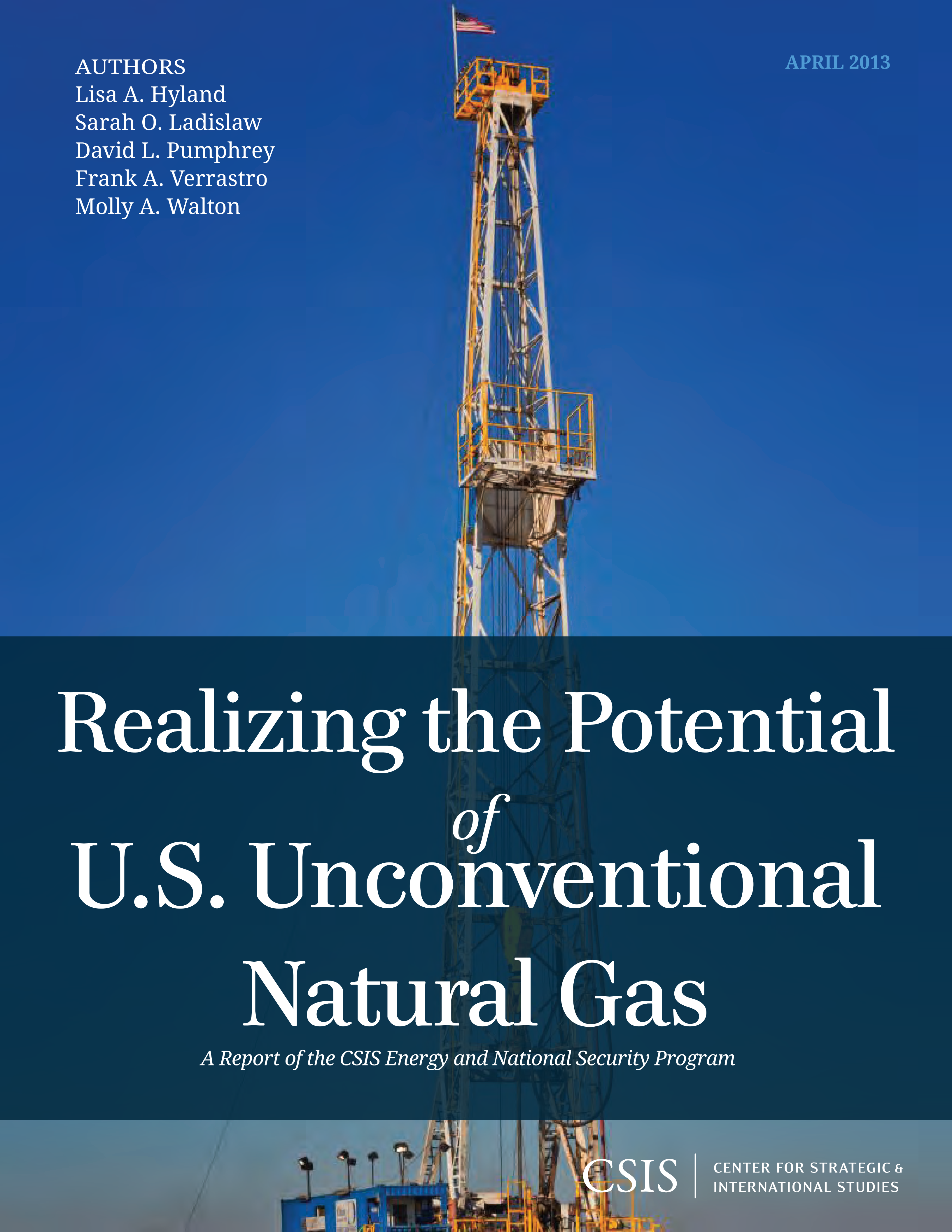

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Realizing the Potential *of* U.S. Unconventional Natural Gas

A Report of the CSIS Energy and National Security Program

CSIS | CENTER FOR STRATEGIC & INTERNATIONAL STUDIES

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This report is the result of a year-long project called the "Project on Realizing the Potential of U.S. Unconventional Natural Gas." Over the course of the past year, we were able—through workshops, in-depth sessions, meetings, phone calls, and outreach—to capture the latest understanding of the unconventional gas development picture and develop themes and findings to facilitate a path forward.

The authors gratefully acknowledge the valuable assistance of their CSIS colleagues throughout this project and the production of this report: researchers Jane Nakano, Leigh Hendrix, and Annie Hudson; and our studious interns Michelle Melton, Mallory LeeWong, Garrett Langdon, Dana Fialova, and Lin Shi.

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Realizing the Potential of U.S. Unconventional Natural Gas

Introduction

The ability of the United States to access and economically develop vast amounts of its unconventional natural gas resources,[1] especially large shale gas formations, has altered the national view of energy and changed the discourse at the federal, state, and local levels. Since 2008, when the economic viability of shale gas resources first became widely recognized, policymakers and industry leaders have worked to better understand the nature of this resource; the risks and opportunities associated with its production, transport, and use; and the potential strategic implications of the United States' new energy reality.

Certain facts are uncontested. First, the resource base is enormous. Current government estimates put the U.S. recoverable shale gas resource base at close to 2,000 trillion cubic feet (Tcf), which represents a nearly 100-year supply at current consumption levels; private and industry assessments run substantially higher. Second, the combination of a reduced demand for electricity and an increased use of natural gas in the power sector has led to lower greenhouse gas emissions (GHGs). Third, new production opportunities (26 basins in 28 states) have contributed to tens of billions of dollars in new investment, economic development, and job creation, and lower relative natural gas prices have aided the economic recovery both by reducing the basic cost of energy inputs for existing gas consumers and by attracting new investment in petrochemical and other gas-related industries in the United States. Finally, in stark contrast with the energy forecasts of as recently as five years ago, the United States is now expected to be capable of becoming a net exporter of natural gas within a decade.

Meanwhile, the location, scale, and operational characteristics associated with shale gas development have prompted heightened public scrutiny, with government, industry, and local communities focusing increasingly on finding ways to maximize the benefits of these abundant resources while effectively managing the associated risks. The public debate now encompasses a number of key areas. Among these are how to manage the risks associated with production, including water protection and use (quality and quantity), air emissions (local and climate change–inducing), seismicity concerns, and health and ecological impacts;

1. Unconventional gas refers to natural gas trapped in low-porosity, low-permeability rock formations that was previously thought to be uneconomic to extract but that can now be produced by a combination of hydraulic fracturing and horizontal drilling. The most common types of unconventional gas are tight gas, coalbed methane, and shale gas. For a full discussion of shale gas and the production techniques, see U.S. Energy Information Administration, "Energy in Brief: What Is Shale Gas and Why Is It Important?" December 2012, http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm.

how to resolve public acceptance issues associated with large-scale production, including landowner compensation, dispute resolution, regulation and enforcement capacity building, and revenue management; what to do with the abundant supplies of natural gas from a demand-side point of view; and how to fit natural gas into the overarching energy policy outlook for the United States. The federal, state, and local community participants engaged in this active public policy debate represent a vast array of environmental, public policy, and commercial points of view.

What is clear is that the landscape for unconventional natural gas is continually evolving as reservoir knowledge, technology, economics, regulations, and community collaboration with operators change. As a result, many of the public policy debates and industry realities are vastly different today from those of only a few short years ago. As a society, Americans are now beginning to experience and analyze the vectors of influence brought about by this development. For example, the same technologies that made unconventional gas production possible are driving a tight oil revolution with similar impacts on and consequences for increased U.S. energy production and reduced trade imbalances and import reliance. Countries around the world are examining the potential to develop their own unconventional gas resources and the potential for technology and knowledge transfer from the United States. Industry players and market analysts are trying to determine how local investment and regional and global markets will be affected by this potential new resource. Valuable natural gas liquids and low-price gas present abundant new opportunities for value added manufacturing in the United States, but pose near-term infrastructure challenges and create temporary price dislocations. Proponents of reducing greenhouse gas emissions for the purposes of climate change mitigation are studying whether and how natural gas can contribute to a long-term vision of emissions reduction. Technologists are looking for ways to deploy new technologies and applications to improve the efficiency, cost-effectiveness, environmental impacts, and broader end use of natural gas throughout the value chain. Finally, industry players of all sizes are trying to anticipate and adjust to a dynamic and uncertain price, regulatory, and policy environment in order to sustain the prudent development of this resource.

The paradox of the U.S. unconventional gas story is that the technologies and industry practices that made it possible have been decades in the making; the public policy and commercial landscape is vastly different from just a few years ago; and the story of this remarkable resource development is still in its infancy. In an attempt to capture the current state of play in resource development, operational practices, risk identification and mitigation, and impact assessment, and to identify strategies that would allow this valuable resource to be prudently developed, the Energy and National Security Program of the Center for Strategic and International Studies (CSIS) undertook this Unconventional Gas Initiative. Over the course of the last year, we were able—in concert with our industry and nongovernmental organization (NGO) supporters—to work with a wide array of regulators, policymakers, environmental, industry, and financial groups, academics, and community stakeholders to capture the latest understanding of the unconventional gas development picture and develop themes and findings that would facilitate an informed discussion about a path forward.

KEY MESSAGES

1. Resource base is enormous and readily available, but industry and regulators are in the early stages of learning how to optimize the value of the resource.

2. Availability of relatively affordable natural gas can create jobs, spur economic growth, and support important manufacturing sectors.

3. Several key domestic energy and environmental policies will drive greater U.S. domestic gas consumption and, along with natural gas exports, can provide an important stabilizing element for gas development.

4. Development risks are manageable today, but understanding risks and evolving cost-effective risk management approaches is a long-term, continuous process.

5. Technology innovation is key to production, risk management, and demand.

6. Public acceptance of unconventional gas development is a critical issue, and the ability to manage risks must be demonstrated.

Why It Matters

Although the shale gas narrative is relatively young, its impact on several sectors and parts of the economy is already evident. The availability of more affordable, lower-carbon, abundant energy matters because it is accompanied by many economic, environmental, and security benefits.

The economic gains of increasing supplies of natural gas have already been manifested as direct and indirect economic benefits: more jobs, the possible revitalization of sagging industrial sectors, and lower electricity prices for many areas of the country. Low-price gas is replacing coal in the electricity sector.[2] Gas can also be exported as liquefied natural gas (LNG), made into compressed natural gas (CNG), and used as a feedstock for petrochemicals and in gas-to-liquid (GTL) facilities.

From an environmental perspective, unconventional gas has a role to play in the transition to a low-carbon future because it emits fewer greenhouse gases than coal, can reduce conventional pollution, and is highly compatible with the more intermittent nature of renewables.[3] Natural gas produces about half of the CO_2 that coal releases when it is burned for power generation. And burning natural gas releases fewer conventional pollutants, such as significantly smaller amounts of nitrogen oxide, which contributes to ozone levels.[4] The ongoing discussion and debate are focused on the potential of methane emissions from natural gas

2. Jeffrey Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity* (Golden, CO: Joint Institute for Strategic Energy Analysis, November 2012), http://www.nrel.gov/docs/fy13osti/55538.pdf.
3. Frank A. Verrastro and Conor Branch, *Developing America's Unconventional Gas Resources: Benefits and Challenges* (Washington, DC: Center for Strategic and International Studies, December 2010), 2, http://csis.org/publication/developing-america's-unconventional-gas-resources.
4. Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector.*

production because methane is a more potent GHG than carbon. (A more detailed assessment of the risk posed by methane emissions can be found later in this chapter and in the appendix.)

As for the impact of unconventional gas on U.S. national security, increased production of indigenous resources would reduce imports, freeing up capital for domestic development and job creation.[5] Similarly, it could enhance security by increasing energy diversity, especially if gas is able to make inroads into the transportation sector.[6] Increased production is already reducing the amount of energy the United States imports, as well as trade imbalances.[7] On a global level, the development of unconventional gas production would increase the amount of LNG available for purchase.[8] However, there are substantial questions about the geopolitical implications of increased U.S. production of unconventional gas and its potential impact worldwide.[9] The combination of transferrable technology and source rock (no geologic risks) means that the potential for the unconventional gas production exists elsewhere as well.

But It Is Evolving

It is clear that unconventional natural gas could have a substantial impact, but the magnitude of that impact remains unclear because the unconventional gas story is evolving. One of the largest challenges facing those attempting to craft effective policy or understand the dynamics of the emerging unconventional gas phenomenon is its ever-changing nature. Much of what has been written, studied, and even understood represents only a snapshot of the story because technology and practices are advancing so rapidly that it has been difficult to keep pace. Indeed, this notion of change and evolution cuts across all components of the unconventional gas story. Regulations, industry composition, technology, practices, and challenges are all changing. Where the United States was just four to six years ago is drastically different from today's landscape.

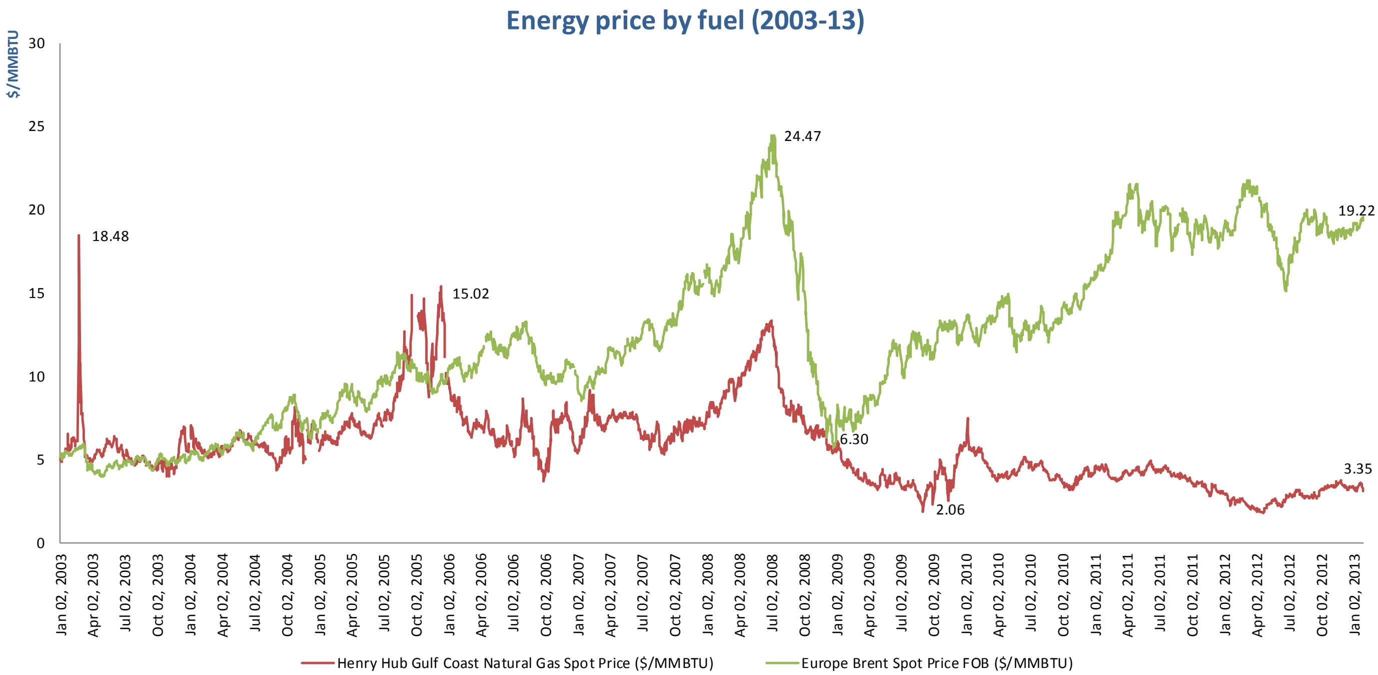
Resource estimates, industry composition, public perception of risk, investment, production capacity, demand, and price have all shifted. The ramp-up in production began in earnest in the early 2000s, led by small, entrepreneurial, independent exploration and production (E&P) companies in the Barnett (Texas) and Fayetteville (Arkansas) shale plays.[10] High prices, improved technologies, and existing infrastructure drew E&P companies to other shale plays across the country such as the New Albany (Illinois, Indiana, Kentucky), Antrim (Michigan), Woodford (Oklahoma), and Marcellus (New York, Pennsylvania, West Virginia) shale plays after the successes achieved with the Barnett and Fayetteville ones. Companies learned with each well that was hydraulically fractured, experimenting with a variety of

5. Verrastro and Branch, *Developing America's Unconventional Gas Resources*, 12.
6. Project on Realizing the Potential of Unconventional Gas, Workshop No. 2: Demand Drivers, Center for Strategic and International Studies, Washington, DC, June 20, 2012.
7. Verrastro and Branch, *Developing America's Unconventional Gas Resources*, 12.
8. Ibid.
9. The CSIS Energy and National Security Program will be looking at these issues in 2013.
10. "Shale Gas: A Supplement to Oil and Gas Investor," *Oil and Gas Investor*, January 2006, http://www.oilandgasinvestor.com/pdf/ShaleGas.pdf.

fracturing treatments and techniques. These improvements in drilling operations and management lessened the amount of time needed to drill a well, improved production rates, and reduced costs.[11]

The price story for natural gas has also evolved. As domestic supplies tightened in the early 2000s, prices rose.[12] However, with the discovery of large amounts of unconventional gas, prices plunged as supply surged and demand could not respond as rapidly. As Figure 1 shows, natural gas prices have also broken a long-standing linkage with crude oil prices. The change in the relative prices of oil and gas is a critical part of the evolution of a new role for natural gas in the economy.

Figure 1. Crude Oil and Natural Gas Prices, 2003–13 ($/million metric British thermal units)



Source: Graph re-created using data from U.S. Energy Information Administration.
Note: FOB = free on board.

As understanding of the resource base, technology, and price of the resource has changed, so too has the composition of the industry. Unlike offshore development, where the number of players is limited to a few big companies, the shale gas industry is large, diverse, and dynamic, with over 7,000 companies, including producers and service companies. Today, bigger companies with a different business model have come into the picture as well. As the

11. Vello A. Kuuskraa, "Economic and Market Impacts of Abundant International Shale Gas Resources" (presentation at roundtable, Center for Strategic and International Studies, Washington, DC, May 5, 2011), http://csis.org/files/attachments/110505_EnergyVello.pdf.

12. U.S. Energy Information Administration (EIA), "Natural Gas Data," http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

price fell, companies with more capital could afford to drill to hold leases but not produce in order to wait for the price of gas to rise, unlike many of the early independents who had to drill and produce to garner enough cash to produce the next well. The success in the North American shale gas plays has caught the attention of national oil companies seeking to invest to gain access to technical and managerial know-how in order to unlock a similar revolution in their home countries. However, the transferability of the "shale gas revolution" experienced in the United States to other countries is unclear.

As companies have progressed, how they manage risk and resources has evolved, and many have become more environmentally sustainable. Such progress is in part a response to unfolding regulations, which have been adapted to recognize this newfound resource. However, part of the industry's response to risk has also been driven by public distrust of industry practices—distrust that if left unaddressed could stymie production. Such public and regulatory scrutiny might be warranted because not all companies have recognized that their risk management strategies must advance. Along the way, certain companies have emerged as leaders, whereas others have not maintained the same level of innovation and foresight. Thus, although the U.S. unconventional gas industry to this point has been highly heterogeneous, it remains to be seen how the composition might change as regulations, practices, and technology evolve.

This notion of evolutionary progress often fails to make its way into the rhetoric surrounding the development of unconventional gas, and often the status of development is judged only on the basis of where it was rather than how far it has moved. This failure is problematic on multiple levels, and it can serve as a barrier to more effective policymaking, data collection, public education and outreach, and industry engagement.

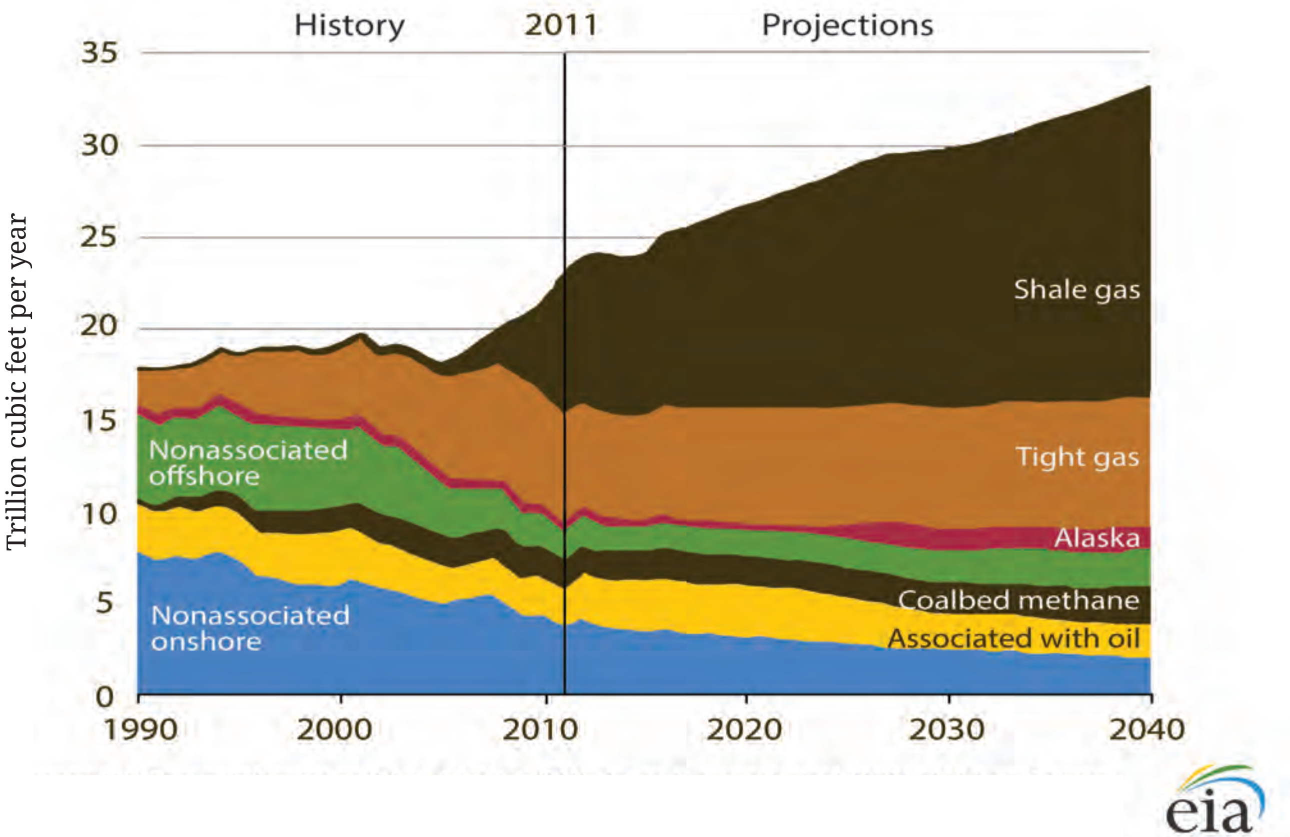
Key Messages

The key messages in this report represent the main findings of a year-long exploration of the current policy, commercial, technological, environmental, and societal landscapes related to realizing the potential of U.S. unconventional gas development. The messages are followed by recommendations for state, federal, and industry players.

Key message 1: *Resource base is enormous and readily available, but industry and regulators are in the early stages of learning how to optimize the value of the resource.*

Unconventional gas production has increased at a remarkable rate in terms of both overall volume and share of total U.S. production. Figure 2 depicts this rapid increase in production as a share of total U.S. gas supplies. Early on, this unanticipated and fast-moving resurgence in domestic gas production gave rise to questions about the long-term viability of the resource base. These questions were further complicated by the fact that markets and infrastructure had to adjust to large and geographically dispersed production increases, as well as a very dynamic commercial environment in which price fluctuations, industry mergers and acquisitions, continual technological and production improvements, and changing regulatory frameworks all made the task of assessing the production dynamics and ultimate recoverability of the resource base difficult to determine.

Figure 2. Increased Contribution of Shale Gas to Total U.S. Supply, 1990–2040 (U.S. dry gas production, trillion cubic feet per year)



Source: U.S. Energy Information Administration (EIA), *Annual Energy Outlook (AEO) 2013: Early Release* (Washington, DC: EIA, 2013).

RECOVERABLE RESOURCE ESTIMATES

North America has both conventional and unconventional natural gas resources. The resource estimates of conventional resources are fairly well understood, whereas understanding of the unconventional resource base continues to evolve.[13] In 2011 the National Petroleum Council (NPC) compiled various academic, government, and industry estimates of the ultimate remaining recoverable resources[14] for the United States and found a range of within 1,000–4,500 trillion cubic feet in the United States and 500–1,250 trillion cubic feet in Canada.[15] According to the NPC, North America's natural gas resource base (which includes shale gas) could meet current demand for nearly 100 years.[16] Within this range of estimates, un-

13. National Petroleum Council (NPC), *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Reserves* (Washington, DC: NPC, 2011), 69.
14. The ultimate recoverable resource is the total amount that will ever be recovered and produced.
15. NPC, *Prudent Development*, 69.
16. Ibid., 10.

conventional gas makes up 60–75 percent (990–2,305 trillion cubic feet) of the remaining natural gas volumes.[17]

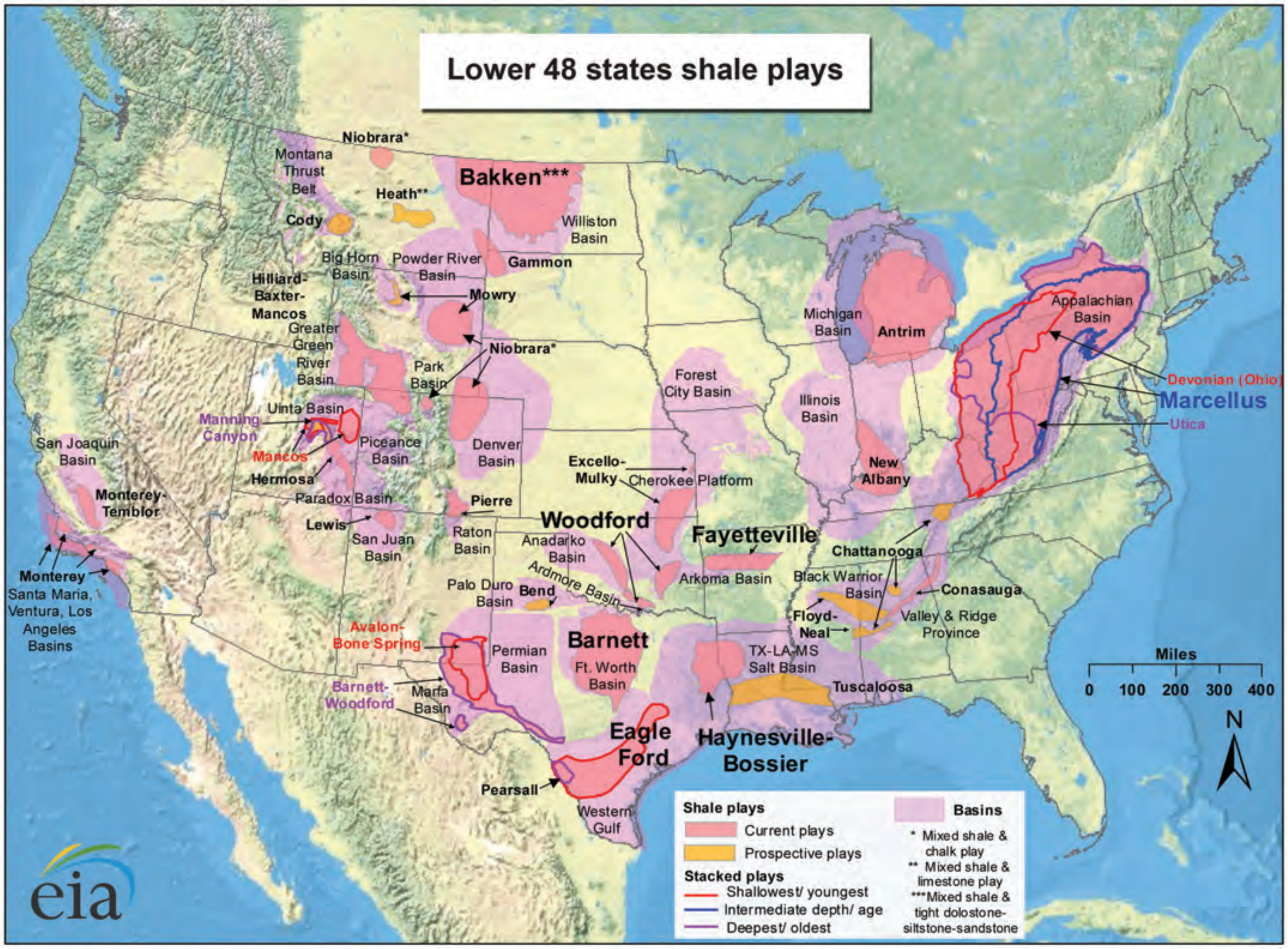
Shale gas is viewed as the most prolific of the unconventional gas resources, amounting to between 700 and 1,800 trillion cubic feet, according to recent industry estimates.[18] In terms of natural gas reserves—a more economically relevant category for the purposes of estimating producible resources—shale gas is becoming a major contributor to the U.S. natural gas reserve base. According to the U.S. Energy Information Administration (EIA), in 2010 shale gas accounted for 44 percent of total U.S. natural gas reserves compared with just 10 percent in 2007.[19]

The ultimate recoverability of shale gas, like that of most energy resources, continues to change as the technology and practices unfold. So far, shale gas resource estimates continue to rise as companies acquire land and develop new acreage. When development first began, resource-related questions had to do with how many unconventional gas plays existed and how many of them could be produced. Over time, the plays grew from a handful of major basins to the 26 well-known plays, covering 28 states, producing gas today. The most active shale plays are the Barnett, Haynesville/Bossier (Louisiana, Texas), Antrim, Fayetteville, Marcellus, and New Albany. As shown in Figure 3, the new plays not only span east, west, north, and south on the map but also occur in deeper geological regions.

Not all shale is created equal, however. The composition of the plays varies widely, both between and within plays in terms of depth, resource characteristics, and ultimate value. For example, wet gas plays contain significant amounts of natural gas liquids (NGLs), and dry gas plays are primarily methane. The Marcellus play contains both wet and dry gas; the wet gas resides in the western part of the play and the dry gas is in the northeastern portion.[20] However, it is not just gas plays that contain NGLs; oil plays also contain significant amounts of NGLs. Because the NGLs can be sold into various markets at oil-linked prices, wet gas is more valuable than dry gas. In some regions, the potential for stacked plays in which one producing zone lies on top of another is furthering the prospects for higher ongoing production. For example, the Utica formation is underneath the Marcellus formation, and the Ordovician formation is underneath both of them.

17. Ibid., 69, 73.
18. Ibid., 73.
19. Calculated using U.S. Energy Information Administration data found at http://www.eia.gov/naturalgas/crudeoilreserves/pdf/table_13.pdf.
20. Marcellus Center for Outreach and Research, http://www.marcellus.psu.edu/images/Wet-Dry_Line_with_Depth.gif.

Figure 3. U.S. Shale Gas Plays, 2011



Source: U.S. Energy Information Administration.

Despite the continual upward revision of shale gas resource estimates over the last several years, a degree of natural uncertainty remains about the ultimate size and production potential of the resource base. According to EIA, many publicly available resource estimates may be based on assumptions about the production profiles and ultimate recovery rates of wells that have limited long-term data because the wells have been in production for only a few years. For example, estimates may not take into account the variability in the recovery rates and production profiles in different parts of the same formation (according to EIA, production rates for different wells in the same formation can vary by a factor of 10).[21]

Various factors can influence estimates of recoverable unconventional gas resources. On the one hand, some early drilling may have taken place in areas that were more productive (so-called sweet spots), thereby biasing the estimates upward. On the other hand, estimates

21. U.S. Energy Information Administration (EIA), "Today in Energy: Geology and Technology Drive Estimates of Technically Recoverable Resources," July 20, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7190.

that do not take into account evolving technologies that allow more cost-effective drilling, hydraulic fracturing, and development practices will tend to underestimate the recoverable resource.[22] As longer production histories in a wider variety of plays become available, the resource estimates will naturally improve. Meanwhile, despite the overarching uncertainty, from a strictly geological perspective there is little doubt that abundant and geographically diverse oil and gas reserves exist and are readily accessible. Moreover, if the history of shale gas production is any indication, technological advances and innovative development techniques will help to increase recovery factors and access to new and emerging plays.

NEAR-TERM BARRIERS TO DEVELOPMENT

Although the resource base is large, production growth is quite predictably constrained by commercial/market and infrastructure conditions that accompany the rapid onset of production, as seen over the last several years. Some members of the public have viewed the slowdown in rig activity or production in a given area as a sign of resource inadequacy when, in fact, normal delays in building the right midstream and end-use infrastructure, along with a period of lower prices and the existence of new gas supplies in oil and liquids-rich gas unconventional plays, have simply curtailed production in these locations for the time being.

In the near term, low natural gas prices and infrastructure lags are the biggest barriers to more expansive natural gas production. Between 2008 and 2011, natural gas wellhead prices dropped from the $8 per trillion cubic feet range to the current price range of $3 per trillion cubic feet.[23] This drop has had a profound effect on the market for gas and overall production activity. In addition, the differential between oil prices and gas prices has prompted drillers to shift rigs toward areas with greater quantities of more valuable natural gas liquids. The price of NGLs (ethane, propane, butane, and natural gasoline) tracks more closely with that of crude oil. The development of gas in these wet gas areas has helped to offset the potential decline in gas production in primarily dry gas areas. Although these commercially dependent production decisions are to be expected, the dynamism in both production decisions and industry players makes it difficult to assess the performance of each resource base.

Building the necessary infrastructure to process and deliver natural gas is also a near-term barrier. Figure 4 shows the existing U.S. infrastructure in place for natural gas that links supply with demand. This network comprises a series of buried transmission, gathering, and local distribution pipelines, processing facilities, and LNG terminals and storage facilities.[24] Historical natural gas production basins located in the Gulf of Mexico, Appalachia, and the Rocky Mountains are connected to the demand centers located in the Northeast, Midwest, and Southeast and on the West Coast.[25]

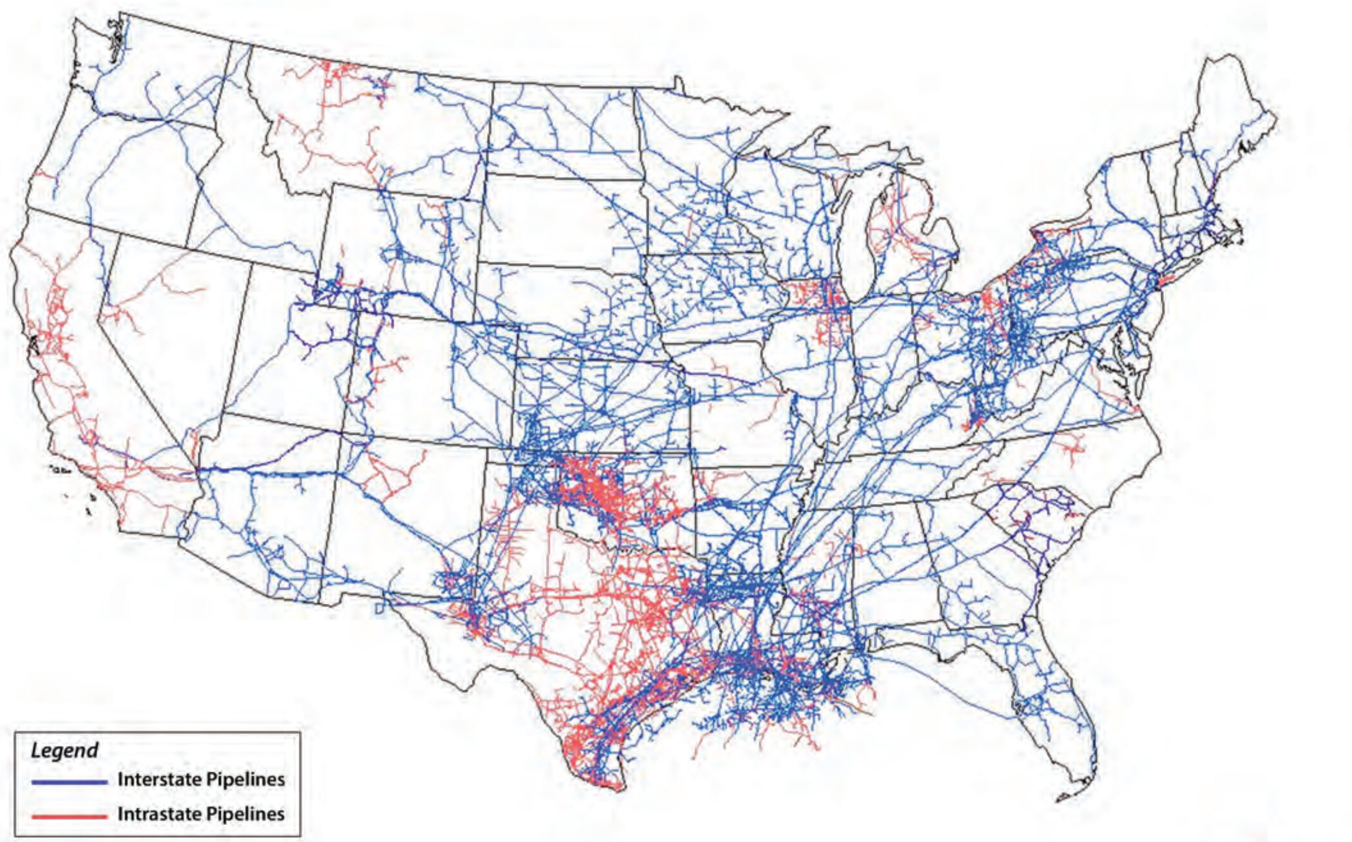
22. U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2011*, http://www.eia.gov/forecasts/archive/aeo11/IF_all.cfm#prospectshale.

23. U.S. Energy Information Administration (EIA), "U.S. Natural Gas Wellhead Price Data," http://www.eia.gov/dnav/ng/hist/n9190us3a.htm.

24. National Petroleum Council (NPC), "Natural Gas Infrastructure," Paper no. 1-9, Gas Infrastructure Subgroup of the Resource and Supply Task Group, September 15, 2011, 3, http://www.npc.org/Prudent_Development-Topic_Papers/1-9_Natural_Gas_Infrastructure_Paper.pdf.

25. Ibid., 4.

Figure 4. U.S. Natural Gas Pipeline Infrastructure



Source: Office of Oil and Gas, Natural Gas Division, Gas Transportation Information System, U.S. Energy Information Administration.

Thus far, the existing regulatory structures and regulations have enabled the development of necessary infrastructure, and the industry has been successful at implementing the necessary infrastructure in response to signals from the market.[26] However, production is occurring in areas that have not previously been major suppliers and so will require the development of new infrastructure to ensure that supply reaches the demand centers. Moreover, much of the necessary infrastructure build-out will occur in areas of high population density. Even in areas that already have a pipeline and infrastructure, more capacity may be needed.[27]

The change in production patterns has altered the flow of natural gas in the United States. Production from the Marcellus play is supplying the East, displacing flows from the Gulf and West. Gas that used to head eastward is now being utilized in the Midwest and West, adding to supply.[28] The continental market for natural gas is becoming more integrated with the increase in and greater dispersal of supply centers.[29]

26. NPC, *Prudent Development*, 52.

27. Ibid., 52.

28. MIT Energy Initiative, *The Future of Natural Gas: An Interdisciplinary Study: Interim Report* (Cambridge, MA: Massachusetts Institute of Technology, 2010), 136, http://web.mit.edu/mitei/research/studies/reportnatural-gas.pdf.

29. IHS Global Insight (USA) Inc., *The Economic and Employment Contributions of Shale Gas in the United States*, (Washington, DC: IHS Global Insight, December 2011), 14.

The United States currently has approximately 38,000 miles of gas-gathering infrastructure and 85 billion cubic feet (Bcf) per day of processing capability.[30] However, investment will be needed in midstream infrastructure, including gathering systems, processing plants, transmission pipelines, storage fields, and LNG terminals, to ensure delivery and a functioning market. Lack of infrastructure could introduce price volatility, delivery bottlenecks, and stranded supplies.[31]

All of this new production and infrastructure will require large investments, which will vary by region. The National Petroleum Council cited the finding by the Interstate Natural Gas Association of America (INGAA) that North America will need an average investment of $8.2 billion per year out to 2035 to account for the increased production of natural gas.[32] The cost of new natural gas transmission infrastructure (including storage/lateral connections) and processing facilities (including liquids separation) is estimated to exceed $160 billion by 2035.[33] Although much of the existing pipeline capacity can be used to move gas to market, it will still require more than 414,000 miles of gas-gathering lines to be constructed and nearly 35,600 miles of new transmission pipelines to be built.[34]

In addition, as more producers seek to develop shale gas resources that are rich in valuable NGLs, more investment will be needed in gas processing facilities near the areas of production,[35] and pipelines may have to be built to transfer NGLs to already established markets.

Building large amounts of infrastructure over short periods of time is often met with heightened regulatory scrutiny and public opposition. Midstream infrastructure requires detailed planning and long lead times, as well as a variety of permits, all of which can create a time lag in the build-out. For example, lack of pipeline capacity may also affect development in the Marcellus play, which will require an extensive build-out of interstate pipeline capacity to transport shale gas to market. Gas processing capacity is also immature in the Marcellus play.[36] Marcellus development is close to demand centers so that transport costs will be lower, but it is also more densely populated, which often makes siting new infrastructure more challenging.[37]

Finally, infrastructure needs are not limited to just the production and distribution of natural gas; they also include the related infrastructure, including water and waste management treatment. Many plays do not have adequate infrastructure in place to deal with the surge in produced water in need of treatment. For example, several of Pennsylvania's municipal wastewater treatment plants were not equipped to process the high levels and type of

30. MIT Energy Initiative, *Future of Natural Gas*, 160.
31. NPC, *Prudent Development*, 51.
32. Ibid., 52.
33. INGAA Foundation Inc., "North American Natural Gas Midstream Infrastructure Through 2035: A Secure Energy Future," June 28, 2011, 6, http://www.ingaa.org/File.aspx?id=14911; NPC, "Natural Gas Infrastructure," 25.
34. NPC, "Natural Gas Infrastructure," 25, 29.
35. Ibid., 30.
36. NPC, *Prudent Development*, 141.
37. NPC, "Natural Gas Infrastructure," 16.

wastewater produced by shale gas operations.[38] Therefore, moving forward, infrastructure planning will also need to assess what other types of assets might be needed to aid development in the most sustainable way possible.

The development of shale gas operations can also place new demands on the existing social infrastructure such as housing, schools, and other community services. The influx of new workers and the associated wear and tear on community infrastructure and services also tie heavily into concerns about the impacts on communities. Some communities will be better equipped to handle these changes than others.

All of these barriers are natural features of any market with this scale and pace of development, and many are temporary. Over time and with a longer production history, knowledge of the resource base and its responsiveness will only improve. Over the last several years, as shale gas development has continued to grow, doubts about the abundant nature of the resource base have already begun to abate. It is now widely recognized that the resource base is large and readily accessible. The challenges going forward are to better understand the performance of the resource over time and to manage the challenges and opportunities that accompany the associated infrastructure build-out.

Key message 2: *Availability of relatively affordable natural gas can create jobs, spur economic growth, and support important manufacturing sectors.*

The increased production and availability of natural gas have the potential to make significant economic contributions to the U.S. economy in terms of both direct and indirect employment and broader macroeconomic effects. If sustained, the increased availability of natural gas at relatively low and stable prices is forecast to result in sector-specific economic gains, such as in the petrochemical, steel, and other energy-intensive industries, as well as indirect economic effects that will spread throughout the broader economy.[39]

According to one recent estimate, the direct and indirect activities related to new hydrocarbon (oil and gas) production, along with lower consumption, could increase the U.S. real gross domestic product (GDP) by 2–3.3 percent by 2020.[40] Another estimate, based on a different model that looks only at natural gas, suggests that U.S. GDP will be between 0.6 percent (conservative) and 2.1 percent (optimistic) higher as a result of unconventional gas production between 2013 and 2020.[41] It is important to note that it is difficult to differentiate the

38. Robbie Brown, “Gas Drillers Asked to Change Method of Waste Disposal,” *New York Times*, April 19, 2011, http://www.nytimes.com/2011/04/20/us/20gas.html.

39. Because unconventional gas has been having an impact on the economy for several years, many of the existing economic implications scenarios are based on projecting counterfactual scenarios and assessing the opportunity costs for the development of shale—that is, where capital and labor might have gone without the shale gas revolution.

40. Edward L. Morse, “Energy 2020: North America, the New Middle East” (presentation given at Center for Strategic and International Studies Global Security Forum 2012, Washington, DC, April 11, 2012), http://csis.org/files/attachments/120411_gsf_MORSE_ENERGY_2020_North_America_the_New_Middle_East.pdf.

41. From a forthcoming study by Trevor Houser, *Fueling Up: The Economic and Environmental Implications of America’s Oil and Gas Boom* (Washington, DC: Peterson Institute for International Economics, forthcoming), chap. 5, 17. As Houser points out, this estimate is comparable to the effect of the American Recovery and Reinvestment Act of 2009.

economic gains achieved through oil versus gas production because oil production is often accompanied by associated gas production, which can be captured and marketed (similarly, some natural gas production includes valuable oil price–linked natural gas liquids that are separated from the gas stream and sold for a variety of end-use applications).

Natural gas production provides economic benefits in three primary ways. First, it creates jobs. Differences in methodology and definitions have resulted in varied job estimates. For example, the overall net effect on the labor market is heavily influenced by assumptions about the natural rate of unemployment in the economy.[42] The estimates for job creation from unconventional gas industry vary. CITI Group estimates 2.2–3.6 million more net jobs by 2020. IHS CERA estimates total jobs (direct, indirect, and induced) to be 1 million in 2010, 1.5 million in 2015, and 2.4 million in 2035. And finally, a forthcoming study from the Peterson Institute for International Economics estimates an additional 0.8–2.5 million jobs by 2020.[43] Although the majority of direct jobs will be in states with unconventional gas production, indirect and induced jobs will boost employment across the entire supply chain.[44]

Second, lower natural gas prices have an impact on the economy through lower basic energy costs. Lower costs benefit industrial consumers of natural gas as a feedstock, consumers of electricity, and residential and commercial consumers of natural gas for heating and cooking. In fact, lower natural gas prices resulting from the increased production of shale gas have already led to more stable electricity prices for both individual and corporate consumers. In turn, lower electricity costs have increased consumer purchasing power, affecting all sectors of the economy.

Lower prices could have a significant impact on industries that consume large amounts of energy. For most industries, though, the reduction in energy costs will have only a marginal impact on their bottom lines. Even within the U.S. manufacturing industry, for example, only about 10 percent of firms have both energy expenditures greater than 5 percent of the value of their output and serious exposure to foreign competition.[45] In percentage terms, expanded output from this segment of manufacturing will have a modest impact on total employment. Less than one-half of 1 percent of U.S. workers are in manufacturing industries in which the price of electricity affects their competitiveness. In times of significant unemployment, however, these new jobs can play an important role in creating opportunities for expanding the job base.

42. If there is surplus labor and capital in the economy, new investment is less likely to take capital and labor away from existing sectors through higher interest rates. High levels of unemployment mean that the increased demand for workers will generally not result in wage inflation across the broader economy.

43. Morse, "Energy 2020"; IHS Global Insight, *Economic and Employment Contributions of Shale Gas in the United States*; Trevor Houser estimates an additional 0.8–2.5 million jobs in his forthcoming report *Fueling Up*, chap.5, 17.

44. There are several barriers to increased job creation from expanded natural gas production, at least temporarily. A significant barrier is a structural challenge in the labor market. Labor mobility is limited because of ongoing issues in the housing market. The result is that workers who would normally move to take advantage of job opportunities in natural gas production may not be able to do so.

45. W. David Montgomery et al., *Macroeconomic Impacts of LNG Exports from the United States* (Washington, DC: NERA Economic Consulting, December 2012), 2, http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf.

Finally, low gas prices and abundant supplies have allowed the United States to regain a competitive advantage, particularly in chemical manufacturing. As a result of lower natural gas prices, several major companies have announced intentions to build chemical production capacity or expand the existing production capacity in the United States.[46] The chemical industry stands to benefit from cheaper natural gas prices because it has both high energy costs and uses natural gas and NGLs directly as a feedstock (feedstock costs make up a significant portion of the cost structure in the chemical industry).[47] In 2006 the chemical sector used nearly a quarter of all fuel and nonfuel energy in the manufacturing industry.[48] As the price of natural gas has dropped, U.S. natural gas–based feedstock has once again become competitive with that of other regions with low feedstock costs, such as the Middle East, putting the United States in a beneficial position relative to chemical producers in Asia and Europe who rely on higher-cost naphtha.

Should natural gas prices remain low and stable enough to allow U.S. chemical manufacturers to remain competitive, there could be enormous economic benefits. In addition to the direct impact of lower input prices, low natural gas prices could fundamentally change market demand for plastics and encourage the long-term substitution of plastics for other materials.[49]

The long-term economic impact of cheaper natural gas prices could be significant, but whether these gains materialize depends on a variety of policy and economic factors. Assessments of the economic gains must account not only for the outlook for the medium- and long-term price and price stability of natural gas, but also for its price relationship with oil, the price elasticity of natural gas (and therefore not just the absolute price but the price of natural gas relative to its competitor products), policy changes such as natural gas exports and emissions targets, technological breakthroughs, interest rate changes, and the relative position of the U.S. dollar. Changes in any one of these areas could potentially affect the scope and scale of the impact of natural gas on the U.S. economy.

Currently, the indirect effects of natural gas on the economy are larger because of the existing slack in the capital and labor markets. The indirect economic impacts of natural gas are likely to be sustained because production requires long-term investments. Production is also expected to have an indirect impact by contributing to GDP and job growth, and it will be a revenue generator for federal, state, and local treasuries.

The macroeconomic implications of the shale gas revolution are still unfolding, and the long-term economic impact of increased natural gas production depends on price and price stability in both the United States and the rest of the world. If natural gas prices remain low in the United States, U.S. consumers and the U.S. manufacturing industry will reap long-term benefits. The size and scope of these benefits will depend not only on price but also on global economics, policy decisions, and technological innovation.

46. "Saudi Firm Wants to Invest in US Feedstocks," *EnergyWire EE News*, December 3, 2012, http://www.eenews.net/energywire/2012/12/03/.

47. IHS Global Insight, *Economic and Employment Contributions of Shale Gas in the United States*, 36.

48. Based on EIA data for 2006 Energy Consumption by Manufacturers, http://www.eia.gov/emeu/mecs/mecs2006/pdf/Table1_2.pdf.

49. PricewaterhouseCoopers (PWC), "Shale Gas: Reshaping the US Chemicals Industry," October 2012, 13, http://www.pwc.com/en_US/us/industrial-products/publications/assets/pwc-shale-gas-chemicals-industry-potential.pdf.

***Key message 3:** Several key domestic energy and environmental policies will drive greater U.S. domestic gas consumption and, along with natural gas exports, can provide an important stabilizing element for gas development.*

Rapid development of unconventional natural gas resources has created a situation in which productive capacity has exceeded demand, leading to low prices in the market place. The demand for natural gas has not been able to adjust to this reality, thereby raising the concern that investment in natural gas will drop significantly. The realization that the United States has an abundant unconventional gas resource base has stimulated discussion of how these resources might be utilized to meet strategic policy objectives. Some of the suggested strategic uses for U.S. gas include increasing the use of gas as a transportation fuel to reduce reliance on gasoline and diesel fuel; promoting more gas in combination with renewables in the power sector to drive down greenhouse gas emissions; exporting LNG as a way to increase export earnings and to help alleviate geopolitical tensions surrounding the gas trade; and, as mentioned earlier, revitalizing the U.S. manufacturing base and improving industrial competitiveness.

In reality, future gas demand is being driven by a variety of existing and proposed policy and regulatory mechanisms, as well as commercial factors that will, all else being equal, increase the domestic consumption of gas. According to analysis conducted by ClearView Energy Partners, the existing policies could result in increased consumption of natural gas in the United States of about 13 billion cubic feet per day by 2018, representing about 18 percent of U.S. gas consumption in 2018 as projected by the U.S. Energy Information Administration.[50] These drivers of demand are summarized in Table 1.

Table 1. Incremental Demand, Sunny Day Scenario: United States

Demand options	Example users	Potential impact (Bcf/day)
Transportation	CNG/LNG transportation	0.92
Generate	Power plants	5
Export	LNG	5.4
Convert	F-T liquids/methanol/DME	1.3
Refine	NSPS-compliant process fuel	2
Manufacture	Process fuel or feedstock	2.16
Incremental demand: 17.1 Bcf/day by 2018 (13 Bcf/day beyond current power fuel switching)		
Total consumption: 73.1 Bcf/day by 2018		

Source: Project on Realizing the Potential of Unconventional Gas, Workshop #3: Policy Pathway Forward, December 13, 2012, CSIS.

Note: CNG = compressed natural gas; LNG = liquefied natural gas; F-T = Fischer-Tropsch; DME = dimethyl ether; NSPS = New Source Performance Standards; Bcf = billion cubic feet.

50. U.S. Energy Information Administration (EIA), *Annual Energy Outlook (AEO) 2013: Early Release* (Washington, DC: EIA, 2013), http://www.eia.gov/forecasts/aeo/er/pdf/0383er%282013%29.pdf.

Numerous studies are being conducted to evaluate and advocate for specific solutions and policy drivers for gas end use. At the core of these studies are two key questions: How will the U.S. gas supply base respond to increasing gas demand? And will greater gas consumption, either domestically or exported, drive gas prices up to levels that will erode some of the economic advantages created by gas as described earlier in this report? The most recent and comprehensive of these studies focuses on the question of the economic impacts of natural gas exports.[51]

Until recently, the United States was projected to be a major importer of LNG. However, the discovery of abundant domestic resources and low prices has changed this trajectory. The U.S. Energy Information Administration reference case forecast projects net LNG exports by 2016 and net natural gas exports by 2022.[52] As of December 2012, 15 LNG export applications were awaiting authorization from the U.S. Department of Energy (DOE), with one facility already approved and scheduled to begin shipping LNG to any country in the world in 2015. If all of these projects were to proceed, the maximum total volume of exports would amount to almost 24 billion cubic feet per day.[53] Although there is a wide range of estimates of eventual export levels, many studies indicate a range of 5–7 billion cubic feet per day export capacity over the next decade in view of the permitting uncertainty and timelines, financing hurdles, economic viability of these projects, and competition from other LNG suppliers.[54]

The resulting domestic policy discussion has focused on the impact that exports would have on the domestic price of natural gas. There has been substantial pushback on the export of LNG, especially from sectors that fear that exports will drive up the price of natural gas and make the U.S. gas market more volatile, eroding any sense of competitive advantage.[55] Various studies have looked at the impact U.S. exports would have on the domestic price.[56] The recently released study commissioned by DOE, *Macroeconomic Impacts of LNG Exports from the United States,* concluded that LNG exports would have a net positive impact on the U.S economy in all demand and supply response scenarios, would have limited impacts on natural gas prices, would be unlikely to produce export volumes at the larger end of the spectrum, and would create both winners and losers in certain conditions.[57] The study's conclusions have sparked an ongoing debate over the studies' assumptions and methodology.

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51. Montgomery et al., *Macroeconomic Impacts of LNG Exports from the United States*.
52. EIA, *Annual Energy Outlook (AEO) 2013: Early Release.*
53. Jane Nakano, "Next Steps for U.S. Natural Gas Exports," *CSIS Commentary*, December 17, 2012, http://csis.org/publication/next-steps-us-natural-gas-exports.
54. Michael Levi, "A Strategy for U.S. Natural Gas Exports," Discussion Paper 2012-04, Hamilton Project/Brookings Institution, Washington, DC, June 2012, http://www.brookings.edu/~/media/research/files/papers/2012/6/13%20exports%20levi/06_exports_levi.pdf.
55. Ibid.; Nakano, "Next Steps for U.S. Natural Gas Exports."
56. Montgomery et al., *Macroeconomic Impacts of LNG Exports from the United States*"; Levi, "Strategy for U.S. Natural Gas Exports;" Deloitte MarketPoint LLC and Deloitte Center for Energy Solutions, "Made in America: The Economic Impact of LNG Exports from the United States," 2011, http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_MadeinAmerica_LNGPaper_122011.pdf ; Kenneth B. Medlock, "U.S. LNG Exports: Truth and Consequence," James A. Baker III Institute for Public Policy, Rice University, Houston, August 10, 2012, http://bakerinstitute.org/publications/US%20LNG%20Exports%20-%20Truth%20and%20Consequence%20Final_Aug12-1.pdf.
57. Montgomery et al., *Macroeconomic Impacts of LNG Exports from the United States*.

Currently, supply prospects are outpacing demand. Despite a wide variety of possibilities for gas demand in addition to exports (avenues of demand include transport, electricity generation, manufacturing needs, and use in refineries), counteracting forces may affect the ultimate level of demand. Such factors include economic considerations such as the domestic financial and fiscal stalemate; the fight between domestic fuel sources and their attendant economic and political overlays (coal, biofuels, etc.); and the potential for upcoming policies in both the transportation sector—biofuels, CAFE standards, advancement in vehicle technology (electric and hybrids)—and the electricity sector—renewables standards, federal GHG standards, efficiency gains, and other industrial efficiency policies—that would either bolster or destroy the demand for natural gas.

One of the biggest uncertainties in natural gas future demand scenarios is the mechanism for and the rate of adoption of new technologies. This is particularly true in the transportation sector, where the debate between product development and infrastructure development continues. The debate has centered on how to develop natural gas vehicle technologies and fuel distribution systems so that they happen on the same time scale. Some organizations are making limited investments in projects such as LNG corridors for heavy trucking, but have not found a way to properly give consumers the incentive to make the upfront capital investment in a new product that has not yet been proven in the marketplace. Infrastructure may emerge as big companies (e.g., UPS, FedEx, and Frito Lay) make a transition to a natural gas–powered fleet. Challenges remain, however, including conversion costs, labor availability, regulatory and tax standards, energy content, driving radius, resale market uncertainty, and safety. Several recent studies have concluded that the internal combustion engine, with an increasing trend toward hybridization, will continue to dominate the market for light-duty vehicles.[58]

Historically, the boom-bust price cycle has posed a challenge for energy production. At the high end of the price cycle, companies will use higher revenues to invest in greater production while consumers are lowering their demand levels in response to higher prices. The resulting oversupply can cause prices to fall, and energy companies begin to reduce investments and supply while consumers increase demand. Historically, these cycles have at times resulted in large changes in prices because gas development projects, such as those offshore, often involve long lead times and major investment.

A key feature of shale gas development has been the ability to bring new gas production on line within a relatively short time frame, especially in areas with developed infrastructure. Because these resources are well known, stacked, and continuous, the risk element common to other oil and gas operations is also much lower, and the opportunity for long-term investment is greater. In fact, shale gas development has become similar to a manufacturing process in which great attention is paid to the lower marginal costs of operation. These features offer the possibility that shale gas production levels will be responsive to

58. NPC, *Advancing Technology for America's Transportation Future* (Washington, DC: NPC, August 2012), http://www.npc.org/FTF-80112.html; International Energy Agency (IEA), *World Energy Outlook 2012* (Paris: IEA, 2012); EIA, *Annual Energy Outlook (AEO) 2013: Early Release*; ExxonMobil, *The Outlook for Energy: A View to 2040* (Irving, TX: ExxonMobil, 2013), http://www.exxonmobil.com/Corporate/Files/news_pub_eo2013.pdf.

positive price signals.[59] The rapid increase in gas production in response to high prices in 2007–08 was not balanced with increases in demand and created the current oversupply situation.

All else being equal, it appears that the drivers of greater gas demand in play today, along with the uncertainty that comes with the adoption of new technologies that can have transformative effects on both the production and the demand sides, have created an important stabilizing role for gas development in the near and medium term. Although the political rhetoric surrounding this discussion appears to be balancing a scarcity versus an overabundance mindset, it appears that the supply and demand dynamics on the table are likely to have a stabilizing effect on an industry that has recently experienced a period of extreme volatility. The policy factors that will drive gas demand will serve as an important base for absorbing this production capability and send producers the right signal to continue investment in new productive capacity and the necessary infrastructure build-out.

Key message 4: *Development risks are manageable today, but understanding risks and evolving cost-effective risk management approaches is a long-term, continuous process.*

The rapid onset of unconventional gas production has raised concerns about the potential environmental and social impacts of its development.[60] A variety of factors are all part of the fabric of the risk mitigation landscape. These factors include the application of various drilling technologies and operational practices in proximity to local water resources; the industrial footprint, including noise, air emissions, and infrastructure demands; the potential for induced seismicity resulting from drilling or wastewater injection; the management of chemicals and water resources; the potential impact on health; the capacity of regulators to create and enforce appropriate oversight of industrial activity; and the ability of companies to operate in ways that minimize risks through the use of innovative technologies and recommended practices,. Public concern about the proper management of unconventional gas development has been an important driver of public policy and commercial practices in this sector. A number of studies have been completed, and many more are still under development at the federal, state, and local levels to analyze the various risks associated with production and assess the capabilities of industry and regulators to respond to public concerns and manage these risks going forward. Seminal studies already completed include:

- *Prudent Development,* National Petroleum Council[61]
- *Future of Natural Gas,* MIT Energy Initiative[62]

59. Medlock, "U.S. LNG Exports," 15.
60. U.S. Department of Energy (DOE), "Second Ninety-Day Report," Secretary of Energy Advisory Board (SEAB), Shale Gas Production Subcommittee, November 18, 2011, http://www.shalegas.energy.gov/resources/111811_final_report.pdf.
61. NPC, *Prudent Development.*
62. MIT Energy Initiative, *Future of Natural Gas.*

- "Ninety-Day Report," Secretary of Energy Advisory Board (SEAB), Shale Gas Production Subcommittee, U.S. Department of Energy[63]
- "Second Ninety-Day Report," Secretary of Energy Advisory Board (SEAB), Shale Gas Production Subcommittee, U.S. Department of Energy[64]
- *Golden Rules for the Golden Age of Gas*, International Energy Agency (IEA).[65]

Each of these studies concluded that the risks associated with unconventional gas production were manageable, but that proper regulation and improved industry practices were necessary to ensure proper conduct.

Within this universe of possible impacts, public debate seems to have moved from one issue to another. Water quality and quantity have been a key area of concern, although the risks that are prioritized within each category have shifted as understanding of the interaction of water and unconventional gas production has grown. Methane emissions have been another area of concern, and ongoing debate has revolved around the nature and seriousness of the risk. Other issues, such as induced seismicity, have only recently come onto the public's radar, largely caused by the earthquakes in Youngstown, Ohio,[66] in December 2011. More recently, the health impacts of air emissions and the noise pollution associated with production are receiving increased scrutiny. In each case, some risks have proved to be genuine, whereas others are only perceived risks and have since been debunked, However, no one risk can be deemed a "showstopper" (i.e., an unmanageable risk that would require widespread reconsideration of current recommended practices).

Overall, understanding of the nature and type of risk has evolved as the development of unconventional natural gas has progressed. Some of this understanding can be attributed to advances in scientific understanding, and some can be attributed to the development and implementation of technology and a more deliberate focus on utilizing risk management techniques and practices. Often, the identification of risk highlights an opportunity for where technology or procedures can develop and mitigate the risk.

The technologies utilized for shale gas development have been in use by the industry for years, and the risks associated with development, as well as risk mitigation measures, are well understood by many in the industry. The scale of unconventional gas development, however, means that these traditional issues have increased in importance and impact and have become more constraining. Although individual operations may be low-risk, the

63. U.S. Department of Energy (DOE), "Ninety-Day Report," Secretary of Energy Advisory Board (SEAB), Shale Gas Production Subcommittee, August 18, 2011, http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.

64. DOE, "Second Ninety-Day Report."

65. International Energy Agency (IEA), *Golden Rules for the Golden Age of Gas* (Paris: IEA, 2012).

66. Investigative research to date points to induced seismic activity that resulted from the injection of wastewater (at high pressure and volume) into a certified injection well site. The seismic activity was not found to be connected to local hydro-fracturing or drilling activity. For more information, see the seismicity section of the appendix.

cumulative impact raises concerns.[67] Moreover, many communities have not experienced oil and gas operations on a scale associated with shale gas development and therefore may not have the regulatory or infrastructural capacity in place to deal with development and its impacts. Moreover, although many of the issues and concerns are local and vary from location to location, they do not occur in a vacuum—political and sociological overlays affect community and state responses.

Even though the current evidence suggests there are no showstoppers, regulation of unconventional gas development should ensure proper risk management without unnecessarily driving up the cost or causing significant or unpredictable delays in the production process. A failure to resolve outstanding issues and areas of concern will affect timing and production profiles. At present, industry, NGOs, communities, regulators, and other stakeholders are immersed in ongoing discussions to strike the right balance and develop a long-term process that allows production to go forward while simultaneously addressing key risks.

Current research suggests that the risks associated with any one unconventional gas development operation can be adequately managed through a combination of regulation, technology, and recommended practices, but that further collaboration is required to address the regional impacts of large-scale development. Further study may be necessary to contribute to the public knowledge of the cumulative impacts of development on things such as regional hydrology or seismicity.

What follows is a summary of the current state of unconventional gas risk management in several key areas. Because risk mitigation was one of the biggest, most in-depth areas of inquiry for this study, a longer discussion of risks and potential management pathways appears in the appendix.

WATER

Water is a central issue in the debate over the shale gas revolution because it is a critical component of the hydraulic fracturing process as currently practiced. Perceived water risks can be separated into two broad categories: impacts on water quantity and impacts on water quality. The risks for each category are highly dependent on the geology, geography, size of the play, and technology utilized. Risks and impacts vary among plays, but they can also vary within plays.

The scale of operations matters in terms of quantity and quality because it affects the amount of water withdrawn, the frequency of drilling, and the amount of produced and flowback water that must be either recycled or sent for disposal. Moreover, scale should be considered against regional variables such as water availability, competing users, geology, and population growth. The cumulative impacts matter, and the overall impact will be influenced by both the number of wells drilled and the implementation of more recycling and widespread utilization of less water-intensive technologies (see Table 2).

67. Melissa Stark et al., *Water and Shale Gas Development: Leveraging the US Experience in New Shale Developments* (New York: Accenture, 2012), 22, http://www.accenture.com/SiteCollectionDocuments/PDF/Accenture-Water-And-Shale-Gas-Development.pdf.

Table 2. Water Quantity Concerns and Potential Impacts

Concern	Potential impact
Water sourcing	Surface water: Ecosystem impacts Impact of hydrology of water body Overburdening of municipal water supply
	Groundwater: Drawdown of aquifers and water table faster than recharge rate Saltwater intrusion
	Alternative: Abandoned mine drainage Treated wastewater Brine and other nonpotable water
Competing users	Less water available for more end users: industry, agriculture, residential, habitat
Timing of withdrawal	Water availability—seasonal or perennial Water quality Pass-by flows
Amount of produced water/flowback	Volume to be treated or disposed of Storage of large quantities of flowback/produced water Transport of large volumes and potential accidents
Water transport	Increased truck traffic Road degradation Accidents Pipelines and necessary right of way

Source: Project on Realizing the Potential of Unconventional Gas, In-Depth Session #3: Water Management, November 13, 2012, CSIS.

Although much of the public discourse has centered on the possibility of contamination of drinking water from hydraulic fracturing, thousands of hydraulic fracturing operations have been performed, and no instance of contamination of groundwater by fracturing has been substantiated.

Table 3. Water Quality Concerns and Potential Sources

Concern	Potential source
Groundwater contamination	Methane migration Faulty casing/cementing Hydraulic fracturing and fracturing fluids Injection wells
Surface water contamination	Spills/leaks of produced/flowback water Spills/leaks of fracturing chemicals/fluids Erosion and stormwater runoff from pads, truck traffic, potential accidents transporting wastewater

Source: Project on Realizing the Potential of Unconventional Gas, In-Depth Session #3: Water Management, November 13, 2012, CSIS.

Questions about the potential for groundwater contamination generally fall into two categories: (1) whether fluids used in hydraulic fracturing can migrate from a production zone into groundwater aquifers, and (2) what chemicals and other materials are used in hydraulic fracturing fluids. The migration of fractures to the aquifer is highly unlikely because hydraulic fracturing occurs at 6,000–10,000 feet below the aquifer and is separated by layers of non-permeable rock. However, there is a risk of contamination from the well because it must pass through the aquifer on its way to the target zone. Therefore, the integrity of the well, in terms of concentric casing and cementing, is critical; the casing must serve as an adequate barrier between the well and the aquifer. Many states and local communities have enacted regulations calling for greater disclosure of the chemical composition of hydraulic fracturing fluid. The oil and gas industry has also established a website, FracFocus, designed to foster greater transparency of fracturing fluid content on a voluntary basis.

The potential for surface water (and groundwater) contamination from poor above-ground water management is perhaps a more important issue. Companies are seeking solutions, utilizing some straightforward fixes such as berms and pit linings on well sites to minimize the risk of water degradation from runoff or surface spills.

Companies confront a host of challenges associated with wastewater management, including limited disposal options (geological constraints for deep wells), long haul distances, long waits in line, costs for disposal or even reuse, truck traffic, treatment challenges due to volume and chemical composition, and increased regulatory and public scrutiny.[68] Currently, a multitude of management techniques and technologies exist to deal with both the quantity and quality concerns of water management, including recycling and reuse, on-site evaporation in impoundments, on-site injection into wells, disposal at a centralized facility via evaporation or underground injection, treatment through surface water treatment plants, mobile treatment units, closed-loop drilling systems, limited use of open impoundments for mixing flowback with freshwater, use of protective liners on pad sites, and utilization of more benign green hydraulic fracturing fluids.[69]

AIR

One factor often mentioned by proponents of increasing domestic shale gas production is that natural gas has the lowest carbon content of any fossil fuel, making it a more environmentally friendly energy source, especially where it would push out coal in electricity generation. However, the production of shale gas, including exploration, drilling, venting/flaring, equipment operation, gathering, and the associated truck traffic, results in emissions of volatile organic compounds (VOCs), NO_x, SO_x, particulates, and greenhouse gases, including methane.[70]

Many reports have examined the overall impact on the climate of switching from other fossil fuels to natural gas. Because of uncertainty about methane emission rates, there is

68. Su Gao, "Fracking's Water Problem: What Goes Down Must Come Up," *Bloomberg New Energy Finance*, July 6, 2012, 5.

69. Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector*, 88.

70. DOE, "Ninety-Day Report," 15. VOCs are hydrocarbons such as benzene and propane that evaporate quickly and can contribute to ground-level smog.

considerable debate in academic and policy circles about the extent to which switching to natural gas may result in net reductions of GHG emissions. Much of the public attention and many research efforts on methane emissions have focused on well completion—specifically, how much is produced and emitted during flowback.[71] Following hydraulic fracturing, some of the initial fluids used to fracture the well begin to return to the surface over the course of a week to 10 days. Reduced emission completion (REC) technologies can dramatically reduce emissions of the methane that is brought to surface with flowback fluids. Understanding the extent of such completion emissions is a key point of research.

Another area of concern is wellbore cleaning or liquids unloading, which is a period during which a well is taken out of production to clean out liquids that may have accumulated. While the liquids are being removed and captured, the gases have traditionally been vented or flared, not captured. Because most unconventional wells that have been fractured are newer, the data on the potential of methane releases during liquids unloading are more preliminary than those for flowback periods.

Green completion can reduce methane emissions by 1–1.7 million short tons[72] and VOCs by 95 percent.[73] It is the process by which the flowback is contained in a closed-loop system: water and fluids are captured and treated, solids are filtered out, and the methane is separated out for later recovery.

There remain challenges, however, and cost is one often cited. Another is fugitive emissions—that is, emissions of methane and VOCs that occur at various points along the supply chain because of leaking valves, pumps, pipes, and so on. Regulation of fugitive emissions at the federal and state levels has thus far been inconsistent and is being highlighted as one of the key areas of opportunity for further emission reductions.

SEISMICITY

Seismicity, which is not a new concern,[74] can be caused by a variety of activities. Any time pressure is applied or reduced from an underground rock formation there is at a minimum a risk of induced seismicity. The water injected during hydraulic fracturing does not pose a high risk for seismic activity.[75] This is largely because the amount of pressure applied, area of application, and duration of a hydraulic fracturing operation are generally not enough to trigger detectable seismic activity.[76] The real risk for seismic activity is posed by the disposal

71. Francis O'Sullivan and Sergey Paltsev, "Shale Gas Production: Potential Versus Actual Greenhouse Gas Emissions," *Environmental Research Letters* 7 (December 2012).

72. This amounts to 19–33 million tons of CO_2 equivalent.

73. U.S. Environmental Protection Agency (EPA), "Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet," April 17, 2012, http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf.

74. Lawrence Berkeley National Laboratory, "Induced Seismicity: Oil and Gas," http://esd.lbl.gov/research/projects/induced_seismicity/oil&gas/.

75. National Research Council, *Induced Seismicity Potential in Energy Technologies* (Washington, DC: National Academies Press, 2012), 76.

76. Lawrence Berkeley National Laboratory, "Induced Seismicity: Induced Seismicity Primer," http://esd.lbl.gov/research/projects/induced_seismicity/primer.html.

of wastewater from hydraulic fracturing operations. To date, minor earthquakes have been associated with wastewater injection, although none has caused loss of life or major damage. However, not all wastewater disposal wells cause earthquakes; the Department of Interior estimates that of the over 150,000 Class II injection wells, including nearly 40,000 oil and gas wastewater disposal wells, only a tiny fraction has induced seismicity.[77]

Regulators and operators are already taking measures to reduce the likelihood of seismic activity from wastewater injection, including assessing seismic risk when identifying or permitting injection sites, requiring seismic monitoring at active well sites, and limiting well pressure thresholds by reducing the amount of water pumped into wells, as well as the pressure at which it is pumped. Discussions are also under way about whether and how to handle the issue of large-volume injection at or near fault zones.

States have responded quickly to seismic activity (either suspending or stopping operations) and have implemented more frequent monitoring and review of operations and existing regulations. Indeed, many states acknowledge the need to increase monitoring of disposal wells and to better understand whether existing wells fall along a fault line.[78] At the federal level, the underground injection of fluids is regulated by a framework established by the Safe Drinking Water Act (SDWA). However, the SDWA does not cover induced seismicity, nor does it prescribe a mechanism for how to manage, investigate, and regulate induced seismicity.

The challenges and uncertainty surrounding induced seismicity are multidimensional. On the technical side, there is a need to better understand the regional variations in subsurface geology and tectonics, the interaction of fluids and geology, and the impact that varied technologies can have. In general, the midcontinent geographic and stratigraphic data are poorly understood. There is a need to identify the location of fault lines and where they are in relation to producing areas. Also needed are better measures of the geologic state of stress and the cumulative impacts on the geologic state of stress. There is also a lack of data on fluid injection (location of injection wells, depths, volumes and pressures, and time frames).[79] For the seismic data that do exist, there is a need to increase and improve their availability and transparency (currently, information is fragmented) and to close the information gap between legacy states and new producers.

Similarly, a major challenge is to understand the level and variety of risks (within the context of the geology) and to be able to translate this data into appropriate mitigation and response measures. At the same time, when evaluating risk there is a need to understand what the risks of alternatives disposal methods might be (e.g., not injecting wastewater but doing something else to it) and weigh the costs and benefits.

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77. David J. Hayes, "Is the Recent Increase in Felt Earthquakes in the Central US Natural or Manmade?" U.S. Department of Interior, April 11, 2012, http://www.doi.gov/news/doinews/Is-the-Recent-Increase-in-Felt-Earthquakes-in-the-Central-US-Natural-or-Manmade.cfm.

78. Private conversations with a wide range of regulators.

79. Don Clarke, "Induced Seismicity Potential in Energy Technologies" (presentation at USC HF-IS Workshop, June 8, 2012, slide 27), http://gen.usc.edu/assets/001/81342.pdf.

HEALTH

Recently, concerns have been raised about the possible impact of shale gas development on public health. Any industrial process, including the development of conventional and unconventional gas, has inherent environmental and social risks. Studies have thus begun to look closely at the health impacts associated with shale gas production. Although many of these studies have identified areas of potential risk, no one empirical, peer-reviewed study has linked health issues to shale gas development. Some of the risks identified include the air quality implications of truck traffic, the diesel-powered pumps used on well pads, intentional or unintentional flaring, and pollutants from the other equipment and materials used.[80] These studies are site- and time-specific, and usually measure local impacts, not the cumulative impacts.

Because of the sensitivity of the possible health impacts of unconventional gas production, further study and research are warranted to increase awareness, further understanding, evaluate risks, and ensure proper management and risk abatement strategies.

No single risk explored in this study appears to pose an insurmountable obstacle to the prudent development of unconventional gas resources. Just because risks can be managed, however, does not mean that they will be managed in the most appropriate and cost-effective manner. It is clear that greater awareness of the risks and impacts of development, the application of new technologies, the role for enhanced operational expertise, and proper regulation all must be brought to bear to ensure that risks are managed appropriately.

EVOLVING REGULATORY ENVIRONMENT AND BEST PRACTICES

Regulations must be flexible, adaptive, and performance-based in order to adjust to the changing understanding of the unconventional natural gas landscape. There must be a commitment to continual improvement on the part of both the regulators and the industry. Challenges associated with effective regulation include establishing a proper understanding of the risks presented, navigating complex jurisdictional issues between various levels of government and within regional areas of responsibility, updating existing regulations to protect against real or perceived risks in a way that also allows companies to comply with the rules in a cost-effective and efficient manner, and adopting fair and effective ways of enforcing the regulations. Although this description of the challenges seems intuitively easy to overcome, in reality there is a complex patchwork of related regulatory and policy changes at the federal, interstate, intrastate, and local levels that makes any summary understanding difficult to achieve. Despite the flurry of regulatory activity over the last several years, regulatory uncertainty still exists at all levels.

Several existing federal statutes, involving a variety of federal agencies, oversee the development of unconventional gas and are described in Table 4.

80. U.S. Government Accountability Office (GAO), *Information on Shale Resources, Development, and Environmental and Public Health Risks* (Washington, DC: GAO, September 2012), 33, http://www.gao.gov/assets/650/647791.pdf.

Table 4. Federal Statutes Overseeing the Development of Unconventional Gas

Statute	Description
National Environmental Policy Act (NEPA)	Requires that exploration and production on federal lands be subject to full environmental impact analysis
Clean Air Act (CAA)	Requires permits for air emissions for drilling equipment and associated drilling and production equipment
Clean Water Act (CWA)	Regulates all surface water discharge of liquids related to drilling and production
Safe Drinking Water Act (SDWA)	Regulates underground injection of oil- and gas-produced waste and injection of fluids that contain diesel
Emergency Planning and Community Right-to-Know Act (EPCRA)	Requires operators to have in place emergency plans and notification procedures, to adhere to the Toxics Release Inventory, and to report storage of hazardous chemicals
Endangered Species Act (ESA)	Requires the protection of endangered and potentially endangered species in areas where projects are under way
Toxic Substances Control Act (TSCA)	Regulates the process for the manufacturing and use of certain chemicals
Resource Conservation and Recovery Act (RCRA) and Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	Regulates the handling of drilling waste

Source: Baird Equity Research, "Energy Policy: Upstream: Unconventional Drilling Regulations," March 16, 2012, 5, http://www.rwbaird.com/SharedPDF/emailTemplates/InvestmentBanking/CleanTech/EnergyUnconvential.pdf.

Despite this overarching regulatory structure, uncertainty remains about what level of regulatory oversight the federal government will choose to exercise in the coming years. Several government regulatory changes, proposed rulemakings, and national studies are under way that might affect development, including but not limited to the following:

- In October 2011, as part of section 304 (m) of the Clean Water Act, the U.S. Environmental Protection Agency (EPA) initiated rulemaking to set discharge standards for wastewater from shale gas extraction, and it plans to release the new standards for public comment in 2014. EPA could add pretreatment standards to the existing wastewater guidelines for oil and gas development in the Oil and Gas Extraction Effluent Guidelines.[81]

- In December 2012, EPA released a progress report on its "Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources."[82]

81. U.S. Environmental Protection Agency (EPA), "Shale Gas Extraction," http://water.epa.gov/scitech/wastetech/guide/shale.cfm.

82. U.S. Environmental Protection Agency (EPA), "Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report," December 2012, http://www.epa.gov/hfstudy/pdfs/hf-report20121214.pdf.

- In April 2012, a memorandum of agreement among the U.S. Departments of Energy and Interior and EPA was announced on collaboration on unconventional oil and gas research.[83]
- EPA developed draft Underground Injection Control (UIC) Class II permitting guidelines for oil and gas hydraulic fracturing that uses diesel. Public comment closed August 23, 2012.[84]
- EPA is updating chloride water quality criteria under CWA section 302 (a) (1). The draft criteria will be released in early 2013.[85]
- In April 2012, EPA issued oil and natural gas air pollution standards.[86]
- In mid-2011, EPA created a National Technical Working Group on Injection Induced Seismicity that was given the task of releasing technical recommendations directed at injection-induced seismicity for UIC and Class II wells.[87]

Uncertainty is prevalent at the state level as well because states are at vastly different places when it comes to regulation. Colorado, Oklahoma, and Texas face the challenge of updating regulations on existing and ongoing oil- and gas-related development, whereas North Carolina, New York, and Pennsylvania must revamp outdated regulations or create new ones where none previously existed. Some of this uncertainty is the by-product of incremental and more frequent changes such as in Colorado, which has undergone successive regulatory changes over the last three years.

In addition, in each state various issues have sparked public policy debate or concern, and so the states must work to find solutions that address those issues. For example, Louisiana, Kansas, and Colorado have added fracturing fluid disclosure rules for all chemicals, whereas Pennsylvania and Michigan require only the disclosure of chemicals that are hazardous; Arkansas has increased the number of monitoring wells following induced seismic activity, and Ohio has updated its Class II regulations following the earthquake in Youngstown, making them even more stringent; Maryland has enacted rules governing the replacement of water supply tied to drilling permits; Colorado and Wyoming require the use of green completions; Pennsylvania law encourages the use of nonpotable water in drilling; and Colorado and Idaho are grappling with the local communities issuing prohibitions on drilling permits. Each of these issues also has federal and state overlays, which has given rise to the increased uncertainty and fragmentation in the regulation and management of shale gas development.

The management of water in shale gas development is a perfect example of this complexity. Federal, regional, state, and local oversight work both together and separately to manage water in shale gas development. The chart in Figure 5 is representative of this complexity.

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83. U.S. Environmental Protection Agency (EPA), "Memo: Multi-Agency Collaboration on Unconventional Oil and Gas Research," April 13, 2012, http://www.epa.gov/hydraulicfracture/oil_and_gas_research_mou.pdf.

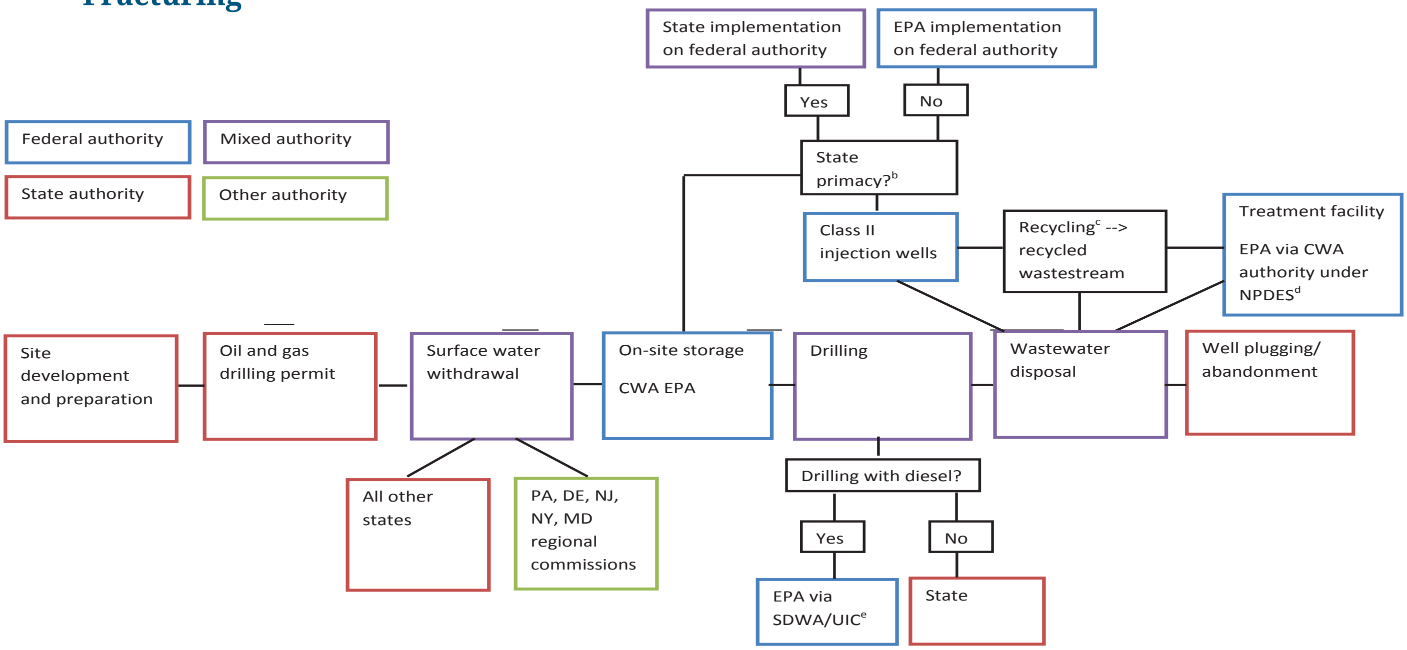
84. U.S. Environmental Protection Agency (EPA), "Hydraulic Fracturing under the Safe Drinking Water Act," http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/hydraulic-fracturing.cfm.

85. U.S. Environmental Protection Agency (EPA), "Natural Gas Extraction—Hydraulic Fracturing," http://www.epa.gov/hydraulicfracturing/.

86. U.S. Environmental Protection Agency (EPA), "Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet," Washington, DC.

87. Mike Soraghan, "EPA Looking for Ways to 'Manage or Minimize' Injection Earthquakes," *EnergyWire*, March 15, 2012, http://www.eenews.net/public/energywire/2012/03/15/2.

Figure 5. Federal, Regional, and State Authorities for Water Use in Hydraulic Fracturing[a]



a. The federal government has other air quality authority, emergency authorities, and NEPA review on federal lands.
b. In many cases, when EPA has authority under the CWA or SDWA, it has approved state-level management of those programs and the states carry them out.
c. Recycling itself requires no permit. Exceptions include when water is pretreated and the residual needs to be disposed of or when recycled water is used for something else (de-icing).
d. EPA will write technical standards for pretreatment, out in 2014.e. EPA is now finalizing the guidelines for diesel injection.

Source: CSIS.

Note: EPA = Environmental Protection Agency; CWA = Clean Water Act; NPDES = National Pollutant Discharge Elimination System; SDWA = Safe Drinking Water Act; UIC = Underground Injection Control Program; NEPA = National Environmental Policy Act.

Although much of the concern about mitigating the risks associated with unconventional gas development is focused on the regulatory framework that governs allowable practices, there is widespread recognition of the need for an ongoing collaborative process between industry and regulators.[88] In addition to the regulatory changes just described, numerous companies have established their own internal guidelines for managing risks and organized various regional industry consortia to evaluate and structure recommended practices. Several groups such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and the American Petroleum Institute (API) are well known, and others have emerged for the express purpose of dealing with the risks associated with unconventional gas (and oil) development such as the Marcellus Shale Coalition, the Appalachian Shale Recommended Practices Group, and several others.

Initially, many of these groups focused on laying the foundation for proper safety and environmental protection. But now that many operators and regulators believe a baseline level of confidence has been established, the focus on cost-effective regulation going forward to drive further improvements is also an area of joint work.

88. DOE, "Second Ninety-Day Report"; NPC, *Prudent Development*.

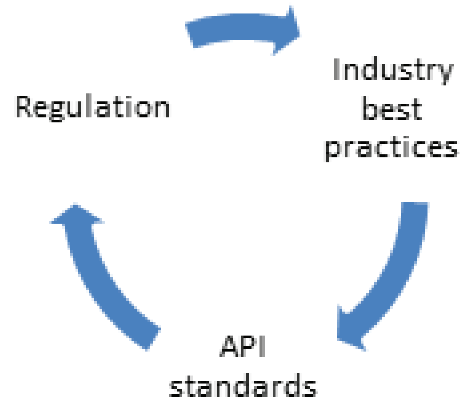
An economic case may be emerging for better practices that protect human health and environmental safety, as well as practices to minimize impacts on communities. Several organizations have sought to quantify the additional cost that may be associated with implementing better safety and environmental protection, but these figures are subject to variations in baseline practices, regional factors, and resource characteristics, among other things. These cost estimates and the potential savings derived are highly controversial for both methodological and political reasons, but focusing on cost-effective regulation is an important part of the ongoing public policy dialogue. Many advocates of performance-based regulations highlight the ability of companies to evaluate and choose the most cost-effective compliance pathway, as compared with regulations that are more prescriptive in nature.

A great deal of room for synergy between industry and state regulators exists, but the synchronization and sequencing of standards, regulations, technology, and development are difficult to coordinate. The current process for the development of industry best practices, API standards, and regulations can be described as a feedback loop whereby the practices, standards, and regulations build on one another as they progress. This process does provide the context for continuous improvement, but the necessary time lags between the finalization of new standards and regulations, the challenge of developing and applying new technology, and evolving industry practices often appear to frustrate policymakers, who strive for certainty in an evolving system.

Up to three years can be required to develop a standard, and standards must be re-evaluated every five years. Most standards are performance-based in order to encourage innovation. Often, those writing regulations add to or overlay the standards. Meanwhile, questions arise about the lag time of standards, the capacity of regulations to keep pace, and the ability of both to adapt and adjust to rapid technological change and development within the sector. Thus communication between industry and regulators is essential to keep pace with the tremendous speed of technological change and development in the sector.

The importance of building flexibility into the oversight process cannot be underscored enough. It needs to be recognized that the landscape will shift, and that regulations and standards must be drafted to allow room to readjust and fine-tune as awareness and practices evolve. The Secretary of Energy Advisory Board (SEAB) has called for a "systematic commitment to a process of continuous improvement to identify and implement best practices."[89] A perfect example is the disclosure laws implemented by many states, which have recently come under fire because of the loopholes that allow for trade secrets to go unreported. Instead of pointing to such laws as a failure, however, it should be acknowledged that they are part of the process and are integral to a pathway toward a better policy. It is important that states and the industry have in place the right mechanisms to continually move forward and improve.

89. DOE, "Second Ninety-Day Report," 10.



OPPORTUNITIES AND CHALLENGES

Effective management of the risks posed by unconventional gas development faces many public perception, regulatory, and technical challenges. Management practices and risks are not uniform, and what works in one play may not work in another. Moreover, regulations vary between plays as well, making certain options unfeasible. Not only does such variation make evaluation hard, but it also inserts uncertainty—in terms of the transferability of practice, cost, and risk mitigation potential—into the equation for industry because companies may need to alter their management strategies for each play. From a broader perspective, stakeholders must continue to grapple with a host of related challenges, including:

- *Public engagement.* Stakeholders must conduct continual public engagement to increase the public literacy of the risks associated with gas development but also to understand, investigate, and respond to emerging areas of public concern.
- *Data availability.* Reliable and available data remain a critical issue from a broader, cumulative risk management standpoint. For example, very few public data are available on total water withdrawals, total wells drilled, flowback volumes, water recycle rates, and wastewater management, making it difficult to conduct comprehensive risk assessment and develop applicable and efficient management strategies on a regional basis.[90] Certain resources do exist, such as STRONGER and FracFocus, that are working to increase public access to information. Similarly, although many companies have adequate seismicity data to evaluate the risks posed by any one injection or drilling operation, the cumulative impacts of drilling in any one area or the ongoing seismological changes in a given region are not adequately explored or studied.
- *Point in time assessments.* Many studies have looked at the varying components of the water management systems and air emissions at sites where unconventional gas production is occurring. However, observational data always look backward, and often the landscape has already shifted. Current and ongoing studies are needed to evaluate properly how changes in development practices or other factors have altered the risk profile or public policy management issues going forward, as well as how to measure progress in mitigation impacts.

90. Ibid.; Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector*, 7.

- *Missing analysis.* Several studies have pointed out that the limited scope of cost/benefit analysis and the transferability of practices from play to play are a major hindrance to good management.[91] How does one evaluate trade-offs when water or air quality is not valued appropriately?

- *Capacity constraints.* There is a limited capacity to evaluate and manage these issues from both a company and a regulatory perspective. Although optimum solutions likely exist, many of the stakeholders seeking to meet these challenges are operating with a limited capacity in both infrastructure and human resources. Cost is also a key issue when designing effective risk mitigation solutions.

- *Research needs.* Because of the infancy of many of the technologies being utilized, research should continue. Some major research topics are how to best translate data and technology into policy; how to allocate treatment costs; health impacts; and the costs and trade-offs of implementing best practices in water management.

Despite the challenges, stakeholder collaboration is increasing. Companies and regulators are seeking to manage the challenges through innovative strategies and cooperative efforts that include pooling resources and joint logistics coordination. Similarly, industry, governments, and nonprofits are teaming to advance greater regional and public understanding of risk and risk management through further study and research. It is important to note that no two regulators or companies deal with the confluence of risks and need for engagement in the same way. Small and large operators will find effective ways of managing risks in very different ways, and regulators must find solutions that meet region-specific needs and characteristics. These differences in approach and solution have made it increasingly difficult for all participants in this process to understand the evolving regulatory and recommended practices environment. Of all the issues studied in this project, however, proper risk management is the most critical area of public policy concern.

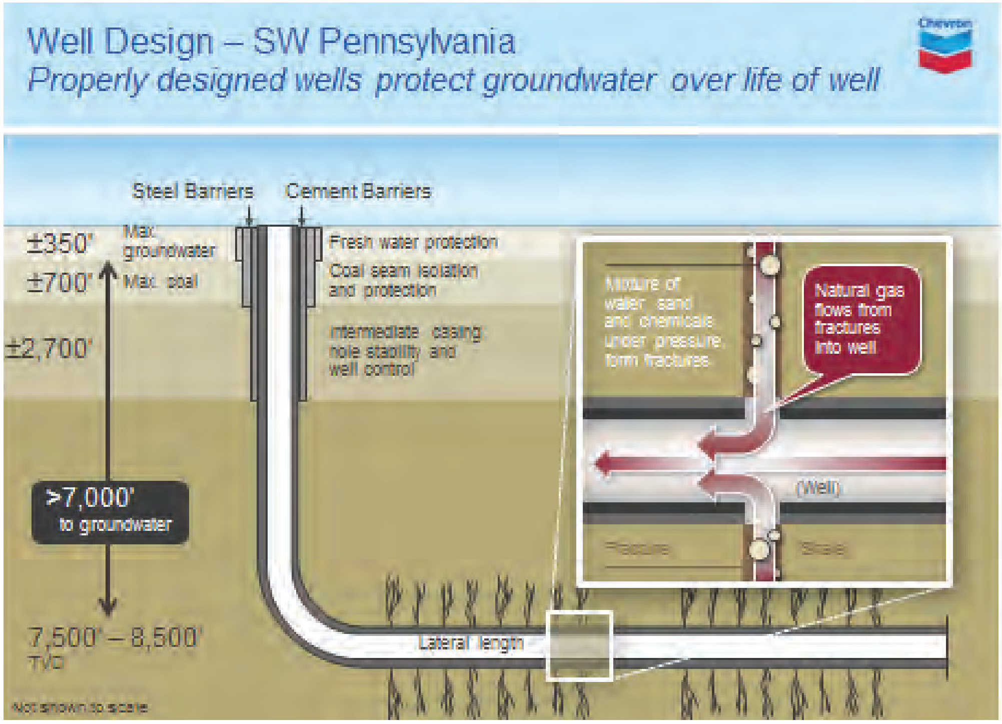
Key message 5: *Technology innovation is key to development, risk management, and demand.*

Technology is at the heart of the unconventional gas boom in the United States. Hydraulic fracturing has been an integral part of oil and gas development for over 60 years, progressing in order to adapt to a wide variety of reservoir qualities and advances in complementary technologies.[92] The combination of hydraulic fracturing and horizontal drilling has allowed ultralow-permeability reservoirs to be exploited economically.[93]

Neither technology has remained static. Hydraulic fracturing and horizontal drilling are constantly being refined through changes in the additives and proppants used, perforation placement, well completion techniques, and monitoring, and they are undergoing improvements via longer laterals, more fracturing stages/wells, and pad drilling, among other things.[94]

91. Ibid.
92. National Petroleum Council (NPC), "Hydraulic Fracturing: Technology and Practices Addressing Hydraulic Fracturing and Completions," Paper no. 2-29, Operations and Environment Task Group, September 15, 2011, 9, http://www.npc.org/Prudent_Development-Topic_Papers/2-29_Hydro_Frack_Technology_Paper.pdf.
93. NPC, *Prudent Development*, 145.
94. NPC, "Hydraulic Fracturing," 13.

Figure 6. Hydraulic Fracturing Operation



Source: Chevron U.S.A. Inc.

Hydraulic fracturing has allowed producers to extract gas from formations of low permeability by injecting a mixture of water, proppants, and chemicals into the formation at high pressure to fracture the rock (see Figure 6). Horizontal drilling has increased the exposure of the wellbore to the formation, and continual improvements in technology have allowed increasingly longer lateral lengths, from the early stages of 3,000–4,000 feet to almost 10,000 feet.[95] This extended reach has allowed a single horizontal well to replace several vertical wells, thereby reducing costs and reducing the above-ground footprint of operations. For example, in the past at least 16 vertical wells (each with its own pad) may have been required to develop one square mile, whereas now six to eight horizontal wells can be drilled from a single pad.

Technology is advancing rapidly in order to reduce the drilling footprint, increase production, and increase the environmental sustainability of production. Operators are increasingly aware of the scrutiny and impacts of their operations and are looking for ways to not only cut costs but also improve the environmental impact of those operations.[96] Thus companies are continually looking for ways to marry the two—a fact that has driven the advancement of technologies for percussion drilling, green chemistry, water management, hydraulic fracturing design and management, green completions, and data compilation.[97] One such example is the advancement and more widespread implementation of recycling technologies,

95. Ground Water Protection Council and ALL Consulting, *Modern Shale Gas Development in the United States: A Primer* (Washington, DC: Office of Fossil Energy and National Energy Technology Laboratory, U.S. Department of Energy, April 2009), http://www.netl.doe.gov/technologies/oil-gas/publications/epreports/shale_gas_primer_2009.pdf.

96. NPC, “Hydraulic Fracturing,” 6.

97. Ibid.

which have not only decreased the cost of water transport and amount of truck traffic but also reduced the amount of water that must be drawn from other sources. Similarly, some companies have begun to explore the possibility of replacing on-site diesel generators with gas or solar power systems in order to address air pollution concerns. The technology continues to evolve, driven by the desire to reduce costs, to comply with advances in regulations, to anticipate forthcoming regulations, or to respond to pressure from local communities.

Just as technologies are being developed and utilized to improve operations and manage the risks associated with development, they also have an important role to play in driving infrastructure and end-use efficiencies and new applications that can expand the reach of natural gas in the economy while also increasing its efficient use (see appendix for a more in-depth discussion of technology options for managing risks). For example, environmental regulation and the desire to capture more of the fugitive emissions from natural gas production are driving a suite of technology solutions to ensure greater emission capture rates throughout the gas value chain. Moreover, industry and government are actively looking for new, cost-effective ways to use natural gas in all sectors of the economy, including by driving greater industrial efficiency, various transportation applications, and various conversion technologies.

Technology will remain a key driver of progress throughout the natural gas value chain as companies and regulators look to technology solutions to facilitate access to more resources at lower cost, manage risks, reduce the environmental impact of production and use, create new markets or more efficient uses of natural gas resources, and comply with new regulations.

Key message 6: *Public acceptance of unconventional gas development is a critical issue, and the ability to manage risks must be demonstrated.*

Many unconventional gas-related studies have highlighted the high level of public skepticism that has accompanied unconventional gas development and the many issues that public reluctance to allow drilling have presented for industry and regulators. In some places, failure to manage public concern has led to an outright moratorium or substantive delays in unconventional gas development. However, many regions of the country also have ample public support for unconventional gas development because of the economic growth and job creation that accompany resource development. This difference of opinion, along with the legitimate public policy concerns associated with resource development, have made unconventional gas drilling a subject of great public debate. This public debate has been informed by academic and scientific studies, as well as popular movies and media stories. As a result, public engagement is an increasingly important component of unconventional gas development.

The impacts, both positive and negative, felt by communities from increased production activity are well documented and fall into overlapping social, economic, and environmental categories. In general, risks and impacts are localized and vary by geographic location;

population density; existing infrastructure; legacy of oil and gas development; and speed, scale and type of development, and duration of activity.[98]

Impacts include population growth and ”imported workers”; air and visual pollution, noise, and traffic congestion; diminished environmental quality; impact on other local industry; public safety (crime, traffic); stress on human services agencies, courts, schools, and housing; effects on road maintenance; impact on recreation and tourism; and effects on public health, environment, and quality of life.[99] Local economic impacts include the creation of primary and secondary jobs, forthcoming job potentials, higher tax revenues, wealth creation from leasing activity and business growth, and distribution of costs/benefits (revenues, environmental costs, etc.)

The habitat degradation and fragmentation associated with almost all forms of development are an important concern for many communities. Companies have responded to these concerns, and many technological advances have helped reduce the impacts of production sites. Advances in hydraulic fracturing and horizontal drilling have allowed companies to reduce the footprint of their operations by decreasing pad sizes. To reduce the need for water retention ponds, companies are employing closed-loop technology to manage water more efficiently to minimize surface impacts. Similarly, there are opportunities for multiple companies operating in the same area to either share infrastructure (especially for water pipelines) or utilize already established rights of way for pipelines. This notion of shared infrastructure and rights of way ties into the larger questions on the crafting of best practices and regulations.

In many ways, the most visible element of community dialogue has been claims and counterclaims. The debate can be polarized by extreme voices on the fringes, often missing a middle. For this very reason, companies are seeking to hire prominent local figures to assist with community engagement and outreach. Moreover, it is recognized that longevity in a play is highly contingent on community acceptance. Community engagement has become a key focus of most companies, but each company faces its own capacity, reputational, and philosophical limitations or advantages.

In some cases, public concern is increasingly difficult to address. Because of social media, small incidents can quickly become larger incidents when news is not contained by state or town borders. Incidents that occur in one town may heighten concerns in other towns across the country—even if such concerns are not justified. In the information age, access to both positive and negative information and misinformation is increasing. In many cases, public concerns have led to a prohibition on development. Several Colorado counties have imposed drilling moratoriums or banned hydraulic fracturing. [100] Over 100 municipalities in New York

98. NPC, “Second Ninety-Day Report.”

99. Ibid., 25.

100. Jack Healy, “With Ban on Drilling Practice, Town Lands in Thick of Dispute,” *New York Times*, November 25, 2012, http://www.nytimes.com/2012/11/26/us/with-ban-on-fracking-colorado-town-lands-in-thick-of-dispute.html.

have enacted temporary moratoriums on hydraulic fracturing.[101] In both instances, the states are fighting these local community actions.

Transparency, communication, and availability of data are critical elements in fostering an informed debate on public concerns and a necessary component of efforts to alleviate those concerns where possible. Communicating what does and does not constitute real risk has proven to be difficult. Hydraulic fracturing is the most tangible example of how one part of a development cycle (albeit an important and defining one) has received widespread public notoriety. Many of the concerns associated with hydraulic fracturing are legitimate and valid, but many others are disproven or associated with a separate part of the development process. For example, there is no evidence that hydraulic fracturing at depth causes aquifer contamination; however, faulty well design and integrity and poor surface management may contaminate groundwater aquifers. A lot of research about the environmental risks associated with unconventional gas resources is only now being undertaken and was not available in adequate detail or certainty when public concerns first arose. As for the environmental effects of technologies that are still being constantly modified, there is currently a dearth of information about many of them, and it is an ongoing struggle for stakeholders to provide this information in a timely and effective way to influence public concerns. This has been a challenge for researchers, policymakers, and regulators who are trying to not only assess the risks associated with unconventional gas production but also be responsive to public interest.

Ultimately, communities must feel as though their interests are being protected and advanced by the presence of unconventional gas development. This requires proper community engagement at all levels, early and often, and throughout the value chain of gas development. Even with this type of comprehensive engagement, the bar to achieve public acceptance in some regions may be too high to allow development.

Recommendations

STATES

The advent of unconventional gas development in the United States and the ensuing public debate over how to properly manage the risks and impacts of production have played out for the most part at the state and local levels. Throughout the duration of this study, it has been clear that the states are on the frontlines in addressing many of the public and private concerns associated with development, but capabilities in terms of oversight, regulation, and enforcement vary. Many states have worked to increase capacity, update regulations, revamp laws, and conduct extensive community outreach, and the progress in some areas has been remarkable. However, states may be reaching a second generation of challenges that will require addressing new areas of concern, a renewed focus on enhanced enforcement, and re-evaluation of the effectiveness of solutions only recently enacted. Our recommendations follow.

101. Joseph De Avila, "'Fracking' Goes Local," *Wall Street Journal*, August 29, 2012, http://online.wsj.com/article/SB10000872396390444327204577617793552508470.html; FracTracker Alliance, "Current High Volume Horizontal Hydraulic Fracturing Drilling Bans and Moratoria in NY State," December 27, 2012, http://www.fractracker.org/maps/ny-moratoria/.

1. *Given the regional nature of the geology and hydrology, as well as local infrastructure, population density, and community impacts, the primary regulatory responsibility should continue to lie with state governments.* This does not preclude federal-level oversight or setting of minimum standards, and the federal government already has several air and water standards that states regulate and enforce. The execution and flexibility of specific regulations and oversight should continue to be left to the state level.

2. *That said, state regulators should review and update all regulations that affect unconventional gas development to ensure that the most effective standards are in place.* These standards should be flexible, adaptive, current with new technology, and performance-based, balancing economic and environmental benefits. The process of updating or creating, in some cases, regulations to govern many of the processes associated with unconventional natural gas development has been an all-consuming endeavor that included, in many cases, collaborative work with environmental groups, industry players, and other state or regional regulators, as well as local stakeholders. The process of regulation and recommended practices setting should be seen as an ongoing and constantly evolving dialogue.

3. *Auditing of state regulations should be enhanced.* Several studies have also suggested that more support needs to be provided for state-level regulatory oversight through organizations such as State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and the Groundwater Protection Council (GWPC).[102] These types of organizations provide not only a valuable service to state-level regulators but also an important public confidence and information-sharing service that helps to reinforce and enhance the iterative nature of regulatory improvements over time.

4. *Continual data improvement.* Many state and local areas are generating drilling-related data. There is also a need for baseline data (regional hydrology, seismicity, emissions). Making these data readily available could help the regional governance of other basic resources such as water and air, and assist citizens, the academic community, and local planners better evaluate the nature of the resources around them and strive for better management of those resources over the long run.

5. *Process must be transparent.* It is important to strive for transparency and clarity in the ongoing state-level gas-related study, regulation, and engagement. Given that community support can be fractured around issues of natural resource development, this transparency is an essential part of maintaining public confidence, ensuring an open and productive relationship with industry and investors, and sharing important lessons learned that might be transferrable to other locations.

6. *Adopt a more holistic approach to issue management.* Even today, despite all the work that has been done to evaluate the various risks and risk management techniques associated with unconventional gas development, the cycle of public and industry concern tends to gravitate toward the latest issue of the day whether it is water quality,

102. NPC, "Second Ninety-Day Report," 3.

seismicity, severance taxes, or public health. Going forward, it is important to take a broad view of the issues that must be managed with unconventional gas development and try to deal with them from a more comprehensive and holistic view, ensuring that risk mitigation is balanced with cost-effectiveness and timeliness.

FEDERAL

The federal government has an important role to play when it comes to realizing the potential of the U.S. unconventional natural gas resource base beyond the regulation of federal lands. Instead of being viewed as an inhibitor of regional energy development, the federal government can find effective ways in which its oversight, guidance, and support can enhance investment certainty and boost public confidence. The lack of clear direction through either delay or inconsistent signals creates and perpetuates structural regulatory uncertainty that will undermine the long-term development of the resource. This report does not seek to be prescriptive about the outcome or details of certain federal government actions, but it does highlight ways in which the federal government can and should play a supportive role in prudent and sustainable resource development. Our recommendations follow.

1. *Set an energy narrative for the country that articulates a clear role for natural gas.* Perhaps the most important goal for the executive branch is to set an energy vision for the country that allows stakeholders to gauge how the government views various fuel sources and technologies and the role they play in reaching that long-term vision. The present administration in particular came into office with plans to set a course toward the decarbonization of the energy sector over the next half-century. With the realization of abundant domestic oil and natural gas supplies from unconventional sources and the failure to pass economy-wide cap and trade legislation, this narrative has changed. The administration has signaled its support for domestic natural gas production, but a more detailed view of the energy vision for the country that includes natural gas is a critical component of communicating the government's intentions.

2. *Finalize reviews and regulations in the government's area of responsibility.* EPA, DOE, and the Bureau of Land Management (BLM) all have ongoing areas of inquiry that may lead to regulation of various parts of the natural gas value chain. It is important that these studies be conducted in a thorough, scientifically sound but timely manner to ensure that unwarranted speculation and uncertainty over the outcome are kept to a minimum.

3. *Ensure organizational oversight and monitor key issues.* Given the strategic importance of this resource and the multitude of questions generated by its continued development, the executive branch should ensure proper oversight and continued interagency coordination of issues related to its development and use. The Department of Energy, working with the relevant White House offices and other agencies, is the best positioned agency to utilize and build on its existing range and level of technical and policy expertise to lead the coordination of and continued attention to unconventional gas development. Recognizing the current fiscal climate and the limitations it imposes, the government should create a special office or appropriately staffed office within the department to

provide the type of analysis, oversight, and interagency coordination that had heretofore been provided on an ad hoc basis by the secretary of energy's Advisory Board.

4. *Contribute to improved data through work by the U.S. Geological Survey (USGS) and other relevant agencies, as well as the National Academies.* Several parts of this report have highlighted the need for ongoing study of the cumulative impacts of unconventional oil and gas development in key areas of risk mitigation—namely, water management, seismicity, methane emissions, and health concerns. It is important to note the industry and local regulators are confident that they can generate adequate data and information to effectively mitigate the risks of any one drilling site or point of operation, but the regional or cumulative effects are not as well studied and require additional and unbiased attention. Organizations such as the U.S. Geological Survey and the National Academies are uniquely equipped to carry out such studies given the proper funding and mandates. Where federal data and assessments lag or substantially diverge from field experiments, government and industry collaboration and an exchange of views are highly recommended to reduce uncertainty and increase the clarity of the resource base and provide the best available information and measurements.

5. *Promote R&D for technologies to increase recovery, improve environmental performance, and explore industrial and vehicle usage.* The technologies that led to today's unconventional gas production development were the product of sustained government and industry collaboration on core technologies and practices. While industry continues to innovate throughout the value chain of unconventional gas development and use, there may be appropriate areas for continued government support or industry collaboration. It was beyond the purview of this study but well worth the effort to review the ongoing collaborative R&D activities in industry and government in order to assess the potential for new and expanded opportunities if they exist.

6. *Demand side clarity.* Much of the speculation about future demand for U.S. unconventional gas resources has to do with whether federal government policies will impede or drive demand through a limited number of policy levers. As this report reviewed in several sections, gas demand is likely to grow in the United States. One area where the federal government has the ability to significantly affect the internal and external market dynamics for gas is in export permitting. While there is a need to evaluate and ensure that natural gas exports are in the "public interest," it appears that U.S. trade policy, well-substantiated trade theory, and several recent studies all suggest that the federal government can and should allow exports of natural gas to non–free trade agreement countries. The decision to do so would comport with the basic recommendation of this study, which is to alleviate where possible market or regulatory barriers to greater, more stable demand consistent with the adequacy of the domestic resource base.

7. *Improve structural regulatory certainty.* Given all the areas of public concern and debate that have emerged over the short time that unconventional gas has been produced, industry and investors are understandably wary of any and all efforts to regulate the production or use of gas that would effectively end or significantly limit production. It is

important to recognize that federal, state, and local governments have the responsibility to protect the public interest through proper regulation, enforcement, and oversight and that a great deal of work has been done over the last several years to ensure that industry operations, regulation, enforcement, and oversight become sufficient to handle the task at hand. The U.S. government could oversee and fund the creation of a clearinghouse to facilitate collaboration with states, industry, and technology stakeholders in order to develop best practices and regulations that recognize the regional diversity of the geology and hydrology. It is important to avoid a process in which structural regulatory uncertainty makes it difficult for investors to risk spending the large amounts of capital required to acquire, produce, transport, and consume these natural gas resources. In the end, a delicate but manageable balance must be struck to ensure a stable path forward.

INDUSTRY

Companies face a range of economic, commercial, geologic, environmental, social, political, and technological challenges in developing unconventional gas resources, and each company faces this suite of challenges in different ways. Companies must operate at the highest standard and remain at the forefront of innovative techniques and practices or risk creating mishaps that could threaten profitability, performance, reputation, or, for some, their very existence—indeed, a mistake by one can affect the entire industry. Our recommendations follow.

1. *Best practices are a component piece of community support.* Many companies are putting a premium on developing and communicating their commitments to the highest operating standards. Not only is this an important part of industry and internal self-regulation and a component of the dialogue that forms sound regulation, but it is also a critical component for achieving community acceptance and a competitive advantage. Best or recommended practices by companies, industrial organizations such as API, and regional organizations should continue to be used as a vehicle for ensuring progress in all of these areas.

   In certain regions, regional best practices groups or centers of excellence have emerged as useful venues for industry groups to draft, compare, communicate, and promote recommended practices for that specific region. While such regional groupings may not be needed everywhere, they can provide a useful foundation for coordinating regionally based industry standards of excellence.

2. *Continual improvement of technology to reduce risks.* Throughout this study, the role of new technologies and technology applications were at the heart of risk management and cost-competitiveness strategies. These technologies are created by companies and are essential for the long-term sustainability and ultimate potential of this resource. Continued investment in and attention to developing and deploying these technologies should be a strong focus for industry.

3. *Need to take a lifecycle approach to community engagement.* Each industry player interprets community engagement differently. Some view it as an ongoing and essential component of doing business in communities where they operate, while others view it

as something that may be necessary for periods of time or in certain communities, but is otherwise an elusive and unnecessary core business focus. Any company seeking to achieve and sustain public confidence must be proactive and forthright about the full range of risks inherent in the operation and the range of risk management techniques that will be employed. Companies should be more transparent regarding their development plans and share data with the public, other industry members, and regulators—including where and how many wells are being drilled; what chemicals are being utilized in fracturing fluid; how much wastewater is being produced, recycled, or disposed of; and the level and type of emissions released. Similarly, more attention should be paid to the sequencing and timing of projects and the potential for shared collaboration with other industry partners, as well as the implementation or use of shared infrastructure (shared water collection, recycling and treatment, distribution, shared pipeline right of ways, etc.).

Companies need to be a partner with regulators and local communities in evaluating the facts and alleviating public concerns. While this is standard operating procedure for many companies, it is important to ensure a broader, more proactive approach to maintaining social license from the industry as a whole.

Conclusion

The potential to develop vast amounts of domestic unconventional natural gas resources has changed the U.S. discourse on energy and has spurred policymakers and industry leaders to better understand the size of this resource; the risks and opportunities associated with its production, transport, and use; and the potential strategic implications for the United States.

One of the largest challenges for those attempting to craft effective policy has been the evolving nature of unconventional gas development. Regulations, industry composition, technology, practices, and impacts continue to change. Although the shale gas narrative is relatively young, its impact on several sectors and parts of the economy is already evident. Risks exist, but they are manageable if the right regulatory environment is created and proper steps toward responsible development are taken. Regulators and industry are engaged, and must continue to engage, in an iterative dialogue to improve and manage these risks, as well as other impacts of production.

However, significant uncertainties remain about the details of how the future development of this resource will unfold in terms of timing, scale, economic impact, technological changes, and environmental implications. It is clear that natural gas could have a substantial impact on the U.S. energy landscape in a number of ways, but how one thinks through the next steps is critical to ensuring the prudent and sustainable development of unconventional natural gas.

Appendix

Risk Management

Water

Water is a central issue in the debate over the shale gas revolution because it is a critical component of the hydraulic fracturing process as currently practiced. Perceived water risks can be separated into two broad categories: impacts on water quantity and impacts on water quality. The risks for each category are highly dependent on the geology, geography, and size of the play, as well as the technology utilized. Risks and impacts vary among plays, but they can also vary within plays. Moreover, water risks and the management of these risks have evolved over time. Since the inception of unconventional gas development, the regulatory landscape, industry structure and practices, and public understanding of water-related development risks have largely improved. Even with this evolution, opportunities to improve risk mitigation and regional water management issues at scale still exist and must be further explored. In addition, as industry continues to improve its own practices and respond to a changing regulatory landscape and shifting commercial realities, companies are investigating the cost-effectiveness of various water management technologies and the options that are available.

Several issues span both quantity and quality concerns. First, the scale of operations matters in terms of quantity and quality because it affects the amount of water withdrawn, the frequency of drilling, and the amount of produced and flowback water that must be either recycled or sent for disposal. Moreover, when scale is considered against regional variables such as water availability, competing users, geology, and population growth, its importance is amplified.

Second, technologies and management techniques are being employed and developed to address water-related production risks, but scale may stress such capabilities. For example, a technology or water management technique might reduce the water impact but introduce a new impact on energy or air.[1] Even if this new impact is minimal, it still represents a trade-off that must be calculated when evaluating environmental sustainability or impact on operations. Part of this situation can be attributed to the nascency of shale gas production, but it is also symbolic of the broader lack of understanding of the life cycle of water and its real economic value.

1. NPC, "Management of Produced Water from Oil and Gas Wells."

Finally, capacity is another issue confronting water management and shale gas development in terms of the existing infrastructure and the human capacity to monitor and assess risks and enforce regulations. Many areas seeing rapid production growth do not have adequate infrastructure in place, and states have been working to adapt.

POTENTIAL RISKS

Quantity

Shale gas production withdraws and consumes water.[2] On average, it takes 65,000–600,000 gallons to drill[3] and 3–5 million gallons to fracture one well.[4] The sourcing and the timing of the withdrawal can be, depending on the region and other competing users, very important. The regulatory oversight of water withdrawals varies by state—and may be managed by a state, local, or regional agency. The significance of concerns about water quantity is highly dependent on a host of other factors, including the number of wells drilled, amount of water used per well, degree of recycling, ability to use nonpotable water, local water availability, competing uses, and population growth.[5] Each of these factors varies over time and space.

Producers must consider several factors when considering water supply, including the access and proximity of the supply to the drilling pad; piping versus trucking; seasonal or perennial availability; quality; permitting complexity; shared resources with other operators; drilling schedule compatibility with permitting schedule; and cost.[6] Table A1 is an overview of several main concerns associated with water quantity and their potential impacts.

The use of water for hydraulic fracturing should be viewed in the context of other water users. As Table A2 shows, in areas where hydraulic fracturing has been in extensive use, other water users represent a much larger share of the total water used.

2. According to the USGS, withdrawal can be defined as the amount of "water removed from the ground or diverted from a surface water source for use"; consumption refers to the amount of water that is "evaporated, transpired, incorporated into products or crops, consumed by humans or livestock or otherwise removed from the immediate water environment." Joan F. Kenny et al., "Estimated Use of Water in the United States in 2005," U.S. Geological Survey Circular 1344, Reston, VA, 2009, 47, 49, http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

3. Chesapeake Energy, "Water Use in Deep Shale Gas Exploration: Fact Sheet," May 2012, http://www.chk.com/Media/Educational-Library/Fact-Sheets/Corporate/Water_Use_Fact_Sheet.pdf..

4. J. Daniel Arthur, Mike Uretsky, and Preston Wilson, "Water Resources and Use for Hydraulic Fracturing in the Marcellus Shale Region," 3, http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000797_WaterResourceIssues.pdf.

5. Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity*.

6. David Yoxtheimer, "Water Resource Management for Natural Gas Development" (presentation at Marcellus Center for Outreach and Research, Penn State, University Park, PA), http://www.acus.org/files/EnergyEnvironment/BrusselsWorkshop/Yoxtheimer_Water_Usage_Sourcing.pdf.

Table A1. Water Quantity Concerns and Potential Impacts

Concern	Potential impact
Water sourcing	Surface water: Ecosystem impacts Impact of hydrology of water body Overburdening municipal water supply
	Groundwater: Drawdown of aquifers and water table faster than recharge rate Saltwater intrusion
	Alternative: Abandoned mine drainage Treated wastewater Brine and other nonpotable water
Competing users	Less water available for more end users: industry, agriculture, residential, habitat
Timing of withdrawal	Water availability—seasonal or perennial Water quality Pass-by flows
Amount of produced water/flowback	Volume to be treated or sent for disposal Storage of large quantities of flowback/produced water Transport of large volumes and potential accidents
Water transport	Increased truck traffic Road degradation Accidents Pipelines and necessary right of way

Source: Project on Realizing the Potential of Unconventional Gas, In-Depth Session #3: Water Management, November 13, 2012, CSIS.

Table A2. Total Water Use per Shale Play by User

Shale play	Public supply (%)	Industrial and mining (%)	Power generation (%)	Irriga-tion (%)	Livestock (%)	Shale gas (%)	Total water use (billion bbl/yr)
Barnett	82.70	4.50	3.70	6.30	2.30	0.40	11.15
Fayetteville	2.30	1.10	33.30	62.90	0.30	0.10	31.9
Haynesville	45.90	27.20	13.50	8.50	4.00	0.80	2.15
Marcellus	11.97	16.13	71.70	0.12	0.01	0.06	85

Source: J. Daniel Arthur and Jon W. Seekins (ALL Consulting), “Water and Shale Gas Development” (presentation at National Association of Royalty Owners National Convention, Pittsburgh, October 7, 2010), 24, http://www.all-llc.com/publicdownloads/ALL-NAROShaleWater.pdf.

Note: Shale gas water use is based on one peak year projections; bbl/yr = barrels per year.

Similarly, compared with other energy forms, shale gas is less water-intensive per Btu of energy produced than other fossil fuels such as coal, conventional oil, oil sands, and oil shale.[7] However, some caveats are in order. One is the time frame for withdrawals, which can occur over a couple of weeks, potentially placing strain on resources in a short amount of time.[8] Another is that the water withdrawn for hydraulic fracturing is mostly consumptive because it is either lost to the formation or disposed of in injection wells.[9] Finally, cumulative impacts matter, and the overall impact will be influenced by both the number of wells drilled, as well as the implementation of greater recycling and less water-intensive technologies.

If production continues to grow, the number of wells needing hydraulic fracturing stimulation will increase, pushing up water requirements. Moreover, several wells will have to be hydraulically fractured multiple times to continue production. However, not all of the water used to stimulate a well is consumed because 25–75 percent of the fracture fluid pumped down the well returns to the surface within weeks as flowback or produced water (which varies, depending on play and geology); additional water from the formation returns over the lifetime of the well.[10] Some of this water can be recycled and reused for other fracturing jobs—though this practice, too, elevates concerns about waste disposal and surface management of the produced water, as well as the disposal of the remaining waste stream.

Companies have also looked at using nonpotable water instead of freshwater, such as mine pool water and other industrial wastewater. However, significant questions remain about the legal liability associated with the abandoned water and the need for both a state and federal release from liability. Thus while the use of nonpotable water presents a big opportunity, it remains at the beginning stages. It is evident that even though steps have been taken to address the volume of water required for hydraulic fracturing, the technology and processes are still evolving, and not every producer has adopted them.

Quality

Although much of the public discourse has centered on the possibility of contamination of drinking water from hydraulic fracturing, thousands of hydraulic fracturing operations have been performed, and no instance of contamination of groundwater by fracturing has been substantiated. A more likely source of groundwater contamination is from faulty well construction through improper casing or intersection with old abandoned wells. A consensus is emerging that the potential for surface water contamination is greater than for groundwater contamination.[11]

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7. Jordan Macknick et al., *A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technologies*, Technical Report NREL/TP-6A20-50900 (Golden, CO: National Renewable Energy Laboratory, March 2011), http://www.nrel.gov/docs/fy11osti/50900.pdf.
8. Gao, "Fracking's Water Problem."
9. Ibid.
10. U.S. Environmental Protection Agency (EPA), *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (Washington, DC: EPA, November 2011), 23, http://www.epa.gov/hfstudy/HF_Study__Plan_110211_FINAL_508.pdf.
11. Alan Krupnick, Hal Gordon, and Sheila Olmstead, *Pathways to Dialogue: What the Experts Say about the Environmental Risks of Shale Gas Development* (Washington, DC: Resources for the Future, February 2013), http://www.rff.org/Documents/RFF-Rpt-PathwaystoDialogue_FullReport.pdf.

However, identifying the cause of contamination (see Table A3), should it occur, can be difficult for a variety of reasons, including a lack of baseline testing of water wells prior to production, trade secrets regarding the hydraulic fracturing chemicals used, and a complex and often poorly understood hydro-geologic environment.[12]

Table A3. Water Quality Concerns and Potential Sources

Concern	Potential Source
Groundwater contamination	Methane migration Faulty casing/cementing Hydraulic fracturing and fracturing fluids Injection wells
Surface water contamination	Spills/leaks of produced/flowback water Spills/leaks of fracturing chemicals/fluids Erosion and stormwater runoff from pads, truck traffic, potential accidents transporting wastewater

Source: Project on Realizing the Potential of Unconventional Gas, In-Depth Session #3: Water Management, November 13, 2012, CSIS.

Questions about the potential for groundwater contamination generally fall into two categories: (1) whether fluids used in hydraulic fracturing can migrate from a production zone into groundwater aquifers, and (2) what chemicals and other materials are used in hydraulic fracturing fluids. Concerns have been raised about the potential for fractures to link the shale formation to the aquifer, thereby providing an avenue for gas or fluids to migrate. However, most experts agree that this is highly unlikely because the actual fractures occur at a depth of 6,000–10,000 feet from the bottom of the aquifer. Moreover, several thousand feet of nonpermeable layers of rock lie between the fractures and the aquifer.

Even though the perceived risk regarding hydraulic fracturing and methane and fracturing fluid migration may not be substantiated, another risk is associated with the potential for methane migration via faulty wellbores and poor cementing and casing. The Groundwater Protection Council (GWPC) recently released a white paper based on a conference held in the summer of 2012 that concluded that there are multiple potential sources of stray gas, including poorly constructed wellbores and natural shallow methane formations. However, it acknowledged that methane was already present in many water wells before drilling.

Producers have begun to conduct baseline testing before drilling to determine the quality of the water before and after operations. However, many water wells are private, and owners can refuse to have them tested. In places with a history of oil and gas drilling, the issue of mapping and dealing with the presence of abandoned wells is also an issue for both unconventional gas drilling and water well construction.

12. Mary Tiemann et al., *Marcellus Shale Gas: Development Potential and Water Management Issues and Laws* (Washington, DC: Congressional Research Service, January 2012), 3, http://www.arcticgas.gov/sites/default/files/documents/12-1-27-crs-marcellus-shale-gas-development-potential-issues-laws.pdf.

The most active policy discussions have centered on the disclosure of the hydraulic fracturing fluid chemicals used in operations. In response to public concerns about the possibility that harmful materials will be used in drilling operations, many states and local communities have enacted regulations calling for greater disclosure of the chemical composition of hydraulic fracturing fluid. The oil and gas industry has also established a website, FracFocus, designed to foster greater transparency of fracturing fluid content on a voluntary basis. Although such efforts have alleviated some concern, the debate continues about what level of disclosure is required to ensure public confidence. Certain industry voices claim that some combinations of chemicals constitute trade secrets that should be protected when it comes to disclosure. The timing of disclosure has also become an issue, with some environmental advocates pushing for more frequent and even predrilling disclosure to give local communities more oversight over the drilling process. Finally, regulators are working to determine how best to keep up with innovations in drilling fluids and processes in order to properly evaluate, regulate, and disclose information about the operations to local communities.

The potential for surface water (and groundwater) contamination from poor aboveground water management is perhaps a more important issue. This issue includes potential contamination from runoff and erosion via land disturbance from pads, pipelines, and road use; handling and storage of flowback/produced/hydraulic fracturing fluids; accidental releases (either by storage leakage or transportation accidents); and release of treated flowback/produced water into nearby rivers and streams.
Companies are seeking solutions, utilizing some straightforward fixes such as berms and pit linings on well sites to minimize the risk of water degradation from runoff or surface spills.

WATER MANAGEMENT: TECHNOLOGICAL AND REGULATORY ADVANCEMENTS

Water management is not a new challenge for the oil and gas industry. However, the scale of development, the centrality of water to operations, and heightened public scrutiny have introduced new challenges. The cost of water and the price of the disposal of water in injection wells have increased. This increase is in part driving industry to develop new technologies and to look at alternative reuse technologies to reduce the volume of freshwater required and reduce the amount of water sent for disposal. Similarly, evolving regulations are also pushing operators toward alternative methods either to comply with existing regulations or to be ahead of the curve in anticipation of more stringent standards.

Companies confront a host of challenges associated with wastewater management, including limited disposal options (geological constraints for deep wells), long haul distances, long waits in line, costs for disposal or even reuse, truck traffic, treatment challenges due to volume and chemical composition, and increased regulatory and public scrutiny.
Currently, a multitude of management techniques and technologies exist to deal with both the quantity and quality concerns of water management, including recycling and reuse, on-site evaporation in impoundments, on-site injection into wells, disposal at a centralized facility via evaporation or underground injection, treatment through surface water treatment plants, mobile treatment units, closed-loop drilling systems, limited use of open

impoundments for mixing flowback with freshwater, use of protective liners on pad sites, and utilization of more benign “green” hydraulic fracturing fluids.

Not all options are available in every play, and this has resulted in fragmentation of the industry. To date, injection wells have been the primary mechanism for disposal, but recent concerns about earthquakes and the rising costs of water have elevated other techniques.

The extent to which an operator is able to treat and then utilize produced/flowback water is contingent on how much and how quickly it returns to the surface. This rate largely varies by play, and the range of the water recovery rate is wide, anywhere from 25 to 75 percent. Another factor determining the feasibility of reuse is the chemical composition of the water that returns; it does vary by location, geology, production lifetime, and operation. Flowback water can have high levels of total dissolved solids (TDS), and additives are in the fracturing fluid, as well as compounds that are naturally occurring in the formation.

Recycling has become the dominant management choice for treating water, especially as requirements for surface discharge become more stringent and costly (see Box A1). Recycling also provides several co-benefits because it reduces the number of trucks needed to haul freshwater, decreases the amount of water injected into disposal wells, and addresses concerns about potential seismic challenges. Although such technologies are a step toward the minimization of freshwater use, they will only reduce the amount of freshwater needed, not eliminate it completely. Flowback volumes will need to be supplemented with additional freshwater to match the required volume for fracturing, and the logistics of transporting this water to the next well must also be tightly coordinated. Moreover, the level of activity determines not only the need for recycling but also the amount of produced water available for blending. Some producers have found themselves to be net water producers.

Despite the advances, recycling and reuse still create a waste stream, and operators will have to find a cost-effective way of disposal. Other uses for the waste stream are also starting to emerge, whereby it is mixed into other usable products such as road asphalt, well site fluids, and de-icing materials for frozen roads. The economic benefits of these options remain unclear, and the regulations overseeing this type of discharge method are still evolving.[13]

Another management technique being utilized is a closed-loop drilling system that eliminates the exposure of contaminated water to air because it eliminates the need for pits to store drilling fluids.[14] Similarly, an emerging trend in fracturing fluid composition is the use of “green” hydraulic fracturing fluids that are biodegradable and nonbioaccumulating.[15] Companies are also looking at the possibility of using waterless hydraulic fracturing fluids, such as liquid propane or CO_2 or nitrogen gas foams or gels, although waterless hydraulic fracturing fluids are not yet widely used because they each have their own challenges.[16]

13. CSIS, Project on Realizing the Potential of Unconventional Gas, In-Depth Session No. 3: Water Management.
14. Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector*, 88.
15. Ibid.; Stark et al., *Water and Shale Gas Development,* 28.
16. Stark et al., *Water and Shale Gas Development*, 28.

Box A1. Variation in Wastewater Treatment between States, Colorado versus Pennsylvania

How producers approach water management is influenced by the state and play in which they are operating—geology, regulations, costs, and existing infrastructure all influence their choices. Management of wastewater in Colorado versus Pennsylvania is a perfect example of the inherent unevenness of existing practices and of how location factors influence management choices.

The ongoing trend is toward greater recycling rates of flowback/produced water over disposal. Pennsylvania, which has limited disposal wells because of its geology, has been an interesting test case for water management. In 2009 it instated regulation increasing the stringency of TDS levels allowed in surface water discharges, making it uneconomic for producers to continue to utilize municipal water treatment. All of these factors, in addition to advances in technology, have supported the trend toward recycling. In 2008, 80 percent of produced water and 54 percent of flowback were treated and disposed of via surface water discharge. In 2011 less than 1 percent of flowback and produced water was treated using that method. Instead, industry has shifted toward centralized disposal facilities and recycling, which now handle 80 percent of produced water and 99 percent of flowback volumes.

Comparatively, in Colorado surface water discharge of produced water and flowback has increased from 2 to 11 percent over the same time frame, and management is dominated by the use of on-site injection pits and evaporation ponds, although they did decline from 72 percent in 2008 to 58 percent in 2011.

The use of centralized disposal facilities increased in both states over the noted time period, but more so in Pennsylvania (10 percent to 44 percent) than in Colorado (26 percent to 31 percent).

Source: Jeffrey Logan et al., *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity* (Golden, CO: Joint Institute for Strategic Energy Analysis, November 2012), 73, 84, http://www.nrel.gov/docs/fy13osti/55538.pdf.

Most companies realize that much of their social license to operate hinges on their prudent management of water in terms of both quantity and quality. Better water management has widely become an integral part of companies' sustainable development initiatives. Thus it appears that community perception of industry responsibility is a key driver of the push into these alternative technologies. At the same time, the shift is also a reflection of an improving business and economic case for environmental management.

Air

One factor often mentioned by proponents of increasing domestic shale gas production is that natural gas has the lowest carbon content of any fossil fuel, making it a more environmentally friendly energy source, especially where it would push out coal in electricity generation. However, the production of shale gas, including exploration, drilling, venting/flaring, equipment operation, gathering, and the associated truck traffic, results in emissions of volatile organic compounds (VOCs), NO_x, SO_x, particulates, and greenhouse gases (GHGs), including methane.[17] Methane is of particular concern because it has a greenhouse gas warming potential significantly greater than that of carbon dioxide, and its relative impacts are greater on a shorter time scale.[18]

POTENTIAL RISKS

Air issues are unique in that they are simultaneously a local and a regional issue, as well as a national and even a global issue. Again, the location and type of play can greatly affect the type and level of potential emissions. As shale development has increased, so, too, have the concerns about the environmental impacts from air emissions related to shale gas development. Significant air quality impacts result from the processes and equipment used during production. Much of the equipment used to produce shale gas is powered by diesel fuel and emits NO_x, SO_x, particulates, and other air contaminants that can increase air pollution. Industry, recognizing this as a concern, recently began working to displace diesel on-site, utilizing instead cleaner on-site gas.[19]

Much of the debate over air-related issues has centered on the estimates of GHG emissions, in particular the amount of methane leaked into the atmosphere during the production, gathering, processing, storage, transport, and distribution of natural gas. Methane accounts for nearly 90 percent of natural gas, and it is a greenhouse gas more potent than carbon dioxide.[20] The concern, therefore, is that the benefits to the climate of switching to natural gas from other fossil fuels could be significantly undermined by methane leakage.

Many reports have examined the overall impact on the climate of switching from other fossil fuels to natural gas. Because of uncertainty about methane emission rates, there is considerable debate in academic and policy circles about the extent to which switching to natural gas may result in net reductions of GHG emissions.

Much of the public attention and many research efforts on methane emissions have focused on well completion—specifically, how much is produced and emitted during

17. DOE, "Ninety-Day Report." 15; VOCs are hydrocarbons such as benzene and propane that evaporate quickly and can contribute to ground-level smog.

18. Intergovernmental Panel on Climate Change, *Climate Change 2007: The Physical Science Basis*, ed. Susan Solomon et al. (New York: Cambridge University Press, 2007); Ramon A. Alvarez et al., "Greater Focus Needed on Methane Leakage from Natural Gas Infrastructure," *Proceedings of the National Academy of Sciences of the United States of America* 109 (April 2012), http://www.pnas.org/content/109/17/6435.

19. DOE, "Ninety-Day Report," 3.

20. Susan Harvey, Vignesh Gowrishankar, and Thomas Singer, *Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste* (New York: National Resources Defense Council March 2012), 3, http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

flowback.[21] Following hydraulic fracturing, some of the initial fluids used to fracture the well begin to return to the surface over the course of a week to 10 days. Reduced emission completion (REC) technologies can dramatically reduce emissions of the methane that is brought to surface with flowback fluids. Understanding the extent of such completion emissions is a key point of research.

Another area of concern is wellbore cleaning or liquids unloading, which is a period during which a well is taken out of production to clean out liquids that may have accumulated. While the liquids are being removed and captured, the gases have traditionally been vented or flared, not captured. Because most unconventional wells that have been fractured are newer, the data on the potential of methane releases during liquids unloading are more preliminary than those for flowback periods.

MEASUREMENT AND DISCREPANCY OF RISK

In 2011 EPA substantially revised its greenhouse gas inventory numbers for natural gas, showing much higher estimates for methane emissions. It attributed some of this increase to the growth of unconventional gas production.[22] Several studies of the life cycle of greenhouse gas emissions from shale gas—notably those by Robert Howarth at Cornell and the National Oceanic and Atmospheric Administration (NOAA)[23]—have claimed figures much higher than the emissions estimates made by EPA, thereby raising concerns that the levels of methane being released during the production of shale gas are higher than those of conventional gas production and could result in natural gas being even worse than coal from a climate perspective.

Subsequent studies have questioned the analysis conducted by Howarth,[24] and several life cycle studies released have indicated that methane releases are more likely comparable with those for conventional gas and significantly lower than those for coal.[25] Part of the discrepancy of these studies derives from the different data sets available, including the variations across shale plays, the number of wells, as well as the year when the data samples were gathered. And, ultimately, all studies have suffered from the lack of robust empirical data on emissions. These discrepancies track closely with a recommendation made by a Secretary of Energy Advisory Board (SEAB) report, which stated the need to develop common definitions, parameters, and techniques for measurements so that data and the various studies can be adequately compared.[26] SEAB noted that, although work is beginning on measuring the GHG footprint of

21. Francis O'Sullivan and Sergey Paltsev, "Shale Gas Production: Potential versus Actual Greenhouse Gas Emissions," *Environmental Research Letters* 7 (December 2012).

22. U.S. Environmental Protection Agency (EPA), *Draft Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011* (Washington, DC: EPA, February 2013).

23. R.W. Howarth, R. Santoro, and A. Ingraffea, "Methane and the Greenhouse Gas Footprint of Natural Gas from Shale Formations," *Climatic Change* 106 (June 2011): 679-690; G. Pétron et al. "Hydrocarbon Emissions Characterization in the Colorado Front Range: A Pilot Study," *Journal of Geophysical Research: Atmospheres* 117 (2012).

24. U.S. Department of Energy and National Energy Technology Laboratory, *Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery, and Electricity Production* (Washington, DC: U.S. Department of Energy, October 24, 2011), http://www.netl.doe.gov/energy-analyses/pubs/NG-GHG-LCI.pdf.

25. O'Sullivan and Paltsev, "Shale Gas Production."

26. DOE, "Ninety-Day Report," 17.

natural gas over the entire fuel cycle, more work needs to be done so that policymakers can adequately and appropriately compare fuels when considering future policies.[27]

MANAGEMENT: TECHNOLOGICAL AND REGULATORY

In April 2012, EPA issued new federal regulations to improve air quality by lowering emissions from oil and gas operations. These regulations will require the use of reduced emissions completions, or "green" completions, on all gas production wells that are hydraulically fractured. These measures will significantly reduce both VOCs and methane emissions.[28] Notably, the new EPA standards do not address completion emissions from oil wells or co-production wells, which can result in significant venting of VOCs and methane to the atmosphere. Nor do the new standards address liquids unloading—another potential source of methane emissions, as noted earlier.

Green completion is the process by which the flowback is contained in a closed-loop system: water and fluids are captured and treated, solids are filtered out, and the methane is separated out for later recovery. This process can reduce methane emissions by 1–1.7 million short tons[29] and VOCs by 95 percent.[30]

Green completion technologies provide well operators with another option for capturing the gas during liquids unloading or workovers. In addition, in areas with limited infrastructure, flaring of the gas has been an effective means of reducing the amount of methane vented during the beginning of the production phase, although this process still releases VOCs and CO_2. EPA regulations require flaring gas well completion emissions until the green completion regulations go in effect in 2015.

Colorado and Wyoming have required green completions since 2009 and 2010, respectively, as do several cities such as Fort Worth, Texas.[31] Thus far, the required implementation of green completions has not affected the pace of development in Colorado and Wyoming, and in each state the number of horizontal drilling permits issued has risen.[32] Companies are increasingly using these technologies, and they have been successful in capturing a saleable product, resulting in economic gain.[33] One company has acknowledged that it is able to capture an average 16 million cubic feet of gas, and it has reduced the cost to capture it from $20,000 per well to near zero.[34] Another has echoed the economic sensibility of capturing stray gas, reporting that it has implemented systems to capture the gas on more than 90 percent of its wells.[35]

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27. Ibid.
28. EPA, "Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet."
29. This amounts to 19–33 million tons of CO_2 equivalent.
30. EPA, "Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet."
31. Ibid.
32. Baird Equity Research, "Energy Policy: Upstream: Unconventional Drilling Regulations," March 16, 2012, 11, https://baird.bluematrix.com/docs/pdf/70b8e0c5-7762-49ca-be28-3d8b3bcc12ba.pdf?co=Baird&id=jpolson@bloomberg.net&source=mail.
33. Jim Efstathiou Jr., "Drillers Say Costs Manageable from Pending Gas Emissions Rule," Bloomberg, April 17, 2012, http://www.bloomberg.com/news/2012-04-17/drillers-say-costs-manageable-from-pending-gas-emissions-rule.html.
34. Ibid.
35. Ibid.

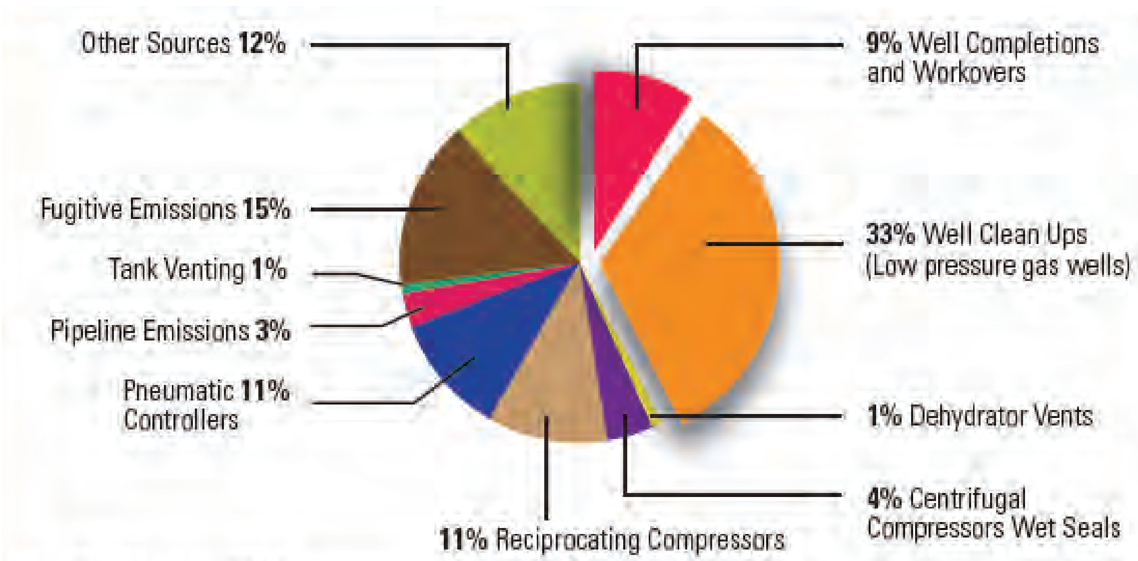
CHALLENGES

Cost is an oft-cited challenge for effective implementation, though estimates of compliance costs vary widely. EPA has estimated that the income from the sale of the methane captured would offset the costs of the new required systems and technologies by $11–19 million by 2015.[36] API, at the other end, has estimated that the cost of compliance would add an estimated $180,000 per well, increasing costs industry-wide by $783 million over the course of four years and reducing gas output by 9–11 percent.[37] An independent estimate has found that the regulations would cost producers an average of $316–511 million a year, using a gas price of $3-4 per trillion cubic feet (which equates to less than 1 percent of revenues).[38]

Fugitive emissions—emissions of methane and VOCs at various points along the supply chain because of leaking valves, pumps, pipes, and so on—can be a major source of air pollution. Regulation of fugitive emissions at the federal and state levels has thus far been inconsistent and is being highlighted as one of the key areas of opportunity for further emission reductions.

Figure A1 shows the emission sources along the natural gas supply chain. Depending on the location of the play and composition of gas, numerous smaller fixes may be feasible along the supply chain—storage tanks, compressors, pipeline valves, and other equipment used to deliver gas from wells to consumers.[39]

Figure A1. Sources of Natural Gas System Methane Emissions



Source: Susan Harvey, Vignesh Gowrishankar, and Thomas Singer, *Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste* (New York: National Resources Defense Council, March 2012),10, http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

Note: Total emissions in 2009 were 715 billion cubic feet.

36. EPA, "Overview of Final Amendments to Air Regulations for the Oil and Natural Gas Industry: Fact Sheet."
37. Efstathiou, "Drillers Say Costs Manageable from Pending Gas Emissions Rule."
38. Rich Heidorn, "Fracking Emissions Rules: Re-estimating the Costs," Bloomberg Government Blog, July 19, 2012, http://about.bgov.com/2012/07/19/fracking-emissions-rules-re-estimating-the-costs/.
39. A detailed list of possible technology and cost estimates is available in Harvey, Gowrishankar, and Singer, *Leaking Profits*, 18.

New research and data are becoming available on the overall picture of the greenhouse gas risk, providing stakeholders with a clearer understanding of the risk areas and of the ways and technology options to reduce possible leaks.

Seismicity

Concerns about the potential risk posed by induced seismicity (minor earthquakes caused by human activity) increased after several small to medium-size seismic events in Arkansas, Colorado, Ohio, Texas, and Virginia in 2011.[40] Despite the fact that many of these earthquakes were minor, they heightened concern among the public about the safety of hydraulic fracturing and shale gas extraction and the potential for increased seismic activity. The combination of the lack of detailed regional geological knowledge, the gap between public perception and reality regarding seismic hazards, and the differing political and economic agendas create a complex set of challenges for regulation and policy development.

Seismicity, which is not a new concern,[41] can be caused by a variety of activities such as mining, driving piles for bridge or building construction, drilling geothermal wells, or injecting fluids at high pressure in seismically active areas. Any time pressure is applied to or reduced in an underground rock formation, there is at a minimum a risk of induced seismicity.[42] Nevertheless, because of the increase in shale gas development, the uptick in seismic events midcontinent, the heretofore minimal damage and impact, the dearth of publicly available data and understanding, and the fact that many of the earthquakes have occurred in areas with little recent history of seismic activity, the potential for induced seismicity warrants further study and attention by regulators, policymakers, and industry members.

POTENTIAL RISK

The water injected during hydraulic fracturing does not pose a high risk for seismic activity.[43] This is largely because the amount of pressure applied, area of application, and duration of a hydraulic fracturing operation are generally not enough to trigger detectable seismic activity.[44] According to a study requested by Sen. Jeff Bingaman (NM) and conducted by the National Research Council looking at the potential for induced seismicity related to all energy development, the only seismic event that is confirmed as being caused by hydraulic fracturing occurred in Blackpool, England, in 2011.[45] Although many cases have cited hydraulic fracturing as the culprit,

40. Statement by Dr. William Leith, "Note: Virginia Quake Was Not Associated to Oil and Gas Development," U.S. Senate Committee on Energy and Natural Resources, "Induced Seismicity Potential in Energy Technologies: Hearing before the Committee on Energy and Natural Resources," 112th Cong., 2d sess., June 19, 2012, http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=7d03cfce-b4f6-4a3c-a048-d42c9583b96e.

41. Lawrence Berkeley National Laboratory, "Induced Seismicity: Oil and Gas," http://esd.lbl.gov/research/projects/induced_seismicity/oil&gas/.

42. Frank A. Verrastro, Lisa Hyland, and Molly A. Walton, "Fracking and Seismic Activity," *CSIS Critical Questions*, January 12, 2012, http://csis.org/publication/fracking-and-seismic-activity.

43. National Research Council, *Induced Seismicity Potential in Energy Technologies*.

44. Lawrence Berkeley National Laboratory, "Induced Seismicity: Induced Seismicity Primer."

45. National Research Council, *Induced Seismicity Potential in Energy Technologies*, 76.

so far no direct causal link has been established between hydraulic fracturing for unconventional gas and earthquakes in the United States.[46]

The real risk of seismic activity stems from the disposal of wastewater from hydraulic fracturing operations. According a report by the National Research Council, the "injected fluid volume, injection rate, injection pressure, and proximity to existing faults and fractures are factors that determine the probability to create a seismic event."[47] The report also noted that the potential area affected by seismic activity is not limited to the site or point in time of injection; rather, impacts could occur within several square miles and many months after disposal stops.[48]

To date, some minor earthquakes have been associated with wastewater injection, though none has caused loss of life or major damage. However, not all wastewater disposal wells cause earthquakes. The Department of Interior estimates that of the over 150,000 Class II injection wells, including nearly 40,000 oil and gas wastewater disposal wells, only a tiny fraction has induced seismicity.[49]

The increase in production of natural gas, however, has resulted in an increase in the amount of wastewater requiring disposal. In some cases, such as in Pennsylvania, which does not have its own Class II injection wells, wastewater has been trucked to Ohio for disposal. Such an approach could lead to a concentration of wastewater injection in the future, especially if production in Ohio takes off. Thus the long-term, cumulative impact of increased wastewater disposal and injection requires continuing study.[50]

Under EPA and state regulations, disposal of wastewater requires injection in permitted Class II injection wells, a common activity for decades. When large volumes of water are injected under pressure in seismically active areas, as the water enters fissures it could lubricate fault lines that could slip and cause tremors. There remains a high level of uncertainty about seismic activation mechanisms, and several seismic triggering mechanisms are under further research.

A recent example of seismic activity linked to wastewater injection from nearby oil and gas drilling is Youngstown, Ohio.[51] The wells in question have been closed pending further investigation. In the days immediately following the seismic activity in Youngstown, Ohio's Department of Natural Resources (ODNR) closed the injection well nearest the epicenter of the December 31, 2011, earthquake and also suspended activity at four other nearby injection wells to more fully evaluate the situation. Reports indicate that the sites had been accepting

46. Ibid.
47. Ibid., 156.
48. Ibid.
49. David J. Hayes, "Is the Recent Increase in Felt Earthquakes in the Central US Natural or Manmade?" U.S. Department of Interior, April 11, 2012, http://www.doi.gov/news/doinews/Is-the-Recent-Increase-in-Felt-Earthquakes-in-the-Central-US-Natural-or-Manmade.cfm.
50. National Research Council, *Induced Seismicity Potential in Energy Technologies*.
51. Ohio Department of Natural Resources, "Preliminary Report on the Northstar 1 Class II Injection Well and the Seismic Events in the Youngstown, Ohio, Area," March 2012, http://ohiodnr.com/downloads/northstar/UICExecSummary.pdf.

brine disposal since 2010, but that the injected volumes grew significantly in 2011. ODNR, in response to the Youngstown earthquakes, introduced new regulations for Class II wells to manage brine disposal, and they are some of the strictest in the nation.[52]

Earthquakes in Arkansas and Colorado were also causally linked to wastewater injection, and investigations are ongoing into the causes of earthquakes in Oklahoma and Texas.[53] Although none of these earthquakes caused major damage or injury, they did instill uncertainty into the public conscious.

EVALUATION AND MANAGEMENT OF RISK

Regulators and operators are already taking measures to reduce the likelihood of seismic activity from wastewater injection, including assessing seismic risk when identifying or permitting injection sites, requiring seismic monitoring at active well sites, and limiting well pressure thresholds by reducing the amount of water pumped into wells, as well as the pressure at which it is pumped. Discussions are also under way about whether and how to handle the issue of large-volume injection at or near fault zones.

In general, states are well aware of the potential risks posed by seismic events and of the elevated public concern. California, because of its seismic potential and history, has a well-developed regulatory framework around seismic hazard risk assessment (from natural tectonic sources). Other states have responded quickly to seismic activity (either suspending or stopping operations) and have implemented more frequent monitoring and review of operations and existing regulations. Indeed, many states acknowledge the need to increase monitoring of disposal wells and to better understand whether existing wells fall along a fault line.[54] Two states in particular—Colorado and Arkansas—are actively reviewing underground injecting permits to assess the potential for induced seismicity.[55] The Colorado Oil and Gas Conservation Commission (COGCC) has proposed a policy that would require the Colorado Geologic Survey to assess any Class II injection permit application for the potential of inducing seismicity.[56] Similarly, the Arkansas Oil and Gas Commission (AOGC) has introduced regulations that institute a moratorium that stipulates that for an area of over 1,000 square miles no Class II injection wells can be granted a permit without a hearing with the AOGC.[57]

At the federal level, the underground injection of fluids is regulated by a framework established by the Safe Drinking Water Act (SDWA). However, the SDWA does not cover

52. Ohio Department of Natural Resources, "Ohio's New Rules for Brine Disposal among Nation's Toughest," March 9, 2012, http://ohiodnr.com/home_page/NewsReleases/tabid/18276/EntryId/2711/Ohios-New-Rules-for-Brine-Disposal-Among-Nations-Toughest.aspx.

53. Statement by Mark D. Zoback, U.S. Senate Committee on Energy and Natural Resources, "Induced Seismicity Potential in Energy Technologies: Hearing before the Committee on Energy and Natural Resources," 112th Cong., 2d sess., June 19, 2012, http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=4f086706-79aa-43df-a6e9-1ce1169f6312.

54. Private conversations with a wide range of regulators.

55. National Research Council, *Induced Seismicity Potential in Energy Technologies*, 119.

56. Colorado Oil and Gas Conservation Commission (COGCC), "COGCC Underground Injection Control and Seismicity in Colorado," January 19, 2011, http://cogcc.state.co.us/Library/InducedSeismicityReview.pdf.

57. Arkansas Oil and Gas Commission (AOGC), "Final Rule H-1—Class II Disposal and Class II Commercial Disposal Well Permit Application Procedures," February 17, 2012, http://aogc.state.ar.us/PDF/H-1%20FINAL%202-17-2012.pdf.

induced seismicity, nor does it prescribe a mechanism for how to manage, investigate, and regulate induced seismicity. Thus the agencies that maintain oversight and compile research, including EPA, the state agencies with primacy for underground injection control, the Bureau of Land Management (BLM), the U.S. Forest Service (USFS), and the U.S. Geological Survey (USGS) often have responded to perceived induced seismicity in an ad hoc manner.[58]

In addition to the management steps that state and federal regulators can take to monitor and reduce the risks associated with wastewater disposal, a suite of technologies being employed or developed will help reduce the amount of wastewater in need of disposal. One such option is to recycle and reuse wastewater, thereby reducing the volumes that ultimately must be disposed of in injection wells. Technological advances are increasingly making this a cost-competitive option. In addition, firms are now developing and employing "green" hydraulic fracturing components, finding better ways to treat and recycle the liquids flow, and exploring ways to reduce the amount of water used in hydraulic fracturing operations through advanced minimization technologies—all of which could result in the generation of less wastewater. (For a lengthier discussion of water management options, see the section on water).

CHALLENGES AND AREAS IN NEED OF FURTHER RESEARCH

Most experts and reports have called for greater and more thorough research and data on seismicity. Currently, USGS is coordinating with EPA and the U.S. Department of Energy to better understand induced seismicity, and it is also working with universities to fund research on the impacts of wastewater disposal technologies and induced seismicity.[59] Several states are also undertaking in-depth studies, working with their geological surveys and university experts. Several questions have emerged from this and other research efforts, including: identification of data needs, detection of the causal factors that trigger seismic events (hard-to-pinpoint specific causal factors), and determination of the seismic risks across the shale gas production chain, whether injection can cause or make seismic incidents more frequent and increase the distribution in frequency and magnitude, what the real extent of impact and the probability of ground motion might be, and whether technology can more adequately monitor and predict activity.

The challenges and uncertainty surrounding induced seismicity are multidimensional. On the technical side, there is a need to better understand the regional variations in subsurface geology and tectonics, the interaction of fluids and geology, and the impact that varied technologies can have. Similarly, a major challenge is to understand the level and variety of risks (within the context of the geology) and to be able to translate these data into the appropriate mitigation and response measures. At the same time, when evaluating risk there is a need to understand what the risks of alternative disposal methods might be (e.g., not injecting wastewater but doing something else to it) and weigh the costs and benefits.

An overarching lack of data is a recurring theme within both reports and discussions. According to the report by the National Research Council's Committee on Induced Seismicity

58. National Research Council, *Induced Seismicity Potential in Energy Technologies*, 123.
59. Hayes, "Is the Recent Increase in Felt Earthquakes in the Central US Natural or Manmade?"

Potential, “We are unable to accurately predict the occurrence or magnitude of such [seismic] events because of the lack of comprehensive data on complex natural rock systems and the lack of validated predictive models.”[60] In general, the midcontinent geographic and stratigraphic data are poorly understood. There is a need to identify the location of the fault lines and where they are in relation to producing areas. Also needed are better measures of the geologic state of stress and the cumulative impacts on geologic state of stress. Data are also lacking on fluid injection (location of injection wells, depths, volumes and pressures, and time frames).[61] This information would aid regulators and industry alike in ensuring that development and disposal are not carried out in seismically prone areas and allow them to better coordinate disposal and monitor the risk of seismic activity and have baseline data before and after an induced seismic event. For the seismic data that do exist, there is a need to increase and improve their availability and transparency (currently, information is fragmented) and to close the information gap between legacy states and new producers.

Another lingering question is the cost of managing the risks related to induced seismicity. According to the National Research Council, as of yet there is no cost-effective way to evaluate the potential for induced seismicity in the proximity of injection wells or to map unexplored faults and measure in situ stress.[62]

There are also challenges associated with communication and public perception. Although much of the seismic activity to date has been minor, the public, especially in areas unaccustomed to seismic activity, have an elevated sense of risk. Increased seismic monitoring would help increase the amount of data available and may help allay public concern. Constant and transparent communication to the public about the potential risks, ongoing operations, and management practices in place is essential to regain public acceptance after an event has occurred. California and its regulatory framework might provide a guideline for other states on how to manage the gap between perceived and real risk.

As has proven true of other risks of shale gas development (such as water and community impacts), the perceived risk of seismicity is often different than the real risk. Again, it begs the question of whether it matters that the industry evaluation of risk does or does not match the public risk profile. Reaching a consensus on the level of certainty necessary for continued production activity will require pursuing ongoing discussions with operators, policymakers, regulators, and the scientific community, as well as establishing a means to communicate the outcome of these discussions to local stakeholders.

60. Don Clarke, “Induced Seismicity Potential in Energy Technologies” (presentation at USC HF-IS Workshop, June 8, 2012), http://gen.usc.edu/assets/001/81342.pdf.

61. Ibid., slide 27.

62. National Research Council, *Induced Seismicity Potential in Energy Technologies*, 156.

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