Economics of Unconventional Gas

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With the sharp recent rise in well drilling and particularly well stimulation costs, some are concerned that much of the unconventional gas resource in the U.S. is becoming uneconomic. Concerns about the economic viability of unconventional gas have been raised since the initial pursuit of this resource, sometimes rightly so. However, in our view, improvement in the unconventional gas knowledge base and technology progress using industry/government partnerships can maintain the economic viability of this large, often marginally productive resource. Past reservoir characterization methods and traditional means of linking a wellbore to the low permeability unconventional gas reservoir are no longer sufficient. As such, the discussion of the economic viability of unconventional gas is as much a story of technological advance and the pursuit of efficiency, as introduced in the third and fourth articles in this series, as it is a story of costs, financial risks and wellhead prices.

Even though the overall economic trends for unconventional gas are currently unfavorable - - with finding and development (F&D) costs rising faster than wellhead prices - - significant examples of economic success nonetheless exist. This fifth article in the series presents a number of examples of how selected companies, with diligent pursuit of knowledge and technology, have converted previously judged uneconomic unconventional gas plays into economically viable prospects. In addition, this article discusses potential actions that could help maintain the future economic viability of unconventional gas in the U.S. Finally, the article describes several threats and opportunities on the horizon that could influence the future economics of domestic unconventional gas.

Outlook for Cost Increases. *How long will the sharp increases in well drilling and completion costs continue, thus harming the economic viability of unconventional gas?* With increases in natural gas prices and the subsequent boom in unconventional gas development, oil field service companies have been able to increase the prices they charge for their services and products. For example, rig rates that were quoted at $12,000 per day several years ago are now routinely priced at $18,000 to $20,000 or more per day; hydraulic fracturing services and tubulars have seen similar, if not higher, rates of pricing growth.

In our view, the rise in well drilling and completion costs is coming to a close - - in part due to expansions in service industry capacity, and in part due to producer reluctance to accept these high, increasing prices. For example:

- The supply of domestic drilling rigs, that account for 20% to 25% of the costs of a typical well, has expanded greatly, with over 200 land rigs added last year and another nearly 300 land rigs expected this year. Several of the active unconventional gas producers, such as Chesapeake, Southwestern and Williams, facing a tight, costly rig market, have taken the extraordinary step of contracting for "purpose built rigs" and establishing their own drilling companies.

- The supply of high pressure pumping services (for well stimulation and hydraulic fracturing), which account for 30% to 35% of the costs of a typical unconventional gas well, increased by about 25% (by about 700,000 HHP) last year. With expanded service capacity and several new companies entering this line of business, there is promise that pumping service costs will stabilize and possibly decline.

- Following sharp increases in the price of steel, the prices for oil field tubulars have stabilized and even show a slight decline this year. Tubulars account for 10% to 15% of the cost of a typical unconventional gas well.

Nonetheless, these higher drilling rig, pumping service, and tubular prices place even greater pressures for "relentless pursuit of efficiencies" in developing unconventional gas, as is further discussed later in this article.

Economics of Rocky Mountain Unconventional Gas Plays. Our Model for Unconventional Gas Supply (MUGS) provides us with an up-to-date perspective on the economic viability of 94 distinct unconventional gas plays in the U.S. This economic model shows that using a long-term NYMEX gas price of $6/Mcf, 27 of these plays (holding 260 Tcf of recoverable resources) are economically viable, with another 21 plays (holding 140 Tcf of recoverable resources) being marginally economic. As confirmation and quality control for our model, we periodically review and examine the actual economic performance of unconventional gas plays. A portion of our latest review is provided below.

For the traditional Rocky Mountain unconventional gas plays, we provide three examples of unconventional gas costs and economics, using public data provided by Bill Barrett Corporation and selected other producers, Table 1.

- The first example is for the Williams Fork/Measaverde tight gas sands of the S. Piceance Basin, now producing nearly one Bcfd. This play provides a 36% rate of return (to Bill Barrett Corp) and requires a gas price of $4.50/Mcf (at the CIG hub) to be economically viable.

- The second example is for the Big George coalbed methane play in the Powder River Basin. This play provides a 53% ROR and requires a $3/Mcf (at the CIG hub) to be economically viable. However, geologically less favorable portions of this coalbed methane play will have less robust economics.

- The third example is for the new Wasatch/Mesaverde tight gas play in the Uinta Basin, outside the traditional Natural Buttes field area. This play has a 52% rate of return and requires a gas price of $3.90/Mcf (at the CIG hub) to be economically viable. Optimization of well completions by EOG Resources is helping improve the economic returns for this gas play.

Table 1. Economic Performance of Three Established Unconventional Gas Plays

		Tight Gas Sands Williams Fork/Mesaverde S. Piceance Basin	Coalbed Methane Big George Powder River Basin	Tight Gas Sands Wasatch/Mesaverde Uinta Basin
Realized Gas Price [1]		$7.58	$6.34	$6.80
Less:	Production Taxes	(0.45)	(0.93)	(0.39)
	LOE/Other	(0.86)	(1.95)	(0.52)
	F&D Costs	(2.34) [2]	(0.71) [3]	(1.43) [4]
Net Margin		$3.93	$2.75	$4.46
ROR		36%	53%	52%
Min. Required CIG Gas Price		$4.50	$3.00	$3.90

[1] Mid-2007 Rockies strip with BTU/sales adjustment
[2] Assumes net EUR of 0.81 Bcf/well and D&C costs of $1.9 million
[3] Assumes net EUR of 0.28 Bcf/well and D&C costs of $0.2 million
[4] Assumes net EUR of 2.1 Bcf/well and D&C costs of $3 million

Economics of Emerging Unconventional Gas Plays. Certain of the emerging unconventional gas plays in the U.S. also exhibit attractive economics. We start with a look at the economics of the Deep Bossier tight gas play in East Texas. According to Chesapeake Energy, assuming average well costs of $10 million, average gross estimated ultimate recoveries (EURs) of 5 Bcf per well, and a realized wellhead gas price of $6.30 per Mcf, this play can provide a ROR ranging from 70% to 100%, depending on the extent to which drilling costs decline with increasing experience, Table 2.

A second example is in the Woodford gas shale in Southeast Oklahoma. Assuming well costs of $4.3 million per well, average gross EURs of 2.2 Bcf per well, and a realized gas price of $6.30 per Mcf, this play can achieve RORs of 18% to 25%, depending on drilling costs, again according to Chesapeake Energy.

Table 2. Economic Performance for Two Emerging U.S. Gas Plays

	Tight Gas Sands Deep Bossier East Texas	Gas Shales Woodford SE Oklahoma
Realized Gas Price [1]	$6.30	$6.30
EUR/Well		
• Gross	5.0 Bcfe	2.2 Bcfe
• Net	3.75 Bcfe	1.76 Bcfe
Cost/Well	$10 million	$4.3 million
F&D Cost	$2.67	$2.44
ROR (%)		
• Current Well Costs	~ 70%	~ 18%
• Reduced Well Costs (-15%)	> 100%	~ 25%

[1] Assumes a NYMEX Price of $7/Mcf and $0.70/Mcf for gathering plus differentials.

A more speculative look involves the economics of the emerging deep Dakota-Entrada-Navajo tight gas play in the Uinta Basin. Here, the initial well costs are in the range of $9 to $10 million for a 15,000 foot well. However, with expectations of achieving EURs per well of 5 to 6 Bcf, the economics of this play appear viable, especially should well costs come down. The initial discovery well in this play tested at over 11 MMcfd (gross) in the Dakota, Entrada and Navajo formations, followed by wells testing at 6 to 10 MMcfd (gross) in the Navajo formation.

Pursuing Efficiencies in Unconventional Gas Development. Faced with rising costs, industry is rigorously pursuing efficiencies and cost reductions in drilling, well completions and operations. A notable example is the reduction in days - - from 35 days in 2001 to 17 days in 2006 - - to drill a well in the tight Cotton Valley gas sands at Overton Field by Southwestern Energy, Figure 1. Similar gains in well drilling efficiencies are noted by other unconventional gas producers such as EOG Resources and EnCana. While significant efficiencies have been achieved in the past, the rate of efficiency gain has slowed in recent years due to reaching practical limits in "what is possible" with traditional well drilling methods and rigs.

1. Pursuing Efficiencies in Well Drilling and Completion. Continuation of this pursuit of efficiency (and costs savings) in well drilling and completion is illustrated by EnCana's experience. As the gains in drilling efficiencies with conventional rigs were diminishing, EnCana contracted for "fit for purpose" rigs and equipment that enabled it to reduce drilling days from over 40 days per well to about 30 days per well, with further gains expected in future years, Figure 2.

EOG Resources has experienced similar efficiency improvements in its horizontal wells in the Wolfcamp tight gas sand play in the New Mexico portion of the Permian Basin. In this play, average well costs have dropped to about $830,000 per well for its most recent wells, compared to $1.3 million per well in 2005, Figure 3. These wells now take about 20 days to drill, compared to over 30 days in 2005.

Continuing improvements in horizontal drilling and completion technologies are also key to lowering costs and improving the economic attractiveness of emerging shale plays such as the Fayetteville and Woodford shales. In the Fayetteville Shale, for example, Southwestern Energy is using a combination of horizontal wells plus slick-water frac jobs to carry pumped sand deep into the formation. With average well costs of $2.3 million, EURs of 1.3 to 1.5 Bcf per well, and gas prices above $6.50 per Mcf, the economics of this play are attractive.

Similarly, in the Woodford Shale, Newfield Exploration, after drilling mostly vertical wells, is now drilling mostly horizontal wells and completing them with five-stage fracs. Newfield found that higher frac density translates into higher initial production rates and higher expected EURs. While such wells cost $5 to $6 million to drill and complete (compared to earlier vertical wells that cost about $2 million), these increased costs appear to be more than offset by higher production rates and ultimate recoveries per well.

2. Pursuing Efficiency in Production Operations. Efficiency gains are also being achieved in what are generally considered to be mature unconventional gas plays. For example, in the San Juan Basin of New Mexico, which has been producing from both coal seams and tight gas sands for many years, a number of companies are pursuing strategies to maximize the potential of this mature gas-rich basin. For example, to offset its declining production in this basin, Williams Cos. established a cross-functional team to develop strategies to maximize production from its more than 800 wells operating in the basin. By investing in a $15 million effort to reduce line pressures, install new pumping units and compressors, change tubing size, and perform well workovers, production was increased by about 20%, with lower lease operating costs.

3. Pursuing Efficiencies in Water Treatment and Disposal**.** Water treatment and disposal can constitute a major cost item for coalbed methane development, particularly in environmentally sensitive basins. In addition to use of evaporation ponds and reverse-osmosis, one promising method is electrodialysis, an electrically driven membrane filtration process where desalted water is separated from a concentrated saline solution, Figure 4. The desalted water can be disposed of at the surface and the saline water re-injected. GTI has operated an electrodialysis pilot in the Wind River Basin in Wyoming for several years, showing that the process is technically feasible, and has conducted a test in the Powder River Basin showing CBM produced water could be treated for about $0.15/bbl (Hayes et al., IPEC Conference, 2006).[1]

4. Pursuing Efficiencies in Finding and Development Costs**.** In the U.S., the cost to find and develop all gas resources, including unconventional gas, have risen considerably over the last five years, These rising costs, along with the shift of U.S. gas production to unconventional gas, has lead some, like Credit Suisse, to believe that unconventional gas will set the “floor” for future natural gas prices, Figure 5. However, in our view, the domestic natural gas price will be set by many factors, including imports

of LNG. As such, if domestic unconventional gas is to compete for investment capital and remain economically attractive, the recent efforts to reduce F&D costs must continue. Clearly, further efforts like those to reduce drilling, completion, and stimulation costs, along with increased well recoveries, will be essential.

Lemons or Lemonade? Barriers and Opportunities to Future Unconventional Gas Development. The following section discusses potential barriers to the unconventional gas industry, such as land use and environmental concerns, including issues of access to Federal lands and prudent management of produced water. At the same time these barriers provide opportunities for innovative, forward-thinking firms.

<u>1. Resource Access</u>. Access and land use policies on Federal lands continue to pose formidable constraints on unconventional gas development. For example, for the unconventional gas resource that remains to be developed (Lower-48), approximately 15% is inaccessible, while another 64% is accessible but only under conditions more restrictive than standard lease terms (U.S. DOI, 2006).[2]

However, some firms are working collaboratively with government agencies to develop innovative "win-win" strategies to address seasonal restrictions in exchange for enacting more environmentally friendly drilling practices. For example, Questar Corp., a Rocky Mountain-based natural gas production and pipeline company, faced heavy lease restrictions on its lease in the Pinedale Anticline of Wyoming. In response, the firm used information gathered through an extensive outreach program with local organizations and government officials to develop a plan whereby it could perform year-round drilling on previously seasonally restricted portions of its lease. In exchange for the exceptions, the firm proposed to make investments that would significantly reduce its environmental footprint by directionally drilling multiple wells from a single well pad and piping gas to central compression facilities instead of using tanker trucks. In 2005, the Wyoming BLM approved the plan, giving Questar rights to drill year-round, including through the previously restricted winter months. Questar reports that these modifications will eliminate the need for an extra 89 well pads and 25,000 annual tanker truck trips. (Greenhawt Testimony, March 2007)[3].

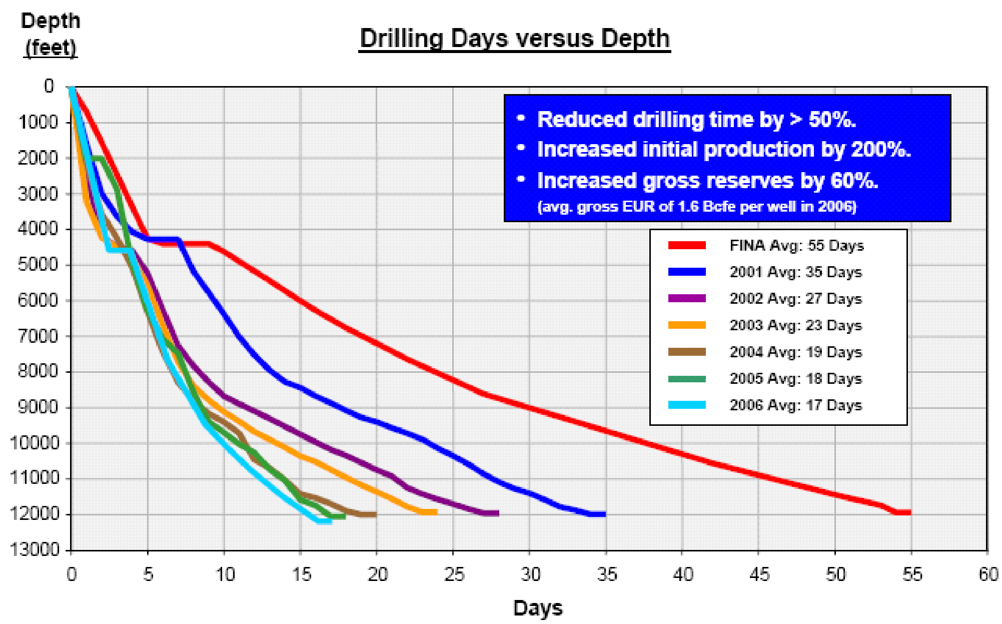
2. Produced Water Management. One increasingly visible and contentious issue is coalbed methane produced water management. An in-depth DOE study demonstrated that the cost to treat produced water from coalbed methane operations could significantly impact the economics of recovering natural gas (U.S. DOE, November 2002). [4] Depending on the regulatory requirements and management options used, capital costs for CBM produced water management could range from as little as $1,500 to as much as $72,300 per well.

In response to the barrier posed by managing produced water, Andarakro Petroleum implemented an innovative solution that creates synergies between its coalbed methane and oil production investments. The firm has recently completed a 48 mile, 24 inch Powder River Basin Water Pipeline to transport 400,000 to 450,000 barrels per day of water produced from its coalbed methane wells to the Madison aquifer at Salt Creek. This pipeline will significantly reduce water handling expenses for Anadarko, and establish a predictable cost structure for future water handling costs, reducing the risk in existing and future CBM development projects in the region. Additionally, the water injected into this reservoir will replenish a low cost source of water for enhanced oil recovery at the firm's nearby oil fields. As one of the low cost sources of water in the area, the Salt Creek reservoir had been depleted due to past waterflood and EOR activity.

3. Storing CO_2 Emissions**.** Another example of turning a barrier into an opportunity is to use coal seams for value-added CO_2 storage. Coals are frequently located near large point sources of CO_2 emissions, especially power plants. In addition, the injection of CO_2 into coal seams can also enhance the recovery of methane (enhanced coal bed methane, or ECBM) from coal seams, though the technology is relatively new at this stage. Nonetheless, analyses by Advanced Resources have shown that CO_2-ECBM can be economic with today's gas prices across a broad range

of geologic environments, though a substantial amount of research and demonstration will be necessary to push its application.

Summary. The economic viability of U.S. unconventional gas resources remains in a precarious balance. Though drilling and completion costs are likely to level-off and be partially offset by advances in technology, the economic viability of unconventional gas is at the mercy of service, raw material and environmental management costs, all of which are increasing. This paper has outlined how innovative, efficiency-minded firms have found ways to circumvent these barriers and enjoyed lower costs and higher RORs as a result. To remain a viable source of energy into the future, the unconventional gas industry as a whole will need to continue to build on the successes mentioned in this article by promoting greater cooperation between industry and government, by accelerating the pace of technological progress and by tirelessly promoting efficiency and innovation in its decision-making.



Source: Southwestern Energy Corporation, 2007

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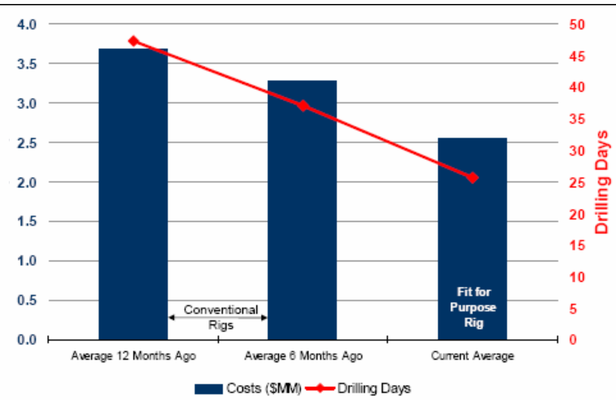
Figure 1. Overton Field: Improved Drilling Results with Greater Experience in a Play

Conventional	Fit-for-Purpose
Mechanical drive	Electric drive
Manual pipe handling	Automated pipe handling
Rig jacking company	Hydraulic self leveling substructure
Rotary table and kelly bar	Top drive
Manual slips	Automated slips
Pipe tongs	Automated pipe connection
700 HHP mud pumps	1,000+ HHP mud pumps
Rng 2 drill Pipe	Rng 3 drill pipe



Source: EnCana, 2006

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Figure 2. Benefits Associated with Fit-for-Purpose Rigs (EnCana)

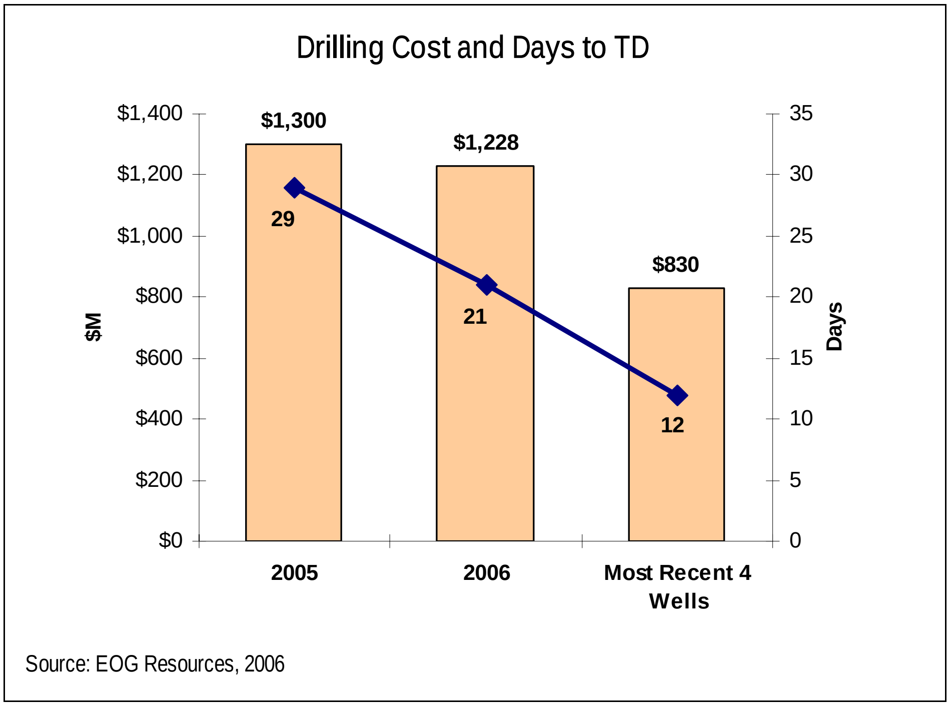

Figure 3. Impact of Improvements in Permian Basin Horizontal Wells (EOG Resources)

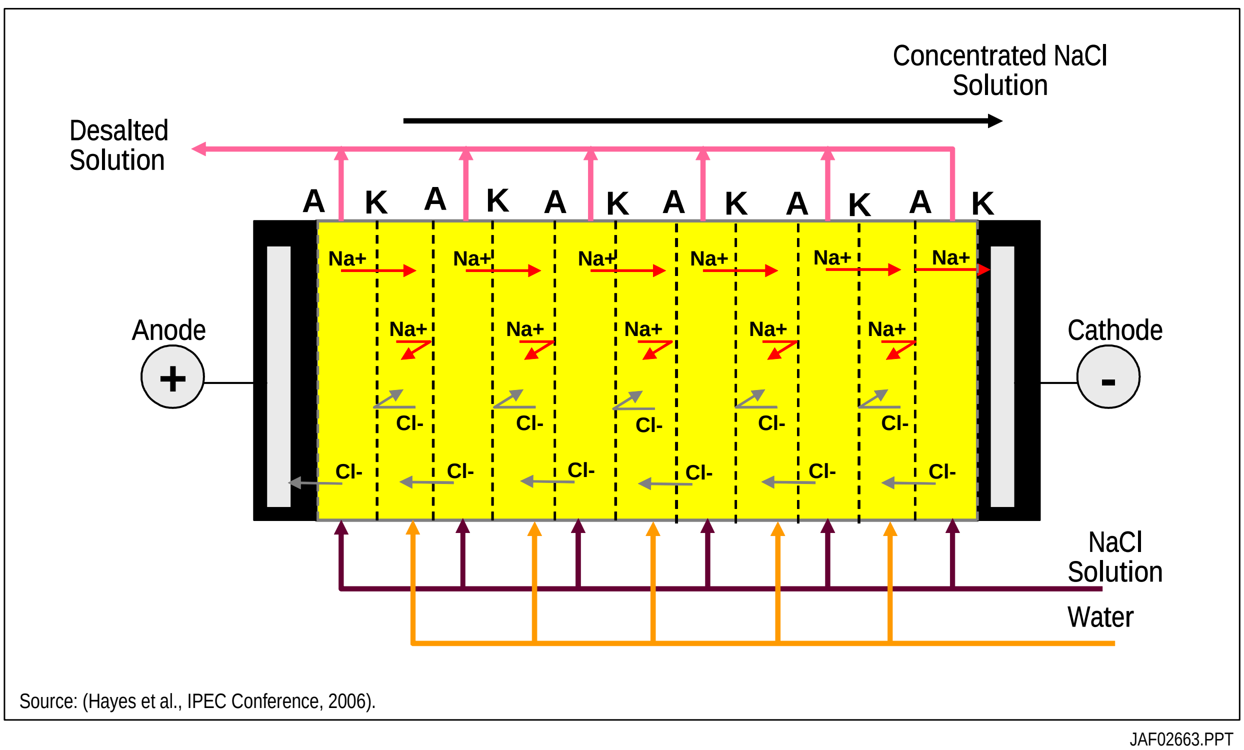

Figure 4. Schematic Diagram of Electrodialysis Process for Produced Water Treatment

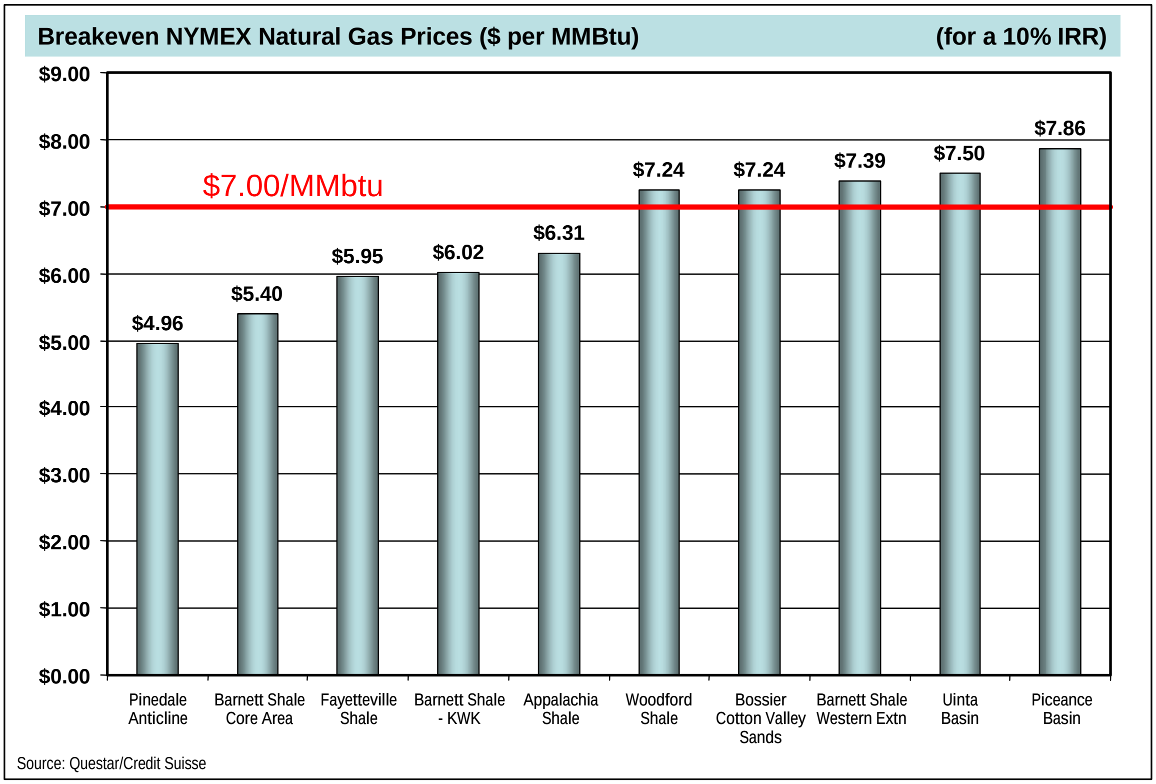

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Figure 5. Rising Costs and the Shift to Unconventional Reservoirs Sets a "Floor" for Natural Gas Prices

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