


LNG and Renewable Power

Risk and Opportunity in a Changing World

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Executive Summary

Two important trends are transforming the energy industry across the globe. The production of relatively low-cost unconventional sources of natural gas—primarily in the United States and Canada, but potentially also in other parts of the world—has led to much heightened attention to the possibility of increased use of Liquefied Natural Gas (“LNG”) in world markets and a large number of proposed LNG export projects in North America. Several LNG export projects are under construction in North America (and will begin exporting in the next few years), and many more are proposed with the hope of being part of a “second wave” of LNG projects to begin service in the post-2020 time frame. At the same time, both technological progress and concerns about climate change risks are stimulating the development and deployment of various types of renewable energy sources around the world.

While the natural gas industry has traditionally viewed LNG as a substitute for oil in many markets, this paper explores whether the evolution of renewable energy sources suggests that LNG may be competing less with oil and more with renewable energy sources in markets outside of North America in the coming years. Such competition is evident in electricity generation markets as natural gas combined-cycle units and renewable energy sources compete to serve future electricity demand. Competition between natural gas and efficient electric heating (using heat pumps, for example) is less prominent, but emerging in some countries (*e.g.*, Germany). Thus, there are important and intensifying linkages between global natural gas and electricity markets that will impact developments in renewables markets and have feedback effects into the natural gas market.

This emphasis on LNG development takes place against a backdrop of several important market dynamics, including the recent collapse in world oil prices, a slow-down in China’s economy and its demand for natural gas, the commissioning of new LNG export projects in Australia, and a reduced need for natural gas in Japan due to the re-start of some of the country’s nuclear power plants. As a result of these factors, Asian LNG prices, which had risen to \$15/MMBtu (or more) in recent years, have now collapsed to roughly \$6-\$7/MMBtu, and the significant price differential between world oil prices and North American natural gas prices (that gave rise to the North American LNG projects now in development) has now declined dramatically. The deterioration of this price differential is bad news for both the LNG export projects in development (but not under construction) in North America and the energy companies that

signed up for long-term LNG export capacity from the new North American export projects (that are under construction and one of which will begin service in early 2016). These market suppliers need LNG delivered prices in Asia to be in the \$10-\$11 range in order to be profitable. With several more LNG export projects coming online in the 2015-2020 period and an expectation of continued low oil prices, global LNG markets are likely to be oversupplied for the next several years and the low LNG prices now observed seem likely to persist for some time. The fate of many of the proposed North American LNG export projects is increasingly uncertain in the new price environment (and some LNG export projects have already been delayed).

Thus, two important questions facing global LNG markets today are how quickly LNG supplies associated with the new LNG projects coming online over the next few years will be absorbed, and at what point in the future there might be a rebound in global LNG prices such that new LNG export terminals (beyond the terminals now under construction) are needed. The LNG export developers in North America (as well as buyers of LNG from the projects now under construction) are hoping that the worldwide LNG supply glut is temporary and that market conditions in the post-2020 time frame will improve.

The analysis in our paper suggests that market participants should be very cautious in thinking that the LNG supply glut is necessarily a temporary problem, because another important dynamic in world energy markets is the declining cost of renewable power and the prospect of increased penetration of renewables in the global power generation mix and thus competing with LNG as a “fuel source” for power generation. In fact, in some regions such as Germany and California, where renewable penetration has been high, gas demand growth has already been stunted by the penetration of renewables in the generation mix (causing a reduction in gas demand growth for power generation).

There is a real possibility of a significant shift towards more renewable power generation in some of the key Asian markets targeted by the LNG industry. While the current shares of wind, solar, and gas in China are each less than 5% of China’s total electricity generation, all three sources of electricity generation are projected to increase substantially over the next 25 years as the share of coal generation as a percentage of total generation is projected to decline significantly from

around 75% today to roughly 50% by 2040.¹ Gas, wind, and solar (as well as nuclear) will therefore all be competing to serve China's growing electricity needs. The relative costs of LNG and renewables discussed in this paper will likely be a significant factor determining which technologies achieve the highest penetration levels. Of course, the uncertainties regarding the costs of both renewables and delivered LNG over the coming decades remain significant and other factors not discussed in this paper will influence China's future electricity generation mix. Nonetheless, the expectation of declining costs of renewables (discussed in this paper) relative to LNG is noteworthy and creates the possibility of a potential shift towards even more renewable generation than is currently forecast in key Asian markets.

Since many LNG forecasts suggesting that the LNG supply glut is temporary rely on the assumption that natural gas demand from China and other countries in Asia will more than double in the next 20 years (in part due to gas demand in the power sector), these forecasts should be seen as highly uncertain given the potential for a significant shift towards more renewable power in China and throughout Asia that could limit the growth in gas demand and the need for LNG. Likewise, in Europe, despite the fact that declines in domestic natural gas production (as well as the perpetual desire to diversify away from Russian-sourced natural gas) are leading many to look at LNG as a potential alternative, the on-going shift towards more renewables may reduce the incentive to import significantly larger amounts of LNG.

LNG infrastructure is very capital intensive across the entire LNG supply chain. As a result of the billions of dollars of fixed costs, LNG projects and associated financing arrangements usually require long-term contractual arrangements for the necessary infrastructure. These contractual arrangements allow the developers of the LNG infrastructure to pass the risk of their projects on to their counterparties. For example, the developers of LNG export projects may sell their export capacity to large energy companies (such as BP, BG, Total) who then assume the risk for selling LNG to overseas customers. In other cases, the developers may contract directly with overseas

¹ See, for example, World Energy Outlook 2015, p. 634, which forecasts the share of gas-fired generation (as a percent of total electricity generation) in the New Policies Scenario to grow from 2% in 2013 to 8% in 2040. WEO forecasts the share of wind generation to grow from 3% to 10%, and the share of solar PV to grow from 0 to 3% over this time period. Growth in generation from gas, wind, and solar PV over this time period is forecast to be 788 TWh, 886 TWh, and 353 TWh, respectively. Growth in installed capacity from gas, wind, and solar PV over this time period is forecast to be 160 GW, 321 GW, and 258 GW, respectively.

end-users. In either case, the risks can be substantial, especially because how much gas will be needed overseas is uncertain, *e.g.*, for gas-fired electricity generation purposes future needs may not be known with any meaningful precision at the time long-term contracts are signed. LNG project developers will also not be completely shielded from risk for several reasons: the capital recovery period may extend beyond the term of their initial long-term contracts, the capacity of a given LNG project may not be fully subscribed, they will be subject to the ongoing creditworthiness of their counterparties, and they may face demands for contract price adjustments as market conditions and the competitive LNG landscape changes. Thus, market participants along the LNG supply chain need to understand how the development of renewable resources in overseas markets could impact the need for LNG imports in those markets.

Ultimately, investments in North American LNG terminals² require that the prices paid for LNG in overseas markets are greater than or equal to the price of U.S. natural gas supplies (*e.g.*, at Henry Hub) plus the cost of all infrastructure necessary to liquefy and deliver LNG to overseas markets (including a fair rate of return on that infrastructure). If the cost of renewable generation is low enough overseas (*i.e.*, below the cost of new gas-fired generation burning LNG from North America), it could dampen the attractiveness of North American-sourced LNG as a fuel for electric generation and the willingness of market participants to continue to contract for LNG export infrastructure.

We find that the competition between renewable power and gas-fired generation using LNG delivered from North America is increasing in overseas markets. Our conclusion is based on an analysis of the costs of developing new gas-fired generation in Asian and European markets that use LNG from North America as a fuel source compared to the costs of developing new renewable generation in those markets. Our estimate of the delivered cost of LNG from North America includes both the forecasted commodity cost of North American gas supplies (from the U.S. Energy Information Administration) and the infrastructure costs of liquefaction, shipping, and regasification necessary for North American gas to be consumed in Asian and European markets.

² While this paper specifically discusses the risks posed by the declining cost of renewable energy to North American LNG developers and their customers, a similar dynamics between renewables and LNG could also broadly apply to other regions.

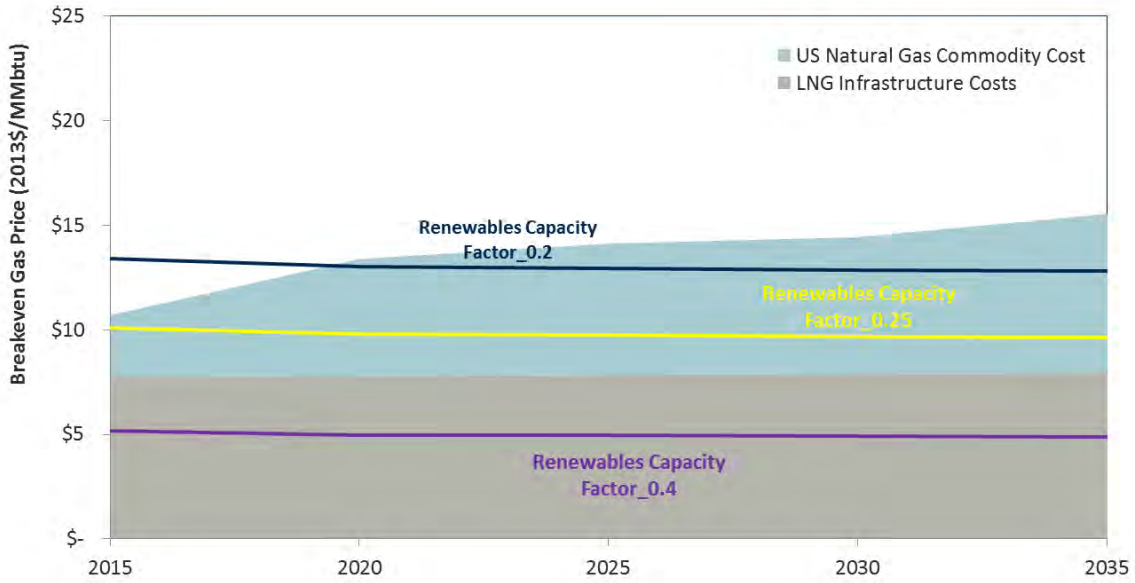
The delivered cost of LNG is shown as the gray and blue shaded areas of the chart in Figure ES-1 below. To compare the delivered LNG cost to the cost of renewable generation, we calculate the equivalent gas price (shown as lines) at which new gas-fired power generation would have the same levelized cost as new renewable generation (assuming regional costs and at various assumed capacity factors).³ As can be seen in Figure ES-1, in China this comparison suggests that wind generation with a capacity factor of 25% (the yellow line in Figure ES-1) would already be competitive with power generation using LNG delivered from North America at a delivered cost to China of roughly \$11/MMBtu (reflecting full recovery of LNG infrastructure costs and a U.S. gas commodity cost of approximately \$3.00/MMBtu). Moreover, our analysis shows a risk that wind power in China with capacity factors as low as 20% may become competitive with combined-cycle generation using North American LNG within the next 5 years (at which point delivered LNG prices are forecast to exceed \$13/MMBtu).

These are important findings, especially with respect to the many proposed LNG export projects in North America (in the U.S. Gulf Coast, Alaska, and Canada) that are still in the early development phase. The investment risk of these proposed LNG export projects is increasing because there is a significant possibility that, over the 20 years of a typical LNG contract, power production from renewable energy sources will become less costly than the LNG sales prices needed to justify the upstream LNG investment cost (even without considering the value of avoided greenhouse gas emissions).

While LNG looks more favorable when compared to stand-alone solar PV and wind in Germany, which, due to its emphasis on renewable energy, we use as an example for potential LNG exports to Europe, a mix (hybrid) of wind and solar and/or a strengthening carbon price could equally lead to renewables becoming less expensive than combined-cycle generation using North American LNG in the coming years, as shown in Figure ES-2.

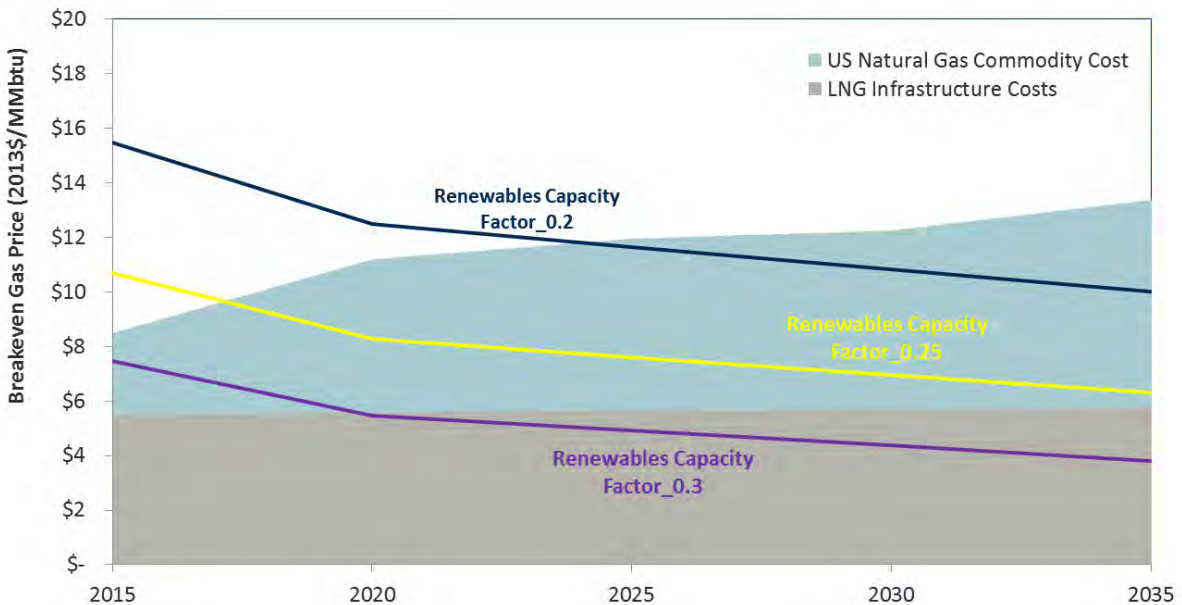
³ First, we calculate the levelized cost of electricity (LCOE) for renewables in \$/MWh using assumed capital costs, fixed operations and maintenance (FOM) costs and renewable capacity factors. We then transform this LCOE in \$/MWh into an equivalent gas price in \$/MMBtu by calculating the natural gas price that makes the LCOE (in \$/MWh) of a new combined cycle gas plant equal to the calculated LCOE for renewables in \$/MWh (using assumed capital costs, FOM, VOM, and heat rate of a new gas-fired combined cycle power plant).

Figure ES-1:
Wind costs (in \$/MMBtu) compared to the cost of New Gas-Fired Combined Cycle in China
Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes: World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario). Delivered LNG cost breakdown from Figure 7 in main report.

Figure ES-2:
The economics of a hybrid wind-solar plant and LNG-fueled power generation in Germany
with carbon emissions' cost of \$30/ton
Based on Forecast Delivered Cost of LNG from U.S. to Europe



Sources/Notes: World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario). Using forecast of delivered cost of U.S. LNG to Europe from Figure 8 in main report.

Of course, this simple analysis does not account for all costs that affect the economic attractiveness of using imported LNG or renewable power. For example, we exclude electricity transmission and distribution infrastructure costs as well as other so-called “renewable integration costs” from our analysis, even though they may be significant at higher levels of renewable penetration and hence could make them less attractive compared to LNG. On the other hand, carbon pricing could become important in LNG export markets other than Europe and tip the scale further in favor of renewables. Also, the cost-overrun and delay risks associated with the massive infrastructure investments needed to export LNG are potentially significant.

Developing a deeper understanding of the relationship between the cost of LNG-fueled gas-fired and renewable power generation is therefore critically important in assessing the outlook for both renewable power and the potential demand for LNG and associated infrastructure. The competition between LNG-fueled gas-fired generation and renewable resources represents a risk to participants in the LNG industry in that higher than expected renewables penetration could reduce future natural gas demand growth (and LNG demand growth) in some of the key overseas Pacific Asian markets. Of course, the reverse is also true: lower renewables penetration in countries planning to develop substantial renewable resources could potentially lead to higher than expected gas demand and LNG growth. While many other factors could impact the demand for LNG in overseas markets (such as the future of nuclear generation, overall load and population growth, potential competition from pipeline imports, etc.), this paper focuses on the specific relationship between the cost of gas-fired generation using LNG and renewables.

The increasing competition between renewable power and gas-fired generation using LNG should be considered carefully by participants in the global LNG markets. This competition increases the uncertainty in global gas demand and the future LNG requirements in markets now being targeted by North American LNG export developers. Both investors in LNG infrastructure and buyers of LNG under long-term contracts will want to consider these risks before making large and long-term commitments to buying or selling LNG.

I. Introduction

The development of unconventional natural gas resources primarily in North America and the relative abundance of natural gas in other parts of the world including Australia and the Middle East have triggered a fundamental rethinking of the future global energy system and the role of Liquefied Natural Gas (“LNG”). While these regions, and particularly the United States and Canada, are hopeful for an energy future characterized by low energy costs as a result of these abundant natural gas supplies, much of the rest of the world faces relatively higher natural gas prices and pressures to move away from coal as a major source of energy, and has few low cost alternatives.

Not surprisingly, the abundance of shale gas in North America, expectations that the cost of these shale resources will remain relatively low, and corresponding expectations of relatively high natural gas prices in much of the rest of the world have led to a wave of proposed large-scale infrastructure projects designed to profit from the apparent arbitrage opportunities. These LNG export projects will allow low-cost American natural gas to be transported and resold into markets with high natural gas prices. North American LNG exports will therefore increase the LNG export-related activity already strong in the Middle East and expanding in Australia.

At present, over 40 LNG export projects representing over 50 Bcf/d of export capacity (or roughly 70% of U.S. gas demand) are proposed in the United States, and over 20 projects representing around 31-47 Bcf/d of capacity are proposed in Canada. As of the end of 2015, 10 LNG terminals have received U.S. Department of Energy (“DOE”) approval to export approximately 14 Bcf/d of LNG to non-Free Trade Agreement (“non-FTA”) countries, and five of these are now under construction.⁴ Since LNG infrastructure is extremely capital intensive, its construction rationale relies significantly on assumptions that gas prices in the North America will remain relatively low and gas and oil prices (and gas demand) in the rest of the world will remain relatively high. Such assumptions are typically justified based on a combination of factors, including expectations

⁴ The terminals under construction include Sabine Pass LNG (2.76 Bcf/d), Cameron LNG (1.7 Bcf/d), Freeport LNG (1.8 Bcf/d), Cove Point LNG (0.82 Bcf/d), and Corpus Christi LNG (2.14 Bcf/d). See North American LNG Import / Export Terminal: Approved, FERC, as of October 20, 2015 available at: <http://www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf>.

of the continued availability of low-cost U.S. shale supplies, growing demand for natural gas in relatively fossil-resource-poor parts of the world, on-going gas-on-oil competition, and the difficulty and/or high cost of opening up these markets to gas supplies other than through LNG (*i.e.*, through pipeline imports).

Perhaps the key factor driving these LNG export project proposals was the expectation that the substantial divergence between North American gas prices and world oil prices that existed until recently (shown in Figure 1) would persist over the long-term. Since natural gas imports in many areas (especially in Asian Pacific markets) are priced based on oil market linkages, North American LNG export developers have been selling LNG export capacity—and hope to sell additional export capacity—to market participants that could capture this gas-oil spread by exporting LNG overseas and obtaining an-oil linked price.

Figure 1
NYMEX Prompt Month Prices
Brent Crude Oil vs. Henry Hub Natural Gas
January 2000 – November 2015



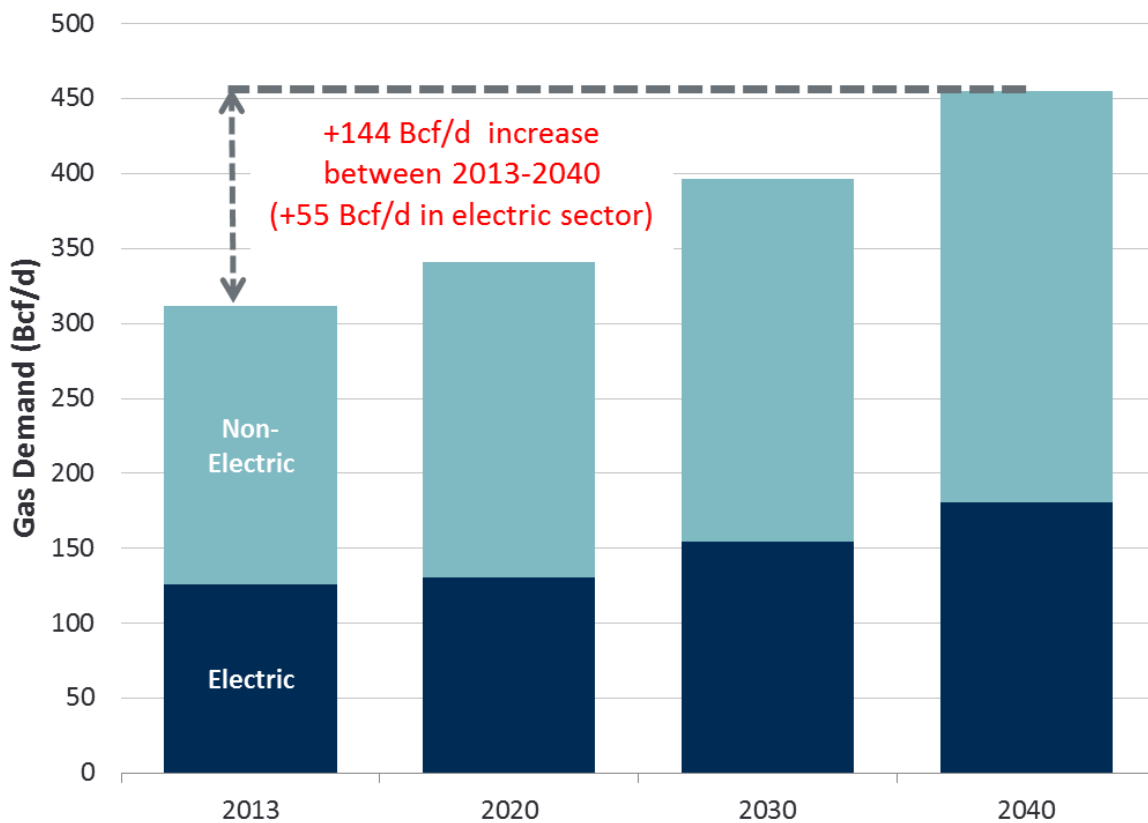
Sources/Notes:

NYMEX data downloaded from EIA and Bloomberg. The natural gas line shows the prompt month Henry Hub prices. The crude oil line shows the prompt month Brent oil prices.

Another factor driving the development of LNG export infrastructure is the expectation of growing natural gas demand in overseas locations without substantial indigenous gas supplies,

and therefore the need to import gas supplies either by pipeline from nearby countries or in the form of LNG. Worldwide gas demand forecasts show substantial growth over the next 20-25 years. For example, the International Energy Agency (“IEA”) forecasts worldwide gas demand growth of 144 Bcf/d through 2040, of which 55 Bcf/d (38%) is electric sector gas demand (see Figure 2). IEA projects gas demand growth in India and China of 45 Bcf/d of which 20 Bcf/d (44%) is electric sector gas demand. Much of the projected non-electric gas demand and its increase over time are attributed to space heating.

Figure 2
Global Natural Gas Demand
Electric Vs. Non-Electric Sector



Sources/Notes:

IEA World Energy Outlook 2015, Reference Case (New Policies Scenario).

However, will a significant gas-oil price spread really persist and will these gas demand growth projections really come to fruition? There are clearly many uncertainties associated with these expectations, as demonstrated by recent changes in world oil markets that have substantially reduced the oil-gas price spread. In fact, the steep oil price declines beginning in the second half of 2014 (see Figure 1) and persisting today are already leading to concerns about the economic attractiveness of Asian imports of North American LNG and the viability of proposed North

American LNG export projects with Henry-Hub linked pricing.⁵ Alternatively, shale gas production in the U.S. could prove to be more costly than now expected, and similarly lead to a narrowing of this spread. LNG export capability growth could exceed LNG demand (perhaps as importers lean more heavily on pipeline imports), and such an LNG supply overhang could make it difficult to achieve oil-linked LNG prices. A worldwide move to more nuclear generation, technological change (even though appearing relatively unlikely at present), enabling the development of coal generation with carbon sequestration, a shift from gas to electricity for the heating sector and, last but not least, more rapid deployment of renewable energy resources, could limit the need for natural gas.

In this paper, we focus on this last issue, namely on the relative costs of LNG (originating in the U.S.) and renewables as one important factor impacting future LNG import demand. We explore the issue by asking a very simple question: **How high does the sale price of LNG have to be to justify investing in LNG infrastructure, and how much competition from renewables might exist for LNG at that price level?** Typically, LNG suppliers think of pricing their product (the LNG they plan to sell) based on gas-on-oil or gas-on-gas competition. We suggest an alternative view on the pricing options and constraints for LNG, namely gas-on-renewables competition. Recognizing that, as illustrated above, a significant portion of the expected growth of natural gas and hence LNG demand over the coming decades is tied to increasing amounts of electricity production, we analyze how vulnerable investments in LNG infrastructure or holdings of long-term LNG export capacity may be to increasing competition from renewable energy sources also capable of meeting future electricity demand.

For the purposes of this paper, we ignore the possibility of producing incremental electricity from oil, coal, or nuclear – all real possibilities in various parts of the globe – and focus on renewable energy sources, which have seen a trend towards declining costs and hence could increasingly challenge natural-gas fired power generation depending on the costs of gas-fired generation in the future, of which the LNG price is an important driver.

⁵ See, for example, “Weak oil threatens US export of LNG, leaving Asian buyers stranded,” Reuters, October 21, 2014. See also “Moody’s: Liquefied natural gas projects nixed amid lower oil prices,” Moody’s Investors Service, April 7, 2015.

If renewable energy production were to become significantly cheaper than making electricity from LNG, this would raise some important questions about: a) the risks of buying LNG or LNG export capacity rights under long-term contracts to meet increasing electricity demand, b) the risk profile of LNG contracts with various forms of price review and adjustment clauses, and c) the economic rationale for investments in LNG infrastructure by both equity investors and lenders.

The remainder of this report explores these questions using a straightforward framework. In the next section, we briefly summarize our basic assumptions concerning the likely cost of LNG infrastructure. In Section III we do the same for various types of renewable energy. In Section IV, we compare the resulting costs of LNG-based and renewable power generation. In Section V, we discuss the implications of our results. In Section VI, we discuss how electric market uncertainties and gas market competition are impacting LNG markets, and in Section VII we draw some conclusions and look forward.

II. The Cost of LNG Infrastructure

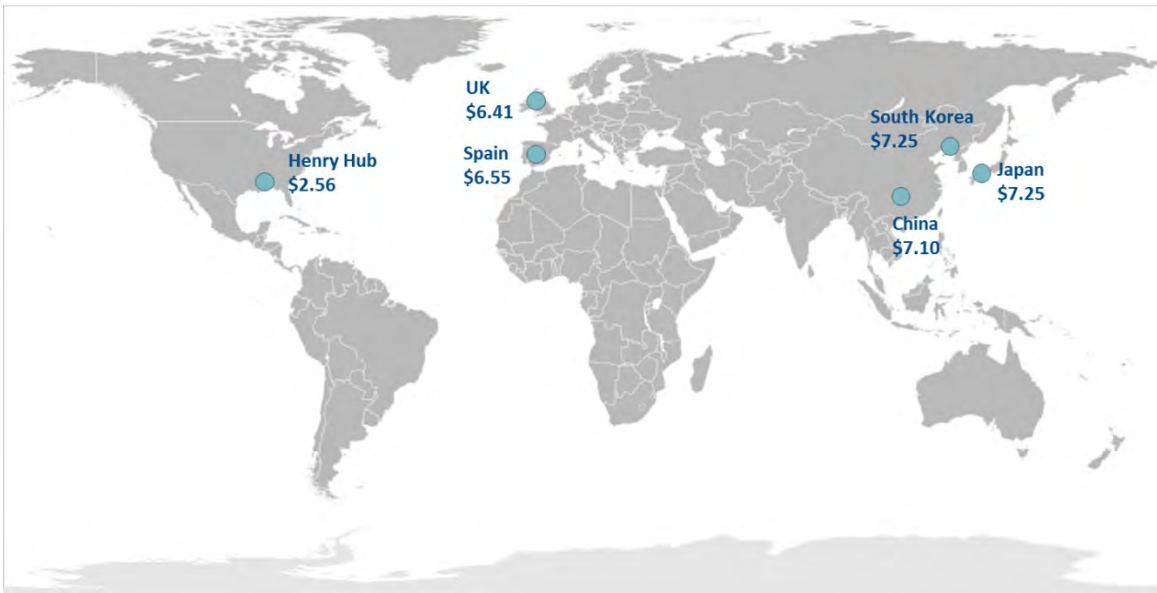
The price paid for LNG by an LNG importer differs by region and source of the LNG imported (and by contract vintage, as discussed below). Figure 3 below shows the average estimated landed LNG prices for October 2015 across several countries along with the Henry Hub price in the U.S. As can be seen, at roughly \$7.25/MMBtu⁶ Asian LNG prices are among the highest in the world. European prices are slightly lower (around \$6.40/MMBtu⁷), but still significantly higher than prices in the U.S. The prices shown in Figure 3 are much lower than the prices that prevailed prior to the recent collapse in oil prices. For example, in November 2013, Asian LNG prices were around \$15-\$16/MMBtu, while European prices were \$10-\$11/MMBtu and U.S. prices were a little more than \$3.00/MMBtu.⁸

⁶ Federal Energy Regulatory Commission, National Natural Gas Market Overview (updated October 2015) available at <http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf>.

⁷ Id.

⁸ See <http://ferc.gov/market-oversight/mkt-gas/overview/2013/10-2013-ngas-ovr-archive.pdf>.

Figure 3
October 2015 Landed LNG Prices for Select Countries
\$/MMBtu



Sources/Notes:

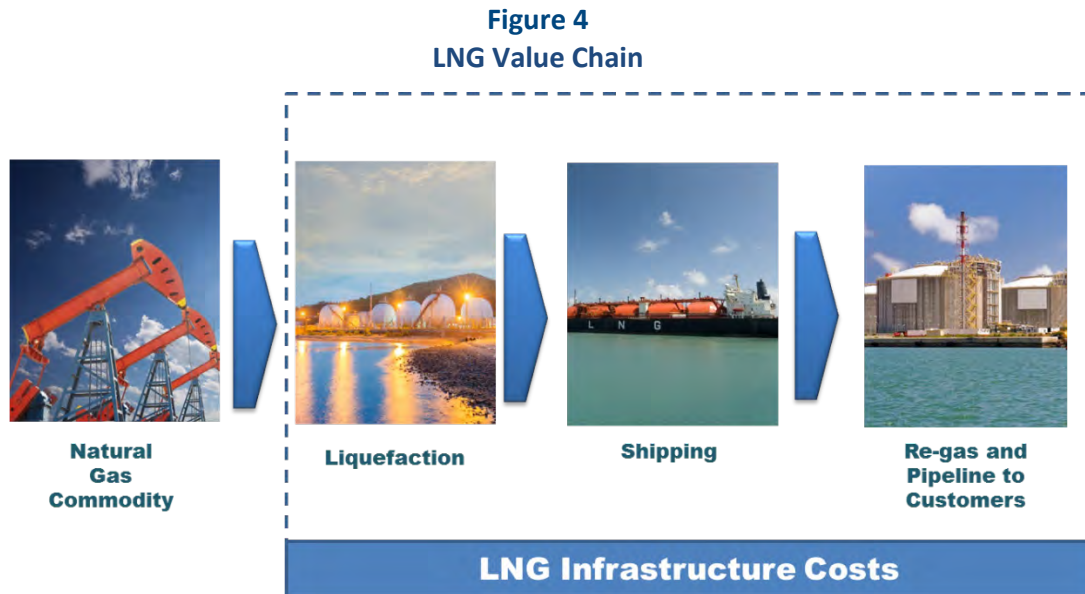
Henry Hub prices are from Platts. Estimated LNG landed prices are from the Federal Energy Regulatory Commission, National Natural Gas Market Overview (updated October 2015) available at <http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf>.

Note that the LNG prices shown above might be quite different from the delivered cost of LNG which represents the costs (including an appropriate rate of return) of the infrastructure required across the LNG value chain. The prices shown in Figure 3 represent the average landed price of LNG, and large variations may exist between the price of imported LNG based on various factors such as country of origin, whether LNG was imported on a spot or contractual basis, when the contract was signed, etc.

Furthermore, while world LNG trading is much more complex, we simplify our analysis in this paper by assessing the delivered LNG costs for a limited set of origin/destination markets. Specifically, we limit our analysis to the delivered cost of LNG from the U.S. to Asia (China) and Europe, even though similar analyses could be performed for other potential LNG export and import markets. Our two examples thus serve as case studies of a sort, with likely implications for other origin-destination pairs.

We derive the delivered costs of LNG by adding up the costs across the LNG value chain. They consist of: a) the commodity cost of gas at the source, b) the cost of liquefaction at the facility (converting natural gas to super cooled liquid form), c) the cost of shipping from the origin

country to the destination country, and d) the cost of regasification (converting LNG to natural gas) and storage at the destination country along with the cost of pipeline transportation from the regasification facilities to the natural gas consumers (e.g., electric generators). The value chain is shown in Figure 4.



For our analysis, we use information contained in a NERA Economic Consulting (“NERA”) study evaluating the economic impacts of U.S. LNG exports⁹ as the basis for the cost estimates across each step in the value chain (excluding the commodity cost of gas). This study (referred to as the “NERA LNG report”) provides forecasts for liquefaction and regasification costs in five year increments between 2015 and 2035. The NERA LNG report also provides point estimates for shipping and downstream pipeline costs, which we keep constant in real-value terms during the forecast period. All of these costs, which are provided in real 2010 dollars (\$2010) in the NERA LNG report, are converted to real 2013 dollars (\$2013) using GDP deflator forecasts from EIA’s Annual Energy Outlook 2015 (“EIA AEO 2015”).¹⁰ Together these cost components, including liquefaction, shipping, re-gasification, and downstream pipeline costs, make up the infrastructure

⁹ “Macroeconomic Impacts of LNG Exports from the United States,” NERA, December 3, 2012.

¹⁰ “Annual Energy Outlook 2015”, EIA, April 14, 2015, available at: <http://www.eia.gov/forecasts/aeo/>.

costs. The infrastructure cost breakdown for delivered LNG from the U.S. to China/India and Europe for two representative years, 2015 and 2035, is provided in Figure 5 below.¹¹

Figure 5
Breakdown of Infrastructure Related Delivered LNG Costs from U.S. to Asia and Europe
2015 & 2035
(\$2013/MMBtu)

		2015		2035	
		China/India	Europe	China/India	Europe
Liquefaction Costs	[1]	2.26	2.26	2.47	2.47
Shipping Costs	[2]	2.96	1.34	2.96	1.34
Regas and Downstream Pipeline Costs	[3]	2.51	1.93	2.52	1.97
Total Infrastructure-Related Costs	[4]	7.73	5.53	7.95	5.78

Sources/Notes:

“Macroeconomic Impacts of LNG Exports from the United States,” NERA, December 3, 2012. The costs were converted to real 2013 dollars using the GDP deflator forecasts from EIA AEO 2015.

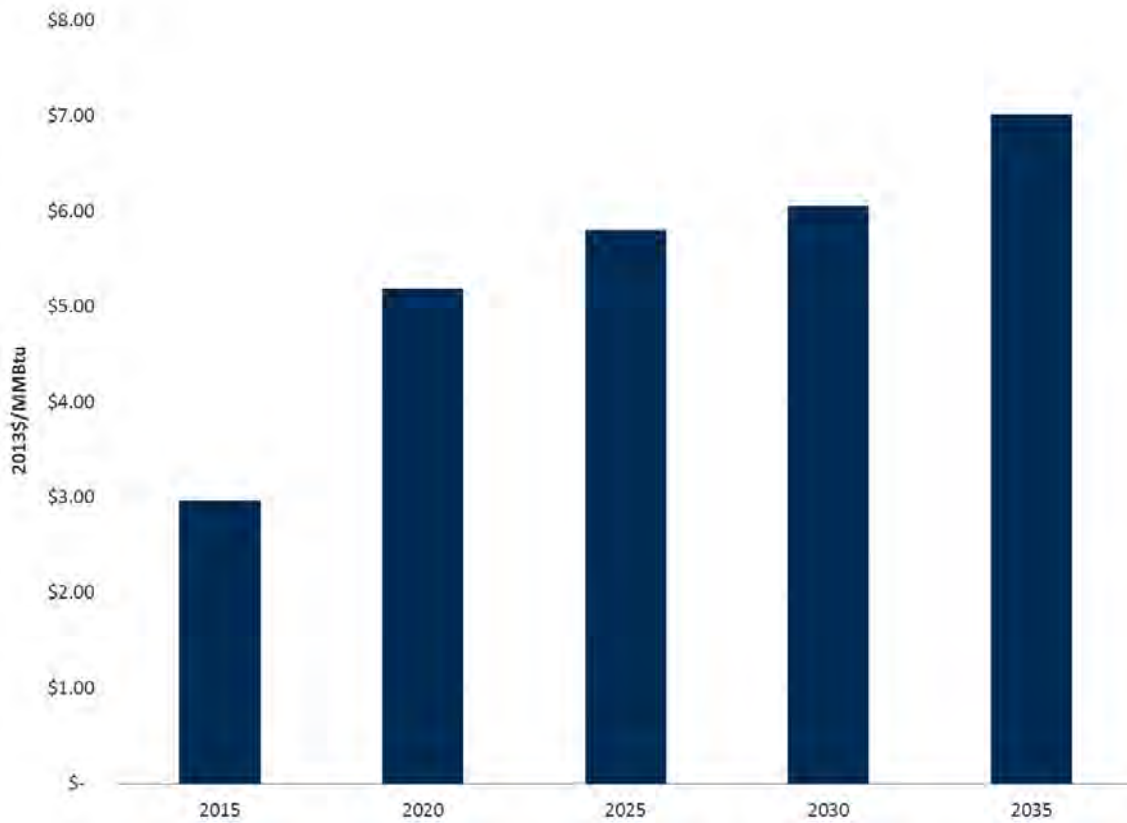
For the cost of feed gas (*i.e.*, the commodity cost of gas) in the U.S., we use the Henry Hub gas price with a 15% adder.¹² The 2015 Henry Hub gas price was obtained from EIA’s December 8, 2015 Short Term Energy Outlook (STEO).¹³ Henry Hub gas price projections thereafter (2020-2035) are from EIA AEO 2015. The Henry Hub price forecast (in \$2013), inclusive of the 15% adder, is shown below in Figure 6.

¹¹ Several of the LNG sales contracts for projects in the U.S. Gulf Coast have LNG pricing structures with a fixed liquefaction fee of around \$2.25/MMBtu-\$3.50/MMBtu (see, for example, slides 28 and 32 of the Cheniere Energy, Inc. presentation at the December 9, 2015 Capital One Securities Energy Conference). Thus, the forecasted liquefaction costs provided in the NERA LNG report (and reproduced in Figure 5) appear to be towards the lower end of the spectrum.

¹² The 15% adder is based on several of the Gulf Coast LNG sales contracts, in which the LNG sales price includes a fixed liquefaction fee plus a variable commodity-based charge of 115% of the Henry Hub natural gas price.

¹³ The 2015 Henry Hub price reported in the STEO is comprised of historical monthly spot prices between January 2015 and November 2015 and a projected price for December 2015.

Figure 6
115% of Henry Hub Price Forecast
(2015 – 2035)

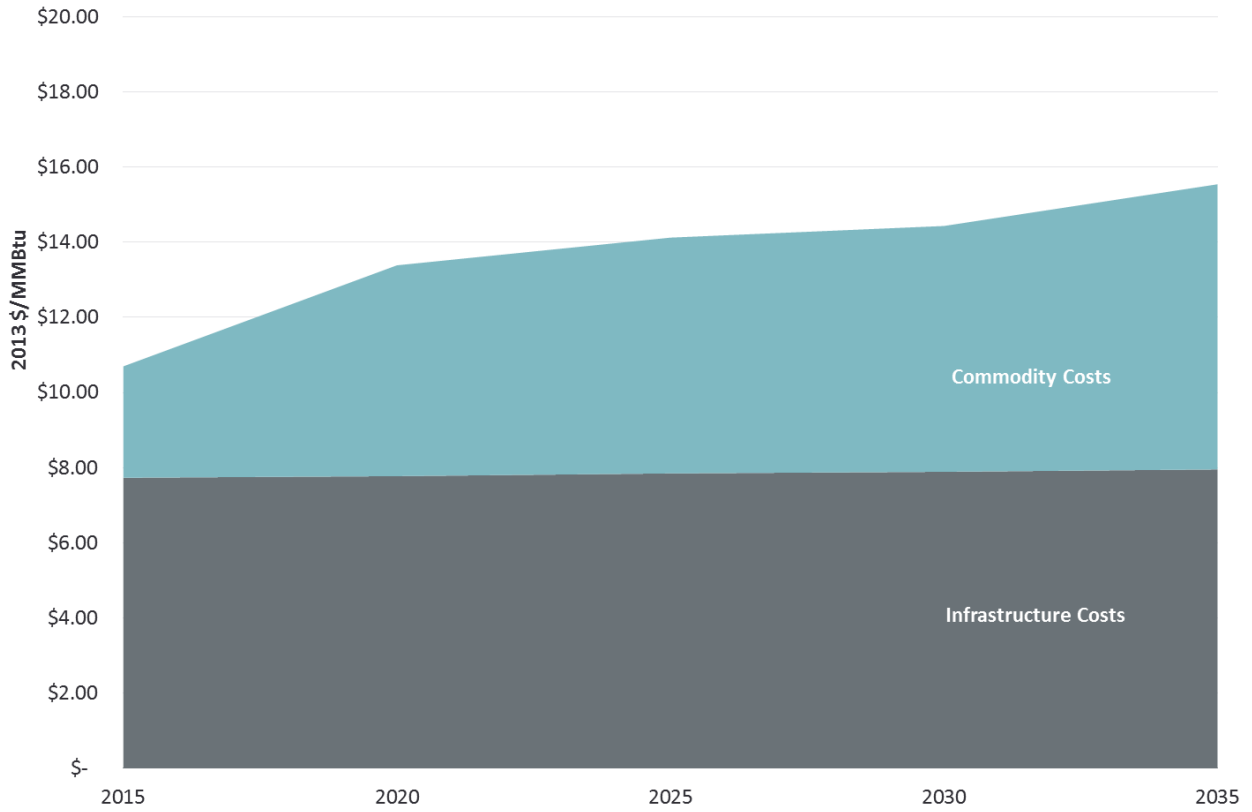


Sources/Notes:

2015 Henry Hub price from EIA Dec 8, 2015 STEO. 2020-2035 Henry Hub prices from EIA AEO 2015.

The delivered cost of LNG is the sum of the commodity cost of gas (shown in Figure 6) and the appropriate destination dependent infrastructure costs (shown in Figure 5). For example, the estimated delivered cost of LNG from the U.S. to China (in 2015) is \$10.70/MMBtu (\$2013) which is comprised of \$2.97/MMBtu (\$2013) of commodity cost and \$7.73/MMBtu (\$2013) of infrastructure-related costs. Figure 7 and Figure 8 show the breakdown of the forecasted cost of U.S. LNG delivered to China and Europe, respectively, between 2015 and 2035. Our analysis of the delivered cost of US LNG assumes that certain components of the LNG infrastructure costs (upstream pipeline, shipping, and downstream pipeline) remain constant in real terms between 2015 and 2035.

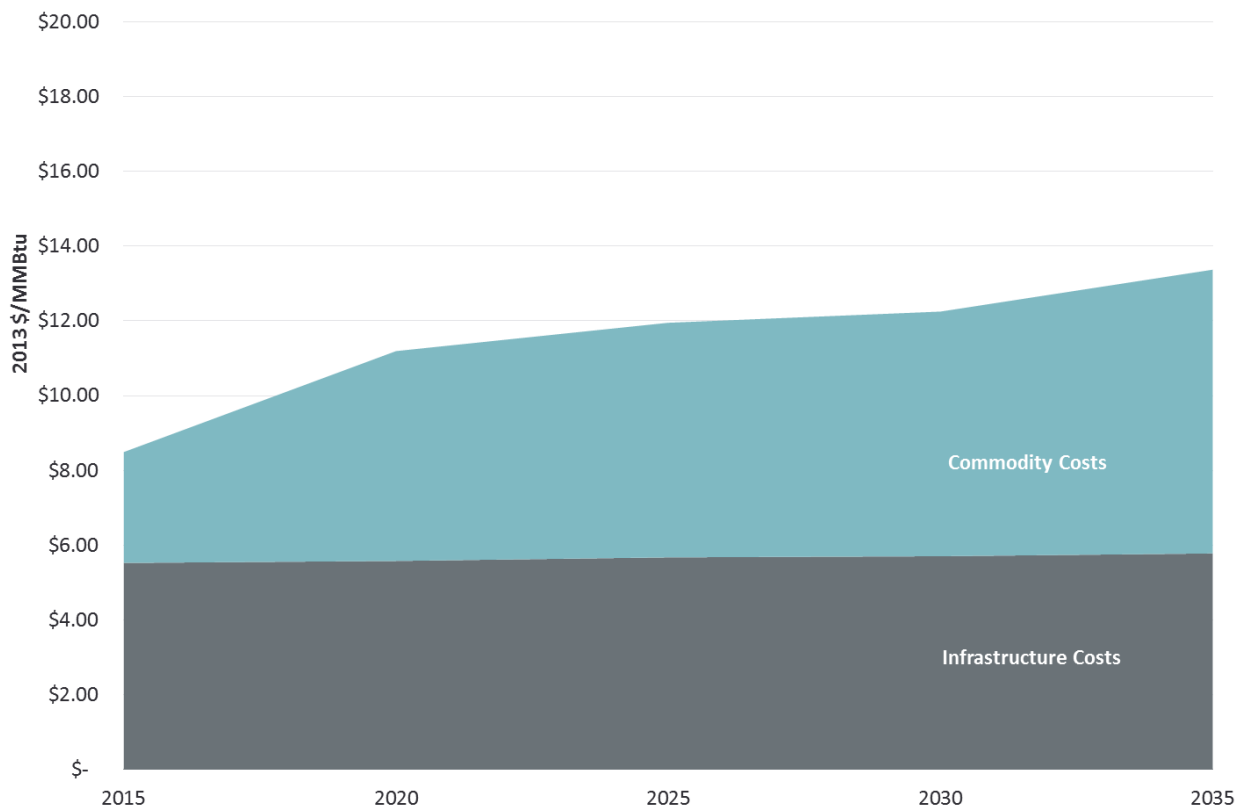
Figure 7
LNG Delivered Cost Breakdown
U.S. to China
(\$2013/MMBtu)



Sources/Notes:

2015 commodity cost based on 2015 Henry Hub price reported in EIA December 8, 2015 STEO. 2020 – 2035 commodity costs based on Henry Hub forecast from EIA AEO 2015. Data for other LNG costs components from the NERA LNG Report. The LNG cost forecasts are converted to real 2013 dollars using GDP deflator forecasts from EIA AEO 2015.

Figure 8
LNG Delivered Cost Breakdown
U.S. to Europe
(\$2013/MMBtu)



Sources/Notes:

2015 commodity cost based on 2015 Henry Hub price reported in EIA December 8, 2015 STEO. 2020 – 2035 commodity costs based on Henry Hub forecast from EIA AEO 2015. Data for other LNG costs components from the NERA LNG Report. The LNG costs forecasts are converted to real 2013 dollars using GDP deflator forecasts from EIA AEO 2015.

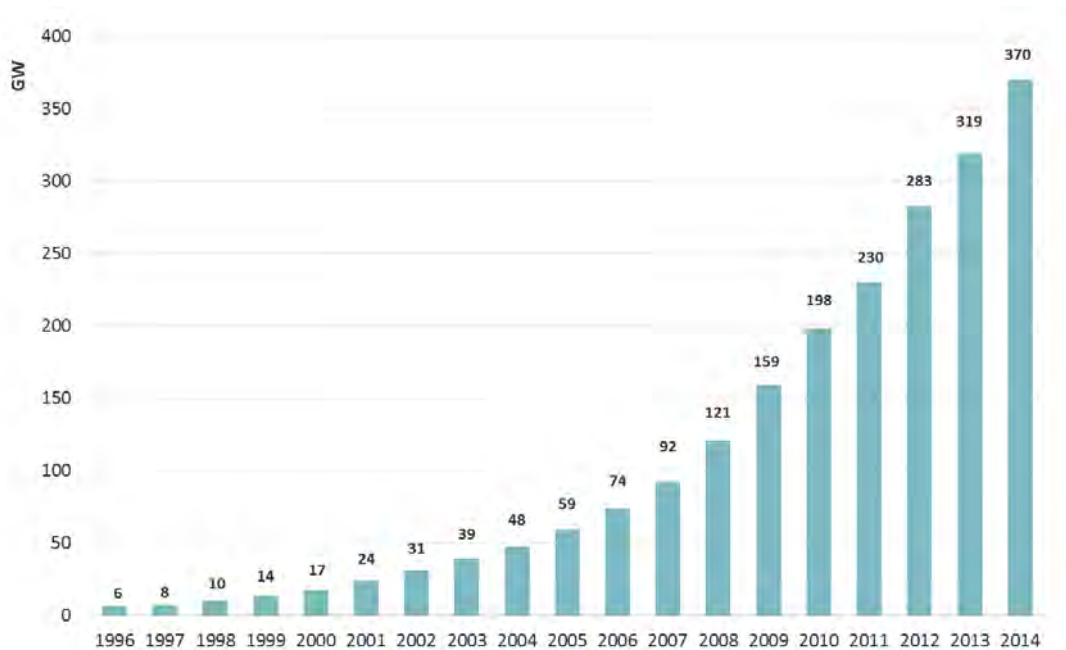
The costs of LNG throughout the value chain are both highly location specific and subject to considerable uncertainty, as exemplified by the construction cost of liquefaction facilities, which can be subject to cost inflation and cost over-runs. These cost uncertainties can have a significant impact on the economic risk of LNG infrastructure. While we do not focus on these risks in this paper, we address potential implications of these cost uncertainties in our conclusions.

III. The Cost of Renewable Power Generation

Another important change in world energy markets is the continued evolution of renewable sources of power generation. Over the past decade the world has witnessed rapid growth in

installed renewable electric generation capacity, dominated by wind and solar technologies. As shown in Figure 9, total installed global wind capacity increased from about 6 GW in 1996 to 370 GW in 2014 (an average annual growth rate of 26%). 51 GW was added in 2014 alone. This increase has occurred mostly in Asia (mostly China), North America, and Europe.¹⁴ Likewise, solar power generation has experienced substantial growth. As shown in Figure 10, total installed global PV capacity increased from 1.4 GW in 2000 to 177 GW in 2014 (an average annual growth rate of 41%). 40 GW was added globally in 2014, with growth mainly occurring in China, Japan and the U.S. while Germany was the major source of growth in the early years and still has the largest cumulatively installed capacity.¹⁵

Figure 9
Global Cumulative Installed Wind Capacity
1996-2014



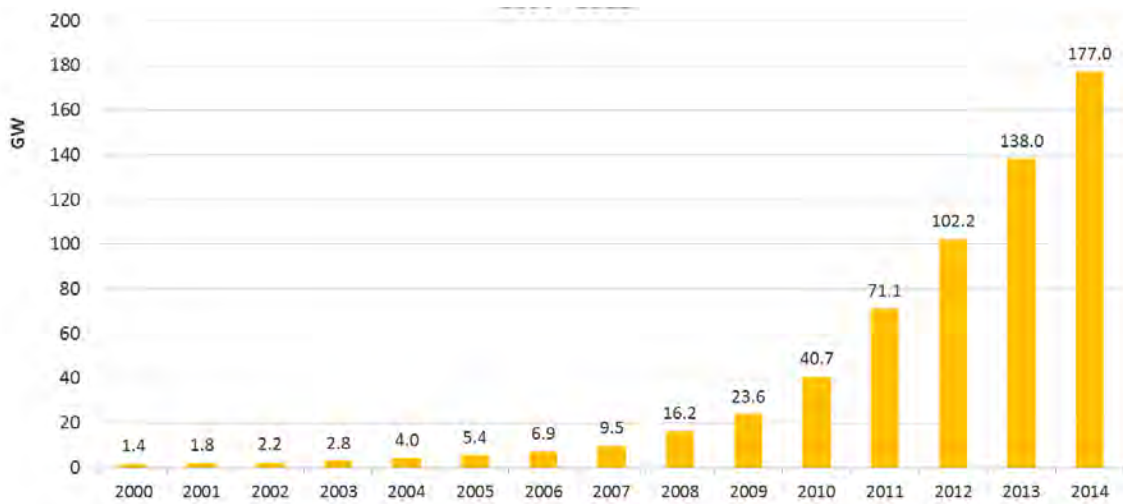
Sources/Notes:

Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, and Global Cumulative Installed Wind Capacity 1996-2012, Global Wind Energy Outlook, 2012.

¹⁴ Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, Page 71 and Global Wind Energy Outlook (GWEO), 2012, Annual Installed Capacity by Region 2005-2012, Page 13.

¹⁵ Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, Page 59.

Figure 10
Global PV Cumulative Installed Capacity
2000 - 2014



Sources/Notes:

Renewables 2015, Global Status Report, Renewable Energy and Policy Network for the 21st Century, and Global Market Outlook for Photovoltaic 2013-2017, EPIA.

The cost of generating electricity from these renewables resources has declined significantly over time, due to technological change and manufacturing advancements, economies of scale, and performance improvements. For example, since 2009 wind turbine prices have fallen by 20% to 40%. This has contributed significantly to U.S. installed costs falling by \$580/kW since 2009 to \$1710/kW in 2014, a reduction 25%.¹⁶ Solar PV system costs have fallen by 75% in less than 10 years.¹⁷

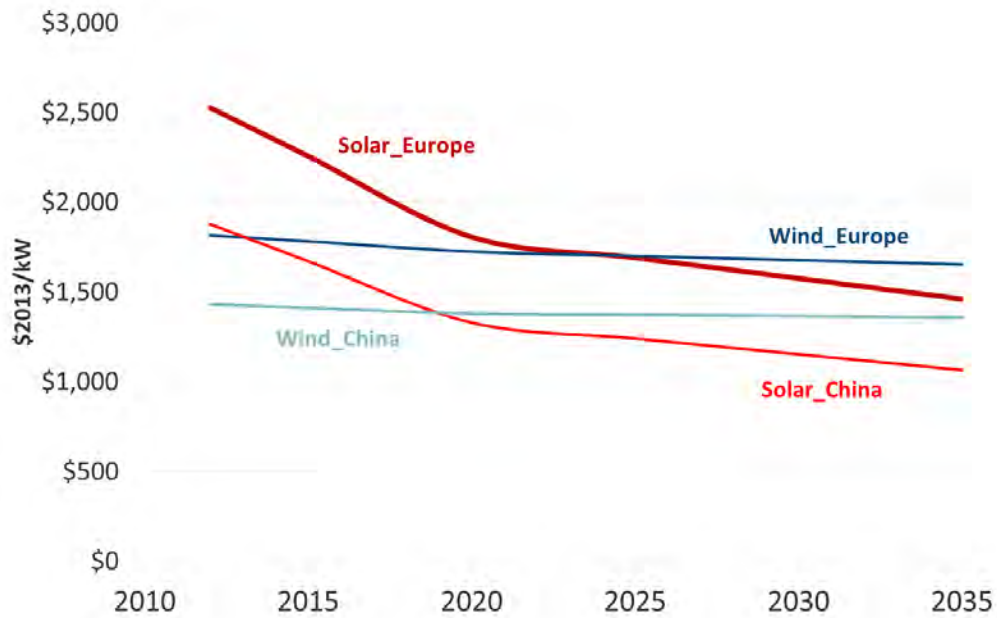
Despite the small temporary increase in wind generation capital costs between 2005 and 2010 (driven by rising commodity and raw materials prices, increased labor costs, improved manufacturer profitability, and turbine improvements), the cost of wind generation is expected to continue to fall (but at a slower pace) given expectations of continued increases in turbine size, design advancements and possibly lower capital costs. Solar PV costs are expected to continue declining more significantly. As shown in Figure 11, according to the World Energy Outlook 2013 published by the IEA, the capital cost of wind projects in Europe is projected to decrease

¹⁶ 2014 Wind Technologies Market Report, Department of Energy, Aug, 2015.

¹⁷ Source: Global Market Outlook For Solar Power / 2015 – 2019, Solar Power Europe, 2014

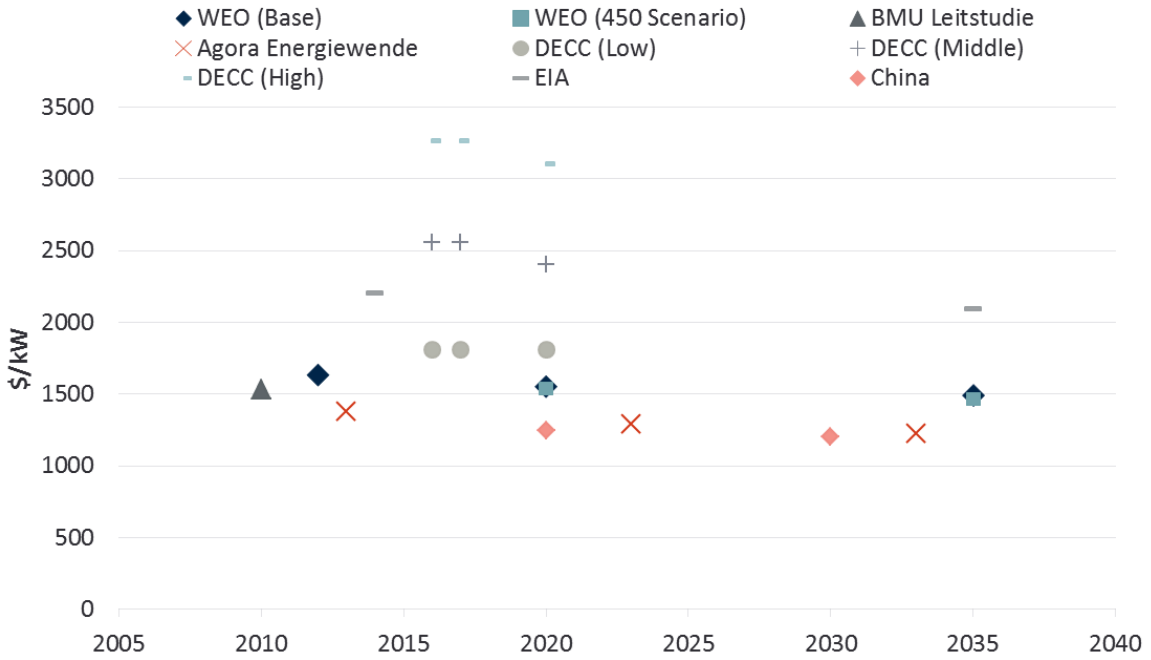
from \$1790/kW in 2012 to \$1630/kW in 2035, a reduction of about 10%. Capital costs for utility scale solar PV in Europe are expected to decrease from \$2500/kW in 2012 to about \$1800/kW in 2020, and further decline to \$1440/kW by 2035, a reduction of more than 40%. In other countries, such as China, renewables are expected to experience similarly declining costs. While the cost of renewables differs significantly by location and technology (due to differences in resource quality and the maturity of local markets), the IEA cost projections are broadly in line with projections made by other organizations, as shown below in Figure 12 and Figure 13. As such, we use the IEA figures in our analysis and report the results here.

Figure 11
Projected Capital Cost for Wind and Solar Power Plants by WEO 2013



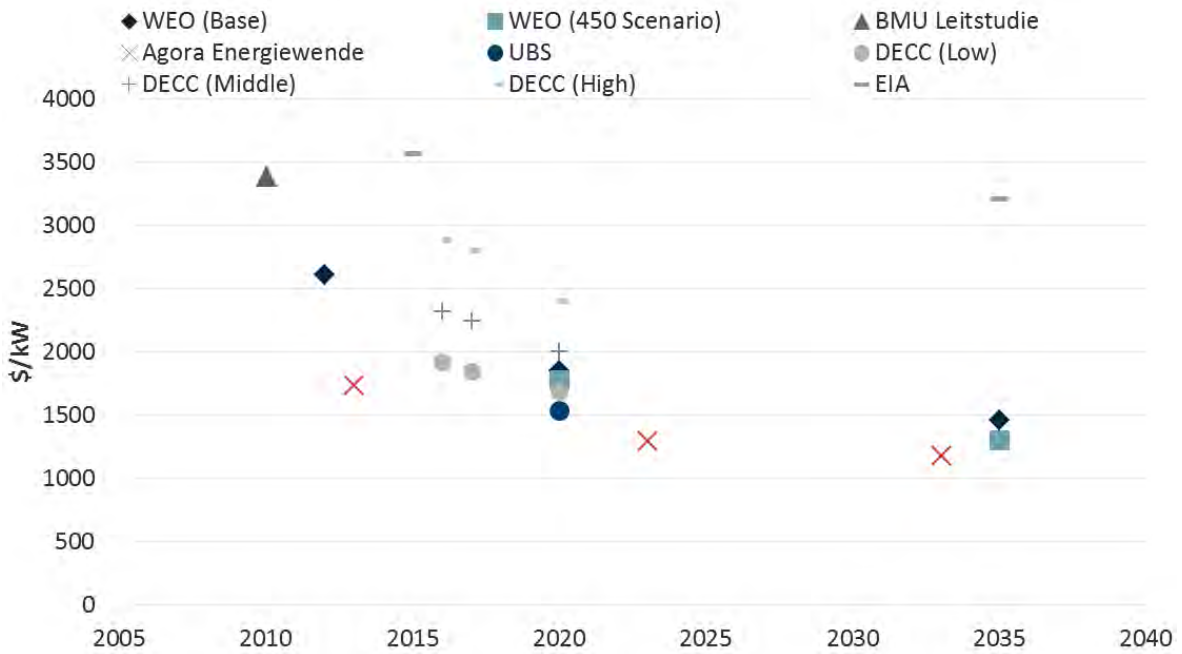
Sources/Notes:
 World Energy Outlook 2013, NPS Scenario

Figure 12
Wind Capital Cost Projections by Different Organizations



Notes: when regional figures are reported, average across regions is taken.

Figure 13
Solar PV Capital Cost Projections by Different Organizations



Notes: when regional figures are reported, average across regions is taken.

Although renewables (especially solar) may not have reached grid parity (*i.e.*, a cost that makes them cost-competitive with incumbent fossil-fuel fired generation) in many markets, and may not do so for some time, continued technological improvements will likely allow renewables to increasingly compete with conventional fossil technologies, such as natural gas fired electricity generation, especially in countries where natural gas prices are high or if natural gas prices increase over time.

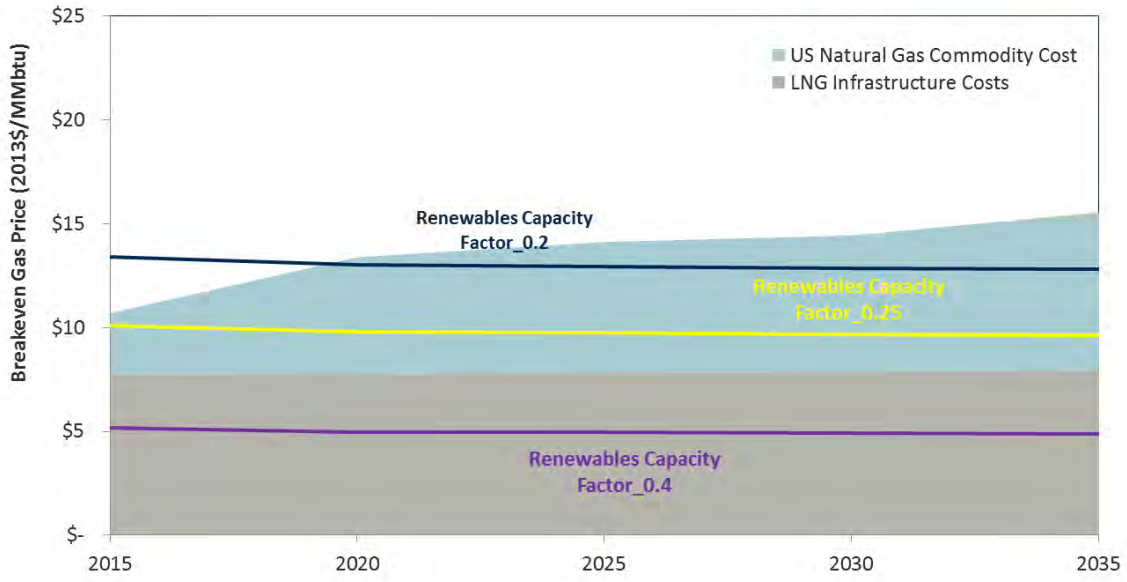
The next section explores the relative economic attractiveness of renewables and natural gas fired power plants fueled with U.S.-sourced LNG by using China and Germany as examples since both countries are experiencing rapid development of renewable technologies and have to rely largely on imported natural gas supplies (including, potentially, imported LNG) for meeting the fuel requirements of their natural gas fired power plants.

IV. Comparing the Cost of LNG and Renewables

Figure 14, Figure 15, and Figure 16 combine the insights from the above two sections by comparing the forecast delivered cost of U.S.-sourced LNG (shaded regions) expressed in \$/MMBtu with the equivalent cost of wind, solar and a combination of wind and solar, also expressed in \$/MMBtu, (*i.e.*, as the price of natural gas at which the respective technologies break even).¹⁸ As described above, actual landed prices may be quite different from the delivered cost of LNG. In the analysis below, we use the forecasted delivered cost of LNG (including all infrastructure costs) as a proxy for the price of LNG. As long as the delivered cost of LNG is below the break-even prices for renewables (expressed in \$/MMBtu), generating electricity using LNG would be less expensive than generating power from renewable sources. Conversely, if the delivered cost of LNG is above the break-even prices for renewables, then generating electricity using renewables would be less expensive than generating power from LNG.

¹⁸ First, we calculate the levelized cost of electricity (LCOE) for renewables in \$/MWh using assumed capital costs, fixed operations and maintenance (FOM) costs and renewable capacity factors. We then transform this LCOE in \$/MWh into an equivalent gas price in \$/MMBtu by calculating the natural gas price that makes the LCOE (in \$/MWh) of a new combined cycle gas plant equal to the calculated LCOE for renewables in \$/MWh (using assumed capital costs, FOM, VOM, and heat rate of a new gas-fired combined cycle power plant).

Figure 14
Breakeven Analysis for Wind Renewables and New Gas-Fired Combined Cycle in China Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes:

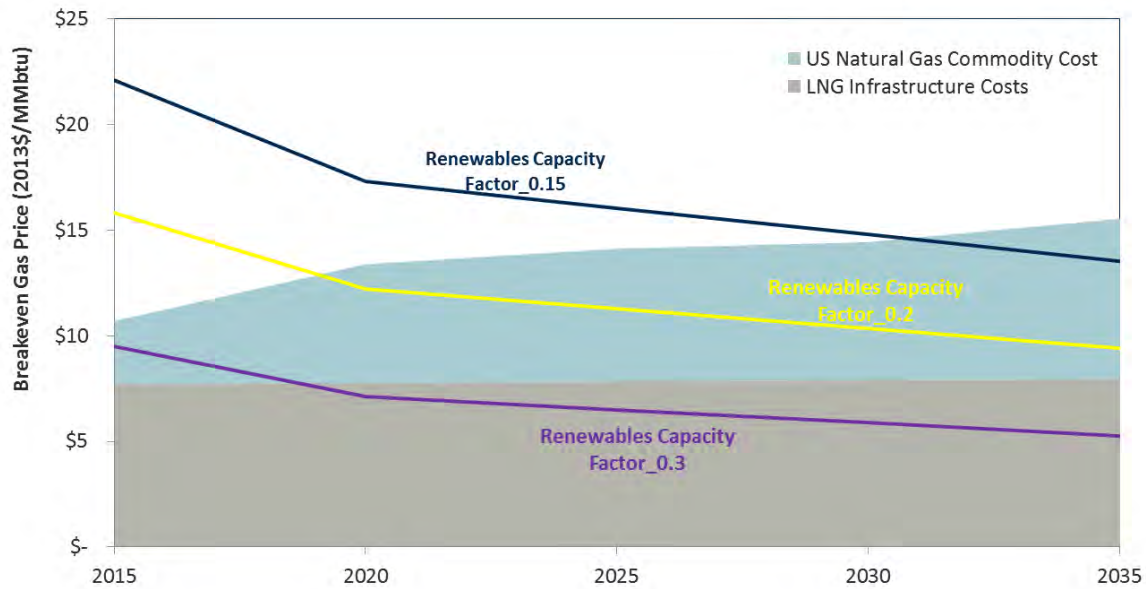
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario).

Delivered LNG cost breakdown from Figure 7.

As can be seen from Figure 14, it appears that generating power in China using wind with a capacity factor of 25% or greater would already be competitive with generating power with new combined cycle gas turbines using LNG. Such wind capacity factors are not unrealistic for some locations in China.¹⁹ By 2020 or 2025, about the time when many of LNG projects now under consideration (but that have not yet advanced to construction) might be able to deliver LNG, wind with a capacity factor of 20% becomes competitive with generation using LNG. Based on this simplified analysis, capacity factors of between 20% and 25% would suffice for wind to be cheaper than LNG over the typical LNG contract length of 20 years.

¹⁹ McElroy, Michael B., Xi Lu, Chris P. Nielsen, and Yuxuan, Wang. 2009. Potential for wind-generated electricity in China, *Science* 325(5946): 1378-1380, Figure 1.

Figure 15
Breakeven Analysis for Solar PV and New Gas-Fired Combined Cycle in China
Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes:

World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario).

Delivered LNG cost breakdown from Figure 7.

Figure 15 shows that electricity generation from solar PV is more expensive than generation from new gas-fired plants using LNG through approximately 2020 unless the solar capacity factor is 20% or higher. But if technology development reduces the cost for solar and gas prices increase over time, solar with a capacity factor of 15% could become competitive with gas before 2035.

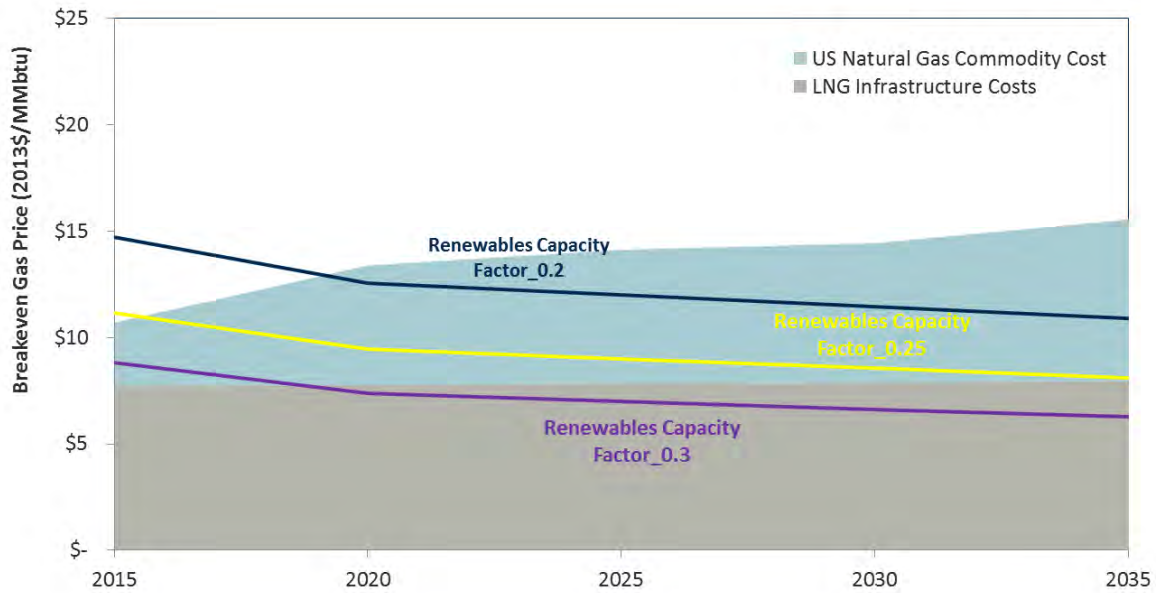
However, this does not mean that solar with a capacity factor of 15% should not be considered competitive relative to a gas-fired plant before 2035. The reason is that solar can complement wind in that wind speeds tend to be lower in the summer (in the northern hemisphere) when the sun shines brightest and longest, and wind tends to be strong in the winter when less sunlight is available. Consequently, since the peak operating times for wind and solar systems occur at different times of the day and year, a hybrid system might better match with demand than wind or solar PV facilities by themselves. To illustrate how this could affect the competitiveness of wind and solar as compared to a natural gas power plant, we constructed a

hypothetical hybrid renewable plant composed of both wind and solar PV capacity.²⁰ The ratio between the two technologies is chosen such that the hourly renewable production profile of the hybrid renewable plant leads to a better match with the hourly load profile than either wind or solar PV alone. The capital cost of the hybrid plant is estimated as the weighted average of the capital costs for the wind and solar plants, and the capacity factor of the hybrid plant is the weighted average of the capacity factors for the wind and solar plants.

Figure 16 shows the breakeven gas price of a hybrid renewable plant in China. The hybrid renewable plant is developed using wind, solar and hourly load profiles in the Midwest region of the U.S. in 2012. Even though it is likely that the actual wind, solar, and hourly load profiles in China are different, the complementarity between wind and solar generation profiles is likely nonetheless applicable, as is the directional impact on the economic attractiveness of a wind and solar hybrid plant. It shows that a mix of wind and solar could well be competitive with LNG around 2020 even if relatively low capacity factor solar (15% capacity factor) is available to complement relatively modest capacity factor wind (25% capacity factor).

²⁰ For the hybrid plant, we chose a ratio between wind and solar capacity of 1.25 (for every 1 MW of solar PV there are 1.25 MW of wind generation capacity). Although this may not be a system that can best match load at least cost - determining the optimal mix would require a much more complicated analysis - it represents one possible hybrid system that better matches the load than wind alone. This means that if, for example, the capital cost in China by 2015 is about \$1390/kW for a wind plant and \$1650/kW for a solar plant, as assumed in WEO 2013, and the capacity factors for wind and solar are 25% and 15% respectively, the hybrid renewable plant in China is assumed to have a capital cost of \$1520/kW and a weighted-average capacity factor of 20.6% (close to the 20% line we show in the graphs). Similarly, with this capacity ratio, a wind capacity factor of 30% and a solar capacity factor of 20% results in a capacity factor of 25.6% for the hybrid plant. A wind capacity factor of 40% and a solar capacity factor of 20% results in a capacity factor of 30.6% for the hybrid plant.

Figure 16
Breakeven Analysis for Hybrid Renewables and New Gas-Fired Combined Cycle in China
Based on Forecast Delivered Cost of LNG from U.S. to China



Sources/Notes:

World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario),
 Delivered LNG cost breakdown from Figure 7.

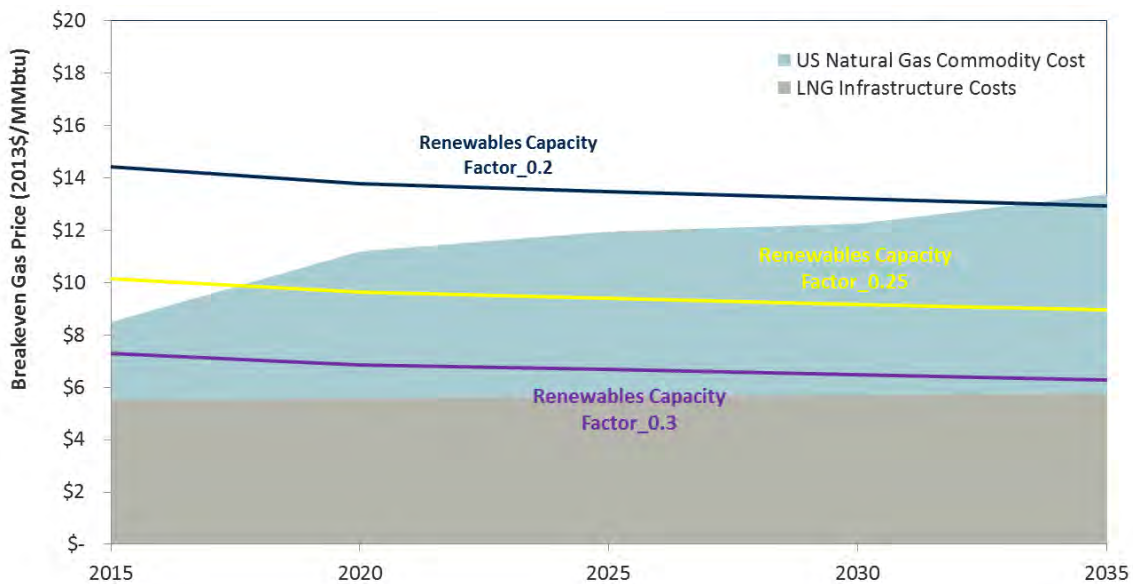
Figure 17, Figure 18, and Figure 19 below show a similar analysis for the breakeven gas prices for wind, solar PV, and hybrid renewables in Germany.²¹ Note that there are no LNG import terminals currently operating in Germany.²² For illustrative purposes, we use the forecast cost of U.S. LNG delivered to Europe to represent the cost of LNG for Germany. As shown in Figure 17, currently wind with a capacity factor of 30% would already be cheaper than a new gas-fired plant fueled with LNG imported from the U.S. Wind with a capacity factor of around 25% would become competitive before 2020; and wind with a capacity factor of 20% would become competitive by 2035. Typical annual capacity factors for German on-shore wind facilities are

²¹ The hybrid renewable plant is constructed using 2012 wind, solar, and hourly load profiles from 50Hertz and Amprion, two of the transmission service operators in Germany. A capacity ratio between wind and solar of 1.25 also leads to a better match with the load profile than wind alone.

²² EIA Country Profile - Germany, <http://www.eia.gov/countries/country-data.cfm?fips=GM&trk=m>, accessed on May 6, 2014.

currently between 20-25%,²³ so that at least some wind appears to be competitive with LNG-fueled gas-fired power generation over the time horizon of typical LNG contracts. However, the current forecast cost of delivered LNG of roughly \$8-13/MMBtu results in cheaper power production from imported LNG than solar PV at solar capacity factors below 20% (see Figure 18). Typical solar PV capacity factors in Germany are 15% at best, suggesting that gas-fired power generation should be less expensive than PV power, even if such generation were fueled by imported LNG. However, solar as a part of a hybrid renewable plant with a capacity factor of 20% would be cost-competitive with LNG-fueled gas-fired power generation around 2030 and before 2020 if the capacity factor is 25% (see Figure 19). Given typical capacity factors, in particular for onshore wind in Germany, it seems unlikely that a hybrid wind-solar plant would be able to reach such a capacity factor in the foreseeable future, at least absent explicit pricing of avoided CO₂ emissions, an issue we discuss next.

Figure 17
Breakeven Analysis for Wind Renewables and New Gas-Fired Combined Cycle in Germany
Based on Forecast Delivered Cost of LNG from U.S. to Europe



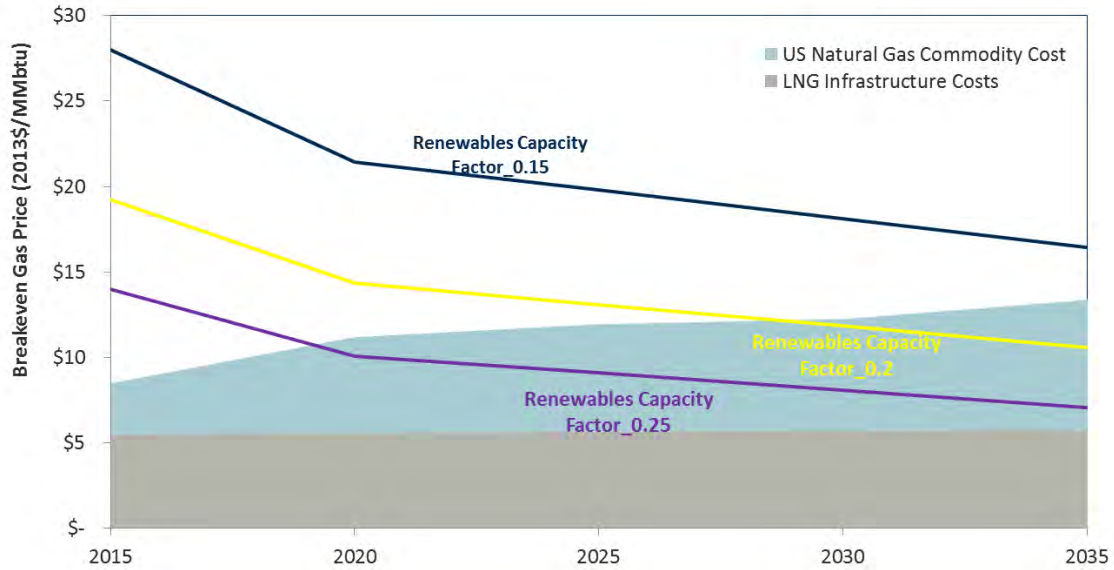
Sources/Notes:

World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)

Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

²³ See, for example, Fraunhofer ISE, Stromgestehungskosten Erneuerbare Energien, November 2013, page 13, which assumes the equivalent of 2000 hours of power generation at full capacity for better on-shore wind sites in Germany, the equivalent of a 23% annual capacity factor.

Figure 18
Breakeven Analysis for Solar Renewables and New Gas-Fired Combined Cycle in Germany
Based on Forecast Delivered Cost of LNG from U.S. to Europe

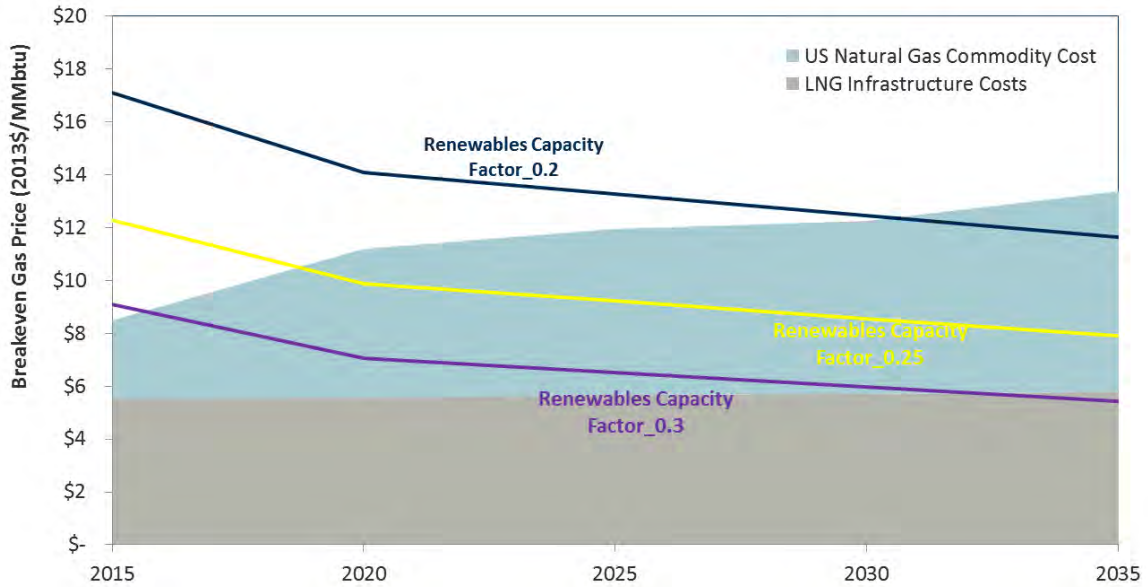


Sources/Notes:

World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)

Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

Figure 19
Breakeven Analysis for Hybrid Renewables and New Gas-Fired Combined Cycle in Germany
LNG Delivered Cost Breakdown from U.S. to Germany



Sources/Notes:

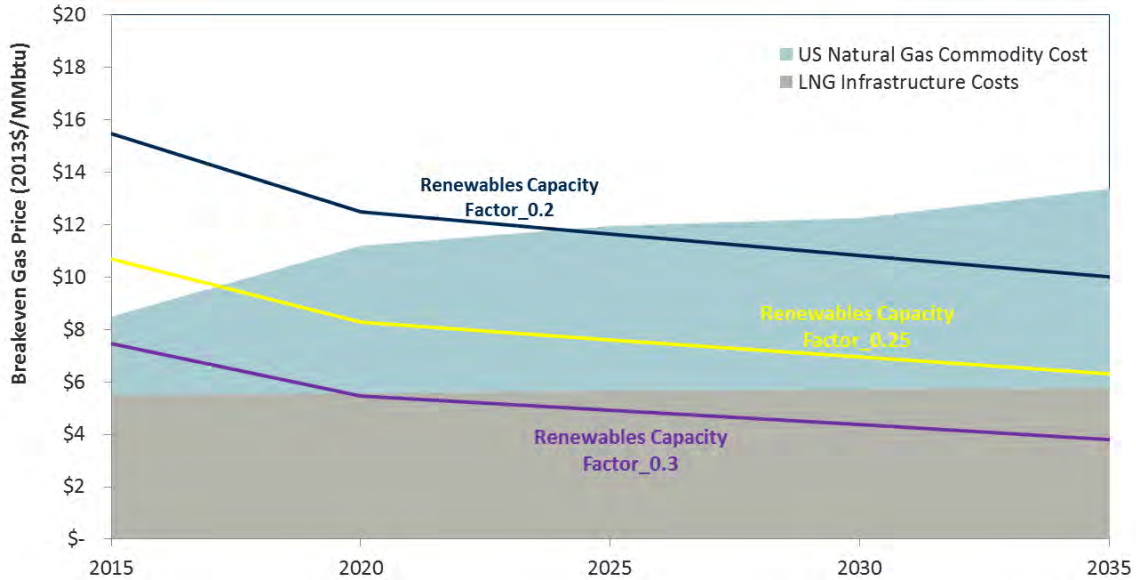
World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)

Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

Including the cost of carbon emissions associated with gas-fired power generation would make gas-fired power generation more expensive relative to renewables. While there is a lot of uncertainty about the price of carbon in Europe going forward, the European Union's (EU) ambitious long-term GHG reduction goals and past EU Emission Trading Scheme (ETS) prices suggest that a price of \$30/ton of CO₂ to illustrate the impacts of carbon prices on the competitiveness between renewables and LNG in Germany is reasonable.²⁴ An allowance price of \$30/ton of CO₂ would add about \$1.60/MMBtu to the cost of LNG, or about \$10/MWh for the electricity generated from a new gas-fired combined cycle plant with a heat rate of about 6,200 Btu/kWh (as assumed by WEO 2013). This results in the breakeven prices shown in Figure 20. As shown, at a \$30/ton carbon price, a hybrid renewable plant with a capacity factor of 20% (achievable for example with a combination of wind at a capacity factor of 25% and solar at a capacity factor of 15%) would be competitive with an LNG-fueled gas-fired plant before 2025, about 5 years earlier than without the inclusion of the value of avoided greenhouse gas emissions.

²⁴ Allowance prices under the European Union Emissions Trading Scheme ("EU ETS") ranged between €20 and €30/ton of CO₂ prior to the financial crisis of 2008. \$30/ton corresponds to approximately €22/ton at current exchange rates. While current prices under the EU ETS are far below this historic level, there is widespread agreement that low current allowance prices are not reflective of the levels needed to achieve the EU's longer term carbon reduction goals.

Figure 20
Breakeven Analysis for Hybrid and New Gas-Fired Combined Cycle in Germany with Carbon Emissions' Cost of \$30/ton
Based on Forecast Delivered Cost of LNG from U.S. to Europe



Sources/Notes:

World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)

Using forecast of delivered cost of U.S. LNG to Europe from Figure 8.

Figure 20 shows that pricing GHG emissions could further tip the scale in favor of renewable energy sources even in places such as Germany, where neither wind nor solar PV resource quality is very high.²⁵ When and how highly GHG emissions will be valued (either explicitly through the creation of carbon markets or carbon taxes or indirectly through policy making that impacts of the choice of generation mix) therefore has a significant impact on how quickly renewable energy sources might gain a cost advantage over LNG-based power generation. Very recent developments in China²⁶ leading up to the Conference of Parties (COP) in Paris in December 2015 suggest that pricing GHG emissions may happen sooner rather than later.

²⁵ Recent U.S. onshore wind projects in the Midwest are achieving capacity factors in excess of 50%. Solar PV plants in the Southwestern United States can achieve capacity factors between 20% and 25%. Some of the difference is due to different resource quality (more wind, more sun), but some is also a reflection of ongoing technological advances, which will likely lead to increased capacity factors of new wind and solar PV resources in Germany as well.

²⁶ China to Announce Cap-and-Trade Program to Limit Emissions,

V. Discussion

The above analysis shows that renewable energy may be able to compete with imported LNG under a number of conditions in the near future and most likely during the lifetime of the long-term LNG contracts supporting new LNG export infrastructure (*i.e.*, contracts that have already been negotiated for new export terminals now under construction as well as contracts being pursued by export terminals currently in the development phase). Advances in renewable energy technology and related cost improvements, which are further helped by an increasingly mature supply chain, economies of scale and increased competition, could result in renewables putting competitive pressure on LNG as a source of fuel in the electric generation sector in many target markets for North American LNG. Such competitive pressure could lead to lower demand for LNG relative to current forecasts, and lower prices for LNG in world markets, all else equal.

In areas with good conditions for renewable energy production (high average wind speeds and/or high solar irradiation) renewable energy is already beginning to compete with fossil generation, even at relatively low natural gas prices and generally with low or no price on carbon. Evidence of this competition can be seen in some of the recently signed long-term renewable contracts in the United States – where gas prices are amongst the lowest in the world – at prices that are deemed to be lower than those from competing fossil fuels, and in particular gas-fired generation projects. For example, in 2014 the national average levelized price of wind PPAs that were signed fell to around \$23.5/KWh in the U.S.²⁷ PPAs for solar PV projects have also decreased significantly, with some evidence that in good locations long-term contracts can be obtained at prices below \$40/MWh.²⁸ Even if existing subsidies for renewable energy sources are netted out of these prices,²⁹ renewable energy sources in these examples would in the worst case not be

Continued from previous page

<http://www.nytimes.com/2015/09/25/world/asia/xi-jinping-china-president-obama-summit.html? r=0>.

²⁷ See, for example, U.S. Department of Energy, 2014 Wind Technologies Market Report, August 2015, page 56.

²⁸ <http://www.utilitydive.com/news/nv-energy-buys-utility-scale-solar-at-record-low-price-under-4-centskwh/401989/>, accessed on October 7, 2015.

²⁹ Solar PV projects benefit from an investment tax credit covering 30% of the investment costs. Until year-end 2013, wind projects benefitted from a production tax credit of 23 cents/kWh, and all renewable projects benefit from accelerated depreciation allowances.

significantly more expensive than power from new gas-fired generation, and in many cases cheaper. In this sense, the recent experience in the United States is an illustration of the declining break-even cost of renewable alternatives to natural gas fired power generation.

These trends in the costs of renewables suggest some risks associated with the use of LNG for gas-fired power generation in overseas markets, and for purchasers of LNG under long-term contracts who may be counting on strong world LNG demand for power generation based on the presumption that power generation using LNG will be cheaper than non-gas generation alternatives such as renewables. We discuss these risks and uncertainties in the next section.

It is, however, important to recognize that our analysis is deliberately simple and thus omits factors that would likely move the relative cost of imported LNG versus renewables one way or the other. Several factors would have the tendency to improve the value of imported LNG when compared to renewables relative to our simple analysis above.

First and foremost, the results presented above illustrate that the ability of renewable energy to outcompete imported LNG depends critically on the quality of the available renewable resource. In many cases, the ideal locations for renewable energy sources will not be close to load centers, so that potentially significant additional costs will be incurred to bring such resources to market, even if sufficient locations with good resource quality are available. As a case in point, bringing large amounts of high-quality wind power in China to market will likely require very significant investments in additional transmission infrastructure, as the best wind resources are located in the very Western and Northern parts of China, whereas the demand centers are located in the East and South. Corresponding incremental infrastructure costs are likely less important for LNG imports, since large demand centers are often located near the coast and hence LNG infrastructure can be located in relative proximity. Gas-fired power generation can also be located near the coast and the resulting electric transmission to bring power from such plants to load centers will often be less expensive than building transmission infrastructure from Western China to the coast. Hence, if the costs of connecting high quality renewables to demand centers are high, the actual cost of renewables will likely be higher than our estimates.

A second often discussed issue relates to the intermittency of renewable generation and the “integration” costs required to manage the disconnect between renewable generation and demand in contrast with gas-fired generation, which can serve demand reliably and be controlled to reflect fluctuating demand. The level of renewable integration costs depends on the mix of renewable resources used, the amount of renewable energy generation and the shape

of the demand. Also, market structures and the available technology to integrate renewables matter. For example, advances in battery technology and associated costs may well lead to lower integration costs in the future. A number of studies have attempted to estimate integration costs as a function of the various factors cited above. In general, cost estimates have shown a range of approximately \$2-5 per MWh of renewable generation.³⁰ This translates to a range of \$0.3-0.8/MMBtu, which suggests that, at least at moderate penetration levels, including renewable integration costs would likely not fundamentally alter the results of our analysis. At high levels of renewable generation, integration costs could become much more significant, and consequently the economics of renewables relative to LNG could deteriorate significantly absent cost reductions for enabling technology corresponding to cost reductions for renewable energy itself.³¹

Third, while our comparison of LNG and renewables accounted for expected declines in the cost of renewables, it did not assume reductions in the cost of gas-fired generation or LNG supply chain costs. For example, some project developers in Australia are now considering floating liquefaction projects as a potentially less expensive alternative to onshore LNG projects (with potential savings on the order of 20-30%).³² Such savings in the cost of LNG export projects or in other parts of the LNG supply chain could improve the economics of LNG relative to renewables.

Fourth, the cost of feed gas for LNG (*i.e.*, the commodity cost of gas) is itself uncertain and will depend upon various factors including the potential for additional technological improvements in the production of natural gas. The uncertainty in the commodity cost of gas directly affects the relative attractiveness of renewables and LNG. If, for example, the commodity cost of gas in the U.S. is lower than the projections we have assumed (resulting in a lower delivered cost of LNG), LNG can become more competitive with renewables in LNG destination markets such as China.

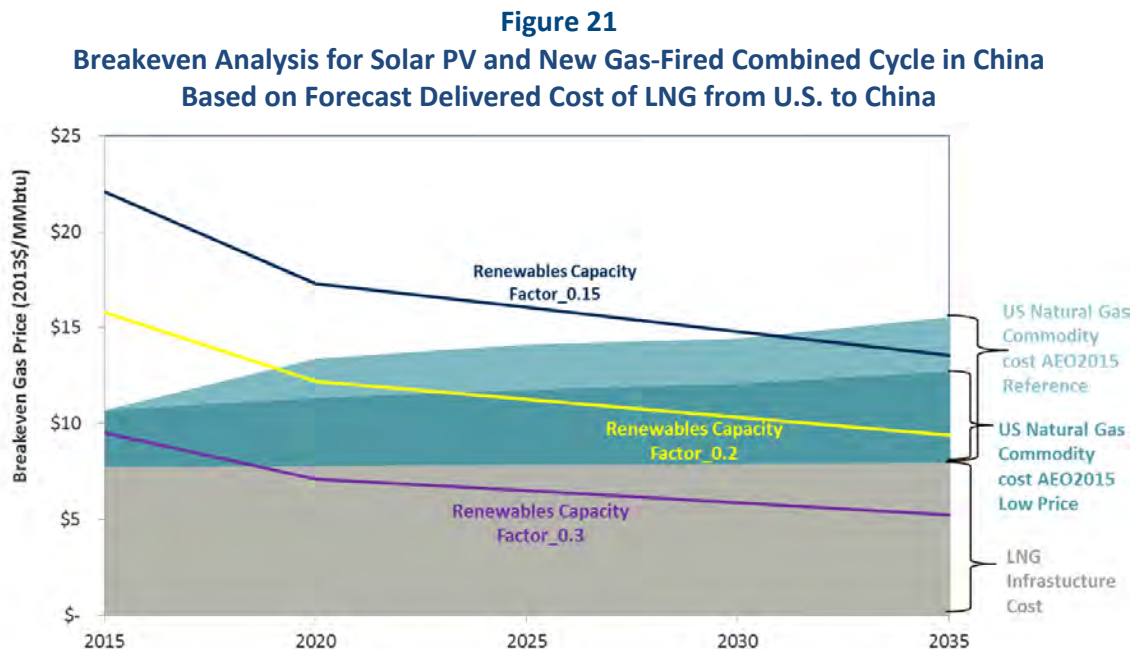
³⁰ See, for example, Michael Milligan, Wind Integration Cost and Ancillary Service Impacts, presentation, August 10, 2006, which cites many previous studies. Since then, many additional studies have been conducted. One main conclusion is that renewable integration costs increase potentially sharply above some minimum threshold of overall renewable energy penetration.

³¹ It should however be noted that as the deployment of variable renewable generation has increased, so has the ability to integrate these resources through a mix of operational changes, market rule changes, and technology. As a consequence, the penetration threshold of renewable resources that would result in significantly higher integration costs will likely continue to increase.

³² See “High-Cost Australia May Miss \$180 bln LNG Expansion Wave,” Reuters, April 11, 2014.

As an example, Figure 21 recreates the comparison between the cost of solar PV and the cost of gas-fired generation using LNG in China under two gas commodity cost scenarios—the “Reference Case” (which is the same as in Figure 15 above) and the “Low Price Case”. As shown in Figure 21, generating electricity from solar PV with a capacity factor of 20% becomes less expensive than generation using LNG in around 2020 under the “Reference Case” commodity cost projection. However, the same cross-over point occurs roughly five years later in around 2025 under the “Low Price Case”.

Finally, renewable energy is subject to important performance uncertainties whereas natural gas combined cycle generation has a longer history of reliable performance. Even though windmills have been around for centuries, current wind technology represents recent advances in engineering. Similarly, PV technology is advancing at a significant pace. As a result, there is likely non-trivial uncertainty regarding the longevity, maintenance costs, and long-term performance of renewable energy facilities being installed today. If the performance of renewable energy projects is less than expected, or if future cost declines for renewables are lower than currently anticipated, the economics of LNG versus renewables would also shift in favor of LNG.



Sources/Notes:

World Energy Outlook 2013 for renewables cost assumptions (NPS Scenario)

Delivered LNG cost breakdown for the Reference Case from Figure 7. The 2020-2035 Low Price commodity cost is based on 115% of Henry Hub prices from EIA AEO 2015 High Oil and Gas Resource case. 2015 commodity cost (for both Reference Case and Low Price Case) is based on 115% of 2015 Henry Hub price reported in EIA’s Dec 8, 2015 STEO.

However, there are also factors that could shift the balance further in favor of renewables. First, unlike renewable energy sources, which can be scaled from just a few kW for single rooftop solar PV systems or a few MWs for small wind projects to 100s of MWs for large wind or solar farms, traditional onshore LNG infrastructure projects represent huge one-time commitments of capital and result in hyper-complex building projects such as those in Australia, where the most expensive projects have capital costs ranging from \$30-\$60 billion. There is significant evidence that with large single infrastructure projects the risks of cost-overruns and completion delays are substantial. In fact, several of the Australian LNG projects have experienced significant cost-overruns. Both cost-overruns and construction delays can have substantial, negative effects on the economics of such projects, although some contracting practices (such as cost-sharing provisions) can help mitigate these impacts. These types of cost-overrun risks are not accounted for in our analysis.

Second, as discussed above, the environmental advantages of renewables and the potential inclusion of carbon costs in the future would further improve the economics of renewables relative to LNG, as shown in our analysis of Germany. However, it is important to mention that climate change considerations work against imported LNG if imported LNG is assumed to displace renewable energy production. If, on the other hand, LNG imports were to displace new or existing coal-fired generation, LNG imports could provide a significant and positive contribution towards reducing greenhouse gas emissions. Of course for LNG to displace coal but not renewable energy (even in cases where our charts show renewable energy may be cheaper) would require that LNG would be cheaper than coal, but that somehow even cheaper renewable energy does not displace coal. While this would seem unlikely in theory, it may well be the case in practice, due to any number of factors, many of which are likely very location/country and context specific, such as the fact that the time required to get new transmission infrastructure for renewable energy planned, approved, financed and built may be significantly longer than the time required to build new coal-fired generation or the fear that renewable energy may not be “reliable” enough to displace traditional fossil power generation sources.

To summarize, while the relatively simple analysis presented in this paper leaves out important factors affecting the relative attractiveness of LNG-fueled and renewable power generation, it does not appear that the omission of these factors clearly bias our results one way or another.

VI. Electric Market Uncertainties and Gas Market Competition: Implications for LNG Markets

The electric power sector is a critical sector impacting worldwide natural gas and LNG markets. Uncertainty regarding the future mix of electric generation capacity creates uncertainty in demand for natural gas and LNG. Thus, developments in the electric sector have important ramifications for natural gas markets. The competition between gas-fired generation capacity and other types of power plants (renewables as discussed in this paper, but also potentially nuclear) creates risks for participants in natural gas and LNG markets.

Forecasts of LNG demand (as distinct from natural gas demand) made prior to the recent oil price collapse projected LNG demand growth from current levels of about 32 Bcf/d to levels of 65-85 Bcf/d by 2030 (*i.e.*, growth of 33 to 53 Bcf/d).³³ More recent forecasts of LNG trade (following the collapse in oil prices) have varied widely. For example, BP's Energy Outlook 2035 (released in February 2015) projected LNG demand to grow from 32 Bcf/d to roughly 70 Bcf/d by 2030 and to approximately 80 Bcf/d in 2035.³⁴ IEA's World Energy Outlook 2015 (released in November 2015) projects significantly lower growth in LNG trade, to approximately 40 Bcf/d by 2025 and to roughly 50 Bcf/d by 2040 (*i.e.*, growth on the order of roughly 18 Bcf/d between now and 2040).³⁵ The uncertainty in LNG demand, as shown by this range of forecasts, is substantial. Reduced gas demand in the power sector, as a consequence of the factors described in this paper (which could also include more nuclear generation in addition to a shift towards more renewables, as a result of cost and/or climate change issues), could have a significant impact on overall LNG demand and thus the need for LNG liquefaction terminals. For example, a 6 Bcf/d reduction in LNG demand would be the equivalent of three to six fewer LNG liquefaction terminals (assuming an average LNG terminal size of 1.0-2.0 Bcf/d).

In general, the uncertainties in the electric power sector, especially in Asian markets, combined with other uncertainties are creating significant risks in global LNG markets. In the near-term, global LNG markets can be characterized as a buyer's market due to the oversupply conditions

³³ See, for example, "US Manufacturing and LNG Exports, Economic Contributions to the US Economy and Impacts on US Natural Gas Prices," Charles River Associates, February 25, 2013, page 31.

³⁴ See BP Energy Outlook 2035, slide 56.

³⁵ IEA World Energy Outlook 2015, Reference Case (New Policies Scenario), page 220.

that have developed recently. Spot LNG prices in the aftermath of the oil price collapse have converged globally to the \$7/MMBtu range. Gas demand growth has slowed in key Asian and European markets for a variety of reasons, including mild winters, the availability of cheap coal, the development of renewable resources, and slower economic growth. In addition, new LNG supplies have started to come online, such as the Queensland Curtis Island LNG project in eastern Australia. These conditions may persist or worsen over the next several years as a substantial amount of additional new LNG liquefaction capacity is set to enter service both in Australia (8 Bcf/d of new liquefaction capacity) and the U.S. (9 Bcf/d) between 2015 and 2020. A restart of some of Japan's nuclear fleet may also result in lower LNG demand for power generation by Japan, further contributing to the oversupply situation in the next few years.

Thus, the questions facing global LNG markets today are how quickly the new LNG supplies coming on line over the next few years will be absorbed, and at what point in the future there might be a rebound in global LNG prices such that new LNG export terminals (beyond the terminals now under construction) are needed. Many market observers believe the answers to these questions will hinge on how gas demand growth (including electric sector demand) develops in Pacific Asian markets, especially markets in China and India. In addition to the dynamic of renewables versus gas competition discussed in detail in this paper, other important factors include overall economic growth in these markets and competition to serve growing gas demand in Asian markets from pipeline imports and indigenous supply sources. A recent example of this competition can be seen in China's decision in May 2014 to enter into a long-term contract for pipeline gas from Russia. The deal is reported to be a 30-year contract under which Russia will supply China with approximately 3.7 Bcf/d of natural gas (roughly the size of 1-2 LNG export terminals), at a price in the range of \$9-\$11/MMBtu.³⁶ A second (non-binding) deal between China and Russia was signed in November 2014, also reported to be a 30-year contract under which Russia will supply China with an additional 2.9 Bcf/d of natural gas.³⁷ China is also understood to have substantial indigenous shale gas resources, but is only in the early stages of developing those resources.

³⁶ "Sino-Russian Gas and Oil Cooperation: Entering into a New Era of Strategic Partnership?" Oxford Energy Institute, April 2015, pp. 7-8.

³⁷ *Id.*, pp. 8-10.

From the North American perspective, the current market conditions and future uncertainties create various risks. The five LNG liquefaction terminals now under construction in the US have largely shielded themselves from these risks by signing long-term offtake contracts with LNG buyers. The US LNG offtake agreements are typically structured such that the purchaser agrees to take LNG at the tailgate of an LNG export plant, at a price linked to Henry Hub (usually multiplied by a scalar, e.g. 115% of Henry Hub), plus a fixed infrastructure charge to cover liquefaction in the range of \$3/MMBtu. Thus, the energy companies signing contracts for U.S.-based LNG are assuming the risk that Henry Hub prices may become uneconomic in world markets, in which case they can forgo exporting LNG from the US, but still have to pay the infrastructure charge to the LNG developers (which must be paid even if the buyer does not take LNG from the facility). Thus, it is the LNG buyers in these long-term agreements that are exposed to global LNG conditions. The LNG developers are shielded from these conditions, at least during the term of their initial contracts with buyers, unless the buyers go bankrupt or otherwise default on their obligations. The risk facing the LNG buyers that purchase under these long-term agreements with LNG exporters is likely significant, especially if the buyers are signing up for U.S. LNG export capacity in advance of signing LNG sales contracts with ultimate customers. The buyers of U.S.-sourced LNG are hoping strong gas demand growth is forthcoming in global gas markets so as to make their long-term contractual commitments for U.S. LNG profitable.

More generally, the current market conditions and longer-term uncertainties create the risk that market participants may not be willing to enter into additional long-term commitments for LNG export capacity in North America until some of the uncertainties (with respect to overseas gas demand, including electric sector gas demand, in turn partially determined by the dynamics described in this paper, and need for North American LNG) are resolved or become clearer. With the decline in oil and LNG prices, North American LNG (with Henry Hub linked pricing) may not be as attractive an option as it was prior to the price collapse, and oil-linked LNG might be seen as a more competitive alternative. Some observers have forecast that of the dozens of proposed U.S. export projects, only the five export terminals now under construction will be operational before 2020.³⁸ Moreover, some proposed LNG terminals have been delayed, most

³⁸ See, for example, “LNG Projects Not Viable at \$65/b Crude: Report,” Gas Daily, June 2, 2015 (referencing Bentek Energy’s expectation that only Cove Point, Sabine Pass, Freeport, Cameron, and Corpus Christi will be operational before 2020).

notably BG postponing an expected final decision regarding the Lake Charles LNG facility from 2015 to 2016.³⁹ BG's postponement in deciding to move forward is particularly significant and is indicative of the uncertainties now facing the LNG markets following the collapse of oil and LNG prices.

The current market also creates uncertainties for the more than twenty LNG projects proposed in Canada. Unlike the U.S., none of the LNG export projects proposed in Canada has advanced to the construction phase, which provides further evidence of the uncertain need for North American LNG. These Canadian green field projects likely have some disadvantages relative to some of the US-based projects that already have infrastructure and certain permits in place as they were initially developed as LNG import terminals. Also, the Canadian projects require significant investment in upstream pipeline infrastructure that is not as easily sited and approved as is the case in the U.S. Gulf Coast.

Nonetheless, some of the Canadian LNG projects have attracted equity investments from Chinese energy companies, such as Sinopec's investment in the Pacific Northwest LNG project, PetroChina's investment in LNG Canada, and China National Offshore Oil Corporation's (CNOOC's) investment in Aurora LNG. The Pacific Northwest LNG project is reported to have made a final investment decision that is conditional on various approvals by Canadian governmental authorities. The participation of Chinese energy companies in these Canadian projects—as equity investors and as potential or likely buyers of the LNG from these projects—indicates that these companies may themselves be keeping their LNG procurement options open while they wait to see how LNG demand in China unfolds. The relative cost of renewables versus power generation fueled by LNG, discussed at length above, will be one of the potential factors to monitor as they consider whether to move forward with purchase agreements for Canadian-sourced LNG.

Another factor is that Chinese energy companies have alternatives to North American LNG, including LNG sourced from Australia and Russia. In Australia, Sinopec has an equity stake in the Australia Pacific LNG project and in Russia the China National Petroleum Corporation (CNPC) has an equity stake in the Yamal LNG project being developed in the Russian Arctic.

³⁹ See “US LNG Projects Hit by Energy Price Slide,” Reuters, March 13, 2015.

In sum, the need for LNG from North American sources in the medium term (2020 and beyond) is subject to many uncertainties. Among these, as discussed in this paper, will be the extent to which natural gas is consumed for power generation in Asian market versus alternatives such as renewables, but potentially also nuclear, as well as the competition to serve evolving natural gas needs from competing sources (pipeline gas, indigenous supply, and other sources of LNG).

VII. Conclusions

Our analysis suggests that even though the availability of substantial supplies of low-cost unconventional gas resources in North America would point to significantly increased market potential for LNG exported to Asia and perhaps Europe, the traditional comparison of delivered LNG prices to prevailing oil prices may miss an important dynamic, namely the fast progress of renewable energy technologies capable of providing an alternative to one or more of the major sources of demand for LNG, electricity production and in the future perhaps heating.

With all the caveats discussed above, it appears that in many potential markets for LNG exports, the relative economics of LNG and renewables may in the coming years be less favorable to LNG imports than casual enthusiasm about the potential for vastly increased LNG exports suggests. While our analysis by no means implies that there is no need or no sound economic rationale for some—and potentially significant—increases in LNG exports, our analysis does suggest that a more precise estimation of how much incremental demand for LNG imports can be justified based on economics alone requires a more detailed analysis of country-level circumstances.

It seems relatively certain that the progress of renewable energy technologies will continue for some time. It also seems at least conceivable that significant technological progress along the LNG supply chain is at least possible. These dynamics raise important questions and answers to these questions will likely be helpful in assessing the risks of investing in, building, or buying from future LNG infrastructure.

Perhaps the single most distinguishing feature of LNG infrastructure with respect to the risks we discuss is the fact that LNG supplies require massive, sunk and largely irreversible investments in infrastructure. Such investments tend to require certain revenue streams for decades or, alternatively, very large balance sheets with an appropriate appetite for the risks involved. More generally, some of the important risks facing LNG markets include:

- Risk to project developers, owners of LNG projects, and LNG export capacity holders due to uncertainties related to gas and ultimately LNG demand (and LNG prices);
- Stranded asset/contract risk;
- Price risks for counterparties related to price review clauses in LNG contracts;
- Competition from pipeline imports or LNG imports from other regions, or from the development of indigenous gas supplies;
- Risk for potential buyers that commit to a long-term LNG contract (and associated infrastructure) in light of the potential for locally sourced renewable energy to be cheaper; and
- Risk for third party financiers to tie up large amount of investment dollars for potentially marginal infrastructure investments.

The purpose of this paper is to raise what we believe to be a relevant set of considerations at a high level. Perhaps the key insight, not limited to this topic but particularly relevant in our context, is that option value is of particular importance when making large irreversible investment decisions in a quickly changing world. This lesson applies both to potential buyers and sellers of LNG. For buyers, signing long-term contracts represents such a long-term commitment. Signing such contracts exposes LNG buyers to the risk that their contracts may end up out-of-market, meaning that the prices they pay for LNG and associated infrastructure may be greater than the value LNG has in world markets, or that their gas-fired generation assets are not competitive in a scenario where the penetration of renewables in the generation mix is particularly strong. For LNG sellers attempting to pass risk on to their customers through long-term contracts, those contracts may ultimately not completely shield the sellers completely from risks of recovering their investment in the LNG export terminals. For example, LNG sellers may face cost over-runs, have customers who default on their obligations (possibly due to market conditions), have price exposure due to contractual price review provisions, or face exposure to re-marketing risks (especially if they need additional time to recover their investments beyond the initial contract period). Hence, our analysis provides high-level support for an argument that both potential buyers and sellers of LNG should carefully analyze the relevant economics of LNG and renewables (along with other factors) as they make investment decisions based on the assumption that LNG will be a natural source of supply to meet increasing electricity demand over the coming decades.

Even though our analysis is primarily motivated by a discussion of the potential use of imported LNG to meet increasing electricity demand, we do not mean to imply that there are not risks

associated with LNG demand in the residential, commercial, and industrial sectors (which represent 57% of the total forecasted growth in global gas demand between 2011 and 2035). It is worth pointing out that the traditional separation of gas demand for heating and electricity production is beginning to show at least some signs of weakening. While electric heating has traditionally been primarily confined to areas of minimal heating demand (such as Florida in the United States) or areas with abundant very cheap sources of electricity (Quebec in Canada, for example), technologies such as ground and air-source heat pumps have recently been tilting the economics of heating in favor of electric solutions in more locations. In addition, excess supply of renewable electricity during certain time periods is beginning to incentivize the production of synthetic renewable hydrogen and methane, both of which can be used as perfect substitutes for natural gas in heating (and perhaps even industrial) applications. For the moment, these developments seem largely confined to a few countries such as Germany. The technological progress achieved there however does imply that LNG might face competition from renewable energy sources not just to meet electricity demand, but also in other sectors such as heating and industrial gases, for which there has so far been no alternative to the use of natural gas. Given the longevity of the infrastructure needed to justify LNG in the first place, such developments, even if only in their infancy at present, should be carefully considered when deciding on how to provide energy in various parts of the world over the next 20-30 years.

Finally, since the timeframes for LNG infrastructure development and subsequent contracting of LNG capacity are typically 20 years or longer, the possibility that climate change concerns will become increasingly important going forward can and should not be discounted. As our analysis has shown, even with relatively moderate carbon prices, the economics shift significantly in favor of renewable energy, creating an additional and likely substantial risk for LNG as a fuel in a likely increasingly carbon-constrained future.

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