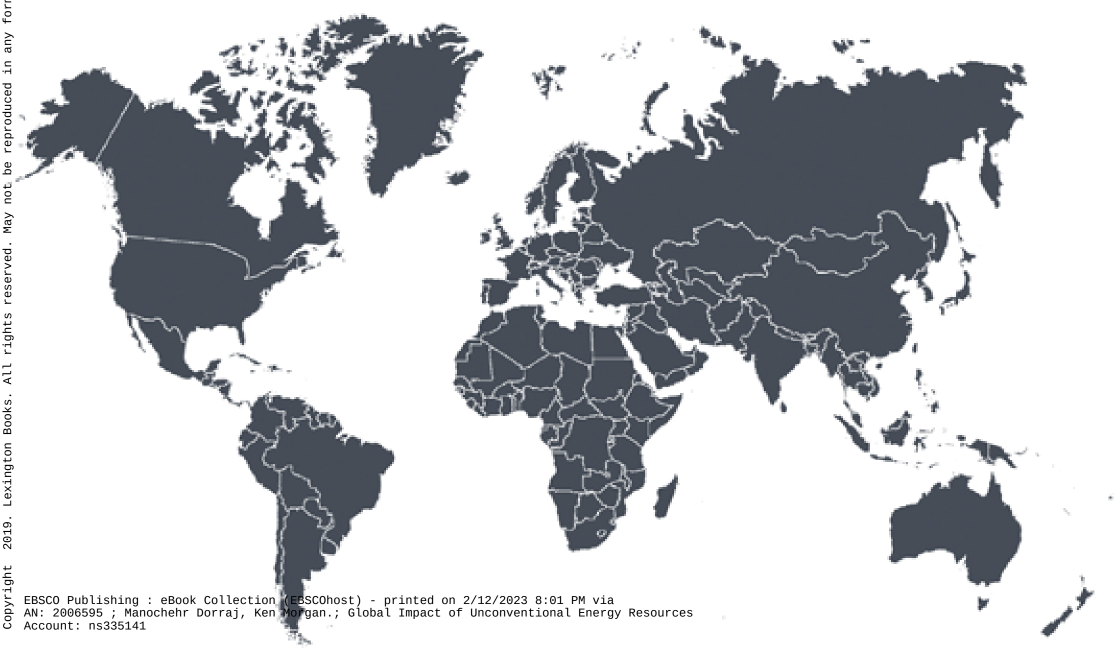
EDITED BY MANOCHEHR DORRAJ
AND KEN MORGAN

GLOBAL IMPACT OF UNCONVENTIONAL ENERGY RESOURCES



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Global Impact of Unconventional Energy Resources

Edited by
Manochehr Dorraj and Ken Morgan

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This publication contains a wide array of papers presented at the Global Impact of Unconventional Energy Resources Conference held by the Texas Christian University (TCU) Energy Institute September 21–22, 2015, at TCU in Fort Worth, Texas, United States. This timely and important event brought invited experts together from all over the world to address the current state of affairs and shed light on the future development of unconventional oil and gas resources from shale. The editors would like to express their gratitude to the contributors for their timely and thoughtful analysis and their cooperation in doing the necessary revisions. They would also like to thank TCU and our numerous sponsors for their support. We would like to recognize and thank the indispensable work of Veronica Merrill and Victoria Barth in organizing the conference and making it a great success. We would also like to express our appreciation for the assistance of Carlene Coover and Victoria Barth in preparing the manuscript for publication. Last, but not least, we would like to thank editors Joseph Parry and Jayanthi Chander for their stewardship of the project and editorial assistance to guide the manuscript through the publication process.

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Chapter 1

Global Impact of Unconventional Energy Resources

Manochehr Dorraj and Ken Morgan

INTRODUCTION

Some of the energy analysts project that by 2040 two billion more people would be living on the planet. The global economy would expand by 150 percent and the demand for electricity is going to rise by 90 percent and the overall energy demand is going to expand by 35 percent. Asia, led by China and India are going to be responsible for the lion's share of the rising global energy demand. About 60 percent of this escalating demand would be supplied by oil and natural gas, and natural gas is going to surpass coal as the second largest fuel source. This would contribute to lowering the levels of CO_2 emission.[1] Hence, the 2016 Organization of Petroleum Exporting Countries (OPEC) world outlook concludes that the world will need 109 million barrels per day (mbd) by 2040, an increase of more than 16 mbd is required not only to meet the rising demand, but also to compensate for the declining rate of production of old oil wells.[2] These statistics clearly indicate that we would need more energy in order to be able to respond to the increasing global demand and foster economic growth and prosperity around the world.

With the increasing demand, as the conventional sources of energy have steadily diminished, the search for unconventional resources began in earnest. The discovery of new sources of energy in the United States made possible by new technologies used in hydraulic fracturing and horizontal drilling in the last two decades has transformed the country from a net energy importer to a future natural gas exporter. This expanding demand for energy compelled US energy companies to look for new ways of accessing previously inaccessible sources of energy, thus ushering in a mad scramble for securing long-term energy supplies. With the discovery of gigantic "shale plays" and the resulting dramatic growth of domestic production of oil and gas,

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US companies are looking for even newer strategies for producing cheaper energy.

Hydraulic fracturing was first introduced in 1947, but it was not until mid-1950s that it gained acceptance as a viable method to extract shale gas. While the US department of energy invested $20–$30 annually between 1978 and 1981 to do research on improved method of gas extraction, the substantial exploration and development of shale gas did not materialize until 1990s. The US "shale revolution" found a new momentum in 1999 when Mitchel Energy and Devon Energy teamed up to successfully perform horizontal drilling and "water fracking" on the Barnett Shale just north of Fort Worth, Texas. This was followed by shales discoveries in Arkansas, Oklahoma, Kentucky, Pennsylvania, New York, Montana, North and South Dakota to just name a few. Developing new technologies, and using horizontal drilling and hydraulic fracturing opened up vast amounts of natural gas at first and then oil from shales, thus expanding the US national energy production substantially. Within a few years, the word was out that organic rich shales throughout the country, long thought to be only source rocks, were now considered to also be reservoirs for tremendous supplies of natural gas (Barnett, Haynesville, Eagle Ford, Marcelleus Shales, and others) and eventually for oil (e.g., The Eagle Ford and The Bakken) if maturation temperatures were right. From the Appalachians to the Rocky Mountains leasing and drilling for shale gas and oil resources were developed at a dramatic rate, mostly by small independent US energy companies.[3] Consequently, the production of oil in the United States sharply increased from around 300 million tons in 2008 to an estimated 500 million tons in 2013, whereas the production of gas expanded starting in 2005 and the output grew more than 40 percent in 2013 to around 670 million tons of oil equivalent.

The economic impact in the United States was immediate, the boom provided by the newly found oil and gas to some extent shielded the energy producing states from the great recession of 2008, touting the possibility that United States may be heading toward energy self-sufficiency between 2030 and 2040. By 2014, the United States overtook Saudi Arabia as the number one oil producer in the world with an output of 13 percent of global production versus the Saudi output of 12.9 percent and the Russian output of 11.41 percent, respectively.[4] Thanks in large part to "shale revolution," despite the plunging oil prices, by 2016, with a production level of 13.6 mbd, United States ranked as the number one producer of oil and condensates in the world.

Several critical factors contributed to this success: abundance of organic rich shales, rising oil and gas prices for a decade prior to 2014, rapid deployment of drilling rigs, development of "water fracking" technologies and the fact that many Americans held "mineral rights" below their properties. This created a "win-win" situation for both the drilling companies and the mineral

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owners (up to 25 percent royalties) that resulted in a very positive environment for leasing and drilling. In just over a decade, the United States became self-sufficient in natural gas supplies and significantly reduced oil imports. Chapters by Brogdon and Morgan in this volume chronicle these events that eventually led to the reentry to older mature basins such as the Midland Basin (Morgan) combining conventional and unconventional techniques by drilling into multiple producing horizons to capture even more oil and gas.

Overlaying all of these developments in the industry is the impact of social media groups that continue to point out their concerns related to drilling and fracking. Recent studies (Murphy and Yoxtheimer) point out the effectiveness of social media groups to influence local and regional decisions that have led to new regulations and even moratoriums on drilling in some areas of the United States.

Several energy industry leaders argue that the first half of the twenty-first century would be a "golden age" for natural gas. Demand for natural gas is expected to expand in all regions of the world. The global demand for natural gas is projected to increase by 50 percent around 2040. This is two times faster than rate of growth of oil.[5] Natural gas burns much cleaner than coal, emitting 60 percent less CO_2, and in the Paris environmental conference of 2015, in which 195 nations participated, many countries have pledged to reduce their carbon footprint. Therefore, the immediate future for natural gas seems promising. Thus, there would be a momentum to replace natural gas and renewables for coal as the source of electricity in many metropolitan areas in the world. Another factor that bodes well for the future of natural gas is that it is regarded by many within the industry and policy making circles as a "transitional energy" that would take us to the "green energy" of the future.[6] In fact, some reports indicate the energy giant Royal Dutch Shell is gradually shifting toward more environmentally friendly natural gas and is working toward creating a market for gas-fueled vehicles.[7]

Both of these developments within the forward-looking sector of the industry points out to the future viability of shale gas in the United States. According to the US Energy Information Agency (EIA), there are 7,299 trillion cubic feet (tcf) of technically recoverable "unconventional" shale gas reserves. The EIA estimates that the United States' share of shale oil amounts to 58 billion barrels, or 17 percent of the global deposits. This puts the United States in second place in the world. With the shale gas reserves of 665 tcf, or around 10 percent of the total global resources, the United States ranks fourth in the world.[8]

In fact, while until a decade ago United States' ability to supply for the domestic consumption in natural gas was negligible, by 2013, shale gas was responsible for about 50 percent of United States' domestic consumption of natural gas, and since 2009, United States has overtaken Russia as the

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number one producer of natural gas in the world. The major gas producers in the United States aspire to emerge as the main exporters of natural gas in the world in not too distant of a future.[9]

The success of the United States to tap into these new sources of energy previously regarded as inaccessible has generated great deal of interest in different parts of the world revolving around the question that if the American experience can be replicated elsewhere. Through a case study of different regions of the world, in this volume, we attempt to assess the extent of applicability of American experience to other countries and identify the impediments to development of shale oil and gas and other unconventional energy resources. To do this, the first part of the book is dedicated to a selective case study of the United States' experience in Texas and Pennsylvania. The second part of the book focuses on the global pursuit of unconventional energy resources.

The future viability of these fuel sources is contingent on a number of factors, including the economic and the environmental cost. In case of the United States, for example, where the cost of production of shale oil is estimated to range between $40 and $50 per barrel, in most cases, such ventures are profitable when the price of oil exceeds $50 per barrel. In the aftermath of the collapse of energy prices in 2014 many shale oil and gas companies have come up with new methods of cutting cost, including multilateral and pad drilling, as well as the consolidation within the industry; still in terms of cost of production US shale oil and gas producers operate at a disadvantage compared to their Saudi counterpart whose estimated cost of production is between $5 and $9 per barrel and still makes a good profit at $50 oil price level or below.

Oil prices dropped about 80 percent between mid-2014 through early 2016, going from $114 per barrel to $29 a barrel. A confluence of events converged to crash the price of oil. Perhaps the most significant factor was the United States' ability to produce massive amount of shale oil and gas alluded to earlier, that led to substantial increase in supply of oil and created a glut in the market. In this sense United States became a victim of its own success. The Saudi's ability as a "swing producer" to flood the market in order to diminish the power of non-OPEC producers with the hope of driving them out of the market—most significant among them, the United States—was arguably no less significant. The economic slowdown in China, a country that is the largest importer of oil in the world, also played a significant role in pushing down the prices. Many of the petroleum-exporting countries in OPEC, most notably among them Saudi Arabia and Venezuela, badly needing the flow of petro-dollar to keep their economies afloat, began to pump more oil, further saturating the market and pushing the prices even lower. In 2015, with the lifting of sanctions on Iran and the addition of its

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two million barrels of oil per day production to the market, the hopes for any immediate recovery of prices were further dashed.

This gloomy picture however, began to change when on November 30, 2016, OPEC members pledged in Vienna to reduce production by 1.2 mbd as of January 1, 2017. On December 10, 2016, the non-OPEC members, led by Russia, also pledged to reduce production by 60,000 mbd. This helped the prices to recover slightly—despite United States' refusal to cut back on its production—and reach the price of \$50–\$60 per barrel by December 2016.[10] The two lingering questions that determined if the 2016 price recovery was sustainable in future were as follows: First, how quickly can the cuts reduce the record production level of 3 billion barrels of oil in 2016? Second, how effectively the pledged production cuts can be implemented and monitored. The financial pinch in Riyadh and Moscow necessitated cooperation between these two energy giants in order to support upward swing of oil prices. To balance their budget, the Saudis needed to sell their oil about \$70 per barrel. To neutralize the negative impact of expanding Western sanctions on their economies, the Russian government also was eager to find ways to push up the price of oil beyond \$60. This convergence of economic interests convinced the two countries to cut back on their production levels further. By April 2018, this cooperation boosted the price of oil to the range of \$75 per barrel from the low of \$29 per barrel in 2014.

Clearly, should this upward swing of oil prices prove to be temporary, and if what lies ahead is a prolonged period of depressed prices, this would not bode well for the future of unconventional fuels in the short term. Already, the long-term impact of the downturn in oil prices has led many energy companies to opt for "shorter-cycle projects." About \$620 billion of projects through 2020 have been deferred or canceled. And enthusiasm for long-term investment has waned.[11] However, the cycles of booms and busts are prevalent in the energy markets. In due time, the profitability is likely to return to shale production as the cost-cutting initiatives discussed earlier would become institutionalized within the industry. In the December of 2017, US Shale industry selling the United Arab Emirates (UAE) 700,000 barrels of light domestic crude because UAE needed extra-light condensate to process in a unit known as splitter is a sign of things to come; the future for United States' shale oil and gas may not be as bleak as some observers project.[12] In fact, as the oil prices rebounded in 2018, the United States' sales of oil and refined gasoline abroad may begin to soar further.

A second concern in regard to the unconventional sources of energy surrounds the issue of balancing between our need for the additional supply of energy that the unconventional sources produce and the protection of the environment. Another factor that would determine the future viability of unconventional fuels globally is linked to viability of renewable sources

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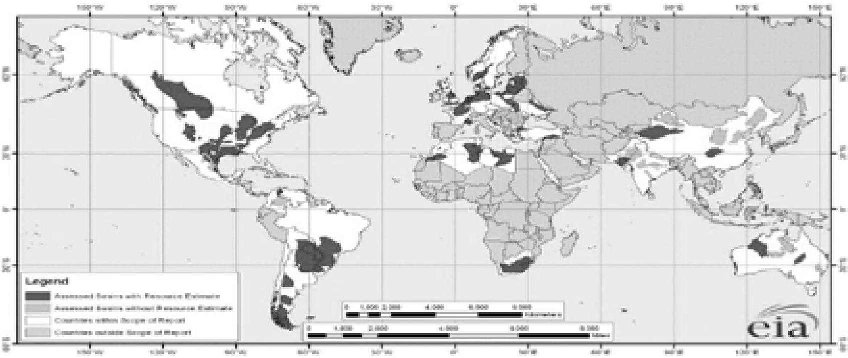

Figure 1.1 Map of Basins with Assessed Shale Oil and Shale Gas Formations, as of May 2013. *Source*: US Energy Information Administration (EIA), "Technically recoverable shale oil and shale gas resources: An assessment of 137 shale formations in 41 countries outside the United States," June 10, 2013.

of energy such as wind, solar, and hydraulic. Among other concerns with hydraulic fracturing are that it requires large amount of water supplies which is also needed as drinking water and for agricultural purposes. Closely associated with this is the disposal of the waste water and the impact of tremors and small earthquakes—that the critics often associate with hydraulic fracturing—on adjacent communities. Michael Slattery discusses some of these issues more elaborately in the final chapter of this book.

Unlike conventional energy resources, nearly 52 percent of which are located in the Middle East, unconventional shale oil and gas resources are scattered around the world, see Figure 1.1.

Figure 1.1 indicates that while these resources exist abundantly around the world, there are technological, financial, environmental, and political challenges that must be met to render them as the viable sources of energy in the near future. In this book we attempt to capture the nuances, the complexities and the future prospects for the exploration, development, and the economic and political impact of these unconventional resources in different parts of the world.

CONTRIBUTION OF THIS VOLUME

The nascent rise of unconventional fuels has generated a good deal of intellectual curiosity among academics, students, policy makers, the energy industry, and the environmentalists. As such, it is of great interest to a large and diverse audience. As an underinvested topic with great financial, political,

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and social impact, we believe, this volume takes a small step in filling the gap in the study of the subject at the global level.

While much has been written on the success the United States has experienced in the development of its shale oil and gas reserves, the research on the global pursuit of such sources of energy remains sparse and scattered. Our volume seeks to present the reader with a comprehensive account of development of these resources globally. As such, this study provides the reader with a comparative perspective that would enable them to situate the unique US experience in a broader global context and appreciate the limitations of reproducing it elsewhere in the immediate future. Our volume should also enable the readers to assess the economic and the environmental viability of these new sources of fuels and decide if this is a "flash in the pan" or the fuel source of the future with profound geostrategic impact.

If the promise of unconventional fuels materializes, it has the potential of changing the epicenter of global energy from the Middle East to America, with the United States becoming one of the most important actors in global energy picture. This is only one of the geostrategic impacts that would be discussed in this volume.

The chapters in this volume represent the latest thinking on the development and exploration of unconventional energy resources in the United States, Canada, Australia, Europe, Russia, Asia Pacific, Middle East, Latin America, and Africa and shed light on its potential and future prospects in these respective regions. The diversity of thinking about the "shale revolution" is also evident in our case studies. Throughout many countries in Europe for example, there is a strong preference for investment in renewable sources of energy over the fossil fuels. In addition to environmental concerns, the falling price of renewables, have also made them more attractive financially. Consequently, global investment in renewables is outpacing that of fossil fuel two to one.[13] Watching this trend, the Chinese government has pledged to invest $360 billion on renewable energy in 2017. This would make China the largest investor in development of renewables in the world. Other obstacles to development of shale oil and gas in other parts of the world include lack of adequate shale resources (Africa), the abundance of conventional energy resources (Middle East and North Africa), high cost of production (Russia, China, Japan), and political opposition to hydraulic fracturing (France and Poland). Despite these sentiments the economic imperatives (providing employment) also play a significant role—as Michael Slattery points out in his chapter—in determining the future prospects for unconventional energy resources globally.

For the sake of clarification, unconventional fuels refer to shale oil and gas, tight oil, sand tars, heavy oil, pre-salt oil and gas, deep water oil, methane hydrates (flammable ice), and so on. The authors of this volume have

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employed a combination of empirical analysis, utilizing the latest data (tables, charts, and graphs) and quantitative and qualitative analysis, to shed light on the current dynamics and the future prospects for these fuels with an eye on their economic and political impact.

SUMMARY OF CHAPTERS AND THE CONTENT OF THE BOOK

In chapter 1, Dorraj and Morgan introduce the major themes of the book. They discuss the larger issues surrounding the emergence and the development of unconventional energy resources and the factors that contribute to their current dynamics and the future viability.

In chapter 2, Larry Brogdan tells the reader the story of shale gas exploration in Texas, from its tentative beginnings to its success. As a geologist and an energy executive, Brogdan was intimately involved in the process of exploration and development of shale oil and gas in North Texas. He knows the key players and the challenges they faced, as such, he is particularly qualified to tell this story. As he reveals, it was small entrepreneurial oil and gas companies following the success of George Mitchell that ushered in the early unconventional Barnett Shale development, which in turn led to a "US Shale Revolution." Eventually, larger well-capitalized companies with qualified personnel and infrastructure acquired these assets and turned the play into gas farming operations. Lessons learned in the Barnett spread rapidly to other "shale gas plays" and eventually led to successful exploitation in the "oil window." A combination of digital technology, private ownership of minerals, and access to capital and incentive has led to a "Shale Revolution" that has brought employment and economic prosperity to many communities in the United States.

In chapter 3, Ken Morgan focuses on one of the older, well-known conventional producing basins and the use of the latest technological shale plays in the very large, historically prolific Midland Basin in West Texas. Re-entering an old, established oil and gas field to attempt new drilling strategies on not one, but multiple potential producing horizons is currently going on in a big way around Midland, Texas. This has opened up a whole new potential for using horizontal drilling and hydraulic fracturing into multiple "tight rocks," not just shales, for potential production. He examines this "game changer" for United States in production by looking at what is going on in a big way in the historic Midland Basin.

In chapter 4, Thomas Murphy and David Yoxtheimer argue that for ten years Marcellus shale has been an active geological target of energy companies that were looking at the new gas resource opportunities that were showing

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promise in numerous regions of North America. This "unconventional" shale development is located in what was then considered to be a largely played out area of the Appalachian basin of northeastern United States. Although the shale was known to have substantial quantities of natural gas embedded in the rock, the combination of technologies needed to extract it were only more recently showing the potential for commercial success. In late 2005, with large private ownership of minerals in the basin and an increasing wave in the leasing of oil and gas rights from landowners throughout the multistate region, the "shale gale" swept through these states and is still making its impact felt in a variety of significant ways.

With over 16 billion cubic feet of natural gas now being produced in a region where only a fraction of that was possible prior to 2005, the Marcellus shale transformed Pennsylvania from the being the tenth largest natural gas producing state in the United States to the second largest producer, only behind Texas, and the number one producer of shale gas in the United States, with over 20 percent of national production coming from Pennsylvania. Economic implications from new leasing and royalty incomes to landowners, government revenue generation, and substantial spending on public infrastructure fueled by this energy development activity have been very apparent, along with changing workforce patterns, business development, and housing constraints. Beyond those issues, there were and continue to be, an overlay of social implications inside communities influenced by shale development. Additionally, interest in environmental policy and oversight has sharply risen in the public dialogue. And in a parallel manner, the emergence of social media as a means of disseminating information and influencing the public debate has had great impact on the range of key issues tied to Marcellus shale development, from creating an expanded activist community, to steering local and state elections.

In chapter 5, Anas Alhajji focuses on the international impact of US "Shale Revolution." He contends that the shale revolution that reversed energy trends in the United States has also reshaped global energy landscape, not only in crude, but also in products and NGLs (Natural Gas Liquids). In fact, the refusal of Saudi Arabia in 2014–2015 to cut production and the consequent steep decline in oil prices reflects the deep impact of the US shale revolution on the international energy markets. Alhajji reviews energy trends in the United States and investigates the impact of the US shale revolution on the international energy markets. He concludes that the overlooked impact is as important as the visible impact, especially on the major oil-producing countries. The oil price war was not only about market share in crude, but about market share in all: crude, products, NGLs, and petrochemicals.

In chapter 6, Silke Popp illuminates the facets of unconventional oil and gas exploration and production in Canada, beginning with its history and

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subsequent development, discussing the current state of the industry and how it impacts and is impacted by policy, society, and the environment of Canada. Due to the complex techniques involved in the extraction and resource-intense development of shale oil and gas, the industry involves a large number of stakeholders, each having strong opinions about the right way to undertake development—if at all. These parties range from the business-minded executives to the die-hard environmentalists, and all the scientists, politicians, regulators, and everyday citizens in-between. Popp discusses and identifies the different voices in the debate, and details how they have each been impacted by unconventional oil and gas development, and how they have in turn influenced the development of policy governing the exploration and production of unconventional energy resources in Canada.

As Popp explains, Canada's regulatory scheme is split between the provincial and federal government, and in many ways the two bodies are still learning how to allocate responsibility and oversight of the unconventional oil and gas industry. Some provinces have a much longer history of conventional oil and gas production and are adapting existing regulation to unconventional production, while others lack conventional resources and historical production but hold vast deposits of unconventional oil and gas. This creates an opportunity for education, information, and governance to be shared among the provinces deciding to forge ahead with production. This chapter evaluates and discusses unconventional shale production within each province, and provides summaries of the most recent regulatory activity therein. It also analyzes policy and regulation on the federal level, while outlining the structure and oversight accorded to each governing body.

After addressing policy, Popp explores the everyday impacts of unconventional oil and gas development, which varies based on the unique resources that each province has to protect. From the pristine coastlines and vital watersheds to the towering Canadian Rockies and wide-open prairies, Canada's environmental resources are both breathtaking and unparalleled. Each province offers a unique resource that is critical to maintaining a healthy ecosystem, and as a result the potential impacts and applicable regulations can vary significantly from one locale to the next. Popp identifies the critical energy resources of each region, and address the existing and conceivable impacts of unconventional exploration and production in that context.

In chapter 7, Tina Hunter presents an analysis of origins and development of shale gas, shale oil and coal seam gas (CSG) in Australia. Outside of the United States, Australia has been one of the first countries to commercially develop its unconventional petroleum resources with the development of CSG reserves on the east coast of Australia (in Queensland). To date, Australia is the only country in the world to commercialize its CSG resources, and is poised to develop its massive shale gas reserves. The rapid commercial

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development of the CSG reserves on Australia's east coast exposed severe shortcomings in the legal framework regulating unconventional petroleum development. In particular, the legal regime was ill suited to regulate the environmental and technical aspects of CSG development, especially produced water and well integrity. In the early development of CSG resources, little attention was paid to technical (especially well integrity) and environmental concerns. In addition, the development of CSG in Queensland precipitated massive community concern regarding environmental impacts and damage to water resources, leading to the formation of such groups as Lock The Gate.

Hunter asserts that as a consequence of the development of CSG in eastern Australia, there has been much negativism toward the development of all forms of unconventional petroleum in Australia. Such negativism has prompted some regulators (such as Western Australia and the Northern Territory) to review its legal framework to ensure that it is capable of regulating all aspects of unconventional petroleum exploration and production. Other jurisdictions, such as South Australia, are reconsidering the existing legal regime capable of comprehensively regulating unconventional petroleum activity. Still others, such as New South Wales and Victoria, have seen a major public outcry at the very thought of unconventional petroleum development, particularly since the release of the movie, *Gasland* in 2010. Hunter also discusses the impact of unconventional fuel development on indigenous people and speculates on future prospects.

In chapter 8, Andreas Goldthau provides a comparative study of unconventional energy in Europe. He focuses on shale gas, which features most prominently in the European unconventional energy sector. The chapter features four selected country's case studies—Poland, Romania, Germany, and the United Kingdom. This selection covers Eastern Europe where gas supplies are firmly tied into geopolitics; the more competitive Western Europe gas market; as well as frontrunners (Poland and the UK) and laggards (Germany and Romania). Goldthau discusses the diversity of regulatory and policy choices related to unconventional gas in each country, sketches the environmental discussions and concerns, and offers some conclusions on the economic viability and the potential impact of unconventional energy in Europe.

In chapter 9, Tatiana Mitrova discusses the development of Shale oil and gas in Russia. She contends that Russia is in the very early stage of studying its shale gas reserves. The preliminary estimations on shale gas differ considerably, from 20 to 200 trillion cubic meters. There is no serious discussion in Russia concerning the future of shale gas in the country. Most experts, Gazprom and Russian Energy Ministry representatives, agree that shale gas production in Russia in the near future is not economically feasible as compared to various conventional gas projects.

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The situation with the shale oil is quite different—though in terms of the resource base there is similar uncertainty (total tight oil reserves in Russia have been put in the range of 15 billion to 1.05 trillion barrels), Russian companies are demonstrating strong interest in the development of these resources. Moreover, they are supported by the Ministry of Energy, which has already provided significant tax breaks, stimulating shale oil production. Nevertheless, future shale oil production in Russia faces numerous challenges: geological (which is quite different from the United States), technological (especially under the sanctions), economic (shale oil breakeven level in Russia currently exceeds $200 per barrel), regulatory (as the tax breaks given are still not sufficient for the profitable development of these resources and subsoil access is also quite restricted). Among other challenges are strongly concentrated corporate landscape and the lack of service companies (which increased further under sanctions). Taking into account all the limiting factors, it seems that Russia is unlikely to experience a shale revolution in tight oil similar to the one in the United States. Production will probably gradually materialize, but it will be years before it is a contributing factor to the output of any of the majors. The government's projections of over 400 kbpd (barrels per day) of tight oil by the end of the decade do not seem to be achievable under sanctions with the absence of international technologies and expertise.

In chapter 10, Isidor Morales Moreno analyses the nascent nonconventional hydrocarbon industry of Latin America, with a focus on the market, infrastructure, Policy, stakeholders, opportunities, and constraints. Argentina, Brazil, and Mexico possess the most prodigious unconventional shale and pre-salt energy resources. The three countries are ranked among the top ten nations with most of the technically recoverable shale oil/gas reserves, according to US EIA figures. From 2005 to the present, Brazil has been developing its huge potential of pre-salt oil and gas reserves. If the three countries become successful in developing their unconventional resource potential, they will converge with the energy revolution already underway in both Canada and the United States at the turn of this century, transforming the western hemisphere into an energy powerhouse with global economic and geopolitical consequences. However, though the three Latin American countries have leveled the playing field according to international standards, allowing private companies to operate and/or participate in upstream activities, their respective "unconventional" industries are still nascent, facing market, technology and infrastructure constraints, and demanding rapid and flexible policy environments in order to attract the right investors in order to develop their unconventional energy resources.

In chapter 11, Manochehr Dorraj expounds on the development of unconventional energy resources in China and Japan, two of the largest consumers of energy in the world. More specifically, Dorraj focuses on the development

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of shale gas in China—that its reserves are projected to be twice as much as the US— and the pursuit of massive deposits of methane hydrates (flammable ice) that is found off the coast of Japan. The current state of explorations, and the assets and liabilities of both nations, as well as the technological, financial, and environmental challenges to the development of these energy resources and their future viability and impact are assessed. Dorraj also discusses the success and failure scenarios in both countries and their impact on the global energy markets and their larger geostrategic implications.

In chapter 12, Bijan Khajehpour discusses the features of shale oil and gas development in the Middle East and North Africa (MENA). As Khajehpour observes, based on the latest data published in the British Petroleum (BP) Statistical Review of World Energy, the countries in the MENA region hold about 52 percent of the world's oil reserves with Saudi Arabia, Iran, and Iraq being the top reserve holders and Saudi Arabia, The UAE and Iran as top producers. The same group of countries produces about 34 percent of the world's crude oil output. In terms of natural gas, the MENA countries hold about 44 percent of the world's proven conventional reserves with Iran and Qatar holding the overwhelming majority of those resources and Algeria a distant third. According to the BP Statistical Review of World Energy, Iran now holds the world's largest natural gas reserves followed by Russia and Qatar. However, Iran's actual gas production corresponds to about 5 percent of the global production and its gas exports are negligible, though the country has recently become a net exporter of gas. The most significant gas exporter in the region is Qatar, which has positioned itself as a major producer of Liquefied Natural Gas (LNG), exporting it to international markets. Despite the overwhelming resource base, in the past few decades, the reserves of this region have been underutilized, mainly due to political upheavals, wars, regional uncertainties, and external sanctions. This trend is set to continue considering the existing sources of war and conflict and political instability in the region.

Another reason for underutilization of the actual potential has been the vast energy inefficiency in the entire region. Subsidized fuel prices have led to unsustainably high-energy consumption in all these countries so that a considerable amount of their primary energy production is used for domestic consumption. One important fact about the MENA region is that despite the availability of huge hydrocarbon reserves, the region as a whole is a net importer of natural gas. Iran, as the world's largest natural gas reserve holder, consumes almost its entire production domestically and Qatar's excess gas production potential is essentially needed by all the other markets in the Persian Gulf. In North Africa, Algeria remains an important gas exporter, especially to Europe, but Egypt has lost its capability to export gas and is now considering importing gas from an unlikely source, that is, Israel. This imbalance has compelled key energy producers in the region to look for

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alternative energy sources, including unconventional oil and gas production as well as renewable and nuclear technologies. Khajehpour investigates whether unconventional oil and gas production would be developed as a new source of energy in this region that still has abundant conventional resources. Rising domestic energy consumption and the growing significance of gas as a clean source of energy will certainly compel the respective governments to consider shale gas as an option to improve their overall energy balance. Nonetheless, the question remains whether the economic, environmental, and social costs associated with shale gas development will be regarded acceptable by these countries. Khajehpour analyzes the unfolding regional dynamics through a case study of Saudi Arabia, Iran, Algeria, and Morocco. The actual debates on shale gas development as well as plans and activities and the outlook for the future are discussed.

In chapter 13, Stefan Andreasson discusses the impact of US shale revolution on exploration and development of African unconventional energy resource. According to Andreasson, the US shale gas and oil revolution has had a significant impact on US energy imports from sub-Saharan Africa. Following the 9/11 terrorist attacks the assumption was that as much as 25 percent of US oil imports would come from West Africa as the United States sought to reduce its oil imports from the Middle East and diversify its sources of imports. Today those imports from Africa are rapidly dwindling as domestic US production is increasing. The rapid drop in oil and gas exports to the United States will have a significant economic and political impact on major African exporters like Nigeria and Angola and African exports will over the longer term be reoriented toward the emerging markets, in particular China. At the same time, new discoveries of oil and gas across sub-Saharan Africa will result in an increasing number of countries becoming significant energy producers and exporters. So far, however, African countries do not feature significantly in debates on the global expansion of unconventional fuels exploration and production. For instance, only South Africa is deemed to have significant and viable deposits of shale gas to exploit. This chapter reviews the current evidence regarding the prospects for unconventional energy exploration and production in Africa in the context of how the recent developments in the United States, as well as expectations of a proliferation of unconventional energy production worldwide, will impact African countries that are dependent on energy export revenues to finance their development.

In chapter 14, Michael Slattery presents an analysis of the environmental impact of the unconventional fuels, through the prism of the trade-offs involved in our need for the new sources of energy and the economic payoff versus the protection of the environment. Slattery examines the long-term sustainability of unconventional energy extraction. As he observes, from an economic standpoint, the shift toward energy independence, specifically in

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the United States, will rely heavily on unconventional oil and gas extraction but the environmental trade-offs are complex. For example, natural gas is, unequivocally, a greener alternative to coal, emitting about half the carbon emissions compared to coal on a unit-per-unit basis. Natural gas also emits far lesser air pollutants, such as mercury and sulfur dioxide. However, there are concerns over groundwater contamination by fracking and even louder opposition to the issue of water use and wastewater treatment. Similar issues apply to Alberta's Athabasca oil sands, estimated to contain about 170 billion barrels of economically recoverable oil. Extracting and refining the bitumen is a very labor- and resource-intensive process, requiring large volumes of water and natural gas. Critics argue the oil sands industry is wasting a relatively clean fuel (i.e., natural gas) to make one of the dirtiest, effectively turning "gold into lead." Studies have also shown that production from Canada's oil sands results in up to three times more greenhouse gas emissions per barrel (or barrel equivalent) on a "well to tank" basis. Critical boreal forest and wetland habitats, home to a diverse range of species, are being systematically destroyed by oil companies scraping thousands of acres to mine oil sands. On the other hand, business analysts estimate that oil sand related employment in Canada will increase by 300,000 jobs within the next decade. The issues surrounding extraction are thus complicated and difficult to summarize in a fair way for the public, especially when such economic impacts are taken into account.

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Chapter 2

The Miracle of the US Shale Experience

The History, Technology, People, and Infrastructure that Led to Success

Larry D. Brogdon

INTRODUCTION

The history of the rapid almost spontaneous phenomena of unconventional shale gas and later oil development had its origin literally under our feet here in the Fort Worth Basin. As small oil and gas operator's we never dreamed that the best projects we would ever be a part of were found under our neighborhoods, parks, schools, hospitals, churches, cemeteries, golf courses, business districts, highways, lakes, and rivers. As an example, Texas Christian University is probably the only university in the nation and perhaps the world that has a horizontal well that was drilled and now producing that traverses down the middle of the football field and terminates near the north goal post. As the birthplace of the unconventional shale revolution, Fort Worth and the surrounding municipalities and counties prospered economically, with low unemployment in spite of a deep national and worldwide recession.

The importance of George Mitchell, the father of the Barnett Shale play, and the larger independent companies that followed have often been told in books and magazine articles. The story not often told is the roll of the small entrepreneurial oil and gas businessmen that rapidly advanced the play. There was a confluence of factors' that led to a "Perfect Storm" that ignited this new approach to drilling and completion techniques. These factors include incentive, private ownership of mineral rights, Texas law, local politics, availability of capital, new technology, and commodity price appreciation.

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BRIEF HISTORY OF GEORGE MITCHELL AND MITCHELL ENERGY

George Mitchell was the son of Greek immigrants. He graduated from Texas A&M University with a degree in Petroleum Engineering in 1939 and started an oil company in the mid-1940s. In the early 1950s he drilled and completed his first wells in the Fort Worth Basin in Wise County, just north of Fort Worth. These wells required frack stimulation to produce from the Boonesville Bend Conglomerates, conventional reservoirs above the Barnett Shale. The Conglomerates stored the gas but it was sourced from the Barnett Shale below. The gas was initially sold to the local market. He eventually lured Natural Gas Pipeline to take the gas that would be delivered to the Chicago Market, but he had to deliver 100 MMCF of gas per day as per the contract to maintain a favorable price. By the late 1970s well deliveries were beginning to decline as depletion was taking its toll. He had to find a new source of gas or the company would eventually be in deep trouble. George instructed his geological staff to identify every potential gas-bearing zone in the Basin. They identified about twelve potential targets, one of which was the Barnett Shale. It was not at the top of the list.[1]

In 1981 Mitchell Energy began attempting completions in the Barnett Shale by recompleting and deepening existing wells and by doing expensive gelled chemical fracks and or CO2 fracks. One of the attractive characteristics of the Barnett Shale is that it is ubiquitous, that is, a well drilled deep enough in the Basin always encountered the Barnett Shale. There was no risk of missing the formation. Over a sixteen-year time span Mitchell had recompleted and drilled over 300 vertical wells in the Barnett Shale with little success. Many within the company thought the Barnett would drag the company to economic ruin. Then a young Mitchell engineer, Nick Steinsberger, suggested a frack design using mostly water and very little chemicals. Not only were the fracks significantly less costly, the wells performed better and became more economically viable. The key to the Barnett had been found. In addition the work of a Mitchell geologist, Kent Bowker, proved the Barnett stored 185 billion cubic feet (bcf) per square mile. By late 1999 the price of gas was trending up making the wells even more profitable. Mitchell Energy was being watch closely and many small operators were starting to make their move.

Independents

Many of the small independent oil and gas companies particularly those active in the Fort Worth Basin had suffered reservoir depletion from conventional zones above the Barnett Shale just like Mitchell Energy had. In addition, Mitchell had a better gas price by way of his contract with Natural

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Gas Pipeline and also had an additional revenue stream from their products plant in Bridgeport, Texas located in Wise County. It was very difficult to make ends meet with these disadvantages and it was struggle for survival. Most independents had to promote investors on a quarter working interest pays a third of the cost basis or by turnkey and drilling when leasing capital was not readily available.

Production from the Barnett Shale had been limited for the most part to a small portion of the Fort Worth Basin located in southeastern Wise County and Southwestern Denton County. The reason for this is fourfold. First, wells at this time were vertical drilled wells. In order to establish economic Barnett production a hard physical barrier above and below was needed to contain the frack to the shale. The Marble Falls Limestone above and the Viola limestone below were those barriers. Without these barriers the fracks tended to migrate upward or downward and penetrate water-bearing zones. In other words, the energy of the frack was not concentrating in the Barnett but was lost to non-productive or water-bearing zones below or above the Barnett. These areas in Wise and Denton Counties had the barriers in place, so up to this time had the only economic production in the gas play.

Secondly, the Rhome fault zone trending southwest to northeast was located in the south part of Wise County. Wells drilled and completed in the Barnett south of the faulted area were poor to nonproductive. The reason for the poor performance was that this area was so faulted and fractured that the Barnett could not be stimulated.

The third reason was that north of the good Barnett production the British Thermal Unit (BTU) content of the gas that measures the heat content of the fuel increased and the methane production decreased to the point where the wells economics were not as favorable based on the value of the various products at that point in time. It was also thought that the enlarged size of the molecules of propane, butane, ethane, and other products compared to the simple methane molecule made it very difficult the find their way through the very tight rock even after frack stimulation. This would later change as the price of methane dropped as opposed the other products.

The fourth reason was further south into Tarrant County, you began to encounter urbanization with houses, businesses, streets and highways, City Councils, and Planning and Zoning Committees—and all the infrastructure of towns and cities. Mitchell Energy initially avoided these areas, probably based on past litigation and the fact that they already held nearly 500,000 acres under production and term leasehold.

There are forty-one incorporated municipalities located in Tarrant County alone, none of which had an Oil and Gas Ordinance until Fort Worth adopted theirs in 2001. Mitchell played a major role in shaping the Fort Worth Ordinance along with other independent operators but there is no way Mitchell could handle the forty other towns with all the educating of drilling and

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completion practices, recognition of the laws of the State of Texas, field trips, education of City Engineers unfamiliar with oilfield practices, Railroad Commission permit requirements, pipeline construction rules, and many more complications. Prior to the Barnett Play there was no oil and gas production of any significance in the county and virtually no gas gathering pipeline infrastructure.[2]

Small independent operators began to lease land in northern Tarrant County in and near the incorporated portion of north Fort Worth and the towns of Haslet, Saginaw, Roanoke and the Fort Worth Alliance Airport and Commercial Center. Companies including Chief Oil and Gas, Four Sevens Oil and its partner Sinclair Oil Company, Hollis R. Sullivan, Western Production Company, Republic Energy, and many others too numerous to mention were now acquiring leasing positions. Leasing in the area was explosive but reasonable in bonus and royalty cost compared to later times and lots of work was done with the towns trying to obtain drilling permits. Results from vertical drilling and the new slick water fracks were working for the small independents just as they were for Mitchell Energy. Pipelines infrastructure was being built to market the gas. It was a dream come true for the small independents as it was for Mitchell Energy because you now could drill down to the source rocks, Barnett, and complete wells without the hit or miss risk with conventional reservoirs. No need for mapping structural highs or stratigraphic traps. Here was a play where you wanted no structure—you just had to stay away from major faults and karst areas below the Barnett. The perfect play as many of us saw it and it was right here under our feet the whole time. As Dick Lowe with Four Seven's put it, "It was like an airplane was flying over town and throwing out money and only a few of us were picking it up." The small independents reacted to the opportunity fast and the larger companies responded slower. It was obvious that a play like this could become like farming operations, covering large areas to harvest the gas.

In September of 2000, the first Barnett Shale Symposium was held at the Fort Worth Petroleum Club. An unexpected large crowd attended including representatives from Exxon, Texaco, Shell, Devon, and XTO, but most were small independents. There was an undercurrent of excitement that something new and different was happening and people wanted to know about it. The questions were, could this really be big? Was the play always going to be confined to areas where there were barriers above and below the Barnett to contain the fracks? After all, the Barnett Shale is found in over nineteen counties in the Fort Worth Basin. Could the play really be that big? These were the thoughts of the attendees at the conference. George Mitchell would not allow his staff to make presentations at the symposium as he didn't want to fuel more competition, but it didn't matter. The cat was out of the bag. In 2000 there were eighty-four Barnett completions by eleven operators.

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By 2001 there were 288 completions by 42 operators not including Mitchell Energy. The nimble and quick small operators were making the most of this opportunity.[3]

In January of 2002, Mitchell Energy merged with Devon Energy. Devon's management recognized that different technological applications would be required to move the play out of the developed areas (where there were barriers above and below the Barnett) and into higher-risk areas. In May of 2002, Devon filed their first horizontal permit and six others shortly thereafter. Three of the permitted horizontal wells were located in developed areas with good barriers. Four of the horizontal permits were located in areas with either a barrier above or below was absent. By April of 2003, all seven of the horizontal permitted wells had been drilled, completed, and put on production. The three wells in the developed area outperformed anything previously seen in the Barnett. Two wells in the higher-risk areas performed nearly as good and two were producing but poorer wells. The results were startling and changed the play from that point forward. Devon took strong security measures to keep the competition in the dark as to completion procedures and production results. But that proved very difficult with independents swarming the area for information. The entire gas community including oil and gas field hands, service companies, mineral owners, and operators were abuzz with excitement. By the end of 2003, there were 100 plus or minus horizontal wells permitted from 25 different operators not including Devon Energy. One horizontal well of note was drilled by Four Sevens, operating inside the city limits of Haslet, called the Brumbaugh #2. This well was a short lateral about 2,000 feet in length with a modest single stage frack stimulation and was put on production on November 1, 2003, at a rate of over 6 mcf of gas per day. It was the best well ever completed in the Barnett up to that time and showed the upside potential of drilling horizontally in the play.

Larger Independents were now taking notice of the potential of the Barnett Play and eager to get a position. In order for the small independents to fully develop their properties it would take an enormous amount of capital and people infrastructure. The price of natural gas was climbing significantly to the $5 and $6 range per mcf with peaks as high as $12. Nationally, import facilities were being permitted and planned due to under supply of the commodity. Lease bonuses were going through the roof. Exit strategies by the small independents to sell assets to the large independents were developing.

Looking back over time, the major transfer of assets took place during a five-year period from 2004 to early 2009 as the gas price continued to increase. XTO Energy and Chesapeake Energy were the major buyers taking out Chief Oil and Gas, Four Sevens Oil Company, Antero Resources, Hollis R. Sullivan, Hallwood Energy, and many other small companies too numerous to mention. Billions of dollars were transferred to those that were very

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early to the play and that took on the risks when they were very real. It was when the play turned into gas farming or harvesting projects that required significant human infrastructure and capital that the transfer of assets took place. It is also interesting to point out that several of the small operators sold out multiple times to multiple companies.

The service company sector was prospering also. Two brothers from Cisco, Texas who were brick masons started a hydraulic fracturing company called Frack Tech in 2002. After riding the rush of Shale Gas drilling for nearly a decade they sold the company for $3.5 billion dollars. Pumpco Energy Services, a well cementing and pressure pumping company sold in 2007. Other service sector companies were being born, such as water transport companies, food and janitorial services for rig and completion crews, independent directional drilling companies, pipe liners, and so on. Also, the local legal profession was booming as thousands of businesses and property owners needed legal representation. Land lease brokers and title analysts were in high demand. There were literally hundreds of small enterprises born supporting the Barnett shale play and jobs were plentiful, well-paying, and diverse.

Minerals Rights and Texas Law

Under Texas law, land ownership includes two distinct sets of rights, or "estates": the surface estate and mineral estate. Regardless of whether the mineral estate and surface estate are held by one owner or have been severed, Texas law holds that the mineral estate is dominant. This means that the owner of the mineral estate has the right to freely use the surface estate to the extent reasonably necessary for the exploration, development, and production of the oil and gas under the property.

Certainly private ownership of minerals and the right to develop them were key to the rapid development of the Barnett Shale play. Because there was no prior significant oil or gas production in the very urban Tarrant County, mineral ownership was not heavily severed. When property was sold from one party to another, the seller often did not retain any minerals because there never had been any production in the area. Most people had no idea that when they purchased their house they also purchased the minerals. The same went for churches, schools, hospitals, golf courses, municipalities, airports, shopping malls, and so on. The minerals ownership gave the owner "skin in the game." They could enjoy financial gain through Lease Bonus and Royalty Distributions.

This made it palatable to endure some surface development, truck traffic, and other inconveniences of drilling and completing wells. It became even more acceptable when multiple wells could be drilled horizontally from one well pad. Individuals could receive revenue from wells being drilled that they

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couldn't see or didn't know were being drilled. Financial gain is a powerful motivator. Field development in the urban area would have never been politically acceptable without private ownership of minerals. It would be hard to imagine that the Barnett Shale would have developed as quickly or at all had the minerals been retained by the Federal Government.

Texas Relinquishment Act

There is an interesting chapter in Texas History that may be of some interest to those from areas of the world where mineral ownership is retained for the benefit of their government. It's called the Texas Relinquishment Act.[4]

Texas won its independence from Mexico in 1836, and in 1845 it joined the United States as its twenty-eighth state. When Texas entered the Union it retained all of its public domain not already sold by Spain or Mexico to private citizens. When Texas became an independent nation, it recognized the titles of landowners who had acquired their lands by Spanish or Mexican grants, including the state's retention of mineral rights under those lands. Under the constitution of 1876, Texas set aside more than 42,500,000 acres of unsold land as "public free school land," and provided that the sales of those lands would be set aside in a permanent fund to finance the provision of schools in Texas. The constitution also provided that the State release to the owners of lands previously sold "all mines and mineral substances" under their lands. Therefore, Texas decided that, unlike Spain and Mexico, it would not retain title to minerals under lands it sold for settlement and development.

After 1895, Texas sold lands pursuant to various acts and under those acts the State classified the land before sale as either "grazing land," "minerals land," "agricultural land," or "timber land." Almost all lands not previously sold by the state by 1895 were in West Texas, and the State classified most of those lands as "mineral lands." If the lands were "mineral" classified, the statues provided that the State must retain all minerals when it was sold.

In the first few years of the twentieth century, Texas became the center of oil exploration, and many large oil fields were discovered by major companies and wildcatters. Those explorers applied to the State to obtain leases on lands in West Texas that the State had sold with mineral classifications. The statute governing such leasing provided that the surface owner would be paid ten cents per acre annually during the life of the lease as compensation for damages to the surface caused by oil exploration.

Landowners understandably were unhappy about this situation, and lobbied the Texas Legislature to change the law. In response, the Legislature passed what has become known as the Relinquishment Act of 1919. It purported to relinquish to the owners of the land the State's oil and gas rights

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in the land, retaining a 1/16th (.0625 percent) royalty interest for the state. This was challenged in the courts and in 1928 the Texas Supreme Court held that it made the landowners the agent of the State for the leasing of oil and gas rights, and granted to the landowner the right to one-half of all bonuses, royalties and other benefits accruing from those leases. In effect it made the landowner the holder of the leasing rights, but kept the mineral ownership in the state. Finally, in 1931 the Legislature passed a new sales act providing that, for sales thereafter of State lands, the State would retain only a 1/16th royalty.[5]

So, for sales of mineral-classified public free school land in Texas after 1895 but before 1931, the State owns the minerals under those lands, but the surface owner has the right to lease those lands and receive one-half of the bonus, royalty and other consideration payable by the oil company. The lease must be on a form approved by the General Land Office of the State and must be filed with and approved by the General Land Office.

Perhaps other countries without private ownership of minerals might consider adopting something similar to the Relinquishment Act to stimulate oil and gas activity, commerce, and jobs.

Technology

For those of us that have been in the oil and gas business for an extended period of time the technology advances over the past ten or fifteen years have been stunning. From rigs that walk from one location to another, to remote collection and analysis of real-time rig data, horizontal well steering software and technology, digital production data collection by satellite, to communication devices by cell phone, email, and now the Cloud. The recent disruption to the global oil supply and demand balance and the oversupply of natural gas in the United States is the result of the maturing and deployment of new technologies that enabled the economic production of oil and gas from shale. The likes of Bill Gates and Steve Jobs probably never envisioned playing such a part in hydrocarbon development, but the role of Silicon Valley may be as important as that of George Mitchell. Today the industry can drill as many wells and about the same footage with half the number of rigs we used just ten years ago. Drilling multiple wells from one pad site with the use of a "walking rig" has significantly contributed to rig productivity as well as lowering the environmental impact. Gains in rig productivity continue because of operational experience, application of higher pressures, more effective chemicals, and better spacing of multiple wells. The effectiveness of completions has greatly increased with changes in proppant concentration and mesh size and length of lateral. Initial production from wells have increased dramatically and production after the first three years has increased over 200 percent.

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In late 2008 and early 2009 when the huge surge of gas came to market from the Barnett Shale and other Shale plays, the price of natural gas nosedived to below $3 per mcf. Gas rig counts dropped but gas production continued rising and continues to rise to this day. This phenomenon is a testament to gains in rig and completion technology.[6]

Economic and Political Impact

The Fort Worth Chamber of Commerce engaged the Perryman Group to study the Economic and Fiscal Contributions of the Barnett shale. The results are stunning. They found that the region benefits since 2001 include $110.7 billion in gross product and 993,600 person-years of employment. Tax effects within the region have totaled about $4.5 billion to the local governments and more than $6 billion for the state.[7] They do not address the Federal Tax benefit. As our mayor at that time, Mike Moncrief, often stated, "We were the last to go into the great recession of 2008 and the first to come out of it because of the Barnett Shale." Similar results have been seen in the spread of unconventional plays throughout this country, most if not all of which are found in areas of private mineral ownership.

The country as a whole has benefited by reduced prices at the gasoline pump, very cheap, and huge reserves of natural gas, which allows the country to be very competitive worldwide. One-third of all jobs created after the recession were related to the oil and gas industry. Just how good has the fracking boom been to US manufactures? Very good. Thanks to the newfound abundance of domestic oil and gas, factories' energy costs have plummeted. US industrial electricity prices are now 30 percent to 50 percent lower than those of other major exporters. As a result, the average cost of manufacturing in the United States is now only 5 percent higher than in China. Job creation from this sector is significant.

From a political standpoint, the United States is in the enviable position to be energy independent if it has the will to do so. Energy security has been in doubt since the oil embargo in the 1970s. A more rapid conversion of truck fleets to compressed natural gas would be a positive step forward putting downward pressure on US oil demand. The US boost in domestic oil production has had a positive effect for consumers but has negatively affected oil and gas companies' bottom lines and forced more emphasis on efficiency. Additional pressure has been placed on Petro States to provide support for their citizens while enduring a lower oil price. Export of natural gas to Europe could lessen the threat of Russia shutting off gas deliveries as added leverage in disputes. I am sure George Mitchell never dreamed that the revolution he began in shale development would contribute so much to economic windfall and change in the political landscape.

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CONCLUSION

Why did the unconventional shale play happen so quickly in the United States? Well it didn't. It took George Mitchell and his staff seventeen years to make the Barnett economic. But once he did so, the small independent oil and gas entrepreneurs catapulted the play forward years ahead than if another path had been taken. Financial incentive, early recognition of the plays potential, quick decision making, and hunger for success all played a vital role. It cannot be over stated how important private ownership of minerals has been to the plays. Politically, it's too difficult to get things done if there is no direct benefit to the people where the activity is occurring.

The purpose of this narrative is not to provide a blue print or model for other countries and governments. It has been simply to tell the story of why the birth of unconventional shale development happened in this country and why it happened so quickly. Finally, a monument or statue should be erected on a highway coming into Fort Worth to honor George Mitchell for his vision, tenacity, and gift he has given to the people of this country and the world.

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Chapter 3

Midland, Texas

The Next Evolution in Shale Drilling Strategies

Ken Morgan

INTRODUCTION: THE GAME BEGINS

We are witnessing dramatic growth in energy demand from countries such as India, Brazil, and, of course, China just to name three. China is projected to become the largest energy user in a few short years passing both Europe and the United States in energy demand.[1] There are projections that the world will need an additional US equivalent amount of energy (100 quadrillion BTUs) by 2030.[2] Even with this additional energy production, almost one-third of the world will still be using biomass energy for cooking.[3] Just think about the entire continent of Africa and the potential for energy market need and growth.

With the discovery of gigantic "shale plays" in this country and the resulting dramatic growth of domestic supplies of oil and gas, maybe we have a real chance at swinging the energy game to our favor. Cheap energy has a way of winning over markets. As a geologist and professor I witnessed the amazing story of shale production right here near Fort Worth by the Mitchell Energy and Devon Energy teams over ten years ago. This great event was followed by several other domestic independent oil and gas companies (entrepreneurs) that developed the tremendous shales plays we know about in the United States today.

Certain realities exist in the global energy game:

- Energy and a lot of it is needed now and even more so for the future.
- Oil and gas continue to make up the majority of energy production.
- Shale plays have opened up vast opportunities for oil and gas production.

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- Cleaner Natural gas is more abundant now than ever before.
- Many countries have shales and the potential to reduce their imports.
- The United States can be a dominant global player for natural gas production.

Natural gas has a long history as a reliable fuel source for home heating, industrial manufacturing, and electrical generation. However, securing long-term supplies has always been tied to the discovery and development of conventional "oil and gas reservoirs" that over time became more difficult and expensive to find and often occurred in environmentally or politically sensitive areas throughout the world. For many years, there was very little interest in building "new markets" for the use of natural gas because long-term domestic supplies could not be guaranteed. Also, imported oil was relatively cheap, easy to get, and a well-developed refining and marketing infrastructure was in place. Everything has changed in the last few years.

Geologists have long known that the source for our known traditional oil and gas deposits was actually from deeper plankton-rich mud layers that, over geologic time, hardened into black shales. When these shale "source rocks" are subjected to heat and pressure that can transform the original organic matter into oil and natural gas that migrates upward into overlying "geologic traps" to form traditional major targets for drilling worldwide. For over 100 years, conventional thinking was that these "sourcing shales," which often still contain most of the original hydrocarbons, were too impermeable to ever produce commercial supplies of either oil or gas. As a result, shales were written off as "too tight" to be economic reservoirs. All that changed in 2002 near Fort Worth, Texas when two small independent producers (Mitchell Energy and Devon Energy) decided to drill horizontally and fracture the gas-rich but nonproductive Barnett Shale source rock. Their engineers pumped millions of gallons of water mixed with sand, under very high pressure down the drill hole. The "water-sand frack" hit the tight and brittle Barnett Shale like a hydraulic sledgehammer, freeing up tremendous amounts of stored natural gas.

Soon after 2002, relatively unknown entrepreneurial companies like Four Sevens, Dale Resources, and Chief Oil and Gas moved in aggressively to lease up acreage in and around Fort Worth, Texas. Other, now well know, independents such as XTO, Chesapeake, Devon, and EOG moved in and the race was on. In no time at all, the excitement of shale-gas exploration spilled out from the Barnett to the Fayetteville, Eagleford, Haynesville, and Marcellus shales contributing to the growth of even more companies such as Range Resources, Quicksilver Resources, Petrahawk Energy, Pioneer Resources, and now many others. By 2008, the industry was teeming with small to medium sized "domestic" companies sitting on vast amounts of

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"unconventional shale-gas" throughout the country and all jockeying for position in what became a rather stagnant natural gas market in a sagging economy. Throughout 2009 and 2010, the focus on natural gas began to build across the country. Even Congress began promoting cleaner energy sources in a more serious way. Americans, now more than ever, want to go "greener," reduce spending on imports, create more domestic jobs, and do something to reduce the national debt.

A big shot-in-the-arm for the natural gas business took place when a well-kept secret broke loose on in 2010. A really, really big company, that had been away for many years investing in foreign oil markets, made its way back into the domestic market for natural gas in this country as ExxonMobil announced the purchase XTO for a mere $41 billion! This was soon followed by Total (a French company) investing 2.5 billion with Chesapeake Energy in the Barnett. Quicksilver Resources also "partnered" with ENI (Italy) to expand their exploration efforts and Devon Energy garnered a larger exploration war chest by selling some of their offshore resources for $7.1 billion to British Petroleum.[4]

It is now obvious that global energy companies believe in unconventional shale deposits and potential markets in the United States This can be good news for the country and good news for the natural gas business. Let's not kid ourselves, their "investment" is a clear signal that the "majors," and other countries, want in on what will be a growing industry—US oil and gas. Imagine that, the major oil and gas companies are actually returning to the United States after more than forty years of focusing on foreign exploration.

While independents still control the playing field, there is a real chance now that, with some added resources from the majors thrown in, the natural gas industry and the country may benefit in a big way. Together, the independents and majors will want to develop new and expanded markets for the tremendous supplies of natural gas stored in shales throughout the country. These markets will include using more natural gas as a base fuel for electrical production, as a back-up fuel for wind and solar and now even more attention for compressed natural gas and liquefied natural gas as a transportation fuel. Just check out the commitments being implemented by AT&T, Waste Management, UPS, and taxi companies. Also take note of widespread diesel conversions being implemented for city and school system buses. Perhaps these activities are part of the reason why GM, Ford, and Chrysler are introduced "dual fuel" trucks and vans starting in 2011.

So, during the past seven years, George Mitchell turns the oil and gas industry upside down with the discovery of the Barnett Shale, which leads to giant shale-gas development in the country, followed by the need for new markets and industry jobs. Then to top it off, the return of ExxonMobil back

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to the United States which triggered other "majors" to get in on the action. For example, in 2010, Shell bought East Resources ($4.7 B) and Chevron acquired Atlas Energy ($4 B), both shale-gas drilling companies in the Marcelleus.

If that was not enough, in 2011, China National Offshore Oil Corporation (CNOOC) bought into both the Barnett Shale (Texas) and the Niobrara Shale (Colorado) with Chesapeake Energy. Then on January 3, 2012, the BBC announced that Sinopec, another Chinese oil company recently agreed to a $2.5 billion deal with Devon to help drill 125 new US shale-gas wells in 2012. They, of course, will be taking this technology back to their own vast shale deposits. Not to be outdone, Total (French) also announced a new agreement with Chesapeake and EnerVest for $2.3 billion.

These are just a few examples of how quickly the shale drilling business has changed in just a few short years. From Mitchell Energy and Devon Energy's first discovery, to the dramatic growth of independents to the majors stepping into the action and now the international energy companies buy seats at the "shale-gas table."

But all of this rapid development of shale plays in the United States has not been without concerns from some environmental groups.

Some of the biggest issues are as follows:

- Water Use and Recycling
- Size and Impacts of Fracking Operations
- Potential Methane Emissions
- Disposal Water Handling
- Occurrence of Seismic Events
- Well Casing and Cement Designs
- Impacts on Drinking Water

In June 2015, the US Environmental Protection Agency (EPA) released a draft report "Hydraulic Fracturing Drinking Water Assessment." This study looked at water acquisition, chemical mixing, well injection, flow back water, and water disposal. Driving this study is the fact that shales are often large in area coverage and that from 2000 to 2013 over 6,000 public water systems and nine million people lived within one mile of a "frack job."[5]

The following is taken directly from the EPA study findings (page ES-6).

From our assessment, we conclude there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water resources. These mechanisms include water withdrawal in times of, or in areas with, low water availability; spills of hydraulic fracturing fluids and produced water; fracturing directly into underground drinking water

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resources; below ground migration of liquids and gases; and inadequate treatment and discharge of wastewater.

We did not find evidence that these mechanisms have led to widespread, systematic impacts on drinking water resources in the United States. Of the potential mechanisms identified in this report, we found specific instances where one or mechanisms led to impacts on drinking water resources, including contamination of drinking water wells.[6]

FRACK QUAKES

Controversy exist on the causes of the increase in small-scale seismic events related to oil and gas production in the United States. Are these "quakes" due to fracking or something else? While this chapter is not an exhaustive listing of research articles on this issue, recent, credible, studies point to the likelihood that these sporadic seismic events are not due to fracking for production but more likely due to disposal wells for wastewater[7]. Studies and examples specifically point to those wells that pump the water into perhaps unmapped and unknown underlying faults located near disposal and injection sites. It certainly makes sense that high volume or high-pressure disposal of water can increase down-hole pore pressures and promote some measurable slippage along fault planes.

While most of these quakes have been relatively low energy events (2.0–4.0 Richter), perhaps better subsurface investigations and siting of disposal and injection wells along with more recycling could help alleviate the issue entirely. To address these issues in Texas, which has thousands of injection and disposal wells, the Texas Railroad Commission announced new regulations that began November 2014.[8]

There are four main components of the new regulations:

- "Applicants for disposal wells must conduct a search on the US Geological Survey seismic database to determine if there is a history of earthquakes within a one-hundred-square-mile area around the site of the proposed disposal well."
- "Clarify that the Commission will have the authority to suspend or terminate a disposal well permit if there is any indication from scientific data that seismic activity in the area could occur due to the disposal well."
- "Under the new regulations, disposal well operators will have to disclose annual reported volumes and pressures more frequently if the Commission determines that there is a need for the information."
- "The applicant of the disposal well will be required to provide information to the Commission to demonstrate that disposal fluids will be confined

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when the well is located in an area with conditions making the migration of fluids likely."[9]

Next on the list of reasonable solutions is to push harder for more wastewater recycling in the oil and gas producing states. Recycling, alternative pressurizing techniques and reducing water use in fracking operations would go a long way in creating a more positive perception by the public.

MIDLAND: THE WOLFBERRY TREND

Soon after Mitchell Energy and Devon Energy successfully water fracked the Barnett Shale. Smaller, unknown companies like Four Sevens, Dale Resources, and Chief Oil and Gas moved in aggressively to lease up acreage in Tarrant and Johnson Counties. In just a few years, these companies were then bought out by the now well-known independents such as XTO, Chesapeake, EOG, and others. In no time at all, the excitement spills out of Texas to the Fayetteville, Eagleford, Haynesville, and Marcellus contributing to the growth of even more companies such as Range Resources, Quicksilver, Petrahawk, and so on. By 2008–2010, the industry "energy pond" is just teeming with small- to medium-sized companies sitting on vast amounts of unconventional shale-gas throughout the country and all jockeying for position in a rather stagnant natural gas market, affordable oil imports and a sagging economy. At the same time, techniques are being developed to extract the big prize from the shales "oil." The northern part of the Barnet was already producing a mixture of oil and gas (particularly by Devon) but then the up dip "oil zone" is explored for in the Eagleford Shale. It was so prolific that in a short time, rigs moved from the less economical gas zones to the very profitable oil play in the Haynesville even with rapid decline curves . . . lots of wells . . . lots of production. Throw in oil production from the giant Bakken play (much less decline curves) and the United States gets back into the domestic oil producing business in a very big way. With near $100 oil and sure hits in the oil producing zones of vast shale deposits and then energy landscape, both for the United States and globally, begins to change. So, technology is developed to open up tremendous gas supplies in previously ignored shales, drilling techniques are tweaked to open up shale oil production. So much so that in short order, the world's biggest consumer of oil begins to emerge as one of the world's biggest oil and gas producers! The United States is now self-sufficient in natural gas and producing enough oil to cut deeply into exports. Could it really get any better?

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In 2011–2012 we began to get inquiries from companies to store core samples of rocks other than shales at our TCU Core Storage Facility. The core samples were from the well-known Sprayberry Formation out in the great but aging Permian Basin in west Texas. Throughout the 1950s, 1960s, and 1970s numerous attempts were made to ramp up production from some sands and siltstones in this rather shale formation. Many times, the production would start out pretty good but fall rapidly and quickly becoming uneconomic. Research showed lots of oil (and gas) but this "tight" formation just would not give it up without a fight . . . or new technological thinking. So for decades (even up through the 1990s), the vast Sprayberry, while tantalizingly large in potential, was just too often uneconomic with few successes because of low permeable (tight) rocks. Sound familiar?

Companies that had been successful exploring existing unconventional shale plays (the Barnett, Eagleford, Bakken etc.) began to look at the Wolfcamp Shale in the Permian Basin. The attraction to the Wolfcamp Shale is that it is rich in organics as a source rock and sits under the giant Sprayberry, a poorly producing reservoir. The Wolfcamp is really enticing as it has several rich zones within the formation (designated A, B, C, and D). Companies can focus on horizontal drilling in one or more "oil-rich zones" and can even go deeper to another unit, the Cline Shale. Don't forget, we have the Sprayberry just up hole with multiple opportunities too!

In essence, what we have in the Permian (Midland) Basin is a mature production area, wide open spaces, little urban interference, a community used to drilling and now are two or three large area source/reservoir "tight" rock layers stacked on top of each other. So, the thinking developed that why not apply the same unconventional drilling technologies used so effectively in other shale plays to both the Wolfcamp and the Sprayberry. Hence, the term "Wolfberry Trend" became the hottest drilling ticket for companies with enough resources to get in on this unconventional technology applied to a well know, traditionally drilled (vertical wells) oil and gas basin. The Midland Basin was ripe for aggressive land acquisition, pulling together drilling crews, tapping into existing infrastructure, and applying horizontal fracking technologies into multiple rocks and horizons. Some estimates say fifty billion recoverable barrels are at stake in the Wolfberry Play! A Giant by anyone's standards, due in large part by unconventional thinking in shales taken to a whole other level—into a mature traditionally drilled basin. As a matter of fact in January 2017, ExxonMobil announced the purchase of all the Bass Enterprise leases totaling $5.56 billion! Thus planting a giant flag back into US domestic exploration. This was followed with similar significant investments by Shell, Noble Energy, and Marathon Oil. Within six months, over $10 billion was pumped into the Midland area by several major oil and gas companies.

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The earlier development of the shales for gas about fifteen years ago has grown to include "oil from shales" and now to tight reservoir rocks above the prolific shales. From all indications, the "new Midland Basin" is a huge success for the industry as well as for the jobs and economy in an aging oil field area, Midland, Texas. As my friend and colleague, Larry Borgdon has said to his TCU class, Prospect to Production, "What was thought to be unconventional will eventually become conventional." The Midland Basin and the Wolfberry Play is a case in point.

No wonder there is so much interest in what might happen over the next few years given our nation's focus on finding more oil to offset imports along with also utilizing or selling abundant supplies of natural gas. We have begun to focus on the tremendous supplies of natural gas being found in the United States in both gas shales and now often associated with oil found in other tight rocks along with interest in vast amounts of gas hydrates stored in deep offshore ocean deposits. One thing is certain, in just over a decade, the United States has clearly emerged as "the" major shale-gas country in the world.[10] As a matter of fact, we have approved our first natural gas high seas exporting facility in Louisiana, Cheniere Energy, who should begin exporting by the end of 2015. This is occurring just as the Panama Canal is being enlarged to handle larger ocean vessels. As a matter of fact, a whole new area of "marine transportation" using cheaper and cleaner natural gas is getting serious attention by many shipping companies. We already export almost 3 billion cubic feet per day of natural gas to central Mexico by pipeline!

In the United States, we are noticing that major transportation companies are converting to natural gas vehicles to meet their local and long-haul trucking needs. UPS, GE, Ryder Trucking and many others have announced plans to move toward using natural gas because of its domestic, abundant, cleaner burning and appears to be a cheaper fuel long into the future. This clean and dependable fuel is making natural gas a favored leader in alternative fuels as companies "go greener." In Fort Worth, we have had natural gas buses for almost twenty years. All of our city buses use this cleaner alternative fuel rather than traditional diesel. DFW Airport has converted almost 60 percent of its tarmac vehicles to natural gas and wants to do more. Dallas, Texas recently voted to also convert its bus fleet over to natural gas.

To help promote more use of natural gas in region, we organized the North Texas Natural Gas Vehicle Consortium of 180 companies that helped promote the adoption of Senate Bill 20 in 2012. The focus of the bill was to create the Texas NGV Triangle to for infrastructure development. This bill funded a startup package of twenty new refueling stations and funding to convert 500 semi-tractor trucks to natural gas between DFW, San Antonio, and Houston. This route handles almost 10 percent of the United States'

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yearly trucking business. Private investors jumped into this expansion so that forty new stations have been built so far and almost 1,500 trucks were converted!

Interest has been so strong, that we recently launched The Texas Natural Gas Foundation (TXNG.ORG), a nonprofit organization to promote teacher education programs about the benefits uses of natural gas. Specific education curricula areas include transportation, home uses, railroads, marine, and manufacturing. Over time, we will provide free and easy access to facts and teaching exercises for K–12 teachers about the benefits of using more of our domestic natural gas or maybe even sell lots more to a very interested world.

CONCLUSION

Over the past year, the TCU Energy Institute has hosted over twenty countries interested in our country's successful development of shale drilling for oil and gas. They also wanted to know more about the issues we have faced across the country related to fracking, disposal, water use, and air emissions. These visiting countries have also shown a particular interest in the changing energy landscape now that the United States is potentially a much bigger player as we inch toward more energy independence. They recognize we are already self-sufficient with natural gas and take notice that US oil production continues to climb offsetting some substantial importing.

Remember, traditionally we have been the biggest oil buyer in the world. The question most often asked is "Will the US export its overabundance of natural gas in a big way and at a lower cost than current world prices?" The central theme seems to be, if we did there would be great global interest. As mentioned earlier, the United States is about to open its first exporting facility on the Gulf Coast of Louisiana as Cheniere Energy begins shipping natural gas later in 2015. If the United States does not develop internal market growth sufficient to use and stabilize domestic natural gas, many argue it's time to ship it to places that need this great fuel at fair market prices. There are, of course, arguments on both sides of this "use it or sell it" controversy. It seems that selling to new global markets would help stimulate more natural gas drilling and jobs here in the United States, provide a reliable clean energy source to our new market friends around the globe and help level the geopolitical playing field in many areas of the world.

Most believe the United States certainly has the potential to emerge as a global provider (seller) of at least natural gas. We should not forget that shales are not constrained to the United States, but are found throughout the world. Many countries are interested not only in a stable partnership using our domestic supplies but also in developing their own shales for both natural

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gas and oil (i.e., Japan, Poland, and China). Some OPEC countries may even have the luxury of exporting their oil and developing their shales for their own internal uses in transportation, heating, and manufacturing.

Another development that may affect greater use of natural gas in the United States is President Obama's announcement on August 3, 2015, through the US EPA, that electric utilities must reduce carbon emissions by 32 percent of 2005 levels by 2030! This will greatly impact coal use and possibly quicken the move to using even more domestic cleaner burning natural gas for electrical generation in the United States.

Time will tell how this all plays out especially given the predictions of global demand increases expected in the future from such areas as Asia, South America, and Africa. Realistically, how else are we going to even think about solving the problems related to predicted global energy growth needs, feeding another new billion people and helping economic development in developing nations unless we explore and develop the tremendous potential and benefits of natural gas?

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Chapter 4

Eastern US Shale Development

Implications for North America and Globally Involving Economic, Social License, Public Policy, Environmental Impacts, and the Influence of Social Media in These Issues

Thomas B. Murphy and David A. Yoxtheimer

INTRODUCTION

Since 2004, Marcellus shale has been an active geological target of energy companies that were looking at the new gas resource opportunities showing promise in numerous regions of North America. This "unconventional" shale development is located in what was then considered to be a largely played out area of the Appalachian basin of Northeastern United States. And although the shale was known to have substantial quantities of natural gas embedded in the rock, the combination of technologies needed to extract it were only more recently showing the potential of commercial success. In late 2004, with largely private ownership of minerals in the basin and an increasing wave of leasing the oil and gas rights from landowners throughout the multistate region, the "shale gale" sweep through these states and is still making its impact felt in a variety of significant ways.

With over twenty-one billion cubic feet per day (bcf/d) of natural gas now being produced in a region where only a fraction of that was possible in previous conventional gas resource exploration, the Marcellus shale transformed Pennsylvania from the number ten natural gas producing state in the United States, to the second largest producer, only behind Texas, and the number one producer of shale gas in the United States, with over 24 percent of national production coming from Marcellus. Economic implications from new leasing and royalty incomes to landowners, government revenue generation, and

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substantial spending on public infrastructure fueled by this energy development activity have been very apparent, along with changing workforce patterns, business development, and housing constraints. Natural gas utilization in power generation, expansion of petrochemical capacity, and liquefied natural gas (LNG) exports are now largely driven in the United States by large increases in shale gas production. Beyond those issues, there were, and continue to be, an overlay of social implications inside communities influenced by shale development. Additionally, interest in environmental policy and oversight have sharply risen in the public dialogue. And in a parallel manner, the emergence of social media as a means of disseminating information and influencing the public debate has had great impact on the range of key issues tied to Marcellus shale development, from creating an expanded activist community, to steering local and state elections.

BACKGROUND OF SHALE GAS DEVELOPMENT IN THE EASTERN UNITED STATES

The advent of the shale gas rush in the Appalachian basin of the eastern United States was based in a large part, on successes to that point which occurred in the gulf states of the United States, most notably the Barnett shale located near Fort Worth, TX. Commonalities in geology, matched to first generation shale gas extraction technologies, led first movers to take strong lease positions in the Marcellus region. Just prior to this move, a small handful of companies were drilling into the deeper Trent Black River limestone formation with limited successes in NY and PA, and typically less than a 50 percent probability of establishing a commercially viable well.

Building oil and gas industry confidence in producing natural gas from the shale source rock, and later oil as well, in more distant states encouraged risk taking and eventual early well development in PA, OH, and WV. Initial shale gas wells were vertical and commonly drilled on single pads. Although the norm in the years prior to 2006, this trend changed with the advances that were being made to adapt directional drilling to shale development. This combined with evolving well stimulation techniques that used larger volumes of water, proppant (generally sand), and better matched chemicals, allowed the shift from common vertical drilling to a horizontal format. And with that sift there was also a move to multi-well drilling pads, as companies were now able to reach further from a single pad in extracting the energy resource. This lowered the cost of producing the gas, increased the volumes per capital invested, and further attracted attention, both in North America and globally, that shale was emerging as an attractive opportunity and one that could have historic implications as an energy resource.[1]

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This growing acknowledgement in the O&G industry helped fuel the search for additional shale resources in the United States, Canada, and globally which could have similar expectation of outcome. With proximity to the largest energy demand center of Northeast United States and eastern Canada, along with the sizable geographical extent of the shale, Marcellus was seen as a rising star in the energy profile of the country overall. This new resource was viewed, at least initially, even more positively in the energy deficient metropolitan areas from Washington DC, north through New York City and Boston.

Historically the premium market for natural gas was this same region of the United States and Canada with supplies commonly moving from the Gulf of Mexico, the Rockies, and western Canada to demand centers north and east.[2] Decades of transmission pipeline investment in new capacity, confirms this trend. With natural gas priced at the Henry Hub market in Louisiana, the premium paid in the Northeast normally had a basis change differential of $1.00–$1.50 over Henry Hub. And along with the demand for cheaper gas moved by pipeline, there was limited (but sizable) investment made to enhance capacity through the construction of strategically located LNG import facilities.

The search for other shale energy reserves in the continental United States led to numerous locations that advanced overall domestic supply. Most notably where the Haynesville in LA, the Bakken in ND, the Eagle Ford in TX, the Utica of OH, and the Niobrara of CO (Figure 4.1). Along with the expanding production of the Marcellus and Barnett, these new resources continue to contribute the bulk of new US production along with more recent volumes surging from the Permian of west TX.

Early shale gas production was based on the Barnett shale model of development from drilling and hydraulic fracturing to waste fluid disposal and overall regulation. The successes of the companies working in that region of TX, transferability of below ground technologies, the availability of a large pool of drill rigs and frack sets with experienced crews, and companies looking to expand into frontier shale regions before others leased prime acreage, drove the process ahead quickly. Wall Street rapidly seized on the opportunity and made large amounts of needed capital available to finance the risk of drilling wells in areas where there was no legacy of commercial shale energy production.

APPALACHIAN SHALE PRODUCTION TRENDS

Drilling and completion of wells in the Appalachian basin was slow to start with the first shale gas well credited to Range Resources in 2004 in the southwest region of the state near Pittsburgh. Followed quickly by another

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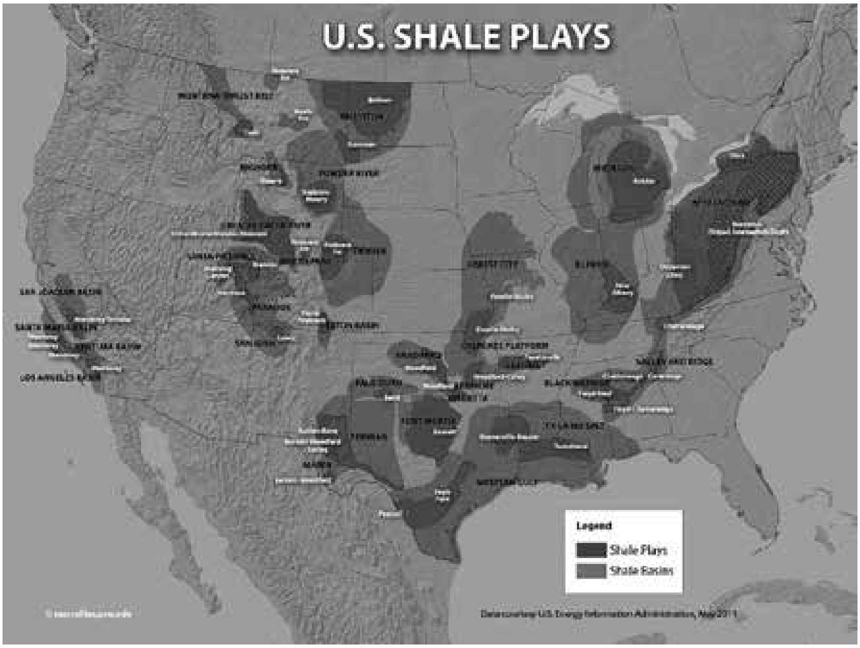

Figure 4.1 Shale Gas Resources of the Continental United States. *Source*: US Energy Information Administration, May 2011.

to confirm their earliest finds, Range moved next to drill north of Williamsport, PA in the north-central portion of the state in 2006. Other independent O&G companies were also building a parallel inventory of leases including in the entire northern tier of the state that went on to be the most drilled and productive Marcellus geology of the state. Of the top six early producing counties of the Marcellus footprint, all were in PA and included Susquehanna, Bradford, Lycoming, and Tioga in the northern tier and Greene and Washington Counties in the southwest.[3] Although Marcellus shale underlies two-thirds of PA, these six counties have continually constituted over 75 percent of all the shale gas and natural gas liquids (NGLs) produced in PA.

Through the end of June 2015, state government agencies in the tristate area of PA/WV/OH charged with regulating new shale wells, indicated over 14,600 wells had been permitted and at the minimum, spudded, with almost 65 percent completed and commercially producing gas[4] (Figure 4.2). This includes over 9,600 Marcellus wells in PA, the largest producer to date of shale energy in the Appalachian basin. The pace of development essentially doubled year on year from 2004 to 2013, until the market price of gas went through a strong enough decline that drilling substantially slowed.

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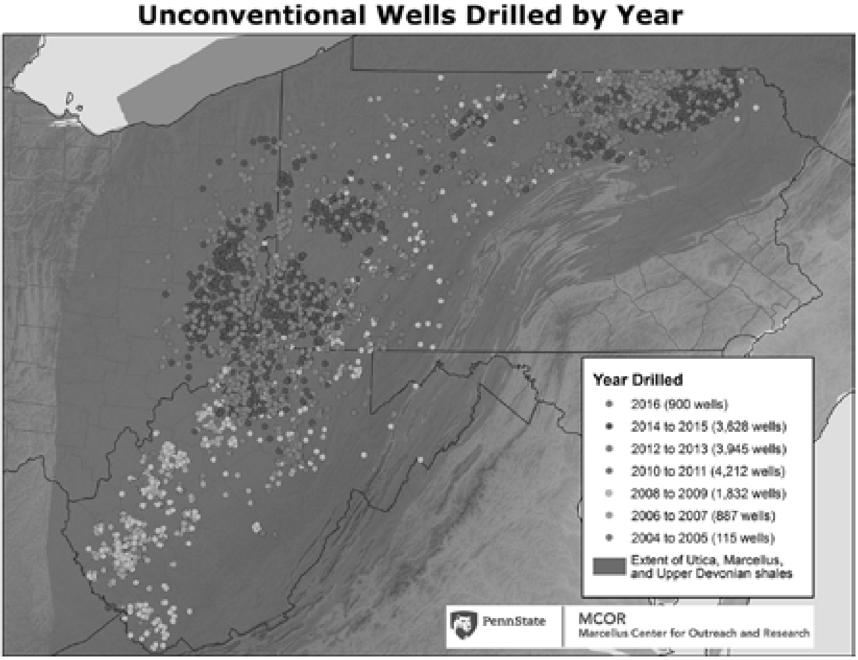

Figure 4.2 Map of Unconventional Shale Wells (primarily Marcellus and Utica) Drilled in Ohio, West Virginia, and Pennsylvania. *Source*: Penn State, Marcellus Center for Outreach and Research, (2016).

And although the bulk of the Appalachian shale wells were drilled into the Marcellus as the target, there were also a number of wells drilled into the Utica and some of the more promising upper Devonian shale group including the Burkett and Geneseo which were showing significant gas volumes as well. This includes the over 2,000 Utica wells now drilled in OH.[5]

With more than an estimated 300,000 gas wells drilled in PA since the mid-1800s, the more recent history of the state places it as a low overall producer of natural gas, with a 10th place national ranking in 2008. Most all of these historically were conventional wells drilled commonly into shallow sandstone formations that produced low volumes of low pressure gas (less than 100 mcf/d at under 150 psi) for extended periods of time normally measured in decades. This changed with the advent of shale gas wells which commonly produce volumes exceeding 5–10 mmcf/d at 600 or greater psi with some over 5,000 psi. For comparison, transmission pipelines carry gas to a maximum of 1,050 psi on most mainlines.[6] All of this pushed PA, which had become a net import state to exporter status in mid-2011 (Figure 4.3).

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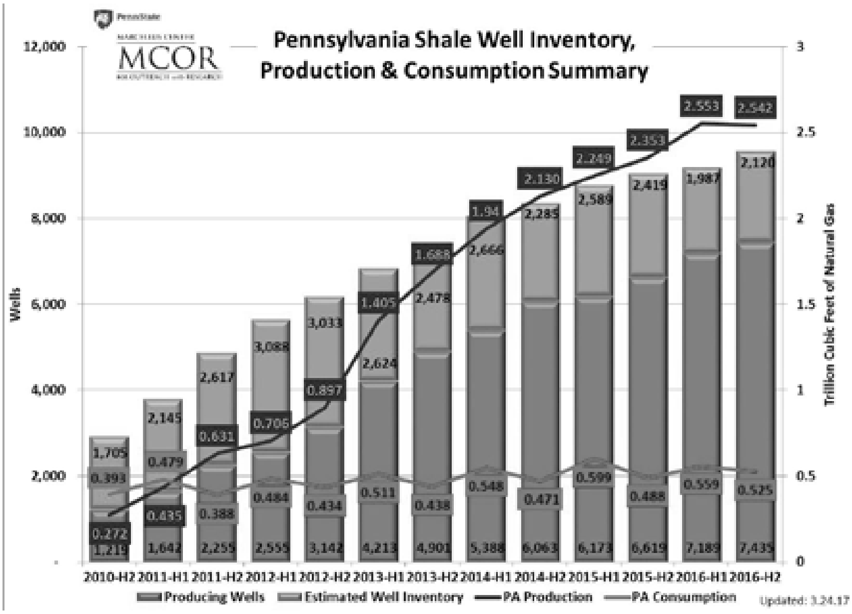

Figure 4.3 Number of Unconventional Wells Drilled and Resulting Production for Pennsylvania. *Source*: Penn State University Marcellus Center for Outreach and Research, (March 24, 2017).

Company expectations for early wells drilled in Marcellus were in the 2–4 mmcf/d range. Due to new drilling and completion techniques, companies are now producing the majority of their wells with initial production (IPs) rates in the low double digits. Decline curves plotted with over 4,000 Marcellus wells indicate these are not necessarily sustained yields but do contribute to the large volumes of gas that have been part of the recent EIA assessment that 85 percent of new production is originating from Appalachian shale resources compared to production of other US shale resources[7] (Figure 4.4).

The original estimate by US Geological Survey (USGS) for the Marcellus was approximately 2 tcf of gas.[8] At the same time, Terry Engelder, a geologist and researcher at Penn State University was predicting this particular shale resource could contain up to 500 tcf of gas.[9] Over time, government and industry forecasts have risen as more drilling was conducted and better assessments were made using actual shale rock core pulled during drilling. To date, over 19 tcf of Marcellus has been produced with over 5 tcf in 2016 alone. O&G company estimates would have Pennsylvania's portion of the Marcellus at approximately 15 percent drilled, indicating the higher estimate by Engelder is technically plausible and that is without accounting for advances in technologies.

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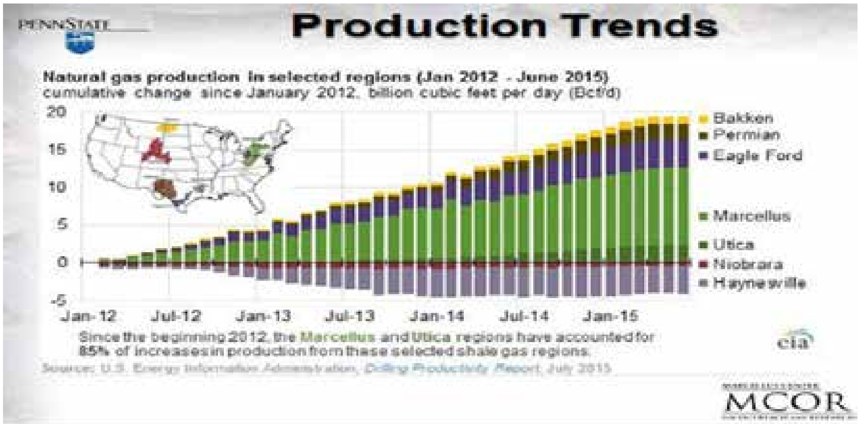

Figure 4.4 Shale Resource Production Trends in the United States. *Source*: US Energy Information Administration, Drilling Productivity Report, July 2015.

When viewed in total, the production from the US eclipses the global effort by a considerable margin due largely to availability of capital, ease of acquiring rigs, and talent, a substantial transmission infrastructure, largely favorable regulatory environment, and the private ownership of minerals. And mineral ownership is credited by many as being one of the key drivers of development success due to making a "social license" from the community more easily attainable.

Other countries with significant commercial shale energy production include western Canada, Argentina's Neuquen Province, and China. Of the group, Argentina is seen as the most likely to advance quickly due to easier geologic hurdles to surmount, the availability of drilling and service companies already in the region, and strong market and governmental incentives to produce. Poland has drilled over sixty-five shale wells but continues to see an exodus of experienced companies due to complexities of the underground resource and regulatory/taxation issues that have been slow to resolve. There are large numbers of other countries also looking at shale energy production but they are in the very early stages and have not made the leap from exploratory to commercial production.

WATER RESOURCES AND ENVIRONMENTAL ISSUES ASSOCIATED WITH SHALE GAS DEVELOPMENT

Although not seen as a major concern by many during the early years of shale gas drilling in eastern shales, environmental issues, particularly the short and

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long-term impact to groundwater, became a key concern of many stakeholders after observing the leading edge of the drilling process they were not accustomed to experiencing in their communities. As with any type of energy development, there are associated environmental risks to manage. Baseline testing of individual drinking water supplies, followed by assessing entire watersheds, became more common over time to spot potential impacts, which state and Federal regulators indicated to be minimal. Whereas the concern most often expressed has been migration of frack fluids from depth, the more common occurrence has been methane migration associated with wellbore integrity issues (twenty shale wells in PA) and surface spills of fluids.[10]

Studies done in areas of the Marcellus shale play indicated methane migration can impact nearby drinking wells, with over 200 identified in one review of the state regulators files. Closer analysis continues to advance to identify the drinking water wells impacted by naturally occurring methane vs. that sourced from nearby shale gas wells. Overall, in PA, a Penn State study in 2007 indicated over 22 percent of the state's 1.2 million private water wells had detectable levels of methane prior to the onset of shale drilling. In Susquehanna County, a more recent USGS study found up to 80 percent of water wells had preexisting methane impacts that could be geographically predicted when contrasting glacial alluvium in valleys with more consistent geology in nearby ridgetops.[11]

These trends continue to advance the call to evolve state environmental regulations dealing with water, acknowledging the new realities of shale gas, and offer greater transparency to stakeholders interested in monitoring the outcomes. This has also extended to the now routine predrill baseline testing of potable water supplies at a prescribed distance from new gas well construction in most states. Additionally, in the case of surface spills, new regulations now mandate the use of secondary and tertiary controls such as well pad liners and closed-looped drilling systems to reduce and prevent impacts to ground and surface waters. Wellbore design and construction has also been better matched to the local geology and is regulated and inspected more closely by the states. Taken together, field application of new technologies, paired with updated regulation have greatly reduced environmental impacts associated with water and are now practices commonly being utilized in shales developed in other areas of North America and globally.

Additionally there have been ongoing concerns about large quantities of water used in the process, remediation of waste fluids, fugitive methane and other air emissions, induced seismicity, and the broader implications to the landscape caused by the construction of well pads, access roads, and a large build out of thousands of miles of new pipeline.[12] This has raised additional issues of forest fragmentation, riparian protections at numerous stream crossings, and impacts to wildlife.

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National greenhouse gas emission trends reported by EPA (2013) show that methane emissions from natural gas operations have decreased 17 percent since 1990, and methane emissions from shale wells has decreased 73 percent since 2011, even though natural gas production has been increasing in the United States.[13] Green completions are routinely implemented in the United States to capture methane during, and soon-after, fracturing operations so that methane venting and flaring is not needed, which has significantly contributed to the overall reduction in fugitive emissions.

Drilling waste, with an emphasis on fluids, has seen increasing research and investment to resolve associated issues dealing with volume reduction, mobile remediation technology to reduce truck traffic, underground disposal well design to prevent induced seismic events, and isolation of products in the waste stream for commercial reutilization including large quantities of brine.

Whereas the drilling for shale energy is an industrial process with lingering physical impacts to the landscape, there are growing regulatory, government/academic research, and industry efforts to reduce the longer-term implications to both communities and the environment. These outcomes, and the legislative and regulatory efforts that mobilized them, are being closely studied and adapted to other global locations experiencing shale energy development.

ECONOMIC CONSIDERATIONS OF EASTERN SHALE GAS EXTRACTION—NEW HISTORIC TRENDS

Commercial viability of eastern US shales has been largely based on proximity to market, a generally favorable regulatory environment, projected increases in commodity demand from industry and the power generation sectors, and federal mandates driving national energy policy.[14] Underpinning all of those factors has been the historically favorable pricing basis which natural gas has received in the NE US market, paired with the strong network of transmission pipeline in place throughout the region.

Price basis has been generally positive at most pricing points in the Marcellus of PA though 2012 with an average premium of $0.30 to 1.20 over Henry Hub. Basis trends have now largely moved the other direction and fall under Henry by nearly $0.50 with some locations in the Marcellus under by $1.50 at times due to low seasonal demand and/or pipeline constraints.[15]

Near term projections on price forecast Henry Hub pricing moving in a sideways direction for the next 2–4 years due to anticipated volume coming to market from new onshore gas development and associated gas from offshore projects.

The EIA's 2014 Annual Energy Outlook projects a 56 percent increase in total natural gas production from 2012 to 2040 due to increased development

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of shale gas, tight gas, and offshore natural gas resources. Shale gas production is the largest contributor, growing by more than 10 tcf, from 9.7 tcf in 2012 to 19.8 tcf in 2040. The shale gas share of total US natural gas production increases from 40 percent in 2012 to 53 percent in 2040. Tight gas production and offshore gas production increase by 73 percent and 78 percent, respectively, from 2012 to 2040, but their shares of total production remain relatively constant. From 2017 to 2022, US offshore natural gas production declines by 0.3 tcf, as offshore exploration and development activities are directed primarily toward oil resources in the Gulf of Mexico. Offshore natural gas production increases after 2022, growing to 2.9 tcf in 2040, as natural gas prices rise. Alaska's natural gas production also increases during the projection period, because of Alaska LNG exports to overseas customers, beginning in 2026 and increasing to 0.8 tcf (2.2 bcf/d) in 2029. Alaska's LNG exports level off at 0.8 tcf per year over the last decade of the projection. Alaska's total natural gas production in 2040 is 1.2 tcf.[16] Although US natural gas production rises throughout the projection, the mix of sources changes over time. Onshore non-associated production (from sources other than tight gas, shale gas, and coalbed methane) declines from 3.9 tcf in 2012 to 1.6 tcf in 2040, and in 2040 it accounts for only about 4 percent of total domestic production, down from 16 percent in 2012.

The Henry Hub natural gas spot price averaged \$2.87/mmcf in February 2015, a decline of \$0.12/mmcf from January. EIA projected monthly average spot prices to remain less than \$3/mmcf through May 2015, and under \$4/mmcf through the end of 2016. They projected Henry Hub natural gas price averages \$3.07/mmcf in 2015 and \$3.48/mmcf in 2016.

Natural gas spot prices fell at most locations across the United States (outside of the Northeast) during 2014. Northeastern spot prices have greater seasonal volatility with day-to-day swings that can range widely over short periods of time, especially during the winter months where short-term price spikes due to cold weather occur. Prices at the Algonquin Citygate, delivering to Boston, and Transco Zone 6 NY, delivering to New York City, both experienced greater than 30 percent price swings within a day during late January 2014. Forecasting through 2016, Marcellus-area prices remain low, despite modest increases and trade for around \$1.15 per mmcf, roughly the current (as of 8.1.15) price in north-central PA.

The costs to develop and produce natural gas vary from basin to basin and between operators. Breakeven costs within the eastern shales of Marcellus and Utica range from \$2.34 to \$6.60/mcf. The current low-price environment of natural gas makes many basins economically unattractive, especially for smaller operators who cannot leverage the economy of scale. The Marcellus does have a distinct advantage to many other basins as transmission costs are lower which helps offset low commodity pricing. There is also rising regional

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demand to replace coal-fired electrical generation, and to some degree to replace older nuclear power plants heading offline, due to reduced electric rates and competition from newer gas turbine plants.

SHALE GAS TO MARKET—THE IMPLICATIONS OF MIDSTREAM INFRASTRUCTURE

Over 150 years of natural gas development in the Appalachian basin of the United States has generated hundreds of thousands of wells drilled in the region. Associated with that period of extraction is a large array of pipelines and right of ways. Those wells and pipelines were constructed to handle low volumes of low pressure gas and not engineered for the technical parameters of shale gas production. Hence an ongoing new build of a gathering and transmission pipeline system has been critical to the successful development of shale in eastern United States. That need and outcome is similar to other regions of North America and internationally where shale energy extraction is occurring presently or is planned in the near term. A large oil field service company forecast that 80 percent of shale energy is likely to be produced in countries that now produce 30 percent of the current world supply.[17] An outcome of that statistic can be interpreted to mean that most countries attempting to develop their shale resources, do not have the transportation infrastructure to move the commodity, once extracted, without a significant pipeline construction program. In the United States, O&G industry estimates have suggested that this new construction of needed midstream assets could total approximately $10 billion/year for ten years. In 2013, Federal Energy Regulatory Commission (FERC) indicated that nearly 50 percent of the midstream being constructed in the United States was directly or indirectly associated with the impact of the still emerging Marcellus shale play. Of that aligned with the Marcellus, some is new construction, others enhanced or renovated transmission lines and compression, and some line reversals to allow the movement of new Appalachian volume to be exported from the region.

Notable examples include the larger scale projects such as the newly opened Rockies Express Pipeline (REX) line that was initially conceived and built to bring gas from the mid-continent and Rockies to the eastern states and the Empire line in NY that was previously used to bring western Canadian gas to the same eastern gas markets.[18] With the Marcellus and then Utica, along with Gulf coast pipeline shipments largely meeting the gas requirements of the now formerly premium market of the Northeast, it made commercial sense to slow or reverse historical gas flow patterns and redirect gas to other markets. This has not just been a volume-based decision but also one impacted by the steep drop in market price offered in the NE. Transmission of gas from the

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Gulf States for instance, has been as low as 45 percent of capacity. Underutilization of existing gas transmission capacity has also occurred in Canada, with a similar volumetric reduction as more eastern US shale gas finds its way across the border to the eastern provinces of Canada.

Export of US gas to eastern Canada has been steadily rising and is forecast by EIA to reach 4 bcf/d by 2020. Displaced Canadian gas is flowing into western United States that have reduced coal-fired power generation, along with nuclear going offline in one region of California, and to meet overall increased demand for power. So in this manner, the North American gas market has largely been reorganized by the influence of large-scale shale gas development in eastern United States, with similar impacts generated from other shale resources being commercialized across the country. This includes the expanding exports of natural gas to Mexico that are also forecast to reach 4 bcf/d in the short term.[19]

Increasing quantities of NGLs are also being produced in large quantities in the eastern US shales, and without legacy commercial capacity to process them into petrochemicals and other value added products, much of this volume is also being moved by pipeline to ethylene crackers on the Gulf coast, similar capacity in the Midwest and Ontario, and now new European buyers via seagoing barges. These are significant quantities with the strong production of "wet gas" regions of SW PA/WV/OH contributing up to 25 percent+ of total gas volume as NGLs. This has created the increased need for new pipeline capacity to move these NGLs long distances to existing or new fractionation units along with the cracking/manufacturing infrastructure. To take advantage of this new supply and a large multistate market for polyethylene, Shell announced in 2016, the construction of an approximately $6 billion ethane cracker to be built in western PA.

Coupled with transmission has been a very large increase in the gathering pipeline capacity engineered to connect newly producing wells to the larger midstream system. This gathering system is essentially all new and even in areas with legacy conventional gas production, due to a variety of technical factors, cannot use existing gathering systems. Whereas transmission lines generally have Federal oversight through FERC in placement including the potential for eminent domain, gathering pipelines in eastern shale regions are negotiated agreements between landowner and pipeline company, which can be a third party midstream company or an branch of the O&G company developing the shale resource in that localized region.

Some locations in shale regions have seen an extensive build out of this midstream capacity and will continue to do so for the foreseeable future as new shale footprint has wells drilled within it. But with multi-well pads now the common theme of drillers, once a pad is connected to the gathering grid, new wells drilled on the pad don't necessarily equate to new pipelines.

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For example, Bradford County, Pennsylvania, in the heart of the north-central dry gas region of the Marcellus, and the leading producer of PA with over 1,500 wells drilled, has over 807 miles of gathering line currently in the ground and 200 miles still planned.[20] With much of the county now on the gathering grid of one of the companies operating there, and most pads having 50 percent or less of planned wells drilled on them, the volume of drilling is likely far from peaking but the amount of gathering pipe construction is nearing its high point. This has many ramifications from environmental issues to workforce to regulatory to community and infrastructure impacts.

Beyond the placement of gathering lines and the legal and financial considerations attached to it, there are also regulatory and inspection components that have largely been unknown to landowners which now have these new pipelines on their properties or in close proximity. There is also increasing interest from local jurisdictional officials that have new questions on regulatory oversight generated by their constituents.

In 2014/15, the Department of Energy was charged by the White House to perform the Quadrennial Energy Review (QER).[21] The theme of this review was on the current status of the US pipeline infrastructure and projections of what would be needed going forward. It took into consideration the new quantities of shale oil and gas being produced, new demands for natural gas-fired power generation to replace coal units going offline, and the advent of LNG exports that have been permitted and are under construction. Although the QER had extensive recommendations of what needs to occur going forward for the United States as it relates to pipeline infrastructure, a common point made in many of them is the need to modernize the overall system and build out a more extensive system to account for the new realities of a changing energy mix that includes increasing quantities of shale energy. Also key to the recommendations is the replacement of older capacity that is nearing its useful life or needs to deploy advanced safety technologies that have been developed since the original line was placed into service.

THE MOVE TOWARD US LNG EXPORTS: THE ECONOMIC AND POLICY IMPACTS OF SHALE GAS IN THE GLOBAL DIALOGUE

Increasingly large volumes of natural gas are being produced from shale reservoirs in North America, primarily from 8 to 10 large basins in the United States. There has been an increasing interest, both by the domestic users, and with international buyers, to source this relatively new shale energy resource. As part of a larger global shift to natural gas due to new found abundance, IEA has dubbed this the "Golden Age of Gas" with more countries worldwide

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promoting the exploration of shale energy within their borders.[22] This has amounted to an historic shift in how energy is being considered, from its economic opportunities, to the new geopolitical ramifications connected to discovery and production. With sizable levels of probable shale gas resources estimated by EIA in these countries, a new energy paradigm is being drawn, which indicates the United States being the world's largest producer of natural gas, and a sizable exporter in the near to mid-term (Figure 4.5).

Due to decades of declining natural gas production in the United States and increasing demand, policy related to trade in natural gas had focused mainly on the import of gas, other than cargoes of stranded gas that were being exported as LNG from a single terminal in Alaska. Billions of dollars in capital had been spent during the 1980s and 1990s to construct various import facilities on the US coastline, that in most cases, never reached optimum operating capacities. Although this led to increased expertise in evolving LNG technology during that timeframe, there was a related policy shortfall that lacked an updated assessment of the emerging supply of natural gas from shale. This generated domestic concerns related to the export of large volumes of natural gas away from an industrial base at the leading edge of a renaissance, and a newly energized environmental movement in opposition to upstream shale gas development. Within the broader political dialogue at the Federal level, there was a less than clear understanding of the policy protocol that allowed investors to secure export permits.[23] And beyond all of those considerations, was the fact that the United States had become accustomed to importing energy in a large-scale fashion, including by pipeline from Canada,

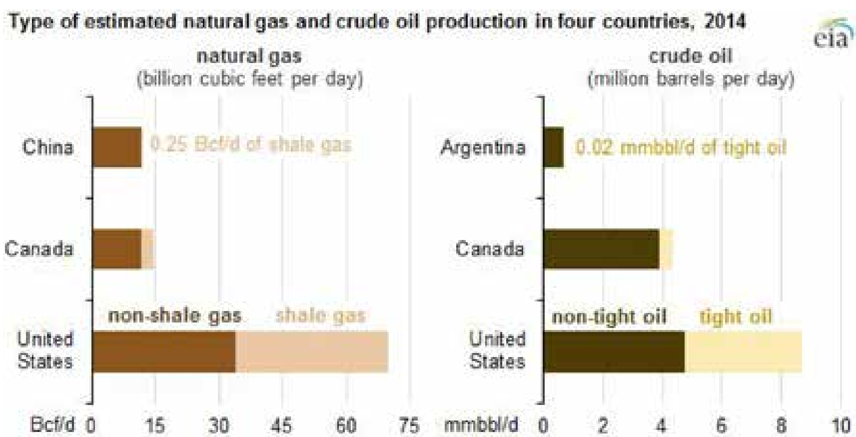

Figure 4.5 Top Countries Producing Shale Energy Resources in 2014. *Source*: Energy Information Administration, 2014.

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and now was struggling with the political challenges of reversing that discussion with constituents.

Existing LNG import facilities in the United States have been largely underutilized, particularly in the past five years, due largely to the amount of natural gas produced from shale now reaching the marketplace and displacing imports, whether as LNG from the Middle East or by pipeline from Canada. With current shale production trending strongly upward, such as the Marcellus shale now producing over 21 bcf/d, and becoming an increasingly larger share of total US natural gas production, forecast by EIA to exceed 50 percent of US dry gas supply in the mid-term.[24] This has led to a number of existing LNG import facilities being proposed for conversion to export. As "brownfield" locations, these existing LNG facilities have clear advantages over the development of a "greenfield" proposal. Factors such as existing transmission pipeline access with compression capacity, high voltage electrical power, delineated marine channel and piers, and commonly isolated locations associated with current import facilities give an edge to these locations being converted from import to export facilities. Adding to the advantage are previous environmental assessments already in place for this type of facility combined with a local, trained workforce that largely understands LNG technology and a community that has grown accustomed to this type of industrial activity.

Greenfield locations, if built, where there is no existing infrastructure, can have advantages in that newer LNG-related technologies don't need to be adapted to "fit" into the confines of currently in place facilities and structure. Downsides can include additional environmental scrutiny, difficulty sourcing key real estate with deep water access and transmission take-away capacity, longer lead times to build workforce expertise, and lack of needed political support, due to limited legacy knowledge of the process, associated risks, and mitigation technologies aligned with LNG. Although political support is key at the Federal level with critical DOE and FERC permits, it is crucial as well at the local jurisdictional level for access and building licenses, air quality permitting, and attaining the "social license" that is becoming more and more important to these large projects showing up in communities unaccustomed to having them nearby local populations of people.

The increasing levels of environmental activism in opposition to the siting of these facilities, either as conversions or new builds, is gaining traction in political circles and cannot be underestimated. Several North American environmental NGOs have taken on a mission of stopping, or at least slowing the permitting of the facilities, with the ultimate goal of preventing upstream shale gas development. Various NGOs have a parallel effort currently in motion, to stop new and/or expanded export ship loading facilities for coal headed to Asia on the US west coast, or to Europe off the east coast. Although their collective goal is to hamper fossil energy development in the United States,

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the overall trend in permitting of these sites and the affiliated infrastructure continues to expand, although with greater levels of public scrutiny.[25]

As of mid-2015, there were over forty-five LNG facilities announced, in some phase of permitting, and/or planned in the United States and Canada. Due to a number of considerations, with project financing, challenging permitting, and an increasing oversupply of LNG in the global natural gas market being key factors, there is a growing expectation that a significant number of these projects will not be built.

A recent report by Ziff Energy, indicated that there is a potential 60 percent addition to supply beyond estimated market demand by 2022 with 60 Mtpa coming to the market by the end of 2016, the majority of it in Asia.[26] This will lift LNG supply in the market to nearly 350 Mtpa.

Numerous analysts have indicated that the closing gap between Brent-priced LNG and that pegged to Henry Hub, largely due to oversupply of crude in the market, coupled with the decision of Organization of Petroleum Exporting Countries (OPEC) to maintain crude oil production levels, is eroding incentive for some LNG buyers to source North American LNG supplies. This is causing a reevaluation of selected projects, and in some cases, a pull-back in planned investment to construct.

Of the facilities which have been announced, secured a final investment decision (FID), and are moving to construction, there is a significant amount of global investment capital being attracted. This is also seen by DOE as being a consideration in the ultimate approval of LNG facilities licensed in the United States. Announced investment in US-based LNG projects includes:

Table 4.1 Announced investment and capacity in U.S.-based LNG export projects as of March 4, 2015

Project	*Committed Investment ($ in billions)*	*Capacity (billion cubic feet per day)*
Sabine Pass (Cheniere)	12+	3.76
Cameron LNG (Sempra)	10	1.7
Freeport LNG (Freeport LNG)	11	1.8
CovePoint (Dominion)	3.5	0.82
Corpus Christi LNG	7.5	2.14

TRENDS IN NEXT 3–5 YEARS ON SITING FACILITIES IN NORTH AMERICA

In the past several years there has been a growing expectation that there is a large amount of capacity to produce natural gas from the emerging shale resources in many locations of North America. Most of these new resources are also in relative proximity to one of the North American coasts or they

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are near existing transmission capacity to move the gas to newly proposed LNG export facilities which in a number of cases are near preexisting import terminals. These existing import sites are typically linked to high capacity interstate transmission pipelines, a nationwide underground storage network, and key parts of the midstream infrastructure which could be repurposed to export LNG with the proper level of capital expenditures. There has until late 2014, been a certain exuberance in the marketplace with an expanding queue of investment groups and companies proposing new export facilities for permitting and possible construction. That trend is one of the key reasons that DOE revamped their permit review process, to let those with the best chance of commercial success float to the top of the queue, complete the FERC environmental review "test," and move to construction if the final license was acquired from DOE.[27] Much of this expanding investment interest was based on the favorable spread between projected Henry Hub based pricing of US sourced LNG, in comparison to Brent-indexed LNG. Brent pricing was considerably higher, particularly for Australian LNG which has high development costs factored into the underlying cost of the unit of gas.

When the price of crude started dropping in 3Q14, this strategy seemed less certain as the spread between Hub and Brent-indexed LNG narrowed, and in some cases favored crude-indexed LNG. At the same time, there has been an influx of new natural gas production, originating from both conventional and unconventional sources, projected to reach the market in the near term. Additionally there have been an increasing number of LNG cargoes chasing the market, which has favored the buyer. Mixed into that was Japan's decision to restart their nuclear power generation capacity, similar signals from some of South Korea's offline nuclear power fleet, and China finally working out a decades long supply deal with Russia ($400 billion) to use pipeline gas from Siberia as Gazprom "leans East."[28]

All this has taken what was once thought to be predictable stability in the LNG market and created much uncertainty going forward. Already a number of LNG export facilities proposed in several areas of the United States and western Canada have been temporarily suspended or more permanently canceled due to poor financial market outlooks for the higher cost locations. An example of this would be some of the LNG export capacity planned for eastern Canadian Maritime locations in New Brunswick and Nova Scotia along with proposed facilities in British Columbia. With the Maritimes locations, without a sustainable source of local gas, the facilities would become "end of pipe" with higher costs for the energy to be exported and substantial basis changes to move the gas to the point of liquefaction and export. Since much of that gas was planned to be sourced from the Marcellus and Utica shales, facilities in the mid-Atlantic region of the United States would enjoy a competitive advantage due to proximity to the resource. In the case of the

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British Columbia locations, most of the proposed facilities are greenfield sites with high environmental mitigation costs, new pipeline construction needed, and tough issues negotiating pipeline right of ways with aboriginal First Nations groups. There is however, measurable political support at the provincial government level, to make a strong "investment" in the regulatory and social license with the population to create this large new export market. British Columbia provincial support includes a new tax scheme that is more favorable to LNG terminal operation to encourage new construction. That contrasts with most of eastern Canada where provincial politics are generally hostile to fossil energy development with the notable example of Newfoundland, which has a thriving offshore O&G industry.

In a like manner, there has been an expanding United States queue of new greenfield terminals proposed that followed the initial wave of planned brownfield locations such as Cheniere's Sabine Pass site on the Gulf coast and Dominion's Cove Point site on the Atlantic coast. With the steep drop of the price of crude in the second half of 2014, the dynamics of which terminals will get built and which will not, has changed considerably. There is somewhat of a revolving door of existing applications at DOE being dropped by their promoters due to the realization of poor economics associated with unique locations, and others that have a different business model. Brownfield locations have real cost advantage and are more likely to reach a positive FID, particularly if they have contractual agreements in place with buyers.

With the price of crude expected by many analysts to stay off its past highs above the $100 barrel threshold for the next several years, due principally to the influence of shale oil, this is expected to continue to be a factor providing a more efficient market-based limit to terminal construction via new risk assessments allocated to capital expenditures. Although it is likely still too early to fully appreciate the trend in longer-term shale oil production in the United States, following OPEC's firm stance on holding member state's crude production lower, there is a growing view that North American shale oil is going to be the new "swing" production vs. Saudi Arabia in the past. Because shale wells can be drilled relatively quickly and cheaply when compared to conventional oil reservoirs, some or all of that production likely will come back online in the United States, short of the highest cost wells, as the price of crude cycles to higher margins for drillers, when demand and production balance. This could be further skewed though as efficiencies to drill shale wells increase and costs decline, allowing even some marginal production to find its way back to the market. That is already happening now and is likely to encourage additional production of both oil and gas to come to the low-price marketplace.

Another variable is an initial wave of shale energy companies moving toward bankruptcy due to large drops in the value of the underlying hydrocarbon commodity and the large leveraged position that some companies

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face going forward. If this capacity is purchased and consolidated with other independent shale energy companies, when the price stabilizes, the acreage would likely be produced. On the other hand, if they are acquired by major international oil companies (IOCs), they will have to compete for capex with other larger scale but less nimble conventional reservoir development in their global inventory.

There have been large amounts of industry, government, and public commentary pertaining to the expanding capacity of North American natural gas reserves, both conventional and unconventional (shale). Current projections by DOE/EIA have natural gas production in the United States alone at over 75 bcf/d in 1Q15. Of that, 21 bcf/d is now coming from the single Appalachian shale play of the Marcellus with Utica adding almost another 4 bcf/d. Most of the Marcellus volume is coming from Pennsylvania, a state that was the number ten producer of natural gas in 2005. This has also made the contiguous states of Pennsylvania, Ohio, and West Virginia collectively a net export region of the United States that as recently as 2010, were importers of natural gas.

These three states also have the benefit of proximity to the historically premium markets of northeastern and Mid-Atlantic States. Over 40 percent of the American population lives in that region, so demand for energy, in this case natural gas by pipeline or LNG, has been higher than other regions of the United States. A similar comparison can be made with Canada, with the majority of its citizens living within one hundred miles of the US border and more than half of them from Ontario east to the Atlantic.

THE RISE OF SOCIAL MEDIA AND THE CHALLENGES OF SOCIAL LICENSE IN THE PUBLIC POLICY ENERGY DEBATE

On a parallel path during the rapid expansion of shale gas development, was the explosive interest and use of social media.[29] Access to faster broadband on home computers and the much more common ownership of internet-enabled smartphones, have allowed people worldwide to locate others with similar interests. This coincided with the movement of shale gas exploration and production, along with the associated infrastructure build out of compression and pipelines, in much closer proximity to larger populations of people that were politically active and did not have legacy knowledge of what large scale shale development looked and “felt” like during its more active phase. There was also a political and science overlay that pulled the conversation of climate change into the public dialogue in a much more dynamic fashion.

This influenced the discussion and created a debate between those that professed natural gas from shale, as a bridge to an energy future that had

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increasingly higher quantities of renewable technologies deployed, and those that saw any type of fossil energy development being inherently a poor short and long-term decision. The influence of social media acted as an equalizing tool that allowed anyone to become an included voice in the conversation and attempt to influence outcomes that fit their view of energy development or overall policy. And whereas in similar large scale debates of the past, typically conventional media, politicians, academics, industry leaders, or slower grassroots campaigns might have been the dominant mechanism that was utilized to influence the dialogue, now anyone with access to a social media account, became a voice in the discussion and much more easily call into question the direction that energy development was moving on a localized scale or more globally in nature.

One of the outcomes of the advent of a new group of stakeholders emboldened by this communication tool, was that it changed the definition of who constituted the "local" community. With shale gas exploration moving closer to people and their communities, government and industry officials that traditionally would have had a series of town hall meetings to connect with the local citizens, saw the "community" evolve over time to include stakeholders that lived at a distance from a planned project, sometimes in a different country. NGOs also leveraged social media as a pathway to enter a growing number of these conversations, to rally new stakeholders difficult to find and organize in the past, creating new strength to further their goals[30]. This has led in some cases to a disconnect between those living in a community that have local concerns with shale gas development such as road impacts, noise, or workforce access, and more distant stakeholders driven by climate or larger environmental concerns.

The winners of the social media engagement strategy to change or influence public opinion around shale issues, seem to lean toward those attempting to stop or at least more tightly regulate the development of shale going forward. Typically this group has been more active and nimble in their messaging. Elected officials and industry leaders have commonly taken a more conservative approach and fallen behind in the debate. Seeing successes in this realm has led most all parties to take a more aggressive approach to the use of social media as a tool to deliver their message and convey information. Many would argue that this type of media has now completely changed the manner in how information and stakeholders are connected, now, and increasing so, in the future. And in a larger fashion, social media has influenced the dialogue on a global basis, not just in the shale regions of North America.

And with the discussion becoming more polarized, many would also argue that finding science-based answers is increasing more challenging, regardless of which side a participate in the debate might come down on the issues. And with a growing lack of trust in where the science might fall on one or

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more related issues, citizens in communities are challenged to feel comfortable offering "social license" to a company or government to explore for, and produce shale gas. With private ownership of minerals in most locations of privately held land in the United States, there has been stronger overall acceptance of shale development in locations where it is commercially viable. In most other countries of the world, the opposite has become the trend, largely due to social media questioning the value to the local community and openly discussing the risks associated with energy production.

CONCLUSION

The recognition of shale gas as a resource that can be exploited has significantly altered the energy landscape in North America and around the globe. This new source of natural gas is now providing nearly half of the US dry gas supply, with the winter of 2015 seeing record levels of natural gas production, even during a time of some of the lowest wholesale gas prices recorded since the early 1990s. A similar story is also occurring with shale oil production in the United States, with just over 50 percent of US crude oil production now coming from shale wells, and nearly half of that production coming from wells drilled since 2014.

New shale exploration and production technologies, deployed alongside of an updated state and federal regulatory environment, and a strong capital commitment from the financial community, is leading to this revolutionary increase in hydrocarbon supply. And at the same time as it is quickly advancing in the United States and Canada, many other countries worldwide are looking in the direction of shale energy as a means of establishing a greater sense of energy security within their borders. The successes seen in the United States are looked upon as a pathway to new opportunities to source a local energy supply, change their balance of payments, expand and develop local businesses, and open up additional options to train a newly skilled workforce.

Shale energy has also changed the world gas market through its new found abundance, an upending of the global price of gas with the expansion of the LNG market, and the entry of the United States into a space where it had never expected to participate as an exporter. By 2017, it is estimated that with increasing pipeline volumes moving to Mexico and Canada, combined with new LNG shipments that the United States will become a net gas exporter. This is an historic shift that is having global impacts and will likely expand further as the United States claims the number three spot as a LNG export nation by 2020.

These changes are also impacting the energy mix globally as well, with gas now replacing coal as the top fuel for power generation in the United States

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and trending that way in many other countries around the world. The United Kingdom is planning to completely divest of coal in its power gen portfolio by 2025 and the EU collectively is moving natural gas further into its broader energy equation as it adheres to the climate guidelines agreed to in the Paris COP21 document. As renewables rise in overall installed capacity globally, there is expected to be an ongoing trend toward greater pairing of clean energy technologies with expanding gas-fired base power generation.

All of these changes are predicated on the achievement of a greater social license contract between communities where shale gas is being developed and the industry that is deploying their latest technology to make that occur. Overarching this is government regulation that is critical to prevent and remediate impacts as they might occur in all types of energy production, including natural gas from shale. Communities of people increasing want to see a level of protection that they understand and can influence based on the science associated with energy development as it continues to evolve over time. The need for social license is becoming the greatest single factor in some regions of the world that dictates whether the resource will be developed in the immediate or mid-term.

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Chapter 5

The International Impact of the Shale Revolution

Anas F. Alhajji

INTRODUCTION

The spectacular rise of US oil and natural gas production in recent years led to profound changes, not only in the energy mix of the United States but also in global direction of trade in oil and natural gas. Probably the most pronounced impact was the split of the Organization of the Petroleum Exporting Countries (OPEC) into two halves: those who lost their market share in the United States and those who did not. Interestingly, it was not only the quantity of oil that US producers brought on line that split OPEC, it was largely the quality of crude. The light sweet crude that is produced from various shales meant, in light of the ban on US produced crude, that local production replaced imports of the same quality. However, the crude export ban was lifted by 2015.Those who export heavier and more sour crude were not affected as much.

In this overview chapter, which draws on previously written articles by the author,[1] I highlight the trends that the shale revolution created and explain the impact on OPEC members in general and Saudi Arabia in particular. Within this discussion, we will understand the reasons that led Saudis to wage an oil price war.

In the next section I will highlight production, demand, and trade trends and how the shale revolution reversed these trends. In section 3, I highlight the impact of the shale revolution on Saudi Arabia, the Saudi reaction, and the impact of the Saudi reaction on the US oil drilling activities. The Saudi-led oil price war makes it logical to start with Saudi Arabia rather than OPEC. In section 4, I discuss the impact of the shale revolution and the Saudi price war on OPEC members. In section 5, I move from economics to politics and focus on the impact of the shale revolution on the US foreign

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policy to see whether it should lead to any major shifts. The conclusions are presented in section 6.

TRENDS IN US OIL PRODUCTION, DEMAND, AND TRADE

We call it the shale "revolution." It flipped the conventional wisdom on its head. Every decreasing trend became increasing, and every increasing trend became decreasing. Figure 5.1 illustrates the impact of the shale revolution on production and net imports.

US oil production had been declining since the early 1970s. The shale revolution changed that trend. Since early 2009, US oil production increased by about 5 MMBbl/d. The increase is more than the exports of two OPEC members combined, Kuwait and the UAE Recently, US oil production declined slightly, after months of low oil prices.

US oil demand increased until 2007 when it declined as consumers responded to the large increase in gasoline prices. Demand declined further during the financial crisis of 2008–2009. Surprisingly, demand continued to decline even after the end of the financial crisis despite positive economic growth. The decline during the post financial crisis could be attributed to high unemployment, low labor participation rate, and a change in youth culture, including the use of social media. Uncertainty about the future of US automakers during and after the financial crisis might have also contributed to

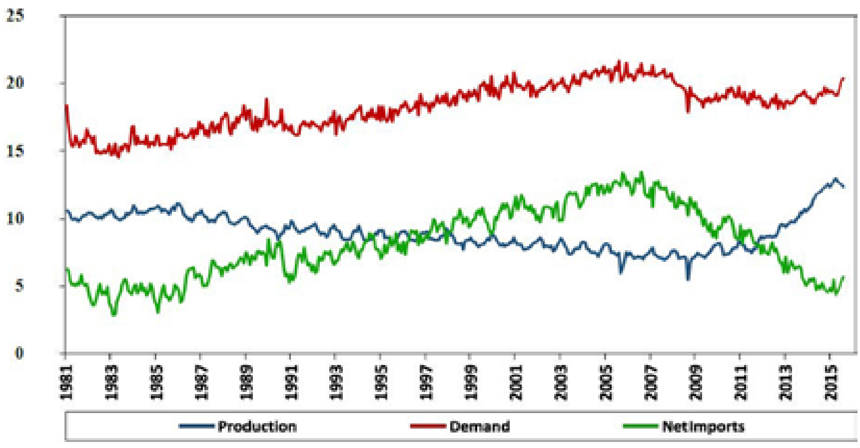

Figure 5.1 US Oil Production, Demand, and Net Imports (MMBbl/d). *Source*: EIA 2015.

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the delay in auto purchases that in turn lowered oil demand. US oil demand increased by about 500,000 barrels day (b/d) in 2015 as oil prices declined by more than 50 percent, unemployment declined slightly to above 5 percent, and labor participation rate and incomes increased.

As a result of these changes in supply and demand, net imports decreased by about 5.7 Millions of barrels per day (MMBbl/d) since early 2009. US oil imports declined from 13.2 MMBbl/d in early 2009 to an average of 9.5 MMBbl/d in 2015. Imports from Algeria, Angola, and Nigeria have declined and almost came to a complete halt while imports from Saudi Arabia and Kuwait were not affected as much.[2] The shale revolution has not displaced imports from the Middle East that its crude tends to be heavier and more sour.

It displaced oil imports from North and West Africa. Since the United States bans the exports of US produced crude, the increase in shale oil production replaced imports of the same quality, which came from North and West Africa.

IMPACT ON SAUDI ARABIA

The shale revolution threatened all the strategic objectives of Saudi Arabia. It threatened the Saudi market share in crude, petroleum products, Natural Gas Liquit (NGLs), and petrochemicals. It also threatened the unity of Organization of Petroleum Exporting Countries (OPEC). OPEC and its unity is more important to Saudi Arabia than to other OPEC members for several economic and political reasons. The Saudis responded by a price war to eliminate all these threats at once.

After several years of denial, Saudi oil officials realized the direct and indirect impact of the US shale revolution on Saudi Arabia. In the early years of the shale revolution, many Saudi oil officials viewed the news of the shale revolution with suspicion. Until the end of 2014, the Saudi newspapers were publishing articles labeling the shale revolution as a "bubble." At first they acknowledged the shale revolution and the possibility of coexistence.[3] But when Western African oil that was intended for exports to the United States started competing with Saudi oil in China, Saudi Arabia launched a price war.

US shale oil did not compete directly with Saudi oil. US shale oil is light sweet while US imports from Saudi Arabia are heavier and sour. The impact was indirect. US shale oil replaced imports of the same quality: light sweet crude from Algeria, Angola, and Nigeria, all are OPEC members. These countries lost most of their market share in the United States and started competing with Saudi Arabia and other OPEC members in Asia and Europe. Saudis faced a dilemma: most of the oil produced in the Gulf region is sour, while most of the global oil surplus is light sweet. A production cut by the

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Gulf countries will not solve the glut problem. The only solution was to let prices decline to levels that eliminate or reduce the growth in North American oil production. This decline meant that those OPEC members who are competing with Saudi Arabia in Asia can retrieve their market share or some of it in the United States. From the Saudi's point of view, low prices should help Saudi Arabia preserve its market share in crude oil and OPEC unity at the same time.

Since the 1970s, the Saudi government realized, with the help of the World Bank and the International Monetary Fund, its comparative advantage in energy intensive industries, which include, among others, petrochemicals and refineries. At the same time, to boost revenues, Saudi Arabia expanded exports of NGLs, which are not counted in OPEC quotas.

By the time these projects started paying off, the US shale revolution was in full swing. The key to the competitiveness of Saudi Arabia's petrochemical industry was its use of natural gas and ethane, which was far less expensive than the oil product naphtha on which its global competitors depended. But now that the United States is producing massive amounts of low-price natural gas and ethane, Saudi Arabia's competitive advantage—and market share—is beginning to deteriorate with the return of major petrochemical players to the United States.

The same goes for refining. Since the United States did not allow exports of US produced crude oil, the shale revolution pushed down the US benchmark price, the West Texas Intermediate (WTI), relative to international crude prices, sometimes with differentials as wide as \$20. US refiners took advantage of lower prices to increase their exports of petroleum products—so much so that they now threaten Saudi's market share in Asia and elsewhere. During the shale oil revolution, imports declined by more than 50 percent, while exports almost tripled.

Likewise, US companies increased NGL production considerably, enabling the country to slash its liquefied petroleum gas (LPG) imports and expand its NGL exports significantly. As a result, Saudi Arabia lost market share to US producers in Central and South America.

While imports declined by about two-thirds since 2007, exports increased by more than twelve fold. Since global demand for NGLs did increase by the same percentage, US NGLs producers expanded their market share at the expense of others, mainly Saudi Arabia.

THE SAUDI REACTION

The Saudis want to preserve their market share in crude, petroleum products, NGLs, and petrochemicals. They also want to preserve the unity of

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OPEC. The only choice that enabled Saudi Arabia to achieve all these objectives at once was to let oil prices decline low enough to achieve these objectives.

At first, the Saudis refused to cut production.[4] When oil prices did not decline enough, Saudis increased production. Prices declined to the low starting bid of $40 per barrel. Until then, the Saudi objectives were purely economic as stated above, but they did not mind seeing some oil producers, mainly Iran, Iraq, Venezuela, and Russia, getting hurt. They all oppose the Saudi policy in Syria and Yemen. The political component of the Saudi pricing policy started to appear when the Obama Administration signed the nuclear deal with Iran.[5] The Saudis not only increased production, they also made it clear that their high production levels will continue indefinitely. This policy was accentuated when Russia decided to be involved militarily in Syria. Saudis might have achieved most of their economic objectives, especially in the long run, but it is clear that low oil prices is a strong bargaining chip with Iran and Russia that they do not want to drop until the game is over.

Under these circumstances, it is likely that Saudi Arabia will continue to refuse to slash oil production, leaving prices low until market forces trigger a rebound. Even then, the price increase could be limited. From the Saudi point of view, prices should rise, but only to levels that allow a small growth in non-OPEC production that commensurate with growth in global demand.

In short, it is in Saudi Arabia's interest for oil prices to rise high enough to sustain its own economy, but not so high that they can sustain any significant hikes in the non-OPEC supply. In order to keep prices in this ideal range, Saudi Arabia may even increase production again.

In 2005 all the phases of the Saudi policy of low prices mentioned above. Given the current Aramco's drilling program, the ability to use foreign reserves and borrow from domestic and international markets, experts agree that Saudi Arabia can withstand this high level of production and low prices more than other OPEC members.

THE IMPACT OF THE SAUDI ACTION

While the Saudi price war is directed at shale oil and natural gas producers in the United States, it is not in the Saudis interest to kill the shale revolution. It is however, in the Saudi's interest to limit oil production growth in a way where growth in non-OPEC production commensurate with growth in global oil demand. The Saudis have already achieved their objective. US oil production growth ended and now production is declining. One of the unintended consequences of the Saudi policy is the massive project delays around the world, mostly in deep offshore and in Canada. Since 1987 there has been a

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spectacular increase in rig count during the shale revolution between 2009 and 2014. It also shows the impact of the Saudi policy: the largest and steepest drop in oil-directed rig count in US history. However, percentage wise, the decline fits the historical averages.

THE IMPACT ON OPEC

We would have had a better picture of the impact of the shale revolution on OPEC members if it were not for the Arab Spring that led to the loss of the Libyan oil and the economic sanctions on Iran that reduced its production significantly. One of the most important effects of the United States shale revolution on global oil markets is price stability. The loss of oil production in the Arab Spring countries increased substantially in 2012–2014 while tightening sanctions on Iran reduced its production by more than 1 mbd. At the end of 2013 and early 2014, disruptions reached 3.7 mbd. If it were not for the continuous increase in US shale oil production, oil prices would have continually increased to record highs. Most of the disruptions came from OPEC members such as Libya, Iran, Iraq, and Nigeria. Between early 2012 and late 2014, prices were relatively stable around $100, mainly because of the increase in US oil production. The chart shows that as disruptions declined and US production continued to grow, a surplus started building up, which contributed to lower prices.

As discussed earlier, OPEC members in West and North Africa lost most of their market share in the United States. When these countries tried to compete with other OPEC members in Asia, Saudis reacted by launching a price war. It was a double whammy for those countries. Revenues for most OPEC members declined by more than half.[6]

While the governments of the oil-producing countries are flexible and can reduce their budgets by delaying or canceling projects, reducing subsidies, and raising taxes, people's need, or the social cost, are not as flexible. Flexibility might help these governments in the short run, but they cannot withstand low oil prices for a long period. In general, the governments of OPEC members are more flexible than most experts think.

Angola, for example, lowered its spending significantly and now it needs a price of $40 instead of $98 in 2014.[7] The smaller difference for some countries is due to smaller oil prices needed to support spending in 2014. Even Saudi Arabia used a price in the $40 range for its 2016 budget after it delayed or canceled projects.[8] Given that the social cost is higher than the price needed for the budget, it is clear that current oil prices are not sustainable in the long run. OPEC members need a high price to main peace in the streets.

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THE IMPACT ON US FOREIGN POLICY TOWARD THE MIDDLE EAST

The shale revolution was the result of efforts of independent oil and natural gas producers and medium size companies. It was not the result of any energy policy of the Obama Administration. While there is support to claims that the United States can reduce its dependence on oil imports by an additional 1.5–2.0 MMBb/d by 2020, an amount that is equal to current US imports from the Middle East, which amounts to about 16 percent of total oil imports, the United States will not be able to eliminate its dependence on oil imports from the Middle East, but it might reduce them. In fact, the use of the term "Middle East" is misleading. While the Middle East encompasses a massive swath of land with large number of countries including countries that are "unfriendly" to the United States, the United States imports oil only from three "very friendly" countries: Saudi Arabia (1.2 mbd or about 11 percent of total oil imports), Iraq (0.46 mbd or about 4 percent), and Kuwait (0.2 mbd or 1.7 percent).[9]

Assuming a bounce in oil prices, oil from Saudi Arabia, Iraq, and to some extent Kuwait, will continue to flow to the United States, because of several economic and strategic factors:

1. Saudi production spare capacity is needed during a crisis and to fill the US Strategic Petroleum Reserves (SPR). As long as hurricanes roam the Gulf of Mexico and turmoil is taking its turn in the oil-producing countries, the United States needs the Saudi spare capacity.
2. Quality of Iraqi and Kuwaiti crudes is suitable for US refineries.
3. The strategic alliances between these countries and the United States are significant and it is unlikely that the United States will forgo such alliances just because of an increase in its own domestic oil production.
4. From an energy policy point of view, diversity of imports is important to reduce risk of interruptions. Eliminating imports from those countries means more concentration somewhere else.

If the United States eliminates its dependence on oil imports from the Middle East, or lower imports significantly, will the United States reduce its presence and interest in the Middle East? The answer is, again, NO. There are several economic and strategic reasons that will keep the United States in the region, as interested as ever:

1. The Middle East is not only about oil and the United States has other interests than oil.
2. The United States wants to prevent Iran from projecting power in the region.

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3. In the post September 11 world, the United States sees its presence in the region as important to protect itself.
4. Friendly regimes have weak militaries and they need US military protection.
5. US presence in the region means that the United States can still control oil supplies to China, Europe, and others—an advantage the United States will not give up.

CONCLUSION

The shale revolution threatened all the strategic objectives of Saudi Arabia and split OPEC into two halves. Oil from North and West Africa that was displaced by US shale oil competed head on with Saudi oil in Asia and Europe. The shale revolution threatened the Saudi market share in petroleum products, NGLs, and petrochemicals. The Saudis reacted by lowering oil prices by more than 50 percent. Their objective is to regain market share in crude, petroleum products, NGLs, and petrochemicals. At the same time, they can bring unity to OPEC in the long run through the recovery of some market share in the United States and increase in demand for OPEC crude.

The Saudi objective was purely economic, but the extension of the period of low prices might be political. Saudis have already achieved most of their economic objectives. Growth in US oil production came to a complete halt after a 60 percent decline in drilling activities. The Saudis have already raised enough doubt about natural gas and NGLs supplies. The migration of chemical companies is expected to be slower than initial estimates. However, it remains to be seen if Saudi Arabia will achieve any of its political goals. In negotiations with Iran and Russia regarding regional security, especially in Syria and Yemen, low oil prices might be perceived as a wining chip in the hand of Saudi Arabia and it will not let go until an agreement is reached or the game ends. However, the Saudi policy might backfire. In the short run, excessively low prices could trigger political instability in some oil-producing countries, driving up prices. Similarly, delays in upstream investment, especially mega-projects, could push prices above the ideal level in the medium and long term. The increase in production to lower prices led to a large decline in the Saudi production spare capacity while oil inventories in the consuming countries increased to a record high. The Saudi policy of higher production and lower prices means the Saudis have given up their role as a swing producers and lost their strategic significance of spare capacity. In case of supply disruption, the cushion is in the consuming countries in the form of large inventories, not in Saudi Arabia.

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On the geopolitical impact of the shale revolution on the Middle East, the data shows that the shale revolution direct impact was on imports from North and West Africa, not on imports from the Middle East. All the political hype about energy independence and reduction of imports from the Middle East is just that: hype.

Even if the United States reduces its imports from the Middle East, the United States still needs the Middle East. United States presence in the Middle East is not expected to decline because of the shale revolution for the reasons discussed in the text.

NOTES

1. See, for example, "Living the Saudi Dream" http://www.project-syndicate.org/commentary/saudi-arabia-oil-market-dominance-by-a--f--alhajji-2015-03 "When "NO" Shakes the World" http://www.worldoil.com/magazine/2015/january-2015/columns/oil-and-gas-in-the-capitals "Nuclear Deal with Iran Impacts U.S. Producers Negatively" http://www.worldoil.com/magazine/2015/july-2015/columns/oil-and-gas-in-the-capitals "Shale Revolution has Direct and Indirect Impacts on OPEC" http://www.worldoil.com/magazine/2014/january-2014/columns/oil-and-gas-in-the-capitals
2. Now the ban on crude exports is lifted, oil trade between the United States and other countries is expected to increase. The United States will export light sweet crude and will import heavier and more sour crudes, mainly from the Middle East. In other words, dependence on imports of oil from Middle East is expected to increase.
3. See, for example, "Al-Naimi: US Shale Oil Helps Keep Oil Markets Stable" http://www.arabnews.com/news/511651
4. See, for example, "OPEC: No Cut in Oil Production and Prices Keep Falling" http://money.cnn.com/2014/11/27/news/opec-oil-prices/
5. The P5+ 1 reached a deal with Iran on July 14, 2015. For more, see "Deal Reached on Iran Nuclear Program; Limits on Fuel Would Lessen With Time" http://www.nytimes.com/2015/07/15/world/middleeast/iran-nuclear-deal-is-reached-after-long-negotiations.html?_r=0
6. According to the EIA, OPEC revenues declined drastically in 2015. http://www.eia.gov/beta/international/regions-topics.cfm?RegionTopicID=OPEC
7. See "Angolan Parliament Passes 48 bln 2016 Budget" http://www.newzimbabwe.com/business-26572-Angola+Parly+passes+$48bln+2016+budget/business.aspx
8. As an example of this flexibility, the government of Saudi Arabia announced its budget for 2016 on December 28, 2015. Among the main characteristics of the budget is a large budget deficit and a reduction in fuel subsidies. For details, see http://www.bloomberg.com/news/articles/2015-12-28/saudi-arabia-aims-to-cut-spending-to-840-billion- riyals-in-2016
9. Monthly Energy Review, IEA, December 2015 http://www.eia.gov/totalenergy/data/monthly/

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Chapter 6

Facets of Unconventional Oil and Gas Exploration and Production in Canada[1]

Silke Popp

INTRODUCTION

Although unconventional gas is a relatively new segment of the global natural resources industry, Canada has a long history of oil and natural gas exploration and production. This chapter examines the many types of unconventional gas resources found in Canada, the foundation of the current regulatory system, as well as the extent to which existing and proposed regulations govern the exploration, development, and production of unconventional oil and natural gas. As of August 2016, Canada is only one of four countries in the world, apart from the United States and China, which is a major producer of commercially viable quantities of unconventional gas.[2] In many ways, Canada's approach to development and production of its unconventional gas resources has seen a more tempered pace than in the United States, avoiding some of the frenzied activity witnessed, for instance, at the advent of production in the Bakken formation in North Dakota. However, as the petroleum industry endures yet another protracted collapse in pricing, the restrained growth, political climate, and stricter regulations imposed by Canadian regulators may have long term impacts on the development and recovery of Canadian unconventionals. Canada's vast geography and breadth of political sentiment is reflected in its policies—which range from some of the most comprehensive and detailed regulations in the world in some provinces, to complete moratoria in others. A survey of the existing and proposed regulations in Canada reveals that the country's favor of strong governance has translated to its oversight of the development and production of unconventional gas, with clear attempts by the relevant agencies to carefully consider the many impacts—and potential rewards—of an unpredictable unconventional gas industry.

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Energy independence is a crucial component of the economic and political security of any nation-state. As evidenced by the recent turmoil in Eastern Ukraine and Russia's annexation of Crimea, political alliances, and regional stability depend heavily on the resources a country can rely on in times of crisis.[3] In a world where fuel—be it in the form of gas, oil, or other renewable energy sources—is perhaps the most precious commodity, countries are becoming increasingly resourceful in their quest to unlock previously undevelopable resources.

The most obvious example of this mission is the current continued shale gas development in the United States of America, where production has witnessed a sevenfold increase since 2007, from 1,990,145 million cubic feet (mcf) to 15,475,887 mcf in 2015.[4] The estimated technically recoverable reserves in the United States total 665 trillion cubic feet (tcf).[5] Although the United States ranks fourth in the world for estimated reserves of shale gas behind China, Algeria, and Argentina, it currently leads global production of shale gas.[6] Trailing behind the United States in production is Canada, with an estimated 573 tcf of technically recoverable reserves.[7] While Canada has similar reserves to that of the United States, annual production from its two major shale plays topped out at a rate of only 2 BcF/d in 2012.[8]

This chapter examines the current state of the unconventional gas industry within Canada, provides an assessment of existing and proposed unconventional oil and gas regulation in Canada, and creates context to the regulations by illustrating incidents, current litigation, and differences between the provinces. In order to assess the current state of unconventional oil and gas regulation in Canada, this chapter will first examine the various types of unconventional resources available for exploitation and development. Next, the chapter will examine the history of regulation in Canada, as well as its geographic epicenter. Finally, it will discuss more recent changes to the applicable federal and provincial regulatory schemes, as well as briefly mentioning specific case studies or events which illustrate the efficacy of the existing rules and regulations and challenges presented by implementation.

Unconventional gas production has already overtaken conventional production since gaining momentum in the mid-2000s, and is poised to almost entirely supplant conventional gas by 2035, according to a 2013 study on the future of Canada's energy resources.[9] These statistics represent a dramatic shift in development and production over just the last few years, and presents a significant challenge to regional, national, and industry regulatory bodies as they adapt to the changing technology at a blistering pace. Although its neighbor to the south has also witnessed a dramatic increase of unconventional gas production, the ownership, governance, development, and production of shale gas and other unconventional oil and gas resources in Canada differs in a number of ways from the United States.

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One of the most obvious differences is the fundamental issue of mineral ownership in Canada. Unlike the predominately private ownership of minerals in the United States, most of the oil and gas in Canada is owned by the Provincial and Federal Crown.[10] While there are some "freehold" mineral owners in Canada due to a failure by the various early governmental entities to reserve oil and gas in early land grants, the majority of minerals are owned either by the respective provincial government or the federal government.[11] The share of ownership between the respective Crowns differs significantly within each province, due to the history of its settlement, but generally the provincial Crown holds title to significantly more lands than the federal Crown.[12] As a result, regulations heavily dictate the leasing, development and production of unconventional oil and gas, and a number of regional and federal regulatory bodies exist to enact the applicable rules.

At a federal level, the National Energy Board (NEB) regulates the international and interprovincial logistical components of the natural resources and electric utility industries.[13] The NEB has some very broad responsibilities, including oversight of construction and operation of domestic and international oil and gas pipelines, international power lines, and certain domestic power lines, taxation of pipelines under its jurisdiction and the export of natural gas, oil, natural gas liquids (NGLs) and electricity, and importation of natural gas.[14] The NEB also maintains publicly accessible records detailing current pricing, statistics, and oil and gas production in Canada. The board also publishes forecasts of future production and seasonal energy outlooks. The price of natural gas was regulated through a series of federal-provincial agreements from 1979–1984, however in 1985 the price of natural gas was deregulated, and dropped sharply.

Immediately thereafter, suggesting that prices had been set too high.[15] From a resource management and environmental perspective, both Natural Resources Canada (NRCan) and Environment Canada work to regulate the responsible development and production of natural gas in Canada.

Canadian aboriginal and tribal land also contain proven reserves of unconventional gas, and are governed by Indian Oil and Gas Canada (IOGC), as well as Aboriginal Affairs and Northern Development Canada (AANDC), depending on the cultural history of the tribe.

While regulation at the federal level covers some of the more general aspects of unconventional oil and gas development, as well as offshore production and most international aspects of importing and exporting the resource, provincial governance is key to the operational regulations which impact unconventional oil and gas development at the source. As discussed in more detail below, Alberta is the country's oldest and largest producer of unconventional gas.[16] As a result, it has one of the most comprehensive regulatory schemes in Canada, and is often looked to as a source for regulatory

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standards within the country. Other Provinces which boast either existing production or proven unconventional gas sources include British Columbia, New Brunswick, Saskatchewan, Manitoba, Ontario, Quebec, and Nova Scotia.[17] While experts estimate that the Northwest Territories (NWT) and the Yukon hold significant shale gas potential, both of these territories have thus far only been subject to preliminary exploration.[18]

TYPES OF UNCONVENTIONAL GAS RESOURCES IN CANADA

Before discussing the details of various regulatory schemes governing the development and production of unconventional gas resources in Canada, it is important to distinguish the types of proven unconventional gas resources. The figure below is taken from a report published by the NEB, and depicts the state of natural gas production from the year 2000 through November 2013, estimating the makeup of natural gas production in Canada through 2035 (see the figure 6.1 below). The drastic decline of conventional gas production is primarily replaced with production from tight and shale gas development, although an overall decline in production is apparent through at least 2018, when shale and tight gas production is expected to escalate significantly.

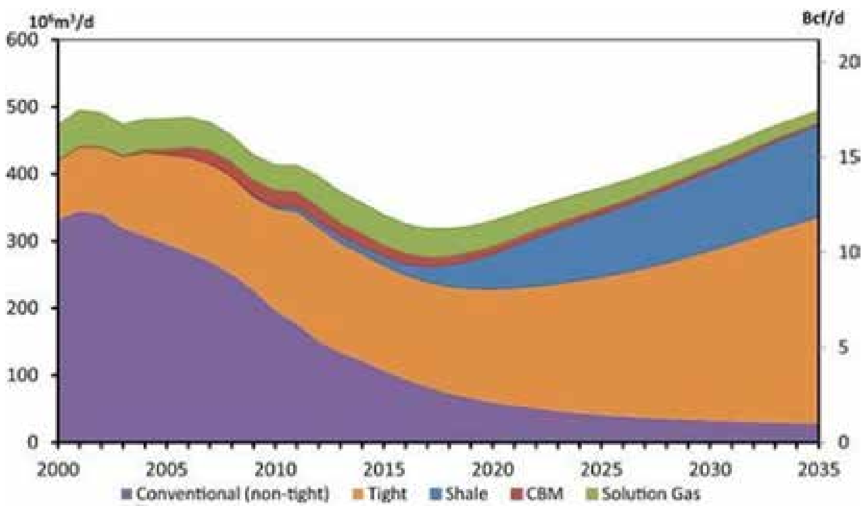

Figure 6.1 Energy Brief: Understanding Canada's Shale Gas (November 2009). *Source*: NEB, https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009nrgbrf-eng.pdf.

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SHALE GAS

Although it does not presently have a significant presence in the Canadian gas market, one of the most promising and potentially significant unconventional gas resources is shale gas, which until recently was not considered to be economically recoverable. Shale gas is natural gas which permeates shale, the most abundant sedimentary rock on earth.[19] Traditionally, "conventional" gas, which has until recently has been the primary source of natural gas, is comprised of various forms of "unconventional" gas which has had the opportunity to migrate over thousands of years and collect in underground formations. However, as these pools of conventional gas are developed, trillions of cubic feet of shale gas remain trapped within the tiny pore space of shale rock. Without a way to harvest this gas, it would have remained trapped within the shale rock. However, in recent years, an unconventional technique called hydraulic fracturing (also sometimes referred to as "fracking"[20]) releases the gas and allows operators to economically harvest the remaining shale gas. Hard rock and low porosity are nothing new in the oil and gas industry, and the technique of hydraulic fracturing has been enabling production from difficult formations since the 1940s.[21] However, the process of adding chemicals to the mix, known as slick water fracturing, has only more recently been applied to shale rock in order to obtain commercially viable production.[22]

Shale gas basins are enormous repositories of shale rock deep under the surface of the earth, although not all shale rock necessarily contains gas. The largest distribution of gas-bearing shale rock in Canada is found in the Western Canada Sedimentary Basin (WCSB), which encompasses numerous smaller formations to cover approximately 1,165,000 square kilometers.[23] Its tremendous geographic span extends from the NWT through the southwestern portion of Manitoba, and is primarily composed of the following shale gas basins: (1) the Horn River Basin, the Cordova Embayment and the Liard Basin (located in British Columbia and the NWT); (2) the numerous shale gas and shale oil formations and plays in Alberta, such as the Banff/Exshaw, the Duvernay, the Nordegg, the Muskwa, and the Colorado Group; (3) and the Williston Basin's Bakken Shale in Saskatchewan and Manitoba. This geographic area comprises the majority of the shale gas resources in Canada, containing an estimated 538 tcf of risked, technically recoverable shale gas.[24] Other potential areas which present an opportunity for shale gas recovery include the Utica Shale in Quebec, the Maritimes Basin in Nova Scotia, the Cretaceous and Devonian formations in the NWT, and the Arctic islands.

At the moment, however, the WCSB presents the most accessible opportunity for recovery, due to the formidable hurdles that each of the alternative

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basins present. The issue of hydraulic fracturing—the only existing economic means by which shale gas can be extracted—is highly controversial in the Quebec. Although the province is estimated to hold over 30 tcf of risked technically recoverable reserves, a de facto ban on hydraulic fracturing has been in place since 2011 after a study by the Bureau d'audiences publiques sur l'environnement (BAPE), pending further environmental studies.[25] Although in 2016, the National Assembly passed a bill which may ultimately permit oil and gas exploration in the province once again.[26]

Although the Maritimes Basin in Nova Scotia and New Brunswick has an extensive history of onshore and, more recently, offshore oil and gas operations, hydraulic fracturing has a much more limited role at this point for both logistical and political reasons. While the basin contains significant estimated shale gas reserves, it has proven difficult to effectively produce.[27] After securing rights in the Windsor Block via a farm-in agreement, Triangle Petroleum Corporation, by way of its Canadian subsidiary, Elmsworth Energy Corporation, drilled a number of vertical test wells, treating two of them with fracturing or diagnostic micro-fracturing procedures, however preliminary results indicated negligible gas production.[28] The recent shale gas activity has also drawn protests against hydraulic fracturing activity in Nova Scotia and New Brunswick by local citizens, hydraulic fracturing activists, and First Nation groups.[29]

The NWT and Canadian Arctic islands are also estimated to contain significant reserves of shale gas deposits, collectively holding approximately 60 tcf.[30] But while these vast regions may hold a wealth of shale reserves, they also pose significant logistical challenges. Severe weather, extreme cold, and remote locations all pose considerable hurdles to economic production and transportation of shale gas.

As it stands right now, the lowest hanging fruit on the tree of Canada's natural gas resources remains the WCSB, spanning a number of Western Provinces that are both easier to access logistically and generally more welcoming of the oil and gas industry. On the northern end of the basin, British Columbia contains some of the largest estimated shale formations in Canada, including the Liard, Horn River, Cordova, and Deep Basins.[31]

The US Energy Administration (EIA) has estimated that Alberta's plays contain an estimated 987 tcf of shale gas in place, with an estimated 200 tcf of risked technically recoverable resources.[32] A 2012 report covering the Duvernay, Muskwa, Montney, Basal Banff/Exshaw, Wilrich, north Nordegg, and Rierdon formations published by Alberta's oil and gas regulatory body, places the estimated total resources (P50 value) in place at 3,424 tcf of shale gas.[33] While the estimates may vary rather significantly from one

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reporting agency to the next, it is clear that the shale gas potential in Alberta is significant, and as further exploration and studies continue, operators and respective governing agencies will gain a better understanding of the full extent of the technically recoverable resources.

TIGHT GAS

Although shale gas seems to get all the press, in Canada tight gas likely exceeds the amount of shale gas in place, and is predicted to account for 62 percent of all natural gas production by 2035, compared with shale gas accounting for only 28 percent of all production. Tight gas is a type of unconventional natural gas which is produced from low-permeability sandstone, siltstone, and carbonate reservoirs. As with shale gas, this resource is primarily found within the WCSB, more specifically in certain Cretaceous zones in the Deep Basin; the Milk River, Medicine Hat and Second White Specks formations in southeast Alberta and southwest Saskatchewan; and the Jean Marie and Montney formations in northeastern B.C.[34] The low permeability of the rock in which tight gas is trapped requires the wells to be hydraulically fractured in order to achieve economic production. Estimated reserves of tight gas rival, if not exceed that of shale gas, with approximately 1,311 tcf of gas in place, and anywhere from 215 to 476 tcf of recoverable resources throughout Canada.[35] Half of that amount is estimated to be in Deep Basin and that part of the Montney formation located in Alberta, while the remaining half is found in northeastern British Columbia.

SHALLOW BIOGENIC GAS

Shallow Biogenic Gas (SBG) is a natural gas which—unlike most of the deeper thermogenic gas which is produced by heat and friction—is produced at much shallower depths and is the by-product of "anaerobic microbial degradation of organic matter."[36] Although production rates of SBG wells tend to be lower than conventional gas wells, the associated completion costs of the shallower wells are also generally lower and therefore more economic.[37] In Canada, most SBG is found in the WCSB, specifically, the Medicine Hat, Milk River, and the Second White Specks/Belle Fourche Formations. Early estimates place 10–12 tcf of SBG in the Milk River formation, 4–6 tcf in the Medicine Hat formation, and 2–3 tcf in the Second White Specks formation.[38]

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REGULATORY AGENCIES

Federal Oversight

The NEB could be compared to a combination of the US Bureau of Ocean Energy Management and Bureau of Land Management, providing the operational and regulatory framework of leasing in Canada, while regulation of the environmental aspects of unconventional gas on federal lands is governed by NRCan and to a lesser extent, Environment Canada. The NEB issues energy production reports, forecasts, and oversees the operations located in Nunavut, the Arctic offshore, Hudson Bay, West Coast offshore, Gulf of St. Lawrence, a portion of the Bay of Fundy and onshore Sable Island, and any other applicable federal Crown lease lands, and will also continue to provide a transitional role in the devolution of regulation within the NWT.[39]

With regard to unconventional gas production, the NEB recently released Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing in September 2013. The requirements, administered by the NEB pursuant to the Canada Oil and Gas Operations Act (COGOA), detail numerous steps that an operator must undertake before drilling a well which will be subject to hydraulic fracturing. This includes the requirement that the operator conduct an environmental assessment (EA) for any proposed activity.[40] Prior to the NEB EA requirement, the Canadian Environmental Assessment Act (CEAA) ensured that any federally governed project was subject to an EA. Where NEB lacks jurisdiction, the CEAA EA requirement still applies.[41] The NEB mandated EA requires detailed descriptions of potential environmental impacts, which must account for the impacts of possible malfunctions or accidents and mitigation plans.[42] The EA must also include consultations with the local community and any aboriginal groups that could be impacted by the activity, including detailed socio-economic impacts that the proposed activity could have.[43]

After the EA, the operator must next submit numerous plans which detail the following various operational components in order to obtain an Operating License.[44]

Finally, in order to obtain specific well approval, the operator must submit plans which detail specific components of the well itself, such as well schematics, the directional plans, the proposed drilling schedule, target formations, geophysical data, groundwater protection, wellbore integrity plans, and drilling fluids, among other requirements.[45]

In February of 2014 the NEB began requiring that operators submit drilling fluid composition to fracfocus.ca within thirty days after hydraulic fracturing is completed.[46] The fracturing fluid composition information includes the trade name, purpose, ingredients, ingredient percentage in additive by

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percentage mass, and ingredient concentration in fracturing fluid percentage by mass.[47]

If unconventional gas wells are drilled on First Nations reserve lands, the operation falls under the purview of IOGC. The IOGC currently permits hydraulic fracturing on reserve lands, but implements certain requirements prior to and during drilling operations, summarized as follows:

Prior to oil and gas activities taking place:

1. an environmental review must be conducted;
2. when hydraulic fracturing is proposed IOGC must ensure companies conduct baseline water testing for water wells located within 500 meters of any oil or gas well prior to drilling; and
3. all applications, regardless of whether hydraulic fracturing is proposed, must demonstrate that the environment will be protected.

New regulations are currently being developed to deal specifically with hydraulic fracturing and the potential for mitigation as the result of any adverse impacts caused by drilling and fracturing operations.[48]

While the federal component of unconventional gas governance represents relatively robust industry oversight coupled with ongoing studies as the unconventional gas industry continues to grow, the most significant source of regulation is found at the provincial level in Canada.[49]

Provincial Oversight

Alberta

Alberta, as Canada's largest oil and gas producer, invests significant resources into developing some of the most comprehensive and influential regulations in the country. Over the years, the governing organization, currently known as the Alberta Energy Regulator (AER), has adapted to the dramatic changes presented by the industry, either as a result of waning production or, as is the case more recently, as technology has evolved to produce a resource previously considered unreachable. The most recent name change is more than just a rebranding—the AER is a combination of the province's former energy conservation board and the energy development environmental protection responsibilities formerly managed by Alberta's Environment and Sustainable Resource Development.[50] In other words, the resulting agency is attempting to streamline and unify the operational and environmental regulatory components of oil and gas exploration and development.

As of October 2013, the AER reported regulation of 185,000 wells, 405,000 km of pipeline, and 775 gas processing plants, among other

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facilities.[51] Of those wells, over 94 percent, or 174,000 wells, have been fractured, although only 7,700 wells have been treated with multi-stage hydraulic fracturing, the technique responsible for the recent shale gas revolution.[52] With more than eight shale gas formations in the province, the number of multi-stated hydraulically fractured wells stands to increase significantly over the coming years.

The AER's regulatory authority is found in the following six acts:

- Responsible Energy Development Act
- Oil and Gas Conservation Act
- Environmental Protection and
- Enhancement Act
- Public Lands Act
- Water Act

In a presentation specifically addressing the challenges of unconventional development in Alberta, the AER identified specific objectives of its management practices, including the development of regulatory fundamentals, a focus on unique regional aspects, enhanced planning and community engagement, and accounting for new technological challenges.[53] A significant component of the AER's handling of unconventional gas development is the common theme of stakeholder engagement, with a focus on soliciting feedback from both industry members and the local community when drafting regulation or issuing a decision.[54]

Many of the guidelines which dictate how, when, and where a well may be drilled, and also detail the requirements of the public disclosure and consultation process are issued as directives.[55] When directives are drafted or revised, they are released on the AER website in draft form, a period during which industry members and stakeholders may provide feedback. Bulletins posted on the AER website alert the public to the draft directives. The AER website also provides various manuals to help an operator navigate the application and regulatory process, and also details the operational responsibilities of AER personnel. The topics covered by the manuals range from a detailed description of the application and permitting process to a specific list of what is potentially examined during drill site, pipeline, and waste management inspections.[56]

Another aspect of regulatory change in Alberta in the face of increased unconventional production is the traditional concept of well spacing. As unconventional production often results in multiple wells drilled from a single pad, operators have asked for, and generally received exceptions to the standard spacing requirement of one well per section.[57] As a result, the AER has removed subsurface well-density controls for coal bed methane

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and shale gas wells across Alberta, and in certain gas zones in southeastern Alberta.[58]

As global demand for resources grows and the corresponding development increases, the inevitable conflict between operator and landowner will continue to shape the future of regulation and governance. With its long history of development and tremendous potential for unconventional gas production, the regulatory framework of the AER sets a powerful standard for oil and gas regulation throughout the country and will continue to frame the discussion for future development in Canada.

British Columbia

British Columbia is the second largest producer of natural gas in Canada, accounting for over a quarter of the country's marketable natural gas production in 2016 (a figure which includes conventional gas).[59] Its regulatory body is an independent Crown Corporation, known as the BC Oil and Gas Commission (BCOGC). It has a much shorter history than the AER, and was first founded in 1998 as the result of an agreement between British Columbia and the Canadian Association of Petroleum Producers (CAPP) designed to encourage oil and gas exploration and development in the province.[60] The BCOGC was originally established under the Oil and Gas Commission Act (OGCA), and currently operates pursuant to the province's Oil and Gas Activities Act (OGAA) and Petroleum and Natural Gas Act (PNGA), but it also operates pursuant to specific provisions under the Forest Act, Heritage Conservation Act, Land Act, Environmental Management Act, and Water Act.[61] Since 2008 its regulatory constituency has essentially flip-flopped: in 2008 85 percent of the wells managed by the commission were conventionally drilled wells. By 2013 that number decreased to only 14 percent of wells, while 86 percent of wells are now unconventional.[62]

While the BCOGC also issues directives, unlike the AER, most of its operational guidelines are contained in the OGAA, which provides detailed requirements on issues ranging from well spacing to casing requirements. The OGAA also addresses certain hydraulic fracturing requirements, such as hydraulic isolation between porous zones, fracturing fluid records, and special approval as part of the permitting process for fracturing at or above certain depths. [63]

Failure to comply with the OGAA requirements or other directives issued by the BCOGC fall either into a quasi-criminal or an administrative category, depending on the nature of the offence.[64] If the violation is deemed to be quasi-criminal, then it passes to the Crown Council for prosecution, however the BCOGC may also issue tickets, if appropriate, under the Water Act or Environmental Management Act. If the violation is administrative, then it

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will ultimately result in a financial penalty, and may prevent the operator from carrying on development or production.[65] Environmental components of gas regulation include well site reclamation,[66] air discharge permitting,[67] waste management and disposal,[68] and habitat interaction and protection guidelines.[69]

As in Alberta, the BCOGC has faced criticism of a lack of oversight and transparency in light of the escalating number of hydraulically fractured wells and associated incidents.[70] While the vast majority are "low risk" incidents which merit only minor fines, critics of the organization point to a lack of disclosure regarding the identity of the offenders.[71] Since the publication of the article criticizing the agency for lack of transparency, the BCOGC has issued quarterly Enforcement Action Summaries which detail incidents, penalties, and also identify the operator.

New Brunswick

After initially drafting proposed "Rules for Industry" in February 2013 targeting unconventional gas production and its potential environmental, safety, and health impacts, the government ultimately chose to impose a moratorium on hydraulic fracturing, which has been indefinitely extended pending satisfaction of various conditions imposed on the industry imposed by the provincial government.[72]

Other Provinces

Currently, the remaining Provinces and territories in Canada either do not have significant unconventional gas production, have not yet promulgated rules to address the issue, or have instituted actual or de facto bans. While Ontario holds promise for potential unconventional gas drilling, it has not witnessed significant interest in developing those resources, and has not created specific rules governing exploration and production, although oil and gas is otherwise regulated by the Oil, Gas, and Salt Resources Act.[73]

Although it's not a province, the Yukon maintains relative self-governance, and this extends to its management of oil and gas. The Yukon gained control of its land and natural resources in 2003 through amendments to the Yukon Act, based on the Yukon Northern Affairs Program Devolution Transfer Agreement.[74] The Yukon's unconventional gas resources are managed by the Oil and Gas Resources section of the Department of Energy, Mines and Resources.[75] Its Oil and Gas Drilling Production Regulations, made pursuant to the Oil and Gas Act, detail specific requirements regarding licensing, spacing, casing, and environmental concerns.[76] In April of 2015, the Yukon government agreed to permit hydraulic fracturing in the Liard Basin region of the territory, but only with support of the affected First Nations.[77]

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In the NWT, the Standing Committee on Economic Development and Infrastructure (SCEDI) conducted a study tour in Alberta in order to gain a better understanding of the industry and its impacts.[78] After the tour, the SCEDI requested that the Government of the Northwest Territories (GNWT) respond to the report with a plan to develop policy on the issue of hydraulic fracturing.[79] Since the tour, management of oil and gas resources in the Northwestern Territories has devolved from the federal Crown to the GNWT's department of Industry, Tourism and Investment (ITI).[80] Under the devolution of management, the ITI has adapted the Petroleum Resources Act and the Oil and Gas Operations Act (OGOA) from the federal legislation managed by Aboriginal AANDC.[81]

CURRENT STATE OF THE INDUSTRY

Since the development of unconventional oil and gas resources in Canada began to increase significantly beginning in the mid-2000s, the corresponding boom in domestic production in the United States has created a glut of oil and gas in the open market.[82] An overabundance of oil and gas in the North American market, coupled with continued production by the OPEC consortium and Russia, has contributed to a global collapse in the prices of oil and natural gas. Despite the reduced prices, the number of wells drilled in Canada has grown significantly over the past year, with an expected 64 percent increase in 2017 over the previous year.[83] After sinking to a low of just 4,084 wells in 2016, well drilling has rebounded with almost 6,680 wells expected to be drilled in 2017 (down from a boom period that saw around 11,000 wells being drilled annually between 2012 and 2014).[84]

While provinces struggle with permitting or increased hydraulic fracturing activity in their respective jurisdictions, another realm holds real potential, even in light of depressed prices: Liquefied Natural Gas (LNG). Asia alone accounts for more than half of all global import of LNG, followed by the European Union countries.[85] On the west coast, British Columbia is well poised to deliver and export significant LNG to the Asian market with its significant levels of domestic production and extensive coastline. According to the Northwest Institute for Bioregional Research, there are currently seventeen planned LNG export facilities planned in British Columbia.[86] A report by the Canadian Energy Research Institute has predicted that even a modest amount of exported natural gas would help to stabilize the price of natural gas and encourage sustained growth.[87] While the Asian demand for LNG is expected to nearly double in coming years, the licensing process is extensive and complicated, and there does not appear to be a proposal for an expedited procedure on the horizon.[88] Coupled with the construction of LNG export

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facilities is the construction of corresponding pipelines to transport the natural gas to the liquefaction facilities. A current study predicts the creation of 100,000 "direct, indirect, and induced LNG-related jobs" if the LNG facilities are constructed.[89] In any event, permitting and construction of LNG export facilities is still a few years away from being a reality, despite its potential to stabilize price and boost production of unconventional natural gas.

CONCLUSION

Although the production of unconventional oil and gas is currently enduring a serious setback with the recent glut in supply, global markets continue to demand affordable sources of energy as energy insecurity and the pace of industrial development continues to grow. Coupled with its tremendous unconventional gas potential, Canada offers some of the most untouched and pristine wilderness in the world, an asset that all Canadians—environmentalists and operators alike—are keen to protect. While existing regulation in Alberta and British Columbia provides an excellent and robust starting point, the changing landscape of the Canadian natural gas industry will demand that regulations adapt to allow for more predictability within the industry and instill confidence in the public. As the market searches for a degree of stability, time will tell whether and to what degree each province is open to direct development of its resources or the accompanying infrastructure, such as LNG export terminals and pipelines. If the recent market volatility has demonstrated anything, it is that each component of the industry—whether a government, private entity, citizen action group, or politician—is deeply affected by the factors contributing to and the benefits flowing from the development and production of unconventional resources.

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Chapter 7

The Socio-Legal Dimensions of the Development of Unconventional Petroleum in Australia

Shale Gas and Coal Seam Gas

Tina Hunter

INTRODUCTION

Australia is blessed with huge amounts of both conventional and unconventional petroleum resources. Like many other countries, to date it has been Australia's conventional petroleum resources that have been developed, with onshore gas production for commercial purposes occurring from conventional reservoirs for over fifty years.[1] The production of gas commenced with the exploitation of the giant Moomba field in the Cooper Basin, operated by Santos, which has been a constant and voluminous supplier of petroleum, especially gas, to the densely populated eastern states via a series of pipelines. The Moomba field exists in central Australia, in an area that is sparsely populated and which most Australians do not even know exists. Other conventional gas extraction has occurred in the Cooper Basin in South Australia, the Otway Basin in Victoria, and the Amadeus Basin in the Northern Territory.[2] Conversely, the production of conventional petroleum from Western Australia (WA) has been small to date. With the exception of the giant Moomba field in the Cooper Basin, onshore conventional petroleum resources have been relatively unspectacular, contributing little Australia's energy supply.

To date Australians have had little exposure to the development of petroleum resources, given the location of the Moomba gas fields in the Central Australian desert area and the offshore oil and gas fields. To most Australians, gas magically appears at the end of a tap in the home, with little thought to how the gas arrives in their home. This is especially the case in New South Wales (NSW) and Victoria, which is heavily reliant on gas for industry and

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domestic use. In the western areas of Australia there is a heavy reliance on gas, given the low coal resources that WA possesses. This gas has, until now, been provided largely from offshore gas fields, making WA vulnerable to interruptions to gas supply. Such vulnerability was illustrated by a 30 percent reduction in gas supply in 2008 as a result of the Varanus Island Gas pipeline explosion.[3] In order to ensure security of supply, the Western Australian government is committed to investigating and developing its unconventional gas resources as an additional source of gas for the WA domestic and industrial population.

At the beginning of the 2000s, extraordinary interest was shown in the small amounts of coal seam gas (CSG) (which is also known as coal bed methane)[4] that had been produced from the coal reserves in Queensland's Surat Basin,[5] on the back of increased interest in shale gas in the United States. The development of CSG in Queensland has been undertaken by a number of Australian and international petroleum companies, including British Gas, Arrow Energy, Shell, Petro-China, Santos, Queensland Gas Company (QGC), Conoco Phillips, Total, Petronas, Kogas, Origin, and Sinopec. Extraordinarily, the Queensland Government has not coordinated the development of field infrastructure, transport, and processing facilities. Rather, these facilities have been developed by each of the consortium of companies that have been established to develop Queensland's CSG resources. This has resulted in the triplication of pipelines, storage, processing and shipping facilities, and facilitated the need to reclaim Curtis Island for port facilities and undertake large-scale dredging in an area within the Great Barrier Reef Marine Park off the coast of Gladstone. The rapid development of CSG resources in Queensland over the last ten years has led to the Queensland government scrambling to effectively legislate the development of CSG in a manner that addresses the social issues arising from CSG development in a predominantly agricultural area.

Conversely, shale gas, where Australia is predicted to have huge reserves,[6] has been slow to be developed. This is largely attributable to two reasons. The first is the vast distribution of shale gas reserves in an area of Australia that is sparsely populated and with little existing infrastructure. The other is due to community reservations and concerns regarding shale gas development, largely as a result of the movie Gasland in 2010. Gasland, alongside community concerns relating to the development of CSG in Queensland, prompted community groups in WA to engage in community protest and question the government regarding the regulation of shale gas development. As a consequence, the WA government undertook a review of its shale gas regulatory framework to ensure it is fit for purpose. Similarly, there have been concerns regarding the development of shale gas resources in the

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NT, particularly from cattle farmers and indigenous groups. As a result of these concerns, the NT government also undertook a study of its regulatory framework for unconventional gas resources, and as a result is reforming the onshore petroleum regulatory framework.

The concerns that have been raised by communities and farmers regarding the development of UPR generally fall into three categories. First, and perhaps the greatest concern expressed by the community, is the effects of hydraulic fracturing (HF) on the ground water and communities. An examination of social activism and protest relating to UPR development in Australia places this issue at the forefront of other concerns.[7] The main concern with HF that is voiced by such community groups is that it poses a risk to human health and the environment, largely due to the chemicals utilized down-hole. As such, chemical use and disclosure is associated with these concerns. The second community concern related to the development of UPR is the use of valuable water resources, and the disposal of produced water after HF. This concern is largely attributable to the scarcity of water in Australia,[8] particularly in areas where shale gas development is likely to take place, and the importance of water resources on the east coast, where CSG development is occurring, for agricultural production and sustenance of life.[9] Thirdly, concerns about the development of UPR in Australia broadly relate to land, and incorporate damage to productive farming land, land access and compensation, and long-term indigenous land protection.

Given the level of activity in Queensland and the community concerns that have been voiced over the last five years relating to unconventional petroleum resources development and future development of UPR in central and Western Australia, there has been a plethora of legal reform associated with UPR development. This chapter examines the legal reforms concerning UPR that have occurred in Australia in response to such community concern. In particular, this chapter will examine the legal framework relating to UPR in Australia, incorporating (but not confined to) an examination of legal reform associated with the areas of concern, namely HF and chemical disclosure, water use and treatment, and land access, and compensation.

SCOPE AND METHODOLOGY

This chapter examines the legal systems that exist to regulate the development of UGR in Australia. The contribution of this chapter to the wider study of UPR regulation is that it considers the structure of the law, and how the law has developed and exists in response to socio-legal issues related to UPR development, namely the impact of HF on communities, community

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concerns related to water use and treatment associated with UPR development, and land access and compensation arising from UPR development.

Given the socio-legal issues, this analysis utilizes a socio-legal research methodology, analyzing the law itself, and its relationship with the wider society. As part of the socio-legal research methodology, it embraces doctrinal research as a tool to examine the legal doctrine within the broader society, and its implication and effect. Doctrine can be defined as "a synthesis of rules, principles, norms, interpretive guidelines and values. It explains, makes coherent or justifies a segment of the law as part of a larger system of law. Doctrines can be abstract, binding or non-binding."[10] In the instance of this study, doctrine is limited to the rules, principles and norms related to UPR development in Australia. Utilizing the doctrinal research approach, this chapter provides a systematic exposition of the rules governing UPR development. It then places these laws within the social context within which the laws have developed.

UNCONVENTIONAL PETROLEUM RESOURCES IN AUSTRALIA

Australia is a geologically old and complex continent, spanning over 3.8 billion years of the earth's geological history and containing almost all known rock types.[11] UPR in Australia are geographically separated, with CSG reserves dominating the east coast of Australia, and shale gas reserves dominating the central and western areas of Australia. This physical division in the location of UPR broadly follows the geological division of Australia, with western and central Australia dominated by Precambrian geology, and the eastern third dominated by Cambrian and Phanerozoic geology, with an abundance of tertiary geology.[12]

Without exception, all unconventional gas resources in Australia occur on land. The recovery of UGR is divided geographically, according to geological basins, illustrated in Figure 7.1 below:

- Shale Gas Resources (SGR), primarily found in Central and Western Australia in the
  - Canning Basin (WA)
  - Perth Basin (WA)
  - Amadeus Basin (NT)
  - Georgina Basin (NT)
  - Beetaloo Sub-Basin (NT)
  - Cooper-Eromanga Basin (SA)
- Coal Seam Gas (CSG), primarily found in Eastern Australia in the
  - Bowen/Surat Basins (Qld),

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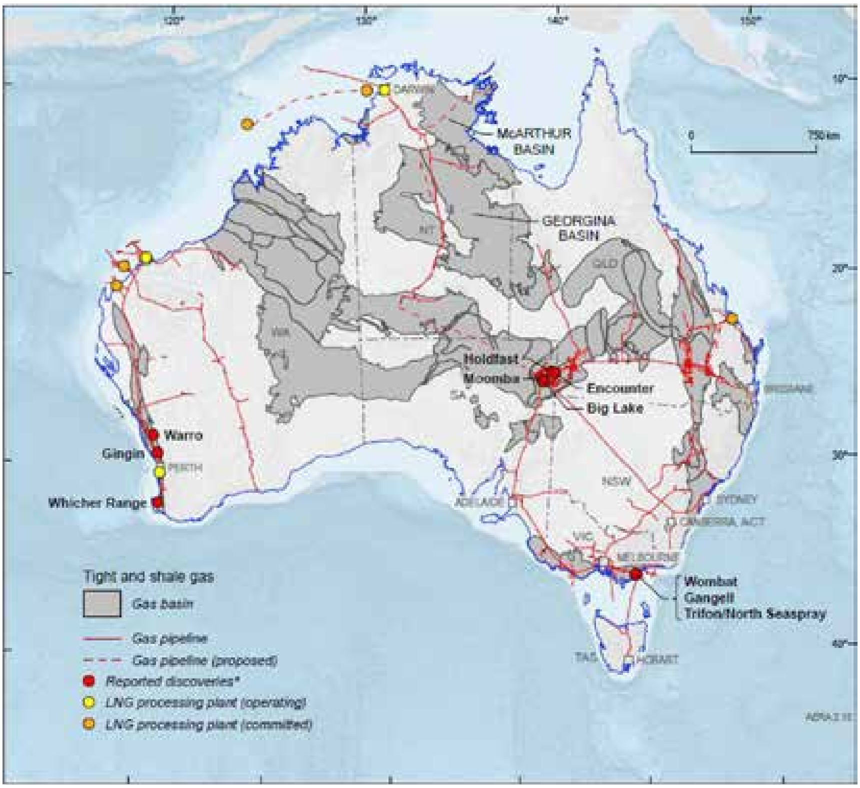

Figure 7.1 Overview of Unconventional Petroleum Basins in Australia. *Source*: Geoscience Australia (February 2015).

- ◦ Gunnedah Basin (NSW)
- ◦ Sydney Basin (NSW)

SHALE GAS RESOURCES (SGR)

There are a number of prospective Australian shale basins, illustrated in Figure 7.1, with major shale gas potential existing in four major geological basins. With the exception of the small, scarcely explored Maryborough Basin in coastal Queensland, SGR in Australia are located in Western Australia, the Northern Territory, and South Australia.[13] A US Energy Information Agency (EIA) 2013 estimate of SGR in Australia places the reserves at 437 trillion cubic feet (tcf), the seventh largest country in the world in terms of reserves.[14] Similarly, a 2013 estimate of shale oil resources in Australia places the reserves at eighteen billion barrels of oil, ranking Australia's reserves as the sixth largest global reserves.

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Western Australia

Western Australia has demonstrably large SGR, with the US Energy Information Agency (EIA) estimating the presence of shale gas reserves of 288 tcf, almost double that of offshore conventional gas reserves.

The Perth Basin in the smallest of the WA shale gas-bearing basins. However, due to its proximity to Perth, and favorable climatic conditions it is perhaps the best explored to date. Initial shale gas exploration has been undertaken by AWE Limited (AWE) and Norwest Energy, targeting the prospective marine shales of Triassic and Permian age. To date little commercial shale gas has been identified, however exploration continues.

The large Canning Basin in Western Australia has deep, Ordovician-age marine shales that are roughly correlative with the Bakken shale in the Williston Basin.[15] Buru Energy, an Australian exploration and production company, holds significant exploration permits (EPs) in the Canning Basin. In 2010, Mitsubishi agreed to fund an A$152.4 million exploration and development program to earn a fifty percent interest in Buru's permits. The two companies executed a State Agreement is adequate with the Western Australian Government in 2012,[16] enabling them to undertake extensive exploration of the Canning super basin. The SA, which extends for twenty-five years and an option of a further twenty-five years, enables appraisal work undertaken to relieve the exploration permits from their existing relinquishment obligations, and to enable exploration work to be credited against adjacent EPs that are not covered under the State Agreement.[17] In addition, under the terms of the SA the WA Department of State Development will take the lead-agency role in the development of an LNG facility in the Pilbara as well as a domestic gas pipeline from the Canning Basin in order to secure domestic energy supplies in the future.[18] The primary role of the SA, and the exploration for and development of shale gas, is to secure long-term accessible domestic supplies of gas for WA.

Buru has also undertaken exploration in the Yulleroo gas field, after reporting gas-mature and organic-rich shale from the Yulleroo-1 conventional exploration well drilled originally 1967 on permit EP-391. Cores from Yulleroo-3 (2012) and Yulleroo-4 (2013) wells demonstrate strong gas shows at depth.[19] In addition, reservoir stimulation of Yulleroo-2 in 2010 demonstrated that the Yulleroo reservoir is capable of flowing gas of good quality with significant hydrocarbon liquid content. Buru Energy has approval to undertake hydraulic fracturing (HF) of Yulleroo-3 and Yulleroo-4 during the dry season of 2016 (May–October) to determine the commercial nature of shale gas in the Yulleroo field.[20] New Standard Energy (NSE) also holds substantial exploration licenses in the Canning Basin. In September 2011, NSE formed a joint venture with ConocoPhillips to accelerate exploration

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with ConocoPhillips, and has announced that it will fund an exploration program over four years for up to $US119 million.[21]

Northern Territory

In the Northern Territory, the Precambrian shales in the Beetaloo Basin and the Middle Cambrian shale in the Georgina Basin have reported oil and gas shows in shale exploration wells. If proved commercial, these two shale petroleum basins would become some of the oldest producing hydrocarbon source rocks in the world.[22] Aside from the now depleted Mereenie and Palm Valley conventional petroleum fields, the NT utilized gas from the Blacktip gas field for domestic energy supplies. As such, the development of SGR in the NT will be for export purposes.

The Amadeus Basin, located in central-southern NT, contains producing conventional oil and gas fields (Mereenie and Palm Valley), is one of the most prospective onshore areas in the NT for unconventional petroleum.[23] The Georgina Basin, covering an area of 330,000 sq. km is located in central-eastern NT, and extends into western Queensland. The Basin is also one of the most prospective for UPR, with organically rich shale rocks demonstrated. Exploration is still in a frontier stage, and given the limited amount of seismic data and geological data available,[24] no estimate is available for potential SGR in the NT section of the Georgina Basin.[25] The Beetaloo Sub-Basin has attracted a considerable amount of exploration activity, probably since it is a significant subsurface depositional center within the McArthur Basin.[26] To date the Sub-Basin has been delineated as a result of the collection and interpretation of seismic, drilling, and magnetotellurgic data.[27] Like the two other NT Basins it is a target for UPR exploration. Whilst there has been little shale gas exploration activity in the NT to date, interest in UPR in the NT has rapidly increased. In 2001, approximately 10 percent of the NT was under exploration permit applications (EPAs). At present approximately 90 percent of the Territory is under EPAs. Furthermore, the area under EPs has risen from less than 2 percent to over 10 percent in 2012.[28]

South Australia

Not only has South Australia (SA) been Australia's leading onshore gas producer, it has also been a pioneer in the exploration for and development of shale gas. The shale gas formations in SA are confined to the Cooper Basin, which partly extends into southern NT and Western Queensland (although the majority of the field lies within SA). To date several exploratory shale gas wells have been drilled with Beach Energy's Encounter 1 well the first shale gas exploration well drilled in the Cooper Basin in 2010. Unlike other

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basins in Australia, much of the shale gas in the Cooper Basin is located below operational conventional gas fields. Santos, a major operator in the Cooper Basin, estimates the potential range of net recoverable gas from under existing conventional petroleum licenses to be 15–125 tcf.[29] Of the six shale basins assessed, the Cooper Basin, with its existing gas processing and transportation infrastructure, has provided the first commercial source of shale hydrocarbons (comprising a small amount of shale gas).[30] Santos, Beach Energy, and Senex Energy continue to explore the Cooper Basin shale reservoirs, expecting to find huge commercial reserves of gas that will be utilized via existing infrastructure.

Given the existing conventional petroleum activities extent of and associated infrastructure for delivery of gas to east coast markets, it is highly likely that shale gas from the Cooper Basin will be the first shale gas to market in Australia.

DEVELOPMENT OF CSG RESOURCES IN QUEENSLAND

Australia is endowed with massive coal resources, possessing 6 percent of the world's black coal and 25 percent of recoverable brown coal.[31] CSG reserves in Australia are largely confined to the east coast of Australia, with a small amount in Western Australia's Perth Basin.[32] The primary CSG activity has been confined to Queensland, where gas production has occurred since the late 1990s, with small-scale commercial exploitation of the methane gas from coal seams in 1996 in Queensland.[33] Since the mid-1990s commercial production of CSG has increased, initially providing gas for Queensland electricity generation. Today the large-scale development is also targeted at the export of LNG to Asian energy markets on long-term forward contracts.[34]

The pioneering development of CSG occurs in the Surat and Bowen Basins over an area of around 270,000 km^2, with additional area for pipeline corridors and LNG processing and transport facilities on Curtis Island. This development has occurred since the mid-2000s, and has involved four individual consortia, with a capital investment exceeding $60 billion. To date, Australia's annual CSG production has increased from 1PJ in 1996 to 285 petajoules (PJ) in 2013–2014,[35] around 10 percent of Australia's total gas production. Of the 2013–2014 production of 285 PJ of CSG, 119 PJ was produced from the Bowen Basin, and 166 PJ from the Surat Basin.[36]

At present there is a major development of infrastructure for CSG resources in Queensland, with at least three large consortia to develop fields and infrastructure for the export CSG as LNG from 2015.[37] The gas is to be transported

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by pipeline from the CSG fields to Gladstone Harbour/Curtis Island for LNG processing prior to shipment to Asian markets.

The first consortium is the QCLNG (Queensland Curtis LNG) consortium, formed by the partnership of QGC and British Gas (BG). It is the world's first project to turn gas from coal seams into LNG.[38] The project acquired licenses in the Surat Basin during the mid-2000s and began seeking approvals for development at that time. With approvals in place, construction of the necessary infrastructure, alongside the development of wells for production has occurred since 2010.[39] The project involves the development of CSG field in the Surat Basin, further exploration in the Bowen Basin, and the construction of a 540 km pipelines linking the fields to Gladstone, where QCLNG has also built a two train LNG processing facility, two LNG storage tanks and LNG loading facilities on Curtis Island near Gladstone, Queensland.[40] The capital investment has been enormous, with over $20 billion of investment from 2010 to 14. The project has culminated in the first shipment of gas in January 2015, which was also the first export of gas from Australia's east coast.[41]

The Gladstone LNG (GLNG) consortium comprises Santos, Petronas, Total and Kogas, with fields in the Bowen and Surat basins. The consortium is also developing, independently of other LNG consortia, a 420 km pipeline to its two LNG processing trains and associated LNG storage and loading infrastructure on Curtis Island.[42] First gas from this consortium was delivered to the processing facility on Curtis Island in March 2015,[43] and the delivery of first gas to customers is expected in the second half of 2015.

Australia Pacific LNG (APLNG) is the third CSG consortium that is also developing CSG production, transport and processing/LNG loading facilities. It is a partnership between Origin, ConocoPhillips, and Sinopec. Similar to the GLNG consortium, APLNG has gas fields in the Surat and Bowen Basins, and is constructing a 530 km transmission pipeline from the gas fields to the LNG processing and loading facility on Curtis Island,[44] as well as supplying domestic gas.

A fourth consortium, Arrow LNG, comprising Arrow Energy and PetroChina, (as well as Shell prior to January 2015), planned to construct similar production, transport, and processing facilities for the export of CSG produced from its tenements in the Bowen and Surat Basins.[45] However, a change in Commonwealth law relating to requirements under the principal environmental act[46] meant that approval for the construction of such facilities by the Arrow Consortium were delayed significantly. As a consequence of the delayed approval for the necessary infrastructure, the Arrow Consortium has instead decided to secure higher marginal sales for its gas by selling downstream.[47] To that end, Arrow is building pipelines from the Surat and Bowen Basins to Gladstone, in order to connect its gas with high value overseas markets.[48]

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Regulation of Unconventional Gas Resources in Australia: Overview of Regulation-Jurisdiction and Competence

The regulation of UGR in Australia is complex, primarily as a result of the preexisting Australian colonies at the time of federation, and the Australian Constitution that entered into force on January 1, 1901.[49] Australia is comprised of six states,[50] each with their own political and legal system, as well as two self-governing territories: Northern Territory and the Australian Capital Territory (ACT). Given that Tasmania and the ACT do not have shale gas reserves, they will not be considered in this analysis. All onshore petroleum activities are regulated by the states/Northern Territory, as there is no enumerated power for the Commonwealth to regulate petroleum and mineral activities under the Australian Constitution.[51] In contrast, each Australian state has the capacity to regulate all other activities not enumerated in the Australian Constitution for the "peace, welfare and good government" of that state.[52] All onshore petroleum activities, be they conventional or unconventional, are regulated under the relevant petroleum legislation in each state/Northern Territory, with the exception of Victoria, where CSG activities are regulated under the Mineral Resources (Sustainable Development) Act 1990 (Vic) (MRA). The reason for this difference relates to the regulation of coal mining activities under the MRA in Victoria, with CSG viewed as an extension of coal mining activities and therefore to be regulated under the MRA.

The exploration for, and extraction of shale gas in Australia is generally governed by the main Petroleum Act in each jurisdiction, with petroleum[53] defined in the section following:

- Petroleum (Onshore) Act 1991 (NSW)—s 6;
- Petroleum Act (NT)—s 5;
- Petroleum Act 1923 (Qld) and Petroleum and Gas (Production and Safety) Act 2004 (Qld)—s 10;
- Petroleum and Geothermal Energy Act 2000 (SA)—s 4;
- Petroleum Act 1998 (Vic)—s 6 (conventional petroleum) and Mineral Resources (Sustainable Development) Act 1990 (Vic) (unconventional petroleum)—s 5; and
- Petroleum and Geothermal Energy Resources Act 1967 (WA)—s 5.

Although each of the state/territory Onshore Petroleum Acts defines petroleum in a slightly different manner, each definition has a common thread. Generally each of the Acts (with the exception of Tasmania) defines petroleum as any naturally occurring hydrocarbon (whether in a gaseous, liquid or solid state), or any naturally occurring mixture of hydrocarbons.[54]

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Similarly, the regulation of environmental issues relating to shale gas (and CSG) in Australia is a matter for the individual states, under the ambit of the states' constitutional plenary power to make laws for the "peace, welfare and good government" of the state. The Commonwealth does not have an enumerated power to make laws with respect to environmental matters. However, there are sections of the Australian Constitution where the Commonwealth has the capacity to regulate environmental management of petroleum activities. In particular, the Commonwealth can regulate under the trade and commerce power (s 51(i) of the Constitution) given the High Court decision in Murphyores.[55] In this unanimous decision, the court held that given the trade and commerce power was a purposive power, legislation allowing the Minister to prohibit the activities of a company that exports mineral sands pending the outcomes of an environmental inquiry was a valid exercise of the trade and commerce power. Similarly, the Commonwealth has the capacity to regulate the activities of companies under the Corporations power (s 51(xx) of the Constitution), especially given the outcome of the Work Choices case.[56] However it is under the External Affairs power (s 51 (xxxi) of the Constitution) that the Commonwealth government is able to regulate environmental matters.

The primary legislative tool for environmental protection at the Federal level is the Environmental Protection and Biodiversity Conservation Act 1999 (Cth) (EPBCA), which gives effect to the numerous environmental treaties and conventional that Australia is a signatory. This Act provides for protection of the environment in a number of circumstances, as well as protection of biodiversity, including some habitats. While the EPBCA is Commonwealth legislation and has as its ambit environmental protection, it does not apply to all petroleum activities. Rather it only applies where the activity falls under an area where referral for assessment is required under the EPBCA. Day-to-day environmental management falls under the ambit of state/Northern Territory law. Therefore while the EPBCA is not core environmental legislation, it is nonetheless important, and needs to be considered when examining environmental regulation of petroleum activities.

Under the EPBCA an action will require approval from the Environment Minister if the action has, will have, or is likely to have a significant impact on a matter of national environmental significance (MNES). Under s 523 of the EPBCA, an action is defined broadly to include a project, a development, an undertaking, an activity or a series of activities, or an alteration of any of these things.[57] A significant impact is defined as

> an impact which is important, notable, or of consequence, having regard to its context or intensity. Whether or not an action is likely to have significant impact depends on the sensitivity, value and quality of the environment which

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is impacted, and on the intensity, duration, magnitude, and geographic extent of the impacts.[58]

The MNES comprises:

1. listed threatened species and ecological communities;
2. migratory species protected under international agreements;
3. Ramsar wetlands[59] of international importance;
4. the Commonwealth Marine Environment;
5. world heritage properties;
6. the Great Barrier Reef Marine Park;
7. nuclear actions; and
8. a water resource in relation to CSG development and large coal mining development (the "water trigger").

To determine whether an action requires approval by the minister, the project is referred to the designated assessing department if the project includes one of the MNES (known as a referral). The project can be referred by either the project proponent themselves, or a third party such as a Minister, or a government agency. Generally, the project proponent will refer the project to determine whether the referral requires assessment under the EPBCA. An application for referral is then assessed to determine whether it requires assessment by the Minister (a controlled action), on the grounds of posing a significant risk to a MNES. If it does not pose a significant risk (an uncontrolled action), the project may not be referred to the Minister for assessment. Where an action is deemed to be a controlled action, it is referred to the Minister for assessment. The action is assessed under the EPBCA, and will either be approved or not. If approved, the action will also be assessed under the normal EP assessment and approval process under the OPGGSA.

Prior to 2013, the MNES only comprised the first seven criteria listed above. The "water trigger" was implemented by reforms to the EPBCA, implemented by the Environmental Protection and Biodiversity Conservation Amendment Act 2013 (Cth). The "water trigger" deemed that water resources are a MNES, and coal mining and CSG production activities need approval from the Commonwealth due to the likely impact of the project on water resources.[60] This amendment to the EPBCA has had a significant impact on the development of CSG in Australia. Unlike the QCLNP, GLNG, and APLNG consortia, the Arrow LNG CSG project required additional Commonwealth EPBCA approval under the "water trigger." The other consortia projects had already been approved at the time of the commencement of the water trigger, and did not have retrospective effect, meaning that the each of the consortia's projects did not have to resubmit their already approved

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projects. However, EPBCA approval for the Arrow LNG project was pending at the time of the amendment. Since approval had not been granted, the project was now subject to the "water trigger," requiring additional studies and assessment. The additional approval delayed the project by at least one year, and altered the project scope significantly.[61]

One of the limitations of the EPBCA "water trigger" is its scope of application. In its current form, the "water trigger" only applies to water resources in relation to CSG and coal mining projects. It does not apply to water resources in relation to shale gas projects. This is a significant weakness of the water trigger, given the vast SGR in Australia, the location of most of those resources in areas of low rainfall, and the amount of water required to HF the SGR to enable the production of shale gas. With the production of CSG, wells are generally de-watered, with only around 8 percent requiring HF.[62] Conversely, 100 percent of shale gas wells require HF, with each well often requiring multiple fractures. Data from the United States demonstrates that each fracture treatment often requires between 1.8 and 5.7 million gallons of water, depending on the geology being fractured.[63] Given the volume of water required to fracture a well and the low rainfall in many areas where shale gas occurs, it is logical that the "water trigger" as a MNES should also apply to shale gas projects.

Although the Commonwealth does not have constitutional capacity to regulate shale gas and CSG activities, Commonwealth Energy and Resources Ministers have nonetheless utilized the Standing Council of Energy and Resources (SCER), a subcommittee of the Council of Australian Governments (COAG), to address the issue of unconventional petroleum development. Responding to concerns raised by the community regarding the development of natural gas from coal seams, the SCER has developed a framework to address these concerns. This framework is known as the Harmonized Regulatory Framework for Natural Gas From Coal Seams ("the framework"), and addresses the following areas of community concerns:

- Well integrity
- Water management and monitoring
- Hydraulic fracturing; and
- The use and disclosure of chemicals in operations.

Whilst the framework is called a regulatory framework, it is not, given that the Commonwealth has no power to regulate in this area. Rather, it is an overview of issues that all state and territory governments should consider when developing coal seam gas resources, and provides guidance in developing the regulatory tools required to sustainable manage the development of CSG.[64] Whilst the framework focuses on a harmonized regulatory approach to CSG,

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SCER recognizes that the frame may have some applicability to shale gas development.[65] Many of the principles that are outlined in the framework are applicable, and as such the framework should be expanded to incorporate shale gas activities. However many of the principles relating to water use and disposal are not. This is because CSG requires the dewatering of the coal seams, producing large quantities of briny water, which requires large amounts of treatment and disposal.

REGULATION OF EAST COAST CSG

Queensland

Traditionally a mining state rather than a petroleum producing state, the escalating development of CSG in Queensland in the early 2000s created significant legislative pressure on existing petroleum legislation. From the commencement of the rapid development of CSG activities in Queensland, the regulatory approach has been that of "adaptive management." This method of "learning by doing" is implemented through the imposition of layered duties for the operator (reporting and monitoring), alongside obligations to compensate landholders, and "make good" any harm caused.[66] The reasoning for adopting this form of environmental regulation was due to the uncertainty surrounding the impacts of CSG activities, so the government sought to approach the regulation of CSG activities in a "learning by doing" basis, instigating changes where necessary.[67] Such a type of regulation is very much reactive type regulation, which responds to regulatory issues rather than anticipating and legislating for problems prior to the activity taking place. Given the limitations of the existing Petroleum Act 1923 (PA),[68] the Queensland government undertook reform of the existing PA through the implementation of the Petroleum and Gas (Production and Safety) Act 2004 (Qld) (PGPSA). However, as a result of existing native title regulation under the PA that was not incorporated into the PGPSA, the PA is still in force in some native title areas.

Although there are two Acts applying to the regulation of the extraction of CSG in Queensland, the regulation of all exploration and production activities occurs under the PGPSA. Since the PGPSA was implemented under the concept of adaptive management, the legislative framework for CSG has been subject to multiple and major amendments over the last ten years. An examination of the endnotes of the PGPSA identifies over 1,000 amendments to the PGPSA, with more than forty consolidated versions of the Act released. The PGPSA will be further altered under the Modernizing Queensland Resources Acts Program (MQRAP), which is integrating five

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separate resources Acts in to a single Act.[69] Added to this is a change of government in 2015, whose vision for regulatory reform is unclear at the time of writing. Therefore, it is possible that much of the legal framework will substantially be altered. Together, these impending and possible changes have created a legal framework that is ever-changing, thereby affecting both investment and stakeholders.

As at August 2015, the regulatory approach to CSG extraction and regulation of the impact of CSG activities in Queensland is still based on the philosophy of adaptive environmental management.[70] This method of "learning by doing" is implemented in Queensland primarily through the imposition of layered monitoring and reporting duties on the CSG operator alongside obligations to compensate and "make good" harm caused.[71] This regulatory approach clearly demonstrates that Queensland continues in a "learning phase" of regulation, and the approach recognizing the uncertainty surrounding the impacts of these activities.[72] It also seeks to put in place a system "to monitor and instigate change where necessary,"[73] to meet the expectations of the community. Such adaptive management frameworks are "widely used to address unknown and unintended impacts when making important management decisions" regarding environmental impacts of CSG extraction activities.[74] These adaptive management techniques are regulated under a plethora of legislation, especially the Environmental Protection Act 1994 (Qld) (EPA), where numerous legislative changes have been made to accommodate this approach.

The current Queensland CSG framework under the PA and the PGSPA is supported by other legislation, including the following:

- Environmental Protection Act 1994 (Qld)—the EPA has the extremely broad objective of achieving "ecologically sustainable development" in Queensland by setting out a program for the identification and protection of important elements of the environment and by creating a range of regulatory tools for controlling the activities of individuals and companies,
- Regional Planning Interests Act 2014 (Qld)—a legislative and planning framework designed identify and protect areas of regional interest including regional communities, high quality agricultural areas, and strategic cropping land.

One of the greatest community issues in Queensland regarding the extraction of CSG in Queensland is that of land access and compensation, which has had significant impact on landholders whose land is affected by CSG production. In the report Management of the Murray Darling Basin Interim Report: The Impact of Mining CSG on the Management of the Murray Darling Basin (Murray-Darling Report)[75] a number of landholder issues

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were identified. In particular, the Murray-Darling Report identified concerns relating to the insufficient compensation paid to landholders for the impact of CSG extraction, and the inability of landholders to control access to their land for CSG extraction activities.[76] Under Queensland law, like all other Australian states and territories, the Crown reserves rights to petroleum.[77] This reservation enables the Crown to grant petroleum titles (for exploration or production) over land that is owned in fee simple or held as a leasehold estate. This means that mining titles can be granted over privately held freehold land, as well as Crown leases, and land over which native title is held.[78] As a result of Crown reservation of petroleum, under s108 of the PGPSA, the titleholder is entitled to carry out any activities associated with the extraction of CSG despite the rights of the landholder over the land. The legal right of the titleholder creates conflict between landholders and titleholders, which are potentiated due of the long-term impact of the extraction of CSG on land (generally over twenty years). Given the level of community consternation regarding land access and use by titleholders,[79] the Queensland government realized the need to amend the law to address the community consternation over land access. In 2010 the Queensland government developed the Land Access Code LAC, which was introduced November 2010. The aim of the LAC was, and continues to be, to balance the interests of the agriculture and resource sectors in order to address issues related to land access for resource exploration and development.[80] Integral to this balancing act is the establishment and maintenance of good relationships between these groups, assisted by adequate consultation and negotiation,[81] in order to improve transparency, equity, and cooperation between the stakeholders to create a more level playing field for all.[82] The LAC attempts to regulate land access and provide a framework for the negotiation of compensation for the access to land, without addressing the legal basis for the access given to the titleholder and the limits of that right and the legal rights of the landholder. The obligations under the Land Access Code derive from s 153 of the PGPSA,[83] and regulates communication between titleholders and landholders, the negotiation of agreements landholders and titleholders, and stipulates the compulsory requirements regarding access as defined in Schedule 1A of the PGPSA. Although the LAC experienced teething issues, it appears to be a satisfactory attempt to balance the concerns of landholders need for access by the titleholders once access to land is granted. On September 1, 2016, an amended version of the LAC was introduced, and reflects alterations in legislation as the Queensland Legislation undergoes alteration as part of the MQRAP. It is expected that a new regulatory framework for all resources extraction activities will be introduced in Queensland between 2016 and 2020, leading to significant changes to the regulatory structure but not to the policy, intent, or legislative effect of the PGPSA.

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A critical issue impacting landholders in Queensland is the impact of CSG extraction on water resources. In the report Management of the Murray Darling Basin Interim Report: The Impact of Mining CSG on the Management of the Murray Darling Basin (Murray-Darling Report).[84] Issued identified by the affected landholders, and dealt with in the Murray-Darling Report include the acknowledged impact of CSG extraction on groundwater, especially local aquifers and the Great Artesian basin, and the potential for aquifer pollution from CSG extraction. Furthermore, the National Water Commission has noted that while there are benefits of CSG to Australia, there are other risks that, if not adequately managed and regulated, may have "significant, long-term and adverse impacts on adjacent surface and groundwater systems."[85] Of critical concern to farmers has been the impact of CSG on agricultural water resources that (both the use of water and the contamination of water resources), given that much of the land where CSG extraction occurs in agricultural land used for cropping and grazing. The use of water in Queensland, including for CSG activities, is regulated under the Water Act 2000 (Qld) (WAQ). Recognizing the critical importance of water resource management, the Queensland government established the Office of Groundwater Impact Assessment (OGIA) under the Water Act 2000 (Queensland). The role of the OGIA is to assess water impact of CSG activities, including cumulative impacts, and to map predicted water level impacts of CSG operations. However, there has also been the need to address concerns relating to water produced from CSG activities. The processing of produced water (often called associated water or CSG water) is regulated under s 111A of the PGPSA, which was inserted in amendments in 2012 in response to farmer concerns. The produced water is treated to remove salts and other chemicals, and then disposed of. Such disposal relies on the beneficial use of the water extracted, since it cannot be re-injected into the producing formation.[86] Traditional options for disposal include surface discharge, underground injection into aquifers, and surface impoundment.[87] Given that CSG production in Queensland occurs in an area of water stress, innovative disposal options after appropriate treatment, as required under the PGPSA include aquaculture, coal washing at existing coal facilities, irrigation, feedlot watering, and wash-down water.[88]

New South Wales (NSW)

Whilst NSW has few SGR, like Queensland, it has vast coal seam gas resources, and as such has set about to develop a regulatory regime for the development of CSG. To date there has been much interest in exploring for and producing CSG, but community concern and activism has restricted the

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development of CSG to date, with the exception of a small production facility south of Sydney.[89] Vast CSG resources are found on the coal measures of the Gunnedah Basin in northern NSW, and the coal deposits in the Sydney Basin. It is the CSG in the Gunnedah Basin that is of particular interest of CSG companies, with the gas targeted primarily for the domestic market. If the gas is to be realized for the export market, it is likely that the gas will be transported to existing east coast export facilities rather than additional facilities being built on the NSW coast.

The extraction of CSG in NSW is regulated under the Petroleum (Onshore) Act 1991 (NSW) (POA) and associated regulations, as well as the Environmental and Planning Assessment Act 1979 (NSW) (EPAA). While the POA is designed to regulate conventional petroleum activities, it has struggled (along with environmental protection legislation) to regulate existing CSG petroleum exploration. Consequently, in December 2010 the NSW Government introduced a moratorium on the use of HF in the development of CSG.[90] This moratorium remained in place while the NSW Legislative Council undertook a review of the impacts of CSG activities, reporting the findings in May 2012.[91] The NSW Chief Scientist was directed by the NSW government in 2013 to conduct a comprehensive review of the environmental and human health related impacts of CSG. Her report, published in 2014, made a number of recommendations. Heading these was that the government establish a world class regime for the extraction of CSG.[92] Such a regime is currently (as of August 2015) being developed.

In response to the findings of the report, the NSW Government has implemented a comprehensive suite of regulatory reforms across the spectrum of CSG activities prior to the resumption of new CSG exploration and production, including land access and community engagement, environment, water, and well activities. Under the POA, the legal framework regulating CSG activities comprises:

1. The Office of Coal Seam Gas (OCSG) within the NSW Department of Trade and Investment, Resources, and Energy. The OCSG regulates the development of CSG through development consents. For development to occur, a license is required, including exploration and production licenses, issued under the POA.
2. The independent Environment Protection Authority provides a lead regulatory agency for the environmental and health impacts of CSG activities in NSW, under the EPAA and subordinate legislation. It is the EPAA that has responsibility for compliance and enforcement for CSG. As part of the reform after the Chief Scientist report, a Land, and Water Commissioner was created, to provide guidance to landholders regarding land access

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arrangements and to provide basin-wide oversight of the exploration license process.

3. The establishment of a statewide Aquifer Interference Policy, designed to protect the underground water resources of NSW, license water use, and balance the water use requirements of the multiple land users, including towns, farmers, horse-breeders, and the CSG industry.[93]

Under this tripartite regulatory regime all CSG activities in the upstream petroleum chain, including exploration development and production, require an environmental protection license (EPL) in addition to the approval requirements under the POA development consent process. The EPL contains legally enforceable conditions that the EPL holder must comply with in order to protect the environment. The EPL incorporates water, air, waste, and noise requirements, as well as a "community right to know" provision. The EPA undertakes inspection of CSG activity sites to ensure compliance with the EPL, and also has the capacity to audit license holders. The information contained within the EPL is available as public information through the EPA Public Register, in order to address the concerns of the public.[94]

To protect groundwater, two codes of practice were implemented in September 2012. The NSW Code of Practice for CSG Well Integrity (the Well Code) was implemented in September 2012. The Well Code has been developed as a practical guide for CSG titleholders to assist in complying with a condition of title for CSG imposed under s 23 of the POA. The Code applies to the design construction production, maintenance, and abandonment of CSG wells in NSW. In addition, the NSW Code of Practice for CSG Fracture Stimulation Activities was also implemented, setting out the principles, values, standards and rules of behavior that govern the decisions, procedures, and systems related to well stimulation. Further reform measures to address community concerns include a 2 km exclusion zone for new CSG activities around residential areas, including areas identified as areas of future residential growth, and exclusion zones for "critical industry clusters" where businesses such as viticulture and equine industries are located.

Victoria

Victoria is dominated by conventional petroleum production and the transport of gas from the well-established fields in the Otway and Gippsland Basins (both onshore and offshore). As such there is a well-established petroleum regulation framework for conventional petroleum that can be equally applied to shale gas. Under the existing onshore petroleum framework, petroleum approvals are granted by the Department of Primary Industries under the Petroleum Act 1998 (Vic), the Petroleum Regulations 2000 (Vic), and the

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Pipelines Act 2005 (Vic). This legal regime is complemented by several guidelines, including guidelines for permit conditions and administration, and guidelines for the preparation of pipeline consultation plans under the Pipelines Act 2005 (Vic).

Whilst there are no known SGR in Victoria, there is some CSG, which is presently regulated under the Mineral Resources (Sustainable Development) Act 1990 (VIC) (MRSDA).[95] An indefinite moratorium has been placed on the development of CSG in Victoria, along with a community call for an overhaul to the legislative framework for unconventional petroleum. UPR regulation in Petroleum in Victoria comprises shale gas petroleum activities, regulated under the Petroleum Act 1998 (Vic) (PAV), the Petroleum Regulations 2000 (Vic) (PR) and the Petroleum Regulations 2011 (Vic) (PR 2011 (Vic)), as well as CSG regulated under the MRSDA). The environmental requirements for each activity will be considered separately. In addition, petroleum activities take place within the confines of the Environmental Protection Act 1970 (Vic) (EPA VIC), and the Environmental Effects Act 1978 (Vic) (EEA) for major projects.

In order for any shale gas petroleum activity to occur onshore (including surveys, drilling, production and decommissioning), an Environment Plan is required under the environmental legislation. The preparation and submission of an EP for a petroleum activity includes geotechnical information. The requirements for the EP are outlined in Pt 2 (rr 8–12) of the PR:

- The EP must describe the environment, including any relevant values and sensitivities, and also describe any relevant cultural, historical, aesthetic, social, recreational, ecological, biological, landscape and economic aspects of the environment that may be affected by the petroleum operations: r 8.
- a description of the environmental risks: r 9.
- define the environmental performance objectives and standards against which the titleholder's performance in protecting the environment will be measured: r 10.
- contain an implementation strategy that includes measures, systems, and standards, as well as outlining adverse effects: r 11.
- contain a statement of corporate environmental policy of the titleholder, details of consultations between the titleholder and relevant agencies, and all environmental legislation that applies to the petroleum operations: r 12.

While the regulations do not specify the format of the EP, project proponents are referred to the Commonwealth Guidelines for the Preparation and Submission of an Environment Plan.

The potential environmental effects of a proposed development may also have to be assessed under the EEA. Unlike the EPAVIC, the process

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under the EEA is not an approvals process, but rather an assessment process (through the environmental effects statement (EES)), enabling statutory decision-makers (including Ministers, local government authorities and other statutory authorities) to make decisions regarding whether a project with potentially significant impacts would proceed. Where required by the Minister for Planning, a project proponent is required to prepare an EES and undertake necessary investigations. The EES is then released for public comment and consultation, and the Minister provides an assessment to the relevant decision-makers. The Department of Planning and Community Development coordinates the process.

The future development of both shale gas and CSG in Victoria is to be postponed until at least 2017, given the public concerns over HF, with the development of CSG dependent upon the outcome of a parliamentary inquiry which is due to be released on December 1, 2015.[96] Once the report released, it is likely that there will be reform on the legislative framework currently applicable to UPR exploration and production.

CENTRAL AND WESTERN AUSTRALIA SHALE GAS DEVELOPMENT

Western Australia

Western Australia is currently undergoing something of a "shale gas revolution," with the Canning Basin in Central Eastern Western Australia an attractive province for shale gas exploration. Although there has been no production of shale gas for commercial use, interest from petroleum exploration companies and concerns from community groups remain. As such, the Western Australian Department of Mines and Petroleum (WADMP) as an experiences regulator has developed comprehensive environmental regulations for the upcoming increased interest in the onshore petroleum resources. Gas accounts for almost 70 percent of the energy source in Western Australia, and therefore is a vital component of the state's energy mix.[97] This reliance on gas means that there is a recognized need to diversify sources of gas, with the onshore unconventional SGR being targeted by the Western Australia Government. To support this need, Western Australia has a domestic gas reservation policy.[98] Fortunately, Western Australia is a petroleum resource-rich state, with vast amounts of onshore gas (mainly unconventional) as well as some oil.

Given the prospectivity of the Canning Basin, the WADMP realized in 2010 that a robust and comprehensive regulatory framework was required to effectively regulate future unconventional gas activities. At the same

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time, increased community activism relating to CSG activities in eastern Australia, social media, and films such as Gasland influenced community attitudes regarding the development of shale gas in WA. In response to these community concerns and impending future unconventional gas activities, the WA government commissioned an independent assessment of the capacity of the existing regulatory framework to effectively regulate shale gas activities in 2011. The resulting report (known as the Hunter Report)[99] made a number of important findings. While recognizing the strength of the internal processes presently applied to petroleum activities, the Hunter Report noted that the regulatory framework underpinning these processes was underdeveloped, lacking enforceability in many aspects. In particular, the Hunter Report noted that the use of guidelines rather than regulations for the effective regulation of environmental and well activities was required to establish a legally enforceable framework that would also provide community assurance.[100] The regulatory reform recommended by the Hunter Report included the drafting of environment regulations and resource regulations that included field development and well management.[101] The WADMP concurred with the recommendations, undertaking to write both regulations; although contemplation for the two had occurred as early as 2003, but had to await passage and commencement of amendments in the Petroleum and Energy Legislation Amendment Act 2011, which provided the heads of power for regulations.

The existing petroleum regulatory regime is well developed, with regulation of petroleum activities undertaken by the Western Australian Department of Mines and Petroleum (WADMP) for petroleum activities (both onshore and offshore) for over fifty years. Onshore petroleum activities are regulated under the Petroleum and Geothermal Energy Resources Act 1967 (WA) (PGERA), the Petroleum and Geothermal Energy Resources Regulations 2000 (WA) (PGERR), the Petroleum Pipelines Act 1969 (WA) and environment, resource management, and safety regulations.[102] Given the reforms introduced from 2013 as a result of the Hunter Report, the regulatory framework for shale gas in WA comprises thus (see Figure 7.2):

The WA regulatory framework is an integrated system, designed to provide operators with certainty and predictability, and assurance to the community. Aside from the legally enforceable Acts and Regulations, the Western Australia regulatory framework is accompanied by a number of guidelines, including

- criteria for the assessment of applications for the award of petroleum EPs and petroleum drilling operations;
- permit conditions and permit administration guidelines;
- petroleum acreage bid assessment process state waters and onshore; and
- petroleum acreage release approval process.

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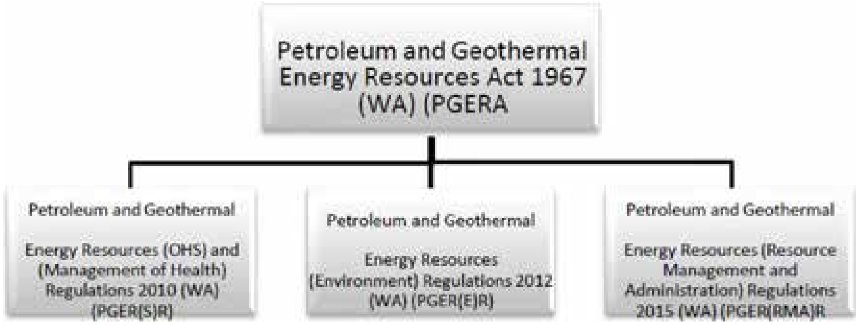

Figure 7.2 Diagrammatic Representation of the Shale Gas Regulatory Framework in Western Australia. *Source*: Tina Hunter, 2017.

The environmental impact of onshore petroleum activities in Western Australia is regulated by the WADMP. The regulatory framework developed by the WADMP for the regulation of petroleum activities is well established, it having regulated onshore petroleum activities since the establishment of the PGERA. The framework is premised on the PGERA and subordinate environmental regulation (PGER(E)R). The regulation of the impact of onshore petroleum activities on the environment in Western Australia is premised on two primary objectives:

1. minimizing harm to the environment from petroleum activities by identifying and reducing the risks; and
2. managing the environmental effects of the petroleum activity.

In order to achieve these two primary objectives the WADMP regulates two aspects of petroleum activities: regulation requiring risks to be identified and reduced; and regulation of activities to manage their environmental impacts. These two objectives are regulated through PGER(E)R, which requires the operator of a petroleum activity to have an approved environmental plan (EP) in place prior to a petroleum activity being undertaken.[103] The object of the PGER(E)R is to ensure that any petroleum activity carried out in Western Australia occurs in a manner consistent with the principles of ecologically sustainable development, and in accordance with an EP that demonstrates that environmental impacts and risks associated with the activity will be reduced to "as low as reasonably practicable" (ALARP).[104] In order to achieve this risk reduction, the EP is required to have appropriate environmental performance objectives and standards, and appropriate measurement criteria to determine whether the objectives and standards have been met.[105]

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Similar to the Safety Case Regime (SCR) and associated framework that was implemented for the regulation of safety after the Piper Alpha disaster, the PGER(E)R is based on the concept of reducing the risk to ALARP. This framework requires the operator to develop an EP that meets the key objectives of the PGER(E)R (as required under r 3). It shifts responsibility for environmental management, rightly so, from the regulator to the operator. The operator is required to:

- identify the risks in the specific environment in which they are undertaking the activity;
- identify the impact of those activities;
- assess the identified risks and impacts; and
- then formulate a plan to reduce those risks to ALARP.

The content of EPs are set out in Pt 2 of the PGER(E)R—Environment Plans. Specific requirements for an EP are outlined in rr 13–17 of the PGER(E)R, and further clarified in the Guidelines for the Preparation and Submission of an Environment Plan (the Guidelines). Given the principle-based nature of the PGER(E)R, operators have flexibility in preparing an EP. The document must comply with Pt 2, Div 3 of the PGER(E)R that stipulates the requirements for the EP, but the method in which they comply is entirely up to the operator. The Guidelines are a comprehensive document that provides guidance to operators as to what a petroleum activity includes (section 1.2.3), and what needs to be contained in an EP.

Complementing the requirements for an EP under Pt 2 of the PGER(E)R, Pt 4 of the PGER(E)R outlines the environmental requirements relating to emissions and discharges, including the monitoring and reporting requirements for such emissions and discharges. Part 3 of the PGER(E)R outlines the reporting requirements in the event of an incident, stipulating what are reportable incidents, and how and when operators are required to report such incidents. This part of the Regulations also stipulates how and when records should be kept, and the conditions on which records are to be made available.

While the environmental effects of onshore petroleum activities are primarily regulated by the Petroleum Environment Branch of the WADMP (PEB–WADMP), it is important to note that other departments within the Western Australian Government play an important role in assessing the environmental impact of the development of onshore petroleum. As outlined in Figure 7.3, the WADMP plays a lead-agency role in the regulation of environmental impact of shale gas activities, with other agencies also part of the environmental assessment process.

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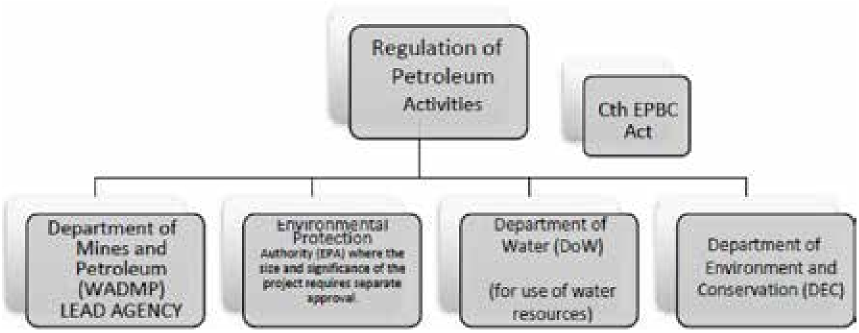

Figure 7.3 Government Agencies Responsible for the Regulation of the Environmental Impact of Onshore Petroleum Activities in Western Australia. *Source*: Hunter and Chandler, Petroleum Law and Policy in Australia (2013): 238.

South Australia

As at August 2015, the Department of State Development (SA) regulates petroleum activities in South Australia under a clear and unambiguous framework. Petroleum activities are regulated under the Petroleum and Geothermal Energy Act 2000 (SA) (PGEA) (formerly the Petroleum Act 2000 (SA)) and the associated Petroleum and Geothermal Energy Regulations 2000 (SA). This Act arose as a result of a major review of onshore petroleum legislation in South Australia in 1996, which recognized that significant benefits lay in adopting objective-based regulation.[106] The review required an extensive process of industry and public stakeholder consultation, and took four years to complete.[107] It was intended that the new legislation would be aligned to the South Australia Government objective for the management of their petroleum resources, which is to maximize the public benefit derived from Australia's discovered and undiscovered petroleum resources.[108] The resultant Act represents a significant departure from the Australian legislative tradition of prescriptive, rule-based legislation. The new PGEA seeks to provide certainty, openness, transparency, flexibility, practicality, and efficiency.[109]

Petroleum activities in South Australia are advanced, with conventional oil and gas extraction (particularly gas) occurring for over forty years, as well as the first commercial unconventional gas flowing from the Cooper Basin. Given the advanced level of knowledge and activity, the South Australian Government has developed a comprehensive environmental regulatory framework that applies to all onshore petroleum activities, including shale gas activities. Given the location of these petroleum activities, and the location of shale gas, both in remote SA, there has been little community consternation regarding shale gas activities to date.

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The principal Act regulating environmental management of onshore petroleum activities in South Australia is PGEA Unlike other onshore jurisdictions, the principles of environmental management are embedded in the principle Act (the PGEA), and no petroleum activity under petroleum licenses can be undertaken unless there is an approved statement of environmental objectives (SEOs), as required under Pt 12, Div 4 of the PGEA (s 99). PGEA s 99 also requires an environment impact report (EIR) for low impact or medium impact activities or an EIA under Pt 8 of the Development Act 1993 (SA) for high impact activities (which includes shale gas development).

The SEOs is required to be prepared in accordance with Pt 3 (r 12) of the Petroleum and Geothermal Energy Regulations 2013 (SA) (PGER), addressing the natural, cultural, social, and economic aspects of the area, locality, or region where the petroleum activity occurs.[110] An SEO for a petroleum activity is required to outline the environmental objectives to be achieved in carrying out the activity, and the measurement criteria used to assess whether the licensee has achieved the objectives. Therefore, the SEO must also include conditions and requirements for achieving the stated objectives, such as incident reporting requirements. In accordance with the regulatory principles of certainty, openness, and transparency, the performance of the titleholder against the SEO is publicly disclosed annually on an environmental register, as are the contents of the EIRs, SEOs and the Minister's determination of the level of impact of all proposals.[111] An SEO may relate to either a specific activity carried out at a specific location, or a particular activity type (e.g., drilling, seismic activities, the construction and operations of facilities and pipelines) carried out within a specific region or land system.

Given its experience in the development of onshore petroleum resources, South Australia is leading the development of best practice regulation of unconventional petroleum activities. This has been accomplished to date through the implementation of lead agencies (one-stop shop, similar to WADMP) with a single approval process through the lead-agency rather than a separate agency for environment assessment. The PGEA facilitates such an approach, enabling integration with the requirements of the Environment Protection Act 1993 (SA).

To further capture and address possible community concerns regarding shale gas development, in 2010 the SA Government set up the Roundtable for Unconventional Gas Projects in South Australia. This was established to assist in developing the burgeoning unconventional gas industry. The roundtable comprises industry, government, universities, academics, media and key individuals, and takes a holistic approach to the regulation of unconventional petroleum activities. The group was responsible for the Roadmap for Unconventional Gas Projects in South Australia, December 2012, with further work to be completed by the end of 2015.[112]

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Northern Territory

Although sources of energy are secure for the Northern Territory, there is much interest in developing the unconventional petroleum in the Northern Territory. However, many groups in the community, including indigenous groups, cattle farmers (the peak body being the NT Cattlemen's Association—NTCA), local government agencies, and residents, have expressed consternation regarding the impending development of SGR in the NT. The three most pressing concerns for the community regarding shale gas development in the NT is land access (currently there is no mandatory land access code, only a requirement for private negotiations), water use, and contamination of surface and subsurface water resources from Shale gas extraction.

Petroleum activities are regulated under the Petroleum Act 1984 (NT) (PANT), the Petroleum (Environment) Regulations 2016, and the Northern Territory Schedule of Petroleum Onshore Requirements 2016 (the Schedule). An assessment of the NT regulatory framework in 2012 by the Author[113] (the 2012 Review) concluded that there was a need for extensive legislative reform required in order for the regulatory framework of the Northern Territory to be able to sufficiently regulate shale gas activities in the NT. This assessment has been followed by several other reports, including an inquiry into HF in 2014, headed by Dr. Allan Hawke (The Hawke Report),[114] and the Environmental Defenders Office report regarding HF operations.[115] There has been universal recommendation that the current legal framework is lacking, and that legislation regulating well integrity and the environment requires implementation in the NT. The new Petroleum (Environment) Regulations were also drafted as a result of the assessment, and entered into force in 2016.

Prior to the Northern Territory elections in 2016, work had commenced on the drafting of the Petroleum Resource (Management and Administration) Regulations to replace the existing Schedule. However, upon gaining government in the Northern Territory, the Labor Party introduced in December 2016, a moratorium on shale gas activities in the Northern Territory and launched the independent Scientific Inquiry into HF of Onshore Unconventional Reservoirs in the Northern Territory. The outcome of this Inquiry will determine whether the moratorium will continue or be lifted.

ENVIRONMENTAL REGULATION

The regulation of environmental processes and management, and the protection of the environment are unique in the Northern Territory. Rather than uniform environmental protection legislation (such as the Environmental Protection Act 1986 (WA)), regulatory requirements for the protection of the

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environment during petroleum activities are contained within the Petroleum Act 1984 (NT) (PA (NT)). Part V, Div 2 (ss 117AAA–117 AAE) of the PANT applies to environmental offences under the Act. Section 117 AAC of the Act makes it an offence to commit environmental harm, including the release of a contaminant or waste material above or under the land.

Unlike other Australian jurisdictions, there is no separate environmental protection legislation in the Northern Territory, which is a source of concern for many in the community. Provisions within the PANT regulate protection of the environment during onshore petroleum activities. Environmental management requirements (environmental management plan (EMPs) and environmental assessments (EAs)) are undertaken under the Environmental Assessment Act (NT) (EAA). Where a petroleum activity could have significant effects on the environment (stipulated in a memorandum of agreement between the Northern Territory Department of Mines and Energy (NTDME) (formerly Northern Territory Department of Resources, or NTDoR) and the Northern Territory Department of Environment Protection (NTDEP) (formerly Natural Resources, Environment and the Arts (NRETA)), the EEA sets out the procedures to be followed. The proposed activity is referred by NTDME to NTDEP through a notice of intent (NoI), which subsequently assesses the proposal and issues a public environment report (PER) and environmental impact assessment (EIA) if requested by NTDME. The assessment of the proposed project by NTDEP under the EAA is returned to NTDME with environmental recommendations. At present there is no legal requirement for NTDME to enforce these recommendations, although the recommendations usually are enforced. In addition, matters of "national significance" are referred to the Commonwealth for assessment and approval under the requirements of the EPBCA. The environmental framework was also addressed in the Hawke Report and the EDO Report. Given the outcome of all of these reports, Legislative changes for the management of environmental protection and assessment processes are expected in 2016 or 2017, which are also likely to be similar to those implemented in Western Australia.

HARMONIZATION OF UNCONVENTIONAL PETROLEUM REGULATION IN AUSTRALIA

Although the Commonwealth does not have constitutional jurisdiction to regulate shale gas and CSG activities, relevant Commonwealth, state and territory ministers have nonetheless utilized the Standing Council of Energy and Resources (SCER), a subcommittee of the Council of Australian Governments (COAG), to address community concerns relating to the development of UPRs. Responding to community calls for action, SCER has developed

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a framework to address these concerns. This framework, known as the Harmonized Regulatory Framework for Natural Gas From Coal Seams ("the Framework") addresses the following areas:

- Sustainability and coexistence (although little treatment of the contentious issue of land access)
- Well integrity
- Water management and monitoring Hydraulic fracturing; and
- The use and disclosure of chemicals in operations.

Although the Framework is called a regulatory framework, it does not actually regulate these aspects of CSG development. This is because the Commonwealth government has no constitutional capacity to regulate in this area. Rather, it identifies leading practices that can be adopted by regulators to provide a harmonized approach to managing activities associated with the development of natural gas from coal seams,[116] as well as providing guidance in developing the regulatory tools required to sustainable manage the development of CSG.[117] Whilst the framework focuses on a harmonized regulatory approach to CSG, SCER recognizes that the frame may have some applicability to shale gas development.[118] Many of the principles that are outlined in the framework are applicable, and as such the framework could be expanded to incorporate shale gas activities. However, at this time there are no plans to expand the framework to encompass shale gas activities.

CONCLUSION

This chapter has addressed the socio-legal dimension of the development of UPR in Australia By examining the legal framework of states and territories with shale gas and CSG reserves and activities, it has demonstrated that although there are universal community concerns regarding the development of UPRs, the legal responses to such concerns have been diverse. Some states, such as WA and SA, have focused on developing a strong, objective-based framework, borne out of decades of experience in onshore conventional petroleum activities. Other states, such as Queensland, have opted for an adaptive management approach, which sees constant legislative reform as a method to address concerns and issues. Still other states, particularly NSW, the Northern Territory, and Victoria, have opted for a moratorium on HF until a suitable and acceptable (to the community) legal framework for HF has been established. Whichever state or territory the activity occurs, the development of UPR in Australia will provide challenges for regulators for many years to come.

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NOTES

1. Australian Bureau of Statistics, South Australia Year Book, (1999): 19.http://www.ausstats.abs.gov.au/ausstats/subscriber.nsf/0/CA25687100069892CA256888001DB9A2/$ File/13014_1999.pdf accessed July 14, 2015.

2. Refer to the map in figure 1 below for the location of these basins.

3. Kym Bills and David Agostini, Offshore Petroleum Safety Regulation: Varanus Island Incident Investigation (2009): XV.

4. Coal seam gas is the Australian term for coal bed methane. The two terms are interchangeable.

5. Refer to the map in figure 1 below for the location of the Surat basin.

6. US Energy Information Administration, "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 14 Countries Outside the United States," (2013): III–2.

7. Protests calling for a ban on fracking have been active in Australia since late 2000s, and include organized groups such as No Fracking Way and Lock the Gate Alliance.

8. Australia is the world's driest inhabited continent, with an average annual rainfall of just over 600 mm. The areas of Australia where shale gas resources are located are mainly where annual rainfall is 500 mm or less on average. See Australian Bureau of Statistics, Australian Yearbook 2012: Geography and climate (2012) http://www.abs.gov.au/ausstats/abs@.nsf/Lookup/bySubject/1301.0~2012~MainFeatures~Australia's climate~143 accessed July 12, 2015.

9. Water security in Australia's east coast, where the vast majority of the population are located, is critical as competition for water resources intensifies. There is a National Water Commission in Australia, established under the National Water Commission Act 2004 (Cth). The NWC has developed a National Water Initiative, which provides special conditions relating to water allocation for mining and petroleum sectors. Para 34 of the Intergovernmental Agreement on a National Water Initiative, agreed to by the Commonwealth and all Australian mainland states and territories except Western Australia, provides a carve out for water allocation in mining and petroleum recovery activities. The paragraph recognizes that there may be special circumstances facing the mining and petroleum sectors that will need to be addressed by policies and measures beyond the scope of this Agreement. Specific proposals will be assessed according to environmental, economic and social considerations.

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25. Ibid, 138.

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27. Ibid.

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29. Santos, Cooper Basin Unconventional Gas Opportunities & Commercialization: November 2012 (2012). http://www.santos.com/library/121112_EABU_Cooper_Basin_Unconventional_Gas_Opportunities_and_Commercialisation.pdf accessed July 12, 2015.

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36. Department of Natural Resources and Mines, Queensland's Petroleum and Coal Seam Gas 2014–14 (2015) https://www.dnrm.qld.gov.au/data/assets/pdf_file/0020/238124/petroleum.pdf accessed August 1, 2015, 5. Geoscience Australia, Australian Atlas of Mineral Resources, Mines and Processing Centers, 2012 (2012). http://www.australianminesatlas.gov.au/education/fact_sheets/coal_seam_gas.html accessed July 10, 2015.

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50. These states are New South Wales (NSW), Queensland, Western Australia, South Australia, Victoria, and Tasmania.

51. The only powers which the Commonwealth could regulate the extraction of UGR is under s 51(i) of the Constitution (Interstate and overseas trade and commerce), or s 51(XX) of the Constitution (Corporations power).

52. For example, the preamble (s (a)) of the Constitution of Queensland 2001; s 5 of the Constitution Act 1902 (NSW); and s 2(1) of the Constitution Act 1889 (WA)—"to make laws for the peace, order, and good Government."

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53. Shale gas is a gaseous form of hydrocarbons, and therefore falls under the definition of petroleum in the various acts.

54. Such as the definition in 5 of the Petroleum and Geothermal Petroleum Resources Act of 1967 (WA). Other state Acts define petroleum in similar terms.

55. Murphyores Inc. Pty Ltd v Commonwealth (1976) 136 CLR 1.

56. The Work Choices case refers to *New South Wales v Commonwealth* (2006) 229 CLR 1. In this case the High Court held by a majority of 5:2 that changes to the Workplace Relations Act were valid, thus enabling the Commonwealth to enact a comprehensive regime of industrial relations law, and substantially widening the scope of the corporations power. More importantly, the landmark decision signified a shift in the distribution of power from the states to the federal parliament.

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58. SEWPaC, Glossary, 2013, http://www.environment.gov.au/epbc/about/glossary.html#significant.

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62. Gas Industry Social and Environmental Research Alliance (GISERA), Frequently asked questions on coal seam gas and fracking (2011) http://www.gisera.org.au/publications/faq/faq-csg-extraction- fraccing.pdf accessed august 1, 2015.

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76. Ibid. 3–14.

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78. Michael Weir and Tina Hunter, "Property Rights and Coal Seam Gas Extraction: The Modern Property Law Conundrum," *Property Law Review* 2 (2012): 71–83, 724.

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80. Department of Employment, Economic Development and Innovation, Guide to Queensland's New Land Access Laws: November 2010 (2010), https://www.dnrm.qld.gov.au/data/assets/pdf_file/0005/193082/guide-queensland-land-access-laws.pdf accessed July 12, 2015, 1.

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101. Ibid.

102. Department of Mines and Petroleum (WA), http://www.dmp.wa.gov.au/7367.aspx.

103. Petroleum and Geothermal energy Resources (Environment) Regulations 2012 (WA) r.7.

104. Petroleum and Geothermal energy Resources (Environment) Regulations 2012 (WA) r.3.

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110. See http://www.pir.sa.gov.au/petroleum/legislation/regulation/seo

111. The environmental register can be found at http://www.petroleum.dmitre.sa.gov.au/environment/register.

112. See http://www.pir.sa.gov.au/petroleum accessed July 12, 2015.

113. It is important to note that the NT government never made the contents of the report public, although there was some consultation with affected community groups. However, the NT government has responded to the recommendations made in the report, which can be found at http://www.nt.gov.au/d/Minerals_Energy/?header=Legislation%20Review%20-%20Petroleum

114. Allan Hawke, "Report of the Independent Inquiry into Hydraulic Fracturing in the Northern Territory" (2015) at http://www.hydraulicfracturinginquiry.nt.gov.au/docs/report-inquiry-into-hydraulic-fracturing- nt.pdf accessed July 12, 2015.

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Chapter 8

Unconventional Energy in Europe

Policy Issues, Impact, and Prospects

Andreas Goldthau[1]

INTRODUCTION

Over the past years, European policy makers, industry representatives, security analysts and environmental activists have carefully observed the US "revolution" in unconventional hydrocarbons. Their motivations are as diverse as is Europe's energy policy agendas. As the world's largest energy importer, the EU foots an annual bill of EUR 400 billion for sourcing oil, gas, and coal—money which politicians would like to see staying at home for investment and consumption. Against the backdrop of turmoil in the Middle East and a more assertive Russia, the EU's energy import dependency rate of 53 percent has given rise to renewed security concerns in Brussels and national capitals.[2] Comparably high energy prices have made EU industry leaders look to the other side of the Atlantic for growth prospects, which has triggered a debate on Europe's looming deindustrialization. Adding to this, the economic boon that low energy prices in the United States have given to the nation's manufacturing sector would be very welcome on a continent plagued by stalling economic growth and a persisting financial crisis. Finally, indigenous production could give additional impetus to Europe's Single Market project in energy, which so far suffers from not only a scattered market structure but also few available sources of supply and hence lacking gas-on-gas competition.

That said, European policy makers are pressed hard not to compromise on environmental standards and the EU's ambitious decarbonization targets. The potentially negative environmental effects of hydraulic fracturing, and particularly the chemicals entailed in the fracking fluid, have given rise to safety concerns for groundwater and habitat. In fact, unconventional gas, and notably the fracking technology, has become a contested policy issue all over

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Europe, not the least because of a—compared to the United States—higher population density. Fears are also arising that unconventional hydrocarbons might lock Europe into a carbon intensive pathway. In short, the rapid rise of the unconventional energy sector in the United States has both put a spotlight on the benefits and highlighted the concerns coming with indigenous hydrocarbon production in Europe.

This chapter offers a comparative study of unconventional (fossil) energy in Europe. While occasionally giving reference to oil, the chapter focuses on unconventional gas,[3] for its importance in the power and heating sectors and as a feedstock for industry, and because of the geopolitical tensions over EU gas supplies. According to estimates of the US Energy Information Administration, Europe sits on 883 trillion cubic feet (tcf) of recoverable reserves of nonconventional gas—or roughly sixty years of cumulative consumption.[4] Yet, the European shale gas industry remains in its infancy at best. In fact, only few exploratory wells have been struck so far, and a number of countries have put moratoria or bans on the fracking technique. As this chapter will explain, this is due to several factors, relating to regulatory governance, the economics of the sector and market structure but also social acceptance.

Four selected country case studies are conducted, with a view to shedding light on the regulatory and policy choices related to European unconventional gas, the environmental discussions and concerns, but also the economic viability and the potential impact. Country case studies include: Poland, a country with 148 tcf of estimated reserves, Europe's largest; Romania (51 tcf), the second largest Central and East Europe (CEE) reserve holder; Germany, sitting on 17 tcf; and the UK (26 tcf), so far the only West European country with both significant reserves and an expressed political will to foster its extraction. This cross-section of cases covers a sample of countries that possess substantial unconventional energy reserves. At the same time, it also accounts for the political environment in which the nascent shale gas industry operates in Europe.

The study finds that the US "shale revolution" is not likely to be replicated in Europe. This is for reasons related to regulation, industry structure, infrastructure but also geology. While some countries such as the United Kingdom will likely push shale gas ahead, the volumes produced will remain comparably small for the foreseeable future.

In terms of data, this chapter faced the challenge of the European unconventional gas sector not having made it beyond the exploration phase so far, which by definition limits the availability of key economic data points such as well costs and economic break-even points. To the extent necessary the chapter therefore works with forecasts, preliminary assessments, and estimates. Analysis is also informed by a series of *sur place* interviews conducted in Eastern Europe between 2012 and 2014.

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The next section maps the state of play of unconventional gas in Europe, explores the regulatory and policy context in more detail and provides an overview of the economics of European shale gas. Sections 3–6 are dedicated to individual country case studies. The case studies first assess the regulatory governance and policy context for each country before sketching the prospects for commercial development of national shale gas development. A final section revisits the findings and concludes.

UNCONVENTIONAL ENERGY IN EUROPE: RESERVE ESTIMATES AND POLICY CONTEXT

It was the 2011 Environmental Impact Assessment (EIA) report on unconventional gas that for the first time provided an indication of the unconventional energy reserves in Europe.[5] Since then, the initial excitement over the prospects of indigenous shale gas production has calmed. New estimates led to revisions of reserves estimates, mostly downward, whilst many serious policy and regulatory challenges have surfaced. As a result, the economics of European shale look difficult. This section discusses these issues in more detail.

RESERVES

By sheer numbers, the potential of European unconventional energy is significant, particularly in natural gas. Judged by the technically recoverable reserves, the largest reserve holder by far is Russia, followed by Poland, France, and the Ukraine. Together, these four countries make up for roughly 80 percent of European shale gas deposits. Mid-range reserve holders include Romania, Denmark, the Netherlands and the UK (see Table 8.1). To put these deposits in context: in Russia, shale gas reserves would give Russia another thirteen years of cumulative gas output. In terms of current consumption, they would cover roughly 250 years of demand in Poland, eighty years in Ukraine, in France ninety years, and in Romania 115 years. Germany's reserves amount to six years of consumption, the UK's deposits would last ten years, and Bulgaria's even 182 years (which is a function of a very small gas market). This compares to eight and nine years of oil demand that unconventional reserves could cover for instance in France and the Netherlands respectively. It is important to note that these estimates come with the important caveat that they are so far not validated through physical tests. This is because of the limited number of wells that have been drilled so far (see also "Regulatory Frameworks and Political Context").

For the purpose of this study, we leave aside countries which have either put a lasting moratorium on shale gas, or which for political reasons are not

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Table 8.1 Risked and Technically Recoverable Unconventional Energy Reserves in Europe

Select countries	Risked Gas-in-Place (Tcf)	Technically recoverable (Tcf)	Risked Oil-in-Place (Billion bbl)	Technically recoverable (Billion bbl)
Russia	1,941	287	1,267	75.8
Poland	763	148	65	3.3
France	727	137	118	4.7
Ukraine	572	128	23	1.1
Romania	233	51	6	0.3
Denmark	159	32	0	0
Netherlands	151	26	59	2.9
UK	134	26	17	0.7
Germany	80	17	14	0.7
Bulgaria	66	17	4	0.2
Sweden	49	10	0	0
Spain	42	8	3	0.1
Lithuania	4	0	5	0.3

Source: EIA/ARI, EIA/ARI World Shale Gas and Shale Oil Resource Assessment. Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States, Washington, DC, Department of Energy, (2013).

susceptible to developing an unconventional energy industry any time soon.[6] In the EU, this includes Bulgaria, a country that has put a ban on the fracking technique in 2012; France, where a ban on hydraulic fracturing was imposed in 2011, and it has been confirmed by the constitutional court in 2013; and the Netherlands, where a temporary moratorium on fracking was enacted in September 2013. Outside EU-Europe it includes the Ukraine, a country in political turmoil and plagued with a civil war in its eastern territories of Lugansk and Donetsk; and Russia, which because of the Western sanctions regime enacted in 2014 will face difficulty in getting access to the necessary technology.[7] Moreover, the geopolitical dimension of the shale gas debate merits a discussion of both Western and Eastern European countries. This leaves us with Poland, Romania, Germany, and the United Kingdom. These country case studies will be explored in further detail in sections 3–6.

REGULATORY FRAMEWORKS AND POLITICAL CONTEXT

For an analysis of the prospects of European shale, it is important to appreciate the regulatory and political context. This is done best by contrasting the European situation to the US experience. In a nutshell, almost all the factors

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that enabled the US shale gas (and later oil) sector to scale up quickly are absent in the (nascent) European unconventional energy sector.

- *Subsoil resource rights ownership*: in Europe, much as in most countries other than the United States, subsoil resource rights belong to the state not the individual land owner. As a consequence, there is no direct incentive for individual land—owners to lease out their land for exploration. Whilst this does not principally hinder the development of unconventional deposits, it increases the number of players involved in the exploration and production (EandP) process, as state authorities on various levels including municipal level typically become involved. Compensation and revenue sharing mechanisms would also need to be designed in such a way that they give local communities and land owners a material stake in hydrocarbon extraction.
- *Market competitiveness*: the European gas markets is far from being fully integrated and competitive. To the contrary, despite three consecutive sets of EU legislative "packages" in 1997, 2003, and 2009 aimed at deregulating national energy markets, fostering market opening, and enhancing market competitiveness, national markets remain segregated. Moreover, although gas-on-gas competition is on the rise, a significant share of European gas is still priced on the basis of pegging the gas price to a basket of substitutes (typically oil and oil products), which in Southern and South-Eastern European markets can be up to two-thirds of traded volumes.[8] Whilst this traditional pricing model is slowly giving way to more market based pricing arrangements, long-term gas supply contracts (LTC) prevail in most of Europe outside the UK. Moreover, because Europe sources almost all its imports from only three suppliers—Russia, Algeria, and Norway—the degree of competition faces limits. This, in turn, impacts on the degree to which market forces may eventually incentivize the development of unconventional reserves.
- *Energy sector maturity*: the European extractive industry in energy rests on a limited number of multinational corporations such as Shell, ENI and BP but lacks the deep service sector and the numerous midcap companies characterizing the energy sector in the United States. This is partly a function of an underdeveloped EU gas market. It also reflects the fact that Europe kick-started its domestic energy industry only in the 1970s, when developing offshore fields in the North Sea—roughly 100 years after the first oil well was struck in Titusville, Pennsylvania. The call, therefore, primarily is on the IOCs and particularly non-EU companies (notably from the United States) to make shale happen.
- *Energy infrastructure*: as a corollary of Europe's import dependence and lower levels of market integration and maturity, infrastructure remains a challenge, both upstream and midstream. As Figure 8.1 reveals, Europe's

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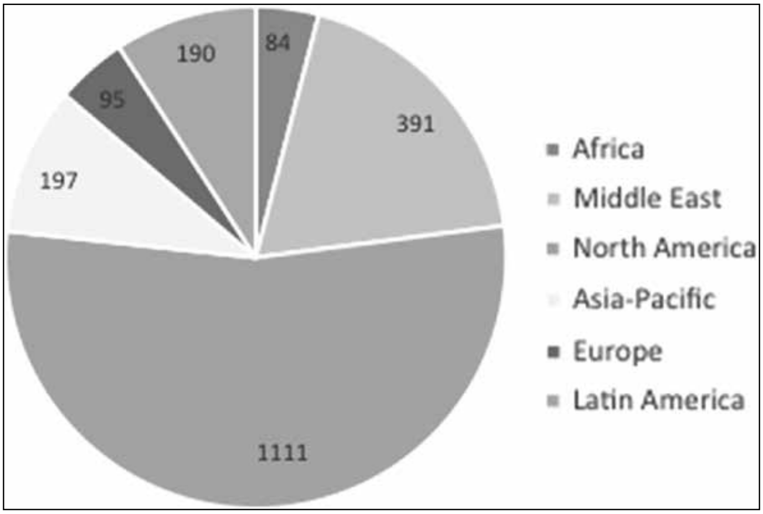

Figure 8.1 Global Oil and Gas Rig Counts. *Source*: Baker Hughes Announce May 2015 Rig Counts, (June 2015).

rig counts remain small by international comparison, even after the US rig count has fallen dramatically in the wake of the 2015 oil price drop. In terms of midstream, it is both the pipeline infrastructure within countries and across national markets that remains underdeveloped. This presents a serious obstacle for bringing domestically produced gas to market. Reacting to this, the EU has put forward select "Projects of Common Interest," many of which interconnectors, which may receive financial support with a view to enhancing cross-border flows of gas (and electricity).

- *Regulation*: European shale gas regulation rests on various governance levels. Relevant EU level regulation comes in the shape of Regulations and Directives pertaining to environmental protection, including on the Water Framework Directive, REACH (Regulation on Registration, Evaluation, Authorization and Restriction of Chemical Substances), the Groundwater Directive, the Mining Waste Directive, and the EU Directive on Environmental Impact Assessments. In addition, the Commission has issued several non-binding documents, including the "Commission Recommendation of January 22, 2014 on minimum principles for the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing"[9] and the "Communication on the exploration and production of hydrocarbons (such as shale gas) using high-volume hydraulic fracturing in the EU."[10] Member states such as Poland or the United Kingdom are keen on retaining decision-making authority over shale gas development and extraction on the national level, which will prevent EU level regulation

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for the foreseeable future. On the national level, shale gas is essentially subject to regulatory frameworks designed for the conventional extractive industry—to the extent it exists in individual EU countries. While this may allow some countries to emerge as front-runners, it also cements varying national standards that may eventually prevent a Europe-wide use of technical equipment or other. Several countries including Poland have struggled when putting in place regulatory frameworks and fiscal regimes for shale gas exploration, which has put off foreign companies.

- *Social acceptance*: while public opinion varies across countries, social acceptance of shale gas remains generally low in Europe, a reason why several governments have put in place temporary or even permanent moratoria on unconventional hydrocarbon extraction using the fracking technique. To be sure, fracking has been used for well stimulation in conventional oil and gas production in Europe since the 1950s, with more than 300 "frack jobs" carried out in Germany alone.[11] Because of the use of contested fracking fluids and high volumes of water in the hydraulic fracturing process, environmental concerns have featured prominently in European debates on fracking. Anti-fracking initiatives exist in all European countries, and while protests so far remain local in the United Kingdom (e.g., Lancashire county) or Poland (Zurawlow), they went national in Bulgaria (2011) and France (2011).
- *Data*: shale gas reserves in Europe remain preliminary estimates. This is because production in Europe historically focused on offshore deposits in the North Sea. The detailed geological mapping that had been carried out in the United States by the US Geological Survey and the DoE, and the resulting data that benefited wildcatters such as Mitchell Energy in what should become the US "shale gale," are not available in Europe. With so far an only limited number of drillings carried out in Europe, data availability remains a challenge for energy companies. As has been mentioned above, reserve estimates therefore need to be treated with caution. A case in point is Poland, where initial estimates on shale gas reserves were corrected downward by 90 percent in 2013.[12] Geology has so far also proven much more difficult than initial data had suggested, which has made several oil majors pull out of particularly East European countries.
- *State support*: While some European countries, including the United Kingdom and Poland, are determined to support a nascent shale gas industry, the scope and impact of this support remains limited. Several pro-industry choices in shale gas regulation that helped grow the unconventional hydrocarbon sector in the United States are clearly absent in Europe. This includes the 2005 exemptions of fracking fluids from the US Clean Drinking Water Act, or the right of eminent domain granted to private energy companies when putting in place oil and gas infrastructure. It also includes

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the various ways in which the DoE lent support to the unconventional gas industry in the 1980s, notably through its public private partnerships in technology development, as well as the tax breaks the federal government granted to selected shale gas projects.

Overall, the market fundamentals, policy context and regulatory environment in point to significant challenges facing the nascent European shale gas industry.

ECONOMICS

Besides the "above ground factors" [13]and geology, the economics of European shale are a function of energy market fundamentals. It therefore is crucial to briefly shed some light on key patterns and trends in European gas before turning to cost estimates for European shale.

In terms of gas demand going forward, European consumption has been stalling for years. This is to do with a still lingering economic crisis in major European countries, cheap US coal crowding out natural gas, and what industry representatives term "demand destruction"[14] stemming from policies promoting renewables. Going forward, the IEA, the rich world's energy watchdog and a long-term promoter of a "Golden Age of Gas"[15], now projects an only modest demand growth in OECD-Europe up to 2020 (IEA, 2015). By 2040, according to the IEA, European demand would stand at 503 bcm or 17.7 tcf of annual consumption, up from today's 448 bcm or 15.8 tcf.[16] Production, by contrast, will continue to fall, stand at 25 percent below its 2010 level by 2020 and merely reach 210 bcm or 7.4 tcf in 2040 (IEA, 2015, IEA, 2014). This implies growing import requirements, which the IEA estimates to increase by almost one-third between 2014 and 2020.[17]

Whilst this would make a case for additional supplies in the shape of European shale gas, the market environment represents an important factor in determining the portfolio of supply sources going forward. As indicated above, the European gas market remains still segregated between individual countries. Moreover, price regulation remains in place in many East and South European countries, whilst hub trading dominates only in North-Western Europe and the United Kingdom. This implies that persisting high gas prices for imported Russian gas will not directly translate into price signals that could push the exploration for additional domestic sources such as shale. What is more, poor physical market integration and the fact that the incumbent long-term gas supply contracts come with pricing terms specified on individual country levels still limit the degree to which

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companies can exploit price differentials for arbitrage. Put differently, whilst some of the Baltic countries paid 1.6 times the German gas price in 2014[18], this did not stimulate more cross-border trade or swaps. The prevalent situation is only slowly giving way to more integrated and competitive market structures, not the least because of vested interests in industry and politics particularly in some Eastern European countries. In terms of prices, finally, current trends suggest that Europe will retain somewhat of a mid-level position by international comparison. Whilst there has been a long-time spread between the UK NBP hub and LTC import prices, caused by surplus LNG landing in Europe as of 2008, this spread is likely to wither away in the medium term. One of the reasons are price adjustments on part of Gazprom, Statoil, and other external suppliers, a reaction to a changing pricing environment post-2008. Moreover, an additional 150 bcm of annual LNG capacity will come online this side of 2020, half of this in Australia. This will likely bring down LNG prices further which have fallen already significantly from their record highs in 2011–2013. In light of this, the IEA forecasts that LNG imports into Europe will double between 2014 and 2020.[19]

In a 2015 price environment, which obviously only represents a snapshot, European shale would essentially need to be brought to market at prices below $10 per Mmbtu to be competitive. Yet cost estimates for European shale gas vary. Early estimates by Gény set costs at $8–12/mbtu.[20] Pearson et al. report break-even prices ranging between $5 and $12/mbtu, depending on the study and underlying assumptions.[21] According to evidence of Bloomberg New Energy Finance presented in the UK House of Lords, the costs of shale gas extraction in the United Kingdom may in the long run range from $7.10 to $12.20 per MBtu, which compares with break-even prices of $3–$7 in the United States.[22] Particularly in the context of a soft international gas market, European shale are currently rather dim.

To be sure, technological progress, pricing pressure and ongoing learning curves have brought down costs in the United States, and the unconventional oil industry has shown a remarkable ability to optimize well costs in the face of the steep oil price decline that occurred since mid-2014. This would suggest that similar developments can take place also in Europe once production starts in earnest. Yet, as a 2014 study by the European Commission suggests, this might not happen to the extent that it did in the United States. Factoring in the differences assessed above in more detail—a mature oil and gas industry in the United States, lower population density, a deep service sector and economies of scale—the study suggests that a significant cost premium will persist in Europe. The latter amounts to a 50 percent premium on capital costs over United States well costs and a 25 percent cost premium on operating and maintenance costs compared to the United States.[23]

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Next, we delve into the country cases to explore state level dynamics in more detail. To this end, we assess the regulatory context and contrast and compare the economic and policy prospects of shale gas for Poland, Germany, Romania, and the United Kingdom.

POLAND

Poland's gas production of 4.2 bcm or 0.14 tcf covers roughly 25 percent of annual consumption.[24] The country's remaining demand is covered by external supplier, Russia. Domestic production has remained relatively stable for years, and at current production rates Poland's own gas reserves are expected to last for another twenty-three years.[25] Poland issued the first shale gas exploration license in 2007, and awarded 111 licenses for shale gas development.[26] Around sixty exploratory wells have been drilled so far, and there is no commercial production of shale gas as of yet.

REGULATORY GOVERNANCE AND POLICY CONTEXT

In line with EU level energy regulation the Polish gas sector has seen several steps of liberalization and deregulation. Whilst the market principle now governs Poland's energy sector there still remain significant barriers to rendering the domestic energy market truly competitive.

Among the reasons are vertically integrated national oil companies (NOCs) such as LOTOS Group, PKN Orlen, and PGNIG that retain a dominant role in the market, persisting price regulations, and lagging regulation. NOCs exclusively operate in oil and gas upstream whereas International Oil Companies (IOCs) are active in trading.

The 1997 Energy Law and the 2011 Act on Mining and Geological Law (amended in 2014), represents the key framework for governing shale gas exploration and production in Poland. On the federal level, the Treasury oversees NOCs (in addition to legally owning the country's hydrocarbon deposits) while the Ministry of Environment grants licenses and exerts environmental oversight. A newly created Ministry of Energy is responsible for the country's energy policy and for managing its mineral deposits. In addition, the Ministry of Foreign Affairs resumes an important role in flanking the government's efforts to develop a domestic unconventional gas sector, by way of fostering international exchange with political leaders and industry representatives, notably from the United States. The regional or voivodeship level comes in, among other, through granting water resource rights. In all, therefore, shale gas is governed through a multi-level system in Poland.

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The Polish government has been keen on pushing shale gas and the development of an unconventional gas sector in Poland. Poland's historical trauma of being partitioned by Soviet Russia and Nazi Germany has left a deep impact on the country to the effect that retaining national sovereignty and independence is the overarching policy goal—also in energy. Enhancing supply security in natural gas and reducing Poland's strong reliance on Russian gas imports therefore is a top policy priority for Warsaw. In light of this, Polish governments—regardless of their political orientation—has been determined to foster shale gas as a domestic source of energy, and particularly as a means to decrease the country's exposure to Russian geopolitical influence.

In contrast to other European countries, the Polish population remains overly supportive of exploring unconventional gas prospects.[27] To be sure, protests have emerged in local communities, some of which, such as in the village of Zurawlow, have made international news.[28] Still, as the author's own field research reveals, the national security narrative, coupled with prospects of job creation and economic benefits for local communities has strong traction among the population and provides a robust basis for the government's pro-shale policies.[29]

Besides security and economic rationales, it is EU decarbonization targets that drive Poland's quest for shale. As the country's power sector relies for 88 percent on coal,[30] Poland is exposed to EU climate policies and the possibly negative effects stemming from rebounding carbon prices going forward. Shale, therefore, is perceived among political and economic elites as a potential "price hedge" against EU level carbon policies.

PROSPECTS FOR COMMERCIAL DEVELOPMENT

By European standards, Poland represented one of the front runner in shale gas development. The country drilled most exploratory wells so far, issued most licenses and has been most determined to develop a domestic unconventional gas sector. Poland's shale prospects received great interest among international energy companies and Warsaw made great efforts to bring IOCs into the country for shale gas exploration. In order to build up national expertise in unconventional gas production, the Polish government also made state owned corporations team up with IOCs and foreign mid cap corporations such as Talisman, Cuadrilla, and Lane Energy.

Yet, the high hopes on Polish shale ended up facing a harsh reality check. On the one hand geology has proven more difficult than expected. The Polish Ministry of Environment plans for 309 exploration wells to be struck by 2021[31], a goal which will likely not be reached. In fact, the number of exploratory wells drilled per year has slowed down from twenty-four in 2012 to one in 2015.[32] This implies that scientific knowledge about the geology

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of the Polish deposits—crucial for properly estimating the actual size of reserves—will remain limited. Moreover, Polish shale reserves are reported to be deeper than expected and high in clay, which presents serious technical challenges and deteriorates the prospects of producing at economic costs going forward.

On the other hand, observers have repeatedly pointed at inadequate regulation, inapt administrative procedures, and a flawed fiscal regime governing Poland's nascent shale sector. While the Polish government eventually reacted by amending the Mining and Geological Act in 2014, it is particularly the fiscal regime that is still met with criticism. What is more, Poland's revised regulation on EIAs is considered to be at odds with EU provisions, put Warsaw on collision course with Brussels and adds to regulatory uncertainly. Overall, an assessments carried out by the Polish Supreme Audit Office Overall concluded that an "indulgent" state administration and poor institutional procedures had put the brakes on Poland's shale gas and delayed exploration "at least for several years."[33] As a result, most international companies have given up on Polish shale prospects, leaving the field to Polish NOCs and few smaller foreign companies. Poland's focus also shifted to importing LNG through their newly built Świnoujście terminal, and more recently a new pipeline through the Baltic Sea, linking the country with Norway through Denmark.

Overall, it is too early to write off Polish shale as the international price environment might change again, encouraging shale development. Still, getting the "above ground factors" right will, in addition to overcoming geological challenges, primarily determine the prospects of unconventional gas production in Poland.

GERMANY

Germany produces 7.7 bcm or 0.27 tcf of conventional gas per year, which covers roughly 11 percent of annual domestic consumption.[34] The country's main sources of gas imports are Russia, Norway, and the Netherlands. Domestic production peaked in 1979 at 20.3 bcm and has since then been declining. Ceteris paribus, the country's own gas reserves are expected to be depleted in six years.[35] Germany has for decades used the fracking technique in conventional gas production from sand stone, notably in the state of Lower Saxony.

REGULATORY GOVERNANCE AND POLICY CONTEXT

The German gas sector is deregulated and liberalized, though public utilities remain important on municipal level. Whilst traditional long-term contracts

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with external gas suppliers prevail, hub trading has gained traction throughout the past years, and the downstream market is highly competitive. Extractive activities have been historically covered by frameworks and regulations in mining law, water law, and environmental law. However, there is no national legal framework pertaining to hydraulic fracturing and unconventional gas as of yet.

As a federal state, Germany features shared competences in regulating hydrocarbon production. On the federal level, it is the Ministry of Economy and Energy and the Ministry of the Environment that set the legal frameworks. Permission processes, by contrast, sit with the states, or *Länder*. As a result, it was the *Länder* that so far have decided on individual fracking projects, and on a case-by-case basis. Some, such as North Rhine-Westphalia, have enacted moratoria and put permission processes on hold; others such as Hesse have cited lacking federal frameworks as a reason for not acting on permitting processes. As a result, one single gas well has so far been fracked in Germany, in 2008.

The German population tends to be generally skeptical toward fracking, for reasons related to environmental concerns and groundwater safety. This coincides with a long-standing German tradition in eco-activism, the existence of a well-organized environmental movement whose origins date back to the 1970s, and elaborate expertise in resisting contested technologies such as nuclear. Some established parties such as The Greens, which form part of many *Länder* level governments, also have their roots in the antinuclear protest movement. Moreover, the numerous grassroots level groups that started to organize against fracking typically comprise both left-leaning activists and more conservative constituents such as farmers. Even some industry groups such as the German beer brewers' association have voiced concerns over fracking. This gives protest groups strong momentum on local and regional levels but also influence in state level politics, even in *Länder* that are historically governed by conservative parties. Reacting to this, several *Länder* government have sought to enact a nation-wide ban on fracking by way of changing the mining law, and have initiated a move in the federal chamber in this regard.

In 2016, the German government essentially prevented hydraulic fracturing by way of amending the national mining and water acts. Key elements of the regulatory package entail a ban on "unconventional fracking" (shale gas and coal bed methane) above 3,000 meters of depth; a ban on conventional fracking (sandstone) in "sensitive" areas; and tough regulatory hurdles (e.g., pertaining to fracking fluids) for permissions of conventional fracking. This implies that Germany's shale gas regulation goes beyond the guidelines issued by the European Commission (section 2). At the same time, the legal framework will allow the implementation of four scientific—that is non-commercial—pilot studies in order to gather data on the environmental impact

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of fracking. An independent commission will be asked to assess these pilot studies as of 2021. It will be on *Länder* level authorities to eventually decide on permits for commercial exploration projects in shale gas.

PROSPECTS FOR COMMERCIAL DEVELOPMENT

In light of the above, there hardly is an economic case for extracting shale gas in Germany. This is to do with the stalling of exploratory drilling and the restrictive regulatory context as put forward by the German government. Prospects beyond the 2021 time frame remain uncertain.

At the same time, German shale gas needs to be seen in the context of broader energy policy choices. Since 2011 the energy policy priority of the German government rests on the energy transition or *Energiewende*, which involves both phasing out nuclear by the year 2022 and replacing the bulk of fossil fuel consumption with renewables by 2050. The *Energiewende* brings about a complete overhaul of the German energy system, which includes the construction of large scale infrastructure in the shape of North-South power links, the decentralization of energy supply, a redesign of market frameworks in order to accommodate renewables, and, as a result, fundamental shifts in the product portfolios and business cases of the energy industry. The prospects of large scale infrastructure have already triggered protests among affected communities across the country, which suggests that an expansion of the power transmission grid will become a key political challenge in the context of Germany's decarbonization pathway going forward. Rising energy prices for households have also impacted on public opinion. Still, the majority of the German population remains supportive of the *Energiewende* and its goals.

The government and political elite will therefore likely use their political capital to implement core elements pertaining to the *Energiewende* project. This suggests that shale gas will not receive great political support nor become a policy priority. Also, the unprecedented surge in renewable energy production over the past years—now covering some 30 percent of Germany's power consumption[36]—has pushed other energy policy challenges in the forefront of public debates, including the call on capacity markets, an overhaul of state support and the redesign of electricity markets. Moreover, due to a dysfunctional ETS coupled with state support for renewable energy sources, natural gas has come to be squeezed between renewables on the one hand and, ironically, coal on the other, dampening the prospects of natural gas in Germany's energy mix. Finally, although natural gas is typically labeled a "transition fuel," the German debate has come to focus on the risk of "carbon lock-in" that possibly comes with enhancing the role of natural gas in the energy mix. Overall, the prospects of German shale gas can be

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summarized as low, with a best-case scenario from an industry viewpoint being slow moves toward pilot drillings until the end of the decade.

ROMANIA

Romania produces 11.4 bcm or 0.4 tcf of gas per year, which covers almost the entire annual consumption of the country.[37] Romania's gas production has been falling since its peak at 37 bcm in 1982 and its R/P ratio stands at roughly ten years. Romania's low import ratio therefore is a function of faltering domestic demand related to a staggering economy, the deployment of renewables, and the country's recent push toward deregulating the domestic gas market. Russia traditionally was the only external source for imported gas. Romania has a long history in conventional (oil and) gas production in which the fracking technique has also been used.

REGULATORY GOVERNANCE AND POLICY CONTEXT

The Romanian gas sector is essentially deregulated and has been opened up to competition. Gas prices for industrial consumers are now liberalized, while households will remain subject to regulated prices until the end of 2018. Oil and gas exploration and production is regulated under the 2004 Petroleum Law. Romania has not put in place specific legislation pertaining to shale gas but treats conventional and unconventional hydrocarbons equally with regard to licensing and authorization procedures.

Relevant authorities in the sector are the Ministry of Economy's Energy Department (responsible for energy sector monitoring), the National Agency for Mineral Resources (NAMR, deciding on agreements, licenses and permits and monitoring environmental provisions) and the Romanian Energy Regulatory Authority (ANRE, licensing companies). In addition, the Environmental Protection Agency and sub-state regulators come in during later phases of the exploration and production process. At the time of writing, the Romanian government is in the process of overhauling the legal framework for upstream operations, including the provisions on royalty taxes for the oil and gas sector.

Whilst Romania's gas production is dominated by domestic companies Romgaz and OMV Petrom, private international corporations such as Amromco Energy and ExxonMobil entered the market, notably with a view to exploring Black Sea offshore reserves. Attracted by Romania's shale gas prospects, a number of foreign companies acquired exploration permits, including Chevron, the US major, international mid cap companies

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(e.g., Sterling Resources and Transatlantic Petroleum) but also foreign state owned corporations such as Hungary's MOL. Domestic Romgaz, which had already explored for shale gas in Western Romania, stated it also considers joining the bid for licenses in unconventional gas.

The Romanian population tends to be generally skeptical toward fracking, and the country saw major anti-shale protests starting in 2012, mainly against exploratory drillings conducted by Chevron. However, a short-term moratorium that had been put on fracking expired in 2013 and the country remains—legally—open to shale gas exploration.

PROSPECTS FOR COMMERCIAL DEVELOPMENT

Because of the small number of exploratory drills the geological conditions of Romanian shale remain unclear. This makes it difficult to generate statements on the future potential of Romanian shale, and its economic viability. Arguably, the prospects of Romanian unconventional gas will primarily hinge on the regulatory context. This first of all pertains to politics: the Ponta government, in power since 2012, performed a remarkable flip-flopper strategy regarding shale gas. Having run on an anti-shale platform during the 2012 elections, Ponta first imposed a moratorium, subsequently turned into an open proponent of unconventional energy, before eventually announcing during his 2014 presidential bid that "Romania does not have shale gas" after all.[38] This led to confusion among the population and the business community. Romanian unconventional gas policy therefore represents a mere symptom for a highly volatile political environment in the country.

Moreover, regulatory procedures are in need of updating. Because Romania's shale gas sector operates on authorization procedures that were designed for conventional oil and gas production, "micro-management procedures" and "ad hoc interpretations" characterize licensing processes.[39] This adds to a generally weak state apparatus governing the energy sector and numerous blank spots in shale gas legislation, pertaining to concessions, environmental oversight, or tax issues. Slow progress on the draft law on taxes and royalties, which has been pending since years, also led to the holding back of thirty-six new concessions for onshore and offshore hydrocarbon licenses.

Finally, fracking has been met with growing opposition from social groups and environmental organizations, for reasons related to none-transparent decision-making, lacking communication with affected communities and concerns related to groundwater safety. Protests have lasted since 2012 and occasionally even turned violent, which has been cited as a reason why foreign companies let go on Romanian shale gas assets.[40] Chevron left the country in 2015, officially a result of disappointing test

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drillings and unfavorable international business environments, while Sterling Resources sold its Romanian shale gas assets to Carlyle, the investor group.

In all, while Romania has not gone down the path of neighboring Bulgaria and enacted a ban on shale[41], the mid-term prospects of exploration are dim and will depend on the ability of the political elite to reinstate trust into the regulatory environment and the institutions overseeing fracking operations.

THE UNITED KINGDOM

The UK has for long been one of Europe's major gas producers. Yet, its annual output has sharply come down from its peak at 108 bcm in 2000 to 36.6 bcm or 1.29 tcf in 2014. Domestic production now covers roughly half the country's demand and the UK's R/P ratio in natural gas is 6.6 years.[42] Imports come from Norway, the UK's prime external source and LNG (mainly Qatar) but Russia is gaining share as well. Fracking has been used for well stimulation in the conventional oil and gas industry since 1965. Since the debate on shale gas prospects gained traction in 200, the UK government awarded a number of licenses to explore unconventional gas reserves in the country.

REGULATORY GOVERNANCE AND POLICY CONTEXT

The UK has a long-standing history in the onshore and offshore oil and gas industry. Though shale gas is not explicitly mentioned in regulations pertaining to hydrocarbon production, an elaborate regulatory apparatus governing the extractive sector covers crucial aspects of the value chain, including environmental oversight. Petroleum Exploration and Development Licenses (PEDLs)—which cover both oil and gas—are granted by the UK's Department for Business, Energy and Industrial Strategy (BEIS). Additional levels of regulatory authorities are involved when it comes to operating wells (Environmental Agency or Health and Safety Executive and their equivalents in Wales and Northern Ireland) or acquiring local drilling permissions (e.g., Minerals Planning Authority, which also involved representatives from districts and county councils). A nation-wide short moratorium was imposed on shale gas in 2011 but lifted again in 2012.

In the 1980s the UK was the first country in Europe to deregulate and privatize its gas market. The country features a mature energy industry that includes specialized companies in energy services. The main corporations active in shale gas at present are Cuadrilla, IGas, and Third Energy, though

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also IOCs such as France's Total and GDF Suez joined in through consortia. The Cameron government strongly pushed the development of a shale gas industry in the UK, and the subsequent May government stays on a pro-shale course. The main drivers are the country's rapidly increasing import dependence in natural gas and the perceived economic benefits to local communities and the UK economy as a whole. To that end, London granted tax incentives to shale gas development and doubled the share that local governments can pocket from shale gas developments.

As polls suggest, the British public remains by and large positive toward fracking, though the proponents' margin is shrinking.[43] Local protests, however, have gained momentum, especially around focal points of exploratory activities such as Lancashire or Balcombe. This led to growing political resistance among county councils when granting permits and effectively stopped some projects.[44] Nation-wide protest groups such as "Frack Off" voice concerns about groundwater safety, or the potential impact on tourism as the basis of the local economy. Concerns also relate to seismic activities that have occurred between June 2011 and April 2012 and which are attributed to exploratory shale gas drillings. Reacting on this, the UK Government announced to toughen regulatory requirements for the latest (14th) round of PEDLs for oil and gas (which includes shale gas), with a particular focus on seismic risk analysis and environmental monitoring.

PROSPECTS FOR COMMERCIAL DEVELOPMENT

Its elaborate regulatory governance in oil and gas production, a well-developed service sector and a mature energy economy should put the UK in the position to emerge as the front runner in European shale gas extraction, and probably the only country seeing commercial shale gas production in the EU any time soon. The UK is capable to put in place attractive investment conditions and to implement a reliable and robust regulatory framework, that is, to "get the above ground factors right." Despite lower reserve estimates than in Poland or other parts of Europe, the UK is therefore likely to become the destination of choice for international investment in shale gas.

That said, progress remains slow. Reportedly, the shale gas wells struck so far fall short of the up to forty wells that are needed to judge the country's shale gas deposits.[45] As everywhere else in Europe, the UK's shale gas industry remains nascent, and the persistently low number of exploratory drills does not allow for more robust estimates of the prospects for commercial development. In light of this, a UKERC study cautions that it might be way into the 2020s that domestic shale gas could become a significant source of

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energy supply. The report also suggests that a 2–3 year exploration program would be needed to judge the economics of UK shale going forward.[46]

Politics will remain a crucial factor as well. Despite the government's efforts to "buy in" local communities and to sweeten the presence of drilling activities for example, by offering financial rewards for "host communities," local resistance will probably persist. What is more, although the Tory government championed the development of UK shale gas since taking the majority in 2010, the Conservative Party is split over the issue, with resistance coming mainly from land—owners in rural areas. The Labor Party remained modestly positive while the Greens oppose fracking on environmental grounds. The Scottish National Party, which emerged a major political force, fostered a moratorium on planning permits for shale gas, which went into effect in Scotland in January 2015.

Overall, therefore, we should expect the UK to lead Europe in developing shale, but at slow pace and low output rates judged by US standards.

CONCLUSION

This chapter offered a comparative assessment of unconventional energy in Europe, with a focus on unconventional gas. As the chapter revealed, the European shale gas industry remains in its infancy. Few countries have so far taken a deliberate decision to foster shale and unconventional energy more generally, whilst others put moratoria or bans on the fracking technique. As the case studies show, environmental concerns cause strong political resistance, a pattern that exhibits all European countries, even in pro-shale UK. In addition, regulation remains a challenge. A case in point is Poland where regulatory uncertainty and administrative hurdles added to disappointing geology and made companies leave the country. Romania's flip-flopper policy on shale will have a lasting effect on foreign investors' appetite to put money into developing the country's unconventional gas reserves. Finally, diverging policy priorities influence and shape shale gas policies. For instance, Germany's *Energiewende* not only absorbs much political capital and executive capacity but also put other energy policy agendas on the backburner.

As a result, the number of exploratory wells so far remains limited, which prevents detailed estimates about reserves and the economic prospects of European shale gas. Moreover, many European countries will keep on struggling to put in place the appropriate regulation and to establish a governance framework conducive to nurturing the nascent unconventional energy sector. Some front runner countries such as the UK will arguably experience a learning curve, which may enable them to offer best practice to other European

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states that are willing to give shale green light. Still, none of this will arguably happen this side of 2020.

The EU's recent moves toward a veritable "Energy Union" entail a focus on strengthening European supply security by way of enhancing domestic supplies, possibly including shale gas. Yet strongest emphasis is placed on pushing energy market integration through regulation, more energy infrastructure, and increased transparency in the market, notably with a view to contracts with external suppliers.[47] In short, the Energy Union is about the "software" and "hardware" of the EU energy market, not about unconventional reserves. Overall, therefore, European shale gas will not scale up quickly, and the US "shale revolution" is not likely to be replicated in Europe.[48]

NOTES

1. The author gratefully acknowledges that the research leading to these results (page 1) has received funding from the People Programme (Marie Curie Actions) of the European Union's Seventh Framework Programme (FP7/2007–2013) under REA grant agreement n° PIOF–GA–2012–331962.

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Chapter 9

Development of Shale Oil and Gas in Russia

Tatiana Mitrova

INTRODUCTION

Russia is in a very early stage of its shale hydrocarbons development. In terms of the shale oil resource base there is huge uncertainty about the actual capacity of Russia. Total tight oil reserves in Russia are estimated to be in the range of 15 billion to 1.05 trillion barrels. Russian companies are demonstrating strong interest in the development of these resources. Moreover, they are supported by the Energy Ministry, which has already provided significant tax breaks, stimulating shale oil production. Nevertheless, future shale oil production in Russia would face numerous challenges: geological (which is quite different from the United States), technological (especially under the sanctions), economic (shale oil breakeven level in Russia currently exceeds $200/bbl), regulatory (as the tax breaks given are still not sufficient for the profitable development of these resources and subsoil access is also quite restricted), and institutional (strongly concentrated corporate landscape, lack of service companies, which increased further under sanctions). Taking into account all the limiting factors, it seems that Russia is unlikely to experience a revolution in tight oil similar to the one in the United States. Production will probably gradually materialize, but it will take a long time before it is a material contributing factor to the Russian liquids output, especially under sanctions with the absence of international technologies and expertise.

Russia has also vast shale gas resources. There is no serious discussion in Russia concerning the future of shale gas in the country: most experts, including Gazprom and Russian Energy Ministry representatives agree that shale gas production in Russia in the nearest future is not economically feasible as compared to various conventional gas projects.

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UNCONVENTIONAL OIL RESOURCES IN RUSSIA

The discovery of shale oil and oil shale in Russia is dating back as far as the 1960s to the 1970s,[1] but it has largely gone undeveloped due to constraints in Russia's oil industry and availability of huge conventional fields. It has however become much more interesting following the improvements in the technology for the extraction of shale oil and gas developed in the United States over the past decade.

A number of recent estimates suggest that the resource base to be exploited across Russia is enormous, although uncertain. According to the EIA assessment, Russia holds more than 20 percent of the identified shale oil resources in the world (See Figure 9.1).[2] The bulk of these 75 billion barrels of the Russian shale oil according to the EIA is provided by Bazhenov Rock—shale formation, which is prevalent almost right across Western Siberia and is the world's largest oil shale formation.

However there is a huge level of uncertainty in this resource estimate; the level of this uncertainty is captured in the wide spread of high and low estimates—total tight oil reserves in Russia have been put in the range of 15 billion to 1.05 trillion barrels.[3] Even individual companies have very broad assessments of their own resources, with Rosneft quoting numbers in the range of 6–18 billion barrels. Moreover, even the classification of the reserves is quite discussable. The very definitions of unconventional reserves

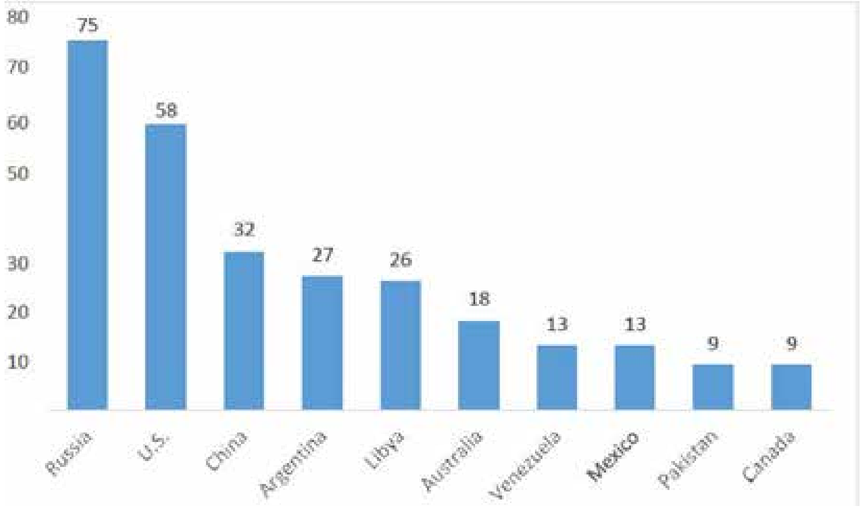

Figure 9.1 Technically Recoverable World Shale Oil Resources, Billion Barrels. *Source*: IEA (June 2013).

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in Russia are quite sophisticated. The broadest definition is "hard-to-recover" oil, which includes shale resources, such as those found in the often-cited Bazhenov geological layer, but also bitumen, a very viscous crude that is extracted from shallower reservoirs using mining or steam heating techniques, as well as oil that comes from conventional reservoirs that happen to have low permeability and/or porosity.

The existing resource estimates are quite misleading, as putting together tight oil, Bazhenov, and shale oil could create an impression that simply applying the US technologies to Bazhen could provide for the repetition of the shale revolution in Russia. However, the reality is quite different. Russian shale resources are concentrated mainly in Western Siberia in deep layers—in Abalak, Bazhen, Tuymen, Frolov, and Domanik formations with low permeability and/or porosity, but with high oil content, which have completely different geological and technical characteristics.[4]

BAZHENOV FORMATION

Bazhenov formation is the most often-cited source of unconventional oil in Russia. It is widespread (at 2.6 mln km2—it is twenty-two times the size of the Bakken in North Dakota).[5] Bazhenov features high-quality crude oil in reservoirs of low thickness (10–40 m), and covers an extensive area in Western Siberia, home to the country's aging conventional oilfields, spreading below an estimated 40 percent of the region's territory. Bazhenov sediments can be found within Khanty-Mansi autonomous okrug (KhMAO)—Yugra, Tazovsky Peninsula, Gydan Peninsula, and the eastern and central parts of the Yamal Peninsula. Bazhenov formation deposits occur from depths of 600 m at the edge of the formation to a maximum depth of 3,500–3,800 m with most part of the formation at a depth of below 2,100 m. The KhMAO has 172 discovered deposits of the Bazhenov-Abalak formation, mainly in the central part of the region, in the fields of Salym (Big Salym group), as well as the Krasnoleninsky, Fedorov, and Surgut fields.

Indeed, the possibility of commercial development at Bazhenov has engrossed industry experts since its discovery in the late 1950s. Bazhenov formation oil deposits were discovered at over seventy fields so far. However, they have not been developed due to limited information and a lack of appropriate production technology.

From the geological point of view, Bazhenov is an oil source rock in which the transformation of organic matter (kerogen) into oil has not yet been completed. The composition of Bazhenov formation's sediments is very heterogeneous, but the main organic components are liquid hydrocarbons and kerogen; the non-organic components are clay minerals, silica,

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and carbonates. Bazhenov formation rock contains two different types of reservoirs:[6]

- Virtually impermeable porous-fissured reservoirs (with micro fractures), a matrix which mainly consists of bituminous claystone containing organic material (kerogen);
- Highly permeable fissured-cavernous reservoirs (with macro fractures), a matrix, which contains almost no organic content and is not oil source rock.

What the Bazhenov formation deposits do have in common with, for example, Bakken's oil shale, is that they both possess source-rock properties; both contain large amounts of kerogen, and the tight rock forms oil reservoirs in both cases. They differ mainly in the thickness of their pay sediments and their distribution across the section. Bakken formation reservoir rock has a thickness of over 40 m and is located between smaller rocks rich in organic matter. In Bazhenov, a typical cross section shows reservoir layers of 0.5–3.0 m thick, located at several stratigraphic levels, separated by benches of thin rock reached by organic material, with an average thickness of 2.5–10.0 m. Therefore, Bazhenov reservoirs are associated with very thin, disconnected layers across the section. Based on its hydrocarbon composition and content, Bazhenov formation rock is highly analogous with the most common oil shale of the Green River formation in the United States, which is not yet being developed. For this reason, the EIA included Bazhenov formation resources in its assessment of worldwide technically recoverable resources of shale oil.

It is important to stress, that though in many respects Bazhenov formation is similar to the oil shale resources of Bakken and Green River, but it greatly differs by the thickness of the pay reservoirs, their non-uniformity and distribution across the section. A crucial feature of the Bazhenov formation is the significantly varying composition of its rock (kerogen, clay, carbonaceous and siliceous components) depending on the area of occurrence. The rock composition may differ greatly even within the same deposit. Moreover, as a result of the intensity and type of secondary transformation processes, the Bazhenov formation's reservoir properties are very poor and may vary considerably through the cross section. For example, in its activity areas, Surgutneftegas distinguished eight different lithotypes of Bazhenov formation rocks. A distinctive feature of the Bazhenov formation is the presence of zones with anomalous composition, where the uniform mass of bituminous argillites is interstratified by highly penetrating silt sandstone beds.

These Bazhenov's abnormal sections possess a high proven oil reserves potential. The interbedding of source rock highly saturated with organic matter with highly permeable silt sandstone "sweet spots" makes it possible for

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the oil formed by natural processes to migrate to these "sweet spots." Current oil production from the Bazhenov formation is mainly conducted from the sections of abnormal structure.

Bazhenov formation resource estimates vary considerably. For instance, according to the Government of KhMAO's official data, initial total oil resources in the Bazhenov formation in the region amount to about 3.1 billion tons (over 20 billion barrels), nearly the same assessment which is provided by Rosneft. According to estimates by the US Geological Survey, Bazhenov formation resources are 5.9 billion tons (43 billion barrels). The EIA estimated the Bazhenov formation's resources much higher and at the time of the 2013 assessment,[7] the total oil resources contained in Bazhenov formation rock (oil-in-place) were estimated at 170 billion tons, 10 billion tons of which were technically recoverable resources (74.6 billion barrels). IHS CERA survey indicates as much as 143 billion tons (meaning an extraordinary one trillion barrels, nearly four times the size of Saudi Arabia's oil reserves or thirty years of world supply at current rates of consumption).[8] Merrill Lynch analysts estimated the play's resource potential between 8.5 billion and 20 billion tons of oil.[9]

The main question concerning all these estimations is the application of oil recovery factor. For example, the oil recovery factor used by EIA for the Bazhenov formation is assumed to be 6 percent, which is typically applied to a "favorable" play with a low clay content, moderate geological complexity, and favorable reservoir properties.[10] However, it is unlikely that all of these characteristics can be applied to the Bazhenov formation. An oil recovery factor of 3 percent is typically adopted for less "favorable" deposits, while 2 percent is generally used for unfavorable deposits. Therefore, should the evaluation of the Bazhenov formation sediments' "favorability" characteristic be amended, its technically recoverable resources could instantly fall two or three times (from 10 billion tons to 3–5 billion tons). And even this assessment may be overstated. The EIA methodology assumes that an appropriate technology for hydrocarbon production exists but this is not the case for the Bazhenov formation, with the exception of the anomalous sections. In addition, as mentioned above, no other formation provides an accurate comparison, which could be used to conduct precise assessment of the oil recovery factor.

It is necessary to stress that resource potential of the Bazhenov formation is first of all associated with the development of technologies to extract oil from kerogen. Oil resources that can be extracted from kerogen are estimated at between 35 and 43 billion tons. However, many experts do not share these optimistic views on the future potential developments of the Bazhenov formation. Its heterogeneous reservoir properties and limited reservoir knowledge would require significant investment and time to test and

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implement efficient technologies to convert kerogen to oil and subsequently recover it.

The Bazhenov formation's potential is, in theory, tremendous, but currently there is no technology for its commercial development. Therefore, the cumulative oil production in Bazhenov-Abalak play since its discovery (for about fifty-five years) just slightly exceeds 11 million tons. At the moment, Russian companies develop Bazhenov formation by natural depletion without reservoir pressure maintenance, since maintaining reservoir pressure appears impossible due to extremely poor connectivity of the rock. Currently, pilot commercial development of the Bazhenov formation is being undertaken by three companies: Surgutneftegaz, Rosneft, and RITEK. The highest activity is carried out by Surgutneftegaz, which has drilled more than 600 wells in the Bazhenov formation over the last thirty years. The drilling results indicated that 37 percent of the wells were "dry," and that 63 percent had oil flows (maximum up to 300 tons/day). In 2011, Surgutneftegaz produced 512 Ktons of oil, Rosneft produced 82.4 Ktons of oil, and RITEK, in 2010, produced 117 Ktons of oil from the Bazhenov formation.[11] Surgutneftegas's experience shows that wellbore construction technology, which tested overburden pressure on the formation, results in dramatic reduction of well productivity due to the abnormally high formation pressure.

Russian oil companies have recently stepped up their testing work on the development of industrial technologies suitable for extracting hydrocarbon resources at the Bazhenov formation. The pilot projects under implementation can be divided into two main groups:

- Thermogas techniques for oil recovery enhancement (Surgutneftegas, RITEK);
- Adaptation of the American experience to Russian conditions with multistage hydrofracturing in horizontal wells for shale gas and tight oil deposits (Surgutneftegas, Rosneft in conjunction with ExxonMobil, Gazprom Neft and Shell in the Salym Petroleum Development).

Multistage hydrofracturing technology is currently efficient in shale gas and condensate production, while for enhanced oil recovery it is appropriate mainly for homogeneous tight rock. Adapting this technology for Bazhenov, even for its abnormal sections, would be difficult because of the heterogeneity of the deposits. Nevertheless, Gazpromneft-Noyabrskneftegaz, together with Dowell Schlumberger, experimented with multistage hydrofracturing at Salym. As a result, the well production rate, where the oil influx was nonoverflow (the fluid level in the borehole could not reach its mouth), rose to 33 cubic meters per day (cmpd); it dropped by half to 18 cmpd in just seventeen days of operation. Another identified Bazhenov characteristic is its

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flow rate pattern, with the production rate dropping sharply after hydrofrack operations.

Applying hydraulic fracturing to Bazhenov is also greatly complicated by its extensive depths, high temperature, and abnormal pressure zones. In particular, the abnormally high formation pressure prevents fractures from opening up completely. In some cases, there was a rapid formation-pressure reduction in the productive zone following hydrofracturing. The application of hydrofracturing requires high pressure to be provided, and artificially created fractures to be securely fixed, which is extremely difficult to achieve in clay rock. Numerous instances of hydrophobic behavior by Bazhenov's reservoirs are also an important feature.

One of the technological development challenges for the Bazhenov formation will be creating secondary permeability in the oil-saturated matrix by a system of directional fractures using hydrofracturing. However, it is difficult to predict how long it will take to refine this technology, and what its economic result will be.

OTHER FORMATIONS

Achimov Formation

Achimov oil and gas deposits are located above Bazhenov, making them easier to reach. Oil is locked in tight sandstones confined by shale. Achimov bedrocks feature average porosity but low permeability, but nevertheless have a tendency to have better flow rates and lifetime production than the Bazhenov layer—the predictability is often better than that at Bazhenov. At Yuganskneftegaz's Priobskoye field, for instance, test wells drilled to Achimov have shown higher initial flows and lifetime flows that are potentially almost twice as high as at Bazhenov (though still only half as high as at the traditional horizons on the field). The cost of drilling at Achimov is slightly lower than at Bazhenov due to smaller depth and, in practice, fewer stages of hydrofracturing.

Tyumen Formation

The Tyumen formation represents a mix of permeable and impermeable layers of continental origin, covers the same geographic area as the Bazhenov but at a lower depth of 2,800–3,200 meters, and tends to contain narrower reservoirs with mixed permeability, making it a more difficult target for drilling and generally more expensive to develop.[11] Generally deeper than Achimov and Bazhenov, the formation is characterized by poor collector characteristics

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and low thickness of pay zones, making it a risky exploration target. That said, oil and condensate may be of a high quality as a result of the protracted impact of high reservoir temperature.[12]

Domanik Formation

Reservoirs in carbonate and siliceous rocks of the Frasnian Domanik formation, is also a source rock for the accumulations. Oil is produced in several fracture zones, which may be considered sweet spots in continuous unconventional accumulation. The principal source rock is the middle Frasnian Domanik formation, which stratigraphically widens into the Tournaisian in the Kama-Kinel basins. The formation is 25–40 m thick and contains as much as 25 percent TOC. Matrix porosity of Domanik carbonate and siliceous rocks is low and the rocks are essentially tight. Oil production is controlled by development of fractures.

Russian Potential Shale Production

At present, mainly Bazhenov formation sediments are developed. Annual oil production here amounts to about 800,000 tons (approximately 500,000 tons of which is produced by Surgutneftegas, about 100,000 tons by RITEK, about 100,000 tons by Rosneft, and about 50,000 tons by Russneft).

Most of the Bazhenov production is provided by Surgutneftegas from formation deposits located in abnormal sections and characterized by higher reservoir properties. Surgutenftegaz has the longest experience of Bazhenov Rock development—without any foreign partners. Since the 1970s Surgutneftegas has drilled more than 600 wells in the Bazhenov formation, only 157 of which produce commercially now. This is due to the lateral heterogeneity of the reservoir properties: production rates of closely spaced wells can vary widely due to the extremely uneven distribution of fracturing zones even in the drainage zone of the same well. As a result, there can be three "dry" or low-productive wells per normal producing well.

Today the oil recovery factor in the Bazhenov formation amounts to 2–3%. Implementation of existing technologies can increase the oil recovery factor to 35–40%.[13] High interest toward the Russian unconventional oil arose during 2010–2012, when it became obvious that the US shale revolution is not a myth. Tight or shale oil, known in Russian by the looser term "hard-to- recover" oil, became a target of a major push by the Russian government as it was hoping to replicate the US shale revolution in Russia. The problem for Russia is that despite the fact that it is one of the

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recognized world leaders in the liquids production, the depletion of traditional fields urgently requires development of the new resource provinces. Large unconventional oil resources were found exactly in Western Siberia—in the areas with developed oil producing and transportation infrastructure. Therefore, the idea of shale oil potential development became very popular, and a number of joint projects with the Western majors were established, but annexation of Crimea and conflict with Ukraine in 2014 resulted in technological and financial sanctions against Russian oil companies, announced by the United States and the EU. Now it seems that the sanctions made Russian shale oil production growth hopeless in the near future.

But future tight oil production forecasts vary significantly. In the years 2012–2014 the large resource estimates have encouraged the Russian government and oil industry to believe that the development of unconventional oil in Russia could be the short- to medium-term solution to the risk of a potential production decline. Indeed a number of corporate and ministry production forecasts have been made that suggest the possibility of significant output being achieved by the end of this decade. In 2012 Rosneft has estimated that it could be producing 300,000 bpd of unconventional oil by 2020[14], while GazpromNeft has suggested that it could produce a similar amount.[15] More optimistic overall forecasts have emanated from the Russian Energy Ministry and the Ministry of Natural Resources (Figure 9.2), the latter suggested in 2012 that total tight oil production in Russia might exceed 1 mn bpd by 2025 and will reach 1.7 mn bpd by 2030.[16]

This uncertainty reflects difficulties in a number of areas, including licensing, levels of taxation, definition of strategic resources, environmental legislation, availability of sufficient oil service equipment, and a lack of variety in the companies developing the resources, but at the most basic level the issue of geology remains the primary concern at present. It is clear, then, that despite the huge resource potential of the Bazhenov and associated tight oil strata in Russia, the geology is yet to be fully understood, and it is this fact that has heightened calls for increased government support for companies, which are preparing to investigate the possibilities for commercial production. At the same time all the experts agree, that now the future of sanctions and availability of domestic technologies became the most critical factor.

In our view, there will be no significant increase in oil production from Bazhenov and other formations during the next ten to fifteen years in Russia, the drilling of new wells will at best help to maintain the current level of oil production, mainly from abnormal Bazhenov sections (about 1.0–1.5 Million Tons per year).

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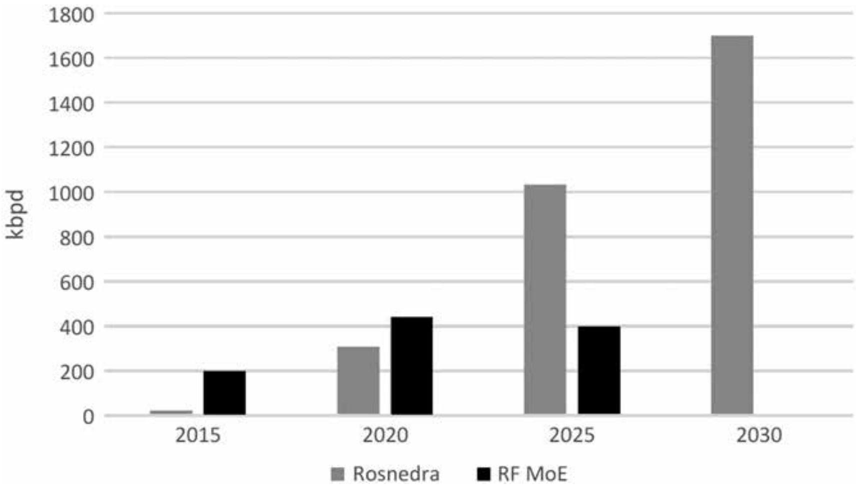

Figure 9.2 Location of the Bazhenov Formation. *Source*: SKOLKOVO Energy Center (2013).

MAIN LIMITING FACTORS AND IMPACT OF SANCTIONS

Technological and Economic Uncertainty

Despite the huge resource potential of the Bazhenov and associated tight oil strata in Russia, the geology is yet to be fully understood, and it is this fact that has heightened calls for increased government support for companies which are preparing to investigate the possibilities for commercial production. Well costs in tight oil production are high and, in common with most shale reservoirs, decline rates are rapid, meaning that costs need to be recovered early in the production cycle if an economic return is to be made, especially in the current 50$/bbl oil price environment. Furthermore, it is not just oil company investment that is required but also significant expenditure by oil service companies on new rigs and fracking equipment, a lack of which could easily delay the achievement of production targets. The question is whether without Western technologies Russian companies will be able to monetize these ambitions.

Aside from the major issues of the economic viability of unconventional oil development in Russia and the availability of sufficient oil service capacity, there are a number of other questions that will need to be answered before companies make significant investment decisions:

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Taxation

Under pressure from the oil companies, the Russian government has adopted full MET breaks to Bazhenov oil for a period of fifteen years, with greater breaks, vis-à-vis the previous proposal, for other formations, predicated on the permeability and the thickness of the payzone. In summer of 2013 the Duma approved the long-awaited tax exemptions on tight oil—10–15y MET breaks for the most widely targeted Bazhenov formation, and 60–80 percent MET discounts for other low-permeability plays, such as the Achimov horizons. Though some of the experts still regard these MET breaks as insufficient,[17] a tax regime that focuses on royalty payments per barrel of oil produced or exported without regard for cost recovery is always going to make it difficult for oil companies to generate commercial returns from their investments. Reductions in export tax rates may also be required, but a more rational long-term approach would be a restructuring of the regulatory system to focus on taxing profits rather than revenues. The Russian administration is reluctant to do this for fear that "creative oil company accounting" will result in the majority of oil production being classified as "hard-to-recover," with a consequent loss in tax revenue, but it may be the case that the need to incentivize the development of Russia's unconventional resources can provide an additional spur to action on a profit-tax regime for the Russian oil industry.

Law on Strategic Reserves

One legislative issue, at least for foreign companies, concerns the Law on Strategic Reserves which was introduced as an amendment to the Subsoil Law in May 2008,[18] and which limits foreign involvement in fields with reserves above a certain size, namely 70 million tons (c.500 million barrels) for oil and 50 bcm (c.1.75 Tcf) for gas. Any fields larger than this, or located offshore, must have a Russian company as a majority shareholder. However, because shale oil resources are much more complicated to define in compartmentalized blocks compared to conventional fields, which generally have a defined areal extent and depth below a trap of some kind, the Russian authorities may struggle to define accurately whether a particular company owns a strategic resource or not. This could in future create problems for any foreign company that might start as a majority shareholder in a license area only to find that its position is illegal. This problem was resolved through the formation of JVs between Russian companies with a 51 percent stake and foreign companies with a 49 percent stake, but the sanctions destroyed all these plans.

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Corporate Landscape

This raises a second more subjective question about the corporate environment needed to catalyze successful development of unconventional reserves. The Unconventional Gas Centre in North Dakota lists eighty-nine companies that operate in the Bakken shale area of the United States alone,[19] and it is this diversity of corporate involvement as well as the small and adaptive nature of many of the companies that has been at the heart of the success of the unconventional oil and gas industry in that country.

The corporate landscape in Russia is in sharp contrast to the dynamic smaller company model in the United States, with a few large companies leading the way, dominated by the country's NOC Rosneft. In Russia only four large and vertically integrated companies (now that Rosneft owns TNK-BP) are heading the drive to develop the Bazhenov reservoirs.

Licensing

The relatively tight nature of Russia's corporate landscape is also exacerbated by the licensing regime for tight and unconventional oil, which tends to favor larger companies. Much of the Bazhenov shale reservoir lies below existing licenses and fields in West Siberia and is the main source rock for oil in the region. In some instances, the licenses for shallower reservoirs also extend down to the deeper shale layers, and so the large companies that dominate Russian production have extensive Bazhenov exposure by default. Even if the current licenses do not currently extend down to the Bazhenov, however, it is expected that companies owning the shallower licenses will be able to extend their exploration to the deeper horizons as a matter of course. As far as new licenses are concerned, GazpromNeft has identified acreage containing a potential 8−10 billion tons (60–75 billion barrels) of resources that are yet to be allocated in the Khanty-Mansiisk region alone, so the possibility of new entrants arriving still remains.[20] Given the current government preference toward state-controlled institutions, however, and the implications of the Law on Strategic Reserves discussed above, it would seem likely that the majority of this new acreage will go to the same group of companies that currently dominate the industry.

Environmental and Water Issues

Russia's huge geographical expanse means that it is unlikely to be troubled by the environmental concerns that are currently facing more densely populated countries where lobby groups are raising concerns about the possible impact of fracking on supplies of potable water and the risk of seismic

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disturbances. Nevertheless, Russia does have some strict environmental laws that can impose severe fines on companies that cause damage through leaks or harmful waste disposal, and it is currently unclear whether these might need to be adapted further to account for the increased activity that would result from significant horizontal drilling and well fracking involved in the development of tight and shale resources.[21] Given that activity on tight reservoirs using these techniques has been underway for some years under current legislation one might assume that this will remain the situation if drilling for unconventional resources expands. Given the difficult terrain in Siberia, however, combined with the extreme weather conditions, which means that the landscape changes from a frozen wasteland in winter to boggy marshes in summer, it would not be surprising if the Russian authorities decided that new legislation is required to manage a different type of development activity that involves high levels of liquid injection and the need to deal with the return of at least 15 percent of injected water to the surface. Any examination of this issue could clearly take some time and cause delays to operational activity.

One of the other main environmental issues may also concern the use of water. Although there would seem to be little risk of drought in Siberia, the fact that temperatures remain below zero for a significant part of the year means that the issue of water provision could be a significant one. This may require state approval for a broader network of heated pipelines to manage winter water supply, the expansion of road transport fleets and storage facilities to cater for water provision at different times of the year and an adaptation of the rules for water extraction and injection that are currently managed by the Ministry of Natural Resources. None of these issues are insurmountable, of course, but could nevertheless lengthen the process of moving from the exploration to full development of Russia's shale oil and gas resources.

Manpower Requirements

Another question concerns the availability of sufficient skilled labor in Russia's oil heartland to meet the requirements of the much more intensive work required to exploit unconventional oil and gas. In Russia much of the country's skilled oil industry workforce is already heavily engaged in stemming the decline of the country's existing assets and indeed the economy as a whole could be facing labor shortages as the population declines, with the consequence that if a dramatic increase in drilling is required to accelerate unconventional output then it is likely that significant additional manpower will be required that cannot just be shifted from existing fields.

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Service Industry

Availability of rigs of high enough quality and power to drill the numerous horizontal wells that would be needed if 1 mbpd of production was to be achieved, is a huge problem—not only will it be difficult to build enough new rigs, but also that the oil service industry may well be reticent to invest heavily until it more fully understands what the future of the unconventional oil industry in Russia may be.

Another key question for the development of Russia's shale and tight oil resources will be the expansion of the oil service industry. The number of heavy oil rigs, which are capable of drilling the deep horizontal wells needed to exploit the Bazhenov reservoirs, will need to triple if the Ministry of Resources' target is to be met, raising a question about the ability of the oil service industry to meet the possible $15 billion expenditure requirement. Furthermore, the industry will also have to expand its ownership of fracking equipment and other operational items, and this will put pressure both on its ability to finance so much purchasing in a relatively short period of time and its willingness to take the risk of investing in what remains an uncertain resource base.

Overall, then, although Russia undoubtedly contains huge potential for the development of unconventional oil resources, it would seem unlikely that the aggressive Ministry of Natural Resources target will be met even before the sanctions were imposed. Anyway, taking into account all the limiting factors, it seems that Russia is unlikely to experience a revolution in tight oil similar to the one in the United States. Production will gradually materialize as the state is talked into extending further tax grants, but it will be years before it is a material contributing factor.

IMPACT OF THE SANCTIONS

Europe and the United States placed restrictions on the Russian oil sector in mid-September 2014, limiting the ability of Western companies to engage in exploration or production of Arctic, deep water and shale oil resources. The impact of these sanctions is likely to be small in the near term, however, the Russian government sought to attract Western expertise in these areas by offering tax breaks for shale oil projects, which came into effect in 2014. Western majors rushed to take advantage, with ExxonMobil, Shell, BP, Total and Statoil all signing shale joint ventures.

Executives and lawyers say the sanctions effectively prohibit Western oil companies from any involvement in Russian shale projects—in particular by inhibiting the service companies whose expertise is essential to carrying

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Table 9.1 Shale-oriented JVs with Participation of the Western Companies in Russia and their Status under the Sanction

Project	*Participants*	*Description*	*Current*
Shale oil in Western Siberia	JV between Rosneft 51 percent and ExxonMobil 49 percent	The joint venture was supposed to drill for selected Rosneft license blocks in Western Siberia in the RN- Yugansknefte gas activity area, including the Bazhenov and Achimov reservoirs. The project's pilot phase provided for the drilling of thirty wells at a total cost of $300mn. The partners chose horizontal drilling with multistage hydrofracturing as the primary testing technology.	Suspended
Domanik shale formation in the Samara region	JV between Rosneft 51 percent and Statoil 49 percent	The joint venture was supposed to conduct a three-year pilot program to assess the potential for commercial success held by the Domanik shale. Statoil was also planning to perform a pilot survey for twelve license blocks, set to include data acquisition and drilling and fracking of pilot wells. JV has agreed to drill at least six exploratory wells in the region prior to 2021.	Suspended
Domanik shale formations in Central Russia's Volga-Urals Region	JV between Rosneft 51 percent and BP 49 percent	The plan was to jointly explore for Domanikshale oil in the Volga-Urals region of central Russia. BP was supposed to compensate part of the historical costs to Rosneft for exploration of the Domanik formations and to provide carry financing of up to $300 million for the pilot program in the Orenburg Region.	Frozen
Bazhenov rock development in Khanty-Manssiisk District	JV between Total 51 percent and Lukoil 49 precent	The companies were planning joint exploration activities at three shale oil blocks in the area: Vostochno- Kovensky, Tashinsky, and Lyaminsky in Klianty-Manssiisk district, spending $120–150 mln.	On June 25, 2015, Total transferred its share in the project to Lukoil
Salym project (Bazhenov)—pilot production at Jurassic deposits represented by the Bazhenov, Abalak, and Tyumen Formations	JV between Shell 50 percent and Gazprom Neft 50 percent (Salym Petroleum Development)	The companies planned to drill five exploratory wells in 2015, large-scale drilling was scheduled for 2017–2018.	On October 3, 2014, Shell suspended work on the project.

Source: Abovementioned data companies compiled by the author, Tatiana Mitrova (2015).

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out the complex drilling operations that characterize shale production. Withdrawal of the foreign partners from the joint shale projects in Russia has automatically led to their suspension (see Table 9.1). The main reason is the lack of experience, as well as the need to use in the special technologies and equipment, which Russian partners do not have. One of possible solutions to the problem could be inviting companies from China and India that are interested in the development of the resource base in Russia. However, these companies (as well as Russian) do not yet have the necessary technology and expertise.

Government's hopes of 440,000 b/d of Russian shale oil production by 2020 now seem unlikely. Some Russian companies believe they will be able to develop shale resources without Western assistance, but, in fact, the impact of the sanctions goes further, challenging the transfer of cutting-edge technology and expertise to Russia altogether.

Just as financial sanctions against certain companies have triggered a wider freeze in lending to Russia as a whole, so the energy sector sanctions have caused a ripple effect of "sympathy sanctions," as Western companies step back from the Russian market as a whole, regardless of the letter of the sanctions. The move has the greatest potential impact in the service sector—the companies that actually drill the wells, manufacture specialist parts, and provide the expertise to analyze the result. These functions are overwhelmingly provided by Western companies—the likes of Schlumberger, Halliburton, and Baker Hughes—at Russia's most technically challenging projects. Western companies account for about half of the technology used in hard-to-recover oil projects and more than 80 percent of the technology used offshore, according to Russia's energy ministry.[22]

While techniques such as fracking and horizontal drilling are associated with shale, they are also widely used to maximize production from more conventional oilfields, with pockets of oil held in harder-to-access rock formations. It makes a broader retreat by Western service companies deeply concerning for Russia's oil executives. It is important to understand the kinds of services they now have to provide without when developing tight oil. It all boils down to two things: drilling a horizontal well and fracturing it. The drilling itself can be accomplished by Russian companies (such as EDC) using rigs. The point is to make it effective. For that, two kinds of technologies are used: measurement-while-drilling (MWD) essentially steers the drill bit through the formation to capture the better part of the pay zone, while logging-while-drilling (LWD) measures the formation in order to give some idea of what the well's performance will be like. Crucially, both of these relatively new tools allow measurement and adjustment to take place during drilling without stopping the process itself. That makes them especially useful when drilling expensive horizontal wells, and in fact both technologies have grown with the

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increase in horizontal drilling in Russia. Both kinds of procedures, especially logging, need specialized equipment that can send data via the drill string while withstanding high temperature and pressure. As far as LWD goes, the top four Western players seem to have cornered the market for this equipment (MWD appears to be a more accessible technology). The fact that the Western providers are involved in the higher-end part of the MWD/LWD business is clearly seen from the fact that they have captured 80 percent of the open market's revenues in Russia. All of these services can no longer be offered for tight oil drilling. The fines in the United States are $20 mln for each violation and up to thirty years in prison for executives who made the decision (plus US lawyers' fees). The Europeans do not have designated penalties that we know of, leaving fines to the discretion of the member states.

Russian companies could learn these techniques and perhaps even acquire some of the equipment. After all, MWD and LWD have been around for a while. Indeed, Integra and Burintex are two Russian firms already offering both services. So why aren't the Russian competitors winning a greater market share, given that they seem to offer their services at a significantly reduced price? The answer lies not just in technology. The biggest difference between the Western majors and the Russian providers (or indeed the Russian oil companies themselves) is that the Western majors collect, preserve, and analyze all the information that they receive in the course of the job, going back decades—something that Russian companies were never taking care of. This allows Western majors to tailor the services they provide to extract the maximum effectiveness, based on the evaluation of how similar formations have behaved before.

What Russian firms also could not do is provide the necessary proprietary equipment for hydraulic fracturing. Fracking involves the pressure-pumping of water into a well to crack the formation and the injection of a "slurry" (fluid with proppant, such as sand or ceramics, as well as guar gum and acid) to propagate and develop the fracture. Domestic companies lack the technology for the multistage hydraulic fracturing that allows several such injections through the length of the horizontal well bore using a single drill string, cutting the time several-fold and saving materially on costs. The foremost such necessary technology is the complete integrated systems that determine how many fractures to make, and where exactly along the horizontal stretch. While CAT Oil, for instance, can do the job itself, it needs that type of system, which is offered in Russia exclusively by US or Canadian companies. More mundanely, there are not enough producers of strong enough pumps for multistage hydrofracturing in Russia. The Russian Fracturing Company (RFK), the only domestic producer of the equipment, offers aggregates whose gas-fired pumps appear to be just one-tenth the strength required for multistage fracking. That is why Lukoil's CEO Vagit Alekperov has identified

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hydraulic fracturing as the weakest link for Russian oil production, and one sphere where the US sanctions could hit the hardest.

Analysts believe Russian shale deposits are unlikely to be developed extensively without Western expertise and equipment. In an earlier statement, Gazprom Neft said it had begun drilling its first horizontal well in the Bazhenov. Surgutneftegaz, another top Russian oil company, is also developing shale oil without a Western partner. So there will be some production, but a revolution this will not be.

SHALE GAS IN RUSSIA

Russia has the second largest gas reserves in the world (after Iran),[23] the bulk of it provided by conventional reserves. The country is on a very early stage of studying its shale gas potential. The preliminary estimations of shale gas resources in Russia vary significantly: from 20 to 200 tcm. The most in-depth research was presented in the National Program for Mineral Resources Base Preparation and Hydrocarbon Production from Unconventional Sources prepared by the All-Russia Research Geological Oil Institute (VNIGRI) in 2011. According to the Program, the potential shale gas resources in Russia are estimated at 48.8 tcm, most of them are concentrated in Western and Eastern Siberia (Figure 9.3).

Due to the lack of regulatory and legal framework, shale gas exploration wells and clearly defined plans for unconventional hydrocarbon mining,

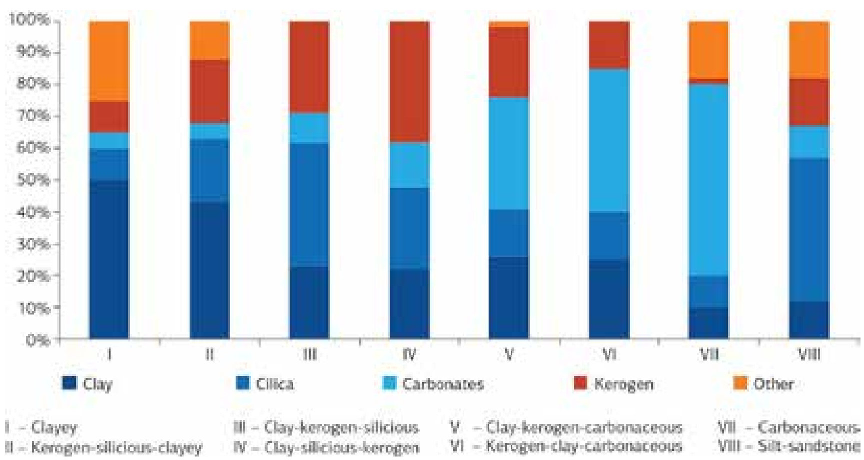

Figure 9.3 Contents of Various Bazhenov Formation Lithotypes. *Source*: SKOLKOVO Energy Center (2013).

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VNIGRI was able to estimate these shale gas resources in Russia only by analogy with American shale gas plays, using minimum analogy factors of 0.1–0.2. This approach, quite reasonable under non-availability of sufficient data, provides relatively conservative estimates.[24] If the real drilling will be initiated, reserves estimates most likely will be reviewed upward, but so far there are no stakeholders interested in this business development in Russia, as proven reserves of conventional gas are 44,5 tcm.

CONCLUSION

Currently the country is facing huge gas oversupply as domestic gas demand is stagnant. With weak demand in Europe and the CIS, coupled to the drive toward reducing dependence on Russia, the traditional export markets provide little relief and the recently signed deal with China is only a medium-term prospect. In this situation of gas bubble, there is no serious discussion in Russia concerning the future of shale gas in the country: most experts, Gazprom and Russian Energy Ministry representatives agree, that shale gas production in Russia in the visible future is not economically feasible as compared to various conventional gas projects.

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Chapter 10

The Nascent Nonconventional Hydrocarbon Industry of Latin America

Market, Infrastructure, Policy, Stakeholders, Opportunities, and Constraints

Isidro Morales

INTRODUCTION

Argentina, Brazil, and Mexico witness the potential take-off of their respective nonconventional hydrocarbon industries, that is, shale and pre-salt resources. The three countries are ranked among the top ten countries with most of the technically recoverable shale oil/gas reserves, according to US Energy Information Agency (EIA) figures. From 2005, Brazil started to develop its huge potential of pre-salt oil and gas reserves with rapid success. If the three countries become successful in developing their nonconventional resources potential, they will converge with the energy revolution already initiated in both Canada and the United States at the turn of this century, transforming the western hemisphere in an energy powerhouse with global economic and geopolitical consequences. Though the three Latin American countries have leveled the playing field according to international standards, allowing private companies to operate and/or participate in upstream activities, their respective "nonconventional" industries are still nascent, facing market, technology, and infrastructure constraints, and demanding rapid and flexible policy environments in order to attract the right investors. This chapter highlights the major market (either regional or international), infrastructure and policy opportunities and constraints, in which current and potential stakeholders operate in each country.

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THE ENERGY MIX AND NONCONVENTIONAL FOSSIL FUELS POTENTIAL OF THREE KEY LATIN AMERICAN PLAYERS

Hydrocarbons dominate the energy mix in both Mexico and Argentina, though the use of natural gas is more important for the latter, amounting to 52 percent of overall supply. By contrast, Brazil witnesses a more diversified primary energy supply, in which oil and gas account 37 percent and 5 percent of the energy balance, respectively, while biofuels and hydro account for 28 percent and 13 percent, respectively. Since Brazil was until recently a major net importing country, the development of biofuels, mainly ethanol from sugarcane, became an energy state-led strategic program since the 1970s. At the same time, hydro became a major source for generating electricity in this country, accounting for 75 percent in power generation, a major differentiation regarding the other two Latin American countries—that is, 11 percent for Mexico and 22 percent for Argentina.[1] However, hydro-generation in Brazil seems to have reached its limits, since climate change and seasonal uncertainties in rainfall have rather generated a hydro vulnerability in power generation. This explains why Brazil—alike Mexico and Argentina—has switched progressively in building thermal generation plants mainly run by natural gas.

Though the allocation of energy resources varies in the three countries, the common denominator for the three of them is their enormous potential in nonconventional hydrocarbon resources. According to the famous study elaborated by the US EIA,[2] assessing the world potential of shale resources, the three countries are among the top ten major reservoirs of shale gas resources worldwide. Argentina ranks first, not only in Latin America, but in the Western Hemisphere, and second, only after China, at global level. Technically recoverable resources (TRR) are estimated to amount, according to the EIA-sponsored study, 802 trillion cubic feet (tcf), equivalent to 646 years of production according to Argentina's current annual production (see Table 10.1). Argentina's potential shale resources heavily contrast with its proved conventional gas reserves, amounting to only 12 tcf. According to the same source the country's shale oil potential amounts to 27 billion barrels (Bb).

The most important prospective region is the Neuquina Basin, located center-west of the Patagonia, and encompassing four provinces (Neuquén, Mendoza, Río Negro, and La Pampa). Los Molles and Vaca Muerta (Dead Cow) areas are estimated to contain 583 tcf of shale gas, more than the overall amount estimated for Mexico.[3] Other prospective areas are located in the south, at the San Jorge and Austral-Magallanes basins and in the north, in the Argentinean side of the Paraná Basin. Though still a nascent industry, Argentina is the only one, out of the three countries here reviewed, which has sponsored a government plan to develop its shale industry. After the

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Table 10.1 Wet Natural Gas Production and Resources

Region Totals and Selected Countries	*2014 Natural Gas Production*	*January 1, 2013 Estimated Proved Natural Gas Reserves*	*2013 EIA/ARI Unproved Wet Shale Gas Technically Recoverable Resources (TRR)*
North America	34 BCM	403 BCM	1,685
Canada	5.7305	68	573
Mexico	2.044	17	545
United States	26	318	567
South America & Caribbean	4	269	1,430
Argentina	1.241	12	802
Bolivia	0.7665	10	36
Brazil	0.6935	14	245
Chile		3	48
Colombia	0.4015	6	55
Paraguay		–	75
Uruguay		–	2
Venezuela	1.022	195	167
Total World	122	6,839	7,201

Sources: For Columns 1 and 2: British Petroleum (2015) *Statistical Workbook of Energy*.
For Column 3: U.S. EI A (2013), Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 127 Shale Formation in 41 Countries Outside the United States, *Washington, D.C. pp. 6–7.*

nationalization of Yacimientos Petrolíferos Fiscales (YPF) from Spanish equity in 2012, the new National Oil Company (NOC) established a joint venture with Chevron in order to develop the plays located in Vaca Muerta. So far, other companies such as Apache, ExxonMobil, and Total have started operations there. Investors have remained interested in keeping and increasing their operations, in spite of the decline in world oil prices since mid-2014 and the transition to a new political regime at the end of 2015 with the election of Mr. Mauricio Macri as president of the country. Private capital and associations with YPF are heavily needed in a country in which macroeconomic stability is traditionally weak, taxes and caps to oil exports are imposed and exchange controls existed until very recently. According to Argentina's minister of energy and mining Juan José Aranguren, investments in Vaca Muerta are anticipated to reach around \$15–\$20 a year in a six-year period from 2019.[4] According to independent analysts, Vaca Muerta could reach 113,000 barrels of oil equivalent daily (boe/d) by 2018, from a current production estimated at 77,000 boe/d. Production could eventually peak at 1.25 million boe/d by 2031.[5]

Mexico ranks second at the Latin American level, and six worldwide,[6] with TRR amounting to 545 tcf, or 266 years of its current gas production. Most of Mexico's shale gas (and oil) potential is located in a geological extension of the Eagle Ford plays located in Texas, a major basin in which

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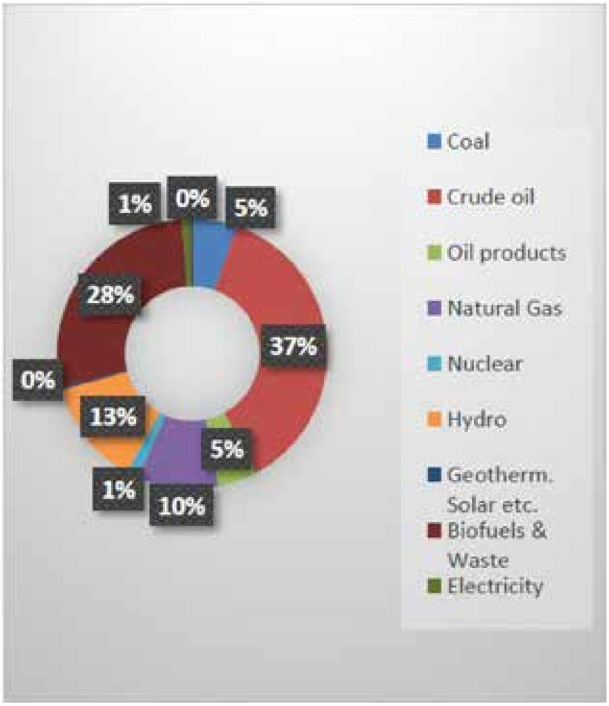

Figure 10.1 Brazil. Total Primary Energy Supply (2012), Shares. *Source*: Brazil, OECD, 2014, energy balances of non-OECD countries, Paris.

United States' current shale boom is taking place.[7] According to Mexico's National Hydrocarbon Commission (NHC), a watchdog and regulatory independent agency assisting the Ministry of Energy (SENER) with technical information and in charge of supervising Mexico's bidding rounds, nonconventional resources are mainly located in three sedimentary basins: Sabinas (North Coahuila), Burgos (North Nuevo León and Tamaulipas), and Tampico-Misantla (south Tamaulipas and northern Veracruz). Until recently, Petróleos Mexicanos (PEMEX) maintained a monopoly in the exploration and production of hydrocarbon resources, either conventional or nonconventional. This explains why the first shale plays in this country were explored by this firm. Currently, the state company has drilled around fifteen wells out of which four are already producing small though declining volumes of shale gas.

In contrast with US EIA's estimations, NHC estimate the current potential of Mexico's shale resources in 141.5 tcf. Shale oil resources are estimated to be 31.9 Bb.[8] The development of shale resources in this country remains uncertain though the Constitutional reform of December 2013 allows, for the first time since 1938—when the industry was expropriated—private

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participation in all chains of the industry. However, most of the government focus is to increase oil production and attract private capital for exploring and developing oil and gas fields located in shallow and deep waters in the Gulf of Mexico. So far SENER has signed thirty-nine contracts with forty-eight new private firms (worth 49 billion dollars) during the four auctions of round one ended up in December 2016. The three bidding processes of round two have already been completed during the first half of 2017, but no unconventional play was listed in neither of the rounds.[9] The bidding of nonconventional fields have been postponed so far, the government is arguing the prevalence of weak prices of gas in North America, making more attractive cheap imports coming from the United States (*supra*). (See Figure 10.2).

Brazil ranks tenth worldwide according to its shale gas potential, amounting to 255 tcf, and equivalent to 353 years of current production.[10] Those resources are mainly located in two sedimentary basins in the northern part of the country: Amazonas and Solimoes, in which oil exploration and

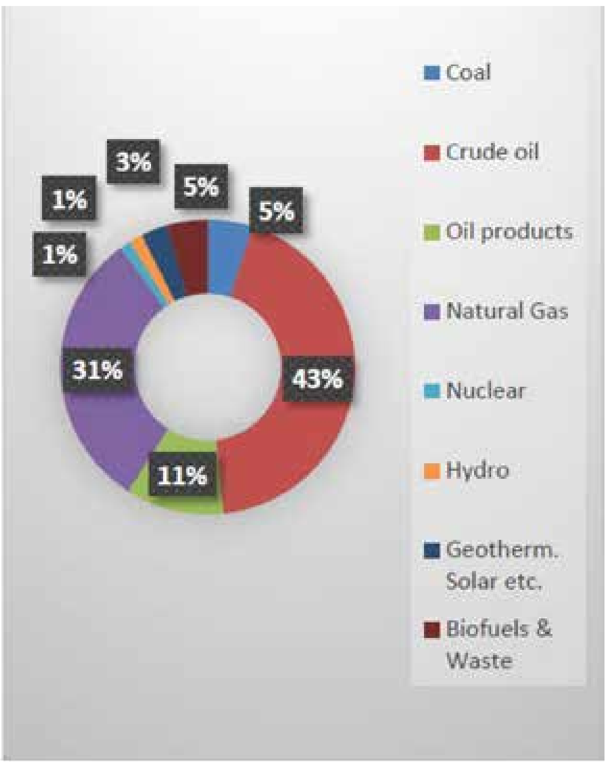

Figure 10.2 Mexico. Total Primary Energy Supply (2012), Shares. *Source*: Mexico, Aouexw OECD/IEA, (2014), energy balances of OECD countries.

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production is already in place, and in the southern production basin of Paraná, whose geological properties get extended to Uruguay, Paraguay, and northern Argentina. Though, most of the shale gas potential is located in the northern basins (around 164 tcf), these regions are less urbanized and lack pipeline infrastructure for shipping commercial production to major urban settlements located in the south.[11] By contrast, the Paraná Basin is well connected with the pipeline system of the country, including the cross-border lines carrying gas from Bolivia and Uruguay into the country.

Since the 1990s, Brazil is producing marginal volumes of shale oil from this Basin. However, the Brazilian government does not anticipate a United States–like boom of these resources for the next ten years, though exploration and development of shale plays could be encouraged in the San Francisco, Paranibo, and Reconcavo basins, located respectively in the center and northern part of the country.

Though Paraná is a major onshore oil producing area, 92 percent of Brazil's production comes from offshore fields, a priority supported by the Brazilian government since the 1980s. Though the thirteenth round, launched in 2015, bid some blocks in the Amazon basin, the government's focus remains in the development and production of oil and gas offshore fields. 91 percent of oil production and 73 percent of gas come from offshore fields, out of which associated gas is 67 percent of the total gas output.[12] From 2008 to the present, Petroleo Brasileiro (PETROBRAS), the country's NOC, producing 93 percent of overall oil production and 92 percent of gas, has successfully increased the oil output coming from pre-salt geological formations, that is, production coming from below a 2.5 kilometers thick geological layer of salt, reaching depths of 5,000 meters or more. The discovery of the first pre-salt field in 2006 prompted Brazilian government authorities to enact a new legislation in 2010 to regulate production coming from this ultra-deep layer. The new legislation (Law 12.351) established a polygon encompassing both the sedimentary Santos and Campos basins, in front of the state of Rio de Janeiro (see Map 10.3, the polygon is highlighted in a red line). This polygon is known as the "legal pre-salt" encompassing two layers: the geological pre-salt, that is, the fields below the thick salt layer, and the post-salt layer, also covered by the legislation. Brazilians currently distinguish pre-salt potential resources located outside the polygon established in 2010, as "extra-legal pre-salt" (ELP).[13]

The extraordinary success of the pre-salt program led the government to create a new company: "Pre-Salt Petroleum" (PPSA), bound to the Ministry of Mines and Energy (MME), with the target of doubling "legal pre-salt" production in year 2020, from approximately 2.1 Mbd to 4.0 Mbd. Though PETROBRAS has adjusted its ambitious target after the collapse of oil prices during the second half of 2014, and after being involved in corruption

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scandals, the leading company in the pre-salt area still bets to increase its oil production from 2 Mbd to 2.8 Mbd in year 2020.[14]

THE REGULATORY-BUSINESS ENVIRONMENT, INFRASTRUCTURE CONSTRAINTS, AND POLICIES PREVAILING WITHIN TWO CROSS-BORDER REGIONAL ENERGY MARKETS

There are clearly two major trans-border energy markets in the Western Hemisphere: the North American market clustered around the United States and the southern cone market centered on Brazilian needs. In North America, the United States has traditionally remained a net importer of petroleum and gas while Canada and Mexico as traditional oil suppliers. Canada also

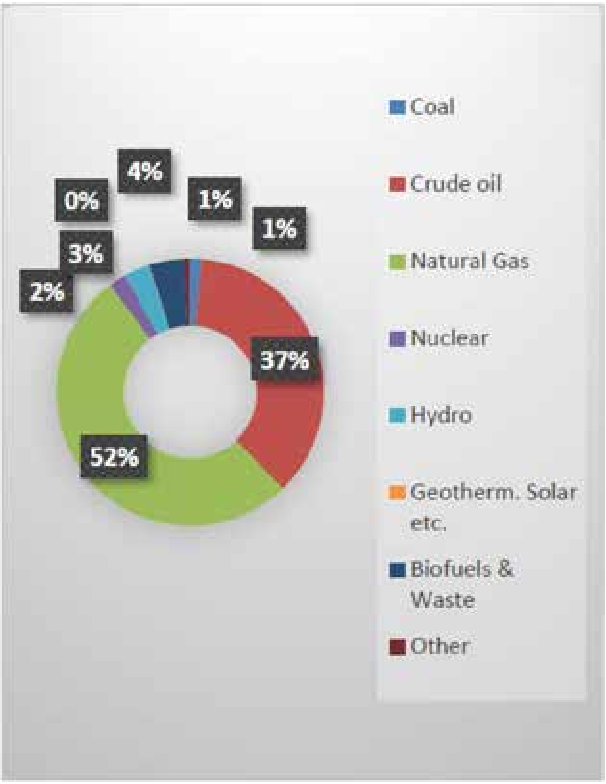

Figure 10.3 Argentina. Total Primary Energy Supply (2012), Shares. *Source*: Argentina, OECD, 2014, energy balances of non-OECD countries, Paris.

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remains a major gas supplier of the United States while Mexico is increasing its gas imports from these countries and from overseas. At any rate, there is both a de facto and de jure integration in the region, featuring cross-border pipelines throughout the three countries, electricity interconnections, crude and petroleum products exchanges compensating for subregional imbalances,[15] and a framework of economic and political cooperation anchored on the foundations and values of the North American Free Trade Agreement (NAFTA),[16] signed by the three countries in 1992 and in force since 1994.

However, Mexico's energy sector traditionally remained a state monopoly under the governance of PEMEX, for hydrocarbons, and the Compañía Federal de Electricidad (CFE), for the generation of electricity. Through the monopoly regime PEMEX guaranteed oil income revenues to the federal government—around 35 percent to 40 percent of overall fiscal income—and a volume of oil exports through which rents were ensured in order to maintain government expenditure and a myriad of subsidies to national energy consumption. A radical constitutional reform—enacted at the end of 2013 and reinforced by secondary legislation throughout 2014—ended up this monopoly regime—both in the hydrocarbon and electricity industries—and set the grounds for building a market-oriented environment for developing key production chains of the industry. Though still very early to assess trends, it is very probable that Mexico's oil, gas, and electricity industries will evolve according to the regional transformations that are taking place in the United States and in general terms in North America. This has definitely conditioned the market and policy choices for developing nonconventional hydrocarbon resources.

Out of the three Latin American countries here compared, Mexico is the only key net oil exporter, whose exports volumes are mainly sold in the US coast of Gulf of Mexico. However, Mexico's oil production peaked in 2004 and since then it declined to 2.021 Mbd during the second half of 2017. While still a net exporter, a growing domestic demand is reducing foreign income coming from exports and stressing the country's energy balance with growing oil products imports, mainly gasoline. As for gas, Mexico imports around 32 percent of its consumption, mainly by pipelines linked to the United States, though three Liquefied Natural Gas (LNG) terminals are in operation for processing imports coming from South America (Perú) and the Middle East. LNG imports amount around one-third of overall imports. Mexico plans to revert these trends by attracting foreign investors to develop oil and gas resources from shallow and deep waters in the Gulf of Mexico. The development and extraction of shale resources will be hindered and delayed due to growing and cheaper imports anticipated to come from the United States. Hence, Mexico's short to midterm goal is to increase its overall oil and gas production from shallow and deep-water fields, as the record of the two bidding Rounds held from 2015 until mid-2017 has proved.

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By contrast, in the southern cone, Brazil has traditionally remained the major energy consumer and oil and gas importing country while Bolivia, Argentina, and Trinidad-Tobago have played the traditional gas suppliers of Brazilian needs. The analysis of the trends for the three countries reveals that Brazil has increased its consumption of natural gas, mainly for power generation. Currently, Brazil imports 42 percent of its overall consumption of gas, mainly from Bolivia, thanks to a pipeline built (Gasbol) in the 1990s for supplying the major urban centers in the south of the country.

However, Brazil, similar to what prevails in Mexico and Argentina, has progressively relied on GNL imports (32 percent of total imports). This is astonishing in a region that could easily become self-sufficient if energy imbalances of involved countries could be satisfied by market and cooperation agreements. This is in fact how electricity generation from hydropower started in the region, as witnessed by the binational construction of the Itaipú power station built between Brazil and Paraguay in 1984 and the Yaciretá dam built in 1998 between Argentina and Paraguay. In both cases, the three countries aimed to commonly exploit power generation from the Paraná River. It was with the same spirit that Brazil, traditionally short of natural gas, aimed to connect with both Bolivia's and Argentina's gas resources and potential.

However, and despite UNASUR's and Mercosur's respective rhetoric of "southern energy integration,"[17] national economic and political factors witnessed by key countries have trumped integration trends. The nationalization of the hydrocarbons industry by President Evo Morales in Bolivia, in 2006, affecting PETROBRAS investment in that country and modifying export prices, prompted Brasilia to diversify its gas imports from "out of area" sources, explaining thus the construction of LNG terminals, which currently amount to three, one located in the south and two in the northeast. Brazil has clearly opted—similar to Argentina and Mexico—to natural gas as a backstop for electricity generation, since droughts, seasonal rainfall uncertainties, and climate change impact has increased its hydro vulnerability. In 2014, for instance, the reservoir levels located in the Southeast-Midwest of the country dipped below 14 percent due to a severe drought,[18] provoking a surge in LNG imports in order to increase supply from thermal plants. This explains why installed capacity in those plants amount to 32,778 MW, equivalent to 27 percent of total electricity demand.[19]

Argentina's debt default in year 2000 modified its domestic energy environment. Traditionally an oil self-sufficient country and a major net exporter of gas, the financial crisis canceled investments in the industry and squeezed gas exports to Chile and Brazil while imports from Bolivia and overseas increased. Argentina's LNG imports amount to 57 percent of total imports and the country began to import oil in 2012.

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Compared to what prevails in North America, in which the Henry Hub has become the reference price of an emerging cross-border natural gas market between the United States and Mexico, there is no price convergence in natural gas and other fuels within the Mercosur countries. Subsidies to domestic consumption vary among countries—being Argentinean ones the highest—and policy and geopolitical priorities seem to privilege self-sufficient targets, at least in the hydrocarbons domain.

Indeed, Brazil's and Argentina's hydrocarbon shortages could dramatically change if the former becomes successful in developing its pre-salt resources while the latter is able to establish the right environment for developing its shale gas and oil wealth. In the remaining part of this section I shall explain the policy choices taken by each individual country and the short to midterm consequences of the paths already taken.

BRAZIL'S AMBITION FOR DEVELOPING ITS PRE-SALT RESOURCES

In contrast with Argentina and Mexico, Brazil still maintains a state monopoly regime in its oil and gas industry, PETROBRAS being a NOC of mix capital (though majority owned by the government), playing a leading role in the development of conventional and nonconventional resources. The monopoly regime is maintained by constitutional mandate, alleging both the strategic nature of the industry and national security concerns, the goal of which is to guarantee the supply for a growing domestic market. In 1997, nonetheless, a new Petroleum Law was enacted that inaugurated market competition in upstream operations. A two tier contractual scheme was envisioned, through which private firms could participate either by getting block concessions or production sharing contracts from government. Within the first mechanism, companies get ownership of what they extract from the blocks, while in the second one, part of the production belongs to the state depending on the conditions and terms of the contracts.[20] In spite of this first liberalization effort, PETROBRAS remained Brazil's flagship in the energy sector, and a model of a state-led model of development, since the company has had to comply with high local content regulations, expand its operations downstream and respect subsidies for the domestic consumption of fuels even if these mean losses for the company.

Once the pre-salt resources were discovered, the new legislation that created the "legal pre-salt" and the PPSA also expanded and privileged the positioning of the NOC. According to the legislation enacted in 2010, resources explored and developed in the "legal pre-salt" could only be done under the production sharing agreements (PSA) formula. That is, no concessions are

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allowed in the polygone. Though PPSA will rather operate as a regulator, the new company has the mandate to supervise the PSAs tendered by the Brazilian government by the creation of a consortium of which half of its members and the president will be appointed by PPSA. This committee must also ensure that PETROBRAS be the operator of the contracts in the pre-salt and strategic areas, and be entitled to a minimum take of 30 percent in the consortia created to exploit, via the PSAs, pre-salt resources.[21]

Furthermore, as part of the new regulations, an Onerous Transfer of Rights Agreement was reached between the Brazilian government and PETROBRAS, through which the NOC got the concession of seven blocks in the pre-salt polygone, to be solely explored and exploited by the firm, during forty years, to produce up to 5 billion barrels of oil equivalent (BBOE). If those fields proved to be productive beyond that amount, PETROBRAS could continue operating them, even with third partners, under the PSA formula. Signed in 2010, the "Transfer or Rights" arrangement included fields such as Franco, Tupi, and Surrounding Iara, which were considered as the new giant fields discovered in the Western Hemisphere after the Cantarell block found in Mexico in 1976. In exchange of transferring those exclusive rights—through no bid nor contract cancellation if the NOC failed to accomplish the mandatory exploration program—PETROBRAS had to pay $42.5333 billion to the Brazilian government until the end of September 2010, in government bonds or federal securities denominated in Brazilian Reais.[22] That is, the 5BBOE were transferred at an average cost of $8.5 per barrel, a generous price even if the Agreement contemplated royalties at 10 percent of production plus income taxation. Local content mandates during the development stage of production were 55 percent for production starting in 2016, 58 percent for that beginning between 2017 and 2019, and 65 percent for output starting in 2020.[23] PETROBRAS was successful in rapidly exploring and developing most of those fields, and in June 2014 reached a PSA with the government for producing "surplus oil"—that is, beyond the cap of 5BBOE.[24] In October 2013, PETROBRAS joined Shell, Total, China National Offshore Oil Corp. and China National Petroleum Corp, to get the Libra field—estimated to hold 8–12 BBOE in recoverable resources.[25]

With such a success and privileged position, Brazilian NOC launched an aggressive plan of investments targeting mainly the development of pre-salt resources, though the expansion of downstream resources and international operations were also considered. At the beginning of 2014, PETROBRAS' five year plan envisioned to invest up to $220.6 billion from 2014 to 2018. About 70 percent of that investment ($153.9 billions) were planned to be invested in upstream operations, while 18 percent in downstream, 5 percent in gas and power, and 4 percent in international ventures.[26] Mrs. Silva Foster, PETROBRAS CEO at that time, estimated that the company could produce

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4.2 Mb/d only in Brazil, in year 2020, and that overall average production could reach 5.2 Mb/d between 2020 and 2030 if third partners and government production was added.[27] In order to fund such an amount of investment PETROBRAS debt skyrocketed, reaching \$126.5 billion at the end of March 2014.[28] Though the collateral of that long-term debt was promising, investors became nervous once international oil prices started to fall down during the second half of that year. Indeed, PETROBRAS ambitious expansion plan was anchored under the supposition that the Brent price would stay at \$100 per barrel on average from 2014 to 2030. Once price halved, the NOC ought to consider its projections. In June 2015, the company announced a 37 percent cut from its five year plan of the previous year, adjusted to a total of \$130.3 billion to be disbursed during the following five years. Eighty-three percent would be channeled to fund upstream operations while a 2015/2016 divestment program of \$15.1 billion was announced. In 2016 new budget cuts and divestment plans were announced and production schedules for 2021 were adjusted to reach 2.8 Mb/d, and 3.4 MBOE per day if gas production and overseas operations are included.[29] This new information was released in a completely modified environment, in which stock shares of the company were falling, former president Dilma Roussef was impeached (August 2016) and some of the company's key executives were involved in a scandal of corruption.[30]

In spite of its success for developing the pre-salt resources, it is clear that Brazil will remain a net importer of both oil and gas in the foreseeable future. Though most of pre-salt production will dominate the country's new oil and gas output, the fall down of international prices and the financial and political pressures to be borne by PETROBRAS will keep the country dependent on imports. An aggressive development of shale gas resources was not considered by the Brazilian government even before the oil bust.

According to the MME/EPE ten-years projection plan of 2014, shale gas production coming from the San Francisco, Parnaiba, and Reconcavo basins was considered possible from year 2020, amounting 7 percent of overall gas production in 2023.[31] At any rate, the rich Amazon sedimentary basins will remain untapped, since most of the gas transportation infrastructure of the country is located throughout the coast or in interconnections with Bolivia and Argentina. Independent analysts also estimate unlikely large-scale shale gas development before 2026.[32]

WILL ARGENTINA DETONATE THE SHALE REVOLUTION OF THE SOUTHERN CONE?

Resource nationalism came back in Argentina's energy industry since the beginning of the Kirchner era, signaled by the two terms in office of Nestor

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Kirchner (2003–2007) and the subsequent two terms of his wife, now widow, Cristina Fernández de Kirchner (2007–2015). This meant the coming back of state-driven energy policies the main goal of which was to increase production for supplying the domestic market.[33] Since the Kirchner administrations inherited the financial and social consequences of a major debt default at the turn of the century, energy policies attempted to maintain low prices for fuels either by controlling production prices or maintaining growing subsidies. Gasoline prices have systematically remained lower in relation with other Mercosur partners, such as Brazil and Uruguay. The price of Compressed Natural Gas (CNG), used extensively in Argentina in the transport sector, ranges from a third to a half of Brazil's price. The price of natural gas for residential use, remained lower than 2 dollars per million of BTU from 2009 to 2013, while in Uruguay the price hiked up to 24 dollars.[34]This wide price differential shows well how the Argentinian government pretended to maintain low domestic prices, even to the detriment of gas and electricity exports which reverted, as previously said, into net imports.

This systematic policy of price controls and subsidies modified the investment environment in the hydrocarbons industry impacting negatively oil and gas production while accelerating domestic demand. While YPF[35] plays doubtless a strategic role in the industry, it is not as dominant as PETROBRAS is in Brazil or PEMEX in Mexico.

Currently, 37 percent of total oil production is done by YPF, while there are more than thirty-three operators in charge of the rest of upstream output. Eighty-eight percent of oil production and 67 percent of gas come from the Neuquina and San Jorge Basins.[36] By contrast, in the gas sector Total Austral is the dominant producer, providing 30 percent of production while YPF ranks second with a share of 25 percent of production.[37] This suggests that the investment environment in the country is more complex and diversified than that prevailing in Brazil and Mexico.

One year after the Ministry of Planning was created, in 2003, the Kirchner government launched a long-term Energy Plan, which was continued until the end of the second term of the Cristina Kirchner administration. The development of the gas industry was one of its targets. A new state enterprise was created, Energía Argentina (ENARSA), of which one of its goal is to ensure the open transmission of natural gas through the pipeline grid, which connects well the two major productive basins with major urban centers located around Buenos Aires. From 2003 to 2014, transmission capacity increased by 23 percent and more pipeline interconnections were built, including another one connecting the northeast part of the country with Bolivia pipelines.[38] In 2008, when the country began to import LNG, the so-called Gas Plus project was enacted, with the aim to reinvigorate the investment climate for developing mainly shale or tight gas. For so doing, a multiple-tier price

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mechanism was incepted, allowing a higher price for nonconventional gas. During the first semester of 2013, for instance, the average gas price for residential use was 0.45 dls per MBTU, while the price of CNG was 2.5 dls, and for industrial use 3.95 dls. “Gas Plus” price was 5.20 dls per MBTU, and the government authorized up to 7 dls for some projects.[39] The rationale of this multiple-tier approach was to create incentives for attracting risk investments in the exploration and development of shale resources. So far, 10 percent of gas production comes from the Gas Plus project, suggesting that a wellhead price ranging 5–7 dls per MBTU is attractive enough for developing some of the nonconventional resources of the country. That price is more than the double of Henry Hub’s, averaging 3 dls per MBTU during the past recent years.[40] The Henry Hub is the reference price for estimating regional prices in the United States and Mexico. Due to the shale gas boom in the United States, gas prices became decoupled from oil prices making United States the cheapest market in the world. This explains why in spite of the decline of oil prices, nonconventional gas production continues growing in that country. As witnessed by the Brazilian case, the collapse of the oil market has mainly affected production coming from frontier fields in deep waters.

At any rate, it seems that the Gas Plus project of the Argentinian government is setting the conditions for encouraging the development of nonconventional gas resources. This new price “flexibility” seems to attract investors and increase domestic supply at a lower cost than imports. Prices for Bolivian gas amount to 10.55 dls per MBTU, while LNG’s are above $16. The choice is clear, though environmental, health, and social costs are not yet estimated[41] and price controls and high export taxes still refrain the industry from expanding.

The future of Argentinian oil and gas industry seems promising under the new center-right administration. Mauricio Macri’s efforts during the first year of his presidency were focused to solve the long debt default featured by the Kirchner administration. Now that the country regained access to global financial markets, investors feel more confident for upgrading their investment in the Neuquina Basin. Government officials consider attractive to invest in the Vaca Muerta plays if oil prices range the $50 dls/b. At the same time, the Macri administration has increased to $7.50/MBTU the price to pay for new gas production through 2018. Prices then will gradually decline to $6/MBTU in 2021, before being fully liberalized in 2022.[42]

MEXICO’S CURRENT BET TO DEVELOP RESOURCES FROM SHALLOW AND DEEP WATER

In contrast with Brazil and Argentina, Mexico is the country that shifted its energy policy from resource nationalism to market trends dominating in

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North America. Similar to what prevails in the southern cone, gas, oil, and electricity markets are already integrated throughout North America, from the Province of Alberta to the oil fields and refineries located along the Gulf of Mexico shore. Mexico has even signed an agreement with the United States in order to commonly develop cross-border fields located in Gulf of Mexico deep waters.

However, until the end of 2013 Mexico furiously maintained a state monopoly regime in both hydrocarbon and electricity markets, allowing for private participation only as providers of PEMEX. Once monopolistic production started to decline, imports of fuels and gas to soar, and new production fields turned highly disappointing, in spite of an impressive increase in investment—as it has been the case of the Chicontepec area, located in the Misantla-Tampico Basin—Mexico's ruling class became convinced that the monopoly regime ought to be transformed. At the end of 2013, and during the first half of 2014, a bipartisan agreement was reached between the PRI (the ruling party) and the PAN (which was in power between 2000–2012) in order to radically open all production chains of the industry to private participation and settle a new market environment for developing Mexico's proved and prospective resources.

As a byproduct of the new regulatory environment, the government leased to PEMEX 83 percent of the stock of proved, probable reserves, and 21 percent of prospective resources, amounting to more than 42 billion BOE.[43] Prospective resources, either conventional or nonconventional were opened to private participation, either to individual companies, consortia, or in association with PEMEX, by signing production, profit sharing contracts, or licenses with government authorities. Blocks have be auctioned according to a five-years bidding plan pursued until now by SENER, aiming at attracting private capital for increasing Mexico's oil production up to 3 Mbd. The Mexican government also anticipates to increase natural gas production, but not from shale gas plays. New volumes of this product are anticipated to come from gas fields or associated gas coming from oil fields located in shallow and deep waters. As already explained in the previous section, Henry Hub gas prices witness a historical down due to the shale gas revolution triggered off north of the Río Bravo. Consequently, even before the legislative reform of 2013–2014, Mexican authorities had decided to rely on cheap natural gas imports coming from the shale plays of Texas. The fact that Mexico is still importing growing volumes of LNG is because northwest and northeast Mexico still lacks the adequate pipeline infrastructure in order to ship Texas surpluses. At any rate, Mexico plans to stabilize its domestic output at around 5 BDCF at the turn of the next decade. At that time, production coming from new investments developing conventional fields will come on stream. It is not clear however when shale gas production will start.[44]

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Meanwhile, an aggressive investment plan for enlarging the gas pipeline grid has been launched, mainly to connect the northern part of the country with imports shipped from the United States or gas production coming from southern maritime fields. There are currently eighteen new gas pipeline expansion projects around the country, to be terminated in the next years, the largest one being Los Ramones, a pipeline 855 kilometers long connecting Nuevo León, Tamaulipas, and Veracruz. If the gas grid is extended successfully, the Mexican government estimates that LNG imports will be terminated in year 2017, imports being supplied from the Texas fields.[45]

Similar to PETROBRAS' aggressive expansion production plan, Mexico's anticipated production figures were established when prices were above 100 dollars per barrel. Since production in deep-water Gulf of Mexico rather ranges at the higher end of marginal costs,[46] a price below 70 dollars per barrel becomes discouraging for maintaining production. Mexico still has to learn how to deal with market fluctuations in order to build the right environment to attract the right investors. After the disappointing outcome of Round 1's first auction, in which fourteen blocks were bid in order to stimulate exploration in shallow waters (only two of them were auctioned), the government decided to redefine the contractual requirements for bidding blocks located in deep waters. In December 2016, eight licenses contracts were auctioned by SENER to private investors in order to explore and develop some promising areas in deep waters Gulf of Mexico. Consortia created by Statoil, BP and Total, or Total with ExxonMobil were some of the winners. Pemex also got a block by joining Chevron and Inpex, and reached an association deal with BHP Billiton, an Australian firm, in order to explore and develop the Trion play.[47]

In contrast with the success witnessed by the deep waters bidding, it is not clear yet how Mexico's NOC will be transformed as a "State productive enterprise." Will it follow the PETROBRAS or YPF model, in which private participation will be accepted and stock shares traded? So far, PEMEX's budget and expenditure is still subject to the needs and priorities of the Ministry of the Treasury, provoking a continuous deficit for the company. If PEMEX is not rapidly transformed to the new market environment built by the legislative reform, Mexico's falling oil and gas production will continue.

CONCLUSION

Nonconventional oil and gas resources in the three Latin American countries here surveyed appear impressive and attractive. However, only Argentina has put in place a development program—the so-called Gas Plus—aimed at

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increasing its nonconventional gas output in order to reduce imports. Export constraints, domestic price caps, and subsidies will prevent, somehow, this country to spur a "shale revolution" similar to that taking place in the United States. Though integrated markets of gas, oil and electricity already exist in Latin America's southern cone, both Buenos Aires and Brasilia have privileged energy policies targeting the development of domestic resources for supplying national needs. At present, Argentina's Gas Plus project aims at abating imports, while the Brazilian government focuses on developing its pre-salt oil and gas potential in order to achieve energy self-sufficiency. After the collapse of international oil prices during the second half of 2014, Brazil's target will be delayed, more and more due to political reasons than economic ones, while Argentinean shale gas production remains attractive compared to imported gas from Bolivia or LNG prices.

Mexico, by contrast, moved from a state monopoly regime to a full-liberalized market approach for developing its energy industry. This radical move—done through constitutional amendments and secondary legislation enacted during 2013 and 2014—attempts to boost net oil exports and reduce growing gas imports. However, in the short to midterms new production is anticipated to come from shallow and deep waters blocks, already being auctioned according to a government bidding schedule. Some nonconventional gas blocks could be tendered in Round 3 or 4, but the government does not anticipate any significant shale production coming on stream during the following decade. Meanwhile, the prevalence of low prices for natural gas, weak prices for oil, and the uncertainties and surprises conveyed by the new liberalized energy market could delay new investments and consequently a recovery in the country's oil and gas performance. Under those circumstances, Mexico bets to reduce oil exports and to rely on cheap gas imports coming by pipeline from the United States.

NOTES

1. OECD, IEA, *Energy Balances of OECD Countries* (Paris, 2014).
2. US Energy Information Administration, *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 127 Shale Formation in 41 Countries Outside the United States* (Washington, D.C., 2013).
3. US Energy Information Administration, *Technically Recoverable Shale . . .* opcit. *V-2.*
4. Platts Energy Economist, "Argentina's Neuquen offers Vaca Muerta licenses" (June 1, 2017).
5. "Vaca Muerta output to reach 113,000 boe/d by 2018," *Oil and Gas Journal* (May 15, 2017): 10.
6. Coming after China, Argentina, Algeria, the United States, and Canada.

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7. US EIA's estimations just for the Eagle Ford plays amount to 119 tcf of shale gas, United States Energy Information Administration, *Technically Recoverable Shale* . . . opcit. (2013): c-3.

8. See NHC's website: www.cnh.gob.mx/ñ US EIA's estimations are less optimistic, amounting to 13.1 Bb.

9. All information from National Hydrocarbon Commission (CNH in Spanish) website: https://www.gob.mx/cnh/articulos/rondas-mexico?idiom=es.

10. Out of the three countries here compared, Brazil has the lowest shale oil resource potential: 5.3Bb according to USEIA.

11. US Energy Information Administration, *Technically Recoverable Shale Oil* . . . op.cit. (2013): VI-2 and Agencia Nacional do Petroleo (ANP), *Oil, Natural Gas and Biofuels Statistical Yearbook* (Rio de Janeiro, Brazil, 2014).

12. Ministério de Minas e Energia (MEM)/Empresa de Pesquisa de Energía (EPE) *Plano decenal de expansao de energía 2023,* Brasilia, MEM/EPE (2014): 222.

13. Ibid., 226.

14. Still in 2014, before the depreciation of oil prices, and the corruption scandals that have escalated into top government officials, PETROBRAS anticipated to increase its oil production from 2.0 to 4.2 MBD in the year 2020. If gas production is included, overall production would reach 3.3 Mbdoe, down from 5.3 Mbdoe that was previously anticipated, PETROBRAS *Strategic Plan. 2017–2021 Business and Management Plan* (2016): 41.

15. Canada's Central and the Atlantic provinces have traditionally relied on crude oil and oil products imports (the latter coming from the United States), while surplus production coming from the West Sedimentary Basin has traditionally gone to American markets. Northeast Mexico relies on cheaper gas imports coming from the United States rather than gas production associated to oil located in southern Mexican fields, where infrastructure gaps has hampered the development of a wider national market.

16. NAFTA's chapter 6 is about energy, by which Canada engaged in becoming a reliable oil supplier to the United States. While Mexico's energy industry remained out of this chapter at the time of NAFTA's signature, the progressive liberalization of this sector, and the major Constitutional amendment of 2013, ended up the state monopoly regime that prevailed in the overall energy industry and has made feasible a faster integration with American markets.

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Chapter 11

China and Japan's Pursuit of Unconventional Fuels

Manochehr Dorraj

INTRODUCTION

In this chapter we would examine the development of China and Japan's energy sector, their transformation into major importers of fossil fuels and would assess their potential to tap into unconventional fuels, namely shale gas and methane hydrates as viable sources of energy.

As the two major economic powers in the world, China and Japan lead the world in energy consumption and are projected to lead the global energy demand into 2050 and beyond.[1] With the expansion of energy consumption in part due to economic and demographic growth, their dependence on energy imports has grown steadily in the last two decades. Since much of this import originates from the politically volatile region of the Middle East—for China 51 percent of its oil imports and 41 percent of its gas exports,[2] and for Japan these figures are respectively 81 percent and 29 percent[3]—worries about the security of energy supplies compels them to look for their own untapped domestic energy supplies. In case of Japan, the large budget deficit and economic constraint also plays a large role in its aspiration to reduce the cost of energy imports, especially Liquefied Natural Gas (LNG) which is more expensive than regular natural gas. As the environmental concerns loom larger internationally in the aftermath of 2015 Paris climate change conference, both countries are also keen to reduce the share of coal in their energy mix and expand the portion of natural gas that burns much cleaner than coal.

In this chapter we will also analyze the Chinese and the Japanese endeavors to tap into their unconventional energy resources and assess their viability: their technological ability to tap into this resources and the financial cost effectiveness of doing so.

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CHINA

With the ascendance of Deng Xiaopeng to power in 1976 and the implementation of his reform policies by 1979, the modernization of Chinese society accelerated. Since then China has experienced a rate of growth of 6–10 percent annually. With the economic development came urbanization, the rise of middle class, and the migration of large number of peasants to the cities. The concomitant rising demand for housing, appliance, and automobiles increased the energy consumption exponentially. While endowed by substantial domestic energy resources, by 1993, the domestic resources no longer sufficed, China became a net importer of energy. As the second largest economy in the world, China has been the world's largest energy consumer since 2011. In 2012, China was the world's number one importer of fossil fuels.[4] In 2013, it surpassed the United States as the number one oil importer in the world.[5] To illustrate the scale of China's reliance on external sources of fossil fuels, the following charts below show China's production and imports for, respectively, petroleum (oil and products refined from oil), natural gas, and coal.[6]

According to the Energy Information Agency (EIA), China's oil consumption growth was responsible for 43 percent of world oil consumption growth in 2014, and even with a slower rate of economic growth in 2015, China was responsible for more than 25 percent of world oil consumption growth in 2015.[7] China's use and imports of natural gas are both currently significantly smaller than its consumption and imports of oil. The future plans call for an expansion of natural gas in the energy mix.

In addition, China's energy supply is heavily dependent on coal—about 65 percent of the energy supply. China is the world's largest producer, importer, and consumer of coal; it is responsible for roughly 50 percent of the world's coal consumption.[8] Coal as an energy source has several draw backs when compared to natural gas, in particular carbon dioxide emissions, smog, and its adverse effect on health and well-being of population. As the graph below reveals, by 2012, coal was responsible for 66 percent of China's energy mix.[9] As by 1990s, pollution in major Chinese cities and its attendant negative impact on public health reached chronic levels, it became imperative to move away from high reliance on coal. See Figure 11.1.

Currently, China is the number one in emission of carbon monoxide and carries the mantel of number one pollutant in the world (28 percent), followed by United States (14 percent), European Union (10 percent), and India (7 percent). Between 2012 and 2013 alone, the rate of India's emissions have gone up by 5.1 percent, China's emissions have grown by 4.2 percent, United States by 2.9 percent, and European Union had a negative rate of growth of 1.8 percent.[10] Yale University's Environmental Performance Index from 2014 ranked China's air quality 176 out of 178 countries examined.[11]

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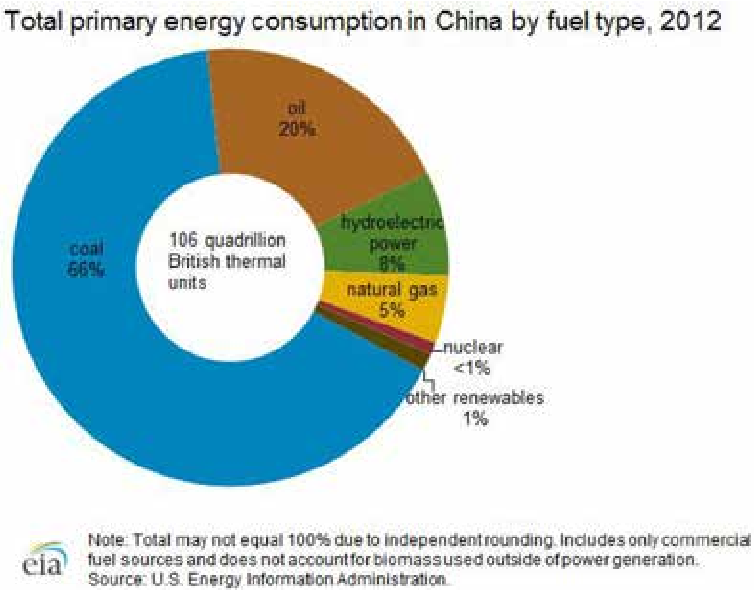

Figure 11.1 Total Primary Energy Consumption in China by Fuel Type, 2012. *Source*: US Energy Information Administration, (2012).

There is a direct link between China's large dependence on coal and its dangerous air pollution levels.[12] China's coal induced smog has an adverse effect on public health and quality of life. One recent study by researchers from MIT, Peking University, Hebrew University of Jerusalem, and Tsinghua University compared the health and life expectancy of Chinese individuals living north of the Haui River, where a government program subsidized coal boilers for residential use since the 1950s, and south of the river where the government did not and coal use was much less. The study showed that living near the area where coal consumption was high shortened life expectancy by years.[13]

This may explain why Chinese government plans to expand the share of non-fossil fuel source of energy from the current 11 percent of the energy mix to 15 percent by 2020. And the share of natural gas and LNG would rise from the current 6 percent of the energy mix to 12 percent by 2020 as well.[14] Chinese authorities are allocating $ 4.5 billion in the next three years to close 4,900 coal mines, and redirect one million coal miners, or 23 percent of the total coal mining workforce, to other employment.[15] In 2016, Chinese officials announced they intend to invest $269 billion globally in renewable energy.

In contrast to coal, natural gas burns much cleaner. For example, electricity generated with natural gas creates just over half of the carbon dioxide as the

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coal necessary to produce the same amount of electric power.[16] However, half of China's gas imports are LNG which is more expensive than regular natural gas, and almost 75 percent of it comes from only three countries. These are respectively Qatar (34 percent), Australia (24 percent), and Indonesia (16 percent).[17] The $400 billion signed contract with Russia in 2015 to import Russian gas by pipeline through Siberia is designed to achieve two goals: (A) to expand China's sources of natural gas imports, (B) to reduce China's dependence on LNG imports.

Additionally, since China's domestic conventional oil fields are largely mature and in decline, it needs additional supplies of domestic oil and natural gas to, respectively, reduce its dependence on foreign oil imports and replace coal with a cleaner energy source. This increasing demand for natural gas rendered the domestic sources inadequate and by 2007 China was a net importer of natural gas and the domestic demand for natural gas continued to climb since then. All the future projections also indicate that this increase in demand would continue to expand.

Therefore, China has several important incentives to explore its unconventional sources of oil and gas. The central question is whether these unconventional sources are viable long-term supplies.

CHINA'S SHALE OIL AND GAS PROSPECTS

According to the US EIA, China has 1,115 trillion cubic feet of technically recoverable shale gas and 32.2 billion barrels of shale oil.[18] In contrast, in 2013, the United States possessed 949 trillion cubic feet of technically recoverable shale gas and 78.2 billion barrels of shale oil.[19] Seen in this comparative context, China's shale oil and gas reserves are impressive indeed. See Figures 11.2 and 11.3, which, respectively, show global ranking of shale gas reserves that ranks China as the number one in the world, and the map of China's shale oil and gas reserves in the seven prospective basins.[20]

The richest shale basins are the Sichuan (626 tcf), Tarim (216 tcf), Junggar (36 tcf), and Songliao (16 tcf). There are also several geographically more challenging and riskier basins, the most notable among them are: Yangtze platform, Jianghan, and Subei basins, with a combined shale gas resources of 222 tcf.[21] The year 2014 was particularly a good year for China's unconventional fuel production. China's production of unconventional gas totaled 4.9 Bcm in 2014, up 42 percent from the year before. Coalbed methane output rose 23 percent, and shale gas was at 1.3 Bcm, five times higher than 2013. China's pursuit of fracking and drilling technology lead to record production in 2014.[22]

Among these basins, Sichuan has been targeted for significant exploration. Royal Dutch Shell, Chevron Corp, British Petroleum, and Exxon Mobil are all participating with Petro China and China National Offshore Oil Company

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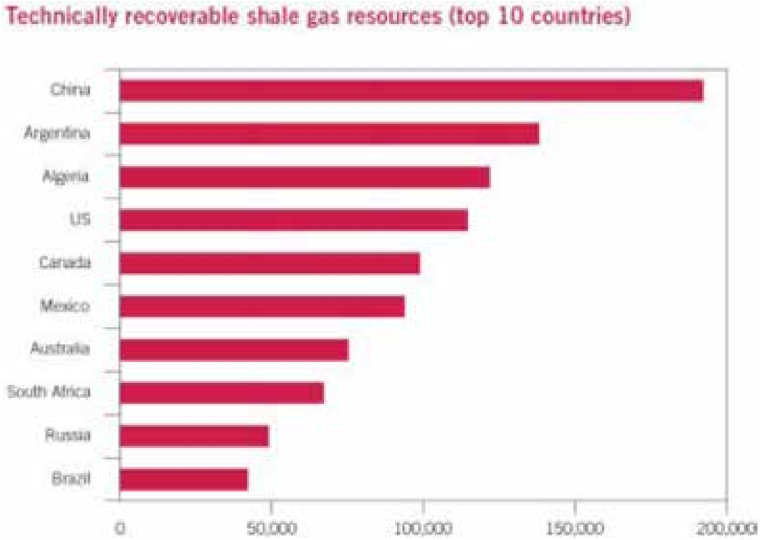

Figure 11.2 Technically recoverable shale gas resources (top 10 countries). *Source*: Eli Rognerud, The Impact of the Shale Gas Revolution. (2015).

Figure 11.3 China EIA/ARI Shale, Gas and Oil Assessment. *Source*: Advanced Resources, Inc., (2013).

in the exploration of the Sichuan Basin. So far 400 exploratory shale wells have been drilled. Reportedly, Petro China Company Ltd has produced more than 1.8 Bcm of shale gas as of October 2016, surpassing the target of

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1.5 Bcm.[23] Tight gas has been produced from Ordos Basin in northern China for the last seventeen years and currently it counts for the 15 percent of domestic natural gas production.[24]

China's abundance of oil and gas reserves notwithstanding, there are several hurdles to the viability of China's oil and gas shale production on a large scale. These challenges are: First, Some of the shale formations lie below rocky mountain range that renders accessing them more challenging and financially costly. Second, other basins lie in the desert (parts of Western China), where there is shortage of water supplies that is necessary for hydraulic fracturing. Third, other basins are near agricultural communities and many farmers would resist the idea of drilling on their farmland. Fourth, the inadequacy of technology, infrastructure, and pipelines constitute additional challenges. Fifth, the waxy quality of shale oil and gas and the possibility that they may lie in clay formation render their extraction more challenging.[25] Hence, unlike the United States, in China, the mineral rights are owned by the state rather than individuals. Unless state permission is obtained, the exploration of these unconventional resources would face obstacles. Thus, only state-owned energy companies can invest in shale oil and gas exploration. As such, ownership, legal, and regulatory challenges are persistent throughout.

The high cost of exploration of shale oil and gas is perhaps the most formidable challenge. Although by mid-2015, Sinopec was able to cut the cost of drilling a horizontal well by 23 percent respectively from \$11.3 and \$12.9 million per well to \$11 in the Sichuan Basin, still China's cost per well is almost twice as high to drill compared to what it costs to drill a horizontal well in the United States.[26] The average cost of drilling a horizontal well in Permian Basin for example, was \$7.7 million in 2014, but was cut to \$7.2 million in 2015.[27] With the steep plummeting of oil and gas prices in 2014–2016, the financial viability of shale oil and gas, and their more costly extraction, remains questionable in the near future.

To remedy this problem, and provide for the expanding natural gas demand, China has opted for a three-pronged strategy: First, to buy substantial shares in shale oil and gas assets abroad. Second, increasing its investment in building a pipeline network that would import the necessary gas from its neighboring countries, most notably, Central Asia and Myanmar. Third, utilizing the technological capacity of major Western energy companies in order to expand shale oil and gas production.

Since 2010, China's National energy companies have invested more than \$10 billion in acquiring US upstream assets, most of which are unconventional. China's Petroleum and Chemical Corporation has acquired Mississippi Lime Properties in Oklahoma from Chesapeake and China's National

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Offshore Oil Corporation has purchased substantial assets of Canadian oil and gas producer Nexen. Since 2008, Chinese companies have acquired a total of $44.2 billion energy assets in North America, their largest acquisition in the world.[28]

China's total imports of energy through pipelines in 2014 were 1,333 Billion cubic feet, up 20 percent from 2013. Central Asian countries such as Turkmenistan, Uzbekistan, and Kazakhstan are the major exporter of energy to China through pipelines. China's import of LNG has also increased in recent years. Currently, China ranks third in the world in LNG imports.[29]

By enlisting the investment and the technological assistance of major Western energy companies, China is gradually expanding its domestic output of natural gas. Ultimately, the future viability of shale oil and gas exploration would depend on overcoming the obstacles chronicled above and reducing the cost of production substantially.

JAPAN'S ENERGY NEEDS AND THE PURSUIT OF METHANE HYDRATES

As post-World War II Japanese economic reconstruction and modernization accelerated in the 1960s and the 1970s, and Japan emerged as a major global economic powerhouse, its energy consumption soared. By 2015, with a GDP of $4.3 trillion, Japan ranked as the third largest economy in the world, trailing the United States and China. Unlike China, lacking substantial domestic energy resources of its own, Japanese imports of oil, coal, and natural gas increased exponentially since 1960s. Currently, Japan is the world's third largest importer of crude oil, the second importer of coal and the number one importer of LNG in the world. Japan is fifth in the world in total energy consumption, lagging behind the United States, China, Russia, and India.[30] In addition, 80 percent of Japanese oil imports originate from politically volatile region of the Middle East. Therefore, in terms of energy security Japan feels very vulnerable. To provide a remedy for its energy insecurity, Japanese energy companies are investing in shale gas production in the United States. Tokyo Gas Company, Ltd. has participated with Quicksilver Resources in Barnett Shale, supplying Japan's largest gas utility with 0.35 million to 0.5 million tons per year of natural gas supply.[31] In a larger context, this, however, is a small down payment on Japan's energy security considering the magnitude of challenges faced by the country.

In 2009 and 2010, nuclear energy constituted 27 percent of Japan's electricity generation, and the country ranked third largest in the world in

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consumption of nuclear power.[32] After the Fukushima nuclear meltdown of 2011, Japan's share of nuclear energy consumption diminished substantially. All the nuclear plants were shut down and by 2013 only two of forty-two reactors were reopened after a two-year gap. Only five to seven more reactors were expected to reopen by 2016. This has diminished the role of nuclear energy from 30.3 percent prior to Fukushima meltdown to about 1 percent after the accident and it is projected to rise to 20–22 percent by 2030.

This turn of events had a significant impact on Japan's reliance on LNG imports to satisfy the domestic consumption need. The two charts below respectively illustrate Japan's energy mix and its expanding use of LNG. Japan spent about $270 billion, which amounts to 58 percent more, for fossil fuel imports in the three years following Fukushima accident.[33] Japan's domestic reserves of recoverable natural gas dropped by almost 50 percent between 2007 and early 2015 to 1.4 trillion cubic feet. Japan's LNG imports increased by more than 25 percent between 2010 and 2013, in order to find a substitute for nuclear power following the Fukushima-Daiichi disaster, but that growth trend has slowed. However, Japan is still the world's largest importer of LNG, accounting for approximately 37 percent of world-wide LNG purchases since 2012.[34]

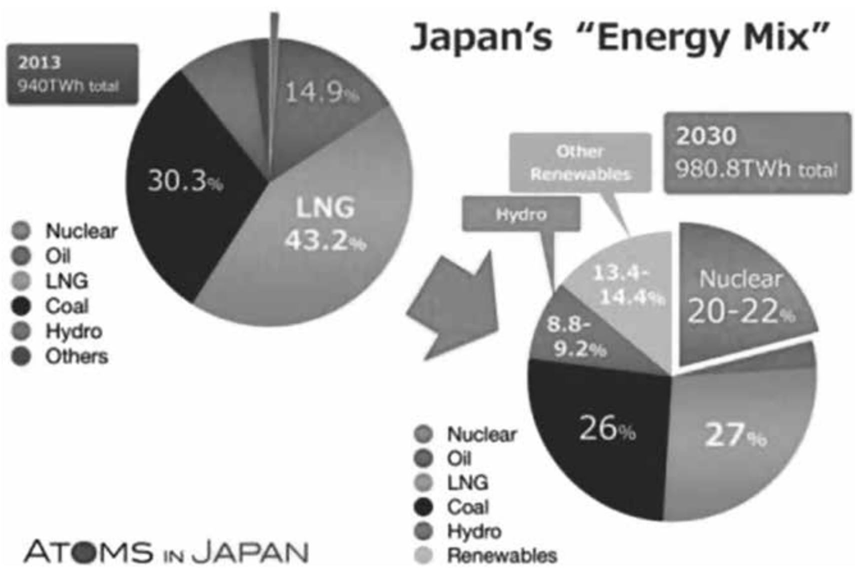

Figure 11.4 Japan's Energy Mix 2013–2030. *Source*: Atoms in Japan, World Nuclear News, June 3, 2015.

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Japan relies on import of LNG from, Malaysia (19 percent), Australia (18 percent), Qatar (15 percent), Indonesia (12 percent), Russia (9 percent), and Oman (5 percent). Gasifying LNG for shipping purposes renders it very expensive. At \$16–\$18 per million British Thermal units, the imported LNG in Japan is four times more expensive than what it sells for in the US market. In addition, in 2013 alone, the additional import of energy resources cost Japan \$35.2 billion and the deficit increased to \$112 billion.[35] Hence, the gross domestic product of Japan was forecasted to increase by 0.7 percent in 2016 and 0.4 percent in 2017.[36] Thus, to save money, the Japanese government has much incentive to look for alternative sources of energy in general and a more affordable source of natural gas in particular. This reality has accelerated Japan's search for other sources of natural gas. The most significant available source is massive deposits of methane hydrate found off its coast on the bottom of Pacific Ocean.

PROSPECTS FOR METHANE HYDRATE EXPLORATION IN JAPAN

Methane hydrates, also known as flammable ice, are gas deposits trapped in ice under the ocean floor. These hydrates can only form in areas of high pressure and low temperature, such as under permafrost or in sediments of the deep ocean floor where temperatures are near zero degree Celsius and pressures are nearly forty times atmospheric pressures.[37] Methane hydrate is the most abundant form of fossil fuel on the planet, and it can be found off the coast of every continent. There is an estimated 3 trillion tons of carbon in hydrate formation, as compared to only 31 billion tons in coal, oil, and gas combined.[38]

Japan has massive amount of flammable ice off of its coast. Early estimates indicate the amount to be 40 tcf or 1.1 trillion cubic meters of methane hydrates exists in the eastern Nankai Trough off Japan's pacific coast. Japan has been experimenting with ways to explore it in an environmentally safe way, utilizing sophisticated technological tools to separate the ice from gas without unleashing a massive landslide of methane hydrate into the atmosphere. Scientists are concerned that the warming of the ocean could destabilize the methane hydrates and release methane into the atmosphere and substantially escalate global warming.[39]

So far Japan has been successful in extracting small amount of methane hydrates by drilling 300 meters below the mud line in 1,000 meters of water in Nankai Trough which is located about 60 kilometers off the Southeastern coast of Japan.[40]

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In March 2013, Japan announced dedicating 14.4 billion yen for exploration of methane hydrates and managed to produce 120,000 cubic meters or 20,000 cubic meters per day, of gas from methane hydrate after a decade of research utilizing various technologies. In 2014, a joint venture of eleven Japanese companies joined forces to undertake further exploration and development of the flammable ice; they announced that they are hoping to begin commercial production in 2018.[41] In 2016, Japan became the world leader in methane hydrates exploration.

To increase its chances of success, Japan Oil, Gas, and Metals National Corporation has partnered with US Department of Energy and ConocoPhillips to run tests of natural gas extraction from methane hydrates. However, the technology and expertise necessary to extract methane hydrates safely, without destabilizing the ocean floor and unleashing a huge cascade of methane gases and their emission into the environment is in its early stages of development. Hence, the contentious issues surrounding mineral rights in the extra-territorial waters in the ocean could prove to be another impediment to large-scale development of methane hydrates. To bring down the cost of production of methane hydrate is another challenge to be met. It is estimated that producing natural gas from hydrates could cost \$30–\$60 per million cubic feet, which is about twenty times the cost of producing shale gas in the United States, and three to four times the cost of LNG imports.[42] As one of the major

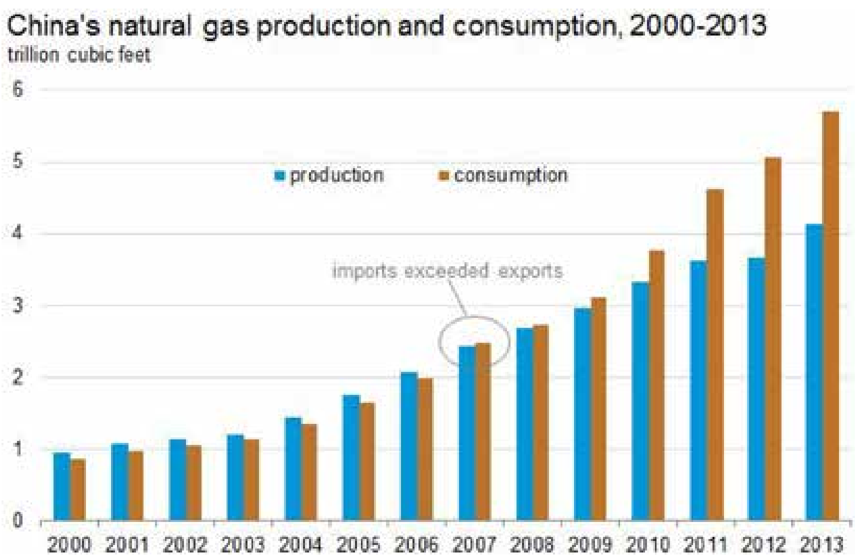

Figure 11.5 China's natural gas production and consumption, 2000–2013. *Source*: U.S. EIA, International Energy Outlook, (2015).

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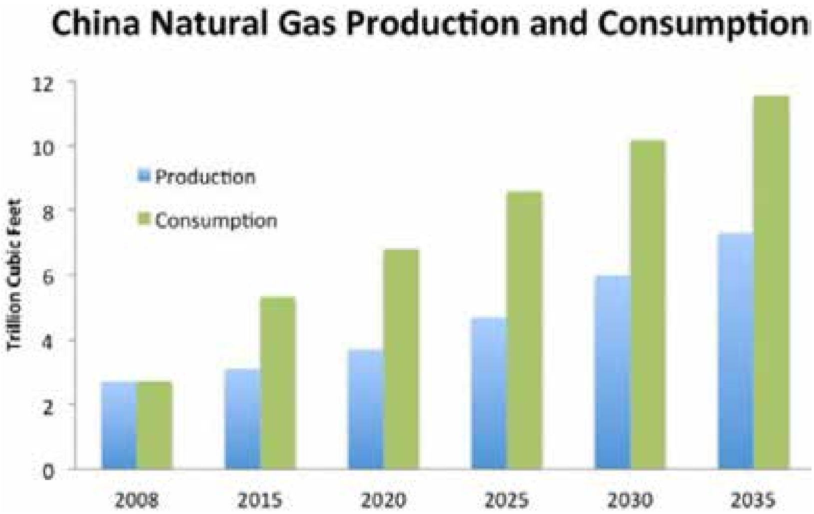

Figure 11.6 China's Natural Gas Production and Consumption. *Source*: U.S. EIA, International Energy Outlook, (2011).

leaders of hydrate exploration in the world, Japan is investing substantially to refine the technological tool necessary in order to reduce the cost of production. Should they be able to do this successfully by 2030, this would a game changer with profound impact not only on Japan's energy future but also on the global energy market.

CONCLUSION

Compared to the United States, China, and Japan's attempts to explore their unconventional energy resources are in early stages of their development and face a myriad of technological and financial challenges in the near term in order to become a viable long-term source of energy for these two countries. Given the expanding demand in both countries for natural gas, chronicled above, and the desire to cut the cost of energy imports, there are plenty of incentives in both countries to develop their own massive unconventional energy resources. Thus, the investment in research and development as well as joint ventures with major Western energy companies are likely to expand in future. Should the technological innovations and breakthroughs continue to reduce the cost of exploration and extraction of these resources in the near future, their financial viability would be enhanced and so would their commercial large-scale production. This, however, requires overcoming numerous challenges that may not be met easily in the short-term.

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Chapter 12

Outlook for Shale Gas Development in the Middle East and North Africa (MENA) Region

Bijan Khajehpour

INTRODUCTION

The Middle East and North Africa (MENA) region has been one of the principal hubs for oil and gas production in the past few decades. Based on the latest data published in the BP Statistical Review of World Energy the countries in the MENA region hold about 52 percent of the world's oil reserves with Saudi Arabia, Iran, and Iraq being the top reserve holders and Saudi Arabia, UAE, and Iran as top producers. The same group of countries produces about 34 percent of the world's crude oil output.[1]

In terms of natural gas, the MENA countries hold about 47 percent of the world's proven conventional reserves with Iran and Qatar holding the overwhelming majority of those resources and Algeria a distant third. Incidentally, according to the BP Statistical Review of World Energy Iran now holds the world's largest natural gas reserves followed by Russia and Qatar. However, Iran's actual gas production corresponds to about 5 percent of the global production and Iran's gas exports are negligible, though the country has recently become a net exporter of gas. The most significant gas exporter in the region is Qatar that has positioned itself as a major producer of Liquefied Natural Gas (LNG), exporting it to international markets.

Despite the overwhelming resource base, in the past few decades, the reserves of this region have been underutilized mainly due to political upheavals, wars, regional uncertainties, and external sanctions. This trend is set to continue considering the existing sources of conflict and uncertainty in the region.

Another reason for underutilization of the actual potential has been the vast energy inefficiency in the entire region. Subsidized fuel prices have led

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to unsustainably high energy consumption in all these countries so that a considerable amount of their primary energy production is used for domestic consumption.

As such, developing unconventional oil and gas resources could be a natural strategy for the MENA countries. Nonetheless, the experience in other regions has underlined the complexities of such a strategy. A further complicating factor would be the current low oil price that not only makes the development of unconventional energy less economical, but also limits the financial resources of the MENA governments. Conventional wisdom would conclude that developing alternative energy sources in a low oil price environment may be more challenging in a region that still has abundant conventional resources. Nonetheless, there are significant developments in the field of shale gas that need to be examined. Interestingly, in the global assessment of regions and countries with shale gas potential, in the MENA region, only Algeria features as a country with significant shale gas potential.

The fact is that rising domestic energy consumption and the growing significance of gas as a clean source of energy will certainly compel the respective governments to consider shale gas 2 as an option to improve their overall energy balance. Nonetheless, the question remains whether the economic, environmental, and social cost associated with shale gas development will be accepted by these countries.

Evidently, there will be different dynamics in diverse countries. As such, the chapter will focus on four countries with diverse features, that is, Algeria (a country fast losing its export capacity), Saudi Arabia (largest oil reserve holder), Iran (largest gas reserve holder), and Morocco (an energy importer). As will be seen, each selected country has experienced its own dynamics on shale gas development. Before discussing the individual approaches, the chapter will shed some light on the general energy sector and economic developments in the MENA region and also take a closer look at the complexities of shale gas development in the target region to set the scene for an assessment of country approaches to the sector.

ENERGY SECTOR AND ECONOMIC STATISTICS IN THE MENA REGION

The MENA region (see Table 12.1) is known for its abundant conventional oil and gas resources. In fact, some of the largest conventional petroleum reserve holders in the world are located in the MENA region, especially around the Persian Gulf that can be considered the most significant oil and gas hub globally.

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Table 12.1 Oil and Gas Reserves in MENA Countries

Country	*Oil Reserves (in billions)*	*Share in Global Reserves (%)*	*Gas Reserves (in trillions)*	*Share Global (%)*
Iran	157.8	9.3	34.0	18.2
Iraq	150.0	8.8	3.6	1.9
Kuwait	101.5	6.0	1.8	1.0
Oman	5.2	0.3	0.7	0.4
Qatar	25.7	1.5	24.5	13.1
Saudi Arabia	267.0	15.7	8.2	4.4
Syria	2.5	0.1	0.3	0.2
United Arab	97.8	5.8	6.1	3.3
Yemen	3.0	0.2	0.3	0.1
Total Middle East	**810.5**	**47.7**	**79.4**	**42.5**
Algeria	12.2	0.7	4.5	2.4
Egypt	3.6	0.2	1.8	1.0
Libva	48.4	2.8	1.5	0.8
South Sudan	3.5	0.2		
Sudan	1.5	0.1		
Tunisia	0.4	w		
Total North	**69.6**	**4.1**	**7.9**	**4.2**
TOTAL MENA	**880.1**	**51.8**	**87.3**	**46.7**

Source: Bijan Khajehpour, 2017.

As Figure 12.1 indicates, five of the nine top hydrocarbon reserve holders in the world are Persian Gulf littoral states.

Table 12.1 summarizes the hydrocarbon reserves of the leading countries in the region.

One important fact about the MENA region is that, despite the availability of huge hydrocarbon reserves, the region as a whole is short of natural gas.[2] Iran, as the world's largest natural gas reserve holder[3] consumes almost its entire production domestically and Qatar's excess gas production potential is essentially needed by all the other markets in the Persian Gulf. In North Africa, Algeria remains an important gas exporter, especially to Europe, but Egypt has lost its capability to export gas.[4] This imbalance has compelled key energy producers in the region to look for alternative energy sources, including unconventional oil and gas production as well as renewable and nuclear technologies.

However, the development of unconventional resources, especially shale oil and gas, faces multiple challenges in the MENA region including economic, environmental, and social challenges. The most significant challenge in the medium term will be of economic nature. In fact, the negative impact of the low oil price on the economies of the MENA region has limited the ability of the respective governments to invest in new developments. Between June 2014 and July 2015 international oil prices dropped by approximately

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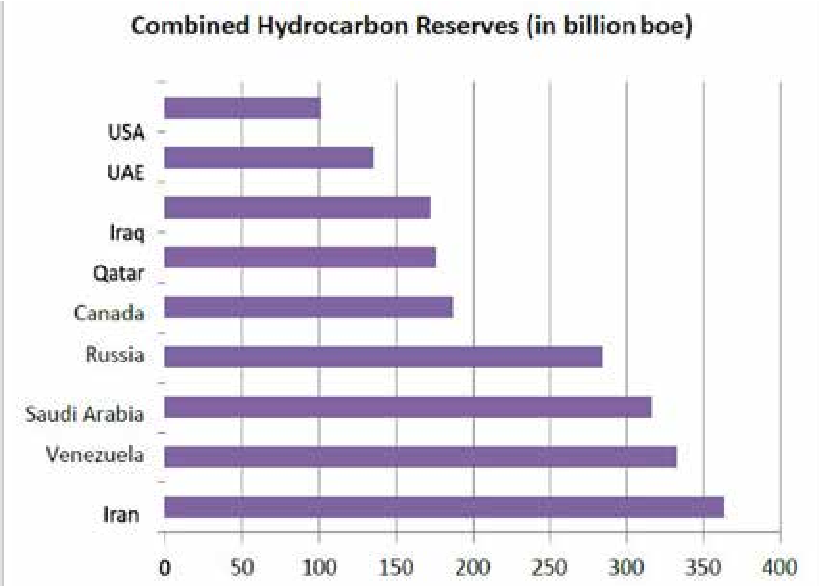

Figure 12.1 Top Hydrocarbon Reserve Holders. *Source*: Accumulated by the author based on data in BP Statistical Review of World Energy 2015.

60 percent that translated into major budget deficit and economic challenges for oil exporting countries in the MENA region (see Figure 12.2).[5] Though most of the governments in the MENA region enjoy healthy hard currency reserves, the tendency to invest in new ventures during low oil price cycles is low.

The MENA region has both oil exporters and net oil importers. Evidently, for oil importing economies, low energy costs lead to greater potential for economic growth; however, in oil exporting countries, the low oil price has led to real negative and psychological impacts on the economy. At the same time, in most of the MENA countries, energy prices are generally subsidized and therefore the end consumers do not experience cheaper fuel prices, hence the positive economic impact of low energy costs is not experienced by the consumers. Consequently, in the studied regions, the core question in every market will be how dependent the economy is on oil export revenues.

At the same time, as a recent International Monetary Fund (IMF) report[6] points out, many of the countries in the mentioned region need to respond to the demands in their societies (demand for housing, energy, infrastructure, etc.). Therefore, experts agree that while governments need to find financing solutions for the more urgent needs, there will be little room for new investments. Furthermore, all key players in the region are also plagued by the

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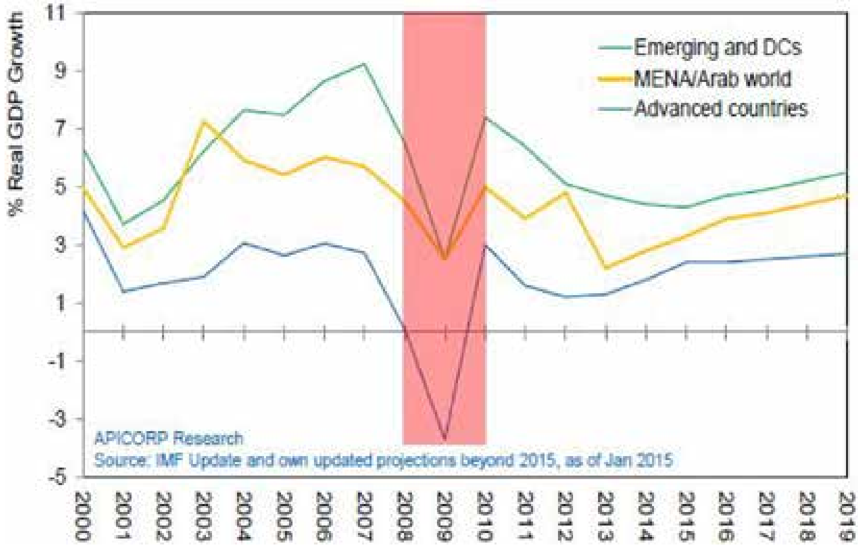

Figure 12.2 Economic Outlook in MENA Countries. *Source*: APICORP Research, IMP Update and own updated projections beyond 2015, as of January 2015.

increasing costs of security and their struggle against terrorism. One example is the huge cost of the Yemen war on the Saudi finances.[7] The overall economic growth trends will be modest and as depicted in the below graph MENA economies will experience a slower growth pattern compared to emerging and developing countries.

WATER SCARCITY AND SHALE GAS DEVELOPMENT

Before attending to individual country cases, it is important to look at the controversial nature of shale gas development. Though shale oil and gas technology has made the enormous production increase in North America possible, its fate has been very different in other regions. In fact, the main technique, that is, fracking has been banned in France and has become increasingly controversial in the United Kingdom[8] and Germany. Consequently, European companies are looking for new regions including MENA to develop potential shale reserves.

There are a growing number of environmental and social concerns regarding shale gas development, but the most important one in the MENA region is the availability of needed water resources. Mohamed Balghouthi, cofounder of the Economic and Scientific Intelligence Unit of Tunisia (GIEST), was one

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of the first Tunisian figures in 2011 to denounce how shale gas extraction in Tunisia is primarily a question of water and therefore food sovereignty.[9]

In fact, according to the Stockholm International Water Institute[10] the total water requirement for a fracking well during its entire lifetime (20–40 years) can be anywhere between 24 million and 500 million liters. To put these figures into perspective in the MENA region, one can look at the plans that the company Shell has for the Tunisian project called Kairouan. The 740 planned wells in that project would need a minimum of 17.8 billion liters of water in the next fifty years. This would correspond to Tunisia's drinking water consumption for the next 100 years.[11] Though Tunisia is facing a harsher water scarcity compared to the rest of the MENA region,[12] the general fact that fracking will use desperately needed water resources will irritate many stakeholders in the MENA region.

A fact that complicates the situation further is the chemical treatment of the water used in shale activity, making the wastewater from shale extraction unusable for other purposes—in addition to potentially contaminating other stressed water resources in the region.

Proponents of shale gas development on the other side argue that key technological innovations have allowed engineered processes that limit the environmental impacts of hydraulic fracturing.[13] They also argue that horizontal drilling techniques have improved the overall environmental footprint of fracking.[14] However, both these facts would also translate into the dependence of MENA countries on state-of-the art drilling and fracking technology to achieve their shale gas potential at lower environmental costs.

Nonetheless, one challenge will always be the management of the wastewater and fluid muds. In fact, a variety of waste fluids are generated at shale gas wells that need to be managed carefully.[15]

A technical analysis of the environmental disadvantages of fracking is beyond the scope of this chapter. However, considering that the MENA region is "the most water scarce region in the world,"[16] it is clear that the availability of water would play a key role in the question whether shale gas would be developed in any of the MENA countries. Nonetheless, a number of these countries have announced shale gas programs and below we will look at the dynamics of the debate and development in some of these countries.

FOCUS ON ALGERIA

Algeria has the highest potential for shale gas reserves and one of the MENA countries with an active shale gas program. (see Figure 12.3 for Algeria's energy balance). However, economic and social dynamics have hampered the country's plans. Economically, Algeria is strongly hit by

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the current low oil prices. According to IMF, in Algeria, the hydrocarbon sector accounts for 97 percent of the country's total exports and 58 percent of its total fiscal revenues.[17] The falling oil prices meant that Algeria experienced a budget deficit in 2014 corresponding to 18 percent of its GDP—for the first time in fifteen years. Though Algeria has a healthy hard currency reserve, it is also vulnerable to social unrest. Consequently, the government has increased state spending in the 2015 budget by 15 percent, pushing up the budget deficit to 22 percent of the GDP.[18] Though experts deem it unlikely, Sonatrach[19] insists that Algeria will stick to its $90 billion investment plan in its oil and gas industry even at low prices. A small segment of this investment ($400 million) will be dedicated to a shale gas project.[20] Algeria is expected to maintain its economic growth at 3 percent (4.2 percent excluding hydrocarbons) in 2015, that is, at the same level as in previous years. However, the country's export potential is declining: as the following graph indicates, Algeria's exports peaked in 2005 and have decreased by about 20 percent in the past decade due to falling production levels and increasing domestic consumption.

However, according to experts, Algeria's main issue remains the lack of an energy strategy. The recently appointed minister of energy, Salah Khebri has stated that Algeria aims to "rapidly increase production," therefore efforts being directed toward exploration schemes in proximity to producing

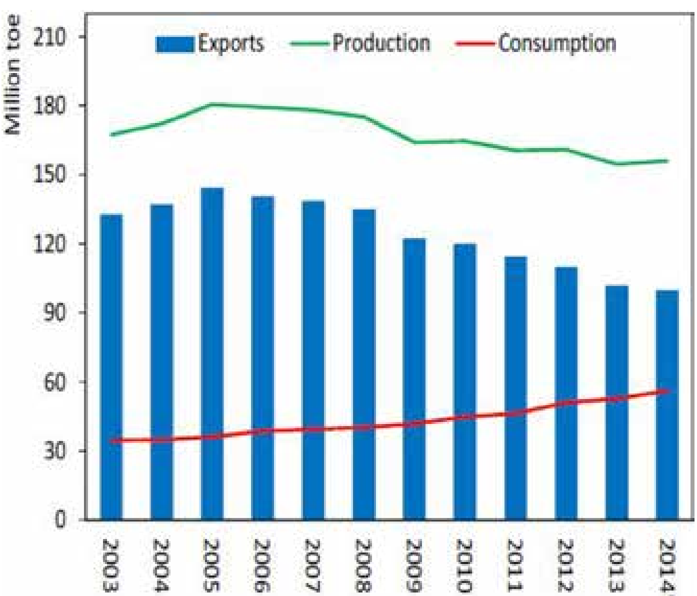

Figure 12.3 Algeria's Energy Balance. *Source*: Algerian Ministry of Energy, 2015.

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areas. Experts argue that Mr. Kherbi's statements point to a desire not to get irritated by the controversial shale policy of his predecessor. Instead, he would focus Sonatrach's efforts on conventional low risk ventures and rapid results.[21]

In other words, two key factors lower the significance of shale gas development for the Algerian government: on the one side the current financial challenges and on the other side the need for a rapid increase in production. Evidently, shale gas does not fit into a rapid development due to its abovementioned complexities. Incidentally, as the regions that Algeria has earmarked for shale development are located in the water stressed regions of the country, important social and environmental challenges have been faced.

In fact, in January 2015 different regions in Algeria witnessed social unrests protesting fracking activity after the Algerian government announced the drilling of the first well for shale gas development.[22] One irony of the situation was that the company carrying out the project was Total that was banned from fracking in France. While popular protests in Algeria may also be connected to political alienation and a general exclusion of the society from key strategic decisions, the issues are real and governments who wish to develop shale gas projects in water scarce regions will face a backlash from the society and other stakeholders.

FOCUS ON SAUDI ARABIA

Saudi Arabia is in a peculiar situation. Though it has the world's largest crude oil reserves, it is actually gas-poor. In 1998, the Kingdom commenced its so-called Gas Initiative which aimed to develop natural gas resources to fuel the growing domestic energy demand, but it failed to deliver results[23] essentially leading to the country using a sizable segment of its exportable crude oil and liquids for domestic power generation.

In the absence of gas imports, Saudi Arabia will continue to face a dilemma of utilizing its crude potential for its rampant domestic energy consumption.[24] Consequently, developing the Kingdom's shale potential could be one viable strategy for Saudi Arabia to address the issue of gas shortage. Other viable strategies could include the development of renewable energies or even nuclear power.

One key challenge to Saudi Arabia has been its galloping domestic energy consumption. Even in a regional comparison, the Kingdom's per capita primary energy consumption is high (see Table 12.2). This rampant consumption is caused by subsidized fuel and energy sources, but it presents a challenge as energy consumption is growing faster than the country's GDP.

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Table 12.2 Per Capita Primary Energy Consumption (in kg of oil equivalent per year)

	Mtoe/y	*Per Capita*
Turkey	131.3	1,690
Iran	267.2	3,340
Saudi Arabia	264.0	8,370

Source: BP Statistical Review of World Energy 2016.

Unlike Algeria, Saudi Arabia does not have a short-term financial challenge as it has huge hard currency reserves.[25] Nonetheless, there are also domestic risks associated with the current low oil price scenario. A continuation of the low oil price environment will lead to financial limitations. The resulting cuts in welfare spending and salaries for civil servants will have social consequences. Though the hard currency reserves are enough to prevent big budget cuts, the perception by domestic and international investors will lead to lower investment activity and higher unemployment. Consequently, the Kingdom's economic growth and overall investment activity will also slow down.

In addition to available finances, Saudi Arabia also has enough shale reserves. In fact Saudi Arabia may have the world's fifth largest shale gas reserves in the world.[26] However, also in this case the shortage of water is acting as the main obstacle.

Nonetheless, Ali al-Naimi, former minister of petroleum and mineral resources of Saudi Arabia, said the country will soon start the production of shale gas to supply industrial projects in the Kingdom.[27] Mr. al-Naimi said that the Kingdom had made promising shale gas discoveries and acquired the technologies to produce it at a reasonable price.

Saudi Aramco announced in 2013 that it was ready to commit shale gas for the development of a 1,000-MW power plant. Currently, unconventional gas is being explored in three areas including northwest, south Ghawar, and the Rub'a al-Khali (Empty Quarter). The company also said that activities as site development, rig preparation, drilling, fracturing, completion, well tie-in, production, and maintenance would grow rapidly by 2020 to facilitate the development of the shale gas sector. In February 2016, it was reported that Saudi Aramco was on the verge of awarding a shale gas project,[28] but the project has failed to attract the needed attention.

An additional irritant in the case of Saudi Arabia is the current military conflict in Yemen. In fact, experts argue that the Yemen conflict would worry domestic and international investors more than the low oil price environment.[29] Fact is that the Yemen conflict as well as the growing phenomenon of jihadist terrorist activity (in the form of Islamic State or Al-Qaeda) has increased the cost of security for international companies hence making new developments and investments more challenging. Another current example is

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the tensions between Saudi Arabia and Qatar which have led to a blockade of Qatar by Saudi Arabia, Egypt, UAE, and Bahrain.[30] Such events are just a reminder of the complexities of geopolitical parameters and their continuous impact on commercial and economic developments.

Time will tell whether Saudi Arabia will consider shale gas strategic enough to commit some of its financial and environmental resources to continue developing shale gas. Experts interviewed by the author opined that the Kingdom would be more likely to invest in other alternative energies and return to developing its shale gas potential, once oil prices return to a higher level. One alternative strategy that Saudi Arabia could adopt instead of developing its shale resources is to implement energy efficiency schemes to reduce the per capital primary energy consumption in the country which is more than three times that of the global average.[31]

The Kingdom has created an entity called "Saudi Energy Efficiency Center"[32] and is aiming to reduce energy consumption in a twenty-year horizon. Experts agree that in countries like Saudi Arabia it is cheaper to conserve energy than to produce energy through unconventional sources. Therefore, it is more likely that the initial focus in a low oil price environment would be on increasing energy efficiency as opposed to investing in expensive shale gas projects.

FOCUS ON IRAN

Unlike Saudi Arabia, Iran has sizable unassociated conventional gas resources that are being developed aggressively, despite external sanctions that have undermined the Iranian petroleum sector (Figure 12.4). In fact, between 2008 and 2015 harsh external sanctions connected to Iran's nuclear program slowed down the development of the Iranian gas sector. After agreeing on a Joint Comprehensive Plan of Actions with world powers on July 14, 2015, Iran is now reengaging the international community to attract foreign investment and technology to modernize its petroleum sector, especially its gas potential. In fact, the first major contract to be awarded to an international consortium was the agreement with a Total-led consortium to develop South Pars Phase 11.[33] That after President Trump pulled out of the nuclear deal in 2018, the total share of investment was take over by Chinese energy companies. Now that key nuclear sanctions have been lifted, the country will again have access to the technology and investment volumes that it will need to develop its conventional resources. In fact, the country's deputy petroleum minister, Amir-Hossein Zamani Nia has stated that Iran would require $185 billion of investments by 2020 to develop its petroleum sector including major expansion plans in the conventional gas sector.[34]

As mentioned earlier, Iran has the largest proven conventional gas reserves in the world. The country currently produces 190 billion cubic meters of gas

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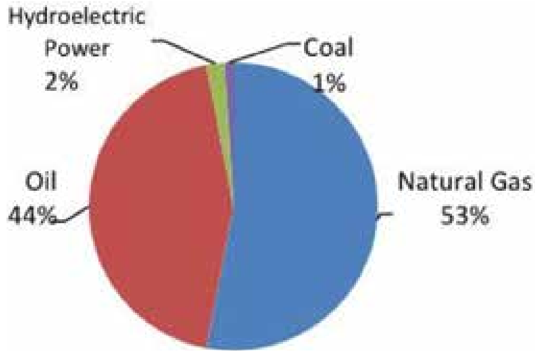

Figure 12.4 Iran's Energy Basket. *Source*: Ministry of Energy, Tehran, tabulated by Bijan Khajehpour, 2017.

per annum (bcm/a) and consumes 175 bcm/a of refined gas domestically, that is, 67 percent of the country's total primary energy use. (see Figure 12.5 for Iran's gas production, 1970–2014) Iran has very ambitious plans to double its gas production by 2020 that is a reflection of the country's enormous resource base. Interestingly, despite a fast pace growth in the actual production capacity, most of the produced gas is consumed domestically, especially fueling the growth of gas-based industries.

Experts agree that the main story in Iran's energy sector will be gas: on the one side, it is the country's most valuable resource that can attract foreign

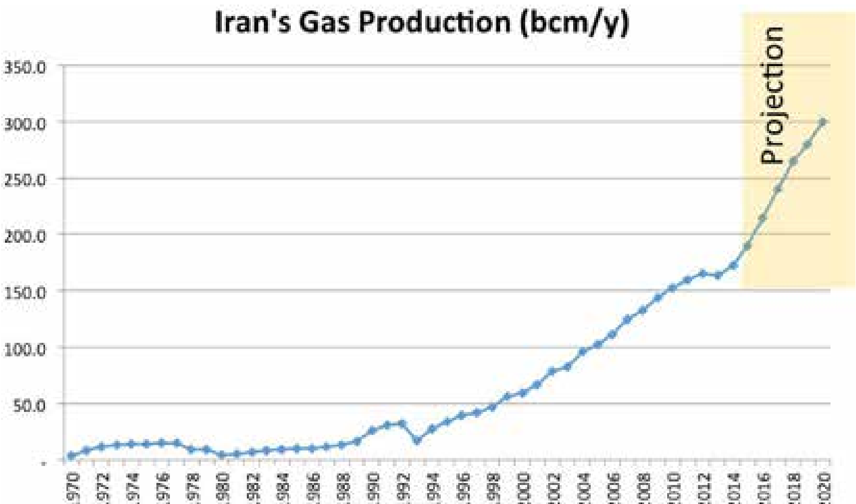

Figure 12.5 Iran's Gas Production 1970 to 2014. *Source: National Iranian Oil Company* (NIOC), projections by Bijan Khajehpour, 2017.

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investment and technology in diverse sectors. On the other side, the key industries will be gas-based to optimize the economic benefits of this natural resource. Furthermore, gas and electricity exports will be the backbone of Iran's regional trade relations with its immediate neighbors that are mostly in need of gas or electricity imports. As such, Iran's gas potential will not only facilitate economic growth, but it can also help it reduce tensions with countries such as Pakistan and Saudi Arabia, similar to how energy relations have eased tensions between Iran and Turkey.[35]

As such, developing the gas sector will be a core strategy for Tehran. However, due to the existence of abundant conventional resources, developing unconventional resources has not become an issue in Iran. Though the country has announced the discovery of shale oil and gas reserves[36] the development of such resources won't be a priority in the foreseeable future.

According to Dr. Narsi Ghorban, respected Iranian energy economist, one reason shale gas won't become a priority in Iran is the fact that the country has not yet fully explored its conventional gas potential. "The enormous gas resource that we have discovered in Iran, has mainly been realized when exploring for oil!"[37] In other words, Iran will need to explore the country for conventional gas first before moving to shale gas exploration and development at a later stage.

Furthermore, similar to Saudi Arabia, Iran also can benefit enormously from increased energy efficiency. The country has introduced a phased subsidy removal program since 2010, and is investing in energy efficiency schemes. Based on assessments in Iran, the cost of saving one barrel of oil in consumption is about one-third of the cost of producing one barrel of oil.[38] Considering that Iran is a low cost oil producing country, it is clear that saving energy is much more low-hanging fruit for Iran compared to developing shale gas potential.

In addition to the availability of conventional oil and gas reserves that are ready to develop at relatively competitive cost levels, Iran has also embarked on a number of other strategies including an aggressive investment program in renewable energies as well as in the development of a civilian nuclear program. Though the share of unconventional energy resources is still negligible in the country's energy basket, it is set to grow significantly in the next decade. Since 2012, the Iranian government has pursued a campaign to promote renewable energy generation in order to free up more hydrocarbon resources for export.[39]

Finally, Iran is also considered a water scarce country[40] and developing shale gas based on fracking would undoubtedly lead to social backlash. Therefore, as long as shale gas is not needed desperately, it won't be developed.

Considering all of the above facts and development, especially the vast potential in conventional gas, it is conceivable that shale would not be a topic in Iran for some time to come, especially not in a low oil price scenario which also limits Iran's ability to invest in new sectors.

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FOCUS ON MOROCCO

Our last case study deals with a net importer of energy. Morocco represents an interesting case as it is not among the conventional hydrocarbon reserve holders and it imports about 90 percent of its energy needs. Incidentally, energy imports made up 23 percent of the country's imports in 2013.[41] Therefore, developing shale oil and gas resources would be a viable strategy for Morocco to reduce its dependence on imported energy.

The government started offering international oil companies (IOCs) exploration blocks in 2010 to broaden the country's energy base and increase energy independence. In the meantime some of the projects have borne fruit. In late June 2015, Ireland's Circle Oil announced that gas had begun flowing from its first shale well. The project has reached a stabilized flow rate of 1.9 million cubic feet per day at a well in the Lalla Mimouna onshore permit area.[42] Another company, Gulfsands Petroleum, has confirmed a new shale gas discovery within the Rharb Centre Permit in Northern Morocco.[43]

The country is estimated to have about 566 billion cubic meters of shale gas reserves as well as some shale oil reserve that will be produced in the future. However, despite the impact of the country's shale potential on its energy strategy, Morocco must also take into account the impact of shale development on the arid country's water resources.

Similar to other countries in the region, the Moroccan authorities need to take into account the interests of a complex set of stakeholders that are affected by the shale oil and gas development. These stakeholders include the agricultural sector (competing for water resources), the tourism sector (concerned about the impact of oil and gas activity on tourist attractions), and environmental NGOs. In the case of Morocco, one additional complexity is the country's tense relations with Algeria. In fact, Rabat's plans to explore for gas in the border regions with Algeria could lead to further tensions as well as environmental challenges.[44]

A further layer of complexity in the case of Morocco is the status of Western Sahara that is occupied by Morocco. One of the potential shale plays in the country is bordering Western Sahara. Experts agree that the flow of oil or gas in that region would further complicate the security situation.

Another important layer in the case of Morocco is the fact that the country is a major gateway for smuggling activity between Africa and Europe.[45] This phenomenon adds security challenges to the conventional issues such as lack of infrastructure and operational challenges in the less developed regions of the country. Consequently, it is understandable why major IOCs have been reluctant to move into Morocco for exploration and production activity.

All in all, it is valid to argue that while Morocco has a viable rationale for developing shale oil and gas resources in order to reduce its dependence on energy imports; it will continue to face major challenges in further

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developing this sector. It should also be considered that Morocco's plan to reduce dependency on energy imports took shape in a high oil price environment. As such, it is conceivable that the program will slow down due to the fact that IOCs would be less interested in developing more costly shale resources.

CONCLUSION

Veteran energy expert Daniel Yergin believes that shale gas represents "the biggest energy innovation so far in the twenty-first century."[46] There is no doubt that this phenomenon has transformed the hydrocarbon potential of North America, but its role in the MENA region would be limited in the foreseeable future.

The limiting factors on shale development in the MENA region can be summarized as follows:

- Economic limitations in a low oil price environment: The low oil price restricts the ability of energy exporting countries to invest in new sectors. In fact, as long as oil prices stay low, most oil producing economies in the MENA region will have to adjust to new realities and rethink their domestic welfare commitments and approaches to economic development. For energy importing countries like Morocco or Tunisia, while the rationale of developing shale resources is still valid, there may be limitations in the willingness of international companies to invest in shale oil and gas projects.
- Availability of conventional resources: The majority of the MENA countries are endowed with considerable conventional resources that are still to be developed. Developing shale gas may be an option for those countries that are short of conventional gas resources, but its economic and environmental costs may undermine the prospects for the foreseeable future.
- Lack of needed infrastructure: Even if MENA countries opt to develop shale oil and gas resources, they will need to create the needed infrastructure for such a development. Expert analyses underline that the US shale revolution was a function of the availability of transportation and storage infrastructure,[47] therefore, one can consider the lack of infrastructure in most of the MENA region as a limiting factor.
- Lack of security: A number of domestic as well as regional insecurity factors are also hampering the needed investments in the MENA region. Phenomena such as jihadist terrorist activity, cross-border smuggling activity, regional conflicts, and domestic political instability (such as in Libya) are delaying all types of investments, especially the development of new sectors in the entire region.

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- Energy efficiency programs: When contrasting the investments and technologies needed for the development of shale oil and gas against the effort and investments needed to improve energy efficiency, it becomes evident that the majority of MENA countries would initially opt to improve energy efficiency to improve their overall energy balance. Shale gas development could always become an option at a later stage, but it does not present itself as a high priority for the time being.
- Environmental issues, especially water scarcity: As outlined above, most MENA countries face water scarcity and they cannot justify the utilization of their water resources for the development of shale resources. Additional complication in the water issue is the fact that water used in shale operations would be chemically treated requiring special fluids management.
- Regulatory frameworks: Any country that opts to develop its shale resources would also require an appropriate regulatory framework to address the various issues relating to resource ownerships, conflicts of interests, stakeholder relations, and so on. Though the majority of the MENA countries have oppressive political structures, it is conceivable that the lack of appropriate legal structures would lead to tensions and protests. This fact was highlighted in the social protests in Algeria and will be an impediment in a number of other countries developing their shale resources.
- Other alternative strategies: Finally, as mentioned earlier, a number of the MENA countries have also started investing in alternative energy sources such as renewable or nuclear energy. Though the role of these resources would be small in the overall energy basket, they could pose a threat to the logic of developing shale resources.

The above list of limiting factors underlines the challenges that shale development will face in the MENA region. This does not mean that the announced programs of Algeria, Morocco, and Saudi Arabia won't continue, but it seems that all of them will lose steam and be treated as a lower priority as long as the mentioned issues are not addressed. Morocco may present an exception due to its dire need for domestic energy resources, but even there one will have to analyze the impact of the low oil price environment on the overall market development.

NOTES

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Chapter 13

Unconventional Energy in Africa

Impact of the US Shale Revolution and Prospects for African Exploration[1]

Stefan Andreasson

INTRODUCTION

The US shale gas and (tight) oil revolution has had a significant impact on global energy markets, including on exports from sub-Saharan Africa. Following the 9/11 terrorist attacks it was widely assumed that West Africa would eventually supply a quarter of US oil imports as the United States sought to diversify its sources of oil supply. The rapid decline in African oil and gas exports to the United States since 2010 have, however, had a significant economic and social impact on major energy exporters in Africa that are highly dependent on energy export revenues. African exports will over the long term be reoriented, especially to China, India, and other growing Asian markets. And new discoveries of hydrocarbon deposits across Africa will result in an increasing number of countries becoming significant energy producers. In 2014, eleven of the twenty largest oil and gas discoveries worldwide were in offshore sub-Saharan Africa.[2] In addition, nine of the twenty largest oil and gas discoveries worldwide in both 2015 and 2016 were in Africa,[3] although total oil and gas discoveries have declined sharply, to a sixty-year low in 2017.[4] So far, however, the region does not feature prominently in research on unconventional energy exploration and production. This chapter examines prospects for unconventional energy resources in sub-Saharan Africa in the context of developments in the United States, as well as an increasing interest in unconventional energy worldwide. Unconventional energy exploration in sub-Saharan Africa is, outside ultra-deep water oil and gas, still in its embryonic stages. The chapter focuses therefore on the region's one relatively high-profile case of exploration for shale gas, in South Africa's Karoo Basin, to

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shed light on the wider sociopolitical and economic context that will impact on the emergence of any future unconventional energy industry.

IMPACT AND PROMISE OF THE US SHALE REVOLUTION

It is difficult to understate the impact on global energy markets of the rapid increase in production of US shale gas and oil that commenced in the early 2000s and became known as America's shale revolution. According to Wang et al., "the biggest energy story that has happened in the twenty-first century so far is the extraction of natural gas from shale rock formations in the United States"[5] as US shale gas production increased tenfold during the 2000s.[6] An estimate of 15.8 trillion cubic feet (tcf) of natural gas was produced from shale and tight oil resources in 2016, contributing 60 percent of total US production. The US Energy Information Agency (EIA) projects that shale gas production will increase to 29 tcf by 2040, constituting 69 percent of total US gas production.[7] Representative of the excitement surrounding American shale, an article in *Foreign Affairs* highlighted America's "energy edge" and projected the United States as the next "energy superpower."[8] Jones and Steven likewise assume a greatly enhanced agency internationally for an emerging US energy superpower.[9] The United States was, according to Securing America's Future Energy, "in the midst of the most important shift in domestic energy production in a generation."[10] The International Energy Agency described these developments as a "supply shock . . . as transformative to the [global energy] market over the next five years as was the rise of Chinese demands in the last 15 years."[11]

The impact of increased US production is being felt throughout global energy markets, including sub-Saharan Africa's producers that are highly dependent on energy export revenues. Having peaked at 22 percent of US oil imports in 2006, when the key African exporters of oil to the United States (Algeria, Angola, Cameroon, Gabon, Nigeria, and Republic of Congo) shipped a combined 2.47 million barrels per day (mbpd) to the United States, exports declined rapidly after 2010. While most African exporters have been impacted by what became the virtual disappearance of the US market, Nigeria and Angola were hit particularly hard. Nigerian exports to the United States declined from 1,174,000 bpd in September 2010 to 48,000 bpd in August 2014, and Angolan exports from 417,000 bpd to 129,000 bpd during that same time. By October 2014, the *Financial Times* reported that Nigeria had become "the first country to completely stop selling oil to the United States due to the impact of the shale revolution—an astounding reversal" as it was previously one of its five largest suppliers of oil.[12] Nigeria's then oil minister,

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Diezani Alison-Madueke, identified US shale as "one of the most serious threats for African producers."[13] Nigerian exports to the United States have recovered since, to 332,000 bpd by April 2017, but Angolan exports have plunged even further, to 84,000 bpd, and revenue streams remain severely impacted by persistently low prices.

A UK Overseas Development Institute (ODI) report estimated that US shale production reduced US-African trade from around $95.55 billion a year in 2008 to $14.3 billion in 2014, and that African exporters have lost earnings of $1.43 billion in gas and $30.55 billion in oil revenues. These losses amounted to $13.39 billion in Nigeria and $5.72 billion in Angola alone.[14] This loss of revenue is further exacerbated by a collapse of the global oil price, from nearly $110 per barrel of West Texas Intermediate (WTI) crude in June 2014 to a fourteen-year low of just above $29 per barrel in January 2016. The US EIA estimates the reduction from 2012 to 2016 of annual net oil export revenues in Nigeria and Angola to, respectively, $71.3 and $45.5 billion.[15] Worst affected are African producers for whom oil revenues constitute more than 50 percent of GDP (Equatorial Guinea, Angola, and Republic of Congo) and more than 70 percent of export revenues (Chad, Angola, Libya, Gabon, Nigeria, Republic of Congo, Sudan, and Equatorial Guinea),[16] even if they are not equally exposed to the US export market. Together these developments constitute a pincer movement against sub-Saharan Africa's exporters with potentially dire consequences for economic development and social stability, never mind the prospects of turning the region's oil exporting into what Ovadia terms "petro-developmental states."[17]

The US shale revolution not only reshaped geostrategic aspects of global energy markets, but came with the promise of substantial job creation wherever it might be replicated even if the evidence on the benefits from shale remains contested.[18] Paredes et al. argued that spillover economic benefits of the shale industry in the Marcellus shale region have been "minimal," although there have been significant employment benefits.[19] But Wang et al. demonstrated "profound economic impacts" of the US shale industry, including supporting some 600,000 jobs, likely to rise to 870,000 by 2015 and eventually to more than 1.6 million by 2035.[20] Key to this job creation is the "employment multiplier," whereby every job created in the shale industry creates another three "indirect and induced" jobs. This is particularly attractive for developing countries that are burdened with high levels of poverty and unemployment. The authors furthermore estimated that whereas the shale industry contributed $76.9 billion to the US economy in 2010, this would have increased by 54 percent, to $118.2 billion, in 2015 and to a further estimated $231.1 billion in 2025, a 300 percent increase on the 2010 figures.[21] But recent events have overtaken these estimates, rendering them increasingly uncertain. The oil price crash has resulted in the global oil and

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gas industry shedding some 70,000 jobs and deferring at least $200 billion in project spending by the summer of 2015.[22] This depressed and increasingly uncertain price environment placed both shale and conventional producers under severe financial stress due to their urgent need for financing,[23] and despite their impressive and rapid operational efficiency gains.[24] A return to profitability and increased production among resurgent shale oil and gas producers by 2017 does not yet provide a great deal of clarity about the future trajectory of economic benefits from the industry.

Lower natural gas prices have also made energy-intensive industries in the United States more competitive due to the substantial price advantage they now enjoy compared to competitors in Asia and Europe. The US gas price reached a seventeen-year low in January 2016, at just below $2 per British thermal unit (btu). Moreover, carbon emissions were reduced by about 430 million metric tons CO2 in the United States between 2006 and 2011, more than in any other country as industry shifts away from coal and oil toward cleaner gas.[25] Global companies in energy-intensive industries are now investing in US plants to take advantage of its lower energy prices, even if Levi argues that energy costs constitute a relatively small percentage of overall costs and are therefore "rarely pivotal" in investment decisions.[26] The potential for increased economic competitiveness and substantial emission reductions is attractive to rising powers of the Global South that bear the brunt of environmental and public health problems associated with rapid industrialization.

US developments might prove instructive when evaluating the potential for shale production elsewhere. Countries endowed with substantial shale deposits look to the United States in the anticipation that they too could reap substantial economic and strategic benefits from replicating the American shale boom. Contrary to suggestions that a low-carbon shift in the global economy is imminent, Collier argues that we are only in the early stages of the era of natural resource extraction as developing regions of the world have substantial natural resources including unconventional energy that remain to be discovered and exploited.[27] The EIA's *World Energy Outlook 2016* forecasts energy demand growing by 30 percent to 2040, with oil, natural gas, and coal contributing, according to its New Policies Scenario, around 74 percent of total energy production. Demand for gas will grow by nearly 50 percent, faster than any of the other fossil fuels.[28] The US government also promotes its shale gas industry worldwide. The Unconventional Gas Technical Engagement Program (UGTEP), launched in 2010 by the US Department of State, is dedicated to furthering the interests of the US shale industry and its extension worldwide with partnerships in numerous countries worldwide including (in Africa) Botswana, Morocco, and South Africa. In 2013, the US ambassador to Germany, John B. Emerson,

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spoke with "enthusiasm and optimism" about the "safe" and "amazing" US shale industry having the potential for becoming a "win-win for the world."[29]

However, the US shale revolution remains the only viable one to date (irrespective of some commercial shale gas production in Canada and China, and shale oil production in Canada and Argentina). It represents the only substantial evidence to date of the costs and benefits produced by the shale industry, which impedes the ability to generalize and predict what the consequences of exploiting shale resources across a variety of cases may be. Ultimately there are many ways in which the potential for shale in other countries with substantial reserves differ from developments in the United States. The geology of shale formations is not similar and the water supplies required to exploit them by means of hydraulic fracturing is not equally distributed worldwide. Relevant technological expertise including the presence of a wide range of highly skilled energy companies, financial institutions suited to and experienced in financing this emerging and dynamic sector and even the required social acceptance of large-scale extractive industries, is not sufficiently present in all shale-rich countries.[30] Jones Luong and Weinthal have suggested that the largely private and decentralized ownership structures in the US shale industry reduces the risk of the economic and societal problems associated with extractive industries[31]—the so-called resource curse.[32] Given the many complications associated with extractive industries in resource-abundant African and other developing states,[33] they may have a greater cause for concern about unconventional energy production, too, than is the case in developed countries.

UNCONVENTIONAL ENERGY IN AFRICA

As noted above, energy export revenues constitute a major source of government revenue for several African states and have done so for a long time among established producers like Nigeria, Angola, and Gabon. Long-term fluctuations in such revenues will inevitably have a major impact on state revenues and the ability to finance and plan development across the region. In addition, Kessides has demonstrated how, despite impressive economic growth rates in the twenty-first century, Africa's persistent economic difficulties are manifested most obviously in its ongoing energy crisis.[34] Twenty-five of forty-eight countries in sub-Saharan Africa are experiencing "crippling" shortages of electricity and regular blackouts, the economic costs of which have been significant. Kessides estimates such costs at 2.1 percent of sub-Saharan Africa's GDP, and exceeding a staggering 5 percent of the GDPs of Malawi, Uganda, and South Africa.[35]

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The crisis has, somewhat ironically, been exacerbated by the regions until recently impressive economic growth rates and now threatens to seriously inhibit further economic development. It stems primarily from a lack of “significant capital investment, from either the private or public sectors, into Africa’s power sector” for the past two decades. In 2013, total installed capacity in sub-Saharan Africa was 68 gigawatts (GW), which compares to that of Spain; excluding South Africa, the total capacity (28 GW) is equal to Argentina’s. Total energy consumption in the region was a mere 3 percent of the world total although the region is home to 15 percent of the world’s population.[36] These ongoing problems are the reason why, according to a *PwC* report on the future of Africa’s oil and gas markets, African policy makers are now considering gas a “viable power feedstock.”[37]

African governments are certainly not ignoring the potential of their energy resources but will in almost all cases need major international investment and technology to help monetize them. In a major survey of oil and gas resources in Africa, Brown notes that there is at least some exploration or production for hydrocarbons in all but three of Africa’s fifty-four continental and island nations (the only ones with no such activity being Burkina Faso, Lesotho, and Swaziland).[38] Africa is moreover likely to increase in importance for the energy companies of North America, Europe, and China that, according to the abovementioned *PwC* review, are expected to provide a combined 73 percent of all foreign direct investment into African oil and gas—that is, 26 percent from North America, 25 percent from Europe, and 22 percent from China.[39] Indeed, Africa will likely need more than $2 trillion in oil and gas sector investments by 2035 in order to fully realize its energy producing potential.[40] While much of this investment will be into conventional energy resources, Ramin Lakani, a regional general manager of Halliburton, notes the potential for “an unconventional oil boom” in Africa as a key area of future focus for investment.[41]

Any such “boom” is most likely to emerge in ultra-deep water oil and gas. This is a source of hydrocarbons arguably considered unconventional given the high technological demands, economics costs, and operational risks associated with drilling at depths exceeding 5,000 feet, a depth which the industry generally identifies as the threshold for what can be considered “ultra-deep water.” Such exploration is mainly conducted in offshore blocks in Angola, Ghana, Ivory Coast, Liberia, Nigeria, and Sierra Leone. Western energy majors including Total, Chevron, BP, ExxonMobil, and Eni, independents including Afren, Hess, Tullow Oil, Kosmos, and Noble Energy, and state-owned energy companies from the emerging markets such as Sinopec and Petrobras, as well as African ones like Sonangol, are exploring and producing deep water hydrocarbons along the entire West African coast,[42] notably in the Gulf of Guinea which together with Latin America and the Gulf of Mexico

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comprises the traditional Deepwater Triangle. There is also deep water exploration outside the established West African offshore region, along the East African coastline, from Egypt to Mozambique, and offshore South Africa.[43]

Although ultra-deep water energy resources have been identified as a key future source of energy production growth, the prospects for such growth are now increasingly uncertain as the oil and gas price is predicted to remain low and stagnant for the foreseeable future. *BMI Research* highlights "frontier exploration," including in West Africa's ultra-deep water resources, to be most at risk of losing investments.[44] The future also looks much less certain as the 2000s commodities super-cycle came to an end by 2014, with demand for commodities slackening, especially in China. According to *Market Watch* analyst Craig Stephens, "the oil market is unlikely to find another country, or even a continent, that can take over this degree of heavy lifting in [oil] demand growth."[45] China's decision to substantially devalue its currency will put further pressure on Africa's energy export prices to remain competitive in the Chinese energy market.

Brown notes other unconventional energy resources across the continent as well, such as tight gas (in Western Africa's Congo Basin), oil sands, and coal-bed methane (CBM).[46] The short-term viability of oil sands, which are found in the Congo Basin and Madagascar, is highly uncertain. By August 2015, the oil price in Canada's oil sands stood at $20 per barrel, which was less than half the price of already very low crude oil prices and meant that Canadian tar sands oil had become the cheapest crude oil available worldwide.[47] The price dropped further, to $16 per barrel, by February 2016 to then recover to a modest $38 by May 2017. Given more challenging logistics and sources of finance, it is unclear how African oil sands could be a viable prospect in this price environment. CBM constitutes a potentially important source of unconventional energy production across southern Africa, especially in Botswana and South Africa, but also in Zimbabwe, Namibia, and Mozambique. While Botswana is already proceeding with extensive exploration of its CBM resources, the potential for exploiting CBM resources in Zimbabwe is highly uncertain due to the country's volatile political situation and recent economic collapse. Mozambique is likely to focus instead on its recently discovered and massive conventional offshore gas resources.

Significant shale gas deposits have been discovered in South Africa, as well as across North Africa (in Algeria, Libya, Tunisia, and Ethiopia). According to the US EIA's estimates, the Top ten countries with the largest technically recoverable shale gas reserves include Algeria with the world's third largest reserves (707 tcf) and South Africa with the eighth largest (390 tcf).[48] Libya is the only African country featuring among the Top ten countries with technically recoverable shale oil resources (fifth, with an estimated 27 billion barrels). The number of countries with recoverable shale gas deposits

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has increased by 28 percent (from 32 to 41) between 2011 and 2013, and the world's estimated total reserves of shale gas increased by 10 percent (from 6,622 to 7,299 tcf) during that same time.[49]

While these figures are rough estimates and have in several instances been subject to revision, they nevertheless provide a reasonably good picture of the global distribution of significant shale gas deposits. However, in locations outside the United States where exploration has been much less extensive, indeed minimal, there is even greater uncertainty about the actual amounts of recoverable shale gas. Moreover, these are defined as technically—not economically—recoverable reserves. They do not consider factors such as prolonged periods of low energy prices that will have a significant impact on the willingness of energy companies and governments to invest in relatively high-cost shale exploration and production. The Petroleum Agency SA (PASA), which regulates South Africa's exploration and production activities, notes that the shale gas in the Karoo Basin is merely a "prospective resource at present" and that "possible scenarios" indicate that it contains between 30 tcf and 500 tcf of technically recoverable shale gas.[50] In other words, it is a rather cautious assessment.

AN OPPORTUNITY FOR SOUTH AFRICA?

This context makes it useful to consider South Africa's potential for exploring its substantial shale gas deposits. It is one of the few cases (outside ultra-deep water) in sub-Saharan Africa where the potential for unconventional energy production has received serious attention by the global oil and gas industry, policymakers, and other energy analysts. And a revival of South Africa's economic fortunes is currently a pressing matter. The country's economic growth rate has stagnated as its competitiveness is hampered by infrastructural bottlenecks, increasing problems with corruption, faltering educational provision, and persistently high unemployment. These developments contribute to a corrosion of the social fabric, thus rendering the country's erstwhile role as Africa's economic powerhouse and diplomatic leader increasingly doubtful.[51]

South Africa's current economic problems are, among other things, inextricably tied to an energy supply crisis.[52] Managed rolling blackouts across the country to avoid a country-wide energy shutdown—what the state energy company Eskom, as well as the South African public and media, refers to as "load shedding"—has become a regular feature of South African life. Load shedding is necessary as Eskom, which currently supplies some 95 percent of all electricity, is unable to supply the energy demanded by private and industry consumers. As load shedding became increasingly frequent, households as well as big companies have been investing in alternate sources of energy

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as they attempt to become less reliant on Eskom. And whereas South African consumers enjoyed the world's cheapest electricity prices prior to 2008, at R0.25 per kWh ($0.03), prices have been rising steadily since 2010 when the government announced annual tax increases of 25 percent to be levied annually until 2013, and then by 8 percent annually until 2018. By 2014, electricity prices had increased by 260 percent to R0.65 per kWh. They are now predicted to rise as high as R1.10 per kWh by 2020, a staggering 440 percent increase on 2008 costs.[53] These price hikes impact significantly on both industry and individual consumers, even if a study commissioned by Eskom argues that South Africa's electricity prices remain "low by international standards and do not yet reflect the full economic cost of supplying power."[54]

Rising energy costs have taken a toll on South Africa's important, politically influential and energy-intensive mining industry, as well as putting pressure on the South African Rand and its credit ratings.[55] Combined with periods of costly labor unrest,[56] the energy crisis has caused serious doubts about the future viability of South Africa's mining industry. Detrimental effects are not limited to interruptions in the daily routines of South African citizens and to the operations of its industries, serious as these are. The crisis also hampers the country's ability to portray itself to international investors as a desirable and cost-effective place to invest. Reporting from the 2015 Invest in African Mining Indaba in Cape Town, the world's premier gathering for the global mining companies seeking to exploit opportunities in Africa, York noted that, "Foreign investors can't avoid the electricity crisis. The shortage is obvious even in their swish Cape Town hotels, where their rooms are often plunged into darkness from rolling blackouts."[57] Improving access to energy and reducing the spiraling cost of producing it is therefore vital to reviving South Africa's flagging economic fortunes.

In addition, South Africa's economy is heavily polluting with a detrimental environmental impact that is severe even when compared to major economies of the Global South, such as China and India. This is a consequence of South Africa's energy-intensive industries and their overwhelming reliance on coal that generates about 90 percent of the country's energy in ageing coal plants that no longer can supply the country with sufficient energy.[58] South African energy experts therefore consider the economic rationale for investing in South African shale gas favorable, as the gas would be used to generate electricity rather than fuel.[59] Recent concerns about the profitability of the shale industry in the United States due to low oil and gas prices may therefore be less relevant in South Africa: shale gas could address its pressing problem of inadequate power supply and steep increases in electricity prices.

Generating electricity from gas would be a step in the right direction in a country with South Africa's almost entirely coal-dependent and energy-intensive industrial profile. Ultimately there are efficiencies to be gained by

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moving from coal to gas that are attractive for reasons beyond economic ones. In his study of the US shale boom, Gold notes the greater efficiency and flexibility of natural gas power plants as compared to coal (and nuclear) plants.[60] The former can easily be switched on and off according to need, as well as run on partial capacity. Moreover, the main problem with renewable energy sources is that they are intermittent as they depend on specific weather conditions (i.e., sunshine and wind). The expansion of renewable power generation will therefore also "drive demand for more gas-fired plants that can turn on and off quickly . . . gas and renewables [thus form] a 'symbiotic relationship.'"[61]

But doubts have also been raised about the potential benefits of shifting the South African economy away from coal toward natural gas, as well as the ability to actually accomplish such a shift. Fig and Scholvin note that gas has been an insignificant contributor to the country's energy mix in the past and suggest it is unlikely to be a significant contributor in the future.[62] South Africa's Integrated Resources Plan, which determines the national energy strategy ahead to 2030, emphasizes coal, nuclear, and renewables rather than natural gas. While South Africa could do more to harness the southern African region's ability to supply it with a range of energy sources—from hydropower to natural gas—there is at present no clear strategy to do so.[63] There are, for instance, no clear plans for supplying the infrastructure necessary to import natural gas from Mozambique and Tanzania once the vast gas reserves of those countries come onstream. Arguably Eskom and the South African government "have already taken a path not related to gas-fired power generation."[64] These are problematic issues that proponents of shale gas exploration in South Africa may choose to discount when making their case to the government and international investors. But they are important issues nevertheless that discerning companies and investors will have to consider when deciding whether South African shale is a viable bet.

Ultimately the potential and desirability of South African shale production remains uncertain. Environmental concerns about sparse water supplies and pollution of the ground water on which farmers in the semi-arid Karoo are dependent for their livelihoods produced a significant "anti-fracking" environmental movement.[65] It is also unclear whether natural gas can act as a "bridge fuel" to a low-carbon economy given the risk of substantial methane gas emissions in hydraulic fracturing operations.[66] For Hedden et al., however, an optimal path toward shale gas production in South Africa could be what they term a "Blue Bridge scenario": a tax regime would be developed to specifically target the funding of renewable sources of energy from the revenues generated by shale production.[67] This would harness the economic benefits of shale and, over the long term, reducing its role as compared to renewables and thereby produce tangible environmental benefits.

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Since the initial excitement about potentially vast reserves of recoverable shale gas in the Karoo, however, more recent developments suggest less encouraging prospects. The precipitous drop in oil prices combined with a glut of oil and gas supplies in global markets cast doubts on the robustness of the American shale revolution, although its more recent resurgence points to a more resilient industry than was anticipated in the doldrums of 2015 and 2016. Lingering uncertainties will, however, shape perceptions of the opportunities and risks of investing in South African shale. Fig and Scholvin note other worries on the horizon too.[68] There may be much less recoverable gas in the Karoo than was initially anticipated. Opposition to hydraulic fracturing among South African civil society organizations and special interest groups might prove unexpectedly resilient, as the experience with promoting shale gas in Britain has shown. Many of the South African government's optimistic prognostications about economic benefits and job creation may simply prove unfounded, or at the very least elusive. There are more questions arising about the prospects for a shale revolution in South Africa than there are answers. But irrespective of whether shale gas will eventually be successfully extracted in South Africa, it is possible to discern something of the complex politics influencing the quest for unconventional energy production in frontier regions like Africa by examining the particular constellation of interests involved in the debates for and against shale production in South Africa.

CURRENT DEVELOPMENTS AND THE POLITICS OF ENERGY

In early 2015, a report in *Oil Review Africa* anticipated that the South African Department of Mineral Resources would shortly publish long-awaited regulations for shale gas exploration.[69] These regulations would then allow for exploration licenses to be granted from July 2015, with actual exploration of the Karoo Basin commencing "immediately thereafter." South Africa stood poised to finally begin the process of properly exploring its shale gas potential after long delays and much hesitation on part of government about how best to regulate oil and gas exploration. These delays included a moratorium on shale gas exploration declared by the government in 2011, only to be rescinded a year later because of concerns about losing a valuable economic opportunity as the US shale revolution was grabbing global attention.[70] Shell South Africa, along with smaller exploration outfits Bundu Oil and Gas based in Johannesburg and Falcon Oil and Gas based in Dublin, had filed applications for exploration before the 2011 moratorium was declared, and were thus hoping to commence exploratory drilling later this year.[71]

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Following the announcement in February 2015 of a R108 million investment in research into the regulatory requirements for licensing shale gas exploration and hydraulic fracturing, the South African government announced in May of that year that regulations would be published imminently. By this time, however, Shell had announced that it was shelving its plans for shale exploration on the 23.5 million acres, or almost 25 percent of the entire Karoo, for which it has applied for an exploration license, due to the falling oil price and on account of being disappointed by the ongoing delays by government to grant exploratory licenses.[72] Having been considered a late entrant into the US shale market where its initial investment of over $24 billion in US shale plays was widely considered a failure, the caution exercised by Shell in pursuing South African shale is hardly surprising. In the words of then Shell CEO Peter Voser, "Unconventionals did not exactly play out as planned,"[73] although the company has since reconsidered its approach and is now aiming to turn shale gas investments in the United States, Canada, and Argentina into "a key engine of growth."[74]

Nor has there been any closure and final clarity on the issue of shale gas regulation in South Africa since. Persistent concerns have been voiced by the oil and gas industry about The Mineral and Petroleum Resources Development Amendment Bill. Initially published for comment in 2012, it has been passed back and forth between Parliament and the President and its most recent version contains some fifty-six additional amendments. The bill proposes a 20 percent "free stake" for the state in any new oil and gas projects. This share would have to be granted by companies even before they can recoup costs and could furthermore be increased at "an agreed price" once a project is profitable, with no upper limit of government ownership being stipulated.[75] The South African Oil and Gas Alliance (Saoga) argues that exploration will prove impossible unless the 20 percent state carry interest is lowered, ideally to 10 percent, as the proposed state stake would threaten the economic feasibility of any South African project in light of an increasingly competitive global environment.[76] According to Teneo Intelligence senior vice president Anne Fruhauf:

> At a time of low oil prices and exploration budgets being slashed, the onus is on governments to put in place clear and attractive investment conditions. . . . The longer the government takes to clarify fracking regulations, the less sense it makes for a company like Shell to maintain anything more than a holding operation in relation to its South African shale project.[77]

While the South African government has largely considered this process a prudent approach to regulating a complex industry of major economic significance and high environmental risk, the oil and gas industry has come

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to view it as characteristic of problems with South African regulation more generally. South African business respondents from the oil and gas industry stand out (together with respondents from Mozambique, Nigeria, and Kenya) in a 2015 *PwC* survey of oil and gas in Africa as particularly concerned about "community/social activism/instability and unstoppable political events" having significant detrimental impacts on their operations.[78] Respondents are also concerned that "uncertain" regulatory frameworks stems from African governments lacking a proper understanding of the industry. Again, this is particularly the case in South Africa where the largest number of respondents in any African country lists uncertainty about regulation (and cost of compliance) as their biggest challenge to doing business.[79] Such concerns are likely to dampen the willingness of energy companies to make a bet on South African shale.

To understand what forces shape decisions on energy policy in South Africa more generally, we need a historical perspective on the country's political economy of energy. The end of apartheid sanctions in the early 1990s and subsequent internationalization of South Africa's major corporations "led to a rapid growth of energy-intensive industries and hence hardened the country's entrenchment in the path of energy-intense industrialization."[80] Long-established and close ties between mining, energy, finance, and manufacturing sectors remain in place. The emergence in the post-World War II decades of rapid industrialization, what Fine and Rustomjee describe as the "minerals-energy complex" (MEC), is crucial to any understanding of these links between politics, industry, and energy in South Africa.[81] The MEC has acted as a conduit, "[providing] domestic and foreign capital with cheap and plentiful coal-generated electricity [that] is no longer economically or environmentally sustainable."[82] It constitutes a vivid picture of key networks of power in the South African political economy, notably the links between finance, parastatals, government, and the private sector.[83]

The Energy Intensive Users Group of Southern Africa (EIUG) is a key factor in the MEC and represents businesses that together account for about 44 percent of South Africa's total energy usage.[84] The EIUG is made up of South Africa's industrial giants—including among others Anglo Platinum, AngloGold Ashanti, Arcelor Mittal, BHP Billiton, Glencore, Lonmin Platinum, SABMiller, SASOL, and Transnet—and remains closely connected to the government. Leading government officials have played various roles on the boards of the EIUG's constituent companies or are otherwise closely involved with them, including the country's deputy president Cyril Ramaphosa who has held numerous executive chairmanships across the South African business landscape and is one of the country's richest men. The EIUG thus remains a "highly influential lobbying organization"[85] due to its "enormous collective bargaining power."[86]

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South Africa's coal industry has a powerful voice in the MEC. Its current difficulties in providing South Africa with sufficient energy would find the industry in direct competition with an emerging shale industry should there be any substantial production of shale gas in the country. The ongoing shift from coal to gas in power generation in the United States resulted in a 10 percent reduction in CO2 emissions between 2007 and 2012, while during that same period lower gas prices as a result of increasing production led to an 11 percent decline in coal production.[87] The South African government pledged at the 2009 Copenhagen Summit a 32 percent reduction in its carbon emissions by 2020 in return for receiving financial support and technical support to accomplish such substantial reductions.[88] Thus the pursuit of shale gas becomes an increasingly attractive, if not straightforward, proposition. The MEC, and the coal-fuelled economy it has produced and sustained, "has been able to resist pressures for more profound change [in energy policy] and to apply the brakes on more radical notions about how to advance a low-carbon economy."[89] It is therefore likely that it would also play an influential role in shaping, and indeed complicate, the possibilities for developing any future shale industry.

While it is not entirely clear how the coal industry will ultimately position itself on the issue of shale gas, any sustained replacement of coal-generated energy with that of natural gas runs counter to its own business interests. Coal is, moreover, very much a part of South Africa's energy future. The government commissioned the construction of the Medupi coal power complex in 2007. Combined, six units will supply South Africa with 4,800 MW of power once they are all completed and online in 2019. However, the Medupi project has been plagued by constant delays (it was initially slated for completion in 2011) and cost overruns (an initial cost estimate of R69 billion has now risen by 223 percent, to R154 billion), further highlighting South Africa's difficulties in resolving the energy crisis.[90] Indicative of the strong backing the coal industry still enjoys in the South African government, a media statement on the future role of South African coal released by the Department of Mineral Resources just days before the Invest in Africa Mining Indaba took place in February 2015 stated that

> the development of a national Coal Policy will reposition South Africa's coal sector back on the global map, and ensure that coal infrastructure requirements are sufficiently considered in the national infrastructure program in order to achieve world-class efficiencies and promote competitive local supply.[91]

The statement also quotes then minerals and energy minister Ngoako Ramatlhodi stating that "coal will remain a significant strategic input to energy security and power generation." Whatever the merits of a shale industry in South Africa,

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it proponents and would-be investors and operators will have to make their case in the face of a strongly positioned coal industry. There may be reasons optimism ahead though, as regards alternatives to coal. An updated Integrated Resources Plan was published for public comment in November 2016 and favors other sources of energy to supply South Africa's base load, especially wind but also natural gas. The Plan envisages that, by 2050, the country's energy generation portfolio will rely on wind for a remarkable 29 percent of total generation, 27.3 percent would come from natural gas and a, by comparison to today, miniscule 11.6 percent from coal. There are, however, doubts about the ability of wind to become South Africa's primary base load supply, and that gas, even assuming shale gas will become economically viable, can eventually contribute more than a quarter of supply. That means that coal is likely to remain a substantial and possibly dominant source of South African energy, especially if carbon capture and storage technologies can be successfully harnessed.[92]

CONCLUSION: WHAT FUTURE FOR UNCONVENTIONAL ENERGY?

Fig and Scholvin consider shale gas a tenuous proposition for South Africa, likely to disappoint across all key dimensions of government assumptions about its outcomes including economic benefits, job creation, and environmental impact.[93] But they also doubt the ability of "anti-fracking" organizations to prevent shale gas exploration from moving ahead as public participation in environmental affairs has been circumscribed following the abolishing of consultative bodies such as The National Environmental Advisory Forum. Debates on these matters are now largely confined to business and government. Describing the proceedings of a technical advisory group tasked with providing inputs into the modeling process for the Integrated Resource Plan for electricity (201–030), Baker et al. note that the group

> was heavily criticized for consisting largely of representatives from coal miners, the EIUG, Eskom, and government . . . a Who's Who of the coal-mining and energy-intensive users in South Africa [failing] to include representatives from the renewables industry, civil society or experts from the fields of social impacts and environmental quality.[94]

Despite the pressures facing the global oil and gas industry, this is ultimately an environment in which the shale industry can expect to receive a fair hearing. This remains the case despite the many concerns about the lack of speed and determination with which the government is proceeding when considering how best to regulate the proposed exploration of shale gas.

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South African president Jacob Zuma has insisted that "it is this government's hope that we will find practical opportunities to enhance the economic opportunities the shale gas sector has to present" and that "[the South African government] continue[s] to pursue the development of an energy mix as energy security is critical to economic growth and social development."[95]

After all, the extractive industries have long dominated South Africa's economic and, by extension, sociopolitical landscape. Much like Texas, South Africa is a country that sees itself as being built on and defined by an enterprising ability to turn natural resources into great wealth. As Houston was built tall and brash by the fortunes of Texas oilmen, so did Johannesburg emerge vertically out of the empty veld on the backs of the African miners that dug the profitable mines of the Randlords. A confluence of power at the intersection of government, energy-intensive industry, and corporate finance has determined South Africa's energy path and seems destined to continue doing so. Shale gas may yet prove a bet both the South African government and the energy companies are willing to take, whatever the ultimate economic, social, and environmental consequences may be.

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Chapter 14

The Environmental Impact of Unconventional Fuels

The Trade-off

Michael C. Slattery

FRAMING THE ISSUE

Everyone uses energy—everywhere, all the time. Being able to supply enough of it safely, reliably, efficiently, and affordably is the basis for a well-functioning society. Think for a moment how much our infrastructures are dependent on just electricity: traffic lights, heating/AC systems, appliances, charging phones, computers—all require a steady flow of electrons. Without exaggerating, I think we can safely say that almost *everything depends on electricity*.

Our dependence upon electricity was driven home to me on a trip to South Africa in 2015. The country was in the midst of an electricity crisis with the national utility, Eskom, overseeing a controversial load shedding (or rolling scheduled blackout) program, which has been in place since November 2014. A ten-year delay in the completion of two, 48 gigawatts (GW) coal-fired power plants, caused by policy indecisions and by execution delays, put an enormous strain on the power grid. The results have been disastrous. Energy intensive mining operations, critical to the South African economy, have been particularly hard-hit. In January 2015, the Bureau for Economic Research (BER) revised down their GDP growth forecast from 2.9 percent to 1.9 percent based solely on Eskom's load shedding schedule. The South African Reserve Bank also revised down its 2015/2016 GDP growth forecast from 2.5 percent to 2.2 percent out of concern over the electricity supply. Businesses, particularly those in the service industry like restaurants, routinely published load shedding schedules online and had to operate around two to three hours of no electricity supply each night. There was a national gas and

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diesel shortage. Although the situation has eased somewhat, the public outcry was widespread.

While the situation in South Africa will undoubtedly improve, my point is simply this: access to electricity is one of the key drivers of economic activity. This much we know. How we get that supply, however, remains controversial and divisive, especially when it comes to the environmental impacts of the various generation technologies. The challenge is made all the more acute when we consider that, by 2050, we will have added somewhere between 2.2 and 2.5 billion more people to the planet. New generating capacity will need to be brought online timeously to match economic and social development.

So, how do we achieve this? Those in the coal industry argue that oil price uncertainty and our continued dependence on foreign sources, safety issues surrounding the storage of high-level nuclear waste, and the intermittency of renewables such as wind and solar justifies our continued investment in coal, particularly so-called clean-coal technologies. The fact that coal deposits are widespread and extensive globally, and still remain the cheapest way to boil water, supports this argument very well. Proponents of nuclear, on the other hand, hope that concerns over climate change will result in growing support for atomic-based power, but skyrocketing costs, long construction times, and high environmental risk suggest that, perhaps, it too is not a long-term solution. There are some clear signs in this regard with Germany, Italy, and Switzerland pledging to phase out nuclear power within a decade. Antinuclear sentiment in Japan remains high following the Fukushima disaster. But there is also growing support for more nuclear power, particularly in the United States, Britain, Russia, and Canada, among others. In November 2013, four highly respected scientists released an open letter calling on world leaders to support the development of safer nuclear energy systems.[1]

To many, natural gas offers the most viable solution for electricity generation in the near-term, especially unconventional shale gas whose reservoirs are ubiquitous both here in the United States and abroad. From an emissions perspective, natural gas makes a lot more sense than burning coal, a topic I will explore later in the chapter, but global demand for liquids is expected to increase to 109 Mb/d by 2035, growth driven exclusively from rapidly growing non-OECD economies such as China and India.[2] Still, others have suggested that bioenergy represents our best opportunity to reduce greenhouse gas (GHG) emissions, but rapid growth in biofuels production will make substantial demands on the world's land and water resources at a time when demand for both food and forest products is also rising rapidly.[3]

Simply stated, there are no easy answers to the question of energy supply. However, there are two things of which we are certain. First, world energy consumption is going to increase, by some estimates as much as 56 percent

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by 2040.[4] Second, liquids will remain the dominant fuel for transportation into the foreseeable future, largely because there are few alternatives to replace them.

In the spirit of full disclosure, let me state that I am vocal proponent of wind power and other renewables, such as hydropower and solar, and have argued that they should continue to be aggressively exploited in locations where that makes sense.[5,6,7] To some extent, their expansion and future role will depend on the degree to which climate change shapes future policy. But I think it is pretty clear that we must decarbonize energy production globally and we must do so, *now*. In this chapter, I will discuss some of the environmental trade-offs that I believe will be necessary as we continue down this path toward a lower carbon future, with unconventional fuel sources, specifically shale gas, the focus of that discussion. While we must invest in renewable technologies, such as wind and solar, and speed up the integration of renewables into our daily lives, I argue that unlocking shale gas, if done responsibly, remains the most viable way forward if we are to make real progress toward reducing carbon emissions enough to significantly slow further global warming.

TO FRACK, OR NOT TO FRACK, THAT IS THE QUESTION

Natural gas is frequently called the "Prince of Hydrocarbons" and is becoming an increasingly important fuel source in the world energy system. It also appears to offer a number of environmental benefits over other sources of energy, particularly other fossil fuels. Emissions from burning natural gas are significantly less than either coal or oil, the former being composed of more complex molecules with higher carbon, nitrogen, and sulfur contents. This means that when burned to produce heat or electricity, coal and oil release higher levels of harmful pollutants, such as nitrogen oxides (NO_x), and sulfur dioxide (SO_2). In fact, compared to coal, natural gas emits roughly half the carbon dioxide (CO_2) of coal per kWh produced and about 25 percent less compared to oil (Environmental Protection Agency, 2015; Energy Information Administration (EIA), 2015). Another advantage of natural gas is that it generates almost no solid waste, unlike the massive amounts of ash from a coal plant, and very little particulate emissions. It is relatively easy to transport and easy to use. Overall, it seems to be a vast improvement over either coal or oil.

The apparent benefits of natural gas raise the question as to why we aren't using a lot more of it to generate electricity rather than continuing to burn

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coal. Well, the simple answer is we are!. Hydraulic fracturing (or fracking), the process used, along with horizontal drilling, to extract unconventional tight natural gas (such as shale gas or coal bed methane) from formations deep underground, is the principle reason for this ongoing switch to natural gas.[8] However, the surge in natural gas production over the past fifteen years from unconventional sources has also been accompanied by public concerns about a number of potential risks to the environment and human health, especially relating to water quantity and quality as well as air quality. In Canada, there are now limits and moratoriums on fracking in several provinces and New York State and Maryland have banned the practice in the United States. A key question that emerges is: Are these concerns valid or are they being overblown by opponents of fracking?

WATER USE

We know that fracking is water intensive (although the average reported water usage per well varies considerably, depending on a number of factors, such as the exact nature of the rock formation, the operator, whether the well is vertical or horizontal, etc.). For example, Nicot and Scanlon[9] quantified net water use for shale gas production using data from the Barnett, Haynesville, and Eagle Ford formations in Texas. These authors found that water use for horizontal wells in the Barnett ranged between 2,900–20,700 cu. m/well (0.75–5.5 Million gallons, Mgal), with a median of 10,600 cu. m/ well (2.8 Mgal), based on approximately 14,900 wells. Fracking water use in the Barnett in one year (2010) alone represented approximately 9 percent of the water used by the city of Dallas. In the Haynesville and Eagle Ford formations, water use ranged between 0.7 and 8.9 Mgal/well. Overall, Nicot and Scanlon[10] estimated that water use for shale gas in Texas is lesser than 1 percent of statewide water withdrawals, relatively minor when compared to withdrawal for irrigation (56 percent) and municipal (26 percent).

Chen and Carter[11] conducted a comprehensive survey of the amounts of freshwater and recycled produced water used to fracture wells from 2008 to 2014 across fourteen states, including Texas. Results showed that the annual average water volumes used per well in most of these states ranged between 1,000 cu. m and 30,000 cu. m (0.26–7.93 Mgal). In total, 929.93 million cu. m (245.7 billion gallons, Bgal) of water was used to fracture 80,047 wells. Texas consumed the most water with 457.42 million cu. m (120.8 Bgal) of water used to fracture 40,521 wells, followed by Pennsylvania with 108.67 million cu. m (28.7 Bgal) of water used to treat 5,127 wells. The median value in water used per well was 11,259 cu. m (2.97 Mgal).

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These numbers appear large, and indeed they are, but as Chen and Carter demonstrate, the percentage of water used for hydraulic fracturing in each state was relatively low compared to water usages for other industries. Encouragingly, more than half of the 2.97 Mgal of water used per well came from recycled wastewater. That said, the *overall* impact of water use for fracking on statewide water resources has yet to be determined with any real certainty. For example, about half of the fractured wells were situated in high or extremely high water stress regions in Colorado and Texas. Projected population growth in states like Texas, coupled with the potential effects of anthropogenic climate change, such as amplified drought and aridity, is likely to only increase demand for this precious resource.

FRACKING AND EARTHQUAKES

There has also been a lot of publicity about the link between fracking and earthquakes.[12] Over the past five years, parts of Oklahoma and Texas have experienced marked increases in the number of small- to moderate-sized earthquakes. There is now widespread agreement among scientists that the majority of earthquakes near drilling operations are not caused by the drilling or fracking process itself (though this can occur), but by those operations' disposal of wastewater, including flow back and produced water, in deep rock formations.[13] A recent study by scientists at Stanford University[14] showed that the increases in seismicity follow five- to tenfold increases in the rates of salt-water disposal which principally comes from produced water—saline pore water that comes out of the ground with the oil and gas that is then injected back into deeper sedimentary formations as waste. The wastewater appears to be causing active faults in the formation to slip, which causes earthquakes. According to Walsh and Zoback,[15] most of the recent earthquakes have posed little danger to the public, but they also caution that the possibility of triggering damaging earthquakes and active faults cannot be discounted. Some have described the spike in earthquakes as a "game changer" for the fracking industry.[16] And in what amounts to an about-face, Oklahoma's state government recently embraced the scientific consensus that the earthquakes impacting the state are largely caused by the underground disposal of billions of barrels of wastewater from the oil and gas wells.[17]

GROUNDWATER CONTAMINATION

The potential effects of fracking on groundwater have been at the center of the debate on the future of unconventional gas development. In December

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2011, the Environmental Protection Agency (EPA) released a draft report of an investigation near the town of Pavillion, Wyoming, conducted in response to complaints by domestic well owners regarding objectionable taste and odor problems in well water.[18] High concentrations of synthetic chemicals, like glycols and alcohols, as well as benzene and methane, were found in groundwater samples from two deep monitoring wells, and the agency announced that the presence of these compounds could only be explained by hydraulic fracturing. The study caused a furor. Opponents of fracking used the Wyoming data as a rallying call to ban fracking in their own communities. However, those in the gas industry (and many in the scientific community) contend that fracking is indeed safe and that, because wells are located in such fine-grained rock with exceptionally low porosities so far below the water table, the likelihood of groundwater contamination is extremely remote. In the case of Pavillion, a tight sand gas field, the fracking took place in and immediately below the drinking water aquifer and in close proximity to drinking water wells—production conditions that are very different from those in most other areas of the United States. This fact was effectively lost in the media frenzy surrounding the Pavillion data. Interestingly, the EPA was supposed to submit their findings to an independent scientific review panel that promised to settle the dispute. That never happened, and the agency instead handed the study over to the state of Wyoming, effectively walking away from the controversy. Industry advocates argued that the EPA had overreached on fracking and that its science was critically flawed. The fact that the EPA was unable to definitively link the chemicals to any release from the gas production wells certainly weakened their case.

Hildenbrand et al.[19] presented an analysis of 550 groundwater samples which they collected from private and public supply water wells drawing from aquifers overlying the Barnett shale formation in Texas. They detected elevated levels of ten different metals and the presence of nineteen different chemical compounds, including benzene, toluene, ethyl benzene, and xylene. Although these scientists were unable to identify fracking as the *direct* cause of contamination, like in the Pavillion study discussed above, the fact that many of the compounds detected are known to be associated with fracking techniques has once again raised concern about the safety of the industry. However, data from many thousands of hydraulic fracturing jobs support the assertion that, if done well, hydraulic fracturing is indeed safe in terms of potential groundwater contamination. Fisher and Warpinksi[20] have shown that hydraulic-fracture heights are relatively well-contained within unconventional reservoirs. These authors mapped real fracture-growth during thousands of fracturing treatments along with aquifer depths in order to determine whether fractures could potentially grow up to the surface and create communication pathways for frack fluids or produce hydrocarbons to

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pollute groundwater supplies. The study by Fisher and Warpinski is an especially important one because they provide definitive evidence of the amount of vertical growth exhibited by hydraulic fractures. They show no method by which a fracture can propagate through various rock layers and reach the surface and suggest that groundwater contamination, while possible, is much more likely to result from wastewaters spilled at the surface or through poor sealing around well casings, rather than the migration of chemicals from fissures within the unconventional reservoirs. This was also confirmed in a study by Werner et al.[21]

METHANE AND CLIMATE FORCING

Finally, let me address briefly the growing concerns about the impact of unconventional natural gas development and production on the atmosphere. As noted earlier, there is no question that carbon emissions (as well as NO_x and SO_2 emissions) from natural gas are significantly lower than those of coal or oil.[22] But CH_4 is an extremely potent GHG, far more effective than CO_2 at "trapping heat" in the atmosphere on a pound for pound basis. The latest The United Nations Intergovernmental Panel on Climate Change IPCC report notes that CH_4 is, in fact, thirty-four times stronger a heat-trapping gas than CO_2 over a hundred-year time scale, so its global-warming potential (GWP) is 32.[23] According to the EIA, although CH_4 emissions account for only 1.1 percent of total US GHG emissions, they account for about 8.5 percent of the greenhouse effect of US emissions based on the GWP.[24]

We tend not to hear much about CH_4 in the general debate over global warming, primarily because the overall volume of CO_2 emissions into the atmosphere is so high. However, several researchers have suggested that the net GHG emissions from shale gas are actually higher than those from coal. Howarth et al.[25] found that between 3.6 percent and 7.9 percent of the CH_4 from shale gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. This would be a significant addition to the atmospheric stock of GHGs. Karion et al.[26] estimated that 8.9 percent plus or minus 2.8 percent of the CH_4 produced in the Unitah basin gas field of Utah was lost to the atmosphere based on airborne measurements, though it should be noted that these data were collected on just one day in 2012. Nevertheless, this is more than twice the average loss rate estimated by Pétron et al.[27] for an oil and gas field in northeastern Colorado in 2008, based on a mix of tower and ground-based measurements and inventory data (average 4 percent; range, 2.3–7.7 percent). Alvarez et al.[28] found that a shift to compressed natural gas vehicles from gasoline or diesel vehicles actually leads to greater radiative forcing of the climate for 80 or 280 years, respectively,

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before beginning to produce benefits. The authors do note, however, that compressed natural gas vehicles could produce climate benefits on all times frames if the well-to-wheels CH_4 leakage were capped at a level 45–70 percent below current estimates. The point is that when results like this are taken into account, scientists argue, emissions associated with shale gas are no better—or may even be worse—than those from coal.

So, do anti-fracking activists have a point when they say that "fugitive emissions"—that is, accidental CH_4 leaks—coupled with routine venting not only reduces the comparative climate advantage of natural gas for electricity generation, but may also make compressed natural gas a questionable choice for fuel-switching in vehicles? They may well, but I think it is also important to acknowledge that there remains considerable debate regarding the extent of GHG emissions from the entire life cycle of unconventional shale gas compared to other fossil fuels like coal. Allen et al.,[29] for example, conducted an extensive study of CH_4 emissions at 190 onshore natural gas sites in the United States. These authors used direct measurements coupled with EPA national inventory estimates and computed 2,300 Gg of CH_4 emissions from natural gas production annually. This amounts to just 0.42 percent of the gross gas production in the United States each year. And in a recent study, Goetz et al.[30] used mobile air monitors to measure emissions from wells, compressor stations, and processing facilities at fourteen Marcellus Shale gas sites and found no evidence of elevated volatile organic compounds although methane levels were identified as being "slightly elevated." Overall, these authors noted a net benefit to the environment in terms of the reduction of greenhouse gas emissions derived from using natural gas for electricity generation instead of coal.

Proponents of natural gas argue that the overall decline in the carbon intensity of US electricity generation is due, in large part, to the ongoing displacement of coal in the energy mix by cleaner-burning natural gas. There is widespread support for this hypothesis among the scientific community. The outstanding paper by De Gouw et al.[31] estimates that, as a result of the increased use of natural gas, CO_2 emissions from US fossil-fuel power plants were 23 percent lower in 2012 than they would have been if coal had continued to provide the same fraction of electric power as in 1997. These authors also showed that the increased use of natural gas led to emission reductions of NO_2 (40 percent) and SO_2 (44 percent) over the same time period. From an emissions perspective, then, it is hard to argue against the notion that natural gas is simply far cleaner than coal. There is an important caveat to this assertion, however: quantifying the total CH_4 leakage associated with natural gas production, distribution and use is a hugely challenging task and, as Moore et al.[32] note, one of several factors confounding our ability to adequately assess the industry's environmental impacts. Polarizing political viewpoints,

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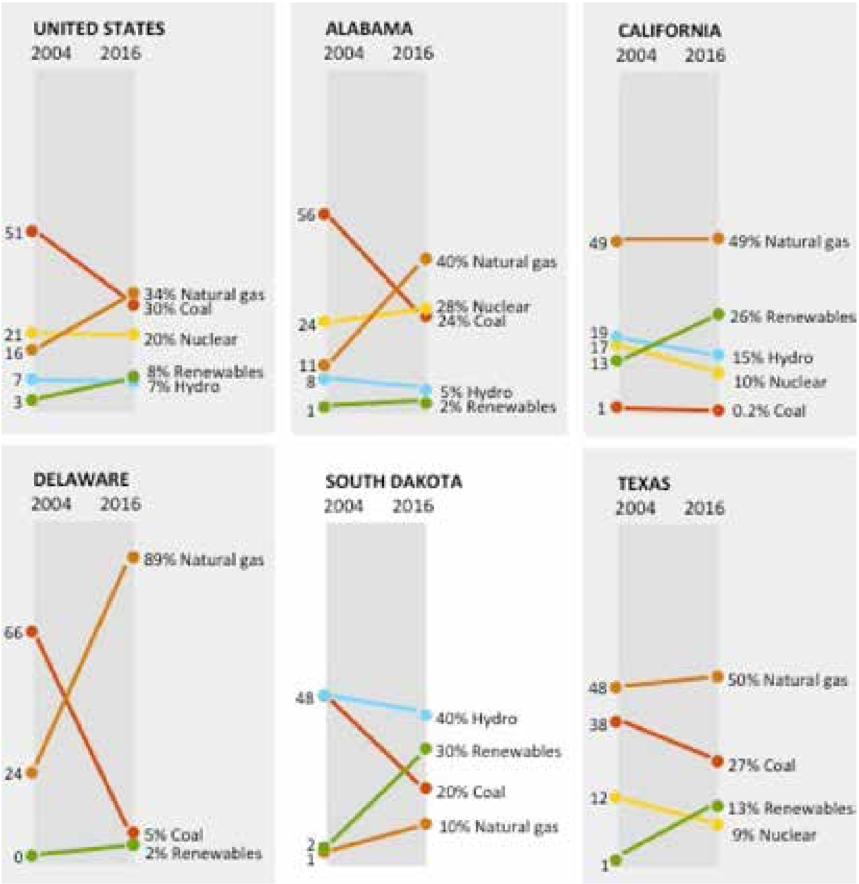

Figure 14.1 Electric Power Generation by Source for the United States, Alabama, California, Delaware, South Dakota, and Texas. *Source*: *US Energy Information* Administration (redrawn from NPR with credit to Christopher Groskopf, Alyson Hurt, and Avie Schneider) (2015).

along with contradictory scientific results, have further impeded our ability to adequately quantify the risks and assess the actual impacts of shale gas extraction. It is absolutely critical, therefore, that we get quality data on the amount of CH_4 leaking at all stages of the natural gas cycle.

CONCLUSION

Many questions remain about the impact of shale gas extraction techniques on the environment. There is simply no clear-cut answer on whether these

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technologies are good or bad per se. While the climate implications of shale gas production are uncertain, I think that, on balance, the reduction in emissions from increased natural gas use appears to outweigh the potentially detrimental effects of increased methane emissions. Thus, the increased use of natural gas in the place of other, dirtier fossil fuels could serve to lessen the emission of greenhouse gases in the United States and elsewhere. Notice that I use the terms "appears" and "could" here very carefully, because the potential benefits to air quality and climate from switching to natural gas must be weighed against the potential increase in emissions of methane, VOCs, and other trace gases that are associated with the production, processing, storage, and transport of natural gas. The issues are not only scientifically complex, but they are also difficult to summarize and communicate in a fair and balanced way to the public who remain divided on whether to support it.[33]

Natural gas is seen by many as the future of American energy. The International Energy Agency (IEA) predicts that the United States could be 97 percent energy self-sufficient by 2035. Scientists and policy makers alike have argued that the shift toward so-called energy independence will rely heavily on unconventional gas (and oil) extraction. Environmentalists will likely bemoan this scenario, but it is naïve to think that we can simply turn our back on fossil fuels in the short term, which is why the Obama administration supported expanding gas development. It is unclear yet exactly what the Trump administration's strategy will be, but I suspect it will undoubtedly focus on moving us from an economy dependent on foreign oil to one that which relies on domestic fuels sources like natural gas, while far from perfect from an environmental perspective, are simply going to be part of that mix for decades to come.

The fact is, all forms of energy production pose environmental risks. Methane leakage may well turn out to be significant enough to reduce the comparative advantage of natural gas for electricity generation, but if natural gas is not going to be embraced as the bridge fuel to the future then, what is? To this end, I call on the natural gas industry to be more open and transparent about hydraulic fracturing, including full disclosure of the fracking fluids and how these fluids are either disposed of or recycled at the end of the fracking process. This will go a long way toward relieving public distrust in the fracking industry.

It is also critical that we account for fuel-cycle CH_4 leakage when considering the climate impacts of fuel-technology combinations. The natural gas industry absolutely can be part of the climate solution. To this end, I urge the industry to help the science community obtain better emissions data by supporting sound, independent research on CH_4 leakage from natural gas infrastructure. Recent reports in the scientific literature and the popular press have suggested that current CH_4 leakage rates are higher than previously

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thought. We simply need better data to validate industry-reported emissions. By taking the lead in this endeavor, the natural gas industry will go a long way toward ensuring a higher degree of confidence in the climate benefits of natural gas fuel-switching. I truly believe that this is essential if the general public is ever going to believe that shale gas development is a safe source of natural gas.

While proponents and opponents of hydraulic fracturing will likely continue to disagree over the potential links between the fracking process, the potential for groundwater contamination, and the magnitude and impact of CH_4 leakage, there is no doubt in my mind that we need to expand shale gas extraction here at home *responsibly*, which should strengthen our energy security, at least in the short term. But we also need to aggressively (and responsibly) develop renewable sources of energy. In this regard, I would hope to see many more wind farms and other renewable technologies built in the central part of the United States where the geography is appropriate.

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Larry Brogdon, board chair and partner of Four Sevens Oil Company, Fort Worth, Texas, has been a practicing geologist since 1974, actively involved in petroleum exploration and production. Four Sevens sold their Barnett Shale properties in 2004 to XTO Energy. In 2006, they sold their newly acquired Barnett acreage and production to Chesapeake Energy and did the same again in 2007. For the last several years, Brogdon has taught the "Prospect to Production" graduate class through the Texas Christian University's (TCU) Energy Institute. He previously served as chairman of the board of advisors to the TCU Energy Institute. The TCU Energy Institute provides unique opportunities for students, faculty, and industry professionals to conduct leading-edge research and to explore energy and land management issues, an educational link between industry and the community and a forum for experts seeking viable solutions. It serves as a center of information as innovative energy technologies and strategies are developed and policies determined.

Manochehr Dorraj, Professor, received his PhD from the University of Texas at Austin. His areas of expertise are in International Relations, International Political Economy, and Energy, and Global Geostrategy. Dorraj has been the recipient of several awards for his research, teaching, and mentoring at TCU. He has published extensively on issues surrounding energy and global geostrategy. He is the author, coauthor, editor, or coeditor of six books, including *China's Energy Relations with the Developing World* (Continuum, 2011), and more than eighty refereed articles and book chapters. He has been invited to present his scholarship in national and international conferences and symposiums, including at John Hopkins, Yale, and Harvard University. And he has been an invited speaker in such think tanks and international organizations as the Hudson Institute and the World Bank. During 2012–2013 he was a Visiting Fellow at Georgetown's Center for International and Regional Studies in Doha, Qatar. Dorraj has granted numerous interviews to international, national, and local media. His commentary has appeared in *The New York Times*, *The Los Angeles Times*, *The Economist*, *The Associated Press*, the *United Press International*, *The Agence France Press*, *The Huffington Post*, and *The Atlantic Post*, among others. He has been interviewed by ABC, NBC, CBS, and PBS television networks. Dorraj is also active in lecture circuits and has delivered many speeches to universities, think tanks, and community groups in the Dallas/Fort Worth area and throughout the United States, Canada, Europe, China, and the Middle East.

Bijan Khajehpour is a managing partner at Atieh International, the Vienna-based international arm of the Atieh Group of Companies, a group of strategic consulting firms based in Tehran, Iran. Khajehpour cofounded the Atieh Group in 1994 to advise international companies on investing in

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Iran. The Atieh Group has been recognized as one of the leading consulting firms in Iran and Bijan is an internationally recognized commentator of Iranian political and economic developments, especially the country's energy sector. International clients of the Ateih Group include a wide range of firms operating in and outside of Iran. Khajehpour is also an editorial board member of the *Persian Review*, *Goftogu* and a regular contributor to *Al-Monitor*. His publications include contributions to *The Caspian Region at a Crossroad: Challenges of a New Frontier of Energy and Development* (St. Martin's Press, 2000), *Iran at the Crossroads* (Palgrave, 2001) *Security in the Persian Gulf: Origins, Obstacles, and the Search for Consensus* (Palgrave, 2002), *L[1]économie réelle de l'Iran* (L'Harmattan, 2014) and *Social Change in Post-Khomeini Iran* (CIRS, 2014). He completed his graduate studies in management and economy in Germany and the UK and his Doctorate of Business Administration at the International School of Management in Paris.

Tatiana Mitrova is Head of the Oil and Gas Department in the Energy Research Institute of the Russian Academy of Sciences . Dr. Mitrova has twenty years of experience in dealing with the development of Russian and global energy markets, including production, transportation, demand, energy policy, pricing, and market restructuring. She is leading annual "Global and Russian Energy Outlook Up To 2040" project. Dr. Mitrova is a member of the Governmental Commission of the Russian Federation on fuel and energy complex, Russian Council on Foreign and Defense Policy and Valdai Club. She is also a member of the Board of Directors in E.ON-Russia JSC. Dr. Mitrova is a graduate of Moscow State University's Economics Department. She is an assistant professor at the Higher School of Economics and Gubkin Oil and Gas University and Visiting Professor at the *Institut d'Etudes Politiques de Paris* (Sciences Po) Paris School of International Affairs. She has more than 120 publications in scientific and business journals and four books.

Isidro Morales Moreno has published extensively on energy, integration, and trade-related topics. His most recent edited book, *National Solutions to Trans-Border Problems: The Governance of Security and Risk in a Post-NAFTA North America*, was published by Ashgate (UK) in 2011. He was Founder Director (2011–2013) of Foreign Policy, Edición Mexicana, a bimonthly magazine edited and published by EGADE, Business School at Tecnológico de Monterrey and Director of the EGAP, Government and Public Policy, Estado de México campus (2011–2013). He is currently research professor at EGAP, Santa Fe campus in Mexico City, contributing expert at the Baker Institute's Mexico Center, and founder and Editor in Chief of Latin American Policy, a biannual journal distributed worldwide by Wiley-Blackwell. He holds a PhD from the *Institut d'Études Politiques de Paris*, France.

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Ken Morgan obtained degrees in geology, environmental engineering, and resource management before starting his career as a professor at TCU in 1978. In 1981, he started and became Director of the TCU Center for Remote Sensing and Energy Research for energy resource mapping. Morgan has lectured extensively throughout the United States, Europe, Asia, and the Middle East about resource mapping, energy technology, and emerging natural gas markets. In 2008, he founded and became Director of the TCU Energy Institute and established an Advisory Board of twenty-four energy companies. Morgan is also the director of TCU's School of Geology, Energy and The Environment. He has published numerous articles on the potential use of domestic natural gas in the United States. He currently chairs the Texas "Metroplex Natural Gas Vehicle Consortium" of over 160 companies and helped lead the successful legislation for the Texas NGV Transportation Triangle, Texas Senate Bill SB-20. He recently met with General Dempsey, Chair, Joint Chiefs of Staff, to discuss using more domestic natural gas at US military installations. Morgan enjoys driving a Honda GX-NGV to help promote natural gas vehicles.

Thomas Murphy is Director of Penn State's Marcellus Center of Outreach and Research (MCOR). With twenty-nine years of experience working with public officials, researchers, industry, government agencies, and landowners during his tenure with the Outreach branch of the University. His work has centered on educational consultation in natural resource development, with an emphasis specifically in natural gas exploration and related topics for the last nine years. He lectures globally on natural gas development from shale, the economics driving the process, and its broad impacts including landowner and surface issues, environmental aspects, evolving drilling technologies, critical infrastructure, workforce assessment and training, local business expansion, resource utilization, and financial considerations. MCOR's mission is to pursue science-based research and understanding for the many issues surrounding the development of shale energy in PA and around the world. This ranges from environmental risk mitigation strategy to legal and regulatory implications of energy development in local communities. As part of MCOR's outreach, examining the role of "social license," and its many components, is a vital feature of the shale dialogue prior to, and during the energy development phase. In his role with MCOR, Tom provides leadership to a range of Penn State's related Marcellus research activities and events. Mr. Murphy is a graduate of Penn State University.

Mike Slattery (PhD, Oxford), Professor at Texas Christian University, is Director of the Institute for Environmental Studies and Lead Scientist on the TCU-Nextera Wind Research Initiative. Originally from South Africa,

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he is an internationally trained geographer and environmental scientist who has written more than eighty scientific articles and a book on environmental issues. In 2007, he testified before the US Congress on mercury contamination from coal-fired power plants. He serves on the editorial board of the *Annals of the Association of American Geographers* and *AIMS Energy*, and on the executive research board of the Botanical Research Institute of Texas.

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