ONEONONE

An Investor's Look Into the Corner Office

FALL 2012

HARTENERGY

A SPECIAL REPORT FROM THE PUBLISHER OF

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MIDSTREAM Business

ONEONONE
An Investor's Look Into the Corner Office

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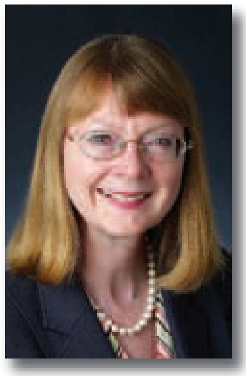
IN THE CORNER OFFICE



These days, investors find themselves pondering the macro picture: oil and gas prices, the direction of U.S. tax policy after the presidential election, and other uncertainties.

But in the end, to zero in on the individual company matters most. What does the balance sheet say? Is the company outspending cash flow? Is it growing production per share? Is it transitioning to drilling for liquids? What about the order backlog?

We find that talking to a CEO about the ongoing strategy is very revealing, although it's perhaps a less tangible way to get a bead on the way a company may perform.

That's why here in this special report, we have chatted with 13 executives. The companies included vary in size from Marathon Oil Corp. (market capitalization about $18.6 billion) to newly public Bonanza Creek Energy Inc. (market cap of about $692 million). It's an interesting variety that makes for a wide range of investor choices.

MRO split from its downstream group to fly as a pure independent even though its antecedents date to 1887, more than 100 years ago. It operates in several countries. Bonanza Creek, meanwhile, is focused in the U.S. and is on its third iteration since 2001, yet its first as a publicly traded entity, having gone public in December 2011.

There's plenty to ponder here, in addition to the raw data you can get from a company's website and other presentations. We like to know what the thinking is in the corner office.

—Leslie Haines, Editor-in-chief

Disclaimer: Spokesmen for these companies may have made certain forward-looking statements. These statements are subject to numerous assumptions, risks, and uncertainties. Factors that may cause actual results, performance, or achievements to be materially different from those anticipated in forward-looking statements include, among others, the following: commodity price volatility; adverse economic conditions in the United States, Canada and globally; difficult and adverse conditions in the domestic and global capital and credit markets; changes in domestic and global demand for oil and natural gas, and technical factors occurring during drilling or production.

These factors are described in the "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" sections of a company's 2011 annual report on Form 10-K, as amended, filed with the Securities and Exchange Commission (SEC).

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TABLE OF CONTENTS

MARKET BUZZ

TRENDS FOR THE INVESTOR TO CONSIDER

WELL COMPLETIONS

"U.S. oil well completions in the second quarter increased 13% to 7,195, helped mainly by a boost in drilling on state and federal properties. Natural gas well completions, however, dropped 24% to 2,472 in the period."

–American Petroleum Institute (API)

S&P ENERGY-SECTOR OUTLOOK

"We believe the sector's significant year-to-date underperformance positions it for outperformance if all but the worst global macro outcomes come to pass. Elevated geopolitical risks, the lowest valuations of the 10 S&P 500 sectors, and historically defensive characteristics, combined with S&P Economics' forecast for crude to average above current levels in 2013, lead us to believe this sector can surprise to the upside. Lastly, our technical opinion of the sector is increasingly constructive."

–S&P Capital IQ Research

SERVICE STOCKS OUTLOOK

"Services stocks are discounting an approximate 20% decline in U.S. drilling activity, along with pumping rate (frac) declines of 25%, and land rig rate declines of 15%. However, the market appears to be ignoring that lower well costs will support activity.

"The largest components of well costs are stimulation (fracing), casing tubing, and drilling, and we expect declines of 25%, 10% and 15%, respectively. Overall, these lowered costs should lead to a decline in total well costs of approximately 12.5%.

"Our analysis of E&P spending suggests that cash flow should decline about 6% from first-half 2012 to the second half, less than the 20% activity decline embedded in stocks. We recommend HAL (Outperform) and also names under the offshore growth theme: ESV, NE, RIG, SLB, NOV (all Outperform)."

–Bernstein Research

CAPITAL SPENDING

"In North America, despite a planned reduction in capital budgets by several small-to-mid-sized independents brought on by low natural gas prices, companies we surveyed still expect to increase spending within the U.S. by 9.6%, compared with an 11% increase in spending that these companies indicated in our year-end 2011 survey," says James Crandell, managing director of Dahlman Rose & Co. Research in New York.

"Spending in the U.S. is expected to receive a boost from supermajors and large, oil-weighted independent E&Ps. Canadian E&P spending is expected to grow by 6% in 2012."

–Dahlman Rose & Co. Spending Survey

FINDING & DEVELOPMENT COSTS

"Our 2011 Finding & Development (F&D) Cost Study examines year-end reserve data from the 100 largest domestic, public oil and gas companies that existed over the past five years. These aggregated data include over 332 trillion cubic feet (Tcf) of natural gas reserves, over 44

U.S. Spending By Company Budget Size

	U.S. Spending ($MM) 2012E	2011	Year-to-Year % Change	Companies Surveyed (1)
Spending Less Than $50 Million	1,216	1,258	-3%	130
Spending Between $50 and $100 Million	1,514	1,280	18%	19
Spending Less Than $100 Million	2,729	2,538	8%	149
Spending Between $100 Million And $1 Billion	24,651	23,353	6%	55
Spending More Than $1 Billion	115,098	104,174	10%	35
Total U.S. Spending	$142,699	$130,165	10%	239

(1) breakouts based on 2012 spending estimate Source: Dahlman Rose & Co. estimates

Selected U.S. Budgets–2011, 2012
($MM)

	2012E	2011	Year-to-Year $ Change	Year-to-Year % Change
Apache Corp.	4,550	2,768	1,782	64%
BHP Billiton	4,400	2,800	1,600	57%
Chesapeake Energy	6,500	6,250	250	4%
ConocoPhillips	6,600	4,600	2,000	43%
Continental Resources	2,040	1,735	305	18%
Devon Energy	4,730	4,950	-220	-4%
Encana	1,800	2,500	-700	-28%
EOG Resources	6,000	5,900	100	2%
Hess	3,400	3,000	400	13%
Noble Energy	2,400	2,100	300	14%
Occidental Petroleum	4,814	4,275	539	13%
Pioneer Natural Resources	2,380	1,940	440	23%
Plains Exploration & Production	1,500	1,700	-200	-12%
Range Resources	1,200	1,200	0	0%
SandRidge Energy	1,700	1,700	0	0%
Ultra Petroleum	550	1,300	-750	-58%
WPX Energy	830	1,250	-420	-34%
Sub-Total	55,394	49,968	5,426	11%

Source: Dahlman Rose & Co. estimates

billion barrels of liquids reserves, average daily production of 68 billion cubic feet (Bcf) of gas (about 20% of global production) and 11.2 million barrels of liquids (about 12.5% of production), and cash flow in 2011 of $1.96 trillion (up 27% year-over-year and now larger than Russia's GDP, the ninth largest in the world).

"Drillbit F&D costs moderated year-over-year; they are down big over the last five years. The 2011 cost to turn the bit to the right and book either an Mcf of gas or a BOE (barrel of oil equivalent) of proved oil reserves declined 7% year-over-year to $17.76 per BOE. Average drillbit F&D costs have declined by a staggering 33.6% over the last five years ($26.97 per BOE in 2007), as the industry's capital has been aggressively reallocated into unconventional resource plays."

–Global Hunter Securities' annual F&D Cost Study

OIL PRICES

"Brent oil prices are now down about 30% from their March-2012 peak of $126 per barrel, and have recently been trading at and below the marginal cost of production, which was $92 in 2011.

"At this level we believe an Overweight strategy is now warranted.

"Further oil price downside is limited in our view due to (1) economic pressure on marginal/stripper wells, (2) pressure on OPEC budget breakevens, (3) non-OPEC supply risks in 2H 2012, (4) limited further demand destruction and (5) falling levels of OPEC spare capacity. Accordingly, we now seek exposure to more oil price-leveraged stocks…"

–Bernstein Research, July 2012

NATURAL GAS SUPPLY

Domestically produced natural gas from unconventional operations is projected to rise to 67% of total gas supply in 2015, and jump to 79% by 2035, according to an IHS study.

–IHS

In March 2012, onshore U.S. production of natural gas was 67.1 Bcf a day. Total Lower 48 production that month was 71.8 Bcf a day, per the EIA-914 data compiled each month from producers by the Energy Information Administration.

–EIA

NATURAL GAS PRICES

"Given the current gas price of about $2.80 per Mcf and our belief that coal-to-gas switching begins to deteriorate at the $2.50-Mcf level—and could actually reverse in the $3-Mcf range—we suspect this will limit near-term upside for gas prices. It is our contention that coal has become the marginal supplier of power generation during the warmer-than-average summer months and we continue to forecast prices to remain range-

Projected Year-End 2012 Capex
($MM)

	2012 Projection	2011 Final	Year-to-Year % Change
U.S. Spending	$142,699	$130,165	9.6%
Canadian Spending	$46,237	$43,591	6.1%
International Spending	$405,842	$363,754	11.6%
Worldwide Spending	$594,778	$537,510	10.7%

Source: Dahlman Rose & Co.

bound at $2 to $2.75 per Mcf through September."

–Raymond James & Associates

"While we are encouraged by the rate-of-change in reducing the storage surplus, we still have some concerns around fall and suspect current strength could still be undercut by full storage. We view 2012 as a pivotal year for gas, recognizing excess supply on the sidelines likely mutes potential upside over $3 to $4 per MMBtu over the near and medium term."

–Michael Hall, director and senior analyst, E&P Equity Research, Robert W. Baird & Co.

INVESTOR OUTLOOK FOR E&PS

"Given the sharp pullback in both oil and natural gas liquids (NGLs) prices during the second quarter, the reduction in the rig count, and fluctuations in differentials, we expect investors likely will focus on both costs and pricing for the quarter. We would not expect significant impact on 2H12 capex budgets, although some companies may trim spending.

"The median company is now outspending by 49% in 2012 and 25% in 2013. Although gas-weighted companies outperformed the group during 2Q12, in our view, liquids-weighted companies, in general, still generate higher returns and offer better growth."

–Nicholas P. Pope, managing director, Dahlman Rose & Co.

OIL DEMAND, CALL ON OPEC

"The IEA's global oil demand estimate for 2012 is left flat at 89.9 million barrels a day, with

some emerging market weakness. Full-year OECD demand is expected to be 45.3 million barrels a day (up a slight 0.1 million a day). Non-OECD demand is expected to reach 44.6 million barrels a day (down 0.1 million a day).

"The IEA estimate for full-year 2013 demand is being initiated at 90.9 million barrels a day (up 1.0 million a day, year-over-year).

"Global oil supply fell by 0.5 million barrels a day in June 2012 (versus a 0.2-million barrel increase in May). Non-OPEC liquids production was responsible for 75% of this decline.

"The IEA's full-year 2013 non-OPEC supply estimate has been initiated at 53.9 million barrels a day (up 0.7 million a day, year-over-year), ahead of the expected 0.6-million-a-day 2012 increase. The third-quarter 2012 call on OPEC crude rises to 31.2 million barrels a day (up 0.3 million a day), while the average 2012 call on OPEC is raised to 30.5 million a day (up 0.2 million a day). Forward demand cover was 58.9 days in May 2012, some 1.4 days above the five-year average."

–The International Energy Agency, Oil Market Report, July 2012

HOW TO VALUE ENERGY STOCKS

WHAT FINANCIAL CRITERIA SHOULD INVESTORS USE WHEN BUYING OIL AND GAS STOCKS? ANALYSTS INDICATE THERE IS MORE THAN ONE YARDSTICK FOR PICKING WINNERS.

As any investor has learned in recent market times, landing the big catch among publicly traded energy stocks is a function not only of patience, but of applying the right financial criteria when analyzing upstream independents, service companies and MLP's.

Just what are these criteria? Analysts use several yardsticks to determine if a company's shares or an MLPs units are worth buying. In the main, they pay attention most to these factors:

- The company's present and potential cash flow per share;
- Total capitalization or total enterprise value/EBITDA (earnings before interest, taxes, depreciation and amortization);
- Full-cycle return on investment; and
- Share price versus a company's breakup value or appraised net worth.

"The managements of E&P companies aren't being judged by the market on their ability to generate net income, but rather on their ability to take the cash they generate from production and invest it in existing or new properties to improve the underlying asset value of their companies," says one Dallas buyside analyst.

Another market seer, this one in New York, agrees. "We consider annual earnings numbers an unreliable tool for comparing upstream companies. That's because some operators use successful-efforts accounting whereby they expense—or subtract from earnings—exploration costs in the same year they occur; those using full-cost accounting, on the other hand, fully capitalize and then amortize their exploration costs over future years.

"With cash-flow analysis, we add back in the exploration expenses for successful-efforts companies, thereby creating more of a level playing field—one that allows for similar comparisons."

But there's a more compelling reason why the analyst places a premium on cash flow. "That's what an operator must use (to fund drilling or acquisitions) to replace the reserves he produces in a given year. As such, it serves as a gauge of his ability to grow his asset base."

Echoes another Wall Street analyst, "The future success of upstream companies depends on their ability to ward off production declines by cost effectively finding new reserves with cash flow generated from current sales. Those that grow their cash flow by growing their production profiles are the ones that are going to improve their bottom line and the ones in which you want to invest."

E&P analysts, however, don't regard cash flow analysis as *the* stand-alone tool for measuring an upstream operator's investment worthiness. On the contrary, they believe an investor should also place a premium on a company's share price versus its net asset value (NAV).

"Every now and then, you come across a situation where an independent has hit a home run or is about to tremendously increase the underlying value of its reserve base—but the market hasn't recognized this yet in the company's share or unit price," observes the Dallas buysider.

"It's well to consider *where* upstream operators are trading relative to their NAVs. In many cases, you'll uncover producers that are significantly undervalued by the market and hence, worth future scrutiny."

When valuing E&P companies, an analyst may focus on total enterprise value (stock market equity plus debt and preferred shares)/EBITDAX (earnings before interest, taxes, depreciation, amortization and exploration expenses).

"It's a debt-adjusted ratio that takes into account a company's unlevered cash flow," one analyst says. "That's a useful equalizer in comparative valuation analysis in that it eliminates the effect of varying high- to- low-debt capital structures on cash flow."

This valuation yardstick, also known as total capitalization/EBITDA, can be an eye-opener for investors. Here's a hypothetical example: Alpha Oil Co. and Beta Oil Co. both have EBITDA of $10 million. But while Alpha has $100 million of equity and no debt, giving it a total capitalization of $100 million, Beta has $100 million of equity and $100 million of debt, giving it a total capitalization of $200 million. Thus, the total cap/EBITDA multiple for Alpha is only 10 while the same multiple for Beta is 20.

Explains the researcher, "Having compared both companies on the same debt-adjusted cash flow basis, and having recognized the financial leverage of both and their ability to fund drilling programs, you'd rather invest in the hypothetical Alpha company with the total cap/EBITDA multiple of 10."

Among other investment criteria, the Denver analyst also studies NAV to identify stocks that are trading below their inherent asset or liquidation value. "Similarly, scrutinizing stock price/discretionary cash

AN INVESTOR'S GLOSSARY

Break-up value Also called liquidation or appraised net asset value. Represents the estimated net asset value of a company, assuming that all tangible assets, liabilities and preferred stock were liquidated.

Break-up value per share The estimated net asset value accruing to a company's common shareholders, assuming all tangible assets, liabilities and preferred stock were liquidated.

Cash flow Annual net income (after-tax earnings) plus depreciation, depletion and amortization (DD&A), deferred taxes and other non-cash charges.

Cash flow per share/unit Annual net income plus DD&A and other non-cash charges divided by number of common shares or units outstanding.

Cash flow multiple Stock price divided by annual cash flow per share.

Discount to break-up value The percent of discount that a company's common shares trade at relative to that company's estimated break-up value per share.

EBITDA Earnings before interest, taxes, depreciation and amortization.

EBITDAX Earnings before interest, taxes, depreciation and amortization, and exploration expenses.

Finding costs The costs incurred to find and develop oil and gas reserves, exclusive of lifting, operating and G&A costs.

Full-cycle return on investment Cash flow per equivalent barrel divided by multi-year average finding costs.

Price-to-book Ratio of current stock price divided by book value per share.

Return on capital employed EBITDA divided by the difference between total assets and current liabilities.

Total enterprise value Also referred to as total capitalization, it is the value of common equity plus long-term debt plus preferred stock.

Total enterprise value to EBITDA Also called total capitalization/EBITDA. It is common equity plus long-term debt and preferred stock divided by EBITDA. This ratio allows company's cash flow to be viewed on a debt-adjusted basis, thereby taking into account the impact of financial leverage on that company's price/cash-flow multiple.


NEW YORK STOCK EXCHANGE

A Total Cap/EBITDA Worksheet

EBITDA	Equity	Debt	Total Capitalization	Total Cap/ EBITDA
$10 million	$100 million	$0	$100 million	10
$10 million	$100 million	$100 million	$200 million	20
X	Y	Z	Y+Z	Y+Z/X

flow helps identify stocks that are comparatively undervalued, this time on an after-interest, after-tax, cash-flow multiple basis," he says.

In addition, he looks at cash flow per unit of production/finding costs. The reason? "This ratio is a good proxy for return on investment and implied growth rates."

Warns the analyst, "An investor should be wary of operators with declining or flat production, high finding costs versus cash flow generated per unit of production, lack of high-growth-potential areas, and too much debt."

Emphasizing yet another valuation metric, one Houston-based market seer places a high premium on full-cycle return on investment (cash flow per barrel equivalent divided by multi-year average finding costs).

"Cash flow growth means nothing unless a producer is making money on that incremental dollar that it invests," he explains. "Calculating a full-cycle return on investment directs investors toward those companies that are making efficient capital investments and away from those that are making inefficient investments.

"Put another way, it helps investors avoid paying five times cash flow for upstream stocks with poor returns versus paying five times cash flow for those with tremendous returns."

When it comes to cash flow or NAV analysis, the analyst argues that investors should pay particular attention to underlying pricing assumptions for oil and gas, given the volatility of these commodities.

"The way we deal with the problem of volatility in our analysis is to use price-normalized cash flow and asset values, that is, we use historical five-year-average oil and gas price assumptions in our valuations—not current spot prices." This can lead to a better perception of investment opportunities, he points out.

Another caveat the analyst advances: when investors today scrutinize a producer's discretionary cash flow, they should pay more attention to how much maintenance capital spending is needed just to keep that company's asset base flat—and how much free cash flow is actually left over to grow that producer's reserve base.

"If two operators each have $100 of discretionary cash flow, and one of them has to use all of it just to replace what has already been produced, then that company is just standing in place," he insists. "If the other, meanwhile, has finding and development costs only half as much as the former producer, it's clear that's the one that's going to have the free cash flow to grow."

Yet another Houston-based analyst places a high value on break-up or NAV analysis. If an investor can buy a producer's reserves in the stock market for less than what an independent engineering report says they're worth, then there's an opportunity to make money as those reserves are produced and sold in future years.

"If the net present value of a producer's future oil and gas cash stream—plus the value of its other assets less debt—is $1 per share, and that company's stock currently trades at 50 cents per share, then I've discovered a stock that's selling for half its break-up value," he says.

Naturally, the analyst also focuses on cash-flow analysis—and with good reason. "You might be looking at the greatest bargain in the world as far as the discount-to-break-up value of a producer's reserves in the ground, but if the company doesn't have the money or wherewithal to produce and sell those reserves at a profit, then those reserves can't really be fully exploited."

And neither can the investment. ■

ALERIAN

ALERIAN.COM

KENNY FENG, CFA, president and CEO, has been with Alerian since 2005. When he is not busy playing guitar and serenading audiences at MLP conferences, he leads a company focused on providing information and product access to the MLP asset class.

Tell us about Alerian.

Founded in 2004, Alerian is an independent provider of master limited partnership (MLP) indices and analytics. We strive to be the Wikipedia of MLPs—the source of objective information and data for the MLP stakeholder community, including current and potential investors, sell-side research analysts, media outlets and MLPs themselves.

Our indices are licensed to third parties for the creation of passively managed investment products. Approximately $9 billion is currently linked to the Alerian indices through one exchange-traded fund (ETF), six exchange-traded notes (ETNs), and other structured products, including Canadian return-of-capital (ROC) notes.

Describe the four main Alerian indices.

The leading benchmark for MLP equities is the Alerian MLP Index (NYSE: AMZ), a composite of the 50 most prominent energy MLPs that captures more than 90% of the sector's market capitalization. Launched in June 2006, the AMZ was the first real-time MLP index, and is calculated using a float-adjusted, capitalization-weighted methodology, much like the S&P 500.

We launched the Alerian MLP Infrastructure Index (NYSE: AMZI) in March 2008 in response to investor requests for a benchmark focused on partnerships that own midstream energy assets. The AMZI consists of 25 MLPs that earn the majority of their cash flows from the transportation, storage and processing of energy commodities.

We launched the Alerian Natural Gas MLP Index (NYSE: ANGI) in January 2010 to capture the performance of MLPs with exposure to the rapid development of natural gas shale plays across the United States. The ANGI is comprised of 20 MLPs engaged in the transportation, storage and processing of natural gas and natural gas liquids (NGLs).

We also launched the Alerian Large Cap MLP Index (ALCI) in January 2010. It's a performance benchmark for the 15 largest MLPs by market capitalization.

How do you determine the constituents and weightings for the MLPs that make up an index?

Because we believe that the ongoing effectiveness of a benchmark is dictated by clarity and transparency in the constituent selection and weighting process, a detailed methodology guide that governs the aforementioned determinations for each of our indices is publicly available on our website. We begin by keeping track of all MLP public filings, including press releases, annual and quarterly reports (10-Ks and 10-Qs), prospectuses and supplements, proxy statements and current reports (8-Ks). The information in these documents enables us to calculate each partnership's float-adjusted market capitalization. The partnerships that are selected for the index rank highest on this metric and meet a series of eligibility criteria, such as thresholds on distribution payments, trading liquidity, size and public float. The AMZ and AMZI are weighted by adjusted market capitalization, while the ANGI and ALCI are weighted equally.

Why do investors own MLPs?

MLPs represent an investment in the build-out of U.S. energy infrastructure over the next few decades. Energy infrastructure MLPs operate toll-road businesses that benefit from long-term contracts with built-in inflation hedges, regional monopoly footprints, and inelastic energy demand. These assets generate predictable cash flows and have enabled MLPs to pay consistent and growing quarterly cash distributions over the past 25 years. Sector distribution growth, as measured by a weighted average of the constituents of the AMZ, has averaged 7% annualized over the past 10 years.

Interest in the sector has spiked over the past few years in particular as investors scour the market for yield. The AMZ currently yields approximately 6%, which compares very favorably with U.S. 10-Year Treasury Bonds at 2%. Industry analyst estimates of weighted-average distribution growth for the asset class over the long term range between 3% and 8%, lending further credence to the belief that MLPs are an excellent source of current income and will continue to be for years to come.

How have MLPs performed historically?

Over the past 10 years, the AMZ has returned 17% annualized on a total-return basis.

How big is the MLP market in the U.S. and what is the trajectory of the asset class?

The sector has grown dramatically over the past 10 years, with the number of MLPs increasing fourfold to 85 securities and the aggregate market capitalization growing 15-fold to $300 billion. Future growth in the asset class will stem from both organic growth projects as well as asset acquisitions.

The Interstate Natural Gas Association of America (INGAA) predicts that the U.S. will need $200 billion of new natural gas infrastructure investment during the next 25 years, driven by both new sources of supply and growth in demand. On the supply side, developments in drilling technology and technique have led to significant gas discoveries in unconventional plays. New infrastructure will need to be built to connect these emerging supply hubs to population centers. On the demand side, the Energy Information Administration (EIA) predicts that U.S. energy demand growth will average 0.5% annualized over the next several decades.

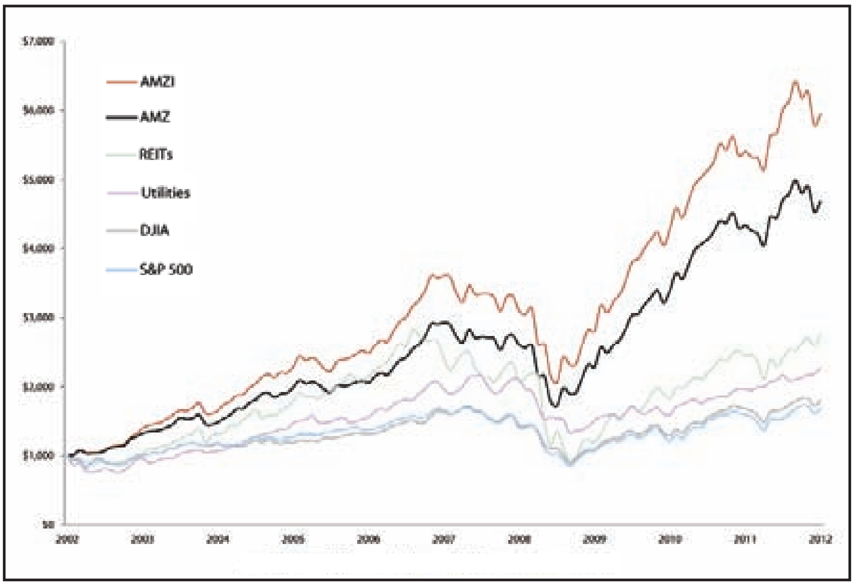
And on the acquisition front, industry analysts estimate that approximately $200 billion of midstream assets are housed in public and private corporate structures, much of which could eventually be acquired by MLPs.

How can I invest in Alerian indices like the AMZ, AMZI, and ANGI?

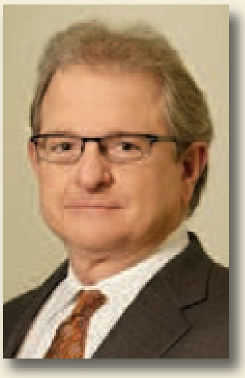
An investor cannot invest directly in an index. However, we license our indices to third parties that create investable products designed to track our indices. As of June 30, 2012, over $9 billion of investable products were directly tied to our indices. The two products with the most assets under management (AUM) are the Alerian MLP ETF (NYSE: AMLP) and the JPMorgan Alerian MLP Index ETN (NYSE: AMJ). The newest product is the UBS Alerian MLP Index ETN (NYSE: AMU), which tracks the AMZ and was launched in July 2012.

What are the benefits to investing in passively managed (index-based) products?

Studies have shown that, including fees, most active managers do not outperform their comparative benchmark index consistently over time or during periods of market stress and volatility. Actively managed products offer higher expenses and fees that can quickly eat into returns. Because there are only 85 securities in the energy MLP universe, and only one-third of which have a market cap in excess of $2 billion, there tends to be a high percentage of overlap in top holdings among the larger active managers—as reported in periodic filings with the Securities and Exchange Commission—due to size and liquidity constraints. Overlap of top 10 holdings versus Alerian's indices can also be meaningful, at times exceeding 70%, resulting in a lack of a meaningful differentiation via security selection.



Over the past 10 years, the Alerian MLP Infrastructure Index (AMZI) and Alerian MLP Index (AMZ) have generated 19.5% and 16.7% annualized returns, respectively.



APPROACH RESOURCES INC.

NASDAQ: AREX | APPROACHRESOURCES.COM

J. ROSS CRAFT, president and CEO of Approach Resources Inc., is a petroleum engineer with 30 plus years of experience drilling in the West Texas Permian Basin. Craft led the Approach team in testing the Wolfcamp oil shale resource play. Although it is early in the play's development, the Wolfcamp is anticipated to become one of the largest producing onshore oil discoveries in our country's history, given current estimates of oil in place and potential recoveries.

Describe the strategy that drives the company, and how you will implement it this year.

Our strategy is to grow production and reserves at low finding and development costs in order to generate value for our shareholders. Since 2004, we have increased reserves and production at a compound annual growth rate of over 40%, primarily through the drill bit.

Our team pioneered the Wolfcamp oil shale resource play in the southern Midland Basin, spurring a renaissance of drilling there and opening up what promises to be one of the largest onshore oil field discoveries in our country's history. For a company our size, we have great exposure to the play with 165,000 acres under lease, providing more than 500 million BOE in gross, unrisked resource potential, or more than six times our current proved reserves base.

Tell us more about the Wolfcamp.

What is exceptional about it is that it has a very thick pay zone of up to 1,200 feet. In order to better define and study this extensive rock column, Approach classified the Wolfcamp into four sub-zones: A, B, C and D benches, and launched a pilot program in 2011 to test the B bench. The pilot proved successful, and we have transitioned into a development mode in this section of the column. In addition, Approach has drilled three test wells–two to the A bench and one to the C bench–with very encouraging results. Another portion of the column, the D bench, remains to be tested.

For the remainder of the year, we plan to drill additional pilot wells targeting the A and C benches as well as test closer well spacing, while we continue working to optimize drilling and completion techniques and drive down costs.

How have high oil prices and low gas prices affected your business?

Over the past several years, we have transitioned to an oil and natural gas liquids (NGLs) focus. In 2012, we expect to produce 65% oil and NGLs. The beauty of the Wolfcamp play is that it works in a wide range of price scenarios. We can achieve economic returns at a $65-to-$75-per-barrel oil price. So, in spite of the recent decline in oil prices, we remain committed to our business plan for the remainder of 2012.

Will you be expanding into any new basins or plays? Why or why not?

We currently have 2,900 drilling and recompletion opportunities on our existing acreage, of which 500 are horizontal Wolfcamp locations. At our current pace of drilling this equates to more than a 30-year drilling inventory. In addition to the Wolfcamp, there are several additional plays that we can explore on our existing acreage. Having said that, the company has established a business development and special projects team to evaluate new play opportunities.

Which projects will yield the best return for the company this year?

The Wolfcamp play has significantly enhanced our portfolio with several high rate-of-return projects. We're running two horizontal rigs targeting the Wolfcamp A, B and C benches. At our target drill and complete cost of $5.5 million, the horizontal Wolfcamp yields more than a 20% rate of return at $75-per-barrel oil, and more than a 40% rate of return at $100-per-barrel oil. Our Wolfcamp recompletions also yield a high rate of return. Prior to our Wolfcamp discovery, we drilled more than 550 wells targeting deeper zones. Now as we re-enter these wells and recomplete to the shallower

Wolfcamp zones, we can achieve very strong rates of return.

What is your projected budget and how many wells is that? How does it compare to 2011?

We have nearly tripled our capital spending over the past two years, going from $90 million in 2011 to $260 million in 2012. The capital is directed toward delineating and developing our properties in the Permian Basin, particularly our Wolfcamp discovery.

Our 2012 drilling program includes operating two horizontal rigs, one vertical rig and one workover rig. We plan to drill 18 to 24 horizontal Wolfcamp wells and 30 to 35 vertical Clearfork and Wolfcamp shale wells. In addition, we plan to use the workover rig to recomplete two to four wells per month in the Clearfork and Wolfcamp shales. This level of activity is expected to drive 28% production growth for 2012.

Are you constrained by midstream capacity at all?

Pipeline infrastructure is adequate in the Permian to accommodate current production rates. However, given the ramp-up in drilling by a number of operators in the area, this could change fairly quickly. We recently purchased four crude hauling trucks. Even so, as production continues to increase, we may find that laying pipelines is the most cost-effective means of transportation.

What is the greatest challenge you face this year?

Our biggest challenge in the year ahead is preparing for large-scale field development. We will likely need to secure or install takeaway lines to efficiently transport our products to the market. In the meantime, we are evaluating options for water sourcing and recycling, purchasing and installing water transport lines and preparing to drill or convert salt water disposal wells.

Simultaneously, we will be working toward optimizing our drilling and completion techniques and testing horizontal stacked laterals and closer well spacing. And, of course, we will continue our focus on driving down drilling costs and increasing our operating efficiencies.

To achieve these goals we will need to successfully hurdle one of the biggest challenges in the E&P industry today: the ability to attract and retain talented individuals. Approach provides equity awards to all employees in order to attract top talent and motivate existing employees as they share in our ongoing success.

Do you foresee any acquisitions this year?

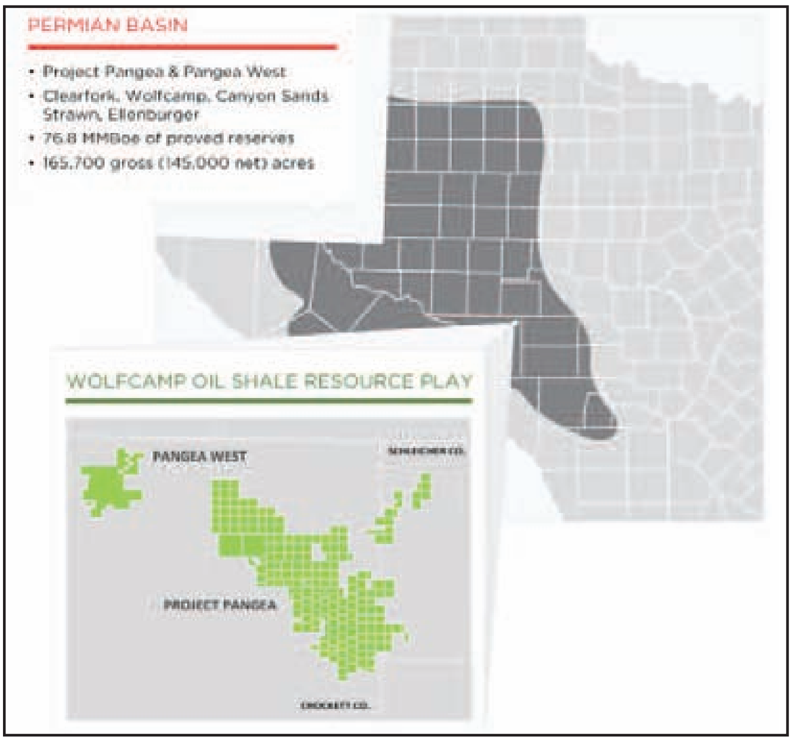
Bolt-on acquisitions are always under consideration. We are very open to the idea of purchasing producing acreage that would contribute to cash flow. In turn, we would invest this cash flow back into the Permian to accelerate our Wolfcamp development.

How much are you hedged?

We currently have 43% of our anticipated oil volumes in 2012 hedged at prices ranging from $85 to $106 per barrel. We have also hedged certain components of the NGL stream, specifically, natural gasoline at $95.55 per barrel and normal butane at $73.92 per barrel.

What is the one thing you want investors to know?

Approach Resources is in growth mode, has great exposure to the Wolfcamp unconventional oil shale play in West Texas, and provides an excellent avenue for investors to participate in the "new Permian" oil boom.



Map of Approach Resources' West Texas properties.

BONANZA CREEK ENERGY INC.

NYSE: BCEI | BONANZACRK.COM

MICHAEL R. STARZER has more than 28 years of experience in the oil and gas industry, having served in various technical and management positions with Unocal and Berry Petroleum. He was a co-founder of the first Bonanza Creek company in 1999 and has served as the company's president and CEO since that time. Bonanza Creek is an independent with assets and operations concentrated in the Rocky Mountains in Wattenberg Field, focused on the Niobrara shale, and in southern Arkansas.

Describe the strategy that drives the company, and how you will implement it this year.

The three priorities for BCEI this year are: 1) efficient project execution, 2) effective communication to the market and, 3) continued financial discipline. Our strategy is primarily driven by the development of the Niobrara shale in the Wattenberg Field, Colorado. We, along with neighbors like Noble, Anadarko and PDC Energy, have experienced terrific results from the Niobrara shale.

Combined with our operations in southern Arkansas, we forecast production to range from 8,700 to 10,000 BOE per day in 2012, an approximate 100% increase over 2011. We also enjoy one of the strongest balance sheets of our small-cap E&P peers and intend to use it aggressively, but prudently, to grow the company. In the short time we have been a public company, BCEI has developed a following of faithful investors who recognize our growth and upside value creation ability. We look forward to continuing to communicate BCEI's excellent results.

How have high oil prices and low gas prices affected your business?

We are fortunate to be oil-weighted. In fact, in first-quarter 2012, some 76% of our production and 93% of our revenues came from oil and liquids. With a realized price of $76.68 per BOE, before the effects of hedging, we have an EBITDA margin of approximately $50 per BOE. Especially important in this period of volatility, our projects possess attractive economics down to $60 per barrel.

With the decline in gas prices positioning the industry's focus more toward oily developments, similar to our Niobrara and Cotton Valley properties, we have not seen development costs increase. Drilling rigs and services that were previously focused on developing gas have become available for the more oil-weighted developments.

Will you be expanding into any new basins or plays? Why or why not?

We pride ourselves on buying right. When you see BCEI announce an acquisition, the word that we want to come to mind is "predictable." Since 2006, we have made 15 transactions to put together our core positions. Aided by a strong balance sheet we are able to act quickly to take advantage of opportunities in the market.

Our bias is to stay close to where we currently operate, but we look at deals every day all over the country that we may bring our core competencies of fracture stimulation and horizontal drilling to development. We will stay oil focused and onshore, and we will make acquisitions that are consistent with our ability to create value for our shareholders.

Which projects will yield the best return for the company this year?

Simply put, our development drilling in 2012 will generate a 100% rate of return at $100 per barrel. All our projects are attractive and equally resilient to lower oil and gas prices. We have tremendous assets that include the Wattenberg Niobrara oil shale fueling much of our proved reserve growth, and the oily Cotton Valley formation in southern Arkansas generating large amounts of cash.

Last year we invested in both regions and grew proved reserves by 33%; over 135% year-over-year proved reserve growth in Wattenberg alone. Southern Arkansas is our cash machine, expected to yield approximately $100 million in cash flow this year to fuel our dramatic growth in Wattenberg. Both assets are approximately 70% oil and liquids, have ready access to services and infrastructure, and receive good price realizations.

What is your projected budget and how many wells is that, and how does it compare to 2011?

This year we plan to spend approximately $230 million to drill 160 wells, including 24 horizontal Niobrara wells. In addition, we plan to spend $20 million to install our third gas-processing facility in the Midcontinent region. This compares to $143 million invested in 2011 to drill 114 wells, and $22 million to install our second gas-processing facility.

WE TRULY BELIEVE THAT THE NIOBRARA, PARTICULARLY WHERE WE ARE IN THE WATTENBERG FIELD, IS A WORLD-CLASS ASSET THAT WILL FUEL DOUBLE-DIGIT GROWTH FOR YEARS TO COME.

Are you constrained by midstream capacity at all?

We do not see any midstream constraints in either the Rocky Mountains or the Midcontinent. People note that Noble Energy plans to invest $8 billion in the Niobrara over the next five years and Anadarko Petroleum will spend $1 billion per year in the area, and they understandably fear capacity takeaway issues. However, our analysis shows that 450 MMcf per day of additional capacity will come online over the next three years, building on top of present capacity. The Wattenberg is a mature field with infrastructure that has been built over the past 40 years. We believe it is positioned well to handle such a ramp-up in production.

Do you foresee any acquisitions this year?

As I mentioned earlier, we are always looking for good deals. While we have a tremendous portfolio of organic projects, a critical part of our growth strategy has been and will remain acquisitions. We won't be shy about using our underleveraged balance sheet to take advantage of attractive opportunities.

How much are you hedged?

We have hedged approximately 60% of current oil production at an average of $90 to $106 per barrel WTI Nymex. As our production rapidly increases, we expect to place more under hedge if priced attractively. We view hedging as the company's insurance policy to protect our capital budget, maintaining strong financial discipline with top-quartile growth.

What is the greatest challenge you face this year?

As a new public company our most important obligation to shareholders is to hit our targets. We want to be known as a company that does what it says it will do. To that end, we forecasted relatively aggressive production growth this year, and so far we have exceeded those projections. It is critical that we execute on our strategic plan, in order to build confidence that this management team will maximize shareholder value.

What is the one thing you want investors to know?

We are serious about maximizing value and growing Bonanza Creek. Our investors are sophisticated, believe in management and in our growth and value creation potential. We have terrific employees and assets, like the Niobrara, that enable us to grow aggressively. We truly believe that the Niobrara, particularly where we are in the Wattenberg Field, is a world-class asset that will fuel double-digit growth for years to come. In addition to the Wattenberg and Cotton Valley developments, we hold a large position prospective for the Niobrara oil shale in the North Park Basin of Colorado, and in Arkansas, our acreage is prospective for the burgeoning Brown Dense play. Together, these and other opportunities represent 250 million BOE of recoverable oil-weighted resource potential in the company.

Any final comments or thoughts?

Bonanza Creek is a team of consummate professionals particularly skilled in creating value. Our board, management and operations teams are the best I have worked with and deserve tremendous credit for their efforts in increasing production and growing reserves. Combined, management and employees own over 7% of BCEI and are closely aligned with our public shareholders. Our board and employees take much pride in what they do and I appreciate their efforts.

BREITBURN ENERGY PARTNERS

NASDAQ: BBEP | BREITBURN.COM

HALBERT WASHBURN is the co-founder and CEO of BreitBurn Energy Partners LP, Los Angeles, an independent master limited partnership focused on the acquisition, exploitation and development of oil and gas properties for the purpose of generating cash flow to make distributions to unitholders. Washburn, a Stanford University graduate in petroleum engineering, also co-founded and has been co-CEO of Breitburn Energy and its predecessors since 1988.

Describe the strategy that drives the company, and how you will implement it this year.

We have followed the same basic operating strategy since BreitBurn was founded 24 years ago. We are an acquisition-and-exploitation company focused on acquiring interests in large oil and gas fields and increasing reserves, production, cash flow, and therefore value, by increasing operational efficiencies and applying the newest technologies. We have proven that we have the discipline to make successful acquisitions and the operational and technical expertise to increase value following the acquisition.

How have high oil prices and low gas prices affected your business?

We have shifted our capital dollars from our gas assets to our oil assets. BBEP is in the enviable position of having a balanced portfolio of oil and gas assets. While we have hundreds, if not thousands, of gas drilling opportunities, our acreage is virtually all held by production, so we don't have to drill those wells today. Instead, we have been focusing on the oil development drilling opportunities in our portfolio. In addition, we have recently completed three acquisitions that add to our oil development drilling portfolio.

Will you be expanding into any new basins or plays? Why or why not?

We are focused on a particular type of asset rather than a specific basin or play. As we have been saying for the past year or so, we expected to enter the Permian Basin at some point. We closed two excellent acquisitions earlier this month that marked our entry into the Permian. We are a large enough company that we have in-house operational and technical personnel with experience in most of the producing basins here in the U.S. So, while BreitBurn may not have operated in a particular basin, the odds are that we have in-house expertise in that basin.

Which projects will yield the best return for the company this year?

We are excited about our oil drilling opportunities in Wyoming, Texas and Florida. However, our highest return project will probably be our infill drilling program in California. In April we announced a significant increase in our capital budget to accommodate drilling

additional infill wells in our California oil fields. Based upon our historical drilling and current oil prices the rates of return on these projects could exceed 100%.

What is your projected budget and how many wells is that, and how does it compare to 2011?

Our total capital budget for 2012 is currently $87 million. That's up from $75 million in 2011. We plan to drill about 40 wells this year and may increase our capital budget and drilling plan again in light of the three acquisitions we recently completed.

Are you constrained by midstream capacity at all?

No.

Do you foresee any acquisitions this year?

Yes. We are focused on growth through acquisition and have publicly set a goal of between $300 million and $500 million of acquisitions in 2012. So far this year we have completed over $300 million in acquisitions, so we are already within the range we set for our goal this year. However, we see a large pipeline of acquisition opportunities for the rest of the year which we will continue to review. We are prepared for further acquisitions if we find opportunities which meet our parameters.

How much are you hedged?

Hedging is an important part of our overall strategy and we have a very strong hedge portfolio. We have almost 75% of 2012, 70% of 2013 and more than 60% of 2014 and 2015 production hedged at very attractive prices.

What is the greatest challenge you face this year?

Our principal challenge this year, and for each of the past 24 years, has been working hard to find the right assets to add to the portfolio. It takes a lot of coordination and hard work to keep the organization focused on finding good acquisitions and pursuing them in a careful and disciplined way.

What is the one thing you want investors to know?

We are very well positioned to continue growing the business and believe that the current commodity price environment is going to create very attractive acquisition opportunities for BBEP.

Any final comments or thoughts?

It has been a very active year for BBEP and we are looking forward to being equally productive through year-end. ■

ENERGEN CORP.

NYSE: EGN | ENERGEN.COM

JAMES MCMANUS is chairman and CEO of Energen Corp. and its subsidiaries. McManus joined Energen in 1986 and has held numerous senior-level positions. In 1997 he became president and COO of Energen Resources and, over the next decade, led the growth of Energen's exploration and production business from a small niche player in coalbed methane development in Alabama to one of the top 20 independent producers in the U.S. and the sixth most active Permian Basin operator.

Describe the strategy that drives the company, and how you will implement it this year.

Energen's strategic focus is on the exploration and development of oil and natural gas liquids (NGLs) in the Permian Basin; the company has operated in this prolific, West Texas basin since the late 1990s.

Over the past four years, Energen has capitalized on its strong balance sheet and financial capacity to acquire more than $900 million of proved properties and unproved leasehold in the Permian Basin. Today it is investing record amounts of capital to develop its five- to eight-year drilling inventory in the vertical Wolfberry play in the Midland sub-basin and its two- to three-year inventory in the horizontal 3rd Bone Spring sands on the east side of the Pecos River in the Delaware sub-basin.

Energen also believes its acreage position holds good potential for participating in the emerging horizontal Cline (Midland Basin) and Wolfcamp (Midland and Delaware basins) plays.

Energen plans to invest a record $915 million to drill and develop its Permian assets in 2012. In the Midland Basin, the company is running seven to eight rigs to drill 170 net Wolfberry wells; and, in the Delaware Basin, five to seven rigs are drilling 43 net wells in the 3rd Bone Spring sands. Energen also is running one to two rigs in the Central Basin Platform to drill producer and injector wells in its traditional waterflood properties.

Record capital investment in the Permian in 2011 and 2012 is driving Energen's double-digit production growth. The company estimates that total 2012 production will increase 20% from the previous year to 24.5 million barrels of oil equivalent (MMBOE), and that oil and natural gas liquids production will rise 39%. In 2013 the company estimates that its oil and NGLs production will have doubled from 2010 levels.

How have high oil prices and low gas prices affected your business?

Although Energen has excellent natural gas properties in the San Juan and Black Warrior basins, as well as in North Louisiana/East Texas, the company re-focused its exploration and development activities to the oil-rich Permian Basin beginning in 2009. This was in direct response to a belief that natural gas prices would continue to fall in a weak economy as shale production increased; conversely, Energen believed that oil prices would likely recover quickly as the global economy began to emerge from recession.

Energen entered 2012 with only $80 million of capital investment planned for its San Juan Basin gas properties; during the first quarter, as natural gas sank below $2.50 per Mcf, the company announced plans to cease all its natural gas development operations at the end of June, thereby cutting capital in its natural gas properties in 2012 down to $35 million.

Will you be expanding into any new basins or plays? Why or why not?

Energen has no plans at present to move into new basins. The company strongly believes that the emerging horizontal Wolfcamp and Cline plays offer substantial expansion within the Permian Basin on its existing acreage position. The success of even one of these plays could translate into many additional years of drilling in the Permian for the company.

Which projects will yield the best return for the company this year?

The 3rd Bone Spring sands are expected to generate the highest pre-tax returns for Energen in 2012. At $90 per barrel of oil and $4 per Mcf of natural gas, the typical 3rd Bone Spring well is estimated to generate a pre-tax return of 56%; the company's legacy waterflood operations offer the next highest return at 48%; and the predictable, vertical Wolfberry wells are expected to generate 26% returns at $90 oil and $4 natural gas.

Are you constrained by midstream capacity at all?

Midstream capacity is not a major problem for Energen at present, but the company has to remain vigilant and work diligently with its purchasers in order to anticipate and prepare for potential issues. Energen expects to see plant warming (ethane rejection) in 2012, and the Midland to Cushing WTI differential has widened in 2012 in response to pipeline capacity constraints; both events have been incorporated into Energen's guidance assumptions.

ENERGEN PROVIDES AN EXCELLENT INVESTMENT OPPORTUNITY FOR THOSE SEEKING A MAJOR PERMIAN PLAYER WITH STRONG OIL AND LIQUIDS GROWTH.

Do you foresee any acquisitions this year?

Energen acquired in February 2012 a small, proved Wolfberry property in Midland County, Texas, from a private seller for approximately $65 million. Energen continues to be open to the acquisition of proved properties and unproved leasehold in the Permian Basin and is an experienced acquire-and-exploit company. Any additional acquisitions in 2012 would most likely be less than $200 million each.

How much are you hedged?

Hedging has been an integral part of Energen's business strategy for more than 15 years. Given the company's substantial drilling and capital plans in 2012 and 2013, hedging to protect cash flows from commodity price volatility has arguably never been more important. Approximately 68% of Energen's total estimated production in 2012 and 2013 is hedged, including 75% to 80% of its estimated oil production at an average Nymex-equivalent price of approximately $89 per barrel.

What is the greatest challenge you face this year?

In the exploration and production business, the greatest challenge typically is commodity prices—and this year is no exception. With record capital investment planned, the single greatest threat to the successful implementation of Energen's strategy and the achievement of the company's objectives is the price of oil, NGLs and natural gas. Importantly, though, Energen's excellent hedge position substantially reduces the company's exposure to commodity prices and helps ensure that the Permian operator can implement its strategy and achieve its production and cash-flow targets.

What is the one thing you want investors to know?

Energen provides an excellent investment opportunity for those seeking a major Permian player with strong oil and liquids growth and excellent assets across the basin. The results of the company's Wolfberry and 3rd Bone Spring plays are strong, as are those from its legacy waterflood operations. Energen has a five- to eight-year drilling inventory in the vertical Wolfberry play alone, a two- to three-year inventory in the 3rd Bone Springs play in the Delaware Basin, east of the Pecos River, and the potential for significant upside from horizontal Wolfcamp and Cline in the Midland Basin, and from 3rd Bone Spring expansion, and horizontal Wolfcamp and Avalon shales in the Delaware Basin.

Any final comments or thoughts?

Energen has been in the oil and gas exploration and production business for more than 40 years. It pioneered the exploration and development of coalbed methane in Alabama's Black Warrior Basin in the late 1980s and expanded its operations into the San Juan and Permian basins in the late 1990s. Over the last four years, Energen has transformed itself into a major Permian oil player through acquisition and the drill bit and is one of the most active drillers in the Permian, running approximately 15 rigs in 2012.

We have made significant progress in recent years shifting our assets to oil and liquids as we expanded in a basin where we have operated for more than a dozen years. Today, we are a major, independent Permian driller with an attractive inventory and substantial potential from a variety of other trends now emerging in the Permian Basin.

Our significant hedge position, strong cash flows and excellent fundamentals allow us to move forward with record capital and drilling programs that are expected to result in double-digit production growth in 2012 and 2013.

ENERGY XXI

NASDAQ: EXXI | ENERGYXXI.COM

JOHN D. SCHILLER JR. has been chairman and CEO of Energy XXI since its inception in 2005. His career spans more than 30 years in the oil and gas industry. Previously, he served in executive positions with Devon Energy, Ocean Energy and Seagull Energy. Energy XXI has implemented an "acquire-and-exploit" growth strategy to build a geographically focused portfolio with some of the highest per-unit margins in the industry, with core properties in coastal and offshore Louisiana.

Describe the strategy that drives Energy XXI, and how will you implement it this year?

We founded the company on an "acquire-and-exploit" strategy. Over the past several years, and most recently with the acquisition of the shelf assets of ExxonMobil in December 2010, we have added two significant components to our strategy, those being "develop" and "explore." We are just beginning to experience the potential of our exploration efforts.

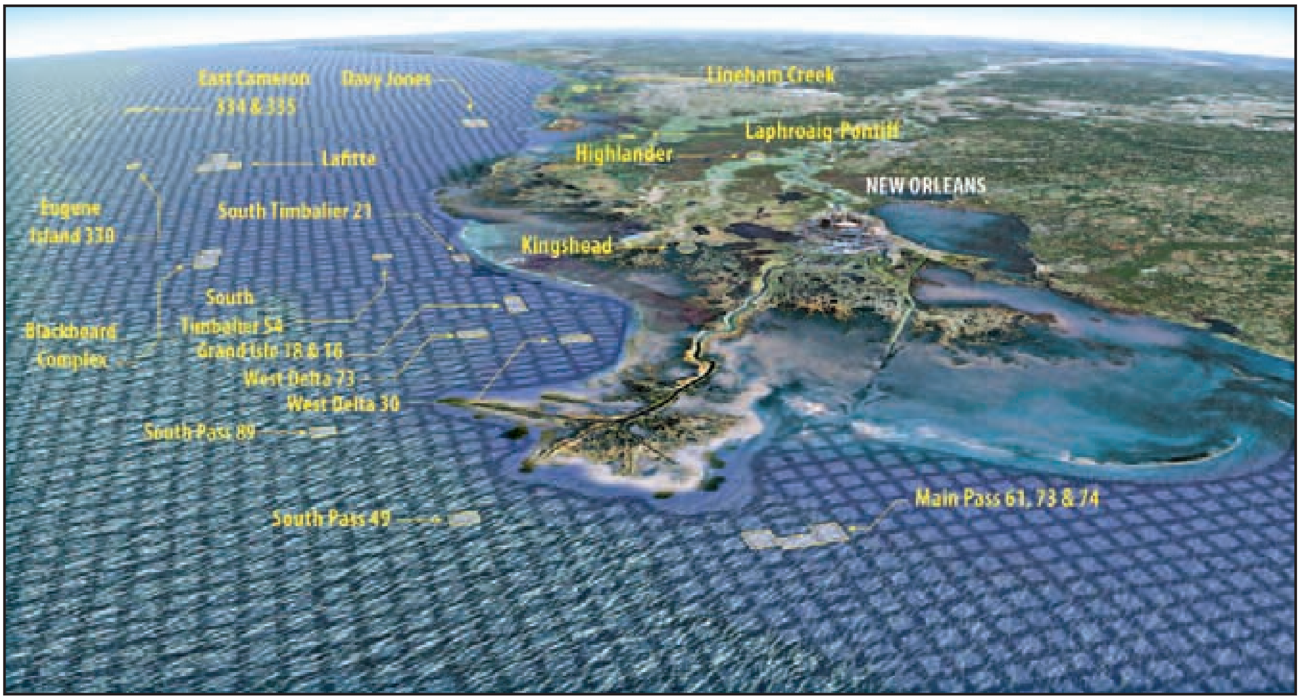
Have commodity prices affected your business?

Obviously, current oil prices have helped producers. Gas prices do not affect us as much as some companies because our production is about 70% oil. In fact, at one point this past fiscal year, we had north of 95% of our total revenues coming from oil wells.

What is your projected capital budget for this fiscal year and how is it funded?

This fiscal year, which began July 1, 2012, we plan to spend $700 million in capital expenditures. Approximately $505 million will go toward drilling and completions, recompletions, and facilities within our core assets. Also, $94 million is allocated to our ultra-deep exploration program with our partner McMoRan. We plan to pay for our capex with cash flow from operations.

Our internal financial models show us generating free-cash flow around $700 million with Brent oil prices at $120 per barrel and $100 million with Brent at $80 per barrel. The reality is we will likely fall somewhere in between. It is hard to find mid-cap independents growing production by 30%-plus year-on-year and delivering free cash.



Energy XXI's primary operations are in the shallow waters of the Gulf of Mexico.

The Rowan EXL III drilling rig at the Grand Isle field in 2011.

Do you foresee any acquisitions that fit into your "acquire" strategy?

We look at almost every package that presents itself in the Gulf of Mexico. I believe there are going to be some opportunities this year to add on to our existing asset base. Our focus is oil, and Energy XXI owns and operates five of the 11 largest oil fields on the Gulf of Mexico shelf. Our goal is to increase that footprint.

What projects will have the best return for the company this year?

Oil-weighted drilling opportunities like ours pay off quickly at today's commodity prices. We will continue to focus on oily opportunities. Our reserves are heavily weighted to oil, with 71% of our current reserves of 120 MMBOE being liquids and only 29% being natural gas. Where an oil well we drill in the Gulf of Mexico can pay out in two to four months, a gas well could pay out in as little as seven months. In our current drilling schedule for fiscal 2013, out of approximately 35 wells, 30 to 32 of those will be focused on oil. This heavily oil-weighted drilling plan carries into future fiscal years as well.

Any final comments to investors?

The next 5% is where we will deliver value to shareholders. If we increase our ultimate recovery in the large oil fields we control in the Gulf, with technology and today's commodity pricing environment, we can double our proved reserves–that is with only a 5% incremental gain from the reservoir. In our Main Pass and South Timbalier fields, we have successfully increased ultimate recovery by 7% since acquiring those properties. The future of Energy XXI in the Gulf of Mexico is very bright.

Energy XXI's Grand Isle operations.

ENSCO PLC

NYSE: ESV | ENSCOPLC.COM

DANIEL W. RABUN is chairman, president and CEO of Ensco plc, a global provider of offshore drilling services. Prior to joining Ensco in 2006, Rabun was a partner at the international law firm of Baker & McKenzie LLP, where he provided legal advice and counsel to Ensco for more than 15 years. He is the 2012 chairman of the International Association of Drilling Contractors. Now the world's second-largest offshore drilling contractor, Ensco has a major presence in the most strategic offshore basins across six continents.

Describe your strategy. How has it changed since last year?

Our strategy is very straightforward. We invest in technologically advanced rigs to continually high-grade our fleet—that means today we have the world's newest ultra-deepwater drilling fleet and largest active premium jackup fleet. We recruit and train the best people on proven systems that are applied consistently across all of our rigs around the globe—this enables us to achieve operational excellence, a superior safety record and the highest level of customer satisfaction in our industry.

And after completing a major acquisition last year, we are leveraging scale with the advantages of a large customer base, more purchasing power and a significant presence in virtually every oil basin in the world.

How do oil and gas prices affect your plans?

Even with the recent price volatility, when we have $70 to $80 Brent oil prices or higher, as we have for some time now, our global deepwater clients have sufficient economics to proceed with their drilling plans. Some shallow-water operations, particularly gas drilling, are shorter term and may have more price sensitivity, but right now we are seeing both deepwater and jackup utilization—and day rates—staying strong.

Do you need to expand capacity (people or equipment) this year? How will you implement these changes?

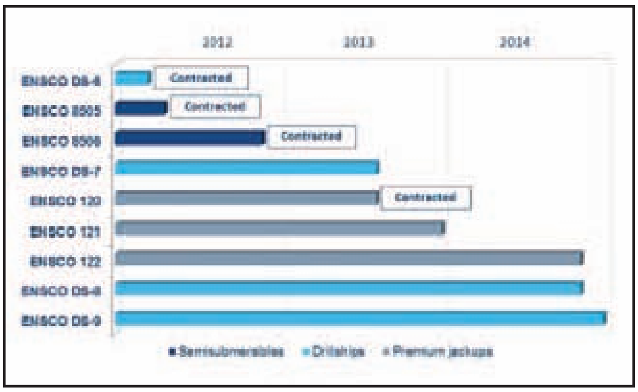
Yes. So far this year we have taken delivery of an ultra-deepwater drillship and two ultra-deepwater semisubmersibles; all three are already contracted. We have three ultra-deepwater drillships under construction for delivery in 2013 and 2014 and three ultra-premium harsh-environment jackups that will be delivered over the same time frame. To crew these rigs, we are promoting, recruiting and training hundreds of employees around the world. Our fleet standardization gives us the advantage of being able to seed new rigs with crew familiar with the layout and equipment.

Where does the most promising opportunity lie for you, U.S. or international?

As a drilling contractor working exclusively offshore, we see broad-based global demand, for both deep and shallow water. The U.S. Gulf of Mexico is one of several key deepwater areas, along with Brazil and sub-Saharan Africa—no surprises there. We are also finding increasing opportunities in the Asia-Pacific region and in the Middle East. New discoveries in emerging basins like East Africa and French Guiana continue to broaden our potential operating arena.

Do you have a backlog and how are you addressing it?

We have $10 billion of contracted backlog as of June 30. With our global presence and large fleet, we are able to take a portfolio approach to managing our contracts. This gives us the benefits of stable



Ensco's newbuild delivery schedule for 2012-2014.

ENSCO DS-8 and ENSCO DS-9 are the first ultra-deepwater drillships based on a new Samsung design.

longer-term agreements along with the flexibility to seize short-term opportunities.

What is your capital budget this year, and versus last year?

Our capex budget for 2012 is approximately $2 billion, compared to $742 million in 2011, due to a number of milestone payments for the newbuild rigs delivered this year. These investments should lead to future earnings growth as the rigs are delivered and command long-term contracts.

Do you foresee any acquisitions in the next 12 to 24 months?

We completed a huge acquisition last year. We believe we are positioned extremely well as the offshore driller of choice and our focus is on growing our business through the construction of new rigs and leveraging the advantages of standardization across our fleet.

Which projects will be most significant and why?

From a rig construction standpoint, we are moving into new generations of rigs in both our drillship and jackup fleets. The ENSCO 120 Series rigs are ultra-premium harsh-environment rigs. They're built to North Sea requirements but are capable of working in almost any shallow-water area of the globe. And our ENSCO DS-8 and ENSCO DS-9 drillships will be the first ultra-deepwater drillships based on Samsung's new GF12000 design.

What is your greatest challenge?

We are fortunate that our greatest challenge is fully capitalizing on the opportunities that are in front of us. To a great extent that means having the right people in place and training them to work safely and efficiently. We are investing in training and in all the components that support recruiting and retaining a skilled workforce.

What is the one thing you want investors to know?

The one thing I'd like investors to take away is an understanding of the distinct advantages we have in our market because of the quality of our fleet and our people, our focus on standardization of equipment and systems, and our commitment to employee development. These elements have produced the highest customer satisfaction scores in our industry, which we believe will lead to outsized returns for investors over time.

Reflecting our positive outlook, in addition to ordering two new drillships since the beginning of the year, our board of directors increased our regular cash dividend by 7%. We believe Ensco is now solidly both an income and a growth investment.

Any final comments or thoughts?

We have achieved all of our major strategic objectives and we're ideally positioned to continue to grow in the coming years with six rigs in the pipeline and the financial flexibility to add more rigs. At this point, it's all about execution, and I'm very confident that we have the right people, processes and systems to succeed.

HALCON RESOURCES CORP.

NYSE: HK | HALCONRESOURCES.COM

STEPHEN W. HEROD is president of Halcón Resources. He was a co-founder and executive vice president-corporate development and assistant secretary of Petrohawk Energy Corp. from 2005 until its sale in 2011. Prior to joining Petrohawk, he was employed by PHAWK LLC from its formation in 2003 until 2004, and was executive vice president-corporate development for 3TEC Energy Corp. Halcón Resources is an independent.

Halcón was started quickly after the sale of Petrohawk Energy Corp. How did Halcon's start-up compare to Petrohawk's?

We followed the same plan, same structure as Petrohawk, but on a much larger scale. We started Petrohawk with $60 million and used it to recapitalize a small-cap E&P company. At the time, that was a solid starting base. Today, it takes a lot more capital to drill and operate in the resource-style plays, especially considering the amount of acreage needed to have anything scalable. We started Halcón by putting $550 million of private-equity money, including some of our own, into an existing small-cap public company (RAM Energy Resources). That's allowed us to quickly acquire the assets needed to build a strong drilling inventory.

Describe Halcon's strategy.

Simple. Agile. Focused. In a nutshell, we're targeting the liquids-rich resource style plays and acquiring large, quality acreage positions. We're being selective about what we buy. We're taking time to do the geoscience and select the acreage with the greatest potential. However, taking too much time can be a risk. You can't sit by waiting for everything to be perfect; you have to be nimble. While we complete our technical work thoroughly, when it comes time to pull the trigger, we pull it. This is an independent company, and we think like an independent.

Tell us about Halcon's capital-raising activities to date.

HALRES LLC, which is comprised of EnCap, Liberty Energy and others, along with members of our management team, recapitalized RAM Energy Resources in February of this year with $550 million, half common stock and half convertible notes. Concurrent with the recapitalization of RAM we closed a new $500-million revolving credit facility and we announced a 1:3 reverse stock split a day or two later. Since then, we raised $400 million of the equity through a PIPE offering and we recently priced $750 million of senior unsecured notes that will be used to fund the cash portion of the GeoResources Inc. acquisition and for general corporate purposes. Since forming Halcón in December 2011, we've been able to raise approximately $2.5 billion in equity and debt.

What is your capex budget, what plays are you targeting and what sort of production growth are you expecting?

Our capex budget is $1.1 billion for 2012, excluding acquisitions, and we expect to spend a similar amount in 2013; however, the percentage we spend on drilling and completions next year will increase from around 40% this year to approximately 75%. This year the majority of our spending will be directed towards building acreage positions in areas we believe are prospective for oil and natural gas liquids. We're targeting the Utica/Point Pleasant formations in Ohio and Pennsylvania, the Woodbine/Eagle Ford formations in East Texas, the Tuscaloosa Marine shale in Louisiana, the Wilcox in East Texas and Southwest Louisiana, the Mississippi Lime in Northeast Oklahoma and three other liquids-rich exploratory plays that we have yet to disclose.

The GeoResources transaction also gives us a solid position in the Bakken, which is in North Dakota and eastern Montana, and we will look to add to this position over time. GeoResources also comes with approximately 200,000 net acres across the Austin Chalk trend in Southeast Texas, which we will evaluate in due course. We expect to produce between 17,000 and 20,000 barrels of oil equivalent (BOE) per day in the fourth quarter of this year and between 32,000 and 38,000 BOE per day in 2013, which is quite a jump from the 4,000 BOE per day we were producing in February.

Will Halcón participate in any joint ventures?

We do not plan to joint venture any of our producing properties in the traditional sense, but we will consider working with other companies through joint development agreements, AMIs (areas of mutual interest) and other strategic alignments where it makes sense to do so. As we did at Petrohawk, we might consider a more traditional joint venture in the midstream as a way to free up capital for our drilling program.

We are in 10 to 11 resource-style plays now, but over time we will filter our asset base down to those that compete best for capital and provide the most economic returns; it's all about tightening up our assets. We kept it simple at Petrohawk. We didn't joint-venture any of our key upstream assets and we sold our noncore assets to maintain a highly focused asset base. We'll do the same thing at Halcón.

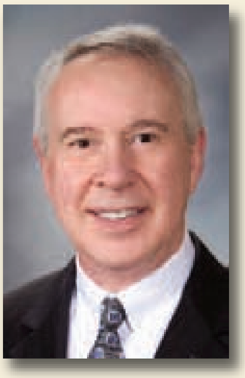
What do you expect will be the greatest challenge for the company?

We're on track for acquiring acreage in our target areas and our focus is now shifting to development. Like many E&P companies, the biggest challenge is executing the drilling program and getting production online. Because of our track record, we have been able to attract a great group of employees that we are adding to every day. They are highly skilled in developing large-scale acreage positions and are moving ahead quickly on the Halcón program.

Any final thoughts or comments?

We are building on the same idea and plan as before, only trying to do it better. Our goal is to rapidly build a strong, liquids-rich E&P company with solid assets and a significant drilling inventory. We'll keep our balance sheet strong and protect our capital program with a low operating cost structure and hedging. Our management team has a proven track record of building companies with quality assets that create significant shareholder value over time. We've done this before, and at Halcón we're going to do it again.

Halcon is ramping up drilling in several liquids-rich plays.



LUFKIN INDUSTRIES

NASDAQ: LUFK | LUFKIN.COM

JOHN F. (JAY) GLICK was elected CEO of Lufkin Industries effective March 2008. He has held the additional title of president since August 2007 and was elected to the company's board in November 2007. Previously, he was vice president and general manager of Lufkin's Oilfield Division and also was general manager of Lufkin's Power Transmission Division from September 1994 until April 2007. He holds a B.S. from the University of Kansas and is a graduate of the Program for Management Development at Harvard Business School.

Describe your strategy, and how it has changed in the past several years.

We are more aggressive in acquiring companies that fit our growth focus. Our size and focus will be bigger, much more international and higher tech. I think we will have more intelligent products in the field. The value delivery from Lufkin relative to our peer group will be significantly higher because of the intelligence and the tighter integration of Lufkin's hardware and software.

Education will be a bigger component of what we do. Our goal is to be the specialist in artificial lift. The Lufkin name has been a respected name when it comes to value, quality and reliability, and as we continue our international growth we must have technically qualified personnel to support our products in all key producing countries.

Lufkin has always been perceived first as a pumping unit company; we are changing this by developing the other artificial lift niches. We are already No. 1 in rod lift and want to remain in this position. I would hope we would move up to No. 1 or No. 2 in the other areas as well, and I would think that our services are already recognized globally as differentiated.

How have high oil prices and low gas affected your plans?

The demand for oil here in the U.S. has increased activity dramatically. This comes at a good time for Lufkin Industries as we carry out our expansion efforts. Our long-term vision for Lufkin has not changed and the fluctuation of our industry business is expected. We have tried to diversify our mix of products to support both the oil and gas businesses; with the drop in natural gas prices our activity and demand for those products and services supporting those areas have been the most affected. We believe this will be short-lived and the demand for these products will return, and we are prepared to weather the downtime.

Do you need to expand capacity (people and equipment) this year? How will you implement these changes?

2012 marks Lufkin Industries' 110th year. We have survived and thrived by staying fresh. One of our first expansions was in Canada, and we will continue to expand globally through our field service groups to support local and global regions.

We expanded into South America in 2002 when we bought Baker Hughes out of a joint venture we had jointly owned in Argentina. Since that time we have made significant investments into manufacturing, engineering, and service and support to give us a Latin American platform in the city of Comodoro Rivadavia. Today the people who work and serve at this facility also focus on operations largely in Latin America.

Our next step is Romania, where we've committed $120 million to build our own manufacturing facility in Ploesti. Our plan will be to move our Eastern Hemisphere headquarters there for Lufkin's Oilfield Group, including engineering and service teams. This operation will become the platform from which we will support the Eastern Hemisphere, including Russia and the FSU, the Middle East, North Africa and Europe. Our Eastern Hemisphere headquarters for power transmission will remain in France.

Where does the most promising opportunity lie for you, U.S. or international?

Being a global company, we see opportunity from a global standpoint. The North American market is a mature market where the well life currently is being rediscovered due to new technologies in drilling and production. International opportunities are bright as well. With the additional capacity that our Romanian facility will bring, Lufkin will be able to take further advantage where as in the past our capacity has been constrained to our North American markets.

Additionally, our product growth will allow us to participate in markets otherwise served in the past by other companies. ESP (electric submersible pumps) wells that have been producing for many years will be converted to rod lift as the cost to maintain ESP wells are very high compared to pumping units. We are excited about the future as we grow our various businesses.

Do you have a backlog and how are you addressing it?

We have several areas of business that focus on different regions and different production needs. This means that at any given time we will have a backlog in at least one area. To address this, we are consistently working with our clients to forecast their equipment and service needs in order to better forecast our internal manufacturing volumes.

We also practice continuous improvements in manufacturing, which have been highlighted by industry analysts for the past several years. These improvements include upgrades in machine tooling, launching technologically advanced facilities globally and acquisitions that increase our focus on research and development. In the last several years Lufkin has made some significant and widely noted investments in our manufacturing processes which have all helped to transform Lufkin into a high-tech artificial solutions provider.

What is your capital budget this year, vs. last year?

Significant investments have been made through recent acquisitions and new facilities strategically located around the U.S. Additionally, we continue to improve manufacturing processes and machinery to strengthen our ability to maintain a constant supply of product quality and reliability. That said, our 2012-2013 capital budget has been earmarked for completing these initiatives and ensuring that we garner the full return on investment for our shareholders.

At the same time, we continue to seek additional opportunities to grow the company whether that is organic growth, through our R&D group, or through acquisition, if the right opportunity presented itself.

Do you foresee any acquisitions in the next 12 to 24 months?

In 2009 the Oilfield Division acquired International Lift Systems (ILS). This acquisition brought Lufkin gas lift, plunger lift technologies and completion products. Pentagon Optimization Services Inc. was acquired in 2011 and further offers Lufkin and its customers an oil and gas optimization company with cost effective and innovative solutions to declining production flow regimes.

In 2010 “Petro Hydraulic Lift Systems” (PHL) was acquired to offer additional rod lifting techniques.

In the area of automation, we have strengthened our product technology by adding Datac, a company serving the oil and gas, power, water, waste water, transportation and marine industries by providing systems integration for supervisory control and data acquisition (SCADA). RealFlex provides real-time server software packages for SCADA and process control applications. One of our more recent acquisitions made in late 2011

Founded in 1902, Lufkin is a vertically integrated supplier. This is its new office in Dickinson, North Dakota.

is Zenith Oilfield Technology Ltd. They are a known international provider of innovative technology and products for monitoring and analyzing down-hole data and related completion products for the oilfield artificial lift market.

Quinn Pumps and Grenco bring to Lufkin manufacturing capabilities for reciprocating pumps and progressing cavity pumps for artificial lift applications. Both companies are recognized as leaders in the service and repair with 20 facilities across Western Canada and 20 facilities situated throughout New Mexico, Texas, Mississippi, California and Alabama.

Lufkin's new manufacturing facility in Romania that is set to open in fourth-quarter 2012.

This lists our primary new acquisitions. We'll be looking at more downhole applications such as a line of packers, and other products that will fill gaps in our current portfolio.

Which projects will be the most significant and why?

With any new acquisition we must effectively integrate and leverage these opportunities. Each company has grown and developed on its own and we have the opportunity to further enhance their continued growth in markets they have not participated in where Lufkin has.

These "bolt-on" acquisitions have been consistent with our long-term goal of integrating quality and complementary assets to enhance our industry leadership position.

What is your greatest challenge?

Maintaining our focus towards quality, safety and technology. As we continue with product and company integration we must do so with technology and safety in the forefront of our process selection. We will build and maintain the quality and reliability expected from Lufkin products that have built our reputation as a leader for many years.

What is the one thing you want investors to know?

That we are investing in our future, by continuing to invest capital through expansion. That support carries forward to our customers by locating our facilities and personnel in regions where operations are most active. Our new service facilities located in Shafter, (just outside of Bakersfield, California), and Midland/Odessa, Texas, serving the Permian Basin, will support our aftermarket business as our installed bases continue to age.

In June of this year we opened our newest location in Dickinson, North Dakota. We anticipate that area to be one of the busiest in the U.S. serving the Bakken and other plays in the region.

We have already spoken of the Romania manufacturing facility that will serve the Eastern Hemisphere with product for many years to come.

We are excited about our future, it's bright, and we want to grow our business to support the developing areas of the globe.

DATAC | QUINN PUMPS | GRENCO ENERGY SERVICES | RealFlex SECURE SCADA SOFTWARE | ZENITH OILFIELD TECHNOLOGY LTD

These recently acquired companies now make up Lufkin's portfolio.


LUFKIN
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LUFKIN

MARATHON OIL CORP.

NYSE: MRO | MARATHONOIL.COM

CLARENCE P. CAZALOT JR. is chairman, president and chief executive officer of Marathon Oil Corp. and a member of the board of directors. He joined Marathon Oil in March 2000. Immediately prior to this, he was president of Texaco's Worldwide Production Operations. He began his career in the oil and gas industry with Texaco in 1972. Marathon Oil Corp. spun off its downstream operations in 2011 and is now a pure-play independent producer with oil and gas operations in the U.S. and nine other countries.

Describe the strategy that drives the company, and how you will implement it this year.

Our strategy includes the following: to maintain a solid base business; to execute on a premium set of liquids-focused growth assets that will help drive our overall estimated 5% to 7% compound annual production growth from 2010 through 2016; and to provide upside to production and growth from our exploration.

As an independent exploration and production company, we're in a unique position in our peer group of having strong, long-life base assets that are expected to generate the cash flow needed to fund our growth assets, which are highly focused on U.S. unconventional resource plays such as the Texas Eagle Ford and North Dakota Bakken, where we have our largest holdings.

Additionally, we continue to invest about $500 million annually in exploration programs that are not factored into our growth projections but provide the potential for additional value creation.

At the end of the day, it comes down to execution, and doing so in a manner that reflects our commitment to safe, responsible operations. Our goal is to deliver top-quartile shareholder returns by capitalizing on our strong, diversified asset base.

How have high oil prices and low gas prices affected your business?

With a portfolio weighted heavily toward oil, we've been less impacted by lower natural gas prices than some competitors. We can't claim to be clairvoyant, but if you look at historical prices, crude oil has nearly always traded at a premium on an energy equivalent basis to natural gas. Additionally, because crude oil is a global commodity–and highly leveraged to growth in emerging markets–we believe it has a more sustainable price than natural gas. That's a key factor behind our focus on liquids-rich plays like the Eagle Ford and Bakken. When you look at our results for the first quarter of 2012, nearly 70% of our production available for sale, including Canadian oil sands, was liquid.

On a forward-looking basis (2010 to 2016), approximately 80% of the production associated with our growth assets is expected to be liquid hydrocarbons.

Will you be expanding into any new basins or plays? Why or why not?

We continue to look for potential entry points in the U.S. as well as additional opportunities around the world in the exploration arena. In the meantime, we've amassed a substantial portfolio of assets in U.S. unconventional plays: more than 1 million acres with approximately 7,000 well locations. Notably, since closing the significant transaction with Hilcorp Energy Corp. and smaller Eagle Ford-related acquisitions in the fourth quarter of 2011, we've entered into agreements to continue to expand our holdings in the core of the play, which we consider to be the premier resource play in North America.

Additionally, we're always assessing existing leases to determine if any are candidates for redevelopment with the application of new technologies. Some areas that previously were not commercial may now make economic sense to develop.

What projects will yield the best return for the company this year?

Developments that are located near our existing base assets and can utilize associated infrastructure–in Wyoming, Norway and Equatorial Guinea, for example–are expected to yield the highest returns because the vast majority of capital investment is behind us. For that reason, the incremental capital invested in those projects can result in a significant increase in value.

But we're also investing for the future and we think our growth assets are well positioned for solid returns. Again, it's our stable portfolio of base assets that's enabling us to invest in longer-term growth assets like the Eagle Ford and Bakken.

What is your project budget and how many wells is that, and how does it compare to 2011?

Our capital, investment and exploration budget for 2012 (excluding acquisition costs) is projected to be approximately $5 billion. That's an increase of 35% from 2011 spending, driven largely by higher spending on liquids-rich U.S. resource plays. On average, we expect capital, investment and exploration spending of approximately $5 billion to $5.5 billion from 2012 through 2016, with approximately two-thirds allocated to our growth assets.

We have a program to drill approximately 250 to 300 net wells in 2012, the vast majority in the U.S. That includes 155 to 170 net wells in the Eagle Ford, where we have 18 rigs operating, and 55 to 70 net wells in the Bakken, where we have eight rigs drilling. In 2011, we completed 109 net wells worldwide.

Are you constrained by midstream capacity at all?

No. One of the many positive factors about the Eagle Ford is its proximity to pipelines and refining capacity in the area. We expect to have excess take-away capacity versus production capacity for many years to come in that play.

In the Bakken, logistical constraints are causing crude oil discounts in Cushing, Canadian, Bakken and West Texas crudes. But our situation is different than many other producers in that region. We sell more than 50% of our production directly to the local refinery in Mandan, N.D. For the remainder, we use pipeline, rail or truck. Additionally, we're encouraged by the number of projects being developed to expand Bakken take-away capacity, including an increase in rail-terminal and unit-train capacity, and increasing pipeline capacity. As logistical constraints continue to be eliminated, price discounts will be eliminated too.

Do you foresee any acquisitions this year?

Reinvesting in our business to add value remains our top priority, and we manage our cash flows to make that possible. We're in a resource business, and a measure of success is replacing more of the resource than you produce in any given year. To that end, we're continuously looking for targeted acquisitions in core areas, such as bolt-on acreage in U.S. resource plays where we already operate.

How much are you hedged?

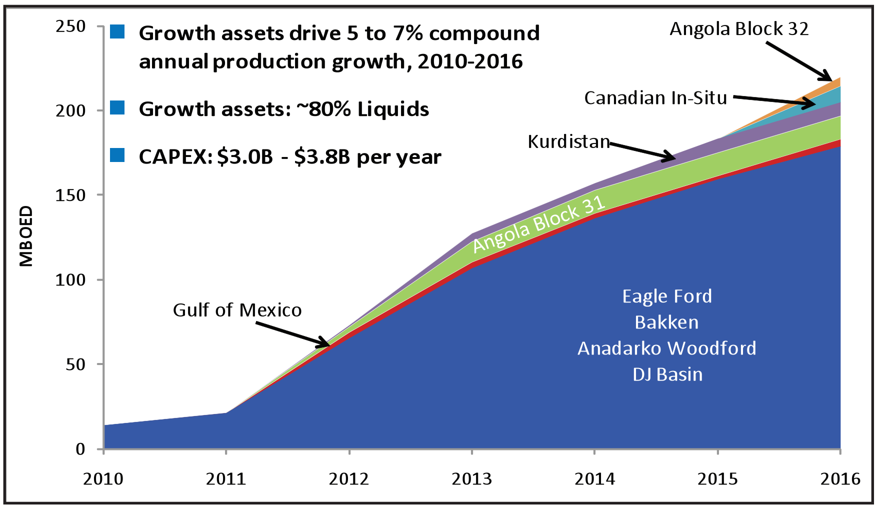
We have no hedges on equity production.

What is the greatest challenge you face this year?

The uncertain policy environment we currently face poses significant challenges to our business. We are poised to enter a new era of oil and gas supply. But to be successful for all stakeholders, we'll need the right legislative, regulatory and tax policies that are rational, fact-based approaches; ones that place a premium on cooperation between the public and private sectors. In addition, they will need to be underpinned by a shared vision of job creation, increased revenues for vital government services and delivering America's energy security for current and future generations.

What is the one thing you want investors to know?

That we are keenly focused on our goal of growing production 5% to 7% on a compound annual basis–and doing so safely and profitably. Our measure of success is simple: We must execute our strategy and put numbers on the board, and we intend to do it.



Marathon Oil's assets provide significant low-risk production growth.

PDC ENERGY CORP.

NASDAQ: PETD | PDCE.COM

JAMES TRIMBLE joined PDC Energy Corp. as a director in 2009 and became president and chief executive officer in June 2011. He graduated from Mississippi State as a petroleum engineer and has worked most basins in the U.S. Before joining PDC, he was president and CEO of Grand Gulf Energy Ltd. He has more than 30 years experience. PDC Energy Corp. has focused its operations in the Niobrara, Marcellus and Utica shale plays.

Describe the strategy that drives the company, and how you will implement it this year.

At PDC, our first priority is to organically grow production and reserves. We are particularly focused on oil and liquids-rich properties to better balance our portfolio mix of oil/NGLs and gas, and expanding our expertise in horizontal drilling. The company considers bolt-on and leasehold acquisitions which complement our current asset base in our core operating areas and are aligned with our operational strengths. We employ this strategy while focused on maintaining a conservative balance sheet, and expanding liquidity, as well as maintaining a balanced hedging program to protect our downside risk and lock in the returns on our capital program.

How have high oil prices and low gas prices affected your business?

We are focused presently in the liquids-rich Wattenberg Field in Colorado and the emerging liquids-rich Utica shale in Ohio. Based on low gas prices, PDC has elected to discontinue drilling in dry-gas basins, including the Marcellus shale and Piceance Basin, where our leasehold is primarily HBP (held by production), until gas prices improve to sustain strong economic returns.

Will you be expanding into any new basins or plays? Why or why not?

PDC has been building a meaningful position in the Utica shale play in southeast Ohio. The company is focused in the wet-gas and oil windows of the play and believes it has the potential to be one of the best new liquids-rich exploration plays in the country. We have acquired approximately 45,000 net acres and are currently pursuing a joint-venture partner to develop the play and expand our position to an estimated 80,000 to 100,000 net acres to the JV.

Which projects will yield the best return for the company this year?

The Wattenberg Field, where we are drilling horizontal Niobrara and Codell wells, is clearly our highest-return area. Costs run approximately $4.2 million per well, and we expect to see cost reductions here as we develop our multi-well pads, with per well EURs (estimated ultimate recoveries) ranging from 300 to 500 Bcfe. Economic returns are strong and continue to exceed our threshold at lower oil prices.

What is your projected budget and how many wells is that? How does it compare to 2011?

PDC budgeted $284 million for 2012, excluding acquisitions. Approximately $178 million is dedicated to development in the Wattenberg Field and approximately $93 million is earmarked for the Utica play, including $60 million for leasehold and $33 million for drilling, completions and gathering geological data. We are drilling fewer wells in 2012, as we are focused on larger, higher-return horizontal wells and very few vertical wells.

Are you constrained by midstream capacity at all?

The company works closely with midstream providers to ensure they are aware of our drilling plans and can coordinate capacity requirements to accommodate our production activity. Drilling activity in the Wattenberg Field by PDC and other operators is increasing, and midstream operators have committed significant capital to maximize existing operations and build new facilities to accommodate growing production volumes.

In the Utica shale, there is an abundance of low-pressure gas gathering lines in eastern Ohio. However, as an emerging liquids play, Utica production will require new processing facilities to keep pace with increased volumes. Midstream companies are already active in the area and soliciting commitments from PDC and other producers to support the construction of new facilities.

PDC Energy is ramping up in the Niobrara play.

Do you foresee any acquisitions this year?

We recently completed the acquisition of 35,000 net acres in the core of the Wattenberg Field for approximately $327 million, further solidifying our position as the third-largest leaseholder and producer in the core horizontal Niobrara play. This acquisition included 29.2 million BOE, net, of proved reserves, 58% of which is oil and NGLs. This includes approximately 700 vertical wells producing approximately 2,800 BOE per day as of May 2012. We have approximately 546 identified horizontal Niobrara locations to develop pro forma for the acquisition, with the potential for additional horizontal Niobrara downspacing opportunities and horizontal Codell wells.

How much are you hedged?

A significant percentage of our production is hedged for 2012 and 2013 for both natural gas and oil. We have hedged approximately 70% of our 2012 projected production volumes for both natural gas and oil. Additionally, a significant portion of our 2013 projected production volumes are hedged for both natural gas and oil. The natural gas and oil production we have hedged is at robust prices which exceed the current pricing environment.

What is the greatest challenge you face this year?

As we previously discussed, the current gas price environment has reduced returns in our dry-gas plays in the Marcellus shale and Piceance Basin, where the company has suspended drilling in both plays pending a recovery in natural gas prices. We have, however, protected a significant portion of existing natural gas production in both basins with hedges that have locked in prices significantly above the current price environment. Additionally, we are focusing our capital budget on liquids-rich plays in the Wattenberg Field and Utica shale.

What is the one thing you want investors to know?

We operate over 95% of our wells and our acreage is over 90% HBP. This provides us tremendous operational flexibility to allocate capital between our projects in response to fluctuating commodity prices, in order to optimize cash flow and project returns.

Any final comments or thoughts?

PDC is a growing E&P company. We are well-positioned in two liquids-rich core areas in Colorado and the Appalachian Basin. Additionally, we have significant dry-gas opportunities in the Marcellus shale and the Piceance Basin. We have been increasing our organic liquids-rich production in our core operating areas through bolt-on acquisitions and organic development. We are committed to increasing our percent of liquids-rich reserves and production to better balance our portfolio of oil/NGLs and natural gas, while maintaining a strong balance sheet and ample liquidity.

QEP RESOURCES INC.

NYSE: QEP | QEPRES.COM

CHARLES STANLEY, the chairman, president and CEO of QEP Resources Inc., has more than 27 years of experience in the upstream and midstream oil and gas industry, including 10 years with QEP and its predecessor company. He serves on the boards of various industry organizations, including America's Natural Gas Alliance and the American Exploration and Production Council. Denver-based QEP Resources specializes in the exploration, production, gathering, processing and marketing of natural gas and crude oil in the continental U.S.

Describe the strategy that drives the company, and how you will implement it this year.

At QEP, we employ a long-term, returns-focused investment strategy. We manage our business by allocating capital toward projects that maximize our return on investment, while maintaining a sustainable inventory of high-potential resource plays. We seek to establish contiguous acreage positions in the core basins where we operate; this investment approach, combined with our commitment to being a low-cost driller and producer, has contributed to consistent growth in years past. In 2011, we delivered a 14% return on capital employed, which we define as adjusted EBITDA divided by gross PP&E. Finally, as those who follow us can attest, we seek to maintain a conservative capital structure which, over time, has afforded us the financial flexibility to pursue new growth opportunities.

We have active drilling programs in several regions of the continental U.S. Our exploration and production subsidiary, QEP Energy, has a large inventory of identified development drilling locations, primarily on the Pinedale Anticline in western Wyoming; the Midcontinent area, including properties in western Oklahoma and the Texas Panhandle; the Uinta Basin Red Wash Mesaverde play in eastern Utah; the Bakken/Three Forks area in western North Dakota; the Haynesville/Cotton Valley area in northwestern Louisiana; and other properties across the U.S.

QEP Field Services is our midstream subsidiary that gathers and processes both our own gas and third-party production. We have enjoyed significant growth in this business in recent years and continue to invest in new projects. By investing in the same basins within both our midstream and upstream businesses, we are able to achieve improved margin capture from our liquids production and generate greater overall operational efficiency. Our midstream business is generally located in areas where we have major production centers in the Rockies and northwest Louisiana.

How have high oil prices and low gas prices affected your business?

We believe our low-cost operating model is a competitive advantage that has contributed to our strong financial performance, even in a low-commodity-price environment. And yet, it isn't simply an issue of being a low-cost operator. As I indicated earlier, we are a returns-focused organization committed to value creation. Our access to a geographically diverse portfolio of high-return upstream and midstream projects, combined with our strong financial position, affords us a wide range of potential capital investment opportunities, even during a period of low natural gas prices.

Given the decline in natural gas prices, our more recent capital investments have shifted toward higher-return crude oil and liquids-rich plays such as those in the Bakken, Pinedale Anticline, Uinta Red Wash, Powder River Basin, and other areas in the Midcontinent region. As a result, during the first quarter of 2012, we more than doubled our total production of crude oil and natural gas liquids (NGLs), when compared to the first quarter of 2011, to 2.4 million barrels, or roughly 20% of total production in the period. In addition, we increased our delivery of liquids volumes in our midstream segment, as new processing facilities came online.

Our board and management team are equally committed to maintaining a conservative capital structure, an approach that has served us well in a variety of market climates and one that continues to help QEP stand out within our industry. On an annual basis, we target capital spending that is roughly in line with our annual adjusted EBITDA projections. Despite this conservative approach toward investing our capital, we anticipate growing production by about 12% for full-year 2012.

Which projects will yield the best return for the company this year?

At our E&P subsidiary, our focus will continue to center on higher-return crude oil and liquids-rich gas plays. This year, we are allocating capital to crude oil activity in the Williston Basin in North Dakota, the Powder River Basin in Wyoming and multiple plays in the Texas Panhandle and western Oklahoma. In addition, we are allocating capital to our extensive acreage and liquids-rich gas reserves in the Red Wash Lower Mesaverde play of the Uinta Basin in eastern Utah, the Pinedale Anticline in Wyoming and the Woodford/Cana play in western Oklahoma.

As we indicated in our first-quarter release in April, we have allocated nearly 90% of our full-year 2012 E&P capital budget toward crude oil and liquids-rich resource plays. Most of the remainder of our 2012 E&P capital budget is allocated toward dry-gas development in the first half of the year, including an 80-acre test field in the Haynesville.

At our midstream subsidiary, our focus remains on owning and operating infrastructure to capture value downstream of the wellhead by extracting liquids from our gas streams, while gathering our owned production to drive down costs.

Given that approximately 70% of our midstream revenue is fee-based, we generally see consistent cash flow from this business. Notably, this business still generated 20% return on capital employed in 2011.

What is your projected budget for 2012 and how does it compare to 2011?

In our first-quarter earnings release issued in April, we provided capital spending guidance in the range of \$1.35 billion to \$1.50 billion for full-year 2012, roughly in line with our anticipated 2012 adjusted EBITDA, versus capital investment of \$1.43 billion in the prior year.

How much are you hedged?

As of first-quarter 2012, our oil and gas hedges represented approximately 63% of forecasted production for full-year 2012 and 30% of forecasted production for full-year 2013 at our QEP Energy subsidiary. To help offset potential weakness in natural gas prices during the shoulder-season, we have approximately 75% of our 2012 natural gas production hedged. Gas was hedged at \$4.76/Mcf and \$5.17/Mcf for 2012 and 2013, respectively. We also have some oil and NGL hedges in place for 2012 and 2013.

What is the greatest challenge you face this year?

Clearly, low natural gas prices and elevated well costs are industry-wide issues. Beyond this, one of the most significant challenges facing our industry involves those public policies that seek to limit or restrict our ability to produce oil and gas on domestic lands.

Delays in the permitting process and the introduction of new regulations designed to hinder exploration and production are significant headwinds to our industry.

Certainly, healthy debate surrounding issues of public land use, hydraulic fracturing, water use, air emissions, taxes, among other areas of discussion, can be useful for setting informed public policies. However, in many cases, misinformation and questionable science clouds the reality of what our industry is and how we contribute to society.

Are you planning to add any new capacity or expand existing infrastructure?

In Field Services, we continue to expand our processing capacity. During the third quarter of 2011, we commissioned the 420-million-cubic-foot (MMcf) per day Blacks Fork II cryogenic processing plant, an expansion of our Blacks Fork processing complex in southwestern Wyoming.

We have two additional midstream projects expected to come online in 2013. Earlier this year, we broke ground on our next cryogenic gas processing plant, the 150 MMcf per day Iron Horse II plant, which is located in the Uinta Basin in eastern Utah. With operations expected to begin in first-quarter 2013, approximately half of the Iron Horse II plant capacity is contracted by a third-party producer under a fee-based processing arrangement, while the other half will be available to process QEP Energy's growing liquids-rich gas volumes from the Uinta Basin Red Wash Mesaverde play. We also have a 10,000 barrel per day fractionator under construction at Blacks Fork (for completion in second-quarter 2013) which will enable us to sell natural gas liquid purity products into the local market. ■

SARATOGA RESOURCES, INC.

NYSEMKT: SARA | SARATOGARESOURCES.COM

THOMAS COOKE (left), CEO and chairman of Saratoga Resources, Inc., has 30 years of executive experience in the independent oil and gas industry. He chaired the Tipro task force on North American Energy Issues. Additionally, he is on the board of the Louisiana Oil & Gas Association (LOGA). **ANDY CLIFFORD**, right, president of Saratoga, has been a geophysicist for Exxon and BHP, where he served as vice president of strategic planning. He has visited or worked in over 100 countries during his career. Saratoga's holdings cover 32,185 gross/net acres in the transitional coastline and protected in-bay environment of parish and state leases of Louisiana, in waters of less than 20 feet.

Describe the strategy that drives the company, and how you will implement it this year.

Saratoga's strategy is to grow production through low risk development of our large inventory of PUDs and PDNPs. Saratoga's capital expenditures will continue to be funded from cash flow. The company aims to continue to increase production through recompletions and by converting our PUD reserves via new drills. We expect that increased production and higher asset values will flow through to a higher share price which would facilitate future equity offerings, which could be used to (a) accelerate development, (b) reduce existing debt, and (c) fund acquisitions.

How have high oil prices and low gas prices affected your business?

Saratoga's production is weighted 60%-65% towards oil. We benefit from premium Louisiana Light Sweet/Heavy Louisiana Sweet crude pricing because of the location of our producing assets in southeast Louisiana and due to the high quality of our crude oil. Our gas is also of high quality and Saratoga benefits from higher than average natural gas pricing with high-Btu gas resulting in a premium over the Nymex Henry Hub. However, the disparity between oil and gas prices has caused us, like many others, to prioritize oil opportunities over gas opportunities and we are fortunate to have such a deep inventory that we are able to be selective of which opportunities to spend our capital on.

Will you be expanding into any new basins or plays? Why or why not?

We will look at opportunities within other basins and if we see an attractive opportunity we will likely enter another basin through acquisition rather than by building a lease position. Saratoga prefers to operate whenever possible and an important driver for us would be whether or not we could gather the expertise and knowhow necessary for a successful entry into another basin. We like where we are in the transition zone of Southern Louisiana so any opportunities would have to compete for capital versus our existing inventory of development opportunities. We are also sitting on top of one of the nation's most exciting plays in the ultra-deep shelf, so we really don't have to go anywhere to participate in that.

Which projects will yield the best return for the company this year?

Most of our capital projects have payouts of less than 12 months, and many of them less than six months. We have new development wells with longer payouts but multiple stacked reservoirs and recompletion opportunities with shorter payouts, some of which had payouts of less than 30 days! Our decision-making is based on balancing production from a specific opportunity versus reserve conversion but we also generally look for a discounted return on investment greater than 2.

What is your projected budget and how many wells is that, and how does it compare to 2011?

Saratoga's 2012 capital budget is approximately $60 million, of which $48 million is to be spent on drilling five wells. Typically our development wells cost $4 to $6 million per well completed. Our 2012 budget is a 100% increase over 2011, during which we drilled three wells.

Are you constrained by midstream capacity at all?

We are not constrained by midstream capacity and, because of the location of our assets in the heart of the largest concentration of midstream and downstream infrastructure in the Gulf Coast, we have multiple options for marketing our crude and natural gas.

Do you foresee any acquisitions this year?

We are actively looking at opportunistic acquisitions, although we are not driven to make any since we have such a deep inventory of investment opportunities in our existing portfolio. However, Saratoga believes that one or more accretive acquisitions make sense from a growth perspective.

How much are you hedged?

We are currently unhedged. We are looking to layer in some hedges (60% to 80% of our current PDP) on the oil side, particularly to protect us on the downside but allow us to participate on the upside. We are not inclined to hedge natural gas at present.

What is the greatest challenge you face this year?

Our biggest challenge is getting our share price closer to our net asset value per share, which we estimate to be a minimum of $12/share on proved reserves alone. This gives no value for our probable, possible and potential reserves. Part of the challenge is getting our story out there to potential investors. We only listed on NYSE MKT and garnered research from analysts in late 2011 but have since attracted heavy hitters like GSO/Blackstone, Wellington, Pimco and Wamco to our story.

What is the one thing you want investors to know?

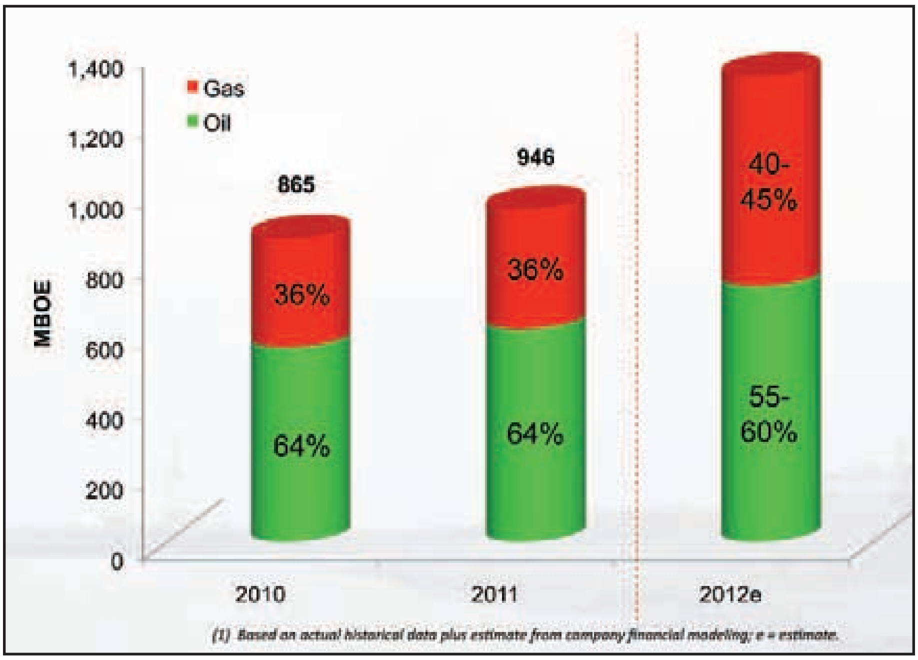
Saratoga is a fairly unique opportunity with assets in the transition zone of Louisiana, weighted towards oil, which trades at a good premium to WTI, with multiple stacked pays and long-lived wells and abundant drilling opportunities, not to mention the multiple trillion cubic feet (Tcf) of potential that we have mapped underlying our assets.

All of our assets are in state waters and parish lands and so we do not have any permit delays due to BOEM and we have an excellent relationship with the state of Louisiana.

We see little or no downside to investing in Saratoga but huge upside, not just in the ultra-deep Davy Jones-type potential we have identified, but in the conventional oil and gas development in normally-pressured reservoirs, which we can access by either drilling or re-completions and, most importantly, we have shallower plugback opportunities which reduce the risk on deeper development wells.

Any final comments or thoughts?

Saratoga prides itself on applying leading-edge technology and by leveraging off strategic relationships with key consultants and institutions such as University of Texas and University of Southern California. Through such technology, we have identified 50 billion cubic feet of shallow gas above 5,000 feet that we can sit on until we need it in the near future, because we have held-by-production (HBP) acreage. Similarly, we have identified over 6.5 Tcf and 600 million barrels of oil of deep and ultra-deep gas and liquids that is also covered by HBP leases and under our existing infrastructure, so we can wait for the play to develop and come to us. Despite their location, history has demonstrated that Saratoga's assets are hurricane-resistant and our annual insurance premiums have been declining year-on-year.



Saratoga expects 45%-55% growth in production in 2012, with an exit rate greater than 5,000 net BOE per day.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SHALE 101

UNCONVENTIONAL RESOURCE PLAYS HAVE CHANGED THE GAME FOR PRODUCERS, PIPELINES, END-USERS AND REGULATORY AUTHORITIES. U.S. ENERGY POLICY AND LNG EXPORTS COULD BE NEXT.

WHAT ARE SHALES?

Shales are fine-grained sedimentary rocks that can be rich sources of petroleum and natural gas. Over the past 10 years or so, the combination of horizontal drilling and advanced hydraulic fracturing has allowed producers to access large volumes of shale gas and oil that were previously not economic to produce.

Shale gas and oil plays are continuous accumulations usually covering immense areas, producing from shale rock. They are unique in that they are both source rock for conventional oil and gas production, and a producing reservoir as well. There is little to no risk in locating the hydrocarbons in these plays, especially if many traditionally drilled vertical wells have been completed in the area, as this provides a producer with well logs and other production history and geological information.

Shale gas and oil are found within shale reservoirs, and the geologic history of an area will determine if a particular shale will produce dry gas, Btu-rich (wet) gas and condensate, or crude oil. Some shale plays, such as the Haynesville and Fayetteville, produce only dry gas. Others, such as the Marcellus and Woodford, produce both dry gas and rich gas and condensate. The Eagle Ford and Barnett plays can produce dry gas, rich gas and condensate and crude oil.

SHALE-GAS PRODUCTION

The production of natural gas from shales has rejuvenated the natural gas industry in the United States. According to the U.S. Energy Information Administration's Annual Energy Outlook 2012 (released in July 2012), U.S. natural gas produc-

Operators are using new techniques in most of these shale plays.

FOR MORE INFORMATION

UGCenter.com	Hart Energy's Unconventional Gas Center
NASQ.hartenergy.com	Hart Energy's North American Shale Quarterly
Anga.org	America's Natural Gas Alliance
EIA.gov	U.S. Energy Information Administration
Energyindepth.org	Educational website for the IPAA

tion is projected to increase from 21.6 trillion cubic feet annually in 2010, to 27.9 trillion cubic feet in 2035, a 29% increase.

Almost all of this increase is thanks to anticipated growth in shale-gas output, which is estimated to increase from 5 trillion cubic feet annually in 2010 to 13.6 trillion cubic feet in 2035. Shale gas will make up an increasing percentage of all U.S. gas produced.

SHALE-OIL PRODUCTION

The most prolific shale-oil production is now coming from the Bakken play in North Dakota and Montana. The surge has vaulted North Dakota past Alaska, to become the second-highest oil producing state in U.S. after Texas. North Dakota was producing 574,000 barrels per day in May; experts think it will reach 600,000 a day by year-end 2012.

RISK FACTORS

The risks of shale drilling stem more from being able to perform effective and economic well completions, such that the fracture stimulations (fracs) do enter the formation effectively to increase production without harming the formation.

In addition, there are risks above ground, in terms of how to handle produced water that flows to the surface from the completed well, and air emissions from production facilities. Also, operators must mitigate the effects on local roads, other infrastructure and communities in which drilling and production occurs.

Today's advances in horizontal drilling and fracture stimulation to boost flow are delivering impressive rates from most shale wells. It is not uncommon for shale wells to report an IP (initial potential) of more than 1,000 barrels of oil

per day, or up to 20 million cubic feet of gas per day, plus associated natural gas liquids or condensate.

After the Barnett shale play in North Texas took off in the mid-2000s, operators began to lease in all other major basins in North America, looking for similar plays in which to apply new horizontal frac methods. They have since developed world-class plays such as the Bakken oil shale in North Dakota, the Eagle Ford oil and gas shale in South Texas, the Haynesville gas shale in northern Louisiana and the Marcellus gas shale in Pennsylvania. Other shale plays are in various stages of development.

The extraction techniques of horizontal fracturing that have proven themselves in shale plays are now being applied to traditional basins and plays to recover more oil and gas. In fact, the oil plays are usually tight sands or carbonates, not strictly shales. The Bakken formation is a great example, technically being a siltstone sandwiched between two shale zones.

INVESTOR ALERT

Investors should keep in mind one important caveat: not all shale plays are alike, not all areas within a single play are alike, and not all producing companies within a play will have the same economic results.

Factors that affect economic returns include current commodity prices, the price paid for leasing the acreage in question, rig rates and completion (frac) costs at the time a well is drilled, and how well the frac job has been tailored to the specific formation (length of lateral or horizontal leg, number of frac stages and spacing of these stages, amount and type of proppant used, etc.).

"The uniqueness of each shale gas or oil play cannot be over-emphasized. There are also significant lateral and vertical variations within shale formations that are best understood by examining the geology of the play, in particular the depositional environment, and integrating this information with the rock and log data," according to Hart's Global Shale Gas Study.

"Most shale plays can be divided into areas with varying potential. The core area contains the best combination of the properties listed above. Beyond the core area will be an area with less favorable properties, called Tier 1 in the Barnett shale, but still viable once the core area infrastructure is in place. Beyond the Tier 1 area will be areas with even less favorable proper¬ties that may or may not be economically viable, depending on gas or oil price and other factors," the Hart study says.

"Shale gas wells produce at high initial flow rates and decline rapidly to a low rate that can continue for many years, following a power law decline function. The power law function was found to fit the data extremely well with relatively minor variations in the parameters of the equation with the exception of the "rate intercept" which is related to the well's initial production rate (IP). This is true for wells in the Barnett shale with several years of production history, wells in the Haynesville shale that are deep and produce extremely high initial rates, and wells in the Eagle Ford shale that produce significant liquids (condensate). It is also true for vertical wells and wells that have been refractured," the study says.

SHALE-RELATED JOBS

According to a 2012 study by IHS Global Insight, between 2010 and 2015, the top 10 producing states (as ranked by unconventional gas-related employment)--Texas, Louisiana, Colorado, Pennsylvania, Arkansas, Wyoming, Ohio, Utah, Oklahoma and Michigan--collectively will experience a compound annual job growth rate of nearly 8%. Pennsylvania and Colorado will lead with expected compound annual growth rates of 14% and 10%, respectively.

Nearly 1.5 million jobs in the U.S. will be generated by the shale natural gas drilling boom by 2015, and 2.4 million by 2035, according to the report. ■

–Sources: Hart's North American Shale Quarterly, Hart's Global Shale Gas Study, Hart's Global Oil Shale Study, Oil and Gas Investor, UGCenter.com, eia.gov, anga.org.

INTROSPECTION AND PROJECTION ON U.S. ENERGY INDEPENDENCE

ENERGY INDUSTRY EXPERTS PONDER THE POSSIBILITIES AND REQUIREMENTS FOR ENERGY INDEPENDENCE.

By Greg Haas*, Manager, Research, Hart Energy*

As investments pay off in oilfield technology and unconventional resources, many experts are pondering the once-unthinkable prospect of U.S. energy independence. Newfound oil and gas production has caused elation in the industry and on Wall Street, but has also caused consternation among environmentalists and others. Domestic developments interact with international supply-side events including threats against Middle Eastern waterborne tanker lanes and the aftermath of a Canadian pipeline permit denial.

The industry is not only making optimistic supply-side projections, but is also gaining introspective insight into how to steward its social license to operate responsibly. Without a national energy policy, can the U.S. energy industry lead the nation through present challenges to energy independence?

RAISING THE SUBJECT

Adam Sieminski was appointed administrator of the U.S. Energy Information Administration (EIA) in January, but served previously as chief energy economist for Deutsche Bank's Global Markets Commodities Research team.

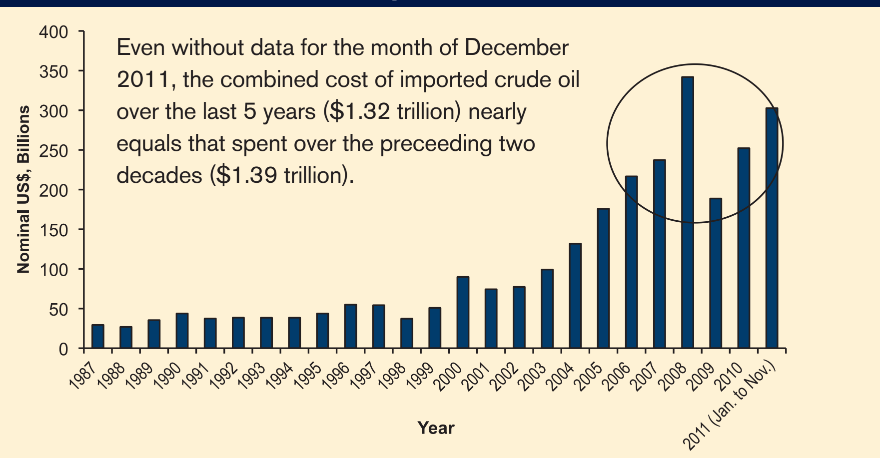
In an address in December 2011 at the Deloitte Oil and Gas Conference, he spoke of the scenario of supply and demand shifts leading to potential North American non-renewable energy independency.

On the coal and gas side, Sieminski said that the United States is already coal-independent "because we export coal." He added that pending liquefied natural gas (LNG) exports could net out pipeline imports from Canada, enabling the U.S. to be "pretty close [to] gas-independence."

However, with North America consuming 19 million barrels a day while producing 8 million a day, future substitution "from crude oil to things like biofuels and electricity" augmented by energy efficiency technologies could lower consumption to 15 million barrels a day, according to Sieminski.

Incremental Canadian oil imports and U.S. production gains in the unconventional "Bakken and Bakken clones," as Sieminski called them, could lower U.S. waterborne tanker imports to 3- to 4 million barrels a day, versus 10 million currently. U.S. net oil import reliance could thereby drop to 30% from 46% in 2010 and an all-time peak of 65% in 2005, resulting in "a fantastic, tremendous opportunity to lowering the trade deficit, creating jobs and boosting the economy. I think this is where we are headed," Sieminski said.

Annual Cost of U.S. Crude Oil Imports



Source: U.S. Census Bureau, Hart Energy Research

OIL AND GAS INDEPENDENCE COMPARED

John Staub, the EIA's exploration and production analysis team leader, told Hart Energy, "You could say the U.S. already has independence from other natural gas market price fluctuations," because U.S. gas markets and prices are insulated from higher global natural gas prices.

Staub views the costly international oil market differently because oil and refined products are easily transported globally in waterborne tankers. If the U.S. produced the entire refinery crude diet, product prices would still be linked internationally. Staub concluded that U.S. independence from global oil and petroleum product prices "likely couldn't be achieved."

COSTS OF U.S. OIL IMPORTS

According to U.S. Census Bureau nominal cost data for crude imports, U.S. oil imports in 2010 have nearly tripled in price since 2000 and cost nearly six times more than the 1990 cost.

By 2011, crude import costs for January through November quadrupled over full-year 2001 costs and exceeded eight times the amount paid throughout 1991. Even without data for December 2011, the available Census data, plotted in the figure here, show that the combined cost to the United States of importing crude oil over the past five years nearly equals that of the preceding two decades.

TODAY'S ENERGY VIES WITH 'NO OIL' CROWD

U.S. refiners rely-on costly waterborne tanker imports and lower cost overland pipeline imports from Canada.

The price to import Mexican Maya crude imported by tanker to Gulf Coast refineries was 70% higher than Canadian crude, at $104.64 per barrel. However, Canadian crude imports need more pipeline capacity to the U.S.

Back in 2008, TransCanada Corp. first sought a U.S. permit for its proposed Keystone XL pipeline expansion, rated at 830,000 barrels per day. In January 2012, U.S. President Barack Obama's administration denied that permit.

On that same day, the North American Energy Resources Summit was coincidentally held at Rice University's Baker Institute of Public Policy. The news about the pipeline permit denial cast a pall over triumphal projections of greater U.S. energy security enabled by technology applied in North American oil sands, shale and tight resources.

The optimism was tempered by the Keystone XL news and by speakers, calling for greater realism amid environmental opposition to "fracking" and energy development.

"It's up to the industry whether the development of more oil and gas resources will remain everywhere a battle or whether this new-found oil and gas can be seen to benefit all Americans," said Peter Lehner, executive director of the Natural Resources Defense Council. "Until the industry has an uncompromising reputation for doing it right…they will have a fight on their hands every time."

John Deutch, institute professor at the Massachusetts Institute of Technology and former director of the U.S. Central Intelligence Agency, noted "enormous but as yet not fully appreciated" potential benefits of resurgent U.S. production. Deutch estimated liquids production growth could reduce U.S. dependency on overseas imports to 29%, within "striking range of the 20% level," recognized as practical energy independence. America need not eliminate all imports because consumption and exports can be throttled or redirected in supply emergencies with little disruption.

A favorable outcome is not assured, Deutch cautioned, due to environmental challenges and the unfulfilled need for government and industry to adjust policies and practices "adequate to deal with this entirely new opportunity."

James Mulva, at the time chairman and CEO of ConocoPhillips, called the vast and rapid U.S. supply resurgence "an industrial revolution. […] As a result, our entire understanding of North American energy potential is changing."

He estimated that domestic natural gas supplies could last for the lifetimes of more than two future generations and pointed to outside estimates that the U.S. and Canadian sources combined could meet a majority of regional demand to "greatly enhance North American energy security."

And on the denial of the Keystone XL pipeline, Mulva added, "if America turns away, others will step forward for this oil" to the detriment of energy security.

Amy Myers Jaffe, the Baker Institute's Energy Forum director, pulled an introspective lesson from the day's events, saying project planning should consider "social and environmental impact" beyond just "physical engineering and the most commercial route. […] We live in a different world today."

She called for regulatory cooperation between industry and government, to tap "tremendous" potential U.S. resources, including those with environmental challenges to overcome.

If the Strait of Hormuz is blocked or another regional upset arises, "the idea that the U.S. does not need Canadian oil is not going to be a popular decision retrospectively," Jaffe said. She called for a "one-year policy, a five-year policy and a 30-year policy, […] not just a 30-year policy."

Jaffe simultaneously warned against abandoning costly non-commercial clean energy technologies and blocking today's fossil fuels as a result of the "no-oil movement."

HOW MUCH CONVENTIONAL ENERGY DOES THE U.S. HAVE?

Ranked on an energy equivalent basis, the U.S. mix of net consumption of conventional energy (excluding nuclear and renewable energy) was comprised of natural gas (42.3%), coal (37.7%) and crude oil (19.9%). U.S. reserves and production of gas and coal could be sufficient for decades, but oil is the standout.

Gas: The U.S. Energy Information Administration's (EIA) 2012 Annual Energy Outlook (AEO) pegs estimated technically recoverable natural gas resources at 2,214 trillion cubic feet (Tcf). That equates to an 86-year supply at the EIA's data for 2010 consumption rate of 25.14 quadrillion British thermal units (24.6 Tcf) per year.

Coal: The BP Statistical Review of World Energy lists U.S. proved coal reserves at year-end 2010 at 237,295 million tonnes (261,570.2 million short tons). At the EIA's 2012 AEO projected consumption rate of 1.026 billion tons per year, U.S. coal reserves equate to a 254-year supply.

Oil: The latest EIA data for total U.S. crude oil reserves show 20.7 billion barrels at year-end 2009, while the next year's gross inputs to refinery crude distillation units came to 15.177 million bbl per day, or 5.54 billion bbl. Even if it were possible (which it is not at present) to domestically produce 100% of the U.S. refinery crude diet, total U.S. proven crude reserves would only equate to a 3.7-year supply. Even at the EIA's 2009 estimated crude production rate of 1.75 billion bbl, the year-end 2009 proven crude reserves equate to less than 12 years of supply.

A FULLER MIX AND A PLAN

At the Hart Energy Breakfast Club seminar held in Houston on February 2, Roland Moreau, manager of ExxonMobil Upstream Research, shared projections from ExxonMobil's newly published "Outlook for Energy: A View to 2040." The Outlook estimates 30% of future natural gas supplies will come from unconventional shale resources that "start loosening U.S. energy reliance" on imported foreign LNG.

Moreau also shared expectations of a 100-year global oil supply although "prices escalate with higher-cost incremental supplies." Plus, renewable energy could be 4% of the 2040 mix if technology developments "catch up."

He also pointed out a sizable role for energy efficiency technology and investment, especially in transportation. "It's really a nice story that a lot of folks don't understand," Moreau said.

Also addressing U.S. energy independence was John Hofmeister, former Shell Oil Co. U.S. president, and now, founding CEO of Citizens for Affordable Energy and author of "Why We Hate the Oil Companies: Straight Talk from an Energy Insider." He offered that increasing U.S. energy supply and energy efficiency "will never happen without a plan." Hofmeister said crude imports are lower than 2008 peaks (see figure) because of reduced demand, not increased production, thereby enabling "the U.S. to buy less from abroad."

Hofmeister noted that eight U.S. presidents, starting with Richard Nixon, have not crafted an energy plan with any legislation. Hofmeister pointed to the energy plan detailed within his book, which stretches out 50 years from the present day. "The only way to achieve U.S. energy independence is to craft a plan accounting for the near-term, the mid-term and the long-term." ■

–Greg Haas, Research, Hart Energy, can be reached at ghaas@hartenergy.com or 713-260-5201

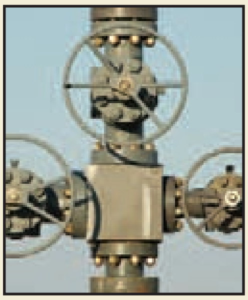
THE MIDSTREAM VALUE CHAIN

The term "midstream" refers to operations that treat gas at the wellhead to remove water, carbon dioxide, hydrogen sulfide and other contaminants, then gather it from production fields and transport it to processing facilities for further separation into liquid products and gas. These products are sold to industrial complexes and end-use consumers. Here are the midstream components.

Wellhead

Once a well is completed, a wellhead comprised of a casinghead, tubing head and a Christmas tree is installed. The casinghead supports the casing string, seals the well and prevents fluids from moving within the wellhead and escaping into the air. The tubing head supports the tubing string, controls the pressure between the casing and the tubing and has connections to control pressure as well as the gas and liquids.

The Christmas tree is a tree-like device of gauges and valves to regulate, measure and direct the flow of gas and fluids exiting the well. The tree also has a choke to change the well's production rate.



Amine treating plants

Gas at the wellhead, unless it is coalbed methane, normally contains natural gas liquids (NGLs), carbon dioxide (CO_2), hydrogen sulfide (H_2S) and water that can corrode pipelines and waste valuable pipeline capacity.

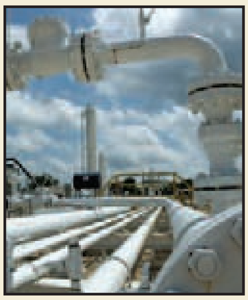
Operators use various types of equipment, such as free-water knockouts, vertical or horizontal separators, or multi-stage separators using gravity, centrifugal force, or a combination of both to remove water and contaminants. Operators may also require conditioning equipment such as heaters or hydrators near the wellhead.

The gas is sent to an amine treater using various amine solutions to remove H_2S and CO_2. As gas flows upward into the treater, it becomes a "sweetened" gas stream and a "rich" amine stream, which is then routed to a regenerator (a stripper with a boiler) so the amine can be reused in the absorber.

Gathering

Gathering refers to low pressure 4- to 12-inch diameter pipelines that connect gas wells to larger diameter trunk lines. Gathering lines are more capital-intensive than trunk lines because incremental connections to new wells must continually be made to offset depletion from existing wells.

Gathering contracts are usually fee-based but can also be percent-of-index-based. Because gathering lines are also sensitive to the absolute prices of gas, operators with fee-based gathering contracts have less direct commodity price exposure than percent-of-index contract operators.



Compression

Compressor stations are usually placed at 40- to 100-mile intervals along the pipeline. Gas enters the compressor station, where it is compressed. Compression stations compress gas to 100 times the normal atmospheric pressure, or more, using reciprocating compressors driven by gas engines, or centrifugal units driven by gas turbines, or electric motors.

Compression stations fueled by pipeline gas contain regulators to lower the high pressure of gas to be used for fuel. Compressor stations have real-time monitoring of critical conditions such as compressor failure, high temperature, excessive or low pressure, loss of power or leaks.

Processing plants

Gas processing plants separate NGLs into separate liquid products including ethane, propane, butane, isobutene and natural gasoline. NGLs are used as feedstocks for petrochemical plants and refineries and for heating.

The amount of NGLs removed from a particular gas stream is generally a function of the characteristics of the gas produced and the market demand for its products. During times of high gas demand, the BTU content of ethane may be more valuable as a component of the gas stream than as a purity product.

There are two kinds of gas processing plants. Field plants are close to the production source, while straddle plants are near gas pipelines. Straddle plants reprocess NGLs from gas processing plants to remove additional NGLs.

There are two principle techniques for removing NGLs from gas—the absorption method and the cryogenic expander. These two processes account for 90% of total NGL production. There are more than 560 gas processing facilities in the U.S., processing some 70 billion cubic feet of gas per day.

While Texas (181) and Louisiana (72) have the most plants, the substantial expansion of production and reserves in the Rocky Mountain states will require more capacity.

Processing contracts types vary from plant to plant and include fee-based, percent-of-liquids, percent-of-proceeds, percent-of-index, keep whole, margin-band and hybrid contracts.

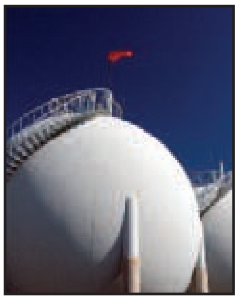
Transmission lines

Pipelines are the only means of transporting gas. They may be intrastate or interstate and are regulated differently. Most interstates do not own the gas they transport.

Three types of contracts generate pipeline revenues: firm, interruptible and no-notice. A firm transportation contract has a rate schedule that has no planned interruption. An interruptible contract means the service may be interrupted at the pipeline's discretion. A no-notice contract allows customers to receive gas as needed and is subject to the available supply. Pipelines generally have stable cash flows because of steady demand and limited direct commodity exposure.

Fractionation

NGLs from gas processing plants may be sent to fractionation plants for further processing. Fractionators separate liquid products by proceeding from the lightest hydrocarbons to the heaviest. In order, fractionators use deethanizer, depropanizer, debutanizer and butane splitters or deisobutanizer units to siphon off the NGLs. Occasionally, if a certain component of the NGL stream has a market value of less than the cost of extraction, a processing plant may reduce the extraction of that NGL from the gas stream, thereby reducing the amount of total NGLs sent to fractionators. Ethane, for example, may be accepted into the NGL stream to be sent to a fractionator, or may be rejected (not extracted) and allowed to enter the gas pipeline as part of the natural gas stream, as a function of market prices.



Storage

Large volumes of gas can be stored in salt caverns, aquifers and depleted gas reservoirs. Depleted reservoirs are the most economical.

Stored gas is classified as working gas or base gas. Working gas is withdrawn from storage for use. Base gas remains in the storage facility to maintain safe pressure. There are two types of gas storage processes: base load storage and peak load storage. Base load is used to maintain equilibrium between seasonal supply and demand, while peak load is used to meet sudden increases in demand.

Depleted reservoirs are used for base load storage and salt caverns are used for peak load storage.

Gas storage capacity in the U.S. is currently about 4 trillion cubic feet. However, if liquefied natural gas imports increase, more capacity will be needed.

Marketable NGL products

Six marketable products (excluding condensate and sulfur), are produced from the NGL stream.

Ethane is chiefly used in the production of ethylene and can be used as a refrigerant in cryogenic refrigeration systems such as liquefaction plants.

Propane is commonly used as a heat source for engines, barbecues and homes, and vehicle fuel as well as petrochemical feedstock. In the U.S., 190,000 on-road vehicles use propane, and 450,000 forklifts use it for power. It is the third-most popular vehicle fuel in America, behind gasoline and diesel. In other parts of the world, propane used in vehicles is known as autogas. About 9 million vehicles worldwide use autogas.

Butane is sold bottled as a fuel for cooking and camping. It is also used as a petrol component, as a feedstock for petrochemicals, as fuel for cigarette lighters and as a propellant in aerosol sprays.

Isobutane is used as a feedstock for petrochemicals. Recent concerns with depletion of the ozone layer by freon gases have led to increased use of isobutane as a gas for refrigeration systems, especially in domestic refrigerators and freezers, and as a propellant in aerosol sprays.

LPG, or liquefied petroleum gas, sold as fuel, is a mixture of propane with smaller amounts of propylene, butane and butylene. Ethanethiol is added as an odorant in case of leakage.

Natural gasoline, or debutanized gasoline, is an NGL with vapor pressure between condensate and liquefied petroleum gas. Natural gasoline is comprised of propane, butane, pentane, hexane, and heptane and is recovered at normal pressure and temperature. Natural gasoline is much more volatile and unstable than commercial gasoline, and is used as raw feedstock for aviation gas, nylon, plastics, explosives and cosmetics. ■

SPEAKING ENERGY

AN INVESTOR'S GLOSSARY

These key terms are used in energy companies' investor presentations, press releases, annual reports and other documents. Investors new to upstream, MLP or service stocks can find additional definitions of unique terminology in most companies' annual reports or websites.

HYDROCARBONS

Liquefied natural gas (LNG) Natural gas (primarily methane), that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure. Once a liquid, it can be more readily transported by ship to end-use markets, then regasified for movement through a pipeline.

West Texas Intermediate oil (WTI or Cushing) A crude oil produced in Texas and southern Oklahoma that is light (low density) and sweet (low sulfur). It serves as a benchmark or "marker" for pricing a number of other types of crude streams. It is physically stored and traded in the domestic spot market at Cushing, Oklahoma, the primary oil trading hub in the U.S. Nymex prices are referenced at Cushing as well, for paper trades.

Dry natural gas is fairly pure methane gas. It is natural gas which remains after 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and 2) any volumes of non-hydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. Note: Dry natural gas is also known as consumer-grade natural gas.

Wet gas includes all the natural gas liquids (see below) and typically has a higher Btu content of at least 1,500 Btus.

Shale gas Natural gas produced from wells that are open to shale formations. Shale is a fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. The shale acts as both the source and the reservoir for the natural gas.

COMMON MEASUREMENTS

M is the Roman numeral for a thousand. Production of 67 Mcf of gas per day is 67,000 cubic feet. MM represents a million, so production of 67 MMcf of gas per day is 67 million cubic feet per day. B represents a billion, thus production of 67 Bcf of gas per day is 67 billion cubic feet. T represents a trillion, so proved reserves of 2 Tcf of gas are 2 trillion cubic feet of gas.

Bbl represents a barrel, or 42 gallons of oil. Production of 80 Mbbl of oil per day is 80,000 barrels.

Cf represents cubic feet and is usually the measurement of natural gas, as in "a well produces 2.5 MMcf per day."

Cfe represents cubic feet of gas equivalent. It is usually the measurement of the mathematical combination of natural gas and oil or gas liquids, ranked together by heating content or Btu value. The conversion is usually 10,000 or 6,000 cubic feet of gas per one barrel of oil or gas liquids. (The ratio usually reflects the recent market value of 1 Mcf of gas in comparison with 1 barrel of oil or gas liquids.)

Thus, 10 MMcfe is 10 million cubic feet of gas equivalent. If the true mixture is 50% natural gas and 50% liquids (oil or gas) and the mathematical rate is 10:1, then 10 MMcfe consists of

5 MMcf of gas and 500 barrels of oil or gas liquids.

BOE is barrels of oil equivalent. It is usually the measurement of a mathematical combination of natural gas and oil or gas liquids. The conversion is usually 10,000 or 6,000 cubic feet of gas per one barrel of oil or gas liquids. Thus, 10 MMBOE is 10 million barrels of oil equivalent. If the true mixture is 50% natural gas and 50% liquids (oil or gas) and the conversion rate is 10:1, then 10 MMBOE consists of 500 Bcf of gas and 5 million barrels of oil or gas liquids.

Cf/d is cubic feet of gas per day. Another abbreviation of this is cfpd.

Bbl/d is barrels of oil per day or barrels of gas liquids per day. Another abbreviation is bpd.

Btu, a British thermal unit, measures stored energy, primarily used to describe the heat content of natural gas. One million Btu is generally the equivalent of 1,000 physical cubic feet; however, some natural gas contains fewer or more impurities than others and therefore has a higher or lower stored-energy content and, thus, market value. Natural gas is traded on Nymex in Btu rather than cubic feet.

API gravity is a measurement of the gravity (density) of crude oil and other liquid hydrocarbons by a system recommended by the American Petroleum Institute (API). The measuring scale is in degrees. The higher the degree, the lighter the oil and the greater the market value because it needs less refining. Some oils produced in North Africa and the Middle East, for example, have API gravity measurements of more than 40 degrees. Heavier oils, such as some produced in southern California, may have API gravity measurements of less than 20 degrees. The oil that is traded on Nymex is West Texas Intermediate, which is a middle-grade oil of approximately 32 degrees.

FIELD TERMINOLOGY

A **reservoir** is a porous and permeable subsurface formation that contains oil or gas and is surrounded by rock that separates the oil or gas contents from other reservoirs.

A **field** is an area that contains a single reservoir or related reservoirs with the same geological structural feature or stratigraphic condition. It may contain dozens or hundreds of wells.

A **trend** or **play** is an area or region where there is a great deal of drilling and production activity and involves a group of geologically related fields and prospects. A play is a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play differs from an assessment unit; an assessment unit can include one or more plays. A play is often used to refer to a natural gas accumulation, i.e., a natural gas shale play, an oil play.

An **exploratory well** is drilled to find oil or natural gas where none has been produced before.

A **dry hole** occurs when no oil or gas is found in the well, or the quantity of oil or gas that was found is insufficient to justify the expense of bringing the well into production.

A **delineation well** or **appraisal well** is drilled near a discovery well. It helps define the boundaries of the oil or gas reservoir, and assists in deciding whether to incur additional spending to drill more wells to fully develop the field and produce the oil or gas. A delineation or appraisal well can be deemed a dry hole.

A **development well** is drilled where there has been a discovery, as a result of an exploratory well, and is usually drilled after delineation or appraisal. Oil or gas is produced from this well. A development well is rarely a dry hole.

A **stripper well** is a gas well that produces 6 Mcf a day or less, or an oil well that produces 10 barrels a day or less. Thousands of such wells are found in 29 producing states. (See National Stripper Well Association at nswa.us.)

Net pay is the thickness of productive oil- or gas-saturated rock that has been encountered during drilling. A company may drill a 15,000-foot well and encounter 300 feet of net pay in several intervals of 100 feet each, for example. The development well is designed to produce only from the net pay.

EUR or **estimated ultimate recovery** is the amount of oil or gas estimated to be produced over a well's lifetime, prior to plugging and abandoning the well because it is no longer economic to produce.

Fracture stimulation (frac job) Also called hydrofracking. An operation that involves large pumps that inject, at high pressure, many gallons of water or other fluids, and pounds of proppant (sand or ceramic) down the well casing and out into the formation. The mixture fractures the rock so oil or gas can be released through the fractures and flow up the well bore.

A **prospect** is a lease or individual well that may be drilled because geology indicates it will probably be productive.

Prospective acreage is where there are geologic, seismic and/or other reasons to believe the subsurface may contain oil or gas. Drilling will be necessary to form a conclusion.

Proved acreage is where the existence of oil or gas has been proven by drilling exploration and appraisal wells.

Proved reserves are reserves of oil or gas that can be economically produced under current economic conditions and commodity prices, and given current technologies, within five years, according to complex guidelines in force by the Securities and Exchange Commission (SEC).

Proved developed reserves. The proved reserves that can be expected to be recovered through existing wells, with existing equipment and known operating methods.

PDP Proved developed producing reserves.

PUDs Proved undeveloped reserves that may be soon drilled and placed into production using existing technologies, recovered from new wells on undrilled, proved acreage, or from existing wells where a relatively major expenditure is required for completion.

OFFSHORE TERMS

Outer Continental Shelf Offshore federal domain divided into lease blocks that may be leased at periodic federal lease sales under a sealed bid system. Such leasing began in 1954. These blocks are from 3 to 230 miles offshore. (Waters less than 3 miles from shore are owned by the states and are called state waters.)

There are more than 7,500 leases on the OCS.

FPSO Floating production, storage and offloading vessel, a ship that collects oil production, stores it, then offloads it into tankers that take it to shore.

Floater Nickname for any offshore drilling rig that floats as opposed to being moored to the sea floor.

Jack-up rig A self-contained combination drilling rig and floating barge, fitted with long support legs that can be raised or lowered independently of each other. The first one was built in 1954.

MODU or mobile offshore drilling unit. Either a semisubmersible unit or a drill ship.

Platform Either a drilling or production facility offshore.

Semisubmersible rig (Semi) A MODU designed with a platform-type deck that contains drilling equipment and other machinery supported by pontoon-type columns. Because they are more stable in wave action, they are able to work in deep water and harsh weather conditions. (For more, and photos, see glossary.oilfield.slb.com.)

Transition zone Shallow water less than 10 feet deep, found in the marshlands between shore and offshore, in state and parish waters of Louisiana.

Shallow water is less than 1,000 feet or 305 meters deep, according to definitions of the U.S. Dept. of the Interior, which manages offshore activity through two agencies: the Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental Enforcement (BSEE).

Deep water is water greater than 1,000 feet or 305 meters deep.

Ultra-deepwater is water deeper than 5,249 feet or 1,600 meters. Companies are now able to drill in water up to 10,000 feet deep, with wells going as deep as 27,000 feet below the subsea surface.

INTERESTS AND CONTRACTS

Working interest is the percentage of ownership that the company has in a joint venture, partnership, consortium, project, acreage or well. A working interest owner pays his share of the well drilling and operating costs, and shares in the cash flow.

Farm-in or **farm-out** is an agreement in which the owner of a working interest in an oil and gas lease gives some or all of that interest to another party (company) that will drill on the leased acreage. The party farming out the working interest usually retains a royalty or reversionary interest from the party that is farming in.

Gross acres or **gross wells** are the total acres or wells in which a working interest is involved. Net acres and net wells are calculated by factoring in working interest. For example, if a company's working interest in 100,000 acres is 30%, then its ownership is 30,000 net acres. If the company's working interest in 100 wells is 45%, then its ownership is 45 net wells.

A **production-sharing contract (PSC)** is a contact in which a host country receives oil or gas production from an E&P company as a royalty payment. The E&P company usually bears all expenses of finding the oil and gas. If successful, the host country may contribute the expense of bringing the discoveries into production.

NATURAL GAS LIQUIDS

NGLs or natural gas liquids are usually measured in barrels rather than in cubic feet. Six marketable products are produced from the natural gas stream at the wellhead. These are separated at a gas-processing plant. During times of high gas demand, the Btu content of ethane may be more valuable left in the natural gas stream, rather than being sold as a separate product.

The components of NGLs are: **ethane** (chiefly used to produce ethylene in petrochemical plants); **propane**, used as a heating source and some vehicle fuel; **butane**, sold as bottled fuel or as a petrochemical feedstock; **isobutane**, used as a petrochemical feedstock; **LPG or liquefied petroleum gas**, and used as fuel; and **natural gasoline**, an NGL with vapor pressure between that of condensate and LPG. It is used as a feedstock for nylon, plastics and cosmetics.

Natural gas processing plant Facilities designed to recover natural gas liquids from a stream of natural gas that may or may not have passed through lease separators and/or field separation facilities. These facilities control the quality of the natural gas to be marketed. Cycling plants are classified as gas-processing plants.

Frac spread A measure of profitability for processing plants. It's the difference between the sales price of natural gas liquids (the processing output) and the cost of natural gas (the processing input).

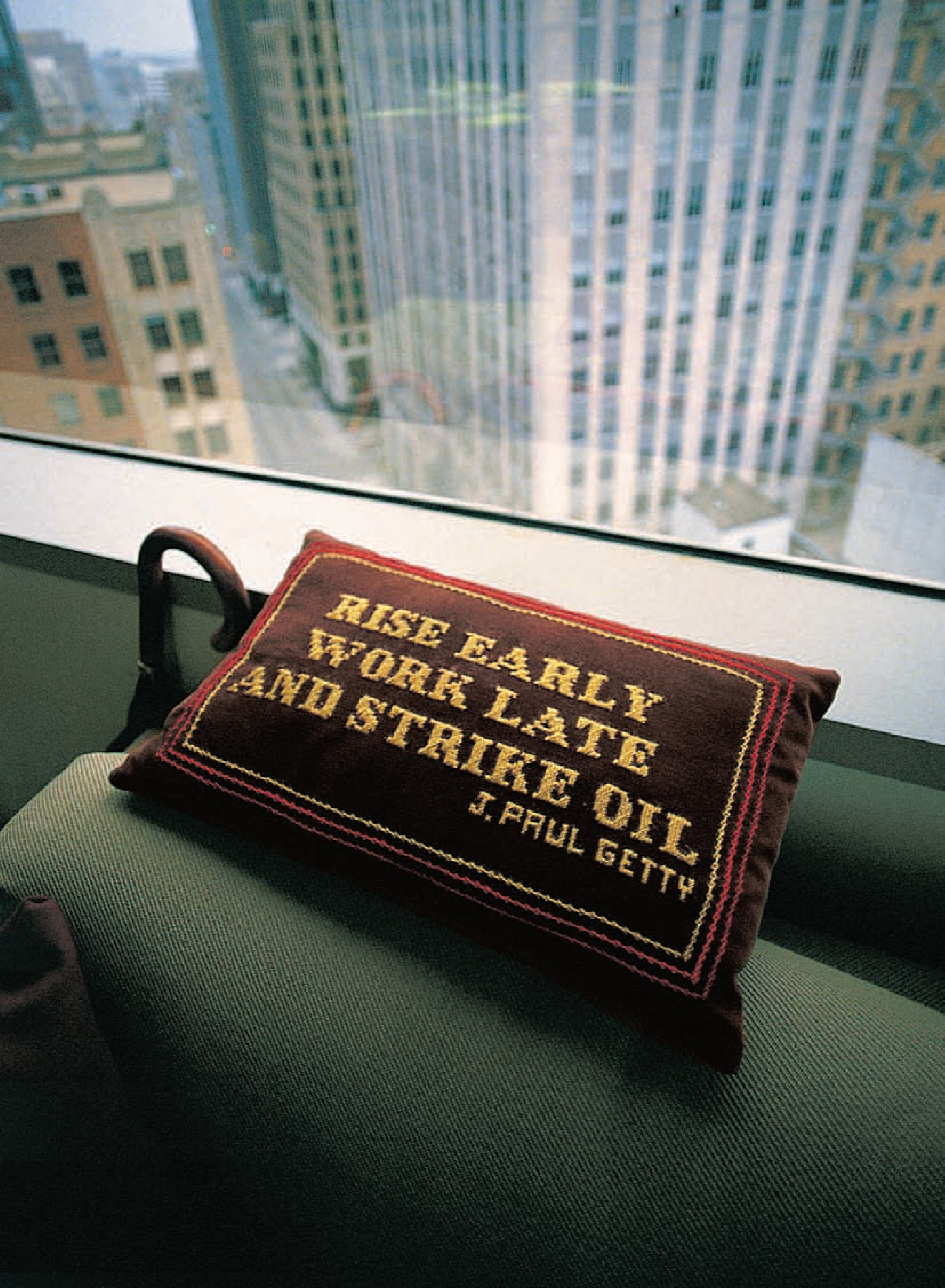
Compression To move natural gas through pipelines, it must be compressed to save space and push it further down the pipeline. Most gas is compressed at 1,000 psi (pounds per square inch).

MISCELLANEOUS

ICE IntercontinentalExchange, operates regulated futures exchanges and over-the-counter markets for energy, emissions, currency, credit and agricultural contracts. ICE Futures Europe hosts trades in half of global crude and refined-oil futures.

Nymex New York Mercantile Exchange. A futures market in which a seller promises to deliver a given quantity of a commodity at a specified place, price, and time in the future. Oil, natural gas and other related commodities are traded on Nymex.

OCTG Oil country tubular goods. Pipe used to drill wells in oil and gas industries, consisting of casing, tubing and drill pipe.


RISE EARLY
WORK LATE
AND STRIKE OIL
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