A Petroleum Tanker of a Different Color: Obstacles to an LNG-based Global Gas Spot Market

Jeff D. Makholm, Ph.D.
National Economic Research Associates, Inc.
jeff.makholm@nera.com
+1 617 927 4540

Laura T. W. Olive, Ph.D.
National Economic Research Associates, Inc.
laura.olive@nera.com
+1 617 927 4588

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Abstract

The production of unconventional gas has driven North American gas prices down to a fraction of those in the EU for more than seven years, representing a wedge in commodity gas prices approaching $100 billion per year between these two largest global gas markets. Will a spot market trade in oceangoing liquefied natural gas (LNG) serve to balance those huge gas cost differences in a global gas market, as oceangoing crude oil trade does for oil markets? Such is unlikely. First, the cost of maritime LNG transport is far greater and more capital intensive at fixed locations than for crude oil (150 percent of the cost of competitive US gas costs in 2016 versus 4 percent for oil). Second, the regulation of the gas industry in major international markets outside of North America effectively precludes competitive entry of any supplies, whether imported LNG or new domestic unconventional production from evidently-widespread and abundant worldwide shale gas basins. As a result, gas price formation in markets outside North America remains tied to oil equivalents, rather than the prices evident in North America that are driven by production costs plus competitive transport. Given its high cost and the uncertainties in reliably gaining competitive access to customers, LNG trade, as large and growing as it is, will likely remain dominated by long-term price and supply contracts instead of the competitive commodity spot markets that typify world oil markets.

Keywords: Liquefied Natural Gas; Oil; Institutions; Asset Specificity; Transactions Costs

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Introduction

Natural gas is widely considered to be the bridge fuel to a lower carbon planet.[1] The fuel—methane (CH_4) with only one carbon atom per molecule—has the lowest per-unit carbon emissions of any fossil fuel. But while it is clean as a fossil fuel and highly useful in particular applications (like home heating, petrochemicals, and efficient power generation with modern combined-cycle power technology), it is inconvenient to transport, requiring expensive and immobile pipelines to even the smallest consumers. Barges, rail cars, and road-based oil tankers that move much of the world's liquid petroleum, particularly in the last stage of transport to consumers, do not work for gas. Gas requires either dedicated pipelines or, if moving liquefied natural gas (LNG) over the oceans in about 1/600th the volume of its gaseous state, highly capital-intensive liquefaction, specialized shipping, and regasification equipment.

The lack of practical non-pipeline transport for gas, combined with the high capital cost of LNG, means that the kind of competitive worldwide spot markets that exist for oil (or for other bulk commodities, such as coal and grain) have not formed for gas. Worldwide crude oil prices indexes tend to follow each other, and each is a center for both spot and robust forward crude oil markets—indicating the willingness of financial markets to trade in the price risk associated with future crude oil deliveries. There is no such worldwide price of gas—quite the contrary. Over the past seven years, apart from transport, Europeans have paid roughly three times what North Americans paid for their gas—amounting to almost $600 billion.

Such lasting price differences, coupled with the impending entry of the United States and Canada as a major exporters of LNG from unconventional gas production, invites the question of whether new global LNG trade can balance supply and demand to produce worldwide competitive spot prices, separated only by the cost of shipping. There are reasons to be doubtful that it can. First, unlike crude oil, gas must be transformed to be shipped over such long distances—a very costly and capital-intensive

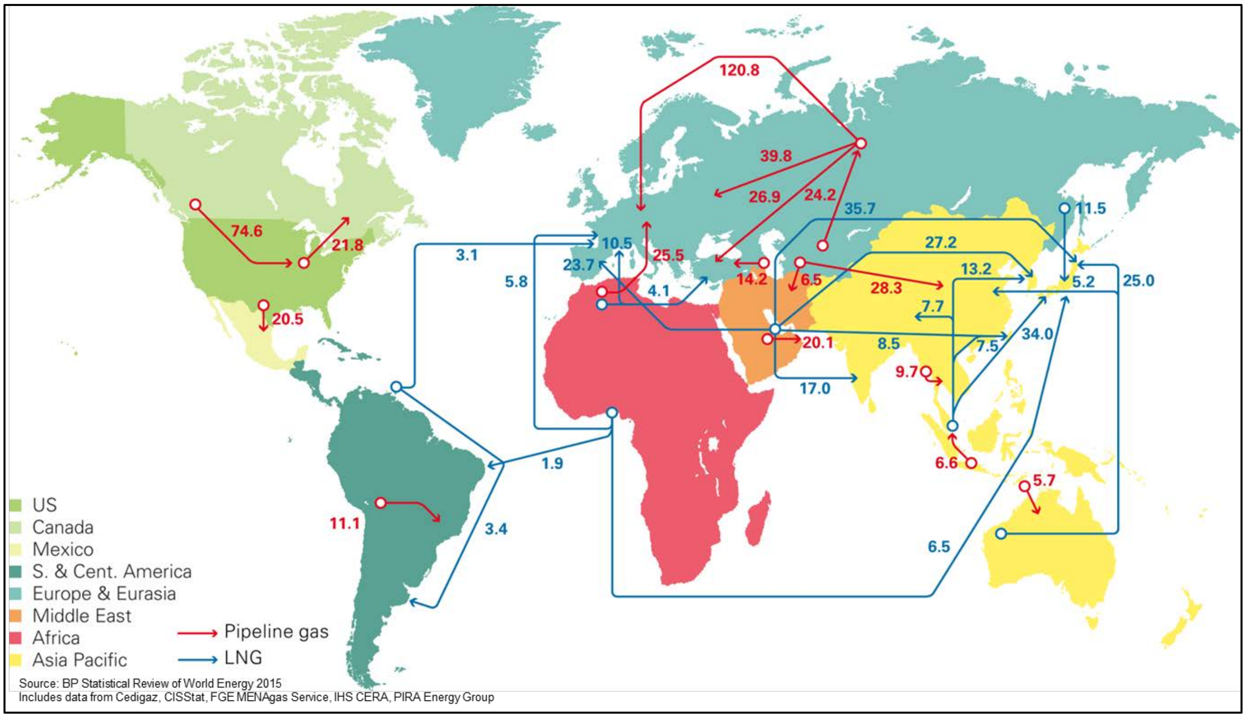
1 See the Symposium "Prospects for Natural Gas in a Low-Carbon Context" in the winter 2015 issue of *Review of Environmental Economics and Policy*, including Neumann, A. and von Hirschhausen, C.; Holz, F., Richter, P.M., and Egging, R., and Makholm, J. D.

process. Second, potential North American LNG suppliers do not have competitive access to gas consumers outside of North America as they have to their domestic customers. Because of the way that pipelines are regulated in major gas markets outside of North America, inland gas consumers cannot access competitive gas supplies that might arrive by LNG tanker, and existing gas suppliers do not see LNG as a competitive threat to their dominance over essentially captive gas customers. Even if such institutional barriers to competitive access were to fall, less costly local unconventional gas production would appear to be a more cost-effective alternative that would have the added benefit of ensuring energy security for countries currently relying on imports. Thus, while gas trade—including LNG—continues to grow, reflecting its role as a transformation fuel, it is unlikely that an international gas spot market will emerge like the world spot market in oil.

The Oceangoing Trade in LNG vs. Crude Oil

LNG plays a vital role in the global supply of gas. Worldwide LNG trade in 2014 amounted to 333 billion cubic meters—the second highest year for LNG on record—as shown in Figure 1 (IGU, 2015).

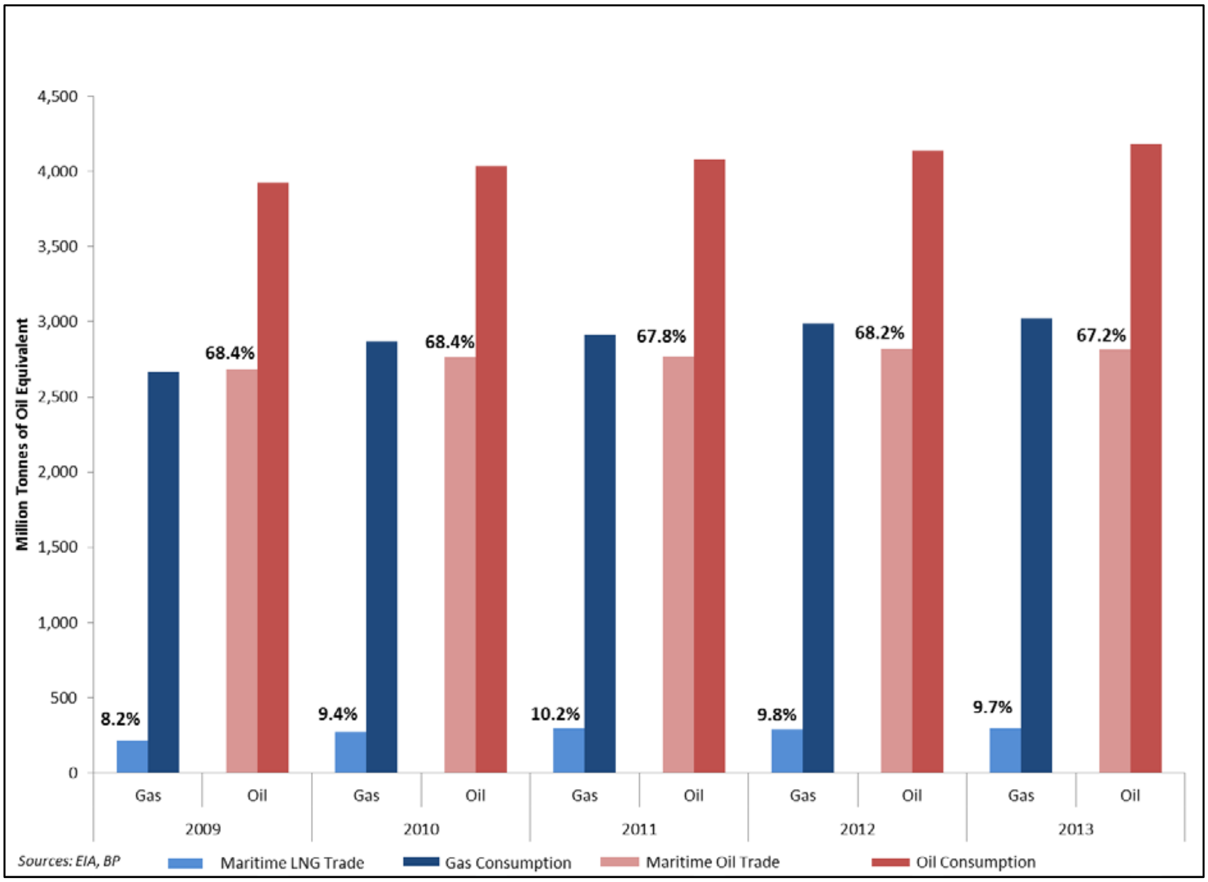
Figure 1: Major Gas Trade Movements, 2014 (billion cubic meters)



Locales with scarce fuel resources, such as Japan and South Korea, or underdeveloped internal resources, such as China and India, rely heavily on imports from resource-rich (but low population or warm) regions such as Qatar, Malaysia, Australia, and Nigeria (IGU, 2015).

Figure 2 shows that global gas consumption is about 72 percent that of oil (3,020 million tons of gas versus 4,185 million tons of oil in 2013—in oil equivalent, measured by heating value). Yet ocean transport constitutes less than 10 percent of global gas consumption (carried by 373 vessels) versus roughly two-thirds for crude oil (carried by 9,033 vessels) (IGU, 2015; UNCTAD, 2015). Furthermore, whereas the entire trade in oil occurs at worldwide spot or forward prices, less than 30 percent of LNG cargoes are spot or short-term (delivered under contracts of four years or less), representing only 3 percent of worldwide gas consumption (GIIGNL, 2015).

Figure 2: Annual Worldwide Consumption and Ocean Transport of Oil and Gas, 2009-2013



The economic literature regarding world oil markets is vast and the evolution of international oil prices is a well-studied topic—for example, see the work of Bassam Fattouh (2011, 2013) and Robert Mabro (2005). There are innumerable studies analyzing the behavior of the global oil market with respect to demand (Atkins and Jazayeri, 2004), the behavior of OPEC (Al-Qahtani, et al., 2008) and factors influencing oil prices (Ederington, et al., 2011). The literature recognizes and reinforces the idea that the market for crude oil is international in scope.

The small proportion of maritime gas trade in comparison to crude oil trade owes to the regional nature of gas markets. The economic literature regarding global gas markets focuses on the regional nature of those markets (Correljé, 2016; Makholm, 2015; Neumann and von Hirschhausen, 2015). The international market for gas comprises three distinct markets: North America, Europe, and Asia (Li, et.al, 2014). Each region is characterized by differing physical, geographical, competitive, and institutional structures. These structures influence the public-private involvement, regulation, and prices of each regional market. International trade of LNG trade may result in increased interconnection of gas markets but the unique social, political, and economic structures of each region complicate greatly any possible global spot market for gas mirroring that in oil (Correljé, 2016; Du & Paltsev, 2014; Foss, 2005; Li, et al., 2014). Despite such evidence of the relatively very minor maritime spot trade in gas and research analyzing the regional nature of gas markets, many are confident that gas is traded in oil-like global markets.

Oil and Gas Prices in World Markets

The United States is poised to become one of the largest exporters of natural gas in the near future (IGU, 2015). As of October 2015, the Federal Energy Regulatory Commission (the FERC) has approved six LNG export facilities, primarily on the US Gulf Coast, representing liquefaction capacity of 10.62 billion cubic feet per day (Bcf/d) (FERC, 2015a). Five of those approved facilities are currently under construction. There are a further 22 pending or pre-filed applications proposed to the FERC, which if built, would add an additional 28.375 Bcf/d of capacity (FERC, 2015b). FERC approval automatically grants facilities the ability to export to countries with which the US has a free trade agreement (FTA countries). However, to export to other countries (non-FTA countries), applicants must obtain additional approval from the Department of Energy (DOE). As of December 2015, the DOE has approved exports to non-FTA countries for all of the facilities currently under construction (DOE, 2015).

Industry and academia alike take the growth in LNG trade as a signal for a developing international market in the fuel. A 2011 report by Bain & Company states that regional gas markets will follow a similar path towards global markets as with coal (Apte & Critchlow, 2011). Economic studies offer the view that the gas market is likely to evolve into one that resembles the world oil market (for example, see Brito & Hartley, 2007). Senior economics faculty (though not necessarily energy specialists) at the most elite US research universities agree. The Initiative on Global Markets (IGM) Forum, sponsored by the Booth School of Business at the University of Chicago, regularly surveys its panel members on business and financial market globalization matters. Since 2012, the group has surveyed its IGM Panel twice on the issue of the economic consequences of US unconventional gas production with the following proposition:

> *"New technology for fracking natural gas, by lowering energy costs in the United States, will make US industrial firms more cost competitive and thus significantly stimulate the growth of US merchandise exports."*

While lower energy costs may well stimulate growth of US merchandise exports, some of the responses (from leading economists at Princeton, Stanford, Berkeley, and Yale) demonstrate that many are under the impression that international gas prices move together:

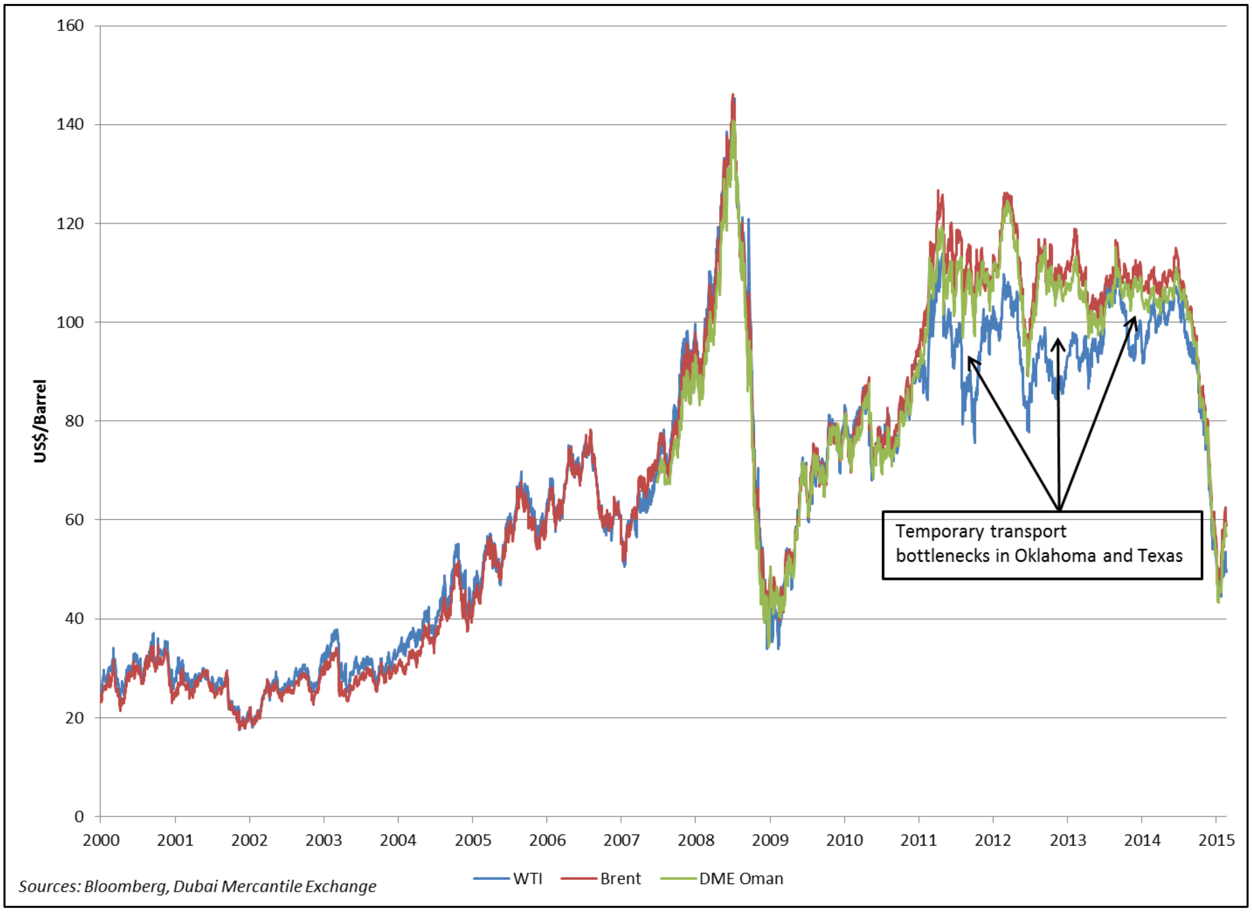
- "US energy prices are driven by world supply and demand, so the effect on US growth is realized only if global prices are moderated."
- "In a global market, natural gas prices would fall worldwide helping foreign economies too."
- "A silly gotcha q! Fracking may lower gas prices but it's traded on world mkt so it won't make any country's exports more cost competitive. Duh"
- "Energy costs are set largely in the world market."
- "At best a short-run and insignificant effect; prices are set in a global marketplace."
- "Fuel prices are largely set on a world market so the supply in any one country does not reduce its producers' input costs markedly."
- "In a global market for energy, US and foreign manufacturing firms will ultimately face the same energy costs." (IGM Forum, 2012 and 2014)

To be sure, these are not necessarily specialists in energy markets (perhaps the most experienced energy economist in the group stated a contrary opinion: “[n]atural gas prices are NOT determined in a world market”) (IGM Forum, 2014). But they were sure of publically sharing their conclusions anyway.

Oil prices are indeed set globally (Gulen, 1999). The current pricing regime emerged in the 1980s in the attempt to generate a marker price in actual physical markets plus some transport cost (Mabro, 2005).There are three key market benchmarks for oil: Brent (named after the Brent oil field in the North Sea), West Texas Intermediate (WTI), defined as the major US hub in Cushing, Oklahoma, and DME Oman (traded on the Dubai Mercantile Exchange since July 2007). Oil companies and traders use these benchmarks to set prices under long-term or spot contracts. Futures exchanges use them to price financial derivative contracts and governments use them for taxation purposes. The benchmarks differ in location (Brent and DME Oman are waterborne crudes while WTI is based on landlocked pipelines) but, except for occasional local constraints, the three international spot indexes move in lock step as shown in Figure 3 (Fattouh, 2011).[2]

[2] Local constraints include the temporary pipeline bottleneck in moving WTI-priced oil south toward the US Gulf Coast as new oil sand production in Alberta and in North Dakota changed the decades-old direction of oil movements.

Figure 3: World Oil Benchmark Prices, 2000-2015



There are no such international benchmarks for gas. Several "hubs" exist that report gas prices, although their growth and function—and the reported prices—are distinctly different. The Henry Hub facilities, in Erath, Louisiana, owned by Sabine Pipeline, connect to nine interstate and four intrastate gas pipelines. The Hub is the physical pricing point for natural gas futures traded on the New York Mercantile Exchange (NYMEX). NYMEX picked Sabine and the Henry Hub as the official delivery mechanism for the world's first natural gas futures contract in 1989 due to its interconnect ability (Sabine Pipeline, 2015). The Henry Hub satisfies the US financial markets' demand for a standardized physical point at which to define futures contracts given the regulatory successes in the United States regarding the open-access gas transport on the interstate pipeline system. In contrast, European hubs such as the National

Balancing Point (NBP) in the United Kingdom and the Dutch Title Transfer Facility (TTF) in the Netherlands are not physical points, but rather “notional” hubs, reflecting a regulatory requirement for the separation of gas commodity sales from the UK or Dutch pipeline systems. The Asia-Pacific market contains several national markets whose prices rely heavily upon maritime LNG rather than gas transported via pipeline. LNG prices in Japan, Korea, and Taiwan—who are the major gas importers in the region—result from long-term contracts largely tied to a the Japanese Crude Cocktail (JCC) index (Correljé, 2016).

Until early 2009, oil and gas prices moved together fairly consistently, tied—in a somewhat rough but discernable way—to movements in the price of oil. In particular, both gas and oil markets reflected the wild price movements in 2008-2009. But in 2009, a split occurred in the United States that reflected the application of new technology in unconventional gas production (hydraulic fracturing, or “fracking”). This split has persisted since—shown in Figure 4. A similar split occurred at the same time for the NBP; however, that split reflected the onset of the global financial crisis, which did not persist (Alterman, 2012).

Figure 4: Henry Hub, UK National Balancing Point, and Brent Prices, 2007-2015

Source: Bloomberg, L.P.

The differential between resulting commodity gas bills in the United States and Europe is staggering. Table 1 shows that, apart from transport, over the past seven years European gas consumers have paid an estimated $571 billion more for gas than their US counterparts.[3] The differences continue into 2015, as the month-ahead futures for the first 10 months of 2015 show US Henry Hub gas prices averaging $2.76 per MMBtu while at the UK NBP (toward the lower end of EU prices indexes) prices average $6.76 per MMBtu (or about $278 million per day additional gas cost for those indexes in the UK).

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3 For comparison, $571 billion is more than the 2015 Greek sovereign debt of roughly $408 billion (which equals 170% of Greek GDP of about $240 billion).

Table 1: Cost of Gas in Europe vs. the United States

Year [1]	Average Price* per MMBtu: Europe [2]	Average Price* per MMBtu: U.S. [3]	European Consumption** (Billion MMBtu) [4]	Average Cost Differential per Unit (US$/MMBtu) [5]=[2]-[3]	Cost Differential (Billion US$) [6]=([2]-[3])*[4]	Cumulative (Since 2009) (Billion US$) [7]
2009	$4.94	$4.16	19.58	0.79	$15.37	$15.37
2010	$6.42	$4.38	21.09	2.04	$42.93	$58.30
2011	$9.34	$4.03	19.77	5.32	$105.07	$163.37
2012	$9.38	$2.83	19.20	6.55	$125.81	$289.18
2013	$10.48	$3.73	19.00	6.75	$128.26	$417.44
2014	$8.37	$4.26	19.00	4.11	$78.14	$495.58
2015	$6.76	$2.76	19.00	4.00	$75.99	**$571.57**

**For Europe, average annual price at UK NBP; for the United States, annual average price at Henry Hub; 2015 average through October 1, 2015*

***2014 and 2015 EIA estimated European gas consumption*

Sources: EIA, Bloomberg L.P.

Why isn’t US LNG flowing to Europe to arbitrage the persistent price differences shown in Figure 4 and Table 1? The reasons lie in the cost of LNG, the inherent protectionism inherent in the gas pipeline regulatory regimes outside North America and the existence of what appears to be less expensive unconventional gas alternatives if such protectionism were somehow to be overcome.

The Cost of Martime Transport of Oil and Gas

Maritime oil transport includes the relatively minor costs of terminal loading and unloading and the lease cost for the tanker and associated fuel. Those costs are approximately $2.05 per barrel of oil, or $0.37 per MMBtu (OPEC, 2013). The cost of transporting LNG by tanker is much higher. There are three steps required for maritime LNG transport: liquefaction, ocean shipping, and regasification, where liquefaction and regasification require large capital expenditures.

Those US export facilities soon to be in-service (with completion dates in 2017 and 2018) tend to be at the lower end of the capital cost spectrum as they are “brownfield” projects—built at existing regasification terminals—whereas “greenfield” projects constructed in locations without any existing infrastructure are significantly more expensive (Maugeri, 2014). Table 2 presents evidence of the current cost of liquefaction available from public sources for US export facilities soon to be in-service.

Table 2: Capital Costs of Liquefaction

Facility Name	Location	Capital Cost (US$M)	Capacity (Mt/yr)	US$/MMBtu
Sempra – Cameron LNG	Hackberry, LA	$9,500	12.74	$2.76
Freeport LNG	Freeport, TX	$14,000	13.49	$3.68
Dominion – Cove Point LNG	Cove Point, MD	$3,600	6.15	$2.26
Cheniere - Corpus Christi LNG	Corpus Christi, TX	$11,750	16.04	$2.72
Southern LNG Company	Elba Island, GA	$1,250	2.62	$1.91

Sources: Cheniere, FERC, and Hydrocarbons Technology.
**Calculated with straight-line 20-year amortization and 10 percent nominal return.*

Transportation of LNG via ocean tanker requires highly specialized ships equipped to carry the product at the appropriate temperature for the natural gas to remain in its liquid form, and also allow the ship to use some of that LNG as fuel. Table 3 shows total transport via tanker costs for an average journey of 4,500 miles from the US to Europe.

Table 3: Cost of LNG Shipping

Cost Component	Units	Cost per Trip
Charter Rate	US$/Day	$50,000
Tanker Capacity	tons	66,000
Tanker Cost for 4,500-Mile Trip	US$	$1,058,603
Fuel Cost for 4,500-Mile Trip	US$	$452,435
Boil-Off Cost for 4,500-Mile Trip	US$	$369,900

Sources: Platts, Searates.

Representative regasification facility costs are shown in Table 4 below.

Table 4: Capital Cost of Regasification

Facility Name	Capital Cost (US$M)*	Capacity (bcm/ yr)	US$/MMBtu
Bahia de Bizkaia Regasification Plant, Bilbao	$411.31	7.00	$0.43
Dragon LNG Terminal, UK	$480.05	7.60	$0.77
Dunkerque LNG Terminal, France**	$1,044.49	11.50	$1.47

Sources: Hydrocarbons Technology, GIE.
**Calculated with straight-line 20-year amortization and 10 percent nominal return.*
***Cost for Dunkerque LNG corresponds to an in-service date of 2014 for the first phase of the Project, thus no depreciation is included. In-service dates for Bahia de Bizkaia and Dragon LNG are 2003 and 2009, respectively.*

Total transport from the United States to European destinations averages about $4.15 per MMBtu.

Table 5: Average Cost of Maritime Transport of Gas

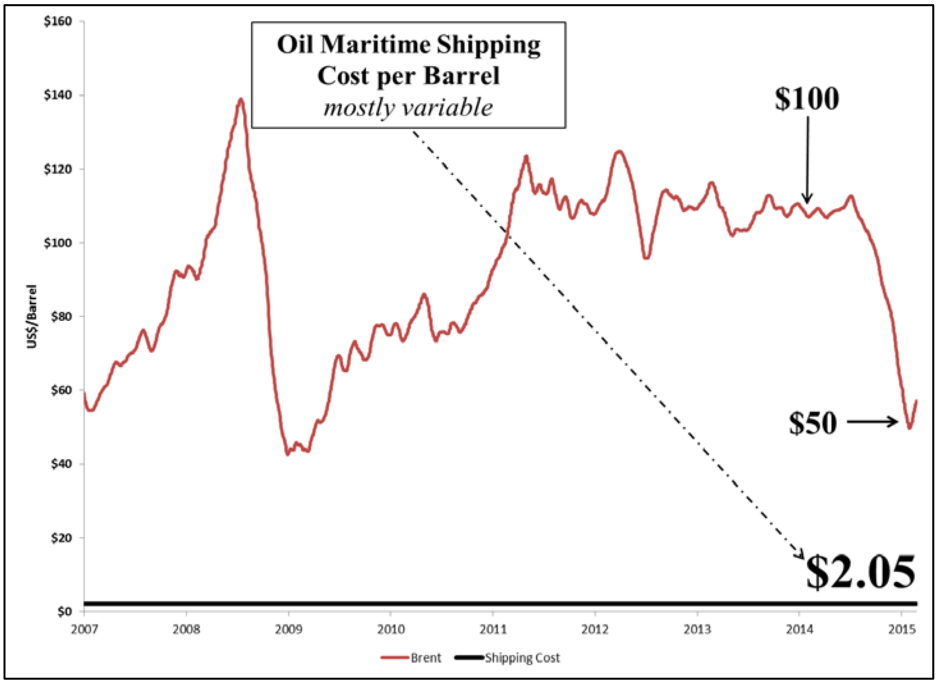
Cost Component	US$/MMBtu
Liquefaction (Average of Five Projects)	$2.66
Shipping (4,500-Mile Trip)	$0.59
Regasification (Average of Three Projects)	$0.89
Total	**$4.15**

Figure 5 shows the proportion of the cost of maritime shipping to the unit value of oil and gas, for a 4,500-mile haul. The costs for maritime oil transport are predominantly fuel-related, variable or mobile (in terms of the tankers themselves). In contrast, the majority of the cost for maritime LNG transport is capital-related at fixed sites, requiring long amortization periods (20 years in our examples) to pull the unit cost down to the maritime shipping line shown in Figure 5.

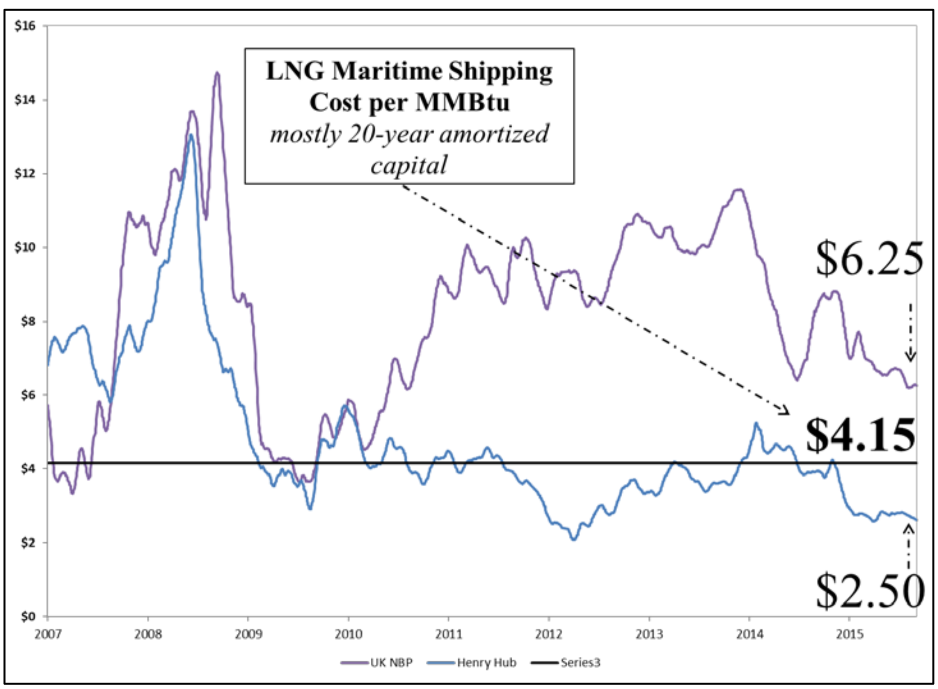
The cost of LNG transport from the United States consumes most—if not all—of the value of the commodity in Europe. Figure 5, shows that oil transport costs represent between 2 percent (at $100 per barrel) and 4 percent of the total value of a barrel of oil (at $50 per barrel). On the other hand, shown in the second graph, the cost of transporting gas from the United States to Europe is about 150 percent of the US gas cost and two-thirds of the price of gas in the UK.

The loading of fixed costs into price comparisons is reasonable, particularly for new LNG facilities, given that those who finance the facilities require an assurance that the capital will be repaid. US interstate pipeline are also highly capital intensive, but the basis differentials between different US gas destinations normally reflects only variable costs, which may call into question the fixed cost loading in our LNG comparison. There are, however, two attributes of US interstate pipelines that make such a comparison to LNG costs inapt. First, the variable cost basis differentials are only applicable off peak when the regulated gas distributors (whose demand built the capacity) do not recall their capacity for their own heating-load customers. Second, the interstate pipelines themselves are financed with the understanding of lenders that both the creditworthiness of those regulated distributors and the transparent and predictable nature of FERC regulation mean that long-term pipelines loans will be reliably repaid over the useful life of the lines (Hooley, 1961).

Figure 5: Relative Cost of Maritime Shipping for Oil and Gas



Sources: Bloomberg, L.P., OPEC.



Sources: Bloomberg, L.P., Cheniere, FERC, GIE, Hydrocarbons Technology, Platts, and Searates.

Competitive Access to Consumers at the End of the LNG Journey

The US gas market is freely competitive because it successfully restructured its federally regulated interstate pipeline system to remove pipeline interests as a barrier to the competitive trade in gas (Makholm, 2012). While every interstate pipeline remains subject to the regulation of the Federal Energy Regulation Commission (the FERC), a genuinely competitive and unregulated market exists in the well-defined FERC-licensed physical capacity rights in those pipelines. Using concepts that gave the late Ronald Coase his 1991 Nobel Prize in Economics and pressed by a highly-effective interest group of independent state-regulated gas distributors, the FERC worked successfully during the 1990s to create such a market in highly specific physical capacity rights.

Through the unregulated “sub-let” market in those well-defined physical capacity rights, gas producers can physically reach any buyer on the interstate pipeline system simply by buying pipeline capacity rights at the going competitive price. Pipelines do not obstruct gas markets, as they are prohibited from owning the gas they transport, do not control the re-sale capacity market, and cannot use the regulated prices for existing capacity to subsidize newly-constructed capacity in order to bar the competitive entry of new transport capacity where the market demands it (Makholm, 2012). If the gas market wants new capacity on existing pipelines, or a pipeline in a new location, pipeline companies (along with customers willing to pay) simply ask the FERC to license an addition supported by long-term contracts with highly credit-worthy state-regulated local distribution monopolies. Such capacity additions then add to the wider competitive pipeline capacity market. Electronic platforms enhance such transparency such that potential new entrants can easily assess whether and where new capacity will be required—and the costs of adding that capacity. The system works, with little active participation by the FERC beyond licensing and cost-based tariff setting. In addition, it is precisely the transparently physical configuration of gas transport that invited the participation of the financial markets around the distinctly physical Henry Hub. The US natural gas pipeline industry exhibits long-accepted characteristics of a freely competitive market: a homogenous good (licensed pipeline capacity); producers—pipelines—and consumers are price takers (cost-based tariffs); perfect information (mandated transparency); and free entry and exit (of pipelines and shippers) (Tirole, 1988).

The pipeline market in Europe shares none of the attributes of its US counterpart, reflecting different histories and institutions. All major gas transport pipelines were built by governments or state-owned companies and most gas distributors are part of large pipeline suppliers—not the kind of independent pressure group that pushed US gas industry reforms in the interest of their connected consumers. EU-wide organs of control have little of the authority, continental reach or transparency of the type of regulation exercised by the FERC. As such, much of the regulation of European pipelines and the gas markets they serve is focused on the individual member state enterprises and the separate organs of member-state control of them (meaning individual "network codes" and regulators of the EU pipeline system in each member state). As a result, each member state is highly protective of its own national gas companies, interests and regulatory agencies.[4]

The institutional and political endowments that facilitated competitive US pipeline transport (e.g., a strong federal regulator, a history of investor participation in interstate pipeline construction, and powerful independent state-regulated gas utilities) have never been shared by the EU or its member states. Existing EU legislation, known as the Third Legislative Package of 2009, was ostensibly created to promote an EU-wide competitive market in gas based on the principles of the EU's competitive electricity markets (EU, 2009) and the apparent success of the entry/exit system in the United Kingdom (Makholm, 2015b). While the US pipeline system relies on point-to-point gas transport that is tightly tied to the physical operation of its pipelines, the Third Package forbids point-to-point contracting on long-distance pipelines in favor of localized "entry/exit" regimes (Noël, 2013). Member states are required to implement notional hubs where gas is injected into the system at "entry" points and is extracted at various "exit" points.

[4] For a description of the particular legislative actions heightening the protectionism of member-state gas companies, see Makholm, J.D. (2015a), 17-19 and Makholm, J.D. (2012), 60-62 and 165-171.

Entry/exit establishes monopoly “islands” where transmission service operators (TSOs) act as central planners, balancing the requirements of producers to inject gas and consumers to extract. Without transparency about where gas actually flows, regulated member state gas companies tightly control these hubs. As such, there is no practical ability for an LNG importer to bypass these regulated suppliers to connect either to individual consumers (like power generators or industrial sites) or consuming groups in urban areas. Unlike oil markets, where competitive distribution of oil from maritime import points to wholesale and retail outlets is eminently practical, no such competitive access to consumers exists in entry/exit regimes where gas supply to ultimate consumers is limited to member state regulated monopolies that traditionally import gas from Europe’s major gas suppliers under contracts linked to the price of oil.

While the share of contracts linked to oil has declined in recent years and so called “gas-on-gas” pricing has increased in Europe, the number of gas suppliers is severely limited as there are only four large suppliers via pipelines (Russia, Algeria, Norway, and the Netherlands) and few countries have LNG import terminals (IGU, 2015; Correljé, 2016). With such concentrated supply sources, traditional importers have the ability to manipulate supply to ensure gas prices in Europe do not fall below a certain floor (Bros, 2015). Furthermore, incumbent member state gas companies have remained dominant in their respective countries—controlling the long-term import contracts (Correljé, 2016; Neumann, et al., 2015). Therefore, much of the limited amount of “gas trading” taking place is essentially trade between member state gas companies and incumbent suppliers. Genuine competitive entry of any significant scale, from independent sources or transport links of the type that drives competitive prices down in the United States is effectively impossible with existing EU institutional arrangements.

Practical evidence of Europe’s lack of entry-driven competitive gas price formation appears in the lack of interest on the part of the financial industry in managing commodity price risk as it does either in oil markets or in US gas markets. Table 6 shows the extent of natural gas futures traded in the United States and Europe alongside Brent crude oil and US corn (for an example of a different bulk commodity).

The lack of realistic competitive entry and competitive pipeline access to consumers at physical points, like the Henry Hub, at which the financial industry can settle its contracts, effectively excludes gas futures trading in Europe.[5]

Table 6: Volume of Commodities Consumed and Traded in Futures

Market	Unit	Consumption	Futures Volume Traded*	Ratio of Futures Volume Traded to Consumption**
European Gas	MMcf/d	43,853	822	0.02
US gas	MMcf/d	93,120	2,494,349	26.79
Brent Crude Oil	Barrels/d	2,700,000	587,924,864	217.75
US Corn	Metric Tons/d	8,955,000	27,808,604	2.74

Sources: Bloomberg, L.P., International Energy Agency, United States Department of Agriculture.

** Futures contract volumes for gas are measured using total number of futures contracts traded for all currently listed contracts in a series. Europe natural gas futures include data for Gaspool, NCG, and the Dutch TTF.*

*** We compare the consumption of the commodity, or production where it serves as a more appropriate measure, per day to the volume of the commodity traded in futures per day.*

That is, in two different gas markets extensively networked by pipelines, similarly supported by storage and supporting similar consumers, industrial and power-generating uses, the financial industry evidently has no interest in participating in European gas markets. The EU trading "hubs" were not created by the financial industry as a location to physically settle contracts, nor are those EU hubs physical points (like the Henry Hub) that themselves are connected by physical means to gas producers and consumers. In addition, the kind of dedicated contractual access to consumers through existing pipelines that producers can secure through the "sub-let" pipeline capacity market are unavailable in Europe.

Competitive access by LNG to gas customers in the EU is thus burdened by the dominance of the incumbent member state suppliers, a lack of transparency and the great complexity of member-state managed entry/exit systems. Those entry/exit regimes both obscure the physical operation and needs of

[5] The gas market in Australia shows a similar pattern where there is essentially no futures market in the commodity gas trade (Makholm and Hitchins, 2015).

the pipeline systems and require highly complicated “network codes” to stich the physical and commercial system back together for the purpose of defining access prices and terms.

Thus, member state gas companies face no realistic bypass threats to either their pipelines or to gas imported under long-term contracts—linked to oil or otherwise. As a result, there is very little private sector interest in new pipeline infrastructure investment to build capacity where it is needed and that leads to public funding of new infrastructure. The European Commission determines “projects of common interest” for natural gas and electricity to be funded by taxpayers. For the period between 2014 and 2020, the European Commission proposed budget of more than $600 million for natural gas infrastructure projects (EC, 2015b).

Competitive entrants in the United States can trace gas physically, from source basins through to consumers or export points via competitively-purchased sub-let pipeline capacity links with no need to deal with regulated prices or regulatory approval. Nothing remotely similar is possible in Europe, and the EU has indicated that it does not intend to alter its current path (EC, 2015a). As a result, European imports will continue to be dominated by the member-state firms that maintain control over access to member state gas consumers and contract for LNG imports.[6]

Similarly, competitive access to Asia-Pacific gas consumers is nearly impossible. The market does not currently have a trading hub to facilitate such competition and natural gas prices are largely government regulated (Correljé, 2016; IEA, 2014). While LNG spot trade (contracts less than two years) has increased in recent years in Asia, the market remains dominated by long-term contracts whose prices tend to be lower than spot trade prices—which often include a premium (IGU, 2015). The Asia-Pacific gas market is not as mature as that in the US (or Europe)—in terms of both supply and demand for the fuel—and thus gas imports will likely remain dominated by long-term, oil-indexed contracts (Correljé, 2016).

[6] For example, PGNiG in Poland and France’s ENGIE (formerly GDF SUEZ). See Neumann, et al. (2015) for a documentation of long-term LNG and natural gas pipeline contracts.

Entry Competition for LNG from Unconventional Gas

Given the burden of EU regulatory institutions and the lack of physical or otherwise competitive pathways to consumers, industries or independent power generators, it is hard to foresee independent LNG imports to Europe. But exiting European unconventional gas basins of the type that are fueling US and Canadian gas exports raise another question. Given the growing knowledge on how to extract shale gas successfully, and the ability to transfer that technology and equipment to where unconventional gas is located, there would appear to be some possibility that the entry of domestic supplies might do what LNG exports cannot.

The continuing prospects for unconventional gas supplies, including the production cost and available future supply, are the subject of intense study in North America (Ikonnikova, et al., 2015a). Some of the most recent work on the break-even price for unconventional wells of various depths indicated that the average shallow zone wells requires a price of $2.74/MMBtu (generating an international rate of return of 10 percent) and $3.30 on average for a well from deep zones. Various estimates of North American unconventional gas put breakeven costs as low as $2 per MMBtu to just over $5 per MMBtu, depending on the play (Ikonnikova, et al., 2015b).

Recent studies show that recoverable shale resources are not simply a North American phenomenon (EIA, 2013b). There is no particular reason, however, to be encouraged about the near-term ability to exploit the US unconventional gas experience elsewhere. Various important institutional barriers particular applicable to unconventional gas production stand in the way. These include the fact that the “farmer owns the gas” in the United States—but not in Europe (where, because of the actions of Napoleon, Bismarck and Clement Atlee, sub-surface unconventional gas is owned by the state). Combined with the highly vigorous oil/gas extraction and support industries (again, vigorous in the

United States but no in Europe) and the nature of the pipeline regime needed to move that gas to market, the institutional barriers are greater that those facing entry competition from LNG (Makholm, 2016).

Conclusion

It is attractive to think of the maritime LNG trade as having the capability to synchronize world gas markets around the global supply and demand for that fuel, as oil markets do with the maritime trade in crude oil. A closer examination of the trade in the two fuels, however, shows why such a global gas market does not exist. Oil moves around the world easily—two-thirds of the world's oil consumption moves by sea for some part of the journey from producers to consumers; all of that at spot market prices. Barely 10 percent of the world's gas supply moves that way, with less than a third of that delivered at spot prices.

The gas trade cannot exist without pipelines to even the smallest consumers or capital-intensive facilities to liquefy and ship it globally. Pipelines provide a ready-made ability to exclude access and undermine competitive entry. Only North America has developed regulatory regimes that consign pipelines to serve only the role of "transporters for hire"—permitting producers and consumers to deal directly with each other without pipeline interests or regulators getting in the way. In the EU, local pipeline monopolies and their regulators control all gas transport and trade within a regime that prevents gas sellers and buyers from accessing the physical and financial means to deal directly as in the United States.

Even if producers and consumers are able to deal directly and physically (over defined pipeline links), the cost of that LNG transformation is vastly greater than the comparable relative cost of crude oil transport. The cost of LNG is indeed comparable, if not greater, than the cost of using modern technology to produce marketable gas from unconventional sources.

Faced with high costs and regulatory difficulties in dealing with pipeline transport outside of North America, the market for LNG appears to be inherently limited to a commodity trade between regions of resource abundance and scarcity, relative to local demand, where investors will seek relationship contracts to tie such regions together long enough to amortize LNG investments. To mimic the global spot market trade in crude oil, gas would need both a vastly reduced maritime cost and a way of getting to consumers without being captive to pipeline monopolies. The former would seem a physical impossibility, and the latter, outside North America, may well be an institutional impossibility. As far as world gas markets are concerned, ocean-going LNG carriers are indeed petroleum tankers of a different color.

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