the United States will take regulatory steps that will "kill the golden goose" and lead to far lower resource deliverability than Neff and LaRose (and Newell and Iler) forecast. Her optimism for the hemisphere is weaker still. Here Foss sees serious backsliding even from the champions of smart frameworks, Brazil and Colombia. Colombia emerged only after a "near death" experience with production decline, and Brazil is sowing the seeds of state dominance and control that dominated the years when it was an energy importer. Politics and state demands for revenue and control are hard to deter in any country. Foss adds a new axiom, warning that "it ain't just the framework, it's the implementation" and, even more, the ability to forestall erosion of political will and commitment—issues of internal politics—that matter in the long run. All of the strategic implications of the Western Hemisphere tight oil and gas boom hoped for in this part (and others) depend on governments making good decisions about the future. Foss expresses hope, but little confidence, that governments will make better decisions in the future than they have in the past.

Note

Chapter 15
North America
Shirley Neff and Angelina LaRose

The past decade has seen a total reversal in the energy supply and demand outlook in the United States, a turnaround that has significant positive implications for all of North America. A decade ago, the outlook was for increasing hemispheric imports of oil and natural gas. Supplies of both were declining in the United States and Mexico, while Canadian demand for natural gas was growing to support development of the oil sands. Competing industry proposals for natural gas pipelines from the North Slope of Alaska and the Mackenzie Delta in Canada were under consideration, as were new import terminals for liquefied natural gas (LNG) in the United States and Mexico.

Unexpected growth in US oil and natural gas production, coupled with declining oil demand growth in the United States, has changed the entire landscape. The focus has now shifted to repurposing some of the infrastructure investments, made less than a decade ago, for export, not import, and shifting continental infrastructure to accommodate regional changes in supply.

The application of horizontal drilling and hydraulic fracturing in shale and other "tight" (very low permeability) formations in natural gas plays...
Oil Production: The United States

US crude oil production, led initially by the deepwater Gulf of Mexico, has increased steadily since 2005, thereby reversing a decline that began in 1986, from 5.2 million barrels per day (mmbpd) in 2005 to an average of 7.0 mmbpd at the end of 2012, the highest monthly production volume in 20 years. In 2012, Texas oil production reached its highest level since 1988, and North Dakota passed California and Alaska to become the second-biggest oil-producing state. Imports of crude oil fell below 8.5 mmbpd for the first time since 1997. The temporary moratorium on deepwater drilling in the aftermath of the BP oil spill in 2010 slowed activity into 2012.

Wood Mackenzie, one of the major industry analysts for the Gulf of Mexico region, issued a report in October 2012, predicting regional production would exceed 2009’s peak by 2018 or 2019 at 2 mmbpd of oil equivalent. The report describes the diversity of opportunities and the range of players in the US Gulf of Mexico as unique in the world, with such a wide range of prospects available from small, low-risk fields to giant targets in extreme conditions. Another province that could add to US production, the Arctic north of Alaska, was expected to see drilling start in 2013. By mutual agreement, the US government and private sector players are taking a timeout to ensure sound planning and execution in the harsher of remote frontiers.

US proved reserves of oil and natural gas for 2010 reflected the extent of new development. US proved oil reserves (which include crude oil and lease condensate) rose to 25.2 billion barrels in 2010, the highest volume since 1991. Natural gas proved reserves (estimated as "wet" natural gas, including natural gas plant liquids) increased to 317.6 trillion cubic feet (tcf), the first year US proved reserves for natural gas surpassed 300.0 tcf.

Over the next 10 years, continued development of tight oil, in combination with the ongoing development of offshore resources in the Gulf of Mexico, will push domestic crude oil production higher. Experience and technological advances are expected to continue to improve recovery rates, with production increasing through 2019. The step change in the US outlook is clearly reflected by the US Energy Information Administration (EIA) in its *Annual Energy Outlook 2013*, which raised the forecast for crude oil and lease condensate production in 2020 by more than 35 percent over that forecast in 2005.
Canadian Oil Production

The emergence of unconventional production as the dominant source of supply growth began in the Canadian Athabasca oil sands in Alberta. Canadian oil production in 2012 was just over 3.8 mmbpd, an increase of nearly 25 percent over 2005. Production from the oil sands, initially developed using conventional surface-mining techniques, is increasing from deeper fields, which are developed using steam drive in situ approaches. Canada has remaining oil reserves of 173 billion barrels, 98 percent of which are oil sands bitumen. According to the Oil and Gas Journal, Canada is in third place globally in terms of proved oil reserves, behind Saudi Arabia and Venezuela. Canada’s National Energy Board (NEB) expects the recognition of Saskatchewan reserves, coupled with new extraction technologies applied to the oil sands, will further increase Canadian reserves.

The NEB’s most recent assessment has forecast oil sands production to triple by 2035, increasing its share to 86 percent of Canada’s total oil supply, up from 54 percent currently. By 2035, Canadian crude oil production is expected to reach 6.0 mmbpd, or about double 2010 production rates. Both the NEB and the Canadian Energy Research Institute predict that the oil sands will be profitable for operators, as well as for the provincial and federal governments, at a price of about $90 per barrel (US currency) of West Texas Intermediate (WTI) in 2011.

Oil sands bitumen extraction is energy intensive and requires large volumes of natural gas as fuel and feedstock. In situ processing uses steam-assisted gravity drainage, which involves pumping steam underground to liquefy the bitumen and pump it to the surface. The majority of the growth is expected to occur in the in situ category; 80 percent of the oil sands reserves are considered well suited to in situ extraction, compared with 20 percent for mining methods. Even though the industry continues working on new technologies and efficiency enhancements to decrease the intensity of gas use over time, the NEB, in its update to the 2011 energy market assessment, projected natural gas requirements for the oil sands development to increase “from 0.7 billion cubic feet per day in 2005 to 2.1 billion cubic feet per day in 2015.”

Mexican Oil Production

Mexico is one of the 10 largest crude oil producers and net exporters in the world. Three-quarters of Mexico’s oil production occurs offshore in the Bay of Campeche of the Gulf of Mexico, over half from two heavy oil fields: Cantarell and Ku-Maloob-Zaap. These heavy “Maya” crudes are largely exported. The remaining quarter of current production is onshore, mainly in the states of Tabasco and Veracruz. The lighter crudes from the onshore fields are kept for domestic refining.

Mexican oil production has been steadily declining since peaking at 3.85 mmbpd in 2004 to 2.94 mmbpd in 2012. The EIA, in its International Energy Outlook 2011, noted that despite Mexico’s potential resources to support a long-term recovery in total production, the outlook was for continued production decline until 2025 in the absence of a dramatic change in the investment environment. Mexico’s state oil company, Petróleos Mexicanos (PEMEX), has two deepwater discoveries in the Gulf of Mexico near the US maritime border. The first was discovered in 2006 but is years from commercial development, given PEMEX’s lack of technical capability or financial means to develop projects so remote from infrastructure.

In contrast to the United States and Canada, where the sector is privatized with active investment by domestic and international companies, Mexico has just one oil operator in the country, PEMEX. Reforms have been enacted in recent years to bring in outside industry experts as advisers, to permit incentive-based service contracts with foreign companies, and to give PEMEX greater flexibility in procurement. In 2011, the first production licensing round in more than 70 years resulted in the award of three contracts to incentivize foreign service companies to increase production from some existing mature fields. The future of PEMEX and the oil sector in general was a major topic in the 2012 presidential election, which brought the Institutional Revolutionary Party (Partido Revolucionario Institucional, or PRI) back to power. Although the PRI’s support of labor was the rationale for creating PEMEX in 1938, the new president of Mexico, Enrique Peña Nieto, and his economic advisers talk of further reforms that could allow private investment to revitalize the sector.

Oil Market Adjustments, Transitions, and Politics

Until recently, most North American crude grades broadly tracked fluctuations in WTI Cushing prices. Pricing differentials were largely explained by the different quality characteristics of the crude oil in each location and transportation costs to Cushing, Oklahoma, the delivery point of the New York Mercantile Exchange contract, with lighter crudes capturing a pre-
mium. The rapid growth of lighter crudes from the Bakken and other tight formations in the mid-continent depressed their relative value. US refineries, especially those in the Gulf Coast, are among the most sophisticated in the world and optimize returns by running the heavier barrels that are less valuable to others; therefore, they are less willing to pay a premium for these lighter crudes.

Transportation constraints in the wake of rising production from fields in western Canada, North Dakota, and Texas are another factor affecting marketing of certain crudes. Limited pipeline capacity has both complicated the logistics and increased the cost of moving crude oil out of the mid-continent to refining centers in the Midwest and Gulf Coast. Rail shipments to East and West Coast refineries are viable alternatives.

Unlike the Bakken, the growth in oil sands was unforeseen, and pipeline expansions were planned to move that production to US refineries. In 2010, Enbridge, the Canadian oil pipeline company responsible for 65 percent of the exports to the United States, expanded its system into the Midwest by 450,000 barrels per day (bpd) with the option to expand to 800,000 bpd. At the same time, Enbridge built a parallel pipeline to transport lighter hydrocarbons back to Alberta for use as diluents to process the bitumen. TransCanada, the major Canadian natural gas transmission company, entered the crude oil transportation market with construction of the Keystone pipeline system. The main line from Alberta to Illinois with capacity of 435,000 bpd entered service in 2010; an additional leg to Cushing commenced operation in 2011, thereby increasing TransCanada’s total export capacity to 591,000 bpd.

Additional pipeline capacity to export the oil sands crude has run into major environmental opposition in the United States and within Canada. TransCanada’s proposed addition, Keystone XL, became a heated political issue in the 2012 US presidential campaign, with environmentalists on one side and energy security interests on the other. The future of the project, which requires a presidential permit for the border crossing, remains a key issue for the US environmental community, which is frustrated over the lack of action to address climate change. Two proposed pipeline projects from Alberta to Pacific ports in British Columbia—expansion of the Kinder Morgan Trans Mountain pipeline and Enbridge’s proposed Northern Gateway pipeline—also attract organized environmental and aboriginal opposition. Here the opposition is focused more on oil spills, both from pipelines and potentially from tanks, than on the greenhouse gas emissions associated with the oil sands development.

Within the United States, the unexpected increase in production has led to reversing the flows of existing liquid lines and repurposing sections of gas pipelines to move liquids. Railroads have been playing an increasingly important role in transporting US crude oil to refineries, especially oil production from North Dakota’s Bakken formation, where pipeline infrastructure is limited. As additional pipeline capacity that is currently under construction between Cushing and the Gulf of Mexico eases transportation bottlenecks, the downward pressure on mid-continent crude prices should lessen.

US crude oil imports during 2012 fell to the lowest level in 15 years, driven by the increase in domestic crude production, coupled with the growth in alternative transportation fuels required under the federal Renewable Fuels Standard. The decline in demand growth in the transportation sector has also been a significant factor. The economic downturn in 2008–09 had a temporary impact on demand growth, but imposition of three major vehicle fuel economy rules over the past decade and higher prices are having a sustained effect. The EIA has projected that net imports will decline to 32 percent of total consumption in the short term, before increasing to 37 percent as tight oil production begins to decline after 2020 (figure 15.2).

Refining and Products

During the 2000s, as US production declined to a low in 2005 and the average barrel of imported oil was growing heavier, US refiners—especially in the Gulf Coast region—invested in upgrading capacity. The result is that the US refining industry is the most technologically advanced in the world, albeit with variations across the different regions. In the United States, refineries have typically optimized production for finished motor gasoline to meet high US demand. This approach resulted in beneficial trading opportunities with Europe, where diesel was preferred to gasoline. In recent years, by fine-tuning the production mix, US refiners on the Gulf Coast have produced historically high volumes of distillate fuels (a category that includes both diesel fuel and heating oil) and motor gasoline.

The United States, in 2011, exported more petroleum products on an annual basis than it imported for the first time since 1949. This trend has continued as increasing foreign purchases of distillate fuel from South and Central American markets have added to European imports of US distillates.
Transportation Energy Consumption

After nearly two decades of stagnation, then decline, in US average vehicle efficiency, a series of three new standards for cars and light trucks under the CAFE (Corporate Average Fuel Economy) rules are having a notable effect on demand for refined products. The EIA's Annual Energy Outlook 2012 includes a scenario in which, by 2035, 80 percent of all light-duty vehicle sales that do not rely solely on a gasoline internal combustion engine for both motive and accessory power (including those that use diesel, alternative fuels, or hybrid electric systems) will meet higher fuel economy standards. Evidence exists of greater consumer acceptance and growing demand for more fuel-efficient vehicles, especially as auto manufacturers are including the interior upgrades that drivers have come to expect in new cars.

Natural Gas

Natural gas expansion has been largely a US story. In the past 40 years, the natural gas sector in the United States has oscillated between supply concerns and supply optimism. Enactment of the Power Plant and Industrial Fuel Use Act of 1978, which barred new construction of gas-fired generation, was a response to perceived scarcity. Once gas markets were restructured and commoditized, an “overbuild” of natural gas–fired electric power plants occurred in the 1990s, followed by the construction of LNG import facilities in the mid-2000s.

Now, the advances in drilling technology with the combination of horizontal drilling and hydraulic fracturing have propelled the United States into an age where domestic natural gas supply seems abundant. US production of natural gas increased 25 percent from 2000 to 2012 because of natural gas production from onshore resources and is now at record levels. Other contributing factors include improved site planning and field optimization, multiwell drilling from a single pad, rising associated natural gas production from oil plays, and improved drill-bit technology.

Of the natural gas consumed in the United States in 2012, about 94 percent was produced domestically. The availability of large quantities of shale gas is expected to enable the United States to produce more natural gas than it consumes. Onshore production growth is largely concentrated in shale plays, with production from the Haynesville shale in Louisiana and the Marcellus shale in Pennsylvania leading growth since 2007. Development of other shale resources, such as the Eagle Ford and Barnett plays in Texas and the Utica play in Ohio, is adding to natural gas production levels. The EIA's Annual Energy Outlook 2013 projects a 44 percent increase in US dry natural gas production, from 23.0 tcf in 2011 to 33.1 tcf in 2040.11 Almost all of this increase in domestic natural gas production is due to projected growth in shale gas production, which grows from 7.9 tcf in 2011 to 16.7 tcf in 2040.

Shale Gas Production

Although the prospects for shale gas production are promising, considerable uncertainty remains regarding the size and economics of this resource. Many shale formations, particularly the Marcellus, are so large that only a limited portion of the entire formation has been extensively tested for
production. Most of the shale gas wells have been drilled in the past few years, so uncertainty exists regarding their long-term productivity. Another uncertainty is the future development of well drilling and completion technology, which could substantially increase well productivity and reduce production costs.

From 1978 to 2003, over 20 percent of the US natural gas gross withdrawals came from offshore resources, largely in the Gulf of Mexico. As more domestic US natural gas production shifts from offshore fields in the Gulf of Mexico to onshore basins, potential natural gas supply disruption risks have shifted as well. The development of shale natural gas plays has created an indigenous supply of natural gas in areas of the United States that have historically relied on regional imports (either from other US producing areas or from foreign imports) to satisfy their natural gas demand. This is particularly true for production of natural gas in the Marcellus shale play, which is located near the major natural gas–consuming region in the Northeast. The development of the Marcellus shale has significantly affected the natural gas supply portfolio in the Northeast.

Northeast Gas Supply

Supply of natural gas to the Northeast traditionally came from Canada, the Gulf region, and the mid-continent producing areas. The completion of the Rockies Express pipeline (terminating in Ohio) in 2009 brought gas from the Rocky Mountains to the Northeast. Then, in 2010, significant regional production from the Marcellus shale play became available. These new supplies from the Rockies and from the Marcellus displaced both Canadian and LNG imports into the Northeast. Expansion of the Northeast pipeline infrastructure, targeted to ease congestion out of the Marcellus and surrounding areas, has placed additional pressure on traditional suppliers and has contributed to both the reversal of a Canadian import point and the expansion of capacity into the West and Midwest for Rockies pipelines.

Pipelines and LNG Terminals

The levels of natural gas imports and exports in the United States have shifted considerably with the growth in domestic production. US net imports of natural gas peaked in August 2007 at 10 billion cubic feet per day (bcf/d). By 2012, average US daily net imports—imports minus exports—were just over 4 bcf/d, the lowest level since 1990.

The decline was the result of a combination of a lower level of imports and a higher level of exports to eastern Canada and Mexico. In 2012, US natural gas imports via pipeline from Canada fell over 10 percent compared with the preceding five-year average. Although gross pipeline imports fell significantly, they still served as a marginal source of supply during times of high natural gas demand or when US pipelines were down for maintenance. For example, when Ruby pipeline, which moves gas from the Rocky Mountains to the West Coast, went offline in December 2011, imports from Canada to the United States rose to about 3.0 bcf/d, up from around 2.5 bcf/d earlier in the month.

LNG imports through US terminals peaked in 2007 at more than 2.1 bcf/d. Average daily deliveries to US LNG terminals were down over 60 percent in 2012 compared with the previous five-year average. Although there are eight LNG import terminals in the United States, two (Everett Marine Terminal in Massachusetts and Elba Island in Georgia) have been receiving the vast majority of LNG cargoes, largely to fulfill long-term contract obligations. Similar to the role of pipeline imports from Canada, Everett also serves as a marginal source of supply during cold snaps, when high prices in the Northeast could attract international cargoes. Higher natural gas prices in competing markets abroad are attracting “spot” LNG cargoes that can be delivered under flexible pricing terms. LNG cargoes have been diverted to take advantage of higher prices at other international markets, including the United Kingdom, Japan, and Belgium, where prices generally traded several dollars higher than at Henry Hub during the year.

US Natural Gas Exports

Although the decline of natural gas imports continues, US exports of natural gas to both Canada and Mexico have increased. Increasing use of natural gas in the oil sands in western Canada has created a market opportunity for US gas to move into eastern Canada. Much of the recent growth in natural gas exports to Canada has been for deliveries on US pipelines to natural gas storage facilities in Ontario.

Exports to Mexico averaged almost 1.7 bcf/d in 2012, nearly 70 percent greater than the preceding five-year average. Mexico has focused on expanding natural gas–fired power generation in the past several years,
and the country’s Federal Electricity Commission (Comisión Federal de Electricidad, or CFE) has called for additional natural gas-fired generation. In its outlook for 2006 to 2016, the CFE forecast increasing use of natural gas in the electric generation sector, as well as some growth in gas consumption in the industrial sector. These projected increases in demand came at a time of declining natural gas production from PEMEX. In 2011, PEMEX’s natural gas production declined 6 percent. Although Mexico has LNG import capacity, low prices have made importing US natural gas via pipeline an economically favorable option.

Both the CFE and PEMEX have proposed projects to expand Mexico’s natural gas pipeline system by approximately 40 percent, with an investment of more than $7 billion. To support the growth of Mexican natural gas consumption, the pipeline projects slated to come online between 2013 and 2018 will have a capacity of nearly 6 bcfd. These projects include three natural gas import pipeline projects that would increase the capacity for US natural gas imports by over 4.5 bcfd.

According to PEMEX, the southern region of the country contains the largest share of proved reserves. However, the northern region, with its shale gas deposits, likely will be the center of future reserves growth, because it contains almost 10 times as much probable and possible natural gas reserves as the southern region. PEMEX started its assessment of Mexico’s unconventional resources in 2010. The oil and natural gas assessment of shale basins resulted in a range of 150 to 459 tcf of technically recoverable resources, with a mean of 297 tcf. As of 2012, minimal test drilling had occurred in these areas. As Mexico considers the development of its own shale resources, the pace and extent of reforms will be critical to attracting expertise and capital. Even with reform, however, the availability of inexpensive US natural gas imports may hinder the development of Mexico’s shale gas.

Mexico may not be the only outlet for the abundance of US natural gas. The combination of high global prices and low US prices has led several companies to apply for permission to construct US LNG liquefaction facilities to export domestically produced natural gas. As of March 2013, the US Department of Energy’s Office of Fossil Energy has received 25 applications to export LNG with nearly 30 bcfd of proposed export capacity; only Sabine Pass in Louisiana and Freeport LNG in Texas have received authorization to export to both countries with which the United States has a free trade agreement and countries with which it does not. Sabine Pass already has signed several long-term export con-

tracts and plans to begin exporting LNG by 2016. Freeport LNG, which was granted a conditional authorization, also has several long-term contracts in place and plans to begin exporting LNG by 2017. Most of the proposed terminals are located at current LNG import facilities and are primarily in the Gulf Coast area.12

A combination of increasing natural gas production, a declining US export market, and relatively low natural gas prices has also strengthened Canada’s interest in exporting LNG to the world market. Four LNG export projects are planned in western Canada, and one facility is proposed in eastern Canada. Three facilities have received export licenses from Canadian regulators. The first, a 20-year export license, was granted to Kitimat LNG in 2011 and has a planned initial capacity of 700 million cubic feet per day. The location of the western Canada LNG export projects, close to higher-valued Asian markets, has an advantage over the proposed US LNG export projects, which are based along the Gulf Coast.

Although both Canada and the United States have regulatory and political hurdles to LNG exports, Canada also faces infrastructure challenges because, unlike most of the facilities proposed in the United States (which are at the site of existing LNG import terminals, connected to pipelines), Canada would have to build both liquefaction facilities and a pipeline connection to supply areas. Canada-based facilities, which may have to offer oil-indexed LNG prices because of higher investment costs, may be at a competitive disadvantage to facilities based in the United States, which have the prospect of LNG prices linked to Henry Hub.

Export as LNG is only one outlet for natural gas from booming domestic production. The resulting low natural gas price environment has opened the door to expanding domestic markets, which include natural gas-fired electric power generation, increased industrial activity, and natural gas as a vehicle fuel. In the immediate term, increased natural gas use for electric power generation has presented itself as the primary outlet for soaking up available natural gas.13

The increased use in natural gas-fired electricity has come at the expense of coal-fired electricity. In March 2012, amid historically low natural gas prices and the warmest March ever recorded in much of the United States, coal’s share of total net generation dropped to 34 percent—the lowest level since at least January 1973 (the earliest date for which monthly statistics exist). Despite seasonally low loads, natural gas-fired generation grew markedly and accounted for 30 percent of overall net generation by March 2012.
The decrease in coal use at electric power plants, combined with strong demand from Europe and Asia and relatively high international coal prices, boosted US coal exports to record-high levels in 2012. Total coal exports reached 126 million short tons, breaking the previous record level of 113 million short tons in 1981. Steam coal exports, which grew about 50 percent in both 2011 and 2012, accounted for 98 percent of the total export growth from 2011 to 2012.

Low carbon dioxide (CO₂) prices, relative natural gas and coal prices favoring coal, and the start of the nuclear phase-out in Germany prompted European electricity generators to use more coal. A series of weather- and labor-related international coal supply disruptions in 2011 and 2012 in major supply areas such as Australia, Indonesia, Colombia, and South Africa also drove European and Asian countries to import more coal from the United States.

More than half of US coal exports were to Europe in 2011 and 2012. Year on year from 2011 to 2012, exports to Europe increased by 12 million short tons, or 23 percent, exports to Asia increased by 5 million tons, or 18 percent. Most of the growth of exports to Asia has been driven by demand from China and India.

Impact on Regional CO₂ Emissions

As a result of increased natural gas use in the United States and increased coal use (particularly in Europe), regional emission levels have shifted. Natural gas has approximately one-half the carbon of coal. In 2012, US annual energy-related CO₂ emissions were at the lowest levels since 1994, at 5.3 billion metric tons. Several factors combined to produce this drop, including slower economic growth, weather, and changes in the prices of fuels, which played out differently in major economic sectors. US CO₂ emissions from coal were down 18 percent to 387 million metric tons in the period from January to March 2012, the lowest first quarter CO₂ emissions from coal since 1983 and the lowest for any quarter since April–June 1986. Energy-related CO₂ emissions have declined in the United States in four of the past five years.

The situation in the United States is markedly different from that in Asia and Europe, which saw an increase in CO₂ emissions in 2011 and 2012. This outcome is particularly remarkable for Europe, which has a region-wide climate policy. High natural gas prices combined with low CO₂ emissions prices contributed to this increase.

Policy Issues

Future prospects for North American energy self-sufficiency may depend more on political will than on resources. The political standoff in the United States and Canada over pipeline infrastructure to move large quantities of crude oil could slow production growth. Limits on US infrastructure to import Canadian crude could lead to higher imports of heavy crude from the Middle East or Venezuela to satisfy the US Gulf Coast refiner preferences. These substitutions might also negatively affect broader economic benefits, because a smaller share of import payments would be recycled in bilateral trade. Likewise, the ability of the new government in Mexico to implement constitutionally valid reforms in the petroleum sector will be the key to timely development of Mexican deepwater discoveries as well as replication of the US experience with shale resources.

The business model for much of the US Gulf Coast refinery complex is now focused on optimizing value from deep conversion of the world's heaviest crudes into light commercial products. Products are then sold to the highest-value market, increasingly throughout the Western Hemisphere. Although this model may make sense from a business perspective, it might also lead to pressure for the United States to allow exports of lighter crudes. Exports of crude oil would require congressional action. Such action would occur only after extensive analysis, fierce debate, and lobbying on all sides.

Similarly, US policy determinations on LNG gas exports to countries with which the United States does not have free trade agreements may affect US natural gas production. A study commissioned by the US Department of Energy recently concluded that the net benefits of LNG exports to the US economy were positive under all scenarios, that US prices did not migrate to world prices, and that market conditions were likely to limit US export volumes to a level far below the volumes that permit applicants are requesting (in aggregate). But the same report noted sectoral shifts in welfare effects, because wage earners paid modestly higher natural gas prices and resource owners earned modestly higher income. These trade-offs pose political complications for policy-makers. The question of whether to let the market decide the level of LNG exports or to impose limits through some formula or bureaucratic procedure is to be addressed in 2013.

This new abundance of oil and gas supply poses tradeoffs for policymakers that did not exist in the long period of relative resource scarcity. Exports of oil, gas, and petroleum products were then unimaginable, but
today they are either already happening or awaiting government approval. The income benefits from these high-value exports could support a weak economy, create new jobs, and improve the US trade balance. The geopolitical benefits of a more competitive natural gas market or increased hemispheric supplies of products or surplus light oil are potentially considerable. However, those concerned with environmental impacts challenge the net benefits of the production of oil and gas anywhere. Those who hope to increase petrochemical and manufacturing benefits dispute studies showing that domestic oil and gas prices will not increase appreciably and argue that more economic and job growth would occur in the absence of increased energy exports. The fault lines cross parties, regions, and industries—and bridging them will be a political and policy challenge of the first order.

Notes


2. *Proved reserves* reflect volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.


8. West Texas Intermediate, or WTI, is a grade of crude oil with relatively low density and sulfur content that is used as a benchmark in oil pricing and is the underlying commodity of the Chicago Mercantile Exchange’s oil futures contracts. Cushing, Oklahoma, is a major crude oil trading hub and has been the delivery and price settlement point for WTI on the New York Mercantile Exchange for more than three decades.


12. Exceptions include the Jordan Cove Energy Project, situated off the coast of Oregon, and the Dominion Cove Point facility, an existing import terminal located on the Chesapeake Bay, south of Baltimore, Maryland.

13. Average capacity factors for the US fleet of natural gas combined-cycle power plants have increased steadily since 2005. Increased use of these plants means that facilities that previously served peaking or, more often, intermediate load needs now contribute more significantly to base load electricity needs. Between 2005 and 2010, average capacity factors for natural gas plant operations between 10 p.m. and 6 a.m. rose from 26 percent to 32 percent. For peak hours—from 6 a.m. to 10 p.m.—capacity factors averaged about 50 percent on a national basis in 2010 compared to about 40 percent in 2005. Both the increasing domestic supply of natural gas and lower natural gas prices, together with the high efficiency of combined-cycle power plants, have contributed to the plants’ increased use.