GLOBAL SUPPLY BOOST HELPED EUROPE RENEGOTIATE SOME GAS CONTRACTS

The US natural gas revolution has already undermined the profits of Russian producers and benefitted European consumers. The displacement of 9.4 bcf/d (97 bcm) of LNG supply that resulted from the US shale boom coincided with a period of sharply reduced European gas demand, due to the great recession in 2009 and the subsequent Euro crisis from 2010.\(^4\) Oil prices rebounded quickly following the crisis, but natural gas prices in Europe remained low, due in large part to this additional supply of LNG. This is significant as most long-term gas contracts are indexed to the price of oil, a pricing system that emerged in the 1960s when oil and refined products were the natural competition for gas. The divergence between oil-indexed and spot natural gas prices in Europe put considerable pressure on Europe’s traditional gas suppliers, particularly Russia’s Gazprom, to amend their oil-indexed price formulas, or ease volumetric commitments tied to take-or-pay obligations. These take-or-pay contracts require a customer to pay for a certain amount of natural gas, whether they take the gas or not. This is generally a high percent of contracted volumes.

Statoil, one of the major gas suppliers to the European market, was the first to respond, introducing spot gas indexation in most of its European contracts.\(^4\) Gazprom was initially less flexible in re-negotiating contracts, and insisted on maintaining oil-indexed pricing. However, most of Gazprom’s large European customers were eventually granted considerable gas price discounts—partly by linking a small percentage of the contracted volumes to hub

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SPOT VERSUS OIL-INDEXED PRICES IN EUROPE

The divergence of oil-indexed and spot natural gas prices in Europe in recent years was initially the result of the 6 to 9 month lag embedded in most oil-indexed pricing formulas, which were originally put in place to protect gas consumers in the event of an oil shock. At the beginning of 2009, oil-indexed gas prices still reflected record-high oil prices seen two quarters earlier, while spot prices were deeply depressed from the recession and the growing glut of LNG previously destined for US shores.\(^1\)

The period of low oil prices proved remarkably short-lived in 2009, and the effect of the temporary oil price collapse remained relatively muted in the 6 to 9 month rolling average levels used in oil-indexed gas price formulas. The Fukushima disaster in Japan diverted some of the flexible LNG volumes away from Europe, and thus contributed to a significant increase in European spot gas prices in 2011.\(^3\) However, spot prices on average were still about 15% lower than oil-indexed gas prices in 2011, when international crude oil futures were settling into the current, historically high average range of over $100 per barrel, a level which continues to bolster oil-indexed gas prices.

Under the so-called take-or-pay obligations included in long-term gas contracts, major European utilities were required to pay for more expensive oil-indexed gas than they actually needed after the recession, while cheaper spot gas was readily available in the global LNG market. The sustained gap between spot and oil indexed gas prices threatened the profitability of the European utility sector, and eventually forced consumers and suppliers to the table to re-negotiate oil-indexed gas contracts across Europe.\(^5\)

The original rationale for linking oil and gas prices in European gas supply contracts—that end-users had a real choice between burning gas and oil products and could thus respond to price changes—is no longer relevant, and the emergence of spot gas markets increasingly allows for gas prices to be based on the supply and demand for gas.\(^4\)
Table 2: Renegotiations of gas supply contracts with Gazprom

<table>
<thead>
<tr>
<th>Company</th>
<th>Primary Market</th>
<th>Year</th>
<th>Renegotiation Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>E.On</td>
<td>Germany</td>
<td>2010</td>
<td>15% spot pricing included in LT contract (for 3 years)</td>
</tr>
<tr>
<td>Eni</td>
<td>Italy</td>
<td>2010</td>
<td>15% spot pricing included in LT contract (for 3 years)</td>
</tr>
<tr>
<td>GDF Suez</td>
<td>France</td>
<td>2010</td>
<td>15% spot pricing included in LT contract (for 3 years)</td>
</tr>
<tr>
<td>Edison</td>
<td>Italy</td>
<td>2011</td>
<td>Agreement reached out of court on price discount and total compensation of $290 mn for FY 2011</td>
</tr>
<tr>
<td>Eni</td>
<td>Italy</td>
<td>2012</td>
<td>Price discount, more flexibility in take-or-pay volumes and retroactive compensation for FY 2011 agreed</td>
</tr>
<tr>
<td>Verbundnetz Gas</td>
<td>Germany</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>GDF Suez</td>
<td>France</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>Wingas</td>
<td>Germany</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>SPP</td>
<td>Slovakia</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>Botas</td>
<td>Turkey</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>Econgas</td>
<td>Austria</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>Senergie Italiane</td>
<td>Italy</td>
<td>2012</td>
<td>Ca. 10% price discount (lower P0) negotiated (for 3 years)</td>
</tr>
<tr>
<td>E.On</td>
<td>Germany</td>
<td>2012</td>
<td>Arbitration started, agreement on ca. 7-10% discount and $1.3 bn retroactive compensation</td>
</tr>
<tr>
<td>PGNiG</td>
<td>Poland</td>
<td>2012</td>
<td>Arbitration started, agreement on ca. 10% discount and $930 mn retroactive compensation for FY 2011 and 2012</td>
</tr>
<tr>
<td>RWE Transgas</td>
<td>Czech Republic</td>
<td>2013</td>
<td>Arbitration court awarded ca. $1.3 bn compensation</td>
</tr>
<tr>
<td>Eni</td>
<td>Italy</td>
<td>2013</td>
<td>Price discount of ca. 7% agreed for FY 2013</td>
</tr>
<tr>
<td>Lietuvos Dujos</td>
<td>Lithuania</td>
<td>2014</td>
<td>Negotiated 20% price discount for renewed contract post-2014</td>
</tr>
<tr>
<td>Eni</td>
<td>Italy</td>
<td>2014</td>
<td>100% spot indexation in all LT contracts from FY 2014</td>
</tr>
</tbody>
</table>

Source: Center on Global Energy Policy based on industry and press reports.

prices, typically 15%, and partly by introducing discounts within the existing oil-indexed formulas (Table 2). These re-negotiations were not always consensual and often took place in arbitration courts.⁴²

The costs for Gazprom were substantial. Starting in 2009, the company agreed to significant concessions on pricing terms in its long-term gas supply contracts with European customers. As a first step in a long series of contract renegotiations, Gazprom allowed three of its largest European customers, namely E.On, GDF Suez, and Eni, to link 15% of their contracted gas volumes to spot gas prices instead of the traditional oil product linkage for a limited period of 3 years.⁴³ Some of these contracts were later further amended.⁴⁴

Other European utilities soon followed suit and started renegotiating existing gas contracts with Gazprom. European long-term gas supply contracts typically contain provisions for the periodic revision of contract terms. These price review clauses allow the contracting parties to adjust the base prices (P zero) and indexation formulas every three years if market conditions changed materially during the last review period.⁴⁵ Between 2011 and 2014, Gazprom agreed to review pricing formulas and reduce prices with most of its European customers, initially for a period of three years.

These price renegotiations took the form of price discounts through adjustments to the pricing formula and retroactive compensation to Gazprom’s main European customers, including France’s GDF Suez, Italy’s Eni, Germany’s Wingas, Austria’s Enagas, Slovakia’s SPP, Turkey’s Botas, and Poland’s PGNiG, among others.⁴⁶ Germany’s RWE settled its pricing dispute with Gazprom in arbitration court, while a similar arbitration proceeding with Italy’s Edison is still ongoing. Although the renegotiated contract terms are not always made public, various media reports suggest that the amount of these discounts ranged between 7% and 10%.⁴⁷ Based on 2013 delivery data, our estimates suggest that the agreed discounts reduce Gazprom’s revenues by about $5 billion each year,⁴⁸ although it is not clear whether these discounts will be extended beyond the current 3-year price review period.

RETROACTIVE COMPENSATIONS COSTLY FOR GAZPROM

Gazprom also agreed to pay an estimated $4.4 billion in retroactive compensation to various European gas buyers through the end of 2013, according to the company’s financial statements.⁴⁹ As of the end of 2013, Gazprom already paid out $3.5 billion in cash refunds for earlier gas deliveries to its European customers.⁵⁰ Some of the awards disclosed in company filings and news reports were indeed substantial. The retroactive adjustment paid to Poland’s PGNiG, for example, was worth $930 million,⁵¹ covering the 2011 and 2012 financial years. E.On’s compensation agreed in 2012 was nearly $1.3 billion.⁵²
Beyond the initial agreement allowing spot indexation for 15% of contracted volumes with its biggest customers in 2010, Gazprom proved reluctant to introduce more spot indexation in its long-term gas contracts during later renegotiation rounds, using base price adjustments for providing discounts instead. However, in May 2014, Eni and Gazprom announced that they had changed the basis of price indexation in all of their long-term gas supply contracts to “fully align it with the market.” Most market commentators and media outlets interpreted this to mean essentially the complete abandonment of oil-indexation and a conversion of all of Eni’s contracts to spot gas indexation. A Sanford C. Bernstein report suggests that Eni’s renegotiated index formula will be linked to spot gas prices at Italy’s PSV (Punto di Scambio Virtuale) gas hub. The changes will apply retroactively from the beginning of 2014, and are estimated to have a $760 million positive impact on the operating profit of Eni’s gas and power division this year.

EUROPEAN COMMISSION ANTITRUST PROBE COULD FORCE MAJOR CONTRACT CHANGES

Potential fines resulting from the European Commission’s antitrust probe against Gazprom, which started in 2012, can also be attributed to the changing gas supply landscape. The EU Commission initiated the antitrust proceedings to investigate whether Gazprom abused its monopolistic position in Central and Eastern Europe to impose higher pricing, prevent the resale of gas, and hinder the diversification of supply in the region. Gazprom’s pricing practices and the rigidities that the Commission suspects may remain in some of the company’s long-term gas supply contracts in Central and Eastern Europe—especially destination restrictions for Russian gas considered illegal under European competition rules—appeared far more onerous with the increasing supply of lower-priced spot gas to Western European gas hubs. Large Western European utilities were also quicker in winning price concessions and retroactive compensation from Gazprom, which temporarily increased the regional differences in the pricing of Russian gas. In 2012, for example, delivered Russian gas prices decreased in Germany and stayed flat for France and Austria. In the same year, Hungary, Slovakia, and the Czech Republic faced sharply higher prices for Russian gas.

An adverse antitrust ruling may further weaken Gazprom’s market position by requiring the company to eliminate any remaining destination restrictions, or possibly even to replace oil-indexation with hub-based pricing formulas in

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Gazprom’s weakened hand in the European gas market may have pushed Russian negotiators towards a swift conclusion of a gas deal with China, following more than 10 years of unsuccessful talks. In May 2014, Gazprom inked a 30-year supply agreement to sell China National Petroleum Corp. (CNPC) 3.7 bcf/d (38 bcm) of gas starting in 2019. The feed gas for the new Russia-China pipeline will be sourced from new East Siberian developments, notably from Gazprom’s Kovykta and Chayanda fields. Gazprom will invest $55 billion to develop these giant greenfield projects, with China ponying up $25 billion in advance payments to assist in this effort.

Pricing details have not been disclosed, but industry analysts estimate the implied gas price in the contract at between $350 and $390 per thousand cubic meters, or between $10 and $11 per mmBtu. This is roughly in line with what Gazprom’s European customers pay and considerably lower than current LNG import prices in Asia. Previous negotiations reportedly failed because Gazprom demanded prices closer to Asian LNG levels, while China was unwilling to pay even the much lower European contract prices. The recent agreement suggests Gazprom likely conceded on pricing as a result of both diminished market prospects in Europe and growing tensions with the West, while China achieved a price level close to European spot prices, which it has targeted throughout the negotiations.

It is important to note that China and Europe will not compete for the same Russian gas supplies, and the current Russia-China gas deal will not give Gazprom the option of diverting gas from Europe to China. The Kovykta and Chayanda gas fields, which will feed the new Russia-China gas link, are greenfield development projects located far from the European market, and would not be developed absent a pipeline to China. Another proposed Russia-China pipeline, the so-called “western pipeline route” connecting West Siberian gas fields with China’s western border, could later enable Russia to physically divert gas supplies from Europe to China. This project is not covered in the recent gas contract, and negotiations on the western Russia-China route are in a relatively early stage.

Map 1: Gazprom’s natural gas export pipeline system to China

Source: Gazprom.
all of its long-term supply contracts. The antitrust case may also result in substantial fines of up to 10% of the company’s annual revenues in the markets in question. Morgan Stanley estimates that Gazprom’s annual revenue from the markets covered by the investigation (Poland, Czech Republic, Slovakia, Hungary, Bulgaria, Estonia, Latvia and Lithuania) is in the region of $17 billion, which implies a maximum fine of about $1.7 billion.60 Even if the EU’s competition authority rules against Gazprom, however, the company may still appeal to the European Court of Justice, which could delay the final ruling by several years. The renegotiation of Russian gas contracts recently caused spot and oil-indexed gas prices in Europe to converge (Figure 8) and Gazprom’s pricing premium has been squeezed. In addition, Gazprom’s share price continues to perform

IMPLICATIONS OF US LNG EXPORTS FOR ASIAN GAS MARKETS

The Asia Pacific region is the largest market for imported LNG and will become the largest concentrated gas consuming region by 2035, surpassing North America and Europe, according to the IEA.1 However, the Asia Pacific region lacks a competitive gas market, and the prospects of developing a sufficiently liquid gas trading hub that could establish a reliable price signal for the region remain limited by institutional barriers and inflexibilities in the long-term take-or-pay contracts. While competitive gas-to-gas pricing of natural gas is gaining ground globally, with the most significant progress towards competitive gas pricing made in Europe, the share of competitively-priced gas in Asia remains stagnant at around 15% since 2007 due to the rigidities of LNG supply and demand in the region (Figure 9).2 Long-term oil-indexed LNG supply contracts are still the predominant form of pricing gas in Asia, and the majority of short-term and spot LNG contracts are also priced in reference to oil-indexed prices, or negotiated in a highly non-transparent manner on a cargo-by-cargo basis.3

US LNG exports will encourage more competition in Asian gas markets by increasing diversity of supply and liquidity. More importantly, these supplies are flexible in their destination. One of the key impediments for the emergence of a competitive market is the prevalence of destination clauses in long-term Asian LNG contracts. These prevent the resale of natural gas cargoes in other markets, where they might fetch a higher price, thereby hindering the convergence of regional gas prices and stiffening the whole LNG supply chain. New LNG export terminals in the US will offer full destination flexibility for their mainly Asian buyers, thereby introducing a large volume of flexible LNG supplies to the Asia Pacific market.4 This will allow buyers to demand greater destination flexibility from other suppliers, and will put pressure on sellers to offer LNG on more flexible terms eventually. While this will take time, the IEA estimated in a recent study that almost 50% of the Asian LNG supply contracts that were in place in 2013 will have expired by 2017,5 creating opportunities for buyers to introduce more flexibility in renewed contracts just as US LNG exports start to ramp up.

Figure 9: Wholesale gas price formation of traded natural gas volumes Bcm/year, gas-on-gas competition % of total

Source: IGU Wholesale Gas Price Survey.
well below its pre-recession levels, due to a combination of diminished pricing power in Europe, growing competition in the Russian domestic gas market from Novatek and Rosneft, the liberalization of Russia’s LNG market, the relentless pursuit of value-destroying geopolitical projects like the South Stream pipeline, and a substantial over-investment in upstream production capacity.\(^{61}\)

**US LNG EXPORTS MAY HEAD TO ASIA, BUT CONSUMER BENEFITS ARE GLOBAL**

As previously mentioned, if the LNG export terminals already approved by the Department of Energy are built and fully utilized, the United States could add another 10.5 bcf/d (109 bcm) to global LNG markets in the coming years beyond the 9.4 bcf/d (97 bcm) already freed up by the drop in US LNG import demand. Export capacity of around 8-9 bcf/d (83-93 bcm) is also consistent with the 5 to 7 US projects many private forecasters expect would be economic to build.\(^{62}\)

When assessing how this additional supply might shape energy economics and geopolitics in Europe, it is important to note that Asia will be the likely destination for a large share of US LNG exports. Delivered LNG prices are higher in Asia than in Europe (Figure 3) as traditional Asian importing countries like Japan and Korea lack meaningful domestic gas production and have been willing to pay a premium for secure LNG supply. Moreover, Japanese and Korean utilities generally have greater ability to pass on high natural gas prices to consumers than their European peers. Emerging Asian LNG markets, most importantly in China, are also paying a premium for LNG relative to European consumers.\(^{63}\) Despite the increased time and cost required to move LNG from the US Gulf Coast to Asia, current price spreads make it the most commercially attractive destination for US gas. The expansion of the Panama Canal will also shave about a dollar off the cost of shipping LNG from the Atlantic Basin to Asia.\(^{64}\) Indeed, more than half of the long-term offtake agreements from prospective US LNG terminals were signed by large Asian import agents or utilities, such as Japan’s Osaka Gas and Korea’s Kogas.\(^{65}\)

Some US LNG will reach European shores—Cheniere, for example, has contracts with Centrica in the UK and two Spanish utilities\(^{66}\)—although on a regular basis the gas is likely to be resold into the Asian market given existing arbitrage opportunities. Still, the absence of destination or resale restrictions in the contracts provides Europeans with increased optionality, so the gas can be brought to Europe when prices there are higher or to meet seasonal demand. Even if not a single drop of US LNG finds its way to Europe, however, additional US LNG exports will impact European gas markets. Expanding the amount of LNG available globally will further increase consumer leverage in price negotiations and put downward pressure on global gas prices. And the more US gas Asian customers purchase, the less gas they buy from other LNG suppliers, expanding the set of non-Russian options available in Europe.

**LOW COST OF US BROWNFIELD LNG PROJECTS ALLOW US TERMINAL OPERATORS TO OFFER BETTER CONTRACT TERMS FOR BUYERS**

Were all the 10.5 bcf/d (109 bcm) of currently approved US LNG capacity added to the market it could replace two-thirds of current European gas imports from Russia, either directly through sales to Europe or indirectly by displacing supply previously destined for the Asian market. However, as discussed in greater detail later, the actual addition of supply to world markets will be limited as higher cost production will not be able to compete. In addition, the actual amount of US LNG will depend on how much capacity the industry finds economic to build. The recent changes to DOE’s export policy that remove the requirement that projects seeking to export to non-FTA countries obtain conditional authorizations will allow commercial considerations to better signal to DOE which projects are most viable and able to finance completion of the FERC authorization process.

The economic viability of the proposed US LNG terminal projects and their level of progress vary considerably. Almost all the terminals that have received approval thus far are so-called brownfield projects looking to outfit existing import terminals with liquefaction equipment. The capital investment required to add liquefaction facilities to already operational import terminals is considerably lower than building a new liquefaction terminal from scratch.\(^{67}\) The primary reason for the lower capital cost is that much of the infrastructure, including pipelines, storage tanks, loading berths and marine loading arms, is already in place. During the previous decade, an estimated $100 billion was invested in these underutilized US LNG import terminals.\(^{68}\)
As a result, most of the proposed brownfield export facilities are among the cheapest LNG liquefaction projects globally. These projects have very favorable netback economics, and are highly competitive with new Australian LNG projects for the Asian LNG market, despite the US terminals’ greater distance from the region. The operators of American brownfield terminals are well positioned to offer a greater degree of volumetric flexibility as well as destination flexibility to prospective LNG importers, which is part of what has attracted Asian utilities and other buyers.

Greenfield projects in the United States face considerably longer permitting procedures, greater execution risk, and have to compete with other major infrastructure projects for scarce engineering and construction services—similar to the difficulties faced by most other LNG export terminal projects around the world. The Jordan Cove and Oregon LNG projects, both located in Oregon, face additional hurdles, although they would have easier access to the most lucrative Asian LNG market. Both West Coast projects are relatively far from the parts of the country where natural gas production is growing, such as the Midwest and the Marcellus play further east, and would source gas from the Rockies and from Western Canada. The long-term production outlook in both areas is also less certain and hundreds of miles of pipelines would need to be constructed to connect them to gas hubs, making their overall economics less favorable.

Some of the other proposed greenfield projects are little more than PowerPoint presentations at the moment, as it only costs $50 to file an export application with DOE.

**US LNG CONTRACT TERMS MAY CREATE FLEXIBILITY AND LIQUIDITY IN GLOBAL MARKET**

US LNG export terminals will operate under a fundamentally different business model than liquefaction terminals elsewhere in world, which could shape global gas markets beyond the direct impact of additional supplies. Constructing LNG export terminals is an extremely lengthy and capital intensive process. As a result, terminal operators generally require long-term sales purchase agreements and relatively inflexible volumetric commitments from the buyers. As discussed, the price of LNG is usually indexed to another commodity, typically to oil or a combination of petroleum product prices in a destination market, most often on a 6 to 9 month rolling average basis. (There is increasing use of natural gas spot price indexation for spot or term LNG contracts in Europe, although long-term contracts often continue to use oil indexation.) In this contractual arrangement, the producer takes the investment risk, and shares the price risk with the buyer, while the buyer takes most of the volumetric risk in the form of take-or-pay obligations.

Several US LNG export projects, such as Cheniere’s Sabine Pass project set to begin operating in 2015, appear likely to operate under a different “tolling type” contractual structure. This means that the terminal operator charges a fixed capacity fee, around $3 per mmBtu in Cheniere’s case, which has to be paid even if the buyer decides not to use the booked capacity. The buyer may be responsible for sourcing gas from the US market, as well as any fuel required to run the liquefaction plant. The buyer is typically also responsible for arranging shipping. Cheniere’s contract structure is slightly different because it also sources the feed gas to convert to LNG, and charges a markup of 115% of the Henry Hub price to cover its procurement and fuel costs.

It is unclear at this point how many other US LNG export projects will use a similar tolling arrangement in their offtake agreements. The deals announced so far suggest that many US LNG exports will be sold under long-term tolling-type contracts, but it is too early to determine whether this model will predominate. Ultimately, the contract structure could have important implications for the volume of LNG that the US exports and thus the impact it has on US gas prices.

Under traditional take-or-pay contracts, even if the US price of gas rose enough to make US natural gas, plus liquefaction and transportation, uncompetitive in foreign markets, the buyer would still be obligated to take the cargo, so the US would continue to export the contracted volumes of gas. Depending on the contract structure, in such a scenario, the buyer might resell the gas into the US market to avoid paying the transportation costs, however.

Without a take-or-pay obligation, if US gas prices rise above a certain level, the arbitrage between Henry Hub gas and alternative LNG supply may not be large enough to make it economic for buyers to take US natural gas. That arbitrage window is not the full $6 to $7 per mmBtu cost of liquefaction and transportation, however, because the tolling fee is a sunk cost. That means that there still may be cases when Asian and European buyers opt to receive the gas even if
the US price rose to levels that seemingly closed the arbitrage window because they would need to pay the $3 tolling cost in any event. Even if Henry Hub prices rise, buyers will continue to take the US LNG, even under a tolling model, until the point at which the arbitrage window narrows to the variable cost of transportation plus liquefaction fuel.

That would be true when the buyer is an end-user, such as a utility, although not necessarily if the buyer were a marketer or portfolio player looking to resell cargoes through spot or term tenders. In the latter case, the marketer will be unable to resell the gas if the end-user has lower cost options, so the marketer would pay the tolling fee but the gas volumes would not be exported from the United States.

From the standpoint of the global LNG market, the long-term commitment to pay the capacity fee is still a substantially smaller commitment than traditional oil-indexed take-or-pay contracts. Thus, the advent of US tolling-type contracts may provide the global LNG market with more liquidity and buyers with more flexibility than the historic alternatives, and shift the balance of power from gas producers to consumers. In addition to the adjustments to European gas contracts with Russia, consumers are beginning to flex their muscles for better terms. Asian buyers are pressing Chevron, the developer of the Kitimat LNG project in Canada, for a natural gas-indexed contract.  

Buyers are also less willing to make 20-year or 30-year LNG purchase agreements. Less than half of the long-term LNG contracts concluded in 2013 were for 20 years or longer, while all other long-term sales agreements signed last year were for periods shorter than 15 years, due at least in part to the anticipated presence of large volumes of flexible US LNG on the global market.

The share of 20-year or longer contracts among the long-term sales agreements finalized in 2012 was 57%, while in 2009, the corresponding share was 67%. Prospective developers of new greenfield liquefaction projects still need to secure 20-year offtake agreements to be able to obtain financing, and to justify the large up-front capital investment associated with LNG projects.

The absence of destination clauses may also reduce some element of gas price volatility because, even if US LNG terminals run at or near capacity most of the time, their supplies can be diverted to different markets in response to price spikes. On the other hand, more spot trading can increase short-term price volatility relative to long-term oil-indexed contracts, as the market responds more quickly to supply and demand shocks and threats.

**EUROPE HAS SIGNIFICANT SPARE LNG IMPORT CAPACITY TO TAKE MORE SUPPLY**

Europe is well positioned to expand the volume of LNG it imports as more supply becomes available. European countries had an extensive LNG import infrastructure with 22 operational terminals and a total regasification capacity of 19 bcf/d (199 bcm) at the end of 2013. Another three terminals were under construction with a combined capacity of 2 bcf/d (21 bcm) at the end of last year. Utilization rates at these terminals have dropped sharply in recent years, from 48% in 2010 to 23% in 2013, with Europe becoming close to a residual market for LNG shipments (Figure 10).

A number of factors account for the decline in LNG consumption in Europe. European gas demand remains stagnant, as subsidized renewables and cheap coal continue to squeeze natural gas out of power generation. The collapse of European carbon prices has further undermined the competitiveness of natural gas relative to coal in the EU. Asian and Latin American buyers are also willing to pay higher prices for LNG than European ones to meet rising demand, bidding away spot LNG cargoes from Europe. LNG volumes that are landed in European terminals as required under long-term take-or-pay contracts are often re-exported to higher paying markets in Asia and South America.

In theory, the European Union already has enough LNG import capacity to almost completely replace Russian gas shipments with imported LNG, were such supply available and affordable. EU member states imported 14.5 bcf/d (150 bcm) of natural gas from Russia in 2013 (Figure 11), while the idle LNG import capacity in the bloc was about 14.1 bcf/d (146 bcm)—although the largest chunk of unused regasification capacity is in Spain, which is not well connected to the rest of the European gas transmission system. The greater European region, including Turkey, Switzerland and the non-EU members on the Balkan Peninsula, imported about 17 bcf/d (179 bcm) of natural gas from Russia last year. Unused LNG regasification capacity in this broader region was at 14.7 bcf/d (152 bcm) in 2013, with another 2 bcf/d (21 bcm) under construction.
Figure 10: European LNG import capacity and utilization

Source: International Group of Liquefied Natural Gas Importers.

Figure 11: European LNG Import capacity vs. Russian gas imports

Source: GIIGNL, Gazprom Export delivery statistics.