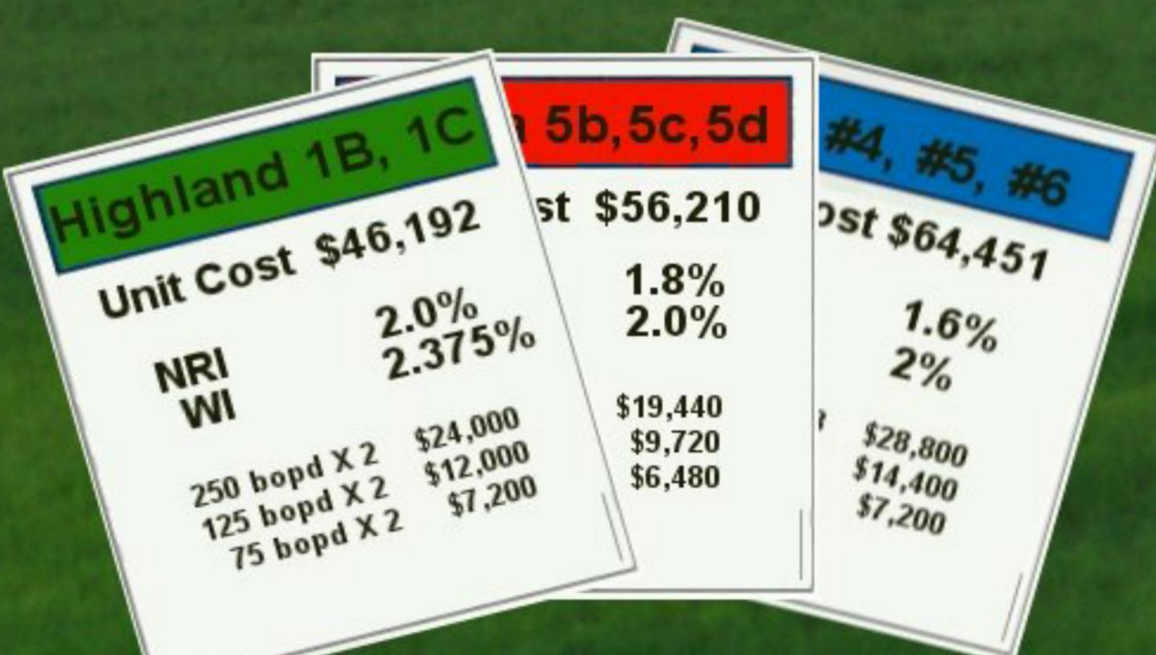
THE INVESTOR'S GUIDE TO INVESTING IN DIRECT PARTICIPATION OIL AND GAS PROGRAMS

What the everyday investor really needs to know without all the insider technical information investors can live without



Steven Imke

LearnAboutOilAndGas.com

The Investor's Guide to Investing in Direct Participation Oil and Gas Programs

What the everyday investor really needs to know without all the insider technical information investors can live without

By Steven Imke

Table of Contents

Preface

While investing in direct participation oil and gas programs are good for some investors, they are not for everyone. Each investor's situation is different, and you should always seek legal, tax, and financial advice to see if investing in direct participation oil and gas programs as an asset class is right for you.

This book is based on my own personal experience as a working interest investor in many oil and gas direct participation programs or as a member in Oil and Gas Limited Partnerships or directly as a heads-up investor. Much of the material comes from my personal research and from interviews conducted with leading experts in the field.

Throughout this book we refer to many industry specific terms. You can access a glossary of common oil and gas terms at the following link. http://www.learnaboutoilandgas.com/glossary.php.

The intent of this book is to act as a companion product to the author's website, http://learnaboutoilandgas.com, which provides comprehensive video instruction, complete with interviews from experts, on all the topics discussed in this book as well as tools to assist the investor in making investment decision.

Chapter 1 - Why should I invest in oil and gas when I have other investment options?

All market-based investments have substantial and inherent risks with regard to their return on your investment. However, direct participation in oil and gas projects are unique amongst most investment vehicles.

Oil and gas is a commodity traded in the world market. With the growing economies of emerging markets like India and China, the demand for oil and oil by-products are expected to remain high. While production of the world's oil supply is scattered around the globe, it is, after all, a finite resource with most of the easy sources already discovered and used up. Therefore with increasing demand and stable or dropping supply, economic theory says that while the price may fluctuate based on investor psychology, in the end: prices must go up.

In addition to the supply and demand issues, oil futures are traded in US Dollars. What this means in terms of an investment strategy is that buyers from all over the world must convert their native currency into US dollars to buy oil and gas futures. Therefore if it takes twice as many dollars to buy a barrel of oil because the US dollar is devalued in the world economy, then owning a barrel of oil is worth twice as much. Therefore, owning a barrel of oil is a hedge against the value of the US currency.

Furthermore, consider that investments you make in American-owned independent oil and gas companies are used to drill for oil and gas on our own soil, and that the money itself is used to pay American oil field workers and buy equipment most often produced by American workers in American factories. Further during production some of the revenues are used to not only pay investors but to pay American farmers and mineral right owners as well as generate much need tax revenues. These facts make a compelling case that your investment helps fellow Americans while reducing our dependency on foreign oil.

Investment in oil and gas, because it remains in our national interest to produce more domestic oil and rely less on imports, continues to experience favorable tax treatment from the government.

Packaged together, investing in domestic oil and gas projects present a rather unique and compelling case for your investment dollar.

Chapter 2 - Why invest in direct participation vs. buying stock in public energy companies?

As an investor with a potential interest in investing in the energy sector, you have several options. Invest your money in large publicly traded companies like Chevron or Exxon Mobil Corporation[1], invest in smaller public companies like Royale Energy or Crosstex Energy, or you have the option of investing in specific projects with an independent oil and gas company. The latter option is known as "Direct Participation."

When you invest in a public entity like Conoco Phillips, you are essentially buying a share of the company's producing assets, such as its lease and production equipment. However, you are also buying a share of the company's non-producing assets, like buildings and furniture. In addition, you own a small portion of all pre-existing projects and future projects commingled into a neat package.

Depending upon their size, publicly traded companies have from a few dozen employees to tens of thousands of employees. Managers and engineers working for the company earn a wage for their efforts. These managers and engineers do not have a direct personal stake in the success of the business. If they recommend a drilling project, costing millions of dollars, which results in a dry hole, the employee typically continues to receive a paycheck. If the same dry hole is encountered at a private oil and gas company, the operator generally does not get paid. Further with an almost endless supply of cash, the program managers of publicly traded companies are freer to spend the investor's money with less regard to the return on investment. By contrast, with an independent operator, return on investment is of the utmost priority since this is the only way they get paid. For independent companies, only essential spending is authorized, which in the end provides a greater return to all investors.

Small public companies have many projects going on at once, and the new investor's money received from a new public offering is pooled along with old money to fund all projects across all risk levels. In essence, as an investor in a public company, you are not in direct control of the company's risk level. As such, you may be exposed to more or less risk then you would like.

Direct investments with private or independent oil and gas companies are generally risk and reward sharing arrangements in a specific project or play. Companies carve up the cost of a program into units and sell the units to investors. The company always has a substantial investment in the offering but wishes to share the risk and reward with other companies or individual investors.

The independents' success rate with previous offerings has a direct relationship on its ability to shop its current and future offers. Therefore, they tend to be judicious with respect to the risk-reward factors. Highly risky projects that would consume valuable assets and affect their ability to market future offerings would likely be passed on, unless the potential rewards were too good to be ignored.

Each deal or play is marketed by itself. Revenue from previous or future projects is not part of the offering, and as such, the investor can assess the risk and reward of a given project. If the risk is acceptable based on the anticipated reward, you can choose to invest. If not, you can pass and wait for the next offering or go to another company. You essentially define and manage your own personal risk profile and invest in projects where you feel comfortable.

Investors in public companies benefit from both stock price appreciation and dividend payments[2]. The dividend payments, for companies that pay dividends, may vary from 1.5% to 5%. The company's stock price is affected by its revenue and the profit margins from these revenues, which is directly tied to the spot price for a barrel of oil. The company's book value and management also affect the stock's price. External factors, such as storms that may disrupt production and political unrest in completely unrelated parts of the globe, can sometimes affect the price of oil and gas. As such, this will also affect the company's share price. Stock prices rise and fall every day based upon a huge basket of variables making the stock price in a public company very volatile.

However, unlike investments in publicly held energy companies where you can set a sell point and preserve a fraction of your invested capital, once invested in a private offering, if the well is determined to be a dry hole, you lose your investment dollars spent by the project up to that point.

However, to offset this all-or-nothing investment vehicle, the government has allowed for some positive tax treatment when the well is deemed to be not economically viable. Further, if the well is deemed to be economically viable, there are further favorable tax treatments on any income produced to induce individuals to continue to invest in domestic oil and gas exploration.

Tax incentives are offered directly to the oil producers. In public companies, tax incentives affect the company's after tax profit, which in turn affects dividend capacity and stock price. Other than dividends paid, the single control element left to the investor is to time the market and buy the stock when it is undervalued, and then sell it when it has reached its apex.

Gains and losses from investments in energy stocks are treated just like any other securities from a tax prospective[3]. Publicly traded stocks are readily traded and can even be handled easily within many tax deferred retirement vehicles, such as your 401k.

By contrast, in direct participation projects, when you have a successful well, your hope is that the cash flow will repay your investment several times over. However, when you own a working interest in a specific program, your shares are not considered securities, which you can trade for cash if you want out. There are some aftermarket auctions, such as http://www.ogclearinghouse.com, where you can sell successful working interest units, but they are not as simple as selling publicly registered stock.

Chapter 3 - Is it risky to invest in direct participation oil and gas deals?

Despite an independent oil and gas company's best efforts to mitigate an investor’s risks through seismic and other tests before drilling a well, some wells simply are dry holds and yield no return to their investors. Tax wise, you can write off the entire loss in that year’s taxes, which when compared to other investments is better than most. Clearly investors in direct participation plays should only invest money they can afford to lose. However, these losses are handled, at lease tax wise, in a very favorable way.

Operators realize that most investors want to lower the risk-reward volatility, and as such operators package several wells into a program thereby spreading the risk and reward across several wells similar to the way mutual funds achieve diversity by holding many different stocks in a portfolio

The risk associated with each well is determined by several factors. One factor is total depth or the point when the drilling stops. A well drilled to 4,000 feet total depth costs less to drill than one drilled to 10,000 feet. Therefore, if the hole is dry, then the investors are out less money.

Well location is another risk aspect. Wells drilled into a potentially virgin reservoir are called “Wildcat” or “Exploratory” wells. The further a prospect well is from proven wells, potentially the riskier it is. Operators generally attempt to mitigate some of the risk when drilling wildcat wells by conducting more up front testing, such as commissioning seismic tests. While these tests add expense to the project, it reduces the risk if the results show a clear trap where oil or gas may be present.

The pay out on a successful exploratory well is often better because of greater bottom hole pressures, which is the force that moves the oil to the well bore. Exploratory wells are most often drilled at the highest point in the structure, or where the pay-zone is at its thickest. Some operators allow investors who participated in the exploratory well program a first right of refusal on future development wells in the newly found reservoir.

On the other end of the well location continuum are “Developmental” or “Offset” wells. Developmental wells are drilled in the proximity of a known producing well. Development wells have a higher degree of success because of the success of adjacent wells. However, development wells are often drilled more toward the edges of the reservoir and run the risk or having greater water and shallower pay-zones.

Another aspect of risk involves doing secondary recovery on an existing well. Some wells are much more efficient at getting oil and gas to the well bore. Others need more help. In the past few years, new recovery techniques have been employed to extract more oil from fields that have exhausted their primary reservoir drives. If dissolved gas coming out of solution provided the pressure to force oil to the well bore is exhausted, there is often still a lot of oil that can get recovered. Of course, nature needs some help. Injecting water or other chemicals into adjacent well(s) in the same field introduces a new reservoir force, or what the industry calls a "Drive Mechanism," to push the oil to a nearby depleted well. Often the amount of recoverable oil in a secondary recovery effort can meet or exceed the production from the primary recovery effort. Since the wells targeted for secondary recovery are known to contain oil, investors can't lose a substantial portion of their investment as they do when a company drills a dry hole. The biggest risk factor in secondary recovery is the volume of recoverable oil or gas that remains and the time-line in which it can be produced.

In addition to any direct risk related to the offering, investors should consider the risk of operator fraud, the volatile nature of oil and gas prices, conflict of interests, etc. As with any investment, investors should always seek qualified legal and tax advice and consult their financial advisor before investing in this asset class.

Chapter 4 - How is my Net Income calculated?

Your return on your investment is established differently depending upon whether we are talking oil or gas.

Oil wells are often located in remote locations far from an oil pipeline, so most wells simply store the oil in a storage tank located near the well. Depending upon the volume of oil being produced by a given well, one or more tanks may be used. Sometimes several low volume wells may share a single tank battery.

In the early days, the operator needed a way to get the oil from the well to a place where the oil could be processed. Lacking options, he used wooden barrels that were designed to store whiskey. These barrels had a capacity of 42 gallons, and since that time oil has been measured and priced in barrels. Even though today we no longer use wooden barrels to store and transport oil, the 42-gallon unit still represents a barrel of oil.

As the on-site storage tank fills with crude oil, trucks are dispatched from an oil-gathering firm or directly from a refinery to collect the crude oil and transport it to the refinery for processing. As the oil is pumped from the tank to the truck, meters record the volume of oil being transferred.

Each month the refinery adds up all the barrels of oil it received from a given well and pays the operator. The price the refinery pays the operator for the crude is based on a specific commodity market price, such as the "West Texas Intermediary" (WTI)[4] price, less some discounts or premiums to account for transportation cost, grade or quality of the oil, and supply and demand factors. In the end, an average monthly price is determined by aggregating each day's spot prices as well as the various discounts and premiums applied. This average price is applied to all barrels of oil shipped during the month and a check is produced and sent to the operator.

The operator takes the revenue it received from the refinery and on paper applies it to the investors based upon their "Net Revenue Interest" percentage, often referred to by the letters NRI. The operator then takes the well's operating expenses and distributes the expenses based on the investors "Working Interest" percentage, often referred to by the letters WI. The operator then distributes the Net Income (NRI dollars minus WI expenses) to the investors, along with a statement outlining his calculations.

Gas produced from a well is not easily stored, and as such, it has to be injected into a national supply line. When a well is located some distance from an existing supply line the operator and investors bare, sometimes substantial, completion cost to lay gas pipe from the well to a sales point on the national supply line. Meters are placed at the sales point to measure the volume of gas being injected. If the distance to a sales point is too great, the operator may be forced to liquefy the natural gas and transport the liquefied natural gas by truck to a sales point or other source.

Gas pipeline companies pay the operator based on a specific index, such as the “Houston Ship Canal” or “Henry Hub” gas price, less discounts and premiums similar to the way refineries deal with oil. As a baseline, one cubic foot of natural gas should produce one thousand BTUs (British Thermal Units). Spot prices are adjusted up or down depending upon the actual BTU of the gas being injected.

Since the majority of products produced from a barrel of oil relate to fuel products, and since fuel consumption is relatively steady day-to-day, the spot price for a barrel of crude does not vary by season[5]. In contrast, the bulk of natural gas is used to heat homes during the winter and to run electrical power plants, and as such too much supply exists in the summer and not enough in the winter, therefore natural gas prices have a seasonal swing to their price.

Chapter 5 - How often do I get paid?

Most operators disburse checks to their investors monthly[6]. Oil and gas companies keep records of all the oil and gas shipments during a given month. In the subsequent month, these records are compared with revenue checks received and the revenue is reconciled. Therefore, after one-month of production, it generally takes an additional month to receive, process, and reconcile the revenue. Also during that second month, the operator processes and pays the operating expenses for the production month. By the end of the second month, the operator applies the revenue to each party based on their Net Revenue Interest percentage and pays the appropriate severance taxes and applies the operating expenses based on the party's Working Interest percentage and cuts a check and prepares a statement.

In the end, the investor gets a check for production in January by the end of February or beginning of March.

Chapter 6 - What is the time frame between writing a check to when I get paid from production?

Independent oil and gas companies either divvy up a project into a few large chunks and offer them to other independent oil and gas companies, which is known as a heads-up deal, or they assemble an offering with one to several wells and divide the project into units, which they sell to individual investors. When an oil company sells units to individual investors, it may take from a few weeks to several months to sell all the units and fund the project. In anticipation of fully funding the offering, the operator will schedule the surveyor to mark the site and contract with the dirt-work contractor to level off the site and dig the pits. The drilling contractor is not scheduled until the project is fully funded or at least very nearly funded since this effort represents a significant chunk of the investment capital. Furthermore, if drilling was completed and it turned out to be a dry hole, it would be impossible to sell any remaining units.

Once the well reaches total depth, a logging truck must perform various electric logs on the well.

With the electric logs, drill stem tests, and drilling logs in hand, we have reached a point in the project called the “Casing-Point Election.” The project geologist and operator review all the available information and make a case to either complete the well or declare it a dry hole and abandon it. This whole process from starting to drill, known as the “Spud” date, to casing-point election can take from one to three week in most cases depending upon total depth achieved, geology, equipment issues, and the time to perform various test that the operator may require to help with the casing-point election decision.

With all indications that the well will produce oil, the well completion phase can begin. Production casing needs to be delivered to the site, and the casing must be screwed together and lowered into the well. When the entire casing pipe is set, a cement job is performed to cement the pipe to the sides of the well. While the cement dries, the drilling rig is disassembled and moved off site and a completion rig is scheduled and set up on site.

The completion rig perforates the well bore at the appropriate pay-zone depth and installs the tubing inside the casing to conduct the oil to the surface. The completion rig may take a few weeks to schedule and get on site and another several days to complete its work.

Once the completion rig is finished, the surface equipment, such as the pump jack or Christmas tree, must be installed. Surface treatment and storage tank installation must also be scheduled and completed. Since some combination of gas, oil, and water are usually present in the fluids conducted from the well, a separator unit may be install. Storage tanks for the oil and flow lines to connect them all are installed. If gas is present, gas lines are run to the nearest sales point on the national gas pipeline. Over all, surface equipment completion can take another month or more from the time the completion rig finishes up.

Production generally begins slowly at first and builds over the next month or more to reach full production. Lastly, you need to add to the production two months or so from production to payment. The elapse time from writing your investment check until you see the first revenue check, assuming a successful well, can span from four months to well over six months.

Chapter 7 - Where do you find oil and gas?

The popular image of a cavity in the earth containing a pool of oil and gas waiting to be pierced by a drill bit and then gushing from the ground in a geyser of oil is not a realistic representation of how it works. First, oil and gas are produced from source rocks deep within the earth. Oil and gas escape from the source rock and migrate toward the surface. Sometimes it makes it all the way to the surface, but more frequently it gets trapped in underground reservoirs called "Traps."

The journey begins millions of years ago. Organic materials like fish and plants die and sink to the bottom of the sea or large lake. Layers and layers of this organic material are built up over time, forming what is known as a "basin." Eventually, the water level recedes with variation in sea levels, tectonic uplifts, evaporation, or simply gets over grown by vegetation and ceases to exist. Other materials are deposited over the top, causing the different layers in sedimentary rock formations. This process happened over and over again trapping the organic material deeper and deeper within the earth. Heat and pressure began to increase and after millions of years, the organic material is essentially cooked, and oil and gas are produced.

Shale is a common "Source Rock" formation and is made up of very fine particles making the extraction of oil directly from shale more difficult. Because of the tight nature of the particles, gas is often found in shale. Many pure gas plays use modern techniques like horizontal drilling and hydraulic fracturing to release gas directly from the shale source rock. The Barnnet Shale formation in Texas is a prime example of large quantities of gas being produced directly from source rock.

There is an oil window that ranges from 7,000 feet to about 18,000 feet where oil is produced. At shallower depths, no enough heat and pressure is generated to cook the organic material into oil. At depths greater than 18,000 feet, the temperature exceeds 300° Fahrenheit, and the oil is transformed into graphite and natural gas.

The creation of gas and oil from organic material causes an increase in volume. This volume increase causes additional stresses on the source rock and fractures are formed. Into these fractures oil and gas flow and escape the source rock. Because oil is less dense than water, when the freed oil encounters subsurface water, the petroleum rises through pores and cracks. Oil and gas migrate upward and laterally for vast distances until it encounters a trap, preventing further upward movement, or until it reaches the surface and creates an oil seep.

In the sixteenth and seventeenth centuries oil, harvested from whales, was used in lamps. In 1859, an oil seep was discovered in western Pennsylvania, and the first commercial oil well was drilled nearby to release more of the crude oil. The oil industry as we know it was born. For the next 50 years, wells were randomly drilled near seeps. It was not until the early nineteen hundreds that geology was applied and the theory that oil and gas was trapped in anticlines and domes underground gave rise to what we now know as reservoir rocks.

When the upward migration of oil and gas encounters an impermeable layer of rock, known as a "Cap-Rock" or "Seal," the oil and gas is trapped. Traps are structurally high areas with a cap rock, such as chalk or salt, that prevents further upward movement. Salt as a cap rock is easy to comprehend as an inland sea evaporates it leaves only a thick salt deposit behind. Traps can sit on top of a basin where the oil and gas were formed, but in addition to upward movement, the water can carry oil and gas laterally quite some distance from its source.

There are many types of traps. However, three types tend to be the most common. First there is the "Anticline," which is a hill in the sedimentary rock that acts as an upside-down bowl. Anticlines are easy to visualize; just look out upon the rolling plains and imagine the next layer of sediment laid down being a cap rock. Over time, the hill would become an anticline.

Another common trap is what is known as an "Angular Unconformity." Here, geologic forces tip the sedimentary rock exposing several strata to the forces of erosion. Then after a time, a new layer of sediment, of the cap rock variety, is laid over the top in what is a different plane. Oil and gas traveling along a porous layer is stopped when it encounters the cap-rock.

A third common trap is caused when a fault misaligns sedimentary layers, ending the pathway for migrating oil and gas.

As oil and gas is removed from a typical reservoir, water pushes the remaining oil and gas to the top of the structure. As the oil-water contact line rises, wells that are up-dip will produce oil longer while wells that are down-dip will produce more and more water until they stop producing oil all together. So wells within the same reservoir that are highest in structure potentially will produce more oil and gas during their lifetime than wells located lower in structure.

A closer look at the reservoir itself would not reveal a cave filled with oil and gas but rock with pores or spaces between the grains to trap oil and gas. Two common types of “Reservoir Rock” are sandstone and limestone. Sandstone, as the name implies, is composed of grains of sand pressed together to form a type of rock. If you were to look closely, you would see spaces between the grains where oil and gas can collect.

The volume of open space to sand grains might be 5% to 20% by volume and is known as its “Porosity.” So a square foot of oil-saturated sandstone with a porosity of 20% would contain one fifth of a cubit foot of oil. The higher porosity, the more space it contains to trap oil and gas. In addition to porosity, fine particles often cement the sand grains together. Sometimes the cement prevents the propagation of oil and gas between the individual pores between the grains. The measurement of a formation’s ability to allow oil and gas for spread between pores is called “Permeability.” Formations with high permeability prevent the movement of fluids and gas and act as a cap-rock that trap oil and gas. Sandstone formations that have a higher-than-average permeability are considered to be “Tight” formations.

Sandstone starts out as concentrations of sand. Some smaller sandstone formations are developed when a slow running river meanders its way across an open plain and deposits sand grains along the inside of a river bend. You can visualize this when you look at how the Mississippi river winds its way toward the Gulf of Mexico. The Miller Creek field in Wyoming is a good example of a sandstone formation created by river deposits.

Windblown sand dunes, like the ones you can see in the Sahara desert, are another way sandstone reservoirs are created. The Nugget Sandstone of the Rockies is an example of sandstone reservoirs created from windblown dunes.

Ocean beaches are another way sand is concentrated in the formation of sandstone. The Clinton oil and gas fields in Ohio were once a beach when an inland sea covered much of the continent.

When a river reaches the ocean, it slows down and deposits sand grains swept up in its flow forming large river deltas. Ancient river deltas get buried and create some of the largest sandstone reservoirs. Offshore drilling near the mouth of the Mississippi River and Niger River in Africa are examples of ancient river delta deposits.

Erosion or the weathering of rocks creates sand, and where ever sand collects, nature will someday create sandstone. The layers are added, and the forces of gravity and time work their magic.

Limestone is another common reservoir rock formation. Limestone is essentially the shell remains for tiny sea creatures. Coral is a common source of limestone formation, and the pores that once held the living creature now serve as tiny pockets to capture oil and gas. In prehistoric times, many shallow seas existed. Warmed by the sun, they created an ideal breeding ground for coral and other shelled creatures. Over time, the seas evaporated, often leaving behind a salt layer that acted as an ideal impermeable cap-rock. Eventually other materials too were overlaid, and these reefs were buried deep below the surface where time and pressure could work their science.

A defining characteristic of limestone is its relative softness. It fractures easy and dissolves in the presence of light acids. Tectonic uplift often creates cracks that allow oil and gas to migrate throughout the formation. Water or other solvents that are slightly acidic help to further open up the cracks and pores making limestone an ideal medium as a reservoir rock.

Simply knowing about the existence of traps is not enough. Geologists need to know how to locate and identify them deep underground. One tool geologist use is what is called “Well Control,” which are cutting records from nearby wells. These records allow geologist to get an understanding of the sequence of layers found in a given area. By comparing information, they can make assumptions about the depth of various rock formations believed to hold hydrocarbons and get a sense about whether they are tipped toward the surface, known as “up-dip,” or getting narrower or pinched. Armed with this information, geologists prepare an “Isopach” drawing that looks like topographic maps of sub-surface structures. However, isopach maps, rather than showing elevations like a topographic map, shows areas of similar thickness in a given pay zone.

To provide better fidelity of their isopatch interpretation, geologist often turn to geophysicists for additional information to prove their prospect. Geophysicists use highly sensitive instruments to measure minute variances in magnetic and gravitational data, which helps to corroborate the presence of anomalies or unconformities. In addition, they may initiate some direct testing using sound waves, known as “Seismic” testing.

2D seismic uses explosives or a thumper truck to send acoustic waves into earth. By measuring the reflection’s energy, a geophysicist produces a “wiggle trace” that shows the relative placement and depths of various strata made up of different densities. 2D seismic runs are performed in straight lines that produce vertical slices of data. Several 2D runs can combine to show the relative boundaries of potential underground reservoirs. Depending upon the surface terrain, a seismic line can cost from $3,000 to $12,000 per linear mile.

3D seismic is essentially several cross sections of 2D seismic data taken at different angles and inputted into a computer system. The computer system then crunches the data and produces a three-dimensional cube model of the target formation. Again, depending upon the surface terrain, 3D seismic can run $30,000 to $50,000 per square mile.

4D seismic is essentially two 3D seismic models taken over a period of several years on an existing field to track fluid movements as a reservoir is drained.

Chapter 8 - Why is understanding well spacing important?

In the old days, finding oil was a very risky and expensive business, and once a wildcat well was discovered oil, new wells were drilled in very close proximity to the strike. Geologists later learned that a single well has an effective area it can drain based on permeability, bottom hole pressures, and/or depth. Today's leases are governed by the state's oil and gas commission and define well spacing so as to provide each well with the maximum amount of unrestricted draining, yet provides for maximum reservoir drainage. Permits are issued in acres and are a product to dividing up a square mile of land. A square mile, known as a "section," is composed of 640 acres. If you divide each side of the square into a quarter mile subsection, you would get 16 40-acre parcels. Forty acres is a typical spacing for most wells drilled to around 6,000 feet. Forty acres represents the most efficient recovery area for well's drilled to this depth. Closer spacing might affect adjacent wells, while further spacing would leave too much unrecoverable oil.

If the formation is known to be particularly tight, as might be the case when oil is extracted directly from shale, then closer spacing such as 10 acres between wells is assigned. Also the deeper you go, the more bottom hole pressure and the greater the spacing is likely to be.

Mineral rights are sometimes granted to a specific depth range, which might allow two directly adjacent wells on the surface to actually produce from different zones. The drilling permit often includes the primary type of hydrocarbon being produced. Exclusively gas producing wells can drain a larger area than oil, and therefore are usually granted greater spacing.

Chapter 9 - What does it take to get a well into production?

Before any well gets drilled, a prospect has to be identified. Geologists and geophysicists review existing data, such as satellite imagery, variations in gravity, and magnetic readings, in a specific area to identify anomalies that might identify a potential prospect. When a potential prospect is located, a review of well data from nearby wells is reviewed and further testing may be called for. Seismic tests may be run to improve the case for a potential prospect. Strata-graphic traps, which define the reservoir boundaries, are identified, mapped, and often modeled.

With a prospect identified, a landman is engaged to secure the surface and subsurface mineral rights. Sometimes the subsurface rights are severed from the surface rights and are owned by different parties. While a farmer may own the surface rights, someone else, often a government or private entity, may own the mineral rights below the surface. The landman, usually a type of lawyer, negotiates a contract to hold the rights granted by the owner. Generally, an upfront bonus is paid along with some royalty on production in exchanged for the rights.

With the prospect defined and the rights controlled, the prospect is often promoted to other individuals or other companies. Big companies such as Exxon Mobil or EnCana[7] may progress right to drilling, but independents general look for investors to share the risk of drilling the prospect. Some independents have a network of other independent oil firms that share prospects, and others have a promotion company subsidiary that specializes in the promotions of the company's prospect to individual investors like you.

The promotion company develops the documentation describing the offering and employs salesmen to sell shares or units in the project. Promotion companies that sell to non-accredited investors, investor making less than $200,000 a year or who have a net worth of less than $1,000,000, are not allowed to advertise their offering and are subject to greater oversight from the Securities and Exchange Commission or SEC. Selling to non-accredited investors requires more legal disclosures and documentation, adding to the projects indirect costs. Indirect costs are costs not related to drilling and completing a well that must be paid for by the investors as part of higher promotion fees. Certain exceptions, such as the ability to advertise projects, are sometimes allowed, provided the promotions company restricts their sales to only accredited investors.

With the project fully funded, the drilling site is prepared. A survey is conducted to locate the exact spot to drill. Roads are then made to provide access to the site from existing roadways, and the pad site is leveled. Pits, used to hold water and mud during the drilling operation, are dug and lined with plastic. Raw materials, such as water and clay to make the mud, are then delivered to the site.

With everything in place, the drilling derrick is moved to the location and set up. Depending on the size of the drilling rig, it may take more than 18 semi-tractor loads and take from one day to several days to set up.

The first step in the drilling process, once the derrick is fully assembled, is to drill an oversized hole about 20 inches in diameter to a depth of about 30 feet. Here, they must install a conductor casing used to keep the surface soil from caving into the hole.

Once the conductor casing is installed, an intermediate size hole is drilled to a depth exceeding the local water wells, and a surface casing is installed. Cement is pumped into the casing and up around the sides to seal and prevent cross contamination between the water table and oil well.

Once the cement is dry, drilling can begin in earnest. The drill bit most commonly used today has teeth on three drums that rotate to break up the rock. Drilling mud, often referred to simply as “mud,” is a mixture of clay and water. This mud is plumbed down the drill pipe and forced between the teeth to help lubricate the bit and to help carry the cuttings back to the surface where the mud and cuttings are separated. The mud is recycled, and the cuttings removed for analysis by the on-site geologist.

The first few sections of drilling pipe are very heavy and are referred to as the “Drilling Collar.” Their weight is more than enough to provide the force necessary to push the drill down through the earth. The drill bit and drilling collar, known as the “bottom hole assembly,” are actually kept from drilling too fast by keeping cable tension in the entire drill stem.

Sections are added to the drill stem in 30-foot increments until the total depth is reached. During the drilling process, the cuttings are analyzed and recorded on a strip log every 10 feet or so. Drilling speeds are also tracked on the strip log. Changes in drilling speeds often denote a different stratum has been reached. Depending upon the well’s location, an operator may request core samples when the target structure is reached to determine the zones porosity and permeability. Also, the operator may call for a drill stem test to be performed, which opens up the end of the drill stem for a period of time to determine information about the fluids or gas that may be present at a particular depth.

Once total depth is reached, the drill stem is removed.. With the drill stem out of the hole, wireline logs are run. A wireline consists of several tools assembled together and resembles a sort of torpedo. The assembled tool is made of a variety of tools to test various aspects of the well bore. The entire assembly is placed into the hole and lowered to the bottom of the hole by a cable connected to a logging truck. Once the bottom is reached, the tools are activated, and the tool is slowly retrieved to the surface. As the tool passes through the various depths and strata, data from the tests are transmitted back to the logging truck. Resistively and spontaneous potential are two tests commonly run, although the operator may call for additional tests to get a more accurate picture of the wells composition. Each test tells a story about the structure.

With the hole drilled and the tests run, the well has reached "Casing-Point." Casing-point is the point at which the decision is made to either complete the well or plug and abandon it. A lot of money has been spent to drill and test the well, but there is no need to complete the well if there are not sufficient quantities of oil and gas to provide a sufficient return on the investment. Better to cut and run than risk more money if the test results do not support an economically viable well. Casing-point takes into account a lot of information, including the going rate of a barrel of oil and the price of gas to make the go/no-go decision.

The decision to complete the well means lowering casing pipe into the well until it is just off the bottom. Cement is pumped down the pipe, and a wiper or bottom plug is inserted. A displacement fluid is added, and the plug is sent to the bottom of the hole, forcing the cement up the sides of the well, securing the casing pipe to the sides of the well usually all the way to the surface.

After the cement dries, water or drilling mud is pressurized and tests are performed to verify the integrity of the well. Any drop in pressure indicates there is a leak that must be addressed.

With the pressure tests complete, a completion rig sets up and a perforation gun is lowered to the pay-zone depth. Either shaped charges or steel bullets are used to shoot through the casing pipe and cement and fracture the nearby reservoir. With a clear path for the oil and or gas to make its way to the well bore, oil and gas will begin to flood the bottom of the casing. Generally the completion rig will extract some of the oil for testing in a process called "swabbing."

Sometimes the oil and gas holding formations are somewhat tight and could benefit from being opened up using a process called "stimulation" to increase flow rates.

A common form of stimulation, primarily used in sandstone, is known as a "sand frac." Here sand and fluids are injected into the well and out through the perforations under high pressure to break up or fracture the formation to allow gas and oil to flow more easily. When the frac is complete, the fluid is drained off, but some of the sand remains to hold open the new fractures,

In limestone formations, stimulation often takes the form of a water solution with about 15% Hydrochloric Acid pushed into the formation under pressure for several days. The acid dissolves and widens the many cracks and cavities, improving the porosity and permeability of the well.

Next production pipe, known simply as "Tubing," with a diameter of 1 to 4 inches is lowered into the casing. Packers are used to center the tubing in the casing and to prevent oil from flowing up the sides of the casing. The tubing is the actual pipe that conducts the oil to the surface.

The pressure at the bottom of the well bore is relatively low compared to the pressure in the formation. Oil and gas flow along the path of least resistance and end up in the well bore. While gas under pressure will escape all the way to the surface, oil often will not make it all the way. Images of gushers spraying oil everywhere while wildcatters danced in a shower of oil came from relatively shallow wells where no displacement fluids like mud were used. Today, most wells are quite a bit deeper, and oil needs some assistance traveling to the surface.

To get the oil to the surface, a lifting device is often necessary. A pump jack operates much like an old fashion water pump with a one-way valve installed in the tubing and a lever attached to a piston to pull the oil the rest of the way to the surface. The motors that operate the pump jacks are powered by either free gas from the well, propane or diesel supplied on-site, or even by electricity.

Oil that reaches the surface may contain salt water and gas still held in solution. A "Heat Treater," or "Separator" as it sometimes is called, uses heat, generally from free gas or from an external propane unit to separate oil, water, and gas. Water is the heaviest and remains at the bottom of the heat treater, oil is next, and gas migrates to the top.

Water extract in this process can be pumped out into evaporation pools where the sun evaporates the water leaving only the salt residue behind, hauled off to disposal sites by trucks, or re-injected into nearby dry or depleted wells.

Gas is bled off the top of the heat treater and sent directly to a national supply line. National supply lines have specific requirements for the gas being injected since it is commingled with gas from thousands of other wells. If the gas has too much moisture content, a dehydration unit is installed to remove the moisture. Generally, a chemical like desiccant is used to dry out the gas. If impurities or acid are present in the gas, sweetening units are installed to remove the undesirable elements. And if the pressure is insufficient to meet the line pressure requirements, a compressor is installed to increase the pressure as it is injected.

While some wells may pump oil into an oil supply line, the vast majority of wells are located in fields far away from any supply line, and oil is pumped into holding tanks near the well head. When a tank contains enough oil, trucks are dispatched to haul it to a refinery for processing. Some wells may have several trucks a day scheduled to pick up oil while some tanks take days, weeks, or even months to accumulate enough oil to justify a pick up. As you might imagine, weather can make access to the tanks a treacherous endeavor, so in places where whether can become a problem, more storage capacity is installed so the well can continue to pump and increased offloading can occur when the weather is better.

Chapter 10 - What can go wrong during drilling and production?

During the drilling phase of the project, every precaution is taken to preserve the investment. However, sometime events occur that affect the drilling operations. While catastrophic problems during the drilling are not commonplace, as an investor you need to be aware that problems can arise that will stall or perhaps cause the well to be abandoned altogether. Nobody could produce a comprehensive list of all potential problems you might encounter during the drilling and production phases of any program because each situation is unique. However, the following are some more common problems operators may encounter.

Geologists and geophysicists can't predict with 100% certainty the structural characteristics of the subsurface world. As such, the well walls can become unstable and cave-in, pinching the drill stem, or a drill bit can get hung up on a formation ledge or break off in the hole. Crew or equipment errors on the rig can cause the drill stem to fall back into the well or a perforation effort may result in water rather than oil to flow into the well. Most of these drilling problems can be overcome given additional time, equipment, and money, but some can be catastrophic and require the driller to abandon the hole..

So who pays for problems encountered during the drilling operation? Some operators offer a turnkey operation to the investor and build into their offering a contingency so that if a problem occurs, the operator has the reserve to cover the additional direct costs. Other operators may not include any contingency and pass along any additional costs directly to the investor. Each deal may be different and the investor should read the prospectus or private placement memorandum very carefully to understand if they have any liability for drilling cost overruns.

On the other hand, sometimes the problem is clearly the fault of the subcontractor. For example, an error by the drilling contractor's crew causes them to lose the drill stem in the hole. In these more clear-cut cases, the contractor or their insurance policy will cover the additional expenses.

Assuming a well is drilled and an economically sufficient quantity of oil and or gas is present to complete the well, and it is placed into production, other problems may arise which limit or prematurely deplete a reservoir.

A delicate balance must be struck between getting as much oil as possible out of the ground as soon as possible to provide a return on the investor’s dollars and not doing damage to a reservoir by being too greedy. If a well is pumped too hard, it can cause water to be sucked into the well bore before the natural oil water contact line reaches the well. This is called “Coning” and can trap oil in pockets surrounded by water essentially isolating it and making it virtually unrecoverable using conventional means.

Over time, salt and other corrosive contaminants can eat away at surface and subsurface fixtures or block the pores in the reservoir restricting flow. Scaling can build up and close up tubing and fowl pumps. Paraffin, essentially a wax common in oil, can clog up equipment as cooler temperatures cause the oil to get thick.

As is the case with drilling problems, most production problems can be fixed using work-over rigs or injecting chemicals into the well to neutralize the effects of undesirable elements. When such remediation is necessary, the operating expenses with the well also increase and therefore reduce the investor’s net profit. However, with any action, an economic analysis is performed and generally the cost is more than offset by the increased production.

Chapter 11 - How is my investment allocated and why is it important?

Most independent oil and gas operator’s produce what is called an “Authorization for Expenditures” or AFE, which they provide to potential investors. The AFE lists all the anticipated expenses associated with the offering. To understand an AFE, the investor has to understand a few concepts as they relate to the process.

Upfront investment in a new well covers two phases, drilling costs and completion costs. Some operators have investors write two checks, one for drilling costs and another for completion costs. Some operators have investors write one check, and they simply hold the completion portion in escrow until the determination to complete the well is made.

After the drilling contractor reaches his target depth and the electric logs are run, the geologist and operator meet. They review the geologist’s drilling logs, any drill stem tests performed, and the results of the electric logs. The team makes a decision to either move forward and complete the well or declare the well a dry hole and abandon it. This meeting and decision is known as the casing-point election.

As an owner of a working interest in the project, you have the right to accept the decision of the team and fund the completion and continue your involvement or walk away in what is called going “Non-Consent.” Most of the time, the working interest investor follows the recommendation of the operator, but in some cases they may choose to go non-consent. When an investor goes non-consent, the other working interest investors must cover the cost. Quite often the operator simply picks up the investors share and assumes his working interest in the well. A working interest partner who chooses to walk away at the casing-point election essentially forfeits their claim to any future production of the well. The portion of the investment attributed to costs incurred before the casing-point election are considered spent and are not refunded to the investor. The investor must simply write the investment off.

Other concepts pivotal to understanding the AFE are “Tangible” and “Intangible” expenses. Expenses that are considered tangible and intangible are covered in section 263 of the tax code. In essence, tangible expenses represent money spent for assets such as equipment. Tangible expenses are generally depreciated over 60 months for tax purposes. By contrast, intangible expenses represent money spent for consumables, such as wages, fuel, water, drilling bits, mud, etc. By definition, these expenses have no salvage value and are used up during the process. Intangible expenses can be deducted in the current tax year and can be used to offset income. If the well is considered to be non-economically viable, then all tangible and intangible expenses can be written off in the current tax year.

An AFE is divided into “before” and “after” casing-point so the investor knows what they stand to lose if they go non-consent after the casing-point election and/or what portion might be refunded if they drill a dry hole and the well is never completed. Further, the investor can see what additional funds will be required if the decision is made to complete the well.

Since most of the expenses associated with drilling a well are labor and consumables related, most costs are considered intangible, and as such, they can be written off in the current tax year.

When a well is deemed to hold economically viable amounts of hydrocarbons and the decision is made to place it into production, the AFE serves to inform the investor and their tax accountant[8] what portion of the completion costs are subject to depreciation and what portion can be written off in the current tax year.

Chapter 12 - How much revenue am I entitled to and how much of the expenses am I obligated to pay?

Cash flow from a productive well is the result of the net revenue interest you hold less taxes and the expenses from your working interest.

Revenue is money received by the operator from selling the oil and gas. Several parties have a claim to some of that revenue in addition to the investors. Property and mineral right owners have a claim to a portion of the revenue of a well. As is the customary practice in the industry, property and mineral right owners do not invest money but provide the surface land and mineral rights to subsurface minerals, including oil and gas, for a share of the revenue if the well is successful. As an additional form of compensation that is not tied to the success of the well, they also are paid a lease rate and usually some type of bonus when the lease is executed.

The interest property or mineral rights owner's hold in the revenue is called a "Royalty Interest." This term dates back to the days when only persons of royal blood could own land. Commoners who worked the land were required to pay a tribute to the landowner. This tribute was called a royalty.

Owning a royalty interest in a well entitles the owner to a portion of the revenue without the burden of sharing in any of the pre-production drilling or completion costs. In addition, royalty owners do not share in the operational expenses during production phase either. They have a right to a portion of the revenue and pay no expenses. The portion of revenue allocated to royalty partners ranges from 1/8th (12.5%) to as high as 5/16th (31.25%).

In addition to royalty owners, sometimes the landmen that do the leasing of the land and the geologist who performed the initial research and identified the prospect have a share of the revenue. Sometimes the operator pays directly for the prospect, and this service appears on the AFE as "Geological and Geophysical" expenses or G&G expenses. Sometimes they provide a unique type of royalty interest called an "Over Riding Royalty Interest" or ORRI. An overriding royalty interest partner receives the same treatment as a straight royalty interest owner in that they do not pay expenses but have a claim to the revenues if the well is successful. By getting paid only for successful wells, over riding royalty interest partners have an all or nothing stake in a successful outcome and would only invest the time and energy in prospects they truly believe hold a high degree of success and payment.

Whereas the use of the word “Royalty” in the interest denotes no expenses paid, the word “Working” denotes expenses paid. However, within the class of working interests, there is a class of interest that is call “Carried Working Interest.” This term means that the partners’ expense share is carried to a specific point, at which time the partner assumes a regular work interest. The Operator is most often a working interest partner in the deal. However, for bringing together and managing the investor relationships and coordinating the drilling, testing, and completion efforts, the operator often structures the deal where their working interest is carried through drilling and often all the way through completion. The carried component is compensation for his efforts as being the operator working interest partner. Once the well is successful and begins production, the operator takes on the full working interest and pays their share of the operating expenses from that point forward.

As the investor or participant in the deal, your cash investment pays for all the expenses through the casing-point election and often all the way through the completion phase. The investor pays all the expenses associated with the lease acquisition (including lease bonus), G&G costs, the operator’s administration costs (including all offering costs such as legal fees, sales commissions, and management fees), as well as the actual drilling, testing, and completion costs. Finally, if the well is successful, royalty owners exert their claim to a portion of the revenue and do not share in the operating expenses. Investors typically pay 100% of the per-production, drilling, and completion expenses. During the production phase, investors share the expenses with the operator in what is known as your working interest. In compensation for covering all the per-production and most of the production expenses they are granted a net revenue interest or NRI, which they share with royalty interest partners. Therefore in the final reconciliation as an investor, you might own 2% of the operating expenses and receive only 1.6% of the revenue since there are more claims on revenue than on expenses**.**

However, before you count on your 1.6% net revenue, net revenue as a whole is subject to state severance tax. Most states levee a severance tax on all oil and gas revenues. Some states, such as Alaska, impose high severance taxes around 15%, while some states, like Illinois, levy zero severance taxes. Most states levy their severance tax based on a percentage of revenue, four states (California, Idaho, Nevada, and Ohio) levy a fixed tax based on every barrel of oil produced, regardless of the price paid for a barrel of oil. Severance taxes may be the same for oil and gas, but some states like Texas impose a 40% higher severance tax on gas production than on oil production. In the end, most states levy a severance tax in the amount of somewhere between 3% and 6% based on revenues.

In the final accounting, once the total revenue for a well is calculated, it is divided up to all the partners based on their net revenue interest. This gross revenue is then subject to state severance tax, resulting in the partner's net revenue figure for the month.

The total expenses for the month are calculated and divided up amongst all the working interest partners based on their working interest percentage. Finally, expenses are subtracted from net revenue and a check is cut.

Chapter 13 - Are there varying degrees of project risk within direct participation deals?

One hundred and fifty years ago, oil wells were drilled next to a seep where oil or gas made it all the way to the surface. Success rates were pretty good, but production was not overwhelming. About 100 years ago, all the known seeps were produced, and exploration companies had to rely on new ways to find new sources of oil and gas. The practice of drilling a well in a new location in the hopes of finding a new oil field is known as drilling an “Exploratory” or a “Wildcat” well.

Wildcatters, as they became known, during the early nineteen hundreds still didn’t quite understand what made one location better than another, and plenty of less than scientific methods were employed in trying to locate the next big strike and lure investors. Some were successful, but most were dry holes. The image of an old codger on his hands and knees sniffing the dirt or using a divining rod to locate the next well left many investors broke and pegged the oil and gas industry as an extremely risky business.

Today, geology and geophysics have evolved into a true science. These days, oil and gas exploration is far more sophisticated and employ satellites that can take photos of surface features from far overhead, revealing clues about subsurface structures. Highly accurate magnetic and gravitational measurements can expose evidence of the three-dimensional world below a farmer's crop. And the use of seismic technology that measures sound propagation through the ground from various points, with the aid of complex computer programs, can produce an x-ray of sorts of the inside of the earth. With all these advances, exploratory drilling still produces more dry holes than producing ones. The science of geology and geophysics can locate and map underground structures, coupled with what is known about the ancient fossil records, they can make a compelling case for drilling in a particular location. However, the real proof comes from drilling the well. Just because the structure is there doesn’t guarantee it will hold oil and gas in quantities sufficient to make the well viable. In fact, many dry holes drilled during periods of low oil prices had oil and gas present, but based on the spot price of the day, the well was deemed to be dry because not enough money could be made to offset the expense of completing the well.

Wildcat wells remain the most risky type of well to drill, but with greater upfront testing, better prospects are produced thereby reducing the risk to the investor at the expense of higher upfront prospect development costs and diluted revenue interests.

Midway down the risk continuum is what are known as “Offset” or “Development” wells. Once a wildcat well has establishes a new field, additional wells are drilled nearby to establish the boundaries of the field. While many offset wells fall within the boundaries of the new field, some will discover the edges and be dry holes. Trends such as formation tops and pay-zone depths are collated with each new well drilled, and an accurate picture of the reservoir is revealed. Back in the old days, once a wildcat well discovered a new field, operators would descend upon the strike and buy up leases left and right that were not secured by the initial operator, and wells would be drilled practically on top of one another. The East Texas oil field discovered by Columbus Marion “Dad” Joiner in 1929 was determined, through the use of development wells, to be 45 miles long by 18 miles wide and contained over 11,000 wells. In some sections of the reservoir, wells were drilled literately right next to each other, leaving the town of Kilgore, Texas, at the heart of East Texas oil field, as having the world’s richest acre of land.

The East Texas oil field was one of the largest fields ever discovered in the continental United States, and because wells were thought to simply tap into an underground river of oil, well spacing prematurely destroyed much of the reservoir. Today, geologist know that oil is trapped in reservoirs made of such materials as sandstone and limestone and have a better understanding of reservoir dynamics, which they use to determine optimum spacing between wells. Many developmental wells are spaced on forty-acre parcels, but depending upon depth and other factors this may be increased or decrease based upon the known subsurface geology.

In the end, offset wells are far less likely to produce a dry hole since the reservoir is known to contain oil and/or gas, so the risk comes primarily from the wells drilled along the edge where the pay-zone is pinched out.

On the least risky end of the oil and gas play are secondary recovery projects. In secondary recovery projects, the investor’s money is not generally used to drill a bunch of new holes but used to buy existing wells that have reached their end-of-life based on the depletion of their primary drive mechanism.

Oil fields employ one or more “Primary Oil Drive Mechanisms.” Some oil drive mechanisms, such as solution gas drive, are poor drive mechanisms resulting in a substantial amount of the oil being un-recovered when the primary drive is exhausted. Secondary recovery techniques employ alternative measures to improve oil recovery once the primary drive is exhausted.

Solution gas drive reservoirs produce from between 5% and 30% of the oil in the reservoir. Said another way, 70% to 95% of the oil is still left in the reservoir. By contrast, a water drive reservoir will produce between 35% to 75% of the oil in a reservoir. Therefore, a solution gas drive reservoir whose wells had reached their end of life based on their primary drive might be acquired by an operator for secondary oil recovery. Assuming the operator took some of the wells and converted them into infector wells, where water is pumped down into the well displacing the oil in the reservoir, then a good portion of the oil left in the ground, after the primary recovery was complete, could be recovered by introducing a new reservoir drive, in this case water.

Reservoir stimulation is not restricted to simply water flooding but may include the injection of gases such as CO_2 or other chemicals in an effort to release more of the oil left in the reservoir. In the end, secondary recovery plays are generally much larger projects that entail complex negotiations between lots of different players and a substantial pool of money to make it all happen. That said, generally no investor's money is expended in drilling new holes that might be considered dry. Each well has a proven track record of producing oil, the underground structures are identified through logs, and each pay-zone is known in terms of quantity and quality. Tax treatment is a bit different on secondary recovery projects, but in the final accounting, they are the lease risky in terms of simply not producing any return.

Chapter 14 - How long and how fast does a well produce and what affects it?

How long and how fast a well will produce it's return on your investment is a product of three key factors: the size of the reservoir, the permeability of the reservoir, and the reservoir drive mechanism. Size is relatively straightforward in that a reservoir that is larger in terms of pay zone should produce more oil over time than a smaller one.

Permeability is more a factor that affects the speed of recovery more than how long a well will produce. Permeability is the force that restricts the well's ability to move oil. Therefore, assuming no remedial action, such as fracing or acidizing, to improve a reservoir's permeability, a well that is more permeable would allow for more oil to flow to the well bore quicker. However, permeability affects the time value of money. While a well may produce 100,000 barrels of oil during its lifetime, one that produces this amount in 7 years provides a better return to its investors than one that produces the same amount over a period of 20 or 30 years based on the time value of money.

The reservoir drive is a key factor in determining the amount of oil that can ultimately be recovered. There are two primary drive mechanisms: water and gas. When water is the primary force that has forced oil into a trap, we consider the reservoir to have a "Water-Drive" mechanism. Since oil is lighter than water, oil and water separate, and oil is found at the top. The horizon or point at which the oil and water touch is known as the "Water-Oil" contact line. As oil is extracted from a reservoir, water replaces the oil in the pores, and the water-oil contact line rises. If allowed to produce at a natural rate, dictated by the permeability of the reservoir, wells with a water-drive mechanism usually produce consistent volumes of oil for periods of 20 years of more. However, if wells producing in a water drive reservoir are produced too fast, essentially at a rate not supported by the permeability of the reservoir, water may be sucked along paths of least resistance and close off large portions of the reservoir in a process known as coning.

Water-drive reservoirs might be slower at producing oil than gas drive reservoirs, but they are the most efficient in terms of overall recovery. A well drilled into a water-drive reservoir will extract from 35% to 75% of all the oil in the reservoir.

Gas-drive reservoirs are the other primary drive mechanism. Gas can be either considered "Free-Gas" or "Solution-Gas." Free-gas drive, also known as "Expansion Drive," is essentially a pressurized gas bubble at the top of a trap that presses down on the oil and pushes oil to the well bore. If a well is determined to have a free-gas drive, initial perforations in the casing are made near the bottom of the oil-producing zone to trap the gas and force the oil to the well bore. Once the gas-oil contact-line reaches the perforation, gas levels increase rapidly and oil production falls off quickly with a loss of drive. Initial production from a free-gas drive reservoir is high, resulting in a quick return on the investor's dollars. Free-gas drive reservoirs, however, do not produce nearly as long as water-drive reservoirs. Typically, a free-gas drive reservoir will produce from five to seven years and will extract between 20% to 40% of all the oil in the reservoir.

Solution-gas is gas that is dissolved or trapped in the oil itself under extreme pressure, much in the same way that CO_2 gas remains in a solution inside a sealed soda bottle. Once opened to the atmosphere, the pressure is allowed to expand, forcing oil and gas to the well bore in the same way that soda and gas spray out of the of the opening of a shaken bottle of soda. Wells drilled into a solution-gas drive reservoir have high initial production, but just as with our soda analogy, reservoir pressure quickly drops as gas comes out of solution. The primary production windows for solution-gas drive reservoirs can range from a few months to a few years. Solution-gas drive reservoirs are the least efficient at producing oil in that they only produce from 5% to 30% of all the oil in the reservoir.

While a reservoir will have a primary drive mechanism, often they may have a secondary drive mechanism as well. For example a free-gas drive reservoir may also have a water drive. When a gas-drive reservoir has no secondary drive, it becomes a candidate for secondary or enhanced oil recovery efforts.

Chapter 15 - What is secondary or enhanced oil recovery?

A large number of reservoirs have a relatively inefficient primary drive mechanism, and as such leave vast quantities of oil unrecovered in the ground. “Secondary Oil Recovery,” sometimes referred to as “Enhanced Oil Recovery” (EOR), is a method where wells that have exhausted their primary drive mechanisms, yet are believed to hold large supplies of unrecovered oil, are stimulated to produce more oil.

During enhanced oil recovery, substances that are not natural to the reservoir are injected into the reservoir to extract some portion of the remaining oil. Enhanced oil recovery involves using heat, gas, water, pressure, and various chemicals injected into some wells to push oil to nearby wells.

Thermal recovery techniques use heat in the form of steam or even fire to lower the viscosity of heavy oil, making it more fluid for recovery. Thermal recovery methods can recover 25% to more than 50% of the remaining oil when used as an enhanced oil recovery technique.

If the reservoir is not plagued by heavy oil, but suffers more from porosity type issues, inert gases like CO_2 can be injected into a well under pressure, causing the gas to dissolve in the oil and making the oil more fluid while the pressure forces the oil to nearby production wells. Carbon Dioxide floods as they are sometimes called, can often recover about 30% of the remaining oil as an enhanced oil recovery technique.

When wells suffer from inefficient primary drive mechanisms, such as solution-gas drive reservoirs, then water flooding is an effective enhanced oil recovery technique. Often simple water flooding is enhanced further with the use of chemicals to produce a chemical flood that further aides in releasing more of the trapped oil. Chemically enhanced water floods inject batches or slugs of water mixed with chemicals, such as detergents to wash oil out of tight pours perhaps followed by water thickened by mixing it with polymers to push oil from injector wells toward production wells. Chemical water floods can recover about 40% of the remaining oil when used as an enhanced oil recovery technique.

Chapter 16 - What are the ongoing production-related tax advantages of investing in direct participation deals?[9]

All operational wells have lease-operating expenses to get the oil to the tanks or gas to the meter. Remember that as an investor, you hold a working interest and must cover the expenses for royalty owners. Your share of the well's expenses is ultimately subtracted from your gross revenue each month before you receive your check each month. These expenses are deductible in the year they were incurred. On an average basis, lease operating expenses for a working interest partner amount to about 5% to 15% of revenue. Some months, it may be less, and others quite a bit more depending upon actions undertaken to stimulate a cantankerous well. Clearly as wells mature, they produce less oil while operating expense may remain relatively flat throughout their life. Therefore, as a well matures the operating expense as a percentage of revenue generally grows.

In addition to being able to deduct lease-operating expenses, the government grants direct oil and gas investors with a depletion allowance. When you buy or lease the mineral right for a piece of property, you are in fact procuring an asset as defined by the IRS. When a regular business buys an asset, such as a computer or other equipment, the IRS allows then to depreciate the value over a period of years usually five to seven years. Mineral rights assets, however, are not subject to depreciation allowances like other assets.

The exhaustion of mineral deposits through production results in a physical depletion and therefore a reduction in the asset's value. The IRS uses a "Depletion Allowance" vs. a depreciation allowance for taxes in oil and gas investments.

From the prospective of the IRS, some of the income received from the well is considered "True income," and is therefore subject to federal taxes. At the same time, some of the income received from the well is considered "Return on Capital" and is not subject to federal taxes. The depletion allowance is the deduction from gross income to allow for the Return on Capital.

There are two methods to compute the depletion allowance. One is called the "Cost of Depletion" method and the other is the "Percentage Depletion" method. Whichever method provides the greatest deduction in a given tax year can be used.

The cost of depletion method is based on a number of units in a proven reserve less the tax year's number of units produced. For example, if a reservoir is estimated to contain 100,000 barrels of recoverable oil and 15,000 barrels were produced in a given tax year, then 15% of the recoverable reserve was produced. If your total leasehold expenses, that amount you invested to buy your share that is considered intangible expenses, was $100,000 dollars, then 15% or $15,000 is the depletion allowance. When the sum of the depletion allowance taken from year to year reaches your total leasehold expense, then no more depletion allowance can be taken.

It is often difficult to assess the proven reserve of recoverable oil in a field, much less for a given well, and therefore cost of depletion is often not used in smaller wildcat or even development projects where extensive testing and costs were not incurred to compute a reservoir's real potential. However, this method has the most tax advantages when oil and gas prices are on the decline.

The most common means of computing a depletion allowance is the percentage of depletion method. The percentage of depletion method is based on a statutory rate of 15% and is based on revenue rather than expenses. For example, if your share of a well's produced was $10,000 in revenue, 85% or $8,500 is considered True Income for tax purposes, and therefore, this amount is subject to the payment of taxes, while 15% or $1,500 dollars is considered Return on Capital and considered exempt from federal taxes.

The percentage depletion allowance is simple to calculate, and thus is used predominantly by the average investor. The percentage depletion method is the most tax advantageous during periods of flat or increasing oil and gas prices.

Depletion allowances are subject to some restrictions. If you are a major league player and invest in wells that return more than an average of 100,000 barrels or 6,000,000,000 cubic feet of gas per day of domestic production, then you can't use the percentage of depletion method.

Another restriction is that your depreciation allowance may not exceed 100% of the net income from oil and or gas production. For example, let's consider that a well's production is $100,000 in revenue income, but due to high intangible drilling expenses you deduct $90,000 in operating expenses, leaving $10,000 in net income. Since the statutory rate is 15% of revenue, or $15,000, you are limited to only deducting $10,000 in depletion allowance since your computed depletion allowance of $15,000 is more than 100% of your $10,000 net income.

A further restriction is that your depreciation allowance may not exceed 65% of total taxable income. If you, as a taxpayer, are able to reduce your taxable income from various sources to just $10,000 in a given tax year, then the maximum depletion allowance you can take is $6,500 or 65% of your taxable income. Any unused depletion allowance can be carried forward to subsequent tax years.

Lastly, if the percentage of depletion is greater than your lease hold expenses, the amount in excess is considered a “Tax Preference” item and subject to Alternative Minimum Tax or ATM.

Investors can take ownership of working interest (WI) in either their own name or in the name of an entity such as a Limited Liability Company (LLC), Limited Partnership (LP) or Trust. Investors that take ownership of their WI in their own name will have Net Profits subject to self-employment taxes. Investors that take ownership of their WI in an LLC, LP, or Trust will have their Net Profits considered as passive income and can therefore avoid the 15.3% FICA contribution. Investors should always seek tax advice from their tax accountant.

Chapter 17 - What is the liquidity of a direct participation investment?[10]

When you invest in a private placement, essentially you are buying a security that is not registered with the Securities and Exchange Commission (SEC), and as such, your working interest cannot be readily traded on the open market. However, there are secondary markets you can access in the form of auctions that can broker various interests after a specific holding period, such as one year. Auctions generally take place on the internet, similar to eBay, but sometimes auctions are conducted by an auctioneer. Generally, several working interests are auctioned off in a package deal. Buyers at these auctions are restricted to operators or folks in the oil and gas business, so SEC rules do not generally apply. Brokers assemble your production information and post or produce an offering and sell the offering at auction. When the sale is complete, the brokers take a commission on the sale price. Generally speaking, your direct participate in a private oil and gas investment is for the purposes of producing a cash-flow with some tax advantages and not for investing in a vehicle you plan to resell down the road.

Chapter 18 - What are some typical types of documents I will see and what do they convey?

The primary document an investor will see is a "Prospectus" or a "Private Placement Memorandum" (PPM) that contains all the salient information needed to make an informed decision. The document should provide a description of the offering, the location of the prospect, net revenue projections, isopach maps or seismic models to present structure features of the trap, opinion letters from geologists, other information material designed to provide background on the prospect, an Authorization For Expenditure or AFE, and sometimes a balance sheet of the operator. This document often serves as a legal instrument designed to disclose various facts that make the offering exempt from oversight by the Securities and Exchange Commission or similar state agencies.

Another document you might encounter is the "Joint Operating Agreement," sometimes called simply the "Operating Agreement." This is a contract between owners or working interest partners that identify the terms in which the project or property will be developed. It designates the working interest partner that is the operator and which are non-operators or participants.

A document you will definitely encounter is the "Participation Agreement," also known as a "Subscription Agreement." This is a document is a contract between the operator and investors. One key element of this document is that it defines the revenue and expense percentages based on the investor's contribution. It also contains a general release of the operator that he has made all disclosures requested, so you and an investor could make an informed decision.

Most operators selling units of share in a project will include some form of a suitability questionnaire to determine the status of the investor as either an accredited or non-accredited investor for purposes of evaluating the offering.

Chapter 19 - **Is there any personal liability I have as an investor when I invest in direct participation deals?**

When you invest in an oil and/or gas play with an independent operator, you are generally considered a limited partner in the transaction. You are limited in the sense that you are limited to losing that which you have invested and no more. For that reason, some investors invest directly with the operator as an individual without using a business entity, such as an LLC, LP, or Trust, to further reduce collateral exposure in the event of a lawsuit.

Drilling company employees have the highest risk for personal injury and are usually independent contractors to the operator. Furthermore, the drilling company and other vendors, which perform the work for the operator, have their own liability and workman's compensation insurance to handle injury and potential lawsuits.

Generally, when your investment involves buying units in a deal, you are investing with an investment company rather than with the operator's company directly. This adds yet another level of insurance and protection.

By design much of the risk to the investor has been removed or mitigated by the process, however each investor's situation is unique and investor's should seek legal counsel before investing.

Chapter 20 - How do I analyze an offering?

Many investors based their decision to invest or not on the relationship or comfort level they have with the person offering of the deal. While this is fine for individuals with the ability to size up advisors accurately, others with the time and energy will want to perform a bit more due diligence on a particular offering to achieve that sense of comfort with the investment.

Individuals that want to verify and analyze a direct participation deal must first understand their risk/reward threshold. Wildcat or exploratory wells hold a higher degree of risk but a greater reward potential, while development or offset wells are less risky but may suffer some depletion from nearby wells.

After selecting a potential deal that meets your risk/reward threshold, you can easily perform a bit of research to determine the kinds of returns that are possible. First, you should determine the potential amount of oil a well can produce during its economic life.

To determine the volume of oil, we need to gather a few facts about the prospect. A government office determines well spacing in various regions of the country based on a wealth of data. While not perfect, it gives you an idea as to the drainage area a well in the area and depth of the prospect can effectively drain.

Each state has a commission that overseas oil and gas production. These organizations collect and often make available online the well data throughout the state. These online databases are an ideal source to gather comparative data. The prospectus or private placement memorandum should also be a good source to data about the prospect. To calculate the drainage area you need to know:

- The well spacing in the area of the prospect,

- The estimated pay-zone depth, which can be gleaned from nearby wells or from seismic data,

- The estimated porosity, which might be part of your documentation or gathered from drilling logs and records of nearby wells,

- An estimation of a recovery factor based on the expected drive mechanism,

• And finally a shrinkage factor, which is based on the oil to gas ratio.

To calculate the recoverable oil, let's assume we have gathered this information about our prospect:

• 40 acre spacing

• 10 feet pay-zone depth

• 15% porosity,

• 50% recover factor

• 80% formation-volume factor

If you were to flood an acre with one foot of oil, it would take 7,758 barrels. Since we have 40 acres we can drain, we would multiple 7,758 by 40. Since our pay zone depth is 10 feet, we can multiple the results by 10. Since our porosity number indicates that 85% of the space is made of sand grains and 15% is the volume left for oil, we would continue the equation by multiplying the product by 0.15 to reduce the volume to account for only the space between the grains. Since the primary reservoir drive is water, we can assume that about 50% of the oil is recoverable, so we continue to multiply the product by 0.5 to account for only recovering 50% of the oil.

The shrinkage factor, sometimes known as the "Formation-Volume Factor," is based on the fact that oil in the ground may have a quantity of dissolved gas, therefore what may take up one barrel of space in the ground, when brought to the surface may only be 0.8 barrels of oil and a bunch of gas. Let's assume an 80% shrinkage factor and multiple our product by 0.8.

7,758	Acre Foot
x 40	Acres
310,320	Barrels of Oil
x 10	Pay-Zone Depth
3,103,200	Barrels of Oil
x .15	Porosity
465,480	Barrels of Oil
x .50	Recovery Factor
232,740	Barrels of Oil
x .80	Shrinkage
186,192	*Barrels of Oil*

The resulting equation would indicate that this well, if successful, should produce 186k barrels of oil based on our data.

186,192	Barrels of Oil
x $70	Discounted Price
$13,033,440	Total Revenue
x .065	NRI (6.5%)
$847,174	Net Revenue
- $50,830	Severance Tax (6%)
$796,344	After Tax
- $79,634	Expenses
$716,710	*Net Profit*

Next you can determine the wells revenue potential by multiplying 186k barrels by what you believe the average price the operator will receive for the oil over the life of the well. Remember that refineries discount the spot price to account for transportation and other costs. If we assume that the average price paid for a barrel of oil is $80 and there is a $10 discount for transportation, making a $70 discounted price, then the revenue potential for our well is now about $13 million.

Since your investment covered 10% of the project costs, and since after royalty interests and promotions costs we are left with 65% of the revenue for working interest partners, your net revenue interest or NRI is 6.5%. If you multiply the $13m by 6.5% NRI, your Net Revenue would be about $847k.

Deduct from the Net Revenue the states severance taxes, say 6%, and account for your share of operating expenses, perhaps 10% of revenue, and your return on investment or Net Profit is reduced to about $716k.

Since not all wells are successful, you have to apply a risk factor. Some operators disclose their success rate in drilling wells, but others do not. If they do not, you may have to guess or perhaps you can do a search on the states well data site to determine just how many dry holes to production holes the operator has drilled. Of course, you have to consider the nature of the prospects as compared to the operator's history. For example, were they drilling mostly development wells in the past, but this prospect is a wildcat well? If so, then the success rate would not be as high.

For our evaluation, let's assume a risk factor of one in three wells being production so we would divide our $716k by 3 to get our $238k.

Of course this $238k is not paid out in one lump sum when we hit oil but paid out over the life of the well. Therefore, we have to apply what economists call the "Time Value of Money".

Assuming a modest 3% discount on money received each year for 10 years, we would discount future payments and come up with a revised present day return of about $209k.

If the total money raised to drill and complete the well was $1,000,000, and your share was 10% or $100,000, you would see a two to one return on your money in today's dollars.

If you feel comfortable with your numbers, this would be a pretty good bet. If not, play with the numbers until you feel them to be about as accurate as they can be. If the return looks good, pull the trigger and invest. If not, wait for another deal. In the end no deal is a guarantee, and it not recommended that you risk funds you can't afford to lose.

Trying to understand and compare different offerings can be time consuming and confusing task. To aid in the effort, we offer a FREE analysis tool to help you process all the information in an offering at www.LearnAboutOilAndGas.com

Successful people make their own luck. Luck is not a random gift but the ability to spot a deal and having the means to execute.

End Notes

1. The author makes no representation for or against the advisability of investing in these companies

2. Not all public oil and gas companies pay dividends

3. Some transactions such as Master Limited Partnerships MLPs, Royalty Trusts, etc may have unique tax treatment.

4. WTI can be found on the NYMEX (New York Mercantile Exchange)

5. Investors should always consider the current events throughout the world, such as actions in the Middle-East, which often effect crude oil prices.

6. Investors should always consult the offering documents to determine when investors are pair.

7. The author makes no representation for or against the advisability of investing in these companies

8. Investors are always advised to consult their tax accountant before investing in any oil and gas program.

9. Since tax laws are subject to change, investors are advised on consult their Tax Accountant before investing.

10. Since securities laws are subject to change, investors are advised on consult Legal counsel before investing.

About the Author

At the time of this writing, Steven Imke is the managing member of KSI Oil & Gas LLC, a Colorado company that operates as an SEC registered Internet Investment Advisor under Section 203(c) of the Investment Advisers act of 1940. The author is personally invested in more than 50 oil and gas wells in Ohio, Kansas, Oklahoma, and Nebraska.

When Mr. Imke retired after the sale of a technical documentation and training company he founded, he began investing in various passive income vehicles. After investing in his first few programs and having the resources to perform extensive due diligence on the offerings, a broker/dealers suggested that Mr Imke take his talents as a writer and in video training development and produce a product to assist investors in understand investing in oil and gas private placement programs as an asset class.

During the course of next two years, Mr Imke traveled the United States interviewing experts in the industry and ultimately produced a video series with over 2.5 hours of content to educate investors. Initially his customers were issuers and broker/dealers that used his video product to educate their less knowledgeable clients. In 2011 Mr Imke became an Investment Advisor so he could bring the video products directly to investors and created http://www.learnaboutoilandgas.com for the purpose of making his videos available to the general public. Since that time, Mr. Imke has continued to listen to sellers and investors and has developed tools to assist investors in understanding and making informed investment decisions within this asset class. In 2013 investors requested a companion product they could reference after watching the videos, which resulted in the writing of this book.

Mr, Imke is also the author of *Interactive Video Management and Production,* Copyright 1991 by Education Technology Publication.