Oil and Gas, Natural Resources, and Energy Journal

Volume 2 | Number 2

July 2016

Excerpt from *Oil Capital: The History of American Oil, Wildcatters, Independents and Their Bankers*

Bernard F. Clark, Jr.

ONE J
Oil and Gas, Natural Resources, and Energy Journal

VOLUME 2 NUMBER 2

EXCERPT FROM *OIL CAPITAL: THE HISTORY OF AMERICAN OIL, WILDCATTERS, INDEPENDENTS AND THEIR BANKERS*[*]

BERNARD F. CLARK, JR.[**]

CHAPTER 8: THE NEW MILLENNIUM

> *"It must be seen in its role in the perennial gale of creative destruction . . . ."*
>
> —Joseph Schumpeter

The arrival of the new millennium brought a collective sigh of relief for borrowers and lenders alike, as computer clocks rolled over from '99 to '00 and a feared, computer-code-based collapse of digital systems failed to materialize. After all of the hoopla, the New Year arrived with a yawn.

The affirmative covenants that crept into loan agreements near the end of the 1990s, requiring that "the Borrower shall take all steps necessary to protect against Y2K" were quickly removed.[855] More importantly, the

* Pagination in this excerpt has been altered from the original book pagination. This material begins at page 311 in the book.

** Bernard F. (Buddy) Clark, Jr. grew up in Houston, Texas, well aware of the needs producers face for capital. As chief financial officer for Mitchell Energy & Development Corp. for 45 years, his father was often flying to New York and Chicago to meet with commercial and investment bankers for funds to finance Mitchell Energy's constant need of capital.

855. Typical language for the borrower's representation included "Year 2000 Matters." "In order to avoid a material adverse effect on the Borrower and its Subsidiaries taken as a

industry was ready to put the bad memories of the prior couple of years behind them and start the year and century anew.

In the early part of the decade, new loan-agreement clauses were needed and additional forms required after the tragic events of September 11, 2001. Congress responded to the attacks by enacting certain anti-terrorism laws, including the Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001, known in short as the USA Patriot Act.[856] Among many other things, the added language to credit agreements required greater disclosures by borrowers and Know Your Customer (KYC) forms, aimed at deterring money laundering and terrorist financing. [857]

Rising oil and gas prices were welcomed relief from the punishing prices of the end of the 1990s that had crippled many producers or caused them to merge with larger companies. Natural gas rose from less than $2 in the summer of 1998 to between $2.60 and $3.80 during the first six months of 2000 and stretched to $6.80 in January of 2001.[858]

The rig count for drilling gas wells increased from fewer than 400 to almost 900 by the beginning of 2001.[859] But the increase in activity was not producing twice as much gas. In fact, total U.S. gas production was roughly unchanged.[860]

Conventional wisdom was that, with the application of 3-D seismic technology, most of the easy gas had been found and developed. As a result, it became necessary to tap smaller and deeper targets onshore and in

---

whole, any reprogramming required to permit the proper functioning in all material respects (but only to the extent that such proper functioning would otherwise be impaired by the occurrence of the year 2000) in and following the year 2000, of computer systems and other equipment containing embedded microchips, in either case owned or operated by Borrower or any Subsidiaries or used or relied upon in the conduct of their business (including, to the Borrower's knowledge, any such systems and other equipment supplied by others or with which the computer systems of Borrower or any of its Subsidiaries interface), and the testing of all such systems and other equipment as so reprogrammed, will be completed by December 31, 1999."

856. Pub. L. No. 107-56, 115 Stat. 272.

857. *Bank Secrecy Act and Anti-Money Laundering*, 31 U.S.C. 5318(i) effective July 23, 2002.

858. U.S. EIA, Independent Statistics & Analysis. "U.S. Natural Gas Wellhead Price." Accessed March 01, 2016. Eia.gov.

859. There were 371 rotary rigs drilling for natural gas in April, 1999, and 871 in January, 2001. U.S. EIA, Independent Statistics & Analysis. "U.S. Natural Gas Rotary Rigs in Operation." Accessed March 6, 2016. Eia.gov.

860. U.S. gas production was 18.8 Tcf in 1999; in 2001, 19.6 Tcf. U.S. EIA, Independent Statistics & Analysis. "U.S. Dry Natural Gas Production." Accessed March 6, 2016. Eia.gov.

the Gulf for which decline rates were high, especially as extraction techniques were improving concurrently.

At the same time, U.S. power producers were bringing more gas-fired power plants online, increasing demand.[861] The result was a treadmill in which, despite dramatic increases in drilling, the industry was unable to significantly increase supply. The risk was that rising prices would drive the most price-sensitive users out of the market, thus resulting in demand destruction.

Meanwhile, WTI, which hit a nadir of less than $11 in December of 1998, began what would become a long 10-year path to just shy of $150 in July of 2008. Also, independents and their bankers were encouraged that Texas-oil-patch-grown George W. Bush was elected the U.S.' 43rd president and took office in January of 2001. The son of President George H.W. Bush, "43" grew up in Midland and Houston and had been a wildcatter with Arbusto Energy Co., Spectrum 7 Co. and Harken Energy Corp. in the 1970s and into the early 1990s.

Moreover, Vice President Dick Cheney had most recently served as chairman and CEO of oilfield-services giant Halliburton Co. With the dot-com bust and rising oil and gas prices, capital began flowing to energy companies and they and their investors took heart that new, higher price floors were sustainable.

Despite the good news on the price front, traditional reserve-based lending markets failed to see any significant increase in loan volume.[862] Producers had not forgotten that, in the first quarter of 1999, following banks' reset of their price decks, many of them had greater amounts drawn on their revolvers than their revised borrowing bases. The sting of this borrowing-base deficit was still fresh in the minds of many producers as they entered the new millennium.

U.S. capital markets were still recovering from the Asian contagion and the dot-com hangover; however, producers were wary of spending beyond their means. Increasing oil and gas prices were a double-edged sword for those looking to grow through acquisitions. They had stronger cash flows and more asset value to borrow against. But they had to convince their brethren, who were also enjoying improved cash flows, to sell at current prices rather than hold out for, perhaps, higher prices in the near future.

---

861. U.S. natural gas demand for power generation increased from 4.6 Tcf in 1998 to 5.7 Tcf in 2002. U.S. EIA, Independent Statistics & Analysis. "U.S. Natural Gas Deliveries to Electric Power Consumers." Accessed March 6, 2016. Eia.gov.

862. Brian A. Toal, "Big Deals," *Here's the Money: Capital Formation 2004, Special Supplement to Oil and Gas Investor*, May 2004, 5.

On the banking side, some of the major energy lenders were consolidating. With the money-center mega-mergers, only half as many energy lenders were around in 2002 as five years prior. NationsBank merged with Bank of America in 1998, Deutsche Bank and Bankers Trust in 1999, Chase Manhattan with JPMorgan in December 2000 and First Union with Wachovia Bank in 2001, to name a few.

The mergers left many medium and small independents either squeezed out of their bank or shuffled up to New York offices when they would have preferred local account management. "What's more, the remaining giants of credit burned by Enron-like exposures have become cautious, lowering the percentage of any energy loan they will hold," *Oil and Gas Investor* reported in November of 2002.[863]

These larger banks sought safety and higher fees, thus chasing larger, publicly held oil and gas clients, leaving an opportunity for growth in local bank portfolios. Smaller independents that didn't fit the surviving, national bank's portfolio design had been encouraged to take their business to local or regional banks.

Most of the capital formation in 2000-2001 was in the mezzanine and merchant-banking markets. Mezzanine markets doubled between 1999 and 2001[864] as many of the merchant banks that sprang up in the late 1990s, trying to copy Enron's success, vied for market share in mezzanine and structured-financed transactions.

Many of the utility and pipeline companies that followed Enron's lead used producer financing to enhance earnings as well as complement their other business lines, including hedging and trading, commodity sales to power plants and through-put on their pipelines. "In the late 1990s through 2001, the merchant players saturated the market with capital. All of them followed in Enron's footsteps," Kurt Talbot, a veteran mezzanine lender, observed in 2004.

"The quest was for earnings, not necessarily cash returns. In the early to mid-1990's, Enron turned the market on its head with its commodity-risk management and volumetric production payments. These were well

863. Brian A. Toal, "Regional Bankers Court Borrowers," *Oil and Gas Investor*, November 4, 2002. "'During the past 18 months, many money-center banks have up-tiered their energy client focus, neglecting the small-cap independent,' says Arthur R. (Buzz) Gralla Jr., senior vice president and director of all U.S. oil and gas banking for Guaranty Bank." Toal, "Regional Bankers Court Borrowers."

864. Tim Murray, Wells Fargo Energy Capital, "IPAA Oil and Gas Investment Symposium Private Capital Conference" (presented at 2005 OGIS Private Capital Conference), April 18, 2005.

structured, low risk and price-competitive. This was a model that was, and should have been, imitated. … Each of the merchant players was attempting to place $300[-] to $500 million of capital a year in the market.

"There was no deal that could not get done. … What started as senior debt morphed into subordinated debt, project equity and even venture capital. Ultimately, that's why many of these portfolios blew up."[865]

Spectacularly, Enron blew up. In December of 2001, it filed for bankruptcy, ending months of analysts' queries about opaque financial statements, accounting disclosures and SEC investigations. The company began in 1985 with the merger of two staid pipeline utilities, following FERC's deregulation of interstate pipelines. Houston Natural Gas Pipeline merged with Omaha-based InterNorth Pipeline. In time, Enron became the most innovative and aggressive trading house in the country.

To survive in a deregulated world, Enron reinvented itself in the 1990s with the assistance of a young consultant from McKinsey & Co., Jeff Skilling. Enron began entering long-term, fixed-priced energy contracts and trading natural gas through the use of forward contracts and other instruments. Over time, Enron concentrated on financial instruments and trading markets, straying from its foundation that had been built on hard assets, particularly pipelines and natural resources.

Between 1990 and 2001, Enron Energy Capital Resources Group had invested nearly $5 billion in E&P companies through project finance, equity, mezzanine debt, senior debt, convertible debt, volumetric production payments and other instruments.[866] Its downfall was unrelated to its capital lending and investments in oil and gas assets. Meanwhile, the innovation it brought to financing U.S. independents is largely unknown by the general public or by new, capital-hungry producers that now access capital under debt structures invented and made commercial by Enron.

In 2002, other major power companies and pipeline operators that were trading commodities in competition with Enron also saw these business units fail. Many of them had also launched energy-finance units, including Duke Energy's Duke Capital Partners and Southern Co.'s Mirant Americas. Late-comers, their units were only dabbling in energy finance, relative to Enron's portfolio; their parents, focusing on their own balance sheets, found

865. Kurt Talbot, Goldman Sachs E&P Capital, quoted by Snow, "Minding the Gap."
866. Nissa Darbonne, "A Major E&P Capital Provider, Enron is Busy With Its Own Finances," *Oil and Gas Investor*, January 30, 2002.

better uses for their capital and decided to abandon this "non-core" business.[867] In 2006, energy attorney James McKellar reported:

> Their lower debt and equity costs, without the regulatory constraints of banks, allowed them to create large profit margins on their producer financing and their hedging and trading businesses. Securitization of the producer finance portfolios allowed Enron and others [utilities and pipelines] to accelerate profits, which further increased the appetite and lowered the cost for producer loans. The model fell apart with the Enron failure. The rating agencies, who had failed to properly account for the risks that the trading, hedging and financing businesses put on balance sheets, moved quickly to downgrade the ratings of these companies. Production financing and hedging operations were sold, spun off or terminated as these companies went into bankruptcy or shed assets to improve capital, save credit ratings and avoid bankruptcy.[868]

The mezzanine market had expanded from $200 million in 1991 to $1.3 billion in 2001. During 2002 and 2003, it declined to between $300- and $500 million.[869] The few still standing included three of the original shops: TCW, General Electric Energy Capital and Wells Fargo Energy Capital.

The loss of sources of mezzanine capital meant less competition and higher pricing. Energy-capital broker Cameron Smith said in a 2002 article, "In the classic theory of supply and demand, yes. I'm more concerned, however, that for a while at least, mezzanine capital will simply be much more difficult to find."[870]

Predictions were that, with the loss of Enron, Shell and others, equity-kickers in the form of overrides would cost more.[871] Another energy financier, Scott Johnson, observed in 2002, "The core market of mezzanine investors has been decimated since the beginning of the year. Of five key mezzanine investors last year, only two are left. The mezzanine financing

867. Producers, such as Royal Dutch Shell and Range Resources Corp., that had producer-finance units struggled with the capital-allocation decision as well and, ultimately, decided to exit the field. Murray, "The Ins and Outs of Mezzanine," 31.

868. McKellar, "'Oil and Gas Financing, 'How It Works,'" III.B.1.

869. Wells Fargo Energy Capital Presentation on Mezzanine Debt Markets, IPAA Capital Markets Conference 2004.

870. Nissa Darbonne, "Where Art Thou Mezzanine Financier?," *Oil and Gas Investor*, June 4, 2002.

871. Darbonne, "Where Art Thou Mezzanine Financier?"

business has certainly been hurt. The remaining investors will be much more selective than ever before, so companies will need to present strong projects and they will need to present them well."[872]

Smith wrote later in 2002, "With the implosion of Enron, Aquila and Mirant, and the withdrawal of Shell, a crucial question may yet be: what assets and team, well-suited to the private-capital psyche, are in, or are about to come into, the market, perhaps as distressed prices, perhaps with books of business yet available for instant gratification?"[873]

The market response to the dire forecast of the dearth of mezzanine providers was quickly answered—perhaps sped on—by the increase in margins that the surviving mezzanine lenders experienced. Within fewer than 24 months, the void was filled by new players: Macquarie Energy Capital, led by former Cambrian Capital bankers; Royal Bank of Scotland, led by ex-Enron lenders; BlackRock Energy Capital, consisting of the producer-finance unit formerly within an E&P company and now known as BlueRock; Petrobridge Investments, led by ex-Mirant and -Shell Capital lenders; Goldman E&P Capital, led by additional ex-Enron lenders; and NGP Capital Resources, formed by private-equity provider Natural Gas Partners.[874]

The Oil and Gas Price Rush of the 2000s

9/11 not only gave rise to new banking regulations; crude oil prices slid on an already-weakened world economy and increases in OPEC production. WTI had exceeded $35 in November of 2000; a year later, it was less than $20 and wouldn't find $35 again until 2003.

Natural gas followed the opposite course, however. The Nymex price had spiked above $10 during in the winter of 2000-2001; after the attack, it fell below $2. But it quickly resumed its steady climb as the winter of 2001-2002 drew down reserves. The price was more than $5 in January of 2003; beginning in December of 2003 and except for a few days, the prompt-month contract did not trade below $5 again until 2009.[875]

---

872. Darbonne, "Where Art Thou Mezzanine Financier?"

873. Cameron Smith, Cosco Capital Management, LLC, "Plenty of Private Capital Available- to the Right Type Companies," *Oil and Gas Investor*, September 4, 2002.

874. Natural Gas Partners formed NGP Capital Resources in November, 2004, to capitalize on opportunities created by an estimated $2 billion of primarily mezzanine capital that had exited the energy space during the prior three years. Brian A. Toal "Focused On Yield," *Oil and Gas Investor*, April 29, 2005; Amiel David, PeTech Enterprises, IAEE/IELE Conference, Houston Texas December 11, 2003.

875. U.S. EIA, Independent Statistics & Analysis. "Henry Hub Natural Gas Spot Price." Accessed March 6, 2016. Eia.gov.

As for oil and also beginning in 2003, its price consistently grew as well—based in part on commentary that the world had found peak oil-production capacity; thus, no future net supply growth was possible.[876] The inability of the U.S. to replace its oil reserves, much less reduce its dependence on imports, was the topic *du jour*. Not since the Arab-embargo-derived oil crisis of the 1970s had the theory of declining reserves espoused by King Hubbert in 1956 gained so much traction and general acceptance.[877]

In 2005, energy analyst and investment banker Matt Simmons' *Twilight in the Desert: The Coming Saudi Oil Shock and the World Economy* was published, asserting that the limitless Saudi fields were, in fact, limited and that their ability to make up the rest of the world's declining reserves would become a crisis sooner rather than later. Simmons' analysis found support by historically low spare OPEC capacity during 2004-2005.

Bill Weidner wrote in 2008, "The numbers are compelling. In 1986, when OPEC had approximately 17 million barrels of excess daily capacity, the world had consumed 566 billion barrels of crude oil since Colonel Drake drilled his first well in Pennsylvania in 1859. In the … years since 1986, however, the world has consumed almost another 566 billion barrels—and OPEC's excess productive capacity has dwindled to a number almost too small to measure." [878]

The U.S.' perceived dependence upon foreign oil was not just an economic issue; it was a national security issue. In January of 2007, at a hearing before the U.S. Senate Committee on Energy and Natural Resources, the director of geopolitics and energy at New America Foundation testified, "Simply put, there is no economically plausible scenario for a strategically meaningful reduction in the dependence of the

876. The root of the advancement was in Hubbert's Peak projection in the late 1960s. It was further propelled by the U.S. invasion of Iraq and post-9/11 economic rebound, rising Asian demand and Gulf of Mexico production disruptions that had been caused by hurricanes Ivan, Katrina and Rita.

877. King Hubbert predicted in 1956 that U.S. oil production was likely to hit its peak somewhere between 1965 and 1970, a theory, "Hubbert's Peak," that would forever be linked to his name. Yergin, *The Quest*, 237.

878. William Weidner, "Private Capital Flow," *Oil and Gas Investor*, March 14, 2008, accessed March 1, 2016, Oilandgasinvestor.com. During much of 2004 and 2005, one analyst calculated OPEC's spare capacity to produce oil was less than 1 million barrels per day. James L. Williams, WTRG Economics, "Oil Price History and Analysis," Wtrg.com, accessed March 16, 2016.

United States and its allies on imported hydrocarbons during the next quarter century."[879]

American production was perceived as being on a terminal decline and dependence upon foreign oil would only increase. Accordingly, the price of oil, which had grown into the $50s and $60s by January of 2007, began to take off on a steep and continuous rise, finding $80 that September and topping out at nearly $150 in July of 2008.

As prices continued their seemingly inexorable rise, oil and gas loans—once perceived as a risky and even "alternative" investment by some bankers—were now highly valued as safe, quality loans. David Reid with Capital One Southcoast Inc. said in a May 2008 article, "The E&P sector has become one of the lowest-risks businesses for banks. For the past decade the loss to the banking industry on proven-reserve-based loans has been virtually zero."[880]

Natural gas was in the money too. Power-generation demand was growing in the 1990s and 2000s as a result of increased use of natural gas, rather than coal; a growing U.S. economy; and increased electricity use via the preponderance of digital services and devices. Hot summers and cold winters piled on, along with a drought in the U.S. Northwest that reduced hydro-generated power supply there.[881]

Further jumps in price during the 2000s were caused by massive losses of production as a result of hurricanes Ivan in 2004 and Katrina and Rita, both in 2005. In December of 2005, the price of natural gas on Nymex exceeded $15 as a result of reduced supply and the fear of another exceptionally cold winter.[882]

George Mitchell and the Shale Revolution

In the midst of the run-up in natural-gas prices, the marketplace wasn't giving much consideration to newly proven production that was possible from shale. The other Hubbert's Peak—the one Hubbert forecasted in the

879. Dr. Flynt Leverett, Director of Geopolitics and Energy at the New America Foundation, Testimony before United States Senate Committee on Energy and Natural Resources, January 10, 2007.

880. Gary Clouser, "Regional Credit No Problem," *Here's the Money: Capital Formation 2008, Special Supplement to Oil and Gas Investor*, May 2008, 20.

881. Mary Ann Capehart, "Drought Diminishes Hydropower Capacity in Western U.S.," *Water Resources Research Center*, accessed on February 15, 2016, Wrrc.arizona.edu.

882. Price figures from U.S. EIA, Independent Statistics & Analysis. "Henry Hub Natural Gas Spot Price." Accessed March 6, 2016. Eia.gov. Storage figures from U.S. EIA, Independent Statistics & Analysis. "Lower 48 States Natural Gas Working Underground Storage." Accessed March 6, 2016. Eia.gov.

1970s for natural gas—was a problem gas producers had persistently faced since the early 1980s. One producer in particular set out to coax gas out of a shale formation, the Barnett, in North Texas.

George Mitchell, a self-made billionaire and social visionary, was born in Galveston, Texas, as the son of a Greek immigrant.[883] After receiving his engineering degree with an emphasis in geology from Texas A&M University and serving in World War II, Mitchell went to work as a wildcatter based in Houston. The company, Christie, Mitchell and Mitchell, eventually became Mitchell Energy & Development Corp.

In a 1998 biography of him and the company, Mitchell said of Harold J. Vance, his petroleum-engineering professor at A&M, "He had a real homespun philosophy. He said, 'If you want to go to work for Exxon (or Humble at that time), fine, then you can drive around in a pretty good Chevrolet, but if you really want to drive around in a Cadillac you'd better go out on your own someday.'"[884]

Vance was influential in the careers of many oilmen and oil bankers. As a professor, for example, he taught oil and gas property valuation to Tom Stevens, who in the 1970s became the head of First City's energy group. Later in his career, Vance himself joined the ranks of energy bankers as the head of Bank of the Southwest's oil and gas department. Full circle, Bank of the Southwest was one of the lenders Mitchell relied upon as he was building his company. Vance became a director of the bank.[885]

Mitchell financed his early production from a core of investors who stayed with him for decades. Joseph Kutchin, the biographer, wrote, "Mitchell began his career partnering with his older brother Johnny and wildcatter, Merlyn Christie to form an independent oil company Christie, Mitchell and Mitchell, just like the generation of wildcatters before him. Without any production to speak of they were unable to get bank financing. Instead, he would work up a prospect from geological information and tips,

---

883. Story told by Mitchell to Budd Clark. Mitchell's father took on the name of his rail-gang paymaster, Mike Mitchell, as he was told that "his name, Savvas Paraskevopoulos, was too damn hard to pronounce."

884. Kutchin, *How Mitchell Energy & Development Corp. Got its Start*, 187. Ironically, while Mitchell owned a few Cadillacs in his day, he never put on airs or acted like his assets were worth hundreds of millions of dollars. For example, anyone could find him eating breakfast most Saturday mornings in his hometown of Galveston at his favorite breakfast spot with childhood friends and the rest of the local breakfast crowd. And, after pitching to the Galveston City Council a public effort he would underwrite to rebuild the city after Hurricane Ike, he and his team rode back in a cab; he jumped in the middle of the back seat.

884. .

885. Tom Stephens, interview by the author, October 12, 2012.

acquire some leasehold on the cheap and try to sell portions of the prospect to local investors."

Mitchell told Kutchin, "I would do the geology and engineering, get the deal together, and then we'd have some land man help us get the leases together and Johnny and Merlyn would go down to the Esperson Drugstore [in downtown Houston] and sell the deals. That's how we started. They'd sell an eighth here and an eighth there, they'd sell over coffee, and the first thing you know, we had a deal that cost $30,000. We'd get maybe at first a 32nd carried interest, and then a 16th carried interest.

"Anyway, first thing you know, we started building, and then we got our quarter net profits, and soon we started taking more of the deals ourselves. So Johnny and I and Merlyn kept building the company gradually. If we'd drill a well, make a well, we'd run to the bank to get some money. If you drill a dry hole, you get nothing."[886]

An early success for the company was the development of Boonsville Field, a gas field north of Fort Worth. The field showed little promise to a number of major oil companies, which had drilled 11 dry holes into the formation and determined the rock too tight to produce; besides, they were looking for oil, not gas.

Based on a tip from a Chicago bookie, Mitchell acquired acreage in the field and began drilling it in 1952. He looked at the geology and knew that a new technology was the answer that prior energy companies exploring in the area failed to employ. He told Kutchin, "Hydraulic fracturing had just come in about two or three years before. Without hydraulic fracturing you couldn't make decent wells. So this is where we combined the engineering with the geology to make it feasible."[887]

After his initial well, Mitchell could see the formation was a large stratigraphic trap. Within 90 days, with help from his go-to investors, Mitchell leased 300,000 acres at $3 an acre.

He needed more money. And just as H.L. Hunt's original loan from First National was based on the bank's president confidence in the East Texas Field, Mitchell found a receptive audience in Vance. B.F. "Budd" Clark had joined the company in 1956 as its chief financial officer and retired in 2002 as its vice chairman. Kutchin quoted Clark, "Fortunately, there was an energy banker [Vance] at Bank of the Southwest who had been George's professor at Texas A&M. He did something that was done very rarely, if at

886. Kutchin, *How Mitchell Energy & Development Corp. Got its Start*, 226-227 (quoting George Mitchell).

887. Kutchin, *How Mitchell Energy & Development Corp. Got its Start*, 5, 193, 228-9.

all, in that he lent George money on the basis of the logs showing what reserves were behind each well, even though the well wasn't producing. He saw the logs and the fact that the wells were good, so he had his department lend against them which was highly unusual."[888]

The story of how Clark was hired by Mitchell in 1956 is another testament to the close relationship of oil and gas men and their bankers. At the time, the company was still Christie, Mitchell & Mitchell. Christie wanted to hire a "Harvard man" to help with the company's business affairs. Clark had received his MBA from Harvard Business School as a Baker Scholar after WWII on the G.I. Bill and had posted his resume with the Harvard Business School alumni group in Houston. Grover Ellis, an energy banker with First City in Houston, passed the resume on to Christie.[889]

The Boonsville Field that Bank of the Southwest agreed to loan against became the foundation upon which Mitchell Energy was built. But, by 1981, after more than 30 years of development and natural declines in the wells' production, the company needed to find more supply to continue to fulfill a contract with Natural Gas Pipeline Company of America that dated back to 1953.

It had been long-known that the source-rock for the gas Mitchell had been producing from the field was the Barnett shale, which had too low a permeability to economically tap with ordinary measures. Beginning with a well drilled in it in 1981, the company failed to produce economic Barnett wells until 1996, when it significantly altered its fracture-stimulation recipe.[890]

As with many discoveries from Columbus on, there were both elements of stubborn perseverance and serendipity in Mitchell's breakthrough.

888. Kutchin, *How Mitchell Energy & Development Corp. Got its Start*, 66.

889. In the summer of 1956, the last person Clark met during a day of interviews with the company was Christie who, deciding it was sufficiently late in the day to start drinking, offered Clark a glass of bourbon. Christie noticed Clark look down anxiously at his Timex wristwatch; he was thinking of how he would make his flight back to New Orleans to his pregnant wife and four young daughters. In his plain-spoken manner, Christie, still holding out the glass of bourbon, said, "Well, do you want the damn job or don't you?" My father accepted both the drink and the offer. For most of his career as the company's executive vice president and chief financial officer, one of my father's primary roles was to keep the channels of capital open to finance the growth of Mitchell's energy operations and, later, to also finance the development of The Woodlands, a planned community north of Houston, maintaining close relationships with many of Houston's and New York's energy lenders over the years.

890. Darbonne, *The American Shales*, 13.

Mitchell had spent millions of dollars and years drilling wells into the Barnett, experimenting with ways to produce the gas he knew was there. His engineers had been using a gel mixture to fracture the shale formation based on the commonly held theory that a water-based fluid would cause the clay in the shale to swell and seal the fractures that were created by the hydraulic pressure.

To save on costs, Mitchell's senior completion engineer, Nick Steinsberger, began experimenting with using a lower concentration of chemicals, but still keeping the fluid a gel that would carry the sand (proppant) mixture downhole to prop open the fractures caused by the pressurized solution. But as the engineers reduced the concentration of polymer chemicals, it became more difficult to maintain the gel consistency of the fluid.

In the summer of 1996, on-site for a frac job, Steinsberger noticed that the gel frac mixed by BJ Services Inc.'s crew wasn't cross-linking. "Instead of Jello, it looked more like a slickwater solution."[891]

Recognizing that the fluid wasn't gelling properly, the crew went ahead with the completion anyway. Contrary to the conventional theory, the well's results were surprisingly good *in spite* of the "faulty," watery fracturing fluid.[892] Steinsberger compared notes with other producers, including Union Pacific Resources Group Inc., which was experimenting with its fracs in tight rock in East Texas.

On the S.H. Griffin No. 4 vertical well, Steinsberger and the group finally came up with a mixture of polymers, sand and water that proved a success.[893] The initial rate of production was strong—1.5 million cubic feet a day—and, unlike prior fracs in the Barnett, stayed strong.[894]

As did Columbus, Mitchell had to go hat in hand to his lenders more than once to continue to fund his exploration. And, like Columbus, through determination, perseverance and stubborn luck, he and his engineers turned a mistake into a discovery that changed the world. Along with the Drake well, Spindletop, the Santa Rita No. 1 and the Daisy Bradford No. 3, the

891. Nick Steinsberger, Vice President-Engineering, Republic Energy, Inc., interview by the author, October 2, 2014.

892. Gregory Zuckerman, *The Frackers: The Outrageous Inside Story of the New Billionaires* (Portfolio, November 5, 2013), 77.

893. Steinsberger, author's interview.

894. In 2012, the S.H. Griffin Well No. 4, which was still producing, had made more than 2.3 Bcf of gas or $11 million worth. It was estimated it could produce another 0.5 Bcf. Russell Gold, *The Boom: How Fracking Ignited the American Energy Revolution and Changed the World* (Simon & Schuster, April 8, 2014), 130.

S.H. Griffin No. 4 should be added to the pantheon of wells that changed history.

As the breakthrough was under way, a lawsuit against Mitchell Energy and unrelated to the Barnett-shale project was filed in Wise County in the spring of 1996, claiming well-water contamination dating back to, at least, 1978. Plaintiffs won a $200-million judgment and their neighbors filed suits as well.[895]

Mitchell went to his bankers for a $250-million letter of credit to secure the company's appeal bond. Manufacturers Hanover was administrative agent of the credit facility at the time and polled the syndicate for support of the special loan.[896] It was more a "life line" than a line of credit; the company had to fight the court decision lest it and copy-cat suits destroyed the company.

One syndicate member was Bank One. It had inherited the Mitchell account when it bought out Bank of the Southwest in 1990, where Vance had led the energy department. Long-time Bank of the Southwest loan officers Buzz Gralla and Dick Sylvan, working as Bank One officers, supported Mitchell's request, but needed the approval of Bank One's credit officer, "who was not an [oil and gas] guy and he didn't want to do it," Sylvan said in an interview in 2014.

Gralla, Sylvan and bank president Charlie O'Connell favored the deal. As the discussion became heated, Sylvan told the credit officer, "Damn it! George is a director of the bank and he's in trouble. The lawsuit is bullshit. It's time to stick by our customer."

After the meeting, O'Connell admonished Sylvan for being "a little aggressive" with the senior credit officer, but, ultimately, the bank approved the loan.[897] The letter-of-credit facility secured Mitchell Energy's appeal bond and right to appeal the jury verdict. The appellate court overruled the trial court. A similar lawsuit was ruled in favor of Mitchell in

895. Kutchin, *How Mitchell Energy & Development Corp. Got its Start*, 68.

896. Mitchell Energy's principal corporate credit facility, as did many other credit facilities at the time, permitted the company to incur liens to secure appeal bonds. A number of Mitchell's senior lenders did not want to support a separate line-of-credit facility, but they were helpless to prevent it under the terms of the loan agreement.

897. Dick Sylvan, Credit Officer, BBVA Compass Bank, formerly Credit Officer, Bank of the Southwest, interview by the author, March 28, 2014. Buzz Gralla, Amegy Bank, formerly Energy Lender at Bank of Southwest from 1977-1999, interview by the author, February 19, 2015.

trial. The other lawsuits were dropped by attorneys who couldn't see a means of getting paid by a victory.[898]

Mitchell Energy "had been victorious, but at a high price,"[899] Kutchin wrote. The stock had been under a dark cloud of litigation for more than a year and gas prices fell in mid-1998 to less than $2.[900] Mitchell had exhausted the patience and credit of his lenders. In annual bank meetings during the early 1990s, he and his officers told the lenders of the Barnett's gas potential, but the low production rates were barely breaking even.

Sylvan said, "One year, at the Mitchell bank meeting, Homer Hershey, Mitchell's vice president in charge of North Texas operations, told the bankers, 'Next year, we're going to be drilling a new formation. We have had mixed success so far; to date, returns are flat right now. But we see a lot of potential. The wells are expensive and all need to be frac'd because it is a tight formation.'"

The following year, Hershey reported again. "Homer said, 'We can report good news in the Barnett—our costs to frac are down by a half, plus we are getting two times the returns on production. We are getting a 4-to-1 return. So we are going to drill a lot more wells.' Only later we found out that the 4-to-1 returns were not the average, but the exception. There were more unsuccessful wells that didn't yield 4-to-1 returns."[901]

Another of Mitchell's lenders recalled, "He was just trading dollars, not really getting back any more from the wells than the cost he spent to drill. (By the end of the '90s), the company had piled on so much debt to afford all its spending that lenders wouldn't offer more."[902]

---

898. .*Mitchell Energy Corporation v. Bartlett*, 958 S.W.2d 430 (Tex.Civ.Ap—Ft.Worth November 13, 1997); *see also*, Dan Steward, *The Barnett Shale Play: Phoenix of the Fort Worth Basin: A History* (The Fort Worth Geological Society, 2007).

899. Kutchin, *How Mitchell Energy & Development Corp. Got its Start*, 69.

900. U.S. EIA, Independent Statistics & Analysis. "Henry Hub Natural Gas Spot Price." Accessed March 6, 2016. Eia.gov. While the *Bartlett* verdict was under appeal and as gas prices fell from $3.40 in a few months to $1.80, the company was under a dark cloud. Its long-term gas-sales contract, at an above-market, fixed price, with Natural Gas Pipeline had ended. The company also owned The Woodlands, a planned community north of Houston. Stock analysts struggled with valuing the company's shares because it was neither an energy pure-play nor a real estate pure-play. The board told George Mitchell, who owned more than half of the company's stock, that he had to choose between his oil company and his visionary planned community. Although he was the first to admit his heart was in The Woodlands, the gas business was not saleable pending appeal of the $200-million *Bartlett* verdict. Mitchell Energy sold The Woodlands for $543 million. Shortly thereafter, the company made its Barnett-shale breakthrough.

901. Sylvan, author's interview.

902. Russell Clingman, Wells Fargo Bank, interview by the author, March 26, 2014.

Mitchell's board concluded it was time to rein in spending, including the company's efforts in the Barnett. By January 1999, Mitchell announced a 20% reduction of its staff.[903] That spring, however, the outlook began to improve with the changed-up recipe in how the Barnett wells were being fracture-stimulated.[904] Upon continued success, Mitchell sold the company to Devon Energy Corp. in early 2002.[905]

Devon took Mitchell's technology and multiplied the results, using horizontal-well technology. "Mitchell's application of water fracs in my opinion proved the Barnett was a viable play. Devon's application of horizontals moved the play into a boom," Dan Steward, a Mitchell geologist, reflected in a 2013 article.[906]

As word leaked, other operators began experimenting with horizontal wells and Mitchell's completion recipe.[907] Producers and investors caught shale fever and began searching from basin to basin for the next bonanza—very much like their brethren of a century earlier as wildcatters moved from boomtown to boomtown, buying up leases and chasing one gusher to the next.

However, instead of seeking leases of a couple of acres—or even less, as in the East Texas Field—these new wildcatters were chasing whole basins, encompassing tens to hundreds of thousands of acres and resulting in thousands of wells. The effort required—and continues to require—massive capital.

Signing bonuses for leases in the area of the Haynesville play, for example, had been going for between $200 and $400 an acre before the

903. Mitchell Energy & Development Corp., "Mitchell Completes Work Force Reduction, Sets Capital Budget," *PR Newswire*, Feb. 22, 1999, Prnewswire.com.

904. Dan Steward, "The Shale Gas Miracle: A Tribute to George P. Mitchell" (presented at the Academy of Medicine, Engineering and Science of Texas, January 12, 2012 Annual Conference "Energy for Life," Houston, Texas).

905. Steward, "The Shale Gas Miracle." By 2000, 186 Barnett wells had been drilled and the play was starting to heat up. Gas prices reached over $9 and landmen checking mineral-ownership records to get oil and gas leases were tripping over each other at county courthouses. Drilling rigs were brought in by the dozen. In 2001, 520 wells were drilled. Mitchell had up to 18 rigs running in its 120,000 acres in the core area of the field. Devon Energy Corp. closed its $3.5-billion acquisition of Mitchell Energy in early 2002. George Mitchell became Devon's largest shareholder. Devon and other operators began experimenting with horizontals in the play. During 2003, 780 wells were drilled; roughly 130 were horizontal and drilled by 27 different operators.

906. Jim Pierobon, "George P. Mitchell: Founder of Shale Gas — Here's How He and His Team Did It," *The Energy Fix*, August 5, 2013, Theenergyfix.com.

907. Natalie Givens and Han Zhao, "The Barnett Shale: Not so Simple After All," Republic Energy Inc. website, accessed October 2, 2014, Republicenergy.com.

play was discovered; this grew to nearly $30,000 an acre in the most competitive area.[908] In the Eagle Ford, one South Texas rancher was handed a $1-billion check to drill his 106,000 acres.[909]

To hold leased acreage, an explorer has to make a producing well prior to an agreed deadline or lose the lease. And these shale wells could cost more than $10 million each. Producers quickly stretched all existing capital sources and needed more.

Banks and other sources responded aggressively to the improving commodity-price environment and demand for capital. In 2005, oil and gas loan volume increased 40% from the prior year; in 2006, it grew another 36%. Loan volume in 2006 was $164 billion, compared with $67 billion in 1997. As banks competed to lend more money to oil and gas producers, they reduced the cost to record lows, maturities were pushed out and covenants were made looser.[910]

In addition, new mezzanine and private-equity providers were looking for ways to get a piece of the hot energy market. As a result, there was a much deeper and broader pool of capital available to small- and mid-cap E&P companies than historically had been the case. From commercial debt and public-market capital to private-equity funds, the array of capital choices and dollars grew to an all-time high heading into 2008. The number of mezzanine providers increased from a handful after the Enron meltdown in 2001 to some 20 by 2007.[911] Around 2004, in addition to the traditional two-tiered senior-bank-debt/mezzanine-debt structures, traditional energy banks began to compete indirectly with mezzanine by offering a new structure between their conforming senior-lien loan (Tranche A) and the mezzanine (junior-lien) loan.

---

908. Chris R. Gideon, CPL, interview by the author, March 17, 2016.

909. DrillingInfo reported that Shell Oil Co. leased Dan Harrison III's 106,000-acre Piloncillo Ranch, spread out over Dimmit and Webb counties, Texas, for a rumored $1 billion in 2010 ($10,000/acre) for Eagle Ford-play development. Just shy of three years later, Shell announced it was selling the lease and taking a $2.1-billion impairment related to its North America shale properties. Proving the old saw that "oil money begets oil money," the Harrison family was one of Texas' original wildcatter families and acquired its original wealth in 1934 when it teamed with J.S. Abercrombie to discover the Old Ocean Field in Brazoria County, Texas.

910. Brian A. Toal, "Rising Credit Tide," *Here's the Money: Capital Formation 2007, Special Supplement to Oil and Gas Investor*, May 2007, 4. The average spreads for syndicated loans in 2006 were Libor plus 210 basis points versus plus 220 in 2005 and plus 245 in 2004.

911. Murray, "The Ins and Outs of Mezzanine," 26.

As commodity prices for oil and gas continued year-on-year increases above historical norms, banks were slow to keep pace in the increases to their price decks used to determine the conforming borrowing base.[912] This meant a considerable gap between bank decks and the 12-month strip—therefore, considerable value above what a borrower could expect from the senior lender's conforming borrowing-base value of its oil and gas assets versus the amount its current cash flow could justify. Thus, an opportunity was created and the lending community responded to fill the void, providing more debt load for the producers to carry.

The structures went by different names, including the "Term B" or "Tranche B" loan, the "Senior Stretch Tranche" and the "Senior Second Out." But these, basically, priced in between senior debt and mezzanine debt—that is, between 100 and 300 basis points over the price of the senior bank debt that enjoyed lien and payment priority over mezzanine facilities.

This intermediate capital was typically employed as a stretch piece to help companies in connection with an acquisition of producing and non-producing properties. By making a stretch loan against the borrower's "lesser collateral"—i.e., more heavily weighted to proved undeveloped (PUD) reserves—lenders were able to compete with the alternative, mezzanine sources. These "stretch" loans were usually intended to be short-term debt with around a one-year maturity and with little to no prepayment penalties. But if rising oil and gas prices stopped propping up the producer's loan, just like musical chairs, bankers and producers could find themselves without a seat when the music stopped.

If made by the producer's existing senior bank group, they could be documented under the same credit agreement and secured by the same collateral as the Tranche A "conforming" loan. These loans were an attractive alternative to a company that had a low-value conforming borrowing-base asset mix and didn't want to incur the expense of negotiating a separate mezzanine facility or the cost of issuing public debt or diluting equity.

The Tranche B was typically a term facility—i.e., non-revolver—fully funded at closing with a fixed amortization and maturity earlier than the Tranche A facility. The expectation was that the borrower would refinance the Term B loans within the stated maturity through an increase in the Tranche A borrowing base due to increased production as a result of drilling and development with the dollars provided under the Term B loan and/or through sales of non-core assets.

912. Clouser, "Regional Credit No Problem," 24.

As the decade progressed, Term B loans were making a strong showing in a number of high-profile transactions from 2004 through 2007. Credit Suisse reported having made three such loans in 2004, five in 2005 and 14 in 2006.[913]

Because of the ever-increasing demand among shale pioneers for debt capital, the popularity of the Term B loans did not squeeze out the alternative lenders, who issued billions of dollars of second-lien loans to the industry. This was remarkable growth for a type of financing rarely employed prior to 2000.[914]

But the success and high rate of repayment of second-lien paper encouraged further growth of mezzanine lending during the middle of the decade. These proliferated as institutional money was drawn to the private-equity-type returns on capital that was secured with collateral and governed by debt covenants. As mezzanine loans to E&Ps grew to more than $100 million per borrower, the ability of the alternative lenders to syndicate their second-lien facilities increased liquidity in this market, making it even more attractive to institutional investors.

Syndicated second-lien term loans looked very much like the senior syndicated loan with administrative agents. In addition to a higher cost and looser financial covenants, which were usually limited to just an asset-coverage test, another difference in the market was the composition of the syndicate members. Unlike the senior-loan market, the second-lien market's participating lenders typically were not commercial banks but were insurance and private-funds investors.

An example was the senior and second-lien loans to Ram Energy Inc. agented by Guggenheim Partners LLC, a private investor. To enter the energy-capital market in 2005, Guggenheim hired Tim Murray, who had been the head of Wells Fargo's energy-lending group, to start its Houston office. In connection with Ram's acquisition of Ascent Energy Inc. in 2007, Guggenheim arranged a $175-million senior secured revolving credit facility and added a $200-million senior secured Term B facility from a syndicate of lenders led by Guggenheim. The loan syndicate consisted of more than 15 institutions, including banks, insurance companies, institutional funds and private equity.[915]

---

913. Ellen Chang, "Term B Loans," *Here's the Money: Capital Formation 2007, Special Supplement to Oil and Gas Investor*, May 2007, 42. Among the financings were ATP Oil & Gas Corp.'s offshore-drilling program and Venoco Inc.'s acquisition of TexCal Energy (LP) LLC.

914. Murray, "The Ins and Outs of Mezzanine," 26.

915. Ellen Chang, "Mezzanine Capital," *Oil and Gas Investor*, March 14, 2008.

As syndicated second-lien facilities became more liquid in the secondary markets, more capital became available to E&P companies. With the relaxation of Glass-Steagall regulations, the lines between investment banks and commercial banks blurred. Commercial bankers were becoming investment bankers and investment banks were arranging and syndicating senior and second-lien secured energy loans.

Not all investment bankers shared commercial bankers' business model of building lasting relationships, providing daily cash-management services and working through the ups and downs of commodity-price cycles that inevitably come with the oil patch. The investment banks generally did not have the ability to make revolving loans or process the borrower's deposits and distribution checks, much less issue letters of credit needed by producers to support regulatory bonding requirements.

Typically, the investment bank or private-equity shop held little of the actual commitments; instead, they syndicated the facility to a larger group that included not only commercial banks but other non-bank investors.[916] As the origination of loans and holding risks were separated, these facilities lightened up their covenants and closed the price gap between senior-lien and second-lien facilities.

Bill Moyer, IPAA's vice president of capital markets in 2007, said in an article, "The competition resulting from the abundance of capital sources led some providers to be more creative and aggressive – perhaps taking on more risks, sometimes, without the corresponding increase in the rate of return or addition of warrants and overrides."[917]

The harvest of the shale revolution was coming on strong, evidenced by the price-ratio divergence of gas to oil. During 2002 through 2006, the ratio was roughly the traditional 6:1—that is, six million Btu of natural gas are roughly equal to the value of one barrel of oil. In 2007, the 12-month strips were 10:1. In 2008, the ratio widened to 12:1 and, in 2009, would surpass 30:1.[918]

916. Kurt A. Talbot, "IPAA Private Capital Conference" (presented at Private Capital Conference), 10.

917. Gary Clouser, "More than Plenty," *Here's the Money: Capital Formation 2007, Special Supplement to Oil and Gas Investor*, May 2007, 19.

918. The crude oil/natural gas price ratio is derived by dividing the spot price of a barrel by the spot price of an MMBtu. U.S. EIA, Independent Statistics & Analysis. "U.S. oil rig count overtakes natural gas rig count." Accessed May 9, 2011. Eia.gov; *see also*, Stell, "Banking Up." 2009 data from Oil & Gas 360, "Natural Gas – Where We've Been and Where We're Going." January 17, 2014, Oilandgas360.com. Accessed October 25, 2015.

The downside of the abundant availability of capital in the earlier part of the decade became evident when global credit markets and both oil and gas prices turned in mid-2008 and into 2009. The producers who needed to work through waivers or amendments found that their second-lien debt had become widely traded and ended up in the hands of opportunistic investors with whom they had no strong relationship, compounded by these investors' minimal experience in E&P. Like public debt notes held by multiple investors, it became impossible to identify and negotiate with the debt-holders to amend the documents—even in the case of a healthy deal.

Much to the dismay of a number of energy companies sitting on a great asset base while facing constrained cash flows to meet debt service during this credit crunch, conference calls to discuss covenant-waiver terms would end up with lenders positioning and arguing amongst themselves, while the borrower died on the vine.[919] One facility, in particular, epitomized the dysfunction of these "loan to own" lender groups when the lead lender's lawyer fired his private-equity-lender client to represent the balance of the lender group with the hope of salvaging a deal to restructure the debt.[920]

Commodity prices kept rising through the first half of 2008 to heights that, to many, seemed unsustainable—and they were. By July, the impact of the global recession and the continued growth in natural-gas supply reversed the price trends for both oil and gas. For those that bet oil prices would fall sooner than they did, the crest came too late. SemGroup LP suffered a $2.4-billion loss on short positions. What had been brewing for months resulted in its Chapter 11 bankruptcy filing in July.[921]

Because SemGroup was a major purchaser of oil, the impact of its bankruptcy was felt by many producers in Oklahoma, Texas, Kansas, New Mexico and elsewhere. Producers' claims, filed in bankruptcy court in Delaware, highlighted the questionable efficacy of a law that had been on the books in Texas and a handful of other producing states since the 1980s regarding the priority and perfection of security interests in oil and gas production and related proceeds.

Prior to the SemGroup bankruptcy, royalty owners, producers and their lenders in these states operated under the assumption that they had a self-

919. Kurt A. Talbot, "IPAA Private Capital Conference" (presented at Private Capital Conference), 11.

920. The loan was ultimately refinanced, the recalcitrant lenders, including the lead lender, were paid off and the oil company was still exploring and producing five years later, albeit after converting some of the original debt into equity as part of the work-out terms.

921. Christopher Helman, "Inside The Semgroup Bust," *Forbes*, July 28, 2008, Forbes.com.

perfected priority lien over the production purchaser's creditors.[922] The Delaware court, however, held that Texas' non-standard provision for automatic perfection in favor of producers would be junior to purchase-money security interests in SemGroup's accounts receivable. Moreover, because SemGroup was a Delaware entity, the law of Delaware governed perfection of liens over the accounts.

When oil prices collapsed in the 1980s, Delaware's legislature did not see fit to follow other states in enacting self-perfecting lien protection for producers and royalty owners. Producers and mineral owners, if any in Delaware, did not comprise as significant a voting block as in Texas.

The only way for them to have a secured lien on SemGroup's estate would have been if they had complied with Delaware's lien laws, which required filing a financing statement with the Delaware secretary of state's office in compliance with Delaware's Uniform Commercial Code—something few, if any, producers had done. Accordingly, many producers—and their lenders—were left with unsecured claims and received 40 cents on the dollar.[923]

As of today, it remains to be seen whether the SemGroup decision affects the credit underwriting and documentation of secured production loans to independent producers. The issue is of greater importance when considering where the producer's assets are geographically concentrated and whether sales of production are to just one purchaser. Likely, given the severe downturn in prices beginning in the second half of 2014, there will be ample data points to see if producers and their lenders learned the lessons of the SemGroup decision.

If a producer's purchaser did become bankrupt, the producer and his creditor should be exposed, at most, for a month or two of production proceeds, if the producer is selling its production under month-to-month contracts. The producer should be able to quickly switch to a solvent purchaser. But even a couple months' production can add up. For example, one producer, Enterra Energy Trust, had a $10-million claim, primarily consisting of sales to SemGroup during June and July of 2008.[924]

Typically, as seen in more-comprehensive mezzanine facilities, there is a requirement that the lender has the right to approve who purchases the

922. *In re Semcrude, L.P.* 399 B.R. 388, (Bankr. D. Del., 2009), aff'd 428 B.R. 590 (D.Del.2010).

923. Chris Moon, "Kansas Oil Producers to Recoup Millions with SemGroup Plan," *Wichita Business Journal*, September 27, 2009.

924. Leslie Haines, "Counterparty and Hedging Risks Grow," *Oil and Gas Investor*, July 29, 2008, Oilandgasinvestor.com.

borrower's production. Accordingly, under such a covenant, an alert lender might be able to protect its collateral—and its borrower's receivables—if it were aware of that one of the purchasers had less-than-stellar financial credentials. At this point, however, most mezzanine lenders fail to exercise such level of oversight; there is even less monitoring of to whom borrowers sell production under conforming reserve-based facilities.

The collapse of the U.S. housing market in 2007 that marked the beginning of the recession only indirectly affected the energy industry.[925] Many of the companies affected by the credit crisis included some of the energy industry's largest commercial-bank lenders which led to bank consolidation. The toxic nature of poorly underwritten home-mortgage loans infected the U.S. and international financial markets.[926]

The effects were multiplied by the use of credit-default swaps and collateralized debt obligations held by hedge funds, money-market funds, investment banks and private-equity funds.[927] Subsequent inquiries by governmental commissions seeking to identify the cause and propose future protections concluded the following in part:

> [T]he banking supervisors failed to adequately and proactively identify and police the weaknesses of the banks and thrifts or their poor corporate governance and risk management, often maintaining satisfactory ratings on institutions until just before their collapse. This failure was caused by many factors,

925. Housing prices rose from 1997 (110 on the index scale), peaked in April of 2006 (206) and, after a 12-month plateau, precipitously dropped by more than 30% between April of 2007 (202) through May, 2009 (140). S&P Case-Shiller 20-City Home Price Index (SPCS20RSA) reported on Federal Reserve Bank of St. Louis, Economic Research, Research.stlouisfed.org.

926. Subprime home-mortgage originations tripled from an average of between 6% and 8% between 1997 and 2003 to 20% between 2004 and 2006 when it fell to historic norms below 10% in 2007. U.S. Census Bureau. "The total value of mortgaged backed securities issued between 2001 and 2006 reached $13.4 trillion. There was a mountain of problematic securities, debt, and derivatives resting on real estate assets that were far less secure than they were thought to have been." FDIC, *The Financial Crisis Inquiry Report, 22.*

927. Fratianni and Marchionne explain in their paper, "Large default rates on subprime mortgages cannot explain the depth of this crisis. Subprime mortgages were the accelerant to the fire after the real estate bust short-circuited in the financial house. The fire spread quickly and globally because this house was built with combustible material, such as structured finance and inadequate supervision; a sudden rush for liquidity and fast deleveraging exacerbated by the practice of fair value accounting kept the fire running." Michele Fratianni and Francesco Marchionne, "The Role of Banks in the Subprime Financial Crises" (April 10, 2009), 8. Papers.ssrn.com.

> including beliefs that regulation was unduly burdensome, that financial institutions were capable of self-regulation, and that regulators should not interfere with activities reported as profitable.[928]

It was a rebuke that bank regulators would take to heart with respect to oil and gas loans as commodity markets turned south again in late 2014.

BNP Paribas was one of the first commercial-lending institutions to feel the effect of the meltdown; in August 2007, it blocked cash withdrawals from three hedge funds in its U.K. branch, citing "a complete evaporation of liquidity."[929] U.S. banks were estimated to have lost more than $1 trillion on toxic assets made up of collateralized subprime debt obligations and other debt derivatives from January 2007 through September 2009.[930]

In 2009, 140 U.S. banks failed.[931] The FDIC estimated that, by the end of the third quarter of 2009, there were 552 "problem institutions" at risk of failure. For seasoned bankers, this was all eerily reminiscent of the mid-1980s, when more than 1,500 U.S. banks failed; this time, however, oil and gas and Texas real estate were not the culprits.

The financial storm that had been brewing hit the financial markets the weekend of September 13, 2008, just as Hurricane Ike made landfall south of Houston. Ike left a trail of destruction over the resort island of Galveston, into Houston and The Woodlands, and north, heading to Dallas, essentially along the Interstate 45 corridor and the energy industry's world capital. Power failures and streets blocked by downed lines and trees prevented many oil and gas executives and their bankers from getting to their offices. Often, Internet access was impossible as well.[932]

As Texas residents were beginning to take stock of the hurricane's destruction in the daylight hours of that Saturday morning, Federal Reserve and Treasury officials were in tense talks in New York with the chairmen of the worlds' biggest investment banks. The goal was to secure a savior for Lehman Brothers, the U.S.' fourth-largest investment bank.

But, when Treasury Secretary Henry Paulson refused to sweeten a Barclays or Bank of America takeover of Lehman with public money, Lehman's fate was sealed.[933] It announced just after midnight the Monday

928. FDIC, *The Financial Crisis Inquiry Report*, 308.

929. FDIC, *The Financial Crisis Inquiry Report*, 250-251.

930. Bloomberg, "US European Bank Write-downs and Losses," November 5, 2009.

931. "Bank Failures in Brief," FDIC, Fdic.gov.

932. Clifford Krauss and James C. McKinley, Jr., "Hurricane Damage Extensive in Texas," *The New York Times*, September 13, 2008.

933. FDIC, *The Financial Crisis Inquiry Report*, 325-339.

morning of September 15 that it had filed for Chapter 11 bankruptcy protection. On the same day, Merrill Lynch, seeing Paulson's writing on the wall, announced it would be acquired by Bank of America.

The following day, the Federal Reserve organized an $85-billion bailout of AIG for an 80% equity stake that was extended further in October by $37 billion and by another $40 billion in November. On Thursday, the Treasury Department issued a guarantee that $1 in a money-market fund was worth $1.[934]

That same day, Paulson and Fed Chairman Ben Bernanke met in the conference room of the House speaker, Nancy Pelosi, to propose a $700-billion emergency fund, telling her and other leaders of Congress, "If we don't do this, we may not have an economy on Monday."[935] The Emergency Economic Stabilization Act, which authorized the Troubled Asset Relief Program (TARP), was signed into law on October 3, 2008.[936]

Meanwhile, Houston's energy executives and bankers and their employees were also keenly interested in when power would be restored to their homes and offices. It was restored up to weeks later in some of the city's most heavily forested neighborhoods. However, recovery of the nation's credit markets would require more time and much more capital before normalcy would return. The congressional commission studying the collapse reported in 2011, "Before it was over, taxpayers had committed trillions of dollars through more than two dozen extraordinary programs to stabilize the financial system and to prop up the nation's largest financial institutions."[937]

Oil and gas borrowers looking for capital were affected along with every other business; the world's capital markets essentially froze. Bernanke reported in 2011 to a congressional inquiry commission, "I honestly believe that September and October 2008 was the worst financial crisis in global history, including the Great Depression."[938]

Following a 10-day, $16.7-billion run on Washington Mutual Bank, which had an energy-lending group, the bank succumbed on September 25 when the FDIC placed it into receivership. With more than $300 billion of assets, WaMu was the nation's largest S&L and was roughly tied with

934. "Treasury Announces Guaranty Program for Money Market Funds," Press Center, U.S. Department of the Treasury, accessed May 3, 2016, Treasury.gov.

935. Andrew Ross Sorkin, "As Credit Crisis Spiraled, Alarm Led to Action," *The New York Times*, October 1, 2008.

936. Emergency Economic Stabilization Act of 2008 (Pub. Law No.:110-343).

937. FDIC, *The Financial Crisis Inquiry Report*, 23.

938. FDIC, *The Financial Crisis Inquiry Report*, 353-356.

Continental Illinois, pre-failure, in terms of relative size to the financial system.[939] It was immediately acquired by JPMorgan Chase.[940]

The same day, Wachovia Bank lost $5 billion in deposits, immediately triggering the FDIC to look for a suitor for it. After a bidding war between Wells Fargo and Citigroup and with further regulatory intervention, Wells Fargo announced on October 3 that it would acquire Wachovia's assets, including the bank's energy-lending team, which was repurposed as an energy investment-banking team. The team, led by James Kipp, had been together since the downfall of First City in 1993.[941]

Credit immediately became less fluid. Banks husbanded their reserves, while unsure of their own exposure to investments in collateralized-debt obligations and other asset-backed securities—and even less sure of fellow banks' investments. Libor more than doubled from 3.11% to 6.44% the day after the Lehman failure. Banks were so wary of lending to each other that, at the end of September, they required an unprecedented premium of 400% above the Federal Reserve Bank's target rate.[942]

Faced with the resulting freeze in interbank lending, the U.S. Treasury was forced to announce on October 14 that, instead of buying distressed assets, it would recapitalize the U.S. banking system by purchasing up to $250 billion of senior preferred shares in nine large U.S. banks.[943] Soon after this announcement, both the prime and Libor rates came down considerably.

For many foreign banks—principally European banks participating in U.S. reserve-based loan facilities—their cost of funds stayed higher than that of U.S. borrowers, effectively putting them out of competition in energy lending—at least for a while. Even among U.S. banks, any borrower in 2009 that was looking to refinance or ask for any type of amendment to

939. William M. Isaac, *Senseless Panic, How Washington Failed America* (Wiley, 2010), 145.

940. "JPMorgan Chase Acquires Banking Operations of Washington Mutual," FDIC Press Release, September 25, 2008, Fdic.gov.

941. In another failure, Guaranty Bank was taken over by the FDIC in August of 2009; all of its assets were acquired by BBVA Compass, including the energy portfolio.

942. The one-month Libor spread over overnight index swap rates showed the strains in interbank lending markets with rates bumping up to 1% in 2007 and early 2008, shot up to more than 3% by fall of 2008, returning to normal rates closer to 0% following the TARP infusion. FDIC, *The Financial Crisis Inquiry Report*, 355.

943. Nabil Khodadad, Dewey & LeBoeuf, "Trends in Financing Mining and Oil and Gas Projects," International Mining and Oil and Gas Law, Development and Investment, April 2009, Conwaygreene.com.

its facility could expect an increase in the price. In many facilities, they also saw a floor on the Libor and prime rates.[944]

Many borrowers were faced for the first time with the concept of "defaulting lenders." Rodney Waller, senior vice president of Range Resources Corp., which had announced a year earlier its horizontal Marcellus-shale discovery well, said in a November 2008 article, "I am concerned that I might have a bank that is going to go away and can't fund its commitment under these conditions from the crunch. JPMorgan, today, on our rollover revolver draws, will no longer give me funds from a bank unless that bank has actually sent that money to them."[945]

Bankers were experiencing this for the first time as well, questioning what right, if any, a participating syndicate lender could continue to enjoy under the loan documents if it was unable to fund its share of borrowing requests when requested. Lehman Brothers itself had only recently begun taking minor commitments in senior reserve-based loans.[946] Administering revolving borrowing-base loans in which Lehman, through subsidiary Lehman Commercial Paper Inc., was a lender became very complicated when Lehman filed for bankruptcy. Senior-bank agents became more selective in whom they were willing to invite into a borrower's syndicate.[947]

Prior to Lehman, the language of the standard form of agented reserve-based loan agreement did not contemplate that a *lender* would ever be in breach of its obligations. The credit agreements dealt only with contingencies for if the *borrower* became in default. In syndicated-loan agreements, certain decisions regarding the loan, such as whether to increase the borrowing base, require a unanimous vote of all "lenders." Getting Lehman's bankruptcy trustee or its counsel to focus on a request for a borrowing-base increase in any reserve-based oil and gas loan in which Lehman had less than a $10-million exposure was perceived as impossible in the midst of more than $1 trillion of claims against the estate.

944. As Libor spiked in October of 2008, there was speculation that even the reported Libor did not reflect banks' true cost of borrowed funds and that reporting banks were under-reporting this, so as to appear to be a better credit risk. This suspicion was proven correct as a few European banks later paid fines in the billions of dollars in the Libor-rate affair.

945. "New E&P Money-Mall Hours," *Oil and Gas Investor*, November 1, 2008.

946. This was to share in the first-lien collateral as security *pari passu* for its hedging exposure to its E&P borrowers.

947. Lehman Commercial Paper Inc. had approximately $11.4 billion of unfunded loan commitments at the end of 2008. Richard M. Gray, Milbank, Tweed, Hadley & McCloy LLP, "Debt Buybacks, Defaulting Lenders and Libor Market Disruption," *LSTA Loan Market Chronicle*, 2009, Milbank.com.

The preferred action was to buy out Lehman's position at par. But, where Lehman also had hedges with a borrower, the process required analysis, review and bankruptcy-court approval. It would take months for the court to permit action that would take Lehman out as a lender.

Following issues with Lehman and questions as to other banks' ability to fund their pro-rata share of borrowings, agent banks and their counsel began adding provisions or addressing "defaulting lenders" in the administration of reserve-based loans. Ultimately, in 2011, the Loan Syndications & Trading Association promulgated "standard language" addressing defaulting lenders that has become a part of the syndicated-loan documentation.[948]

Falling Oil and Gas Prices: The 2008-2009 Edition

Regional energy banks that were not hit as hard by the collapsed home-mortgage market were able to increase their exposure to energy producers by purchasing, at a discount, secured syndicated energy loans from the money-center and foreign banks.[949] These and other healthy banks were able to pick up the slack.

The pullback had begun in August of 2007. *Oil and Gas Investor* reported in January of 2008, "A lot of those banks, [Mark Fuqua, head of Comerica Bank's energy group,] says, recently had problems on some of their underwritings as the credit crunch advanced and the institutional hedge-fund, mutual-fund and insurance-company Term B loan market dried up. 'So now these banks seem more willing to bring other banks like Comerica into deals to spread their underwriting risk.'"[950]

In 2007, the structure and terms of first-lien debt to oil and gas producers were not affected by the liquidity problems suffered by some of the largest energy banks. However, by 2008, borrowers were seeing increases in pricing in response to the generally rising cost of long-term debt capital, especially in the second-lien market. Dorothy Marchand, another long-time energy banker, said in the article, "It appears that the trend we saw in early 2007, in terms of lightening up on covenants, is moderating. Also, because many institutions have pulled back, we see pricing margins or spreads increasing."[951]

---

948. Loan Syndications & Trading Association, Primary Market Committee Model Credit Agreement Provisions 2011, August 2011.

949. Clouser, "Regional Credit No Problem," 16.

950. Brian A. Toal, "Lending Trends," *Oil and Gas Investor*, January 1, 2008.

951. Toal, "Lending Trends."

Just months before Lehman's failure, Mark Thompson, head of energy lending for U.S. Bank, was cited:

> "I would say that credit structures are getting stronger," says Thompson. "Even stretch loans are becoming less aggressive and there is pressure in the credit markets to raise loan-pricing grids. Although the Federal Reserve has been lowering short-term rates, long-term rates really haven't followed. So, the liquidity premium has been expanding and has been since June 2007. … Now, everyone's cost of funds for long-term money has gone up, including banks' costs of funds, and this will likely lead to an increase in loan pricing for producers."[952]

As oil fell from a July 3, 2008, peak of nearly $150 and gas from more than $13, price decks that had been slow to rise were now also slow to drop and the gap between the 12-month strip and the price deck that had provided a slice of the debt structure for "stretch" Tranche B loans evaporated. While the window for commercial banks to offer Term B loans was closing, non-traditional, mezzanine providers that still had dry powder to lend were happy to keep their windows open.

But the subprime-mortgage crisis wasn't limited to money-center banks; in fact, greater impact was felt by some of the private-equity investors and hedge funds. The institutional players that had begun to invest in the energy-capitalization business in the early 2000s in the midst of rising commodity prices began to drop out due to liquidity issues. Tim Murray said in a March 2008 article, "Debt pricing has increased and some institutional players have dropped out.

"The institutional players I'm referring to are generally funds that have some liquidity issues due to the credit crisis, or have capital that is subject to mark-to-market (derivatives) influences. There are very few institutions pulling back from energy due to poor (energy) investments or lack of confidence in the industry."[953]

In general, mezzanine and other second-lien paper were harder to sell. Lenders had to raise pricing with rates increasing from between 3% and 4% in 2007 to between 6% and 8% in 2008.

B.J. Brandenberger with Energy Spectrum Advisors Inc. wrote in March of 2009, "Anecdotal evidence suggests that each tranche of capital, including senior debt, mezzanine debt and equity, is beginning to require

952. Hughes, "Mile High Capital."
953. Chang, "Mezzanine Capital."

returns comparable to their more risky junior counterparts, thus translating into a notable increase in today's aggregate cost of capital for borrowers."[954]

Oil prices had begun falling after June of 2008, further constraining producers' access to capital and willingness to hedge more future production. Just after the mid-September financial-market collapse, Greg Pipkin, a managing director at Lehman prior to its bankruptcy and who immediately moved his group to Barclays Capital, advised, "Start-ups should look for capital from people with whom they have a strong relationship. In a market like we are in today, capital is scarce. Relationships with strong institutions are needed to see an E&P through its business plan, whether three years or 10 years."[955]

With oil prices tanking and general public-equity-market investors' fear of how much the stock market would eventually decline, accessing public markets for capital was too expensive for E&P companies. Capex budgets and acquisitions were cut back. The era of easy credit for the oil patch had ended just as it did for would-be home-buyers.

Range Resources' Waller said, "The E&P side of the energy business had been drilling in excess of cash flow for the last two and a half years. We are going to have to cut back. You can't perpetuate this drilling activity with the credit markets and the fragility of the debt markets. Therefore, that 'wall of gas' (from the shale plays) that everybody wants to talk about, can't get here if nobody wants to drill."[956]

Some acquisitions were restructured and others were cancelled outright. Antero Resources Corp. had announced a $552-million acquisition of Marcellus acreage from Dominion Resources Inc., but had to scale it back due to its difficulty in obtaining follow-on financing "in the current market turmoil."[957]

At the end of September, Forest Oil Corp. completed an acquisition of acreage from Cordillera Energy Partners, but only after amending the deal to reduce the cash portion by $180 million and increasing the stock component of the purchase price. Forest had been trying to sell some

---

954. B.J. Brandenberger, "Transaction Activity vs. Nymex," *Oil and Gas Investor*, March 1, 2009.

955. "New E&P Money-Mall Hours," *Oil and Gas Investor*, November 1, 2008.

956. "New E&P Money-Mall Hours," *Oil and Gas Investor*, November 1, 2008.

957. Dominion agreed to "downsize the transaction and increase the amount [paid] per acre." "Financial Turmoil Cuts into Antero's Marcellus Shale Plans," *Daily GPI, Natural Gas Intelligence*, September 25, 2008. "Dominion Ups Marcellus Shale Acreage Price with Antero Resources," Rigzone.com, September 24, 2008.

properties at the time. Its chief financial officer, David Keyte, said, "The disruption in the credit markets is adversely affecting the timing of our divestiture program as counterparties are challenged to receive adequate financing."[958]

Denbury Resources Inc. announced on October 8 that it would walk away from a $600-million acquisition of Wapiti Energy LLC's Conroe Field, forfeiting a $30-million earnest-money deposit, citing a need to take "significant steps to preserve capital liquidity." It reported:

> In light of the current state of U.S. capital markets, we have taken several measures to assure ourselves that our balance sheet will remain strong during these uncertain economic times. We believe that all of these steps are prudent in light of the current economic environment.[959]

But the "wall of gas" coming online as a result of full-throttle Barnett and Fayetteville production—along with expectations from the recently announced Marcellus, Haynesville and Eagle Ford discoveries—was not to be stopped by anything as *small* as total global recession and a freezing of capital markets. Although the number of active rigs drilling for natural gas dropped in half from October 2008 to October 2009,[960] the shale revolution kept producing results. Annual U.S. natural-gas production continued to grow and was still growing as of the end of 2015.[961]

This was while prices tumbled from more than $10 in the summer of 2008 to less than $2 in the spring of 2012. Wellhead gas prices remained low, but drilling continued as capital continued to flow to gas explorers and producers. Even in the low price environment, wells were being brought online at tremendously economic rates and demand for the gas was growing among power-generation operators and industrials.[962]

---

958. "Solich Takes More Stock, Less Cash, To Close Forest Deal," *Oil and Gas Investor*, October 1, 2008.

959. "New E&P Money-Mall Hours," *Oil and Gas Investor*, November 1, 2008; Denbury Resources Press Release, October 8, 2008.

960. In September, 2008, the U.S. natural gas rig count peaked at 1,606. Baker Hughes Drilling Rig Report, US NG Rig Count.

961. Marketed U.S. gas production increased 18% from 2008 to 2013. EIA.gov, accessed January 12, 2016.

962. In December of 2015, in what is a usually a high-priced winter-demand environment, the prompt-month Nymex gas contract closed at less than $1.70 an MMBtu as a result of persistent supply and a mild winter. U.S. EIA, Independent Statistics & Analysis. "Henry Hub Natural Gas Spot Price." Accessed March 6, 2016. Eia.gov.

In late 2008, Tristone Capital Inc. reported on its survey of approximately 40 energy lenders. "Since starting the survey in second-quarter 2005," it wrote, "the participating banks' oil and gas price decks have continually increased in the extended years from the previous-quarter results. With fourth-quarter 2008 being the first exception to this trend, first-quarter 2009 decks continue to decrease from the last quarter's results."[963] Front-year bank pricing fell 34% for oil and 21% for gas.

All the while, banks became more vigilant in assessing their producer borrowers' ability to repay. Typically, banks set their price decks quarterly, but, as prices changed so precipitously, a number were looking at new decks on a monthly or more-frequent basis. Lenders and borrowers alike were dreading the Spring 2009 borrowing-base-redetermination season.

In addition, the banks themselves had their hands full as borrowing-base season would be soon followed by the national-bank-examination season. *Oil and Gas Investor* reported in March of 2009, "The timing of low oil and gas prices, borrowing-base redeterminations, tight capital markets and the release of E&P audited financial results nearly coincides with an important time for commercial banks—their own national bank examination process … . This confluence of events is unfortunate for distressed companies.

"A bank with E&P clients with borrowing-base deficiencies will soon see those loans downgraded to the high-risk category by examiners, says Tim Murray, Houston-based managing director of private energy capital provider Guggenheim Partners LLC … . The more high-risk loans a bank holds, the more capital it is required to reserve as bank examiners determine necessary capital ratios to protect depositors from bank failure. … If a bank can't get additional capital, it has to sell assets, like loans, to shrink its balance sheet to meet mandated capital ratios."[964]

Expectations among both producers and lenders were that borrowing bases would be between 15% and 30% lower—across the board. A number of producers had already cut back on drilling. Thus, their reserve replacements were short of previous projections—another reason to dread the results of the banks' evaluation. But as the results came in, relatively few were dealt a blow.

"Many feared credit limits would be reset below a company's current borrowings and with no cash to make up the difference," *Oil and Gas Investor* reported in May. "The rolling event was supposed to throw a flurry

963. "Energy Lenders' Price Decks," *Oil and Gas Investor*, December 1, 2008, Oilandgasinvestor.com.

964. Jeannie Stell, "Distressed Finance," *Oil and Gas Investor*, March 1, 2009.

of assets into the marketplace. … The Redetermination Pandemic resulted in few fatalities in spite of the hysteria.

"Why is this? The simple answer is that banks, also under assault in the current economic battle, have no place and no desire to warehouse all of those E&P assets. Like with the single-family housing foreclosure crisis, banks don't want all these assets coming back on the books and tying up their lending ratios. Better to work it out with an otherwise healthy E&P currently making payments than to repo their assets."[965]

While bankers were wary of bringing more problems to their own credit ratings, 2009 was much different from prior commodity-price collapses. This time, many producers, at the direction of their lenders, had a majority of their production hedged out into 2010 or later and at pre-crisis oil and gas futures prices.[966] Banks were able to factor into their redeterminations the producer's hedged volumes, which were at prices above the banks' lowered price decks. Hedges not only provided borrowing-base support; some producers were able to cash in some of their hedges to provide additional cash.[967]

Although wholesale borrowing-base reductions did not occur, for producers whose borrowing bases were merely "reaffirmed"—that is, kept at the same level as in the fall of 2008—it was merely a stay of execution because, without access to additional capital, drilling would be curtailed. No new drilling meant undeveloped reserves would not be converted into production, thus further reducing the cash flow available for keeping up with interest payments.

Bob Wagner, a former First City and Bankers Trust energy lender, co-wrote in a May 2009 article, "Unfortunately, this is the beginning of a death spiral. With no capacity to develop additional cash flow by developing properties further, they will be like their 1990's brethren, producing depleting assets just to pay interest.

"Their assets will deplete but their debt will not, a problem that will only get worse. The business model they pursued, developing properties toward

965. Steve Toon, "Who Put Out The Fire? Banks Soften On Killer Borrowing-Base Redeterminations For E&Ps," May 4, 2009, Oilandgasinvestor.com.

966. In 2000, only 17% of independent producers used commodity-price swaps to manage financial risk, according to an IPAA survey; in 2010, that number was almost tripled.

967. Stone Energy Corp., BreitBurn Energy Partners LP and Energy XXI Ltd. unwound top-of-the market hedges to make headway in preparing for a continued capital drought. Nissa Darbonne, "Capital Asset Envy," *Oil and Gas Investor*, April 1, 2009.

an asset or company sale, is equally dead, with no buyers in sight at prices that will cover the debt."[968]

Having survived the spring, attention turned to what the fall season might produce. In June, Jeff Forbis, a senior energy lender at Sterling Bank at the time, predicted, "If commodity prices remain at their current low levels, the autumn re-set season may be the most challenging. Lower capex budgets mean less drilling and reserve additions, and hedges will have rolled off - as such, borrowing bases may be even lower."[969]

More than 25 oil and gas producers had filed for protection under Chapter 11 by that time—more than twice that of the late 1990s.[970] Tekoil & Gas Corp. filed in June 2008, when oil was in the $100s and before its Galveston Bay assets were hit by Hurricane Ike.[971] Lothian Oil Inc., with West Texas assets, filed the following month.[972]

Coalbed-methane producer CDX Gas LLC defaulted under its first-lien agreement agented by Bank of Montreal, accelerating its $105-million senior obligations on September 30, 2008, and triggering default under its $400-million second-lien term-loan agreement agented by Credit Suisse. It filed for bankruptcy on December 15, citing numerous challenges, including commodity prices, depressed credit markets and general economic turmoil.[973]

Also in December, Ausam Energy Corp. and subsidiary Noram Resources Inc., whose assets were primarily on the Gulf Coast, filed for Chapter 11 protection.[974] The Meridian Resource Corp. announced that month that it wasn't in compliance with certain financial covenants and was in default. In April of 2009, its lenders, led by Fortis Capital, further reduced the borrowing base to $60 million. Its outstanding borrowing was

968. Bob Wagner and David Johnson, "Debt Wars," *Oil and Gas Investor*, May 1, 2009.

969. Gary Clouser, "Banker's Roundtable," *Here's the Money: Capital Formation 2009, Special Supplement to Oil and Gas Investor*, June 2009, 14.

970. Examples include, Edge Petroleum, Delta Petroleum, Crusader Energy, and Energy Partners Ltd. Wagner and Johnson, "Debt Wars."

971. Claudia Perez Rivas, "Tekoil Files For Bankruptcy," *Upstream*, June 11, 2008, Upstreamonline.com.

972. *In re Lothian Oil, Inc.*, No. 07–7012, Doc # 1832 at 2 (Bankr.W.D.Tex. Dec. 17, 2008).

973. "CDX Gas Defaults on Credit Agreement, Files for Bankruptcy," Bloomberg, December 13, 2008.

974. "Ausam, Noram File for Chapter 11 Bankruptcy Protection," Rigzone, December 30, 2008, Rigzone.com.

$95 million. Unable to cure the deficiency, it incurred an additional event of default under the facility.[975]

During the year, Meridian entered into a series of agreements whereby the lenders agreed to forbear from exercising the remedies available to them under the loan documents as a result of the events of default. After an exhaustive marketing effort, Meridian was taken private in an acquisition by Alta Mesa Holdings LP.[976]

Edge Petroleum Corp. and Chaparral Energy Inc. canceled their merger plan in December of 2008. In January of 2009, Edge was hit with a $114-million borrowing-base deficit. It initially exercised its option to cure this in six monthly installments of $19 million each. But, without sufficient liquidity, it filed for Chapter 11 protection in October of 2009.[977]

Saratoga Resources Inc., whose Texas Gulf Coast assets were struck by Ike and its Louisiana properties by Hurricane Gustav a couple of weeks earlier, filed on March 31, 2009.[978] Hallwood Group Inc. had had a good run in the Barnett shale, selling its de-risked leasehold positions to Chesapeake Energy Corp. in 2004 and 2005.[979] Its Hallwood Energy LP unit moved onto the Fayetteville play and to West Texas and filed for bankruptcy protection in March of 2009. It reported, "The U.S. and global capital markets are effectively frozen."[980]

Meanwhile, with a $5-million borrowing-base deficit, Crusader Energy Group Inc. also filed in March of 2009, just nine months after its IPO.[981] Another casualty of the Gulf Coast hurricane season, Energy Partners Ltd.'s borrowing base was reduced from $150 million to $45 million and $93 million was drawn; it filed in May of 2009.[982]

---

975. The Meridian Resource Corp., Form 8-K, April 13, 2009.

976. "Alta Mesa Holdings Completes Acquisition of Meridian," *Oil & Gas Financial Journal*, May 14, 2010.

977. Stephen Payne, "Edge Hires Parkman Whaling To Assist In Paying Credit Facility Deficit," *Oil and Gas Investor*, January 16, 2009; "Edge Petroleum to Sell Most Assets, Files for Chapter 11," *Oil & Gas Financial Journal*, October 5, 2009.

978. "Saratoga Files For Chapter 11 Protection, Cites Hurricane Damage And Lowered Energy Prices As Causes Source," *Oil and Gas Investor*, April 1, 2009.

979. Darbonne, *The American Shales*, 109-110.

980. The City Wire staff, "The ups and downs of Arkansas' natural gas production," *Talk Business & Politics*, Mar 6th, 2009.

981. Crusader's limit had been lowered to $25 million from $70 million. When it missed the first scheduled payment on the $5-million deficiency, it was in default on its senior and second lien loans. Don Mecoy, "Crusader Energy Group Inc. defaults on loan, files for bankruptcy," NewsOK.com, March 31, 2009.

982. "… Energy Partners incurred debt in 2007 before oil prices began their downward spiral. At the same time, the company was dogged by extended production outages in the

By March of 2010, some 60 E&P companies had filed under Chapter 11 or Chapter 7.[983] Delta Petroleum Corp. had a $140-million deficit under its fully drawn, $295-million facility. It held on for a while, but filed by the end of 2011.

In 2008, hedging was more widespread than during the downturn of the late 1990s.[984] So why were there *more* bankruptcies than during the previous cycle? Most bankruptcies occur based on a confluence of events that are set in motion months and years before the filing. Other than a depressed commodity market, this cycle was affected by capital markets that were severely restricted and, for a couple of companies, weather-related interruptions along the Gulf Coast.

Delta, principally a gas producer in Colorado's Piceance Basin, had quadrupled its acreage in 2008 and increased its proved reserves more than 295%. In 2009, it drilled a string of 18 dry holes. Not replacing reserves—combined with what it had that could not be deemed proved under newly lower gas prices—resulted in this collateral declining almost 90%.

Delta's borrowing base under a credit facility agented by JPMorgan Bank in November of 2008 was $590 million. Over time, it was reduced and Delta sold assets to shore up its balance sheet. Notwithstanding, it defaulted on covenants, triggering a workout as its original lenders became fatigued with the company.

It was refinanced by Macquarie Bank Ltd. as an $18-million revolver and $15-million term loan at much higher interest rates. Unable to raise additional capital, find a joint-venture partner or a purchaser, it filed for bankruptcy in December of 2011.[985]

---

wake of Hurricanes Gustav and Ike, which severely damaged some of the third-party operated pipelines Energy Partners relies on." Kimberly Quillen, "Energy Partners files Chapter 11 bankruptcy," *The Times-Picayune*, May 1, 2009, Nola.com.

983. Nissa Darbonne, "Lessons Learned Offered From the 'Zone of Insolvency,'" *Oil and Gas Investor*, March 1, 2010.

984. Bertie Taylor, "Mitigating Risk," *Oil and Gas Investor*, April 1, 2010.

985. Declaration of John T. Young, Jr., Chief Restructuring Officer of Delta Petroleum Corporation, In Support of First Day Relief, *In re Delta Petroleum Corporation, et al.* (U.S. Del. Bankruptcy Court, Case No. 11-14006 (KJC) filed December 11, 2011, at 6. "In 2008, Delta acquired an additional 17,300 net acres in the Vega Area, which increased its position to approximately 22,375 net acres, which has over 1,900 net drilling locations based on 10-acre spacing. During fiscal year 2008, Delta increased proved reserves in the Vega Area over 295% to 719.9 Bcfe … and increased production from approximately 25.0 Mmcf/d … at the beginning of the year to approximately 48.0 Mmcf/d at the end of 2008. However, during 2009, as a result of the combined effect of lower natural gas prices through the year and the new SEC reserve pricing rules and Delta's limited capital development plan, proved reserves

TXCO Resources Inc. was an example of a potential shale player that never got out of the gate in an example of "right place, wrong time." The Eagle Ford play had been discovered in South Texas by Petrohawk Energy Corp. in the second half of 2008.[986] But TXCO, which held acreage suddenly prospective for Eagle Ford pay as well, was already under water.

During the second quarter of 2008, when oil was more than $100 and gas was more than $9, TXCO reported net income of $8.7 million, which was improved from a $1.3-million loss in the year-before quarter. Its operating income was $17.3 million.[987] Meanwhile, a 2008-model Eagle Ford well cost more than $6 million—drilled and completed.[988]

TXCO reported in May of 2009 that it was having "substantial difficulties in meeting short-term cash needs," such as to pay vendors; meanwhile, energy prices and "a deteriorating global economy" were preventing it from accessing debt and equity markets.[989]

James Sigmon, chairman and CEO, said in a news article a few days earlier, "There are companies that are ready to talk to us about buying portions of our acreage block or even the whole company. But that takes time, and in the meantime, our financial situation is deteriorating. We may not have enough time to stay outside of bankruptcy."[990]

The bankruptcy was a lesson for the senior secured lenders. Initial mortgages had been filed against the company's early leasehold position when the loan was closed. Unfortunately, by the time the company filed bankruptcy, a significant number of its vendors were not yet paid. Under Texas law, these "mechanics and materialman" were entitled to liens against the wells they worked on or provided materials to.

Typically, secured banks will be ahead of the "trade" lien-holders by filing their mortgage against the producer's properties before any drilling begins, which is where TXCO's lenders thought they were. As the bankruptcy claims and liens were analyzed, it became apparent that the

decreased to 84.7 Bcfe. As of December 31, 2010, proved reserves in the Vega Area totaled 112.6 Bcfe. Net production in the Vega Area currently exceeds 30.0 Mmcfe/d."

986. Darbonne, *The American Shales*, 227.

987. "TXCO Resources Reports Record Results and Earnings," TXCO Resources Inc., Form 8-K, filed August 8, 2008.

988. Darbonne, *The American Shales*, 222.

989. "TXCO Resources Files Voluntary Bankruptcy Petition Under Chapter 11," TXCO Resources Inc., Form 8-K, May 18, 2009.

990. TXCO Resources Inc., Form 8-K, May 13, 2009, referencing the news article, "TXCO nearing bankruptcy," Vicki Vaughan, *Express-News* (San Antonio), May 13, 2009.

lenders' mortgages did not keep up with the company's property acquisitions.

Lawyers representing the trade claimed that many of the company's leases and valuable wells were not covered by the original mortgages and the bank group was "unsecured" on such collateral. The banks' lawyers placed mistaken reliance on the mortgage's typical "after acquired property" clause, assuming it would cover new leases after the original-mortgage closing.

After-acquired-property clauses are usually effective to create liens on additional interests acquired by the borrower in the same property already described and covered by the mortgage—for example, where a producer's interest in a mortgaged well is increased after initial drilling and completion costs are recouped. But "after acquired property" granting language is only effective to put third parties on constructive notice to the extent the grant is in the chain of title of the property in question. It doesn't cover unrelated leases acquired by the mortgagor after the original mortgage has been filed.

The lenders learned this lesson without catastrophic cost, however—because of the value of the *acreage* rather than of TXCO's *wells* after Petrohawk Energy Corp. had made the Eagle Ford discovery well. In a case where the raw land repaid the loan, the underlying value of TXCO's undeveloped leasehold exceeded the amount of its secured debt and creditors were all paid off 100 cents on the dollar.[991]

The lenders, agented by Union Bank, in the Cornerstone E&P Co. LP bankruptcy were not as lucky.[992] In *Cornerstone*, the court held that liens filed by third parties on properties acquired by the debtor subsequent to the original mortgage were subject to the bank's lien only to the extent that the mortgage was in the chain of title prior to the filing of the third party's lien.[993]

991. "The secured and unsecured creditors and certain preferred shareholders received a full recovery, including interest on their claims, and the common equity holders received a $10 million recovery." "TXCO Resources, Inc. Recovery for all Secured and Unsecured Lenders," *FTI Consulting*, Fticonsulting.com.

992. *In Re Cornerstone E & P Company, L.P.*, 436 B.R. 830 (Bankr.N.D.Tex. 2010).

993. Terry Cross, McClure & Cross, "Statutory Contractor Liens Against Mineral Property," Dallas Bar Association – Energy Law Section, Review of Oil and Gas Law XXX, Dallas, Texas, August 27-28, 2015, citing *In Re Cornerstone E & P Company, L.P.*, 436 B.R. 830, 864 (Bankr.N.D.Tex. 2010).

Kicking the Barrel Down the Road

By September of 2009, oil had improved to $70, which was roughly the price two years earlier and highly economic for most producers. Gas prices, however, did not improve until after third-quarter 2009; price decks had already been reset by lenders. From its quarterly survey, Tristone Capital reported a first increase in bank pricing for crude oil in September, but gas lost another 7%, providing no help for gas-weighted borrowers.[994]

However, most banks accommodated their borrowers that had good fundamentals and just needed more time to get past the fall in prices via an amendment, waiver or extension of maturity. It presented the opportunity for bankers and bank counsel to temporarily loosen covenants—without increasing commitments—in exchange for an increase in pricing, including floors on minimum interest rates.

Meanwhile, with commodity prices at or near the banks' price decks, new hedges could not provide any boost to the borrowing base—as producers who were unhedged were unwilling to do so at sub-$50 oil the previous spring or at sub-$5 gas that spring and into the fall.

For gas-heavy companies, if lower prices held, the future was not going to be pretty. Rolling out the maturity was a way to kick the barrel—or, in this case, the Mcf—down the road in hopes of a price rebound and for the bank to avoid locking in a loss. Meanwhile, oil continued to recover, turning doubtful loans into performers. Under the rubric that "a rolling loan gathers no loss," these amendments were affectionately known by the banking community as "extend and pretend."

Global Recession and the Shale Plays

For many independents, such as TXCO, that were looking to hop onto the unconventional-resource-play train, the market collapse happened at the worst of times. Because producible shale resources can underlie entire counties rather than a few acres and because they are most economical when tapped with horizontal wellbores a mile or more in length, much more acreage is desired and needed. Meanwhile, the cost of drilling and

994. Front-year pricing for oil rose 11%, but decreased 7% for natural gas. Tristone Capital Inc. Quarterly Lender Price Survey, September 2009.

completing a well can be more than $10 million.[995] The most aggressive independents in the shales were carrying massive debt loads in 2008.[996]

A competition between Petrohawk and Chesapeake in leasing the Haynesville shale in the first half of 2008 led to lease-bonus prices of more than $25,000 an acre. Steve Herod, who headed business development for Petrohawk, said in *The American Shales*, that Petrohawk, alone, paid $2 billion for acreage. "Several billion dollars of lease-bonus money went into North Louisiana in five months. … It was pretty amazing."[997]

Dick Stoneburner, Petrohawk's chief operating officer at the time, said, "We went toe to toe with Chesapeake from March to August, just a six-month period. But it was an incredible period to be involved in a play like that with Floyd [Wilson, Petrohawk CEO] and Aubrey [McClendon, Chesapeake CEO] going *mano y mano* to see who could end up with the best position. …

"It was crazy but it worked. I mean, it worked for us. I think it worked for them. It's hard to say. In the long run, it will."[998]

Chesapeake's strategy was copied and envied. To finance its leasing and its drilling to hold the acreage by production before expiration deadlines, it outspent cash flow in all but three out of 34 quarters between 2004 and year-end 2012.[999] During this eight-year period, its spending in excess of cash flow totaled more than $30 billion.[1000]

Meanwhile, the "wall of gas" that was expected to come online as a result of full-throttle shale production was eventually factored into gas futures. Oil futures had rebounded by the end of 2009 to $80.[1001] Gas, however, fell into the $3s by the spring of 2009 and, except for some winter-demand spikes, rarely had a glimpse of more than $5 thereafter.

But most of the shale-gas discoverers and producers knew going in that they would have to drive down their costs via efficiencies of scale in such massive plays. Southwestern Energy Co. amassed 455,000 net acres in

995. With the exception of deep-Utica shale-gas tests in Appalachia in 2015, most shale-well costs across all plays declined in 2015 to significantly less than $10 million each as oilfield-service prices declined.

996. Leveraged producers were carrying a debt load of property value to debt of 0.9x. Wagner and Johnson, "Debt Wars", *Oil and Gas Investor*, May 1, 2009.

997. Darbonne, *The American Shales*, 200.

998. Darbonne, *The American Shales*, 200.

999. Gold, *The Boom*, 194.

1000. Gold, *The Boom*, 194.

1001. U.S. EIA, Independent Statistics & Analysis. "Cushing, OK Crude Oil Future Contract 1." Accessed May 9, 2011. Eia.gov.

Arkansas for an average of about $40 an acre before announcing the Fayetteville play.[1002]

Richard Lane, a Southwestern executive during the discovery, said in *The American Shales*, "Think about doing anything 10,000 times. If you save a buck here and a buck there 10,000 times, it adds up quickly. That's where the 'manufacturing' think comes in. You control your destiny by driving down cost."[1003]

With banks and oil and gas producers feeling optimistic, the dark days of 2008-2009 were soon forgotten. *Oil and Gas Investor* reported in 2010, "Throughout 2009, banks instituted interest-rate floors; shortened maturities; and tightened financial covenants. The major change for 2010 seems to be some leniency on debt maturities, i.e., four years as opposed to 2009's standard three year maturity."[1004]

Having felt the sting of borrowing-base reductions, producers that had the ability to access public debt and equity markets, when these reopened in 2009, raised money and paid down their bank debt. Between the base-redetermination seasons of the spring of 2009 and the spring of 2010, what was drawn under the senior revolvers had fallen from 64% to 44%. As borrowing decreased, bankers competed harder for new customers; loan syndications were oversubscribed, even for drilling deals. Bank pricing remained relatively firm.

Wells Fargo's Marc Cuenod observed, "Now the market's hunger for new loans has resulted in oversubscriptions on many [syndicated] deals. Deal pricing has remained relatively firm and we're seeing good opportunities for drilling deals, especially in the shales."[1005]

The U.S. was becoming more than satiated with new shale-gas supply. However, there was ample room in the market for new U.S. oil supply. New completion techniques in the Bakken tight-oil play in North Dakota and development of other tight oil after 2008 began contributing significant additional volumes of U.S. oil. Lenders were eager to finance shale-oil development. *Oil and Gas Investor* reported in February of 2013:

> "The advent of the shale plays has been kind of a game-changer for the mezzanine business," says Mark Green,

1002. Darbonne, *The American Shales*, 139.

1003. Darbonne, *The American Shales*, 254.

1004. Gary Clouser, "Banker's Roundtable," *Here's the Money: Capital Formation 2010, Special Supplement to Oil and Gas Investor*, June 2010, 10.

1005. Bertie Taylor, "Capital Markets Outlook: The Road Ahead," *Oil and Gas Investor*, August 1, 2010.

> president of Wells Fargo Energy Capital, in Houston. "… The shales have made mezzanine even more attractive because they have significantly reduced the reservoir risk, and it's become more an issue of execution risk," Green says.
>
> "We've seen hardly any dry holes in the mature plays such as the Barnett and the Bakken. However, it takes a lot more dollars than it used to because of the high well and facilities costs, and our challenge is making sure that the drilling is economic in the current price environment."[1006]

Dodd-Frank and Banking Regulations

In response to the 2008 credit-market crisis, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act in July of 2010. As bank failures had been big; the law is similarly big. *The Economist* wrote, "The law that set up America's banking system in 1864 ran to 29 pages; the Federal Reserve Act of 1913 went to 32 pages; the Banking Act that transformed American finance after the Wall Street Crash, commonly known as the Glass-Steagall act, spread out to 37 pages. Dodd-Frank is 848 pages long."[1007]

The act was more like a set of guidelines than a law[1008] and the task of implementing the law was left to federal regulatory agencies with a one-year deadline. This was delayed and delayed. In 2013, according to one law firm's estimate, 13,789 pages of rules containing 15 million words had completed only 39% of the process.[1009] At year-end 2015, only 68% of the total rule-making requirements had been finalized,[1010] the firm reported in an update. Energy banks responded to the prospective regulation—and

1006. Chris Sheehan, "Mezzanine Moves," *Oil and Gas Investor*, February 1, 2013.

1007. "The Dodd-Frank act: Too big not to fail," *The Economist*, February 18, 2012, Economist.com.

1008. Jeff Nichols and Kim Mai, "The Regulation of Swaps and Derivatives and its Impact on Business after Dodd-Frank" (paper presented at State Bar of Texas 11th Annual Advanced Business Law Course, November 7-8, 2013).

1009. According to Davis Polk & Wardwell, "Over the course of the three years since passage of the Dodd-Frank Act, its initial 848 pages of statutory text has ballooned to 13,789 pages (which amount to more than 10 times the length of Tolstoy's *War and Peace*). That page count, high as it is, represents only 39 percent of the required rulemaking contained within the legislation." Joe Mont, "Three Years In, Dodd-Frank Deadlines Missed As Page Count Rises," *Compliance Week*, July 22, 2013, Complianceweek.com.

1010. DavisPolk, "Dodd-Frank Progress Report, Fourth Quarter 2015," Davispolk.com.

repeated investigations and fines by regulators—by getting out of the physical commodities markets.[1011]

The act also prohibited national banks from owning or investing in private-equity funds.[1012] In connection with the relaxation of the Glass-Steagall restrictions on investment banking, beginning in the 1990s, a number of commercial energy banks invested in energy private-equity funds, such as EnCap and Natural Gas Partners, as a means of establishing relationships with these private bankers and, more importantly, with their portfolio companies.

Private-equity sponsors would give their portfolio-management teams the equity capital to make an acquisition or acquire prospective acreage with the intention of quickly turning the investment into proven, producing reserves and a "commercially bankable" company. By investing in equity funds that sponsored start-up E&Ps vetted and underwritten by these experienced investors, the commercial bankers were the first in line when the portfolio companies had sufficient collateral to merit a secured credit facility.

The symbiotic relationship was seen by the commercial bankers as an "energy-loan incubator." For example, Amegy Bank was actively investing in 14 private-equity funds in 2008. Steve Kennedy, senior vice president, said in an article at the time, "This has proven to be a very good place to become involved early on with the new, developing companies.

"And, because of our familiarity with these private equity groups, we have been in a position to help several companies find a good equity sponsor. We have made excellent rates of return on these energy private-equity funds to date, so we anticipate continuing this activity for the foreseeable future."[1013]

1011. *The Wall Street Journal* reported that the Federal Reserve was considering whether new rules are needed to limit banks' exposure to commodities trading. The article noted that such pressures had triggered a series of high-profile exits from the industry, including J.P. Morgan Chase & Co. Sarah Kent and Daniel Fitzpatrick, "J.P. Morgan to sell Commodities Business for $3.5 Billion," *The Wall Street Journal*, March 19, 2014. Morgan Stanley sold its oil-storage and trading business and Deutsche Bank, Goldman Sachs, Royal Bank of Scotland and UBS had exited or planned to as well.

1012. A portion of the Volcker Rule, Section 619 of the Dodd-Frank Act amends the Bank Holding Company Act of 1956 to add a new section 13(a) that provides in relevant part that: "[u]nless otherwise provided in this section, a banking entity shall not … acquire or retain any equity, partnership, or other ownership interest in or sponsor a hedge fund or a private equity fund."

1013. Clouser, "Regional Credit No Problem," 24.

While commercial banks have ceased making further investments in private-equity funds as a result of Dodd-Frank, the funds and their portfolio clients have not suffered for lack of other investor appetite, filling the void. During each year following 2009, they committed record amounts of capital to invest in the upstream and midstream energy markets.

The banks complied with the restriction on future investments in the funds, but some banks with unregulated subsidiaries have turned to making investments alongside the private-equity sponsors directly in the new companies. At least when banks invested in private energy funds, it was into a diversified portfolio of holdings, thereby spreading risk, much like a private individual lacking the resources to check out every public company will spread risk by investing in a mutual fund. With the prohibitions under Dodd-Frank, which intended to reduce risk to a bank's capital by prohibiting investing in private-equity funds, it can be argued that the level of risk has been increased.

Following on the theme of unintended federal regulatory consequences, banks have also complied with the letter of law under the federal flood-insurance act.[1014] The act requires that any real estate with buildings taken as collateral for a loan must obtain either a certificate that the collateral is not located within a flood zone or obtain flood insurance. The law was intended to fund the federal pool for insuring homes in flood-prone areas.

Enforcement of the law took on a sense of urgency after New Orleans and other areas along the Gulf Coast were flooded by Hurricane Katrina. Regulators—hence, banks—became insistent upon literal compliance with the regulation—no matter the kind of real estate involved and even if the real estate consisted of hundreds of oil and gas leases where the value lay thousands of feet underground. Some energy lenders refused to advance funds at closing without the necessary flood survey or flood insurance.[1015]

A work-around for reserve-based loans avoided the act altogether by not taking liens on "buildings" on the collateral. Rather than inspect each oil and gas lease to make sure there were no buildings, the banks modified their lien documents to expressly exclude from the mortgaged properties "all buildings as defined under the Flood Act."

1014. National Flood Insurance Act of 1968 and the Flood Disaster Protection Act of 1973, as amended (42 U.S.C. 4001--4129).

1015. In 2012, a New York bank's counsel inquired as to whether a Haynes and Boone LLP producer client had flood insurance. As the producer operated in the Gulf of Mexico, every one of its properties was under thousands of feet of water. The firm advised bank counsel that such insurance was not available to the client.

While this has satisfied compliance with federal regulations, it has meant that banks are foregoing liens on any buildings associated with the oil and gas properties. The question that has yet to be addressed is how the collateral's value is affected if buildings on the property are critical to continued operations of the oil and gas production. Have banks solved for the immediate documentary headache only to find that—down the road, following a foreclosure or bankruptcy fight—there is a hole in their collateral?

2013: Buyer's Market at the Capital Bazaar

2013 saw continued competitive pressure on a growing pool of energy-capital providers in search of bankable projects. Public-debt markets chasing yield were open. Even sub-investment-grade E&Ps with B- or CCC ratings were able to access the high-yield bond markets at attractive rates. Accessibility of public debt, combined with a decrease in M&A activity, resulted in lower demand for borrowings from commercial banks.

Nevertheless, capital options for the larger independents were as accessible and varied as goods at a Turkish bazaar. Producers were ready to deal as capital providers hawked their products with everyone using $100 barrel oil as the common currency. No one gave much thought to how difficult it would be to untangle the producers' complicated capital structures if oil prices were to fall before all the debt was repaid.

M&A transactions in 2013 were off two-thirds from the prior year: $123 billion in 2012 versus $38 billion in 2013. Not surprisingly, to keep dry powder and moderate floating-interest-rate exposure under credit facilities with fixed-interest-rate bond debt, many borrowers who could do so accessed the public-debt market to pay down their bank revolvers. Commercial energy lenders saw their borrowers' average loan utilization—the ratio of borrowed funds to the availability under the borrowing base—falling as the year progressed. Commercial banks—especially regional and smaller banks lacking capital-markets capabilities to earn fees on the bond issuances—felt the pinch.

Because of the continuing slow recovery in the general U.S. economy and the relative attractiveness of investments in the energy-loan market, a number of new banks entered the reserve-base-lending space, adding further price pressure on loan terms—much to the benefit of producer borrowers. Entrants in 2013 included Pittsburgh-based PNC Bank, which had a long history of lending to the coal industry and, with recent exposure to the local Marcellus-shale play, beefed up its oil and gas lending in Pennsylvania and opened a beachhead in Houston.

Fifth Third Bank out of Ohio, seeing the growth of the Utica-shale play in its backyard, picked up Royal Bank of Scotland's entire Houston team and opened shop in the city. Amegy's Kennedy said in an August 2013 article, "As the capital costs of having an effective presence in a shale/resource play increase, we are seeing more companies narrow their focus into one or two main geologic areas. We are also seeing an increase in private equity investments, as E&P companies realize that the large equity commitments that such firms offer provide a strategic advantage in the new capital intense, acreage intense, shale resource plays.

"For years, companies had to chase conventional reservoir traps, which varied in size, but tended to cover hundreds of acres. Since shale covers thousands, tens or hundreds of thousands of acres, the potentially productive areas are much larger than in the past. Now, one could literally spend a career developing and operating in one continuous geologic play, which was fairly rare in the past."[1016]

BB&T, a large North Carolina bank, was another newcomer to the reserve-based-lending market. Sterling Bank's energy group, led by Jeff Forbis, opened a Houston office for it in 2011.

The structure for reserve-based loans, however, had not changed much during the preceding 40 years—just the pricing and tenor. Forbis said in same the article, "The standard borrowing base revolving credit remains the cornerstone of the energy banking industry. For the most part, new deals are secure, have a five-year term semi-annual borrowing base redeterminations and are priced in the range of LIBOR plus 200 to 275. Covenants are generally: debt/EBITDA -4X, Interest coverage- 2.5X and Current ratio – 1X."[1017]

Another phenomenon affecting not just bank pricing and overall competition for business was the aggressive demands of the larger private-equity funds sponsoring E&P management teams—with some teams having few or no proved reserves. Without the PE muscle behind them, each team would not have commanded much attention of established energy lenders—especially the bulge-bracket banks, such as JPMorgan, Citibank, Bank of America and Wells Fargo.

But, when the profitability of the portfolio company's new loan application was tied to the coattails of a private-equity sponsor's overall commercial- and investment-banking business with these large institutions,

1016. Gary Clouser, "Bankers' Buzz - Plenty of bank capital available for growth-hungry E&Ps," *Oil and Gas Investor*, August 2013.

1017. Clouser, "Bankers' Buzz."

equity firms were able to exact pricing and covenant concessions for their portfolio constituents that, a few years prior, would have been extended only to the largest independents, such as Devon and Anadarko Petroleum Corp.

Some banks were even willing to document "zero dollar borrowing base" loans. In this, no money would be funded upfront; the expectation was that, once the private-equity-backed borrower found an attractive acquisition, the loan documentation would already be in place, providing ready capital on short notice.

Steve Trauber, head of Citigroup's global energy investment banking, observed in an early 2014 *Oil and Gas Investor* article, "The reality is that, because of the amount of capital out there, the bank market is fairly aggressive. They're giving loans and credit facilities out to companies at rates that don't earn an adequate rate of return on a standalone basis. Instead, they rely upon the other businesses in order to get the rates of return they need on their capital."[1018]

Among smaller banks, their return on committed capital was not augmented by the ability to offer other capital products—lacking investment-banking or hedging capability and having a business model of participating in large facilities agented by the bulge-bracket lenders. Regional and local banks complained of losing clients to more aggressive lenders.

Loans became very cheap for producers, according to David Zalman, chairman of Houston-based Prosperity Bankshares. He told FuelFix.com at the time, "Some banks are offering 10-year payout terms for loans that would normally get five-year terms stretching pricing and payout periods, and we've lost business because of it. What we have seen is some of the banks are even lending money on nonproducing property. That's where it's becoming a bigger issue."[1019]

Phil Ballard, one of Trauber's fellow Citi bankers, said in the *Oil and Gas Investor* article, "It's a very competitive market. Some recent deals have probably been a little more aggressive than they historically have been in terms of covenants and borrowing-base amounts. And because there are so many new banks coming in, if someone doesn't like it, someone else will step right in to take its place."[1020]

1018. Chris Sheehan, "Margins Pressure Energy Uplift," *Oil and Gas Investor*, February 2014.

1019. Collin Eaton, "Bank loan standards bending for oil companies amid shale rush," FuelFix, May 22, 2014.

1020. Sheehan, "Margins Pressure Energy Uplift."

Not only were banks increasing the percentage of borrowing-base value derived from proved undeveloped (PUD) reserves—akin to the raw-land deals banked by the S&Ls in the go-go days of the 1980s—they were also including value to "probable" and "possible" reserves in acreage in the fairways of the more prolific shale plays, such as the Eagle Ford and Marcellus.[1021] Although attributing collateral value to non-proven acreage was similar to the "lease line of credit" from earlier days, proved reserves still made up the bulk of the collateral in these producer loans.

Additionally provisions were added in some facilities to allow the borrower's private-equity sponsors the ability to prop up the client's financial underperformance with equity infusions and thereby cure, albeit temporarily, financial-covenant defaults. These were the very same covenants that were built into credit agreements after the bust of the 1980s to alert bankers to the borrower's ability to remain cash-flow positive, thus able to meet debt service on a current basis.

Serving as advance-warning signals, these periodic financial tests provide banks with the ability to take action early in a deteriorating market to address problems before the collateral dissipates to less than what is needed for repayment. With "equity cure rights" these signals can be overridden and delay the lender's ability to take action.

Seasoned bankers, nevertheless, were not ready to pull back on the throttle. Perhaps this time it really would be different. Just like every other time it was going to be different?

Mark Fuqua at Comerica Bank told *Oil and Gas Investor*, "We have this incredible confluence of tremendous resource base in the U.S. – where we are arguably the largest oil and gas producer in the world and still growing – coupled with this abundance of cheap capital. I've been through a lot of booms and busts, and I don't know exactly where this one is going, but the fundamentals of it still feel pretty good to me right now."[1022]

Some experienced bankers by the beginning of 2014, were sounding words of caution, reporting that the commercial-banking sector was moving into a period of "unparalleled excess liquidity," along with a lack of demand for their capital. Scotiabank managing director Mark Ammerman said, "It sounds funny to say, but you really don't make much money lending money any more, certainly not in as challenging a market as we

1021. Clouser, "Bankers' Buzz."
1022. Sheehan, "Margins Pressure Energy Uplift."

have with today's liquidity and increasing regulatory capital. You really make your money selling other products and services."[1023]

Regulators began to take notice of the loosening lending standards. In April of 2014, the Office of the Comptroller of the Currency dusted off its 25-year-old loan-examiner's manual, rewriting its handbook on oil and gas production loans and describing supervisory expectations for prudent policies and procedures for lending to the E&P industry.[1024]

More conservative bankers and regulators, however, were out of sync with borrowers' expectations. Producers' management teams began 2014 with much optimism. A February 2014 survey by *Forbes* and CIT of 141 senior U.S.-based energy executives found their short- and long-term outlooks for both oil and gas pricing and profitability to be unabashedly upbeat. More than 80% of the participants described 2013 as profitable and they were predicting an equally profitable 2014. In addition, 91% anticipated they would be profitable during the next three to five years, 66% expected oil prices to rise and 68% expected natural-gas prices to rise.[1025]

Based on ongoing, rosy forecasts and high capital needs, many small and mid-size producers accessed junk-bond markets when they could to finance drilling. These offerings in the energy space reached $210 billion—roughly 16% of the junk-bond market—a dramatic rise from just 4% of the market 10 years earlier.

The low-interest-rate environment since the financial crash of 2008 and the Fed's $3.5 trillion[1026] of bond purchases, beginning in 2009 and into October of 2014 via its "quantitative easing" program, flooded the markets with debt capital. But unlike equity, debt has to be paid back. And with the availability of different and diverse capital sources, producers ended up with capital structures as complex to navigate as the labyrinth of Istanbul's Grand Bazaar: senior secured first liens under revolver-based credit facilities, second-lien loans from mezzanine providers and various tranches of publicly issued notes held by institutional investors.

The phenomenon that spawned the renaissance of the U.S.' independent producers—the unconventional-resource plays made viable by horizontal,

---

1023. Sheehan, "Margins Pressure Energy Uplift."

1024. Office of the Comptroller of the Currency, "*Oil and Gas Production Lending*," Comptroller's Handbook (April 2014), accessed April 9, 2016, Occ.treas.gov.

1025. Mike Lorusso, "Lending in a Boom Market," *Oil & Gas Financial Journal*, August 11, 2014.

1026. Jeff Kearns, "The Fed Eases Off," Bloomberg QuickTake, September 16, 2015, Bloombergview.com.

fracture-stimulated wells—continued to feed small and mid-size producers' demand for "easy money." As is the nature of the junk-bond market, lots of money flowed to less-capitalized companies with much-riskier drilling prospects than the larger independents, such as EOG Resources Inc., Pioneer Natural Resources Co., Anadarko, Devon and Apache Corp.

Some of the small to mid-size independents were venturing into untested formations and the marginal edges of unconventional plays, while not having a lot of cash on hand—the same reason they couldn't offer investment-grade bonds. The junk market was over-heated even before the price of oil began to decline after June of 2014. *Forbes* estimated that $500 billion in debt had been advanced to producers, consisting of $300 billion in leveraged loans and $200 billion in high-yield public notes. By 2014, energy claimed 16% of the high-yield market, a fourfold increase from the prior decade.[1027]

A New York-based money manager said in a December 2014 Bloomberg article, "There was too much money going into this space that would have resulted in problems long-term – now that timeline has been accelerated."[1028]

CHAPTER 9: OPEC DELIVERS A THANKSGIVING TURKEY

> *"'This time it's different.' The four most expensive words in English."*
>
> —John Templeton

As the oil and gas industry proved a century earlier, nothing breeds failure like success. The flush production brought about by each new field discovery since Spindletop has caused local—and sometimes national—prices to collapse.

The current generation of producers and bankers had grown up in an environment where American oil production had been in decline since the mid-1980s. By 2008, production had fallen 40% from a May 1985 high of 9.1 million barrels a day to 5.4 million.[1029]

1027. Christopher Helman, "Who Will Get Caught When the Oil Debt Bubble Pops?" *Forbes*, December 19, 2014.

1028. Nabila Ahmed and Sridhar Natarajan, "Junk Bonds Backing Shale Boom Facing $11.6 Billion Loss," Bloomberg, December 1, 2014, Bloomberg.com.

1029. U.S. EIA, Independent Statistics & Analysis. "U.S. Field Production of Crude Oil." Accessed May 3, 2016. Eia.gov.

The force of the shale revolution during the aughts turned the tide in the 2010s. By April of 2015, as the Bakken play expanded and the Eagle Ford, Niobrara, Oklahoma Woodford and Permian Basin unconventional-resource plays developed, U.S. production had reached 9.7 million barrels a day—catching up to a peak not seen since April of 1971, 44 years earlier.[1030]

This growth in U.S. unconventional oil production was unchecked by any state regulatory controls, just like the days before successful proration laws kept excess production in line with market demand. Reminiscent of the boom following the East Texas Field discovery, crude-oil storage rose to levels that had not been seen since the early 1930s.[1031]

Such a prodigious increase in production did not escape the attention of Saudi Arabia and its fellow OPEC members. The U.S. was turning oil tankers away.[1032] Saudi Arabia's sales to the U.S. had been reduced to, roughly, the equivalent of as much oil as its own, co-owned refinery on the Texas coast processed daily.[1033]

As a result of the shale revolution, it was not only OPEC losing U.S. oil-market share to American independents. Growing U.S. natural-gas production from shale plays had pushed LNG tankers and Canadian supply away as well. Compared with 44 years earlier, domestic gas production was substantially higher by 2015.[1034]

The Saudis had been hinting during the fall of 2014 that they were no longer going to be the swing producer that balanced world oil supply with demand, propped up prices and indirectly subsidized Iran, Russia and others. The Saudis had played this trump card in 1985 when it increased its

---

1030. U.S. EIA, Independent Statistics & Analysis. "U.S. Field Production of Crude Oil." Accessed May 3, 2016. Eia.gov. In April, 1971, daily production reached 9.769 million barrels; in April, 2015, 9.694 million.

1031. Brian Scheid, et al., "US crude production to rise to 9.3 million b/d in 2015: EIA," Platts, March 10, 2015, accessed May 3, 2016, Platts.com.

1032. Scheid, "US crude production to rise to 9.3 million." The report added, "The growth of US production is expected to continue to eat into net imports of crude oil and other liquids, which fell from 60% of the total share of US liquid fuels consumption in 2005 to an estimated 26% in 2014. That share is expected to fall to 20% in 2016, which would be the lowest level since 1968, EIA said."

1033. John Kemp, "How Saudi Arabia successfully defended its U.S. oil market share: Kemp," Reuters, February 1, 2016, Reuters.com.

1034. Natural gas production in 2015 totaled 28.8 Tcf compared with 22.5 Tcf in 1971. U.S. EIA, Independent Statistics & Analysis. "U.S. Natural Gas Marketed Production." Accessed March 26, 2016. Eia.gov.

exports from 2 million barrels a day to its full quota of 4 million. The result of the Saudis' actions depressed oil prices well into the 1990s.

While American producers sat down for Thanksgiving dinner in November of 2014, OPEC members announced that they would not decrease their output that would have stemmed declining world oil prices.[1035] Sometime between the stuffed turkey and the pumpkin pie, the price of oil dropped more than 10%.[1036] And, as world markets digested the news, WTI fell from more than $73 per barrel prior to Thanksgiving to $53 as the New Year began.[1037]

December is normally quiet in the energy-lending business, but, in 2014, bankers' and producers' holiday plans were interrupted by OPEC's declaration and the market's response. Bankers spent the following weeks re-setting price decks and stress-testing their borrowers' loans against the new value of oil reserves by which their loans were secured. Borrowers in turn were busy revising their forecasted 2015 development-capital spending plans and reviewing their long-term drilling contracts.

Responding to lower prices, producers started the year by slashing their capital-investment budgets. Before the New Year, public companies announced, on average, that they were reducing their capex by a third.[1038] The U.S. rig count that had been averaging close to 2,000 dropped steeply. By March, the number of rigs at work had been cut nearly in half.[1039]

Yet, even with deep cuts in drilling budgets, producers continued to outspend cash flow in the first quarter of the year. If not for the value from above-market oil hedges, producers would have had to cut capital expenditures 70% to balance their books.[1040] Capital investments in the field can take between three and 12 months to turn into production. Thus, it

---

1035. "OPEC 166th Meeting concludes," Organization of the Petroleum Exporting Countries, accessed on March 27, 2016, Opec.org.

1036. U.S. EIA, Independent Statistics & Analysis. "Cushing, OK WTI Spot Price FOB." Accessed March 26, 2016. Eia.gov. WTI closed on November 26, 2014, at $73.70; the following Friday, November 28, at $65.94.

1037. "Simmons Morning Energy Note," Simmons & Co. International Inc., November 26, 2014, and January 5, 2015.

1038. Carolyn Davis, "Domino Effect of Lower Oil/Gas E&P Capex Now Hitting Offshore, Midstream," *NGO Shale Daily*, January 9, 2015, Naturalgasintel.com.

1039. Between 2011 and 2014, the U.S. oil and gas rotary rig count had been between 1,800 and 2,000. In March, 2015, the number was 1,109. U.S. EIA, Independent Statistics & Analysis. "U.S. Crude Oil and Natural Gas Rotary Rigs in Operation." Accessed March 26, 2016. Eia.gov.

1040. "Fractured finances, America's shale-energy industry has a future. Many shale firms do not," *The Economist*, July 4, 2015.

was no surprise that U.S. production remained resilient during the first part of the year—and even continued to grow.[1041]

Part of the reduction in capital costs came at the expense of the rig contractors, who saw long-term rig leases cancelled or the price renegotiated. Additional pain was spread to every additional member of the oilfield-service industry to bring down producers' operating costs.[1042] Even a Houston law firm that specialized in lease acquisitions and title opinions and had caught a 10-year ride on the shale wave shuttered its doors by the end of 2015 as leasing activity came to a halt.[1043] More than 40 oilfield-service companies went out of business or filed bankruptcy during the year.[1044]

Producers who could reduced staff and focused on preserving cash flow—i.e., doing more with less. Productivity gains were made through greater efficiency with multiple well-pad drilling and completions, faster drilling times and higher production rates through better completions and longer horizontals. Some of the gains were made possible, ironically, by newly lower oilfield-service costs and that, as rig and completion crews were being laid off, service providers retained their best employees to work on what remained.

Importantly, producers in all basins high-graded their drilling inventory, putting aside testing outside of the core of their plays and cherry-picking only the best locations to better insure a return on investors' dollars, profit to pay interest on outstanding debt and proved reserves to support their bank loans.[1045] In early 2015, following their December top-down loan-portfolio review, bankers by and large were still positive that their borrowers could survive oil in the $50s—if it didn't last too long.[1046]

While there was limited concern within the banks, energy-loan-weighted, regional lenders watched as their stock prices lost 20% since oil had peaked

1041. *The Economist*, "Fractured finances;" *also* U.S. EIA, Independent Statistics & Analysis. "U.S. Field Production of Crude Oil." Accessed March 26, 2016. Eia.gov.

1042. Pamela King, "Workforce: Not all oil industry segments suffer equally as prices slide," *Energywire*, January 26, 2015, Eenews.net.

1043. Sara Randazzo, "Oil Downturn Sends Texas Law Firm Packing," *The Wall Street Journal*, November 27, 2015. Burleson LLP, formed as an oil and gas title boutique at the beginning of the shale revolution, closed after 10 years at the end of 2015.

1044. "Haynes and Boone Oil Field Bankruptcy Tracker," Haynes and Boone, LLP, March 1, 2016, Haynesboone.com.

1045. *The Economist*, "Fractured finances."

1046. Julie Steinberg, "Falling Oil Prices Worry Regional-Bank Investors," *The Wall Street Journal*, January 21, 2016.

at $108 in June of 2014.[1047] Notwithstanding the market sentiment, banks did not take precipitous action to declare "wild card" borrowing-base redeterminations. In general, the consensus was that OPEC would relent and the markets would quickly rebound.[1048]

In fact, even by the scheduled Spring 2015 borrowing base season, the predictions of substantial borrowing base reductions failed to materialize. A survey of producers and energy lenders early in the year predicted borrowing-base reductions would average 25%.[1049] The borrowers' angst was unmerited: Reductions averaged between 10% and 15%, helped in great part by oil hedges that had many borrowers' production still getting more than $90 barrel.

Banks did drop their price decks as the spring-season redetermination approached, but not as aggressively as spot prices would suggest. Typically, banks set their price decks for determining the borrowing base at a discount of around 80% of the current front-year WTI Nymex price and up to 90% of the five-year forward curve, but, because of the precipitous drop in prices, the quarterly price decks set by the banks were *above* the front-year and five-year curves.[1050]

"Industry executives have let out a palpable exhale as we exit the spring borrowing base redetermination season," *Oil & Gas Financial Journal* reported in June of 2015. " … Ultimately banks settled on modest to no reductions in borrowing bases, [which were accompanied with] numerous amendments that included covenant holidays around [audit opinion] going concerns [exceptions], leverage tests, and asset coverage tests."[1051]

Banks' price decks reflected market sentiment early in the year, which was that prices, while low, would recover. The question being asked on the streets of downtown Houston during the first quarter of 2015 was how quickly prices would recover. Would the recovery be "V" shaped or "U" shaped?

1047. Steinberg, "Falling Oil Prices Worry Regional-Bank Investors." For 13 banks with energy loans that comprise more than 5% of their portfolios, shares were down more than 20% on average since June 20, 2014.

1048. Nicole Freidman, "What Went Wrong in Oil-Price Forecasts?" *The Wall Street Journal*, December 10, 2015.

1049. "Haynes and Boone, Borrowing Base Redeterminations," Haynes and Boone, LLP, September 18, 2015, Haynesboone.com.

1050. Macquarie Tristone's Quarterly Energy Lender Price Survey, "Energy Lender Price Survey Q1 2015," Static.macquarie.com.

1051. Josh Sherman and Sean Clements, Opportune LLP, "Capital Availability for E&Ps," *Oil & Gas Financial Journal*, June 9, 2015.

A bump from $43 in March to $60 by May gave markets and producers a false sense that OPEC's turkey didn't have legs. To generate cash on their books, producers with the strongest assets and management went to the public market, selling equity and/or public debt securities. The biggest wave was during the first week of March with 55 energy offerings that raised $50 billion. In all, by the middle of July, 179 equity and debt offerings had raised more than $127 billion for Texas and Oklahoma businesses of which 90% were energy companies.

But as quickly as the opportunity appeared, it was gone. Nymex traders went on Fourth of July holiday with the prompt-month contract for WTI trading at about $57. When they returned to their desks at 5 p.m. Central time Sunday, WTI declined 8%.[1052]

And the price kept declining. "It was like someone turned all the spigots off," William Snyder, head of Deloitte's Texas restructuring practice told *The Dallas Morning News*. "The money just dried up."[1053]

Investors found out the March bump was more of a dead-turkey bounce than a true bottom. In fact, oil prices dipped even lower—into the $30s. Seeking reassurances that the price drop was not permanent, discussions in boardrooms and bank lobbies began to lean toward whether recovery would be "W" shaped rather than the "V" shape of 2009-10. As prices continued to languish, the feared "U" shape was becoming plausible; the shibboleth "lower for longer" began to creep into discussions.

Producers adjusted again, further cancelling drilling and postponing completion of wells that had been drilled. OPEC's Thanksgiving turkey had created a new specie of oil well—the "DUC" or "drilled but uncompleted."[1054] Because of the relatively higher cost of completing a well with hydraulic fracture-stimulation than drilling it, producers elected to drill but not complete wells until a rebound in prices justified the costs.[1055] Several began to refer to their DUCs as "oil in the bank." When prices improved, they would complete them, bringing on the production when the market price was economic.

1052. U.S. EIA, Independent Statistics & Analysis. "Cushing, OK Crude Oil Future Contract 1." Accessed March 6, 2016. Eia.gov.

1053. Mark Currriden and Natalie Posgate, "Capital Drying Up for Oil, Gas," *Dallas Morning News*, November 30, 2015.

1054. Industry had called these WOC or "waiting on completion." Securities analysts in 2015 began to call them DUCs and industry adopted the new term.

1055. Lynn Doan and Dan Murtaugh, "U.S. Shale Fracklog Triples as Drillers Keep Oil From Market," *Bloomberg Business*, April 23, 2015.

Notwithstanding their efforts at cost cutting, many producers' spend continued to exceed cash flow. Facing potential reductions during the fall borrowing-base-redetermination season, many looked to sell non-core assets and to access more expensive capital. Most asset-owners were not willing to accept offers based on the current, depressed market price, so the delta between buyer and seller on the bid and ask meant few sales were consummated.[1056] In some cases, a price was agreed upon, but the buyer walked away after the Fourth of July, even while having to forfeit the earnest-money deposit.

In addition to asset sales, producers looked to capital markets for a lifeline to tide them over until prices rebounded. Public equity and debt markets had closed by July, but, albeit at a higher cost, private equity and debt were still options that some producers were able to secure.

"[D]ebt investors are thinking about the best ways to play the next energy-industry distress cycle—but they are doing so with the utmost care," *The Deal* reported. "Why the caution? Mostly because the secondary bond market opportunities aren't what they used to be, so investors are betting on new secured debt, bankrupt companies' bonds, and upside/downside strategies that hold promise in either a best- or worst-case scenario. Other financing structures, such as product[ion] payments, may require further clarity, and opportunities to replace bank lenders haven't started materializing yet."[1057]

Given the precarious leverage of some of the more aggressive shale players, capital providers looked for assurances that their investments would be protected in the event the producer went bankrupt. Off-balance-sheet transactions popular in the late '90s were dusted off. Non-banks purchased volumetric production payments or made loans with equity kickers in the form of convertible overriding royalty payments that, upon repayment of the principal, would automatically convert to net profit interests in the financed properties.

A new twist on the type of drilling dollars majors had contributed to independents back in the 1930s to prove up acreage was the financial-partner "DrillCo" agreement, primarily beginning in mid-2015. Instead of

1056. Scott Richardson, RBC Capital Markets, "Volatility Presents Opportunity" (presented to Houston Energy Finance Group, February 17, 2016). In 2014, there were more than 122 property sales of $20 million or more totaling $62 billion; in 2015, the number was 57, totaling less than $24 billion. More than $20 billion of properties put up for sale did not close in 2015.

1057. Lisa Allen, "Danger Lurks for Debt Investors in the Oil and Gas Fields," *The Deal*, March 27, 2015, Pipeline.thedeal.com.

dollars from major oil companies, private-capital providers joined producers in drilling wells in this joint-venture structure in which the producer contributes raw acreage and the financial partner contributes drilling dollars in exchange for a working interest in the wells.

In July, GSO Capital Partners LP closed one of the first such arrangements with Linn Energy LLC in which GSO agreed to finance 100% of the wells, receiving 85% of the net proceeds until achieving a 15% internal rate of return on the wells. After reaching the hurdle, Linn would own 95% working interest and GSO's interest would be reduced to 5%.[1058] Other shale players followed suit.[1059] The DrillCo structure was favored by investors as a "bankruptcy remote" entity that would be separate from the producer's assets in the event of bankruptcy.

The different layers of debt that producers had been able to access in the heady days of $100 oil added complexity as well as cost to the borrower-producer's capital structure. Energy XXI, a Gulf of Mexico producer, already had a fairly complicated balance sheet. At the top of the market, it acquired EPL Oil & Gas Inc. by merger in June of 2014 with an acquisition price of $2.3 billion just before the price of oil began to fall. At the time, Energy XXI already had six tranches of debt, including its bank revolver and various unsecured public notes issued since 2010 totaling $3.4 billion.

In connection with the merger with EPL, Energy XXI issued another half-billion in public debt. It issued another $1.5 billion of second-lien debt in March of 2015, sandwiched between the senior bank revolver and its public notes.[1060] The March issuance was prompted by an anticipated major

1058. "LINN Energy Finalizes Strategic Alliance with GSO Partners," LINN Energy Press Release, July 6, 2015, Ir.linnenergy.com.

1059. PR Newswire, "Lonestar Announces Joint Development Agreement With IOG Capital," July 28, 2015, Prnewswire.com; Globe Newswire, "Legacy Reserves LP and Funds Managed by TPG Special Situations Partners Sign Definitive Agreements to Jointly Develop Legacy's Permian Basin Acreage," July 6, 2015, Globenewswire.com.

1060. Energy XXI Ltd, Form 10-Q Quarterly Report, filed February 2, 2016, for the period ending December 31, 2015, 46. Energy XXI's debt included: (i) a reserve based loan with a borrowing base of $1.5 billion, (ii) $750 million 9.25% senior notes issued December 17, 2010, due December 15, 2017, (iii) $250 million unsecured senior notes issued February 25, 2011, due June 15, 2019, (iv) $5.5 million 4.14% note issued September 2012 due October 2017, (v) $500 million 7.5% unsecured senior notes issued September 26, 2013, due December 15, 2021, and (vi) $400 million in 3.0% Senior Convertible Notes issued November 18, 2013 due 2018, (vii) $510 million in 8.25% Senior Notes due February 15, 2018, (viii) $650 million 6.875% Senior Notes issued May 27, 2014, due march 15, 2024, and (ix) $1.45 billion 11.0% senior secured second lien notes issued March 12, 2015, due March 15, 2020.

cut to its borrowing base and gave these second-lien note purchasers a jump ahead of the existing unsecured debt-holders.[1061]

These financings gave some producers a lifeline, while waiting for the hoped-for rise in commodity prices. For those already smothering under the weight of too much debt, the new money was more of a continuation of life support. For those unable to attract more capital, the only answer was to seek the protection of bankruptcy courts in the hope of restructuring their balance sheets. By May of 2015, 10 producers had filed for protection; this would triple by August and the year ended with 48 North American producers filing bankruptcy with combined aggregate debt in excess of $17 billion.[1062] By April 14, 2016, Energy XXI, with almost $3 billion in secured and unsecured debt, would become the 63rd North American producer to file for bankruptcy.[1063]

Equity stakeholders and creditors owning first-lien, mezzanine and public bonds issued by these producers were confronted with a rude awakening. Producers had built extraordinarily complex capital structures since 2009 on the back of their properties' worth at $100 oil and now were trying to pay it back with $30 oil. This made the orderly resolution of claims much more complicated by the time their collateral had lost up to two thirds in value.

In the downturn during the '80s, oil and gas bankruptcies were resolved between a small, manageable group of stakeholders: the producer, his banker and his trade creditors. In 2015, like a dysfunctional extended family gathering at Thanksgiving dinner, the party had grown larger and more complex, rife with competing agendas between and among the stakeholders picking over the same carcass. Now, stakeholders at the table had grown to also include any one or all of these: junior secured creditors, including mezzanine lenders and private equity note-holders; holders of secured preferred shares; holders of unsecured preferred shares; and holders of convertible bonds. Especially at the bondholder level, latecomers to the party included distressed-debt buyers that had purchased the notes in the secondary market at a discount with no prior relationship with the borrower.

Further complicating restructuring a producer's debt was the phenomenon where some creditors held more than one class of debt. For example, when an involuntary bankruptcy was filed against Energy &

1061. "Distressed O&G Investing," *The Deal*, March 30, 2015, Pipeline.thedeal.com.
1062. "Haynes and Boone, LLP Oil Patch Bankruptcy Monitor," Haynes and Boone, LLP, April 4, 2016, Haynesboone.com.
1063. "Haynes and Boone, LLP Oil Patch Bankruptcy Monitor," Haynes and Boone, LLP, April 4, 2016, Haynesboone.com.

Exploration Partners LLC, it had more than $27 million in trade debt, $375 million in unsecured convertible notes and $765 million of first-lien reserve-based debt. By the time ENXP converted its case to a Chapter 11, a group of the unsecured note-holders had bought into the senior secured debt. As is typical, the senior secured lenders proposed terms under which they would agree to extend credit to ENXP during the pendency of its bankruptcy.

Holding both secured debt and bonds, the "cross-over" creditors had a much different view of the best way to restructure the company than that held by the senior banks, which still held original first-lien debt. Upsetting standard protocol, the "cross-over" creditors proffered their own terms for a competing debtor-in-possession loan that were more beneficial to their unsecured debt-holdings.[1064] Given the precipitous drop in collateral value, the only hope for the out-of-the-money creditors was that the borrower could convert its debt into equity in the restructured company as it exited bankruptcy.

In many bankruptcies, bondholders were wiped out. Junior lenders were unsure of recovery. And even senior lenders were looking at possible impairment of their claims.

New Gulf Resources LLC is an example of a private-equity-sponsored independent that leveraged borrowed capital to jump into the business just before oil prices crested. In May of 2014, it raised more than $500 million to acquire a large position in East Texas. The capitalization consisted of a first-lien RBL from MidFirst Bank with a borrowing base of $50 million, $365 million in 11.75% second-lien notes due in May of 2019 and $135 million in 10%/12% senior subordinated PIK toggle notes due in November of 2019.

Prior to filing bankruptcy, New Gulf explored exchanging the junior debt under the second-lien notes and subordinated PIK notes for notes with higher-ranking seniority in the capital structure (an "up-tier" transaction) in exchange for a reduction in the face value of the junior debt. The company reported, "The debt exchange pricing and the ratios of participating noteholders necessary to provide an adequate recapitalization were not economically viable given the then-current price of oil and gas."[1065]

By the spring of 2016, a few producers had already exited bankruptcy—reorganized, shorn of most debt and with new owners hoping for brighter

1064. "E&P Top 10 Cases," Haynes and Boone, LLP, April 2016, Haynesboone.com.

1065. Affidavit of Danni S. Morris, Chief Financial Officer, NGR, Declaration in Support of the Debtor's First Day Motion, "In re: New Gulf Resources, LLC, et al., Debtors," USDC Del. Case No. 15-12566 (BLS), 18.

horizons. Whether reduction of its debt burden would be enough to permit it to survive to the other side of the lower-for-longer environment remains to be seen.

Producers that were dragged down by more complicated debt structures will be unable to reach escape velocity and will remain in a terminal orbit of intercreditor bankruptcy disputes until their assets are liquidated. No doubt, there were many more companies with billions of dollars of debt yet to file for the protection of the bankruptcy courts before the updraft of the next recovery cycle begins.

Bank Examiners

Since 2014, bank regulators had been more closely scrutinizing underwriting practices for oil- and gas-leveraged loans, publishing a new handbook on this for examiners for the first time in 25 years. The last time guidelines for evaluating oil and gas loans were revised was following the mid-'80s oil-price downturn and subsequent bank failures.

Since the housing-market fiasco and imposition of Dodd-Frank banking regulations, the last thing regulators wanted was to be called before Congress to explain how they missed the next crisis in banking. Given the increasing complexity of independents' capital structures and cognizant of the issues that arose from the shadow banking industry due to collateralized debt obligations carved out of home-mortgage loans that precipitated the 2008 financial crisis, bank regulators focused in on the rising debt obligations of oil and gas producers created by both the banks they regulated and the unregulated private- and public-debt markets.

The Federal Reserve reported in November of 2015, "Aggressive acquisition and exploration strategies from 2010 through 2014 led to increases in leverage, making many borrowers more susceptible to a protracted decline in commodity prices. … Classified commitments—a credit rated as substandard, doubtful, or loss—among oil and gas borrowers totaled $34.2 billion, or 15 percent, of total classified commitments, compared with $6.9 billion, or 3.6 percent, in 2014."

The Fed further warned, "Because of the growing volume of special mention and classified commitments, as well as the significant growth in the leveraged lending portfolio, the agencies will continue to monitor, in particular, the associated underwriting and risk-management processes in the leveraged lending and oil and gas sectors."[1066] In particular, federal bank examiners began to focus on the total debt of the borrower and not just on the senior banks' ability to protect its depositors' money by recovering its first-lien loan. They criticized energy banks on a number of producer loans. Commercial banks appealed some of the criticized loans, but to no avail for the most part.

There was a disconnect between the new regulatory approach and the historical view taken by energy lenders. In addition to looking at a borrower's total debt—both secured and unsecured—regulators were insisting on tighter financial covenants to monitor a borrower's ability to repay. In particular, in discussions between the banks and regulators, including an in-person meeting at Wells Fargo's offices in Houston in September of 2105, regulators insisted that borrowers with a ratio of total debt to Ebitda in excess of 3.5:1 would not be given a passing rating, thus requiring greater bank reserves to be set aside.[1067]

Subsequent to this meeting, bankers and regulators continued to discuss the proper metrics for evaluating energy loans. In preparation for the annual examination in early 2016, energy banks assessed their borrowers' loans using a "total funded debt repayment test." Loans to some of the borrowers with significant unsecured public debt were downgraded accordingly.

However, following these loan downgrades, bank regulators came out with *another* set of revised guidelines for examination of oil and gas loans. In this, it appeared that the regulators stepped back from the "total funded debt repayment test." Instead the guidelines indicated that examiners and the regulated banks should evaluate a producer-borrower's ability to repay its total secured debt—not its total secured and unsecured debt.

Bankers were pleased the guidelines for repayment focused on only producer's secured debt, but questions remained. In addition to a "repayment test," the guidelines set out certain financial-ratio tests in evaluating oil and gas loans. Financial-ratio tests measured against the borrower's total debt and not just its secured debt. Whether this was intended to take back with the left hand what the regulators had given bankers with the right hand was not immediately clear.

What is clear is that, as a result of the 2016 guidelines, it will be more difficult for oil and gas producers to obtain bank financing. The impact is already being felt by producers this spring as banks apply the new

1066. "Shared National Credits Review Notes High Credit Risk and Weaknesses Related to Leveraged Lending and Oil and Gas," Board of Governors of the Federal Reserve System, November 5, 2015, Federalreserve.gov.

1067. OCC Bulletin 2016-9, Occ.gov.

guidelines in their loan policies and procedures during their spring-season borrowing-base redeterminations.

The guidelines were issued at a time when producers were in the greatest need of flexibility from their lenders on their debt obligations and in need of new bank capital due to the lower commodity-price environment. For some producers on the margins, it may mean the difference between survival and bankruptcy. Although the intent of the regulations is to protect against imprudent lending standards, the end result of the new guidelines for banks may be to cause recognition of greater production-based loan losses than has historically been the case.

High recovery rates in prior downturns were due in large part to the cyclicality of commodity prices. Loans that default at the bottom of the cycle have had a high recovery rate for first-lien lenders that exercise patience and wait for the cycle to recover rather than aggressively exercising remedies when prices are at their lowest. A bank's ability to be patient depends, in part, on what it costs it to hold onto the loan. The worse a loan is classified, the more reserves the bank must hold and, therefore, patience comes at a higher cost.

If bank regulators' new guidelines make it harder for producers to get new financing from commercial banks, this could hinder healthy producers in financing property acquisitions. Without able buyers, distressed-property sales could cause market prices for oil and gas properties to fall lower, resulting in lower loan-recovery rates for distressed producers and their lenders.

Texas endured a very slow economic recovery after the oil-price collapse of the mid-1980s. The S&L-triggered real estate bust put billions of dollars of improved and unimproved commercial properties on the market at a time when financial institutions were least able to help finance a recovery.

A longer-term effect of the guidelines may alter the relationship that has existed between independents and bankers. The new guidelines place banks at a disadvantage when competing against providers of unregulated debt. The ultimate impact is hard to predict. One possible outcome is that banks may choose to no longer compete to be first-lien lenders to producers who also owe—or plan to issue—second-lien and unsecured notes.

Certainly, producers with higher debt leverage will find it harder to get financing from regulated commercial bankers. This does not necessarily mean that oil and gas companies will be without access to borrowed capital. Restrictions imposed by the guidelines on commercial banks will create opportunities for alternative capital sources, including mezzanine lenders and private-equity sources. As a result, producers can expect to pay more for leverage going forward.

CHAPTER 10: IN CONCLUSION

> *"The Stone Age came to an end, not because we had a lack of stones."*
>
> —Sheikh Yamani

Sheikh Yamani, Saudi Arabia's oil minister from 1962 to 1986 during the formation and rise of OPEC, predicted the end of the oil age in an interview with *The Telegraph* in 2000. "Thirty years from now there will be a huge amount of oil - and no buyers. Oil will be left in the ground. The Stone Age came to an end, not because we had a lack of stones, and the oil age will come to an end not because we have a lack of oil."[1068]

The same observation can be made that the U.S. didn't stop using the horse and buggy because it ran out of horses. It was gasoline and the internal-combustion engine that drove demand for oil, prompting wildcatters to search for the modern *El Dorado* across the U.S. and the world.

There will come a time when a new disruptive technology will overtake oil as the primary transportation fuel, altering the Hydrocarbon Age paradigm. It is human nature, after all, to innovate, driving perpetuation of our specie. Just as in the early 2000s, as the theory of "Peak Oil" was gaining acceptance within the industry and among policymakers, U.S. producers invented the "Shale Gale," bringing a renaissance to independents and American energy independence.

In contrast, economist Joseph Schumpeter identified another "gale" in the 1940s. The "perennial gale of creative destruction" is the basic architecture of capitalism, he wrote. It "incessantly revolutionizes the economic structure from within, incessantly destroying the old one, incessantly creating the new one. This process of Creative Destruction is the essential fact about capitalism."[1069]

Schumpeter predicted that the same processes that enabled capitalism to succeed the pre-capitalistic framework would also eventually bring its downfall. Innovators would not only push aside "institutional deadwood,"

1068. Mary Fagan, "Sheikh Yamani predicts price crash as age of oil ends," *The Telegraph*, June 25, 2000.

1069. Joseph Schumpeter, *Capitalism, Socialism, and Democracy* (1942), 83.

but, in the end, destroy the partners and structures upon which the foundations of capitalism were built.[1070]

The many cycles of boom and bust within the oil and gas industry seemingly validate the predicate of Schumpeter's theory. With every new discovery in the industry's early history, producers, investors and even cities went broke. Even today, the innovation that made the Shale Gale possible, resulting in a prodigious increase in U.S. oil production and setting records not seen for 40 years, has caused the bankruptcies of scores of producers and wrought the destruction of billions of dollars of invested capital.

It can be argued that Schumpeter's theory is supported by the effect of capitalistic competition for unconventional-resource acreage at unsustainable costs and the desire to spend beyond cash flow to continually increase reserves and boost stock prices. This drive for profit and market share created the tsunami of U.S. natural-gas production growth that has depressed domestic prices for the foreseeable future. This drive has also resulted in a tsunami of U.S. oil production, putting the global market off its supply/demand kilter.

But like prior cycles, contrary to Schumpeter, this is not the final chapter. Contrary to theories about the demise of the U.S. oil and gas industry, the Shale Gale is emblematic of its reinvention, resurgence and resilience. No matter what happens at the surface, the rocks stay the same. The hydrocarbons that were formed millions of years ago remain, waiting to be produced by new producers with new technology that will make it possible to surface oil and gas cheaper and faster. It is only until some disruptive technology, supported by capitalistic profit motive—not central planning—creates the replacement to fuel today's horse and buggy that hydrocarbons will become the institutional deadwood of a new economy.

Innovation and ingenuity financed by private capital have been the hallmark of U.S. independent producers. From the first rudimentary bit, pounding rock to reach a shallow oil deposit near Titusville, Pennsylvania, more than 150 years ago, the industry has evolved into drilling with precision extremely complex wells down thousands of feet below the surface, turning 90 degrees and steering the bit another mile or farther through hard and dense, hydrocarbon-soaked rock.

Just two decades ago, this rock had been considered too tight to ever produce economic amounts of natural gas. That was disproven in the late 1990s by Mitchell Energy in the Barnett shale. Being a larger molecule, it

1070. Schumpeter, *Capitalism, Socialism, and Democracy*.

was believed that it was impossible to extract economic amounts of oil out of tight rock. Lyco Energy Corp. disproved this in 2000 in the Bakken formation in Montana.[1071]

Through such innovation, the technology has changed, but the spirit and drive remains constant. It is the same spirit that drove the early wildcatter to spend his—and his banker's—last dime in search of riches just waiting to be discovered.

With each cycle, capital has been as critical as the producer's determination and his drilling rig. But this capital would never have been as readily accessible if not for the investment opportunities created and nurtured by a stable U.S. legal and regulatory environment—combined with the private ownership of minerals, which has enabled producers to negotiate directly with landowners for the permission and encouragement to drill, develop and produce oil and gas for the past 150 years.

Many countries, including many lesser developed, have equal or greater mineral wealth, but lack the economic, legal or political environment that is attractive to private investment. Many countries have stable economic and legal systems, but lack private mineral ownership that facilitates necessary local support for private development.[1072]

Only in the U.S. has there been the combination of an attractive economic environment, private mineral ownership and ready access to capital—the oxygen continuously inhaled by oil and gas producers. The independents' insatiable demand for capital has been answered time and

1071. Darbonne, *The American Shales*, 48, 63.

1072. Bret Stephens, "The Marvel of American Resilience," *The Wall Street Journal*, December 22, 2012, in a Christmas opinion piece reflected on what a future history teacher might identify as important innovations of the early 21st century: "Why, she might ask her students, did the U.S. dominate its peers when it came to all the really big innovations? Fracking would make a good case study. The revolution happened in the U.S. not because of any great advantage in geology—China, Argentina and Algeria each has larger recoverable shale gas reserves. It didn't happen because America's big energy companies are uniquely skilled or smart or deep-pocketed: Take a look at ExxonMobil's 2004 Annual Report and you'll barely find a mention of 'fracturing' or 'horizontal' drilling. Nor, finally, did it happen because enlightened mandarins in the federal bureaucracy and national labs were peering around the corners of the future. For the most part, they were obsessing about the possibilities of cellulosic ethanol and other technological nonstarters. Instead, fracking happened in the U.S. because Americans, almost uniquely in the world, have property rights to the minerals under their yards. And because the federal government wasn't really paying attention. And because federalism allows states to do their own thing. And because against-the-grain entrepreneurs like George Mitchell and Harold Hamm couldn't be made to bow to the consensus of experts. And because our deep capital markets were willing to bet against those experts."

again—by early oil capitalists, passive investors ranging from former governors to Catholic women's associations, public shareholders, local bankers, mezzanine financiers and private equity, all willing to take a calculated risk on an oil and gas wildcatter's ability to produce a valuable prize hidden underground for millennia.

The cycle repeats with each new wave of producers, bankers and other sources of capital. But the producers' and lenders' hard-learned lessons seemingly must be relearned each time. Perhaps that is the answer: It is not until the lessons from the prior circle are forgotten or discounted ("This time it's different") that the same mistakes can be repeated, beginning the cycle anew.