The 7 Key Factors Driving Small-Cap Oil and Gas Valuations

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As an investor interested in small-cap oil and gas stocks, you already know it's important to understand the oil price environment, stay abreast of the current state of the market, and to base your investing decisions on facts and data, not emotions. But market awareness alone is not enough to drive intelligent investing in the oil and gas sector, or to target which oil stocks to buy.

There are seven key drivers of oil and gas valuations that every savvy investor should understand before investing in a small-cap oil and gas company. And why small cap? Given the right selection of stocks in one's portfolio and a realistic investment horizon, potential returns from investments in the small-cap oil and gas sector can be substantial: This low-price oil environment offers investors a "buy low" opportunity, and as oil prices stabilize and recover, the potential to maximize ROI increases.

This report looks at why those seven drivers make a difference. It's designed to help investors make smart choices by illuminating the key value drivers that, from an analyst's perspective, identify the most promising small-cap oil and gas companies.

The 7 Key Factors Driving Small-Cap Oil and Gas Valuations

1. **Oil price**
2. **Assets and reserves**
3. **Capital spending and risk sharing**
4. **Costs (operating, financing, G&A) and balance sheet strength**
5. **Fiscal regime**
6. **Geopolitical environment**
7. **Management**

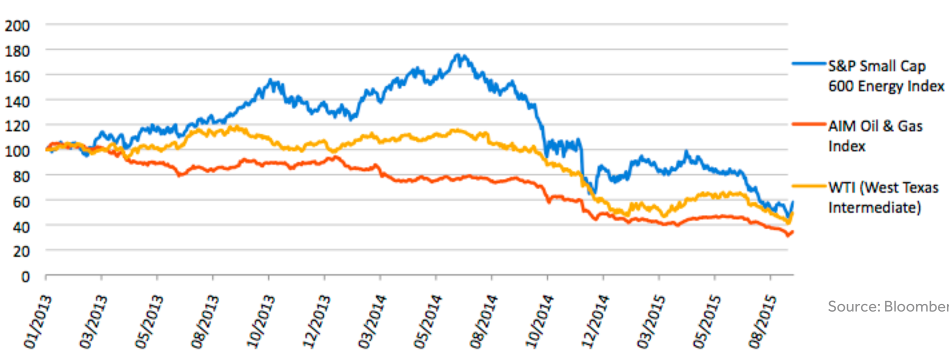
We will look at each of the key drivers in detail, but first it is important to provide some context around current market conditions surrounding the oil and gas sector, specifically:

» How have small-cap oil and gas stocks performed in the past?

» Are there lessons to be learned from markets outside the US?

» How does the industry view equity market valuations?

STOCK PERFORMANCE RELATIVE TO OIL PRICE (REBASED AT 100)



Source: Bloomberg

Stock performance relative to oil price: WTI, S&P Small Cap 600 Energy Index, and London's AIM Oil & Gas Index

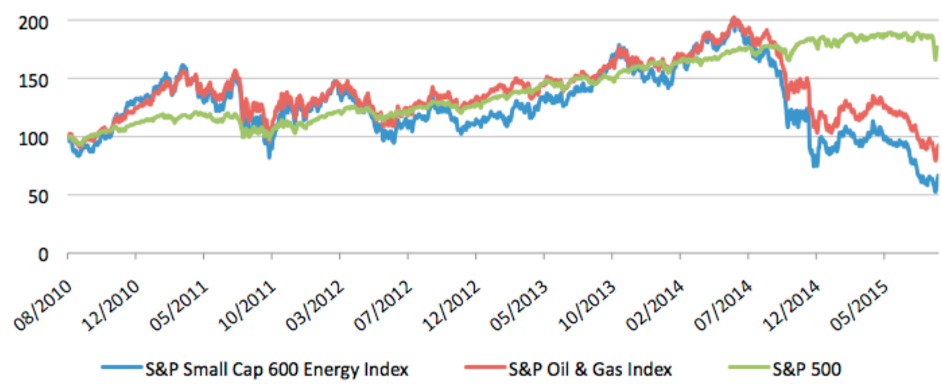
AIM (Alternative Investment Market) is the London Stock Exchange's global market for smaller and growing companies. It is a sub-market that permits smaller companies to participate with greater regulatory flexibility than the main London Stock Exchange. In the case of exploration and production (E&P) companies, the primary LSE exchange would not normally allow them to be listed unless the bulk of exploration was financed out of production income or by third parties. AIM loosened these listing requirements, allowing investors to finance even pure exploration businesses with high risks. The AIM Oil & Gas Index is the international counterpart to the more familiar S&P Small Cap 600 Energy Index. West Texas Intermediate (WTI) is a grade of crude oil used as a benchmark in oil pricing.

Small-cap oil and gas stock performance in the US and UK

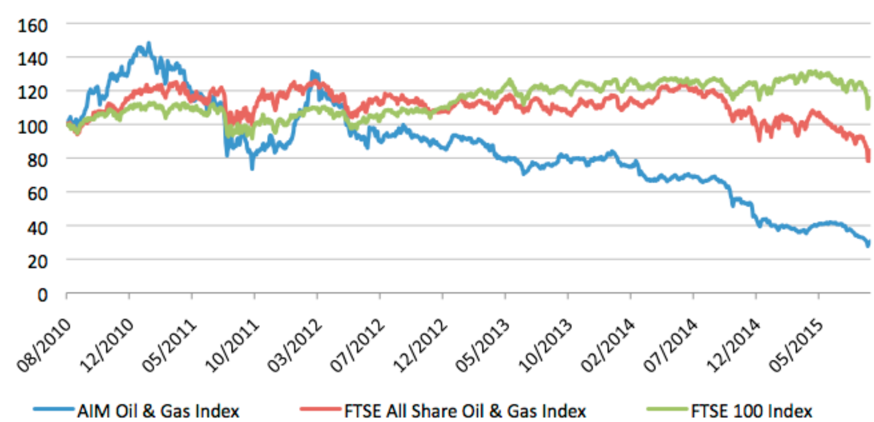
The falling price of oil has pushed small-cap oil and gas valuations down along with it, as demonstrated by the charts. The magnitude of the US index fall shows the significance of oil price for oil and gas valuations.

However, oil price is not the only factor that can materially impact valuations. To illustrate this and what other lessons can be learned from the markets outside the US, we look at London's AIM market, which is home to many small-cap E&P companies with operations all over the world. The following two charts demonstrate the relative performance of the S&P Small-Cap 600 Energy Index versus US main indices (S&P Oil and Gas and the S&P 500), and the relative performance of the AIM Oil & Gas Index versus London's main indices (FTSE Oil & Gas and FTSE 100) over the last five years. While the US small-cap performance was largely in line with the main indices until 2014's dramatic fall in oil price, the AIM small-cap oil and gas index has underperformed for the last three years and lagged even when the oil prices were around $100 per barrel (/b).

S&P SMALL CAP OIL & GAS INDEX PERFORMANCE (REBASED AT 100)



AIM OIL & GAS INDEX PERFORMANCE (REBASED AT 100)



So what caused this discrepancy in market values between the US market and the UK market?

Essentially, the two markets were relying on two different value drivers. While the US sector was driven mainly by shale producers and onshore technological advances, the AIM market was mainly driven by exploration around the world, often offshore and in geopolitically risky regions.

AIM small-cap oil and gas companies were often pure exploration companies that promised high risk / high return, and were popular among more speculative market players with a "*risk on!*" attitude fueled by strong oil prices at the time. These companies' valuations were inflated by market expectations of potential exploration success, and were often much higher than the hard asset value. Eventually, lack of exploration success drove the AIM valuations down.

The quality of the AIM-listed E&P companies was also questionable given the rise in their numbers the past few years: In 2013, there were more than 80 E&P companies on AIM, compared to a measured average of three admissions per year between 1995 and 2005.

This flood signaled that the equity market was willing to provide capital to oil and gas ventures that could not meet the general requirements of a full listing. There was an element of exploitation of those market players who did not understand the nature of exploration and the risks involved, and a "casino" atmosphere for those who did.

Exploration-driven AIM largely failed to deliver promised results

According to global business analysts IHS Inc., the volume of oil and gas found in 2014, excluding shale and other reserves onshore in North America, was the lowest since 1995. Their *Top 10 Discoveries in 2014* (as of August 2014) shows that 90% of discoveries were deep offshore gas and gas-condensate with estimated contingent resources for each in the range of 110 to 377 million barrels of oil equivalent (mboe), approximately 66% of which are offshore Africa.

In other words, there were no new giant oil field discoveries in 2014, despite the fact that exploration activity was still high (the number of exploration and appraisal wells drilled worldwide was only 1% lower than in 2013).

Disenchantment in exploration and a decrease in oil prices put more investor and analyst focus on production, cost control, cash generation, and near-term monetization options. As a result, as of the writing of this report, many E&P companies are trading at or below the value of their production and development (P&D) base, with exploration potential not priced in by the market.

The value gap: industry vs. market

An interesting phenomenon inherent to oil and gas valuations is the difference between industry and equity market valuations, or what's known to analysts as the value gap.

In 1997, Lasmo (acquired by Eni in 2001) paid a debt-funded US$453 million for the Dacion block in Venezuela, and its market capitalization rose by US$428 million. You could have argued that the industry was risk averse, while markets were risk seeking. Majors paid full value (often a premium) for production, but demanded much higher risk premium than markets for assets with less certainty, i.e. exploration. Analysts attributed this distortion in risk appetite to the industry's much more conservative view on the risks (geological, fiscal, political, commercial) and more conservative oil price decks for project economics.

But that was 1997: Things are not quite the same today. While industry transactions can be used as valuation proxies, it is important to understand that any valuation method, however complex or simplistic, is only an approximation.

Valuation is based on a number of assumptions (often subjective) that can change with time and they can also be prone to human error. Consider a recent commercial transaction, the acquisition of BG by Shell.

In April 2015, Shell announced terms that valued BG at approximately $72 billion, roughly a 50% premium. BG's cheap asset value and operational synergies were the main reasons for the deal, according to the press release. However, Shell's appraisal of BG's intrinsic asset value assessment was based on a range of long term oil price assumptions, where Shell used Brent oil prices of $70 per barrel (2016), $90 per barrel (2017), and $110 per barrel (2018-2020) – a price deck that may not look as conservative today as prices fight to stay near $40 per barrel.

Another good example of the gap between industry and equity market valuations is TAG Oil (TAO CN). At the time of writing, the company's stock is trading between $0.33 to 0.60/share. Compare that to an estimated share price of $1.90/share of NPV10 after tax reserves value, based on year-end reserve work by Sproule, an independent petroleum consulting firm specializing in the evaluation of oil and gas reserves and resources. ("NPV10" is commonly used in the energy industry to estimate the present value of a company's proved oil and gas reserves: Present Value of Estimated Future Oil and Gas Revenues / Net of Estimated Direct Expenses / Discounted at an Annual Discount Rate of 10%.)

In this case, industry estimates are healthy, but the market is deflating the company's share value.

The flood of AIM-listed, E&P companies signalled that the equity market was willing to provide capital to oil and gas ventures that could not meet the general requirements of a full listing. There was an element of exploitation of those market players who did not understand the nature of exploration and the risks involved, and a "casino" atmosphere for those who did.

The market's risk appetite has also changed

In December 2011, Cobalt Energy (CIE US) signed the production-sharing contract (PSC) for Block 20 offshore Angola and stated that the Cameia-1 well in the neighboring block "confirmed the existence of hydrocarbons." In the next two months, the share price doubled, delivering a $4 billion-plus appreciation in market capitalization. It then tripled in value, as the company successfully tested the Cameia-1 well offshore Angola. The well was targeting 1 billion barrels (Cobalt's working interest is 40%) prior to drilling.

Today, the Cameia development is estimated to contain 300-500 million barrels. Start-up is scheduled for 2018, and Cobalt Energy's market capitalization is $1.95 billion at the time of writing.

Compare Cobalt's case with the recent case of Cairn Energy (CNE LN), which made two discoveries in Senegal, one of which the company claims "is potentially the largest global oil discovery in 2014." On the day of the first announcement in October 2014, the share price rose a mere 2%, and it has been drifting lower since.

What does it all mean?

The dramatic drop in 2014 oil prices has had an inevitable and substantial negative impact on the valuations of small-cap E&P companies. This has caused market players to question the intelligence of being involved in this sector and to ponder the opportunities that cheap valuations may offer. The questions on every oil and gas investor's mind are:

» Is now the time to invest in small-cap E&P stocks?

» If so, what stocks should an investor buy, given the potential value appreciation driven by oil's future price recovery?

» And is price recovery the best way to evaluate upside potential?

Whatever your view on the future oil price trend, it is important to look beyond oil price and consider key factors that play a role in oil and gas valuations. As our example of the AIM market history shows, it is not *just* about oil price. Companies with a healthy balance sheet, and those driven by a mix of production, development, and exploration offering a balanced risk profile, will be well positioned to benefit from a potential oil price recovery when the time comes. And the pendulum always swings back.

Investing in oil and gas stocks at their lows can be a very profitable long-term investment strategy, if one considers the critical fundamentals and cherry-picks the right companies.

Ask yourself:

What are you buying?

When you invest in a stock, you invest in the company's asset base, its balance sheet and growth prospects. But you also go into business with the geopolitical environment where a company does business, the fiscal regime, and the management team.

To evaluate potential, consider what stage of the exploration and production (E&P) cycle you are investing in: Does the company offer you growth from exploration, development, or production, or a combination of the three? Understand that each model has different risks attached, and the most balanced model is a full cycle E&P model: a production base that generates cash flow to fund development and exploration.

How much are you paying?

Before you invest in a stock, consider if you are buying "hard" assets at a discount or at their fair value, and if you are paying for exploration, i.e. are you buying growth "for free"?

Moreover, consider if the company can survive in a low oil price environment: Are the operating costs low enough, and does it have sufficient cash on the balance sheet to weather the storm? Make sure you understand how this cash will be spent (capital expenditure) and what will grow the cash position. Beware of high debt levels and high debt service costs: The 2014 oil price slide has shown the pressure suffered by companies with debt on their balance sheet.

While industry transactions can be used as valuation proxies, it is important to understand that any valuation method, however complex or simplistic, is only an approximation.

Valuation is based on a number of assumptions (often subjective) that can change with time and can be prone to human error.

What is your investment horizon?

Every investor needs to have a realistic investment horizon (mid- to long-term), and nowhere is it more important than in small-cap oil and gas investing with its roller-coaster tendencies. Your investment horizon should concur with your view on the oil price trend, as well as the timing of planned company operational catalysts.

Increasing production or bringing a development project on-stream, for example, often requires more time than drilling an exploration well, and a well-informed investor will be able to take the ramifications of these activities into consideration as he balances his portfolio.

Moving on to our seven key factors

This common understanding of where the small-cap oil and gas market stands and what history has taught E&P investors all over the world should provide a solid base for a more detailed look at our seven key factors driving small-cap oil and gas valuations, and maybe even clarify your own position and appetite for investing in the sector.

We start with the **oil price** and look into the world supply and demand dynamic, as well as the possible recovery of the oil price and its timing. We then move on to discuss the **asset base and reserves**, their categorization and evaluation, as well as their evolution based on the E&P cycle. We also describe how different assets are valued by professionals.

We move on to talk about **capital spending** and its relation to growth, as well as different strategies of risk sharing when it comes to funding. Moreover, we discuss the importance of **cost control and debt** policy. Given that many oil and gas companies operate in countries outside the US, we consider **fiscal regimes** and how they impact valuations.

We also deal with **geopolitical environments** these companies can operate in and demonstrate how they influence risk attitudes and consequently, valuations. And finally, we talk about **management**: their skills, experience, relationships, and integrity. While it may be difficult to immediately quantify management abilities and how they translate into share appreciation, this can be one of the most important factors to consider when investing in small-cap oil and gas companies.

Investing in oil and gas stocks at their lows can be a very profitable long-term investment strategy, if one considers the critical fundamentals and cherry-picks the right companies.

Companies with a healthy balance sheet, and those driven by a mix of production, development, and exploration offering a balanced risk profile, will be well positioned to benefit from a potential oil price recovery when the time comes. And the pendulum always swings back.

KEY FACTOR #1

Oil Price

Oil price is one of the most important drivers of oil and gas valuations, and unfortunately, it's also largely uncontrollable. The dramatic fall in the oil price that began in June 2014 (see Chart 1.1) is primarily due to a supply-side imbalance. The excess supply issue is forecasted to disappear sometime in 2016, while demand growth remains robust. To understand what's causing the oversupply, it is necessary to understand world supply-and-demand dynamics and the key players impacting it.

Key players in supply and demand: OPEC, US, Russia, and Asia

As shown in Chart 1.2, the International Energy Agency (IEA) estimates that total world demand will continue to grow, though at a gradual pace. Demand from the Organization for Economic Cooperation and Development (OECD) countries is driven mainly by the Americas, while non-OECD demand is driven mainly by Asia.

Oil consumption is strongly linked to economic growth, and the bulk of the projected total demand growth is driven by Asia (including India). India is expected to overtake Japan to become the world's third largest oil consumer, at approximately 4.1 mmb/d. The country is now consuming the same amount of oil and gas that China was a decade ago.

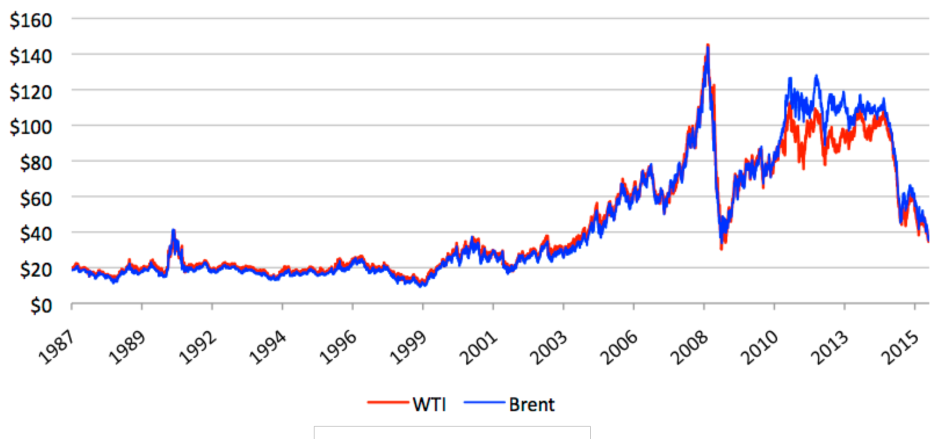
On the supply side, the Organization of the Petroleum Exporting Countries (OPEC) is accountable for about a third of total world supply, dominated by Saudi Arabia (with capacity of around 12.5 mmb/d). Non-OPEC supply is driven mostly by the Americas (US supply is expected to end at around 13 mmb/d for 2015), and former Soviet Union countries, Russia in particular.

When will things ease?

The IEA's latest balances show that while the oversupply will ease from a significant 2.3 mmb/d in Q2 2015, its highest since 1998, the projected oversupply persists through the first half of 2016. It is clear that the re-balance should come from the supply side, and given that OPEC is still reluctant to cut output, it is non-OPEC production that will have to decline enough for oil prices to start recovering.

Higher cost incremental barrels from the US and some other non-OPEC members are likely to be driven out of the market first. So far they have resisted the lower oil price environment, but as of this writing, in late 2015, there are signs of a slowdown in non-OPEC production, though the timing of its impact on the oil price is still an educated guess. For instance, the IEA estimates that, assuming OPEC crude production continues at around 31.7 mmb/d through 2016, the second half of 2015 will see supply exceeding demand by 1.4 mmb/d. The surplus drains down to about 420 kb/d in 2016, with Q3 2016 marking the first quarter of a potential stock draw. This outlook, however, does not include potentially higher Iranian output as EU and US sanctions are lifted and Iran brings its production infrastructure up to date. Those impacts remain to be seen. This means that we may not see supply and demand re-balancing until the end of 2016.

CHART 1.1: OIL PRICE



Driving down US shale production

The anticipated decline of US shale production is also difficult to predict. According to OPEC's latest report, Texas' two main tight oil plays, the Permian and Eagle Ford, showed declines of 42 kb/d month-over-month to average 3.66 mmb/d in May 2015.

Meanwhile, oil output in North Dakota, mainly from the Bakken shale site in the Williston Basin, increased by 32 kb/d to above 1.2 mmb/d. The cost base, production declines, and the way US shale responds to capex are perhaps three of the most important factors.

While well production typically drops 60 to 70% in the first year, it also takes just weeks to drill new wells once capex starts to come back. If average composite full cycle drilling and operating costs of North American producers are estimated to be in the $60-65/b range, given the inventory of wells already drilled, technological advances (refracking, etc.), and hedging in place, it could be argued that it will take some more time for this price environment to take effect.

Looking ahead

In the absence of major geopolitical disruptions, it is unlikely that the price of oil will bounce back to the $100/b level any time soon. The current consensus is "lower for longer," but markets are forward-looking and they react to expectations. Day-to-day volatility is expected, but longer term, reduced industry capital spending should put pressure on future supply growth, and if demand continues above-trend, the price of oil will eventually start its recovery.

In conclusion, it is important to keep the big picture in mind and not get distracted by daily "noise." While this can be a nerve-wracking time to be in the oil and gas business, times such as these also present some of the biggest opportunities to take a long-term position in stocks that would otherwise be out of reach of average investors.

On the supply side OPEC is accountable for about a third of total world supply, dominated by Saudi Arabia (with capacity of around 12.5 mmb/d). Non-OPEC supply is driven mostly by the Americas (US supply is expected to end at around 13 mmb/d for 2015), and former Soviet Union countries, Russia in particular.

CHART 1.2: SUPPLY & DEMAND

mmb/d	**2014 A**	Q1/15 A	Q2/15 A	Q3/15 E	Q4/15 E	**2015 E**	Q1/16 E	Q2/16 E	Q3/16 E	Q4/16 E	**2016 E**
Total demand	**92.6**	93.6	93.9	95.4	95.3	**94.6**	94.8	95.1	96.5	96.7	**95.8**
Opec supply	***30.3***	*30.5*	*31.5*	*31.7*	*31.7*	***31.4***	*31.7*	*31.7*	*31.7*	*31.7*	***31.7***
Total supply	**93.7**	95.0	96.2	96.9	96.7	**96.2**	96.2	96.1	96.2	96.3	**96.2**
Oversupply	**1.1**	1.4	2.3	1.5	1.4	**1.6**	1.4	1.0	-0.3	-0.4	**0.4**

Source: IEA, December 2015

KEY FACTOR #2

Assets and Reserves: Production, Development, Exploration

Gauging assets and reserves are what we consider to be the nuts and bolts – or the blood and bones – of the oil and gas business. This section outlines how these assets and reserves are valued, which will help investors to read between the lines (and spin) of corporate releases and reports. Understanding the cycles of production, development, and exploration is key for assessing the risks.

E&P lifecycle

Small-cap oil and gas companies can either be full cycle (all aspects) E&P companies or they can focus on one particular stage of the E&P cycle (exploration, development, and/or production, see Chart 2.1). As an investor, you want to know which stages the company is involved in. The asset portfolio can indicate that, but sometimes even companies with diversified portfolios of production, development, and exploration can be *either* producers *or* explorers. To know for sure, one must identify what will drive the value appreciation: Is it dependent on a major development project coming onstream and increasing production? A number of exploration wells to be drilled in the hopes of material discovery? Or is it a combination of both?

Even more importantly, investors need to be sure that the company can deliver value appreciation in a time period that does not exceed one's investment horizon. Note that the **risk profile of each stage** is different: Typically, geological risk begins to diminish after a discovery is made, while political and financial risks intensify after that.

So how do analysts value an oil and gas asset? Quite simply, these values are based on the future cash flows that the asset can generate, i.e., how much oil this asset can produce from its recoverable reserves and/or resources.

Reserves and resources: classification and usage

Under US reporting, the Securities and Exchange Commission's (SEC) definitions must be used when it comes to oil and gas reserve accounting. Proved oil and gas reserves are estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic conditions (i.e. prices and costs).

- **Proved developed** are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods;
- **Proved undeveloped** are reserves expected to be recovered from new wells on undrilled acreage or from existing wells where major expenditure is required for recompletion.

SPE definitions (see Chart 2.2):

Proved (1P) reserves are those reserves that, to a high degree of certainty (90% confidence or P90), are recoverable from known reservoirs under existing economic and operating conditions.

Proved plus Probable (2P) reserves are those reserves that analysis of geological and engineering data suggests are more likely than not to be recoverable. There is at least a 50% probability (or P50) that reserves recovered will exceed the estimate of Proven plus Probable reserves.

Proved, Probable plus Possible (3P) reserves are those reserves that, to a low degree of certainty (10% confidence or P10), are recoverable. There is relatively high risk associated with these reserves.

Contingent Resources are those quantities of hydrocarbons which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable because of constraints on their development.

Prospective Resources are those quantities of hydrocarbons that are not yet discovered.

CHART 2.1: E&P LIFECYCLE

Licensing	Exploration	Appraisal	Development	Production	Abandonment
Obtain acreage bids	Seismic survey & other geological studies	More drilling	Field development plan	Managing decline	Onshore:
Work commitments	Target selection drilling	Narrowing resource estimates range	Approvals	Infill drilling	» *Plugging wells*
	Pre-drill prospective resource estimates	Contingent resources	Drilling production & injection wells	Enhanced recovery techniques	» *Restoring land*
			Building infrastructure	Reserve depletion	Offshore:
			Starting production		» *Dismantling platforms (can be capital intensive)*
			Proved developed reserves		

Note that terms like "reasonable certainty" can be interpreted with latitude. There is also a different approach to reserve categorization: the Society of Petrochemical Engineers' (SPE) probabilistic definitions for reserves and resources.

Reserves and resources: evaluation

One of the main things to understand about reserves is that they are estimated, not set in stone.

Consider this example: in 2015, Afren (AFR LN), an ex-FTSE 250 oil and gas company that recently entered administration, announced that 2P reserves and 2C resources of its Barda Rash field in Kurdistan were materially downgraded. Essentially, gross 2P reserves of 190 million barrels just vanished, while gross 2C resources went from 1.2 billion barrels to around 250 million barrels. These were previously certified by an independent reserve auditor and included in the majority of analysts' valuations.

The company stated that the downgrade was due to "the reprocessing of 3D seismic surveys, poor reservoir performance and operational challenges associated with drilling complex fractured reservoirs." The stock was down more than 25% on the day of the announcement.

Whatever the reasons, this example illustrates that oil and gas reserves are not always accurately estimated. And less ethical companies can exploit loopholes or ignore guidelines altogether. While having a Competent Person's Report provides some credibility, it should not lead to overconfidence. The absolute level of recoverable reserves in a given field will never be known until production ends and the reservoir is depleted.

On the other hand, reserves can be upgraded if the characteristics of the reservoir become better understood, if fields are extended laterally, or if new oil and gas reservoirs are found in existing fields.

For instance, the Alvheim field in the Norwegian North Sea operated by Lundin Petroleum (LUPE SS) saw a 50% increase in the current estimated total recoverable reserves compared to its 2008 pre-production estimate, due to improved reservoir understanding, additional development wells, and production optimization. Another example is TAG Oil (TAO CN), which grew its 2P reserves from 154 mboe to 5.36 mmboe in three years due to an aggressive and successful exploration drilling campaign.

CHART 2.2: RESERVES AND RESOURCES CATEGORIZATION

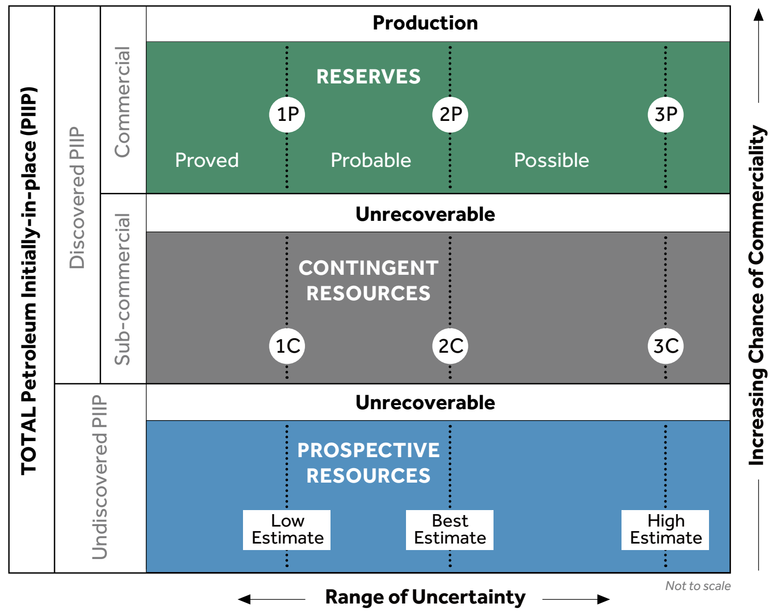
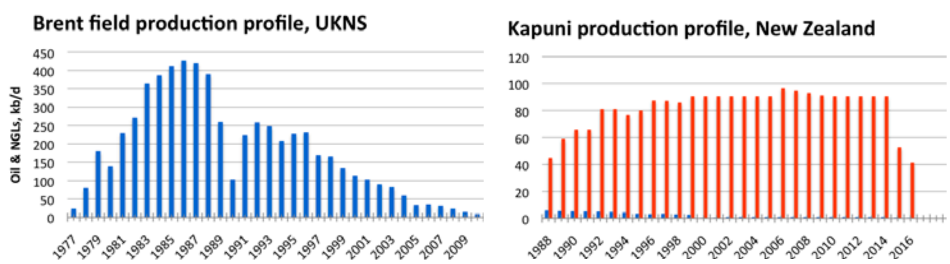


CHART 2.3: PRODUCTION PROFILE EXAMPLES:

Brent oil field North Sea and Kapuni gas/condensate field New Zealand.



Valuing production

The next step in asset valuation is estimating the production profile. Every field will have a different production profile but the typical large conventional oil field production will peak, plateau for a relatively short period of time, and then start declining until production becomes uneconomical.

As CHART 2.3 shows, there are exceptions. For instance, gas fields may demonstrate a different production curve with a much longer plateau, due to a combination of infrastructure constraints and/or demand constraints. A long plateau production period from gas fields is often desirable since customers usually require a stable supply at an agreed upon rate over a few years.

A Working Petroleum System consists of a mature source rock, reservoir rock, trap, and migration pathway.

Source Rock refers to rocks from which hydrocarbons have been generated. Generation depends on three major factors: the presence of organic matter, adequate temperature, and sufficient time to bring the source rock to maturity.

Reservoir Rock refers to rocks that have sufficient porosity and permeability to store and transmit fluids.

Trap is a configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.

Migration is the movement of hydrocarbons from their source into reservoir rocks.

Some companies will employ enhanced recovery techniques to maintain production, but only as long as it is still profitable, since enhanced techniques can increase operating costs. Eventually, though, while production decline rates vary from field to field, every field enters the decline stage. For large, conventional fields this can be in the range of 4.5% to 8% (as estimated by IHS and IEA). For smaller oil fields, output can decline by 15% or more annually. Unconventional fields (shale, for example) typically decline at higher rates than conventional fields: Without additional drilling, these fields can exhibit decline rates of 50% to 70% in a one-year period.

Once the reserves and production profile estimates are in place, revenues are projected using oil price assumptions and cash flows are derived after taking into account operating, financing and capital costs, and fiscal terms. The cash flows are then discounted using an assumed discount rate, and the net present value (NPV) of the asset is calculated.

Valuing exploration

When valuing exploration there are several factors to take into account:

- Undiscovered prospective resources;
- A risk of not finding any hydrocarbons at all;
- Uncertainty around the size of the potential discovery.

To adjust for these factors, risk analysts use the expected monetary value (EMV) method. It is important to understand that any individual well has a binary outcome: It will deliver either negative or zero value in the case of a dry hole, or it will deliver some value based upon the size of the discovery. And of course, there is a difference between technical success and commercial success. EMV is a tool that allows investors to value something today that has some chance of taking place *in the future*, but it is highly dependent on the probability of success or an estimate of the risk. EMV combines profitability and probabilities (or risk) to arrive at a risk-adjusted value using the formula:

EMV = (NPV x CoS) – (CR x {1-CoS})

where NPV is the net present value of the discovery; CoS is the Chance of Success or probability of a discovery; CR is the Capital at Risk, i.e., dry hole costs, geological expenses, etc.

In exploration, geologists try to assess the risk that a recoverable hydrocarbon accumulation exists. There are four key factors that need to be present: mature source rock, reservoir, trap, and timing of migration. To put it probabilistically:

CoS = P(source rock) x P(reservoir) x P(trap) x P(migration)

If any one of these probability factors is zero, the probability of geologic success is zero. Teams of geologists will work on each factor and its probabilities, but it will still be just an attempt at risk assessment. There are some rules of thumb. For instance, exploration in frontier areas (underexplored, new basin, new geological play) will have higher risks, e.g. 5% CoS, than exploration near a producing field (well explored, same basin and same play), e.g. 50% CoS.

Let's take an example

If the first well is a dry hole because there is no source rock or reservoir, then the probabilities of subsequent wells will be materially diminished. If the dry hole was a result of a breached trap but source rock and reservoir were proven, this can be considered a partial geologic success because the trap issue may be present in this well location only. If, however, the well is a success and hydrocarbons are found in commercial quantities, it de-risks the play and can have a positive impact on the probabilities of the subsequent wells in that portfolio. Most exploration companies are well aware of that and will try to diversify their exploration programs by targeting different basins, plays, and structures as cash flow allows.

The EMV method can be applied to development valuation as well. However, instead of geologic chance of success, the chance of development (CoD) will be used and the valuation will focus more on the commercial and geopolitical risks associated with bringing discovered barrels into production.

You can use the reserves' data to analyze the upstream performance of the companies using the following measures:

Finding Costs identify how much the company spent to find each barrel of oil that was added to reserves in the year:

- *Finding cost/barrel = Total exploration costs/discoveries & extensions, revisions, improved recovery*

Finding & Development Costs are the costs of constructing and installing facilities to produce and transport oil and gas, together with any acquisition spend:

- *Development cost/barrel = Total development costs/discoveries & extensions, revisions, improved recovery*

Reserve Life identifies the number of years a company can continue to produce from its existing reserves, should it find no additional reserves, while maintaining the same rate of production:

- *Reserve Life = Total 1P reserves/ annual production*

Reserve Replacement Ratio is a company's ability to replace production with reserve additions in the year under review (excluding organic growth for example, or including acquisitions):

- *Reserve replacement ratio = Movement in reserves / Total production for the year*

While it isn't necessary to know all of the intricacies of oil and gas asset valuations before investing, it is important to know the basics so that you have a better understanding of company reports, reserve auditors reports (CPRs), and analyst reports.

Note that each asset is valued separately and the net present value is based on the reserves the asset holds, its production profile, future cash flow generation, and discounting. The EMV is a separate layer that introduces risk, especially when there are many uncertainties involved. In exploration, it is mostly about the geological risks, while in development it is more about commercial and geopolitical risks.

Market players will often use multiples either as a "back-of-the-envelope" valuation or a quick comparison tool.

A valuation multiple is simply an expression of market value relative to a key statistic that is assumed to relate to that value. In oil and gas, there are some multiples that can be used for these purposes, such as EV/2P (enterprise value to 2P reserves) or EV/b/d (enterprise value to barrel of production) or P/DACF (price to debt-adjusted cash flow).

CHART 2.4: VALUATION METHOD BASED ON THE EXPECTED MONETARY VALUE (EMV)

Country	Asset	Gross Resource *mmboe*	Working Interest *%*	Net Resource *mmboe*	Chance of Success *%*	NPV/boe *$*	Net Risked Resources *mmboe*	Risked NAV *$ mm*	Risked NAV *$/share*	Unrisked NAV *$/share*
Production										
Country A	Asset A	579	44	255	100	6.20	255	1580	5.59	5.59
Development										
Country B	Asset B	583	75	438	80	1.50	350	525	1.86	2.32
Exploration										
Country C	Asset C	355	25	89	35	3.83	31	119	0.42	1.20
Total NAV		**1517**	**144**	**781**		**11.53**	**636**	**2224**	**7.87**	**9.11**
Shares mm		283								

NAV Summary	mmboe	$/boe	$ mm	$/share
Production	255	6.20	1580	5.59
Cash/(net debt)			386	1.37
Development	350	1.50	525	1.86
Core NAV	**605**		**2491**	**8.82**
Risked Upside	31	3.83	119	0.42
Risked NAV	**636**		**2610**	**9.24**

For instance, if you are comparing P/DACF multiples of two oil producers with similar market capitalizations that operate in the same geography and have similar assets and growth strategies, then Company A that is trading at 2.0x 2016 P/DACF will be considered "cheaper" to buy than Company B trading at 4.0x 2016 P/DACF. Similarly, it can be implied that if the historic industry average P/DACF for similar producers is 5.0x, you can back-calculate the "true" market value of Company A by multiplying its 2016 estimated debt-adjusted cash flow by 5.0x.

While it is tempting to use this simple approach, it is necessary to remember that multiples do not fully capture the dynamic nature of business and can result in misleading 'apples-to-oranges' comparisons.

KEY FACTOR #3

Capex and Risk Sharing

Capital spending for E&P companies is directly related to the company's growth. It typically includes funds for items such as planned exploration campaigns (drilling costs, etc.), the acquisition of an offshore production platform for a development project, or purchasing a workover rig to enhance existing production or implement a waterflood project. Capex funds come from internal cash flow, external debt or equity raisings, and/or a combination. The dramatic fall in the price of oil since mid-2014 has resulted in E&P companies cutting their capital spending in order to conserve cash.

From majors to small operators, no one has escaped the need to cut capital spending.

2015 capex (vs. 2014) was cut by:

Exxon: 12%

Sinopec: 12%

BP: 25%

Husky Energy: 42%

ConocoPhillips: 20%

EOG Resources: 40%

TAG Oil: 50%

Since external sources of funds have become difficult to obtain and internal cash flow has come under pressure, E&P companies of all shapes and sizes have, without exception, had to cut their capital spending in one form or another.

The different faces of capex

In these economic conditions, capex flexibility is critical. Key questions that investors should ask about their holdings include:

- Is the company able to scale back capital spending quickly in response to fast-changing conditions?
- Is it able to accelerate capex and growth once conditions improve?

Companies that pay dividends have had to make tough choices. For instance Chesapeake Energy (CHK US) decided to cut its common stock dividend in order to maintain capital expenditure, while ConocoPhillips (COP US) decided to cut back on capital expenditure to protect its dividend. In another example, Genel Energy (GENL LN), a London-listed company operating in Kurdistan, scaled back its 2015 capex by around 70% compared to 2014 levels, just months after the oil price collapse.

For offshore, especially deep offshore, it's an even greater challenge. Abandoning a large offshore platform is not the same as plugging an onshore well, and there are some North Sea companies that are losing significant money on offshore fields, with operating costs exceeding $60/b.

Generally, oil and gas projects are funded by partners according to their working interests in the project. Sometimes (though it's rare), E&P companies will take on 100% of funding risks, and often they will execute a farm-out (see the sidebar on the next page) in order to share the risks.

Let's look at two different scenarios from 2012

Two different companies with clearly different strategies embarked on an exploration campaign offshore Falkland Islands and onshore New Zealand, where exploration risks and drilling costs were relatively high.

- Borders & Southern (BOR LN) kept 100% interest and had $194 million cash balance to fund the two initial wells. After the first well experienced cost overruns, the company raised an additional $75 million in equity and drilled the second well.

Today Borders has around $15 million in cash and a gas condensate discovery (Darwin) offshore Falkland Islands that needs appraisal and further development, which will cost hundreds of millions of dollars. The company is still looking for partners to fund these operations.

- The other company, TAG Oil (TAO CN) successfully farmed out its East Coast blocks in New Zealand in Q2 2011 for $100 mm of potential carry and drilled an unsuccessful but very important well, the first of its kind, on its acreage in 2014.

Monies received from the JV partner substantially paid for the costs of drilling. While no meaningful commercial results were achieved, the company used "other people's money" to drill the wells.

Regardless of the drilling results, this example illustrates that sharing funding risks is important and should be an integral part of a company's strategy. With external sources of funding becoming more difficult to access, funding from within the industry may once again become the primary source for exploration funding.

Operators such as TAG Oil routinely seek JV or farm-in partners to reduce their risk on exploration programs. For example TAG is working to farm out its highly prospective Cardiff acreage, a large potential gas field similar to the Kapuni field.

A **farm-out** is an agreement whereby a third party agrees to acquire an interest in a production license and in the operating agreement relating to it. In oil industry practice, the exchange is typically for carrying out a specified work obligation – known as the "**earning in**" obligation – used in the drilling of one or more wells.

The farming-out party's retained interest is usually referred to as the "**carried interest.**" For example, Company A will earn X% interest in the asset from Company B in exchange for carrying the full cost of the seismic work and the cost of the initial well up to a $Y million cap.

CHART 3.1: BENEFITS AND CHALLENGES OF FARM-OUTS AND FARM-INS

Benefits of the farm-outs/-ins	Challenges associated with farm-outs/-ins
Sharing risks	Governmental consents
Sharing of technology and expertise	Partners' consents
Stronger license group	Keeping up with work obligations and funding commitments
Cheaper method of acreage acquisition	Size of documentation and time and resources needed to prepare them
Accelerated drilling	

KEY FACTOR #4

Costs and Balance Sheet Strength

Production costs (also known as lifting costs) are the expenses associated with bringing oil and gas from the reservoir to the surface, separating the oil from any associated gas, and treating the produced oil and gas to remove impurities such as water and hydrogen sulfide. There are also transportation and storage costs to be factored in.

Where you operate – and how you operate – makes a difference

Operating costs can vary from $1-2/b in Saudi Arabia, to around $50/b on average in the UK North Sea. Given the current oil price, onshore operators are a better bet than offshore, as they are a better able to control their operating costs. Having modern infrastructure in place and access to pipelines also plays an important role in keeping operating costs lower. For instance, TAG Oil (TAO CN), a small-cap E&P company operating in New Zealand, produces oil and gas from the Cheal and Sidewinder fields. The company owns production facilities (oil processing, gas liquids' extraction, gas compression, and electricity generation) that are used to process TAG's own oil and gas, which provide power to run the plant itself. Moreover, TAG's gas production is connected via pipeline to New Zealand's open-access gas transmission line. As a result, the company has low operating costs of $26/b that reflect these efficiencies.

General and administrative (G&A) costs mainly consist of labor and are often overlooked, but being able to control and decrease G&A can sometimes have a material impact on valuation for small-cap E&P companies.

Smart investors will be wary of "lifestyle" companies that tend to have high headquarter expenses, which include not only maintenance and rent for non-field facilities but out of sync executive staff salaries and bonuses. Smart investors also, as a general rule of thumb, avoid small companies that are spread too thin in terms of geography or asset characteristics, as they tend to have higher-than-average G&A spend. These details are available in company financials, which serious investors should read.

The debt quotient

When external capital was readily available, many E&P companies took on debt to fund capex. For example, in December 2014, 17% of America's high-yield bonds were American E&P companies. The recent sharp decline in the oil price has put pressure on these companies. Even as profits decrease, interest still has to be paid. It is essential that the companies you invest in have enough money to cover their interest payment obligations.

There are metrics which can be used to determine whether a company has the ability to service its debt, such as interest coverage ratio, which is expressed as either:

EBIT (Earnings before Interest and Tax) / Interest Payment

or

EBITDA (Earnings before Interest, Tax, Depreciation and Amortization) / Interest Payment

The safest option is to avoid companies with debt on their balance sheet – but that's rare. If a company has debt, make sure it can service its debt and meet covenants (obligations) of that loan. Covenants may require the borrower to fulfill certain conditions that forbid the borrower from undertaking certain actions. These covenants are typically represented by a ratio, such as:

Net debt/EBITDA has to be less than 5

or

EBITDA/Finance Charges has to be more than 3

Often, highly leveraged companies in capital-intensive industries choose to highlight **EBITDA (Earnings before Interest, Tax, Depreciation and Amortization)** in their performance reports. That is because EBITDA shows a more attractive financial picture, shifting investors' attention away from high debt levels and unwelcome expenses against earnings.

It is important to know that EBITDA is not a substitute for operating cash flow, as it ignores changes in working capital – the cash needed to cover day-to-day operations – as well as taxation and interest which are real cash items. Put simply, cash in the bank plus generated cash need to be greater than a company's interest obligations and expenses.

Breaching covenants and not being able to make interest payments leads to default, putting the company and its assets into creditors' hands and destroying value for shareholders. As of the writing of this paper, many U.S. shale companies are suffering under a crushing debt and interest burden due to the decline of oil prices. These companies then scramble to reduce spending, which in turn reduces production and further reduces revenue, creating a cycle where the only constant is interest, and the only thing that grows is their debt. In this environment, investors may want to look to stable E&P players that have producing assets not dependent upon shale. Shale is more expensive to extract and has a shorter life span, thus requiring more constant drilling and exploration to keep the pipeline filled.

An example of how cash, debt, operating costs, and capex can influence market value

To illustrate how cash, debt, operating costs, and capex can influence market value, consider Whiting Petroleum (WLL US). According to media reports, in March 2015, WLL hired bankers to find possible buyers for the company. Whiting is one of the largest producers in the Bakken region with production of approximately170 kb/d.

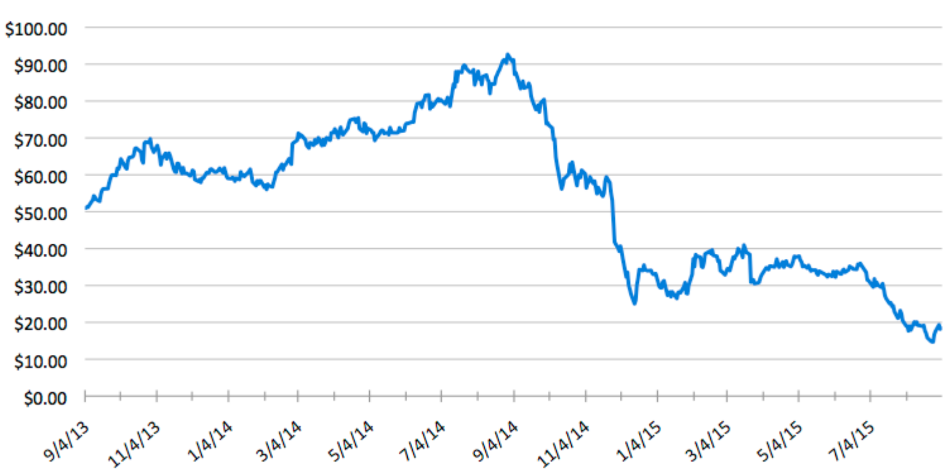
Falling oil prices had an impact on a relatively high-cost Whiting, but a larger part of the pressure came from the $2.2 billion of additional net debt Whiting had taken on in 2014 to buy Kodiak. This acquisition brought the group's total debt to about $5.6 billion. Whiting negotiated new credit facilities and its banking syndicate agreed to a $4.5 billion commitment, which to date remains intact. Whiting now has to come up with its planned $2 billion of 2015 capex (about half 2014 levels) in order to continue delivering attractive growth. The market questioned whether oil prices would recover enough for Whiting to keep its operational plans going and not just burn cash.

Whiting also announced a $1 billion disposal plan of non-core assets. Year-to-date, Whiting managed to sell $400 million of assets. But it also had to issue more equity, diluting shareholders' stock, and take on more debt.

This cautionary tale simply reinforces what smart investors already know: Companies with sound balance sheets and low operating costs have a higher chance of avoiding value destruction. The E&P sector is particularly amorphous now, which is what makes it such an attractive opportunity for investors willing to do their homework. But it's a slippery one for those who don't.

When it comes to debt, oil and gas companies usually issue bonds or get a **Reserve Based Lending (RBL)** loan. An RBL loan is a low interest, secured loan collateralized by the borrower's oil and gas reserves, hence it is only accessible to companies that already have discovered oil and are either producing or are about to develop the resources. Repayment of the RBL facility comes from proceeds derived from the production of hydrocarbons. The amount of the loan is based on the expected present value of future production from the fields in question, accounting for the level of reserves, expected oil price, a discount rate, assumptions for operational expenditure, capital expenditure, tax, and any price hedging. Hence, RBL can underpin the net asset value of the company and its market valuation.

CHART 4.1: WHITING SHARE PRICE



KEY FACTOR #5

Fiscal Regime

The oil and gas industry is an important source of revenue for many countries. So it's no surprise that oil and gas taxation is one of the key factors affecting valuations. When evaluating E&P stocks, it's important to research the countries your investment is operating in, and remember that fiscal legislation varies widely from country to country.

When considering where to invest, investors should consider the prevailing fiscal and regulatory environment, and the stability of that system. Stability is measured by government policy, fiscal systems, and the rate of change, which can also be an indicator of political risk. The greater the stability, the greater the value investors can place on their future income streams.

Oil price volatility has brought a measure of instability to oil and gas fiscal systems: When commodity prices are high, governments race to take greater control over their natural resource assets. As they decline, governments scramble to swing the pendulum the other way. The most stable fiscal regimes have a measured policy in place that benefits both the government and the oil and gas companies in times of high and low oil prices.

Two primary fiscal systems worldwide

There are two main classifications of fiscal systems around the world: concessions and contracts (see Chart 5.1).

In a **concession-based system** (also known as a tax and royalty regime), the company is granted rights to prospect for resources within a defined acreage (onshore and offshore), but pays a royalty on the revenue base (either a fixed percentage or on a sliding scale), and a corporate income tax on profits. Capital expenditure can be recovered against profits (i.e. tax depreciation) and the pace of recovery is set by the government. The tax and royalty system is usually a regressive tax system, meaning that the government captures a smaller share of overall value as the oil price appreciates, and vice versa.

In a **contracts-based system** (production sharing contracts, or PSC) the mineral resource remains the property of the state and the barrels produced are allocated between the resource holder and contractor according to the contract terms. Royalties and taxes may apply, but there are mechanisms that determine how the oil produced will be allocated to cover capital and operating costs (i.e. "cost oil") and in what proportions remaining "profit oil" will be split between contractor and state.

This means that under most PSCs, a significant proportion of revenues are available for cost recovery. The contracts-based system is usually a progressive tax system, meaning the government's share of project NPV rises when oil prices increase, exposing it to oil price upside, but falls when prices decline. That way, the risk-taking contractor obtains some downside protection on its investment in the face of declining prices. There are also service contracts, whereby the contractor is paid a service fee, typically in cash.

Factors to consider in both systems include domestic market obligations, work commitments, signature and production bonuses, and acreage relinquishments.

Reserve determination for contractors

One key point to consider when it comes to these two different fiscal systems is the reserve determination for contractors. In general, there are two methods: the working interest method and the economic interest method.

Under the **working interest** method, the estimate for total proved reserves is multiplied by respective working interest held by the contracting company, net of any royalty.

Main elements of a Production Sharing Contract:

Cost Oil – Share of production used to pay back the contractor for its capital investment and/or operating expenses incurred in the year (typically cost recovery from approximately 50-60% of project revenues). Unrecovered costs in any one year may be carried forward for recovery in subsequent years.

Profit Oil – Oil available for distribution to the partners in the project in line with their equity (or working interest) share. Profit oil is that oil which is available after costs have been recovered.

Capex Uplift – Percentage increase granted by the state on capex spend for recovery against costs (i.e. if capex is uplifted for recovery against revenues at a rate of 50%, it means on a capital spend of $1 billion the contractor will be able to recover $1.5 billion against cost oil).

Mechanisms of profit oil allocation:

Constant – Government entitlement is constant over the life of the PSC.

Production-based sliding scale – Government entitlement increases as field production rises to predetermined levels.

IRR-based sliding scale – Government entitlement increases as the returns from a project move beyond pre-defined levels.

R-factor – Government entitlement increases as a field recovers its cumulative capital invested (determined by the ratio of total revenues to total costs).

Thus, the company is entitled to book all of the barrels to which it is entitled as reserves, even if 99% of the revenues realized from the production of a company's working interest in a field is to be paid away as royalty and tax.

Under the **economic interest** method, the company's share of the cost recovery oil revenue and profit oil revenue is divided by year-end oil price, which represents volume entitlement. The lower the oil price, the higher the barrel entitlement, and vice versa. If the working interest is different from profit entitlement, the economic interest method is a closer representation of actual reserve volume entitlement that can be monetized by a company.

So why do different countries have different fiscal systems?

This is about a balance between maximizing government take through both tax and/or profit share while still remaining attractive to investors. At the same time, the contractor's objective is to maximize its return and protect its investment.

Stability of the fiscal regime increases the predictability of future cash flows. PSCs are considered to provide a more stable fiscal environment, although that may not always be the case. Theoretically, once signed, a PSC is generally not subject to changing legislative conditions, as opposed to the tax and royalty system, which is. Often, even if changes take place, the PSC terms signed prior to that are grandfathered in. However, this is not always the case, and a host country's political landscape can shift dramatically, leaving the contractor vulnerable to changes.

When it comes to fiscal stability, countries that are considered "safe" for investment do not always match our perception, and vice versa. For instance, a recent IHS Fiscal Stability Index showed that among offshore jurisdictions, Kazakhstan and the United Kingdom both rated at the highest degree of fiscal instability. While UK's fiscal regime may be safer in many aspects, the reason for this ranking is the frequency and the degree of changes to the fiscal terms in the past.

Working interest: The contractor's percentage interest in the project as a whole, e.g., if a company has a 50% interest in a project producing 100kb/d its working interest in that project would be 50kb/d.

Entitlement share: The number of barrels of profit oil to which the contractor is entitled from the project in any given year. This will typically represent the contractor's share of cost oil and its equity entitlement to profit oil. If a company has a 50% equity interest in a project producing 100kb/d, the profits from which are distributed 50% to government and 50% to contractor after 10kb/d has been allocated for cost recovery, its share of entitlement barrels would be 27.5kb/d (i.e. 50% of the 10kb/d of cost oil and 50% of the 45kb/d available to the contractors as profit oil).

CHART 5.1: FISCAL SYSTEM EXAMPLES

	Tax & Royalty			**PSC**	
Contractor	Revenue 100%	Government	Contractor	Revenue 100%	Government
	$50/b			$50/b	
	Royalty (20%)			Royalty (20%)	
	$10/b >>>	$10/b		$10/b >>>	$10/b
	Operating Costs and Depreciation of Capital Costs			*Cost Recovery Limit 40% of gross revenue*	
$10/b	<<< $10/b		$20/b	<<< $20/b	
	Taxable Income			*Profit Oil (30%/70%)*	
	$30/b		$6/b	<<< $20/b >>>	$14/b
	Tax Rate (30%)			*Tax Rate (30%)*	
	$9/b >>>	$9/b	($1.8/b)		$1.8/b
	Net Income				
$21/b	<<< $21/b				
$31/b	**Total Entitlement**	**$19/b**	**$24.2/b**	**Total Entitlement**	**$25.8/b**
62.0%	**% of Gross Revenue**	**38.0%**	**48.4%**	**% of Gross Revenue**	**51.6%**

KEY FACTOR #6

Geopolitical Environment

Oil exploration often takes companies to different countries, each with its own unique geopolitical environment. Aside from fiscal regimes, investors must also consider the geopolitical risks associated with oil exploration and production: infrastructure access, employee safety, military actions, social and environmental impact, governmental corruption, and the like.

No matter what discount rate is used, it is important to remember that oil is a highly politicized industry and a politically stable environment is key for successful oil and gas operations.

The general perception is that international E&P companies come with a higher degree of risk, however, such a blanket assessment doesn't take into consideration the different countries, their sovereign risks, political risks and fiscal risks.

A study in contrasts

Let's look at two countries that offer an example in contrast: geopolitically risky Kurdistan and stable, democratic New Zealand. There are many political risk indices that rank countries on the chances of conflict, terrorism, enforced regime change, and resource nationalism. For instance Maplecroft ranks Iraq as "extreme risk" and New Zealand as "low risk." Kurdistan is an autonomous region of Iraq and the legality of the PSCs it signed with international companies were disputed by Baghdad for a long time. Although there has been progress on this issue with the change of the central government, there is still plenty of uncertainty around revenue sharing and stability of payments. And the safety of oil and gas operations and infrastructure in the region was challenged when the so called Islamic State (ISIS) insurgency escalated in 2014.

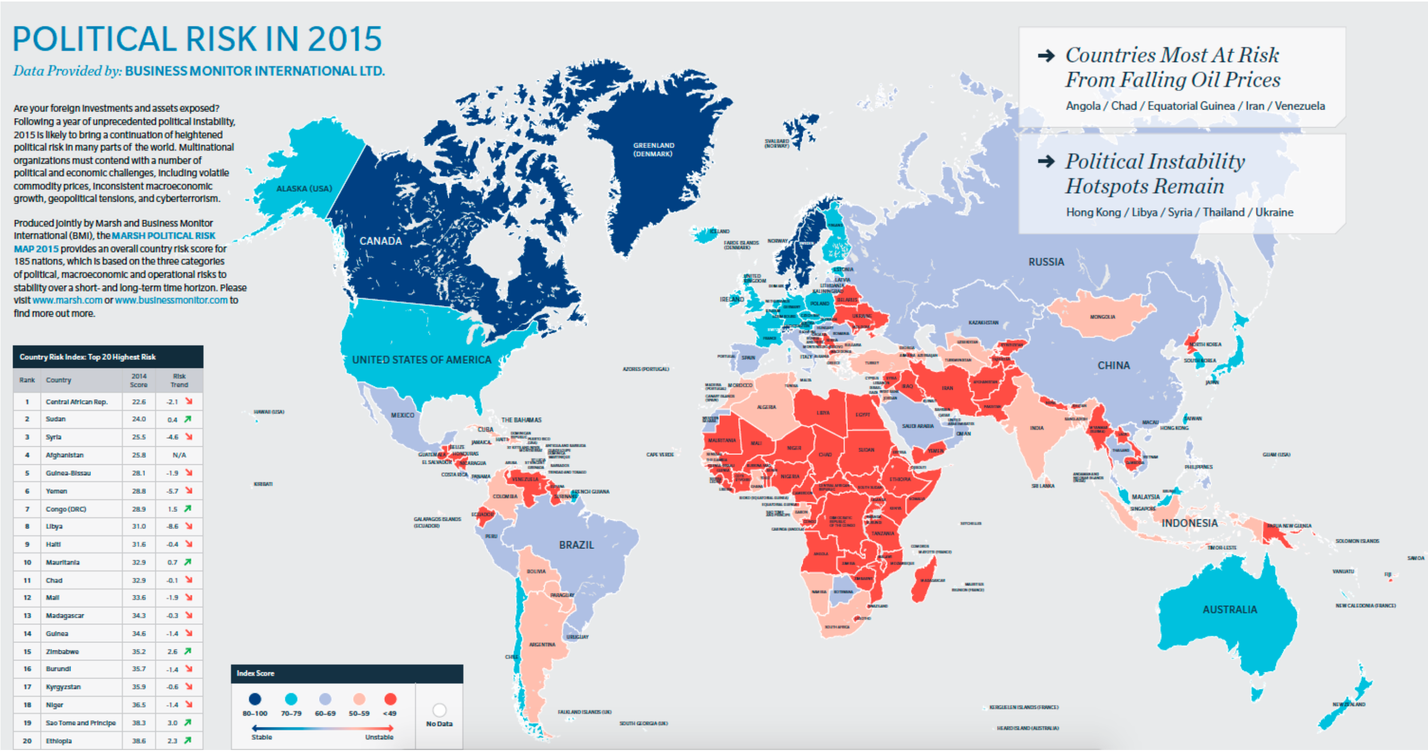
On the other end of the spectrum is New Zealand, which enjoys modern infrastructure, has no security issues, and sports a government supportive of responsible oil and gas exploration. This does not mean there is zero geopolitical risk associated with oil and gas operations in New Zealand. Just as with the US, risk is assessed on a relative basis. It also depends on the individual company doing business in each country: For instance, a company exporting its production may face more geopolitical challenges than a company that sells internally.

Risk perception is often reflected in valuation by a discount rate used to calculate the Net Present Value (NPV). For instance, analysts will use a discount rate of 12.5-15% to value assets in Kurdistan and a discount rate of 10% to value assets in New Zealand. The lower the discount rate, the higher the resulting NPV. The rate selection is, of course, subjective and will vary depending on how the risk is perceived by the individuals performing the valuation.

How does the market interpret geopolitical risk?

Consider two investors looking to take a position in E&P companies operating in Kurdistan. Investor A thinks that the outstanding revenue-sharing issue between Kurdistan and Baghdad will be resolved soon and the companies operating there will get paid for their production. He values the stocks using a 10% discount rate in accordance with his low risk attitude. Investor B thinks that the revenue-sharing issue will not be resolved anytime soon, thus she uses a 15% discount rate in accordance with her high risk attitude.

Let's assume that the market valuations imply a 12.5% discount rate. Investor A's valuation will show that the stocks are undervalued, i.e., they trade below fair value, and he will take a long position in the stocks. Investor B's valuation will show that the stocks are overvalued, i.e., they trade above their fair value, and she may take a short position in the stocks. Note that neither know exactly how the revenue-sharing issue will be resolved; they can only make an educated guess based upon their risk perception, which, consequently, helps shape the market.



Source: Business Monitor International

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The general perception is that international E&P companies come with a higher degree of risk, however, such a blanket assessment doesn't take into consideration the different countries, their sovereign risks, political risks, and fiscal risks.

Remaining objective

When it comes to assessing the geopolitical environment and its risks, it is important not to cloud one's judgment with clichés but to base the evaluation on facts. It can be easy to get sidetracked by loud headlines in the media, but each region, each country, and each company needs to be assessed individually.

We know that utopias don't exist, which makes it all the more important to analyze how the company you plan to invest in can manage and/or mitigate its risks. Make sure that the company is aware of potential threats and has thought of possible solutions ahead of a potential event.

As an investor, you can also diversify your portfolio by country and respective risk attitude. If you are taking on high geopolitical risk, be as sure that the potential return is worth it, and that your portfolio is balanced with low geopolitical risk as well.

KEY FACTOR #7

Management

Management is the glue that holds everything together, and is perhaps the most important factor to consider when investing in a company.

In this turbulent period for the industry, the management team of a listed oil and gas company has to face diverse challenges and adapt constantly to fast-changing economic, regulatory, and risk environments. Most commonly, an E&P company's management team will be more skilled in operations and engineering. But those companies that combine technical knowledge of oil and gas with broad strategic and commercial insight are usually the most successful. Ultimately, a management team has to be able to translate strategic vision into meaningful action.

What to look for in a management team

Experience

What qualifications must the management team (and Board) have for the challenges a small oil and gas company faces? Executives in smaller companies often have to wear many hats and their skills and experience have to be more closely aligned with the company's strategy.

For instance, if a company's growth depends on a development asset coming on-stream, the COO needs to have experience in development, and should have a track record of successfully bringing development projects into production. Assessing an exploration manager's track record can be trickier. A record of oil discoveries isn't the only standard, as a good record can have the down side of being attributed to luck, or even timidity in choice of prospects, versus an actual skill.

If the company operates in a foreign country, it is also important to know the country managers, and consider if C-level management spends enough time "on the ground" engaging in the day-to-day running of the operations.

Relationships and access to high-quality assets

The success of the upstream oil and gas company starts with picking the right assets. Good opportunities are rare and having the right relationships to put together a quality portfolio of assets is key. Consider the previous companies and organizations the managers worked for: Often executives carry their relationships with them and it can shape the strategy of the company. The company with foreign operations will require a management team that has local relationships necessary to ensure a safe and reliable environment.

Integrity

There is a good saying about integrity: "When looking at people, look for three qualities: integrity, intelligence, and energy. If a person is missing the first, the other two will kill you."

Though all publicly listed oil and gas companies are required to have corporate governance procedures in place, that doesn't make the oil and gas industry immune to periodic corporate governance disasters. There is no fail-safe system that prevents misplaced priorities of board members or the manipulation and misappropriation of company resources by management, which is why – besides the experience and relationships – it is important to consider integrity and reputation.

Perhaps the best way to think about management teams is in terms of how much money they have made for shareholders in the past. A great management team can make mediocre assets outperform, while a mediocre management team can make a great set of assets perform mediocrely. When looking at an oil and gas company to invest in it, it's also quite important to understand how much stock a management team and board own of a company (the more the better), how disciplined the team is with the company's capital, and how many boards each individual board member sits on.

For corporate governance structures to work effectively, shareholders must be active and prudent in the use of their rights. As a shareholder, make sure you are aware of whether:

- *The Board is independent, and whether the company engages in outside business relationships with management, board members, or individuals associated with them, for goods and services;*
- *The Board has established committees of independent board members to oversee the audit of the company's financial reports, to set executive remuneration/compensation, to oversee management's activities in areas such as corporate governance, mergers and acquisitions, legal matters, or risk management;*
- *The company has adopted a code of ethics;*
- *The company has clear rules and guidelines overseeing board members' and management's use of company assets for personal reasons;*
- *Compensation paid to executives is commensurate with the executives' level of responsibilities and performance, and provides appropriate incentives.*

CONCLUSION

Small Cap Oil & Gas Market Valuations

The smart investor buys low and sells high. And today's small-cap oil and gas sector is definitely offering investors a "buy low" opportunity, while potential oil price recovery offers patient investors at least one long-term investment catalyst. However, risks and rewards are not solely dependent on oil price trends.

Smart investors also have a realistic investment horizon and invest based not on speculation, but on fundamental analysis of the companies in which they want to invest. To ensure success, try to align your investment horizon with your view on the price of oil as well as the timeline of operational catalysts that will trigger material share price appreciation, such as significant production increase, development projects coming on-stream, or drilling results from an exploration well.

Pure exploration is always a risky proposition – never more so than in a low oil price environment. But selective, full-cycle E&P companies can offer actual cash flow generation and growth plans that are funded from internal sources, which mitigates risk and makes them a better opportunity for the long term.

Intelligent investors also avoid companies with excessive debt on their balance sheets, instead selecting those with lower operating costs that can still generate positive netbacks even in the low oil price environment.

While analyzing prospects and seeing how your finalists stack up, don't underestimate seemingly qualitative factors such as geopolitical environment and management skills: These are often the factors that have the most dramatic impact on the market valuations of oil and gas companies.

Finally, be realistic about what kind of return to expect from each stock, whether you are after capital gains and potential cash return via dividends from production and development, or high-risk / high-return capital gains from exploration. Always remember that risk has to justify reward.

With the right selection of stocks in your portfolio and a realistic investment horizon, potential returns from the small-cap oil and gas sector can be substantial. Be wise, keep your key value drivers in sight, and maximize your ROI by selecting companies that are right for your portfolio.

So again, the seven questions to ask before you invest in a small-cap oil and gas company are:

1. *What is your view on the oil price and does it concur with your investment horizon?*
2. *What stage of the E&P cycle are you investing in and what types of risk are you taking on?*
3. *Can the company fund its growth plans and does it have a healthy balance sheet?*
4. *Is the company generating positive operating profit even in the low oil price environment?*
5. *What is the fiscal regime that the company operates in and is it stable?*
6. *Is the geopolitical environment the company operates in safe?*
7. *Does the management team have the appropriate experience, relationships; and integrity to translate strategic vision into action?*

About the Author

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Ms. Orazbayeva is a respected oil and gas analyst based in London, UK. She has previously worked in GMP Securities and Westhouse Securities. Her coverage has included a number of oil and gas companies with assets and listings internationally, and she has visited oil and gas assets in Africa, Kazakhstan, Argentina and offshore Norway.

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About the Publication

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