Northern lights

Investment opportunities in the UK North Sea

Oil and gas sector

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Despite the negative sentiment around the UK government increasing the marginal tax rate from 50% to 62% in last week's budget, the North Sea independents continue to offer the potential for spectacular returns. The average share price increase from the companies profiled in this report was 192% over the past 12 months. In the coming year, we believe Premier Oil, Nautical Petroleum and Encore Oil offer the best value, with high-impact exploration upside from Faroe Petroleum and DEO Petroleum.

2011 budget: A reminder of the complexities

Evaluating returns on a North Sea prospect requires the critical skill of risk mitigation. Geological complexities, infrastructure access and funding are factors that management teams can influence through having the right technical, commercial and finance teams. The seemingly continuous changes in fiscal regime and potential changes in the regulatory and operating regime post Macondo are, however, more difficult to mitigate.

Reserves based valuations

Recent deals in the North Sea (KNOC/Dana, Dana/Petro-Canada, EnQuest/Stratic) have all been done in excess of $10/boe on an EV/2P basis. The companies profiled in this report trade on an average $8/boe on an EV/(2P + 2C) basis. On these metrics, DEO Petroleum is the cheapest, while Faroe Petroleum is the most expensive. However, it does not automatically follow that they are a buy or sell, as reserves based valuations fail to capture many factors, most notably the skill set of the company at mitigating risks.

Six evaluation criteria we look for in high quality players

We look for 1) experienced management teams and partners, 2) evidence of good subsurface understanding, 3) balanced portfolios, 4) commercial access to infrastructure, 5) ability to mitigate fluctuations in fiscal regime (eg tax losses or access to field allowances), strong safety records and mitigation of decommissioning liabilities, and 6) companies that are financially prudent, have reasonable operating costs and that can fund their commitments in the coming year.

Companies to focus on: Premier, Nautical, Encore

We highlight Premier Oil, Nautical Petroleum and Encore Oil as companies where the risk/reward balance is skewed in the favour of value creation. At present we believe Valiant and Endeavour should be avoided. Serica and Xcite have the potential to become more attractive if they derisk their prospects further, while Faroe and DEO Petroleum both provide high-impact exploration upside.

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COMPANIES PROFILED

DEO Petroleum
Encore Oil
Endeavour International
EnQuest
Faroe Petroleum
Ithaca Energy*
Nautical Petroleum*
Premier Oil
Rheochem*
Serica Energy
Valiant Petroleum
Xcite Energy*

**Edison client*

ADDITIONAL COMPANIES MET

Fairfield Energy
Bridge Energy

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Introduction: Balancing the risks for North Sea independents

After 40 years of exploration, development and exploitation, the North Sea has become a mature area characterised by a large number of small and technically demanding fields. As discoveries became smaller and relative rates of return diminished, the majors started to withdraw, targeting prospective areas overseas with more favourable economics.

In order to stem the tide and retain investment in the North Sea, the UK government introduced measures such as 'Promote licences' to encourage smaller independents to invest in the sector. Additional incentives for development of heavy oil fields and those with high pressure/high temperature (HPHT) characteristics were to follow. With a proactive licensing system and buoyant oil prices, the sector continues to enjoy investment, much of this from the small- to mid-sized independents.

Some of these independents have enjoyed extremely successful value accretion, either growing impressive reserves and production bases, or successfully exiting via a shareholder friendly sale. However, others have struggled and many have fallen by the wayside. Some of this is undoubtedly down to success with the drill-bit which, by its nature, comes with an element of luck. Much is also down to the financial and technical strengths of the company and its partners, the quality of the assets, and ultimately how well equipped management teams have been at navigating the often unique risks that are associated with being an E&P company operating in the North Sea.

In this report we guide the investor through the process of defining the specific risks associated with being an operator in the North Sea today, identifying which are relevant to companies in the sector, and most critically assessing which companies are best placed to mitigate these risks in order to unlock the value potential that both their asset base and balance sheet can offer.

The asset base: Introducing the oil screen

One look at the balance sheet of any E&P company will show that a sizeable proportion of its assets are tied up in the line 'intangibles'. Just like many service, technology or people oriented businesses the main assets within an E&P company are often difficult to quantify. These, of course, are the potential, prospective, contingent, possible, probable and proven resources and reserves of hydrocarbons that an E&P company can potentially extract for profit.

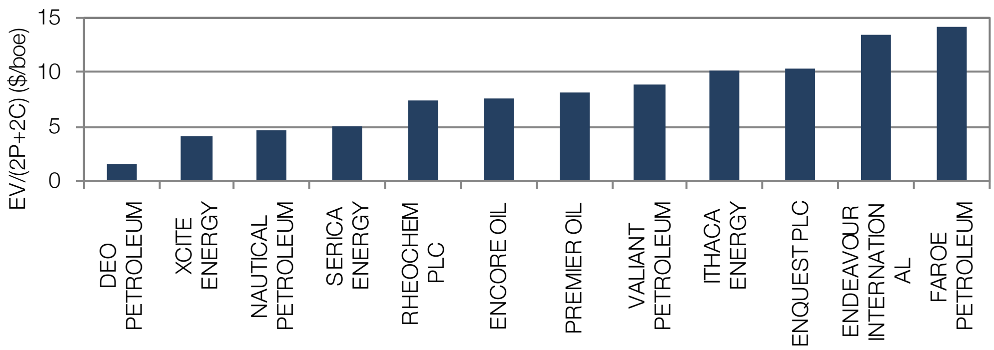
Different reserves and resources obviously carry different economic value, while some companies are much better placed than others to exploit these reserves and resources, giving the investor confidence of a reasonable rate of return on their investment. The initial step is to define the value potential from the asset base and for this we use a systematic screening process that we call our oil screen.

The oil screen quantifies, on a relative basis, the more defined hydrocarbon resources and reserves within a company's asset portfolio as a function of its market derived enterprise value (EV). We select both proven and probable reserves (2P) and corresponding contingent resources (2C) as our basic asset definition screen. By comparing the 2P plus 2C to the company's EV we are able to make relative judgements regarding market recognition for the asset base. A company with a high

EV/(2P+2C) indicates the market is attributing a high value to the assets, or at least those in the 2P plus 2C category. A low EV/(2P+2C) implies the market is ascribing a low value. Describing two such stocks as 'expensive" and 'cheap" is overly simplistic, but it does help highlight where there may be valuation anomalies based on different market values ascribed to the asset base.

For this North Sea report we have considered 12 independent companies, all UK-listed, either on AIM or the Main market. We have laid out their EV/(2P+2C) in Exhibit 1.

Exhibit 1: North Sea independents oil screen



Source: Edison Investment Research, company accounts, Bloomberg

Our screen shows us that North Sea newcomer DEO Petroleum has the lowest EV/(2P+2C) and hence is arithmetically the most undervalued stock within this investible universe. However, this does not mean it is an automatic buy recommendation, or for that matter that Faroe Petroleum with the highest EV/(2P+2C) is a slam-dunk sell. For this we need to dig deeper, both into the other potential, prospective and possible reserves and resources, and most critically to dig under the surface of both the assets and the management teams running these companies to understand which are best equipped to identify, manage and mitigate the particular risks associated with being an E&P operator in the North Sea.

Six evaluation criteria to mitigate risk

Operating in the North Sea is an uncertain business. Operations dealing with hydrocarbons inherently carry a degree of safety and environmental risk, exploration players are exposed to numerous subsurface complications that comprise the geological risk, access to capital is often affected both by macro and micro economic effects, and even the UK government is known to throw in a few curve-balls in the shape of taxation and other regulatory legislation. Companies that are set up to anticipate and mitigate these risks are likely to rise above the competition. We propose six evaluation criteria to identify the exposure companies have to such risks and how they are best placed to deal with them.

1) **Management & partners**: We look for management teams that have impressive track records of managing their asset portfolios. We look at equity partners and consider if they are suitably sized to help contribute to projects without the impediments of strategy conflict, insufficient financial or technical strength, or where they are simply too big to develop assets at the requisite pace. We further look for a track record of attracting supportive partners, especially where abandonment liabilities and/or infrastructure access are issues.

2) **Subsurface understanding/complexity**: We look for management with geology/subsurface experience up to board level, especially where the company is exploration focused or where field developments are complicated. We also consider whether companies can recruit and retain a strong subsurface team to support its exploration and development programme. And ultimately we look for indicators that a company can demonstrate commerciality or a compelling route to commerciality for its leads, prospects and discoveries.
3) **Portfolio balance/upside potential**: We look for asset portfolios that both complement the expertise of the company and provide balance as well as upside potential to the shareholder. We also look at how companies operate in the M&A environment and how best they can leverage this.
4) **Infrastructure access**: We assess which companies need to access infrastructure to develop assets, and if so what are the key constraints, ie tariff, ullage, contract length etc. We again look at partners and infrastructure providers to determine what competing issues may affect companies gaining access to infrastructure on reasonable terms.
5) **Regulatory issues – tax, licensing and abandonment**: We look for companies that have substantial tax losses (Premier Oil and Ithaca) or that at least have access to some field allowances eg Nautical Petroleum and Xcite. In a post Macondo world, we look for players that demonstrate they have exceptional safety records, have strong technical teams and have strong balance sheets. Complexities around decommissioning mean we prefer companies that are not Petroleum Revenue Tax (PRT) paying (see appendix 1), and hence have younger assets, or that have negotiated deals such that previous owners maintain the liability (eg EnQuest and Faroe's Glitne field) or have clearly quantifiable estimates of the costs that are not deemed material.
6) **Financial strength/discipline**: The oil industry is subject to a number of variables, from disappointing exploration through to fluctuating oil prices. First and foremost we look at finance teams who understand this and operate on a prudent basis. As a rule of thumb, we look at whether companies can fund their programmes in the coming 12 months. We also look at whether a company's cost of extraction per barrel is reasonable.

Valuation: Combining the evaluation criteria with the numbers

Having used our evaluation criteria to identify both the risks and how well placed companies are to manage and mitigate these risks, we then combine this with the asset based valuation to determine overall potential valuation anomalies and investment opportunities.

In the case of our North Sea investible universe we have ranked each company against each of our six evaluation criteria and summarised these in the matrix shown in Exhibit 2. We allocate stars based on the criteria of one star is low risk/key strength, two stars is medium risk, and three stars is high risk/weakness. By then reading up and down and across the matrix we can see which are subjectively well placed to mitigate risk across each of the key areas, as well as assessing overall which companies carry the most potential risk from the perspective of exploiting value from the asset base.

Exhibit 2: Evaluation criteria matrix

Note: ★ low risk/key strength,★★ medium risk, ★★★ high risk/weakness.

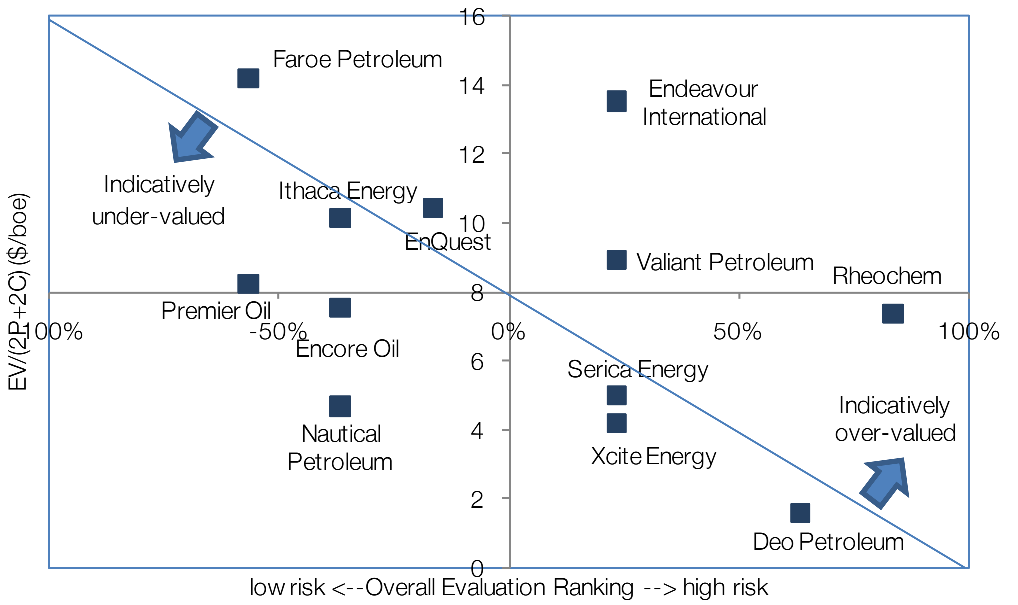
	Deo Petroleum	Encore Oil	Endeavour Int.	EnQuest	Faroe Petroleum	Ithaca Energy	Nautical Petroleum	Premier Oil	Rheochem	Serica Energy	Valiant Petroleum	Xcite Energy
Management & partners	★★	★	★★	★★	★	★	★★	★	★★★	★★	★★	★★
Subsurface understanding/ complexity	★★	★	★★	★	★	★	★	★	★★★	★★	★★	★★
Portfolio balance/ upside potential	★★★	★★	★	★	★	★★	★	★	★★	★★	★	★★
Infrastructure access	★★	★★	★★★	★★	★★	★★	★★	★	★★	★★★	★★	★
Adandonoment liabilities/ tax/ regulatory issues	★★	★	★	★★	★	★	★	★★	★★	★	★★	★
Financial strength/ discipline	★★	★	★★	★	★	★	★	★	★★	★	★★	★★★

Source: Edison Investment Research

With this analysis, exploration-led Encore, Nautical and Faroe Petroleum lead the way alongside strong production and balanced E&P players EnQuest and Premier Oil. All have well regarded management teams, strong balance sheets and good quality assets.

By adding up the stars for each company and weighting them on a scale of -100% to +100% of the peer group range, it is then possible to combine our risk evaluation criteria with the reserves and resource based EV/(2P+2C) valuation methodology. This allows us to determine a more realistic indicative relative valuation for each stock that incorporates the risk balance as shown in Exhibit 3.

Exhibit 3: Combining the risk valuation approach with the asset valuation



Source: Edison Investment Research

Immediately it should be stressed that this evaluation methodology is both highly subjective and prone to inconsistencies. As previously mentioned we account for only 2P reserves and 2C contingent resources in our asset valuation EV/(2P+2C). This does not account for differences in hydrocarbon fluid, lifting and transportation costs, or ascribe any additional value to the company's remaining prospective resources or possible reserves.

For a thorough valuation we would always recommend using the risk-weighted discounted cash flow method to generate an EV for each asset and in turn to derive a per share valuation having adjusted for net cash or net debt and administration costs. This approach also lends itself to scenario planning to assess the impact of different oil price outlooks, costs of capital and chances of success. However, critically our relative analysis can be carried out very quickly and, with the guidance of the evaluation criteria questions, we feel it is a strong platform for investors both to test their own valuation methods and to use when meeting management teams in person.

Valuation: Our conclusions

Focusing on Exhibit 3, our analysis from a relative perspective suggests the companies that offer best value to investors in the North Sea are Premier Oil, Encore Oil and Nautical Petroleum. All three have strong management teams, a wide range of quality assets that are relatively unaffected adversely by infrastructure access and regulatory issues. There is clearly scope within this analysis for the market to ascribe more value to the existing assets in terms of share price gains.

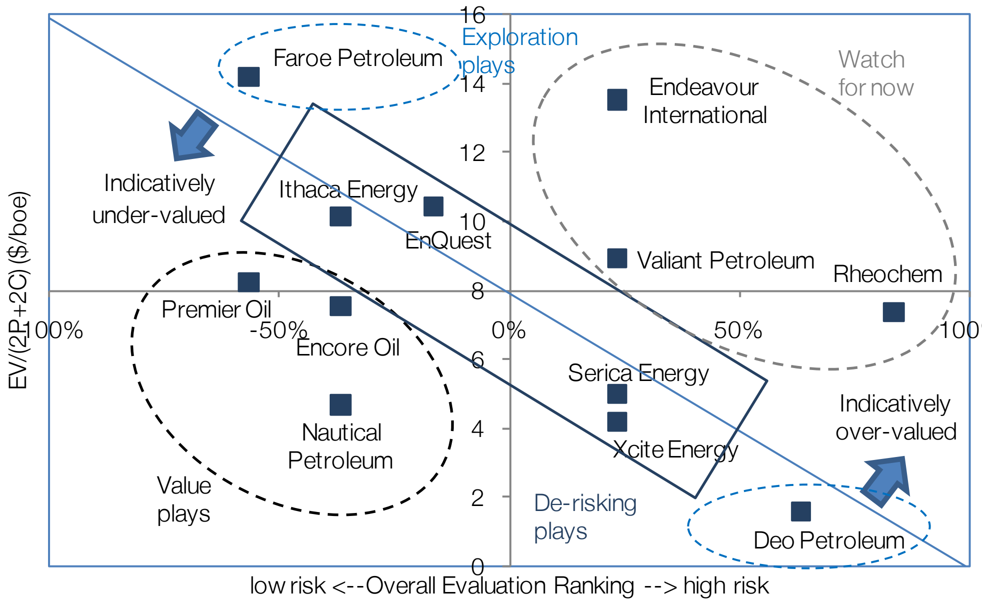
We would also point to two other groups of companies from our analysis where we suggest there is specific upside potential. Xcite Energy and Serica Energy are both well placed to move into the top left quadrant of our matrix as they seek further upside from derisking their development assets. Meanwhile EnQuest and Ithaca Energy appear to be priced correctly, reflecting the relatively developed production and near-production asset base in each company along with strong management teams.

Finally we would look to DEO Petroleum and Faroe Petroleum as exploration companies that offer a different kind of upside. They are not highlighted as value propositions by our analysis because their leads and prospective resources do not feature on our oil screen, thus artificially inflating the EV/(2P+2C) calculation. However, both are exposed to high-impact exploration that, if successful, could have a significant effect on share price.

Valiant Petroleum and Endeavour International appear to offer the least value to investors based on the analysis of the peer group, although the relatively high EV/(2C+2P) valuation for Endeavour may be in part a result of the impact of the company's US unconventional asset base. On the basis of our analysis Rheochem does not look strong currently. It is initiating a shift to focus entirely on E&P and needs to build up a credible track record.

Exhibit 4 shows our analysis again, but with each of the four groups marked on the chart.

Exhibit 4: Combining the risk valuation approach with the asset valuation



Source: Edison Investment Research

Sensitivities: Oil price, timetables and reserves

Our assessment of the North Sea independents is predicated on a number of assumptions. We are of the view that the oil price will remain above $90/bbl on a 12-month horizon and that the majority of projects the independents are working on will remain well above their break-even points. We are expecting activity in the coming year based on timetables set out by companies, but these could be subject to delays or change. Finally, we highlight that the reserves that we base our valuations on can change materially as more information is gathered from modelling and drilling.

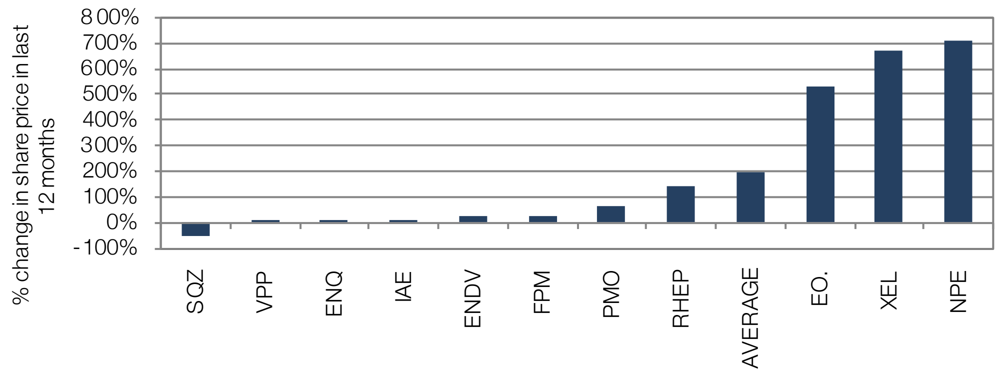
1. The North Sea: An overview

Oil has been extracted from the North Sea for over 40 years. One might therefore be forgiven for thinking it an old and tired place to be operating. Far from it. A licensing regime that encourages independents to exploit resources married with sufficient technical, fiscal and environmental complexities requires investors to find teams with the right skill set. Those that do have the potential to be rewarded from material value creation.

Over the past 12 months, the North Sea independents have rewarded shareholders with spectacular performance when looked at as a group. The three stand-out names are Nautical Petroleum (+706%), Xcite Energy (+674%) and Encore Oil (+531%). Nautical proved up Kraken and Cather at the drill bit, crystallised value in its Mariner licence and successfully raised money that at the same time strengthened its shareholder register. Xcite proved the doubters wrong with a successful flow test at Bentley, a field where it had a 100% working interest (WI). Encore's strong share price performance came from success at Catcher and Cladhan, both light oil discoveries. A simple average of the share price change for this group shows 192% returns, although this is clearly flattered by a number of fund raisings over the course of the last year.

Exhibit 5: Share price performance of North Sea players in past 12 months average 192%

Note: We have excluded DEO Petroleum as this was a cash shell 12 months ago. We have used EnQuest's opening share price following the demerger on 9 April 2010 to calculate performance.



Source: Bloomberg

A brief history

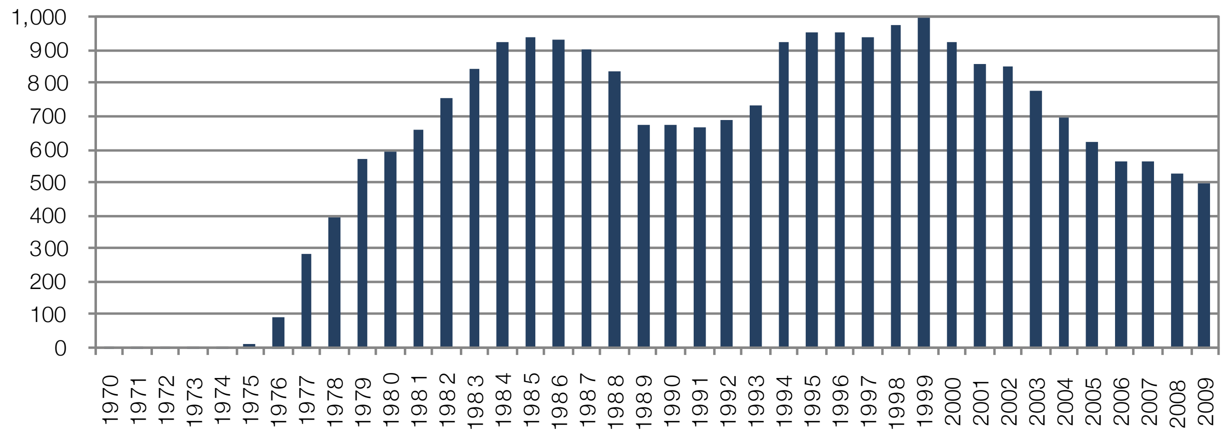
The North Sea has come a long way since gas was first discovered by BP in West Sole in 1965. The discovery of the giant Forties and Brent oil fields in 1970/71 brought the major oil companies to the region and kick started huge investment in the area. During this time, development was dominated by large fields requiring large platforms and major infrastructure. Cutting edge technology was required to overcome the hazardous conditions of the North Sea, paving the way for today's activity West of Shetland and further afield in the deep waters offshore Brazil and the Gulf of Mexico.

The North Sea today

Forty years on, the North Sea is a mature area characterised by a large number of small and technically demanding fields, operated by a diverse range of companies, from super majors to small independents. As discoveries became smaller, the majors began to withdraw and production and reserves replacement began to suffer. So, in the last decade, the government introduced measures, including 'Promote licences' specifically designed to encourage smaller company activity, and this has been considered successful, culminating in 2008 being the best year in 10 years in terms of exploration drilling.

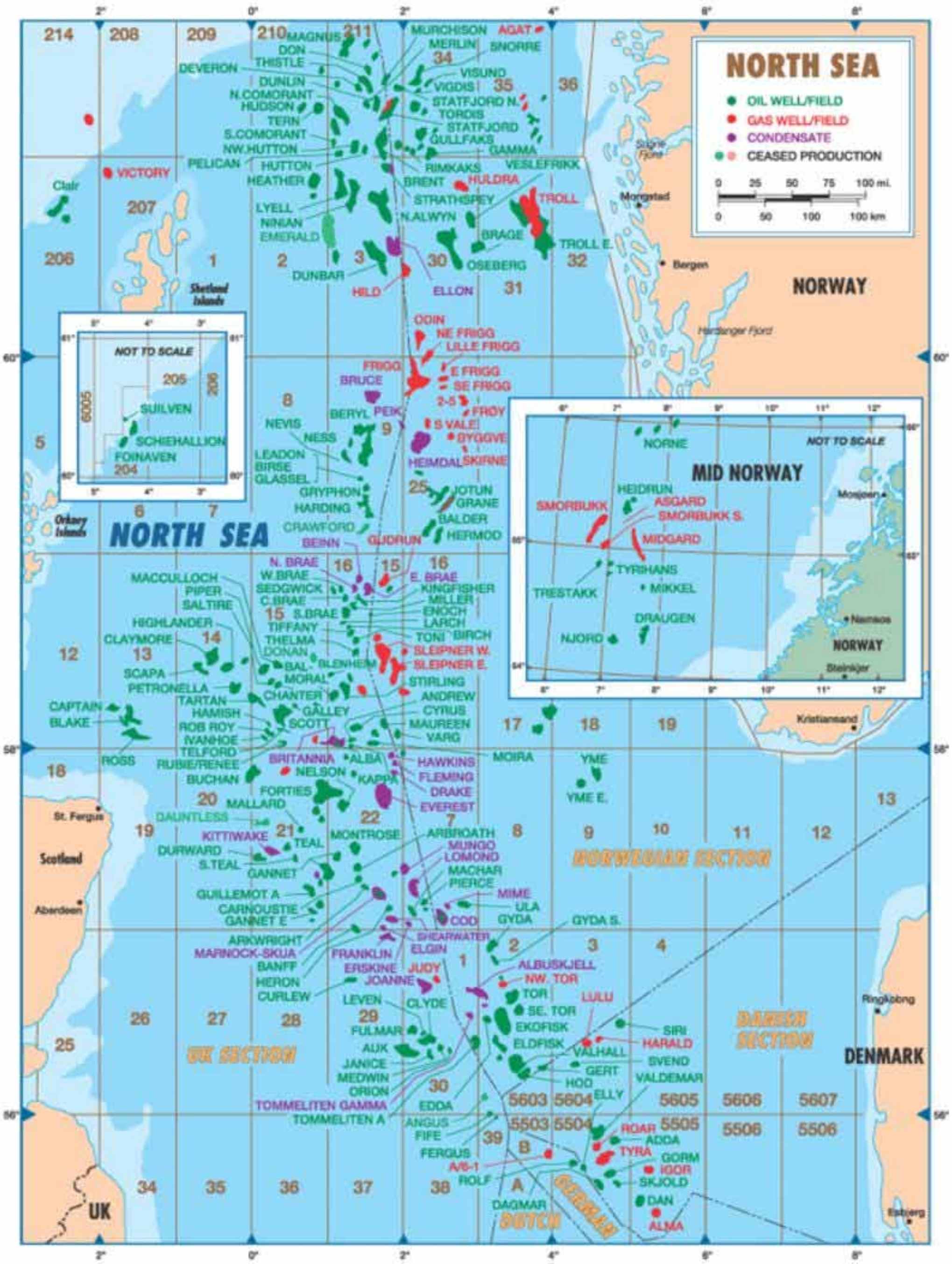
Oil production peaked in the North Sea in the mid-90s, when the region supplied 9% of the world's oil. With 39bnboe produced to date, it is estimated that around 21bnboe remains to be produced, so there is still much to play for. However there are significant challenges which will determine how many of these remaining barrels are extracted. An aspirational target of 3mboepd from the North Sea in 2010 set in 1998 by the joint industry and government partnership PILOT, has not been met, with an estimated shortfall of 0.6mboepd. This has been attributed to the fact that the new fields coming onstream are declining at faster rates than anticipated, partly due to the companies' increased use of infill drilling to effectively drain reservoirs, but also as a result of a decrease in capital investment. Without sustained investment it is estimated that production will fall to half its current rate within five years. The challenge is to maintain production at such a rate that mature assets are kept operating for as long as possible, thereby providing an infrastructure through which small satellite reserves can be developed. Today, half of all fields being considered for development are 20 million barrels or less in size. These fields will require technical innovations to develop cost effectively, but with the current high oil price, there is little incentive for companies to prioritise such technology when easier returns can be found elsewhere.

Exhibit 6: Crude oil production in the North Sea 1970-2009 (mmbbls)



Source: DECC

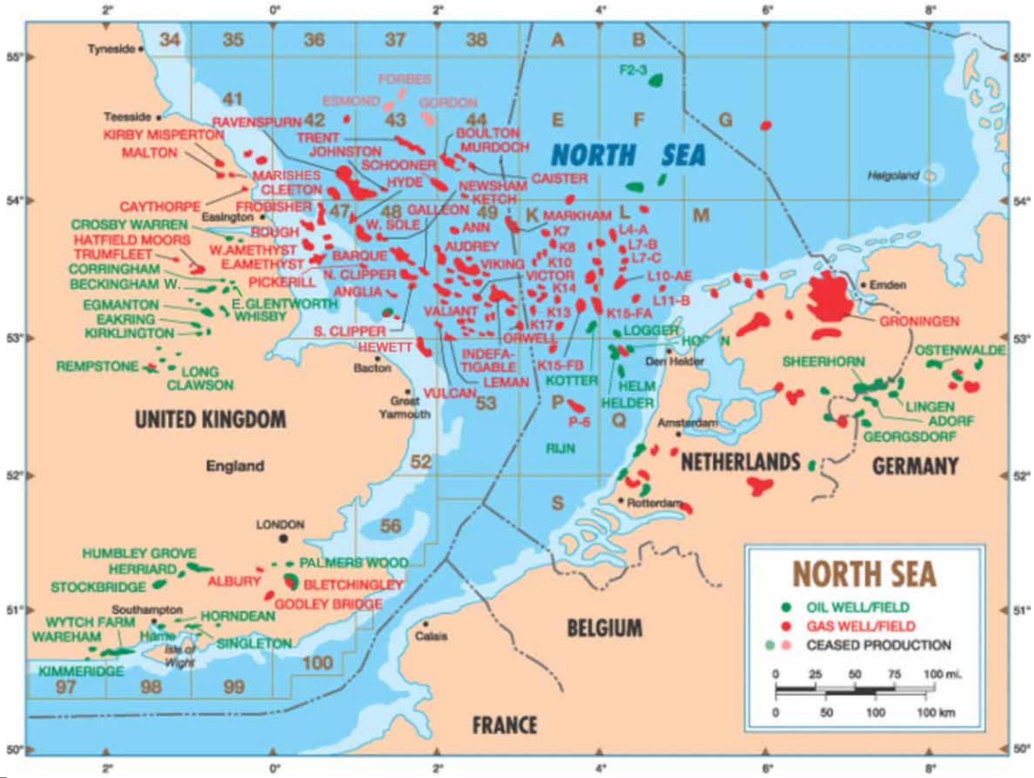
Exhibit 7: Map of the Northern North Sea



Source: Acorn Petroleum Services

The UK Continental Shelf (UKCS) can be broadly divided into four main areas of interest: the Northern North Sea, the Central North Sea, the Southern North Sea and West of Shetland. Each of these areas throws up different concerns and challenges for companies. For example, the area to the west of the Shetland Islands is the largest remaining area of significant prospectivity on the UKCS and is thought to potentially contain up to 17% of the UK's remaining oil and gas reserves. Assets here are typically at the early stage of development, and are expensive and more challenging to drill due to the deep water environment. However, the area is relatively under-explored and therefore has the potential to throw up larger finds.

Exhibit 8: Map of the Southern North Sea



Source: Acorn Petroleum Services

The Southern North Sea contains mainly gas assets and has increasingly become the domain of utility companies.

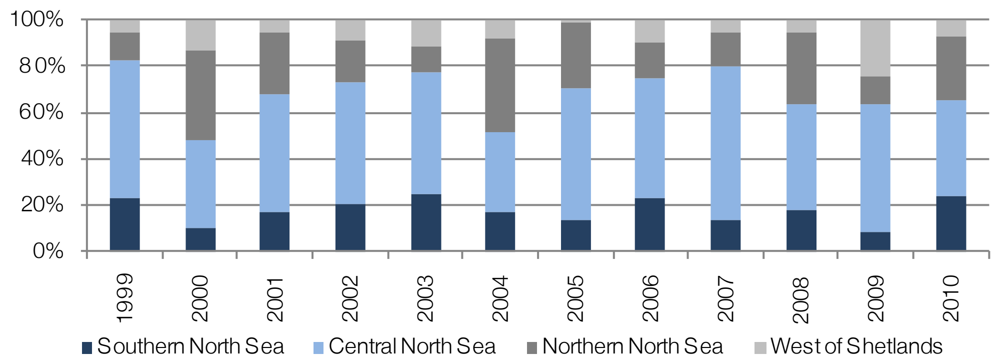
The Northern North Sea is home to many large and ageing fields including the massive Brent and Forties fields. These assets require significant expenditure to maintain operability and operations integrity, with operating costs estimated to be 30% higher for this area than the UKCS as a whole, and for this reason it is not considered attractive to many small companies.

Due to all these issues, a large number of independents choose to mainly operate in the Central North Sea where conditions are relatively benign by North Sea standards, with manageable water depths and existing infrastructure. Prospects here tend to be smaller, requiring tie back through existing pipelines and platforms, with two-thirds of new fields in the North Sea presently developed using subsea tie-backs. Larger finds are still possible, with the 2001 discovery of the 550mmbbls Buzzard field and 2010's Catcher discovery, currently estimated as holding up to 200mmbbls. This area is also the biggest contributor to UKCS production, accounting for 60% in 2009 and expected to still dominate with 40% of total production in 2020 (Exhibits 9 and 10).

As the area has matured and technology has advanced, companies are also increasingly developing prospects that were previously uneconomic or technically too difficult to develop. An example of this is the heavy oil developments typically found at the edges of the Central North Sea.

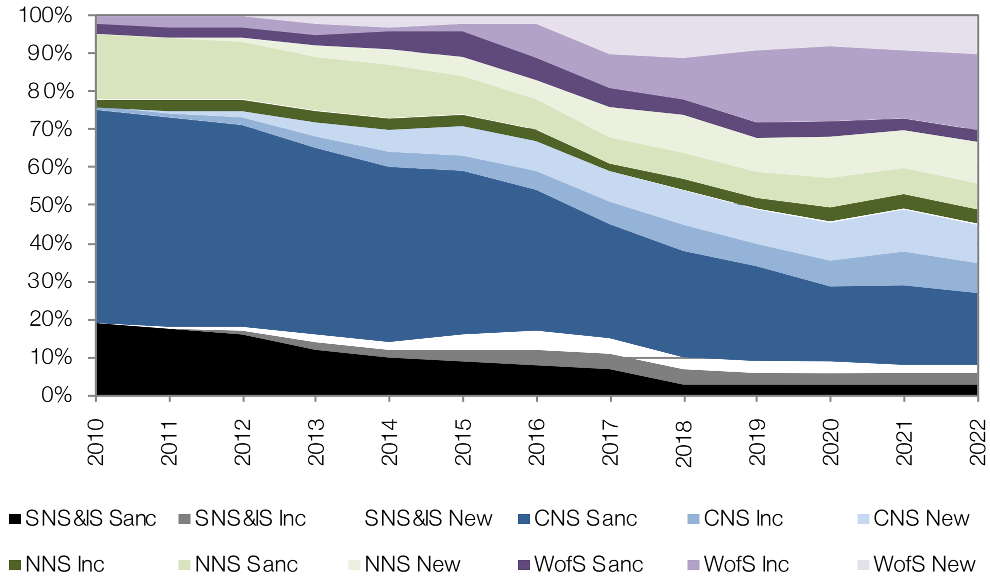
Heavy oil development became possible with advancements in horizontal drilling and new completion technologies, together with higher oil prices. Heavy oil is more sensitive to the oil price due to lower recovery factors and discounts that are applied, but it now accounts for around 10% of UK North Sea production. The government recognised this in its 2009 budget by providing a field allowance of £800 million for new heavy oil developments. A similar amount is also available for new High Pressure/High Temperature (HP/HT) fields, which also tend to be in the Central North Sea. It should also be noted that operators must increase expenditure to develop these more technically demanding fields, with the trade association Oil and Gas UK reporting in its 2010 Activity Survey that new fields were on average 20% more expensive on a cost per barrel basis.

Exhibit 9: E&A drilling activity by region



Source: DECC

Exhibit 10: UKCS oil & gas production outlook, proportioned by region 2010-2022



Source: Oil & Gas UK

Despite these challenges associated with working in the North Sea today, the current outlook is still positive. Oil remains of strategic importance to the UK economy, with the government forecasting that the UK will need oil and gas for 70% of its energy needs in 2020. The number of exploration wells drilled in 2010 was up by 28% with 37 wells spudded, although the 2009 figures were materially depressed by the global financial crisis, and it is estimated that capital investment in 2011 will be £7.7bn, up from £4.4bn in 2010. In addition, the 26th Licensing round announced in October 2010 saw 144 licences being offered to 83 companies, of which seven were new entrants to the UK.

2. Six evaluation criteria to look for

We propose six key criteria that should always be considered when evaluating E&P companies operating in the North Sea. In combination with fundamental and relative valuation techniques we believe these behaviours, issues and challenges provide investors and analysts the best chance of understanding which companies are best placed to thrive and which could struggle.

2.1 Management and partners

Outside of specialist subsurface skills and the unique insights that key management can undoubtedly bring, our feedback from industry players is that most other skills can be covered either through partnering with larger, more developed companies, or through the use of contractors. However, partnering with larger companies can lead to decision making delays and smaller incremental projects do not always get the same degree of focus when part of a major's portfolio rather than in a smaller independent's portfolio. Partners in general, both big and small, bring different advantages to an independent E&P company in the North Sea. The key issues here are set out below.

- Partnering advantages: By farming in and farming out of licence blocks, companies are able to balance risk and reward, while leveraging collective financial and technical resources in the pursuit of monetising hydrocarbon reserves.

  To attract big companies, independents need to be involved in the exploration of larger resources, most probably individual prospects in excess of 50mmboe (Faroe's Lagavulin prospect being a good example). Having large partners on board can also help with securing drilling rig slots, especially for single drill commitments. The drawback to this can be the speed of decision-making among partners, especially if interest structures are complex, and a possibility that senior management within the majors cannot (understandably) devote the same attention to individual projects as would be the case with independents. Despite these problems, our discussions with companies indicate these can be largely overcome through openness and a willingness to work hand in hand with majors. Faroe Petroleum is a good example of this, as is Nautical Petroleum. An alternative approach would be that of Xcite Energy, which, rather than farming down, is attempting to maintain a large working interest while incentivising subsurface, drilling, topside and offtake partners through a leveraged alliance structure. The industry is undoubtedly watching Xcite as a test case in this respect.

- Potential conflicts and concerns: Partnerships that can be problematic result when the interested partners have different strategic goals, or where they have insufficient financial or technical resource to fund an equity share of exploration or development projects. The Greater Catcher Area discoveries (Catcher, Catcher North, Varadero and Burgman) have caught the imagination of the investment community; however, the partners have quite different strategies. Until recently Encore Oil was generally accepted as an exploration and appraisal company, Nautical Petroleum has ambitions to move into development but currently does not necessarily have either the experience or the funding, while Premier Oil and Wintershall are probably best placed to lead development of Catcher given their balance sheet strength. Ultimately the development plan for this field will be resolved, but the risk of delays due to insufficient partner alignment certainly exists. Weak financial partners are equally an issue when considering potential delays. Nautical Petroleum is again an example where progress on developing the Kraken field has undoubtedly been delayed due to lack of funds from partner Canamens.

- **Infrastructure and abandonment considerations**: As well as providing technical and financial support to exploration and appraisal projects, having the right partners on board can help companies during development and production with both infrastructure access and abandonment liabilities.

  Smaller, marginal field developments can be most problematic when negotiating tolling arrangements with infrastructure owners. Serica Energy and Endeavour International have both had difficulty in agreeing tolling arrangements that would potentially have benefited from having infrastructure operators as partners. This is further exacerbated when ullage is limited and there is potential competition from other fields where infrastructure owners have working interest. Overall the complexity of ownership of both individual licence blocks and infrastructure can lead to significant delays in commercial negotiations, and we would always caution investors when looking at companies with pre-FDP projects in need of complex tie-in arrangements in order to monetise reserves.

  Abandonment liabilities also need to be considered when choosing partners. With joint and several liabilities under Section 29 of the Petroleum Act 1998, the ability to partner with larger oil companies and effectively leverage their balance sheet is important. Such deals will face the challenges mentioned above.

Edison investment insights: Management and partners

- Does management have an impressive track record of managing their asset portfolios?
- Are partners suitably sized to help contribute to projects without the impediments of strategy conflict, insufficient financial or technical strength, or are they simply too big to develop assets at the requisite pace?
- Does the company have a track record of attracting supportive partners, especially where abandonment liabilities and/or infrastructure access are issues?

2.2 Subsurface understanding/complexity

Investors place their trust in E&P management, not only to manage companies efficiently, but to also provide assurances that they can extract unseen quantities of hydrocarbons in a commercial manner in line with investors’ economic expectations. To do this we look to management teams with strong subsurface understanding for the assets in their portfolio. This has been an Edison prerequisite for many years when identifying exploration companies with clear upside potential. However, getting this experience often takes years of practical involvement for key management, and this is particularly critical when dealing with more unusual drilling environments such as heavy oil, HPHT and deep water.

During our discussions with management teams it was interesting to compare ideas of what 'significant' experience actually meant. In some cases management felt that one to two years in a geographical area constitutes meaningful experience; in reality we probably side more with the teams who think you need to spend possibly more than 10 years building subsurface experience, especially when dealing with more difficult drilling environments. A number of companies demonstrate this admirably, such as the Xcite Energy management team's direct experience over many years with the heavy oil Bentley field, and Faroe Petroleum's and Nautical Petroleum's CEOs who both have been in the role for many years, leading their companies from a position of technical excellence. We would not dismiss companies with less experienced management teams, but would generally favour E&P experience as the 'CV' driver rather than complementary financial or management skills.

Being able to attract and retain talented staff is also something to be considered. Petroleum engineering expertise is in demand and this leads to a recruitment and retention battle among the different E&P players in the sector. What is apparent is that development focused engineers (principally production technologists and facilities engineers) are favouring working for companies with a balanced and extensive portfolio of exploration, appraisal and development assets where funding is in place to systematically appraise, drill and develop. Smaller companies, or those without a track record of moving from exploration through to development, can struggle to attract and retain people in these roles as a result of not being able to provide sustainable work and/or the impression of job security. Overall we would therefore favour larger companies with a systematic drilling programme such as EnQuest, Premier and Faroe as being best placed to attract and retain this critical talent.

Edison investment insights: Subsurface understanding/complexity

- Does management have geology/subsurface experience up to board level, especially if exploration focused or where field developments are complicated?
- Can the company recruit and retain a strong subsurface team to support its exploration and development programme?
- Can the company demonstrate commerciality or a compelling route to commerciality for its leads, prospects and discoveries?

2.3 Portfolio balance/upside potential

We consider the balance of exploration and appraisal to development and production assets in the portfolio is important. The Fairfield Energy proposed IPO in 2010 appears to have struggled in part because the company did not have sufficient exploration upside built into its portfolio. Pure exploration players can survive as such, but we would always look to more balanced development/production companies such as EnQuest, Premier and Ithaca to also have a pipeline of exploration/appraisal assets in their portfolio to offer the investor upside potential. We also look for a proactive approach to adding new acreage and in particular new licence awards. Valiant Petroleum, Faroe Petroleum and Rheochem (Zeus) were most active in acquiring new awards in the latest 26th round.

Turning to the M&A environment, the UK market is more active than that in Norway. However, the number of independents with significant assets has fallen dramatically over the years such that few are now in direct competition with each other. There are more sellers than buyers, sellers in general being bigger companies looking to divest of declining or marginal fields that can no longer compete for capital when compared within a portfolio of international projects. However, the spectre of abandonment liabilities hangs over these deals and every industry executive, investor and analyst alike has their own views as to how this will play out. Most of the development/production focused companies in the sector have been subsumed by larger players (eg Enterprise Oil and Lasmo at the turn of the century along with Venture Petroleum and Dana Petroleum more recently). Overly aggressive growth companies have also failed, Oilexco being the prime example (see case study 1 for details).

Overall the landscape for M&A deals remains competitive and the recent upturn in the number of farm-out packages coming onto the market suggests there is scope for more activity. However, oil price volatility appears to be creating significant disconnects in bid/ask prices, blocking deals from being executed. Uncertainty around UK fiscal terms following the recent UK budget will not have helped, while reserves based lending (RBL) oil price assumptions significantly below today's $100 plus prices will further impede deals being struck that require debt financing.

Edison investment insights: Portfolio balance/upside potential

- Is the company actively developing exploration upside potential within its portfolio to provide support for share price growth?
- Does the company understand the M&A environment and how best to leverage this?

2.4 Infrastructure access

As the North Sea matures, there is scope for all parties to benefit if new fields are developed, where possible, by utilising existing infrastructure. Owners of infrastructure would clearly look to maximise returns on their assets, while those developing fields are looking to pay as low a tariff as possible. These competing needs create a natural tension between the two parties and, as such, negotiations around access to infrastructure can become at best protracted or even problematic. An example of this is Serica Energy's negotiations to tie in its Columbus field to the nearby Lomond platform, operated by BG. In this case, there is plenty of ullage in the pipeline, so tariff negotiations were not an issue. However, there is limited spare processing capacity at the platform, which is essential for processing the gas condensate from Columbus and so it is planned to install separate processing facilities which will be linked by a bridge to Lomond. These new facilities will also take production from the Arran field, operated by Dana/KNOC, with BG also wishing to maintain capacity for future production from its own nearby exploration prospects. Serica has therefore had to deal with several different sets of partners in order to reach an agreement, making the progressing of Columbus to project sanction more challenging.

There is an Infrastructure Code of Practice (ICOP) that sets out principles and procedures to guide companies through negotiating third-party access. Developed in conjunction with the Department of Energy and Climate Change (DECC) and the UK Operators Association (UKOOA), the code is entirely voluntary. In the event that parties are unable to come to an agreement, a company can call on the Secretary of State for Energy to adjudicate. Endeavour International is the first company to ask for such a ruling on a dispute, arguing that Nexen has set an unreasonably high tariff for Endeavour to transport gas from its Rochelle field through Nexen's Scott platform. Any decision here is likely to set a precedent in how negotiations are handled in the North Sea. In the past it is thought that smaller companies had not taken similar disputes to the Secretary of State in order to avoid 'rocking the boat' in what they already saw as an unequal relationship with major companies.

Edison investment insights: Infrastructure

- Does the company need access to infrastructure to develop assets? If so what are the key constraints, ie tariff, ullage. Which companies must be negotiated with in order to reach an agreement, and what are the competing issues that will affect gaining access on reasonable terms?
- Has the company screened partners to avoid potential conflicts regarding access strategies?
- Does the company have a successful track record in negotiating access?
- Can the company's prospects be fully developed before required infrastructure is due to be abandoned?

2.5 Regulatory environment: Tax, licensing and abandonment

The UK licensing regime is attractive to independent oil companies. One of the DECC's stated goals is to maximise the economic recovery of oil and gas. The licensing regime, which we detail in appendix 1, creates opportunities for existing and new entrants to secure acreage that the majors are neglecting to develop. Examples recently from the companies we examine in this piece include:

- Faroe Petroleum, which acquired 23 blocks or part blocks in the 26th licensing round.
- DEO Petroleum, which acquired its stake in Perth Core through the fallow acreage initiative.
- Nautical Petroleum, which acquired block 9/1a in the 26th licensing round, adjacent to Kraken which potentially could quadruple resources at Kraken.
- Rheochem, which added eight additional licences in the 26th licensing round.

On the flip side, independents who do not progress acreage run the risk of losing their licences. Among the companies we examine in this piece, there are also examples:

- Nautical and Encore face a drill or drop decision on the Spaniards licence this year.
- DEO Petroleum is required to submit an FDP on its Perth asset by September 2011 or potentially risk having to relinquish the acreage.

While the licensing regime is attractive, there are a number of factors within the North Sea that are not, and we look for companies that can mitigate these issues:

- **Fiscal regime:** More than anything, oil companies crave a stable fiscal regime. It allows for greater confidence in project economics. The UK government continues to tweak the UK fiscal regime (see appendix 1 for more detail). The increase in the Supplementary Charge from 20% to 32% in the 2011 budget and language that explained this as effectively a ratchet mechanism linked to the oil price results in UK independents facing a marginal tax rate of 62%, and for those with older fields subject to PRT, a marginal rate of 81%. We therefore look for companies with the ability to mitigate this, either through substantial tax losses (Premier Oil and Ithaca) or that at least have access to some field allowances, eg Nautical Petroleum and Xcite for their heavy oil fields.

- Environmental assessments and safety: Post Macondo, risk aversion has increased considerably, resulting in production shut downs as maintenance is carried out, which ultimately creates lower cash flows (eg Premier Oil had shut downs at Balmoral, Wytch Farm and Scott, which affected production targets). Exploration costs are increasing as a result of higher insurance costs and a doubling of inspections, while development timetables will potentially lengthen due to more stringent assessment criteria. There are also a number of uncertainties about the future operating environment. The most material of these is whether the government will introduce mandatory third-party insurance requirements for independents and whether the government requires independents to demonstrate the ability to pay for the consequences of any incident, something that most independents' balance sheets cannot do. In mitigation of these risks, we look for players who demonstrate they have exceptional safety records, have strong technical teams and have strong balance sheets.
- Abandonment costs: As the North Sea matures, the issues surrounding the abandonment of old platforms have become more pressing. In our discussions with companies operating in the region, it is the issue most frequently raised as causing concern, and, with decommissioning costs up to 2040 estimated at up to $29bn, it is not hard to see why. This is further complicated by the fiscal regime. Decommissioning is complex and requires planning several years in advance. The current regulatory and fiscal regime makes it almost impossible for independents to acquire assets from the majors. The cash that must be put aside for decommissioning on late life fields is such that only players with cash flow generating assets that are in production are able to take over these assets from the majors. Furthermore, the uncertainties created by the PRT being possibly abolished and the recently announced restrictions around decommissioning costs only being allowed against a Supplementary Charge of 20% rather than 32%, plus rules that allow decommissioning costs to be tax deductable only when incurred rather than in advance, raise the costs and the uncertainties around this. In mitigation of these risks, we prefer companies that are not PRT paying, and hence have younger assets, that have managed to get the original owner to maintain the liability (eg EnQuest and Faroe's Glitne field) or have clearly quantifiable estimates of the costs that are not deemed material.

Edison investment insights: Tax, licensing and abandonment

- Are any licences in the portfolio facing risk of relinquishment?
- Is there evidence of a material tax shield?
- Do any of the fields qualify for field allowances?
- What is the health and safety record? In which quartile does the company appear in benchmarking surveys ?
- Are any of the assets in deepwater? What technical expertise does management have to understand and mitigate the risks?
- Is the company paying PRT?
- Are any fields in the portfolio due to be decommissioned in the next three years?

2.6 Financial strength/discipline

The oil industry is subject to a number of variables, from disappointing exploration through to fluctuating oil prices. First and foremost we look at finance teams that understand this and operate on a prudent basis.

Ability to fund projects is critical in being able to capture value, but also in avoiding the situation that Oilexco found itself in (see case study 1 for more details). Nautical Petroleum's sale of its Mariner stake was met with a positive reaction from the market not only because it crystalised the value of their stake, but more importantly it removed a nagging concern about how a company the size of Nautical could possibly fund the development of a field the size of Mariner. As a rule of thumb, we look at whether companies can fund their programmes in the coming 12 months. Ideally companies have production that allows them to self fund their exploration activity. If that is not the case, we look for sufficient cash and other funding lines (bank, SEDA or other) that are already available to allow them to meet their commitments.

We also look at whether a company's cost of extraction per barrel is reasonable. This includes exploration, capex, opex and G&A costs and examines project break-even oil prices. Premier Oil's G&A costs are c $1/bbl, while Oilexco's were running at c $14/bbl.

Edison investment insights: Financial strength and discipline

- Who is running the finance function and what expertise does that individual bring?
- Is there sufficient funding in place to meet committed expenditure in the coming year?
- What are break-even oil prices for the most material projects?
- What are the G&A costs per barrel?
- What is the cost of extraction per barrel?

3. Case studies

Case study 1: Oilexco – largest recent corporate bankruptcy

On 31 December 2008, Oilexco Inc issued a statement that its subsidiary Oilexco North Sea Limited intended to file for administration as soon as practically possible.

Run by Art Millholland, Oilexco entered the UK North Sea in 2002 when it was awarded three 100% Seaward Production licences in the 20th Offshore Licensing Round.

Attracted by the 'UK Promote regime', the business model was one that many of the independents in the North Sea today pursue in whole or in part. Oilexco targeted licences where previously drilled wells had strong oil shows. It attempted to pursue opportunities where it could have a high working interest, and it could compress timetables between discovery and first oil to two years. Its strategy to accelerate the timetable to first oil was to enter into long-term charters of rigs and drill multi leg appraisal wells on discovery.

It acquired minor interests in the Balmoral and Glamis light oil fields, providing it with daily production that ranged between 140bopd to 200bopd.

By 2007 it had bought, appraised and developed the Brenda field (100% WI), together with the Nicol field (70% WI), which came on stream in the same year, bringing production to around 20,000bopd.

By 2008 Oilexco had became one of the most prolific drillers on the UKCS. Between 2004 and 2008 it had drilled 137 wells in the UK North Sea, representing 30% of all exploration and appraisal wells drilled in the North Sea during that period.

At its peak valuation of C$19.5 in June 2008, Oilexco had a market capitalisation of C$4.7bn and an EV of C$5.3bn. However, this figure excluded the $600m of contractual drilling commitments, which effectively sat off balance sheet. At this time the Canadian dollar was trading at near parity to the US dollar and the oil price had peaked at $147/bbl. By the end of the year, the oil price had collapsed to just under $40/bbl and Oilexco's banks pulled out, nervous that the cost of drilling was higher than the revenues received for the oil.

Many industry commentators have reflected on the reasons for the failure. Outside exogenous factors (the oil price and the 2008 credit crunch) the following are worth highlighting when evaluating business models:

- **Sole risking of assets:** Oilexco preferred to maximise its equity participation in the fields it was appraising. While this should ensure upside, it removes a process of checks and balances that working with a partner brings, and increases the financial burden in bringing the field to first oil without additional support. An example of this was Oilexco's 100% WI in the Shelley field. Having appraised the field in 2007, Oilexco entered into a five year fixed contract for the Sevan FPSO, committing itself to c $370m of contractual commitments. Oilexco was guiding production from Shelley to peak at 35,000bopd by end 2008 or early Q109. Once Premier Oil acquired Oilxeco from the administrators, it renegotiated the FPSO contract, and brought the field into production in August 2009.

Initially producing at 11,000bopd, the field laterly was producing at 2,000bopd and was eventually decommissioned in 2010, Premier citing the field to be uneconomic.

- **Poor operational performance:** The disappointing production from the Shelley field was not a one off. The Brenda/Nicol developments were targeting 30,000bopd, a target that the company never managed to achieve. With production and hence revenues coming in behind expectations, the impact on the company's finances was further compounded by the high cost of producing a barrel of oil, estimated at $69/bbl at the end of 2008.
- **Lack of financial discipline:** Oilexco's G&A costs were extremely high at $14/bbl, with peers in the North Sea typically having G&A costs as low as $1/bbl to $5/bbl. The approach to drilling numerous wells has also been criticised by industry observers,
- **Ready to drill, but drill to create value not news flow:** To avoid being held hostage to rig availability and fast track developments, Oilexco entered into long-term charters for rigs, which resulted in wells being drilled to fill the rig schedule. The following extracts from an interview given by Rod Christiansen, Oilexco's senior VP for exploration and development give a picture of the culture within the company: "We have to keep them drilling every day", the company had a willingness to act on "slightly informed information" and "not something I want to do again". "My department had 20 people and we're spread pretty thin."
- **A strong technical understanding of the prospect:** Oilexco targeted Shelley as it appeared to be similar to the Brenda prospect. After five dry holes, the company had to re-evaluate, concluding that while it was a stratigraphic trap, it was not a structure it had seen before. Gas escaping from the Upper Jurassic made seismic difficult to interpret, yet, overruling the in-house geophysicist, a decision was made to drill one more well away from where the seismic indicated. The well found oil, which flowed at 3,000bopd with no water, and the prospect was delineated with 14 side tracks. However, history goes on to show that the field produced poorly. It had been clear that this was a complex reservoir to understand, yet the company was still prepared to commit to a five year contract for an FPSO to develop the field.
- **Be able to fund development projects**: Oilexco did not hedge against oil price falls other than to cover bank debt. A combination of a falling oil price, disappointing production, high operating costs and significant contractual commitments all led to the banks ultimately withdrawing their support.

Case study 2: Fairfield Energy – learning from a failed IPO

Fairfield was established in 2005 to target opportunities in the North Sea by acquiring and developing both mature producing assets with upside potential, and development/redevelopment assets in need of technical focus and capital. Over a period of five years the private company built up an asset base that included four producing fields, five development/redevelopment assets and six appraisal/exploration assets. With 4.6mboepd of production and 94.1mmboe of 2P reserves, of which one third were in production, the company had established itself as one of the largest players in the North Sea, both by production and reserves. Only Premier, EnQuest and Dana could be counted as larger within the context of UK independents in the North Sea at the time.

In 2010, having established its asset base, the company announced its intention to float on the London Stock Exchange with a target of raising approximately $450-500m. The intention was to use approximately 80% of the flotation proceeds across its production and development assets, in particular focusing on the 18.5mmboe net 2P Dunlin field. The remaining 20% was to be spent on exploration and appraisal and business development. On 17 June 2010 the company made its announcement to the market of its intention to float. On 15 July 2010 the company announced it had postponed its IPO as a result of market conditions.

So what went wrong? In preparing this report we were given the opportunity to speak to Fairfield management six months on about the reasons why they thought the flotation was unsuccessful. Initial thoughts, consistent with the 15 July market announcement, were that equity markets remained subdued following the 2008 credit crunch and that the timing was not right for such a sizeable company to come to the market. However, since this time, feedback from the investment community has contributed some additional factors that are worth considering.

- Uncertainty over decommissioning liabilities: The single largest asset in Fairfield's portfolio is its 70% interest and operatorship of the Dunlin field. The Dunlin field came into production in 1978 and had produced by end 2009 some 377mmbbl of predominantly oil, representing a recovery factor of about 48.5%. Although not imminent, realisation that the field was potentially nearing the end of its economic life, the company had started a consultation process with both the DECC and the public around decommissioning options.
  With few large platforms having been decommissioned in the North Sea, and 15 years on from the infamous Brent Spa decommissioning, public interest is high. While the decommissioning industry in the North Sea remains immature, there is considerable uncertainty around the costs involved in the removal of offshore structures, despite the fact that the government, under the DECC, provides comprehensive guidance. Until the industry becomes more established, early decommissioning activities are likely to be more expensive until specialist knowledge and experience is built up.
  In the case of Fairfield's IPO it is likely the uncertainty around both timing and costs for decommissioning of Dunlin would have affected investor confidence.
- Assurances around better platform integrity: Coupled with uncertainty on decommissioning costs there were also issues around platform integrity on an ongoing basis that is now thought to have contributed to investor reticence. While in no way implying that Fairfield was not a safe operator, the company's lack of track record for operating large, ageing North Sea infrastructure probably was an issue.
- Need for a track record: As a relatively new name in the market there is potentially a realisation that companies need to build a track record and cannot be seen to be going "too far too fast". At the time of the planned flotation Fairfield was still relatively small by headcount, with most of its facilities management outsourced, mainly to AMEC. More of a

demonstrable track record in exploration/appraisal and development/production would have helped the company convince investors ahead of its flotation.

- **Operatorship not essential**: The IPO feedback has generated a change of heart for Fairfield regarding operatorship. Whereas previously it was focused on maintaining large working interest operated acreage, the company is now open to smaller non-operated stakes to provide portfolio balance and mitigate risk.
- **A need for a more balanced portfolio**: Finally, there is a realisation that perhaps the Fairfield value proposition was too heavily weighted toward production assets. The story perhaps lacked some romance in terms of exploration upside, with insufficient interest from investors where the company only has end of life fields to offer, no matter how well they are managed.

Since the IPO was postponed Fairfield has secured in principle up to $150m of new investment from its current shareholders to realise the potential value of the company's current asset base, and to successfully position Fairfield for future growth opportunities. Priorities for this will be greater focus on Dunlin integrity, appraisal of its Darwin discovery, funding of its Clipper South gas field (which recently was awarded FDP approval) and potentially the development of its Crawford field with a view to building an additional hub to create diversity in the sector. The new funding demonstrates the existing shareholders' confidence in the company. Undoubtedly market conditions were unfavourable during the summer of 2010, but with the additional market feedback and the new funds available, Fairfield management are confident that they can grow the company successfully. Further funding through an IPO in the future may still be a possibility, but for now Fairfield is focusing on investing in its current asset base.

Case study 3: Buzzard and Edinburgh Oil & Gas

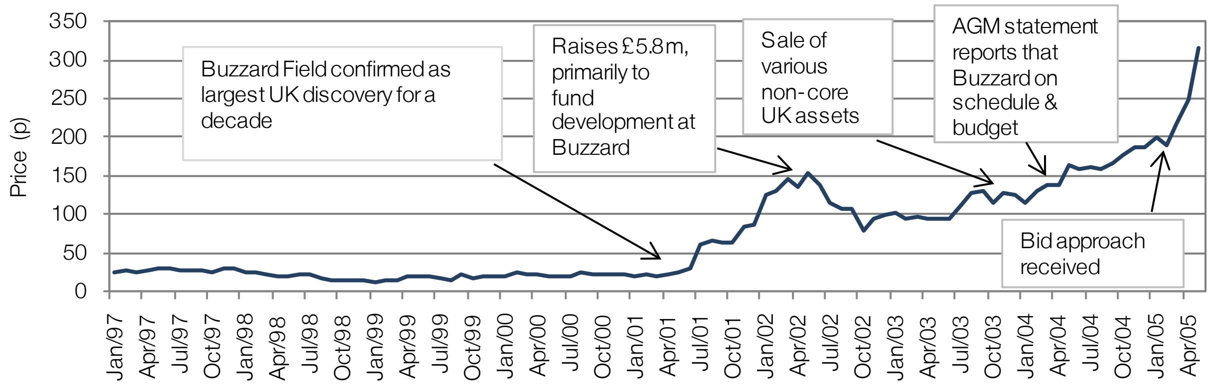
Edinburgh Oil & Gas's share price rose by over 1,500% between January 2000 and May 2005 (a month after the acquisition by Dyon, a JV comprised of Dutch independents Dyas and Oranje Nassau was announced). A success in exploration, we show below how the company demonstrated the five investment criteria we look for.

- **Exploration geared upside:** Buzzard, one of the largest finds in the North Sea was a prospect that many operators had considered too risky to drill. The chance of success was 1:7, making it high risk, but also high reward.
- **Strong sub-surface understanding:** Edinburgh Oil & Gas followed a strategy of partnering in consortiums for licensing rounds with larger independents. Graham Dore, chief geologist at one of the Buzzard partners, PanCanadian, first came up with the idea in 1992. He developed an intimate knowledge of the part of the North Sea Buzzard was located in. While he had a sound geological concept, a key factor in determining the well location was the successful reprocessing of 1995 3D seismic data, which gave the team much greater confidence in the pinchout.
- **Efficient use of capital:** The company was an initial partner (5.2%) in the Buzzard discovery. While its exposure to capital and dry hole cost was limited, the potential upside in a success case was significant.

- **Ability to balance risk and reward:** The company had a targeted strategy of concentrating the majority of its exploration efforts on small working interests in licences with prospects that were high risk in terms of chances of success, but offered the potential for significant reserves.
- **A focus on drilling in the near term:** In 2000 Edinburgh Oil & Gas changed its strategy, moving away from low-risk onshore production and focusing instead on high-reward exploration.

On 11 May 2001 oil flowed from the first well drilled on Buzzard. What also stands out is how efficiently the field was developed. Project sanction was obtained within 2.5 years of the original discovery and first oil production was achieved within a further three years.

Exhibit 11: Edinburgh Oil & Gas



Source: Bloomberg

4. Valuation: Understanding the asset base

The oil screen quantifies on a relative basis the more defined hydrocarbon resources and reserves within a company's asset portfolio as a function of its market derived enterprise value (EV). We select both proven and probable reserves (2P) and corresponding contingent resources (2C) as our basic asset definition screen. By definition this means we focus on oil and gas reserves and resources that are at the more commercial end of the exploration and appraisal process. Wherever possible we try to use third-party audited reserves and resources data using the internationally recognised Resource Classification Framework in the Petroleum Resources Management System as published by the Society of Petroleum Engineers (SPE).

- **2P reserves**: Proven and probable (2P) reserves represent the most commercial quantities of recoverable oil and gas within a proven hydrocarbon system. However, we do not consider possible reserves as defined by SPE given that this forms the upside potential for a given reservoir rather than the most considered view.
- **2C contingent resources**: When oil and gas assets have not been classified as commercial reserves we then include those resources from a hydrocarbon system that are classified as sub-commercial contingent resources. In this case we select 2C contingent resources, reflecting a mid-case level of certainty associated with definition of the resource estimates. Again we do not include the upside case.

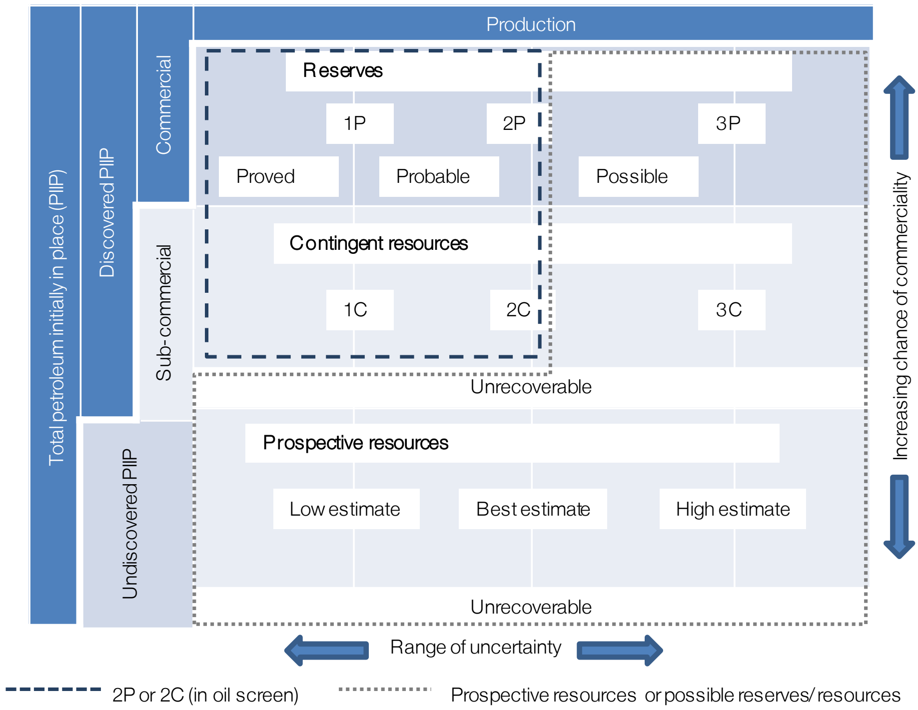
It is important to consider that when selecting reserves and resources for our oil screen we do not include potential hydrocarbon systems that are still unproven or discoveries that are classified as prospective resources. Many exploration focused companies have the majority of their hydrocarbon assets within this category. It is perfectly normal for the market to award a risk-weighted value to these assets within the share price, but we do not capture this in our screen. As previously mentioned we also do not include the upside cases when considering either reserves or contingent resources. A graphical description of the reserves and resources SPE Resource Classification Framework and the sub-set selected for our oil screen is shown in Exhibit 12.

We also do not account for differences in fiscal terms, fluid type, operating and transportation costs and ultimately the timing of revenue generation in our screen. Potential impacts of these can include the following:

- **Production vs appraisal/development**: Having sunk the capital investment required to move an oil and gas field into production the prospective netback on a per barrel basis for producing assets is obviously significantly higher than with pre-development assets.
- **Fiscal terms**: As per appendix 1 the exact fiscal terms for companies operating in the North Sea varies based both on if they pay PRT or enjoy field allowances for developing small fields, those with heavy oil or high pressure/high temperature conditions.
- **Quality and fluid type**: Heavy and/or sour crudes carry a discount to light oil. Gas is also less valuable than oil on a per barrel equivalent basis, although by how much can differ greatly depending on location, infrastructure etc.

- **Operating and transportation costs**: Larger fields are generally more economical on a per barrel basis, while some crudes, such as heavy oil, require special handling and processing that increase operating costs. Tolling through third-party infrastructure can also incur higher than normal transportation costs.

Exhibit 12: SPE Resource Classification Framework



Source: Society of Petroleum Engineers, Edison Investment Research

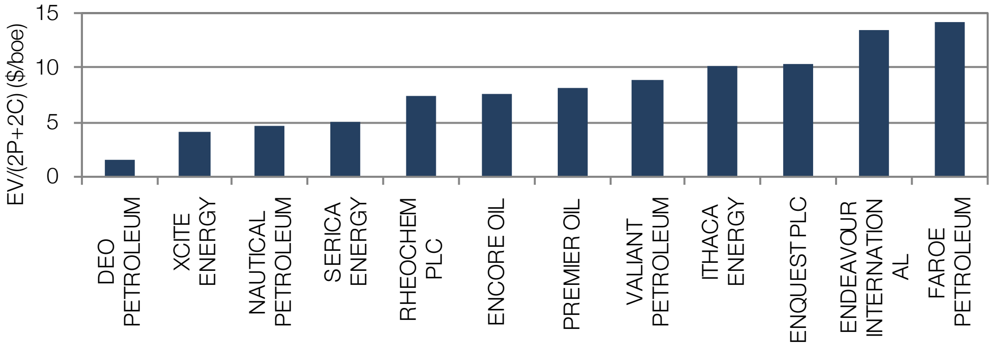
However, caveats aside, we believe an evaluation of market valuation compared with a company's hydrocarbon assets remains the most appropriate screening tool for determining potential valuation anomalies.

Constructing the EV/(2P+2C) oil screen

By comparing the 2P plus 2C to the company's EV we are able to make relative judgements regarding market recognition for the asset base. A company with a high EV/(2P+2C) indicates the market is attributing a high value to the assets, or at least those in the 2P plus 2C category. A low EV/(2P+2C) implies the market is ascribing a low value. Describing two such stocks as 'expensive' and 'cheap' is overly simplistic, but it does help lay out where there may be valuation anomalies based on different market values ascribed to the asset base.

For this North Sea report we have considered 12 independent companies, all UK-listed either on AIM or the Main market, for which we have laid out their EV/(2P+2C) in Exhibit 13.

Exhibit 13: North Sea independents oil screen

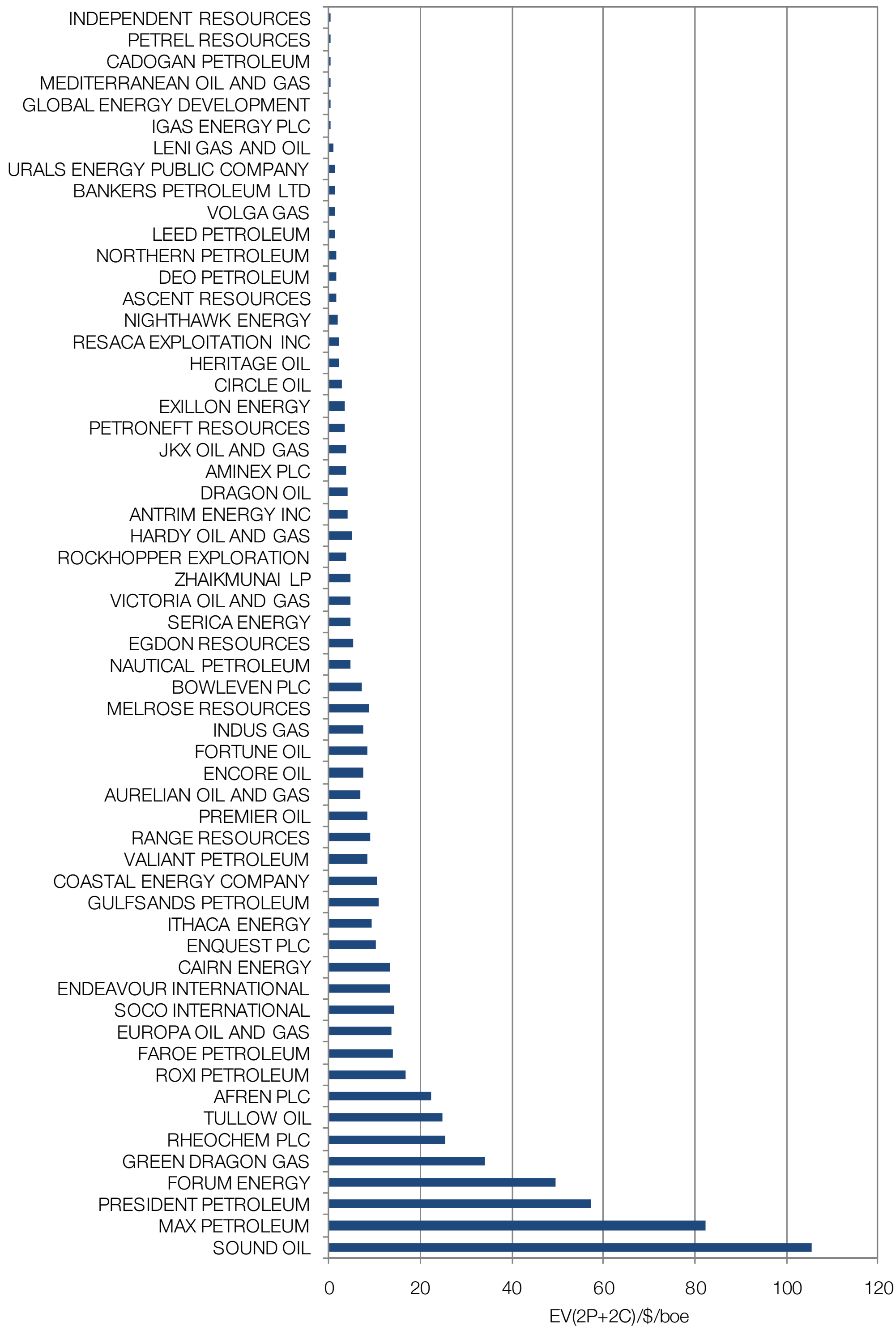


Source: Edison Investment Research, company accounts, Bloomberg

Our screen shows us that North Sea newcomer DEO Petroleum has the lowest EV/(2P+2C) and hence is arithmetically the most undervalued stock within this investible universe. This, however, does not mean it is an automatic buy recommendation, or for that matter that Faroe Petroleum with the highest EV/(2P+2C) is a slam-dunk sell. For this we need to dig deeper, both into the potential, prospective and possible reserves and resources, and most critically to dig under the surface of both the assets and the management teams running these companies to understand which are best equipped to identify, manage and mitigate the particular risks associated with being an E&P operator in the North Sea.

Edison Investment Research also maintains an oil screen database for all UK listed independent E&P companies. Although outside of the scope of this report, we have included a snapshot of the current screen in Exhibit 14.

Exhibit 14: London listed E&P independents oil screen



Source: Edison Investment Research, company accounts, Bloomberg

5. Sensitivities: Oil price, timetable and reserves

Our assessment of the North Sea independents is predicated on a number of assumptions. We are of the view that oil price will remain above $90 on a 12-month horizon and that the majority of projects the independents are working on will remain well above their break-even points. We are expecting activity in the coming year based on timetables set out by companies, but these are subject to delays or change. Finally, we highlight that the reserves that we base our valuations on can change materially as more information is gathered from modelling and drilling.

Oil price: Our view suggests oil prices will hold above $90/bbl

Benchmark light crude prices excluding WTI have trended higher of late driven by the political risks emanating from North Africa and the Middle East. While the risk of a major supply interruption has clearly increased in recent weeks, we believe such an event would be short-lived. Near-term, Brent could easily exceed $120/barrel, but we expect a softening trend.

Our quarterly scenario for Brent is as follows: Q1 $105.0, Q2 $103.0, Q3 $95.0, and Q4 $91.0. The scenarios for Brent reflect a number of assumptions. These are that by the second half of 2011 turmoil in the Middle East/North Africa will ebb significantly, Saudi Arabia will fill the void resulting from lost production in Libya, and that world economic growth will lose momentum under the weight of inflationary pressures along with the policy response and deleveraging. Ebbing Middle Eastern turmoil reflects the assumption that coup d'etats are concluded rapidly as in Egypt and Tunisia or that a combination of mild political reform and repression dampen revolutionary fervour. However, should actions in Libya escalate, the oil price may continue to spike higher. At present, the risks to our views are to the upside for oil companies.

Catalysts and timetables

In examining valuations and evaluation criteria, we have looked for near-term catalysts that we believe could have a material impact on share prices. However, we do highlight that oil exploration, particularly given the weather conditions in the North Sea, is unpredictable and these timetables may be delayed.

Estimation of reserves and resources

Our valuation assessments have been made using reserves rather than cash flow estimations. However, reserves are subject to change. Unexpected geological characteristics or poor recovery rates may lead to downgrades in reserves, which may change our perspective on a stock.

Company profiles

DEO Petroleum

Edison investment research

Year End	Revenue (£m)	PBT (£m)	EPS (p)	DPS (p)	P/E (x)	Yield (%)
12/08	N/A	(0.1)	(0.7)	N/A	N/A	N/A
12/09	N/A	(0.1)	(0.3)	N/A	N/A	N/A
12/10e	N/A	N/A	5.6	N/A	10.1	N/A
12/11e	N/A	N/A	5.6	N/A	10.1	N/A

Note: Based on consensus estimates.

Investment summary: A new comer

DEO Petroleum is a newly formed North Sea oil company. The management team behind it is the former Oilexco technical team based in Aberdeen, led by David Marshall. The strategy is to acquire discoveries and bring them into production, tying back to existing infrastructure. Near-term activity is likely to focus on submitting an FDP for Perth ore and raising funds to bring this field into production. If the group can successfully develop the Perth field, we would see this as a significant catalyst to unlock value and it would provide a platform for further growth.

Assets: Discoveries in the Central North Sea

DEO's principal asset is a 42% working interest (WI) in the Perth field, located in the Central North Sea in shallow water (127m depth). Perth was fallow acreage acquired from Nexen for £10.5m in October 2010. The Perth field can be split into the Perth core area, a discovery with three appraisal wells and one side track, which had tested between 1,000-6,000bopd. DEO also has the undrilled Perth North area to explore, where a nearby 15/21a-7 well drilled 4km to the east indicated the presence of hydrocarbons. Outside of the scope of the CPR, DEO also has a 42% WI in three other discoveries, Dolphin, Gamma Central and Sigma, all of which have previously flowed oil.

Challenges: Complex reservoir and FDP timetable

The principal challenge is the complexity of the Perth reservoir, which is heavily faulted and has the presence of H_2S, CO_2 and cemented sands, making recovery factors low (TRACS assigns between 4.1% and 16.1%, with total STOIPP of 228mmbls). The other challenge is coming up with a suitable Field Development Plan by the end of September 2011, or it risks losing the licence. DEO is likely to have to secure additional equity finance to fund its development and drilling commitments.

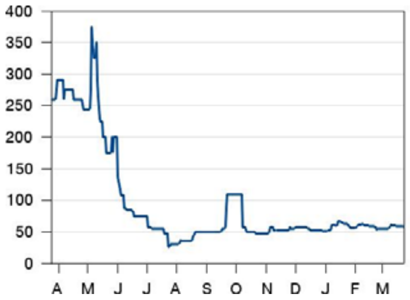
Management and strategy

With the exception of CFO Gregor Goodwin and Mike Cooper (formerly at EnQuest), the management team is made up of the former Oilexco Aberdeen team. They are considered to be experienced, and have attracted farm-in partners such as Faroe Petroleum. The strategy is to acquire discoveries that require development and appraisal, which can be tied back to existing infrastructure.

Price*	56.5p
Market Cap	£24m

*Priced as at 23 March 2011

Share price graph



Share details

Code	DEO
Listing	AIM
Shares in issue	43m

Price

52 week	High	Low
	375p	26.5p

Balance Sheet as at 31 December 2010

Gearing (%)	N/A
NAV per share (p)	N/A
Net cash (£m)	0.1

Business

DEO Petroleum was recently formed, gaining its market listing through the use of a cash shell (Microcap Equities Plc). The group has working interests in the Perth, Dolphin, Gamma Central and Sigma discoveries that it is looking to appraise and develop. Its near-term focus is on the Perth field.

Newsflow catalysts

June 11: Decision on Sigma development

Q211: Tartan or standalone infrastructure agreement

September 11: FDP submission re Perth

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★★	Viewed to be a good technical team. Faroe Petroleum recently bought into Perth, a further endorsement of the DEO management team. Other partners include Maersk and Atlantic Petroleum.
Subsurface understanding/ complexity	★★	Perth Core is a complex reservoir with extensive faulting and low estimated recovery factors, although 2C is based on a 9% recovery factor which is a conservative assumption.
Portfolio balance/ upside potential	★★★	Strong development portfolio, all discoveries that have flowed oil previously. Sigma could potentially be developed earlier than anticipated if a joint development plan is agreed.
Infrastructure access	★★	Ahead of submitting an FDP, DEO is close to agreeing commercial terms with Talisman to tie back the Perth Core field to the Tartan infrastructure or a standalone option.
Abandonment liabilities/ tax/ regulatory issues	★★	Perth Core will benefit from the £75m small field allowance. DEO will need to submit an FDP by September 2011 to DECC.
Financial strength/ discipline	★★	It now has c £4.3m for submission of an FDP and general working capital. DEO is likely to require additional equity funding to develop the Perth Core asset and acquire further acreage.

Location of key North Sea assets

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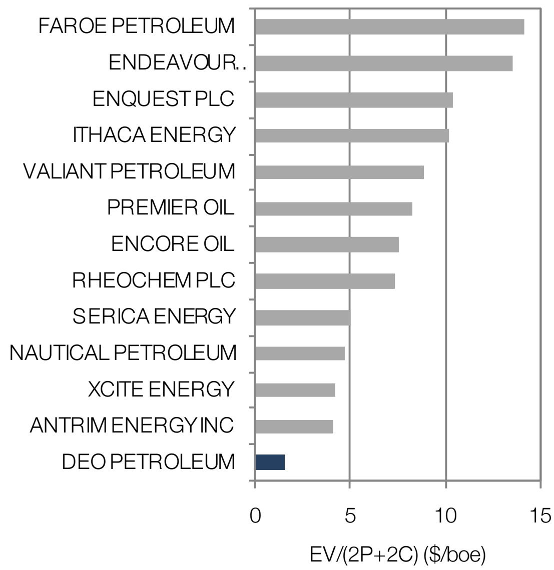
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Perth Core	Oil	8.6	2C	Pre-FDP
Dolphin	Oil	4.2	2C	Pre-FDP
Gamma Central	Oil	8.4	2C	Pre-FDP
Sigma	Oil	3.4	2C	Pre-FDP

Valuation



Source: Edison Investment Research, company data

Deo Petroleum trades at a EV/(2P+2C) of $1.6/boe making it one of the cheapest stocks on our screen.

This reflects its position as a relatively new company which is probably below most investors' radar screens, but also reflects the risks associated with the stock: no production to provide cash flow, a need to raise money to develop the Perth asset and the complexity of the reservoir.

As management takes steps to address these issues and start to build a track record, there is room for significant value creation and we would anticipate an uplift in the EV/(2P + 2C) multiple.

Encore Oil

Year End	Revenue (£m)	PBT (£m)	EPS (p)	DPS (p)	P/E (x)	Yield (%)
06/09	0.0	(1.5)	(0.5)	0.0	N/A	N/A
06/10	0.0	9.6	3.9	0.0	28.2	N/A
06/11e	0.0	(2.5)	(0.7)	0.0	N/A	N/A
06/12e	0.0	(2.3)	(0.7)	0.0	N/A	N/A

Note: Based on consensus estimates.

Investment summary: Experienced and nimble

The Encore team has a wealth of experience in the North Sea and a clear strategy for deploying it in creating value and using Encore as a vehicle to reward themselves and their backers as substantial equity owners. The team has worked together for a number of years and can mark the Buzzard, Breagh, Catcher and Cladhan discoveries on the score card. The long working relationship among management affords it the flexibility of not following rigid processes and remaining flexible to opportunities. Having said it has no desire to build a full-cycle E&P company, management is examining options to spin-out the exploration assets, leaving a development portfolio in Encore that would include Catcher, Cladhan, Cobra and the gas discoveries in Ireland.

Assets: Discoveries in the Central North Sea

Encore has two light oil discoveries in its portfolio. It has a 16.6% working interest (WI) in the Cladhan discovery in the Northern North Sea, where Sterling is the operator. It is the operator, with a 15% WI in the Catcher light oil discovery. Both assets continue to be appraised fully. Other assets with potential near-term activity include Tudor Rose, a heavy oil discovery expected to be drilled this year, Spaniards, where the DECC granted an extension for evaluating a joint development proposal with the partners in Sigma and the Cobra gas discovery, which Encore hopes to develop.

Challenges: Funding exploration activity

Encore has sufficient funding to appraise Cladhan and Catcher. The board is examining options to spin out its exploration assets into a separate AIM company, raising funds to give Encore and other shareholders the ability to retain significant equity stakes in the asset, and for Encore to remain the operator.

Management and strategy

Encore's CEO, FD and exploration director all worked together at Encana UK and were part of the team that made the Buzzard discovery. Highly experienced, the strategy was to capture value for shareholders using their technical skill set in exploration activities. The Catcher success and speculation as to whether the assets would be sold to Premier could be behind the new strategy of spinning off the exploration assets and retaining a development portfolio in Encore Oil.

Price*	105.7p
Market Cap	£310m

**Priced as at 23 March 2011*

Share price graph

Share details

Code	EO.
Listing	AIM
Shares in issue	293m

Price

52 week	High	Low
	151.5p	16p

Balance Sheet as at 31 December 2010

Gearing (%)	N/A
NAV per share (p)	18
Net cash (£m)	30

Business

Listed on AIM in 2005, Encore Oil is focused on delivering shareholder value through its development portfolio. The majority of its assets are in the UK continental shelf, but it does have licences in the Irish Sea and a PSC in offshore Western Sahara. Encore also has a c 30% stake in Egdon Resources, following an asset swap in 2010.

Newsflow catalysts

April 11: Burgman sidetrack result
May 11: Cladhan side track result
June 11: Drill or drop on Spaniards
July 11: Spud Tudor Rose

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

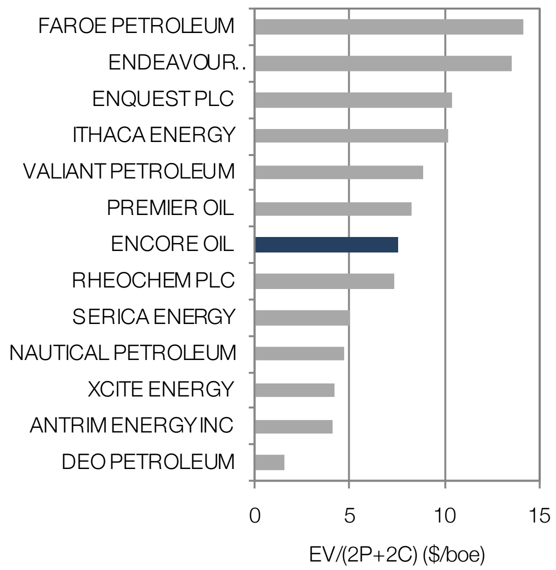
	Exposure	Comment
Management & partners	★	CEO, FD and exploration director ran Encana UK and were part of the Buzzard team. Partners in key assets such as Catcher and Cladham include well regarded companies such as Premier, Nautical Petroleum, Sterling, Wintershall and Dyas. Some debate remains between the partners on Catcher regarding whether to continue appraising or submit and FDP.
Subsurface understanding/ complexity	★	The in-house commercial and technical team has demonstrated success in discovering and appraising prospects numerous times.
Portfolio balance/ upside potential	★★	Looking to spin off exploration assets while retaining a material stake. The end result would create well funded high impact exploration upside backed by a strong development portfolio.
Infrastructure access	★★	Both Catcher and Cladhan do have the potential to be tied back to existing infrastructure, but until full appraisal is concluded, it is too early to say whether the partners would opt for this or an FPSO option.
Abandonment liabilities/ tax/ regulatory issues	★	The DECC has granted extensions for suitable development plans for both Tudor Rose and Spaniards.
Financial strength/ discipline	★	Catcher and Cladhan funded for appraisal, considering spin out option to fully fund exploration assets.

Location of key North Sea assets

©iStockphoto/graite

Field (O=Operator)	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Catcher Main & East (O)	Oil	11.1	2C	Pre-FDP
Catcher North (O)	Oil	0.8	2C	Pre-FDP
Varedero (O)	Oil	6.0	2C	Pre-FDP
Burgman (O)	Oil	6.0	Prospective	Pre-FDP
Carnaby (O)	Oil	6.0	Prospective	Pre-FDP
Cladhan North (O)	Oil	14.8	2C	Pre-FDP
Cladhan Channel & Fans	Oil	27.7	Prospective	Pre-FDP
Tudor Rose (O)	Oil	19.6	2C	Pre-FDP
Spaniards (O)	Oil	20.0	Prospective	Pre-FDP
Cobra (O)	Gas	50.0	Prospective	Pre-FDP

Valuation



Encore Oil trades at a EV/(2P+2C) of $7.5/boe. Our business model evaluation indicates that this is one of the highest quality companies in the North Sea and ought to attract a premium rating for its assets.

Drilling campaigns at Cladhan, Catcher and Tudor Rose potentially can add bookable reserves in the coming year and will be key catalysts for share price performance.

The possible strategic spin out of Encore's exploration assets would crystallise the value of the development portfolio, strengthen the balance sheet and underpin development of Cladhan and Catcher beyond the current appraisal stage.

Source: Edison Investment Research, company data

Endeavour International Corporation

Year End	Revenue ($m)	PBT ($m)	EPS (c)	DPS (c)	P/E (x)	Yield (%)
12/08	170.8	50.0	2.49	N/A	4.7	N/A
12/09	62.3	(94.7)	(3.34)	N/A	N/A	N/A
12/10e	84.9	(18.0)	(1.27)	N/A	N/A	N/A
12/11e	76.2	(20.3)	(0.46)	N/A	N/A	N/A

Note: Based on consensus estimates; $1.62/£.

Investment summary: Conventional developers

Endeavour's North Sea focus is on development plays along the UK Continental Shelf (UKCS). Three significant projects, with Rochelle the biggest, bring around 45mmboe of net reserves with all three expected to be in production within 24 months. The big issues here are around infrastructure access, although recent news does appear to be positive. A US unconventional shale play provides options, although how the two businesses compete for available capital remains to be seen.

Assets: New development-led growth

The portfolio combines a significant US position in unconventional shale plays with three valuable development projects along the UKCS. Focusing on the North Sea, the most significant development is Greater Rochelle, which recently received FDP approval for phase one (East Rochelle), with reserves of 28-39mmboe. Recent exploration success at West Rochelle increases the potential resource base, while Bacchus and Columbus complete the development portfolio.

Challenges: Troubled infrastructure agreements

Greater Rochelle development has been significantly affected by commercial negotiations around infrastructure access. Endeavour failed to agree tolling rates to connect Rochelle to the Nexen-operated Scott platform, despite Nexen being a partner in the Rochelle development. The dispute was ultimately elevated to the DECC. East Rochelle has recently received FDP approval, so we understand tolling arrangements are close to finally being resolved.

Management and strategy

Founding director, CEO and chairman Bill Transier brings significant deal-making experience, not least the acquisition and subsequent 2009 sale of OER Oil AS for $150m. The share price performance is also strong, as indicated by an EV/(2P+2C) in excess of $10/boe. The US unconventional portfolio gives an additional strategic arm to its business model. There has been some doubt as to whether the company would stay in the UK North Sea. Rochelle FDP approval and the sale of the Cygnus gas field with reinvestment in the remaining UKCS assets appear to have resolved this.

Price*	$11.74
Market Cap	$294m

*Priced as at 23 March 2011

Share price graph

Share details

Code	ENDV
Listing	NYSE, FULL
Shares in issue	25.1m

Price

52 week	High	Low
	$14.02	$7.00

Balance Sheet as at 31 December 2010

Gearing (%)	139%
NAV per share ($)	6.15
Net cash/(debt) ($m)	(214.3)

Business

Endeavour International Corporation is an independent energy company focused on the exploration, production and acquisition of energy reserves in the North Sea and United States.

Newsflow catalysts

H211: Bacchus first production
Q211: Likely Rochelle tolling confirmation
H211: Potential first production from East Rochelle, followed by West Rochelle

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★★	Experienced business management team. Partner alignment at both Rochelle and Columbus has been problematic.
Subsurface understanding/ complexity	★★	Proving its credentials as operator of Greater Rochelle, although no geology skills on executive committee.
Portfolio balance/ upside potential	★	Imminent production at Bacchus adds balance to the strong UK development and US unconventional portfolio.
Infrastructure access	★★★	Breakdown in commercial negotiations around Rochelle tie-in has hindered field development. Non-operated interest in Columbus also affected by disputed tie-in negotiations with BG/partners for processing through Lomond platform.
Abandonment liabilities/ tax/ regulatory issues	★	No current decommissioning liabilities. Decision to reinvest proceeds from Cygnus sale means no tax exposure.
Financial strength/ discipline	★★	Sold OER Oil AS in 2009 for equivalent of market cap. Development plays necessitate high gearing, although strong share price indicates confidence in the team.

Description of key North Sea assets

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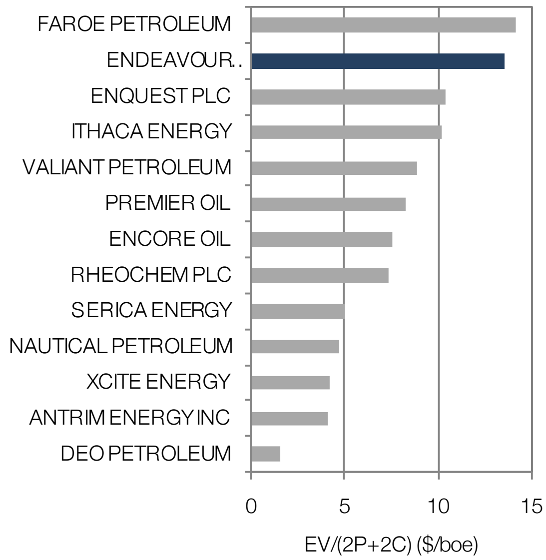
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Bacchus	Oil	4.5-9	2P	Post FDP
East Rochelle (o)	Oil/ Gas	28-39	2P	Post FDP
Columbus	Gas	4.4	2P	FDP filed
West Rochelle (o)	Oil/ Gas			Exploration

Valuation



Source: Edison Investment Research, company data

Trading at $13.5/boe suggests significant value is already priced into Endeavour's share price. However, all reserves are in the 2P category while the recent FDP approval for the East Rochelle goes some way to derisking the development.

We await news on tolling agreements at Rochelle as the principal share price catalyst, while first oil at Bacchus expected in H111 represents the first material production for the company in the UK.

Edison investment research

EnQuest

Year End	Revenue ($m)	PBT ($m)	EPS (c)	DPS (c)	P/E (x)	Yield (%)
12/08PF	348.8	109.8	N/A	N/A	N/A	N/A
12/09PF	316.3	33.9	N/A	N/A	N/A	N/A
12/10e	587.0	93.0	0.1	N/A	N/A	N/A
12/11e	874.0	361.0	0.2	N/A	N/A	N/A

Note: Based on consensus estimates; $1.62/£.

Investment summary: Hub development

Combining the E&P portfolios of Petrofac and Lundin, EnQuest was floated on the Main market in April 2010. It is already the largest independent by production and reserves, with significant upside potential within the portfolio for further exploitation with the drill-bit.

Assets: Strong production with balance

With 20,000boepd of target production and 80mmboe of 2P reserves, EnQuest has been propelled straight to the top of UK-listed independents in the North Sea by size. The company is operator of six producing fields around three hubs, all with high equity interests, and with a clear focus on exploitation both of new satellite acreage and existing production wells. Four new licences awarded during the 26th round have added to the acreage. However, not all these licences are linked to EnQuest's hubs.

Challenges: Where next?

The existing production hubs give EnQuest an enviable platform from which to grow organically, especially given that much of the decommissioning obligations from these fields have been left with previous owners. The focus is, not surprisingly, on production growth, with a target of 20,000boepd in 2010, up 48% on 2009. However, maintaining significant production growth may be difficult, especially with exploration acreage away from the production hubs. With strong cash flow generation the question is therefore where next. Replicating the hub model may be difficult in the North Sea due to decommissioning obligations. This may push EnQuest to look beyond the UK for other mature basins to exploit their exploitation model.

Management and strategy

EnQuest is led by CEO Amjad Bseisu, who previously founded Petrofac's E&P business, Petrofac Energy Developments. Equally of note is COO Nigel Hares who, as EVP of international operations for Talisman Energy, oversaw international production increase from zero to 250,000boepd, while CFO Jonathan Swinney brings corporate finance and banking experience to the team. The strategic growth focus is on hubs and from near-field development. However, business development is also at the fore with both internally generated projects and M&A being considered. The company's first major acquisition was Stratic Energy in November 2010.

Price*	135p
Market Cap	£1,079m

Priced as at 23 March 2011

Share price graph

Share details

Code	ENQ
UK Listing	FULL
Shares in issue	799.5m

Price

52 week	High	Low
	158p	89p

Balance Sheet as at 30 June 2010

Gearing (%)	N/A
NAV per share (c)	102
Net cash ($m)	76

Business

EnQuest is an independent oil and gas production and development company. Its activities are focused on the United Kingdom Continental Shelf (UKCS), which includes the Central North Sea, the Northern North Sea, the Southern Gas Basin, the West of Britain and the Atlantic Margin.

Newsflow catalysts

5 April: prelims, including update on drilling, exploration and appraisal programmes and expenditures

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★★	Experienced executive team that also includes former Talisman CEO, Dr James Buckee, as chairman. Equity partners generally smaller given high WI operating positions but this is not a weakness. The Petrofac legacy also brings strong facilities background.
Subsurface understanding/ complexity	★	Strong sub-surface team moved across from parent companies. Pipeline of developments helps with talent recruitment/ retention.
Portfolio balance/ upside potential	★	27 licences across the North Sea points to significant exploration potential. Large production and reserves provides balance.
Infrastructure access	★★	All current production from owned/ operated hubs. Significant resource potential around hubs although may be more problematic away from hubs.
Abandonment liabilities/ tax/ regulatory issues	★★	Significant liabilities left with previous owners although >$100m remain. Additional tax losses acquired through Stratic acquisition.
Financial strength/ discipline	★	$76m net cash and debt free as at end H110. Careful screening of M&A and farm-out deals demonstrates financial prudence.

Location of key North Sea assets

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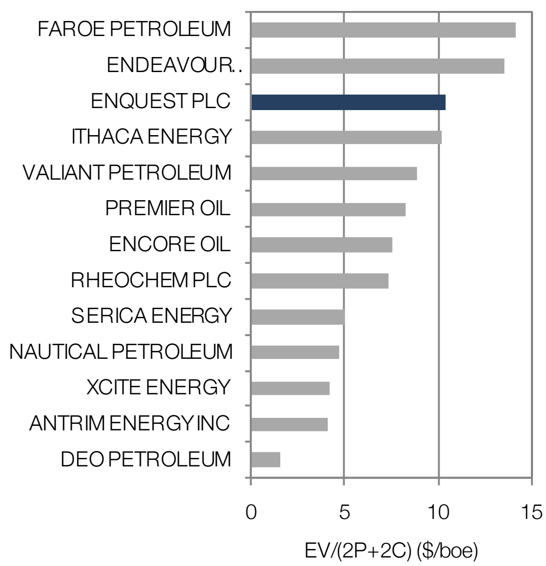
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
West Don (o)	Oil	3.8	2P	Production
Don South West (o)	Oil	13.9	2P	Production
Thistle Deveron (o)	Oil	31.5	2P	Production
Broom (o)	Oil	10.8	2P	Production
Heather (o)	Oil	20.6	2P	Production
Crawford	Oil/ Gas	4.2	2P	Pre FDP

Valuation



Source: Edison Investment Research, company data

EnQuest trades at an EV/(2P+2C) of $10.4/boe, reflecting its strong production bias. Adjusted for tax, this is in line with its acquisition of Stratic.

We see two major catalysts to move the share price on, namely confirmation and continuation of near-term production growth to demonstrate the full potential of the existing hubs/ near field assets, and demonstration of EnQuest's exploitation reach to new hubs either within the North Sea or further afield.

Faroe Petroleum

Year End	Revenue (£m)	PBT (£m)	EPS (p)	DPS (p)	P/E (x)	Yield (%)
12/08	2.3	(28.7)	(17.5)	0.0	N/A	N/A
12/09	7.0	(11.8)	(5.8)	0.0	N/A	N/A
12/10e	17.3	(5.2)	(7.6)	0.0	N/A	N/A
12/11e	30.0	1.3	1.3	0.0	122	N/A

Note: Based on consensus estimates.

Investment summary: Experienced and nimble

Faroe comes out as one of the high-quality players in the North Sea. It trades at a premium to many of the peers in the North Sea on a reserves basis. However, this fails to reflect a highly prospective exploration portfolio coupled with strong technical expertise. There is potential for a material uplift to valuation from the Lagavulin well, which could add c 100p to Faroe's valuation.

Assets: Discoveries in the Central North Sea

Since its AIM listing in 2003, Faroe has built a significant exploration and appraisal portfolio in West of Shetlands, Atlantic Margin and the North Sea through licence rounds in the UK, asset swaps and deals. It has a production from the Southern gas basin and the Blane oil field. Atlantic margin discoveries include Glenlivet and Tornado. There is also a substantial exploration portfolio, the highest impact being Lagavulin, and Cardhu, both being drilled this year. It also acquired 23 blocks or part blocks in the 26th licensing round.

Challenges: Deep water drilling in the West Shetlands

After Macondo, the UK government looked at the implications for deep water drilling in the UK. The report made the point that there is a different regulatory environment in the UK to the US; for example, the UK assumptions around loads applied to casings require them to withstand a greater load. The enquiry did note the appalling weather conditions in the West of Shetlands, and the British Rig Owners Association commented that it would be a challenge to drill relief wells if needed. However, there were no crude oil spillages in water depths of more than 300m in the UK Continental Shelf between 1 January 1999 and 10 August 2010.

Management and strategy

Faroe targets geological plays with the greatest promise and prospectivity, making successful finds appealing to the majors that, in turn, provide funding to develop assets. It has a broad portfolio of licences which allows it to target around five exploration wells a year. Financially prudent, it only commits to wells that it can fund in a year. The eventual goal is to have sufficient cash flow from production to fund an ever growing exploration portfolio, with a target to grow production from 3,000 bopd to 6,000 bopd.

Price*	158.7p
Market Cap	£338m

*Priced as at 23 March 2011

Share price graph

Share details

Code	FPM
Listing	AIM
Shares in issue	213m

Price

	High	Low
52 week	218.25p	106.00p

Balance Sheet as at 30 June 2010

Gearing (%)	N/A
NAV per share (p)	63
Net cash (£m)	72.5

Business

Faroe Petroleum is an independent oil and gas company focused on exploration and appraisal drilling in the Atlantic Margin, the North Sea and Norway.

Newsflow catalysts

March 11: Full year results
April 11: Lagavulin well results
June 11: Fulla spud
September 11: Cardhu spud

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★	A wealth of experience on the board, both Graham Stewart (CEO) and Helge Hammer (COO) have over 20 years' experience in the oil industry. Faroe works with world-class partners, which include BP, Chevron, DONG, ENI, OMV, RWE, Tullow and Statoil.
Subsurface understanding/ complexity	★	Faroe has a strong technical team based in Norway. Four discoveries in a row in 2009/10 cemented this reputation, although the recent Anne Marie prospect did disappoint.
Portfolio balance/ upside potential	★	A combination of production from the Southern Gas basin and the Blane oil field, low-risk exploration in Norway and high-impact high-risk exploration in the Atlantic margin give Faroe a balanced portfolio.
Infrastructure access	★	Glenlivet close to the Laggan gas field where Total is developing infrastructure, while Tornado is 30km north-west of producing fields where infrastructure could be shared.
Abandonment liabilities/ tax/ regulatory issues	★★	Will have to carry a share of decommissioning costs. The most significant of these are on Schooner (£21m cost) and Orca (£15m). Has c £60m of UK tax losses to use.
Financial strength/ discipline	★	£125m of cash with £75m of borrowing facilities, including £22.5m undrawn. CFO Iain Langhan is well regarded and known for implementing strong process and structure.

Location of key North Sea assets

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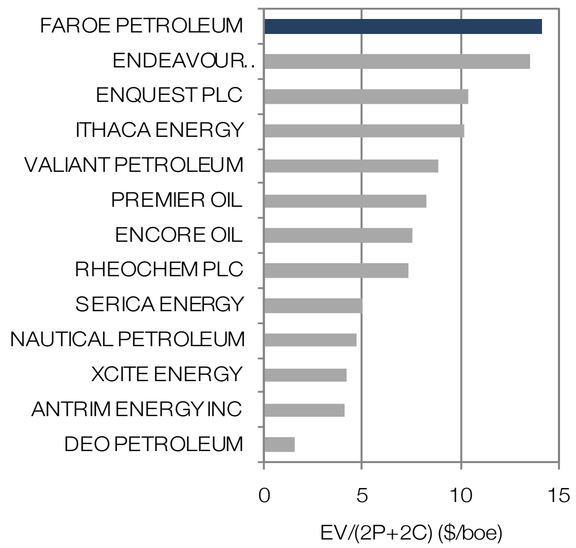
Field (O=Operator)	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Wissey	Gas	0.2	2P	Prodn.
Topaz	Oil	0.3	2P	Prodn.
Schooner	Gas	0.4	2P	Prodn.
Orca Minke	Gas	0.8	2P	Prodn.
Blane	Oil	5.4	2P	Prodn.
Perth	Oil	5.8	2C	Pre-FDP
Lagavulin	Oil	58.0	Prospective	Pre-FDP
Talisker	Oil	13.0	2C	Pre-FDP
Cardhu	Oil	13.0	Prospective	Pre-FDP
Glenlivet	Gas	5.0	2C	Pre-FDP
Tornado	GC	3.5	2C	Pre-FDP
Freya (O)	Oil	27.2	2C	Pre-FDP

Valuation



Source: Edison Investment Research, company data

Faroe trades at $14.2/boe on an EV/(2P+2C) basis, making it the most expensive stock within the North Sea peer group we are evaluating.

In part, this is a premium we would expect given our positive business model evaluation. The EV/(2P+2C) metric does not give credit for tax efficient producing assets, the low-cost exploration activity afforded by the Norweigan tax regime and the highly prospective exploration portfolio Faroe has built.

Ithaca Energy

Year End	Revenue ($m)	PBT ($m)	EPS (c)	DPS (c)	P/E (x)	Yield (%)
12/08	2.5	(12.7)	(20.3)	0.0	N/A	N/A
12/09	101.3	(6.0)	4.8	0.0	52.8	N/A
12/10e	157.5	37.5	13.0	0.0	19.5	N/A
12/11e	164.3	42.2	11.6	0.0	21.8	N/A

Note: *PBT and EPS are normalised, excluding intangible amortisation and exceptional items; $1.62/£.

Investment summary: Development focus

Ithaca Energy focuses on production and near-production development assets exclusively along the UKCS. Through prudent financial management it has developed a 42mmboe portfolio of 2P assets with production anticipated to exceed 20,000boepd within two years. Concentrating on relatively low-risk developments and careful management of liabilities Ithaca provides the investor with multiple upside options while keeping downside risks relatively low.

Assets: Pushing to 20,000boepd

Current production of c 6,000boepd largely comes from the Beatrice/Jacky fields that provide a low-risk cashflow stream, with upside coming from well workovers, re-entries and additional wells. The main production thrust comes from development assets Athena and the Greater Stella Area, with Athena due into production in Q411 and GSA in 2012, propelling production to more than 20,000boepd.

Challenges: Portfolio development

Compared to peers, Ithaca's technical challenges are relatively low. Abandonment liabilities are small due to a combination of leased assets and use of sub-sea platforms. GSA infrastructure agreement is an important step to confirming concept select ahead of FDP submission. However, the key challenge for Ithaca is prudently using its strong balance sheet and available debt facility to develop its portfolio further, both organically and inorganically.

Management and strategy

Ithaca's management has many years' experience in the industry. The company has developed strong partnerships with farm-in partners, in particular with Dyas. Ithaca also has very strong bank support, with a $140m reserves-based lending facility available through BoS, which is currently undrawn.

Price*	156.5p
Market Cap	£399m

Priced as at 23 March 2011

Share price graph

Share details

Code	IAE
Listing	AIM, TSX-V
Shares in issue	255m

Price

52 week	High	Low
	194.5p	102.5p

Balance Sheet as at 30 September 2010

Gearing (%)	N/A
NAV per share (c)	168
Net cash ($m)	193

Business

Ithaca Energy is a Canadian oil and gas exploration, development and production company, focused on the UK segment of the North Sea. Its portfolio comprises oil in inner and outer Moray Firth (Central North Sea), gas condensate in the Central North Sea and dry gas in the Southern North Sea.

Newsflow catalysts

Q211: Reserves update
Q311: GSA FDP submission
Q411: Likely first oil at Athena

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★	Relatively new management team but with longstanding industry experience. Operator focused with strong partners, particularly Dyas, across GBA, GSA and Athena. Strong financial backing.
Subsurface understanding/ complexity	★	Proven subsurface understanding mainly from development of Athena and GSA. Development schemes relatively simple/conventional.
Portfolio balance/ upside potential	★★	Strong development/production portfolio. Helios, Polly, Athena upside + SNS assets provide modest exploration upside.
Infrastructure access	★★	Leasing of Beatrice/Jacky along with Nigg terminal provides integrated infrastructure. GSA agreements still to be confirmed.
Abandonment liabilities/ tax/ regulatory issues	★	Beatrice/Jacky leased, so no abandonment costs. New assets mainly using sub-sea manifolds, hence costs low and managed.
Financial strength/ discipline	★	Strong financial prudence during 2009/10 with farm-outs to keep development programme on track. The result is very strong balance sheet with $190m net cash and $140m facility available.

Location of key North Sea assets

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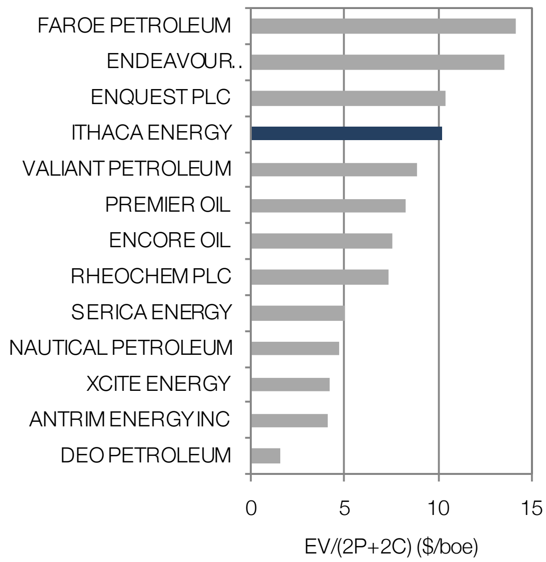
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Beatrice (o)	Oil	2.0	2P	Prodn.
Jacky (o)	Oil	1.7	2P	Prodn.
Anglia (o)	Gas	2.0	2P	Prodn.
Topaz	Gas	0.8	2P	Prodn.
Athena (o)	Oil	5.5	2P	Post FDP
Stella (o)	Oil	14.4	2P	Pre FDP
Harrier (o)	Oil	11.7	2P	Pre FDP
Hurricane (o)	Oil	4.9	2P	Pre FDP
Carna (o)	Gas	1.7	2P	Pre FDP

Valuation



Source: Edison Investment Research, company data

Ithaca Energy trades at a EV/(2P+2C) of $10.2/boe reflecting its strong development/production asset base. We would expect to see further share price gains during 2011 as Athena nears first production and once concept select and an FDP is submitted for the Greater Stella Area development.

We also see some exploration-driven upside potential in the stock, including the Helios field acquired during the recent 26th licence round. However, exploration upside remains relatively low.

The strong balance sheet means Ithaca is able to pursue new field developments both organically and inorganically. Chosen developments will be key to maintaining recent share price upward momentum.

Nautical Petroleum

Year End	Revenue (£m)	PBT* (£m)	EPS* (p)	DPS (p)	P/E (x)	Yield (%)
06/09	0.0	(0.1)	1.0	0.0	N/A	N/A
06/10	0.1	(1.8)	(2.6)	0.0	N/A	N/A
06/11e	0.1	(1.3)	(1.1)	0.0	N/A	N/A
06/12e	0.1	(0.9)	(0.6)	0.0	N/A	N/A

Note: *PBT and EPS are normalised, excluding intangible amortisation and exceptional items.

Investment summary: Major resource gains

2010 was a transformational year for Nautical with success at the drill bit at Kraken and Catcher, the crystallisation of part of its Mariner stake and a placing that strengthened the share register. 2011 has the potential to continue the success, with a CPR that ought to firm up resources at Kraken together with a summer appraisal well and the continued derisking of Catcher. There is also potential exploration upside from Tudor Rose, Spaniards and Merrow.

Assets: Balanced portfolio in the North Sea

Nautical has four discoveries in the North Sea. Three of these are heavy oil discoveries, Kraken, Mariner and Tudor Rose. The other discovery is the light oil Catcher discovery. Nautical was awarded the 9/1a license adjacent to the Kraken field in the 26th licensing round, which potentially could lead to a four-fold increase in contingent resource at Kraken; a CPR in April should firm-up the resource estimate. The Mariner field is operated by Statoil and project sanction is expected imminently. Catcher continues to be derisked following another oil find at Burgman; partners are now drilling a side-track targeting the lower Tay sands. Tudor Rose is expected to be drilled in the summer and a drill or drop decision is expected on Spaniards.

Challenges: Moving Kraken forward

Nautical's partners in Kraken are Canamens (35% WI) and Celtic (30% WI). Canamens is currently up for sale, while Celtic is withdrawing from the North Sea. A CPR on Kraken in April ought to make the partners' stakes more marketable. However, if the ownership of the partner stakes is not resolved, this could potentially delay the development of Kraken.

Management and strategy

CEO Steve Jenkins and commercial director Paul Jennings are extremely experienced oil men. The light oil discovery at Catcher has created a more balanced portfolio. The sale of a 20.7% stake in Mariner to Statoil for £88m and a £30m placing puts Nautical in a position where it can fund the development of Kraken, Catcher and potentially Mariner to first oil. The strategy is to develop these assets while continuing to create shareholder value through targeted exploration. A key task for Nautical in the coming months is to hire staff to operate Kraken.

Price*	395p
Market Cap	£346m

Priced as at 23 March 2011

Share price graph

Share details

Code	NPE
Listing	AIM
Shares in issue	87.7m

Price

	High	Low
52 week	547p	45p

Balance Sheet as at 31 December 2010

Gearing (%)	N/A
NAV per share (p)	159
Net cash (£m)	112

Business

Nautical Petroleum is an AIM-listed oil and gas exploration and production company, with assets in the UK North Sea and France.

Newsflow catalysts

April 11: Mariner project sanction
April 11: Kraken CPR
April 11: Burgman sidetrack result
May 11:Kraken appraisal well spud date
July 11: Submission of FDP

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness

	Exposure	Comment
Management & partners	★★	Steve Jenkins (CEO) and Paul Jennings (Commercial Director) both have around 30 years of experience in the oil industry and jointly founded Nautical Petroleum. Oil companies regularly turn to Nautical for their heavy oil expertise. Partners are technically sound, but there are issues with Canamens (up for sale) and Celtic (exiting the North Sea), who are partners in Kraken.
Subsurface understanding/ complexity	★	Heavy oil reservoirs have their own complexities, particularly with recovery rates, but Nautical is well equipped to mitigate these issues with its technical experience.
Portfolio balance/ upside potential	★	Nautical's portfolio is a well balanced development and exploration portfolio.
Infrastructure access	★★	With FDPs yet to be submitted and conceptual development plans moving, we are not able to comment on this issue.
Abandonment liabilities/ tax/ regulatory issues	★	The DECC has granted extensions on Tudor Rose and Spaniards. A decision to drill or drop Spaniards is expected by mid-2011. Nautical should benefit from the heavy oil field allowances from a tax perspective.
Financial strength/ discipline	★	Nautical sold a significant stake in Mariner, allowing it to fund the development of Kraken and Catcher while continuing with its exploration activities.

Location of key North Sea assets

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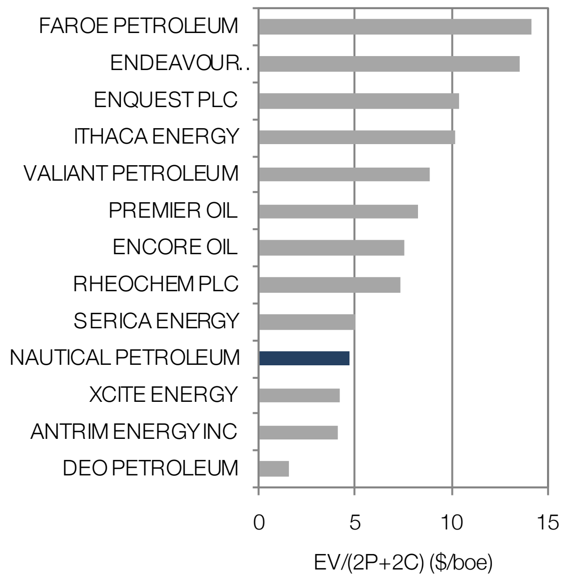
Field (O = Operator)	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Kraken(O)	Oil	125.0	2C	Pre-FDP
Mariner	Oil	25.8	2C	Pre-FDP
Catcher	Oil	17.9	2C	Pre-FDP
Tudor Rose	Oil	9.8	2C	Pre-FDP
Merrow (O)	Oil	24.3	Prospective	Pre-FDP
Spaniards	Oil	15.0	Prospective	Pre-FDP

Valuation



Source: Edison Investment Research, company data

Nautical trades on $4.7/boe on an EV/(2P+2C) basis, well below the North Sea peer group average. When coupled with our evaluation that Nautical has a strong business model evaluation, this makes it one of the more compelling investment stories in the North Sea.

With a number of clearly identified upcoming catalysts, there is potential to unlock this value in the coming year.

Premier Oil

Year End	Revenue ($m)	PBT ($m)	EPS (c)	DPS (c)	P/E (x)	Yield (%)
12/09	621	80	104.1	0.0	30.5	N/A
12/10	764	101	111.9	0.0	28.4	N/A
12/11e*	972	396	156.2	0.0	20.4	N/A
12/12e*	1,596	804	323.2	0.0	9.8	N/A

Note: Based on consensus estimates; $1.62/£.

Investment summary: Corporate activity?

The acquisition of Dana by KNOC led to the inevitable speculation that Premier Oil provides an equally attractive production and reserves base. This accounted for much of the drive behind the 52-week highs earlier this year. With c $1.2bn in cash and bank funding lines, there is also speculation that Premier might acquire additional assets, most notably a larger equity stake in Catcher and Wytch Farm. That aside, the drive to achieve 75,000bopd production (currently c 44,000bopd) by 2012 and move this up to 100,000bopd by 2014 is the underlying value creator for shareholders in an environment of high oil prices. North Sea assets, most notably Huntington, are a material contributor to being able to achieve this.

Assets: Production, development and exploration portfolio

The acquisition of Oilexco bulked up Premier's North Sea activities, now accounting for around a third of the group's production. UK production comes from the Balmoral, Wytch Farm, Kyle and Scott/Telford fields. Huntington was recently given project sanction and is expected to come on-stream by Q112, while a project sanction for Solan is expected during Q211. The largest potential boost to reserves comes from the Greater Catcher area, which is currently being appraised. The group has a number of exploration assets in the North Sea with near-term activity expected at Bluebell and Lacewing.

Challenges: Maintenance on older assets

Since Macondo, Premier's UK production has suffered as much greater risk aversion has seen shut downs from maintenance at Balmoral, Wytch Farm and Scott. This is a feature of the industry that we believe is likely to persist and expect it to lead to marginally higher operating costs per barrel.

Management and strategy

Compare Premier's employee count (over 500) to the 11 at Encore and you should rapidly realise that the organisational and management structure at Premier is one of a full cycle mid-cap E&P company. The North Sea strategy is one of building core areas that can be tied back to existing infrastructure. Where this is not possible, Premier is investigating not permanently-attended infrastructure (eg, Solan). Exploration tends to focus on rift plays, where Premier believes it has strong in-house expertise.

Price*	1959p
Market Cap	£2,280m

*Priced as at 23 March 2011

Share price graph

Share details

Code	PMO
Listing	FULL
Shares in issue	116.4m

Price

	High	Low
52 week	2,140p	1,085p

Balance Sheet as at 31 December 2010

Gearing (%)	36%
NAV per share (c)	971
Net debt ($m)	406

Business

Premier Oil is a full cycle exploration and production company, with exploration and production assets in the UKCS, Norway, Vietnam, Indonesia, and Mauritania. The group also has exploration activities in Pakistan and Egypt.

Newsflow catalysts

Q211: Solan project sanction
April 11: Burgman sidetrack outcome
Q311: Bluebell well
Q112: Huntington comes on stream

Analysts
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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★	Management structure of a full cycle E&P mid cap. Board has plenty of experience and works with a range of majors as well as independents.
Subsurface understanding/ complexity	★	Sticks to what it knows. Likes to target rift and fold belts where it believes it has strong in house expertise. Since 1985 has discovered over 800mmbls net at a 22% success rate, with recent drilling activity delivering close to 50% success.
Portfolio balance/ upside potential	★	The acquisition of Oilexco's assets gave more balance to the geographic portfolio and added exploration upside, most notably with the Catcher discovery.
Infrastructure access	★	Cluster strategy with good access to existing infrastructure. Negotiating tie-back to Scott infrastructure for Rochelle.
Abandonment liabilities/ tax/ regulatory issues	★★	Has a number of old producing fields. This raises concerns about eventually decommissioning costs and, post Macondo, has led to a number of maintenance shut downs. The acquisition of Oilexco does give the company over $1.1bn of UK tax losses to use.
Financial strength/ discipline	★	Balance sheet looks extremely strong, with c $1.2bn of cash and draw down facilities available. Production costs in the North Sea have been rising due to maintenance shut downs, but nothing to alarm investors. G&A costs remain low at less than $1/bbl pa.

Location of key North Sea assets

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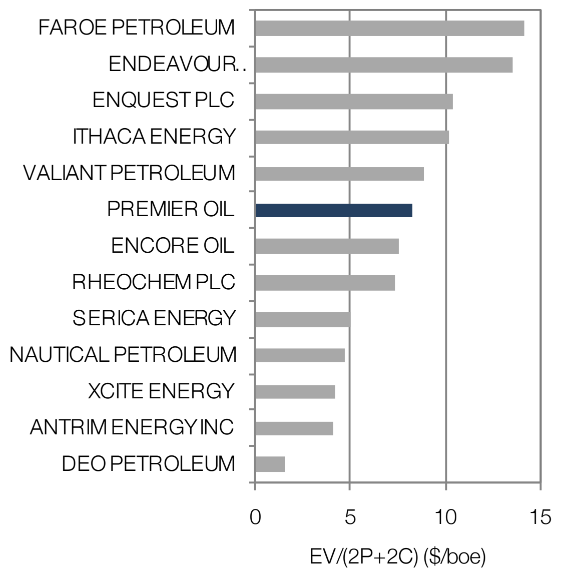
Field (O = Operator)	Fluid	Net resource (mmboe)	Res type	Dev. phase
Balmoral Area (O)	Oil	21.8	2P	Prodn.
Kyle	Oil	5.7	2P	Prodn.
Scott/Telford	Oil	8.2	2P	Prodn.
Wytch Farm	Oil	9.8	2P	Prodn.
Huntington	Oil	10.0	2P	Post FDP
Greater Catcher Area	Oil	69.7	2C	Pre-FDP
Solan	Oil	18.0	2C	Pre-FDP
West Rochelle	Oil	12.5	2C	Pre-FDP
Bluebell	Oil	19.0	2C	Pre-FDP
Bugle North	Oil	7.0	2C	Pre-FDP
Lacewing (O)	Oil	40.8	2C	Pre-FDP

Valuation



Source: Edison Investment Research, company data

With 261mmbls of 2P reserves and 227mmbls of 2C reserves, Premier Oil is currently trading at $8.2/bbl on a EV/(2P+2C) basis. This puts it mid-range on our oil screens.

Given the strong business model evaluation within the North Sea, and further upsides from the rest of its assets in Asia and the Middle East, this would suggest there is further upside, particularly if the group successfully executes its strategy of growing production towards 100,000 bopd in the current +$100/bbl pricing environment.

Rheochem

Year End	Revenue (A$m)	PBT (A$m)	EPS (c)	DPS (c)	P/E	Yield (%)
06/09	10.1	(45.6)	(23.2)	0.0	N/A	N/A
06/10	20.4	2.6	0.1	0.0	N/A	N/A
06/11e	10.1	(3.4)	(1.3)	0.0	N/A	N/A
06/12e	48.0	37.3	10.5	0.0	2.3	N/A

Note: Based on consensus estimates; A$1.60/£.

Investment summary: Hitting the ground running

Following the sale of its drilling fluids business, Rheochem (Lochard Energy when the sale completes) is set to become a fully funded, full-cycle E&P player within the UK North Sea. Strong cash flow generation from a 10% interest in the 24mmboe Athena field provides the funding. With one of the most extensive portfolios of new awards in the recent 26th licence round, the company has the potential to become a sizeable new player along the UKCS.

Assets: Athena plus extensive 26th round acreage

Rheochem has a non-operating 10% interest in the 24mmboe 2P Athena field, which is expected to enter production in Q411. This provides it with a near-term source of cash flow to fund a potentially extensive exploration programme. Rheochem already has two appraisal assets on its drilling radar, targeting 100mmboe of risked net resources in Thunderball and Moby. An extensive portfolio of assets from eight additional awards in the 26th licence round provides further exploration scope with near-term funding underpinned by Athena cash flow.

Challenges: Farm-outs critical

With Athena on track, Rheochem's challenge is to work its exploration acreage. It holds a 90% working interest in the majority of its licences and will need to secure farm-in partners to successfully develop these. In 2010 the company was unable to farm-down its Metis prospect, which then had to be relinquished. To successfully farm-down we would look for high-quality data to be made available/acquired to de-risk prospects. Rheochem is doing this with Thunderball by acquiring new 3D seismic and this, together with an improvement in market conditions, should translate into greater chance of success going forward.

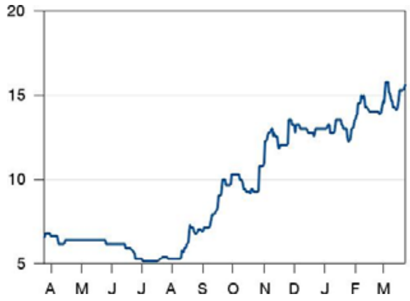
Management and strategy

Rheochem is led by founding director and CEO Haydn Gardner, who largely developed the drilling fluids business. Also on the board is Michael Rose who provides the subsurface understanding and is director of exploration partner, Aimwell Energy. With the shift in emphasis from drilling fluids to E&P, Rheochem will need to further ensure this is reflected in the management team. The company recognises this and is working to bolster industry experience on its board.

Price*	15.13p
Market Cap	£39m

Priced as at 23 March 2011

Share price graph



Share details

Code	RHEP
Listing	AIM, ASX
Shares in issue	249.5m

Price

	High	Low
52 week	15.75p	5.13p

Balance Sheet as at 30 June 2010

Gearing (%)	7
NAV per share (c)	16.6
Net debt (A$m)	2.8

Business

Rheochem is an oil and gas exploration, appraisal and development company with assets in the North Sea. Its development portfolio comprises oil in the Outer Moray Firth with additional exploration assets along the UKCS. It also has a substantial drilling fluids business, but in March 2011 announced the agreed sale of this business for up to $A45m. Once the sale is complete, the company name will change to Lochard Energy.

Newsflow catalysts

Imminent: Completion of drilling fluids sale

Q411: Athena production starts

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★★★	Less E&P board experience than peers, expected to be addressed. Needs to demonstrate ability to work assets to attract farm-in partners.
Subsurface understanding/ complexity	★★	Non-exec Mike Rose currently provides subsurface focus. Needs to bolster team to properly develop new acreage.
Portfolio balance/ upside potential	★★	Good balance of near-production and exploration. Important to develop some exploration/ appraisal acreage to provide future balance.
Infrastructure access	★★	Appraisal targets will require tie-ins if being developed.
Abandonment liabilities/ tax/ regulatory issues	★★	Assets predominantly in the CNS points to relatively low decommissioning liabilities.
Financial strength/ discipline	★★	Clarifying strategy and funding points to good discipline. Key now is to leverage asset base to attract farm-in partners to part fund drilling programmes.

Location of key North Sea assets

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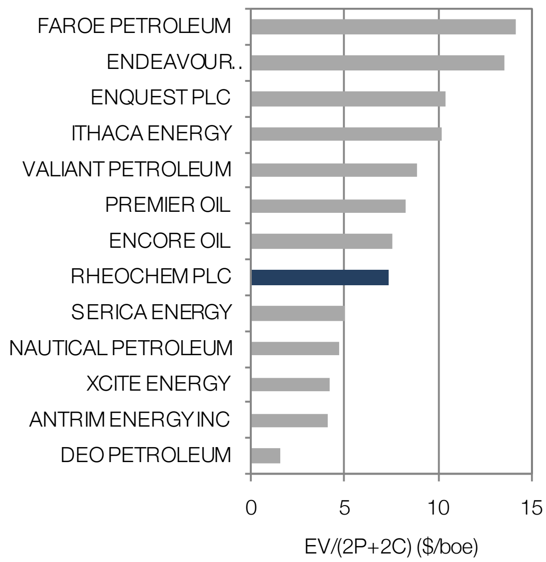
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Athena	Oil	2.4	2P	Post FDP
Thunderball (o)	Gas	47.7	Prospective	Appraisal
Moby (o)	Oil/ Gas	52.8	Prospective	Appraisal

Valuation



Source: Edison Investment Research, company data

Rheochem's change in strategy allows investors a clearer definition of the company's value. We calculate a core net asset value (core NAV) based on the Athena development and cash realised from the drilling fluids business sale of 16p, more than covering the current share price.

Further upside may be realised from the drilling of the Thunderball and Moby discoveries in H112, subject to farm-out. Including this in our valuation we calculate a risked exploration net asset value (RENAV) of 28.3p.

We currently do not include the remaining assets in our RENAV pending clarification on drilling schedules that will be contingent on successful farm-outs.

Serica Energy

Year End	Revenue ($m)	PBT ($m)	EPS (c)	DPS (c)	P/E (x)	Yield (%)
12/08	0.0	(0.8)	0.0	0.0	N/A	N/A
12/09	7.6	7.3	0.0	0.0	N/A	N/A
12/10e	30.6	(1.3)	0.0	0.0	N/A	N/A
12/11e	31.0	10.4	0.0	0.0	N/A	N/A

Note: Based on consensus estimates; $1.62/£.

Investment summary: Risk limiting explorers

Serica's strategy appears relatively simple: a three-step process of identifying opportunities and acquiring high equity acreage, proving them up with 3D seismic and then farming-down before drilling. However, it is the ability of management to continually manage this cycle that is impressive, with 10 farm-outs in the last six years, while retaining substantial stakes.

Assets: Diverse portfolio

Serica has assets in Spain, Morocco and Indonesia in addition to its North Sea and Ireland acreage. Production is currently limited to the Kambuna field in Indonesia, although long-term plans whether to develop or exit this area are under review. The near-term production target in the UK is the Serica-operated 17.6mmboe 2P Columbus field (8.8mmboe net to Serica). After reworking its development plan, the company is looking for project sanction in Q211 with first gas targeted for mid-2013. Upside comes from exploration targets in the Slyne Basin west of Ireland and potentially Spaniards that is subject to partner agreement on drilling.

Challenges: Infrastructure access biggest issue

North Sea exploration targets Oates and Conan both disappointed in 2010, although costs were largely carried by farm-in partners. The Boyne and Liffey prospects west of Ireland are 2011 drill targets. However, nearer-term production target, the Columbus project sanction, is possibly the most material challenge. Key to this is confirmation of access to processing facilities at neighbouring BG's Lomond facility. These negotiations have been difficult, not least because of potentially competing BG exploration assets. Confirming the project sanction will be a major step forward for Serica to establish its North Sea production base.

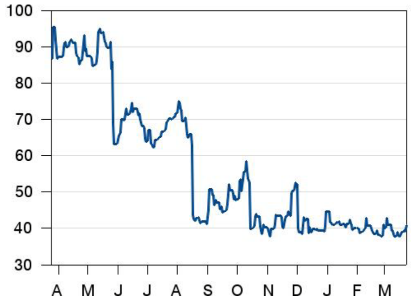
Management and strategy

Serica targets large working interests in prospective acreage. Prudent financial management is then in evidence with a strong history of successful farm-outs, mostly on a 2-for-1 basis. With Indonesian development currently subject to a strategy review the focus is increasingly on UK, Western Europe and Africa.

Price*	39.75p
Market Cap	£70.4m

Priced as at 23 March 2011

Share price graph



Share details

Code	SQZ
Listing	AIM, TSX-V
Shares in issue	177m

Price

52 week	High	Low
	95.25p	37.5p

Balance Sheet as at 30 September 2010

Gearing (%)	17%
NAV per share (c)	96
Net debt ($m)	28.2

Business

Serica Energy is a UK-based upstream oil and gas company, with exploration and production operations in Western Europe and South-East Asia.

Newsflow catalysts

Q211: Columbus project sanction decision
H211: Boyne & Liffey exploration wells
H211: Spaniard drilling (subject to partner agreement)

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★★	Chairman, CEO and FD have all been on board since floating on AIM in 2005.
Subsurface understanding/ complexity	★★	Systematic approach to using 3D to prove up prospects for farm-out now well demonstrated. Exploration success to date has been limited.
Portfolio balance/ upside potential	★★	Exploration model well established. Production focus may be set-back with possible exit from Indonesia. Columbus may fill gap but is dependent on project sanction.
Infrastructure access	★★★	Columbus project sanction depends on agreeing gas processing arrangement via BG operated Lomond platform. Serica is disadvantaged as potentially competing with BG exploration acreage for ullage.
Abandonment liabilities/ tax/ regulatory issues	★	More than $100m of UK tax losses available and carrying no current decommissioning liabilities
Financial strength/ discipline	★	Excellent record of farm-outs to carry the bulk of exploration costs while retaining material interests.

Location of key North Sea assets

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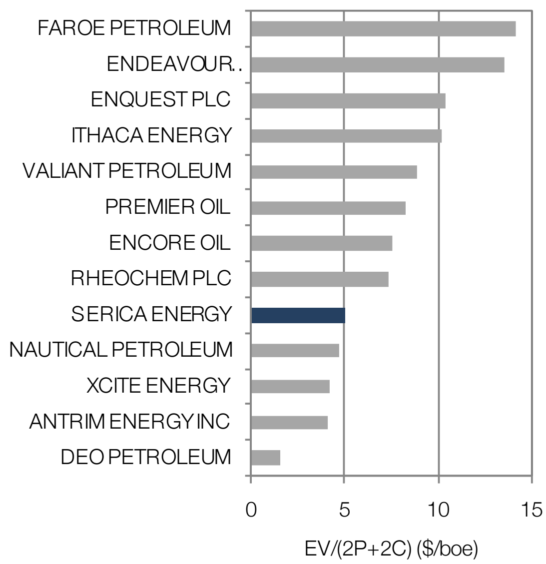
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Columbus (o)	Oil/ Gas	8.8	2P	Post FDP
Slyne Basin (o)	Oil			Exploration
Spaniards	Oil	15	Prospective	Exploration

Valuation



Source: Edison Investment Research, company data

Given that Serica trades at a relatively low EV/(2P+2C) of $5/boe the stock can be viewed as cheap. However, with Columbus project sanction decision imminent and the potential to crystallise value through its strategic review in Indonesia there are near-term catalysts that may provide upside.

A positive decision to drill Spaniards in 2011, subject to partner agreement including those in the adjacent block, also provides interesting additional upside potential.

Valiant Petroleum

Year End	Revenue ($m)	PBT ($m)	EPS (c)	DPS (c)	P/E (x)	Yield (%)
12/08	0.0	-96.4	N/A	0.0	N/A	N/A
12/09	53.4	10.5	55.1	0.0	16.3	N/A
12/10e	133.0	53.0	98.0	0.0	9.2	N/A
12/11e	159.0	80.6	101.0	0.0	8.9	N/A

Note: Based on consensus estimates; $1.62/£.

Investment summary: Needs exploration upside

Valiant Petroleum is a full-cycle exploration and production company with significant non-operated production coming from the Don fields, coupled with an extensive portfolio of development, appraisal and exploration assets. Production covers near-term financing requirements, but with significant gearing Valiant needs prudent financial management and more frequent success with the drill bit than most.

Assets: Well balanced

Approximately 7,000boepd of net production comes from West Don (17.3% interest) and Don South West (40% interest) fields in the NNS, with upside potential from development of the recent E panel discovery along with part of the earlier H panel discovery. Further options come from Causeway, where Valiant is operator and where it is targeting production in 2012. H210 saw some disappointing exploration results at both the southern Don SW H panel and at Viola North. A 2011 programme of two to four wells along the UKCS could include recent 26th round licence additions. Possibly the most interesting target, however, is the 70mmboe P50 Handcross (90% interest) prospect West of Shetland. This potential 2011 deepwater well would demonstrate Valiant's capacity to operate along the technically difficult but highly prospective Atlantic margin.

Challenges: Need some exploration success

Valiant balances risk by targeting both high impact exploration and lower risk, incremental tie-backs to maintain and grow production. Recent exploration set-backs have affected the development pipeline and the company will be hoping for better exploration results in 2011. With significantly higher gearing than most peers at 40% the focus is on prudent cash management. Operating cash flows over the next 24 months, however, should support the drill programme while servicing debt.

Management and strategy

Valiant's main strategy remains focused on the North Sea. Production growth is key with the company looking to Don developments and Causeway to maintain the production engine while continuing to offer upside through high impact exploration. The recent appointment of Paul Mann as COO provides additional industry experience to bolster the E&P credentials of the board.

Price*	555.5p
Market Cap	£220m

Priced as at 23 March 2011

Share price graph

Share details

Code	VPP
Listing	AIM
Shares in issue	39.6m

Price

52 week	High	Low
	761.5p	504.0p

Balance Sheet as at 30 June 2010

Gearing (%)	39.6
NAV per share (p)	630
Net cash/(debt) ($m)	(98.9)

Business

Valiant Petroleum is an independent oil and gas exploration, development and production company, focused on the UK segment of the North Sea.

Newsflow catalysts

H111: Causeway FDP submission
2011: Don phase III clarification
2011: Handcross drilling?

Analysts

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Evaluation criteria

Risk potential based on ★ low risk, ★★ medium risk, ★★★ high risk.

	Exposure	Comment
Management & partners	★★	Management has more of a finance bias than most, with newly appointed COO Paul Mann bringing facility management experience.
Subsurface understanding/ complexity	★★	Senior subsurface experience comes from CEO Peter Buchanan. With an expanding number of assets under operatorship the focus will be increasingly on developing these skills.
Portfolio balance/ upside potential	★	A good balance of production and high impact exploration assets although near-term development options are more limited.
Infrastructure access	★★	Don fields partnership with Enquest provides multiple opportunities for tie-back.
Abandonment liabilities/ tax/ regulatory issues	★★	Acquisition of Antrim Causeway added £37m of potential tax losses. Dons development design limits abandonment exposure.
Financial strength/ discipline	★★	Completed refinancing of existing reserves-based debt facility in December 2010. 40% gearing, however, is high for the sector.

Location of key North Sea assets

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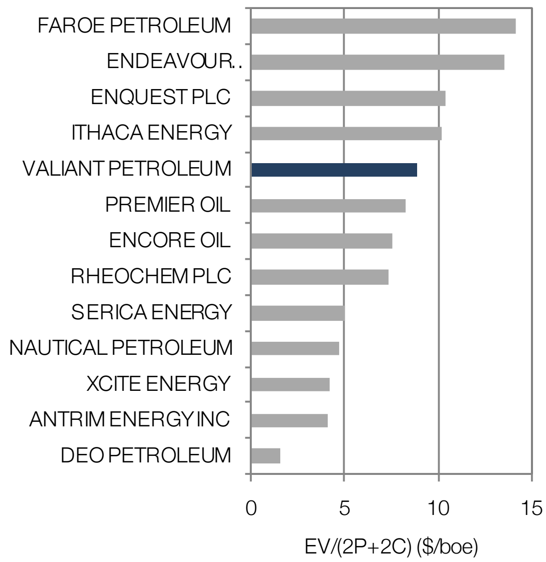
Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
West Don	Oil	3.4	2P	Prodn.
Don SW	Oil	14.0	2P	Prodn.
Crawford	Oil/ Gas	6.4	2P	Pre FDP
Causeway	Oil	1.6	2P	Pre FDP
Banquo (o)	Oil/ Gas	20.5	2C	Appraisal
Helena	Oil/ Gas	6.8	2C	Appraisal
Handcross (o)	Oil	70.0	P50	Exploration

Valuation



Valiant currently trades below NAV while an EV/(2P+2C) of around $8.9/boe puts it mid-table among the peer group. High impact exploration provides multiple opportunities for upside, while Don panel developments and Causeway are probably critical to maintain production and cash flow. Downside risks include oil price exposure affecting operating cash flow, particularly critical in Valiant's case given its debt burden.

Source: Edison Investment Research, company data

Xcite Energy

Year End	Revenue (£m)	PBT (£m)	EPS (p)	DPS (p)	P/E (x)	Yield (%)
12/08	0.0	(0.5)	(0.9)	0.0	N/A	N/A
12/09	0.0	(0.8)	(1.4)	0.0	N/A	N/A
12/10	0.0	(2.6)	(1.9)	0.0	N/A	N/A
12/11e	66.4	30.8	20.8	0.0	26.4	N/A

Note: PBT and EPS are normalised, excluding intangible amortisation and exceptional items.

Investment summary: 100% developers

Xcite Energy has only one asset in its portfolio, the c 200mmboe Bentley heavy oil field. However, through an alliance structure it has kept a 100% working interest (WI) of the field and is pushing for oil production in early 2012 from a first stage production facility. With expertise in heavy oil and the Bentley field built up over many years, Xcite appears well placed to drive valuation gains from derisking of the Bentley asset.

Assets: Single asset, large resource

Oil from the Bentley field is both heavy and especially viscous for the sector. The principle challenge has therefore been to build a technically robust development plan to commercialise the field. Oil will carry a discount to Brent of approximately 10-12%. However, netbacks remain attractive based on current high oil prices.

Challenges: Continuous derisking

Until recently the principle challenge for Xcite was to show a horizontal well could flow oil in sufficient and controllable quantities for commercial production. Having demonstrated this with the 9/3b-6 well, Xcite is now moving to reserves identification, FDP submission and first oil by means of its first stage production (FSP) facility in Q112. The key challenges now are to fund the FSP and then formalise the alliance structure with development partners to move to full field development. Decommissioning costs are high but well understood, while infrastructure access is simple as the field will likely be a standalone development with an FPSO.

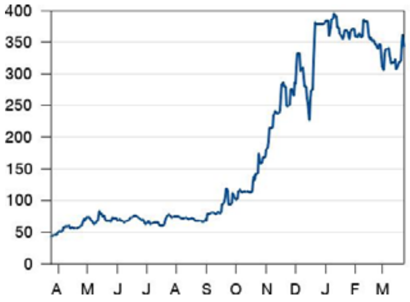
Management and strategy

Given its single asset focus, Xcite's management has built significant experience in heavy oil and the Bentley field in particular over a number of years. Exploration and development director, Stephen Kew, is key to this having worked on Bentley when with previous operator Conoco. The management strategy of retaining 100% WI while seeking to commercialise the field via a development alliance is possibly unique in the sector. Prospective returns to Xcite's shareholders are significant given the equity structure but equally there remain development risks, given we do not expect confirmation of the alliance structure until the FSP has been proven in 2012-2013.

Price*	338.5p
Market Cap	£541m

Priced as at 23 March 2011

Share price graph



Share details

Code	XEL
Listing	AIM, TSX-V
Shares in issue	160m

Price

52 week	High	Low
	395.0p	43.5p

Balance Sheet as at 31 December 2010

Gearing (%)	N/A
NAV per share (p)	49
Net cash (£m)	40.0

Business

Xcite Energy is an oil appraisal and development company focused on heavy oil resources in the UK sector of the North Sea. It has one project, the Bentley field, in which it is has 100% working interest.

Newsflow catalysts

April 2011: Reserves update
Q211: FDP submission/ approval
Early 2012: FSP target start date

Analysts

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Evaluation criteria

Risk potential based on ★ low risk/key strength, ★★ medium risk, ★★★ high risk/weakness.

	Exposure	Comment
Management & partners	★★	Incentivising service/offtake partners through an alliance structure, but model unproven.
Subsurface understanding/ complexity	★★	Strong sub-surface understanding of the Bentley field built over many years. High viscosity oil demands complex development plan, however recent well demonstrates good understanding.
Portfolio balance/ upside potential	★★	Single asset so no portfolio balance. Some upside potential from 26th round acreage although limited.
Infrastructure access	★	Standalone field with FPSO makes infrastructure simple.
Abandonment liabilities/ tax/ regulatory issues	★	Significant abandonment liabilities but simple structure given 100% WI. Minimal tax losses available due to single field development but benefit from heavy oil incentive.
Financial strength/ discipline	★★★	Will require funds for early stage production facility. Alliance structure to be confirmed, without which insufficient funds for full development.

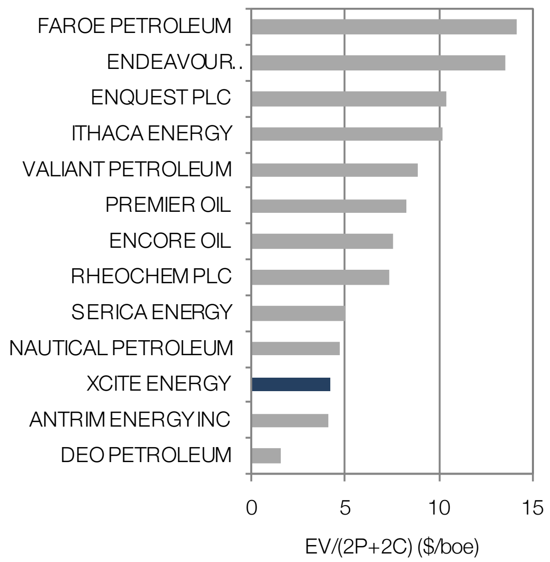
Location of key North Sea assets

©iStockphoto.com/grajte

Field (O)=Operator	Fluid	Net resource (mmboe)	Resource type	Dev. phase
Bentley (o)	Oil	200*	2C	Pre-FDP

* Management estimate

Valuation



Source: Edison Investment Research, company data

Xcite trades at a low EVR multiple compared with peers. However, given it has 100% working interest of an estimated 200mmboe resource(*) this still amounts to an impressive market capitalisation. A 12% discount to Brent must be factored into the valuation. However, further derisking of the field development is expected to result in additional EVR increases. Next catalysts are FDP approval in Q211, approval in Q311 and rig delivery and first stage production drilling in Q411. We currently expect Bentley to enter production in Q112.

(*) management estimate

Appendix 1: Fiscal and regulatory environment in the North Sea

Taxation: An overview

The fiscal regime for oil companies operating on the UK Continental Shelf can be summarised by three components:

- **Petroleum Revenue Tax (PRT):** Introduced in 1975 through the Oil Taxation Act, this is a tax on super-economic profits and is paid in addition to Corporation Tax on all fields given development consent before 16 March 1993. It is currently set at 50%. The tax is calculated on a field by field basis (ie not charged on aggregate profits from a group of fields), meaning costs from one field cannot be deducted against profits from another. The spirit of the legislation was to (a) allow for rapid recovery of costs for a project and then tax profits at a high rate, (b) ensure payments were made rapidly; typically PRT is paid earlier than Corporation Tax, and (c) ensure that projects where there was no economic profit or rent were protected from the tax. The tax was reformed in the 1993 Finance Act.
- **Ring Fence Corporation Tax (RFCT):** this is the standard Corporation Tax applicable to all companies, but disallows profits from oil and gas activities to be offset by losses from other activities or excessive interest payments. At present the RFCT is 30% and did not benefit from the reduction in Corporation Tax in 2007. RFCT is calculated on profits after the deduction of PRT.
- The **Supplementary Charge (SC)**: Raised from 20% to 32% in the 2011 budget, the charge is paid on all ring fence profits from oil and gas production in the UK and UKCS.

In effect this together with the RFCT means that the effective corporation tax is 62% of profits, while those paying PRT, RCFT and SC have an effective marginal tax rate of 81%. The majority of North Sea independents do not have fields subject to the PRT.

Calculating taxable profits for PRT: A rough guide

In broad terms the basis for calculating profits subject to PRT are calculated as follows:

Income from the following sources:

- Revenue receipts from oil and gas production at market value or imputed market value plus one half of the difference between opening and closing stock levels at market value.
- Any tariff receipts in return for the use of assets or services provided.
- Disposal receipts of certain assets

Against this the following costs can be typically deducted:

- Costs of searching for oil within a licence. This includes costs associated with geological field studies, seismic surveys and their interpretation, drilling of exploration wells and their evaluation provided these costs are incurred within 5km of the field boundary.
- Costs of obtaining a licence, typically the annual rental costs for a licence.

- Costs of ascertaining the location and extent of a reservoir. This includes costs of delineating field boundaries and appraisal well costs.
- The costs of 'winning oil', effectively the costs of moving into production. This will include salaries of personnel involved in bringing a field into production, the costs of constructing a platform and the costs of maintaining the equipment.
- Costs of transporting oil. However, this does impose restrictions on transporting oil onshore. This typically includes the capital costs and operating costs of pipelines and tanker loading facilities.
- Costs of disposing or selling the oil providing this is done on an arm's length basis. This will include the costs of a sales office and handling fees.
- Decommissioning costs incurred in closing down a field. The rules around this are complex, but in principle allow on a field by field basis the costs of closing down a field. In 2009 a number of measures were introduced to prevent oil companies from claiming decommissioning costs in advance of the actual decommissioning cost being undertaken. The decommissioning costs of a field are substantial and will exceed the income in the period of decommissioning. PRT allows for the losses created to be carried back to claw back PRT paid in earlier periods, with no time limit.

RFCT: A rough guide and the interaction with PRT

Unlike PRT, RFCT is computed not on an individual field, but on the company's whole UK oil and exploration activities, ring fenced from other operations, ie losses from other operations cannot be deducted from oil income inside the ring fence.

Calculation of taxable profits are done on a similar basis to that outlined above. There are additional factors to be aware of:

- **Accelerated capital allowances:** Oil companies can claim 100% first year allowances (FYA) for general plant and machinery expenditure spend from 17 April 2002, which is wholly for the purpose of extraction of oil from the UKCS if they are part of the RFCT asset pool. Assets which are deemed to be long life assets attract a 24% FYA.
- **Field allowances:** The government introduced a range of field allowances in the 2009 budget to encourage exploration of technically challenging and small fields. These include:
  - £75m small field allowances for oil and gas fields with reserves of less than 2.75m tonnes, reducing to nil on a straight line basis for fields over 3.5m tonnes. The maximum allowance in any one year is £15m.
  - £800m for ultra heavy oil fields (API gravity below 18 degrees and a viscosity of more than 50cp). The maximum field allowance in any one year is £160m.
  - £800m for any high temperature, high pressure fields (HTHP fields defined as having a reservoir temperature of more than 150 degrees Celsius and requiring pressure control equipment with a rating in excess of 10,000 psi). The maximum field allowance in any one year is £160m.

- **Decommissioning costs and the interaction with PRT.** Losses incurred from decommissioning can be carried forward, used against current year RFCT and be carried back against taxable profits from the previous three years. The impact of this is that a refund or PRT more than three years old generates an additional RFCT liability which is not reduced by carrying back of losses against RFCT.

Future of PRT causing uncertainty

There is at present considerable uncertainty around whether PRT might be abolished. Given that decommissioning costs are (a) a certainty and (b) a significant cost, this creates an issue for any company looking to make an investment decision. This is particularly true after the 2009 rules, which prevent oil companies from claiming tax relief for decommissioning costs until the decommissioning works are actually coming on stream. Oil companies are probably reluctant to factor into their investment appraisal the availability of a tax claw back for decommissioning costs given this uncertainty. This is just another complication for mature oil fields being sold on to independents.

Restriction of relief for decommissioning from 2012

The government has announced that it plans to introduce legislation in the Finance Bill 2012 to restrict tax relief on decommissioning expenditure to 20% rather than 32% supplementary charge. This measure is being implemented to disincentivise companies from accelerating decommissioning expenditures.

Regulatory environment: The role of DECC

The Department of Energy and Climate Change (DECC), through its Energy Development Unit (EDU), is responsible for licensing exploration and regulating development of the UK's oil and gas resources. Its principal role can be broken down into the following areas:

- Awarding licences.
- Approving field development.
- Implementing initiatives to maximise the economic recovery of oil and gas, including measures such as the fallow acreage initiative.
- Allowing for economic third-party access to infrastructure.
- Ensuring decommissioning obligations are met.

Licensing: An overview

The DECC awards a range of different licences with distinct permissions, life spans and rental payments. The most common are:

- **Seaward Production licences**: A licence to search, drill and obtain hydrocarbons within a specified area on the UKCS. Licences are normally awarded in annual rounds and typical terms include a four-year exploration term, a second four-year term usually to submit a Field Development Plan and an 18-year production licence. An escalating rental payment per acre is payable on the licence. At the end of the initial term, a licence is expected to relinquish at least 50% of the acreage with a further relinquishment of all acreage not covered by the Field Development Plan.

- **Exploration licences (seaward):** A three-year licence, with a possible three-year extension if conditions are met to acquire geophysical data and samples for areas in the UKCS that are not under a production licence currently.
- **Promote licences:** A two-year licence to assess the prospectivity of acreage without the stringent criteria attached for a traditional Seaward Production licence with a lower (typically 10%) rental fee compared to the traditional licence. However, a promote licence would have to meet all the criteria for a traditional licence to become an operator on the licence.
- **Frontier licence:** Usually available for difficult unexplored areas (eg West of Shetlands) where companies can apply for large acreage. Typically, three-quarters of the acreage is required to be relinquished after initial assessment. The Exploration and Development periods are longer than the traditional licence, normally six years each as opposed to the usual four.

Fallow acreage

The Fallow acreage initiative was introduced in 2002 to ensure that licensees are working assets on a timely basis or divesting them to parties that have more opportunity or incentive to do so. A block or a discovery becomes fallow if:

- The licence was awarded in the first to 19th round.
- The initial term (usually six years) has expired.
- There has been no significant activity (drilling, seismic etc) on the block for three years.

These blocks are divided into two types of fallow acreage. Fallow A are blocks where the existing licensees are seen to be doing all that a reasonable E&P company could be doing. These assets are retained but subject to an annual review. Fallow B are blocks where licensees are seen to be unable to progress due to either partner misalignment, lack of funding or other similar reasons are given a one year (blocks) or two year (discoveries) period to market the asset and develop an activity plan. Failure to deliver a plan would lead to the licence being relinquished. DEO Petroleum recently acquired a 42% stake in the Perth block from Nexen after the block was deemed to be Fallow.

Field development plans

Operators wishing to develop a field are required to submit a Field Development Plan (FDP), together with an Environmental Statement (ES). The DECC is looking for proposed development plans that maximise recovery from the fields. This is one reason why, for example, Encore Oil wants to fully explore the Greater Catcher area. Before an FDP is granted, both an environmental approval and a health and safety approval need to be obtained.

Post Macondo

Following the 20 April 2010 explosion on BP's Deepwater Horizon drilling rig in the Gulf of Mexico, the DECC conducted a review of its safety and environmental regime and found it "fit for purpose".

Two changes were implemented: a doubling of drilling rig inspections and increasing insurance coverage from $150m to $250m, with a possible top up requirement for high-impact wells around the West of Shetlands. In a recent placing, Faroe Petroleum noted that the tougher regulatory regime had led to £6m of additional exploration costs. The UK did, however, resist a deepwater drilling ban that was suggested by the EU.

An inquiry by the Select Committee on Energy and Climate Change held on UK deepwater drilling heard from testimony from industry leaders and associations. The main message that came out was that the UK was seen to have a robust operating regime. The UK made significant changes to its operating regime following recommendations from the Cullen Report on the Piper Alpha disaster in 1998.

On 6 January 2011 the Select Committee published its report and made a number of recommendations. By March 2011 responses to these had been received from the government, Oil & Gas UK and the Falkland Island government.

Among the recommendations we highlight the following:

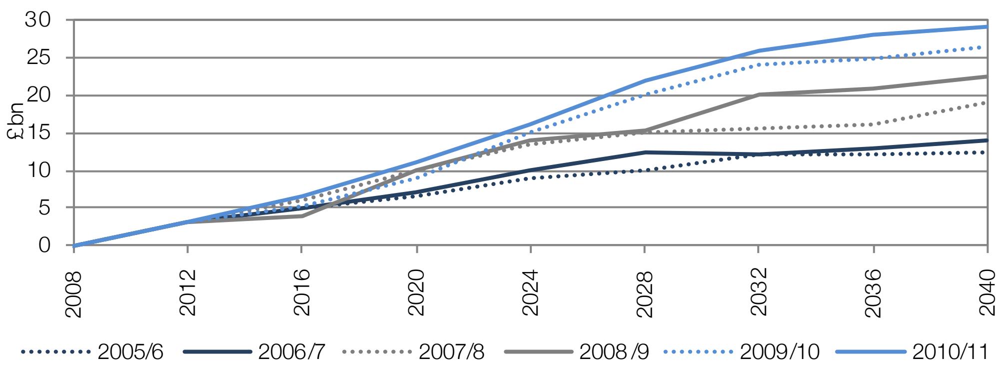
- **Oil company boards should have members with environmental experience:** The UK government response on this suggests that existing legislation is sufficient with regards to directors' responsibility as laid out in the Companies Act.
- **There is someone offshore who can bring a halt to drilling operations at any time.** The UK government highlighted that the DECC already ensures that an Offshore Installation Manager and/or a drilling supervisor have the authority to shut down production.
- **Blowout preventers should be equipped with two blind shear rams.** The UK is looking into this in more detail and is awaiting findings from the US Marine Board, expected in the summer.
- **In light of the response to the Deepwater Horizon incident, if the US establishes a new gold standard of regulation, the UK should be open to exchanging best practice.** The HSE is planning a summit in Autumn 2011 to provide an opportunity to learn from the Deepwater Horizon incident.
- **Compulsory third-party insurance becomes a necessary requirement for small exploration and production companies.** The UK government is considering this.
- **Licensing regimes take full account of high consequence, low probability events.** The DECC has learned more about the behaviour of a deepwater release at the seabed and is feeding it into its impact assessments, the DECC must accept the Environmental Impact Assessments of operators before the necessary environmental approvals are granted.
- **Recommend as part of the licensing process that the licensee prove their ability to pay for the consequences of any incident. The incremental costs should be reflected in the fiscal regime to prevent lack of investment.** The government response suggested that it is satisfied with the OPOL arrangements, but the DECC and OSPRAG are reviewing this area to see if improvements could be made. The field allowance recommendation was commented on in the recent budget and may be announced in 2012.

Decommissioning, abandonment and infrastructure maintenance

As a large-scale and mature oil and gas production province, the North Sea has substantial infrastructure in place in the form of wells, platforms, pipelines, processing facilities and onshore terminals. In the UK sector alone there are approximately 10,000km of pipelines, 5,000 wells, 600 fixed installations and 15 onshore terminals. With field depletion now very apparent in the North Sea, the issue of decommissioning has come to the fore in recent years. According to Oil & Gas UK, the offshore industry trade body, around 284 installations will need decommissioning by 2020. This is expected to cost about $14.5bn at current economics. Total decommissioning costs in the UK North Sea are estimated by Oil & Gas UK at $43bn. The heaviest burden of decommissioning is expected to fall between around 2017 and 2030.

Indeed it can be seen (Exhibit 15) that estimates of the cost have more than doubled in the last five years. These costs are dominated by the Northern North Sea with 44% of the total spend, and the Central North Sea at 34%.

Exhibit 15: UKCS projected cumulative decommissioning costs 2008-2040



Source: Oil & Gas UK

In the early days of the North Sea, it was assumed that it would be possible to abandon most structures by cutting at the base and laying them on the sea bed. The events surrounding Shell's plans to dispose of the Brent Spar oil storage buoy in deep Atlantic waters in 1995 demonstrated that public sentiment would not support such a strategy

Today there are laws preventing platforms and other installations simply being dumped at sea. Effectively, redundant installations will have to be partially dismantled on location and then brought ashore for final dismantling and recycling. The largest platforms contain over 20,000 tonnes of steel all of which will provide useful steelmaking feedstock. At current heavy melt scrap prices of $470/tonne, 20,000 tonnes would generate $9.4m, which provides a partial offset to dismantling costs. North Sea dismantling activity together with the associated logistical and lifting support services is expected to spawn a whole new industry at strategic locations along the UK east coast. An average platform is expected to take about 18 months to dismantle.

While this means that abandonment costs are now higher than originally anticipated, the more immediate concern for the North Sea is the requirement to demonstrate when taking over an asset that the abandonment liability can be paid. The cash that must be put aside for decommissioning on late life fields is such that only players with producing assets that are generating cash flow are able to take these assets over from the majors. For this reason, mid-size companies are in the best position to take on ageing infrastructure. However, there are very few companies occupying this space in the sector, with EnQuest and Fairfield being examples covered in this report.

EnQuest was able to take on its assets only because its parent companies retained most of the liability, so it is questionable whether other independents can repeat its success and, in the case of Fairfield, the need for the company to secure better integrity at its ageing Dunlin platform was seen as a risk by the market prior to the cancellation of its IPO in 2010. In practice, then, it is difficult for majors to sell assets and for small companies to take on the liability, effectively slowing the process of getting the right assets into the right hands and limiting the ability to maximise field life.

Without an effective means of extending the life of the infrastructure in order to facilitate future developments, reserves could be left undeveloped due to premature abandonment. It is in the interests of all parties concerned to find a solution to this problem, and discussions with the government, while reported to be positive, are progressing slowly. In the last few years, lobbying on the part of the major companies has been unsuccessful in repealing Section 29 of the Petroleum Act 1998. Under this legislation, the government can go back through previous operators of an asset until one is found who can pay the liability costs.

At present, technical experience of decommissioning in the North Sea is low, and the heavy lifting equipment required is in short supply. However, real decommissioning projects will become more frequent in the coming years, and costs should come down as expertise increases. Decommissioning has the potential to become an industry in itself, with specialist companies likely to spring up and develop experience, leaving the operators to deal with the financing.

Infrastructure maintenance

Given that much of the North Sea infrastructure has exceeded its design life of 20 to 25 years, corrosion is a key risk for operators. Particularly vulnerable are infield carbon steel pipelines and high pressure gas pipelines. Reflecting the risks involved, corrosion monitoring and management programmes have had to be stepped-up where original design lives are now being significantly extended. Programmes could include pipeline corrosion modelling, corrosion inhibition and the use of pipeline pigging. The last mentioned refers to a device for assessing pipeline integrity in terms of such factors as corrosion and wall thickness.

A key example in recent years of a major anti-corrosion programme in the North Sea is the cathodic protection retrofit for Apache’s Forties field. The retrofit, undertaken by Houston-based Deepwater Corrosion Services Ltd, was commenced in October 2007 and has provided protection for the infield pipelines and the original four platforms. As a consequence, the life of the Forties installations has been extended by at least 20 years.

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