

IF YOU BUILD IT, WILL THEY COME? THE COMPETITIVENESS OF US LNG IN OVERSEAS MARKETS

Jason Bordoff and Akos Losz

NOVEMBER 2016



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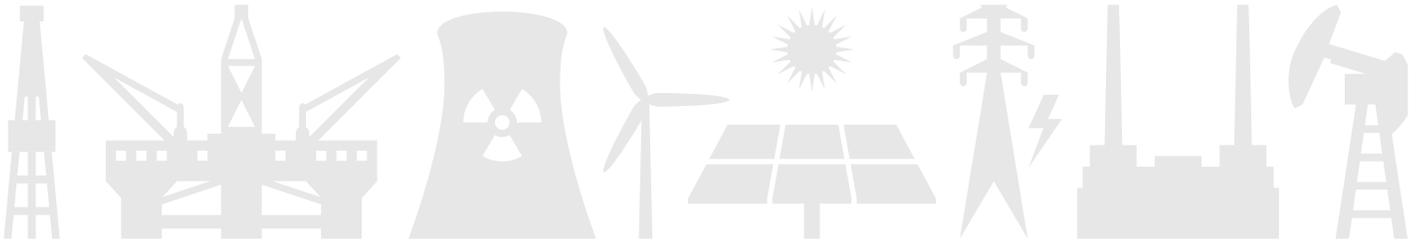
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* **Jason Bordoff** is a professor of professional practice in international and public affairs, and founding director of the Center on Global Energy Policy at Columbia University's School of International and Public Affairs. **Akos Losz** is a research associate at the Center on Global Energy Policy. This paper is an expanded version of research done by Mr. Losz as part of Professor Bordoff's Spring 2016 SIPA Capstone course.

COLUMBIA UNIVERSITY IN THE CITY OF NEW YORK



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EXECUTIVE SUMMARY

The first shipment of liquefied natural gas from the US lower 48 states, made possible by the explosion in production from shale deposits, brought with it expectations of great change for LNG trade. US LNG supplies have already begun to impact global trade, increasing the volume of flexible cargoes available to markets traditionally dominated by long-term contracts between buyers and sellers. By the end of this decade, five US LNG terminals are expected to be operational with a total capacity of nearly nine billion cubic feet per day (Bcf/d).

However, these new supplies from the United States, combined with new production from Australia and elsewhere, have set the LNG market up for a glut that threatens to depress prices. Speculation is now growing as to whether America's new flexible export capacity will be fully utilized in the coming years, or whether some of that capacity will lie fallow in the face of growing competition.

In this report, the authors assess the factors influencing the competitiveness of US LNG around the globe and whether capacity will be curtailed in the near to medium term for economic reasons. The report gives specific attention to the economic and commercial factors under consideration by US LNG exporters and the outlook for US LNG sales into Europe and Asia. In addition, the study examines how the competitiveness of US LNG may evolve in the medium term. In short, the authors find:

- Companies will likely make decisions about whether to utilize US LNG export capacity based solely on variable costs.** The offtakers of US LNG agreed to pay fixed fees in the range of \$2.25 to \$3.5 per MMBtu, which they have to pay regardless of whether they actually lift their contracted LNG volumes. US LNG buyers from the five sanctioned LNG projects will most likely treat these fixed fees as a sunk cost, and base their export decision solely on variable costs. When the offtakers have the option to buy gas from the spot market, they should only elect to lift their contracted US LNG volumes if the variable cost of delivering US gas to the local market is lower than the prevailing market price in the same market. When the variable delivered cost of US LNG is higher than the spot price in the targeted external markets, then the offtakers are better off not taking their contracted volumes from the US terminals.
- The arbitrage window (on a variable cost basis) to export US LNG to the main importing regions remains open, but the margins have become very tight.** At the time of writing, exporting US LNG on a variable cost basis appeared economic to both Europe and Asia. But the margin of competitiveness for US LNG exports has become very narrow, even when the offtakers treat the fixed fees as a sunk cost. The fact that the variable cost of delivering US LNG to Europe or Asia could stay lower than rapidly falling spot prices in both regions is due to a substantial reduction in vessel charter rates, shipping fuel costs, and the travel time from the United States to Asia via the expanded Panama Canal.
- Small changes in a number of variables can, at times, render US LNG exports uneconomic.** While US LNG remains competitive in overseas markets at the moment, this opportunity can easily dry up, even with small changes in Henry Hub prices, vessel charter rates, shipping fuel costs, canal fees, overseas spot prices, and a host of other factors. If the "netback margins" for US LNG exporters were to drop below zero, then the shipping of American gas overseas becomes uneconomic even on a variable cost basis.
- Full utilization of US export capacity seems unlikely, especially if overseas spot prices remain as low as some forecasts suggest.** If spot natural gas prices in the main gas importing regions remain low, and Henry Hub prices, shipping costs, and other variables are volatile over the medium term, then US LNG terminals will probably not operate at high utilization rates at all times. In such an environment, it is more likely that the arbitrage window for US LNG offtakers will open and close periodically, and at least part of the US LNG export capacity will, at times, shut down on economic grounds.

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INTRODUCTION

American LNG exports from the lower 48 states officially started in February 2016, when the first commissioning cargo departed from Cheniere Energy's Sabine Pass terminal with a shipment of liquefied natural gas to Brazil. In the first seven months of the plant's operations (through the end of September 2016), a total of thirty-three LNG export cargoes departed from Sabine Pass to destinations in South America, Europe, the Middle East, and Southeast Asia.¹

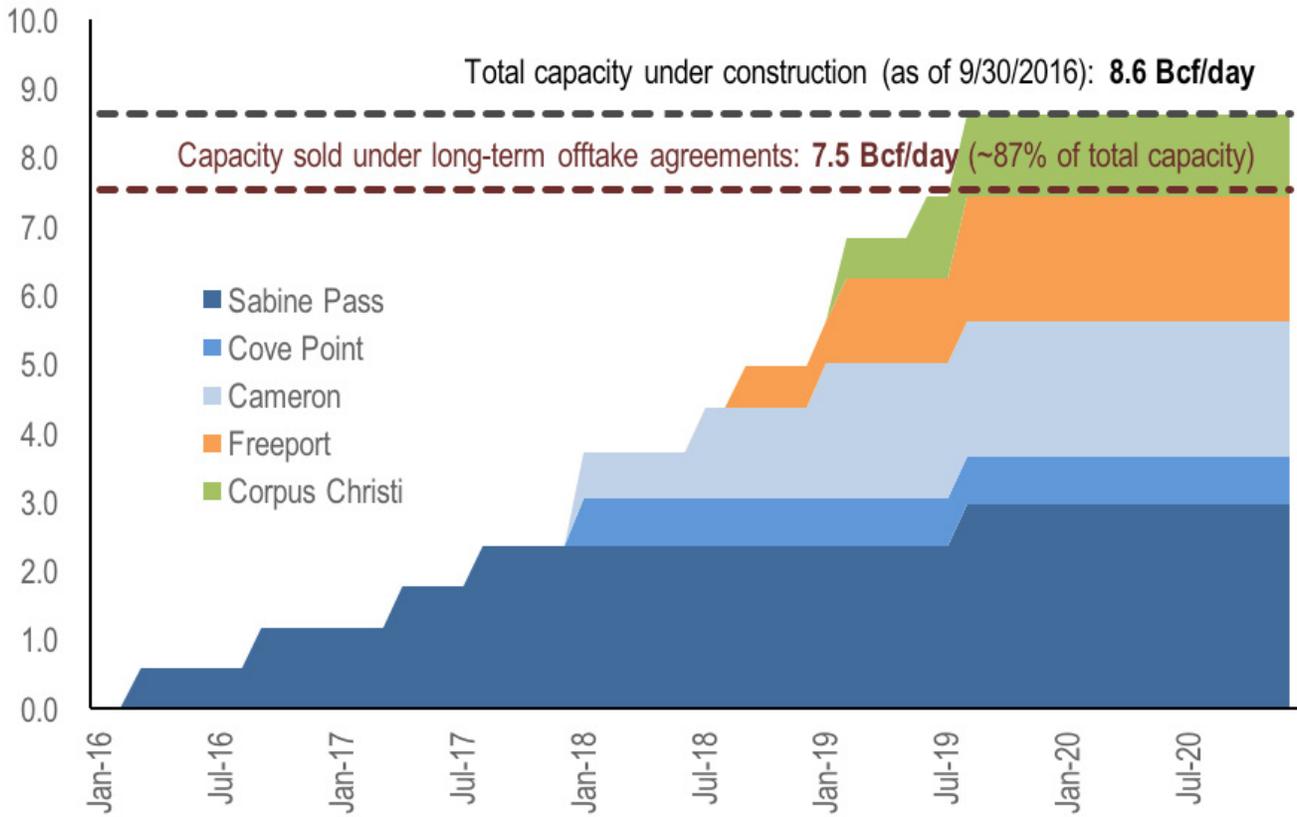
By the end of the decade, a total of five LNG export terminals are scheduled to be in service with a total liquefaction capacity of nearly 9 Bcf/d (**Figure 1**). About 87 percent of this capacity will be sold under long-term offtake agreements, while the remainder will be marketed primarily by project sponsors and their subsidiaries. Thanks to the unique contractual structure of US LNG offtake agreements, US LNG will soon eclipse Qatar as the biggest source of flexible LNG supply that can promptly respond to market price signals around the world.² But just as the US terminals are ramping up capacity, the global LNG market is entering a period of oversupply and weak spot LNG prices across the major gas importing regions. In this new market environment, it seems increasingly uncertain whether America's new flexible LNG export capacity will be fully utilized toward the end of the decade.

A total of twelve projects have received the necessary permits from the US Department of Energy (DOE) to export LNG from the lower 48 states to non-Free Trade Agreement countries,³ and the DOE has indicated that approvals will continue to be forthcoming for commercially viable LNG export projects that complete the regulatory review process at the Federal Energy Regulatory Commission (FERC).⁴ A few years ago, considerable uncertainty existed about whether the Obama administration would approve LNG export terminals at all.⁵ Such concerns have since dissipated. Today, LNG export projects that have not yet taken final investment decisions are held back by market conditions, not by regulatory risks to development. Given how the global gas market has changed, the question new project developers face today is whether the global market will still want to buy LNG from the United States.

This report identifies the determinants of the international competitiveness of US LNG, and assesses the likelihood of US LNG export capacity curtailments on economic grounds in the near to medium term.⁶ The paper first analyzes the economic and commercial considerations driving the decisions of US LNG exporters. It then discusses the current competitiveness of US LNG in Europe and Asia, the two largest LNG importing regions in the world,⁷ and assesses how the main drivers of the competitiveness of US LNG might evolve over time in overseas markets. Finally, it evaluates the medium-term competitiveness of US LNG in the 2020 time horizon and estimates the profitability of US LNG exports under different assumptions.

We conclude that the arbitrage window for US LNG exports remains open at the time of writing, but this window has become very narrow. This means that even small changes in a number of variables can, at times, render US LNG exports uneconomic and force at least some of the US export capacity to shut down when shipping US gas overseas is not profitable.

Figure 1: US LNG Export Capacity in Operation, Commissioning, or Under Construction



Source: CGEP, based on company disclosures.

THE ECONOMICS OF US LNG EXPORTS

Barring regular maintenance and periods of unplanned outages, LNG liquefaction terminals outside the United States tend to operate at very high utilization rates, irrespective of the actual gas market conditions. Liquefaction capacity utilization averaged 84 percent globally in 2015, which includes offline capacity in Angola, Egypt, and Yemen. When excluding offline capacity, the average utilization rate would have been 92 percent in 2015.⁸ This high rate of utilization stems from the fact that natural gas exporters around the world typically require long-term offtake agreements and relatively inflexible volumetric commitments from buyers to justify their upfront investments in highly capital-intensive field development and gas infrastructure assets.⁹ Under traditional long-term take-or-pay contracts, LNG buyers are not required to physically take the contracted gas volumes, but they are obliged to pay for it in full, including for the cost of the natural gas fuel. Long-term LNG contracts, which are most widely used in Asia, typically have provisions for some limited downward quantity tolerance (in the range of about 10 percent of the annual contracted volume) so that buyers can adjust offtake volumes in any given year. But offtakers can only request downward adjustments for operational reasons, and they have to make up for such adjustments in subsequent years. The majority of Asian long-term LNG contracts are also believed to contain destination and resale restriction clauses.¹⁰

US LNG—or liquefaction capacity in the case of tolling agreements—is also sold mostly under long-term twenty-year contracts, but the buyers of US LNG face no destination restrictions and have much greater flexibility in terms of offtake volumes. Depending on the contract type,¹¹ offtakers from US terminals have committed to pay a fixed capacity charge or a tolling fee of approximately \$2.25 to \$3.5 per MMBtu, which they have to pay regardless of exported volumes. But they are under no obligation to lift any of the contracted LNG (or pay for it in full, including for the feed gas and the cost of the natural gas used during the liquefaction process) if the economics of exporting US gas becomes unfavorable on a variable cost basis.

Given the greater volumetric flexibility in US LNG offtake agreements, US LNG effectively competes with spot natural gas prices around the world, even when it is not sold on a spot basis. As long as offtakers have the option to buy gas from the spot market, they should only elect to lift their contracted US LNG volumes if the variable cost of delivering US gas to the local market is lower than the prevailing market price in the same market. The buyers, of course, will still have to pay the fixed capacity or tolling fees stipulated in their long-term offtake agreements, but they will most likely treat these fixed fees as a sunk cost, which will not materially influence their decision to export LNG from US terminals.

Based on this logic, the decision to export American gas from US LNG terminals that are already commissioned or under construction depends on two variables: the delivered cost of US gas (excluding any sunk costs) and the spot gas price in destination markets.¹² If the delivered cost of US LNG is lower than the spot price in any of the targeted destination markets (that is, the so-called netback margin for US LNG exporters is positive), then US LNG exports are economical, and offtakers will most likely lift their contracted LNG volumes from US terminals. If the delivered cost of US LNG is higher than the spot price in the target markets (that is, the netback margin is negative), then the offtakers are better off not taking their contracted volumes, and US LNG export capacity may temporarily shut-in as a result (**Figure 2**).¹³ When the market price in the highest-paying target market remains above the variable cost of US LNG exports but below the full cost (including both fixed and variable costs), as has been the case during most of 2016, then the offtakers will keep lifting US LNG volumes to minimize losses rather than maximize profits. As long as the variable cost of exporting LNG remains below the spot price, the differential will help offtakers reduce their losses from trading on a full-cost basis.¹⁴

The analysis in this report assumes that offtakers of US LNG will honor their contractual commitments and continue to pay their fixed take-or-pay or tolling fees,

even when exporting LNG from US terminals under their contracts is uneconomic for a protracted period. However, some analysts believe that contract sanctity could come under pressure in the future,¹⁵ especially if buyers start to see their US LNG contracts as a permanent financial liability. Unlike typical European or Asian long-term take-or-pay contracts, US LNG offtake agreements have no price “reopeners” or other formal mechanisms to periodically renegotiate pricing terms, particularly the fixed fees.¹⁶ It appears the only way for an offtaker to legally abandon its contractual commitments is to go bankrupt, which is highly unlikely in the case of US LNG projects, given the fact that the offtake agreements have been signed by creditworthy counterparties at

the parent company level (or are guaranteed by the respective parent companies in the event of bankruptcy of the subsidiary).¹⁷ Absent a bankruptcy scenario, US LNG contracts are defensible in arbitration court if an offtaker fails to pay the fixed fees.¹⁸ But delayed payments during a period of arbitration can be especially painful for American terminal operators, as US LNG projects are predominantly debt-financed, and their owners depend on fixed fee revenues to make periodic debt payments. So even though US LNG contracts are considered very strong from a legal perspective, they have yet to be tested in a stress scenario where buyers refuse to pay their fixed fees.¹⁹

Figure 2: The Export Decision for US LNG Offtakers



THE DELIVERED COST OF US LNG

As discussed previously, US LNG offtakers will likely make their export decision based solely on variable costs. Therefore, to understand the current and future economics of US LNG exports, we must first define what constitutes variable cost in the netback equation.

The full cost (or long-run marginal cost) of producing and delivering US LNG to the global market consists of a number of cost components (**Table 1**). The fixed tolling or capacity charge covers the capital investment in the liquefaction plant. The Henry Hub gas price represents the cost of the natural gas fuel itself, while a 15 percent surcharge above the Henry Hub price primarily covers the conversion losses, namely the cost of the natural gas used during the liquefaction process.²⁰ Transportation costs cover vessel charter rates, shipping fuel costs, canal fees (where applicable), and port, insurance, and other charges. The cost of regasification captures the tariff that owners of LNG import terminals charge for the use of their facilities.²¹

Fixed Capacity Charges or Tolling Fees

The fixed capacity charges or tolling fees are a sunk cost. US LNG offtakers have agreed to pay a fixed sum (ranging between \$2.25 to \$3.5 per MMBtu) in exchange for their contracted capacity, regardless of the actual export volumes. Offtakers from the five existing terminals will most likely treat these fixed fees as a sunk cost,²² which are not expected to influence export decisions.

Henry Hub Feedstock Cost

The Henry Hub gas price and the 15 percent surcharge²³ above the Henry Hub price are variable cost items, as the offtakers will only have to pay these if they decide to export LNG from US terminals. To the extent the offtakers have signed long-term contracts to secure continuous feed gas supply for their terminal capacity,²⁴ they can still sell back unwanted gas volumes to the US market at any time at a relatively small loss.

Table 1: US LNG Export Cost Buildup by Region

	Cost Range (\$/MMBtu)	Europe	Asia
Fixed Capacity / Tolling Fee	2.25 – 3.5	Sunk Cost	Sunk Cost
Henry Hub + 15% Surcharge	2.0 – 4.0	Variable	Variable
Transport Costs			
Vessel Charter Cost	0.2 – 0.6	Sunk for Some	Sunk for Some
Fuel Cost*	0.2 – 1.8	Variable	Variable
Canal Tolls	0.2	N/A	Variable
Port / Insurance / Other	<0.1	Variable	Variable
Regasification Cost	0.3 – 0.4	Variable	N/A
Est. Total Cost Range	5.0 – 10.6		

* Fuel cost includes the cost of the boil-off gas (BOG) and the marine fuel that LNG carriers use for propulsion.

Source: Authors' estimates based on a range of industry sources.

Transport Costs

Some LNG offtakers will consider the entire cost of transportation—including vessel charter rates, fuel cost, canal fees, and other cost items—as variable. However, some of the major portfolio players—such as Shell, BP, Total, EDF, Engie, and Cheniere Marketing—most likely have LNG carriers on long-term time charters. To the extent they have no flexibility to redirect these vessels to more profitable routes on short notice, they will likely treat at least part of the vessel charter cost as a sunk cost. Vessel fuel costs and canal fees are variable costs that US LNG offtakers will only have to pay when they lift contracted LNG volumes from US terminals. Various industry sources estimate that the Panama Canal toll for a midsize LNG carrier is in the range of \$570,000²⁵ to \$580,000²⁶ per round trip, for example.

Regasification Cost

The treatment of regasification costs is somewhat inconsistent within the research community. Some industry sources consider the regas cost as part of the delivered cost structure; some include it in Europe, where LNG competes with pipeline gas, but exclude it in Japan and South Korea, where LNG has no pipeline gas alternative; and some exclude it altogether. The question is not trivial, as the cost of regasification is not negligible. Various sources estimate it at around \$0.3 to \$0.4 per MMBtu,²⁷ which can make or break the economics of US LNG exports in the current low overall price environment.

Regasification costs should not be a factor in the export decision to destination markets where US LNG competes only with other LNG sources on the spot market (like in Japan or South Korea). In these markets, all competing LNG marketers have to pay the cost of regasification. On the other hand, US LNG will have to be competitive with pipeline gas in other markets like Western Europe, where significant and increasing amounts of pipeline gas is also traded on the spot market. In these destination markets, the additional cost of regasifying US LNG has to be included in the delivered cost as a variable item. In other words, the gas-on-gas competition is on the pipeline side in Europe and on the LNG side in Japan and South Korea, the two largest LNG importers in Asia. Therefore, regasification costs should be treated differently in the two regions.

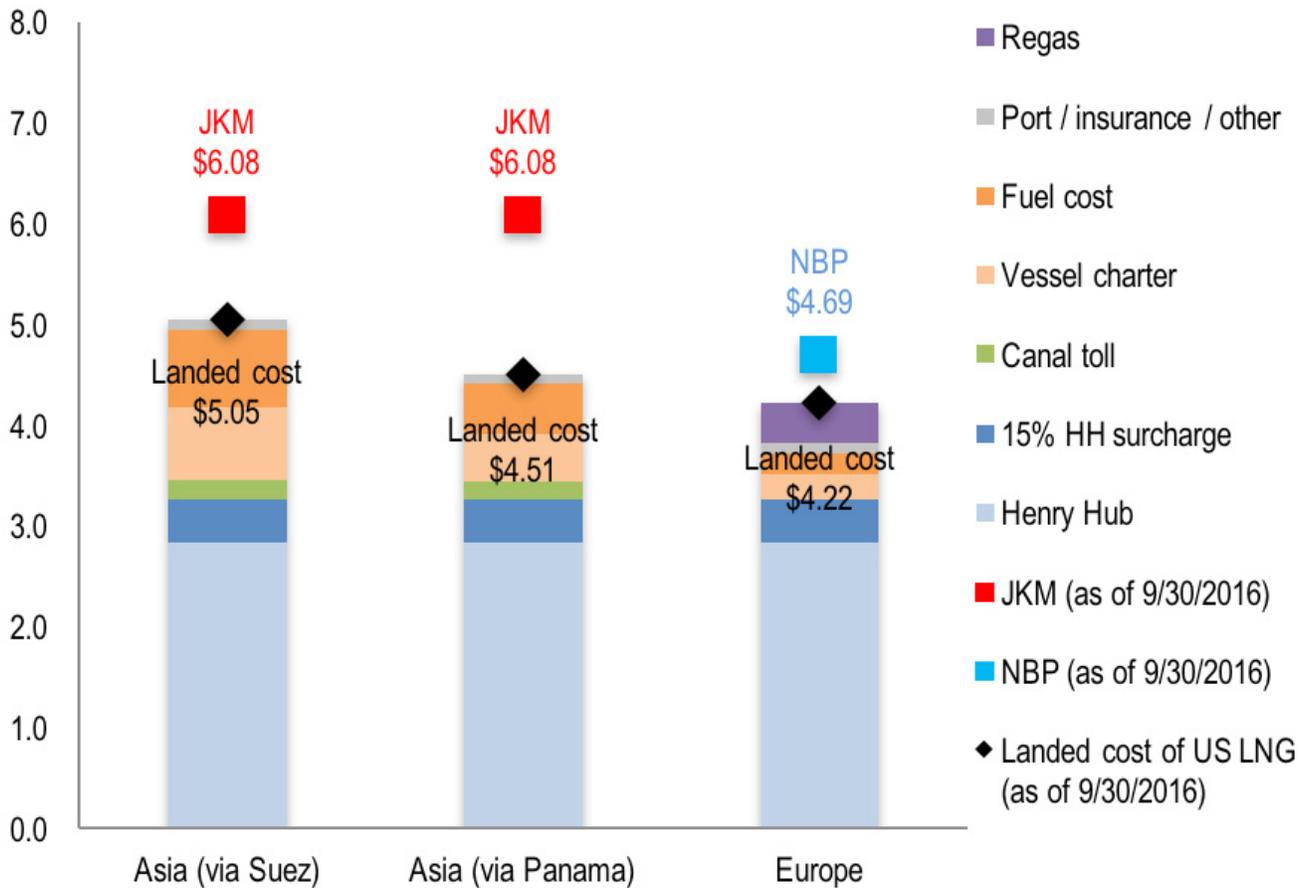
THE CURRENT COMPETITIVENESS OF US LNG IN OVERSEAS MARKETS

Based on our current estimates of the delivered cost of US LNG on a variable cost basis, we find that the arbitrage window remains open (as of September 30, 2016) in both the European and Asian markets (Figure 3). This is quite remarkable, given how much spot natural gas prices have fallen in both regions over the last two years. Gas prices at the national balancing point (NBP) in the UK—one of the most liquid gas hubs in Europe and a widely used proxy for European spot gas prices—were at \$4.69 per MMBtu as of September 30, 2016, down by more than 40 percent from two years ago. The Japan Korea Marker (JKM)—the

most widely used Asian spot LNG price benchmark—was down by almost 60 percent from two years ago at \$6.08 per MMBtu as of the end of September 2016.

The fact that the delivered cost of US LNG could stay lower than rapidly falling spot prices in both Europe and Asia is due to a combination of factors that have reduced the landed cost of US LNG substantially since 2012. The variable cost of delivering US LNG to Asia was about \$8.0 per MMBtu in 2012, but has dropped to about \$4.5 per MMBtu by mid-2016 (Figure 4).

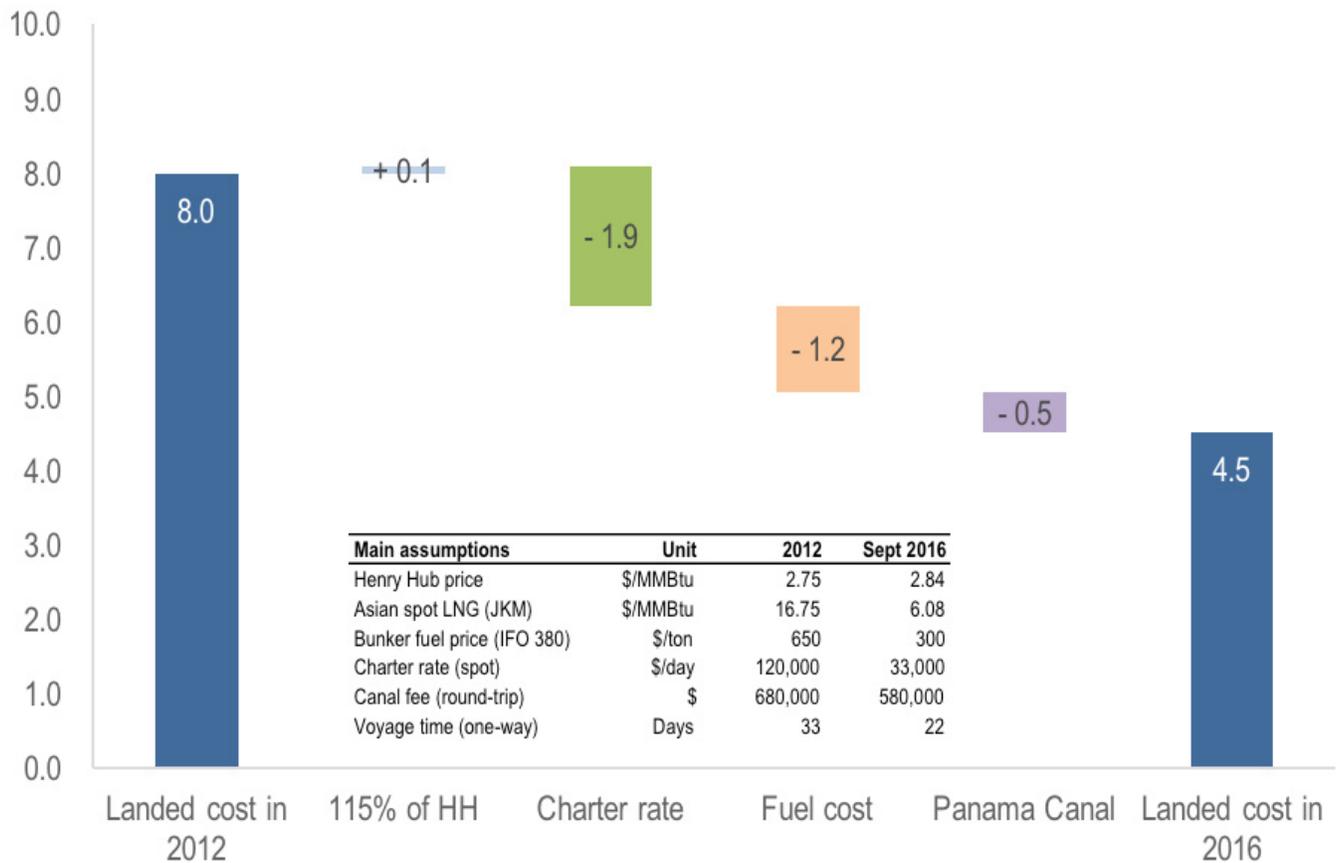
Figure 3: Delivered Cost of US LNG in Asia and Europe (as of 9/30/2016, \$/MMBtu)



Main assumptions: Henry Hub gas price at \$2.84 per MMBtu (spot price as of September 30, 2016), vessel capacity at 145,000 cubic meters, vessel charter rate at \$33,000 per day, bunker fuel cost at \$300 per ton, journey times (one-way) at 33 days, 22 days, and 11 days, respectively.

Source: Authors' estimates.

Figure 4: Delivered Cost of US LNG in Asia in 2012 and 2016 (\$/MMBtu)

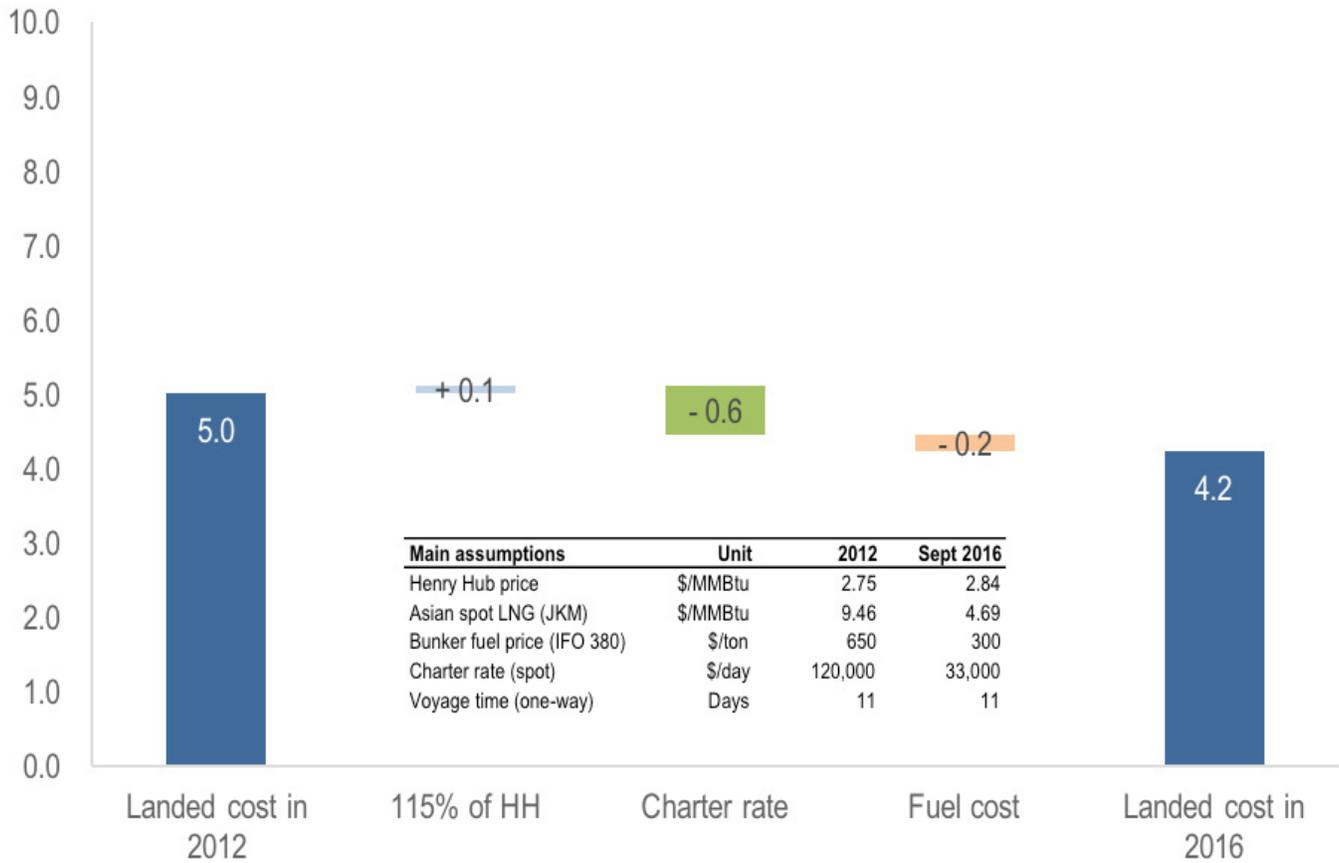


Source: Authors' estimates.

As of September 30, 2016, Henry Hub prices were only slightly higher than the average price in 2012, so the changing cost of the natural gas feedstock played no major part in the sharp decline of the landed cost of US LNG.²⁸ Vessel charter rates and shipping fuel costs have dropped substantially since 2012 (as explained in greater detail in the next section), lowering the delivered cost by an estimated \$1.9 per MMBtu and \$1.2 per MMBtu, respectively. The recently reopened expanded Panama Canal now enables all but the biggest LNG carriers to use a shorter route from the US Gulf Coast to Asia,²⁹ which can further reduce the cost of transporting US LNG to Asian markets.

The delivered cost to the European market has similarly declined from an estimated \$5.0 per MMBtu in 2012 to \$4.2 per MMBtu in September 2016. The same factors (except the Panama Canal expansion) contributed to the lower delivered cost of US LNG in Europe as in Asia (Figure 5).

Figure 5: Delivered Cost of US LNG in Europe in 2012 and 2016 (\$/MMBtu)



Source: Authors' estimates.

DETERMINANTS OF US LNG EXPORT COMPETITIVENESS

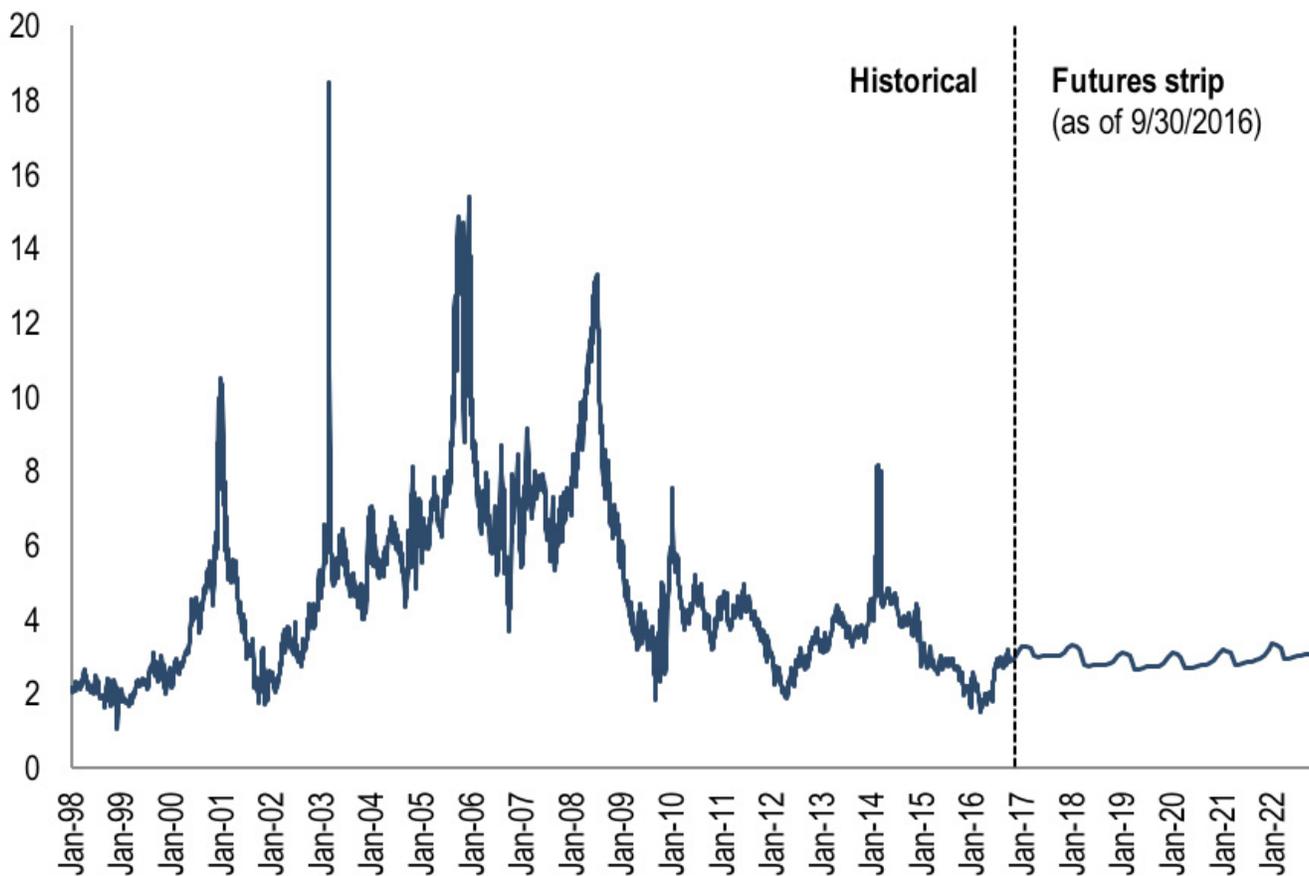
Each of the factors contributing to the overall decrease in the delivered cost of US LNG in overseas markets in recent years is subject to a considerable degree of uncertainty, and changes in each of these “moving parts” can impact the future economics of US LNG exports significantly.

Henry Hub Prices

The Henry Hub gas price—the pricing basis in US LNG contracts—was highly volatile during the 2000–2010 period, fluctuating between \$2 and \$15 per MMBtu. US

gas prices have been generally lower and more stable since the start of the US shale gas production boom and the emergence of the Marcellus and Utica shale plays in particular. Due to the abundance of low-cost natural gas in North America and a substantial drop in shale gas production costs in recent years, medium-term Henry Hub gas price expectations have shifted markedly lower. The current futures curve indicates that the market now anticipates Henry Hub prices to stay in the \$2–4 per MMBtu range in the foreseeable future (Figure 6).

Figure 6: Henry Hub Gas Prices and the Futures Strip as of 9/30/2016 (\$/MMBtu)



Source: EIA, Bloomberg.

However, history suggests that Henry Hub gas prices could very well turn out to be more volatile going forward than the futures curve suggests, which, in turn, could impact the competitiveness of US LNG in overseas markets. The cold spell in Q1 2014 illustrates that Henry Hub prices can be extremely volatile even in the post–shale boom period. In February 2014, the Henry Hub gas price jumped to a monthly average of \$6 per MMBtu from an average of \$4.5 per MMBtu in the preceding two months. Henry Hub prices, at times, exceeded \$8 per MMBtu at the height of the cold spell as gas demand spiked, stock levels fell to historic lows, and well freeze-offs curtailed pipeline gas flows from producers to consumers.³⁰ Such extraordinary seasonal swings may very well force a temporary shut-in of US LNG exports, especially in periods when US netback margins are relatively thin.

Most analysts expect little material upward pressure on Henry Hub prices from the gradual ramp-up of US LNG export volumes. The latest assessment by the EIA (from October 2014) found that even a massive surge in exported LNG volumes—to as high as 20 Bcf/d—would only increase average natural gas prices by 11 percent in EIA’s reference case scenario, and about 5 percent if tight oil and shale gas resources are indeed as abundant as foreseen in the EIA’s high oil and gas resource case,³¹ which has historically been a better guide to the supply potential of American shale plays than the agency’s reference case projections.³² A recent study by IHS Energy suggests that more than 1,400 Tcf of natural gas (equivalent to about fifty years of current consumption) could be economically produced at a break-even Henry Hub gas price of less than \$4 per MMBtu, of which more than 800 Tcf (or about thirty years of current consumption) is available at \$3 per MMBtu or less.³³

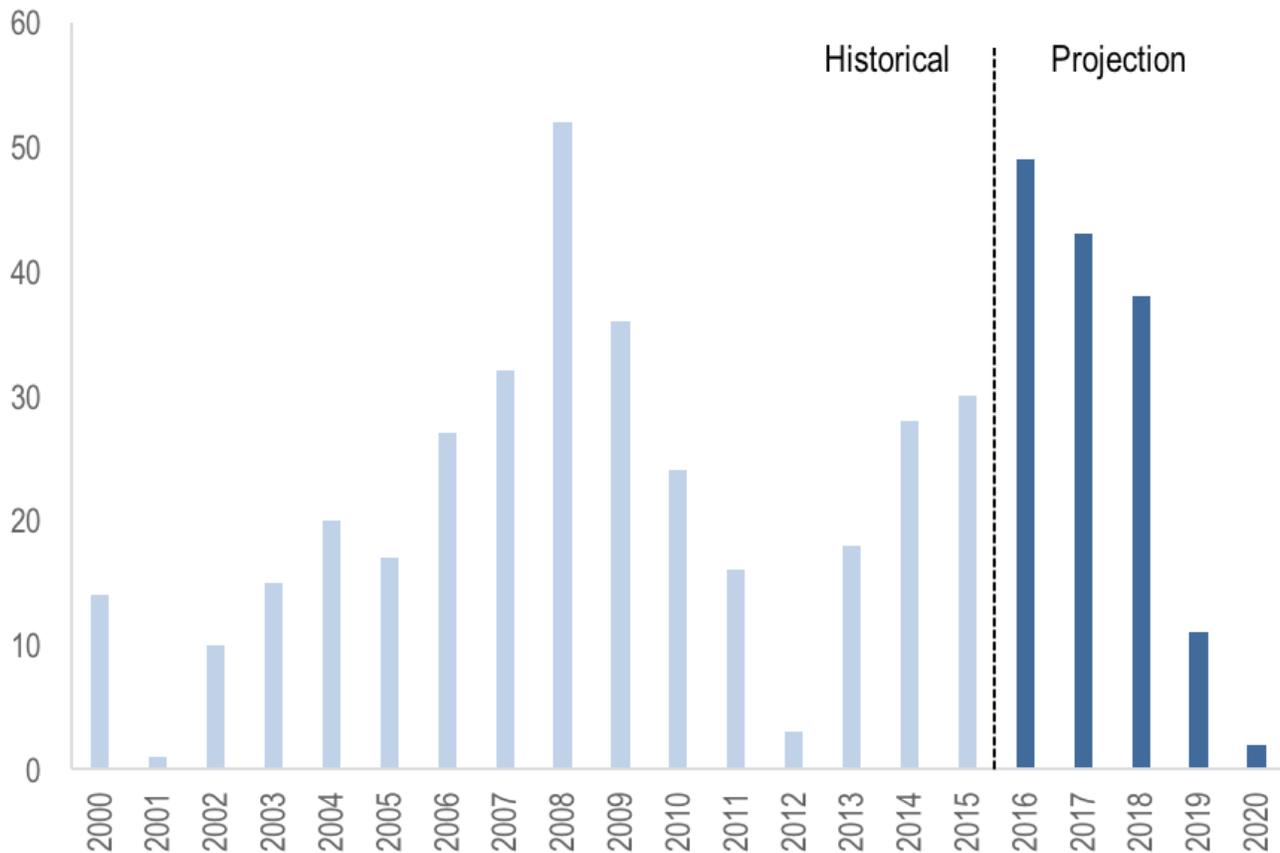
Potential regulatory restrictions on shale gas production, such as further limits on methane emissions, represent another uncertainty for Henry Hub prices. Tightening regulation could drive up production costs, depending on how the actual measures are designed. Furthermore, opposition from a growing “keep it in the ground” movement to new natural gas infrastructure—stemming from concerns over local safety risks and climate change—may also constrain gas supply in some regions and affect prices.³⁴

Vessel Charter Rates

Spot LNG charter rates for an average-size LNG tanker were around \$33,000 per day on the first week of October 2016.³⁵ Long-term rates, by nature more stable than spot rates, remain higher at around \$70,000 per day, which Bloomberg New Energy Finance reckons is “the rate necessary to justify returns” for vessel operators.³⁶ However, we believe that short-term charter rates are more relevant than long-term rates when assessing US LNG export economics, as offtakers using LNG carriers on long-term charters will most likely consider vessel charter costs as a sunk cost.

Spot charter rates have risen sharply in the aftermath of the Fukushima nuclear disaster in 2011 and the subsequent expansion of spot LNG trade. Spot and short-term rates more than doubled from around \$70,000 per day in early 2011 to a peak of more than \$160,000 in 2012. But the high charter rates in the 2011–2013 period—and the expected increase in global LNG trade driven mainly by Australian and US export projects—triggered an order boom between 2011 and 2014, and vessel deliveries under these orders will keep entering the market through the end of the decade (**Figure 7**). Fleet operators increased the size of the global LNG vessel fleet by a quarter between 2012 and 2015. As of January 2016, about 150 new LNG carriers were on order. When delivered, these additional vessels could boost today’s LNG fleet by an additional 35 percent in a couple of years.³⁷

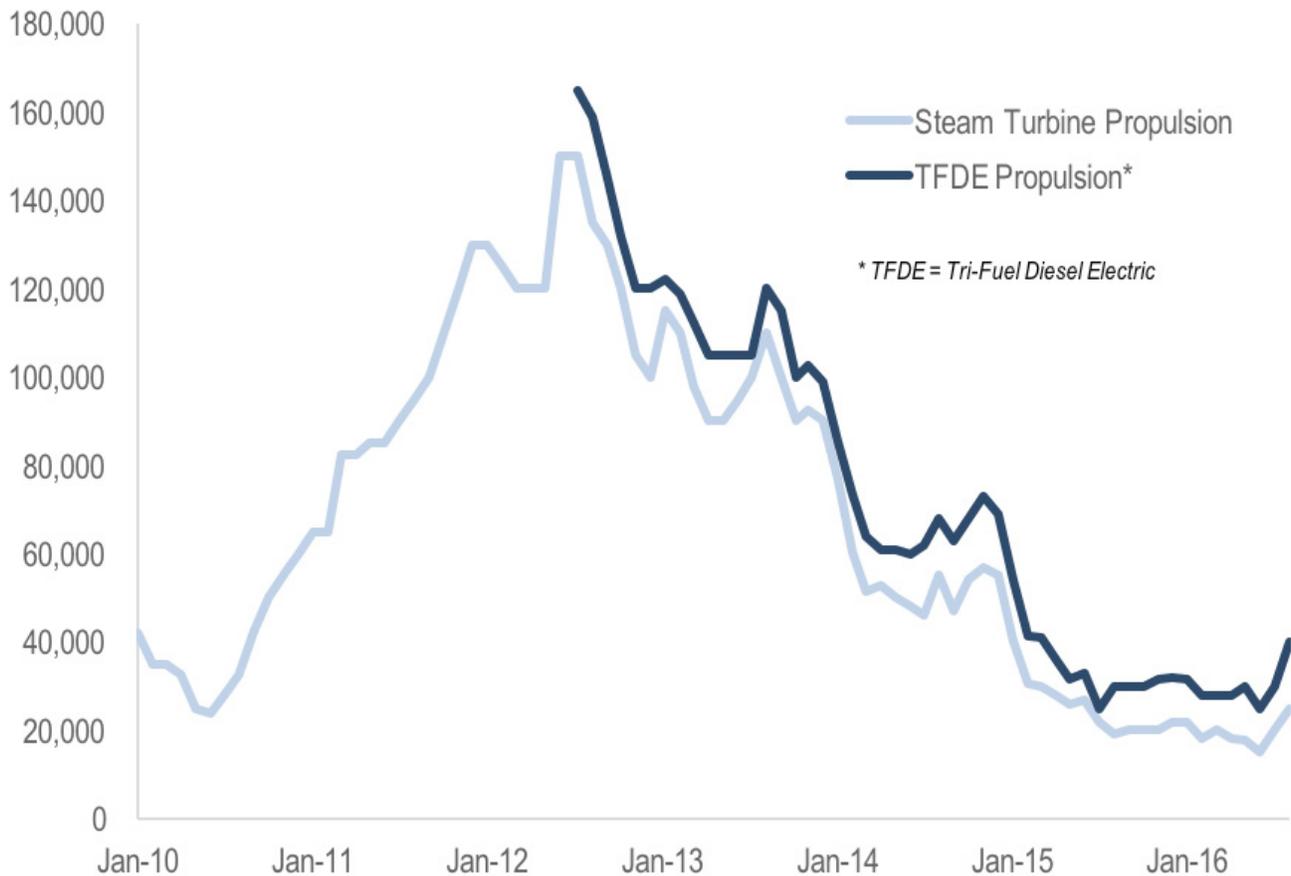
Since the 2012 peak, spot LNG vessel charter rates have dropped by nearly 80 percent to around \$30,000 per day in early 2016 (**Figure 8**). The dramatic drop in spot LNG charter rates is attributable to a number of factors, some of them cyclical and some structural. The growing LNG shipping overcapacity after the 2011–2014 order boom and disappointing LNG demand in some key Asian markets are the most important cyclical drivers of the spot charter rate collapse. Lower oil and shipping fuel prices also helped reduce LNG shipping rates on a cyclical basis.

Figure 7: Number of LNG Tankers Delivered and in the Orderbook

Source: GIIGNL, IGU 2016 World LNG Report, IHS ³⁸

Meanwhile, improvements in vessel design and engine efficiency have reduced boil-off gas losses in newer vessels,³⁹ and rendered older vessels—which are more often forced to compete in the spot market—less competitive at the same time.⁴⁰ This represents a structural reduction in spot charter rates, which will likely be sustained even if the LNG shipping market tightens over time. The emergence of Australia as a major supplier of LNG to the Asian market is also shifting the geographic patterns of LNG trade, shortening voyages and reducing shipping capacity demand on a ton-mile basis. The greater efficiency of the existing fleet (that is, the fact that the same number of vessels can transport more LNG on shorter voyages) also means that supply capacity is de facto expanding even without the addition of any new vessels. This dynamic will further contribute to the structural softening of the LNG shipping market as shorter trade routes emerge.⁴¹

Industry sources generally expect the shipping capacity overhang—and low spot LNG charter rates—to persist in the foreseeable future. Affinity Research, for example, expects overall LNG vessel utilization to stay in the 75–80 percent range until 2018, and remain below 85 percent through the end of the decade (**Figure 9**).⁴² In shipping markets, pricing tends to remain under pressure at utilization rates below 85 percent.⁴³ Some market analysts expect a tentative recovery in LNG spot charter rates toward the end of the decade, as capacity additions slow down and new liquefaction projects gradually absorb the shipping capacity overhang. Hence, there are forecasts that predict spot LNG day rates could rise to as high as \$75,000 by the end of the decade.⁴⁴

Figure 8: LNG Spot Charter Rates (\$ per day)

Source: Affinity Research.

But delays in LNG projects currently under construction in Australia, the United States, and elsewhere represent a downside risk to the outlook for LNG shipping rates in the medium term. A significant portion of LNG carriers in the orderbook have been ordered to serve a specific LNG terminal project. If new LNG projects are delayed, then these vessels, in addition to those ordered “on spec,” will temporarily have to find employment in the spot market.

In theory, scrapping older LNG carriers or converting them to floating regasification (FSRU) or liquefaction (FLNG) vessels can help reduce the current oversupply in LNG shipping capacity.⁴⁵ But given the relatively modern LNG fleet—about 78 percent of the vessels are fifteen years old or less⁴⁶—scrappage and conversions are

not expected to play a major role in easing the capacity overhang in the current cycle.⁴⁷ In 2015, for example, only three vessels were scrapped and another four were marked for conversion out of a total fleet of 449 vessels at the end of the year.⁴⁸

On the other hand, a Fukushima-type “black swan” event can quickly increase demand for spot LNG cargoes and put substantial upward pressure on spot LNG charter rates almost immediately.

Vessel Fuel Costs

Most modern LNG carriers use a combination of traditional marine bunker fuels and boil-off gas for propulsion.⁴⁹ Overall, fuel costs represent about 30 percent to 50 percent of the transportation cost,

Figure 9: LNG Fleet Utilization Forecast

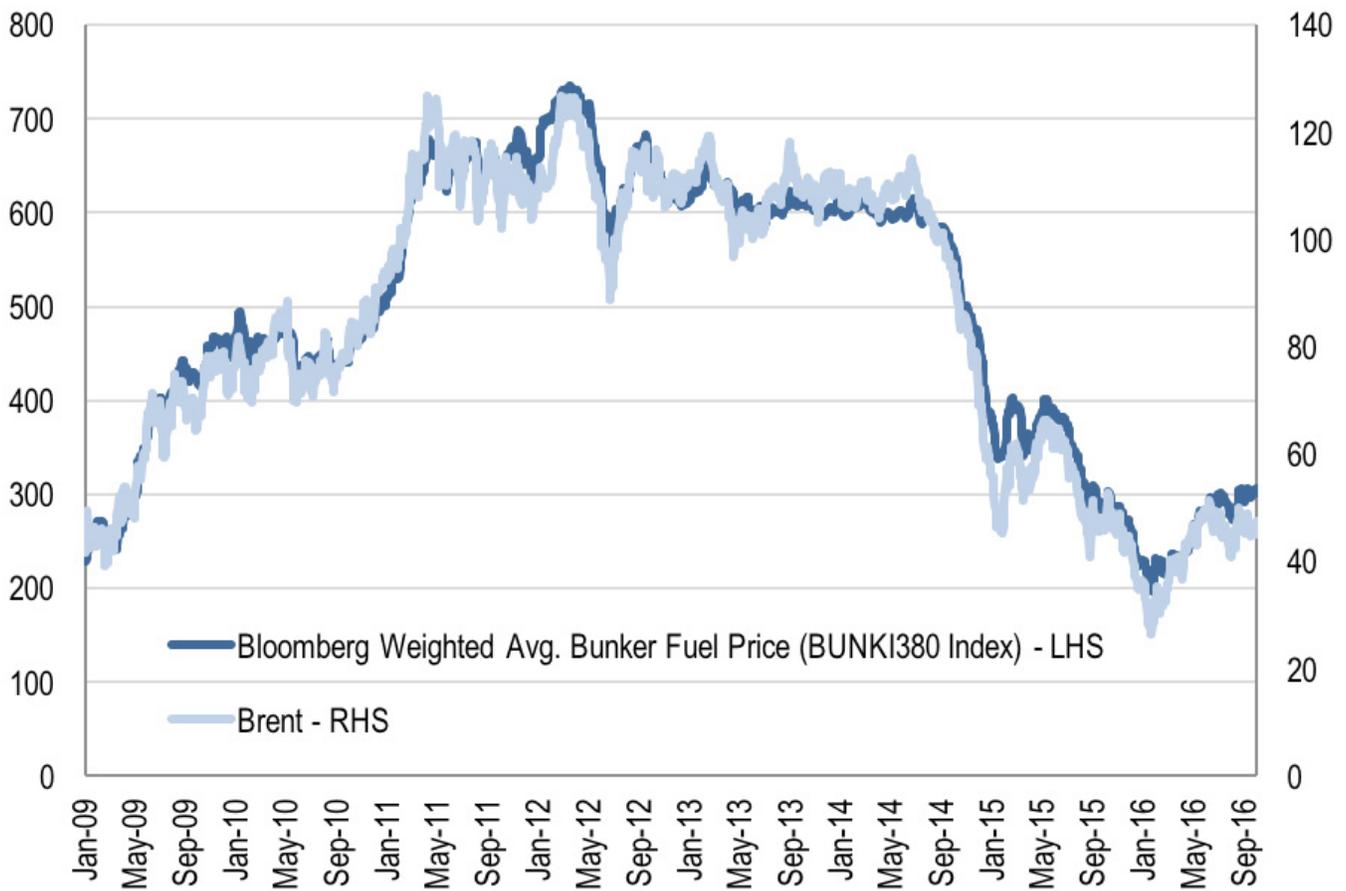
Source: Affinity Research.

depending on the length of the journey and a host of other variables, including oil and gas price levels, vessel size, and propulsion type, among other factors.

Bunker fuel costs have decreased substantially with the 2014–2016 oil price collapse. In the 2011–2014 period, when the average Brent price was \$108 per barrel, the lowest-quality bunker fuel grade (IFO 380) traded mostly in the \$600–750 per ton range (**Figure 10**). As of September 30, 2016, when Brent traded at \$48 per barrel, IFO 380 prices averaged a little over \$300 around the world, according to Bloomberg data.⁵⁰ Marine gasoil (MGO), which is also used in certain types of LNG vessel engines, trades at a premium to fuel oil-quality shipping fuel grades.⁵¹ We can expect bunker fuel prices to remain very strongly correlated with crude oil price movements

in the future, and both will likely exhibit a high degree of volatility going forward, potentially impacting US LNG export economics.

Most LNG carriers have dual-fuel engines, and, in addition to bunker fuels, they also use some portion of the transported liquid gas—the so-called boil-off gas or BOG—for propulsion. The “price” of BOG fuel is the opportunity cost at which the transported LNG could have been sold, should it not have been used for propulsion instead. BOG fuel costs have also declined substantially in recent years, as both spot and oil-indexed LNG prices dropped significantly in major gas markets around the world. Asian (JKM) spot LNG prices averaged \$13.9 per MMBtu in 2014, but only about \$5.1 per MMBtu in the first nine months of 2016. European spot natural gas prices at the NBP hub averaged \$8.2 per MMBtu in

Figure 10: Ship-Use Bunker Fuel and Brent Crude Prices (\$/ton, \$/barrel)

Source: Bloomberg.

2014, but were down to an average of \$4.3 per MMBtu in the first nine months in 2016. LNG prices—and the opportunity cost of boil-off gas—have historically been highly volatile, and we can expect continuing volatility, seasonal swings, and idiosyncratic events to impact the economics of US LNG exports in the future.

The Panama Canal Expansion

The expanded Panama Canal, which opened to commercial traffic in June 2016,⁵² has shortened the journey from the US Gulf Coast to East Asia by about a third from 33 days (one-way) via the Suez Canal route to 22 days.⁵³ In our estimate, the shorter travel time can reduce the delivered cost of US LNG to the Asian market by \$0.5 to \$1.0 per MMBtu, depending on the vessel charter rate (Figure 11). However, a Citi report noted earlier this year that the Panama Canal route may be problematic for spot LNG

cargoes, as canal slots have to be booked several months in advance and unscheduled spot cargoes may have to wait in line.⁵⁴ The Panama Canal expansion represents a structural change that can improve the economics of US LNG exports in the Pacific Basin on a sustained basis. However, potential wait times may erode some of the Panama Canal savings for spot LNG cargoes and, at times, even challenge the practicality of US LNG sales to Asia on a spot basis.

Spot Prices in Target Markets

Spot natural gas and LNG prices in the destination markets are yet another moving part in the US LNG export equation. Spot LNG prices are subject to a great deal of uncertainty, particularly on the demand side. Climate policy efforts—from reducing coal consumption to increasing renewables use and energy efficiency—can

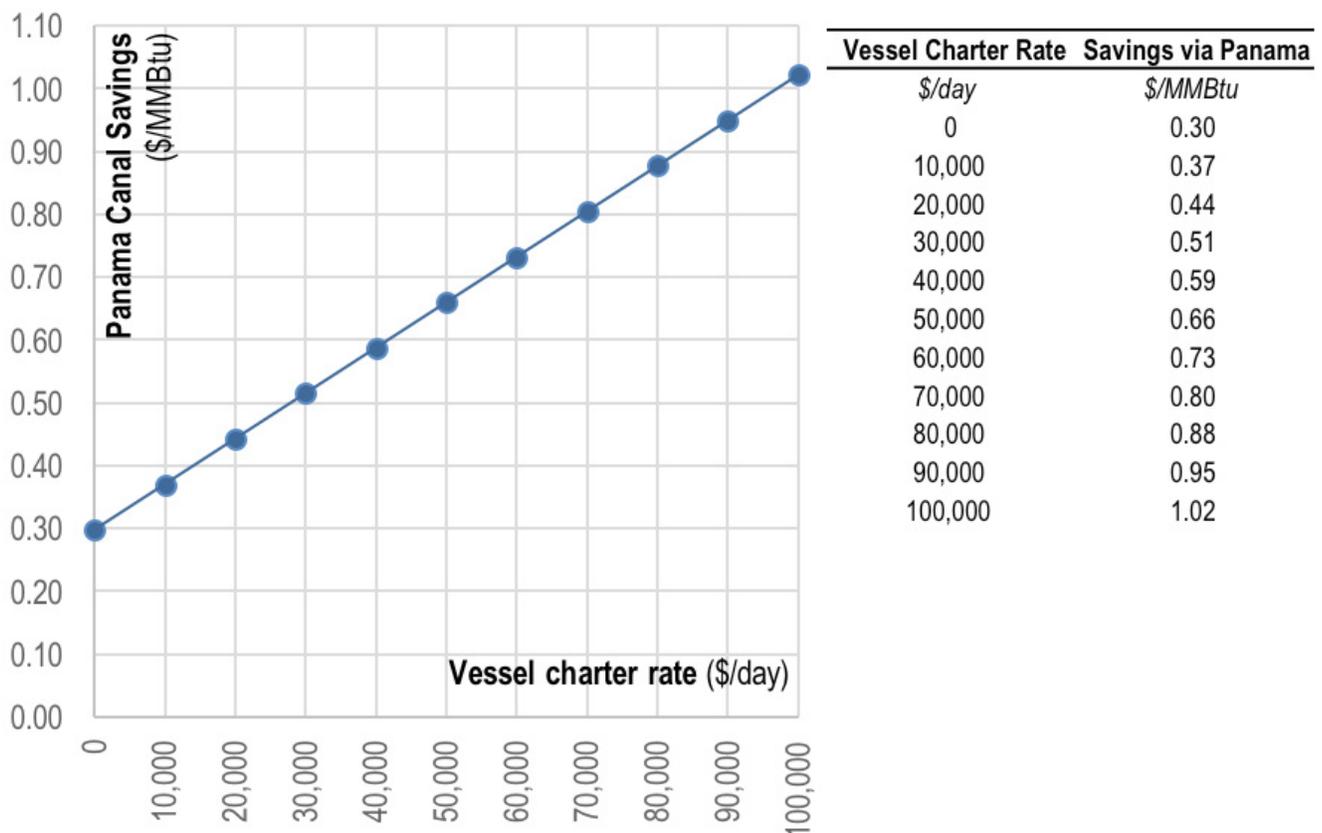
materially impact natural gas demand in major economies around the world. Relative coal and gas prices and the level of carbon pricing will determine how much coal-to-gas switching will take place in the electricity sector.

The pace and scale of nuclear restarts in Japan and the development of India’s gas import infrastructure can both have a significant impact on the demand for spot LNG cargoes and spot natural gas prices in Asia. Normal weather-related demand swings and unplanned disruptions present further demand-side uncertainties for spot LNG prices around the world.

The supply side—though somewhat more predictable than demand—is also highly uncertain. LNG liquefaction

projects are large, visible, long lead time projects, and supply from these terminals could, in theory, be forecasted with a reasonable degree of accuracy at least five years in advance. However, major LNG project sanctions were plagued by substantial delays in recent years, which complicates projections of future LNG supply. An Ernst & Young report found that 68 percent of the surveyed large-scale LNG projects suffered schedule delays.⁵⁵ Goldman Sachs estimated in 2014 that the average delay for an LNG project was close to three years,⁵⁶ although the length of these delays should drop significantly as the much-delayed Australian projects enter service,⁵⁷ and less complex US terminal projects, which are more likely to be delivered on time,⁵⁸ take center stage.

Figure 11: Estimated Savings Due to the Panama Canal Expansion



Main assumptions: Henry Hub gas price at \$2.84 per MMBtu (spot price as of September 30, 2016), vessel capacity at 145,000 cubic meters, vessel charter rate at \$33,000 per day, bunker fuel cost at \$300 per ton, journey times (one-way) at 33 days, 22 days, and 11 days, respectively.

Source: Authors’ estimates.

Existing producers could also upset the supply side of the LNG market balance. A recent note by PIRA Energy Group noted that Qatar and Trinidad, for example, can potentially redirect gas exports to regional and local markets at times of weak spot LNG prices, which could alleviate the growing LNG supply glut and support spot gas prices in major importing regions around the world.⁵⁹ Russia's gas marketing strategy—whether the country will use its substantial spare production capacity to declare a “price war” and defend its market share in Europe—presents yet another source of uncertainty for natural gas supply and prices.⁶⁰

The overall size of the spot LNG market may increase substantially, if expiring long-term LNG contracts are not renewed, and if Japanese LNG buyers—following an antitrust investigation by the country's Fair Trade Commission⁶¹—decide to remove destination restrictions from existing long-term contracts and resell unwanted LNG volumes on a spot basis. Oil prices and oil-indexed gas prices will also indirectly impact the competitiveness of US LNG in overseas markets, at least to the extent that existing oil-linked contracts have some volumetric flexibility embedded in them, and to the extent that anticipated oil price levels impact the competitiveness of future LNG projects—and thus future LNG supply—backed by traditional oil-indexed contracts.

THE MEDIUM-TERM COMPETITIVENESS OF US LNG

To stress test US LNG export economics in Europe and Asia, we used Goldman Sachs's admittedly bearish medium-term price forecasts (from February 2016) for these two markets, and compared them to the delivered cost of US LNG in these respective markets. Goldman Sachs anticipates European and Asian spot LNG prices to average only \$4.0 per MMBtu and \$4.25 per MMBtu, respectively, from 2018 through the end of the decade,⁶² well below the price levels seen in the past ten years. However, future spot LNG prices in both markets may be higher, if LNG demand in China surprises to the upside, for example. This may very well turn out to be the case, if domestic gas production in China continues to disappoint,⁶³ pipeline imports from Russia get delayed (or never materialize),⁶⁴ or regulatory measures—such as further restrictions on coal use or gas market reforms—materially improve the competitiveness of gas vis-à-vis coal in the Chinese energy system.⁶⁵ Greater-than-expected demand from frontier LNG markets using cheap floating regasification terminals (FSRUs) and more widespread use of natural gas in the transportation sector represent further upside potential for spot LNG prices in the medium term.

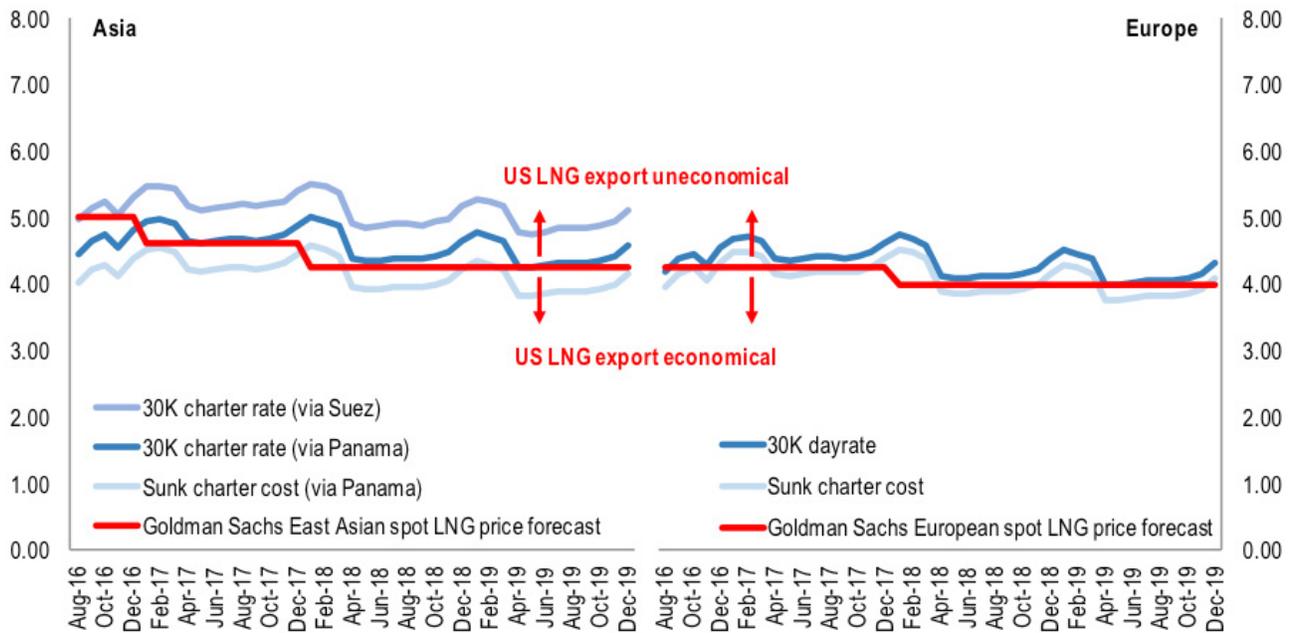
We derived delivered US LNG costs by multiplying Henry Hub futures prices (as of September 30, 2016) by 115 percent, and adding to this our transportation cost estimates to Europe and Asia, as calculated by our model. The results of this exercise suggest that the netback margins for US LNG exporters have become very tight, at least at the relatively low spot gas price levels forecasted by Goldman Sachs. This analysis suggests the arbitrage window for US LNG might not be open at all times. The window will more likely open and close periodically and, at times, may be open for some offtakers (for example, those who treat vessel charter rates as sunk cost) but closed for others (**Figure 12**).

We also calculated the Henry Hub break-even prices that will be required to keep US LNG exports profitable on a variable cost basis in overseas markets. Our analysis suggests that Henry Hub prices will have to remain fairly low (below \$3.0 per MMBtu) on a sustained basis to keep US LNG costs competitive in both Europe and Asia, assuming that gas prices in these markets indeed turn out to be as low as Goldman Sachs's medium-term forecast suggests (**Figure 13**). Current medium-term Henry Hub

gas price projections by various private sources generally fall in the \$3–3.5 per MMBtu range,⁶⁶ while the reference case in the EIA's latest 2016 Annual Energy Outlook anticipates US gas prices to gradually increase to as high as \$4.9 per MMBtu by 2020.⁶⁷ These price levels would not allow US terminals to operate constantly at high utilization rates, unless overseas spot gas prices increase substantially from their current levels and remain well above the price levels envisioned in Goldman Sachs's earlier medium-term projections.

We performed a sensitivity analysis to determine how sensitive US LNG netback margins will be to Henry Hub gas prices and LNG vessel charter rates. Our analysis indicates that US LNG will most likely be competitive in both Asia and Europe at Henry Hub price levels in the \$2.5–3.0 per MMBtu range, even if vessel charter rates increase over time. But if Henry Hub price levels rise above \$3.5 per MMBtu, then the arbitrage window will likely close in both markets, almost irrespective of LNG charter rates (**Figure 14**). Our conclusions assume that both European and Asian spot prices will remain very low, at \$4 per MMBtu and \$4.25 per MMBtu, respectively, over the medium term.

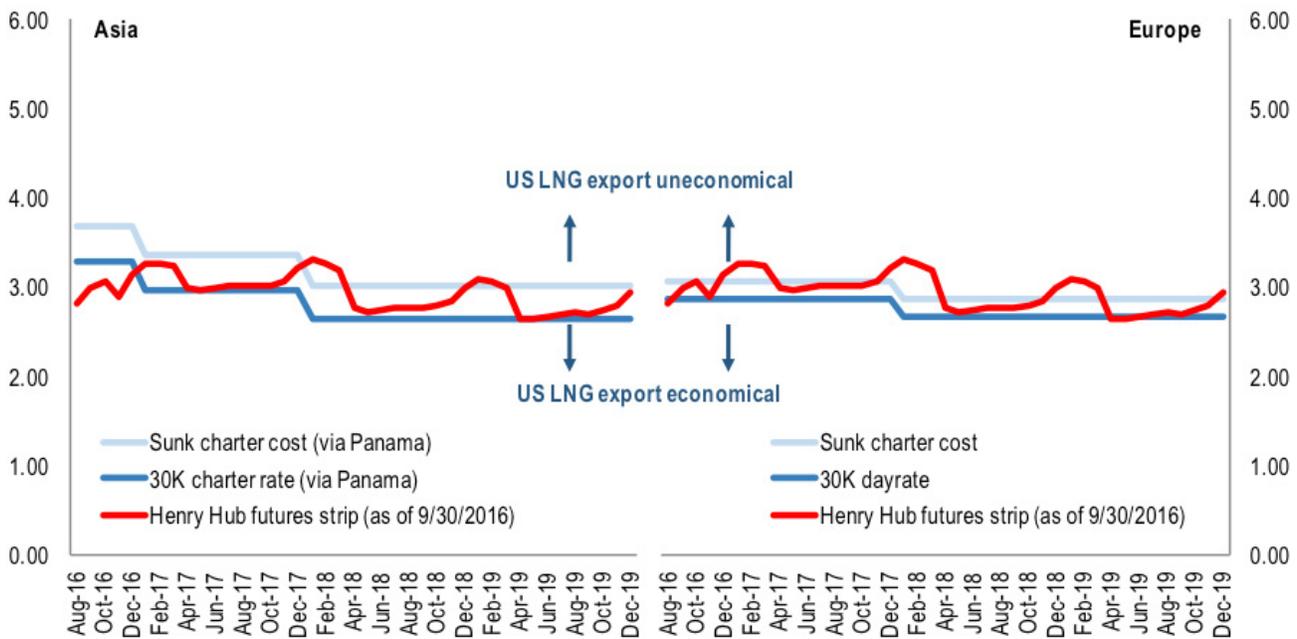
Figure 12: Delivered Cost of US LNG versus Spot Price Forecasts in Asia and Europe



Main assumptions: vessel capacity at 145,000 cubic meters, bunker fuel cost at \$300 per ton, journey times (one-way) at 33 days (Asia via Suez), 22 days (Asia via Panama), and 11 days (Europe), regas cost at \$0.4 per MMBtu (Europe only), Henry Hub derived from futures strip (as of 9/30/2016).

Source: Authors' estimates.

Figure 13: Break-Even Henry Hub Price Required for Positive Netback Margin in Asia and Europe



Main assumptions: vessel capacity at 145,000 cubic meters, bunker fuel cost at \$300 per ton, journey times (one-way) at 33 days (Asia via Suez), 22 days (Asia via Panama), and 11 days (Europe), regas cost at \$0.4 per MMBtu (Europe only), Henry Hub derived from futures strip (as of 9/30/2016).

Source: Authors' estimates.

Figure 14: Sensitivity of US LNG Netback Margins to Henry Hub Gas Prices and Vessel Charter Rates in Asia and Europe

US LNG Netback Margin in Asia (via Suez) \$/MMBtu							US LNG Netback Margin in Asia (via Panama) \$/MMBtu						
Henry Hub Gas Price	LNG Vessel Charter Rate						Henry Hub Gas Price	LNG Vessel Charter Rate					
	0	30,000	60,000	90,000	120,000	0		30,000	60,000	90,000	120,000		
1.50	3.3	2.6	2.0	1.3	0.7	1.50	3.6	3.2	2.7	2.3	1.9		
2.00	2.7	2.1	1.4	0.8	0.1	2.00	3.0	2.6	2.1	1.7	1.3		
2.50	2.1	1.5	0.8	0.2	-0.5	2.50	2.4	2.0	1.6	1.1	0.7		
3.00	1.6	0.9	0.3	-0.4	-1.0	3.00	1.9	1.4	1.0	0.6	0.1		
3.50	1.0	0.3	-0.3	-1.0	-1.6	3.50	1.3	0.9	0.4	0.0	-0.4		
4.00	0.4	-0.2	-0.9	-1.5	-2.2	4.00	0.7	0.3	-0.2	-0.6	-1.0		
4.50	-0.2	-0.8	-1.5	-2.1	-2.8	4.50	0.1	-0.3	-0.7	-1.2	-1.6		
5.00	-0.7	-1.4	-2.0	-2.7	-3.3	5.00	-0.4	-0.9	-1.3	-1.7	-2.2		

US LNG Netback Margin in Europe \$/MMBtu							Main assumptions				
Henry Hub Gas Price	LNG Vessel Charter Rate						Unit	Asia (Suez)	Asia (Panama)	Europe	
	0	30,000	60,000	90,000	120,000						
1.50	2.3	2.0	1.8	1.6	1.4	Vessel capacity	m ³	145,000	145,000	145,000	
2.00	1.7	1.5	1.2	1.0	0.8	East Asia LNG (JKM)	\$/MMBtu	4.25	4.25	-	
2.50	1.1	0.9	0.7	0.4	0.2	European spot (NBP)	\$/MMBtu	-	-	4.00	
3.00	0.5	0.3	0.1	-0.1	-0.4	Bunker (IFO 380)	\$/ton	300	300	300	
3.50	0.0	-0.3	-0.5	-0.7	-0.9	Canal fee (round-trip)	\$	680,000	580,000	-	
4.00	-0.6	-0.8	-1.1	-1.3	-1.5	Regas cost	\$/MMBtu	-	-	0.40	
4.50	-1.2	-1.4	-1.6	-1.9	-2.1	Voyage time (one way)	Days	33	22	11	
5.00	-1.8	-2.0	-2.2	-2.4	-2.7						

Main assumptions: vessel capacity at 145,000 cubic meters, bunker fuel cost at \$300 per ton, journey times (one-way) at 33 days (Asia via Suez), 22 days (Asia via Panama), and 11 days (Europe), regas cost at \$0.4 per MMBtu (Europe only), Henry Hub derived from futures strip (as of 9/30/2016).

Source: Authors' estimates.

CONCLUSIONS

Based on the above analysis, the margin of competitiveness for US LNG exports has become very narrow even on a variable cost basis.⁶⁸ Given the current cost structure and price environment, there is room for US LNG to compete in overseas markets at the moment. But this market can easily disappear in the future, even with small changes in Henry Hub prices, vessel charter rates, shipping fuel costs, canal fees, overseas spot prices, and a host of other factors. If spot natural gas prices in overseas markets remain low, US LNG terminals will not always operate at close to full capacity over the medium term. In this price scenario, it is more likely the arbitrage window for US LNG offtakers will open and close periodically, and at least some portion of the US LNG export capacity will, at times, be forced to shut-in.

Low (or highly variable) utilization at the existing US LNG terminals could have profound implications for the feasibility of other LNG terminal projects awaiting final investment decisions in the United States. Poor utilization rates would mean that offtakers (though not the terminal developers) would most likely lose money on their long-term LNG contracts. Korean utility KOGAS, for example,

has committed to pay \$548 million in fixed fees every year for the option to use 3.5 million tonnes (about 0.5 Bcf/d) of liquefaction capacity at the second train of Cheniere's Sabine Pass terminal.⁶⁹ Other offtakers made similarly large financial commitments to secure US LNG export capacities, which they now may not fully utilize. Lower-than-expected utilization rates at existing projects (and concomitant financial losses for buyers of US LNG) would further temper the appetite of potential offtakers for additional long-term LNG contracts. Without such commitments, the next wave of LNG export projects, which will likely be needed to meet projected future demand sometime in the next decade, may not materialize in the foreseeable future, given the long lead times such projects require.

By adding a vast supply of flexible uncommitted LNG into the global natural gas market, US LNG is already changing gas market dynamics around the world in profound ways. Whether the world will want to buy all that gas, however, will depend on even small changes in a number of key variables, with significant consequences for future investment, technological and commercial innovation, and global gas trade.

NOTES

- 1 Genscape Proprietary Monitoring: LNG Intelligence Alerts, “Maran Gas Sparta Loads Cargo During Four Week Maintenance Outage,” September 28, 2016, <http://info.genscape.com/lng-monitoring-updates-2015>.
- 2 Jason Bordoff and Akos Losz (2016), “The Benign Energy Superpower? The United States Turns On the Gas,” Foreign Affairs, March 4, 2016, <https://www.foreignaffairs.com/articles/2016-03-04/united-states-turns-gas>.
- 3 US Department of Energy, “Long Term Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of October 3, 2016),” p. 1–3, http://energy.gov/sites/prod/files/2016/10/f33/Summary%20of%20LNG%20Export%20Applications_0.pdf. Note: five of the twelve projects with DOE authorization to export LNG to non-FTA countries are small-scale schemes, and one of the large-scale terminal projects with conditional DOE approval, Jordan Cove LNG, was subsequently rejected by FERC. As of October 6, 2016, a rehearing request by the developer of the Jordan Cove project was pending. Source: <http://www.naturalgasintel.com/articles/108005-japanese-energy-buyer-urges-ferc-to-reconsider-jordan-cove-lng-project>.
- 4 US Department of Energy, “A Proposed Change to the Energy Department’s LNG Export Decision-Making Procedures,” May 29, 2014, <http://energy.gov/articles/proposed-change-energy-departments-lng-export-decision-making-procedures>. For a detailed analysis of the procedural change, see David L. Goldwyn, “DOE’s New Procedure for Approving LNG Export Permits: A More Sensible Approach,” Brookings Institution, June 10, 2014, <https://www.brookings.edu/articles/does-new-procedure-for-approving-lng-export-permits-a-more-sensible-approach/>.
- 5 Richard McGregor and Ed Crooks, “Obama Backs Rise in US Gas Exports,” Financial Times, May 5, 2013, <https://www.ft.com/content/5af31212-b59e-11e2-a51b-00144feabdc0>.
- 6 Medium term refers to the time period through 2020.
- 7 Even though about two-thirds of the first 26 cargoes exported from the Sabine Pass terminal were delivered to Latin America, LNG demand in South America will remain highly seasonal, and the market overall will remain too small to absorb a substantial share of US LNG exports, once all five American terminals are operational. Total LNG import capacity in Latin America (including Argentina, Brazil, Chile, the Dominican Republic, and Puerto Rico) totaled 3.7 Bcf/d at the end of 2015, of which only about 1.9 Bcf/d remained unused on an annual basis (and probably much less during the peak season). This is only a small fraction of the 8.6 Bcf/d of total LNG export capacity expected online in the United States by the end of the decade. Regasification capacity in South America will likely grow modestly with small additions in Colombia, Haiti, and Uruguay (totaling less than 1 Bcf/d in aggregate), but these new import terminals will also be used on a seasonal basis. The International Energy Agency’s latest Medium-Term Gas Market Report expects no net increase in LNG imports in Latin America between 2015 and 2021, as reduced LNG demand in Brazil (due to slower electricity demand growth and renewable capacity additions) will offset potential gains elsewhere. In comparison to Latin America, both the European and the Asian LNG markets are vast, and given the right price signals, both markets have enough excess capacity to absorb most—or even all—US LNG exports from the five US export terminals. At the end of 2015, Europe had a total regas capacity of 20 Bcf/d, of which 15 Bcf/d was unused last year, while Asia had a total LNG import capacity of 54 Bcf/d, of which 32 Bcf/d remained unused in 2015. Sources: Jake Horslen, “Interactive: US LNG Avoids Europe, Flows to Higher Premium Markets,” ICIS, September 8, 2016, <http://www.icis.com/resources/news/2016/09/08/10032256/interactive-us-lng-avoids-europe-flows-to-higher-premium-markets/>; International Group of Liquefied Natural Gas Importers (GIIGNL), Annual Report 2016 Edition, http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2016_annual_report.pdf; International Energy Agency, Medium-Term Gas Market Report 2016, p. 114 and p. 123.
- 8 International Gas Union, 2016 World LNG Report, p. 17, <http://www.igu.org/download/file/fid/2123>.
- 9 Jason Bordoff and Trevor Houser (2014), “Natural Gas to the Rescue? The Impact of US LNG Exports on European Security and Russian Foreign Policy,” Center on Global Energy Policy, p. 22, http://energypolicy.columbia.edu/sites/default/files/energy/CGEP_American%20Gas%20to%20the%20Rescue%3F.pdf.
- 10 Credit Suisse, “LNG contracts in Japan—Seismic shift?” July 21, 2016, p. 2–4.

- 11 Cheniere Energy's Sabine Pass and Corpus Christi terminals signed take-or-pay contracts with a fixed capacity charge, while Cameron LNG, Freeport, and Cove Point use tolling agreements with fixed tolling fees
- 12 Note that the economics of US LNG exports look markedly less favorable on a full-cost basis (that is, for those potential offtakers who have not yet committed to any offtake agreements). On this basis, the cost structure of US LNG has to include the fixed capacity charges (or tolling fees) in addition to the variable costs. The full-cycle cost of US LNG is currently estimated at more than \$7 per MMBtu, which is higher than anticipated spot price levels in either Europe or Asia over the medium term. In other words, US LNG is currently not competitive on a full-cost basis, which explains the lack of interest in signing new offtake agreements by overseas customers, and the pause in the sanctioning of new liquefaction trains by US project developers beyond those already operational or under construction.
- 13 This is how US LNG export economics should work on paper. However, there is some disagreement among industry sources about the amount of US export capacity that is actually vulnerable to shut-in. A recent analysis by Barclays Commodities Research titled "Mind the Spread: A US-UK Gas Connection Returns" (April 19, 2016) suggested that a significant portion of US LNG capacity might not shut down, even if LNG exports become uneconomic for the offtakers on a variable cost basis. Barclays believes that "arbitrage values will only matter for 20-30% of the volumes currently under contract." The remaining capacity is sold either to utility end-users, who have guaranteed markets and can pass on their losses to their customers, or to portfolio players with firm resale agreements, which are typically "de-risked" (that is, hedged), according to Barclays. The bank believes that these volumes—accounting for about 70-80 percent of US LNG export capacity under contract—are likely protected from curtailments on economic grounds. Others, including Gordon Shearer, an affiliate at Poten & Partners, and Goldman Sachs, believe that the entire LNG export capacity in the United States can shut down, if the economics of LNG exports turns unfavorable. Goldman Sachs expects the utilization rate of the US LNG export capacity to average only less than 40 percent through 2022, according to a recent report titled "Overpowered: Too Much Fuel Is Competing for the Same Fleet of Power Plants" (February 15, 2016). Portfolio volumes, distance swapping, and LNG/pipeline swapping may further complicate our somewhat simplified approach to netback economics in real life.
- 14 This can be illustrated with a simple numerical example. Assuming that the fixed cost of US LNG exports is \$3 per MMBtu, the variable cost is \$4 per MMBtu, and the spot price in the most profitable overseas market is \$5 per MMBtu (close to the actual values in the first half of 2016), we can calculate the net gain/loss on trade in two scenarios. Note that exporting LNG is lossmaking on a full-cost basis but still economical on a variable cost basis, as the spot price is higher than the variable cost but lower than the full cost. If the offtaker continues exporting LNG, it will incur \$7 per MMBtu in costs (\$3 fixed plus \$4 variable), and gain \$5 per MMBtu on the overseas sale of LNG. The net loss on the trade is \$2 per MMBtu. If the offtaker stops exporting LNG, then it incurs \$3 in fixed costs with no offsetting gain from LNG trading. Thus the net loss is higher when the offtaker stops LNG exports than when it continues exporting despite the overall loss on a full-cost basis.
- 15 Anne-Sophie Corbeau, "Conclusion: LNG Markets—the Great Reconfiguration," in Anne-Sophie Corbeau and David Ledesma, editors (2016), *LNG Markets in Transition: The Great Reconfiguration*, Oxford University Press, p. 569.
- 16 Credit Suisse, "The Cheniere Complex: Pioneers of US LNG Export Remain in a Position of Strength," October 12, 2016, p. 11.
- 17 Barclays Equity Research, "Cheniere Energy: When the Going Gets Tough, the Customers Can't Get Going," February 5, 2016.
- 18 Credit Suisse, "The Cheniere Complex: Pioneers of US LNG Export Remain in a Position of Strength," October 12, 2016, p. 11.
- 19 Ibid.
- 20 Additionally, it also covers base differentials, according to Cheniere Energy's investor presentation from December 2011. See Cheniere Energy Investor Presentation, December 2011, p. 10, <http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9MTE3NjU4fENoaWxkSUQ9LTF8VHlwZT0z&t=1>.
- 21 Filipe Rufino, "Focus on Regasification Costs in Europe," ICIS, February 10, 2010, <http://www.icis.com/resources/news/2010/02/19/9336402/focus-on-regasification-costs-in-europe/>
- 22 See the previous section titled "The Economics of US LNG Exports" and footnotes 12, 13, and 14 for a more complete explanation of this dynamic.

- 23 The 15 percent Henry Hub surcharge is specific to Cheniere Energy's offtake agreements, but most industry sources assume that other US LNG tolling agreements apply a similar charge to cover the fuel losses during the liquefaction process.
- 24 Under tolling-type contracts (in the case of the Freeport, Cameron, and Cove Point terminals), offtakers are responsible for the procurement of their own feed gas. Under the take-or-pay contracts signed by the offtakers with Cheniere Energy's Sabine Pass and Corpus Christi terminals, the procurement of the feed gas is the terminal operator's responsibility.
- 25 Bloomberg New Energy Finance, "Unlocking the Panama Canal for LNG: Where Is Sabine Pass LNG Going and Will the Canal Help?" June 30, 2016, p. 5.
- 26 PIRA Energy Group, "Gas Trading and Shipping Americas—LNG, LPG and Ethane Shifting the Balance: The Role of US LNG in the Global Trade," February 2016, p. 13.
- 27 Goldman Sachs and Citi Research estimate European regasification costs at \$0.3 per MMBtu. See Goldman Sachs, "Structural Headwinds to Gas Supply, Sell Centrica," September 7, 2016, p. 35; and Citi Research, "Global Gas: US LNG Export Arbitrage under Threat," September 21, 2016, p. 3. Bloomberg's LNG netback calculator (using Poten & Partners data, available on the Bloomberg terminal) and Cheniere Energy estimate regasification costs at \$0.4 per MMBtu. For Cheniere Energy's estimate, see Bloomberg Brief: Power & Gas, "Cheniere May Miss Late 2015 Target for LNG Shipment," October 15, 2015, p. 2.
- 28 The same analysis would have led to a different result earlier in 2016, when Henry Hub prices were substantially lower than in September 2016. In the first quarter of 2016, for example, Henry Hub prices averaged only \$2.0 per MMBtu (compared to \$2.8 per MMBtu on September 30, 2016, and \$2.8 in the full year of 2012). Under those market conditions, the landed cost of US LNG was lower by an additional \$1 per MMBtu, and the historically low Henry Hub price (even compared to the already low 2012 average) was a significant contributor to the sharply reduced cost structure.
- 29 The EIA estimates that about 90 percent of the current LNG shipping fleet can now transit the Panama Canal, up from only about 6 percent prior to the expansion. See US Energy Information Administration, "Today in Energy: Expanded Panama Canal Reduces Travel Time for Shipments of US LNG to Asian Markets," June 30, 2016, <http://www.eia.gov/todayinenergy/detail.cfm?id=26892>.
- 30 Federal Energy Regulatory Commission, "Winter 2013–2014 Operations and Market Performance in RTOs and ISOs," April 1, 2014, p. 2–14, <https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf>.
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