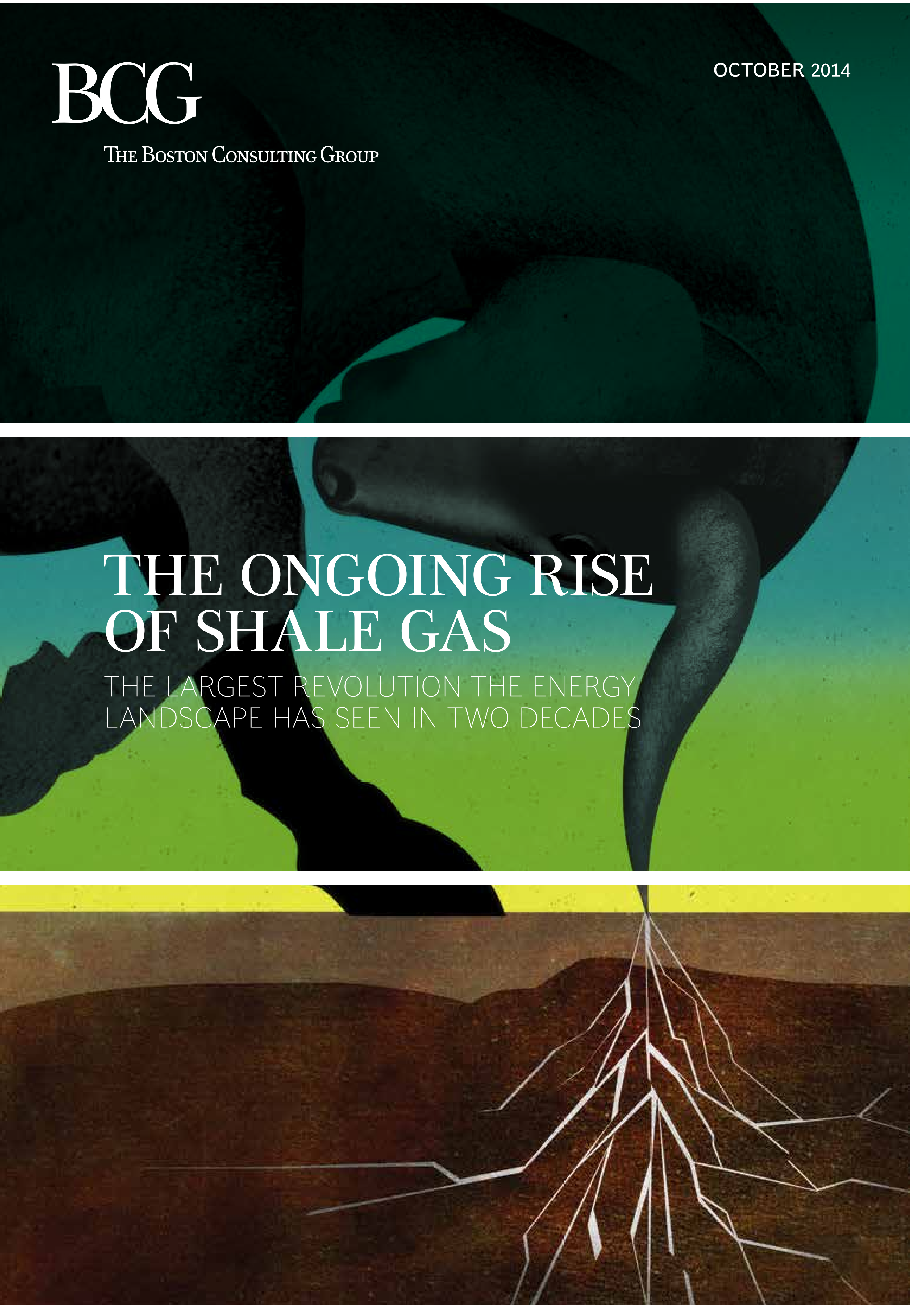

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OCTOBER 2014

THE ONGOING RISE OF SHALE GAS

THE LARGEST REVOLUTION THE ENERGY LANDSCAPE HAS SEEN IN TWO DECADES

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THE ONGOING RISE OF SHALE GAS

THE LARGEST REVOLUTION THE ENERGY LANDSCAPE HAS SEEN IN TWO DECADES

IVÁN MARTÉN

ERIC OUDENOT

ALEX DE MUR

CLINT FOLLETTE

UDO JUNG

JUSTIN ROSE

JAIME RUIZ-CABRERO

HAROLD L. SIRKIN

MICHAEL ZINSER

October 2014 | The Boston Consulting Group

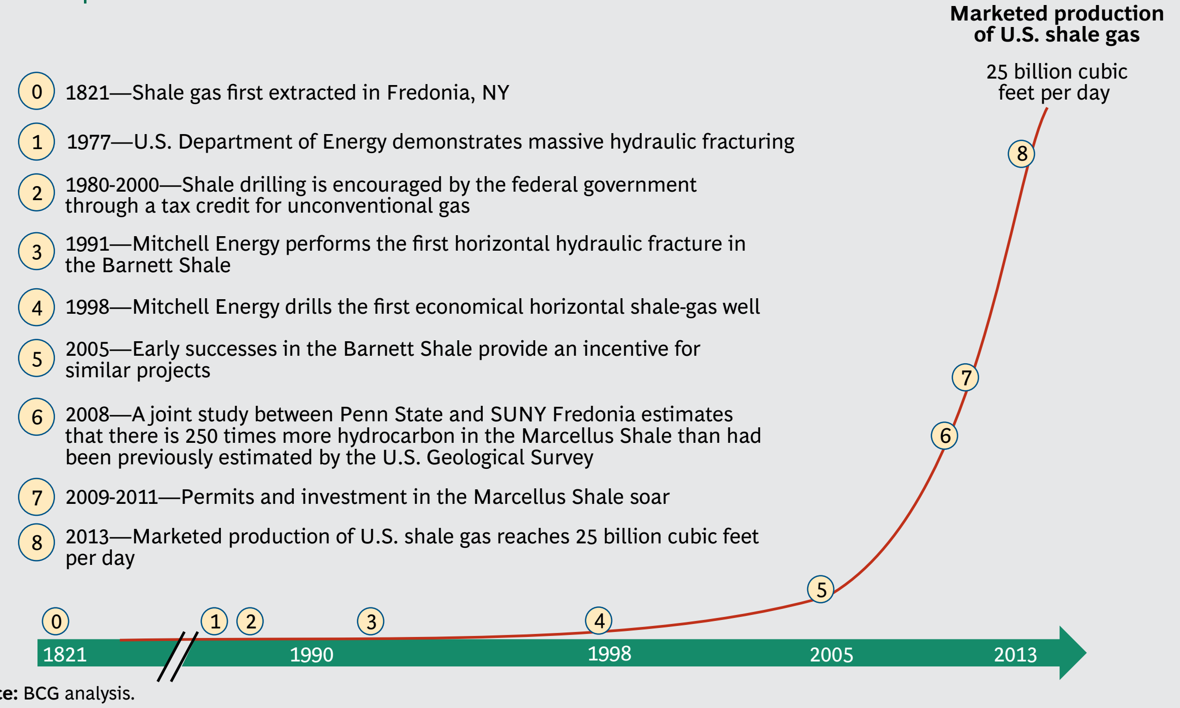
CONTENTS

INTRODUCTION

The so-called shale gas revolution has already had a transformative impact on the U.S. natural-gas market, the country's energy landscape broadly, and a number of U.S. industries, most notably petrochemicals. Its reach promises to expand considerably as development practices continue to improve and as growing numbers of countries, such as Argentina, China, Poland, and the UK, seek to exploit the shale reserves within their borders.

The revolution's arc of development, especially over the last decade, has been remarkable. (See Exhibit 1.) And the march forward continues. Indeed, BCG estimates that the production of liquids and gas from North American shale developments nearly tripled from 2010 to 2013, with production surpassing 10 million barrels of oil equivalent per day by the end of 2013. By the close of 2013, the daily production of liquids from North

Exhibit 1 | The Shale Gas Timeline



Source: BCG analysis.

American shale plays was roughly equivalent to the combined production of Nigeria and Angola. At the same time, the production of gas from North American shale plays exceeded the combined production of Qatar and Iran. (See Exhibit 2.)

The long-term economic impact of the shale gas revolution could be massive.

The revolution's potential longer-term effects on the global economy are a subject for speculation at this point, given the number of unknowns. The regulatory environment in many countries is uncertain. In some nations, public opposition is strong to "fracking," or hydraulic fracturing, the reservoir stimulation technique underpinning shale gas development. Still others face significant logistical challenges to development. In many countries, the actual size of their shale reserves remains unknown, notwithstanding some countries' rather optimistic projections. And, critically, many countries lack a key structural advantage to development that the U.S. possesses: private ownership of subsurface mineral rights. Private ownership translates into a greater share of the economic benefits of shale gas development accruing directly to local residents and landowners; this can be a powerful incentive for local communities to allow and promote development.

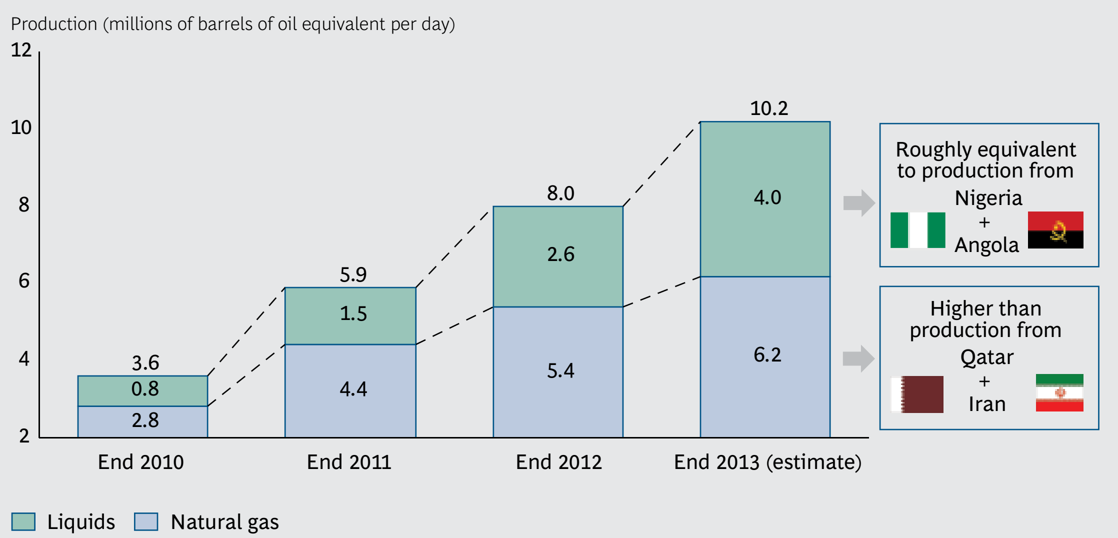
Still there is much to suggest that, in the end, the long-term economic impact of the shale gas revolution could be massive, at least in some countries. For energy and related businesses, the resulting commercial opportunities stand to be commensurately large, provided companies have the right business and operating models. (See Exhibit 3.)

The articles in this e-book examine the shale-gas revolution through a number of lenses:

- "The Great, Global Shale-Gas Development Race: Where to Focus Commercial Resources" examines the second wave of shale gas development that BCG believes will take place—outside North America—over the next five years. The prize—abundant, low-cost natural gas—stands to be an order of magnitude greater than the resources available in North America. But not all shale resources will be commer-

Exhibit 2 | Production from North American Shale Plays Has Surged

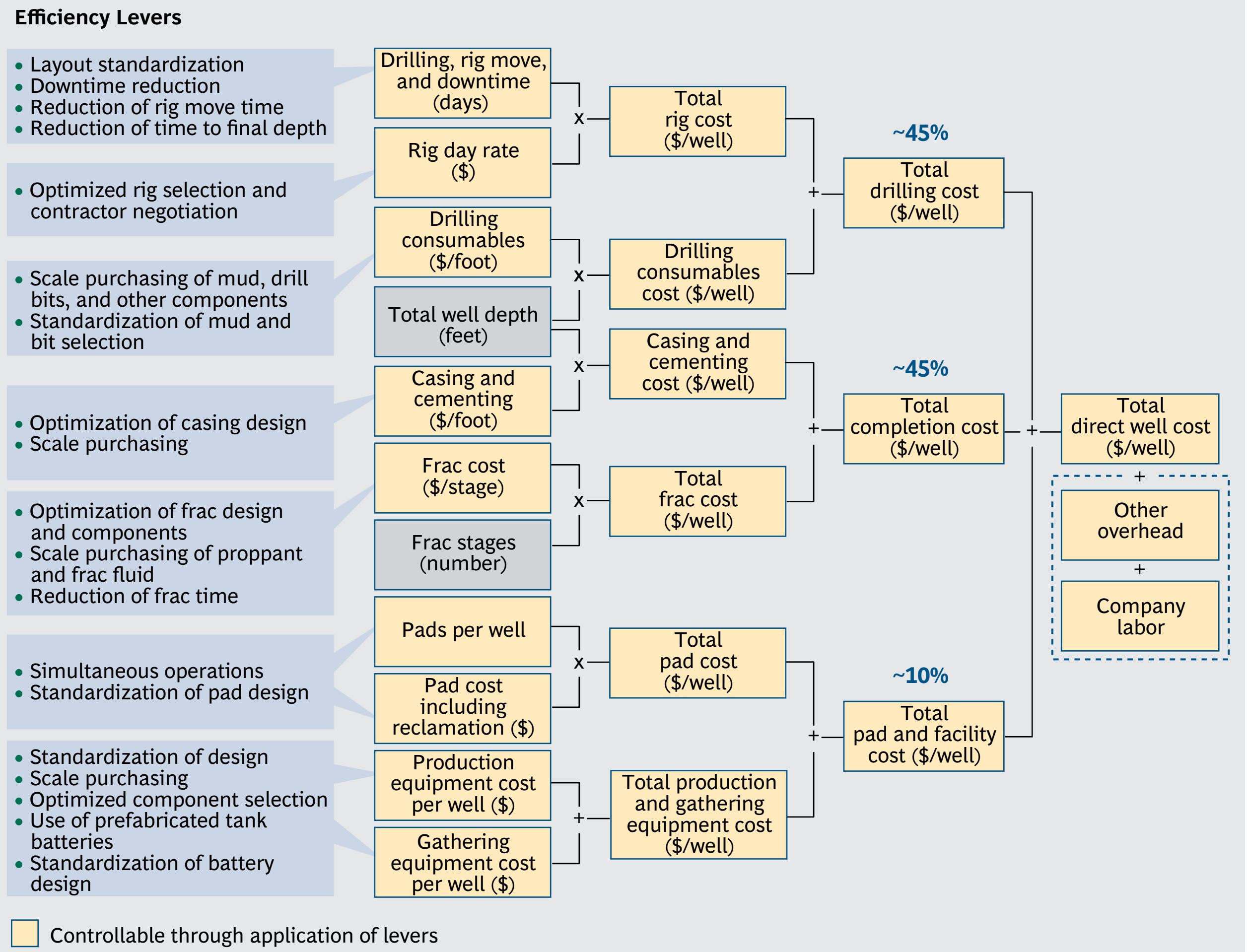
Evolution of daily production from North American shale basins (2010-2013)



Sources: BCG analysis based on data from Rystad Energy's North American shale database, the U.S. Energy Information Administration's *Drilling Productivity Report*, November 2013, and various issues of the U.S. Energy Information Administration's *Natural Gas Monthly* update; proprietary BCG data.
Note: Includes output from the Bakken and Permian basins.

Exhibit 3 | Success in the Shale Gas Arena Requires the Right Business and Operating Models

Drivers of Well Costs



Source: BCG project experience.
Note: Percentages represent the typical share of total costs.

cially viable, and in many regions, geological, commercial, and regulatory challenges could pose significant hurdles to development. To be successful, operators and investors will have to systematically assess each region and understand its challenges.

- "Shale Gas: Ten Levers to Ensure Safe and Effective Development" offers a blueprint for policymakers seeking to develop their countries' resources in the face of sizable challenges. The article details ten levers—spanning such topics as licensing, permitting, fiscal policy, monitoring frameworks, and water treatment and disposal—that can help policymakers ensure successful and sustainable development.

- "Behind the American Export Surge: The U.S. as One of the Developed World's Lowest-Cost Manufacturers" explores the nascent renaissance in U.S. manufacturing, including the critical, contributing role being played by the country's growing supply of low-cost natural gas. An abundance of cheap natural gas helps manufacturers in two main ways. First, natural gas is a key feedstock for chemicals and plastics and a significant cost in the manufacture of primary metals, paper, synthetic textiles, and other products. Second, cheap natural gas has a salutary effect on power costs at U.S. manufacturers. The upshot: the shale gas revolution is translating into economic benefits for a range of U.S. companies beyond the energy and related sectors.

- "How Cheap Natural Gas Benefits the Budgets of U.S. Households" focuses on the direct impact of cheap natural gas on U.S. consumers. The impact is, in fact, material: BCG estimates that the average U.S. household is already saving anywhere from $425 to $725 a year because of lower energy costs that can be attributed to domestically recovered shale gas. By 2020, BCG believes, the average annual household savings could rise to as much as $1,200.

- "Natural-Gas-Liquid Derivatives: The Energy Tsunami's Next Wave" looks at the shale gas revolution's impact on natural-gas-liquid derivatives, such as ethylene, propylene, and butadiene. The new market dynamics and higher price volatility have significant implications for petrochemicals and other industries.

- "The Future of Petrochemicals in Europe: Continuous Retreat or Rising Profitability?" is focused on the challenging competitive terrain facing Europe's petrochemical companies—and what these businesses must do to if they hope to emerge successful. One of the topics examined is the significant price advantage enjoyed by U.S. petrochemical players over their European counterparts in the sourcing of feedstock.

- "Britain's Bowland Shale: What Next?" weighs in on the debate in the UK about whether the country should seek to exploit its shale reserves. Those in favor of development cite the potential for the country to lower its energy costs, help restore industrial competitiveness, and boost job creation, as the U.S. has done; those opposed are concerned about the potential for environmental harm.

Shale gas remains a critical focus for BCG. Over the past five years, we have actively supported a broad range of clients on the topic, including the world's major energy companies, energy producers focused on U.S. shale gas, energy services companies, private-equity funds, and governments. The issues we have tackled include operating-model design, optimization of financial performance and shareholder returns, water management, portfolio management, public acceptability, the creation of tailored organizations for shale developments, and the design of regulatory frameworks. We look forward to sharing our insights on the shale gas arena in future publications.

Iván Martén
Global Leader, Energy Practice

Eric Oudenot
Topic Expert, Shale Gas

THE GREAT, GLOBAL SHALE-GAS DEVELOPMENT RACE

WHERE TO FOCUS COMMERCIAL RESOURCES

by Iván Martén and Eric Oudenot

In the late 1990s, rapid advances in horizontal drilling and hydraulic-fracturing technologies unleashed large-scale commercial production of shale gas in the U.S.[1] By 2005, with the development of the Barnett Basin in Texas and the production bonanza that followed, the shale gas revolution was in full swing. Today, shale gas accounts for nearly 35 percent of total U.S. natural-gas production, compared with only 2 percent ten years ago, and it is on course to reach 45 percent in six to eight years. As a result—and depending on whether the government approves natural-gas exports—the U.S. could go from being one of the world's largest gas importers to one of its largest exporters. Two licenses have been granted so far for liquid-natural-gas export terminals (Sabine Pass, Louisiana, and Freeport, Texas), with at least 15 other applications in the queue.

At the same time, the race has begun to explore and develop shale gas resources elsewhere in the world. The prize—abundant, low-cost natural gas—is likely to be an order of magnitude greater than the resources available in North America. This second revolution in shale gas development will have a significant impact on the global gas industry and ripple effects in many related sectors.

It is also clear that while the technology is mature, there are important challenges—and uncertainties—regarding the geology, economics, regulation, and social acceptability of shale gas development. In order for operators and investors to know whether, where, and when to focus resources, they must systematically assess each region and the specific challenges it poses to resource development.

Key Challenges Affecting Development

Shale gas and shale oil are hydrocarbon molecules trapped in layers of rock (shale), each of which possesses unique attributes; for example, not all shale layers contain exploitable hydrocarbons. Shale gas is referred to as an "unconventional resource" because its geological parameters are different from those of conventional oil and gas reservoirs, with important implications for development.

Conventional and unconventional resources differ from one another in four main ways. (See Exhibit 1.)

- *Source Rocks.* In the development of conventional resources, the hydrocarbons migrate from a source rock to a reservoir rock, where they are trapped. With shale gas, there is no migration: the hydrocarbons remain in the source rock, which is drilled. In many countries, little information has been collected on source rocks, and a limited number of wells have been drilled in these layers.

- *Low Permeability.* Shale gas formations are characterized by very low permeability (the ability of fluids to pass through rock).

EXHIBIT 1 | Differences Between Conventional Gas and Shale Gas

		Conventional gas	Shale gas
Geological factors	Hydrocarbon migration and trapping mechanism	Required: migration from source rock to reservoir rock where the hydrocarbons are trapped	Not required: the hydrocarbons remain in the source rock and do not require a trapping mechanism
	Target zone for drilling	Reservoir rock	Source rock
	Porosity (volume within rock that can contain fluids), %	North Sea fields: 20% to 25%	Low porosity: 4% to 15%
	Permeability (ability of fluids to pass through rock)	Expressed in millidarcy (10^{-3})	Ultralow permeability: expressed in nanodarcy (10^{-9})
Operational and commercial factors	Requires stimulation (hydraulic fracking) to be commercial	Only in some cases: <20% of conventional wells are fracked	Always: ~100% of shale gas wells have to be fracked
	Typical well production profile	Stabilizes at a plateau for a few years and steadily declines thereafter	Peak production in the first 3 months, followed by a sharp decline
	Number of new wells required to maintain production level	Typical well lifetime is several decades, with typical reserves of 50 to 300 Bcf/well[1]	Typical well lifetime is several years, with typical cumulative production of 0.5 Bcf/well[2]
	Ability to plan field development ahead of time	Yes	No: necessary to learn and adjust as drilling proceeds

Sources: Royal Dutch Shell; U.S. Energy Information Administration.
Note: The dashed line denotes the main differences between conventional and shale gas.
[1]In 2011, total reserves (already produced and yet to be produced) associated with the 300 wells at the Groningen gas field in the Netherlands were 100 Tcf.
[2]From 1997 through 2010, 15,000 shale gas wells were drilled in the Barnett Basin, resulting in a cumulative production volume of 7,200 Bcf.

The permeability of shale layers can be 1,000 to 10,000 times less than that of conventional hydrocarbon reservoirs. Consequently, until recently, extracting unconventional resources was generally a significant challenge.

- *Hydraulic Fracturing.* In order to be developed, shale gas layers require hydraulic fracturing. Fracking is a reservoir stimulation technique that pumps a mixture of water, chemicals, and sand into a well at high pressure to fracture the shale and release trapped gas and oil. The fractures extend several hundred feet into the shale layers and are kept open by sand fill, thus increasing the permeability of the formation and the production rate of the well. This technique, which continues to evolve, defines the resource. While less than 20 percent of the world's conventional oil and gas wells are fracked, close to 100 percent of shale gas and oil wells will be fracked.

- *Production Profiles.* Shale gas wells have unusual production profiles that force operators to rethink their traditional processes and develop new operating models. Unlike conventional wells, where production peaks after three to six months and then stabilizes at a plateau rate that can be maintained for up to 10 or 15 years, production of shale gas peaks during the first week, followed by a rapid decline. Thus, maintaining a high production level for a shale gas field involves continuous drilling (known as "factory drilling").

The need for operating models geared to efficient large-scale drilling explains why it was smaller, independent oil-and-gas companies that spearheaded early shale-gas development in North America, and why these companies continue to operate more efficiently than the major oil-and-gas companies, which tend to be handicapped by slower decision making and more rigid organizations—resulting in higher operating costs. Eight years after the start of the shale gas revolution, the vast majority of the companies operating profitable dry-gas plays (development opportunities in which hydrocarbons mainly take the form of gas rather than liquid) are still independents.

But the majors are now adapting the business models of their independent counterparts, whose advantage in developing unconventional plays is likely to diminish. Since 2006, the majors and the national oil companies have spent more than $120 billion on acquisitions of independent shale-gas producers.

A key challenge for operators and investors is determining where to explore for shale gas basins and what "good" shale is. There are six key exploration parameters:

- Formation depth
- Total organic content
- Net thickness of the shale layer
- Thermal maturity
- Formation overpressure
- Silica and clay contents

Once exploration has started, there are seven core parameters for assessing the commercial potential of a shale gas basin:

- Well costs
- Initial production
- Liquid and natural-gas-liquid content
- Estimated ultimate recovery
- Environmental requirements
- Local commodity prices and taxation regime
- Access to infrastructure

The Global Race Has Begun

Until recently, shale gas development was almost entirely a North American phenomenon. According to the latest U.S. Energy Information Administration (EIA) shale-gas study, the U.S. and Canada hold 16 percent of the technically recoverable shale-gas reserves.[2] However, BCG research shows that at the end of 2012, about 110,000 shale-gas wells had been drilled in the U.S. and Canada, compared with fewer than 200 wells in the rest of the world. At that point, North American shale production (oil and gas) stood at about 6.2 million barrels of oil equivalent per day, accounting for 99.9 percent of global shale production.

Although it is clear that large shale resources exist in locations outside of North America, the question is the amount that is recoverable. EIA's 2013 study, which is the new reference in the industry, estimates the technically recoverable shale-gas resources around the globe at about 7,299 trillion cubic feet (Tcf), of which approximately 1,150 Tcf are in North America. The extent of uncertainty is becoming clear as national institutes of geology release their estimates. For example, while the EIA study estimates Poland's technically recoverable shale-gas resources at 148 Tcf, in 2012, the Polish Geological Institute estimated the country's resources at only 12 to 27 Tcf.

A second shale-gas revolution will occur in the next four to six years.

In BCG's view, it is too early in the exploration stage to provide a high-quality estimate of resources outside of North America. More wells need to be drilled, more data need to be analyzed, and more time is needed to understand the source rocks and build detailed reservoir models.

The EIA study proved that large shale resources exist outside of North America and, in particular, in countries that are currently importing gas or have very limited conventional gas reserves. We believe that a second shale-gas revolution will occur in the next four to six years that will have a significant impact on global prices of gas and liquid natural gas, on gas trade flows, and—in some regions—on the price of oil. It is therefore critical that industry players assess the potential impact of shale gas development on their existing operations and determine how best to seize the opportunity that it presents.

The Leaders in the Race for Shale Gas

According to BCG's research, six countries are clearly in the lead in the exploration for shale gas: Argentina, Poland, Ukraine, China, Australia, and South Africa. (See Exhibit 2.) These countries started their exploration efforts at about the same time, but each faces unique challenges that will affect the pace at which production occurs.This is exemplified by the experiences of the top-three leading countries:

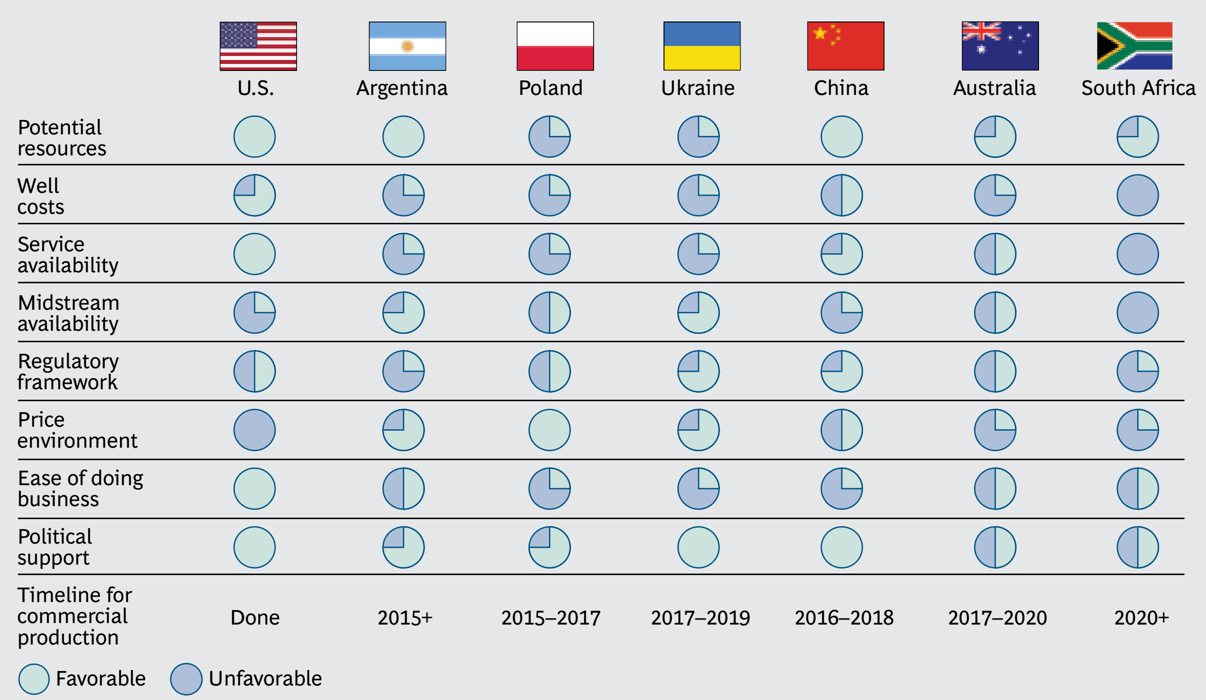
- *Argentina.* As demonstrated by a growing number of positive well-test results in the Vaca Muerta formation, Argentina is the only country where the shale layers that have been tested are productive and respond well to hydraulic fracturing. But difficulties in accessing foreign capital and in setting up a sustainable gas-pricing mechanism to reward producers are slowing the pace of development.

- *Poland.* The main challenge here will be to prove that the source rock can be productive and efficiently stimulated through fracturing. However, the results of the first 50-plus wells that have been tested have not met expectations.

- *Ukraine.* Most of the conditions have been met for rapid development, including the existence of conventional gas fields (and therefore the availability of midstream pipelines). However, the political and business environment remains a deterrent for a number of independent oil companies and could slow development.

Some traditional oil- and gas-exporting countries, including Saudi Arabia, Russia, Brazil, Colombia, and Algeria, are starting to explore for shale and represent a second group of countries where development could take off. In addition to the uncertainty surrounding the commercial viability of these countries' shale-gas reserves, however, their existing conventional resources could weaken the incentive to develop unconventional resources such as shale.

EXHIBIT 2 | Challenges and Potential Timelines for Production of Shale Gas



Sources: BCG analysis.

The Ripple Effect: Other Sectors to Watch

Beyond its direct impact on oil and gas markets, shale gas development outside of North America will have a significant positive economic impact on a number of related sectors. And these businesses represent attractive investment opportunities. There are four core services that are critical to shale gas development. Without any one of them, there can be no production from a given well.

- *Onshore Contract-Drilling Market.* The rapid decline that characterizes shale gas production means that a tremendous number of wells must be drilled. Where a standard large, deep-water oil field would require 40 wells throughout its 20-year life, a shale gas field would require 10 to 15 times more wells to produce the same amount of hydrocarbons over a similar period. Drilling shale gas wells requires a specific type of rig, which has to be powerful (around 1,000 to 1,500 horsepower), mobile, able to drill on multiwell sites, and, ideally, able to use some of the shale gas produced as its own fuel.

- *Pressure-Pumping Market.* Currently this market is almost entirely dependent on the hydraulic fracturing of shale wells in North America. It grew from $10 billion in 2009 to $35 billion in 2012. The unavailability of fracking crews, including engineers and equipment (such as pumps and trucks), has been a key bottleneck in many basins.

- *Proppant Market.* Sand (silica or resin-coated) or ceramic materials are required for every hydraulic-fracturing job to "prop" the fractures open. Over the last ten years, the U.S. market has grown sixfold, reaching $4 billion in 2012. Today about 2,000 tons of proppant—an amount that would fill about 20 100-ton railcars—are required for each well. Reliable access to sand mines and the ability to deliver the material to well sites are thus essential to the fracking process.

- *Oil Country Tubular Goods Market.* Almost every shale-gas drilling site requires specific types of pipe and tube products (known as "oil country tubular goods," or OCTG) able to withstand the stress induced by long horizontal wells and hydraulic fracturing. Shale gas development will boost the global market for premium "seamless" OCTG, as it has in North America.

A second group of less essential sectors will also be important to the industry's expansion.

- *Fracturing Fluids.* The chemicals used in fracking will be governed by local regulations and will likely vary from region to region. Fracturing fluids account for less than 0.5 percent of the volume pumped during fracking, but their chemical properties are critical to the success of the process. Price swings for some of these nonreplicable elements (which cannot yet be synthesized chemically) can be significant. For example, the price of guar gum increased 600 percent in 2011.

- *Pipelines and Railcars.* The history of shale gas development in North America indicates that significant value can be captured by controlling existing midstream pipelines and railways. Railcars are needed to transport OCTG equipment and proppants to well sites, and pipelines are needed to transport crude oil and gas from well sites to refineries.

- *Real Estate and Water Management.* These two sectors could potentially offer high investment returns given their role in shale development, but their attractiveness will depend on local regulations. Water requirements in shale gas development are significant, now reaching approximately 220,000 barrels per well. As to real estate, first movers on promising U.S. acreage for shale gas development have managed to sell some of these properties for around $10,000 per acre, making a five- to tenfold profit on the initial purchase price.

- *Petrochemicals.* This sector could experience a significant expansion, depending on the composition of the shales discovered. In particular, the presence of natural-gas liquids, which are a critical feedstock for the petrochemical industry, will be a key indicator of the magnitude of the opportunity.[3] For example, in the U.S., plans for 14 ethane-cracker facilities have been announced over the past three years, while not a single such plant was built in the previous decade.

Shale gas is a complex resource to develop, and operators have far less experience with it than they do with conventional oil and gas. Not all shales are commercially viable, and in many regions, geological, commercial, and regulatory challenges will prevent the relatively rapid, large-scale development that is occurring in North America.

But vast shale-gas resources are known to exist outside of North America, and development over the next four to six years promises to have a dramatic impact on the global gas and related industries. These are still early days in what is likely to be a long race in a rapidly changing environment. To be successful in focusing their resources, operators and investors must continue to critically assess each region in terms of its changing geological, commercial, and regulatory challenges. Complementing this highly structured and granular view should be the ability to respond rapidly to opportunities as they arise.

NOTES

1. Shale gas was first extracted in Fredonia, New York, in the mid-1820s. It was used to fuel streetlights.
2. U.S. Energy Information Administration, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries,* June 2013.
3. "Natural-Gas Liquids: The Implications of the Next Energy Tsunami," BCG article, October 2012.

Iván Martén is a senior partner and managing director in the Madrid office of The Boston Consulting Group and the global leader of the firm's Energy practice. You may contact him by e-mail at marten.ivan@bcg.com.

Eric Oudenot is a principal in BCG's London office and the firm's topic expert on shale gas. You may contact him by e-mail at oudenot.eric@bcg.com.

SHALE GAS

TEN LEVERS TO ENSURE SAFE AND EFFECTIVE DEVELOPMENT

by Iván Martén and Eric Oudenot

THE SHALE GAS REVOLUTION, with its abundant yield of low-cost natural gas and natural-gas liquids, is reshaping the U.S. energy landscape and delivering significant peripheral benefits, including greater energy self-sufficiency, reduced carbon emissions, and a resurgence of the country's petrochemicals industry.[1] For a number of reasons, relatively few countries have yet attempted to engineer shale gas revolutions of their own. But that trend appears poised to change.

Growing numbers of countries will seek to emulate the U.S.'s success.

Indeed, we expect that over the next four to six years, growing numbers of countries will seek to emulate the U.S.'s success, given the potential economic and related advantages to those nations and the substantial shale reserves that many countries possess within their borders. (See the previous article in this e-book, "The Great, Global Shale-Gas Development Race: Where to Focus Commercial Resources.")

These countries will face sizable challenges, however, ranging from addressing residents' environmental concerns to determining how to structure relationships with operators. To help policymakers chart a course forward, we have defined ten levers that we believe will ensure successful and sustainable shale-gas development.

Ten Key Levers for Development

Safe and successful development of shale gas demands a comprehensive plan. (See Exhibit 1.) We recommend the following actions (we will expand on these actions in a subsequent report):

1. Institute a licensing system that reflects the realities of shale gas development and is aligned with the country's development objectives. The development of shale gas is fundamentally different from the development of conventional oil and gas resources. Shale gas wells produce far less than conventional wells—an offshore well in Angola, for example, will produce about 4,000 barrels of oil equivalent per day (BOE/D), whereas a top-tier shale-gas well will produce roughly 800 BOE/D. Shale wells' output also tails off rapidly: conventional wells observe a slow decline over their roughly decade-long lifetimes, but 50 percent of a typical shale well's production often occurs in the well's first year. The upshot: it takes many more wells to develop a shale gas field than a conventional one. Shale gas fields are also much less predictable than conventional

EXHIBIT 1 | Safe and Successful Shale-Gas Development Demands a Comprehensive Plan

1. Institute a licensing system that reflects the realities of shale gas development and is aligned with the country's development objectives.
2. Authorize hydraulic fracturing for the exploration stage...
3. ...but develop a clearly defined monitoring framework.
4. Set up a transparent, well-resourced mechanism for granting permits.
5. Establish a simple and stable fiscal framework that encourages exploration.
6. Encourage and facilitate the use of top-tier oilfield-services companies by operators during the exploration phase.
7. Promote the acquisition and sharing of data.
8. Plan for the logistics implied by large-scale shale development.
9. Develop a specific strategy for the sourcing, treatment, and disposal of water.
10. Create a win-win partnership with communities, supported by intensive communication efforts.

Source: BCG analysis.

fields for operators. With conventional fields, the long-term rate of development and positioning of wells can be gauged fairly early on, but with shale plays, the learning is constant and the model may need to be refined after every new well.

These realities should factor into the design of licensing policies. To encourage and facilitate exploration, governments should grant operators access to large amounts of land vis-à-vis the allotments typical for the development of conventional resources, reflecting the higher number of wells required (potentially 30 times as high over a ten-year period) to develop shale fields efficiently.[2] Operators should also be granted extended exploration periods, where the main criterion for approval is the commitment to execute large seismic surveys and to drill and fracture a large number of wells. The evaluation of field development plans for the granting of production licenses should allow for alteration of those plans down the line, given that the first batch of development wells will influence the rest of the development concept.

2. Authorize hydraulic fracturing for the exploration stage... A number of national governments have concerns about the safety and efficacy of hydraulic fracturing, which is a reservoir stimulation technique that involves pumping a mixture of water, chemicals, and sand into a well at high pressure to fracture shale rocks, thus increasing their permeability (that is, the degree to which liquids can pass through them). Today, hydraulic fracturing is the only reservoir-stimulation technique that will enable economical commercial development of shale plays. This technique has been used in the oil and gas industry since 1949, and it is widely estimated that a total of more than 2 million hydraulic-fracturing operations have been performed worldwide.

We believe that governments seeking to develop shale gas reserves today essentially have no choice but to authorize hydraulic fracturing, at least for a few exploration wells. Absent hydraulic fracturing, there is no reliable way for governments and operators to determine the quantity of reserves held within a given basin, how the rock will respond to stimulation, and ultimately the potential for the basin's development.

3. ...but develop a clearly defined monitoring framework. Hydraulic fracturing is well tested but, as is the case with all methods of extracting hydrocarbons, not risk free. Governments thus need to put in place a solid monitoring framework to oversee operations that is built on two pillars: regulation and expertise.

Regulations should be transparent and explicit. Critical elements to be defined include the recommended operational processes, the level of disclosure required from operators regarding chemicals used in hydraulic-fracturing fluids, requirements for the submission of well-fracturing plans, details of the monitoring and data-collection process, and standards for the sourcing, disposal, and reuse of water.

Regulation must be backed by technical expertise. Governments must be staffed with enough skilled geologists, geophysicists, reservoir engineers, and field operators to act and be seen as credible stakeholders and have the capabilities necessary to analyze the data and provide advice on policy setting and evolution.

4. Set up a transparent, well-resourced mechanism for granting permits. Shale gas operations require a complex logistical setup, one that has to be repeated by operators a multitude of times for potentially thousands of wells. And permits are required at every step, from drilling to the use of explosives and chemicals. In some countries, more than 30 permits in total are required to drill the first exploration well. Given the sheer numbers, government agencies can become swamped by permitting requests, leading to delays and the rescheduling or even suspension of planned operations. This can translate into higher costs for operators and frustration all around.

To preempt this, governments must do three things. They must design permitting systems tailored specifically to the realities of shale gas development. They must model and test these systems to ensure that the systems are both efficient (that is, that they will allow the government to maintain the right level of control over operations) and practical (that is, that one step of the permitting chain will not create a bottleneck that has an impact on the rest of the chain). And they must staff up to ensure that they have adequate resources to handle the volume of requests.

5. Establish a simple and stable fiscal framework that encourages exploration. The fiscal framework that governments put in place for the exploration and production of shale gas will be a key factor in determining the attractiveness of a given play from the perspective of operators and investors. The two main elements needed are clarity and stability. There is nothing worse for investors and operators than having to navigate multiple unclear layers of tax regulations, with no certainty that those taxes will remain in effect. Simplicity is also critical. For an operator, it is much easier to pay a single 70 percent tax than to pay seven separate 10 percent taxes to seven different entities.

Governments should spell out a simple, clearly defined fiscal framework early on.

Governments should spell out a simple, clearly defined fiscal framework early on, one that allows both operators and regulators to easily forecast the impact on expenditures and revenues. Ideally, the framework should impose a relatively light tax burden during the exploration phase in order to maximize competition among operators bidding for licenses. But that burden should increase significantly for the production phase.

6. Encourage and facilitate the use of top-tier oilfield-services companies by operators during the exploration phase. Oilfield services companies perform a range of critical activities during the exploration phase, including the initial geological and geophysical studies, the actual drilling of wells, and the management of the wells' hydraulic fracturing. How effectively these are executed is a major determinant of a given development effort's overall results and the quality of the information collected. It is essential, therefore, that operators emphasize experienced, tier-one oilfield-services companies during this phase in favor of local players, most of which likely have little or no shale-gas experience. Top-tier players possess better tools, software, and equipment. They also have more-experienced personnel, more-robust processes, and, often, lower costs. Typically, too, they adhere to higher health, safety, and environmental (HSE) standards. Once the exploration phase has been completed successfully, governments can adjust policies to foster the deployment of local service and production companies during the production phase.

To encourage top-tier oilfield-services companies to participate in their country's shale-gas development, governments should exercise a range of levers. These include developing an enticing fiscal policy and a secure, stable legislative framework and facilitating the creation of permanent bases and the granting of work permits.

7. Promote the acquisition and sharing of data. Outside the U.S., one of the main hurdles that governments and operators face in formulating long-term strategies for shale gas development is simply the lack of available relevant geographical, geophysical, and environmental data. Operators in the U.S., for example, had roughly a thousand times the amount of data at their disposal that operators in Poland had at the launch of their respective shale-development campaigns.

To address this shortcoming, governments must do two things: encourage data acquisition and promote data sharing.

Governments can encourage data acquisition among operators by embedding it in the licensing process and fiscal policy. A simple way to do so is to increase the weight of "minimum work programs" in the bid evaluation process that governments use to determine whether to grant exploration licenses. Governments should not hesitate to be very thorough in the definition of these expectations: they should specify not only the minimum number of wells required but the wells' minimum cost and depth, the number of hydraulic-fracturing stages to be performed, and so forth. Governments should also define the set of HSE data and surveys that operators must provide. These efforts can be supplemented by fiscal policy—for instance, operators can be granted special tax treatment for exploration wells and seismic surveys.

To promote data sharing, governments should use regulation. In this traditionally secretive industry, only the regulator is in a position to

Exhibit 2 | The Logistical Challenges of Shale Gas Development Are Considerable

Operators must perform nine key logistical operations for each well.

- Prepare the well site.
- Mobilize the rig and crew.
- Bring drilling fluids and equipment.
- Bring casing and tubing (about 200 tons per well).
- Mobilize the frack fleet (about 25 to 35 trucks).
- Bring water to perform fracking (about 200,000 bbls per well[1]).
- Bring fracking sand (about 2,000[1] tons per well) and fluids.
- Bring water to disposal site (about 100,000[1] bbls per well).
- Transport produced hydrocarbons.

Operators and governments have three main choices for transport of materials...

Pipelines
- High up-front capital expenditure
- Large throughput
- Low cost per volume transported
- Limited flexibility once installed
- High disturbance for communities during construction, low after construction

Railroads
- High to moderate up-front capital expenditure
- In terms of volumes carried, one railcar is the equivalent of some four to eight trucks
- Flexibility depends on the existing network and regulations
- Low disturbance for communities

Trucks
- No up-front capital expenditure
- High cost per volume carried
- The most flexible solution for operators
- High disturbance for communities
- Significant impact on local infrastructure system

...and will have to try to balance four considerations.

Impact on road and rail traffic
Impact on road and rail safety
Potential damage to roadways and infrastructure
Impact on shale economics
- Infrastructure costs
- Operating expenditures

Source: BCG analysis.
Note: Drilling multiple wells on a single pad ("pad drilling") will help reduce the overall logistical requirements but will increase traffic density near the well pad location. bbls = billion barrels.
[1]Based on a 20-stage hydraulic-fracturing job, with 50 percent of the injected water flowing back to the surface and the produced water then disposed of (as is the case in the majority of U.S. basins today).

foster collaboration. Governments could, for example, force operators to immediately share specific types of data, such as HSE data, and define a time period after which more-sensitive data would have to be shared.

8. Plan for the logistics implied by large-scale shale-gas development. Each shale-gas well is an equipment- and supply-intensive operation. (See Exhibit 2.) In planning for the logistical challenges, governments must attempt to address the needs of both operators and local communities. Operators must be able to transport the necessary people (for example, drilling and rig crews), equipment (including drilling and completion equipment, such as cement, casing, and tubing), and supplies (water, proppant [sand or ceramic materials used to "prop" the fractures open], and hydraulic-fracturing chemicals) to and from well sites at a reasonable cost. Communities must be spared the worst effects of the increase in road traffic, rail traffic, or both.

In designing plans, governments should focus on four major considerations: the impact on road and rail traffic, the impact on road and rail safety, potential damage to roadways and infrastructure, and the impact on shale economics. Early preparation is crucial. It is one thing to plan for and mitigate the effects on local communities of four or five exploration wells. It is quite another to do so for a thousand or more wells in the development phase.

9. Develop a specific strategy for the sourcing, treatment, and disposal of water. Hydraulic fracturing is highly water-intensive, with an average well requiring from 15,000 to 20,000 cubic meters of water over its lifetime.[3] For each exploration basin, plans must be made for how the needed water will be sourced and transported to individual well sites. Given that the vast majority of the water will be transported by truck, particular attention should be paid to the potential impact on local roads.

Rules must also be written for the treatment and disposal of water—20 to 50 percent of the water injected into a well returns to the surface during the well's life, with 90 percent of that occurring during the first ten days. At the national level, standards must be set for spent water that is intended for discharge back into streams—must it be of drinking-water quality? At a local level, disposal options will have to be assessed and defined. Three main options are possible: disposing of untreated produced water in extradeep "waste" wells, treating the water and reusing it to fracture new wells to limit the need for fresh water, and treating the produced water to the point where it meets local HSE standards and discharging it into rivers.

10. Create a win-win partnership with communities, supported by intensive communication efforts. In the U.S., landowners also own their property's subsurface mineral rights. In contrast, in many countries, landowners lack those rights. As a result, the argument for local shale-gas development must be sufficiently compelling to win over entire communities, not simply individual homeowners. Governments and operators must determine what communities require to achieve this level of acceptability.

> Government's key role is to encourage and facilitate dialogue among all parties.

Ultimately, this involves answering two questions. First, how can development benefit the local community? This will vary among countries and regions but typically includes such things as tangible job creation, direct financial compensation, and direct and indirect investment in the community, including taxes paid, investment in schools and roads, and money pumped into the local economy. Second, which governance mechanisms are necessary to ensure that communities are engaged and feel that their concerns are being addressed? The answer may include the creation of independent monitoring bodies, the disclosure of operational and key HSE data, and the creation of local forums.

Government's key role here is to encourage and facilitate open dialogue among all parties—and to ensure that the dialogue commences early. Leaving that dialogue until later will only lead to subsequent anger, delays, and disruption.

Implementation Challenges

To fully seize the opportunities afforded by the development of their shale-gas resources, national governments will need to develop new skills and capabilities, create new bodies and processes, and move quickly. This is new territory for many governments and it will be a challenging journey, but the potential benefits are sizable. We strongly believe that the ten levers described herein will help governments establish the right framework for successful and safe development of their shale-gas resources.

NOTES

1. The Boston Consulting Group estimates that, by the end of 2013, the U.S. was producing 32 billion cubic feet of shale gas and 3.7 million barrels of liquids per day from shale plays. In concert with this surge in output, energy-related carbon dioxide emissions in the U.S. declined by 3.8 percent in 2012, even though the U.S. economy grew by 2.8 percent. For a discussion of the implications of the rise in NGL production, see "Natural-Gas Liquids: The Implications of the Next Energy Tsunami," BCG article, October 2012.

2. This calculation compares the number of conventional offshore wells in Angola required to maintain a 150,000 BOE/D plateau for ten years with the required number of onshore shale wells, assuming an average initial production of 500 BOE/D and a typical decline profile.

3. That amount of water would be equivalent to the amount it takes to fill six to eight Olympic-size swimming pools.

Iván Martén is a senior partner and managing director in the Madrid office of The Boston Consulting Group and the global leader of the firm's Energy practice. You may contact him by e-mail at marten.ivan@bcg.com.

Eric Oudenot is a principal in the firm's London office and the company's topic expert on shale gas. You may contact him by e-mail at oudenot.eric@bcg.com.

BEHIND THE AMERICAN EXPORT SURGE

THE U.S. AS ONE OF THE DEVELOPED WORLD'S LOWEST-COST MANUFACTURERS

by Harold L. Sirkin, Michael Zinser, and Justin Rose

Export manufacturing has recently become the unsung hero of the U.S. economy. Despite all the public focus on the U.S. trade deficit, little attention has been paid to the fact that the country's exports have been growing more than seven times faster than GDP since 2005. As a share of the U.S. economy, in fact, exports are at their highest point in 50 years.

But this is likely to be just the beginning. We project that the U.S., as a result of its increasing competitiveness in manufacturing, will capture $70 billion to $115 billion in annual exports from other nations by the end of the decade. About two-thirds of these export gains could come from production shifts to the U.S. from leading European nations and Japan. By 2020, higher U.S. exports, combined with production work that will likely be "reshored" from China, could create 2.5 million to 5 million American factory and service jobs associated with increased manufacturing.

Our perspective is based on shifts in cost structures that increasingly favor U.S. manufacturing. In the first two reports in our Made in America, Again series, we explained how China's once overwhelming production-cost advantage over the U.S. is rapidly eroding because of higher wages and other factors—and how these trends are likely to boost U.S. manufacturing in specific industries.[1] Below, we focus on America's increasing cost-competitiveness in manufacturing compared with leading advanced economies that are major exporters.

Our analysis suggests that the U.S. is steadily becoming one of the lowest-cost countries for manufacturing in the developed world. We estimate that by 2015, average manufacturing costs in the five major advanced export economies that we studied—Germany, Japan, France, Italy, and the U.K.—will be 8 to 18 percent higher than in the U.S. Among the biggest drivers of this advantage will be the costs of labor (adjusted for productivity), natural gas, and electricity. As a result, we estimate that the U.S. could capture up to 5 percent of total exports from these developed countries by the end of the decade. The shift will be supported by a significant U.S. advantage in shipping costs in important trade routes compared with other major manufacturing economies.

These shifting cost dynamics are likely to have a significant impact on world trade. China and the major developed economies account for around 75 percent of global exports. And the U.S. export surge will be felt across a wide range of U.S. industries.

The most profound impact will likely be on industrial groups that account for the bulk of global trade, such as transportation equipment, chemicals, machinery, and computer and electronic products. Production gains will come in several forms. In some cases, companies will increasingly use the U.S. as a low-cost export base for the rest of the world. In other cases, U.S. production will displace imports as both U.S. and foreign companies relocate the manufacturing of goods sold in the U.S. that otherwise would have been made offshore.

> The full impact of the shifting cost advantage will take several years to be felt.

The full impact of the shifting cost advantage will take several years to be felt in terms of new production capacity. And the magnitude of the job gains will depend heavily on the degree to which the U.S. can continue to enhance its global competitiveness. One of the biggest challenges facing U.S. manufacturers is the supply of skilled labor. As we explained in a previous publication, however, our analysis shows that, in the short term, any U.S. manufacturing skills gap is unlikely to be significant enough to curtail a U.S. manufacturing resurgence. Rather, such shortages are more of a long-term risk if action is not taken soon to train and recruit new skilled workers.[2]

Companies should, of course, continue to maintain diversified manufacturing operations around the world. But at the same time, they must be aware that the structural changes in production cost structures represent a potential paradigm shift for global manufacturing that warrants immediate attention.

The Pendulum Swings Back

For much of the past four decades, manufacturing work has been migrating from the world's high-cost to its low-cost economies. Generally, this has meant a transfer of factory jobs of all kinds from the U.S. to abroad.

The pendulum finally is starting to swing back—and in the years ahead, it could be America's turn to be on the receiving end of production shifts in many industries. In previous reports, we cited a number of examples of companies that have shifted production to the U.S. from China and other low-cost nations. These companies range from big multinationals like Ford and NCR to smaller U.S. makers of everything from kitchenware and plastic coolers to headphones. More recently, computer giant Lenovo opened a plant to assemble Think-brand laptops, notebooks, and tablets in North Carolina. Toshiba Industrial has moved production of its hybrid-electric vehicle motors from Japan to Houston. Airbus has broken ground on a $600 million assembly line in Mobile, Alabama, for its A320 family of jetliners; the facility will create up to 1,000 high-skilled jobs. Flextronics, one of the world's largest electronics-manufacturing-services companies, has announced that it will invest $32 million in a product innovation center in Silicon Valley. The company's CEO was quoted in the *Wall Street Journal* as saying that Flextronics may need to add 1 million square feet of manufacturing capacity in the U.S. over the next five years, depending on economic conditions.

There also is early evidence that foreign manufacturers are starting to move production to or expand production capacity in the U.S. for export around the world.

- Toyota has announced that it is exporting Camry sedans assembled in Kentucky and Sienna minivans made in Indiana to South Korea. The company has also suggested that it may ship U.S.-made cars to China and Russia. In press reports, the president of Toyota Motor North America was quoted as saying, "This is just the beginning of a new era of North America being a source of supply to many other parts of the world."

- Honda is adding shifts at its plants in Indiana and Ohio to increase exports. The company has said it expects to double its exports of U.S.-made vehicles in the next few years.

- Siemens announced it will build gas turbines in North Carolina that will be used to construct a large power plant in Saudi Arabia.

- Yamaha has transferred production of all-terrain vehicles from overseas facilities to Newman, Georgia, where it directly employs 1,250 factory workers. Yamaha has also opened a second assembly plant in Newman to produce future Side-by-Side products, including a three-person vehicle called the Viking, for worldwide distribution. Yamaha says it could add another 300 jobs in Georgia over the next three to five years.

- In 2011, Rolls-Royce began making engine discs for aircraft at Crosspointe, a world-class manufacturing facility in Prince George County, Virginia. The company said that some parts made in Virginia would be shipped to Europe and Asia to be assembled in jet engine factories. In coming years, Rolls-Royce plans to invest over $500 million in Crosspointe, generating more than 600 jobs, to serve the global economy.

- Michelin of France announced that it will invest $750 million to build a new factory and expand another one in South Carolina to make large tires for earth movers used in the mining and construction industries. The *Financial Times* reported that at least 80 percent of the additional output will be exported.

While the impact of this trend on U.S. jobs is currently modest, we expect a significant increase in such announcements starting around 2015, as the economic case for reshoring to the U.S. grows stronger—and as companies adjust their global manufacturing footprints accordingly.

The U.S. as a Low-Cost Country

The U.S. now has a distinct production-cost advantage compared with other developed economies that are leading manufacturers. We estimate that due to three factors alone—labor, natural gas, and electricity—average manufacturing costs in the U.K. will be 8 percent higher than in the U.S. by 2015. Costs will be 10 percent higher in Japan, 16 percent higher in Germany and in France, and 18 percent higher in Italy. (See Exhibit 1.) There are three key drivers of this cost advantage.

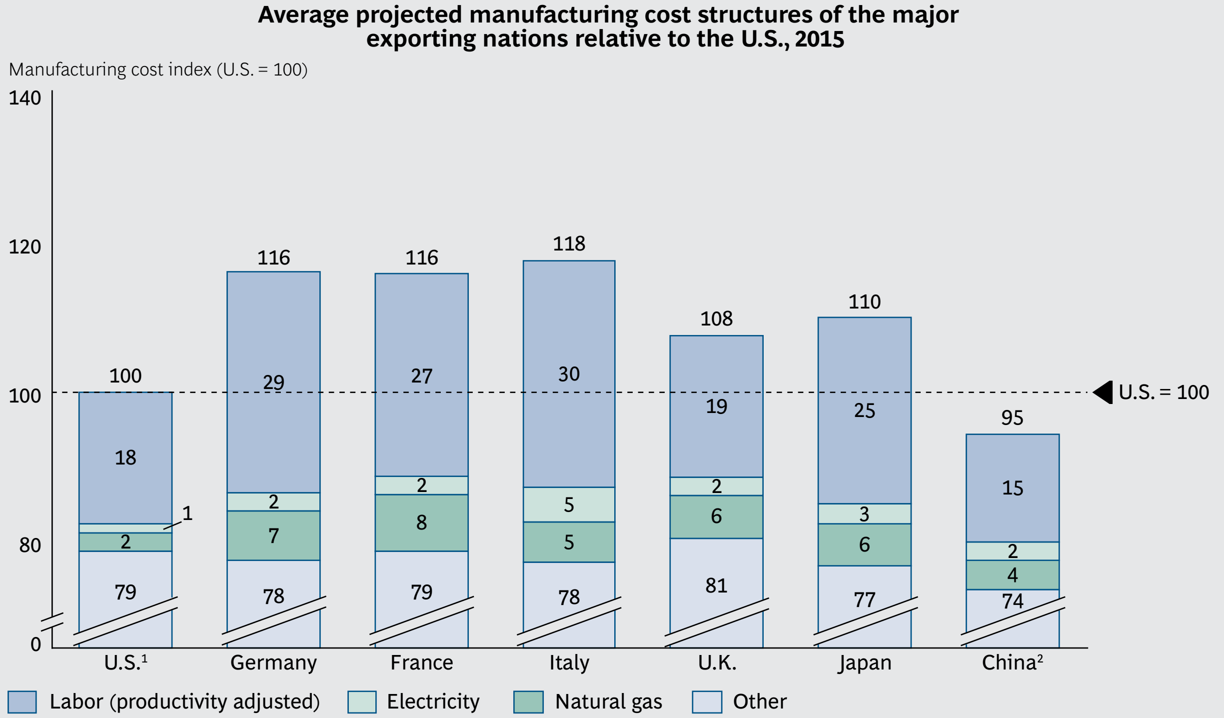
Labor. The U.S. labor market is currently more attractive than that of all other major manufacturers among the developed economies. This is especially true when factory wages are adjusted for output per worker, which is considerably higher in the U.S. than in Europe and Japan. Only a decade ago, average productivity-adjusted factory labor costs were around 17 percent lower in the U.S. than in Europe, and only 3 percent lower in the U.S. than in Japan. The productivity gap between these nations and the U.S. has widened considerably over the past ten years. We project that by 2015, average labor costs will be around 16 percent lower in the U.S. than in the U.K., 18 percent lower than in Japan, 34 percent lower than in Germany, and 35 percent lower than in France and Italy. (See Exhibit 2.)

An added advantage of the U.S. labor market is its relative flexibility. The Fraser Institute ranks the U.S. as the world's third-most-favorable economy in terms of labor market regulation. In contrast, Japan and the U.K. rank 14 and 15, Italy ranks 72, France ranks 94, and Germany ranks 112.

An added advantage of the U.S. labor market is its relative flexibility.

A major reason for this high ranking is that it is far easier and less costly in the U.S. than in most other advanced economies to adjust the size of the workforce in response to business conditions. In Germany, for example, we estimate government-mandated costs of approximately $8 million to shutter an average, 200-worker plant and more than $40 million to close a 1,000-worker plant. These costs are associated with the need to comply with rules governing severance pay and the advance notice that must be given to long-term employees. However, the actual cost of shutting a German factory can be significantly higher. German law mandates that workers may remain on the job, at full pay, for anywhere from a few months to more than a year, depending on how

EXHIBIT 1 | Labor and Energy Cost Advantages Will Make the U.S. One of the Developed World's Lowest-Cost Countries



Sources: U.S. Economic Census; U.S. Bureau of Labor Statistics; U.S. Bureau of Economic Analysis; International Labour Organization.
Note: Cost structures were calculated as a weighted average across all industries. No difference was assumed in "other" costs (e.g., raw materials inputs and machine and tool depreciation). Differences in values are a function of the industry mix of each exporting country.
[1]U.S. figures represent costs in a set of select lower-cost states specified in previous publications.
[2]Chinese figures represent the Yangtze River Delta region.

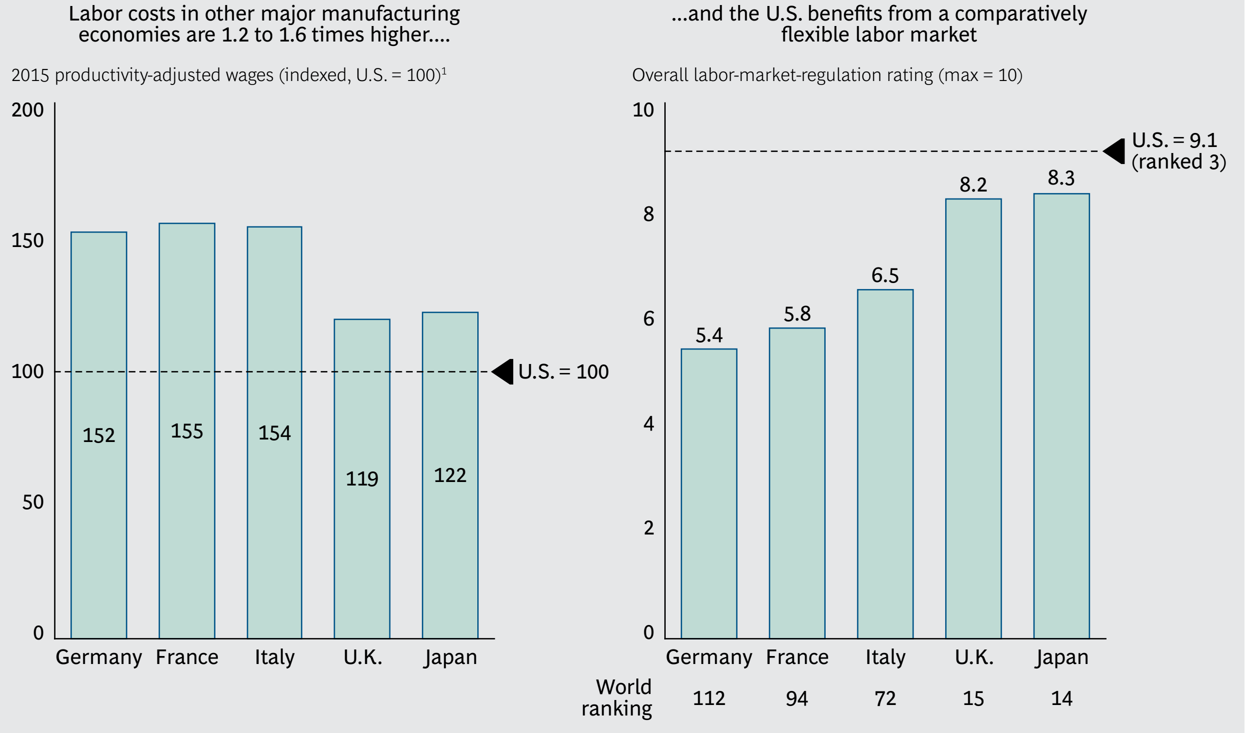
long they have been employed by the company, while layoff terms are being negotiated and after notification of a layoff has been received. Specific union contracts, asset write-downs, requirements to retrain workers, and other factors can also add to exit costs. These are major considerations when European companies decide where to make new long-term investments in manufacturing capacity.

Energy. Rapid technological progress in hydraulic fracturing is making it more economically feasible to unlock vast U.S. natural gas and oil deposits from shale. Since 2003, U.S. production of shale gas increased more than tenfold. This has helped push down the U.S. wholesale price of natural gas by 51 percent since 2005. By 2020, recovery costs from shale are expected to be half what they were in 2005—giving the U.S. a much larger supply of inexpensive natural gas. By 2035, U.S. shale-gas production is projected to double again, to 12 trillion cubic feet.

Most public attention to this development has focused on the implications for U.S. energy security. Less appreciated is the fact that cheap domestic sources of natural gas translate into a significant competitive advantage for a number of U.S.-based industries. Natural gas costs anywhere from 2.6 to 3.8 times higher in Europe and Japan than in the U.S. (See Exhibit 3.) The American advantage will likely grow further in the future: the most recent estimates suggest that the U.S. has more than 350 trillion cubic feet of proven shale-gas reserves, plus another 1,600 trillion cubic feet of potential shale-gas resources. That is more than four times the reserves of Western Europe. Japan's reserves of both shale and conventional gas are negligible.

There are two important implications for industry. First, natural gas is a key feedstock for chemicals and plastics and is a significant cost in the manufacture of primary metals, paper, synthetic textiles, and nonmetallic mineral products. Second, gas-fired power

Exhibit 2 | The U.S. Labor Market Is the Most Attractive of All Major Developed-World Manufacturers



Sources: International Labour Organization; Economist Intelligence Unit; Fraser Institute economic freedom ratings, 2012; BCG analysis.
Note: Fully loaded wages from the Economist Intelligence Unit. U.S. wages are the average for lower-cost states.
[1]Projections for 2013 to 2015.

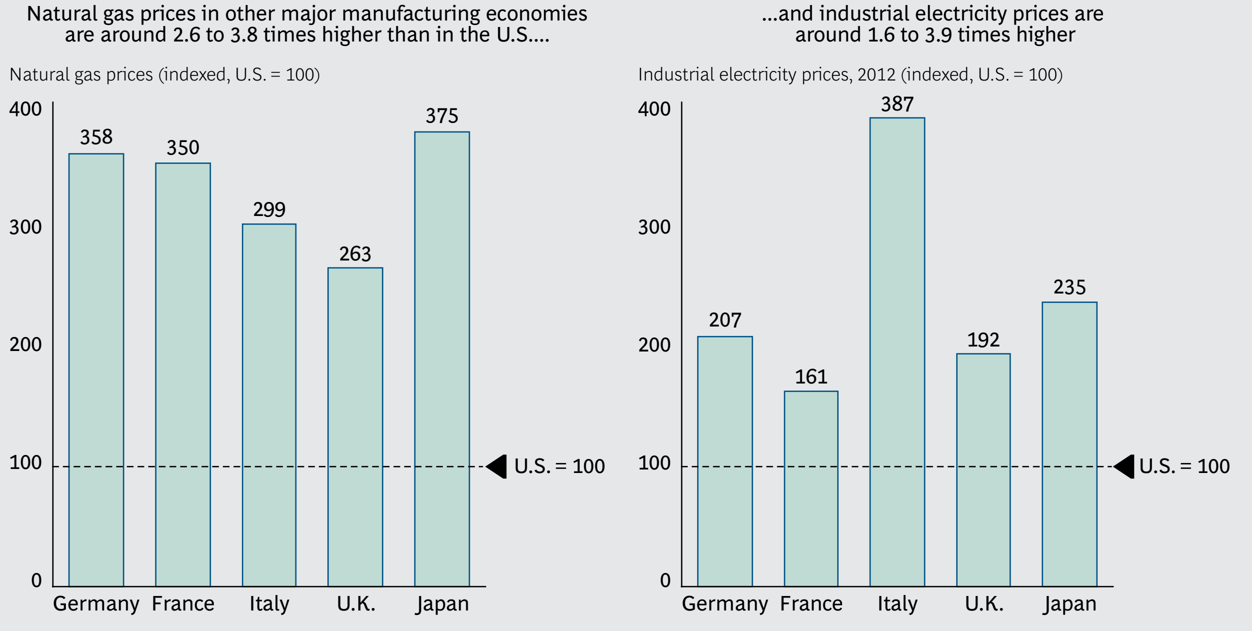
plants are an important source of electricity in the U.S. So cheap natural gas will contribute to keeping power costs lower for U.S.-based industry. Industrial electricity prices are currently 61 percent higher in France, 92 percent higher in the U.K., 107 percent higher in Germany, 135 percent higher in Japan, and 287 percent higher in Italy. Lower electricity rates add a further cost advantage of several percentage points to energy-intensive U.S.-based industries such as metals and paper.

Shipping Rates. Our calculations of manufacturing costs in the U.S. and other developed economies did not factor in a projection for shipping expenses. On several important international trade routes, however, transportation costs give U.S.-based manufacturers another significant advantage. The large trade deficits that the U.S. has run up in the past decade have had a perverse impact on the shipping industry. Containers have been arriving in U.S. ports filled with imported products—and sometimes departing empty.

The ports of Los Angeles, Long Beach, New York, Seattle, and Tacoma all process more than twice as many U.S. imports as exports. Meanwhile, capacity at U.S. ports nearly doubled between 2000 and 2008. As a result, the capacity utilization rate at U.S. ports was only around 54 percent as of 2010—one of the lowest rates in the world. In Europe, ports in 2010 were operating at 59 percent of capacity. Utilization rates were at 69 percent in Northeast Asia and 76 percent in Southeast Asia.

The imbalanced trade flow has translated into low outbound-freight costs on a number of important trade routes. In late 2011 and early 2012, it cost an average of $3,900 per 40-foot equivalent unit (FEU), or around 72 cubic meters of container space, to ship goods from Yokohama to Rotterdam. The comparable shipping rate from New York City was $1,400. Although freight costs from the west coast of the U.S. to Japan are only slightly lower than those from Europe to Japan, U.S. exporters have an advantage because the shipping dis-

Exhibit 3 | Abundant Natural Gas Has Led to a Large Energy-Cost Advantage for Domestic Manufacturers in the U.S.



Sources: International Energy Agency quarterly energy price and tax statistics; BCG analysis.
Note: Energy prices based on 2012 averages.

tance is shorter, meaning they can more quickly get their goods to Japanese buyers. Because so many shipping containers from the U.S. to China are returning empty, freight costs from the U.S. to China are particularly cheap—just $850 per FEU. That compares with $700 per FEU from neighboring Japan. As a result, Japan's proximity to China will not necessarily be enough to offset the U.S. advantage in lower overall production costs for many products that are not time sensitive.

One event that could significantly change the cost balance, of course, is a sharp depreciation of the euro against the U.S. dollar. The dollar did indeed increase in value from around $1.60 per euro in early 2008 to around $1.20 per euro in mid-2012 as a result of the global financial crisis. But the dollar would have to appreciate even more dramatically—to below $1 per euro—for Germany, France, and Italy to approach cost parity with the U.S. by 2015. We will continue to monitor this and other cost factors as we continue our research on the competitiveness of the major manufacturing economies.

Many may assume that most of the production displaced from these developed economies will shift to China rather than to the U.S. But for reasons we explained in an earlier report in this series (*Made in America, Again: Why Manufacturing Will Return to the U.S.*, BCG Focus, August 2011), wages have been rising so rapidly in China that its cost advantage over the U.S. by 2015 is projected to be only around 5 percent for many goods exported to North America. When logistics, shipping costs, and the many risks of operating extended global supply chains are factored in, it will be more economical to make many goods now imported from China in the U.S. if they are consumed in the U.S.

The Impact on U.S. Exports

The U.S. export sector is already a little-noticed bright spot in the U.S. economy. Since 2005, export growth has averaged nearly 8 percent per year—despite the global recession of 2008 to 2009. Exports of U.S. goods, excluding food and beverages, now account for around 10 percent of U.S. GDP, the largest share in five decades. In the 1960s, when the U.S. was the world's dominant manufacturer, exports accounted for only around 4 percent of GDP. What's more, while the share of global exports by Western Europe and Japan declined between 2005 and 2010, U.S. exports have held steady at around 11 percent.

This momentum is likely to accelerate. Because of lower costs, we project that by the end of the decade, the U.S. could capture $20 billion to $55 billion in annual exports from the four Western European nations we studied, which would represent 2 to 5 percent of those nations' total exports. In addition, we estimate that the U.S. could capture $5 billion to $12 billion in Japanese exports by that time, or 1 to 2 percent of Japan's total current exports.

The Impact on U.S. Jobs

We estimate that the increase in U.S. exports and in the domestic production of goods that otherwise would have been imported will create between 600,000 and 1.2 million direct factory jobs. Another 1.9 million to 3.5 million jobs could be created indirectly in related services such as retail, transportation, and logistics. (See Exhibit 4.) We base these estimates on average output per worker and the multiplier effect in each industry category. In the transportation equipment sector, for example, every $140,000 in additional output on average creates one new job. A boost in U.S. production of $3 billion to $9 billion, therefore, would create 20,000 to 65,000 factory jobs. Each transportation-equipment production job, in turn, creates 3.6 jobs indirectly in other areas of the economy. That translates into an overall job increase of 110,000 to 290,000 in the U.S. transportation-equipment industry as a result of increased exports and reshored production.

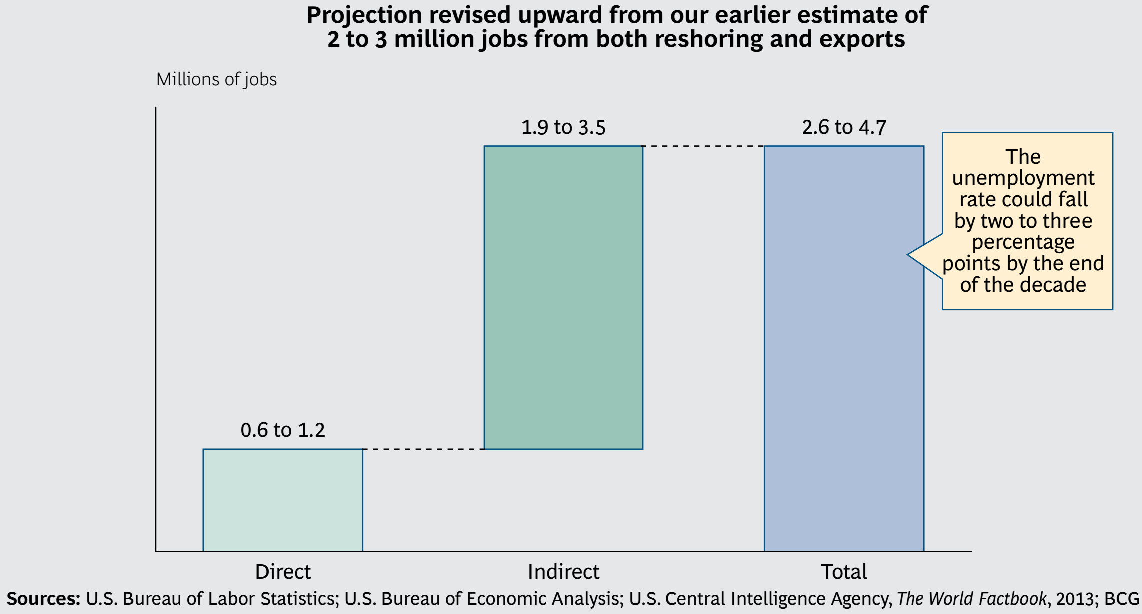
The gains in U.S. exports are likely to be felt across a wide range of industries.

If our projection of 2.5 to 5 million new U.S. jobs is accurate, the U.S. unemployment rate could drop by 2 to 3 percentage points. That would push the U.S. rate toward the "frictional" level, meaning the unemployment that normally occurs in an economy as workers change jobs.

Where the Gains Will Come

The gains in U.S. exports are likely to be felt across a wide range of industries. The U.S. is particularly well positioned compared with the five developed economies to increase exports in seven industrial categories: transpor-

Exhibit 4 | The U.S. Export Surge Could Create 2.5 Million to 5 Million New Jobs



Sources: U.S. Bureau of Labor Statistics; U.S. Bureau of Economic Analysis; U.S. Central Intelligence Agency, *The World Factbook*, 2013; BCG analysis.

tation equipment, chemicals, petroleum and coal products, computer and electronic products, machinery, electrical equipment, and primary metals. (See Exhibit 5.) These seven groups of industries accounted for roughly 75 percent ($12.6 trillion) of total global exports in 2011. Let's look at three of them a little more closely.

Transportation Equipment. This industrial category includes cars, trucks, buses, and aircraft. We project that in 2015, the U.S. will have an 11 percent cost advantage over Germany, which exported $319 billion in transportation equipment in 2011, and a 6 percent advantage over Japan, which exported $191 billion. The lower cost of labor accounts for virtually the entire U.S. cost advantage in this category. When adjusted for productivity, Japanese labor costs in transportation equipment manufacturing will be 22 percent higher than those of the U.S. German, French, and Italian labor costs will be 50 percent higher.

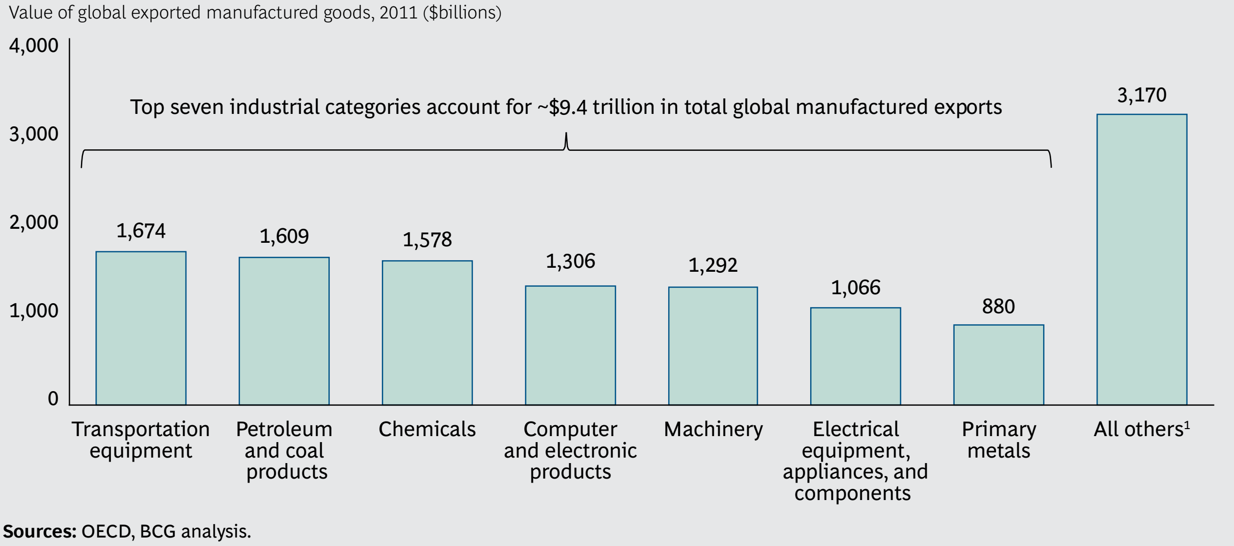
China will still have an average production-cost advantage of around 6 percent in 2015 for transportation equipment. When shipping and other costs are accounted for, however, it will make more economic sense for such products to be made in the U.S. if they are consumed in the U.S.

We project that by 2015, the U.S. will gain $3 billion to $9 billion in exports of transportation equipment from Western Europe and Japan.

Chemicals. The low cost of natural gas in the U.S. will become a particularly significant factor in the production of chemicals, where natural gas is often an important feedstock. Production costs in Germany, a leading chemical exporter, are projected to be 29 percent higher than in the U.S. in 2015. Chemical production costs are projected to be 17 percent higher in the U.K., 27 percent higher in Italy and Japan, and 28 percent higher in France.

A breakdown of the cost structures in each country shows why. Although the cost of German labor will be more than 50 percent higher, for example, the biggest impact will be from differences in natural gas prices, which will be more than three and a half times higher in Germany than in the U.S. Put another way, while natural gas will account for 8 percent of the total production cost of U.S.-made chemicals, it will account for 29 percent of costs in Germany. In the case of Japan, natural gas costs in chemical manufacturing will be nearly four times higher than in the U.S. in 2015. A further consideration is electricity

Exhibit 5 | Three-Quarters of Global Manufactured Exports Are Concentrated in Seven Industrial Categories



Sources: OECD, BCG analysis.
Note: Nominal US$. Excludes countries where industry-level export data are not available (e.g., South Korea, Hong Kong, Singapore, and Malaysia).
[1]Includes food products, textile product mills, miscellaneous, plastic and rubber products, fabricated metal products, paper, nonmetallic mineral products, and wood products.

rates, since chemical production is power intensive. We estimate that lower electricity rates will give the U.S. an additional cost advantage, ranging from 1 percentage point over the U.K., France, and Germany to 4 percentage points over Italy.

The U.S. will have a significant cost advantage over China in chemical production in 2015 as well. We project that costs in China's Yangtze River Delta region will be 16 percent higher, with natural gas prices more than offsetting any advantage that China will have in labor costs.

We project that by 2015, the U.S. will gain $7 billion to $12 billion in chemical exports from Western Europe and Japan.

Machinery. This broad category includes everything from construction and industrial machinery to engines and air conditioners. The U.S. will have a manufacturing cost advantage in machinery of around 7 percent over Japan, where machinery is a $143 billion export industry. Machinery production costs will be around 14 percent higher in Germany, which exported $216 billion in machinery in 2011, 14 percent higher in France, and 15 percent higher in Italy. Labor, a major cost in machinery manufacturing, is the big differentiator.

Projected total costs for machinery production will be around 8 percent lower in China in 2015. But when other costs are considered, it will likely be more cost-effective to produce much of the machinery that is sold in the U.S. in the U.S.

We project that by 2015, the U.S. will gain $3 billion to $12 billion in machinery exports from Western Europe and Japan.

The Key Messages for Manufacturers

Such core U.S. cost advantages as cheap energy and labor adjusted for productivity are likely to persist for at least the next five to ten years. As a result, the steady emergence of the U.S. as one of the lowest-cost countries of the developed world is a trend that is likely to have major implications for manufacturers around the world in a wide range of product categories across a wide range of industries. In the near term, the new math of manufacturing requires that many companies reassess their global production strategy.

We have long advised companies to maintain a diversified global manufacturing footprint in order to have the flexibility to respond to unanticipated changes and to expand or reduce production quickly in response to the competitive needs of specific markets. This advice continues to hold true. We also advise companies to carefully consider the total cost of ownership over the lifetime of the investment when deciding where to build new production capacity.

More companies should consider the U.S. as a manufacturing option.

The shifting cost dynamics, however, suggest that more companies should consider the U.S. as a manufacturing option for global markets. A number of leading manufacturers based in Europe and Asia have already begun to use the U.S. as a major export platform or have announced plans to do so. Others are relocating offshore production to the U.S. of goods to be consumed in North America. We believe that these companies are the early movers in what is likely to become a more widespread trend by 2020.

Companies that fail to take into account these cost shifts when making long-term investments could find themselves at a competitive disadvantage. Improving U.S. cost-competitiveness compared with developed economies, combined with rising costs in such offshore-manufacturing havens as China, represent what we believe is a paradigm shift that could usher in an American manufacturing renaissance.

NOTES

1. *Made in America, Again: Why Manufacturing Will Return to the U.S.,* BCG Focus, August 2011, and *U.S. Manufactur-*

ing Nears the Tipping Point: Which Industries, Why, and How Much? BCG Focus, March 2012.

2. "Why a Skills Gap Is Unlikely to Constrain a U.S. Manufacturing Resurgence," BCG article, November 2012.

Harold L. Sirkin is a senior partner and managing director in the Chicago office of The Boston Consulting Group and the author of GLOBALITY: Competing with Everyone from Everywhere for Everything. *You may contact him by e-mail at hal.ops@bcg.com.*

Michael Zinser is a partner and managing director in the firm's Chicago office and the leader of BCG's manufacturing practice in the Americas. You may contact him by e-mail at zinser.michael@bcg.com.

Justin Rose is a partner and managing director in the firm's Chicago office. You may contact him at rose.justin@bcg.com.

HOW CHEAP NATURAL GAS BENEFITS THE BUDGETS OF U.S. HOUSEHOLDS

by Harold L. Sirkin, Michael Zinser, and Justin Rose

When most analysts cite the economic benefits of rising U.S. production of natural gas recovered from vast underground shale deposits, they tend to focus on the country's declining dependence on imported oil and lower fuel costs for utilities and industry. But how much of the cost savings from cheaper natural gas benefits consumers directly?

More than you may think, according to our research. We project that, by the end of this decade, the savings could translate into the equivalent of an increase in annual discretionary income of almost 10 percent—which is likely to provide a significant lift to the U.S. economy as well.

We estimate that today, the average U.S. household is already saving anywhere from $425 to $725 a year because of lower energy costs that can be attributed to domestically recovered shale gas. This cheaper energy is helping hold down prices for utilities, transportation, and finished goods. By 2020, we project, the average annual savings per U.S. household could rise to as much as $1,200.

To arrive at this conclusion we compared the most recent U.S. Energy Information Administration data on energy spending with estimates of what that energy would have cost had natural gas continued on the trajectory it was following before 2005. In that year, U.S. producers began to massively ramp up recovery of shale gas via hydraulic fracturing, better known as *fracking*—the process of injecting large quantities of fluids and sand at high pressure into subterranean reservoirs in rocks to create small fractures, through which hydrocarbons can flow out more easily. Since 2005, U.S. wholesale natural gas prices have declined by around 50 percent. Those low prices are expected to persist as the U.S. continues to develop its vast shale gas reserves.

Members of an average family in the United States may be surprised to learn that they spend around $9,000 a year on energy. With an average household income of $50,000, that comes to 18 percent of total expenditures. Of that, natural gas accounts for 26 percent.

Only around one-third of this spending is for what we call "raw" energy. This includes the obvious energy bills—heating oil and natural gas for homes, fuel in the power stations that supply electricity, and crude oil that's processed into gasoline for cars. And about half of the raw energy that Americans consume is embedded in the products they use daily—like the petrochemical feedstocks in materials used to make everything from clothing and detergents to plastic bottles.

The far greater portion of what Americans spend on energy is less direct. It is the energy used during processing and delivering finished goods and services that households consume. When Americans buy a car, for example, they pay not only for the vehicle itself but also for the energy needed to process the steel it's made of, illuminate and heat the factories that make it, transport its components, and deliver it to the dealership. The average U.S. household spends around $6,000 a year on such indirect energy costs.

Determining to what degree lower-priced gas translates into gains for consumers is challenging. We estimated what natural gas would have cost in the U.S. today had supplies not risen dramatically because of shale recovery, and we estimated the cost savings that utilities, manufacturers, and other big users of natural gas are passing along to U.S. consumers. Because of the uncertainty, we calculated low and high estimates of household energy-cost savings.

We estimate that only 30 to 50 percent of the cost savings to companies from lower-priced natural gas is currently reflected in the prices of finished goods and services. As a result, average U.S. households are spending less each year than they would have without low-cost shale gas. Our estimated annual savings of $425 to $725 equates to an extra 3 to 6 percent of additional discretionary spending potential each year per household.

But we project that by 2020, the average annual savings could range from $725 to $1,200 per household. The higher end of this range translates into a nearly 10 percent increase in consumers' discretionary spending power.

Why are we confident that the savings for U.S. consumers will continue to grow? One reason is that market forces should eventually drive the benefits of cheap natural gas more fully to average consumers through industrial supply chains. Not all of the benefits will reach consumers, but it is reasonable to believe that 60 to 80 percent of the savings should pass through over the longer term.

Of course, it will take some time for these savings to fully reach consumers. The rates that utilities charge for electrical power don't fluctuate widely on the basis of short-term swings in commodity prices because they often are based on longer-term contracts and must factor in major capital investments. Similarly, a decline in energy costs will not instantly drop to the bottom line of automobile makers or translate into a lower price for detergent on supermarket shelves.

So where do we expect the savings to manifest? We estimate that, by 2025, shale gas could result in around $280 a year in cost savings per U.S. household in finished goods and services, compared with average savings of $90 in 2012. For U.S. household electricity bills, the average savings could rise to $190 from $150 during the same period, while savings on heat for buildings could jump to more than $230 from $190.

The other reason to be bullish is that cheap natural gas is here to stay for the foreseeable future. The U.S. has enough reserves of recoverable natural gas to keep prices at modest levels for more than 50 years. In previous research, we explained why cheap natural gas will translate into a boon to U.S.-based manufacturing.[1] It is now becoming increasingly clear that it will also bring great news for U.S. consumers.

Note

1. *Behind the American Export Surge: The U.S. as One of the Developed World's Lowest-Cost Manufacturers,* BCG Focus, August 2013.

Harold L. Sirkin is a senior partner and managing director in the Chicago office of The Boston Consulting Group and a coauthor of the book GLOBALITY: Competing with Everyone from Everywhere for Everything. *You may contact him by e-mail at hal.ops@bcg.com.*

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Justin Rose is a partner and managing director in the firm's Chicago office. You may contact him at rose.justin@bcg.com.

NATURAL-GAS-LIQUID DERIVATIVES

THE ENERGY TSUNAMI'S NEXT WAVE

by Clint Follette and Yanyu He

THE TSUNAMI THAT YIELDED abundant unconventional-natural-gas supplies has also generated a glut in the byproducts of those gases: natural-gas liquids (NGLs) including ethane, propane, and butane. As we described in a previous article, the unique interplay between the primary and secondary products has set off a self-reinforcing downward spiral in NGL prices as NGL supply quickly outpaced new demand creation. (See "Natural-Gas Liquids: The Implications of the Next Energy Tsunami," BCG article, October 2012.)

Equally important has been a ripple effect down the value chain to NGL derivatives. We have highlighted ethylene, propylene, and butadiene, which are three NGL derivatives that have seen significant market changes with far-reaching implications for many players in the chemical and end-use industries.

At the root of the ripple effect is the feed mix to steam crackers. Traditionally, naphtha (a heavy feedstock from oil refining) and NGLs (primarily ethane) have been the chief inputs. The surge in shale gas production has seen the supply of its byproduct ethane increase; indeed, ethane supply has grown beyond the ability of steam crackers to consume it. The excess supply of ethane has flowed to its next best use, which is as a fuel, and thus the price of ethane has declined to natural-gas parity on a British thermal unit (BTU) basis, in line with this lower-valued application.

In response, petrochemical companies have proactively invested in their facilities to increase flexibility and accommodate ethane cracking. As a result, the U.S. cracker-feed mix has shifted from about 40 percent naphtha in 2005 to about 10 percent currently. Naphtha's share is likely to continue to decline as ethane supply grows.

With ethane feed, there is increased selectivity to ethylene over propylene, mixed butenes, butadiene, toluene, and benzene and also less production of low-value products such as methane and fuel oil. Even with high market prices for byproducts such as propylene and butadiene, ethane's low relative price provides a strong incentive to shift away from naphtha feed.

At recent prices for naphtha and cracking products, the indifference point, the point at which steam-cracking margins are equivalent for naphtha and ethane feed and yields, would be reached when the price for ethane neared $900 per ton. However, actual ethane prices have recently been closer to $200 per ton.

Ethylene: Rebirth with a U.S. Production-Cost Advantage

With ethane feed, the yield to ethylene is about 75 to 80 percent compared with naphtha feed's ethylene yield of approximately 20 to 30 percent. U.S. ethylene production, which had been in a decline instigated by recession-induced capacity requirements, will, as a result of the feedstock shift alone, turn around.

U.S. ethane-based supply has a cost advantage over supplies from most regions.

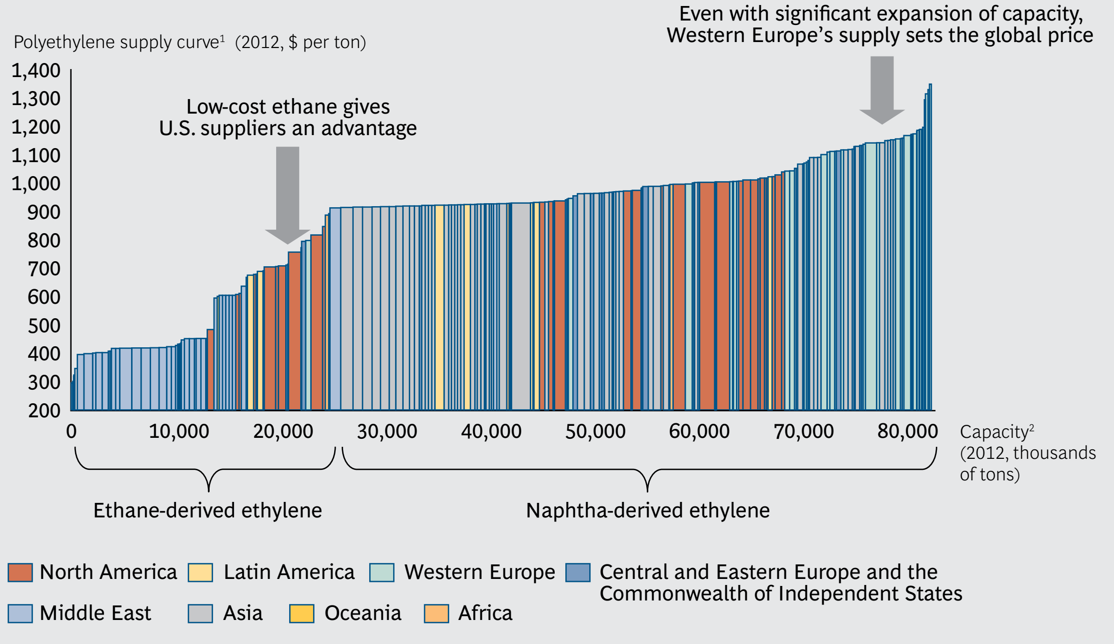
Because of ethylene's physical properties, transporting it is not practical. Hence, producers make polyethylene products close to the ethylene supply and then ship them to export markets rather than exporting the ethylene and producing polyethylene overseas. This means that along with the expansion of U.S. ethylene capacity, U.S. polyethylene capacity has increased to consume the additional ethylene. Thus, as a result of new production, U.S. polyethylene exports have grown and have displaced existing suppliers.

The global polyethylene supply curve illustrates that U.S. ethane-based supply has a cost advantage over supplies from most regions in the world. (See Exhibit 1.) Favorable price dynamics and increased yield are driving investment in new U.S. ethane-cracking capacity. If global capacity outstrips demand growth, the price of polyethylene could decline by as much as $200 per ton. However, even if this decline occurs, U.S. ethane crackers and polyethylene plants would maintain robust cash margins ($300 to $400 per ton).

Looking forward, as the polyethylene supply from the U.S. and other regions (including the Middle East and Asia) increases, European naphtha-cracking capacity and associated polyolefin production are expected to face significant cost pressure. The 6 million tons of pure naphtha-cracking capacity and 17 million tons of mixed feed capacity in Europe will be challenged to operate economically. Thus far, European capacity has been resilient; players have cut costs and improved efficiency to cope with low margins. Over time, though, once opportunities to remove costs are no longer available, the market will see capacity rationalized.

The shift toward ethylene brings with it a shift away from valuable coproducts of the

Exhibit 1 | U.S. Suppliers Can Capture Large Margins in Global Polyethylene Supply



Sources: Icis; *Oil & Gas Journal;* Platts; BCG ChemCom database; BCG supply-curve toolbox.
[1]High-density-polyethylene supply cost.
[2]Both high-density and low-density polyethylene capacities were included.

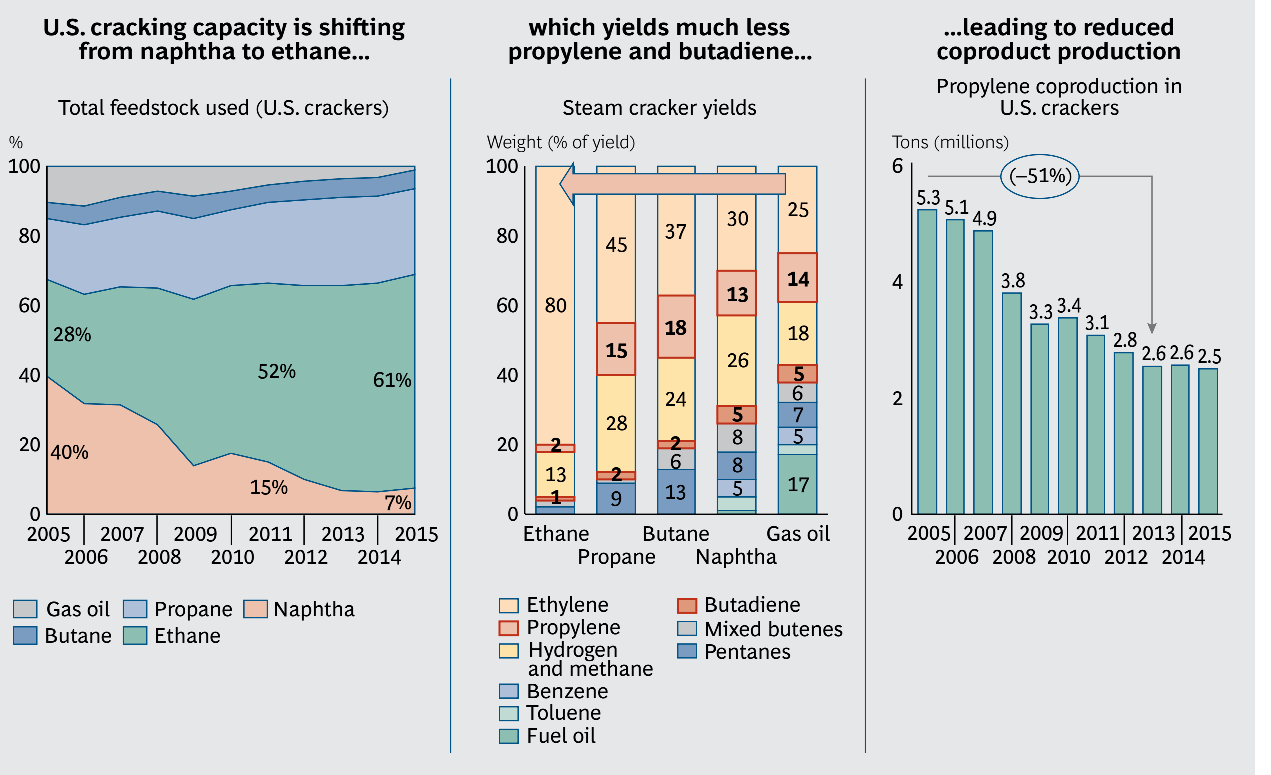
cracking process including propylene and butadiene. The yield to propylene and butadiene with pure naphtha feed is 13 percent and 4 to 5 percent, respectively. With pure ethane feedstock, the yield to propylene is 1 to 2 percent and the yield to butadiene is about 1 percent—a five- to sevenfold decline in both. The feedstock shift from naphtha to ethane has led to a reduction in annual steam-cracking propylene production by 2.7 million tons, or about 50 percent, since 2005. (See Exhibit 2.) Annual butadiene production has declined by 300,000 to 400,000 tons, or about 20 percent, causing both of these markets to experience shortages.

Propylene: On-Purpose Production to Address Tight Market Conditions

At present, propylene demand exceeds supply, as evidenced by the run-up to a 2011 average price of more than $1,600 per ton compared with an annual average price of approximately $1,000 per ton during the previous five years. U.S. propylene prices have been lower than ethylene prices for the past 20 years, but the propylene shortage led to an increase in the ratio of propylene to ethylene prices, from 0.95 in 2005 to 1.5 in 2011. The combination of low-cost propane from shale gas production and high-priced propylene created a significant advantage for on-purpose production of propylene through the propane dehydrogenation (PDH) process.

The Boston Consulting Group (BCG) recently analyzed near-term production costs and compared them with those of competing technologies. We found that PDH is in the middle of the supply curve relative to other technologies. With current prices, naphtha cracking and the on-purpose metathesis process, which cannot benefit from the propane-to-propylene price spread, rank as the most expensive technologies. The current spread and the competitive cost position of PDH on the supply curve have induced Dow Chemical, Formosa Plastics, Enterprise Products, Williams Companies, and Ascend Perfor-

Exhibit 2 | U.S. Steam Crackers Are Shifting to Ethane Feedstock, Which Yields Less Propylene and Butadiene



Sources: IHS Chemical; Deutsche Bank; Wells Fargo; Nexant; BCG analysis.

mance Materials to announce new PDH plants in North America.

Looking forward, the price spread between propylene and ethylene is unlikely to be sustained. BCG's analysis shows that the new PDH additions will eliminate the shortage and that the price on the Gulf Coast will once again be set by the variable cost of the metathesis process, at about $1,200 per ton.

Many of the PDH investors have locked in production contracts with fixed fees, protecting the investors from price fluctuations. However, those that benefit from exposure to high propylene prices will likely experience a negative impact. Conversely, players that benefit from low propylene prices, such as acrylonitrile and propylene-oxide suppliers, would gain from exposure to the market price.

The dynamics of the U.S. polypropylene market differ from those driving the polyethylene market. The U.S. polypropylene supply base exceeds domestic demand and is currently at about 80 percent utilization, but it is not sufficiently competitive to support exports (recently, exports have made up less than 5 percent of total sales). In this highly competitive, self-contained market, domestic utilization fluctuates to meet domestic demand and producers earn little to no profit because low input costs are passed on in the form of low polypropylene prices. With a more diversified feedstock base, price volatility may decline and allow some growth in polypropylene use. This dynamic differs from that of more-global derivatives such as propylene oxide, where a supplier can benefit from reduced input costs yet still sustain higher product prices in export markets.

Butadiene: Shortage and High Prices to Persist

Much as with propylene, the reduction in butadiene production has exacerbated an already tight market in the U.S.

Dating back to World War II, butadiene was produced on purpose through dehydrogenation. However, with the growth in the global chemical industry, byproduct "crude C4" streams containing butylenes and butadiene increased. From these streams, butadiene could be extracted to supply the U.S. market. Currently, all U.S. butadiene producers are operating extraction units to remove butadiene from crude C4 feedstock. With the market short of domestic C4s, prices have spiked to more than $4,000 per ton, a level that has encouraged imports of finished butadiene and crude C4s. Even with high prices, on-purpose production has not been economical in recent history.

The shift in steam cracker feedstock has further reduced the availability of crude C4s, leaving U.S. extraction units without feed and, thus, idle. The lack of butadiene supply has had a significant impact on the downstream chain. Sixty percent of the butadiene market is for synthetic rubber compounds including styrene butadiene rubber (SBR) and polybutadiene rubber (PBR); 75 percent of the volume of these two materials is used in the production of tires. Capacity utilization in the U.S. SBR and PBR industry has been limited to the 60 to 70 percent range since 2008 given the lack of available butadiene supply at competitive prices.

> The price spread between propylene and ethylene is unlikely to be sustained.

U.S. tire manufacturers are meeting their production needs by importing SBR and PBR. At the same time, they are seeing competition from imported tires. A cheaper, domestic source of butadiene supply could find a market by displacing butadiene extracted from imported C4s, supplanting SBR and PBR imports, and enabling domestic tires to better compete with imports.

In the case of butadiene, the solution to the shortage is less clear than it is with propylene. There is no off-the-shelf technology for on-purpose butadiene production. Historically, there have been a few commercial processes for on-purpose butadiene production, including the Houdry catadiene process, the Phillips oxidative dehydrogenation process, and TPC Group's Oxo-D process. All have yields of less than 75 percent, and an improved yield is needed to make investment more economical. Toward that goal, TPC recently restarted a dehydrogenation unit used to make isobutylene and announced an engineering study to investigate reopening an idled dehydrogenation unit to produce butadiene in 2015 or 2016.

Propane and butane prices will remain low, stabilized by exports.

TPC will likely be the first mover, but other global players have expressed interest in on-purpose butadiene technologies. For example, Enterprise Products recently pointed to on-purpose butadiene as one of the potential business opportunities that it is considering.

If TPC or another player is able to successfully commission an on-purpose unit to produce butadiene from butane and achieve acceptable yields, it will have a significant technology advantage in an attractive market. The growth potential for butadiene in the U.S. creates room for approximately two new world-scale plants (with production for each at approximately 270,000 tons per year) while still maintaining a relatively high market price for butadiene. However, until new capacity is available in the market, we expect volatility and prices that exceed $2,000 per ton to continue for a significant period of time.

Implications of Changing Market Dynamics

Even as the U.S. shale-gas boom is depressing the prices of gas and NGLs, oil prices and associated naphtha prices have remained high. These market dynamics have shifted the cracking feed mix from naphtha to ethane and are reducing propylene and butadiene output and increasing their prices.

With NGL market fundamentals in flux, what will future prices look like? BCG's analysis indicates the following characteristics:

- Sustained high oil prices and relatively low gas prices
- Ethane prices that will remain at BTU value until demand catches up with supply
- Propane and butane prices that will remain low, stabilized by exports
- Propylene prices that will decline as PDH capacity comes online to fill the market shortage
- Butadiene prices that will remain high and volatile until a viable on-purpose technology can be developed and deployed

These dynamics will have significant implications for players throughout the petrochemical, polyolefin, and rubber industries and for end consumers.

U.S. Ethylene Crackers. These facilities are likely to be advantaged through 2017 or 2018 until expansion and new building cause capacity to exceed supply.

U.S. Ethylene and Propylene Derivatives. There will be opportunities for profitable new investments down the ethylene and propylene value chains. Increased ethylene will enable profitable growth in ethylene derivatives including polyethylene and ethylene oxide. Propylene's increased availability and more stable price are likely to create growth opportunities in propylene derivatives as well.

European Crackers. Not all industry players will be winners. European players that rely on naphtha as a significant portion of their feed will remain disadvantaged. To improve their competitiveness, European players must improve feed flexibility and may also begin pursuing imports of excess NGLs from North America.

U.S. Polyolefin End Consumers. U.S. consumers of polypropylene will benefit from lower and more-stable propylene prices that make their way through the value chain, but polyethylene consumers may find that prices continue to be buoyed by global demand.

U.S. Synthetic Rubber and Tire Players. With volatile butadiene prices and uncertainty about on-purpose technologies, U.S. synthetic rubber and tire players will remain in a bind. Some may move to control their own destiny and partner to develop and deploy on-purpose butadiene capacity.

Preparing for a Volatile Future

The biggest wild cards in the NGL derivatives market outlook are shale gas development outside North America, the amount of shale gas that is wet (NGL-rich) gas, and the proportion of ethane, propane, butane, and heavier hydrocarbons in the NGLs. A number of countries are in the exploration stage; Argentina, Poland, Ukraine, China, Australia, and South Africa are in the lead. With production not expected before 2015 at the earliest, however, it is unlikely that this new development will be a significant factor for the prices of NGLs and derivatives in the next several years.

There remains tremendous uncertainty regarding how the NGL derivatives market will evolve. Consequently, players must fully understand the supply-and-demand dynamics for oil, naphtha, natural gas, and NGLs. Certainly, the shale gas boom will cause markets to continue to shift and prices to remain volatile—thus having an impact on crackers, polyolefin and rubber producers, and end users. Players that can position themselves flexibly to adapt to industry shifts will reap a competitive advantage—both in the near term and the longer term.

Clint Follette is a partner and managing director in the Dallas office of The Boston Consulting Group. You may contact him by e-mail at follette.clint@bcg.com.

Yanyu He is a former knowledge analyst in the firm's Houston office.

THE FUTURE OF PETROCHEMICALS IN EUROPE

CONTINUOUS RETREAT OR RISING PROFITABILITY?

by Udo Jung, Jaime Ruiz-Cabrero, and Alex de Mur

Europe-based petrochemical companies are finding themselves in a highly competitive environment that is likely to persist for at least the next several years. This situation is the result of a confluence of factors. In the sourcing of feedstock, Europe-based players are at a significant price disadvantage relative to many of their international competitors: margins for European ethane-fed steam crackers can be as much as $900 lower than those for U.S. ethane crackers. Demand for petrochemicals, which is expanding at a healthy rate through much of the rest of the world, is essentially flat in Europe. (From 2008 through 2013, demand for polyethylene in Europe grew only 0.6 percent per year while the global average was 4.9 percent. From 2013 through 2022, European demand is expected to grow at about 0.3 percent annually and global growth is forecast at 4 percent.) European players collectively also have surplus production capacity: from 2008 through 2012, capacity utilization for ethylene in Europe hovered around 80 percent compared with a global average of 86 percent. And many European plants are outdated and inefficient.

European companies are thus being hit from both the demand and the supply sides. To negotiate the challenges, many of these businesses will need to make material moves on the strategic and operational fronts. Some players will need to close plants, for example—or, alternatively, engage in M&A to build scale. Others will need to rethink their product mix and customer targeting. Nearly all will need to maintain an unwavering focus on operational excellence.

For Europe-based petrochemical companies, this is obviously a tall order. But the risks of inaction are sizable.

In a Recovering Industry, Europe Is Lagging

The global petrochemical sector has been under pressure since the start of the financial crisis in 2008. After 2008 and 2009, which were particularly tough, the sector began to recover slowly, albeit with some additional hiccups, such as in the first half of 2012, when the European sovereign-debt crisis increased in severity.

The effects of the ongoing recovery have been uneven by region, however. Most notably, Europe-based companies have experienced far less of a lift than their Asian and Middle Eastern peers and global players. This has extended Europe-based companies' protracted period of underperformance: from 2004 through 2012, Europe-based petrochemical companies had an average annual pretax return on capital employed (ROCE) of only 2 percent, compared with returns of 16 percent, 13 percent, and 17 percent for Asian, Middle

Eastern, and global players, respectively. (See Exhibit 1.)

There is much evidence suggesting that Europe-based companies' woes will persist. They face significant challenges on both the supply and the demand fronts.

- Europe is squeezed between feedstock-advantaged regions, including the Middle East and, now, the U.S.

- Europe-based players also face substantial cost challenges that are not feedstock related. Their plants are, in general, subscale and old. Furthermore, Europe's energy costs are well above those of both the U.S. and the Middle East. In 2013, for example, the price of natural gas in Europe was approximately $10.60 per million British thermal units versus $3.70 in the U.S. and $0.75 in some countries in the Middle East.[1]

- European demand for petrochemicals remains weak, weighed down by the lingering effects of the euro crisis. In Western Europe, annual demand for polyethylene increased by less than 1 percent from 2008 through 2012, compared with 8 percent in Asia and 7 percent in the Middle East.

The challenges facing Europe-based players appear unlikely to ease through the medium term. Local demand will remain weak for the foreseeable future: BCG expects that demand for polyethylene, for example, will grow at an annual rate of only 0.6 to 0.9 percent from 2012 through 2022, depending on the scenario. Compounding these difficulties, additional production capacity is being built in the U.S. Furthermore, other gas-producing countries—such as Russia, Kazakhstan, Azerbaijan, Colombia, and some West African nations—are stepping up their efforts to produce their own chemical industries, taking advantage of their abundant natural-gas supplies.

These forces place Europe's petrochemical companies in a difficult position within the global supply curve. (See Exhibit 2, which depicts global supply curves for ethylene.) In fact, on the basis of these dynamics, BCG estimates that Europe currently has between 0.7 million and 2.5 million tons of excess eth-

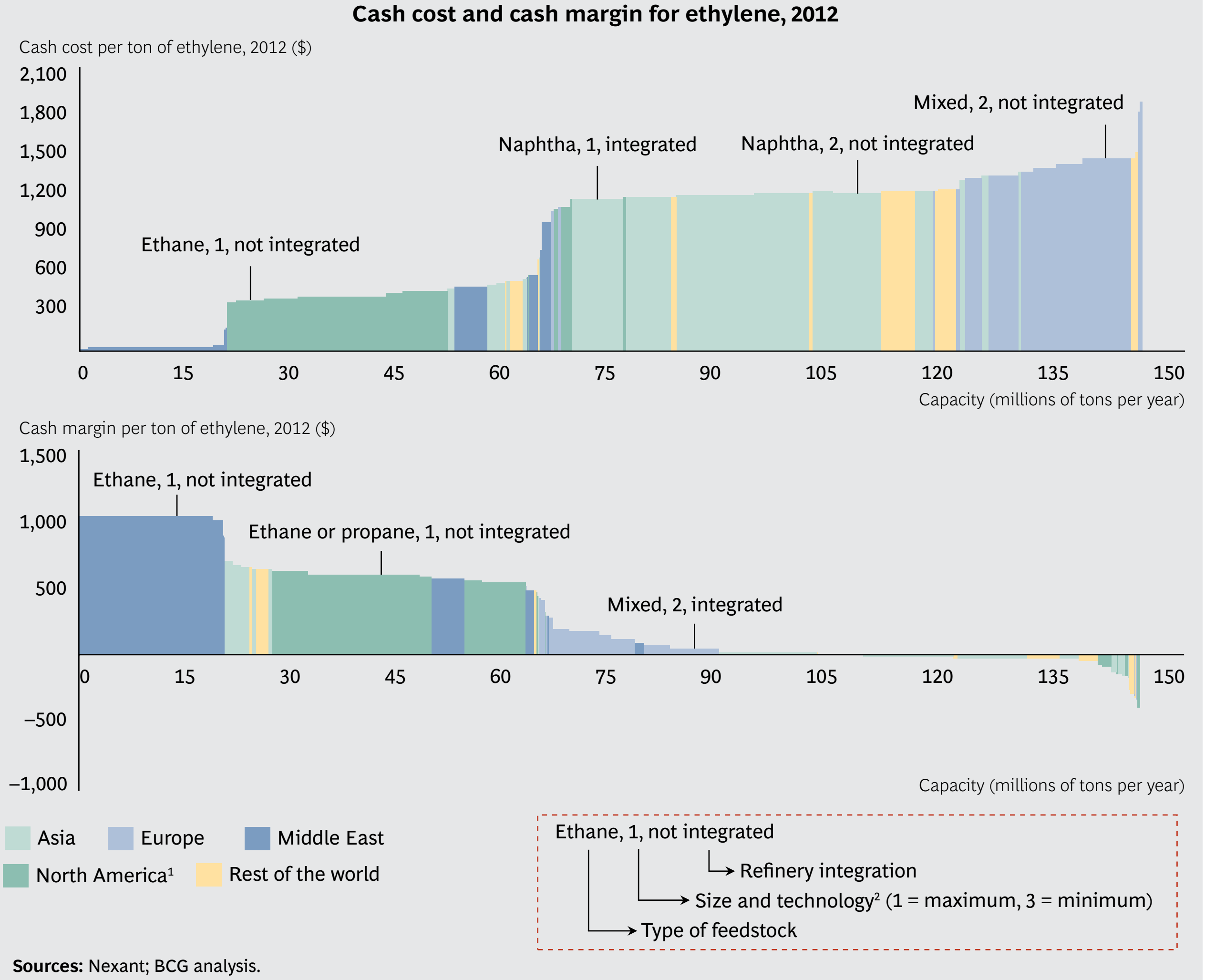
Exhibit 1 | Europe-Based Petrochemical Companies Have Underperformed Their Industry Peers

Sources: Orbis Asset Integrity; BCG analysis.
Note: Maximum and minimum data, where included, are based on the average company's performance. For oil and gas companies, we included the performance of their petrochemical units only.

ylene capacity, which is equivalent to 3 to 10 percent of the region's total ethylene capacity. Whether, and to what degree, Europe-based companies ultimately reduce capacity remains to be seen, however. In the past, quite a few forecasts that called for significant reductions in European capacity proved excessive. In fact, only 1 million tons of ethylene capacity has been taken off the European market since 2008, which is equivalent to 4 percent of total capacity.

Also, the reality is that even though Europe-based players have the highest ethylene-production costs in the world, Europe's product prices, which are higher than those in Asia, make Asian capacity, not European capacity, the marginal producer for ethylene and polyethylene supply, providing only a limited amount of protection to European plants. This rather counterintuitive situation is caused by the logistical costs of trade between the Middle East and Europe—costs that are higher than those between the Middle East and Asia—and reflects differences in the fluidity of the respective trade routes. Another contributing factor is the relative strength of Europe-based petrochemical companies' innovation capabilities and application technologies.

EXHIBIT 2 | Europe-Based Companies Are in a Difficult Position Within the Global Supply Curve



Sources: Nexant; BCG analysis.
Note: Middle East prices assume netback to Asia. "Mixed" feedstock assumes 80 percent naphtha and 20 percent liquefied petroleum gas. In estimating integration synergies, we assumed reductions of 8 percent of energy costs, 9 percent of other variable costs, and 10 percent of fixed costs. Our calculation of synergies derived from the exchange of streams between sites assumes $83 per ton of ethylene for naphtha and mixed-feed steam crackers.
[1]The U.S. produces 80 percent of North American ethylene.
[2]Ethylene production size key: 1 = >700 kilotons per year: 2 = >200 kilotons per year, 3 = <200 kilotons per year. We assume that a company's size and strength of technological capability are related.

Within Europe, Distinct Starting Positions for Individual Plants

A close look at Europe's steam-cracker supply curve reveals significant differences among plants. In fact, for ethylene, the difference in production costs of the median first-quartile plant and the median fourth-quartile plant is well above $300 per ton, a considerable spread.

The variation in the economic competitiveness of the plants is driven by a number of structural factors:

- *Scale.* Greater size can translate into significantly lower fixed costs. BCG research revealed that there is a 40 percent scale curve—that is, a 40 percent reduction in fixed costs for each doubling of capacity—for steam crackers.

- *Integration.* Integration—upstream (with a refinery) or downstream (with polyolefin or other petrochemical plants)—represents one of the most important levers for creating value and one that companies in Europe are now pursuing relentlessly. We believe that the total potential value of integration ranges from $50 to $150 per ton of ethylene, depending on the configuration of the refinery or petrochemical complex. Most of the value derived from integration comes from stream exchanges and the resulting increases in flexibility. However, there is also the potential for lower fixed and variable costs.

- *Feedstock Access and Cost.* Clearly, this is the single largest driver of European plants' lack of competitiveness compared with plants in other regions, especially those that enjoy access to cheap ethane. (Within Europe, only two plants—the Shell Chemicals-ExxonMobil Chemical Mossmorran plant in the U.K. and the Ineos plant in Rafnes, Norway—utilize ethane feedstock.) Access to multiple types of feedstock, including liquefied petroleum gas and nontraditional intermediate streams, can also translate into significant advantage: companies capable of alternating feedstock types on the basis of economic signals can reap margin advantages ranging from $30 to $150 per ton for polyethylene.[2] Best-practice companies set specific annual targets for increasing their feedstock flexibility and their use of nontraditional feedstock.

- *Plant Age and Technology.* Newer, more advanced plants are generally more efficient in their energy use and provide better yields. We estimate that this advantage can represent up to $100 per ton.

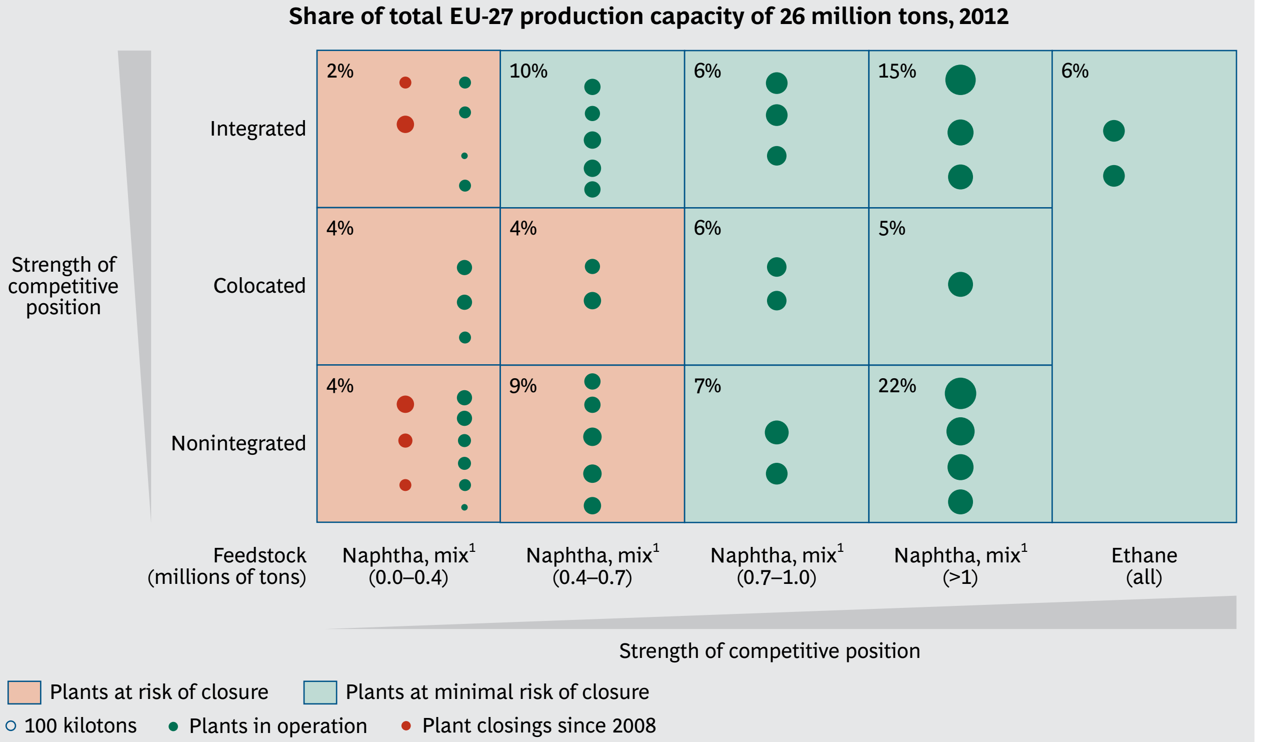
- *Location.* Given the potentially large differences (from $10 to $30 per ton) in logistics costs (for example the costs of integration into pipeline networks), location can have a sizable impact on a plant's cash position. Depending on location, energy and personnel costs can also differ materially across Europe. This was painfully demonstrated by the recent difficulties encountered by one of Europe's largest, most integrated plants, which faced significant profitability challenges that were driven by its high employee-related cost base.

In many cases, subscale, nonintegrated plants possess the least favorable economic profile and are at greatest risk of closure. In fact, all of the 1 million tons of European steam-cracker capacity taken offline since 2008 fall into this category. (See Exhibit 3.)

In addition to focusing on the five structural factors described above, best-practice companies worldwide actively strive to achieve operational excellence in an effort to significantly improve the economics of their plants. In the course of our extensive work with petrochemical companies, BCG has found that an industrial complex can increase its variable margin by more than $100 per ton by tightening operations (including focus on yield improvement, maintenance, energy management, inventory management, procurement, plant optimization, and shared-services costs) and delivering commercial excellence programs (including price realization, product portfolio, channel mix, client, and regional strategies).

On top of the competitive advantages that can be gained through optimization at the individual- or integrated-plant level, competitive ad-

Exhibit 3 | Subscale, Nonintegrated Sites Are the Most Likely to Close



Sources: Nexant; BCG analysis.
Note: In addition to scale and integration, other factors, including a plant's technology and efficiency, can influence its viability. The size estimates focus on ethylene production specifically.
[1]"Naphtha, mix" includes plants that use naphtha or naphtha and mixed liquids as feedstock.

vantage can also be achieved at the corporate level. Possession of global scale and a global footprint can be a highly potent lever, as it permits companies with a larger client and revenue base to fund R&D efforts more easily and to participate in additional specialty and differentiated markets downstream. Furthermore, denser plant networks allow petrochemical players to better balance specific-grade production across plants. This provides companies the capacity to specialize certain plants, reducing operational complexity and bringing related operational advantages. It is important to note that global companies that have significant exposure to Europe have been able to generate very strong returns—returns that exceed those for plants in any single region—by leveraging their international footprint and global portfolio.

How Sustainable Is the Cost Advantage Driven by U.S. Shale Gas?

Much has been written about the U.S. shale-gas revolution and its impact on petrochemicals and other industrial sectors. The revolution has indeed completely transformed petrochemical dynamics in the U.S. (and ultimately worldwide), making the country one of the lowest-cost ethylene producers in the world.

U.S. shale-gas development and its peripheral effects—including the related surge in ethane production—have had, and will continue to have, a direct impact on C2 (ethylene), C3 (propylene), and C4 (including butadiene and butene) olefin value chains as well as on aromatics. Most notably, the sector's resulting shift to cheaper ethane feedstock is increasing the production of C2 and its derivatives while limiting the production of C3 and C4. Shale gas developments will also increase the production of aromatics through the build-up of new condensate splitters.[3]

Our purpose here is not to analyze the broader implications of the U.S. shale-gas revolution for the petrochemical industry—to gauge its impact on, for example, the various value chains or the relative attractiveness of different investment alternatives, such as propane dehydrogenation or on-purpose butadiene. Rather, our focus is on the pricing mechanism for U.S. natural-gas liquids (NGLs), including ethane, butane, and propane, and what it means for the competitiveness of European polyolefins.

In the U.S., significant growth in NGL production has led to a surplus of such products.

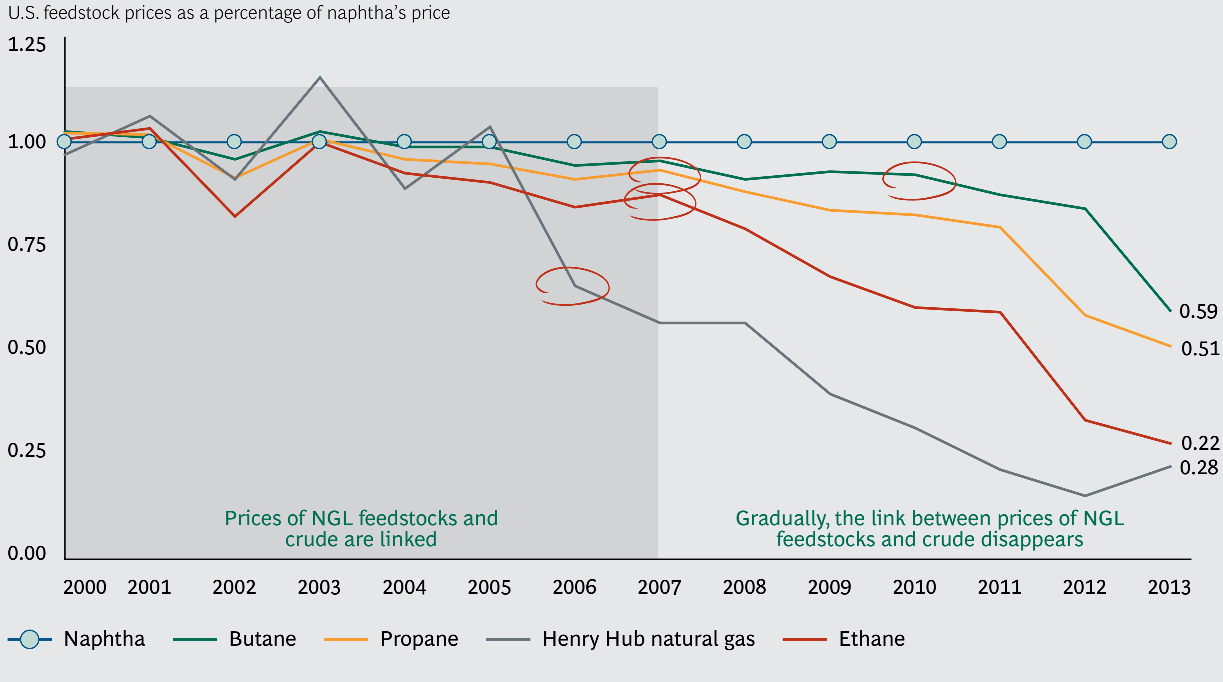
In the U.S., the significant growth in NGL production associated with both shale gas and shale oil development has led to a surplus of such products and an increasing decoupling of NGL prices from prices for crude oil and its derivatives. Exhibit 4 shows the price decoupling of different NGLs versus naphtha (a heavy feedstock from oil refining)—a very relevant comparison, as these are all potential feedstocks for steam crackers.

We can readily observe the gradual decoupling of NGLs, starting with natural gas as early as 2006, followed by ethane and propane in 2008 and, more recently, butane. At the beginning of this century, ethane and naphtha were priced almost at parity, but by 2012, ethane's price was only 33 percent of the price of naphtha (on a weight basis).

The rise in U.S. ethane production—annual production climbed from 250 million barrels in 2008 to 350 million barrels in 2012—has been too large to be absorbed by the country's existing steam-cracker capacity. Production thus exceeds demand from the U.S. petrochemical industry. As a result, ethane, which was priced as an alternative to a feedstock product such as naphtha prior to the shale oil revolution, is today priced for its alternative usage. That is, it is now priced as an alternative or supplement to natural gas. In fact, significant amounts of ethane are "rejected" into the natural-gas pool, because ethane's processing economics remain negative.

The surplus of NGLs—and the cost advantage that surplus provides the U.S. in the global

Exhibit 4 | U.S. Petrochemical-Feedstock Prices Have Lost Their Link to Crude Oil



Source: BCG analysis.
Note: NGLs = natural-gas liquids.

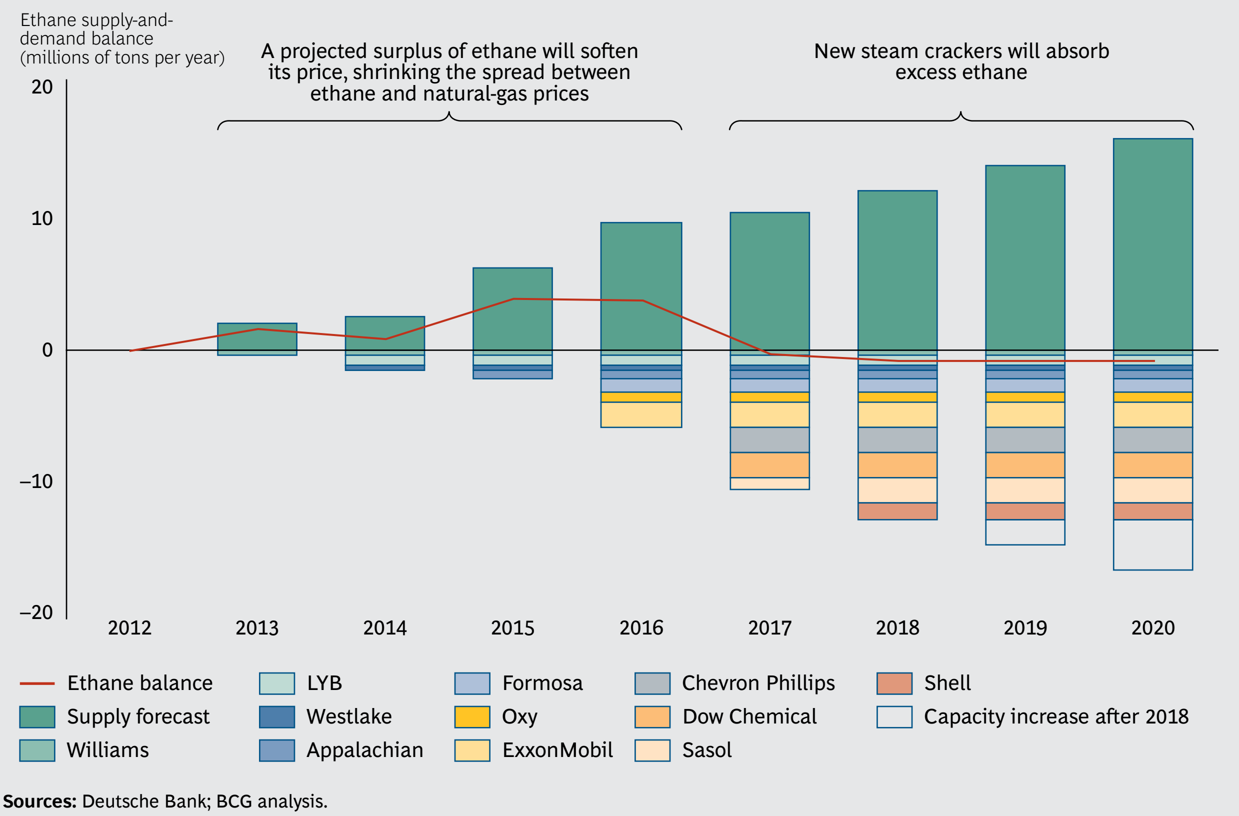
supply curve—is, thus, the key driver behind the U.S. petrochemical-industry renaissance. The question is: How long will this last? To answer the question, we first need to answer another: When (if ever) will all U.S. ethane production again be absorbed by U.S. steam crackers?[4]

Exhibit 5 gives a clear view of the situation. According to our research, growth in U.S. ethane production, which, by 2020, we believe will reach roughly 15.5 million tons per year, will be compensated for by an increase in domestic demand from newly built petrochemical plants and expansion of existing plants by 2017. At that point, ethane will no longer be in surplus, and the pricing mechanism will have changed. In our view, the new price-setting mechanism for ethane will be the polyethylene netback from China and the required ethane price. Our analysis shows that this price will likely be around 60 percent of the U.S. naphtha price, compared with 33 percent in 2012. Ethane will, therefore, remain a price-advantaged feedstock.

Similar analysis can be done for propane and butane, for which price adjustment will come as export parity prices are reached following the development of the requisite export infrastructure. We believe that this will take place in 2014 or 2015. Propane's price will rise to approximately 70 to 75 percent of naphtha's price (versus 55 percent in 2012), and the price of butane will rise to about 90 percent (versus 84 percent in 2012).

It is possible that after 2017, the market will experience alternating periods of ethane surplus and deficit. When the ethane supply again becomes inadequate and its price increases, exploration and production companies will have significant incentive to increase drilling in ethane-rich regions. Establishing new processing and fractionation facilities takes some time—although not nearly as long as building a new steam cracker. Hence, we might see rapid ethane-supply responses that would put the market back in an oversupply situation in as little as 18 months, given the right economic incentives.

EXHIBIT 5 | By 2017, New Plants in the U.S. Will Absorb Surplus Ethane



Sources: Deutsche Bank; BCG analysis.
Note: LYB = LyondellBasell Industries; Westlake = Westlake Chemical; Appalachian = Appalachian Resins; Formosa = Formosa Petrochemical; Oxy = Occidental Petroleum; Chevron Phillips = Chevron Phillips Chemical.

In every scenario, despite the incremental production from NGLs, naphtha will remain the main and marginal petrochemical feedstock and hence the olefins price setter. We estimate that, by 2020, slightly less than 70 percent of global ethylene capacity will still be naphtha based.

Implications for European Olefin Production and Capacity

What will all of this mean for Europe-based petrochemical players? We have defined two possible scenarios.

Base Scenario. In our base scenario, U.S. ethane prices resume their link to U.S. naphtha prices from 2017 onward, diminishing the price advantage of U.S. imports into Europe. The U.S. price advantage remains significant, however, as ethane is priced at around 60 percent of naphtha's price. This scenario is consistent with our views expressed in the section above.

Alternative Scenario. In our alternative scenario, U.S. growth of ethane production outpaces new petrochemical developments in the U.S., and, thus, ethane prices remain linked to U.S. prices for natural gas.[5] In parallel, there are short ethane-deficit cycles that are quickly "corrected" by exploration and production companies through drilling campaigns in ethane-rich regions, as discussed above. In any case, U.S. plants retain a significant cost advantage over their European counterparts, though the difference is much larger in the alternative scenario ($600 per ton) than in the base scenario ($380 per ton).

In both scenarios, U.S. and Middle Eastern companies would increase their exports to Europe. Coupled with expected lackluster growth in European demand—we anticipate aggregate demand growth, from 2012 through 2022, of 1.1 million tons and 0.8 million tons for polyethylene in our base and alternative scenarios, respectively—this will place growing pressure on margins for European steam crackers and will likely force additional plant closures. As noted above, we estimate that European steam-cracker capacity at risk of closure ranges from 0.7 million tons (in the base scenario) to 2.5 million tons (in the alternative scenario). The U.S. ethane-pricing mechanism will play a key role, because it will significantly change the economics of the country's ethylene production and therefore significantly influence the volume of U.S. exports to Europe.

> Well-run companies operating in Europe will still be able to differentiate themselves.

The challenge that imports from other countries pose for European players could intensify greatly depending on Asia's degree of self-sustainability: that is, the extent to which Asian producers meet Asian demand. In the alternative case of China's increased self-sustainability, Middle Eastern producers would increase their exports to Europe in an effort to compensate for the market lost in China.

Weathering the Storm and Moving Toward a Profitable Future

The environment for Europe-based petrochemical companies will remain challenging for the next several years. Indeed, it may become more challenging, as competitive pressure from the U.S. and the Middle East will not only persist but could also rise, set against a backdrop of ongoing moderate growth in local demand.

However, as they have done in the past, well-run companies operating in Europe will still be able to differentiate themselves and improve their financial returns. Consider, for instance, the period from 2004 through 2012, when the average pretax ROCE for petrochemical companies focused solely on Europe was a meager 2 percent. If we de-average the numbers, we find significant differences by company: the top performer had an annual pretax ROCE of 8 percent, while the bottom player's was –6 percent. Furthermore, as we have noted, global companies that have a very relevant asset base in Europe have also been able to reap significant returns, reaching a median pretax ROCE of 17 percent for that period. In short: good performance has been, and will continue to be, rewarded by higher returns.

There are a number of levers that Europe-based companies can deploy to increase their chances of success in this environment. We group these into two main buckets: maximizing the value of existing assets and restructuring the plant portfolio.

Maximizing the Value of Existing Assets. To maximize the value of their existing assets, companies can undertake, or continue to support, a number of key actions:

- *Operational Excellence.* Some companies are launching comprehensive operational-excellence programs, including efforts directed at cost reduction (focused on fixed costs such as maintenance, energy management, and procurement), inventory reduction, and margin enhancement (by, for example, increasing feedstock flexibility and optimizing unit performance and yields). In our experience, petrochemical companies can realize value ranging from $60 to $150 per ton through the combination of such efforts, depending on the company's starting position and its specific configuration of assets.

- *Integration.* Integration—both upstream and downstream—offers considerable opportunity for enhanced operational efficiencies and higher returns on existing assets through increased stream integration and flexibility, coupled with organizational and cultural improvements. Working with our clients, we have observed in several instances that, beyond the obvious streams (for example, C3s from a fluid catalytic-cracking plant), refining and petrochemicals do not necessarily maximize the value of intermediate streams exchanged. This is especially true of intermediate streams whose disposition value changes over time, depending on external economic signals (for example, the value of a raffinate stream from a continuous catalytic-reforming plant that is exported or routed to the gasoline pool or steam-cracker feedstock). Coordination mechanisms and simple and shared analytical tools can help recoup this value for the integrated site. We estimate that companies can achieve savings of $20 to $40 per ton by strategically leveraging these less obvious integration opportunities.[6]

- *Commercial Excellence.* Many petrochemical companies will find that by rethinking their price realization, product portfolio, channel mix, client, and regional strategies, they have substantial opportunity to improve returns on existing assets. In our experience, the typical value at stake can change significantly, depending on the starting position.

Restructuring the Plant Portfolio. Measures to restructure the plant portfolio to ensure that it is optimized in terms of products, scale, and regional exposure include the following:

- *Plant Closures.* Less efficient plants can be closed in order to maximize the value of the company's best plants. Closing a plant is not always simple, however, given the associated costs—both financial and political.

- *Expansion of European Production Networks.* To grow their market footprint and maximize the value of their overall plant portfolio (for example, by rebalancing production and market concentration), companies can increase their overall network scale through joint ventures or M&A. An enlarged network provides more freedom to deploy the operational levers described above. (A larger network affords greater scope for individual sites to take on different roles, for example.)

- *Participation in Cross-Regional Networks.* To mitigate the growing challenges that European asset networks are likely to face in the future, Europe-based companies can integrate those asset networks into cross-regional asset networks through alliances, joint ventures, and M&A.

- *Changes to the Product Portfolio.* To increase their share of (higher-margin) specialty products, some companies are leveraging their innovation capabilities and retooling some of their downstream plants. Note that a shift to higher-end products requires not just plant-specific changes but also strong R&D capabilities, sufficient budget, and a sales force capable of selling specialty products and engaging with clients over the long term.

For most Europe-based players, the required consolidation of their European steam-cracker and petrochemical capacities will entail joining forces (through joint ventures, for example) with other companies. The resulting enlarged-site networks will expand the number of options companies have both for allocating advantaged products to advantaged sites and for closing plants.

We conclude our analysis of the European petrochemical landscape with a key question that remains open and whose answer could have very different effects on companies based in Europe and the Middle East: Will Europe's ethylene price remain higher than prices in other regions? The difference between the prices for European and Asian polyethylene, for example, stood at approximately \$300 per ton in 2012, a gap largely explained by the difference in transport costs (\$230 per ton) and import duties (\$84 per ton). If price differentials stay the same, some European companies—those that have Middle Eastern, or even U.S., petrochemical assets that are capable of improving their supply chains to reduce export costs—could gain a significant advantage by exploiting Europe's prices, which are higher than prices in Asia. A general erosion of the price difference, however, would put further pressure on Europe-based petrochemical companies.

EUROPE-BASED PETROCHEMICAL COMPANIES are in a highly challenging situation. But most have considerable scope to withstand the challenges, strengthen their financial performance, and create defensible positions. It will take the willingness and ability to be flexible, make bold moves, and think long term. Inaction is not an option.

NOTES

1. The source for the European gas price is the National Balancing Point.
2. Among European plants, there is a wide range of capabilities regarding feedstock flexibility. In best-practice and advanced sites, liquefied petroleum gas can account for as much as 50 percent of utilized feedstock, while in some other plants, it accounts for no more than 10 percent.
3. For more details, see "Natural-Gas Liquids: The Implications of the Next Energy Tsunami," BCG article, October 2012.
4. One might argue that exporting ethane could help reduce the gap. However, we believe that exporting ethane will not take place on a large scale since, given the characteristics of the ethane value chain, it is much more feasible for companies to process ethane and export ethylene, especially polyethylene. In addition, exporting ethane would involve, among other things, building ad hoc infrastructure (for example, pressurized and refrigerated tanks), whereas polyethylene has much lower logistical needs, most of them indistinguishable from those for other types of wares.
5. Prices for natural gas itself will also remain decoupled from oil prices.
6. This assumes that basic intermediate streams among sites are already exchanged (for example, C3s from a fluid catalytic-cracking plant to a polypropylene plant or hydrogen gas from a steam cracker to a refinery). Otherwise, the value of integration would be much higher (up to \$150 per ton).

Udo Jung is a senior partner and managing director in the Frankfurt office of The Boston Consulting Group. He is the global leader of the petrochemical sector of BCG's Energy practice. You may contact him by e-mail at jung.udo@bcg.com.

Jaime Ruiz-Cabrero is a partner and managing director in the firm's European regional office. You may contact him by e-mail at ruiz-cabrero.jaime@bcg.com.

Alex de Mur is a principal in BCG's Madrid office. You may contact him by e-mail at demur.alex@bcg.com.

BRITAIN'S BOWLAND SHALE

WHAT NEXT?

by Eric Oudenot

The lines appear to be drawn in the battle over the U.K.'s energy future. On one side are those who see the United Kingdom following in the footsteps of the United States. Thanks to technologies that have enabled U.S. energy companies to extract huge quantities of oil and natural gas from shale rock formations, the United States has transitioned in less than a decade from a large net importer of oil and natural gas to a soon-to-be net exporter.

This camp, which includes Prime Minister David Cameron and the Institute of Directors, argues that exploiting the U.K.'s newly accessible energy reserves, located primarily in the Bowland shale formation in the central U.K., would lower energy costs, help restore industrial competitiveness, and boost job creation.

On the other side of the energy divide are environmentalists and community activists, who see the British Geological Survey's new, higher estimate of U.K. shale resources as an invitation to harm the environment through the controversial technology of hydraulic fracturing, or fracking. This method of extracting oil and natural gas from rock formations, they say, could despoil the landscape and pollute underground water reservoirs.

To resolve such questions, British policymakers and citizens should look closely at the U.S. experience, where fracking has been used to produce natural gas since the 1950s, though it didn't become commercially viable until the early 1990s, after the late Texas oilman, George P. Mitchell, combined the fracking technology with horizontal drilling.

By now, the economic benefits of the fracking revolution should be self-evident. Using Mitchell's technique, U.S. energy producers have been able to increase shale-gas production from virtually nothing in 2005 to the equivalent of more than 5 million barrels of oil per day in 2012, an amount equal to the annual production of Iraq and Nigeria combined. This, in turn, has driven down the wholesale price of natural gas by more than 50 percent. As a result, the price of natural gas today is some 2.5 to nearly five times higher in Europe and Japan than in the U.S.

The low gas price also has driven down the cost of electricity in the U.S., placing European manufacturers at a disadvantage. When combined with other factors, low U.S. energy prices suggest that average manufacturing costs in the U.K. will be 8 percent higher than in the U.S. by 2015.

As Matthew Lynn wrote recently in the *Wall Street Journal*'s "MarketWatch" column, "shale gas is going to rearrange the winners and losers in the global economy." There's no way around this fact. "Cheap energy," he noted, "is the most important competitive advantage for factories."

So the real question for the U.K.—and other countries, including France and the Netherlands, which have preemptively banned fracking, as have several U.S. states—is this: Can shale resources be developed without damaging public health or the environment?

To some, any drilling rig, gas well, or pipeline will be seen as de facto evidence of environmental harm, no matter how highly regulated by government or carefully executed by industry.

The U.K. has two very clear choices: it can fall behind, or it can move forward.

To others, however, the U.S. experience might be instructive. Indeed, as America's very green organization, The Breakthrough Institute, noted in a June 2013 report titled *Coal Killer: How Natural Gas Fuels the Clean Energy Revolution,* cheap natural gas is not only among the most environmentally friendly energy sources there are, but it is also vital to the green movement's sought-after transition to "renewables," providing the grid with needed energy when solar and wind technologies don't.

As for fracking, the report compared its impact with that of the most likely alternative for power generation: coal, the energy source that currently provides 40 percent of the U.K.'s electricity. The institute's conclusion: "Natural gas production generally and shale fracturing specifically have a far smaller impact on mortality and disease, landscapes, waterways, air pollution, and local communities than coal mining and coal burning."

The U.K. has two very clear choices: It can fall behind, or it can move forward. The first challenge is political, because the global shale-gas revolution will proceed with or without the United Kingdom and the Bowland shale.

The proper role for the U.K. government is to both encourage and keep tight control of shale gas development. To earn and maintain the public's trust, the government's policies and activities—from its licensing and permitting systems to its water management strategy and fiscal and regulatory framework—must be totally transparent. The public needs to understand the risks, benefits, and monitoring procedures. In particular, instead of fixating on the water requirements and noise of drilling rigs, organizations need to pay attention to the logistical aspects of development, such as the significant increase in truck and rail traffic and its impact on communities. Often logistical feasibility, rather than ideal geology, will dictate the locations where shale-gas wells will be located.

Every significant advance involves tradeoffs. The fracking revolution is no exception.

Eric Oudenot is a principal in the London office of The Boston Consulting Group and the firm's topic expert on shale gas. You may contact him by e-mail at oudenot.eric@bcg.com.

NOTE TO THE READER

About the Authors

Iván Martén is a senior partner and managing director in the firm's Madrid office and global leader of BCG's Energy practice. **Eric Oudenot** is a principal in BCG's London office and the firm's topic expert on shale gas. **Alex de Mur** is a principal in the Madrid office of The Boston Consulting Group. **Clint Follette** is a partner and managing director in the firm's Dallas office. **Udo Jung** is a senior partner and managing director in BCG's Frankfurt office. He is the global leader of BCG's chemicals sector and European leader of the firm's Operations practice. **Justin Rose** is a partner and managing director in the firm's Chicago office and BCG's topic leader for green energy in the Americas. **Jaime Ruiz-Cabrero** is a partner and managing director in BCG's European regional office. **Harold L. Sirkin** is a senior partner and managing director in the firm's Chicago office. **Michael Zinser** is a partner and managing director in BCG's Chicago office.

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For Further Contact

If you would like to discuss this e-book or learn more about BCG's capabilities in this arena, please contact Iván Martén, global leader of BCG's Energy practice, or Eric Oudenot, the firm's topic expert on shale gas.

Iván Martén
Senior Partner and Managing Director
BCG Madrid
+34 91 520 61 00
marten.ivan@bcg.com

Eric Oudenot
Principal
BCG London
+44 020 7753 5353
oudenot.eric@bcg.com

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