

ISSUE BRIEF

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What Led to the Boom?

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1. Introduction

In this issue brief, we provide an overview of the economic, policy, and technology history of shale gas development in the United States to ascertain what led to the shale gas boom. For a much more detailed review, see our discussion paper (Wang and Krupnick 2013).

In the past decade, shale gas experienced an extraordinary boom in the United States, accounting for only 1.6 percent of total US natural gas production in 2000, 4.1 percent by 2005, and an astonishing 23.1 percent by 2010. This remarkable growth has spurred interest in exploring for shale gas resources elsewhere. A number of countries, including China, Mexico, Argentina, Poland, India, and Australia are beginning to develop their own shale gas resources. Although it is difficult to know definitively the necessary or sufficient conditions for stoking a shale gas boom, a historical review of the US experience can be informative.

For a real boom to occur in the private sector, high profitability, or at least the expectation of future high profitability, is a necessary ingredient. Our review suggests that a number of factors converged in the early 2000s—

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Key Points

- The shale gas boom resulted from factors that ultimately enabled firms to produce shale gas profitably, including technological innovation, government policy, private entrepreneurship, private land and mineral rights ownership, high natural gas prices in the 2000s, market structure, favorable geology, water availability, and natural gas pipeline infrastructure.
- The key question for policymakers in countries attempting to develop their own shale gas resources is how to generate a policy and market environment in which firms have the incentive to make investments and would eventually find it profitable to produce shale gas.

including high natural gas prices, favorable geology, private land and mineral rights ownership, market structure, water availability, and natural gas pipeline infrastructure—to make it profitable to produce large quantities of shale gas, but that the most important factor was innovations in technology. Some of the key technological innovations resulted from government research and development (R&D) programs and private entrepreneurship that aimed to develop unconventional natural gas, but other important technologies were largely developed by the oil industry for use in oil exploration and production.

The seed of the shale gas boom was planted in the late 1970s, when the US government aimed to encourage the development of unconventional natural gas in response to the severe natural gas shortage at the time. Private firms lacked the incentive to make large, risky R&D investments, partly because it is difficult to keep new technologies proprietary in the oil and gas industry, where few technologies are patentable or licensable. Also, in the early years, unconventional gas sources could not compete with conventional oil or gas sources for investment dollars, and most US gas producers were small and did not have the incentive or capacity to do much R&D. In response, the US government funded R&D programs and established tax credits (and incentive pricing) that stimulated the development of shale gas in the Appalachian and Michigan Basins and helped develop some key technologies, such as microseismic fracture (frac) mapping.

It was, however, the private entrepreneurship of Mitchell Energy & Development (Mitchell Energy, hereafter) that played the primary role in developing the Barnett play in Texas, and it was the successful development of the Barnett play that jump-started the shale gas boom. Government-sponsored R&D programs did not target the Barnett play, and tax credits had a rather limited impact on Mitchell Energy. What Mitchell Energy had was the need and the financial capacity to develop the Barnett play. Later, the firm was also motivated by the potential to obtain large financial rewards from its innovations. The firm did this by leasing large tracts of land and the associated mineral rights at low prices and later selling the company—including not only its leases but also its innovations and expertise—at a higher price. This strategy, which is made possible by the private land and mineral rights ownership system in the United States, overcomes the difficulty of monetizing technology innovations in the industry.

We also note that, while environmental regulations of shale gas development are outside the scope of this issue brief, there was a significant effect of environmental lawsuits on Mitchell Energy and the implication that judicial enforcement of liability laws constrains firm behavior, even in the absence of environmental regulations specific to shale gas development.

2. What Led to the Government Policies on Unconventional Natural Gas?

In the 1960s and 1970s, price ceilings on interstate natural gas were set at levels below the equilibrium prices that would arise in a competitive market. By stimulating demand and discouraging supply, these price ceiling resulted in shortages, first in natural gas reserves, and later in production. The shortage led to the passage of the Natural Gas Policy Act of 1978 (NGPA),

which required phased removal of wellhead price controls and provided incentive pricing to encourage the development of new natural gas, including from unconventional sources.

In response to the 1973 oil embargo and the subsequent “energy crisis,” the US government adopted a series of policies, including the consolidation and expansion of energy-related R&D programs, that ultimately led to the creation of the Department of Energy (DOE) to consolidate responsibilities for all federal energy policy and R&D programs. Federal spending on energy research significantly increased in the mid-1970s; for fossil energy programs, spending rose more than 10-fold between 1974 and 1979, from \$143 million to \$1.41 billion (NETL 2010).

Starting in the late 1970s, the US government adopted a series of specific policies to promote the development of new sources of natural gas, which included incentive pricing, tax credits, R&D programs for unconventional natural gas, and policies promoting industry restructuring.

2.1 INCENTIVE PRICING AND TAX CREDITS

Section 107 of the NGPA provided for incentive pricing for Devonian(-age) shale gas and other forms of unconventional natural gas with high extraction costs. The deregulation of wellhead prices for natural gas from Devonian shale and some other sources in 1979 created a huge advantage for these fledgling gas resources. In the early 1980s, the deregulated high-cost natural gas was selling at more than twice the price of regulated natural gas.

The 1979 oil crisis led to the passage in 1980 of the Crude Oil Windfall Profit Tax Act, part of which provided tax credits for producing unconventional fuels. This credit, implemented under Section 29 of the Internal Revenue Code, applied to unconventional gas from Devonian shale, coal seams, and tight gas as well as some other fuels. The size of the tax credit for Devonian shale (and coalbed methane) was determined by a formula that accounted for inflation and contained a factor that would gradually phase out the effect of the tax credit when the price of oil was high, such that the credits would take effect when oil prices were low enough to limit the competitiveness of unconventional fuels.

Gas producers had to select either NGPA incentive pricing or Section 29 tax credits. However, because prices of Devonian shale and coalbed methane were deregulated in late 1979, producers naturally selected tax credits thereafter. As a result, Section 29 tax credits were far more important for the industry than incentive pricing. As we discuss in below, however, the tax credit and incentive pricing had limited impact on Mitchell Energy.

2.2 R&D PROGRAMS

The unconventional natural gas research program under DOE had three components: the Eastern Gas Shales Program, the Western Gas Sands Program, and the Methane Recovery from Coalbeds Program. Here we focus on the Eastern Gas Shales Program, the most pertinent program, and we discuss the relevant contributions of other DOE R&D programs. The role of the Gas Research

Institute (GRI), which managed and funded R&D projects on natural gas, is discussed in our discussion paper (Wang and Krupnick 2013).

NRC (2001) assessed the most important energy-related technological innovations of the 1980s and the 1990s, which included three technologies that are critical to shale gas development: horizontal drilling, three-dimensional (3-D) seismic imaging, and fracturing technology. NRC (2001, 13) rated DOE's role in improving horizontal drilling and 3-D seismic imaging as "absent or minimal," but rated DOE's role in "fracture technology for tight gas" as "influential." Fracture technology for shale gas was related to that for tight gas, which was developed earlier than shale gas. Microseismic fracture mapping, another technology thought to be critical to shale gas development, was not yet fully developed or used at the time of the NRC report.

2.2.1 Eastern Gas Shales Program

NETL (2007, 19) indicates that DOE's Eastern Gas Shales Program "helped unlock a major new ... source of significant natural gas supply. It revitalized gas shales drilling and development in the Appalachian (Devonian) Basin, helped initiate development of other previously over-looked gas shale basins, and took the lead in demonstrating much more efficient and lower-cost gas shale production and recovery technology." Our review of the available evidence supports this conclusion.

Eastern gas shales refer to Devonian-age shales underlying vast areas of the eastern United States, including the Appalachian, Michigan, and Illinois Basins. Shallow and easily accessible, Devonian shales have been commercially exploited since the 1920s but were a minor source of US natural gas production at the start of the gas shales program. The industry had a poor understanding of the Devonian shale, and the estimates of recoverable reserves were highly uncertain. Therefore, the purpose of the program was "to assess the resource base, in terms of volume, distribution, and character and to introduce more sophisticated logging and completion technology to an industry made up mostly of small, independent producers. The goal was to substantially increase production from these basins at a time when increased national supply was critically important" (NRC 2001, 201). Since DOE's program started, total annual shale gas production increased from 70 billion cubic feet (Bcf) in 1978 to 380 Bcf in 1998. The production increase was not due solely to the Eastern Gas Shales Program. Incentive pricing, tax credits, GRI's R&D program, and private firms all made contributions.

NRC (2001) attributes 10 percent of the incremental gas production in the Fort Worth Basin to the DOE shale gas program, even though this basin was not covered by the program and, prior to 2000, was developed primarily by Mitchell Energy. To have had an effect, some technologies, methods, or knowledge developed by the shale gas program must have been applied in the Fort Worth Basin. There is some evidence that suggests that the success of DOE's shale gas program played a role in motivating Mitchell Energy to initiate the development of the Barnett shale.

Horizontal Drilling. Few practical applications of horizontal drilling took place until the early 1980s and it did not achieve commercial viability until the late 1980s. The technology was initially used almost exclusively in oil wells (US Energy Information Administration [EIA] 1993). According to NRC (2001), DOE played little or no role in developing horizontal drilling technology; however, the agency did play a role in adapting the technology to gas shales.

Massive Hydraulic Fracturing. The gas shales program introduced large-scale massive hydraulic fracturing (MHF) to eastern Devonian shales. MHF was not used to stimulate shale wells before the gas shales program, but Agarwal et al. (1979, 172) note that MHF was already “a proven technique for developing commercial wells in low-permeability or ‘tight’ gas formations.” With financial assistance from DOE, Mitchell Energy conducted in 1978 what was, at the time, the largest MHF in a tight gas formation. Mitchell Energy quickly applied MHF to the Barnett shale.

Foam Fracture. This technology was first used by the gas shales program, which conducted more than 50 cost-shared demonstrations with industry in the first four years of the program. Prior to this, Devonian shale wells were stimulated explosively or by water fracs (that is, using water-based fluid). By 1979, “foam fracturing was the preferred commercial method of stimulation for Devonian shale gas wells” (NETL 2007, 31). Although Mitchell Energy used foam fracture in the first few years of its development of the Barnett shale, the firm abandoned foam fracs quickly and returned to water fracking, the first in the Barnett.

2.2.2 Related Technology Innovations and DOE Programs

A few other DOE R&D programs helped develop important technologies for shale gas development. Here, we focus on two such technologies that were targets of DOE R&D programs.

3-D Seismic Imaging. 3-D seismology has transformed oil and gas exploration and development. By measuring acoustic reflections from an energy source, 3-D seismic imaging, writes Bohi (1999), provides a better picture of the structure and properties of subsurface rocks than the earlier two-dimensional (2-D) method. Limited commercial application of 3-D seismic technology began in the early 1980s (Haar 1992). In 1988, DOE started its seismic technology program, on which it expended \$106 million (in 1999 dollars) from 1989 to 2000. NRC (2001, 208) notes that the “advances in seismic technology have been developed mostly by industry, although certain aspects of the DOE program have improved seismic technology.”

Microseismic Fracturing Mapping. Since the early 2000s, microseismic frac monitoring has played a key role in optimizing how shale gas wells are hydraulically stimulated. Unlike 3-D seismic imaging, microseismic fracture monitoring is a passive method that uses sensors to listen for underground seismic energy and record the minor seismic events generated during the fracturing of a nearby well. This technology can reveal the height, length, orientation, and other attributes of induced fractures. NETL (2007) and other trade publications suggest that DOE played a critical role in developing the technology of microseismic fracture mapping.

3. The Development History of the Barnett Shale Play

Mitchell Energy was the primary developer of the Barnett play until the firm was sold to Devon Energy in January 2002. By 1995, Mitchell Energy had completed (that is, prepared for production) 264 Barnett wells, while its eight competitors had completed only 20. Therefore, the development history of the Barnett play is essentially the story of Mitchell Energy, a story documented by former Mitchell Energy executive Dan Steward (2007). Our account of the Barnett development process is based on Steward's book and other trade publications.

3.1 WHY DID MITCHELL ENERGY DEVELOP THE BARNETT PLAY?

When Mitchell Energy drilled its first Barnett well in Texas, in 1981, little was known about the Barnett shale, which was not included in the major early studies that assessed the resource potential of unconventional natural gas (for example, Kuuskraa et al. 1978; National Petroleum Council [NPC] 1980) or even in NPC's later (1992) assessment. Despite the resource and technology uncertainties, Mitchell Energy invested about a quarter of a billion dollars in the Barnett play from 1981 through 1997 without making a profit from the Barnett. Why did then Mitchell Energy pursue the Barnett play?

The initial incentive for Mitchell Energy to develop the Barnett play was its need to develop a new source of natural gas to feed a large gas plant and a gas-gathering system and to fulfill its long-term contractual obligations to Natural Gas Pipeline Company of America (NGPL), which was aiming to replace its natural gas production from shallower conventional formations that were expected to decline in a decade or so (Bowker 2003; Steward 2007). As the largest gas producer in North Texas in 1981, Mitchell Energy was in a financial position to undertake some risky investments. The firm had a long-term natural gas supply contract with NGPL that guaranteed prices considerably higher than market prices, and the financial advantage provided by this contract was critical to the development of the Barnett play.

Mitchell Energy was also able to minimize the financial losses from drilling Barnett wells in the early 1980s because those "exploratory" wells were not purely exploratory in nature. All early Barnett shale gas wells were deepened to the Barnett formation from shallower, gas-bearing formations, giving Mitchell Energy the option of completing the wells to, and thus producing gas from, the shallower formations. This tactic, made possible by favorable geology, significantly reduced the risk and cost of drilling the early wells. The Barnett wells did incur financial losses, as only 1 of the 20 Barnett wells completed by 1987 was deemed "commercial." But, from 1987 to 1997, the financial returns of the Barnett wells gradually improved.

At some point, the possibility of reaping a large financial reward became a major consideration for Mitchell Energy's development of the Barnett play. Because few innovations are patentable and licensable, and it is difficult to keep innovations proprietary, the best way to obtain financial reward from R&D investments in the natural gas industry is by leasing large tracts of land and

later selling those leases at higher prices. Because of the land leases it held and the innovations it made, Mitchell Energy gained significant financial reward from the sale of the company in 2002.

Nevertheless, financial considerations did constrain Mitchell Energy's pace of drilling in the Barnett play. In 1986, when the oil price crash resulted in a decline in the natural gas price, writes Steward (2007, 74), "Mitchell management began to redirect capital expenditures ... away from higher-risk, long-term projects." In July 1995, NGPL bought out its contract with Mitchell Energy. Afterward, says Steward (2007, 90), "the entire Barnett program became questionable" as the company had to sell its gas at lower spot prices. Nevertheless, Mitchell Energy had incentives to continue with its Barnett program. Barnett shale, by 1994, had become the primary source of new gas for Mitchell Energy in the North Texas area. Without drilling Barnett wells, its own drilling rigs would go idle and its gas processing plant would not have enough gas to process. Continued drilling allowed the firm to "keep the infrastructure intact while waiting for an industry upswing, technological breakthrough, or well cost reduction" (Steward 2007, 91).

3.2 HOW DID TECHNOLOGIES AND KNOWLEDGE EVOLVE AT MITCHELL ENERGY?

3.2.1 Hydraulic Fracturing

While Mitchell Energy stimulated the early Barnett exploratory wells with foam fracs they switched to nitrogen-assist, gelled water fracs in 1984. Stimulation costs were still high—in the \$350,000 to \$450,000 range—as a major component of the total cost of developing a Barnett well, which ranged from \$750,000 to \$950,000 at that time. Finally, in 1994, these costs were reduced by 10 percent through incremental modifications.

Then, in 1997, Mitchell engineers began to experiment with slick water fracking, a fracture technique developed by Union Pacific Railroad Corporation (UPR) for use in tight gas formations. By using a large amount of water as the frac fluid and a small amount of sand as the proppant, UPR was able to substantially reduce costs without reducing gas production. Slick water fracking was a radical concept at the time, according to Bowker (2003), because completion engineers then assumed that much more proppant (sand) was needed to maximize fluid conductivity to the wellbore. The use of slick water fracking in shale gas formations was a major breakthrough—reducing the cost of stimulation by about 50 percent with similar initial production rates and higher subsequent production rates (Steward 2008).

But slick water fracking is an innovation in only one aspect of good frac design, and Mitchell Energy found that the method was not effective in stimulating Barnett wells in areas with weak frac containment barriers, where fracs tend to extend out of the Barnett shale and into a water-saturated formation underlying the Barnett. In 1995 and 1997, with assistance from Sandia National Laboratories and GRI, Mitchell Energy attempted to use microseismic fracture mapping, which can improve frac placement and direction, in the Barnett play. But both tests failed. By late

1999 and early 2000, the technology of microseismic fracture mapping had substantially improved, and Mitchell Energy successfully used this technology in a number of wells.

3.2.2 Geological Knowledge

Understanding the geology of the target reservoir is critical for deciding where to drill wells, how many wells to drill, and how to drill and stimulate wells. In the early 1980s, Mitchell Energy focused on understanding the geology of the Barnett by drilling exploratory wells and by acquiring and analyzing 2-D seismic data. Some properties of the Barnett, such as the need to drill wells far from faults, were learned relatively quickly. Some other properties, such as the thermal maturation of the Barnett, were understood quite late (Steward 2007). Mitchell Energy first used 3-D seismic data to analyze the Barnett in 1994 (Steward 2007).

The most important and dramatic geology story of the Barnett is the estimate of its gas-in-place: the volume of recoverable and unrecoverable gas in the reservoir. In 1991, Mitchell Energy and the Gas Research Institute (GRI) jointly estimated the Barnett's gas-in-place—by analyzing rock samples from a Barnett well. Unfortunately, this gas-in-place estimate was proved—by a new evaluation in 1999—to be low by a factor of 2.5 or 3, depending on whether the upper portion of the Barnett was taken into account. The upper Barnett, which is separated from the lower Barnett by a limestone formation, was considered by the 1999 evaluation but not by the 1991 evaluation. All of Mitchell Energy's Barnett wells, prior to the 1999 reevaluation, were drilled and completed to the lower Barnett. After the 1999 reevaluation, Mitchell Energy changed how it developed the Barnett in that it began to (a) routinely frac the upper Barnett along with the lower Barnett, significantly improving the production rates of new wells; (b) refrac existing wells, including the upper Barnett in the refrac process; (c) increase production by drilling additional wells to fill in the space between existing wells; and (d) explore more areas of the Barnett. The optimization of the slick water frac and improved gas prices also played a role in these new developments.

3.2.3 Drilling

Mitchell Energy made significant drilling improvements. From the early 1980s to the mid-1990s, the firm reduced the average duration of drilling by nearly 50 percent, from 18 to 22 days to about 11 days, and the cost of drilling by about 15 percent. Mitchell Energy drilled more than 800 vertical wells, but only attempted to drill four horizontal wells before it merged with Devon.

3.3 DID ENVIRONMENTAL ISSUES AFFECT MITCHELL ENERGY?

Environmental issues associated with natural gas drilling, not necessarily in shale formations, significantly affected Mitchell Energy. According to Kutchin (1998), several plaintiff groups filed lawsuits against Mitchell Energy in the 1990s, claiming that the company's natural gas drilling activities polluted landowners' residential water. In the most important of these, the "Bartlett" case, the plaintiffs were landowners in Wise County who contended that their well water was polluted by 12 Mitchell Energy gas wells. A jury awarded the plaintiffs \$4 million in actual

damages and \$200 million in punitive damages in March 1996. The appeals court, in November 1997, reversed the trial court's judgment because the plaintiffs either filed their cases after the statute of limitations had expired or failed to prove that Mitchell Energy had polluted their water. Nevertheless, Mitchell Energy paid a high price. The litigation cost was over \$20 million. More importantly, the large punitive damage awarded by the trial court, before it was overturned, "was depressing to [Mitchell Energy], in everything from investor perceptions of the company's future through employee morale to future planning," writes Kutchin (1998, 38).

3.4 WHAT EXTERNAL HELP DID MITCHELL ENERGY OBTAIN?

When developing the Barnett, Mitchell Energy benefited, to varying degrees, from sources and activities outside the company:

- In the 1990s, Mitchell Energy cooperated with GRI on a number of research projects, though some were unsuccessful.
- Mitchell Energy benefited in a limited way somewhat from the federal incentive pricing and/or tax credit policies for unconventional natural gas. Barnett shale appears to have been filed under the NGPA category of tight gas rather than Devonian shale, and financial incentives for tight gas were much smaller than those for Devonian shale.
- The company benefitted from some academic publications.
- The company hired employees who once worked for other oil and gas companies, including, notably, a geologist who had gained expertise in the Barnett from his previous job with Chevron and who played a critical role in the 1999 gas-in-place reevaluation.
- Mitchell Energy benefited from the expertise of the service firms it employed.

3.5 HOW DID THE MITCHELL–DEVON MERGER ACCELERATE DEVELOPMENT?

The Mitchell–Devon merger greatly accelerated the development of the Barnett play. When it purchased Mitchell Energy for \$3.5 billion in January 2002, Devon Energy was one of the largest independent oil and gas operators in North America. Shortly after the merger, Devon Energy started to drill horizontal wells in the Barnett. Five horizontal wells spudded in 2002, according to Steward (2007, 182), "out-perform[ed] anything previously seen in the Barnett." Devon Energy then applied for permits to drill more than 80 horizontals in a five-county area in 2003. After the production rates of the first five wells were filed with the Texas Railroad Commission and became public in July 2003, 25 other operators filed for more than 100 horizontal well permits over a seven-county area in 2003.

Horizontal wells, however, were not always successful for a number of reasons. 3-D seismic data are needed to understand the geological setting. Although Devon Energy understood the importance of 3-D seismic data, it kept this knowledge, acquired from Mitchell Energy, to itself. It

is only after Republic Energy, another operator, used 3-D seismic data in 2003 to adjust the lateral placement of a horizontal well and shared this information with other operators that seismic activity in the Barnett exploded. Even with 3-D seismic data, notes Steward (2007, 186), “most horizontals still break out of zone to some extent.” Microseismic fracture mapping is needed to optimize frac placement and height.

4. Other Contributing Factors

Other factors were also important in US shale gas development. These factors may be absent in some countries that are attempting to develop their own shale gas resources.

- **High Natural Gas Prices in the 2000s:** The pace of Mitchell Energy’s development of the Barnett shale was greatly influenced by the price of natural gas. Mitchell Energy accelerated its development of the Barnett in 2000 and 2001 partly because natural gas prices increased significantly in those two years, from an average wellhead price of about \$2/Mcf in 1998–1999 to an average of \$3.85/Mcf in 2000–2001. Natural gas wellhead price decreased to an average of about \$3/Mcf in 2002 but remained higher than \$5/Mcf for most of the 2003–2008 period. Given the success of drilling and fracturing technologies, high natural gas prices imply that firms may realize significant profit margins from drilling shale gas wells. The prospect of high profit margins encouraged existing firms and new entrants to invest heavily in shale gas plays in the 2000s, which eventually drove down natural gas prices.
- **Geology:** Shale gas has become the most important unconventional gas because of its large recoverable reserves (as well as technological innovations). Shale gas plays vary in geology and, consequently, profitability. For instance, Tudor, Pickering, Holt & Co. reports that natural gas needs to be only \$4/Mcf for the Barnett core area to achieve a 10 percent rate of return, but it needs to be over \$7/Mcf for the Eagle Ford play, in south Texas, to achieve the same rate of return.
- **Land and Mineral Rights Ownership:** Shale gas development in the United States has taken place primarily on private land. Private land ownership offered natural gas firms a way to obtain reasonable returns from their early investments in technology innovations through acquiring land, proving its potential and then selling it. A weakness of private land ownership is that some speculating firms may rent large areas of land without making much investment.
- **Market Structure:** Shale gas exploitation is one of the most capital-intensive industries, and Mitchell Energy’s development history in the Barnett play suggests strongly that small natural gas firms do not have the capacity, financial or technical, to make substantial risky investments in shale gas technology. Indeed, it was large, independent natural gas firms that made significant investments in the early stage of shale gas development. The major oil firms, which are much larger than any independent natural gas firm, had the capacity, but for them, shale gas was less attractive as an investment choice than conventional oil and gas.

- **Water Availability:** Slick water fracturing of shale gas wells requires a few million gallons of water per well. In the United States, sufficient water has generally been available, although in some areas, shortages—and conflicts with farmers and other water users—are a growing concern. Thus, water availability may constrain US shale gas production in some areas in the future, as well as production in other countries.
- **Natural Gas Pipeline Infrastructure:** An extensive network of natural gas pipelines existed in the United States before shale gas became a major gas resource. Also important was the policy of open access to these interstate natural gas pipelines (as well as storage facilities) as a result of a series of FERC orders in the 1980s and early 1990s.
- **Capital Market:** Some observers claim that the capital market has played an important role in pushing the shale gas boom forward. After the shale gas boom took off, financial firms provided some natural gas firms with considerable capital to drill, facilitated many deals in which larger oil and gas firms bought out smaller firms engaged in shale gas drilling, and may have contributed to the recent oversupply of shale gas.
- **Other Considerations:** Still other factors have also contributed to US shale gas development: road infrastructure is generally available; underground injection wells for wastewater disposal are generally available; the topography of most shale basins is favorable; most shale gas plays are in areas with low population densities and a history of conventional oil and gas development; and oil and gas service is well established.

5. Concluding Remarks

The shale gas boom resulted from factors that ultimately enabled firms to produce shale gas profitably, including technological innovation, government policy, private entrepreneurship, private land and mineral rights ownership, high natural gas prices in the 2000s, market structure, favorable geology, water availability, and natural gas pipeline infrastructure. Our review suggests that the key question for policymakers in countries attempting to develop their own shale gas resources is how to generate a policy and market environment in which firms have the incentive to make investments and would eventually find it profitable to produce shale gas.

Countries new to shale gas enjoy a major advantage over the United States in that the state-of-the-art shale gas technologies are much more advanced than those that existed when the United States started to develop shale gas. However, many innovations will be needed to adapt existing technologies to geological and hydrological conditions at new plays; perhaps wholly new technologies will be needed. For example, the current cost of drilling a shale gas well in China is widely reported to be several times higher than that in the United States. To lower costs, technology improvements are needed. Where will the innovations come from?

Our review suggests that small firms do not have the capability to make the necessary R&D investments, but very large firms may lack the incentive to do so. For example, China's major national oil firms appear to be reluctant to make large R&D investments in domestic shale gas because of the alternative investment choices currently available to them. In the United States, it was large natural gas firms such as Mitchell Energy that made significant early investments in shale gas development. For countries willing to use industrial policies to promote shale gas development, market structure may be an important component of such policies.

In the United States, government-sponsored R&D programs facilitated innovations in technology and fiscal policies, such as tax credits, created incentives for drilling shale gas. More importantly, the ability to lease land and mineral rights across large areas at a low price was a powerful incentive. The situation in the United States is unusual. In most countries, such as China, below-ground mineral rights are owned by the state. On the positive side, state ownership can help operators piece together contiguous blocks of land for more efficient and thorough exploitation of a play, and governments can lease the drilling rights at below-market rates if they so choose. On the other hand, private mineral rights ownership creates a constituency in favor of drilling and helps resist the temptation of government to raise revenues through shale gas drilling. China has auctioned off drilling blocks and has required a certain minimum investment to develop auctioned blocks within a certain period of time. This should force firms to drill some, but it is not clear if this mechanism would provide sufficient incentive to innovate. A key issue is whether firms would be able to secure large enough acreage positions at low enough prices to potentially reap the benefits of their R&D investments. Another issue is whether partnerships and other deals with international firms can lead to enough additional importation of technologies and innovations to make exploiting these shale gas reserves profitable.

Of course, as we have seen for the United States, high natural gas prices can deliver such an incentive. Before deregulation, severe natural gas shortages occurred, reflecting firms' lack of incentive to explore and exploit new gas resources when the natural gas price was set below market value. Indeed, in China or elsewhere in Asia, the high cost of liquefied natural gas (currently in the \$13 to \$16/Mcf range) could provide huge incentives for innovation if the domestic price for natural gas were deregulated. However, the domestic price of natural gas is currently set at levels far below market value. This and the regulatory uncertainties created by price regulation can diminish innovation incentives. A related policy issue is open access to natural gas pipelines, which facilitates the marketing and transportation of natural gas.

Our review also raises the question of how a country's policy on shale gas should be coordinated with its policy on tight gas and coalbed methane. US government R&D programs and fiscal policies targeted all three types of unconventional natural gas. A shale gas boom may occur in a country without much prior success in tight gas or coalbed methane, but such a country may need to coordinate its policies on unconventional natural gas and oil resources.

Natural gas firms in the United States appear to have been constrained by law long before the environmental risks of shale gas development became controversial. In the absence of effective enforcement of laws and regulations, which may be the case in some developing countries, firms may not use the necessary measures to protect the environment. Even in the United States, it appears that sound environmental regulations and the public's trust in the government's regulatory role in shale gas development are needed to make a shale gas boom sustainable.

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