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In this Issue

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REASONABLE DUE DILIGENCE FOR OIL AND GAS DRILLING PROGRAMS

Frederick Rosenberg and Lawrence Elkus

Introduction

Before oil and gas related securities can be solicited to investors, financial advisors and their clients need to appreciate how hydrocarbons are extracted from the earth and how many levels of investment promotions exist before investors receive a cut of the revenues, a "drop" on their returns.

Hydrocarbons are compounds derived from organic decay trapped in subterranean strata at depths ranging from a few hundred to tens of thousands of feet below the surface of the earth. Extraction of those hydrocarbons is accomplished by drilling wells into the formation whereupon the sub-terranean pressure forces the oil or gas into the well bore where it flows to the surface into tanks or pipelines. Recovery depends on several factors principal of which is the porosity and permeability of the rocks within the formation and the viscosity and chemistry of the oil.

"Porosity" describes spaces in the rock capable of accumulating oil or gas while "***permeability"*** describes the level of communication between pores that allows the hydrocarbon to flow into the well bore. For example, typically an unglazed earthenware brick is 5-7% porous and permeable. Submerging the brick in water will result in water being drawn into the pores. Water flows easily and under pressure much of it can be recovered. But, if the water were replaced by viscous, sticky, crude oil, recovering more than a small fraction of the oil becomes an impossibility. As so it is with oil-bearing rock. There are no pools filled with crude oil below ground sloshing around as if in a swimming pool, only strata of porous and permeable rocks squeezed between impermeable zones that trap the hydrocarbon.

Gas typically flows easily through most formations allowing for recoveries in excess of 50-60%. Oil, however, is a viscous fluid comprised of various chemistries including paraffin, asphalt, naphtha, and Sulphur to name a few. This means that, depending on the porosity and permeability of the production zones, primary recovery can be a minuscule 2% of the oil in place (in areas like the Bakken Shale in North Dakota) to 10% - 15% of the oil (in places like the Permian formations in West Texas and New Mexico) before wells become uneconomic. In fact, even the best U.S. wells leave 80% - 85% of their oil in the ground unless secondary or tertiary recovery methods are utilized to extract perhaps an additional 10% - 25% of the oil in place.

Production rates always decline over a well's economic life, often precipitously in the early months when pressure drops throughout the initial flush production period. "***Flush Production***" is the initial production, typically the highest volume of production in a well's economic life occurring in the first 3 - 6 months. It is the period when the well's reservoir has the most pressure to push the hydrocarbons to the surface. Fracking, water flooding, steam injection and chemical treatments all enhance recovery but add substantial production costs and environmental liability just to boost production for a limited period of time. Those treatments can be repeated at regular intervals to squeeze out more hydrocarbons depending on the formation and type of treatment.

The oil and gas exploration business is built upon risk sharing and joint ventures with over a century of history. Risk is measured by potential losses realized by drilling dry holes or uneconomic wells. The common method for defraying that risk is through "***Promotions***." At each stage of the promotions, someone is attempting to profit for their activities. The first promotion occurs when a production company leases the mineral rights from a landowner and takes on the financial responsibility for drilling and producing the well. The landowner receives a negotiated "***Bonus Payment***" for signing the oil and gas lease and, more importantly, receives a "***Royalty Interest"*** in the well's production. The oil company's lessee interest is called the "***Working Interest***" because, while the royalty interest owner waits for the check in the mail box, the working interest owner must pay for the drilling, completion, operation and plugging of the well. But the promotions do not end there. The Landman who acquires the leases from the landowners and others who originate and engineer a drilling prospect may also take an interest in the well. These interests are typically in the form of an "***overriding royalty***" that is carved out of the working interest's revenue stream. In low risk drilling programs, royalties and overrides commonly exceed 30%, meaning that 70% of the revenues is responsible to pay 100% of all costs.

The production company, the "Working Interest" owner, also defrays its risk by shifting the drilling costs to joint venture partners, typically in an arrangement whereby the production company (the promoter) retains 25% of the working interest without having to pay its proportionate share. In this arrangement, the promoted joint venture companies agree to pay 100% of drilling costs and possibly the completion costs in exchange for 75% of the net revenues after royalties. The Operating Company is said to get a ***"¼ Carried Interest***." For example, the landowner and overriding royalty interests amount to 30% of the revenues, leaving 70% for the working interest owners.

The promoted joint venture partner(s) agrees to pays 100% of the costs for 75% of the 70%, or 52.5 % of the production revenues. The oil company that promoted the deal to the venture partners pays 0% of the drilling and possibly completion costs and receives 17.5% of the revenues. Carried interests may be "***carried through the tanks***" - meaning through well completion and after costs. Typically, with exploratory drilling the carried interest will pay its proportionate share: 25% of completion and production costs as well as 25% of all costs on subsequent wells. Once the well begins production, the Carried Interest begins to pay its share of operating costs, in this case 25% unless "carried through the tanks."

Important Terms in the Extraction of Hydrocarbons:

1. *Prospect Geology*: Typically oil and gas programs identify the type of geology and production anticipated from a particular area of the oil patch. This is important because West Texas operating costs may be 7% - 10% while tight sands and secondary drilling projects often suffer from operating costs of 30%+ of gross production, leaving the working interest owners with barely a profit or a possible loss if costs get out of hand, complications develop, or oil prices drop.
2. *Spacing*: Spacing of wells recognizes that there is a certain amount of area in the oil and gas reservoir that can be efficiently drained by one well. The spacing of wells is typically determined by a State commission based on the potential of each well to produce oil or gas to maximize development of a field, commonly 40 acres or 80 acres, but potentially much smaller in tighter sand areas or mature fields where "Infill" drilling is permitted, and likewise much greater, 640 acres (a square mile), in exploratory regions or in costlier deeper zones.
3. *Production Zones:* Often multiple strata of rock underlying an oil field can or will produce hydrocarbons. Sediments laid down over the millennia created multiple zones separated vertically by hundreds, if not thousands, of feet. The rights to those other zones are not typically part of the leasing rights on developmental projects. Many developmental fields are also "checker boarded" meaning drilling rights extend only to the red squares while proving up the value of the black square controlled by others or the production company.
4. *Engineering*: ***"Petroleum Reserve Engineers"*** assess the economic outcomes of drilling projects for a given geology utilizing volumetric analysis (the estimated amount of hydrocarbons within the drilling area based upon thickness of producing zones and geology across an area), production and decline curves, operational and production and lifting costs, taxes, reworking, fracking, pricing, oil characteristics, disposal

wells costs and completion rates to identify a few areas. As indicated above, only a fraction of the oil in place is ever recoverable depending on several factors. Petroleum reserve engineers assess those factors to determine the economic life of a well or an entire prospect. Proven reserves describe the producing capability of wells based on known characteristics of the oil field at assumed prices. Unproven reserves are a best guess estimate of what may be produced in the future, but which are by no means certain.

5. *Price* - is a key component of calculating reserves because higher prices for crude permit wells to operate in the black for longer periods before their economic limit is reached. For example, at $100/bbl., a well's reserves might be a million barrels over 15-18 years, but at $50/bbl., proven reserves could drop to perhaps 40% of that figure with an economic life of 7-10 years. The impact of price is also felt most significantly with heavily promoted developmental wells drilled into shallower or tighter sand formations and infill wells on tighter spacing.
6. *Developmental Wells* - tend to have high flush production and steep decline curves, meaning economic returns are dependent on early payout even if production is sustainable for several years at low production rates. In a rising market, the wells may be sustainable for years assuming lifting costs are low. Fracking, secondary or tertiary recovery treatments are costly but do result in increased production for relatively brief periods of time. Royalty or carried interest owners who do not participate in the costs of enhanced recovery methods will see increased returns in comparison to the promoted working interest partners who shoulder all the costs. This is a critical element of consideration, namely that the financial interests of the working interests are based on different economics.
7. *Economics of Oil Production*: Oil and gas production produces a stream of revenues that ends when the costs of production exceed the revenues of production. Wells occasionally are shut-in awaiting higher prices, but such delays tend to reduce returns significantly. In terms of financial analysis, oil and gas investments, like mortgages and leasing programs, are annuities that are expected to self-liquidate over time. Residual value typically amounts to salvage value at best. Characteristically, an annuity returns both principal and interest in its cash flows; oil and gas is no different. Principal is recovered through "***percentage depletion***," a tax exemption based upon production revenues available to small producers. While undrilled oil and gas leases can achieve substantial appreciation, once a well is producing it is no longer an appreciating asset like commercial real estate, but a commodity based stream of revenues

discounted to present value and haircut again for risk. This is a very significant factor in making an investment decision.

8. *Payout*: One significant point in the life of an oil or natural gas well is when the revenues from the well equal and begin to exceed the expenditures and costs of the well. This critical moment is known in the industry's "Oil Patch" as "***Payout***" and it signals potential substantive changes in the ownership and revenue distributions among the drilling partners. Some of the drilling partners will experience reductions in their working interest percentages. Production payments may kick in and overriding royalty interests and working interests can shift to actually increase the promotion on working interest owners and drilling partners. Importantly, a well's payout affects the drilling partners differently depending on their level of promotion. Interests often shift when wells achieve payout, yet often significantly before the promoted interest partners achieve their breakeven. For example, while a well must payout about 140+% of its drilling cost to achieve breakeven to the working interest, it must payout nearly 500% of costs for the retail investor to break even in many developmental drilling programs. Each layer of promotion increases the burden on revenues.
9. *Syndication*: Retail investors over the years have been offered participations in wells through syndication. This adds additional promotions, including underwriting expenses, commissions, management fees and revenue and cost sharing formulas that reduce returns and increase risk beyond normal drilling joint ventures. A syndication is offered to the public by a Sponsor or Issuer. Commonly the Sponsor/Issuer is a "non-operating" oil company, meaning the Sponsor does not actually drill wells but instead joint ventures with drilling partners by taking a fractional working interest on a one-third for a one-quarter participation. Non-operating oil companies vary in sophistication; some have extensive geological and engineering staffs while others do not.

Operating oil companies actually originate, engineer and drill the wells with a professional staff that locates and leases prospects. Commonly, operating oil companies joint venture with other oil companies sharing and trading risks and rewards to develop entire prospects and to explore for new areas of production. Rarely do they go the syndication route to deal with dozens if not hundreds of individual investors directly. However, in addition to operating and non-operating companies, there are production companies which drill for their own account and syndicate a portion of their prospects through the securities channel, typically in, a "checkerboard" as described above. This allows the production company to prove-up reserves in adjacent drill sites without taking drilling risk, something they could not do with industry partners as a general rule.

Syndications typically reserve between 15% and 20% of subscriptions for a variety of upfront costs, including legal, sales commissions, first year management fees and general and administrative costs leaving on average about 80% - 85% of all subscriptions for operations including drilling and completion costs and reserves. Furthermore, it is becoming common for a sponsor or affiliate to retain an overriding royalty off the top before operating expenses and to share that override with the selling group either from the outset or as a back-in after the investors receive a full return of their investments. It is a powerful inducement. Based on projections, the shared overrides often promise a back-end revenue stream that exceeds the commissions, a significant inducement to qualifying selling group members achieving sales thresholds.

Sponsors also may retain a percentage of net partnership distributions after expenses, ranging from 1% - 10% before investor payout and increasing thereafter. In recent years, some sponsors have been opting for overrides instead of a proportionate share of revenues because investor payout rarely if ever is achieved in large drilling program without borrowing heavily. An override of 1% - 10% before operating costs can be substantial in drilling projects with high production costs in tight sands, shales or chalk formations, or which utilize secondary or tertiary recovery methods to increase production.

Private placements are offered via an offering memorandum or, in the case of a public program, a prospectus. One of the disclosures in these sales documents is a summary of past performance of prior programs. This breaks down into drilling success rates and cash flows to investors. Drilling success is a nearly meaningless statistic that at most tells you more about the type of production than returns. More important is the question of payout to prior investors. All wells experience predictable production declines based on known geology and technology. Often, developmental wells drilled in known producing areas will decline by 50% - 60% within the first year and perhaps half again in year two. Unless investors attain payout within 36 - 48 months, we believe the probability is they will never recoup their investment within a reasonable number of years. Furthermore, reworking, re-fracking or re-treating wells becomes a necessity, increasing costs. A second frack typically requires nearly double the fluids of the first frack and so on each time driving costs higher to the working interests and reducing the net. Over time, a properly spaced drilling project with secondary or tertiary treatment will become uneconomic for the partners actually paying the costs and who then could be forced to abandon their interests entirely.

Once fully invested, most programs also lack the funds to develop their prospects without an assessment or debt. But rather than assess partners, increase debt or reduce distribution for subsequent development, most syndications "farm-out" their interests to subsequent promoted syndications in exchange for a small overriding royalty, burdening the new investors while depriving existing partners of the full development potential their investments have proven up. This is a common practice for sponsors of large drilling programs who can now re-promote wells that would otherwise be developed without promotion.

Consider collateralized mortgage obligations of a few years ago, where a pool of mortgages was stratified into tranches, each with a priority in distributions. At the bottom of the CMO was the equity tranche, whereby investors got to reap the rewards of higher returns if the CMO performed as pitched. But as we know, it was the equity tranches in CMOs that predictably experienced severe if not total loss, highlighting the inequality of risk from tranche to tranche. The risk and return of oil and gas programs is quite similar. Royalty holders are at the top and pay no costs, one-quarter Carried Interest Owners have a separate set of economics from the promoted Working Interest owners paying one-third of the costs for one quarter of the working interest revenues. Lastly are the equity syndications which adds non-industry level of promotion on top of the already promoted working interest, effectively paying the costs but receiving another haircut distribution.

There is almost no commonality of interest between a retail investor in a syndication and the operating company. Even when venturing with the biggest and best drillers in US, the disparity in economic returns and risk are substantial, particularly given that the working interest owners can rework wells using investors' money without sharing the cost or risk in many instances. Moreover, reworking wells, including fracking, increases production for only a limited period of time before the well reverts to much lower production.

Oil and gas are depleting assets and even when price increases occur, it is the early flush production which usually determines whether or not the investment will payout and be profitable to retail investors. Oil reserves too are subject to wide fluctuations due to price movements. As the recent decline in prices has shown, the economic life of producing wells has been shortened substantially when prices collapsed despite the fact that the oil reserve actually remains undisturbed in the ground.

Oil revenues include both principal recovery and return on investment. Investors need to be cautioned that a sinking fund needs to be established if the investor wishes to recoup original investment. Otherwise, investors run the risk that the asset they thought could sustain them for decades barely if ever returns their original investment. There are substantial tax benefits given to investors who drill wells, however, the investor must also understand the tax preference aspects of the investment, including the alternative minimum tax.

Conclusion

The question a due diligence analyst needs answered for every oil and gas drilling program is this: "How long until the investor gets his money back?" Answering that question before recommending drilling programs requires a depth of understanding due specifically to the vast disparity in financial interest between the retail investor in a syndication and the royalty owner and the production company who operates the program, each of whom is looking for his payout. Recommending a drilling program requires far more than an evaluation of the structure of the private placement because the multiple levels of promotion on top of the investors can and often do make even a seemingly low-risk investment a foreseeable disaster.

A rule of thumb is, we believe, if the track record of distributions on similar sized drilling programs is significantly less than full payout to the investor within 48+/- months, the new offering should probably be rejected. For the most part, oil and gas investments do not stack up well against income investments and carry far greater risk than most. In drilling programs, some of the risk may be defrayed through tax write-offs of the intangible drilling costs, but it is erroneous to suggest to any investor that a developmental oil and gas drilling program can provide a reliable stream of income throughout retirement.

Oil and gas placements must be treated as self-liquidating investments with little residual value in all but the most exceptional situations. An analysis of the impact of all levels of promotion, as well as the geology, decline curves, price assumptions and program costs on the partnership is essential. A petroleum engineer's report to investors projecting returns to the limited partners based on their costs, promotions, and net revenue interests should be a minimum requirement when conducting reasonable basis due diligence for every drilling program.

What follows below is my screening analysis for a drilling program that highlights the issues discussed. Most of the chart is self-explanatory. All the information was taken out of an actual PPM and broker due diligence report in about an hour or two of my review. The analysis projects a 20.7% return to investors at the point of payout to the well, meaning that each successful well needs to payout 4.83 times for investors to break even under the program structure assuming no dry holes. Considering a projected 50% first year decline in production, 27.6% first year return (adjusted for 9-month payout per well), while impressive on the surface, suggests a high probability that investors will not recover their full investment - if ever - within a reasonable period and that investors will begin to experience severe declines in cash flow once the program is fully drilled. In other words, what appears favorable on the surface may very well be problematic under the Earth's surface.

Payout Analysis for Completed Well
Drilling Program
Waterflood Proj
Proj Success rate 90%

Investor Subscriptions		74,250,000			
Partnership promotions, costs, commns	-15.00%	(11,137,500)			
Net in the Ground for Operations(well cost)		63,112,500			
			% Payout	Divisor	
Gross Production Revenue	100.00%	63,112,500	100%	$ 63,112,500	dollars in ground
Production and severance taxes	-7.25%	(4,575,656)			
		58,536,844			
Land Owner Royalty	-13.50%	(7,902,474)			
Overriding Royalties	-20.82%	(12,187,371)			
Net Revenue interest	65.68%	38,446,999			
3/4 Working interest net of carried interest	75.00%	28,835,249	45.69%	$ 63,112,500	dollars in ground
Farm-in overrides	0.00%	-			
Net to Investor Interests at Payout		28,835,249	38.80%	$ 74,250,000	gross investment
Well Op exp & Prod Costs	-33.00%	(9,515,632)			
Partnership G & A Exp & Direct Exp	-2.75%	(792,969)			
GP Net Rev Int (Shared with selling group)	-10.00%	(2,883,525)			
Available for Distribution		15,643,123			
Sponsor interest	-1.00%	(156,431)			
Net Distr to Investors	99.00%	15,486,691	20.9%	of orig. Investment	9.00 months
			4.79	Well Payouts per Investor Payout/well	
			28%	First Year Payout-Constant production	
			43.15	Months to Invtr Payout Const.Prodt'n	
			75%	Production Decline, First Year Avg	