The Future of the European Gas Supply

This decade will be a game changer for Europe
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For global and European gas markets, 2015 will be a watershed year. After gas supplies tighten and prices rise by 30 to 40 percent between now and 2014, there will be a worldwide surplus and a sharp drop in prices. Gas trading hubs will gain credibility, while smart producers will expand trading activities and shrink the degree to which supply contracts are indexed to oil prices. Importers must have flexible gas supply portfolios and expanded trading activities. What will happen to the vertically integrated business model? It will become yesterday’s strategy of choice.

The European gas market has become more dynamic in recent years because of supply and demand changes. Since the economic crisis, gas consumption rates have fallen, the origin of gas has undergone massive changes, and Europe has begun to move closer to international gas markets. Pipeline gas imports have fallen significantly in the past two years, while imports of liquefied natural gas (LNG) rose by 11 billion cubic meters (bcm) in 2009 and 18 bcm in 2010. Between 2008 and 2010, long-distance pipeline gas (LDPG) lost a total of 10 billion cubic meters, which represents a market share loss of roughly 2 percent.

What caused the volatility? An oversupply of LNG, which led to cheap spot market prices. What caused the oversupply of LNG? Three factors: a fall in global gas demand during the recession; a lack of U.S. gas import demand because of the unconventional gas take-off; and new LNG capacity that came on stream in Qatar.

Undoubtedly, 2015 will be a turning point for global gas markets—especially in Europe. The industry’s status quo is about to be disrupted, with both a worldwide surplus and a plunge in prices expected.

Now is the time to prepare. During the next few years, as European gas prices increase, producers and importers have an opportunity to brace for the expected bust by adjusting now for the coming shifts. Regional suppliers and municipal utilities should also anticipate tougher competition in the years ahead. Those who want to come out on top must transform their existing business models.
This paper discusses the game-changing developments in global and European gas markets and answers the following questions about the remainder of this decade:

- How will the gas supply and demand balance in Europe evolve?
- Is the import infrastructure coping with the expected European import demand, or will it represent a bottleneck?
- How will the global LNG supply and demand balance develop, and what impact will the global LNG market have on European gas prices?
- How will trade markets further develop?
- How will pricing regimes evolve in Europe?
- How will and should players’ business models change?

Gas Imports Will Rise Despite Weak Demand

Gas is becoming more important as a global energy source, with an annual growth rate of 1.7 percent (see sidebar: The Gas Market). We expect gas consumption within Europe to increase just 0.4 percent per year—the lower of two scenarios we developed based on our proprietary gas market model that simulates growth in demand for gas at a granular level (see figure 1).

Between now and 2020, the partial switch from nuclear to gas in Europe’s power sector—in the aftermath of the 2011 Fukushima nuclear disaster in Japan and the resulting projected nuclear slowdown in the EU27—is expected to lead to an increase in annual gas consumption of 20 to 40 bcm. Germany shut down seven nuclear power plants in 2011 because of Fukushima and plans to exit nuclear power generation in the next 10 years. Another reason is the expected 20 to 30 percent reduction in newly built nuclear power plants, which will be partially offset by combined-cycle gas turbine power plants. Even if the Fukushima accident hadn’t happened, the increase in gas-fueled power generation would still be the main driver. Gas has been losing ground in the heating market for some years.

However, declining domestic production, mainly in the United Kingdom and the Netherlands, will lead to a 27 percent increase in gas imports—climbing from the current

The Gas Market

In European markets over the years, exchange-based gas prices uncoupled from long-term import contracts, ultimately reaching levels half those of import contracts. Consequently, this destroyed the classic risk-sharing between upstream players and importers based on oil-indexed gas pricing. The gas industry suffered sharp falls in earnings before interest and taxes (EBIT)—upwards of 35 percent for producers with losses running into the billions of dollars for importers. Such losses are reflected in the share prices of the European gas players, whose stock performance is as much as 28 percent lower than the Morgan Stanley Capital International (MSCI) index in Europe.

In the 27 European Union countries (EU27), gas is second to oil, representing 25.6 percent gross energy consumption. But from a reserve perspective, Europe holds only 10 percent of global conventional gas reserves. Gross consumption of gas rose strongly between 1990 and 2010—from 2,200 to 3,400 bcm globally and from 340 to 529 bcm in the EU27.
Gas is becoming more important as a global energy source, with an annual growth rate of 1.7 percent.

327 bcm to an expected 413 bcm in 2020. The rise in gas imports is expected despite our prediction of a rather flat consumption curve. Even so, the 27 percent increase is much lower than predicted a few years ago, when import volumes were expected to more than double.

Additionally, the gas import infrastructure is undergoing massive expansion in both pipeline gas and LNG. A conservative assessment of import infrastructure projects either under construction or in the planning stages reveals a 65 percent increase in pipeline capacity and more than double the LNG import capacity by 2020. We believe overcapacity will reach 77 bcm by 2020, even in a conservative scenario. If the gas consumption growth trend of 2 percent or more continues—albeit this is highly unlikely—capacity usage could reach historic levels (see figure 2 on page 4). As a consequence, we expect more pressure on tariffs and more competition between pipelines and LNG import terminals as they fight for customers at the import level. This will benefit spot LNG in periods of oversupply, similar to 2009 and 2010.
Unconventional Gas is a Game Changer

Unconventional gas is becoming a game changer in the U.S. gas market. In 2010, 12 bcm of LNG was imported into the United States; before this unconventional gas revolution, this number was expected to reach 140 bcm by 2020.

The United States. Unconventional gas now accounts for around 40 percent of U.S. gas production and could turn the United States into an LNG exporter within this decade. Projects are already underway, including the Sabine Pass LNG terminal, which is designed to build up liquefaction capacity. Although the technology to release shale gas has been around for decades, introduced in principle in the late 1940s, major legislation and economic changes have recently propelled a U.S. shale gas revolution. Exempting shale gas exploration from the Clean Water Act during the George W. Bush era gave it a jumpstart, while rising U.S. gas prices and productivity gains pushed the revolution along (see figure 3).

Shale gas acts as flexible supply, with dependable volumes and prices. Drilling for unconventional gas falls as gas prices fall—below the current $3 to $4 per million British thermal units (mmBTU)—or ramps up if Henry Hub gas prices are above this level, a result of low entry barriers for investment.1 Consistently low U.S.

Figure 2
Gas import capacity versus demand

Billion cubic meters

<table>
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<tbody>
<tr>
<td>LDPG import potential</td>
<td>~327 bcm</td>
<td>247.4</td>
<td>80.3</td>
<td>79.8</td>
<td>82.8</td>
<td>77.3</td>
<td>45.7</td>
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<tr>
<td>LNG import potential</td>
<td>~163 bcm</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>6.5</td>
</tr>
<tr>
<td>Pre-Fukushima</td>
<td></td>
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<tr>
<td>Post-Fukushima</td>
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</tr>
</tbody>
</table>

Note: LDPG is long-distance pipeline gas; LNG is liquefied natural gas.
1 LDPG imports from new and existing capacities are based on a utilization rate of 75 percent; LNG imports are based on a rate of 80 percent.
2 Initial phases of Nabucco (8 bcm), no realization of or additional capacities from South Stream and White Stream were taken into consideration.


1 The Henry Hub, owned by Sabine Pipe Line LLC, is a natural gas pipeline in Louisiana that connects many intrastate and interstate pipelines. The settlement prices at this hub are used as benchmarks for the entire North American natural gas market.
gas prices and high oil prices in recent years, with the exception of 2009 during the height of the financial crisis, triggered a shift toward oil-rich shale, with gas being more of a byproduct. With gas prices at $4 per mmBTU and oil prices at $80 per barrel, oil-prone shale such as Permian or Barnett yielded an internal rate of return of greater than 100 percent, while gas-prone shale such as Marcellus yielded on a ceteris paribus level of 12 to 28 percent. The shift to oil shale with a developing north-south liquid fairway leads to a cycle of abundant cheap gas in the United States—strengthening the U.S.’s competitiveness as a future exporter in the global LNG market.

By balancing mid- to long-term volumes and prices, the U.S. LNG market could influence global gas markets. However, the long-term U.S. supply is expected to be small in this decade compared to other LNG exporters, so the direct impact of U.S. gas prices on the global gas market is expected to be limited, especially when compared to the impact of a shortfall on LNG demand. In Europe, U.S. LNG has to compete with cost-competitive LNG from Algeria, West Africa, and especially Qatar. These countries will remain the major LNG suppliers to Europe, with the United States expected to deliver spot cargoes during peak demand periods.

Europe. In Europe, the picture looks completely different. Although there are significant reserves of unconventional gas in European countries, only a handful of countries are capitalizing on them. Poland, for example, wants to gain more independence from Russian gas deliveries, so the country has awarded more than 40 drilling licenses to major U.S. oil and gas companies. Germany has

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**Figure 3**

Productivity gains in unconventional gas

<table>
<thead>
<tr>
<th>Time to drill (days)</th>
<th>Wells per rig per year</th>
<th>Lateral length average (feet)</th>
<th>30-day average production rate (million cubic feet/day)</th>
<th>IP1 additions per rig per year (million cubic feet/day)</th>
<th>Drill and completion costs ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>20</td>
<td>-60%</td>
<td>11</td>
<td>46</td>
<td>+156%</td>
<td>2.8</td>
</tr>
<tr>
<td>11</td>
<td>-60%</td>
<td>18</td>
<td>33</td>
<td>+156%</td>
<td>2.6</td>
</tr>
<tr>
<td>8</td>
<td>-60%</td>
<td>18</td>
<td>2104</td>
<td>+156%</td>
<td>2.6</td>
</tr>
<tr>
<td>11</td>
<td>-60%</td>
<td>18</td>
<td>4503</td>
<td>+156%</td>
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<tr>
<td>8</td>
<td>-60%</td>
<td>18</td>
<td>5000</td>
<td>+156%</td>
<td>2.6</td>
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</tbody>
</table>

1IP refers to initial production
Sources: Southwestern Energy, Bentek; A.T. Kearney analysis

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A single drilling activities underway, mainly focused on the Lower Saxon basin, while France’s lower house of parliament approved a bill that bans shale gas drilling because of environmental concerns in a difficult political environment.

Europe faces higher economic hurdles to exploiting shale gas because geological structures are deeper and more complex, environmental legislation is stricter than in the United States, and the population in relevant areas is denser. Together, these issues mean significantly higher production costs—€25 per megawatt hour (MWh) or higher—which cannot be covered when gas prices are €20 per MWh or lower. Based on current and expected gas prices, we do not anticipate an unconventional gas revolution in Europe in the near future.

Asia Pacific. Asia Pacific is projected to increase production of unconventional gas more than eightfold through 2020, driven primarily by China’s drive for energy independence. China’s goal is to derive 30 percent of its gas production from unconventional sources by 2020 (about 70 bcm). India is also pushing for shale gas as deposits countrywide are projected to be 300 times higher than India’s current largest gas field, the Krishna Godavari (D6) basin. Chinese national oil companies are preparing for an unconventional gas revolution in China and are acquiring the necessary expertise and technologies in countries with advanced experience in shale gas. The shale gas ambitions of China, and to a smaller extent India, have a major downside potential for the global LNG market.

New “Gas Bubble” Expected in 2015 Onward

Since the 1980s, global gas markets have grown at a rate of 2.5 percent per year. In contrast to Europe, demand for gas at the global level will continue to grow at the same speed through 2020. On the supply side, while gas production will fall in Europe, it will increase markedly worldwide, especially in the Middle East and Asia Pacific, with the focus on LNG. The strongest increase in output is anticipated in Iran and Qatar: Iran is expected to increase its production from 131 bcm in 2009 to 226 bcm in 2030, and Qatar’s production will increase from 89 bcm in 2009 to 238 bcm in 2030.

In recent years, there has been a lot of hype about LNG, with annual growth rates of 8 to 9 percent forecast for this decade. Based on our analysis, however, we anticipate demand for LNG to increase by 3.1 to 4.5 percent per year until 2020. This represents a distinct slowdown in global market growth for LNG. The gas demand scenarios differ strongly between the regions (see figure 4).

Demand for LNG will be heaviest in Asia Pacific, rising from the current 180 bcm to somewhere between 254 and 275 bcm by 2020. China and India will be the biggest players. We predict China’s demand for gas will climb up to 350 bcm by 2020—triple its current consumption levels. This is in stark contrast to the country’s domestic gas production capacity of 210 bcm in 2020, with 70 bcm expected to come from unconventional gas sources.
Consequently, China will need to import up to 140 bcm of gas in 2020, although it has already signed pipeline gas and LNG import contracts for a total 90 bcm of gas. Many players and gas-producing countries believe China will have no additional import requirements on top of the capacities for which agreements have already been reached. Even in the most ambitious demand scenario, China would need no more than 50 bcm of additional import contracts split between LNG and LDPG, with limited demand impact on the global LNG market.

In the Americas, LNG demand is not expected to increase significantly as LNG imports to the United States decline while expanding in South America, mainly in Brazil and Argentina. In Europe, we predict higher demand for LNG over this decade, from around 80 bcm to 113 bcm, an increase of 42 percent. On the supply side, gas liquefaction terminal capacity will expand between now and 2020. Based on our assessment of global liquefaction terminal projects, we project global liquefaction capacity to grow from nearly 380 bcm to 541 bcm. In the latter figure, we consider operating liquefaction terminals, terminals under construction, and likely terminals based on a conservative view of current project status. If we were to include potential projects in our analyses, a total liquefaction capacity of 594 bcm would be available worldwide by 2020, driven primarily by Australian LNG projects that are expected to come on stream in the second half of the decade.

Through 2014, we will likely see a global LNG market shortage because of rising demand coupled with minimal growth in liquefaction capacity. Supply will exceed demand by only 10 to 14 percent compared to 39 percent, or 92 bcm

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**Figure 4**

Projected LNG demand by region, through 2020

<table>
<thead>
<tr>
<th>Region</th>
<th>2010</th>
<th>2015</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Latin America</td>
<td>29.1</td>
<td>31.6</td>
<td>34.4</td>
</tr>
<tr>
<td>North America</td>
<td>19.9</td>
<td>21.7</td>
<td>22.4</td>
</tr>
<tr>
<td>Middle East, China, India</td>
<td>87.7</td>
<td>99.5</td>
<td>114.4</td>
</tr>
<tr>
<td>Japan, Korea, Taiwan</td>
<td>152.8</td>
<td>180.1</td>
<td>232.0</td>
</tr>
<tr>
<td>Rest of Europe/Eurasia</td>
<td>79.8</td>
<td>98.5</td>
<td>112.7</td>
</tr>
<tr>
<td>EU27</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Middle East, China, India</td>
<td>180.1</td>
<td>232.0</td>
<td>274.6</td>
</tr>
<tr>
<td>Japan, Korea, Taiwan</td>
<td>152.8</td>
<td>232.0</td>
<td>254.4</td>
</tr>
<tr>
<td>Rest of Europe/Eurasia</td>
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</tbody>
</table>

1Includes Singapore, Thailand, and Pakistan


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Billion cubic meters

Demand split within region (2010)

High/low demand differences

Consolidated demand
in absolute terms, in 2009, as the financial crisis continued. However, from 2015 until the end of the decade, we anticipate market overcapacity and a possible global LNG bubble (see figure 5). Overcapacity will likely hit 40 percent of demand (considering plants operating, under construction, and likely to be built) if the low-demand scenario materializes. This translates to excess supply of up to 154 bcm in absolute terms in 2018. However, even in the less likely high-demand scenario, overcapacity of up to 28 percent of LNG demand could materialize, which is also well above a healthy margin of 10 to 15 percent compelled by terminal availability.

Compared to the 541 bcm of liquefaction capacity expected by the end of this decade, we anticipate a regasification capacity of 1,182 bcm—up from the current 854 bcm in operation. The vast majority of it is being built or is expected to be built in Asia, followed by Europe. In the United States, many regasification terminal projects have been put on hold or canceled because of the recent U.S. shale gas revolution, which will make LNG imports redundant, as previously mentioned. Because LNG does not face regasification capacity shortfalls on a global or European level, excess LNG will be diverted to other swing and European markets as the last price-setting supply in a merit-order curve of all supply sources.

**Gas Prices to Fall in 2015**

European gas hubs have grown steadily and have emerged to be liquid, with National Balance Point (NBP) being the most liquid in Europe. Further gas hubs in continental Europe—such as the Title Transfer Facility (TTF) in the Netherlands and others in Germany, Iberia, Italy, France, and Austria—increased their traded

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**Figure 5**

Projected global LNG supply and demand, through 2020

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*Sources: International Energy Agency, BP Statistical Review, Shell, Global Data — O&G eTrack, Project Webpages; A.T. Kearney analysis*
volumes by an annual rate of 85 percent over the past five years.

More than 90 percent of gas pricing in continental Europe is indexed to heavy and light fuel oil. The intention was to make gas competitive to oil independent from the respective market situation. In combination with take-or-pay limits and contract durations of 20 to 30 years, this pricing mechanism largely hedges volume risks away from upstream players and consequently enables huge investments in exploration, production, and transport infrastructure. This type of contract evolved when oil was a major substitute for gas and there was no alternative price index with sufficient liquidity other than oil available.

Both preconditions changed: Oil-to-gas switching capacity fell in Western European countries, and liquid hubs emerged (see figure 6). This was especially the case in 2009 and 2010 as hub prices were at times half that of oil indexed prices and hub liquidity was on the rise. Industrial and large commercial customers asked for hub-priced contracts to replace previous oil-indexed contracts.

We believe that formula-based price indexing of gas to oil will fade over time and will probably disappear altogether during the second half of this decade, if (or when) the next gas bubble reaches Europe. Then, gas hubs will establish themselves as price benchmarks at the expense of oil-indexed contracts. However price indexing might survive to a limited extent in a different form if commodities other than oil are competitive to gas in specific demand segments.

Nonetheless, in a tightening market, the convergence of hub-based gas prices and oil-indexed prices is likely. This can be observed in liquid markets with no formal link of gas and

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Figure 6
The development of liquid gas hubs

![Figure 6: The development of liquid gas hubs](image)

Note: CAGR is compound annual growth rate

Source: A.T. Kearney analysis

With the exception of the United Kingdom, where gas prices are mainly indexed to competitive gas (and less than 20 percent to oil products).
Formula-based price indexing of gas to oil will probably disappear in this decade if (or when) the next gas bubble reaches Europe.

oil prices, such as the United States when the market is in balance. The liquid European gas markets, including NBP and TTF, have had periods of convergence of oil-indexed gas prices and competitive gas prices, interrupted by periods when market conditions caused prices to de-link. Indeed, this happened in January and February 2006, brought on by the Ukrainian gas crisis, a cold February, and a fire at the U.K.’s Rough gas storage facility. A further decoupling occurred in the unusually warm winter of 2006 and 2007. This combination of events resulted in supply and demand imbalances, reflected in exceptionally high and low hub-based gas prices.

As the global LNG market constricts, Europe’s wholesale gas prices are set to rise anywhere from 30 to 40 percent to €30 per MWh (average of expected price corridor) over the next three years. Consequently, gas wholesale markets will be recoupled to the price of oil in the medium term. But because of the expected global oversupply of LNG beginning in 2015, we predict high price volatility and a sharp fall in competitive gas prices— at times down to around €12 per MWh.

The reason for the price drop is a change in pricing fundamentals, especially in periods of oversupply as the long-run marginal costs of supply to the EU border form the base for setting wholesale prices in European gas markets. In our low-case demand scenario, there is additional import demand of around 86 bcm in 2020, on top of 2010 import volumes; LNG is expected to be the marginal supply source to Europe resulting in a price floor around €12 per MWh, which might be temporarily undercut by Qatari LNG. Russian LDPG with partially higher long-run marginal costs of supply to the EU border, or rigid oil price indexing, is expected to lose ground to LNG—so history might repeat itself.

Get Serious About Your Business Models
These expectations for the international and European gas markets will have serious implications for players along the value chain, raising two strategic questions: What is the future relevance of vertically integrated business models, and what will be the most attractive positions along the gas value chain in this decade?

Future relevance of vertically integrated business models. A variety of business models coexists in the European gas market, with historic convergence taking place among up- and mid-stream players. Convergence occurs for various reasons—one is vertical integration to obtain synergies, especially between the commodity and infrastructure businesses. In contrast, players in mature and competitive gas markets such as the United States focus on single elements of the value chain. For example, upstream and midstream businesses have been largely separated in the United States over the past decade. Liquid traded markets, such as the Henry Hub, eliminate volume risks and avoid price risks if required by individual players.
Based on the market developments discussed earlier, we foresee a decline in vertical integration as vertical synergies are slashed by increasingly effective regulation and liquid traded markets. At the same time, we recognize that the industry continues to overrate the importance of vertical synergies. Liquid markets enable focused business models and leave vertical integration as the one capital-intensive instrument of risk management—both to stabilize cash flows in the event of margin shifts along the gas value chain and to reduce risk in debt markets. Companies with a beta (as a measure for their business model risk perceived by the financial markets) of about 0.6 have a significantly lower return on capital employed (ROCE) of 5 to 10 percent and are perceived as less risky because of vertical integration. Companies that are more on the production side, with a beta of 0.8 to 0.9 and a ROCE score between 15 and 20 percent, are considered more risky.

The attractiveness of discrete positions along the gas value chain changes during the current decade. This decade’s market developments will have implications on players’ positions along the gas value chain. For example, both producers and importers will improve their positions financially over the next two to three years, thanks to the expected increase in European gas prices. Producers and importers now have a window of opportunity to gain financial relief and prepare for the projected bust cycle of natural gas.

Producers. From now through the 2015 price drop, producers should further expand their trading competencies. The international oil and gas majors trade six to seven times more gas in the United States than they produce locally. By comparison, the most relevant producers supplying pipeline gas to Europe trade just 10 to 25 percent of their production volume, including when accounting for third-party sales. Producers must also become more flexible with contract terms, minimum purchase volumes, and pricing based on the wholesale market. They have to develop, over the short and medium term, a clear view on how they might ideally leverage gas wholesale markets with regard to their most advantageous sales strategy and portfolio structure. Otherwise, pipe gas producers will lose significant volumes to LNG as potential oversupply finds easy access to European gas markets that have excess import infrastructure capacity.

Importers. After financial distress followed by relief as markets tighten, European importers will see increasing pressure on their business models, primarily from traders in line with increasing liquidity of the European-traded markets. This will reduce import margins to €0.2 and €0.3 per MWh. Compared with pre-crisis import margins of €0.8 to €1 per MWh and huge losses in 2009 and 2010, the future looks gloomy. So what strategic pathways are available to importers to move to a more sustainable business model that can respond to current and expected market changes? For European importers of natural gas, the focus must be on reducing costs and improving performance; and the gas supply portfolio must in the short term be more resilient to price shocks, through measures such as revenue protection and hedging. In terms of portfolio strategy, importers must increase their share of purchases based on wholesale market prices to the expense of oil-indexed prices, diversify their supply portfolio, and reduce their minimum bill obligations.

From a long-term business model perspective, these companies have three basic options. The first is to work on upstream integration to stabilize cash flows and partially disconnect from wholesale market price volatility. The second is to pursue a strategy of downstream integration. Third,
companies can focus on a single element of the gas value chain. Each option has its challenges. While upstream integration has high capital requirements and is therefore difficult to accomplish, focusing on a specific element of the gas value chain can result in short-term revenue losses, which might be offset by horizontal consolidation activities or geographic diversification. However, both might be hard to achieve because of a limited number of takeover candidates and high entry barriers in international growth markets that are often not yet liberalized.

So what about downstream integration? Regardless of the option chosen, importers must expand their gas trading activities to cope with competition and the changing market environment. In addition, it can be beneficial to access end-customers to secure demand and therefore partially reduce exposure to the volatile traded market. This will help capture additional margins currently taken by intermediaries and local distributors. To implement this downstream integration strategy, importers can build on their available trading and sales competencies—propel the first and develop the latter by addressing required changes with regard to sales approach, products, processes, organization, and IT to serve a far broader and more heterogeneous customer base.

**Distributors.** Regional suppliers and municipal utilities also face a tougher, more competitive environment, with rivals enjoying easier access to gas supplies as wholesale markets develop further. In addition, increasing pressure for their industrial client base is expected as importers move downstream to target large and medium-sized enterprises. As municipal and regional utilities face decreasing market shares in their incumbent customer base, they are acquiring new out-of-area customers to compensate for the losses. As a result, gas retail companies must press ahead with expanding and diversifying their current customer, product, and supply portfolios and must strengthen their risk and portfolio management capabilities to respond to increasingly fierce competition. As price-based competition becomes more important, it is imperative to improve sales effectiveness and cost efficiency across all core business processes.

**The New Gas Market: Preparation**

With a price bust looming for 2015, supply and demand balances changing, trade markets and pricing regimes evolving, and unconventional gas making a major impact, the winners in the gas market will be those that brace for the future. By transforming their existing business models to meet future needs, they will come out on top.
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