Trinidad, whose geographical positions allow them to participate in both markets – Europe and Asia. The quantity of LNG flow to Europe which was supposed to go to Asia due to higher prices (we call such flows to Europe 'counter-flows') was rather substantial, accounting for about 20% of the total cumulative global LNG trade between 2010 and early 2015 (Figure 4). Other large exporters, like Australia, Indonesia and Malaysia, send all their LNG production to Asian markets only. This is due to their relatively close proximity to these markets: for them, the differences in transport distances do not justify 'counter-flows' to Europe. In fact, they can 'freeride' and rely on LNG exporters who have strong positions in both markets to support the high prices in Asia – their main export market.

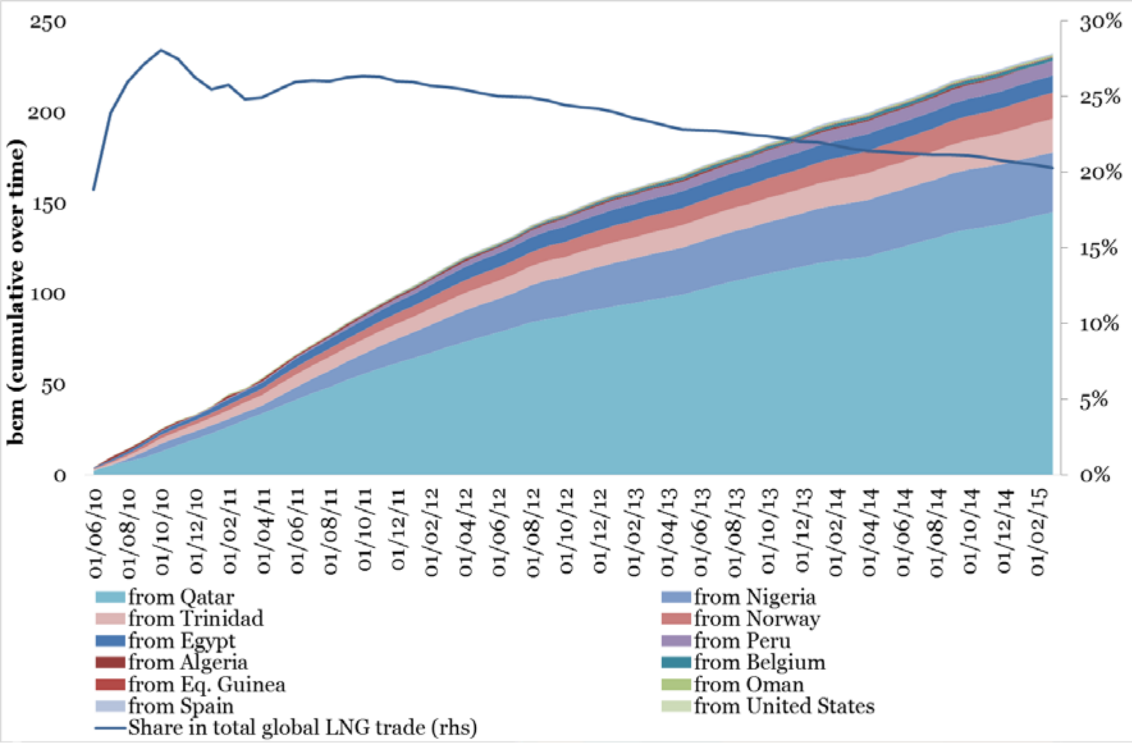

Figure 4: Cumulative LNG flows to Europe against price differentials
Source: authors' calculations based on data from Bloomberg terminal

Apart from strategic trade policy considerations, another reason why the price differentials are not fully arbitraged away could be contractual rigidities. For example, territorial restrictions (the so-called 'destination clause' in long-term LNG SPAs) and other contractual barriers or logistical issues (shipping re-direction, cargo replacement) can indeed make arbitrage a non-profitable venture, simply illegal or technically impossible (see paper by Zhuravleva (2009) for a long list of barriers to LNG arbitrage). In fact, contractual rigidity can partly explain the 'counter-flows' to Europe. Traditionally, LNG long-term SPAs are concluded under either so-called DES (Delivered Ex-Ship) or FOB (Free on Board) delivery conditions (Cogan, 2006). One crucial difference between the two types of contracts is the question of ownership of the gas. Under the DES agreement, the exporter owns the LNG cargo until it is unloaded at its destination point and from there the ownership is transferred to the buyer, whereas under FOB the buyer is the owner of the cargo once the vessel is fully loaded at the port of shipment (Wäktare, 2007). This has an implication for LNG arbitrage in that under a DES agreement the seller can enforce territorial restrictions, whereas under an FOB agreement such a restriction is difficult to oversee (Ashurst, 2009; Bruton and Morean, 2014; Robert and Hobbs, 2005). Hence, compared to the FOB condition, DES contracts are much more rigid and make LNG arbitrage almost impossible (Zhuravleva, 2009). As seen in Figure 5, majority of LNG 'counter-flows' to Europe are covered by LNG contract volumes under the DES condition; thus, we can conclude that the majority of 'counter-flows' can be explained by contractual rigidity.

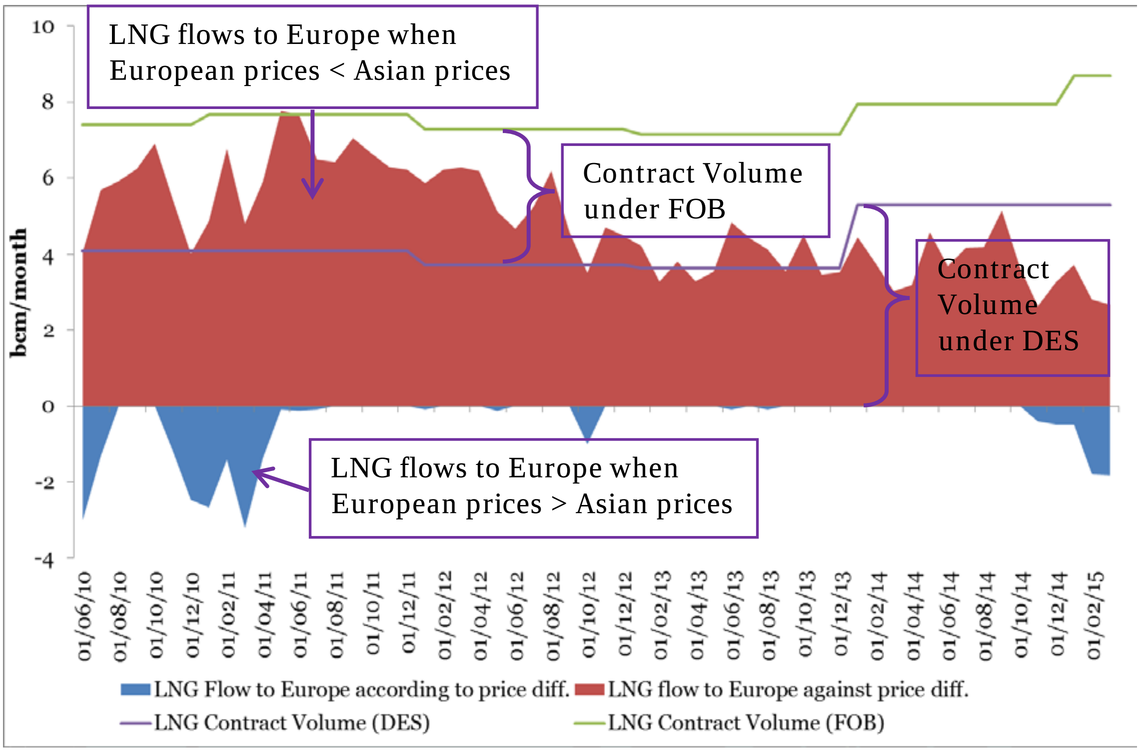

Figure 5: LNG contract volume to Europe vs. actual flows
Source: authors' calculations based on data from Bloomberg terminal

It is also worth noting that the volumes contracted under FOB have been gradually re-directed to Asia since the Fukushima accident (Mar-2011). This can be seen in Figure 5 – by the end of 2012 the 'counter-flow' volume to Europe was reduced to the total volume of LNG contracted under DES, and since then the counter-flow volume has been fluctuating around the DES volume, which is rigid and cannot be diverted to Asia. This later finding is in line with Rogers' and Stern's (2014) conclusion that '*...the pace of re-direction to Asia from Europe post Fukushima was effectively the most rapid possible*' (Rogers and Stern, 2014: p.14).

In the post-Fukushima period the price differential between Europe and Asia was so large – in some instances reaching more than $10/mmbtu in favour of Asian markets – that, to circumvent such contractual rigidity, European importers such as France, Spain, Belgium and the Netherlands have developed re-loading (re-export) capability in their LNG import terminals. This re-loading allows them to unload LNG cargoes and then load the same LNG on their carriers and export to Asia. One can assume that such unloading operations are designed to circumvent the 'destination clause' in DES contracts. Thus, European importers have re-exported in total more than 10 bcm in the last five years, of which 74% has gone to Asian markets and the rest to other European markets such as Greece, Italy, Portugal and Spain. However, compared to the total 'counter-flow' volume to Europe, the 10 bcm of re-exports is rather marginal (less than 10% 0f the cumulative counter-flows to Europe in the last five years; see Figure 6). Another point to note is that since destination clauses affecting European internal markets have been effectively removed by the European competition authority, re-direction from these countries to other European markets could only mean either cross-border physical capacity congestion between the terminals and these markets or that pipeline tariffs justify using reload operations and seaborne transport.

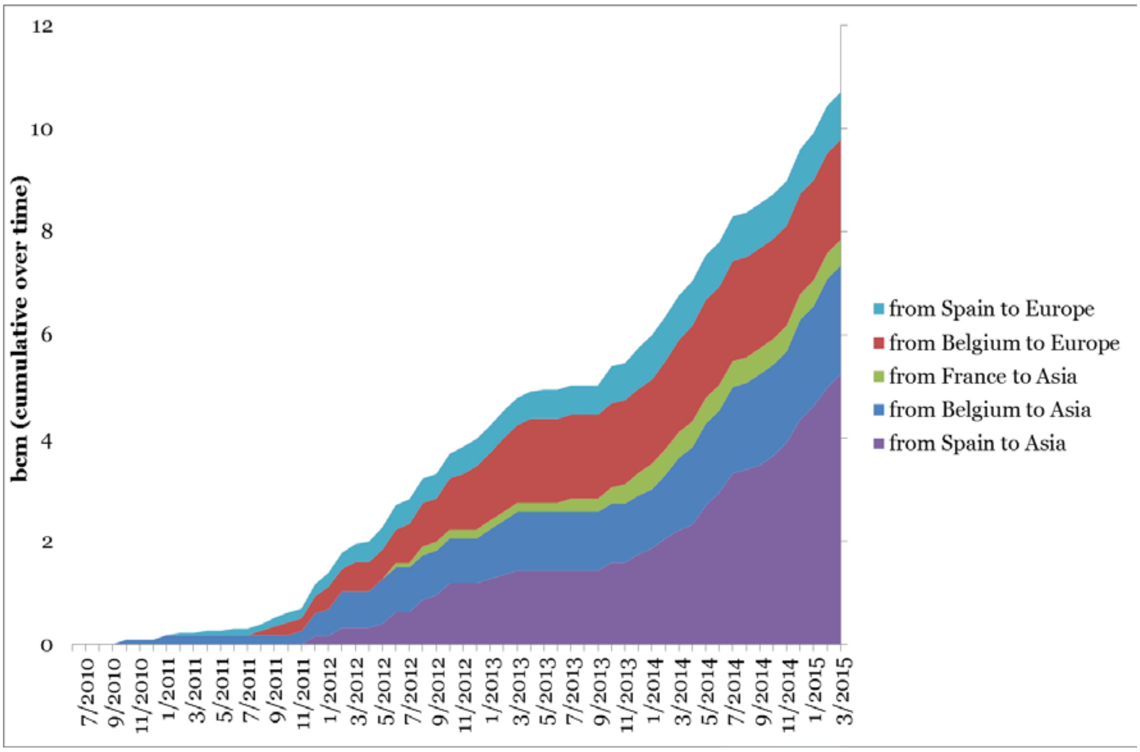

Figure 6: LNG re-exports by European importers to Asian and other European markets
Source: authors' calculations based on data from Poten and Partners LNG Database accessed through Bloomberg terminal

Although the contractual rigidity explanation seems justifiable, empirically (Figure 5 and Figure 6), this explanation can still be challenged from the bargaining perspective (Nash, 1953). If both parties to the contract – the buyer and the seller – can agree to divert cargoes and '*split the net gain*' from diversion (provided that such gain is actually positive, on this see Section 4.2-4.5), according to their bargaining power, then one should expect that, given large price differentials, contracted volumes could have been diverted to Asia. We come back to this important question in Section 4.5, where we analyse the profitability of various profit-sharing mechanisms to facilitate diversion of contractual volumes. However, to do this analysis we should model how diversion could impact regional prices, which is the focus of the next three sections.

4.2. Modelling the impact of LNG diversion on price differentials

In addition to the contractual issues, another barrier to diversion from Europe to Asia could be the price reactions in the two markets; in particular, the additional LNG flow to Asian markets could narrow down the price differential, thereby closing the arbitrage window rather quickly (see Rogers and Stern, 2014). Let us re-write eq. (1) to explicitly state that spot prices in Europe and Asia, as well as shipping costs, are a function of LNG volumes being diverted from Europe to Asia, μ:

$$\delta_i = p_e^S(\mu)[1-\alpha] - r_{i,e}(\mu) - [p_a^s(\mu) - r_{i,a}(\mu)] \tag{2}$$

Changing demand and supply conditions in the spot markets would of course alter prices; however, this would also alter shipping costs. For example, after the shutdown of all nuclear power plants in Japan, with its corresponding sharp increase in LNG demand and hence requirements for short-term and spot vessels, the charter rates for LNG shipping also increased considerably.[15] However, with increased diversion of contractual volumes the demand for spot vessels would decrease because LNG vessels are usually 'attached' to long-term contracted LNG volumes.

To assess eq. (2) we need to model a counterfactual scenario, one in which all LNG volumes that were sent to Europe in 2011-2014 could have been freely diverted to Asia. In particular, we need to model counterfactual spot price development in Asia and Europe as well as the impact of LNG diversion on the shipping rate. We outline our basic econometric models for assessing spot prices in Asia and Europe and also the LNG shipping rate below.

The Asian spot price specification as shown in eq. (3) reflects the fact that the spot market is predominantly used for balancing demand with long-term oil-indexed contractual offtakes and hence there is a link to the JCC oil price – the spot market in Asia is essentially a source of recourse for Asian buyers to balance their positions. Some immature hubs in Europe serve the same purpose – 'balancing hubs' (see Rogers and Stern, 2014: p.17; Miriello and Polo, 2015). Further, from about 2010, when the demand for LNG in Asia surged (see Rogers and Stern 2014), Asian spot prices began to escalate to a level close to oil-linked contracts. This process was exacerbated by the Fukushima accident in 2011 with additional calls for spot LNG due to the shutting down of the Japanese nuclear fleet. To reflect the relationship between demand and supply conditions and spot prices we hypothesised that spot prices are also a function of the ratio of LNG deliveries to Asian markets to global liquefaction capacity. Thus, we use a simple econometric model to assess the dynamics of spot prices in Asia in the following form:

$$p_{a,t}^s = \alpha^a + \beta_1^a JCC_{t-1} + \beta_2^a \frac{D_t^{JKTCI}}{L_t} + \varepsilon_t^a \tag{3}$$

where p_{at}^s is monthly average spot price in Asia, JCC_{t-1} is the average crude import price into Japan with a lag of one month[16]; $\frac{D_t^{JKTCI}}{L}$ is a ratio of monthly LNG deliveries to Japan, South Korea, Taiwan, China and India to global liquefaction capacity, L; ε_t is the error term.

[15] Authors' calculations based on data from Poten and Partners accessed via Bloomberg terminal

[16] There is an average lag of one month between Brent crude price and contract LNG price in Asia. See our discussion in Section 2

For the spot price in Europe, we analyse the impact of LNG diversion on spot pricing in Europe assuming two scenarios: (i) such a diversion could have impacted the way spot pricing evolved in 2011-2014, particularly reversing the trend of stronger spot-indexation and gas for gas competition, or (ii) no matter what might have happened to the flow of LNG to Europe and Asia, the pricing regime and dynamics established in Europe since about 2008 would remain unchanged (on the 2008 'cut-off' point in European gas industry, see Stern and Rogers, 2014). Here, we focus on the first scenario because if the second scenario is considered then we need to use the historical NBP price series for estimating the impact of LNG diversion on price differentials, assuming that it would impact Asian spot prices (eq. 3) and not UK NBP prices.

In a nutshell, our assumption in the first scenario is that diverting LNG to Asia would create a tight market in Europe, therefore weakening the position of buyers against traditional oil-indexed pipeline gas. Had the European markets not been flooded with LNG, European importers would have never been able to renegotiate their long-term contracts with traditional gas pipeline suppliers to introduce spot indexation and receive rebates and discounts from contract prices due to the increased market power of these suppliers. Similarly, Rogers (2012) argued that should we witness low gas production from North America coupled with high gas demand in Europe – that is, a tight gas market globally, including in Europe – European prices would be maintained by the market power of European pipeline suppliers rather than by gas on gas price competition. Thus, in a situation when LNG is re-directed to Asia, creating a tight market condition in Europe, structural breaks in the long-term relationship between the NBP price and continental European oil-indexed prices will not happen (see Koenig, 2012). Before the major waves of LNG influxes into European gas markets, and, in particular, into the UK market – at the end of 2008 – the NBP price was closely correlated to the continental gas price, which at that time was closely linked to oil product prices. In particular, according to Koenig (2012), before 2006, when LNG imports to both the UK and Europe started to increase, NBP prices had a strong long-term relationship with continental oil-indexed gas prices. However, this long-term relationship was weakened thereafter, and at the beginning of 2009 this relationship broke up completely, meaning that NBP prices have been completely decoupled from oil-indexed gas prices (see Koenig, 2012 for rigorous econometric proof of this pricing dynamic).

Thus, should the LNG that landed in Europe in 2011-2014 be diverted completely to Asia, we can assume that the spot price in Europe, p_e^S, in eq. (2), depends on oil-indexed contract prices in Continental Europe. In particular, the spot price in Europe is conjectured to be a function of the average German import price, AGIP, which is a well-known proxy for oil-indexed contract prices in Continental Europe (see Rogers and Stern, 2014). Thus, we assess the following relationship:

$$p_{e,t}^S = \alpha^e + \beta_1^e AGIP_t + \sum_{n=2}^{4} \beta_n^e X_n^e + \varepsilon_t^e \qquad (4)$$

where $p_{e,t}^S$ is the over the counter NBP day-ahead spot price, $AGIP_t$ is average German import price and X_n^e is a vector of dummy variables to account for: (i) seasonality effects (β_2^e), (ii) for the 'unusual' spike in the NBP spot price observed during the winter of 2005/06 (β_3^e) (see Howard, 2010), and (iii) for the effects of a temporary gas glut in Oct-06 until Jul-07 due to increased importation from the Langeled and BBL pipelines and the failure of the IUK to export the surplus to Continental Europe (β_4^e) (Poten, 2007). We assess eq. (4) using monthly data from 2001-2008, that is before the period of major price renegotiations in Europe (see Rogers and Stern, 2014 for details).

Based on the discussions and findings in Section 2.3, we use the following specification to model the shipping rate to Asia ($r_{a,t}$):

$$r_{a,t} = \alpha^{ra} + \beta_1^{ra} p_{a,t}^{s} + \beta_2^{ra} \frac{F_t}{V_t} + \varepsilon_t^{ra} \tag{5}$$

where r_t is the shipping rate measured in \$/mmbtu/1000 miles, p_t^S is the spot price in Asia, $\frac{F_t}{V_t}$ is utilization rate of shipping capacity defined as the ratio of total LNG flow in month t to total deadweight tonnage of all LNG vessels.

Also, the following speciation for the shipping rate to Europe ($r_{e,t}$):

$$r_{e,t} = \alpha^{re} + \beta_1^{re} p_{e,t}^{S} + \beta_2^{re} \frac{F_t}{V_t} + \varepsilon_t^{re} \tag{6}$$

where $p_{e,t}^S$ is the spot price in Europe and other variables are as above.

One should note that we have data for average shipping rates from major LNG exporters to Asia (Japan) and to Europe (UK). The average shipping rates therefore include both short-term (spot) as well as long-term charter rates. As noted in Section 2.3, charter rates, especially short-term spot rates, depend very much on spot prices, therefore we included spot prices in our specification (eq. 5-6). We also included utilization rate of shipping capacity to reflect the impact of overall shipping market dynamics on the long-term rates.

4.3. Results from econometric analyses

Detailed documentation of the data used for assessing the above regressions can be found in Appendix 1. The results of estimating eq. (3-6) are reported in Table 1 below. We should note some interesting insights from the results. First, the Asian spot price, as expected, is highly correlated with the JCC oil price and the 'slope' is slightly higher than oil parity (17%). All else being equal, this means that LNG in the Asian spot market is priced as a premium fuel. This is logical given that the spot market there serves as a balancing market, i.e., Asian buyers enter the spot market as a last resort when they need extra cargoes to meet their downstream obligations. This usually happens in periods of high gas demand (e.g., in winter) and hence there is very low price elasticity of gas demand or high willingness to pay. Furthermore, we found that every percentage increase in total LNG demand in the five largest Asian markets – Japan, South Korea, Taiwan, China and India – relative to global liquefaction capacity drives up spot prices by roughly \$1.33/mmbtu (β_2^a plus constant), all being else equal. Thus, the strong and high priced LNG market in Asia observed in 2011-2014 was a combination of the rise in oil prices as well as the rise in LNG demand, particularly in Japan as a result of the nuclear power shut-down after the Fukushima incident.

The results of the UK NBP model (column 2: Table 1) are consistent with results from other empirical studies (e.g., Koenig, 2012). In the period before structural breaks in the gas pricing regime in Europe (before 2008), the NBP price strongly tracked the continental oil-indexed price, AGIP, especially in the winter months, with a premium of

$0.028/mmbtu above AGIP, perhaps reflecting transport costs from the Continent to the UK and other transactional costs.

Table 1: Determinants of Spot Prices and LNG Shipping Rates

Regressors	Dependent Variable/Regression Models			
	$p^s_{a,t}$ (eq. 3)	$p^S_{e,t}$ (eq. 4)	$r_{a,t}$ (eq. 5)	$r_{e,t}$ (eq. 5)
	[1]	[2]	[3]	[4]
Constant	-14.552	-0.973	-0. 077	-0. 152
	(2.431)	(0.232)	(0.059)	(0.063)
β_1^a	0.175***			
	(0.014)			
β_2^a	15.880***			
	(3.142)			
β_1^e		1.028***		
		(0.033)		
β_2^e		0.882***		
		(0.182)		
β_3^e		5.348***		
		(0.413)		
β_4^e		-2.995***		
		(0.288)		
β_1^{ra}			0.012***	
			(0.001)	
β_2^{ra}			0.262***	
			(0.079)	
β_1^{re}				0.022***
				(0.004)
β_2^{re}				0.270***
				(0.080)
R-squared	0.774	0.935	0.645	0.511
Adjusted R-squared	0.766	0.932	0.632	0.494
No. observations	58	96	58	58

Standard errors are reported in parentheses; *** indicates significance at the 99% level

Further, as we expected, the dynamics of shipping rates in 2010-2015 were partly driven by commodity spot prices in Asia and Europe and partly by the state of supply and demand balancing in the shipping market itself (columns 3-4: Table 1).

4.4. Implications of LNG diversion for price differentials in 2011-2014

Taking the results from the econometric analyses presented above (Table 1) together, we can now estimate possible changes in price differentials (eq.2) between Europe and Asia in a counterfactual scenario where LNG could have been diverted. LNG diversion to Asia would mean that the demand for short-term and spot cargoes (both the LNG commodity and vessels) would be lower than was observed in 2011-2014. Thus, to simulate how LNG diversion could have impacted the spot price in Asia, we subtract the assumed LNG flow redirection from the variable D_t^{JKTCI} in eq. (3). Given fixed liquefaction capacity, additional LNG inflow to Asia would push down the ratio $\frac{D_t^{JKTCI}}{L_t}$ in eq. (3) and hence lower the spot price in Asia.

The assumed re-direction volume should correspond to an increase in short-term and spot purchases by Asian buyers in 2011-2014 (see Table 2 below) because these buyers have long-term offtake commitments that cannot be cancelled due to the standard take-or-pay condition in long-term LNG SPAs. As noted, the spot market in Asia serves as a balancing tool and any shortfalls in supplies are procured through spot and short-term agreements; hence, should redirection from Europe to Asia take place it would target short-term and spot volumes.

Thus, according to Table 2, short-term and spot purchases by Asian buyers totalled 179 mn tonnes of LNG, or 243 bcm[17], an average of 61 bcm per year in 2011-14. This roughly equals all the LNG volumes (ca. 232 bcm) that were sent to Europe in the same period, when prices in Asia were higher than in Europe (net of transport cost and trade margin of 5%: Section 4.1 and in particular Figure 4). Thus, to assess the impact of diverting cargoes on price differentials, we assume that the total LNG volume sent to Europe sent 'against the price differential' (the 232 bcm of LNG) is re-directed to Asia in 2011-2014 to meet increased demand for short-term and spot cargoes.

Table 2: Short-term LNG supplies to Asia (in MN tonnes of LNG)

	Total	Japan	South Korea	India	China	Others
2006	13.9	5.1	5.9	1.2	0.0	1.7
2007	20.7	7.9	6.2	4.0	0.4	2.3
2008	24.3	10.4	7.0	3.2	0.6	3.1
2009	15.7	5.8	2.5	4.6	0.9	1.9
2010	18.3	7.3	5.6	1.6	1.1	2.6
2011	37.3	16.0	10.7	4.2	2.2	4.3
2012	41.5	19.4	9.3	5.7	3.3	3.8
2013	48.5	21.7	11.0	5.5	3.9	6.4
2014	51.6	25.8	8.9	6.7	2.6	7.6

Source: calculations based on data in GIIGNL Annual Reports 2006-2014

As noted already, we consider two scenarios. In the first (i) LNG diversion does not allow price renegotiations and Europe sees higher gas prices linked to oil products (Figure 8: red line). In the second, (ii), in contrast, we assume that the diversion of LNG does not affect the pricing regime in Europe and hence we can use the historical NBP price series (Figure 8: green line) for our analysis.

Thus, in the first scenario, not only would the spot prices in Europe be coupled to oil-indexed contract prices but the contract prices (represented by AGIP) themselves would be 'purely' linked to oil product prices. The LNG influx, demand reduction and regulatory changes allow European importers to arbitrage between cheap spot prices and their oil-indexed contract prices, in particular allowing importers to renegotiate their long-term

[17] Assumed conversion factor: 1 mn tonnes of LNG equals 1.36 bcm of gas

contracts to introduce spot-indexation into contract pricing mechanisms (see Stern and Rogers, 2014). Stern and Rogers (2014) have explained these changes in Europe in great detail and in particular showed that, prior to 2009, the AGIP price closely followed the Brent crude oil price but this date it began to decouple from a pure oil-indexation formula, in particular to include cheaper spot prices (the NBP and TTF indices, for example). We use the formula provided by Stern and Rogers (2014) to calculate the pure oil-indexed AGIP based on gas oil and fuel oil prices (see Stern and Rogers, 2014: p.6) in our counterfactual scenario in which all LNG destined for Europe was hypothetically diverted to Asia. Thus, should one believe that the major reason for the decoupling of European spot prices from oil-indexed contract prices was the gas glut created by the influx of LNG, then the counterfactual NBP price series should be substantially higher than the real price series (Figure 8: compare green and red lines).

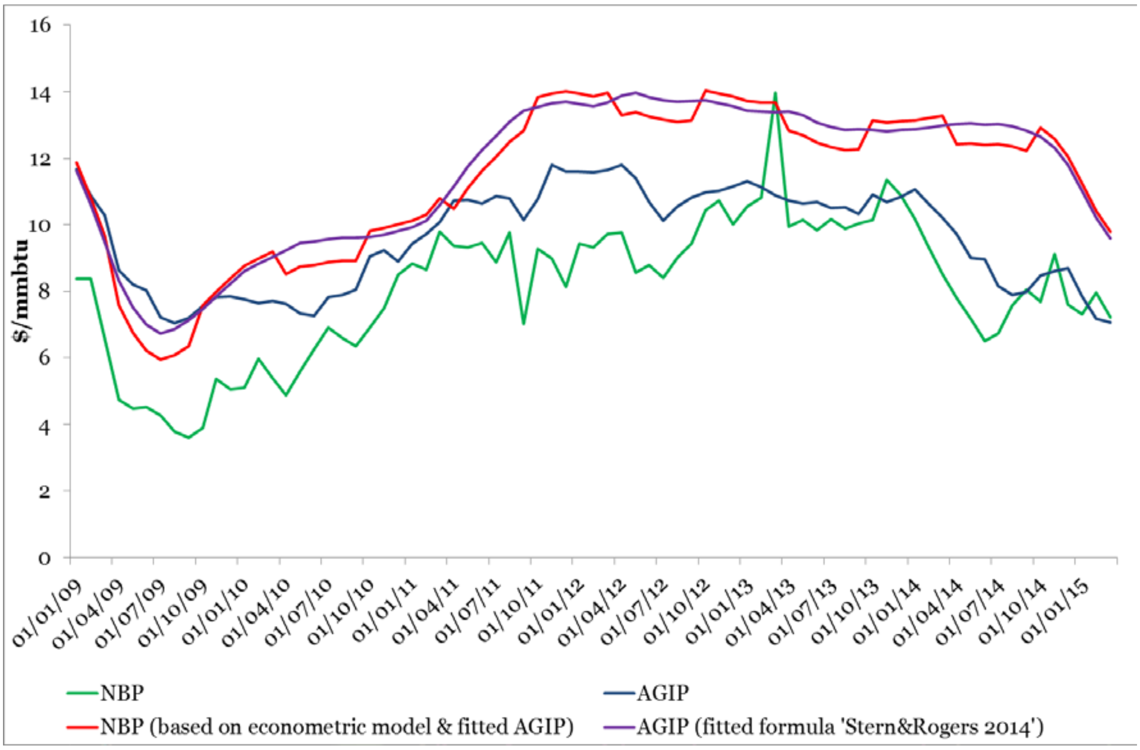

Figure 8: What could have happened to European spot prices (NBP) in a counterfactual scenario of LNG diversion to Asia.
Sources: fitted AGIP is based on the formula provided by Stern and Rogers (2014) and gasoil and fuel oil prices, NBP and AGIP (real price series), are from Bloomberg

Our results (See figures 9 and 10) suggest that diverting all LNG cargoes that were sent against price differentials to Asia would reduce spot prices in Asia while pushing up prices in Europe at the same time. Re-directing such a large volumes of LNG from Europe to Asia – 4.8 bcm/month or 232 bcm from 2011-2014 – would drastically change the picture: Europe would become a stronger market compared to the Asian market. Price differentials from the largest LNG exporters (Figure 9) would favour Europe over Asia. The implication of such a drastic reduction in LNG importation would be that Russian gas would have enjoyed a higher market share as well as higher profits because of the higher prices in this counterfactual scenario.

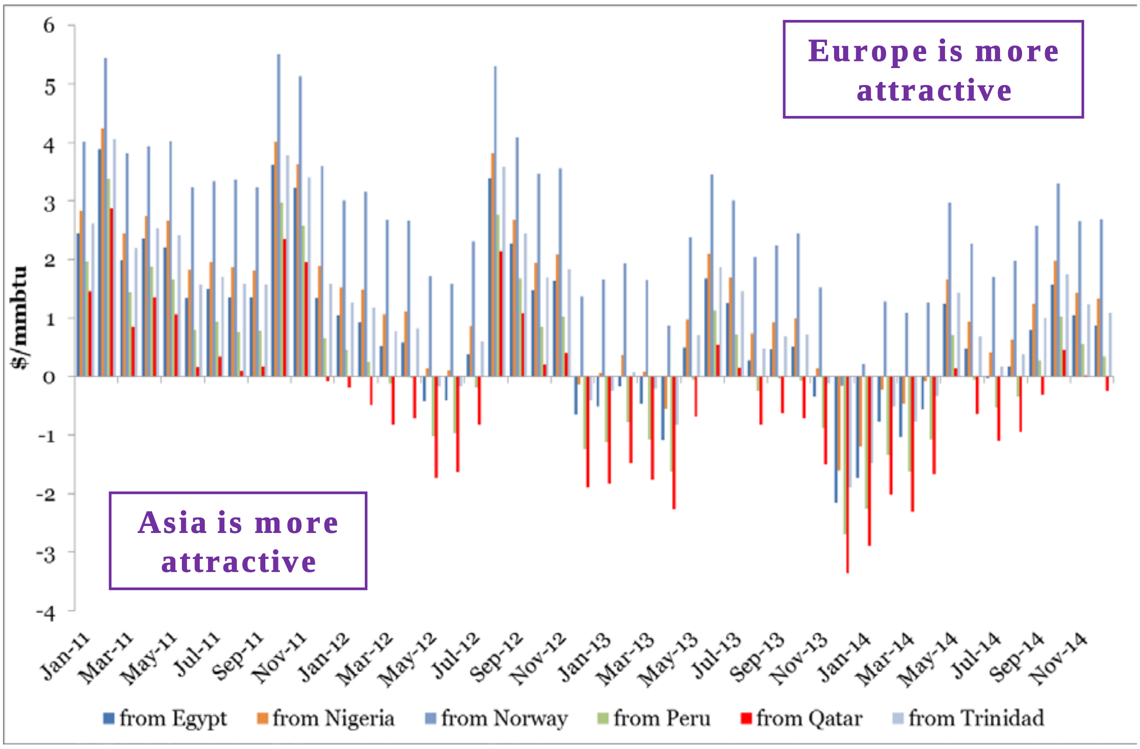

Figure 9: Price differentials under LNG diversion with implications for NBP prices

On the other hand, should the LNG diversion have no impact on the European pricing regime, the price differentials would still favour the Asian markets over European ones (Figure 10), even if all LNG were to be diverted to Asia. This is primarily because even though diverting all LNG to Asia would reduce Asian spot prices substantially, it was the low NBP price in Europe that kept the price differential positive for Asia. This suggests, amongst other things, that European markets were oversupplied, as well as the fact that the structural changes in the pricing regime in Europe allowed the region to enjoy substantially lower prices (Figure 11) than would otherwise have been the case.

Thus, it is not the potential downward pressure on Asian spot prices *per se* that would have closed the price differentials but rather the structural changes in the European markets would have been more important when considering LNG diversion. This is primarily due to high oil prices in 2011-2014. Also, had the structural changes allowing European prices to shift away (partially) from oil-indexation failed to take place, then the spot prices in Europe would have co-integrated with the high oil-linked gas prices (Figure 11: compare the green lines).

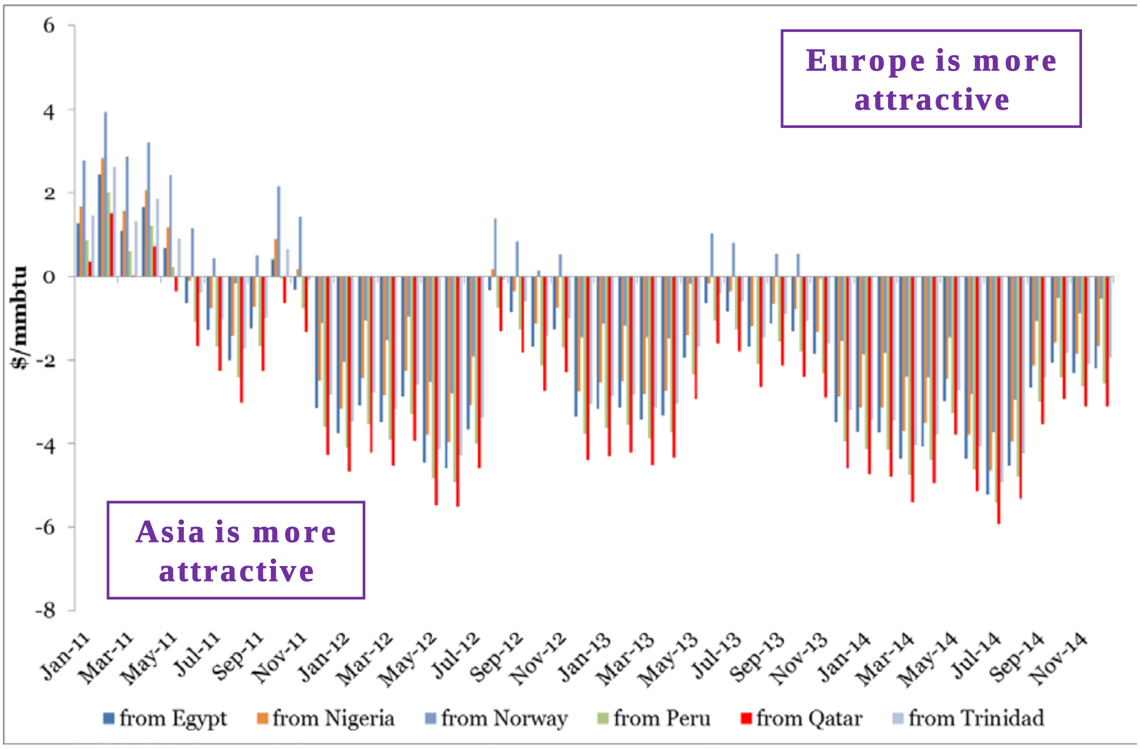

Figure 10: Price differentials under LNG diversion without implications for NBP prices

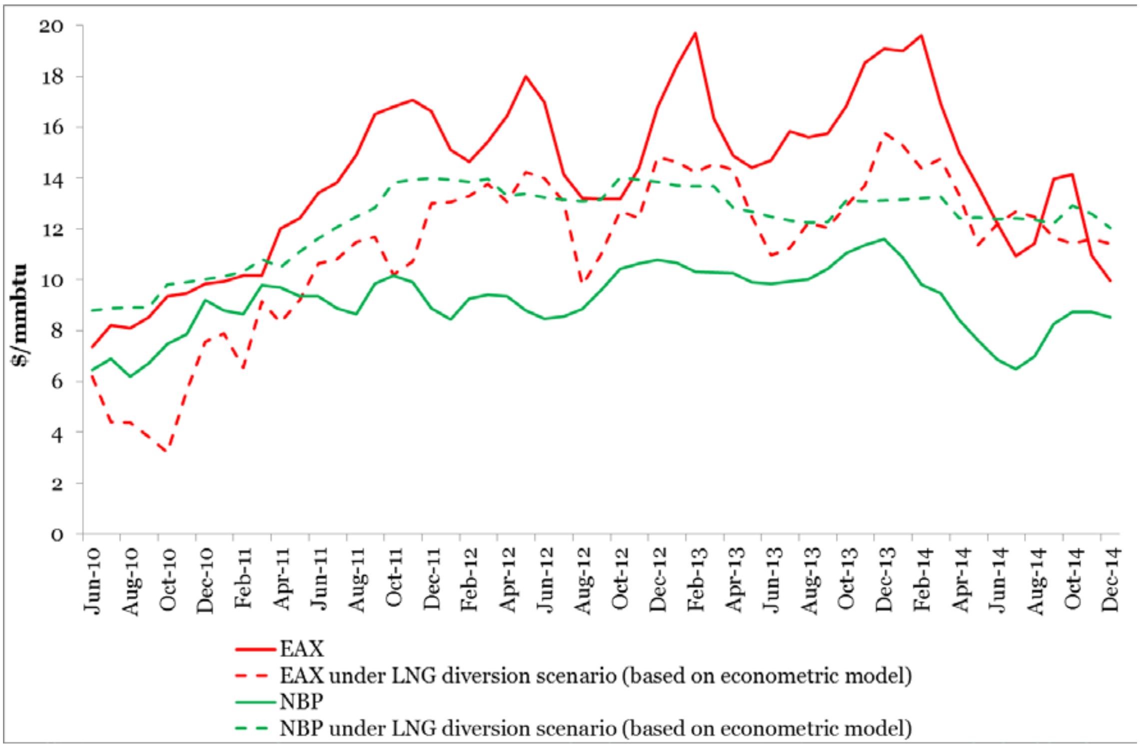

Figure 11: Spot prices in Europe and Asia under LNG diversion scenario vs. historical time series
Sources: EAX Price series – ICIS; NBP Price series – Bloomberg terminal

One should also note that the diversion of LNG would have also alleviated the pressure on the shipping rate (for example, the average shipping cost to Japan – see Figure 12) because such a diversion would use fewer spot and short-term vessels. Figure 12 shows that, irrespective of LNG diversion, both rates increased up until mid-2011, in line with the increase in shipping capacity utilization, reflecting a tight shipping market. Thereafter, the two cost lines deviate: under the diversion scenario the shipping rate would have been lower and would have instead stabilised at ca. $0.25/mmbtu/1000miles, which is roughly 40% less than the peak rate observed in mid-2012. Indeed, the increased demand for short-term and spot LNG cargoes increased the shipping rate between mid-2011 to early 2014, when the number of LNG vessels and total shipping capacity increased by ca. 9% compared to early 2011.

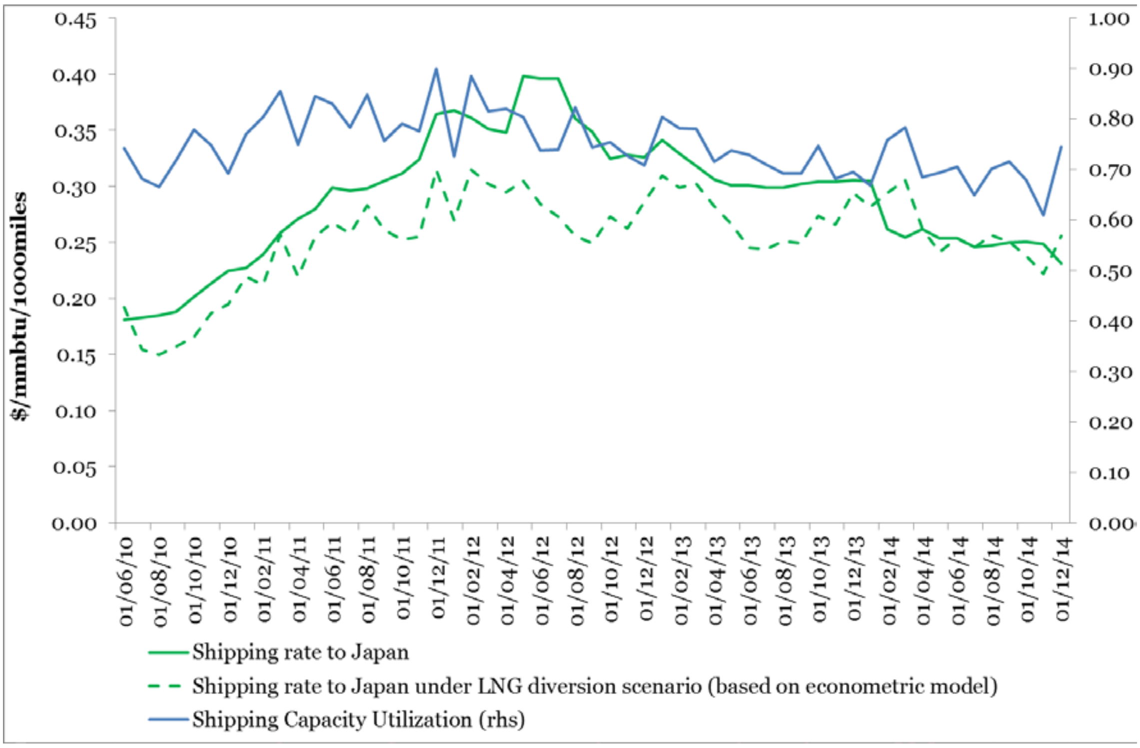

Figure 12: Average shipping cost to Japan under LNG diversion scenario vs. historical trend
Source: Shipping rate to Japan (real) and Shipping capacity utilization were calculated based on data from Bloomberg terminal

Most analyses of LNG trading focus on Asian pricing issues in way or another (Kate et al., 2013; Corbeau, 2014; Rogers and Stern, 2014; Hartley, 2015). However, one major conclusion from the above analysis is that the pricing regime in Europe, and in particular the possible effects of LNG arbitrage on price levels and structural changes in the pricing regime that took place after 2008 in Europe, are perhaps as important as spot pricing developments in Asia. If anything, this also suggests that it is not only LNG exporters who might behave strategically but also European importers – who might have strategic incentives to not arbitrage away price differences. Thus, an important policy question to consider is whether European importers behave strategically in LNG trading, for example by overinvesting in LNG regasification capacities and not fully diverting cargoes to Asia in order to 'counterbalance' the market power of traditional pipeline suppliers to Europe. We look at this issue in the next section.

4.5. The strategic rationale for not arbitraging away price differentials

As already noted, although LNG volumes under long-term contracts are more rigid, these volumes can in principle be diverted to another, higher priced, market provided that both the seller and the buyer of the original contract agree to such a deal. Irrespective of who initiated the arbitrage, the buyer, the seller or indeed an independent trader, the extra profit, net of transaction, logistical and other costs resulting from this diversion, must be shared between the parties to the original deal (Zhuravleva, 2009). This suggested '*split the net gain*' rule or, as it is often called in LNG sales and purchase agreements (SPAs), '*profit sharing (or splitting) mechanism*', from diverting LNG cargoes is a well-established contractual practice in LNG SPAs – see numerous anti-trust cases by the EC Directorate General for Competition (DG COMP) against pipeline gas and LNG suppliers in the 2000s (e.g., Nyssens et al., 2004; Nyssens and Osborne, 2005; Wäktare, 2007). We should, in particular, note the following issues that have come out of EC anti-trust cases against restrictive practices found in gas SPAs:

1. Territorial restrictions are illegal under EU competition law but only affect contracts between sellers and EU buyers and that affect the internal market of the EU.
2. With regard to the profit sharing mechanism, PSM, the competition authority has developed the view that:
    a. A PSM under the FOB condition is clearly a violation of buyers' rights (European) to use their 'property rights' (for LNG cargoes) and, as such, is a violation of EU competition law.
    b. However, a PSM that incentivises buyers under a FOB contract to divert cargoes is acceptable; in other words, if the PSM in a FOB contract restricts the buyer's right to diver cargoes, then it is in violation of competition law.
3. PSMs under DES and CIF conditions are not a restrictive practice as they do not violate the rights of buyers, and diversion under such contracts should be negotiated between the parties

Thus, it is most probable that the high price differentials between Asia and Europe could not be arbitraged away either because of territorial restrictions forbidding re-sales outside Europe contained in the DES LNG SPAs or because PSMs incorporated in the contracts made such diversion unprofitable for both parties. According to Nyssens and Osborne (2005), there are many variations of PSMs in LNG SPAs but they can be summarised into two groups according to their calculation procedures: (i) 'net PSM' and (ii) 'raw PSM'. Nyssens and Osborne (2005) explain that a raw PSM will necessarily limit competitive effects on the buyers' side because it limits buyers' incentives to divert cargoes. On the other hand, the authors explain that a net PSM will encourage buyers to re-export LNG, as this form of PSM will give them higher margin than with raw PSM. They also note that a raw PSM is not really a profit sharing mechanism since the mechanism measures the netbacks from the two markets to the exporter's location and divides the highest netback between the parties according to their bargaining powers.

One issue with the 'raw PSM' methodology is that the buyer cannot verify the upstream gas prices with certainty as part of the calculations. Also, from an economic standpoint, the margins that the parties can obtain by sticking to the original contract are their default positions, and they should pursue a diversion only if such a deal makes at least one of the parties better off without harming the profit of the other party relative to their default positions. A net PSM corresponds to this logic whereas a raw PSM violates this bargaining rationale. For practical reasons (such as the inability to know and verify upstream prices), the following analysis is based on the net PSM principle discussed in (Nyssens and Osborne, 2005). However, the principle is considered more completely than the example of a net PSM considered in (Nyssesn and Osborne, 2005) by taking into account the impact of diversions on prices as well as on the entire gas portfolio of exporters and importers. The latter point is especially important since we want to understand whether LNG diversion would impact (negatively) European importers' overall gas import portfolio and, in particular, their bargaining position vis-à-vis pipeline suppliers.

Let us consider a profit function, π_i, of LNG exporter, i, who is selling short-term and spot LNG to Europe, $x_{i,e}$, and to Asia, $x_{i,a}$, as well as long-term LNG supplies to Asia, $y_{i,a}$, such that:

$$\pi_i = x_{i,e}\left(p_e^s - t_{i,e} - c_i\right) + x_{i,a}\left(p_a^s - t_{i,a} - c_i\right) + y_{i,a}(P_a^K - t_{i,a} - c_i) \tag{7}$$

where p_e^s and p_a^s are the spot prices in Europe and Asia, correspondingly; $t_{i,e}$ and $t_{i,a}$ are the transport costs from exporter i to Europe and Asia respectively; without loss of generality let c_i be the constant long-run marginal cost to producer i; P_a^K is the long-term contract price in Asia, linked to oil prices.

Let μ_i be a positive quantity of LNG diverted from Europe to Asia such that:

$$\mu_i = x_{i,e} - x_{i,e}^* = -\left(x_{i,a} - x_{i,a}^*\right) = -(Y_e - Y_e^*) \tag{8}$$

where $y_{p,e}$ is imports of pipeline gas into Europe without LNG diversion and $y_{p,e}^*$ with LNG diversion. The condition in eq. (8) stipulates that any amount of LNG diverted from Europe, $x_{i,e} - x_{i,e}^*$, to Asia, $-\left(x_{i,a} - x_{i,a}^*\right)$, must be compensated for by additional purchases from pipeline gas suppliers, $-(Y_e - Y_e^*)$.

Thus, the profit of LNG exporters from diversion is:

$$\pi_i^* = x_{i,e}^*\left(p_e^{s*} - t_{i,e}^* - c_i\right) + x_{a,e}^*\left(p_a^{s*} - t_{i,a}^* - c_i\right) + y_{i,a}(P_a^{K*} - t_{i,a}^* - c_i) \tag{9}$$

where the asterisk (*) denotes variables and parameters related to an LNG diversion scenario.

The changes in profit for LNG exporters, $\Delta\pi_i$, is the difference between eq.(9) and eq. (7), and leveraging the definition in eq.(8) we have:

$$\Delta\pi_i = \left(x_{i,e} - \mu_i\right)\Delta\eta_{i,e} + x_{i,a}\Delta\eta_{i,a} + \mu_i\delta_{i,a} + \Delta\pi_{i,a}^K \tag{10}$$

where $\Delta\eta_{i,e} = p_e^{s*} - t_{i,e}^* - p_e^s + t_{i,e}$ is changes in netback price from i to Europe; $\Delta\eta_{i,a} = p_a^{s*} - t_{i,a}^* - p_a^s + t_{i,a}$ is changes in netback price from i to Asia; $\delta_{i,a} = p_a^{s*} - t_{i,a}^* - p_e^s + t_{i,e}$ is the price differential between Europe and Asia net of transport costs; $\Delta\pi_{i,a}^K = y_{i,a}(P_a^{K*} - t_{i,a}^* - P_a^K + t_{i,a})$ is changes in profit from selling LNG under long-term contracts to Asia.

It is helpful to distinguish between direct and indirect effects of LNG diversion on the profits of LNG exporters; thus, the direct effect on the profit of exporters is:

$$S_i = \left(x_{i,e} - \mu_i\right)\Delta\eta_{i,e} + x_{i,a}\Delta\eta_{i,a} + \mu_i\delta_{i,a} \tag{11}$$

The first term in eq.(11) is the positive effect on profits from selling residual LNG to Europe, the second term is the negative effect of selling more LNG to Asia and the last term is profit from arbitraging between Europe and Asia which should be shared between exporters and European importers. The direct positive and negative effects on the profit of exporters from diverting LNG come from the following facts:

$$\frac{\partial p_e^s}{\partial \mu_i} > 0 \text{ and } \frac{\partial p_a^s}{\partial \mu_i} < 0 \tag{12}$$

The conditions in eq. (12) are based on the fact that aggregate demand for spot LNG in each of the two markets – Europe and Asia – is negatively related to spot prices in those respective markets, which is a standard assumption for demand curves in economics problems. Thus, for example, a high μ_i drives up prices in Europe while lowering prices in Asia, all else being equal.

The term $\Delta\pi_{i,a}^K$ in eq. (10) is the indirect effect of LNG diversion on profit from long-term sales. LNG diversion might have a (negative) spill-over effect on profit from long-term sales to Asia because had the exporters flooded the Asian markets with spot LNG then this could have depressed spot prices to the extent that increased the likelihood that Asian importers would arbitrage between their long-term offtake position and spot market if the spot price was below their contract prices. All else being equal, such a scenario would negatively impact the profits of LNG exporters to Asia.

Assessing the impact of diversion on the profits of each European importer is more challenging because, in general, the number of buyers is substantially larger than the number of LNG exporters who could arbitrage between Europe and Asia. Thus, instead of calculating the impact of LNG diversion on each individual importer we evaluate the changes in the combined profit of all importers from re-selling the purchased gas in a number of European markets (details of these markets are below). Thus, the total profit from selling imported gas – both LNG and pipeline gas – to market m is:

$$\pi_m = P_m^f D_m - p_e X_e - p_e^K Y_e \tag{13}$$

where P_m^f is the final price in market m; P_e^K is the average long-term oil-indexed gas price in Europe (AGIP); $X_e = \sum_i x_{i,e}$ is total LNG imports into m; Y_e is total imports of pipeline gas; $D_m = X_e + Y_e$ is residual demand net of any domestic production, which must be met by importation from LNG and pipeline sources.

Following the same logic applied to LNG exporters, the changes in profitability of re-selling gas to market m in Europe when LNG cargoes are diverted to Asia is:

$$\Delta\pi_m = \left(P_m^{f*} - P_m^f\right) D_m - \Delta C_L - \Delta C_P \tag{14}$$

where, as before, the asterisk (*) denotes variables and parameters related to an LNG diversion scenario; $\Delta C_L = p_e^* X_e^* - p_e X_e$ is the change in costs of LNG imports; $\Delta C_P = p_e^{K*} Y_e^* - p_e^K Y_e$ is the change in costs of pipeline gas imports.

Furthermore, if:

$$\left(P_m^{f*} - P_m^f\right) D_m = \Delta C_L + \Delta C_P \tag{15}$$

then the extra cost resulting from diversion of cargoes can be fully passed onto final consumers and $\Delta\pi_m = 0$. However, should $P_m^{f*} = P_m^f$, meaning that the changes in the input costs of m are not passed through to final consumers, then these changes in importation costs should be taken into account in defining total net gains from LNG arbitrage.

We should also note that, similarly to the profit of exporters, there is an indirect (negative) effect of LNG diversion on long-term purchase costs for European importers: $\Delta C_P = p_e^{K*} Y_e^* - p_e^K Y_e$. Diverting cargoes to Asia would increase demand for gas from traditional suppliers ($Y_e < Y_p^*$) in Europe, thereby changing the pricing dynamics of established long-term contracts ($p_e^K < p_e^{K*}$) and hence the profits of all importers supplying market m. Had the European markets not been flooded with LNG, European importers would have never been able to renegotiate their long-term contracts with Russia, Norway and other pipeline suppliers, in particular to introduce spot pricing in the contracts and receive rebates and discounts on contract prices. Thus, two important issues to consider in modelling the impact of LNG diversion on European importers' costs are:

1. Are the European utilities able to pass on the input cost changes to final customers?
2. The reaction of pipeline gas suppliers to the diversion of LNG to Asia: in particular, will they exercise their increased market power and raise prices (P_e^{K*}) in the light of tighter gas markets in Europe?

Regarding the first question, with increased inter-fuel competition (coal vs. gas and renewables vs. gas in the electricity generation sector), as well as increased competition from new market participants due to the restructuring of gas markets to encourage more entry, we consider that importers would not be able to pass through the increased import costs due to LNG diversion. In other words, we assume: $P_m^{f*} = P_m^f$. As for the second question, as noted in previous sections, we consider that should LNG that was delivered to North-Western Europe be diverted to Asia, this could increase the market power of traditional pipeline suppliers and hence reverse the pricing regime in Europe to the pre-2008 period. Summing up the above, the total net gains from LNG arbitrage can be written as follows:

$$V = S_i + \Delta\pi_{i,a}^K + \Delta\pi_m \tag{16}$$

We assess V for LNG trading from three major LNG exporters to Europe – Qatar, Nigeria, and Trinidad and Tobago – to the largest European gas markets – the UK, Belgium, France, Italy and the Netherlands. We focus on these three LNG exporters as they are the major suppliers to Europe and their geographical positions allow them to arbitrage between these two regions. As for European markets, m, the UK, Belgium, France, Italy and the Netherlands are the most liquid and traded wholesale markets, and the LNG inflow has a dramatic impact on these markets. We did not include Spain in the analysis since the country is essentially 'disconnected' from North-West Europe due to a lack of interconnectors.

We should note that it is relatively straightforward to assess the direct effects of arbitrage on exporters' profit, S_i, using the results from our econometric estimation of prices and shipping costs (eq.3-6). However, assessing the impact of LNG redirection on exporters' long-term sales to Asia ($\Delta\pi_{i,a}^K$) and on European importers overall profit ($\Delta\pi_m$) is much more difficult without a detailed game-theoretic modelling of global gas markets which we leave for future research. Hence, we make some simplifications for the analysis (see below). The results[18] of estimating eq. (16) are reported in Table 3.

Diverting LNG to Asia would depress the spot prices there, creating economic incentives for Asian importers to demand renegotiations of long-term contracts, particularly to lower contract prices, possibly moving away from oil indexation and also introducing more flexibility in terms of importation volumes. Thus, from the perspective of large LNG exporters – Qatar, Nigeria, and Trinidad and Tobago – diverting more cargoes to the Asian market to enjoy higher revenues from short-term market imbalances could be seen as a risky business strategy due to possible indirect negative effects on the pricing and market structure of their long-term sales, which have been established in Asia for a rather long time. For example, a potential loss of profit from a hypothetical ten percent[19] discount off the long-term oil-indexed contract price for Qatar alone could have been $2.7 bn/year on average in 2011-2014 (column 22: Table 3), whereas for Nigeria and Trinidad this potential loss is marginal – ca. $0.14 bn/year and $0.03 bn/year respectively, primarily due to their marginal long-term position compared to that of Qatar.

Such a contract renegotiation process has happened to traditional pipeline exporters to European markets since about 2011-2012, and such a possibility is already looming in Asia with spot LNG traded below oil indexed contract prices. Recently, there have been several attempts by buyers in Asia to re-negotiate long-term contracts in the hope of reducing the take-or-pay volumes under existing contracts. China's state-owned energy giant Sinopec has attempted to delay its offtake from the APLNG project in Queensland, Australia. The Origin Energy-operated venture has contracted 7.6mtpa out of a total 8.6mtpa capacity to Sinopec under a take-or-pay contract due to commence in Q1 2016. The Chinese company, however, was unsuccessful in delaying its offtake. As the contract has no destination restriction, Sinopec is likely to seek an alternative market for at least some of its offtake from APLNG. The pricing chain can critically fail when a buyer commits to purchasing volumes on international markets, with the attendant implications of crude price volatility, and selling into a state-regulated downstream pricing environment.

India's state-owned LNG consortium Petronet, which operates the Dahej LNG terminal, concluded a 25-year supply deal with Qatari producer RasGas back in 2002. The contract was re-negotiated on several occasions, which resulted in Petronet paying for LNG on the basis of indexation to the last five years' rolling average of JCC prices. While this formulaic approach initially benefited the buyer when the clause came into effect in 2009, Petronet found itself in very precarious position in 2015 as the company was paying around $13.00/MMBtu for long-term volumes in a spot crude environment of $50.00/bbl. In contrast, Petronet's long-term deal with the Gorgon LNG project in Australia, which is expected to start production in 2016, is indexed to a crude basket based on a rolling average of the preceding year. This will result in prices of around $8.00/MMBtu on the basis of $50.00/bbl crude prices. The spot LNG prices for delivery to India in September were assessed at $7.85/MMBtu by ICIS on 4 August.

[18] Note that for our analysis we assume that all LNG to North-west Europe would be diverted to Asia, that is, $\mu_i = x_{i,e}$ and hence $(x_{i,e} - \mu_i)\Delta\eta_{i,e} = 0$ in eq. (11) and $\Delta C_L = 0$ in eq. (14).

[19] Similarly, it is believed that the Russian gas contract prices (the initial "P0") were reduced by 10% in some of its contracts with European importers.

As LNG is viewed as primarily a long-term business, producers are very reluctant to re-negotiate contract prices on the basis of short-term market moves. One prevailing trend which has emerged as a reaction to the high-priced crude environment back in the 2013-2014 period is attempts to diversify indexation mechanisms. Buyers in both India and Japan, for example, have been seeking long-term contracts linked to US Henry Hub futures gas prices. In addition, there are no guarantees for buyers that spot LNG prices will consistently remain below long-term contractual prices for the entire duration of existing contracts. Hybrid indexation therefore offers an opportunity to diversify risk exposure not only on the physical market but also in terms of hedging the risk via derivative products. The depth of the derivative market around Henry Hub gas futures is arguably the most liquid platform for managing hub-based indexation risk over the whole lifetime of a contract.

Thus, in addition to the potential loss of profit from long-term sales, diversion of LNG cargoes would also negatively impact the profit from spot and short-term sales to Asian markets due to lower prices there (column 28-30: Table 3). For Qatar, profit from short-term and spot sales could have decreased by $0.9 bn/year on average in 2011-2014. One should note that this negative effect of additional sales on spot prices in Asia is limited by (i) high oil prices in that period which drove the spot prices up in Asia (see eq.1 and Table 1), and (ii) spot and short-term sales of other more 'focused' LNG exporters to Asia, such as Australia, Indonesia, Brunei, Malaysia and Russia. Thus, the negative effect of LNG diversion for Qatar would total around $3.6 bn/year, whereas the additional profit from flow redirection (column 25-27: Table 3) would average $6.7 bn/year, giving a net gain of roughly $3.1 bn/year. Similarly, Nigeria would receive an extra profit of just under $0.5 bn/year. However, LNG diversion is not profitable for Nigeria since the net gain from such operations would average $-0.02 bn/year, primarily because of Nigeria's high exposure to short-term and spot sales in Asia relative to its overall export portfolio (under LNG diversion scenarios, the highest loss for Nigeria is lower profit from spot sales, column 29: Table 1).

In total, the combined profit for exporters and importers (sum of columns 22-30: Table 3) from LNG diversion in 2011 would have been ca. $4.8 bn. In 2012: $5.7 bn, in 2013: $0.3 bn, and in 2014: $1.8 bn. If one divides the total gain over 2011-14 by the total quantity being diverted (column 7-9: Table 3) and converts this into $ per million British thermal units one gets roughly $2.9/mmbtu of net gains, which must be shared between both exporters and importers. The rough estimates in Table 3 do not take into account cost items such as transaction and logistical costs, regasification fees – both operational and firm capacity payments – and other shipping-related fees such as ports and trespassing of canals and so on. Should one take all these cost items into the calculation profitability of such arbitrage opportunities, and the fact that these net gains must be shared amongst all parties to the contract, then the net gains may be minimal. Perhaps this also explains why the Spanish LNG importers engaged in re-loading (re-exporting) operations to avoid profit sharing with the original exporters.

We should note, however, that there are reasons why Asian buyers may not be able to renegotiate their contracts. This may, (i), be due to the so-called 'Asian energy security premium', which translates into a rather high willingness to pay for gas, and demand for long-term and stable supplies which results in relatively weaker bargaining positions vis-à-vis LNG exporters. Then, (ii), there is a lack of economic incentives to renegotiate contracts because the majority of LNG importation costs can be passed on to consumers. If this is the case, then we can assume that there will be no negative impact of LNG diversion on long-term oil indexed prices in Asia, that is, $\Delta\pi_{i,a}^{K} = 0$ in eq. (10), and therefore we can neglect columns 22-24 in our calculations. In this case, the profitability of LNG diversion for exporters would amount to the sum of columns 25-30 in Table 3: on average, Qatar would have received an additional profit of $5.8 bn/year in 2011-2014, Nigeria – $0.13 bn and Trinidad – $0.08 bn. This finding suggests, amongst other things, that the strategic behaviours of LNG exporters were 'suboptimal' and, taking all possible negative effects of LNG arbitrage on their short-term and long-term sales into account, sending more LNG to Asia in 2011-2014 would still add extra profit.

More importantly, the above insight suggests that perhaps it was not just LNG exporters who withheld LNG volumes from the Asian market by directing these volumes to Europe. It may also be the case that European importers behaved strategically by investing in LNG terminal capacity and importing LNG volumes to create liquidity on the spot markets, allowing them to renegotiate contracts with traditional gas pipeline suppliers. This is contrary to the currently prevailing view that importers have 'overinvested' in LNG capacity and that these import terminals are running at low capacity, and hence Europe should rely more on LNG imports to fill up these terminals and further diversify its gas import mix. These investments in LNG terminals should be viewed as a strategic bargaining option that European importers have developed to counterbalance the otherwise potentially larger pricing power of traditional pipeline suppliers. In our research interviews with government officials and private energy companies from North-Western European countries, the following thesis reoccurred rather often: every time European utilities sign a long-term contract with pipeline suppliers, they build an LNG terminal as a strategic (and cheap) option for keeping 'pipeline gas prices in check'.

As an example, those importers who have long-term contracts with Russia have clearly benefited from such market development. For example, if one multiplies the annual gas importation from Russia to Western European gas markets (Table 3: Column 10) by the differences between the two AGIP prices (columns 15-16: Table 3) one gets a total net saving of $7.1 bn/year on average or $28.4 bn in total in 2011-2014 (column 27: Table 3). These savings come only from Russian long-term contracts to six gas markets in Western Europe – Austria, Belgium, France, Germany, Italy and the Netherlands. Similarly, if one then takes into account the Norwegian gas sales to the same set of countries then the total savings are roughly $24.6 bn in the same time period (column 32: Table 3). Thus, the savings seem to clearly outweigh any extra profit for European importers from LNG diversion to Asia.

Thus, taking European importers' interests into account, because arbitrage would not be possible without the agreement of importers and given the potentially huge negative impact on their long-term pipeline gas import costs, diversion is not profitable for both sides. Total net gains (column 33, defined as the sum of columns 22-32: Table 3) are negative in 2011-2014 (Figure 13: blue line and Table 1: column 33). This suggests that European importers would lose substantially from diversion should LNG arbitrage impact their import costs and weaken their position vis-à-vis pipeline gas producers. One can see from Figure 13 that only Qatar could have benefited from LNG diversion and that neither the other two exporters nor importers would benefit from large-scale LNG redirection.

This is especially important for the five markets in Europe that we considered – if all LNG from the three largest exporters were to be re-directed to Asia then they would have to pay higher prices for pipeline gas, resulting in huge losses (columns 31-32: Table 3).

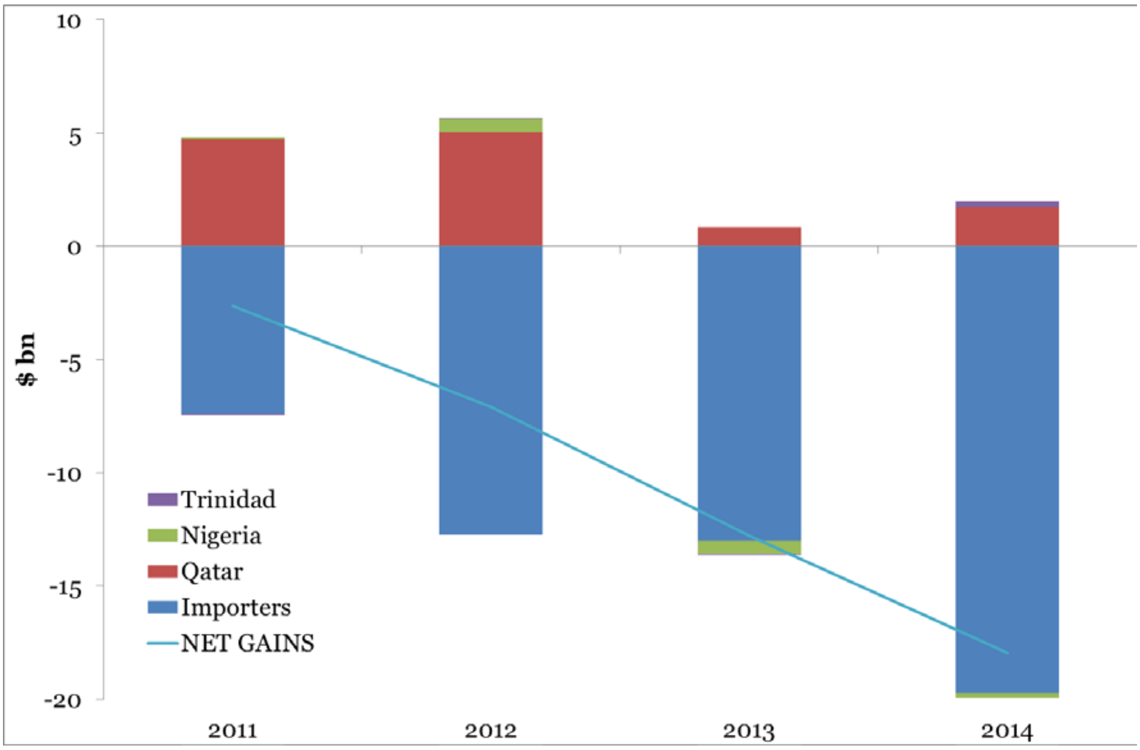

Figure 13: Distribution of net benefits from LNG diversion between exporters and importers

Table 3: Potential profit and losses due to LNG diversion to Asia for exporters and European importers

	LNG Sales (in mn tonnes)									Pipeline Gas Sales (in bcm)	
	Total to Asia			Short-term & spot to Asia			To Europe[a]			To Europe[b]	
From	Qatar	Nigeria	Trinidad	Qatar	Nigeria	Trinidad	Qatar	Nigeria	Trinidad	Russia	Norway
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*	*[11]*
2011	35.9	5.6	2.4	9.5	4.9	2.2	37.1	5.0	1.2	71.1	64.8
2012	47.9	9.4	1.4	11.9	8.0	1.1	26.2	3.3	0.3	65.1	73.4
2013	55.7	8.8	1.3	20.9	6.9	0.8	19.1	1.4	0.4	92.3	65.6
2014	54.7	10.4	0.9	17.7	7.3	0.4	20.1	1.3	1.6	84.0	68.4

	Prices (in $/mmbtu)						Shipping Rate (in $/mmbtu/1000miles)			
	In Asia			In Europe			To Europe (UK)		To Asia (Japan)	
	Contract price[c]	Spot, Reference case	Spot, LNG Diversion case	Contract Price (AGIP), Reference case	Contract Price (AGIP), full oil-indexation[d]	Spot price (NBP)	Reference case	LNG Diversion case	Reference case	LNG Diversion case
	[12]	*[13]*	*[14]*	*[15]*	*[16]*	*[17]*	*[18]*	*[19]*	*[20]*	*[21]*
2011	16.7	13.7	11.5	10.6	12.2	9.3	0.25	0.33	0.29	0.27
2012	17.5	15.1	14.5	11.1	13.7	9.4	0.31	0.36	0.36	0.30
2013	16.9	16.7	14.4	10.8	13.1	10.5	0.27	0.33	0.31	0.29
2014	16.1	14.0	13.8	9.1	12.8	8.4	0.21	0.31	0.26	0.27

	Potential changes in profit from LNG diversion to Asia (in $ bn)											
	For exporters			For exporters & importers			For exporters			For importers		**Net gains (V)**
	due to 10% discount off the long-term price as in [12] ($\Delta\pi^{K}_{i,a}$)			due to LNG diversion to Asia ($\mu_i\delta_{i,a}$)			due to lower spot prices in Asia ($x_{i,a}\Delta\eta_{i,a}$)			due to higher import prices in Europe (ΔC_P)		
From	Qatar	Nigeria	Trinidad	Qatar	Nigeria	Trinidad	Qatar	Nigeria	Trinidad	Russia	Norway	
	[22]	*[23]*	*[24]*	*[25]*	*[26]*	*[27]*	*[28]*	*[29]*	*[30]*	*[31]*	*[32]*	*[33]*
2011	-2.15	-0.05	-0.01	7.9	0.7	0.2	-1.0	-0.5	-0.2	-3.9	-3.5	-2.7
2012	-2.56	-0.08	-0.02	7.8	0.7	0.1	-0.2	0.0	0.0	-6.0	-6.8	-7.1
2013	-2.80	-0.15	-0.04	6.0	0.3	0.1	-2.3	-0.7	-0.1	-7.6	-5.4	-12.8
2014	-3.30	-0.29	-0.04	5.3	0.3	0.3	-0.3	-0.1	0.0	-10.9	-8.9	-17.9

Notes: the calculations for columns 22-33 are based on equations listed in this section: *[33]=[22]+[23]+…+[32]*; the conversion factor from millions tonnes of LNG to mmbtu is *52* and from bcm to mmbtu is *35310734.5*; [a] reported LNG quantities are those sent against the price differential to the UK, Belgium, Netherlands, France and Italy; [b] importation to Austria, Belgium, France, Germany, Italy and the Netherlands; [c] proxy for long-term LNG oil-indexed contracts in Asia = *14.85%*JCC+0.5* (BG, 2015); [d] for the AGIP proxy formula for full oil-indexation see paper by Stern and Rogers (2014: p.6)

Sources: see Appendix 1 on data and sources used for estimating prices under LNG diversion scenarios; the rest of the data is taken from Bloomberg terminal

5. Conclusions

One of the objectives of this study is to understand limitations and obstacles in relying on LNG to fill shortfalls in supplies or to meet peak demand in Europe. Although upstream LNG capacity[20] and European terminal capacity is sufficient currently (and going forward) to fill the gap, unlike pipeline gas, a response from LNG producers to any shortfalls of demand or new market opportunities will take time and logistical accommodation. In a recent EC consultation paper regarding regulation on the security of gas supply (EC, 2015b), it was found that the European gas industry has expressed reservations concerning relying on LNG to fill supply shortfalls or to meet peak demand. One reason for this pessimism is that, on average, it would take at least two weeks to attract an LNG cargo[21]. Our analyses also suggest that, due to the specifics of LNG technology and the industry setup (long-term contracts with inter-regional destinations and other contractual clauses impeding interregional trade), relying on the LNG industry as a source to meet shortfalls is less attractive than pipeline gas. LNG production is limited by the export capacity of existing LNG projects as well as outstanding long-term contractual commitments that are prioritised over short-term sales (which, as we found in Section 4.5, could be rather significant from an economic standpoint). While flexible volumes, which include both spot and incremental sales, accounted for about 26% of total production sold in 2014, this number could increase slightly in the short-term. However, this amount would depend on the strength of recovery of gas demand elsewhere and ramping up of export infrastructure in a low oil price environment.

Furthermore, the limitations of LNG across Europe include issues such as vessel compatibility, interconnection across terminals, port congestion, injection rates and gas quality issues. Any drastic response to European supply short-falls on the short-term LNG market could warrant a rapid price response, such as that seen in Japan on the back of the nuclear disaster in Fukushima. This means that drastic replacement of pipeline volumes by LNG is possible if hub prices trade significantly above long-term contractual prices. While upgrade works are in place across several terminals in Europe, LNG's role has traditionally been seen as supplemental to pipeline volumes there. This differs drastically from markets in Japan and South Korea, where LNG is the primary fuel and supplemented by other energy carriers, such as coal, crude and crude-products. Moreover, while interconnection is relatively advanced in Northwest Europe, it is highly underdeveloped in Southern, Central and Eastern Europe. Flows between the north and south of France are at present constrained, which de facto results in two regional markets. Flows between Spain, France and Portugal are also constrained. Spain, the market with most LNG import terminals, markedly lacks advanced pipeline interconnection with other European markets. Therefore, while LNG can offset some of the shortfalls that might emerge on the back of interruptions to pipeline supplies from Russia, such replacement is currently rather limited, although this situation could change as early as mid-2016 with the ramping up of LNG production in Australia and other sources.

[20] For example, we consider that the Qatari state-owned LNG producers – RasGas and Qatargas – could also increase flows to European customers should hub gas prices be attractive. Both producers currently have underutilized shipping capacity as well as significant reserves to direct LNG flows to Europe.

[21] The last known shortfall in gas supplies through Ukraine in 2009 lasted just over two weeks in total.

Due to mid-stream constraints, the LNG market cannot offer the same level of short-term flexibility as pipeline gas or crude markets given its technical and operational constraints. The vast majority of LNG tonnage on the water today is committed to servicing long-term contracts. Operationally, the arrival and discharge of an LNG carrier requires advance notice, reservation of a slot at the terminal, and arrangements with port and coastal authorities well ahead of discharge, particularly around congested maritime points. Out of around 400 LNG tankers in operation today, only around 30 are available for spot trading as of August 2015. This availability is likely to shrink further as some vessels are awaiting the starting-up of the long-term projects for which they were built. Charter rates grow dramatically in a bull market to over $100,000/day and drop to below the operational-cost level of $20,000-25,000/day in bear markets. There is no mechanism to ensure that sufficient tonnage will be available in a market facing a severe demand crisis. Re-directing a vessel from a long-term project to spot trading typically requires a buyer to absorb optimisation costs. In fact, LNG is probably the most expensive commodity to transport when the mid-stream is reflected as a percentage of the cargo's costs.

In operational terms, the conclusion of spot LNG transactions typically requires several days to complete due to the complexity of credit terms. Therefore, LNG has never been a commodity of choice in terms of fast reactions to energy crises. The relative liquidity and operational simplicity of coal, crude oil and crude products is likely to keep LNG as a secondary choice for buyers with access to crude-fired and coal-fired power generation capacity. Some buyers, however, are entirely dependent on gas-fired power generation capacity and, therefore, have no recourse but to attempt to import LNG despite the costs. This was seen in Japan after the Fukushima incident, although most utility buyers have prioritised coal and oil products.

In the long term, the LNG market is very likely to offer more flexibility. The LNG market is set to grow with the onset of export projects in North America, Australia, Africa and Russia. Importers are being presented with more flexible contractual options that will allow diversions to take place more easily than they are now. In terms of technology, ship-to-ship transfer, floating storage and regasification units (FSRU), as well as small-scale LNG projects and ships are bound to dramatically change the market past 2020. New options will allow a greater level of flexibility and carry the potential to move LNG to the forefront of response options in a potential crisis.

Apart from these current operational and logistic constraints, our quantitative analyses also suggest moving away from stressing the importance of LNG for security of supply, which in policy makers' minds equates to its ability to meet physical shortfalls in supplies in Europe. To secure gas supplies against possible disruptions of pipeline gas LNG could be an option but it is merely the only one. There are other policy options which may be easier to implement and/or more cost-effective and these policy options depend on national context (energy mix, gas consumption structure and so on; for details see e.g., Silve and Noël, 2010; Findlater and Noël, 2010; Noël et al., 2013). Thus, instead, LNG should be viewed as both a means of delivering a short-term diversification option to Europe in an oversupply environment and, more importantly, as a strategic negotiation chip for use with pipeline gas suppliers. In this regard, the results of our analysis showed that, by investing in LNG import terminals as a way of attracting cargoes as an option to strengthen their bargaining power against pipeline gas suppliers, European importers gained more than would have been gained by diverting all LNG cargoes to Asia.

Thus, enforcing a vision of LNG playing an important role in the EU gas mix could bring benefits in terms of giving more bargaining power to European companies against their pipeline suppliers. However, this would also make European markets stronger than without such an explicit LNG strategy commitment and thus call upon LNG exporters to behave strategically. For example, in a hypothetical scenario in which there are significant shortfalls in gas supplies LNG exporters could theoretically decide not to deliver too much gas into the European grid while dumping more gas in Asia to support high prices in Europe – a sort of 'Fukushima in reverse'. The flipside of this LNG strategy is that Europe would then need to keep its other supply options, including all pipeline options, 'open' to counterbalance the power of LNG sources. Another implication of greater reliance on LNG could be the re-introduction of greater linkages between hub prices with oil product prices, should Asian markets preserve oil-indexed pricing systems[22]. This would make European energy prices more volatile given a more responsive oil supply from North America in the form of unconventional oil and gas.

There are therefore implications for European importers and utility companies in terms of how to operate in such environment. The increasingly uncertain world of energy markets – both gas and electricity – calls for European energy utilities to have a more robust and flexible business strategy. In the old days of European energy markets, a traditional hedging strategy of utilities and 'midstreamers' was tailored, bilateral long-term contracts with producers in the upstream and distributors in the downstream sectors. With the development of liquid markets in North-West Europe and increased uncertainties and volatilities, one hedging strategy is to develop and further strengthen energy trading capabilities at the wholesale level, coupled with diversification into LNG and other gas and non-gas energy options as an alternative to traditional, rigid, bilateral long-term contracts. A recent example of a move in this direction is the restructuring of the business model of some European utilities. For example, one large European utility company decided to make its trading arm the interface between upstream and downstream assets (physical and contracts), while the department which used to deal with '*special and strategic relationships*' with upstream gas producers (such as Russia) has lost its prominence and importance in the new energy business realities in Europe[23].

Lastly, we should also note some limitations of this paper which deserve follow up research efforts. One direction for assessing the implications of more interlinkages between Europe and global gas markets more rigorously is a comprehensive econometric analysis of determinants of spot prices dynamics in Europe (short-term dynamics). Secondly, the analyses of economic incentives in LNG trading between Europe and Asia deserve separate research using a game-theoretic global gas market model to examine the impact of short-term arbitrage on the entire energy trade portfolios of upstream producers and importers in both Europe and Asia.

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[22] In addition to Asian oil-linkages, the issue with boil off in LNG shipping and the so-called on-board arbitrage between oil and gas prices to run LNG ships could mean stronger linkages between gas and oil should LNG trade dominate over pipeline gas trading.

[23] Insight based on our conversations with leading utilities in Europe. Note that Noël (2009) concluded that the emergence of a single European gas market, where national markets would be integrated through pan-European competitive trading, would significantly reduce the energy security and foreign policy implications of the EU-Russia gas relationship.

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Appendix 1: Data and sources

We estimate eq. (3-6) based on data obtained from publicly available and subscription-based sources such as Bloomberg and ICIS Heren (Table A1 and A2).

Table A1: Data description and sources

Variables	Comments	Sources
$p_{a,t}^{s}$	Monthly average of daily spot price in Asia [$/mmbtu]	East Asia Index (EAX) provided by ICIS Heren information provider
JCC	Monthly average of all crude prices imported into Japan, as reported by the Japanese Customs Authorities [$/bbl]	Bloomberg terminal
D_t^{JKTCI}	Total monthly inflows of LNG into Japan, South Korea, Taiwan, China and India [bcm/month]	Poten and Partners LNG Database access via Bloomberg terminal
L_t	Total global liquefaction capacity [bcm/month]	Bloomberg terminal
$p_{e,t}^{s}$	Monthly average of daily NBP day-ahead price [$/mmbtu]	Bloomberg terminal
$AGIP_t$	Monthly Average German Import Price as reported by BAFA – German Federal Office for Economic Affairs and Export Control [$/mmbtu]	Bloomberg terminal
$r_{a,t}$	Average shipping rate from all LNG exporters who send at least one cargo to Japan in the period June 2010 – March 2015 [$/mmbtu/1000 mile]	Poten and Parners LNG Database accessed via Bloomberg terminal
$r_{e,t}$	Average shipping rate from all LNG exporters who send at least one cargo to the UK in the period June 2010 – March 2015 [$/mmbtu/1000 mile]	Poten and Parners LNG Database accessed via Bloomberg terminal
F_t	Total global LNG flows [bcm/month]	Poten and Partners LNG Database accessed via Bloomberg terminal
V_t	Total global LNG shipping capacity [bcm/month]	IHS Database accessed via Bloomberg terminal

Table A2: Descriptive Statistics

	$p^{s}_{a,t}$	JCC	D^{JKTCI}_{t}	L_t	$p^{S}_{e,t}$	$AGIP_t$	$r_{a,t}$	$r_{e,t}$	F_t	V_t
Mean	13.75	103.86	18.37	28.86	5.64	6.07	0.28	0.25	27.38	36.72
St. Error	0.45	2.08	0.30	0.12	0.34	0.28	0.01	0.01	0.26	0.26
Median	14.27	110.59	18.03	29.12	4.46	5.36	0.30	0.26	27.09	36.26
Mode	N/A	N/A	N/A	29.12	N/A	4.04	0.30	0.20	N/A	36.06
St. Dev.	3.45	15.85	2.30	0.92	3.32	2.76	0.06	0.05	1.98	1.95
Sample Var.	11.93	251.32	5.28	0.84	11.04	7.64	0.00	0.00	3.90	3.82
Kurtosis	-0.85	1.73	-0.49	3.74	-0.05	-0.23	-0.63	-1.02	-0.03	-0.19
Skewness	-0.28	-1.44	0.16	-2.35	1.03	0.89	-0.10	-0.06	0.15	0.81
Range	12.96	77.42	9.36	3.00	12.53	9.92	0.23	0.18	9.36	7.11
Min.	6.76	49.54	13.82	26.41	1.51	3.01	0.17	0.15	22.83	33.96
Max.	19.71	126.96	23.17	29.41	14.04	12.93	0.40	0.34	32.19	41.08
Sum	797.39	6023.83	1065.29	1674.01	541.57	582.31	16.50	14.35	1587.84	2129.97
Count	58	58	58	58	96	96	58	58	58	58
Conf. Level (95.0%)	0.91	4.17	0.60	0.24	0.67	0.56	0.02	0.01	0.52	0.51