INDUSTRY NOTE

Initiating Coverage

UK | Energy | Oil & Gas Exploration & Production

24 October 2012

Jefferies

EQUITY RESEARCH EUROPE

Oil & Gas Exploration & Production
Initiating Coverage: Old Dog, New Tricks - finding value in the North Sea

Key Takeaway

We initiate coverage of the North Sea E&P sector at a time when well-funded companies have a significant opportunity to create value. We favour hub-style developments and exploitation of existing fields as key organic routes to growth. Recent exploration success has reignited interest in the region, and challenges the common perception that the North Sea is a mature basin. Our top picks are ENQ, FPM, and IAE.

Key value strategies: hub developments and under-explored basins. We believe the best strategies to deliver value in the North Sea are: (1) hub developments, where E&Ps develop several smaller fields in tandem using shared infrastructure and tax allowances to maximise value, and (2) entering frontier regions like the Barents Sea, West of Shetland, and Atlantic Margin, which have seen material exploration success in recent years.

North Sea transaction market offers attractive arbitrage opportunity. A deep and well-understood North Sea sector means there is a very liquid market for both asset- and corporate-level M&A. North Sea transactions have averaged $13.7/boe (EV/2P) over 2010-12, and with equity valuations typically sitting below deal multiples we believe both investors and well-funded E&Ps can successfully exploit this arbitrage opportunity.

Fiscal terms encourage smaller UK fields and Norwegian exploration. The North Sea is considered a low geopolitical environment, despite the UK and Norway's fiscal terms being high in a global context. UK tax allowances encourage investment in small, old, or technically challenging fields, while in Norway tax rebates allow explorers to share risk with the government. These activities fall well within the scope of the E&Ps covered in this report.

North Sea risks include rising opex and decommissioning. Common E&P risks range from commodity price exposure for the producers to delays and cost overruns for the developers. Specific risks include a worsening operating cost environment, unstable fiscal regimes (especially in the UK), rising decommissioning liabilities, and a tight rig market in both the UK and Norway.

Top picks: ENQ, FPM, IAE. We prefer the North Sea E&Ps that have strong management and technical teams, offer significant visible growth that we believe is not yet being priced by the market and, most importantly, are sufficiently funded to execute their planned E&A and development pipelines. We value the E&Ps using a sum-of parts methodology and Jefferies' global commodity price deck ($100/bbl Brent, $9.14/mcf UK NBP). Our top picks are **EnQuest (Buy, 155p/sh PT)**, **Faroe Petroleum (Buy, 240p/sh PT)**, and **Ithaca Energy (Buy, 180p/sh PT)**.

As part of this report we also transfer primary coverage of **Premier Oil (Hold, 415p/sh PT)** and **IGas Energy (Buy, 85p/sh PT)** to Matthew Lambourne from Laura Loppacher.

Current Estimates

Ticker		2012	2013	2014
ENQ LN	EPS	$0.34	$0.18	$0.23
FPM LN	EPS	£0.04	£0.08	£0.15
IAE LN	EPS	$0.28	$0.29	$0.63
¶IGAS LN	EPS	£0.08	£0.09	£0.15
PMG LN	EPS	£0.00	£0.00	£0.00
PMO LN	EPS	$0.52	$0.61	$0.42
PVR LN	EPS	€(0.52)	€(0.06)	€(0.07)
SLG CN	EPS	C$(0.08)	C$0.06	C$0.12

Coverage Summary

Ticker	Rating	Price	Price Target
ENQ LN	BUY	121.00p	155.00p
FPM LN	BUY	153.00p	240.00p
IAE LN	BUY	118.00p	180.00p
¶IGAS LN	BUY	75.00p	85.00p
PMG LN	BUY	13.00p	15.00p
PMO LN	HOLD	367.00p	415.00p
PVR LN	BUY	660.00p	950.00p
SLG CN	HOLD	C$1.42	C$1.45

Share prices are as of Oct 19th

Financial Summary & Market Data

Ticker	Mkt. Cap. (MM)	Shares Out.(MM)	Net Debt
ENQ LN	£971.6	803.0	($92.0)
FPM LN	£324.4	212.0	(£83.0)
IAE LN	£305.6	259.0	($73.0)
¶IGAS LN	£121.5	162.0	£73.0
PMG LN	£99.1	762.0	£0.8
PMO LN	£1,941.4	529.0	$813.0
PVR LN	£422.4	64.0	(€47.4)
SLG CN	C$316.7	223.0	C$65.0

¶Note: Jefferies Hoare Govett, a division of Jefferies International Limited, acts as a corporate broker for this company.

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Table 1: Jefferies North Sea E&P valuation metrics

Company		EnQuest	Faroe Petroleum	IGas Energy	Ithaca Energy	Parkmead Group	Premier Oil	Providence Resources	Sterling Resources
Ticker		**ENQ**	**FPM**	**IGAS**	**IAE**	**PMG**	**PMO**	**PVR**	**SLG CN**
Rating		Buy	Buy	Buy	Buy	Buy	Hold	Buy	Hold
Target price	**p/sh**	**155**	**240**	**85**	**180**	**15**	**415**	**950**	**C$1.45**
Current price	p/sh	121	153	75	118	12.9	367	660	C$1.42
Upside/(downside) %	%	28%	57%	14%	53%	16%	13%	44%	2%
No. of shares (basic)	m	803	212	162	259	762	529	64	223
Market Capitalisation	USD	1,552	518	193	488	158	3,108	680	319
Enterprise Value	USD	1,460	387	309	414	159	3,922	616	383
Avg 3mth turnover	USD	2.88	2.20	0.21	1.02	0.31	8.97	2.51	0.01
Net Cash / (Debt)	USD	92	131	-115	73	-1	-813	64	-65
Net Cash / (Debt)	p/sh	7	39	-40	18	0	-98	63	-C$0.29
Cash % share price	%	6%	26%	-53%	15%	-1%	-27%	10%	-20%
Core NAV	p/sh	144	180	46	180	15	438	1345	C$1.53
P/Core NAV	**x**	**0.84x**	**0.85x**	**1.63x**	**0.65x**	**0.85x**	**0.84x**	**0.49x**	**0.93x**
Total SoP	p/sh	153	239	98	180	20	486	1903	C$1.90
P/SoP	**x**	**0.79x**	**0.64x**	**0.76x**	**0.65x**	**0.65x**	**0.76x**	**0.35x**	**0.75x**
SoP Unrisked	p/sh	183	488	313	186	40	675	5434	C$4.86
2012 SoP	p/sh	149	219	68	180	17	478	1799	C$1.88
2012 unrisked SoP	p/sh	167	438	84	186	27	658	5142	C$4.76
2012 unrisked SoP upside	%	15%	143%	22%	5%	77%	49%	506%	203%
Total SoP unrisked upside	%	25%	164%	288%	5%	157%	51%	535%	209%
Prem/(Disc) to SoP	**%**	**-21%**	**-36%**	**-24%**	**-35%**	**-35%**	**-24%**	**-65%**	**-25%**
EV/2P boe	$/boe	$12.50	$15.02	$32.57	$7.37	$6.22	$12.99	na	$11.61
Average risk of portfolio	%	83%	44%	39%	97%	50%	76%	34%	43%

Source: Jefferies estimates (shares prices are as of Oct 19th)

Table 2: Jefferies European E&P coverage universe

Company	Ticker	Analyst	Market Cap. ($m)	Rating	Price Target (p)	Price (p)	Upside/ (Downside) %	SoP (p)	P/SoP
Tullow Oil	TLW	Brendan Warn	21,132	Buy	1,800	1,455	24%	1,569	0.93
Ophir Energy	OPHR	Laura Loppacher	3,671	Buy	800	574	39%	815	0.70
Premier Oil	PMO	Matt Lambourne	3,108	Hold	415	367	13%	486	0.76
Cairn Energy	CNE	Laura Loppacher	2,774	Hold	385	288	34%	384	0.75
Afren	AFR	Laura Loppacher	2,513	Buy	155	145	7%	154	0.94
Soco International	SIA	Laura Loppacher	1,788	Hold	305	337	-9%	430	0.78
EnQuest	ENQ	Matt Lambourne	1,552	Buy	155	121	28%	153	0.79
Rockhopper	RKH	Laura Loppacher	763	Hold	300	168	79%	329	0.51
Providence Resources	PVR	Matt Lambourne	680	Buy	950	660	44%	1,903	0.35
Faroe Petroleum	FPM	Matt Lambourne	518	Buy	240	153	57%	239	0.64
Ithaca Energy	IAE	Matt Lambourne	488	Buy	180	118	53%	180	0.65
Bowleven	BLVN	Laura Loppacher	377	Buy	195	80	144%	195	0.41
Sterling Resources	SLG CN	Matt Lambourne	319	Hold	C$1.45	C$1.42	2%	C$1.90	0.75
Falkland Oil & Gas	FOGL	Laura Loppacher	316	Buy	115	62	86%	231	0.27
IGas Energy	IGAS	Matt Lambourne	193	Buy	85	75	14%	98	0.76
Borders & Southern	BOR	Laura Loppacher	184	Buy	20	24	-16%	35	0.68
Parkmead Group	PMG	Matt Lambourne	158	Buy	15	13	16%	20	0.65
Desire Petroleum	DES	Laura Loppacher	129	U/P	18	24	-24%	25	0.95
Chariot Oil & Gas	CHAR	Laura Loppacher	96	Buy	36	30	20%	211	0.14
Argos	ARG	Laura Loppacher	88	U/P	12	26	-53%	13	2.03
President Petroleum	PPC	Laura Loppacher	88	Buy	70	22	218%	70	0.31
Tower	TRP	Laura Loppacher	77	Hold	4	3	18%	9	0.34
3Legs	3LEG	Laura Loppacher	59	Buy	100	44	130%	201	0.22

Source: Jefferies estimates (shares prices are as of Oct 19th)

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Executive Summary

We initiate coverage of ENQ, FPM, IAE, PMG, PVR, and SLG CN. We transfer coverage of PMO and IGAS.

We initiate coverage of the North Sea E&P sector at a time when we believe well-funded oil & gas companies have a significant opportunity to create value. M&A activity, a liquid asset market, and licensing rounds allow E&Ps a variety of ways to expand their North Sea portfolios, with many companies seeking growth through new hub-style developments and exploitation of existing fields. Recent exploration success has reignited interest in parts of the region, and challenges the common perception that the North Sea is a mature basin. Our top picks are EnQuest, Faroe Petroleum, and Ithaca Energy.

Key value strategies: hub developments and underexplored basins

We believe the best strategies to deliver value in the North Sea are: (1) creating hub developments, where E&Ps can develop a number of smaller fields in tandem, using shared infrastructure and tax allowances to maximise the fields' economics, and (2) entering frontier regions like the Barents Sea, West of Shetland, and Atlantic Margin, which have seen material exploration success in recent years (e.g., Statoil and Lundin's giant Johan Sverdrup). We believe the companies best placed to exploit these strategies are ENQ, FPM, IAE and PVR.

North Sea transaction market offers E&Ps attractive arbitrage opportunity

The wide range of participants and deep industry knowledge of the North Sea means there is a very liquid market for both asset- and corporate-level M&A. North Sea oil & gas transactions have averaged $13.7/boe (EV/2P) over 2010-12, and with equity valuations typically sitting below deal multiples we believe well-funded E&Ps with solid cashflow generation are best placed to take advantage of this attractive arbitrage opportunity.

Fiscal terms encourage smaller UK fields and Norwegian exploration

The North Sea is widely viewed as a low geopolitical risk environment, and while the UK and Norway's fiscal terms are high in a global context, certain elements of these regimes are valuable for the E&Ps in our coverage universe. The UK regime favours developers by offering tax allowances that encourage investment in small, old, or technically-challenging fields (in fact, we estimate only four of the Top 50 planned UKCS projects will not be able to utilise these allowances). In Norway the regime favours explorers by offering companies tax rebates that effectively allow them to share exploration risk with the government. We believe these types of activities fall well within the scope of the smaller, independent E&Ps covered in this report.

North Sea risks include rising opex and decommissioning costs

The North Sea E&Ps share a number of common risks, ranging from commodity price exposure for the producers to delays and cost overruns for the developers. Specific North Sea risks include a worsening operating cost environment (+25% y-o-y in the UK), unstable fiscal regimes (especially in the UK), rising decommissioning liabilities, and a very tight rig market in both the UK and Norway.

Our top picks are **EnQuest** (ENQ LN, Buy, 155p/sh PT), **Faroe Petroleum** (FPM LN, Buy, 240p/sh PT), and **Ithaca Energy** (IAE LN, Buy, 180p/sh PT)

Top picks: EnQuest, Faroe Petroleum, and Ithaca Energy

We prefer the North Sea E&Ps that have strong management and technical teams, offer significant visible growth that we believe is not yet being priced by the market and, most importantly, are sufficiently funded to execute their planned E&A and development pipelines. We value the E&Ps using a sum-of parts methodology and Jefferies' global commodity price deck ($100/bbl Brent long-term, $9.14/mcf UK NBP long-term).

Our top picks are **EnQuest (ENQ LN, Buy, 155p/sh PT)**, **Faroe Petroleum (FPM LN, Buy, 240p/sh PT)**, and **Ithaca Energy (IAE LN, Buy, 180p/sh PT)**.

Other Buy ratings include **Providence Resources**, **Parkmead Group** and **IGas Energy**. We have Hold ratings on **Premier Oil** and **Sterling Resources**.

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The North Sea E&Ps – key takeaways

Table 3: Jefferies North Sea E&P coverage universe

Stock	Ticker	Rating	Market cap. ($m)	Price	Price target	Upside (%)	SoP Valuation (p/sh)	P/SoP	Core NAV (p/sh)	P/Core NAV
Premier Oil	PMO LN	Hold	3,108	367	415	13%	486	0.76	438	0.84
EnQuest	ENQ LN	Buy	1,552	121	155	28%	153	0.79	144	0.84
Providence Resources	PVR LN	Buy	680	660	950	44%	1903	0.35	1345	0.49
Faroe Petroleum	FPM LN	Buy	518	153	240	57%	239	0.64	180	0.85
Ithaca Energy	IAE LN	Buy	488	118	180	53%	180	0.65	180	0.65
Sterling Resources	SLG CN	Hold	319	C$1.42	C$1.45	2%	C$1.90	0.75	C$1.53	0.93
IGas Energy	IGAS LN	Buy	193	75	85	14%	98	0.76	46	1.63
Parkmead Group	PMG LN	Buy	158	13	15	16%	20	0.65	15	0.85
Average						***29%***		***0.67***		***0.88***

Source: Jefferies estimates (shares prices are as of Oct 19th)

EnQuest, Faroe Petroleum, and Ithaca Energy are our top North Sea E&P picks

Preferred Buy ratings – ENQ, FPM, IAE

EnQuest – Buy, 155p/sh price target

- EnQuest is entering a period of **significant production (14% CAGR over 2010-14) and cashflow growth**. We estimate the company's two flagship developments – Kraken and Alma & Galia – could add up to 119mmbbl of 2P reserves and 34kbopd of incremental production by 2019, potentially doubling the size of the business.

- We believe EnQuest is **fully funded to complete its planned development and E&A pipeline**, and is highly cash-generative; our forecasts suggest c.$900m of post-tax operating cashflow in 2014 (trading at just 1.6x EV/EBIDAX).

- **We rate EnQuest's value creation strategy highly**. In our view, ENQ's strong technical team and solid funding position allows it to access a "sweet spot" of North Sea assets, where it can exploit undeveloped resources and maximise value through hub-style developments and favourable UK fiscal terms for marginal assets.

Faroe Petroleum – Buy, 240p/sh price target

- Faroe's **exploration-led model focuses on high-impact, underexplored basins** in the UK (West of Shetlands) and Norway (Barents Sea), where it aims to drill around five meaningful exploration wells per year. In our view Faroe's drilling record is attractive, delivering c.50% exploration success rate over 2009-2012.

- Faroe's **drilling campaign is entirely self-funded** through tax-efficient Norwegian and UK production, where management aim to extend field life through in-fill drilling. Faroe has also successfully used asset swaps (e.g., the Maria/Petoro deal in 2011) to access capital and avoid development capex – we believe the company is likely to use similar swap-type deals in the future.

- In our view, Faroe's **Norwegian exposure is a key differentiating factor**. In addition to an abundance of underexplored acreage, Norway's highly favourable fiscal regime allows explorers like Faroe to share drilling risk with the government and hold material working interests in blocks with significant resource potential.

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Ithaca Energy – Buy, 180p/sh price target

- **Strong cash generation** – we expect Ithaca to deliver around $800m of post-tax operating cashflow over 2013-14 (more than the current market capitalisation of the entire company) as production quadruples once the flagship Greater Stella Area development is brought onstream.

- We believe Ithaca's production & development-focused strategy offers a **low risk** option for investors wishing to diversify exploration risk elsewhere in their portfolios. Ithaca currently has no E&A wells planned for 2012-13.

- In our view Ithaca is a likely **M&A candidate** following an abandoned approach early in 2012 – we believe the company has many traits (low exploration risk, cash rich, oil-biased) that are appealing to a potential predator.

We also have Buy ratings on Providence Resources, Parkmead Group, and IGas Energy

Other Buy ratings – PVR, PMG, IGAS

Providence Resources – Buy, 950p/sh price target

- The successful appraisal of the Barryroe field in the Celtic Sea has proved **Ireland's first commercial offshore oil development**, with the field now expected to be larger, more productive, and more valuable than previously thought. An updated CPR (due 4Q12) is expected to confirm recoverable resource of 200mmbbl+; in our view, a farmdown announcement (expected 2013) will materially derisk the project and is PVR's key operational catalyst.

- Providence will drill **two very high impact exploration wells in 1H13**. Together the Dalkey Island (1Q13) and Dunquin (2Q13) wells will target c.2bnboe of gross prospective resource, offering unrisked upside of £11 and £18, respectively. Providence is fully funded to drill both wells, including a part-carry from ExxonMobil on the Dunquin prospect.

- It is encouraging to see Providence **partnered with a number of blue-chip oil & gas majors** in its key E&A assets. Companies including ExxonMobil, ENI, Repsol, and PETRONAS have stakes in Providence's key wells, which we believe provides third party validation of the quality and prospectivity of PVR's portfolio.

Parkmead Group – Buy, 15p/sh price target

- Parkmead is in a **phase of rapid growth**, having completed four corporate acquisitions since November 2011. The deals have given Parkmead immediate cashflow from its new onshore Dutch gas fields, and near-term appraisal opportunities from Spaniards East (oil, currently drilling) and Pharos (gas, 2013) in the UK North Sea.

- PMG's **cornerstone asset is the Perth oil development** (13p/sh, 52% operated WI, 22mmbbl net 2P). Perth recently received FDP approval and offers substantial follow-on potential from nearby discoveries that we believe could ultimately comprise a 100mmbbl (gross) Central North Sea hub development.

- The key near term uncertainty, in our view, is **funding**. In addition to a recent £8.5m equity placing and £8m shareholder loan facility, we believe Parkmead is likely to require new external funding to properly execute its material E&A programme over 2012-13. Our forecasts assume a new £20m debt facility is secured in 2013.

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IGas Energy – Buy, 85p/sh price target

- Following the acquisition of Star Energy in 2011 and the Singleton oil field last month, **IGas is expanding its onshore UK footprint** in regions where it has existing conventional oil & gas acreage, effectively creating regional hubs with the potential for tax and operational synergies. We see further upside from these assets through IGas's "chase the barrels" initiative which we estimate offers >10% unrisked upside to our 98p/sh SoP valuation.

- Ongoing appraisal of IGas's 1.8Tcf coal bed methane resource could unlock substantial value, in our view. Pilot production testing is currently underway at the flagship Doe Green site, where **delivering commercial flow rates from the DG-3 and DG-4 wells would be a key milestone** for the company. We value IGas's CBM assets at 33p/sh, with up to 165% unrisked SoP upside.

- IGas's **shale gas resource remains an area of significant upside** (IGas believes the GIIP potential of its shale may be at least twice previous high case estimates of 4.6Tcf), but also carries a number of uncertainties. IGas is currently in the process of securing a farm-in partner with prior shale gas experience to help unlock the shale potential of its licenses through further E&A drilling. Our heavily risked valuation of IGas's shale resource is 2.2p/sh.

We have Hold ratings on Premier Oil and Sterling Resources

Hold ratings – PMO, SLG – better value elsewhere

Premier Oil – Hold, 415p/sh price target (+10p/sh)

- We have updated our PMO SoP valuation to incorporate the impact of the 1H12 results, revised valuations of the Catcher and Solan developments, and PMO's investment in the Sea Lion project. Our SoP has increased slightly from 484p/sh to 486p/sh. Our 415p/sh price target (up from 405p/sh) is set at a 15% discount to SoP to reflect uncertainty around PMO's production and exploration, and with 13% upside to this target we retain our Hold rating.

- Premier's near-term catalysts include E&A well results from Spaniards East (currently drilling, 2p/sh, 1% SoP upside), Cyclone (7p/sh, 3% SoP upside), Luno II (5p/sh, 4% SoP upside) and Lacewing (2p/sh, 2% SoP upside), plus results from the upcoming 27th UK licensing round (due 4Q12). **We forecast PMO to deliver average 2012 production of 59kboepd, slightly below management's 60kboepd guidance** due to planned maintenance and development delays during the year.

Sterling Resources – Hold, C$1.45/sh price target

- The **Breagh gas development** in the UK Central North Sea (first gas estimated late 1Q13) will drive material production and cashflow growth for Sterling, with net output expected to reach 8.5kboepd by late 2014. Breagh offers further upside potential through a Phase 2 development plus the nearby Crosgan discovery.

- Sterling's offshore **Romanian acreage offers significant value potential**, in our view, including a 342Bcf gas development (Ana & Doina) plus 400mmbbl (oil) and 1Tcf (gas) of prospective resource. It is encouraging to see Sterling identify several prospects in a region that has been derisked by a nearby Exxon/OMV gas discovery.

- We believe the **key medium-term risk for Sterling is funding**. Management plan to further rationalise parts of Sterling's Romanian portfolio – and potentially renegotiate or replace its existing RBL facility – in order to meet existing debt covenants and fund its planned E&A campaign over 2012-13. Our C$1.45/sh price target assumes a c.25% discount to SoP to capture this funding risk.

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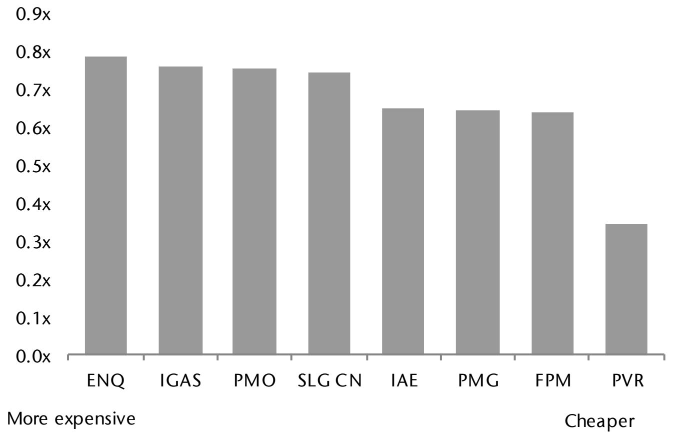
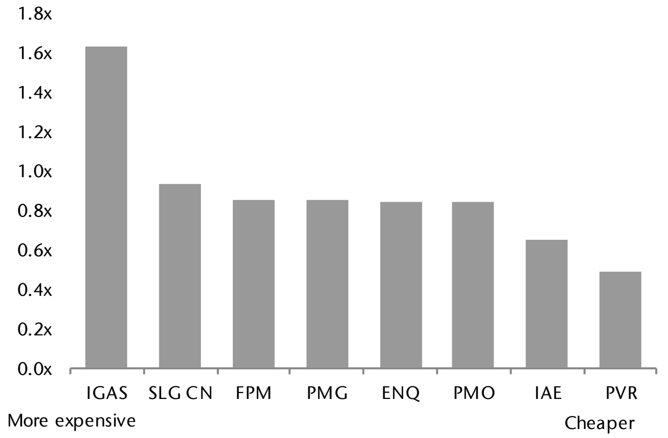
UK North Sea E&P metrics

Chart 1: P/SoP



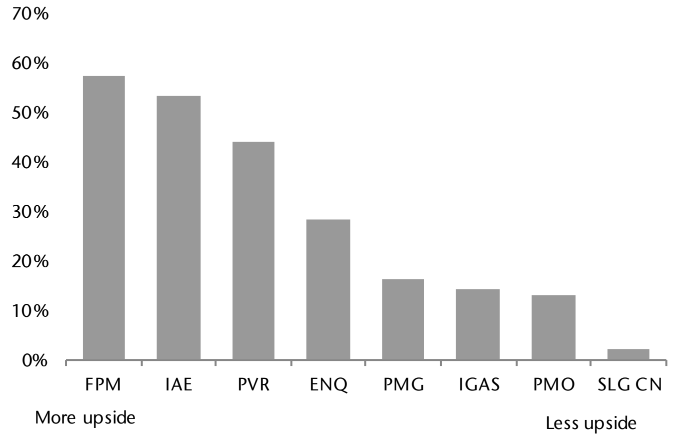
Source: Jefferies estimates

Chart 2: P/Core NAV



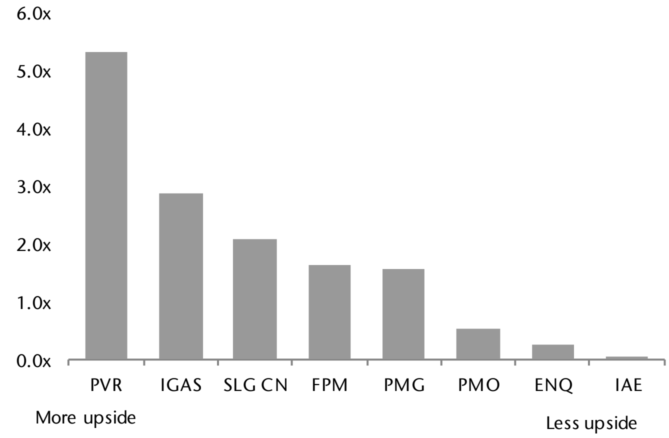
Source: Jefferies estimates

Chart 3: Upside to Jefferies target price



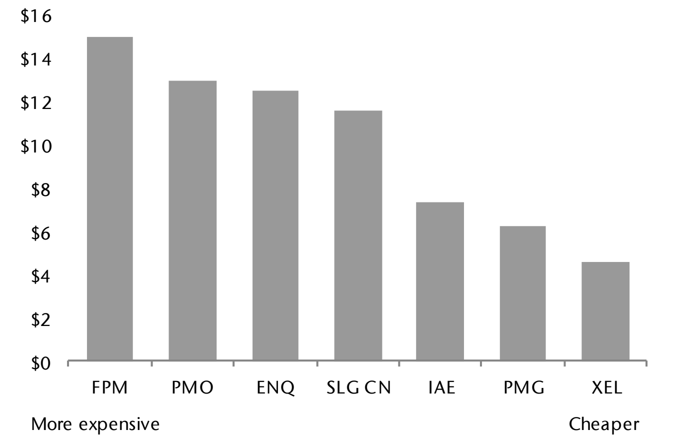
Source: Jefferies estimates

Chart 4: Unrisked share price upside



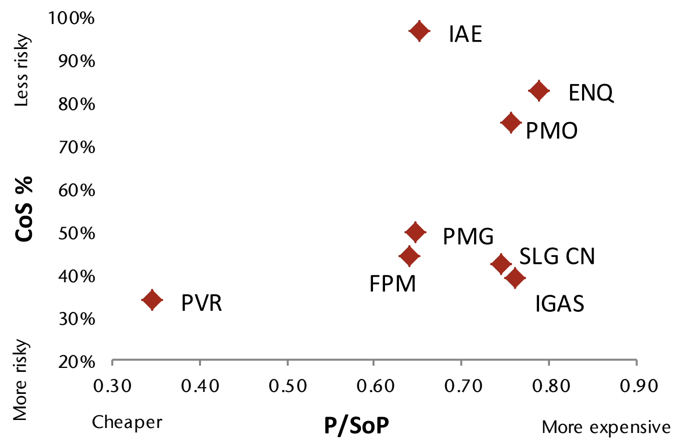
Source: Jefferies estimates

Chart 5: EV/2P boe



Source: Jefferies estimates, company data
Note: XEL EV and 2P reserves based on publicly available data.

Chart 6: P/SoP versus Average CoS %



Source: Jefferies estimates

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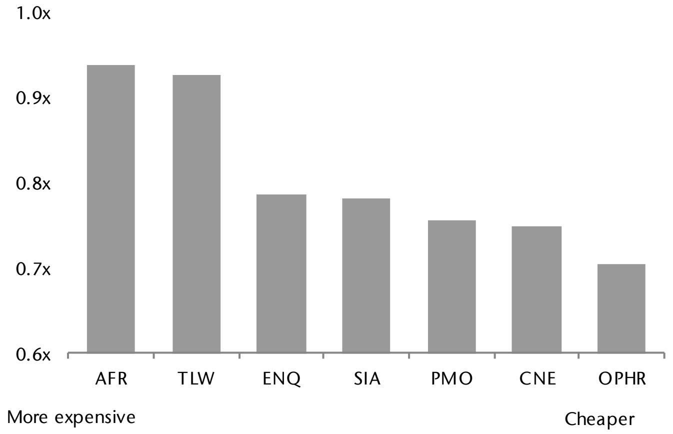
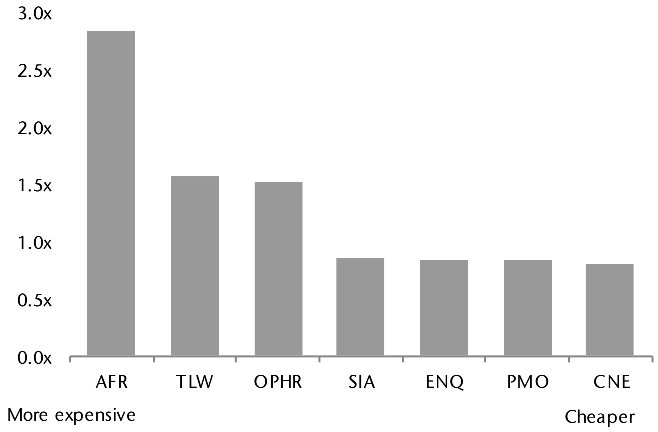
Chart 7: P/SoP – ENQ and PMO versus the mid-caps



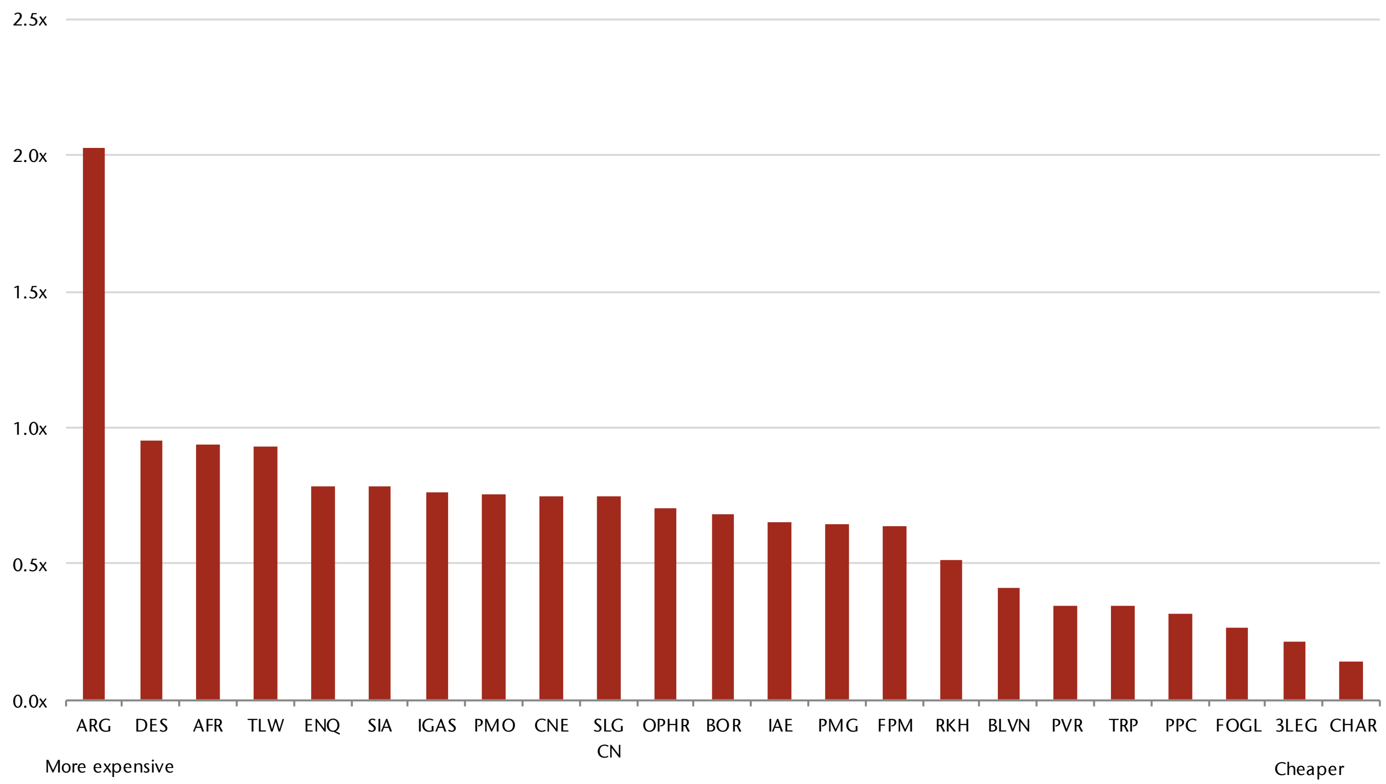
Source: Jefferies estimates

Chart 8: P/Core NAV - ENQ and PMO versus the mid-caps



Source: Jefferies estimates

Chart 9: P/SoP – Jefferies European E&P coverage universe



Source: Jefferies estimates

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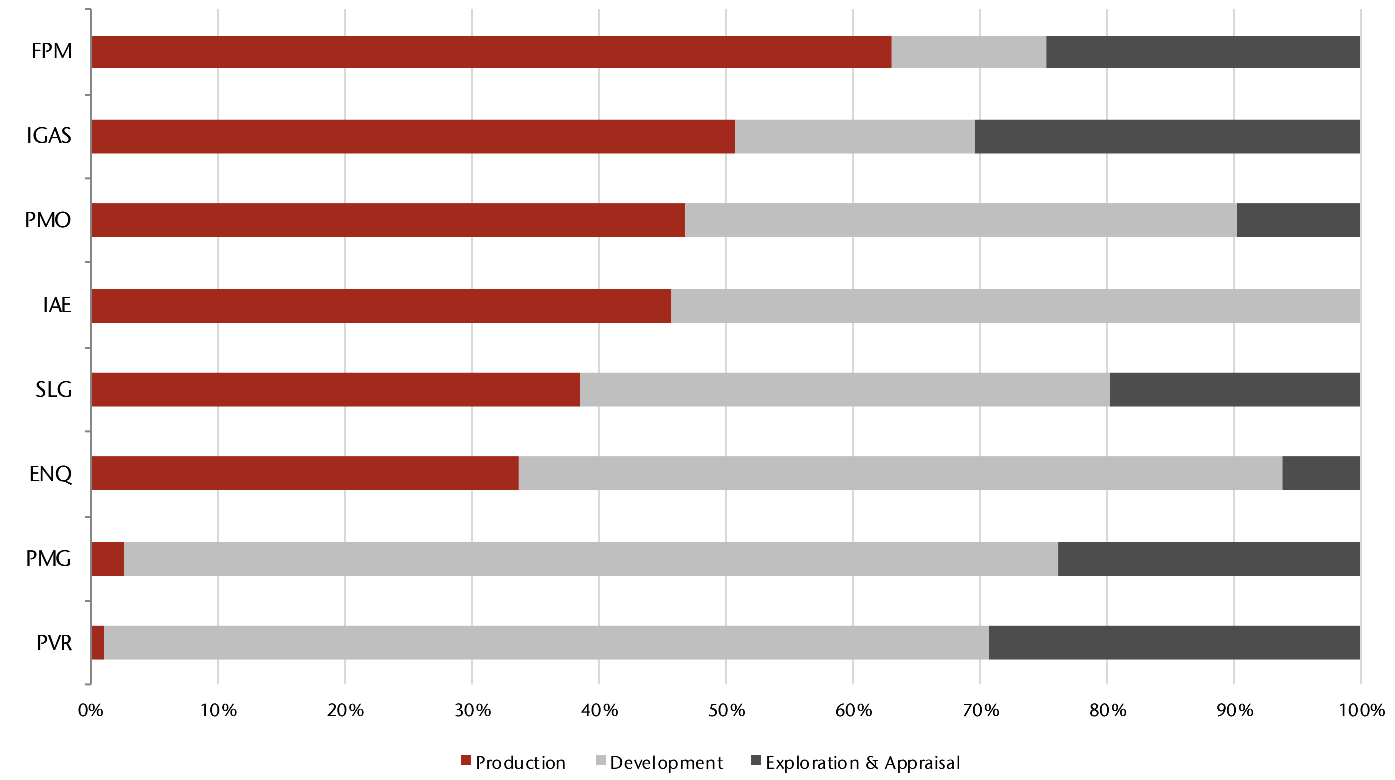
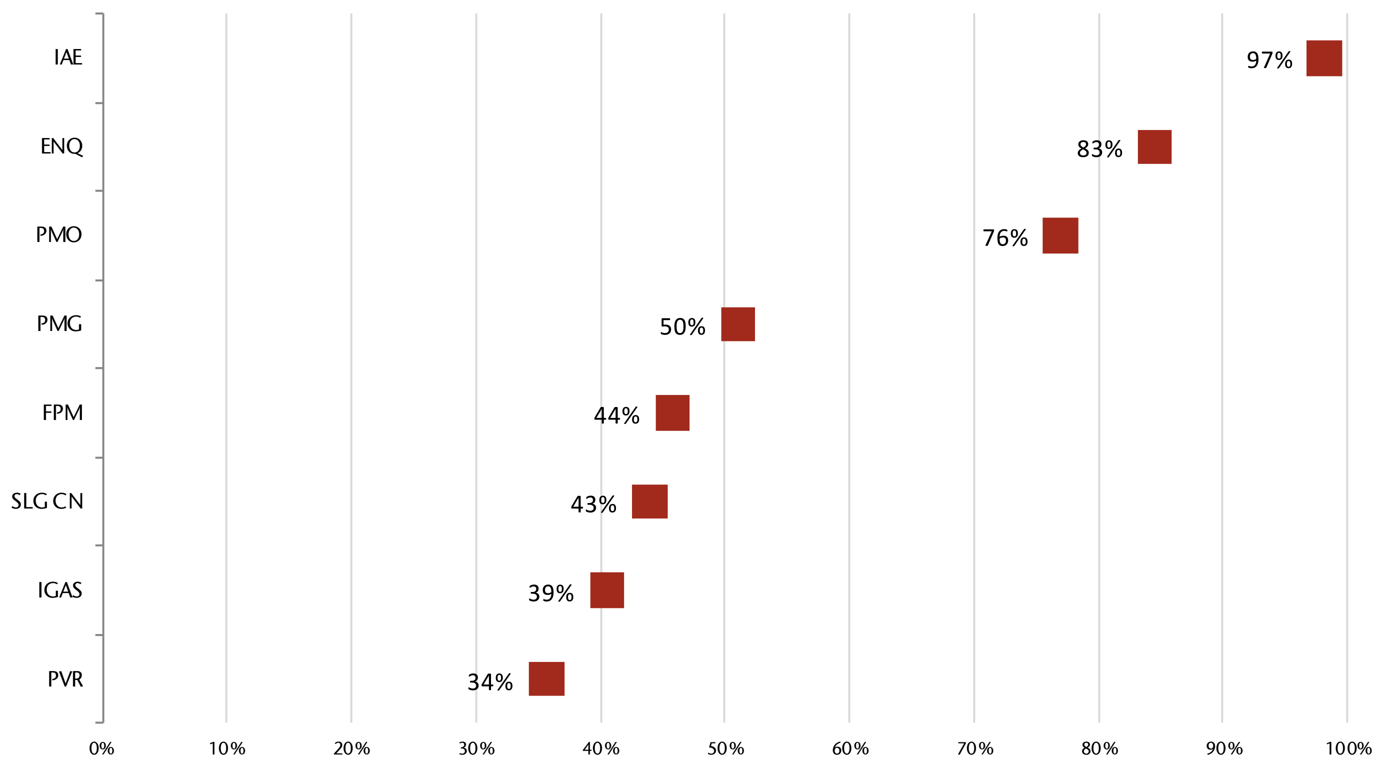
Chart 10: Breakdown of individual company SoP valuations



Source: Jefferies estimates

Chart 11: Riskiness of the North Sea E&Ps – average portfolio CoS %



Source: Jefferies estimates

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2012-3 North Sea E&P drilling calendar

Table 4: Jefferies estimated North Sea E&P drilling calendar

Region	Well	Timing	W.I. %	Gross (mmboe)	Net (mmboe)	CoS %	$/boe	Risked NPV $m	Risked NPV p/sh	SoP upside %	SoP downside %
EnQuest (ENQ LN)											
UK	Kildrummy	4Q12	60%	12	7	50%	9	32	3	2%	-2%
UK	Ketos	Unconfirmed	45%	20	9	30%	10	27	2	3%	-1%
Total 12 month outlook					**16**			**59**	**5**	**5%**	**-3%**
Faroe Petroleum (FPM LN)											
UK	North Uist	4Q12	6%	213	13	28%	8	31	9	10%	-4%
UK	Spaniards East	4Q12	8%	30	3	20%	8	4	1	2%	-1%
Norway	Rodriguez South	1Q13	30%	117	35	18%	5	30	9	17%	-4%
Norway	Darwin	1Q13	13%	450	56	10%	5	29	9	32%	-4%
Norway	Novus	3Q13	50%	70	35	15%	5	27	8	19%	-3%
Norway	Butch SW & E	4Q13	15%	50	8	25%	6	12	3	4%	-1%
Total 12 month outlook					**150**			**132**	**39**	**84%**	**-16%**
IGas Energy (IGAS LN)											
UK	"Chase the barrels"	Ongoing	100%	4	4	50%	12	25	9	9%	9%
UK	CBM Phase 1	Ongoing	100%	30	30	50%	1	17	6	6%	6%
Total 12 month outlook					**34**			**42**	**14**	**15%**	**15%**
Ithaca Energy (IAE LN)											
No E&A drilling planned											
Total 12 month outlook					**0**			**0**	**0**	**0%**	**0%**
Parkmead Group (PMG LN)											
UK	Spaniards East	4Q12	13%	30	4	20%	8	6	1	10%	10%
UK	Pharos	2013	20%	58	12	30%	4	14	1	14%	-6%
UK	Possum	1H13	15%	12	2	30%	4	2	0	2%	-1%
Total 12 month outlook					**17**			**23**	**2**	**26%**	**3%**
Premier Oil (PMO LN)											
UK	Spaniards East	4Q12	28%	30	8	20%	8	14	2	1%	0%
UK	Cyclone	4Q12	70%	30	21	35%	8	60	7	3%	-1%
Indonesia	Matang	4Q12	42%	40	17	10%	5	9	1	2%	0%
Norway	Luno II	4Q12	30%	120	36	20%	6	40	5	4%	-1%
UK	Lacewing	4Q12	20%	58	12	15%	8	14	2	2%	0%
Vietnam	Ca Voi (Block 121)		40%	100	40	10%	6	23	3	5%	-1%
UK	Bonneville		50%	10	5	25%	8	10	1	1%	0%
Indonesia	Kuda/Singa Laut		65%	100	65	35%	5	116	14	5%	-3%
Vietnam	Silver Silago		30%	100	30	20%	6	37	5	4%	-1%
Total 12 month outlook					**234**			**323**	**39**	**27%**	**-8%**
Providence Resources (PVR LN)											
Ireland	Dalkey Island	1Q13	50%	250	125	10%	9	116	114	54%	-6%
Ireland	Dunquin	2Q13	16%	1716	275	10%	7	186	183	86%	-10%
Ireland	Spanish Point	3Q13	32%	100	32	50%	7	108	107	6%	-6%
Total 12 month outlook					**432**			**411**	**404**	**146%**	**-21%**
Sterling Resources (SLG CN)											
Romania	Ioana	4Q12	65%	94	61	10%	3	17	8	36%	-4%
Romania	Eugenia	4Q12	65%	120	78	10%	5	35	16	75%	-8%
UK	Crosgan		30%	17	5	50%	5	11	5	3%	-3%
Total 12 month outlook					**144**			**64**	**29**	**114%**	**-15%**

Source: Jefferies estimates, company data

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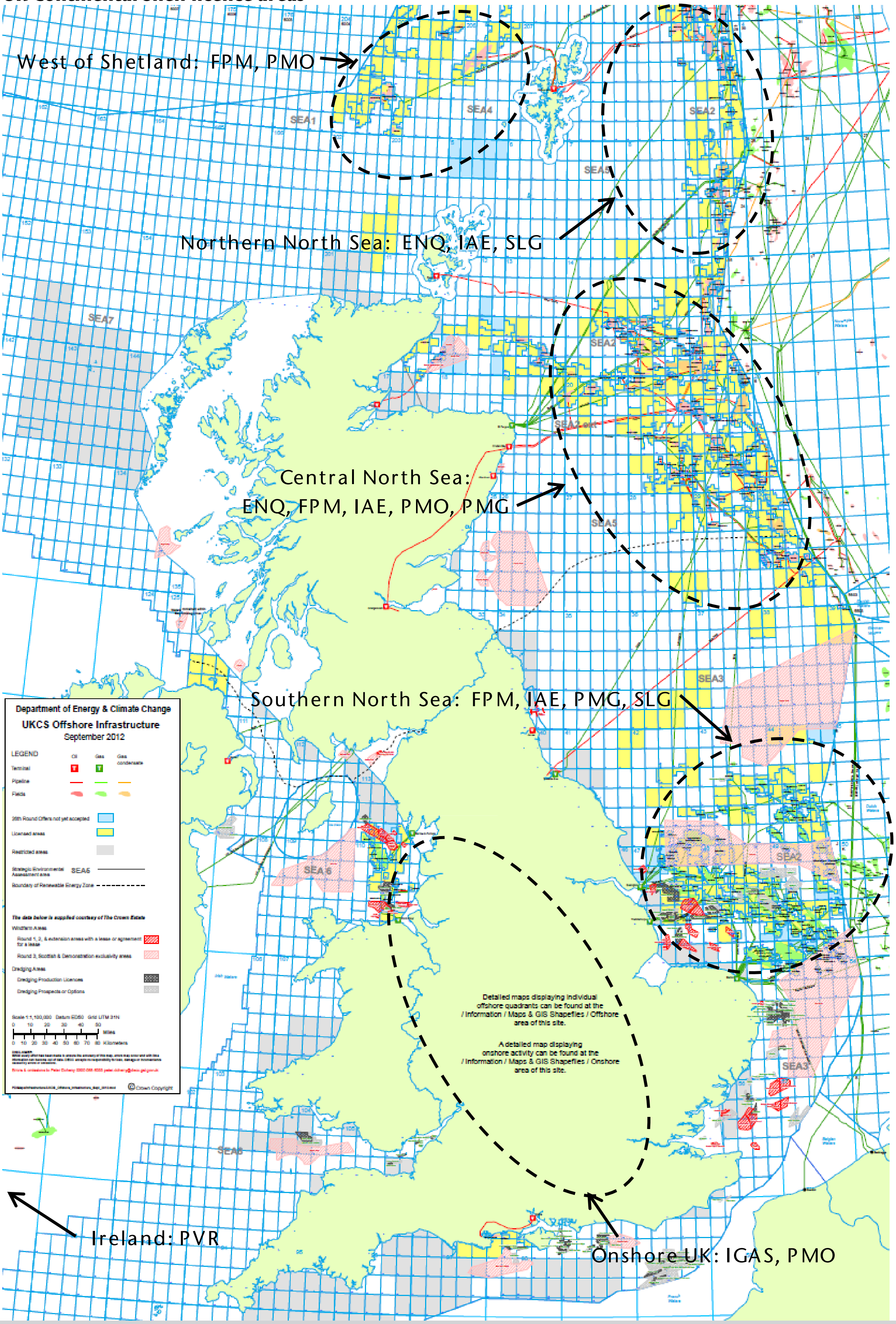
Exhibit 1: UK Continental Shelf licence areas



Source: DECC

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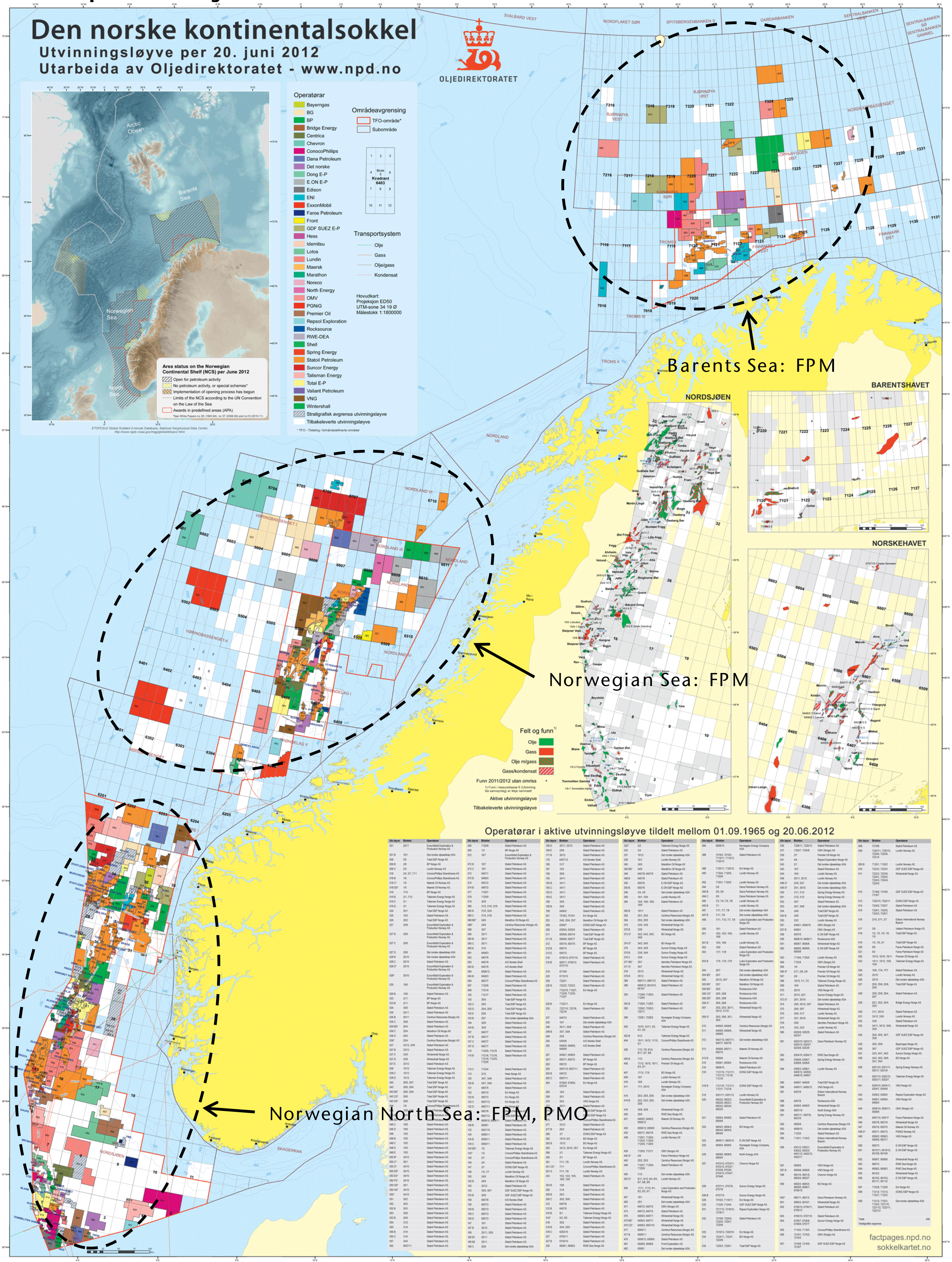
Exhibit 2: Map of the Norwegian Continental Shelf



Source: NPD

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Macro assumptions

We assume $100/bbl Brent and $9.14/mcf UK NBP gas long-term

Our North Sea E&P valuations are based on Jefferies' global commodity price deck, detailed in the table below. We assume Brent crude is the benchmark for all oil produced in the North Sea by the stocks in our coverage, with gas sold at the UK NBP spot price. Given the strength of Brent so far in 2012 we assume an average 2012 price of $112/bbl, reverting to $100/bbl from 2013 onwards. We assume UK NBP spot gas achieves 58p/therm ($8.90/mcf) in 2012, rising to 60p/therm ($9.14/mcf) in the long term. We use a 10% real discount rate when calculating our NAVs.

Table 5: Jefferies global commodity price deck

		2011	2012	2013	2014	2015 & Long term
Brent	$/bbl	111.37	111.73	100.00	100.00	100.00
WTI	$/bbl	95.13	97.85	90.00	95.00	95.00
Henry Hub	$/mcf	3.99	2.68	4.00	4.00	4.00
UK NBP	p/therm	58.87	58.17	59.50	59.50	59.50
UK NBP	$/mcf	9.17	8.92	9.14	9.14	9.14
$/£		1.60	1.58	1.58	1.58	1.58
$/€		1.39	1.27	1.25	1.25	1.25

Source: Jefferies estimates

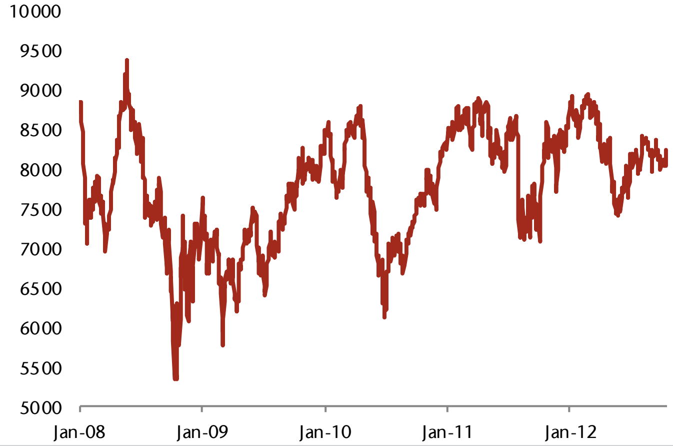
Chart 12: Brent crude

Source: Bloomberg

Chart 13: UK NBP spot gas

Source: Bloomberg

Chart 14: FTSE350 Oil & Gas index



Source: Bloomberg

Chart 15: FTSE AIM Oil & Gas index

Source: Bloomberg

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Old Dog, New Tricks – finding value in the North Sea

Current production declining but...

The North Sea – which for the purposes of this report includes both the United Kingdom Continental Shelf (UKCS) and the Norwegian Continental Shelf (NCS) – continues to attract a wide range of industry participants and increased interest from the investment community. We believe the appeal of the region remains high despite overall production falling in the UK (down 18% in 2011) and staying flat y-o-y in Norway, and developments delivering the lowest volume of new reserves since 1975. In Norway, only three fields began production in 2011, and in the UK the fields brought onstream represented less than 5% of total 2011 production.

...material exploration success has improved the outlook

Recent discoveries challenge the perception that the North Sea is a mature basin

Some significant North Sea discoveries, combined with renewed frontier exploration licensing activity, have helped to rejuvenate the area's "mature basin" status and improved the outlook significantly. It is widely recognised that Norway is significantly underexplored when compared to the UK, and recent success with the giant Johan Sverdrup discovery by Statoil and Lundin has only underpinned the potential for further material discoveries. Underexplored regions like the West of Shetlands and the Barents Sea are areas of increasing focus for both the majors and E&Ps.

A wide network of infrastructure but concern over decommissioning

The wide network of North Sea infrastructure, including over 600 installations, 5,000 wells and over 10,000km of pipeline, gives companies a variety of routes to market for new developments and improves the economics of new discoveries. However, there is concern that rising decommissioning expenditure (expected to top $1.5bn p.a. within a few years) could prove a deterrent to both new entrants and companies investing in older facilities.

North Sea fiscal regimes evolving to favour smaller players

Across the region there is now recognition from host Governments that the only way to sustain industry interest in the region is to maintain a fair balance between what the industry requires to incentivise investment, and what the Governments extract in oil & gas taxation. In the UK, the 2012 Budget brought assurances over companies' entitlement to abandonment-related tax relief, as well as increased allowances for the development of smaller and older fields. This was positive for the industry after 2011's increase in the supplementary tax rate from 20% to 32%, which we believe is a central factor behind the decline in both new developments and exploration activity last year.

North Sea's "safe haven" status driving material increase in M&A activity

Majors repositioning their North Sea portfolios creates a "sweet spot" for smaller, well-funded E&Ps

The perceived economic and political stability of North Sea countries, especially in light of difficult global macroeconomic conditions and political events like the Arab Spring, have all conspired to make the region a safe haven for investors. When combined with a rejuvenated exploration outlook it is no surprise that the last 18 months have seen a significant increase in the number of large North Sea deals, including Perenco's acquisition of BP's Southern Gas fields, Apache's interest in Beryl from Exxon, and Centrica's $1.6bn acquisition of gas-weighted interests from Statoil in Norway. Majors are repositioning their portfolios for growth and numerous non-core disposal programmes are underway, creating a "sweet spot" of acquisition and development opportunities for smaller, well-funded E&Ps.

North Sea continues to offer attractive upstream investment opportunities

As a result of many of these factors, the North Sea continues to provide appeal as a geography where E&Ps can continue to add value for shareholders. In this note, we assess the region in terms of the investment opportunities available, the ability to access that opportunity, and the potential hazards and incentives that face companies who invest in the North Sea.

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What is the opportunity for independent E&Ps?

We believe there are two key routes for independent E&P companies to create value and deliver attractive shareholder returns from the North Sea. The region offers E&Ps the ability to grow:

- **Organically**, through exploration success encouraged by an effective licensing system, and redevelopment of existing fields; or
- **Inorganically**, via asset-level or corporate-level acquisitions made easier by an active and highly liquid asset market.

Organic growth through exploration success and hub-style developments

The UKCS offers substantial undiscovered oil and gas reserves, despite having produced over 40bnboe over the past four decades. DECC estimates there is between 3-12bnboe yet to be discovered in the UK with a 10% or higher geological chance of success, while in Norway a 2012 NPD report estimates that over 15bnboe are yet to be discovered. Access to new exploration licenses in the region comes through license rounds, which usually involve commitments to acquire data and/or drill E&A wells. Awards are discretionary, and unlike other regions of the world do not involve any up-front fee. With regular licensing rounds and an active farm-in market, we believe there are low barriers to entry for companies looking to build a portfolio of exploration licenses in the North Sea.

Production hubs can transform the economics of small fields that on their own would be non-commercial

One way for E&Ps to grow efficiently is through the development of production hubs. Traditionally, production hubs were the end point of the main subsea pipelines to shore, and could be used by nearby discoveries as a collection point through which to evacuate crude oil. However, in recent years E&Ps have developed their own hubs by amassing large acreage positions and then building their own central production facility – these hubs can transform the economics of small discoveries that on their own would be non-commercial. A long-term strategy to build a dominant portfolio in a particular area can involve a number of asset transactions, and is one reason why the UKCS asset market has remained particularly active.

Inorganic growth utilising the liquid asset market

DECC estimates that the UKCS has between 14-24bnboe of discovered hydrocarbons that are still to be recovered, including proven, probable and possible reserves plus undeveloped discoveries. In Norway, the NPD's latest estimate for remaining recoverable resources amounts to 46bnboe, with great uncertainty in the Barents Sea (the region that has attracted many new industry players). Much of the undeveloped resource base lies within the portfolios of existing players, meaning exploiting this resource relies on the asset market. However, development opportunities can arise where previous owners have relinquished assets which may have been uneconomic given the technology or oil price environment.

The North Sea offers a very liquid M&A market; recent transactions have averaged $13.7/boe

The wide range of participants and deep industry knowledge of the North Sea means there is a very liquid M&A market. Outside of North America, the area is one of the most actively traded asset markets in the world, making it highly attractive for companies who wish to enter the region and establish a new core area. With equity valuations currently sitting well below transaction multiples (we estimate North Sea deals have averaged $13.7/2P boe since 2010), at present the quickest (and often cheapest) way of entering the North Sea is via corporate-level M&A. In our view, M&A should continue to provide upward support for the share prices of companies operating within the region.

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Exploration success reignites interest in the North Sea

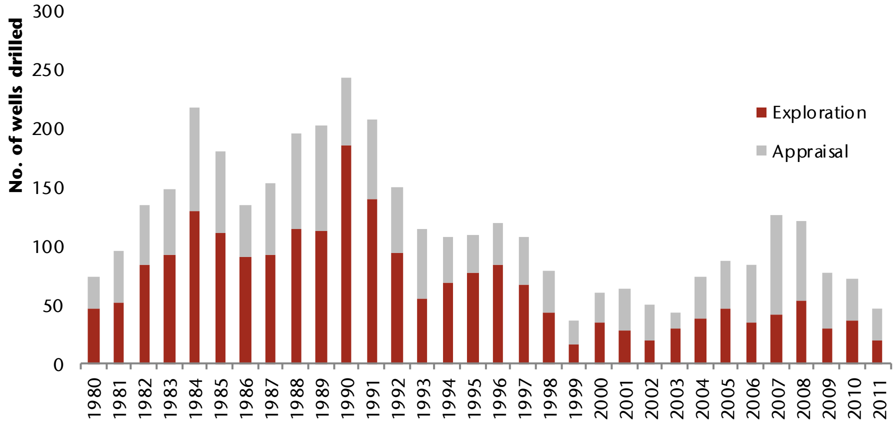
Exploring the UK Continental Shelf

UK drilling activity and discovery size is trending downwards

High oil prices mean smaller discovery sizes remain economic

Over the long term, the size of discoveries in the UKCS has been shrinking, with an average discovery size of 23mmboe in 2011, up slightly from its 20mmboe nadir in 2009. At the same time, the rate of E&A drilling in the last decade has remained fairly steady with an annual average of 61 wells spudded (including a spike in 2007-08 due to high oil prices). However, with changes to taxation in the 2011 UK Budget, which increased the marginal rate of tax, the number of new exploration wells decreased markedly in complete contrast with Norway (see below). In 2011, E&A drilling fell to its lowest level since 2003, and decreased by a third versus 2010 levels – only 19 pure exploration wells were drilled. There has been a small recovery in 2012, and despite the lower rates of drilling the discovery rates have improved (63% in 2011) as the quality of prospects has improved.

Chart 16: UKCS drilling activity, 1980-2011



Source: Wood Mackenzie

UK North Sea has delivered a 1-in-3 success rate in the last decade

Success rates for UKCS exploration wells are around 34%

In the last 10 years success rates for UK North Sea exploration wells have averaged 34%, resulting in an average of 11 potentially commercial discoveries being made each year. Although the total volume discovered each year has been decreasing for some time, the occasional large find has bucked the trend (e.g., the Catcher discovery made in 2010 is estimated to offer 80mmbbl+ of 2P reserves). We are cautious about the sustainability of these success rates, particularly in light of constantly improving seismic techniques and the maturity of the basin.

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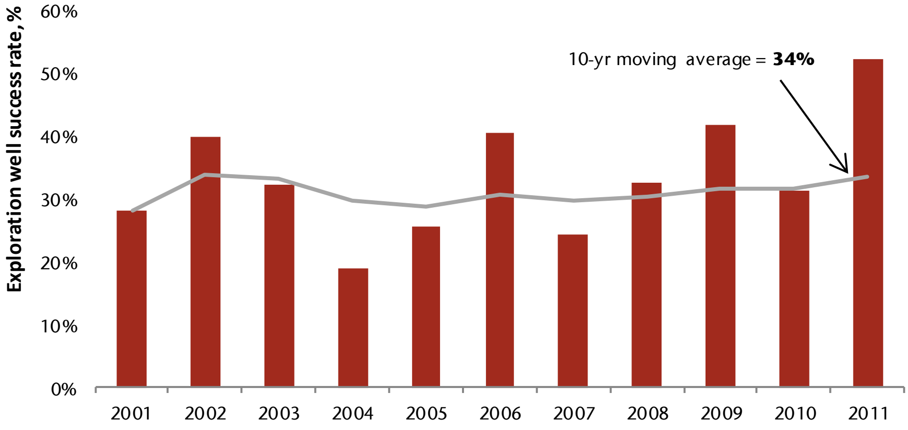
Chart 17: UK North Sea exploration delivers about a 1-in-3 success rate



Source: Wood Mackenzie

Smaller discoveries can utilise existing infrastructure

With the decreasing size of discoveries come challenges regarding development. The smaller size of the accumulations means they typically cannot support their own infrastructure, and so they have to be developed as tie-backs to an existing field (or occasionally to an FPSO). Although tie-backs can bring their own difficulties, utilising neighbouring infrastructure often has compelling economics – we think this is a key reason for the increasing trend in hub-style developments, where several smaller fields are developed in tandem to share project costs and, in some instances, for tax efficiency.

A low barrier to entry through licensing rounds and farm-ins

Despite these issues, in 2012 interest in exploration in the UKCS remained strong, especially in the aftermath of a number of new discoveries. Awards for the 26th licensing round (announced at the end of October 2010) resulted in a total of 190 licences being awarded; the most since licensing began in 1964, highlighting the ongoing attractiveness of the region. The total area awarded was 32,000km^2, with more than half of this in the Central North Sea, a quarter to the West of Shetland, and the remainder split between the Southern and Northern North Sea. The awarded licences are operated by 53 different companies of a wide range of sizes, with a fifth of these being small E&Ps.

Demand for UK blocks remains strong – the 27th UK Licensing Round attracted the most applications since records began

High demand for UKCS blocks continued in the latest (27th) UK Licensing Round, which generated the most applications since licensing began in 1964. A total of 224 applications were received across the 418 blocks on offer, with results expected in 4Q12. We expect many of the E&Ps in our coverage will have bid aggressively in the 27th round, in particular those owners seeking to expand their footprint around existing development hubs (e.g., PMO and CNE near Catcher, PMG and FPM near Perth, ENQ and CNE near Kraken).

Exploring the Norwegian Continental Shelf

Major new discoveries act a catalyst for increase in exploration activity

The number and composition of industry participants on the NCS has changed dramatically over the past few years. The NPD tried to encourage new players onto the shelf in 2003 when it abandoned the "Norwegian model", which consisted of a wholly-owned state company (Statoil), a private sector company (Norsk Hydro) and a Norwegian independent (Saga Petroleum). Following the examples of the UK initiatives, the 2003 Norwegian Kon-Kraft report (*"Norwegian Petroleum Industry at the Crossroads"*) to the Norwegian Government investigated ways of amending the tax system to stimulate greater activity on the NCS, particularly for new start-up companies with no cash flow.

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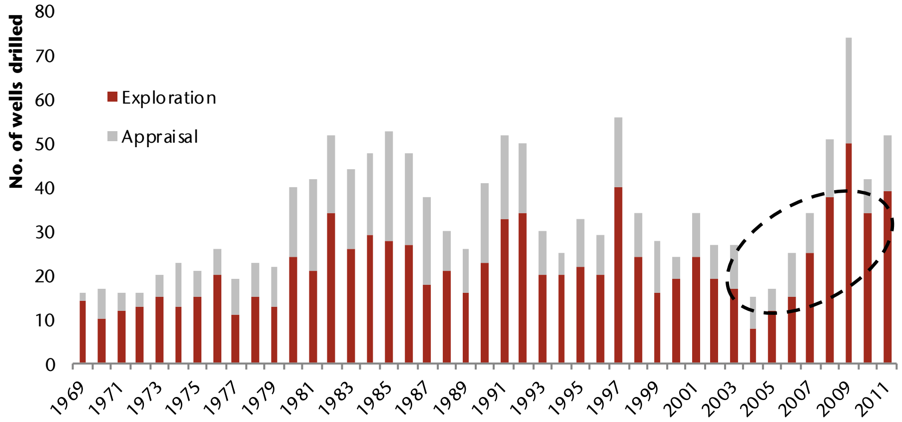
Jefferies

As a result, in 2005 the NPD introduced the exploration reimbursement scheme, where explorers could recoup 78% of their unsuccessful exploration costs. Understandably, this new rebate led to a significant increase in the number of new E&Ps applying to operate on the NCS, and by the end of 2011 fifty companies were active in the sector. The increased number of NCS companies set a new record for drilling activity in 2009, when 65 exploration wells were spudded including 44 wildcats and 28 discoveries. In 2011, this activity slipped a little, with a total of 54 wells were spudded (22 discoveries).

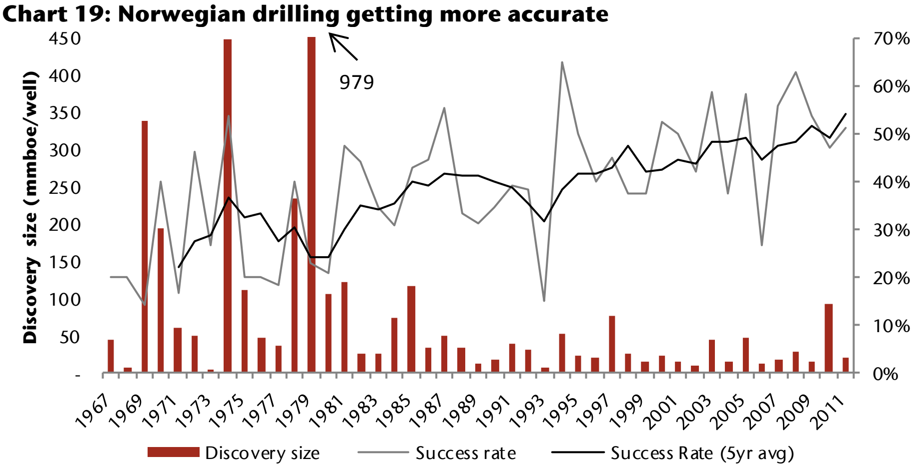
Norway's exploration rebate lifts drilling activity

Chart 18: NCS drilling activity, 1969-2011



Source: Wood Mackenzie

Chart 19: Norwegian drilling getting more accurate



Source: Wood Mackenzie

Record interest in the recent licensing rounds

Large discoveries on the NCS continue to attract explorers

Amongst the discoveries made in the past three years are the giant Skrugard discovery in the Barents Sea and the Johan Sverdrup discovery in the Norwegian North Sea. The Johan Sverdrup discovery has recoverable reserves ranging from 1.7 to 3.3 billion boe, making it the third largest Norwegian find of all time. Given the size of these discoveries, it is unsurprising that recent licensing rounds have reflected the heightened interest in Norway – in 2011, the amount of acreage awarded in the 21st Licensing Round was the highest since 1965. A total of 78 licenses were awarded in 2011, and in total all but three companies increased their acreage positions in Norway, highlighting the attractiveness of the province to explorers.

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Significant exploration success in mature provinces has ignited interest

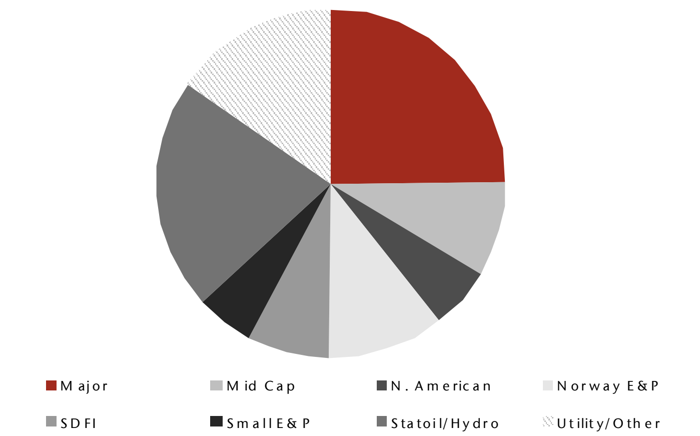
Exploration activity on the NCS began in the Norwegian North Sea and has gradually moved northward, meaning large parts of the NCS are now considered to be mature for exploration. That said, the success of the Johan Sverdrup discovery in what was thought to be a mature area has ignited interest in the region, with excitement also felt in the area around the Ormen Lange field (the Halten Terrace region of in the Norwegian Sea) and the area surrounding Snøhvit in the Barents Sea. In these locations the prospectivity is still high, however so is the requirement for extensive new infrastructure to justify development. The NPD has introduced special licensing rounds (APA rounds) targeted specifically at mature areas, so that resources that rely on existing infrastructure can be developed before it is abandoned.

Frontier areas are now attracting the majors back to NCS exploration

Barents Sea and Norwegian Sea are seeing significant exploration interest

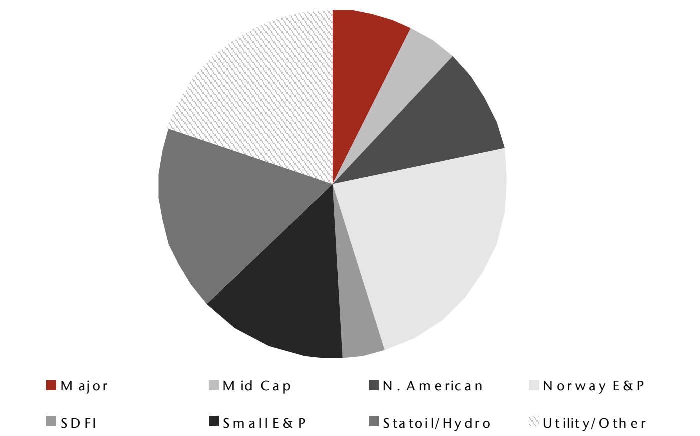
Frontier areas on the NCS include large parts of the Barents Sea and the Norwegian Sea, as well as smaller areas in the North Sea. The most underexplored regions tend to be deep water and the northernmost areas, where risks are greater but the potential rewards are big enough to attract the larger explorers back to Norway – in Norway's 21st licensing round, 21 oil & gas companies were granted licenses covering 24 blocks in the Barents and Norwegian Seas alone.

Chart 20: Discovered reserves in frontier regions, 1999-2012 – Statoil and the majors dominate



Source: Wood Mackenzie, Jefferies

Chart 21: Discovered reserves in mature region, 1999-2012 – local E&Ps most active in more established areas



Source: Wood Mackenzie, Jefferies

Large parts of the NCS remain unlicensed and hold significant potential

There are still large areas of the NCS – primarily the Barents Sea and the Norwegian Sea – that have not been opened up for petroleum activities. In these areas the NPD estimates that there are 15bnboe of undiscovered resources, split fairly evenly between the North Sea, Norwegian Sea and the Barents Sea.

What are the North Sea's new exploration plays?

Newer, more complicated play types of increasing interest to North Sea E&Ps

The North Sea can still produce occasional exploration successes above the long term average size (e.g., Catcher in the UK, Johan Sverdrup in Norway), however the maturity of the basin means that explorers have increasingly had to target new play types in underexplored areas. These new plays have ultimately relied on higher commodity prices to make the play economic (e.g., heavy oil), or new technology to permit either deeper drilling or more complex extraction. The importance of these new plays to the region are highlighted by the fact that out of 25 new developments sanctioned on the UKCS in the past few years, 15 will come from discoveries made in these new plays.

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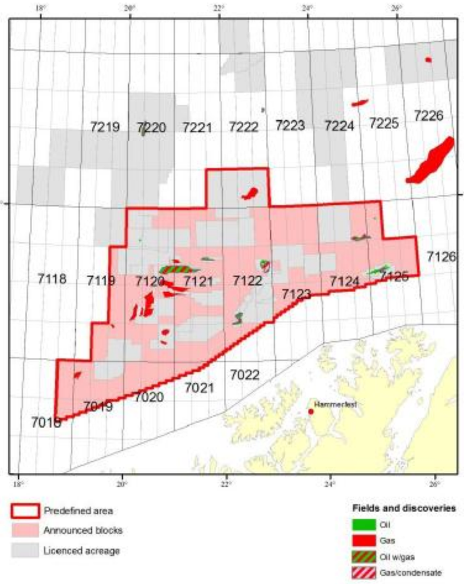
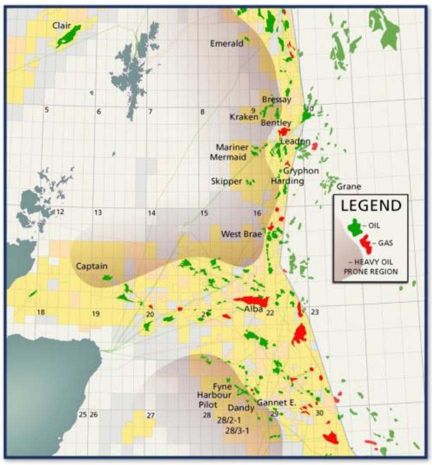
Exhibit 3: Barents Sea licenses



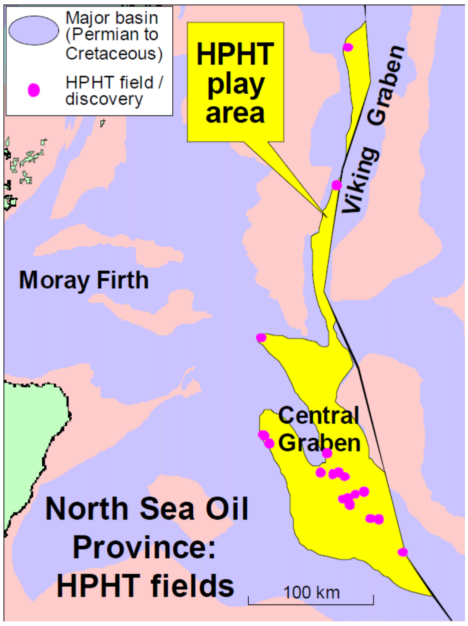
Source: NPD

Exhibit 4: UKNS heavy oil province



Source: Xcite Energy

Exhibit 5: Central UKNS HPHT area



Source: DECC

Table 6: New North Sea play types driven by technology and high oil prices

Play Type	Geology	Key fields	Comments
West Shetlands Platform & Faroes Basin	Dominated by Tertiary volcanics	Clair, Schiehallion, Foinaven	Sparsely developed despite initial discovery in 1970s. DECC estimates 3-4bnboe undiscovered reserves. Deep water, harsh weather. Investment incentivised by recent £3bn tax allowance.
Mid Norwegian Shelf	Direct extension of WoS Platform	Ormen Lange	Primarily a gas play. Investment focused on Halten Terrace, further potential in More and Voring basins.
Barents Sea	Jurassic/Triassic plays	Snøhvit, Goliath, Skrugard, Havis	Underdeveloped following recently-resolved border dispute with Russia. Gas discoveries require new-build infrastructure to reach markets. Significant interest in 22nd Norwegian licensing round.
UK Heavy Oil	Typically Upper Palaeocene and Lower Eocene sands sourced from Jurassic Kimmeridge clay	Kraken, Bressay, Mariner, Bentley	Currently 10% of UK production, expected to grow with key developments onstream over next 5 years. Strong oil prices improve heavy oil development economics. Improved technology such as horizontal drilling lowers break-even costs.
Central North Sea HPHT	Upper Jurassic syn-rift shallow-marine and basin floor sandstones	Elgin Franklin, Shearwater, Jasmine	Limited development since discovery in 1970s due to lack of technology. Only 15% of HPHT discoveries are licensed - opportunity for technically-capable developers.
Southern North Sea low permeability gas	Typically Rotliegendes sandstones that have evolved to tight gas reservoirs	Cygnus, Breagh, Clipper South	Past underdevelopment purely due to lack of technology. New fracturing techniques improve permeability and encourage development.

Source: Jefferies

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Who are the key North Sea players?

The North Sea is now an area which is being harvested for cash...

The North Sea competes globally for investment, but over the period from 2011-13 it is not even in the Top 10 list of countries for planned upstream spending. In addition, North Sea companies which hold portfolios of producing assets are often not the same companies that are active explorers. For example, despite super majors and large IOCs accounting for over 60% of UK production in the last two years, none of these companies appears in the Top 10 list of UKCS explorers. In total, since 1999 the North Sea has tended to be a geography where surplus cashflow has been harvested and invested elsewhere.

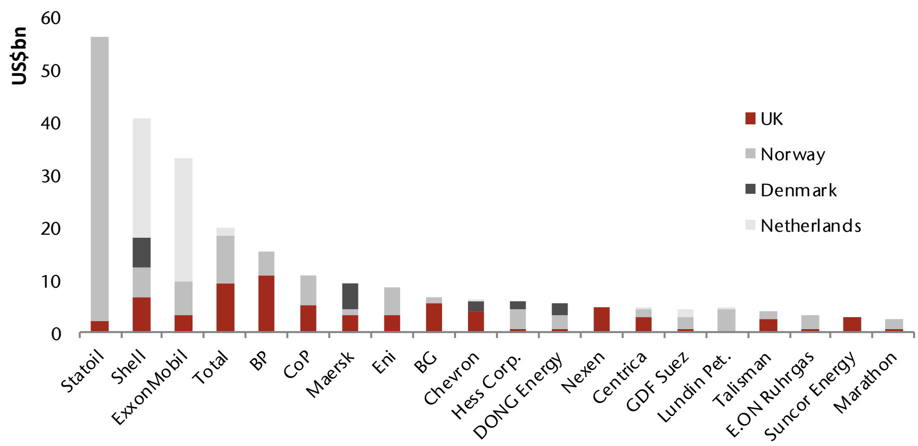
...which has led to significant changes in the structure of the North Sea

Majors rotating out of mature North Sea fields into higher value development assets

The make-up of the North Sea is changing. While the majors still dominate UKCS asset ownership (the Top 20 companies own 87% of the assets by value, with the remainder shared by 112 firms), we are seeing the largest companies recycle capital from mature assets into exploration and development projects in order to rationalise portfolios, mitigate decommissioning liabilities, and reduce debt. Within this group it is clear that there is limited appetite for a complete exit from the region because mature cash generating assets remain core to company portfolios.

Top 20 North Sea players own 87% of the assets by value

Chart 22: Supermajors dominate NW Europe; top 20 firms own 87% of value



Source: Wood Mackenzie

Majors are rationalising non-core assets

This increased turnover of mature fields means that the majors were net sellers of assets over 2011, although with new developments coming onstream the impact on overall reserves was minimal. For example, in recent months BP has sold stakes in its mature Wytch Farm (to Perenco, including operatorship), Southern Gas Basin (Perenco again) and Alba/Brittania (to Mitsui) fields, but has simultaneously committed £3bn (source: FT) to redeveloping the Schiehallion and Loyal oil fields West of Shetland. Other recent investment by the majors includes the $6bn+ development of the 240mmbbl Rosebank field West of Shetland, whose partners include Chevron, Statoil and OMV.

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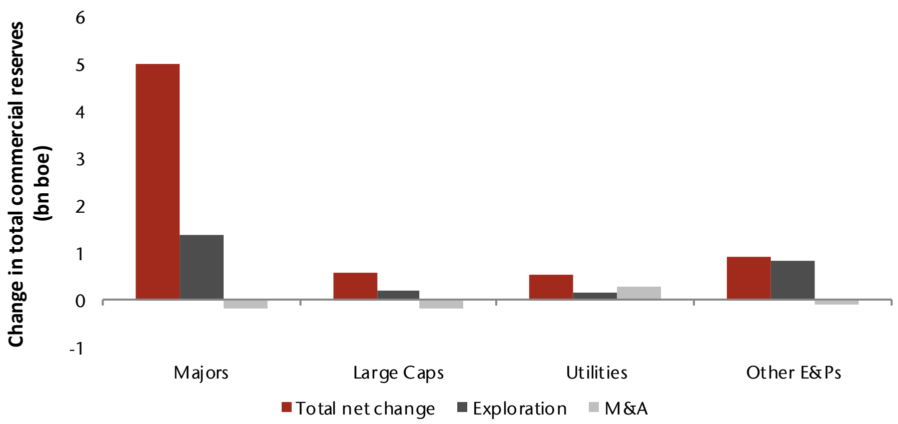
Chart 23: Change in UKCS commercial reserves by owner type, 2008-11



Source: Oil & Gas UK, Jefferies

Mid-cap North American companies are now retreating home to exploit shale gas and oil

The North American mid-cap companies have also shown a shift in strategy – after being the dominant buyers of North Sea assets from 2001-07, they have now been net sellers since 2008. In our view, the rising popularity of North American shale gas and, more recently, shale oil is a key reason for the strategic reallocation of capital away from the North Sea.

Utilities have been looking for gas supplies

Utilities have been quiet buyers of North Sea assets, especially gas assets in the Southern North Sea as they have sought to secure upstream supply to hedge their downstream businesses. In particular, Centrica has been active in the M&A market with acquisitions of Venture Production (2009, $2.3bn) and a package of assets from Statoil (2011, $1.6bn including the Kvitebjørn and Valemon fields) standing out as major transactions. In 2011 the utilities were net sellers of assets, perhaps a reflection of the changing domestic gas market in Germany as a result of the decision to cease nuclear generation.

Independent E&P companies are now drilling most of the operated wells in the North Sea

Smaller E&Ps are drilling more North Sea E&A wells

The trend in the number of operated wells is also indicative of the changing strategies. In 2005, nearly half of the operated wells were drilled by North American independents, but by 2011 this had dropped to just 8% of all wells drilled. In contrast, activity from small independent E&P companies doubled from 16% of all operated wells in 2005 to 33% by the end of 2011. It is no coincidence that this increase tracked a period of stronger oil prices, combined with relatively open equity and debt markets that allowed smaller players to access acreage through M&A. However, we caution that over the medium term we expect only well-funded E&Ps are likely to have the capability to drill new wells; Wood Mackenzie estimate E&Ps will only account for 20% of all wells in the next few years. Furthermore there are now a limited number of commitment wells still to be met from the UK's 25th and 26th licensing rounds.

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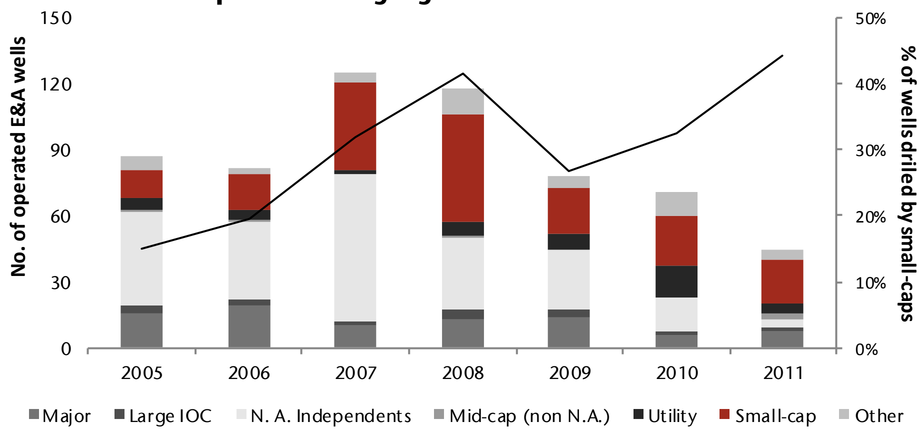
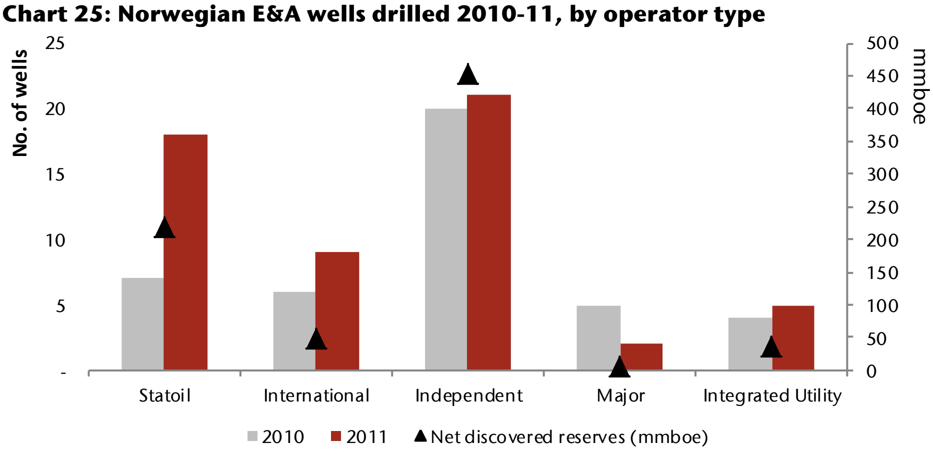
Chart 24: Small-cap E&Ps drilling higher % of UK E&A wells



Source: Oil & Gas UK, Jefferies

Chart 25: Norwegian E&A wells drilled 2010-11, by operator type



Source: Wood Mackenzie

Exploiting the "sweet spot"

Mature UKCS fields present a significant opportunity for well-funded small- and mid-cap E&Ps

We believe the active secondary market in mature UKCS fields presents a significant opportunity for well-funded, small- and mid-cap E&Ps – a "sweet spot" of North Sea assets that are too small for the majors *and* outside the technical/funding capabilities of smaller, underfunded players. When combined with the UK's very liquid market for appraisal and development assets, it is no surprise that small-cap E&Ps represent a material (and growing) proportion of UKCS asset buyers. Already in 2011-12 we have seen rationalisation among smaller players at both the corporate level (e.g., Premier/EnCore, Cairn/Agora, Cairn/Nautical, Parkmead/DEO, and IGas/Star Energy) and asset level (e.g., EnQuest/Nautical for Kraken, Ithaca/Hess for Cook, and ENQ/Fairfield for Crawford).

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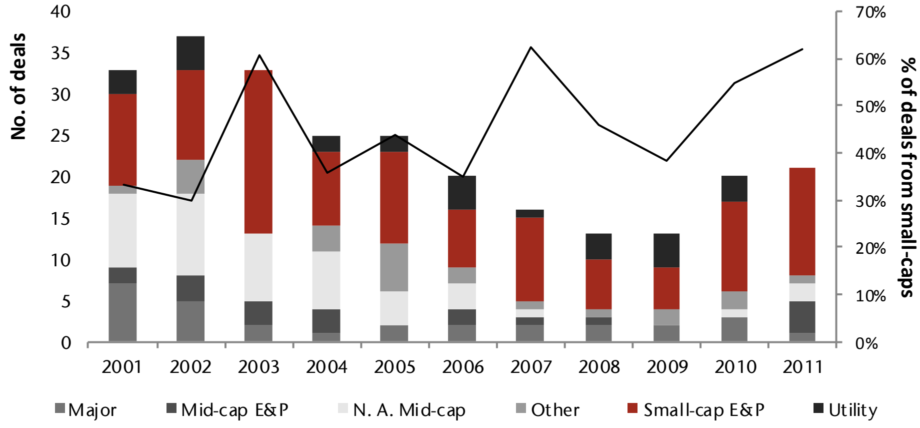
Chart 26: UK deal flow sees rising % of small-cap E&P buyers



Source: Oil & Gas UK, Jefferies

The maturity of the UKCS means that large oil & gas discoveries are increasingly rare. As a result, buying contingent resource on-market (i.e., via corporate-level M&A) or picking up acreage through licensing rounds is often seen as a cheaper means for companies to grow their portfolios than exploration.

This appetite for new UKCS blocks is evident in the level of interest in the 27th UK Licensing Round, which generated the most applications since licensing began in 1964 – a total of 224 applications were received across the 418 blocks on offer. We expect many of the E&Ps in our coverage will have bid aggressively in the 27th round, in particular those owners seeking to expand their footprint around existing development hubs (e.g., PMO and CNE/Agora/Nautical will be looking to take advantage of 3D seismic data gathered on blocks to the north, west, and south of the Greater Catcher Area in Block 28/9).

Licensing rounds are an important source of undeveloped assets as well as exploration prospects

It is worth noting that the popularity of licensing rounds as a means of securing UKCS acreage is not limited to virgin blocks. For operators with sufficient technical capabilities, abandoned/relinquished blocks can provide a cheap entry into assets that would otherwise remain undeveloped – e.g., ENQ was awarded the Alma/Galia fields in the 26th round at effectively zero cost, allowing the company to commence a $1bn development that will deliver 29mmbbl of gross 2P reserves, first oil as early as 4Q13, and peak production of 20kbopd. It would be extremely challenging to bring a North Sea exploration prospect through the appraisal/development phase to full production in the same timeframe and for similar cost.

The best E&Ps are those that are well-funded, technically proficient, and credible within the industry

In our view, the E&Ps that are best placed to expand their UKCS footprint are those with:

- **Funding capability**, whether through existing cash balances, operating cashflow, or debt facilities (e.g., RBL, Norwegian exploration loans);
- **Sufficient technical knowhow** to operate developments, particularly the more complex heavy oil, HPHT, brownfields or deep water projects that are encouraged by the UK tax regime; and
- **Industry credibility** to win new blocks in licensing rounds, especially when also awarded operatorship.

Within our coverage list, the E&Ps that we believe meet the above criteria and will be most successful in North Sea consolidation are **EnQuest** (Buy, 155p/sh PT) and **Faroe Petroleum** (Buy, 240p/sh PT).

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Don't forget the NOCs

National Oil Companies are cash-rich, seek lower risk portfolios, and have low costs of capital – ideal predators for North Sea assets/E&Ps

We are also seeing increasing appetite for North Sea assets from national oil companies (NOCs). These large, cash-rich players typically look to acquire low-risk resources (post-appraisal developments, producing assets or those projects nearing production) in order to hedge their home country's domestic energy demand. Often these players have lower costs of capital than the E&Ps they are bidding against, so can remain competitive even when smaller players are priced out of the market.

The largest and most memorable example of recent NOC activity was KNOC's hostile bid for Dana Petroleum plc in 2010, eventually concluded at £18/sh ($3.5bn) and giving the Korean company immediate access to 275mmboe of 2P reserves (35% gas) and c.66kboepd of production. KNOC has further exposure to both UKCS and NCS E&P activity through a 22.63% stake in Faroe Petroleum that it acquired through the Dana takeover. We have also seen two recent deals from the Chinese, with CNOOC's $15.1bn takeover of Nexen (one of the largest UKNS producers) and Sinopec paying $1.5bn for 49% of Talisman's UK portfolio – together these deals gave Chinese NOCs immediate exposure to c.8% of total UK production.

Table 7: Recent M&A activity by NOCs in the North Sea

NOC	Seller	Date	Asset	Value ($m)	Value ($/boe)	Details
Korea National Oil Company (KNOC)	Dana Petroleum	Jul-10	Portfolio	3,552	16.5	Hostile bid at £18/sh for 100% of shares in Dana Petroleum.
TAQA	Premier Oil	Nov-11	Cladhan	55	12.7	PMO on-sold a 16.6% stake in Cladhan (viewed as non-core) that it acquired as part of the EnCore acquisition.
Kuwait Foreign Petroleum Exploration Company (KUFPEC)	EnQuest	May-12	Alma/Galia	182	17.9	KUFPEC acquired a 35% stake in Alma/Galia development for $182m (back costs and development carry), plus pro rata share of future capex up to c.$500m.
CNOOC	Nexen	Jul-12	Portfolio	na	na	CNOOC acquires Nexen, one of the largest UKNS producers
Sinopec	Talisman	Jul-12	UK portfolio (49%)	1,500	6.74	Sinopec acquires 49% of Talisman UK for $1.5bn

Source: Jefferies, company data

We expect NOCs will remain active players in the region, particularly if we continue to see (a) the majors divesting packages of mature assets (e.g., BP's Southern Gas Basin portfolio sold to Perenco), and (b) UK-listed E&Ps trading at substantial discounts to both consensus NAVs and market M&A multiples.

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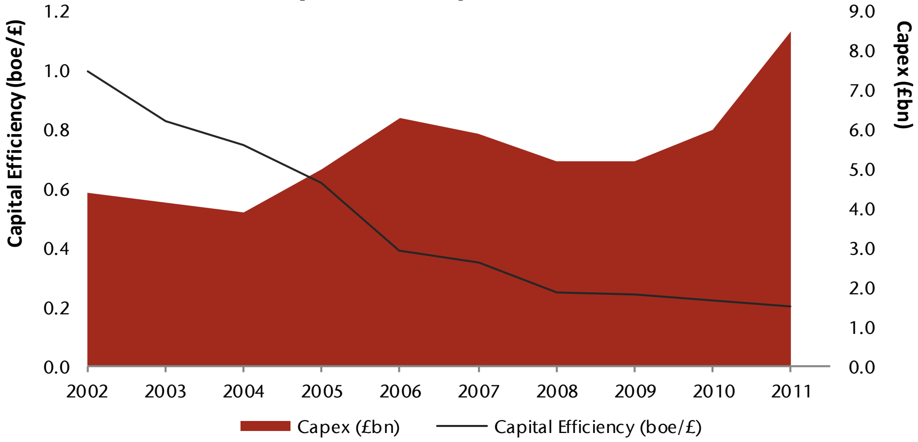
North Sea M&A – liquid asset market creates opportunities for growth

With such a significant resource base that has yet to be developed, in our view the quickest route to constructing a portfolio of North Sea assets is through M&A. The liquidity of these markets in the UK and Norway, and the lack of political interference (which has become a feature of many international transactions), means that more than ever the North Sea is perceived as a favourable region to transact business. In 2011, European M&A activity reached a record 9% of global activity, even before adding in the Norwegian Gassled infrastructure sales.

The North Sea is the largest and most liquid asset market outside of North America

The North Sea is now, by some distance, the most liquid market for trading oil & gas assets outside North America. In our view, this reflects both the region's maturity and the concentration of the reserve base within the portfolios of the majors – as the opportunity cost of capital has risen, majors are recycling their capital into areas with higher rates of return. This is highlighted by indexed capital efficiency – over 2002-12 the amount of oil delivered per dollar invested fell by 70%, despite North Sea capex reaching an all-time high. It appears the UKCS has to work hard simply to stand still, and in an uncertain fiscal environment attracts less than 4% of global oil investment. The consequence has been that sizeable assets have come to the market as the majors have looked to rationalise and high-grade their portfolios.

Chart 27: UK North Sea capital efficiency, 2002-2012



Indexed at 2011 £
Source: Oil & Gas UK

What does this mean for the smaller E&P companies?

Larger companies with established production and reserves have a number of potential exit strategies open to them. There are a large number of firms willing to acquire producing assets for cash, and as larger firms rationalise their more mature assets, smaller, more nimble companies can expand their own portfolios, albeit at a premium price. In addition, an ongoing focus on exploration will continue to attract a range of players from undercapitalised minnows to well-funded large-caps. High commodity prices have given the larger companies an opportunity to accelerate their divestments ahead of potential abandonment liabilities, leaving the door open for new entrants.

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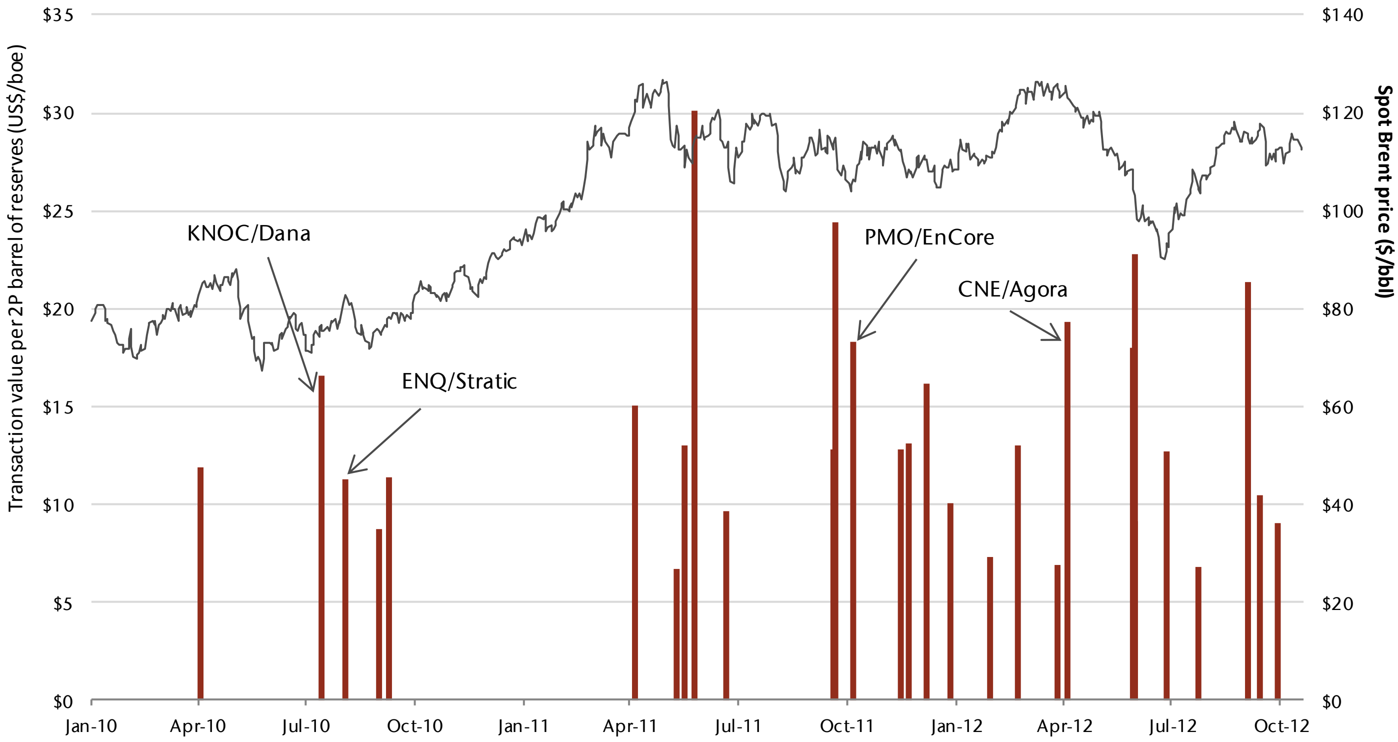
The UKCS transaction market

Chart 28: Per-barrel value of selected North Sea M&A transactions, Jan 2010-present



Source: Jefferies, Thomson ONE, company data

Active asset market and ongoing corporate consolidation
The last 18 months have seen a significant number of completed asset transactions and farm-ins, with over $4 billion of assets traded in the most active asset UK deal market since 2005. There are also numerous ongoing sales processes as larger players (e.g., BP, Murphy, Noble, Carrizo, etc.) attempt to rationalise their portfolios – assets with perceived upside (e.g., Perenco's acquisition of BP's interest in Wytch Farm and Apache's acquisition of ExxonMobil's assets in the Beryl area) have succeeded, but those with limited upside and material abandonment liabilities have struggled. Corporate-level M&A is similarly strong, with a number of entities being acquired at big premia to traded share prices (e.g., Dana, Encore, Venture, Bow Valley, Cirrus and Nautical Petroleum).

Corporate M&A has typically been completed at a premium to equity market valuations

Selective assets are attracting a premium to core values and....
In general the buyers of assets are quite selective, but those who are looking to gain a position or build their positions in the UKCS are highly motivated. Asset-level deals have typically required bidders to pay for a portion of the upside, whereas in corporate transactions acquirers have invariably paid substantial premia for undervalued or strategically desirable targets.

...buyers take into account the stage in the life cycle
Buyers of assets also take into account where assets lie in the E&P cycle. Non –producing assets in the UK have traded at between $3-12 per boe, producing assets have been trading from $5-30 per boe, with the upper end of the value range begin achieved when the oil price has risen over $80 per barrel.

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What is the UKCS worth?

The wide variety of development types, export routes, and tax relief available in the North Sea means that no two developments are the same. Depending on the size of the project, field operators often have a choice between standalone, FPSO, or subsea tieback development designs, all of which may have an impact on tariff costs. As we discuss below, the value of small, old, or technically-challenging fields in the UK may be enhanced by tax allowances designed to encourage development of these marginal assets. In addition, sources of funding (and hence costs of capital) will be different for all North Sea participants, meaning that the NPV per barrel can vary not only between different projects, but also between the partners in a specific project.

Breakeven prices

Entire set of planned UKCS developments are economic at crude prices above $78/bbl

The breakeven oil prices of individual assets are one way of examining the profitability of the North Sea. Recent analysis by Wood Mackenzie examined the breakeven oil price of 50 UKCS fields, representing over 2bnboe of probable reserves, which are expected to be developed over the next few years (see Chart 33 below). The bulk of these fields break even at an oil price below $50/bbl, with over 1.5bnboe of UKCS reserves able to be developed economically when crude trades at $50/bbl or more. The entire set of expected projects is feasible at crude prices above $78/bbl, a material increase from the 2010 breakeven price ($68/bbl) due to rising North Sea project costs. While our $100/bbl long-term Brent crude forecast offers a decent buffer for our E&P NAVs, with UKCS breakeven prices trending upwards there is now less room for cost overruns and field underperformance.

By way of comparison, Chart 34 takes a similar approach to assessing breakeven prices for the 5bnboe of upcoming developments offshore Norway. The vast majority of NCS projects break even at crude prices above $63/bbl, including the giant Johan Sverdrup discovery which Wood Mackenzie estimate adds 2.5bnbbl at a modest breakeven of just $21/bbl.

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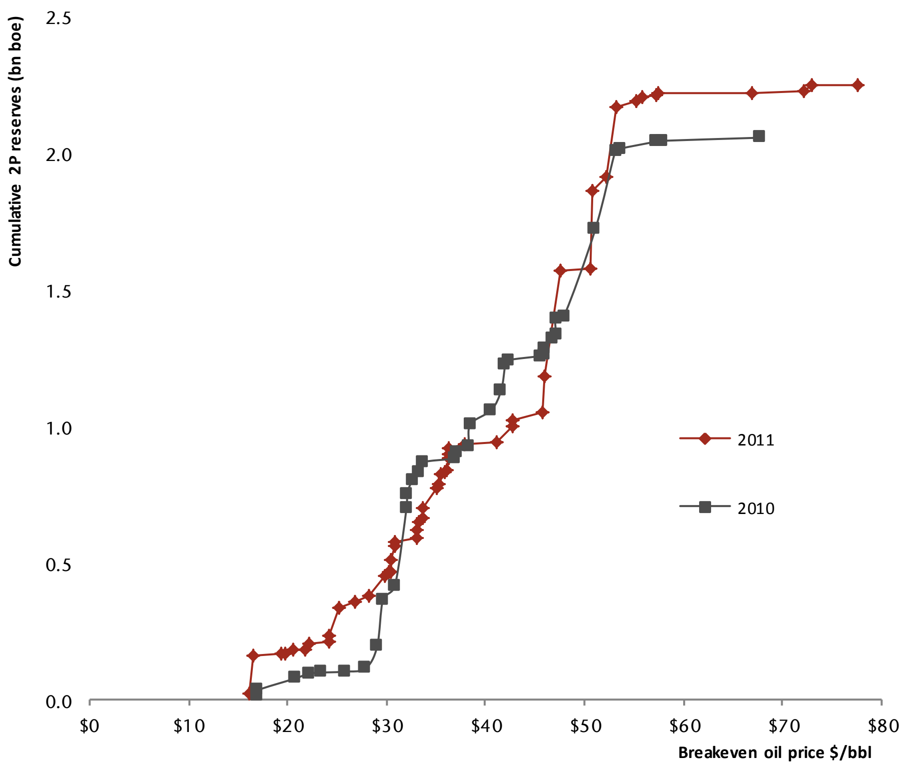
Most UK oil & gas projects are economic below $50/bbl; many below $40/bbl

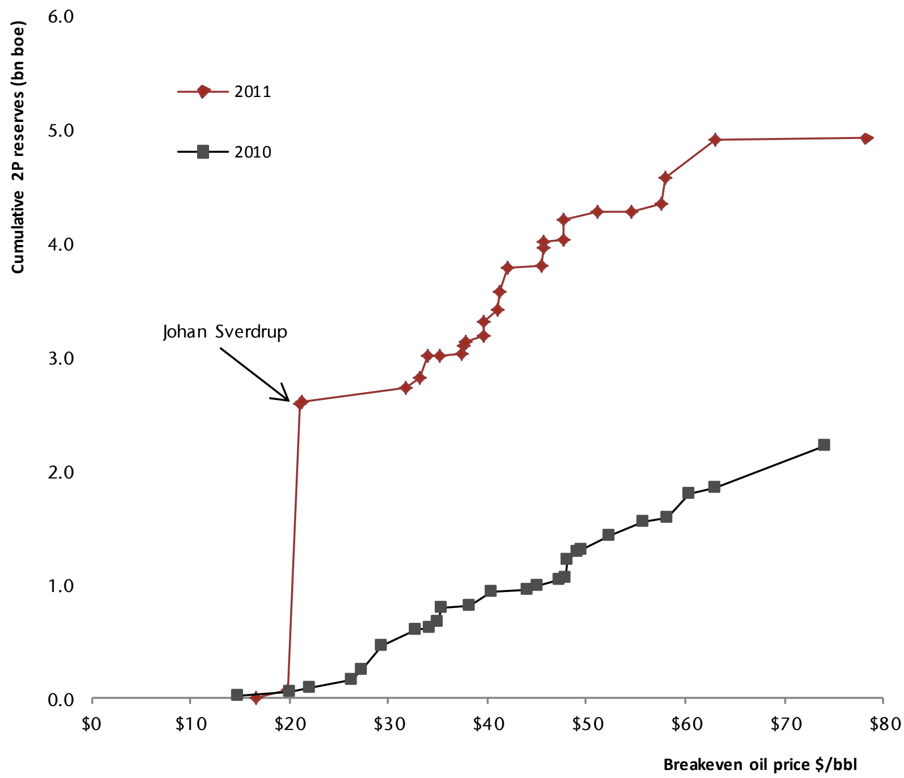
Chart 29: Breakeven oil prices of UKCS developments



Source: Wood Mackenzie

Vast majority of Norwegian developments break even at crude prices above $60/bbl

Chart 30: Breakeven oil prices of Norway developments



Source: Wood Mackenzie

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Five case studies

To illustrate the variation among UK and Norwegian asset valuations, we have constructed five case studies which look at the various development designs (standalone, FPSO, tie-back) commonly used in the North Sea. Each of these projects has passed through the appraisal phase and is earmarked for development in the next few years.

As expected, the flexibility and reduced capex commitment of a leased FPSO development means these fields are generally the most compelling from a valuation perspective (e.g., Catcher at >$14/boe). Subsea tieback and standalone development designs rank second and third, respectively, which makes sense given their higher capital-intensity, reliance on pipeline infrastructure, and decommissioning costs. Per-barrel valuations appear better on the UKCS than the NCS, which in our view reflects Norway's higher cost environment and harsher tax regime (see below).

Table 8: Selected case studies of UKCS and NCS developments

Development	Field	Fluid Type	Probable Design	Equity (%)	2P reserves (mmboe)	Capex ($m)	Capex ($/boe)	Opex ($/boe)	NPV ($/boe)
United Kingdom									
FPSO	**Catcher Area**	Oil	Leased FPSO connected to subsea manifolds at the Catcher, Varadero and Burgman discoveries.	Premier Oil (50%, operator), Cairn Energy (30%), Wintershall (20%)	80	1600	20.0	10.0	14.3
Subsea Tieback	**Columbus**	Gas-Cond	Two well subsea tieback to nearby Lomond platform.	Serica Energy (33.5%, operator), BG (27.5%), EOG Resources (16.75%), Endeavour Energy (16.75%), SSE (5.5%)	17	194	11.3	8.4	13.5
Standalone	**Breagh**	Gas	Seven subsea wells tied back to unmanned Breagh Alpha installation, exported to Teesside via new 100km pipeline.	RWE (70%, operator), Sterling Resources (30%)	105	1100	15.0	12.5	10.4
Norway									
Subsea Tieback	**Maria**	Oil	Two, three-well templates tied back to Åsgard B semi-sub platform; exported via shuttle tankers.	Wintershall (50%, operator), Petoro (30%), Centrica (20%)	116	1622	14.0	6.7	7.9
Standalone	**Ivar Aasen (Draupne)**	Oil/Gas	Fixed platform servicing Ivar Aasen fields (incl. Hanz and West Cable), tied into Luno facilities and then Grane pipeline.	Det Norske (35%, operator), Statoil (50%), Bayerngas (15%)	145	2299	15.9	11.8	5.1

Source: Jefferies estimates, Wood Mackenzie, company data

The gulf between equity market valuations and transaction multiples is encouraging for production-heavy E&PS like ENQ and IAE

The most important takeaway here is that irrespective of the type of development, recent North Sea M&A transactions (averaging $13.7/boe over 2010-12, see below) have typically been completed in line or at a premium to field NPVs. In other words, acquirers are often willing to pay a premium for development assets to avoid exploration and appraisal risk borne by the assets' early owners. This is encouraging for the E&Ps in our coverage that are overweight production and development assets in their portfolios (e.g., EnQuest and Ithaca Energy).

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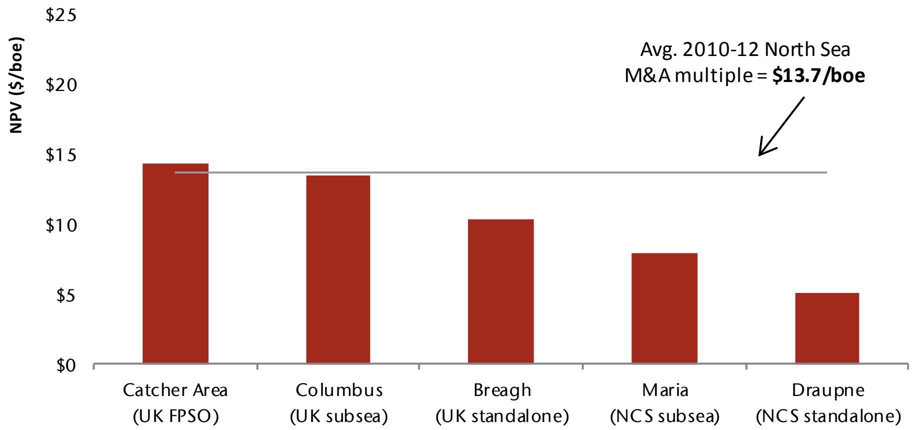
Jefferies

Chart 31: North Sea M&A deals completed at premium to asset NPVs



Source: Jefferies estimates, Wood Mackenzie, company data

Investors benefit from arbitrage between industry and stock market valuations

Equity investors benefiting from arbitrage between industry and stock market valuations

With E&Ps consistently trading at a discount to both consensus NAVs and market M&A multiples, identifying potential takeover targets is a key means for investors to exploit the arbitrage between industry and equity market valuations. The upside is clear when we consider M&A premia paid in the recent acquisitions of Dana Petroleum (59%), Dominion Petroleum (64%), EnCore Oil (55%), DEO Petroleum (40%), and Nautical Petroleum (51%).

The chart below shows our evaluation of (a) the relative appeal of each North Sea E&P to potential predators, and (b) the perceived barriers to any predator successfully acquiring each company. Our assessment of "**attractiveness**" is based largely on asset quality, cashflow and near-term growth potential, while our view on "**barriers**" considers each company's ownership structure (i.e., a tightly-held register equals higher barriers) and the strategic appeal of its portfolio.

We believe IAE and PVR are the most likely M&A candidates in our coverage universe

Among our coverage, we believe the most likely M&A candidates are Ithaca Energy (Buy, 180p/sh PT) and Providence Resources (Buy, 950p/sh PT).

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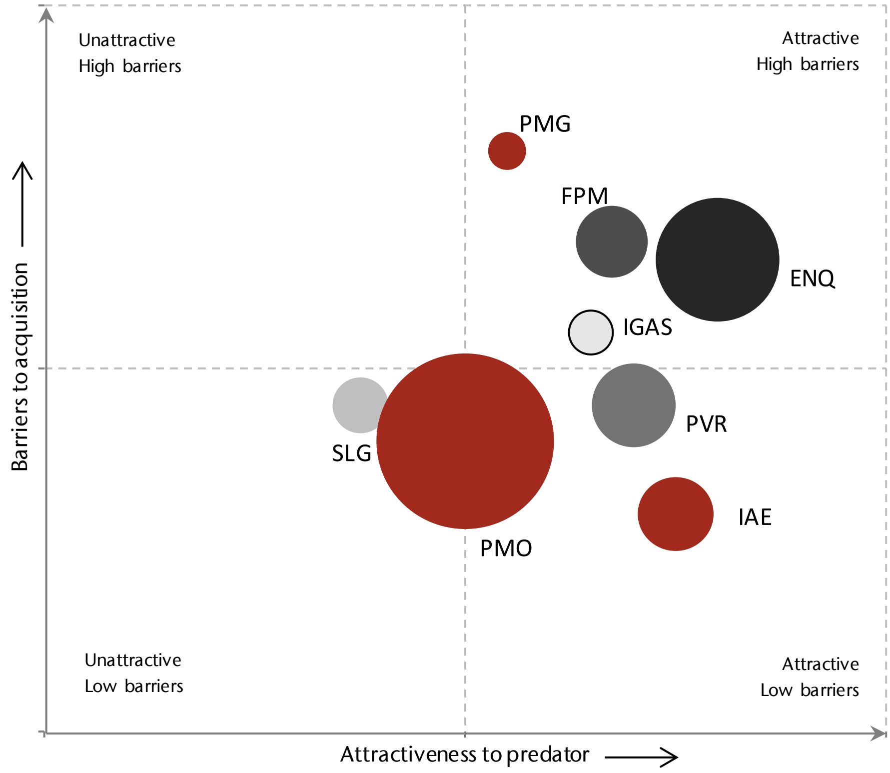
Chart 32: Ithaca and Providence offer material M&A potential, in our view



Bubble size reflects market capitalisation.
Source: Jefferies

The Norwegian transaction market

Increasing liquidity but Statoil and Petoro are still reluctant to let go of assets

The Norwegian M&A market has traditionally been viewed as illiquid, especially relative to the UK. In 2011, only ten commercial asset deals were completed, and M&A activity remains low compared to the UK and the US, however big new discoveries on the NCS could encourage Statoil and Petoro to further dispose mature, non-core assets. In April 2011 Faroe Petroleum acquired a portfolio of producing assets through a swap deal with Petoro, operator of the Norwegian State's Direct Financial Interest (SDFI) – this was the first time in almost seven years that the SDFI had entered the asset market. The fact that Petoro has been willing to begin divesting assets in order to secure growth in its core area could signal further swaps or sales to come.

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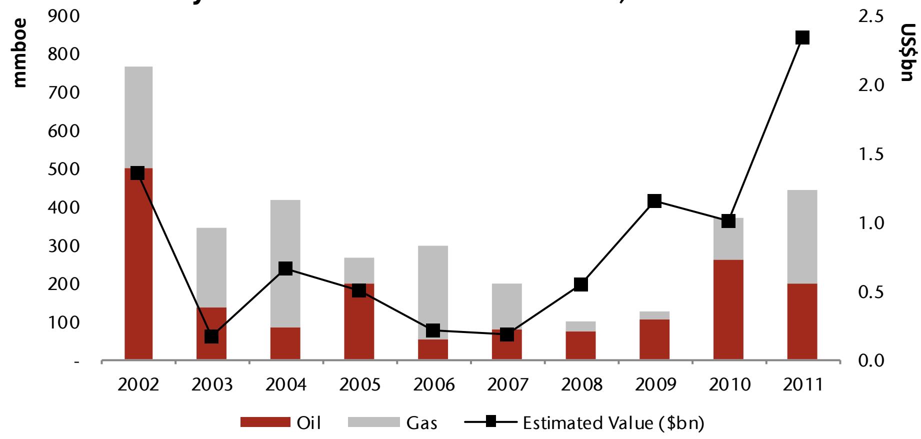
Chart 33: Norway's commercial reserves transactions, 2002-2011



Source: Wood Mackenzie, Jefferies estimates

Small companies active in the asset market to utilise tax incentives

Approximately 24kboepd of Norwegian production was traded in 2011. Among the E&Ps in our coverage, Faroe Petroleum traded its Maria discovery for a portfolio of Norwegian producing assets from Petoro, giving Faroe immediate production, cashflow and tax losses, while avoiding significant capex and decommissioning costs. Core Energy, a new company focusing on more mature fields, gained its first share of production (c.1.4kboepd) by acquiring interests in the Snorre and Brage developments from Hess and Noreco, respectively. Other deals included Statoil increasing its interest in the Snøhvit Area, and GDF Suez increasing its stake in the Njord Area.

Value of reserves traded varies according to the stage in the E&P life cycle

The implied reserves value of assets in Norway is directly linked to the asset life cycle. For example, unappraised discoveries have sold in the past year for around $4/bbl (e.g., spring sale of the Beta discovery to Talisman) whereas Centrica's 2011 acquisition of gas fields from Statoil were valued at c.$13/boe. Production assets have seen deal multiples as high as $23/bbl (e.g., Noreco's sale of its interest in Brage to Core Energy).

Market liquidity to continue after recent exploration successes

In total, 47kboepd of Norwegian production has been traded in 2012 to date. Centrica will increase its output after completing two major deals, including an asset package (interests in Kvitebjørn, Heimdal, Vale, Skirne and Byggve) that was acquired from Statoil, and a deal with ConocoPhillips that lifted its interest in the Statfjord field. More recently, Cairn Energy announced the acquisition of Agora Oil & Gas, a private Norwegian company with interests in six UK and five Norwegian licenses, for $450m.

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Key issues affecting the North Sea E&Ps

This section outlines what we believe are the key issues facing E&Ps investing in the North Sea. As the basin matures and the size of new discoveries and developments shrinks, much of the focus is on the economics of new projects – can investors earn a decent return in a region where costs are rising, taxation is complex, and decommissioning costs are a growing threat? We think the key issues are:

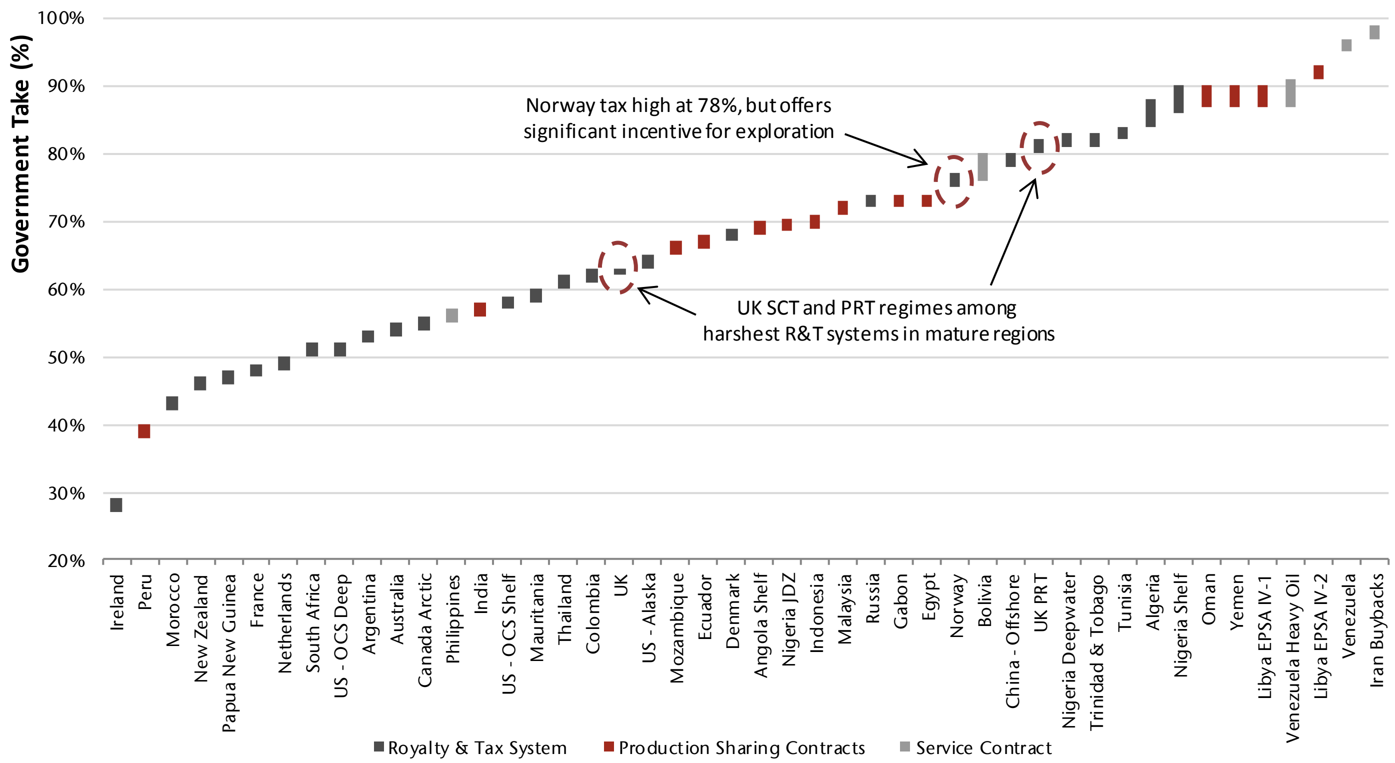
- **The fiscal regimes of the UK and Norway;**
- **The growing popularity of production hubs;**
- **Decommissioning costs;**
- **Operating costs and declining margins;**
- **Rig availability; and**
- **Access to infrastructure.**

The UK fiscal regime

The UK's 62%/81% headline government take puts it among the harshest oil & gas tax regimes in the developed world

Oil & gas companies operating in the UK face one of the world's most stringent royalty/tax regimes for a mature basin. Petroleum revenues from UK fields developed since 1993 face a headline tax rate of 62% (30% corporation tax and a 32% supplementary charge), while older fields subject to PRT can be liable for up to 81% tax. While this high government take makes the UK *fiscally* much less attractive than other regions, the UKCS remain a popular investment destination due to its low geopolitical risk and well-developed infrastructure.

Chart 34: Comparison of global oil & gas fiscal regimes



Source: Journal of World Energy Law and Business

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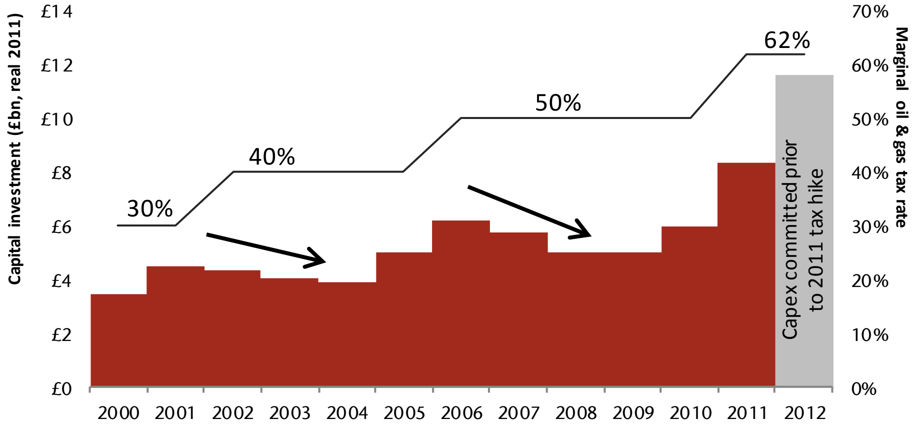
The marginal tax rate on UK oil & gas producers has doubled over the last decade as the Government has gradually stepped up the rate of supplementary charge. Although the effects of the tax hike have been partly offset by field allowances (see below) and strong crude pricing (early 2008 and 2011-12), in general the rising taxation has tended to discourage UKCS investment for the 2-3 years post the tax increase. This presents a key risk for North Sea development over 2012-14.

Chart 35: Impact of UK oil & gas tax increases on UKCS capex, 2000-12



Source: Oil & Gas UK, HMRC, Jefferies

We estimate only 4 of the Top 50 UKCS developments will not be able to utilise tax allowances

With the UK's 62% tax burden now among the harshest royalty & tax (i.e., non-PSC) regimes in the world, we believe UKCS developments must either be (a) very large, or (b) able to utilise field allowances, in order to remain competitive with comparable global projects within a company's opportunity set. This is evident in Wood Mackenzie's list of the **50 UKCS fields likely to be developed in the next few years – of this list, we estimate only four fields (Fram, Edradour, Devenick, and Golden Eagle) will *not* be able to utilise field allowances** to help soften the impact of the high UK tax.

UK field allowances incentivise the development of small or technically-difficult fields

UK offers tax allowances that incentivise investment in small, old, or technically-challenging fields

Contrary to the unexpected increase in supplementary charge announced in the 2011 UK Budget, the Government has also taken steps to encourage the development of more challenging UKCS fields that might otherwise be uneconomic under the new, harsher regime. Substantial tax allowances exist that help mitigate the impact of the higher tax on operators aiming to develop smaller, older, or technically difficult fields, e.g., heavy oil, HPHT fields, deep water gas, or West of Shetlands. These range from £150m for small fields (sub-51mmboe), to £3bn for large deep water fields West of Shetland, and can be used to offset a company's liability for supplementary charge over a minimum of five years.

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Table 9: UK Oil & Gas Field Allowances

Type of Allowance	Criteria	Maximum Amount (£m)
Small Field	Fields with 2P reserves less than 6.25 million tonnes (approx. 46mmbbl) earn full allowance. Thereafter, allowance tapers to zero on a straight-line basis; maximum field size 7 million tonnes (51mmbbl).	150
Brownfields	Only incremental development projects on existing offshore oil & gas fields will qualify. Allowance rises to £500m for older fields paying Petroleum Revenue Tax (up to 81%). Maximum allowance earned when expected capex costs exceed £80/tonne ($16.20/boe) of incremental reserves gained. Allowance tapers to zero on straight-line basis with no allowance for incremental capex below £60/tonne ($12.20/boe).	250-500
Shallow Gas	Water depth must be less than 30m. Fields where >95% of reserves are gas. Gas reserves must be between 10-20bcm (353-706Bcf) to earn maximum allowance. Thereafter, allowance tapers to zero on a straight-line basis; maximum field size 25bcm (883Bcf).	500
Heavy Oil	Fields with API gravity below 18 degrees and viscosity >50cP, at reservoir temperature and pressure.	800
HPHT	Oil fields with reservoir pressure exceeding 862 bar and temperature exceeding 176.67°C, measured at the depth of oil-water contact, earn full allowance. Allowance tapers on a straight-line basis down to £500m at 166°C.	800
Deep Water Gas	Fields where >75% of reserves are gas. Water depth must exceed 300m. Maximum allowance available where gas is transported >120km along a new pipeline to necessary infrastructure; tapers to zero on a straight-line basis with no allowance for pipelines shorter than 60km.	800
West of Shetland	New WoS fields drilled in water depths exceeding 1,000m. Reserves must be between 25-40 million tonnes (183-293mmbbl) to earn maximum allowance. Thereafter, allowance tapers to zero on a straight-line basis; maximum field size 55 million tonnes (403mmbbl).	3,000

Source: HMRC, Jefferies

We believe the UK's small field and brownfields allowances will be most popular

Although the Small Field Allowance and Brownfields Allowance have the smallest financial benefit (£150m and £250m, respectively), we think these two types of relief will be the most popular among operators. This is because they are targeted at a large proportion of the remaining fields in the UKCS, i.e., sub-50mmboe discoveries that (to date) have been sub-economic and subsequently abandoned, relinquished, or left undeveloped; and very mature assets where operators are discouraged from maximising field recovery due to high capex costs. These allowances help make these types of assets financially viable. In particular, the Small Field Allowance encourages the clustering of minor fields into a larger hub development, with individual fields being eligible for the allowance even if the regional development hub is over the size threshold (e.g., EnQuest's 29mmbbl Alma & Galia project, or the Premier-operated Greater Catcher Area).

The impact of these allowances on North Sea investment is evident when we look at planned activity in the UK over the next few years. Fifteen of the top 25 development projects by capex spend fall into the West of Shetland, heavy oil, shallow gas, or HPHT categories, with these fields forming 75% of the >$40bn expected to be spent on the Top 25 over the next five years. It is no surprise that some of these more complex developments will rank higher in terms of total capex (requiring deeper wells, higher well density, standalone platforms, etc.), but the fact they are proceeding at all shows the positive effect that the tax allowances have on project economics – even with Brent trading above $100/bbl, many of these developments would be sub-economic without the UK tax relief available on these marginal field types.

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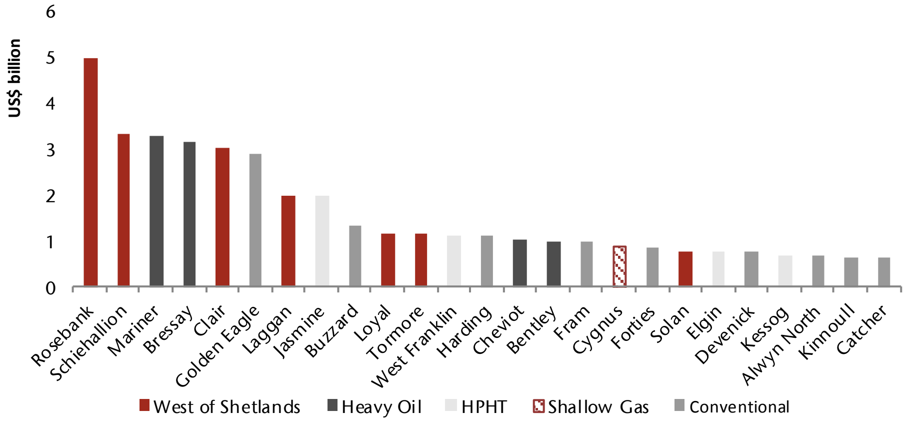
Chart 36: Projected capex spend on Top 25 UK developments, 2011-16E



Source: Wood Mackenzie, Jefferies

The types of developments incentivised by UK tax allowances fit closely with the portfolios and growth strategies of the UK E&Ps in our coverage

The types of developments that are incentivised by these tax allowances fit closely with the portfolios and growth strategies of the UK-exposed E&Ps in our coverage. A flurry of recent M&A activity means that both ENQ and CNE now have material exposures to **heavy oil** developments (Kraken and Mariner) – projects that until recently were marginal due to lower crude prices, harsh taxation and limited technology. In addition, the maturity of the UKCS means that new resource gains will come predominantly from **smaller fields**, benefitting both current owners of small-asset portfolios and those companies whose strategy is to exploit assets below the radar of the majors (e.g., ENQ, IAE, IGAS, FPM, Fairfield Energy). **West of Shetland** activity is limited to PMO and FPM in the small/mid-cap E&P space; among the majors BP, Shell and Total are active in the region.

How might the UK fiscal regime evolve from here?

We cannot rule out the risk of further adverse change to the UK's oil & gas fiscal regime, particularly given the Government's lack of consultation with industry shown at the time of the surprise hike in supplementary charge in 2011. However, in our view the chances of further increases to the headline tax rate are low – we believe future adjustments to the regime are likely to take the form of new or amended allowances, tailored to encourage the development of marginal fields that would otherwise remain undeveloped. With the UKCS in gradual decline, we think the Government will seek to maximise investment in the basin in order to monetise as much of the UK's hydrocarbon resource as possible.

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The Norwegian fiscal regime

Tax rate on Norwegian oil & gas revenues is 78%

Norway has a higher but more stable tax rate than the UK

Petroleum taxation in Norway is based on the rules for ordinary company taxation. Due to the extraordinary profitability associated with oil & gas production, a special 50% tax is added to the ordinary tax rate of 28%, taking the total burden to 78% – among the highest in the developed world. Sales revenues for crude oil are calculated on the basis of administratively stipulated prices, which reflect what the oil could have been sold for between independent parties in a free market. Dry gas and NGL taxation is based on actual sale prices.

Explorers in Norway receive cash rebate of 78% of unsuccessful exploration costs

Exploration cash-back for companies without producing revenues

Companies that are not in a tax position can carry forward both deficits and unused uplift with interest. In addition, since 2005 Norway's tax regime has allowed companies to claim back 78% of their unsuccessful exploration expenditure in the year after drilling – in cash – limiting explorers' financial exposure through the drilling process and providing a significant incentive to invest in Norway. This cash reimbursement means that the effective cost of unsuccessful exploration is just 22 cents in the dollar, a tax relief that has triggered an increase in exploration drilling and which means it is cheaper to explore in Norway then in the UK.

Norwegian fiscal terms essentially transfers exploration risk from E&Ps to the government

The flipside is that once commercial discoveries are made, producers face a 78% tax burden on their oil & gas revenues, however with giant discoveries (e.g., Johan Sverdrup) still being made offshore Norway the risk-reward of Norwegian drilling remains very attractive. The regime essentially transfers part of the exploration risk usually borne by the E&Ps to the Norwegian government. One way of thinking about this is that the government is prepared to part-fund (and hence incentivise) exploration in Norwegian waters in anticipation of any commercial discoveries being subject to Norway's very high 78% oil & gas tax once they enter production. In other words, Norway is prepared to wear the short-term cost of unsuccessful exploration in exchange for the long-term tax revenues of large oil & gas discoveries.

Table 10: Evolution of Norwegian fiscal environment for exploration

Date	Event	Comments
1965-1997	Rounds 1-15 & Barents Seas Project	Numbered rounds offering "frontier acreage" and the Barents Sea Project
1997-1998	Area fee reform	Norway abolishes area fee in exploration period of new licences. Area fees subsequently lowered by 40% in exchange for participants waving their pre-emption rights.
1999-2002	North Sea Awards (NSA) introduced	North Sea Awards established for mature areas
2000-2011	Rounds 16-21	Numbered frontier rounds continue, incorporating acreage outside of the NSAs
2003-2012	APA rounds introduced	NSA converted to Awards in Predefined Areas (APA)
2005	Exploration incentives	Explorers receive 78% tax rebate on unsuccessful exploration, even if the company isn't yet paying tax themselves.
2007	Fallow initiative	Area fee acceleration introduced, along with fee deferral incentive to drill wildcat wells.
2012	APA 2011 awarded	Record acreage awarded in mature round
2012	Round 22 announced	A record 228 blocks nominated by 37 companies, subsequently reduced to 86 offered licenses to be awarded in summer 2013
2012	APA 2012 announced	Deadline for applications, 6 Sep 2012. Expanded area on offer by 48 blocks/part blocks, compared with APA 2011.

Source: Wood Mackenzie

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Production hubs encourage development of marginal fields

Hub-type developments can drive down unit costs and improve profitability

One way to drive cost efficiencies is through the development of production hubs. Traditionally, production hubs were the end point of the main subsea pipelines to shore (e.g., Forties), and could be used by nearby discoveries as a collection point through which to evacuate crude oil. However, the operators often command a lot of economic rent in the form of tariffing, and only where there is direct competition from another hub can tariffs be negotiated down to improve the economics of the satellite fields. We believe this provides a material benefit to E&Ps that can create and control their own hubs.

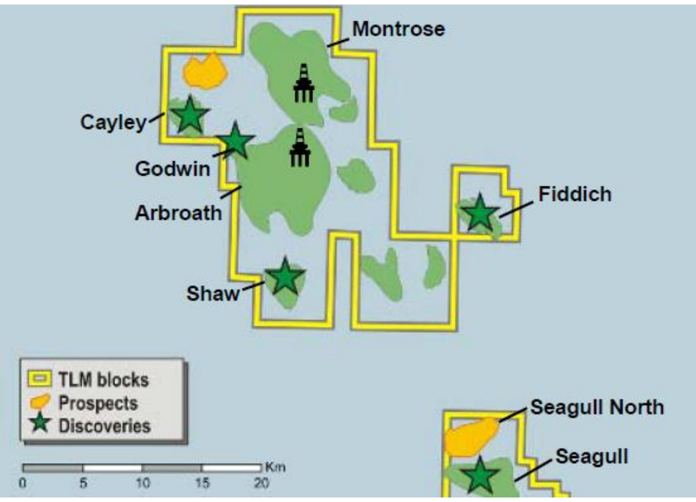
Production hubs allow small, marginal fields to be developed economically

Production hubs can transform the economics of small fields that on their own would be non-commercial

In recent years, companies have tried to develop their own 'hubs' by amassing large acreage positions in certain areas and then building their own central facility to evacuate crude – these hubs can transform the economics of small discoveries that on their own would be non-commercial. A long-term strategy to build a dominant acreage position in a particular area can involve a number of asset transactions, and is one reason why the UKCS asset market has remained particularly active. Examples of North Sea hubs include:

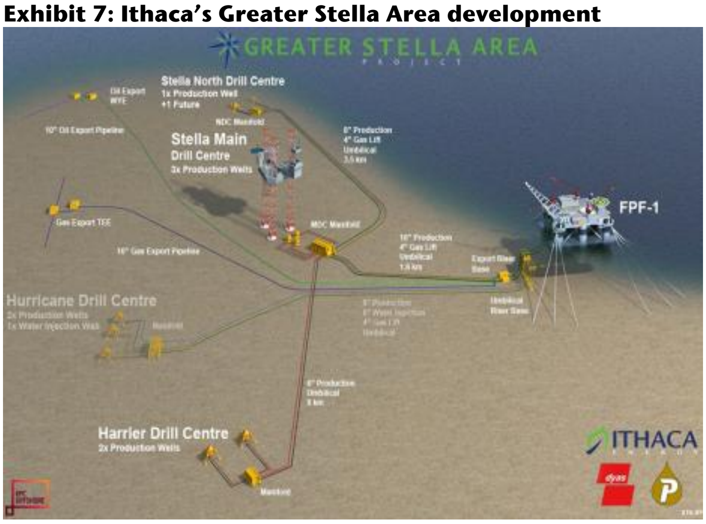
- Ithaca Energy and Petrofac teaming up to create a production hub at the **Greater Stella Area**, where the Stella and Harrier fields will be developed in tandem and tied back to a floating production unit to keep costs low.
- EnQuest announcing in late 2011 that it was creating a new hub to develop its **Alma & Galia** fields (individually eligible for the UK's Small Field Allowance), which if developed independently, and excluding the tax relief, would probably be sub-economic.
- Talisman's **MonArb** hub, which encompasses five oil fields, five discoveries and two prospects, and is expected to both boost production from the assets and extend the life of the facilities.

Exhibit 6: Talisman's MonArb hub



Source: Talisman Energy

Exhibit 7: Ithaca's Greater Stella Area development



Source: Ithaca Energy

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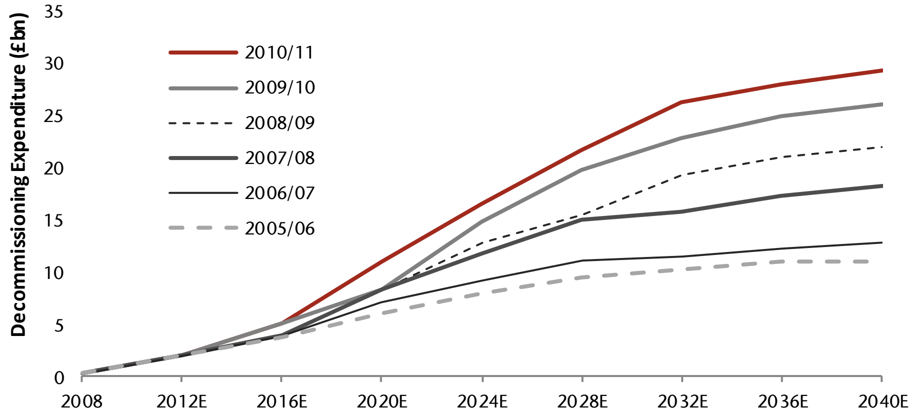
Decommissioning

Decommissioning costs often seen as a deterrent to investment in the North Sea

The magnitude of abandonment liabilities is often seen as a deterrent to new investment

In the UK, future decommissioning expenditure for existing fields is estimated at £28.7 billion (in 2011 money), with new investment on probable developments potentially adding a further £4.3billion of decommissioning costs. There is significant uncertainty regarding the ultimate cost and extent of decommissioning in the UK, with estimates increasing every year for the past six years. The magnitude of the associated liabilities and, more importantly, uncertainty around their future fiscal treatment, is seen as a potential deterrent to new investment in the UKCS.

Chart 37: UK projected decommissioning spend, 2008-2040E



Source: Oil & Gas UK

Higher commodity prices and enhanced oil recovery have delayed impending liabilities

Abandonment liabilities have been pushed further out into the future by high oil prices, but with stable or falling oil prices the clock will start to tick on these impending costs. Abandonment has also been successfully delayed through satellite developments, enhanced oil recovery techniques and cost-sharing arrangements, but this cannot continue indefinitely.

Up to 40% of current UKCS infrastructure could be abandoned by 2020 if current production levels are not maintained

40% of infrastructure could be decommissioned by 2020

Unless current production levels are maintained through new development activity, Oil & Gas UK estimates around 40% of current infrastructure could be decommissioned by 2020, with over 90% requiring destruction at the end of its useful life. North Sea discoveries are typically getting smaller, and the presence of existing infrastructure (i.e., meaning new structures do not need to be built) can often be the deciding factor over the commerciality of a project, thereby having a direct impact on the ultimate recovery from the UKCS. At present, around 10% of UKCS installations are floating structures, 30% are sub-sea, 50% are small steel and 10% are large steel or concrete.

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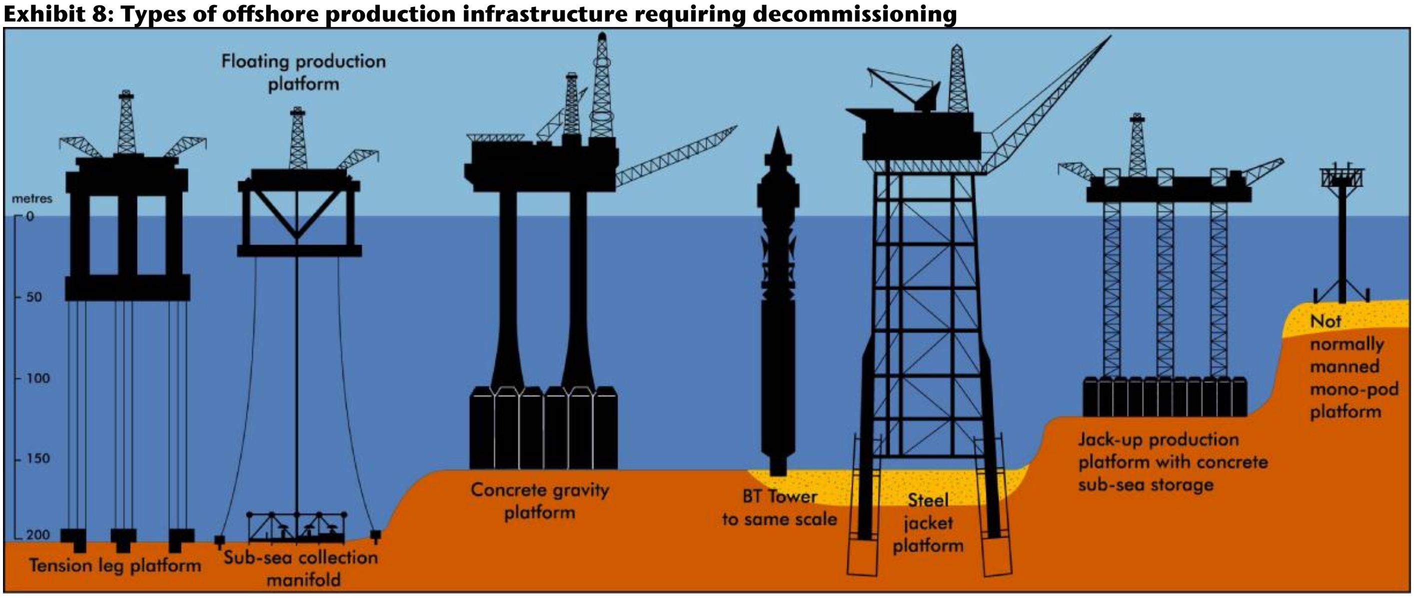
Exhibit 8: Types of offshore production infrastructure requiring decommissioning



Source: Oil & Gas UK

Small E&Ps hit by requirement to post capital against future abandonment

Past UK legislation has stated that previous license owners could be liable for decommissioning costs, should the current partners default. Buyers of assets are often required to post security against future decommissioning costs, thereby reducing the availability of capital for investment elsewhere. This has especially hurt the smaller E&P companies, where capital is scarce, and has also adversely affected market liquidity. As a result, the UK asset market has become increasingly polarised over recent years, with buyers seeking growth assets while many mature asset sales have either stalled or traded at a discount to market valuations due to large abandonment liabilities.

2012 Budget – contractual certainty to abandonment tax relief should boost future asset liquidity

The 2012 UK Budget added certainty to future decommissioning tax relief; this should improve asset liquidity

In 2012, the UK Government committed to creating certainty on the tax relief available for abandonment expenditure, with companies now legally bound to receive 50% tax relief on decommissioning costs should they be forced to pay these costs due to a creditor defaulting. This essentially halves these companies' "securitisation" requirements and releases half of the capital companies had been putting aside (via provisions) for decommissioning costs, allowing reinvestment in North Sea (development or M&A). Unsurprisingly, this has been welcomed by the industry and should improve asset liquidity and increase the number of companies able to buy assets. Note that this still precludes smaller companies from operating mature assets, as the size of the investment required to maintain old facilities could still deter buyers.

Norwegian sector is less mature; abandonment not yet an impending issue

The Norwegian NCS is less mature than the UKCS, meaning abandonment liabilities are less acute. That said, the NPD has decided that, in principle, when extraction activities end everything must be cleaned and removed from the seabed. To date, the NPD has processed ten abandonment plans, and in all cases all facilities will be removed and transported to land (e.g., Odin, Nordost Frigg, Ost Frigg, Lille Frigg, Froy and TOGI). Special dispensation was given to Ekofisk I and Frigg to leave in place the concrete substructures and protective walls, as it was deemed there would be more damage to the environment should they be dismantled.

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Abandonment liabilities can be transferred back to the State for a fee
In Norway, the licensees at the time the abandonment decision is made are responsible for carrying out the disposal. However, in 2009 the Petroleum Act was amended so that if a company sells part of a production licence before abandonment, it retains an alternative liability for removal costs related to its sold share. This is similar to the UK, and covers the event of a smaller company being unable to meet its abandonment obligations. In contrast to the UK, the licensees and the State can agree that future maintenance and responsibilities can be transferred to the State for an agreed financial compensation.

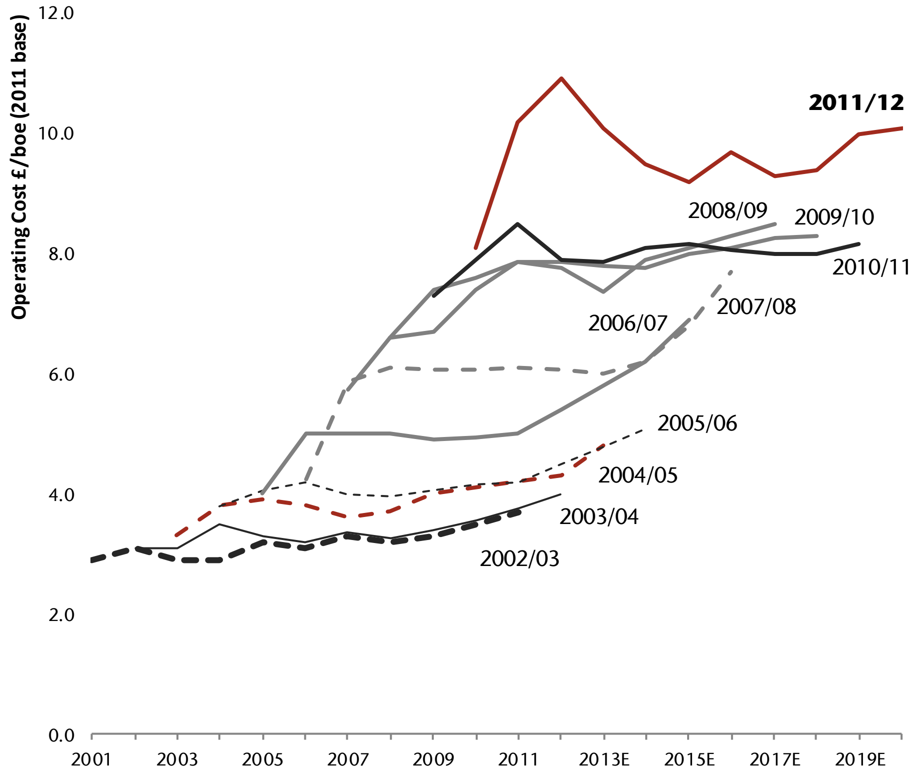
Rising operating costs and declining margins

Larger companies can face declining production and rising costs
Companies with large production portfolios, i.e., predominantly the majors and mid-cap independents, often face the twin threats of declining production and rising costs (e.g., infrastructure, rigs, subsea facilities, pipelines). While the current high oil price environment is concealing this issue at present, any sustained weakness in commodity prices will bring it to the forefront.

Per-barrel operating costs in the UK rose 25% in 2011

UK operating costs up 25% in 2011
Total UK operating costs rose only marginally in 2011 to £7 billion, which against a background of rising labour and commodity prices shows the efforts the industry is making to control expenditure. However, the rise in unit operating costs (+25%) was much more pronounced due to poor production performance – any further acceleration in cost increases could make UKCS production uncommercial for many operators. When combined with the supplementary tax hike in 2011, it is now easy to see why many operators have reassessed their development plans over the last 12 months.

Chart 38: Significant uplift in UK North Sea operating costs in last decade



Source: Oil & Gas UK

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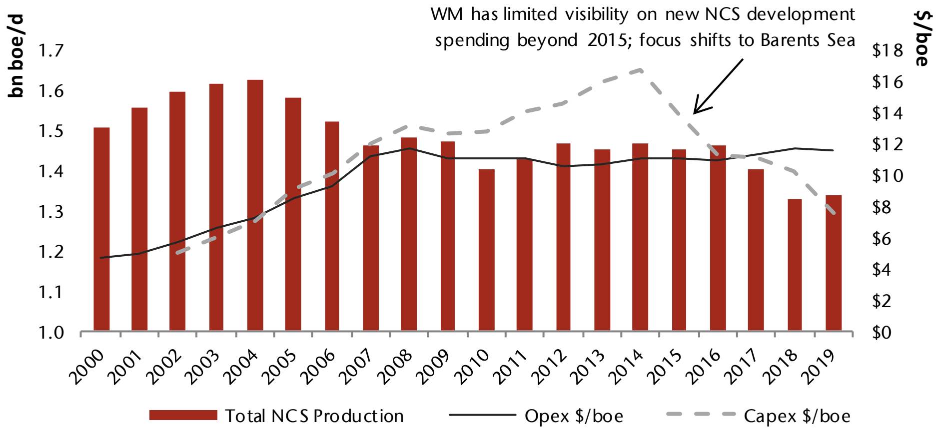
Significant increase in Norwegian development and operating costs

In Norway, the petroleum industry has experienced significant growth in costs over the last decade even greater than in other comparable countries. High oil prices accompanied by all-time high investments and capacity utilization in the supply chain have been key drivers of this development. The growth in investments can be attributed both to the high activity level as well as to significant cost growth. Investments linked to modifications and maintenance on fields in operation account for an increasing percentage of the total investments.

Chart 39: Norwegian capex and opex climbs dramatically since 2000



Source: Wood Mackenzie, Jefferies

Fears that high costs will ultimately affect long term recovery of resources

Norwegian cost growth slowed in 2009 as the global financial crisis and declining commodity prices put many projects on hold. However, in the current market costs are rising sharply again, which is concerning for the industry as it can negatively impact recovery from both existing and future fields, and discourage the development of as-yet undiscovered resources.

Norwegian costs are 20% higher than the UK, with the disparity in drilling costs even higher

Opex in Norway is significantly higher than in the UK due to more expensive rigs, workers, and admin costs

Development and operating costs are more than 20% higher in Norway than in the UK. The difference is partly due to activity associated with production drilling (including rig costs and drilling equipment), with more expensive subsea services and process facilities also contributing to more costly developments on the NCS. In addition, the cost of drilling shallow water (<400m) exploration wells on the NCS are about 85% higher than on the UKCS and 35% higher than on the Brazilian Shelf, due mainly to more expensive rig hire, personnel, field evaluation and admin costs.

Given the current cost level on the NCS, industry players must cooperate to achieve cost savings and keep marginal projects and late-phase projects financially viable. While the industry has implemented many good initiatives to keep cost development under control, in our view stronger measures are probably needed to maximise recovery of the NCS's remaining resource.

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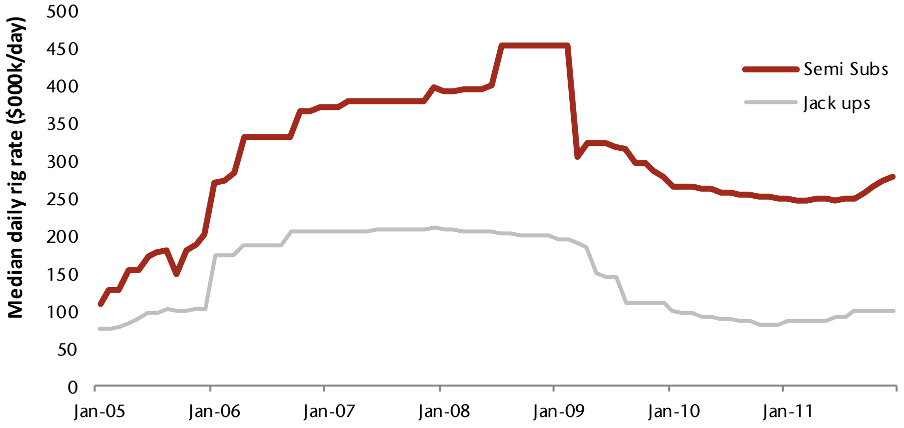
Tight North Sea rig market

Access to rig slots is crucial for smaller E&P companies

Smaller, exploration-biased E&Ps must maintain a calendar of firm drilling slots if they are to provide shareholders with regular exploration catalysts, as without these slots it is unlikely the equity market will give material value to the prospects. In a high oil price environment there is increasing demand for rig time, and as a consequence rig rates for new drilling contracts rose steadily during 2011. Semi-submersible drilling rates averaged $273k/day at the start of 2012 (+7% versus January 2010), with standard jack-up drilling rates sitting between $100-125k/day (+24% versus January 2010).

Chart 40: North Sea rig rates, 2005-2012



Source: Oil & Gas UK

Day rates accelerate in 2012; shortage of capacity could be a constraint

UK rig market remains very tight over 2012-13

Growing global demand has accelerated day rates so far in 2012, with Oil & Gas UK estimating current drilling rig utilisation rates at 83% and 82% for semi-subs and jack-ups, respectively. Competition for drilling rigs is such that three rigs entered the UK from other North Sea regions during the early part of 2012, suggesting there will be continued demand for the remaining rig space in 2013.

Rig capacity in Norway is an even greater challenge

We believe sufficient rig capacity will be a challenge on the NCS in the next three years – contracts for about 30 mobile rigs operating on the NCS will expire over this time, and there is uncertainty about how many will remain. A tight rig market over the last decade has led to several highly-specific rigs being brought to the NCS – of 21 semi-submersible rigs currently operating on the NCS, seven are equipped for drilling at water depths >1000m, meaning they are often not well suited for existing fields.

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Access to infrastructure

UK developments risk being stranded if access is delayed beyond abandonment

Over the next five years, planned decommissioning means that significant infrastructure will start to disappear in the UK. If new and undeveloped discoveries are to avoid being stranded then development must proceed quickly – this has been recognised by the industry regulator, and working groups have been formed in order to seek improvements in third party access. The recent 2011 Energy Act is now in force, including simplified provisions for third party access and new legislative powers.

UK infrastructure holders still hold the power over smaller fields and companies

Despite the new regulations there are still concerns that the balance of negotiating power still very much lies with the large infrastructure holders over the owners of smaller fields which use them. With very little options available to process and export oil or gas, capital investment and risk is almost entirely borne by the user fields. In addition, infrastructure holders are typically risk averse, and as a result negotiations typically delay developments.

The Central North Sea has the least spare capacity and is the area of greatest tension

The more mature areas of the Southern North Sea, with increasing amounts of spare capacity in the infrastructure, offer a choice of pipeline export routes for new developments that cannot support their own pipeline. In other regions, most notably the Central North Sea, there is less spare capacity and gas production is often associated with oil production. In this region in particular, we see the potential for commercial tension between the owners of infrastructure and the owners of fields seeking access.

In Norway access to infrastructure is a prerequisite before development approval is given

In Norway there are strict resource management requirements for the efficient use of infrastructure. In 2005 the NPD laid down regulations relating to use of facilities by others (TPA Regulations) in order ensure that there are sufficient incentives for exploration, new field development and improved recovery.

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The North Sea E&Ps

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EnQuest (ENQ LN): Initiating coverage at Buy, 155p/sh PT

We initiate coverage of EnQuest with a Buy rating and 155p/sh price target. ENQ is an undervalued North Sea oil producer with exposure to two large development projects that we expect will deliver a step change in reserves, production, and cashflow over the next three years. The company has a strong technical team that allows it to exploit mature and undeveloped assets, taking material operated stakes without exposing shareholders to exploration risk. We believe the current share price offers an attractive entry point where investors can gain exposure to a low risk, highly cash-generative and fully funded North Sea oil portfolio with substantial organic growth potential. ENQ is our preferred exposure among the North Sea E&Ps.

ENQ's two major development assets, Kraken and Alma & Galia, could together add up to 119mmbbl to ENQ's net 2P reserves and up to 34kbopd of net incremental production by 2019, potentially **doubling the size of the business**. We value Kraken at 47p/sh and Alma & Galia at 36p/sh. The economics of both projects are enhanced by tax allowances that encourage investment in smaller or technically difficult fields on the UKCS.

Three UKCS production hubs – The Dons Area, Thistle & Deveron, and Heather & Broom – form the core of ENQ's producing portfolio, which together we value at 74p/sh. These assets have driven ENQ's solid production history since its IPO in April 2010, delivering 23.7kbopd of net production in 2011 with an expected 2010-14 CAGR of +14%. ENQ has invested heavily in in-fill drilling to maximise recovery from these mature fields; however, despite this investment we still expect a steady decline in their output over the medium term. Management has given guidance for group production of 20-24kbopd in 2012 (Jefferies 22.2kbopd), and 23-28kbopd in 2013 (Jefferies 27kbopd).

Important **near-term catalysts** for ENQ include results from the UK's 27th offshore licensing round (due 4Q12) and the Kildrummy well (4Q12, 3p/sh risked, 2% SoP upside). Operationally, we think meeting management's targets for Kraken FDP submission (1H13) and first oil from Alma & Galia (4Q13) are also key milestones.

ENQ also offers an **interesting M&A angle**, and in our view is likely to be on the radar of both the majors and national oil companies (NOCs). ENQ's 100%-oil portfolio, low geopolitical risk, and limited exploration risk are all desirable traits, and with net production estimated to approach 50kbopd by 2018 we believe the company's output is increasingly material to a larger predator. In our view, ENQ remains a genuine M&A candidate while its shares continue to trade at a 21% discount to our SoP valuation.

Valuation

We value ENQ at 153p/sh using a sum-of-the-parts methodology. Our 144p Core NAV comprises full-field NPV-10 valuations of ENQ's core production and development assets using our $100/bbl long-term Brent forecast, with upside value provided by 9p of risked exploration assets. We see no funding risk for ENQ as it completes its planned development pipeline, and as such our 155p/sh price target is set broadly in line with our SoP valuation.

Risks

ENQ's 100%-oil portfolio means that a weaker-than-expected Brent crude price scenario is a key risk to our valuation and cashflow outlook. We also see risk to our forecasts from underperformance of ENQ's mature fields, project delays and/or cost overruns at the major Kraken and Alma & Galia developments, and unsuccessful exploration and appraisal drilling. Given ENQ's strong cash position, operating cashflow and debt availability, we do not see material funding risk over the medium term.

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Exhibit 1: ENQ SoP valuation summary

Region	Asset	Hydrocarbon	ENQ W.I. %	Resource Size (mmboe) Gross	Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV p/sh	Unrisked p/sh	Upside %
Producing assets												
UK - Northern North Sea	The Dons Area	Oil	Various		26	100%	26	21	538	42	42	
UK - Northern North Sea	Thistle & Deveron	Oil	99%		25	100%	25	7	169	13	13	
UK - Northern North Sea	Heather & Broom	Oil	Various		19	100%	19	12	229	18	18	
							70		**935**	**74**	**74**	
Development assets												
UK - Central North Sea	Alma & Galia	Oil	65%	29	19	100%	19	24	461	36	36	0%
UK - Northern North Sea	Kraken (incl cost carry)	Heavy Oil	60%	167	100	90%	90	7	596	47	52	3%
UK - Northern North Sea	Crawford & Porter	Oil	51%	27	14	60%	8	7	55	4	7	2%
UK - Northern North Sea	Crathes/Scolty/Torphins	Oil	40%	18	7	60%	4	8	35	3	5	1%
UK - Northern North Sea	Heather South West	Oil	55%	7	4	70%	3	8	22	2	2	0%
							124		**1,170**	**92**	**103**	**7%**
2012 Exploration & Appraisal												
UK - Northern North Sea	Kildrummy	Oil	60%	12	7	50%	4	9	32	3	5	2%
UK - Northern North Sea	Ketos (contingent)	Oil	45%	20	9	30%	3	10	27	2	7	3%
							6		**59**	**5**	**12**	**5%**
Further drilling												
UK - Northern North Sea	Heather South West	Oil	55%	9	5	19%	1	9	8	1	4	2%
UK - Northern North Sea	Moon	Oil	40%	8	3	30%	1	8	8	1	2	1%
UK - Northern North Sea	Cairngorm	Oil	100%	8	8	40%	3	8	26	2	5	2%
UK - Northern North Sea	Pilot	Oil	70%	20	14	25%	4	5	17	1	5	3%
							9		**59**	**5**	**16**	**7%**

Valuation Multiples			
ENQ share price	121p	No. of Shares	803 m
Core NAV	144p	Market Cap.	£970 m
P / Core NAV	**0.84**	Enterprise Value	£911 m
P / SoP	**0.79**	2P Reserves	115 mmboe
Upside to SoP	27%	EV/2P boe	**$12.50 /boe**

ENQ Core NAV	$m	p/sh
Producing Assets	935	74p
Development Assets	1,170	92p
Net Cash / (Debt)	92	7p
G&A	-141	-11p
Decommissioning Costs	-230	-18p
Core NAV	**1,827**	**144p**

ENQ Sum of Parts Valuation	$m	p/sh
ENQ Core NAV	1,827	144p
2012-13 Exploration & Appraisal	59	5p
Further Drilling	59	5p
Sum of Parts	**1,945**	**153p**

Source: Jefferies estimates

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Exhibit 2: ENQ financial summary

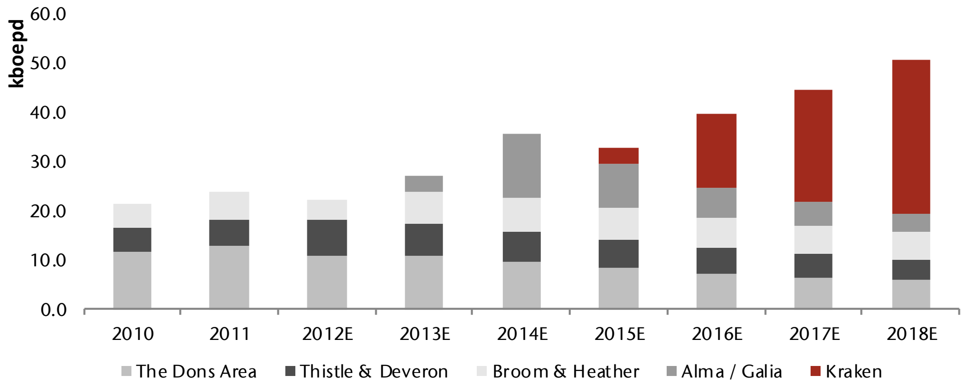
P&L		2010A	2011A	2012E	2013E	2014E
Revenue	$m	583	936	892	951	1257
Cost of Sales	$m	-401	-509	-457	-518	-706
Exploration Writeoffs	$m	-91	-37	-15	-17	-17
G&A	$m	-27	-16	-16	-17	-25
Other	$m	1	3	6	0	0
Pre-tax Operating Profit	$m	66	377	410	400	509
Net Finance Income/(Expense)	$m	-10	-15	-8	-18	-17
Pre-tax Profit	$m	56	363	402	381	492
Tax	$m	-29	-304	-127	-236	-305
Net Profit incl exceptionals	$m	27	58	275	145	187
EBIDAX	$m	330	600	609	663	900
EV/EBIDAX	x	4.4	2.4	2.4	2.2	1.6
No. of Shares	m	799	802	803	803	803
EPS	cps	3	8	34	18	23
DPS	cps	0	0	0	0	0

Cashflow Statement		2010A	2011A	2012E	2013E	2014E
Cashflow from Operations	$m	263	636	558	664	902
Cashflow from Investing	$m	-133	-277	-790	-509	-553
Cashflow from Financing	$m	-95	-23	8	-9	-9
Net Change in Cash	$m	35	337	-224	146	340

Balance Sheet		2010A	2011A	2012E	2013E	2014E
Cash	$m	41	379	157	303	642
Exploration Assets	$m	12	24	150	233	316
Prod'n & Devel. Assets	$m	1136	1274	1881	2043	2122
Long Term Debt	$m	0	0	25	25	25
Provisions	$m	432	772	942	1188	1503
Shareholder Equity	$m	883	934	1215	1359	1546
Gearing: Net Debt(Cash)/Equity	%	-5%	-41%	-11%	-20%	-40%

12-month Catalysts	ENQ WI %	CoS %	Risked NAV $m	Risked NAV p/sh	SoP Upside %
Kildrummy	60%	50%	32	3	2%
Ketos (contingent)	45%	30%	27	2	3%

Production Summary		2010A	2011A	2012E	2013E	2014E
ENQ production WI	kboepd	21.2	23.7	22.2	27.1	35.4



SoP sensitivity to Brent & WACC	LT Brent $/bbl	$70.00	$85.00	$100.00	$115.00	$130.00
WACC	8%	55	115	172	227	276
	10%	45	100	**153**	204	249
	12%	37	88	137	184	226
	14%	29	77	123	167	206

Assumptions		2010A	2011A	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58

Source: Jefferies estimates

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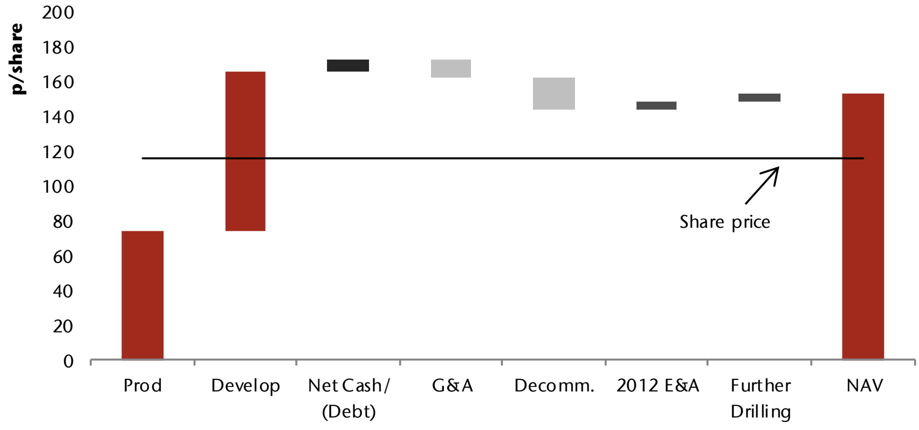
Valuation

Our sum-of-parts valuation of EnQuest is 153p/sh, placing the shares at a 21% discount to SoP. This valuation comprises a 144p Core NAV, built from full-field NPV-10 valuations of ENQ's core production and development assets using our $100/bbl long-term Brent forecast, and upside value provided by 9p of risked exploration prospects. ENQ is fully funded to complete its planned development and drilling campaign, and in our view does not warrant any discount for funding risk. As such, our 155p/sh price target is set broadly in line with our SoP valuation, and with 28% upside to this target we initiate coverage of ENQ with a Buy rating.

ENQ trades at 16% discount to Core NAV, a compelling value argument

At current levels ENQ is trading well below our 144p Core NAV, i.e., the value of the company's producing and development assets (including Kraken and Alma & Galia), adjusted for its net cash/(debt) and capitalised admin/decommissioning costs. This in itself is a compelling bull argument for ENQ at current levels – even if we assume a steady decline in the mature assets, significant cost carries on the Kraken development, and no value for ENQ's exploration upside, the shares still trade at a 16% discount to our Core NAV.

Chart 1: ENQ trades at 16% discount to Core NAV; too cheap for a producer



Source: Jefferies estimates
Core NAV includes DCF valuation of Kraken and Alma & Galia developments

ENQ management has given production guidance of 20-24kbopd in 2012, 23-28kbopd in 2013

Management guidance suggests 2012 group production is likely to dip slightly from 2011 output of 23.7kbopd, with **ENQ's FY12 net output expected to lie between 20-24kbopd; we forecast 22.2kbopd**. This small y-o-y decline reflects the maturity of ENQ's producing portfolio, and is essentially a short-term lull before the step change in production that we expect when the Alma & Galia and Kraken developments are brought onstream in 4Q13 and 4Q15, respectively.

ENQ's early production guidance for 2013 sits at 23-28kbopd (we are at 27kbopd) – over the medium term, we expect a net production CAGR of 14% over 2010-14. At present we forecast first oil from Alma & Galia in 4Q13, implying a 3.3kbopd contribution from these fields in 2013. In the event that the Alma & Galia project faces any development problems that delay production until 1Q14, our 2013 output forecast would be 23.8kbopd, i.e., 7% y-o-y growth versus 2012.

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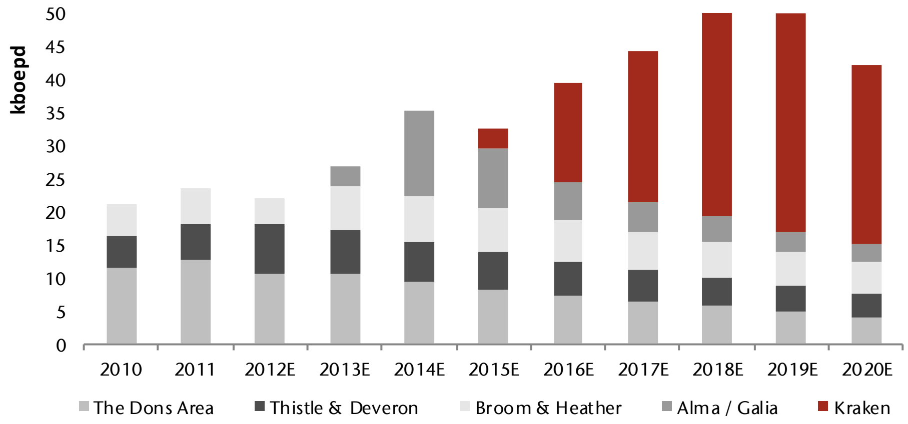
Kraken and Alma & Galia dominate ENQ's medium-term production profile; expected to reach 50kbopd in 2018

Chart 2: ENQ medium term production dominated by Kraken and Alma/Galia



Source: Jefferies estimates, company data

2012 catalysts: Kildrummy appraisal well and 27th UK licensing round

We see value upside for ENQ from several catalysts expected in the next twelve months – the results of the 27th UK offshore licensing round (due 4Q12), and an appraisal well to be drilled at **Kildrummy** in 4Q12 that offers 2% upside to our SoP if fully derisked. We are also excited about the possible Ketos well in the Kraken area – while currently not firmly in ENQ's calendar, we assume Ketos is a 20mmbbl pre-drill resource that could potentially be drilled in 2H13 and ultimately tied back to the adjacent Kraken heavy oil development. We believe results from the 27th round offer a "soft" catalyst for ENQ, where securing new blocks adjacent to its existing hubs will create longer term development opportunities rather than immediate value.

Table 1: ENQ 2012 catalysts

Asset	Timing	ENQ W.I. %	Resource Gross (mmboe)	Resource Net (mmboe)	CoS %	$/boe	NPV $m	NPV p/sh	Upside %	Comments
Kildrummy	4Q12	60%	12	7.2	50%	9	32	3	2%	Appraising 2001 discovery, carrying Talisman's costs up to net $32m drill spend.
27th UK Offshore Licensing Round	4Q12									Opportunity to secure blocks adjacent to existing hubs, and new redevelopment assets.

Source: Jefferies estimates, company data

Operational milestones (e.g. Kraken FDP in 1H13, Alma & Galia first oil in 4Q13) are also important catalysts

We believe ENQ will also be measured on its ability to meet key operational milestones, particularly given the impact of its Kraken and Alma & Galia projects on the company's production and cashflow. Successfully submitting the Kraken FDP on time in 1H13, plus achieving first oil from Alma & Galia on schedule in 4Q13, are two of ENQ's most important medium-term targets.

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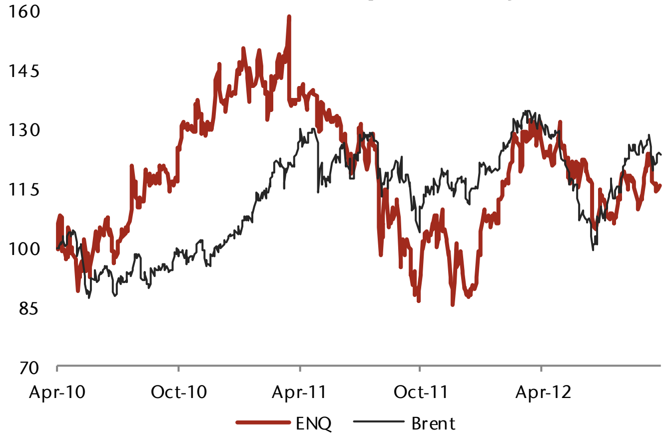
Oil price assumptions

ENQ's 100%-oil portfolio means it is highly levered to the oil price

ENQ's 100%-oil portfolio means it is one of the most highly oil price levered stocks in our coverage universe. As shown below, since its IPO ENQ has tracked the Brent crude price fairly closely, and was directly impacted by the downward trend in the oil price earlier in 2012. To mitigate this exposure the company has hedged 3mmbbl of its 2012 production, utilising put spreads at $70-95/bbl and calls at around $121/bbl.

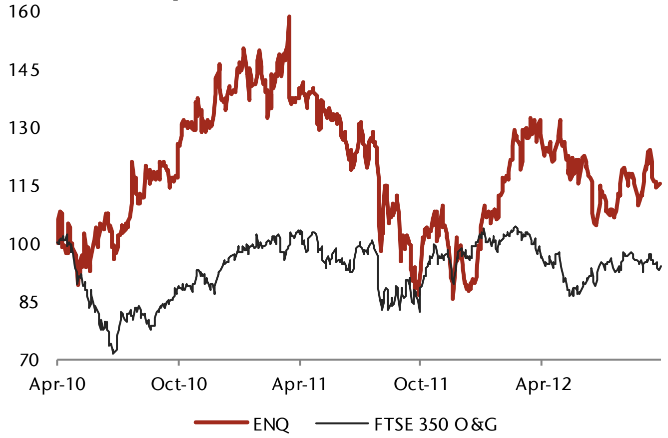
As with all our E&P valuations, our ENQ SoP uses a long-term Brent crude price assumption of $100/bbl, below both the current one-month forward price and the 2012 peak of $125/bbl. In our view this price deck represents a level that OPEC (and in particular Saudi Arabia) is willing to defend, and is supported by the marginal cost of non-OPEC supply. Sustained global economic weakness presents a key downside risk on the demand side.

Chart 3: ENQ has tracked Brent prices closely since IPO…



Index = 100 at IPO date
Source: Bloomberg

Chart 4: …and performed well vs. the FTSE350 O&G Index



Index = 100 at IPO date
Source: Bloomberg

Understandably, ENQ's cashflows (and hence our SoP valuation) are highly sensitive to prevailing crude prices. The table below shows how our valuation moves with shifts in Jefferies' long term Brent forecast.

Table 2: ENQ SoP valuation highly sensitive to LT oil price assumption

	LT Brent $/bbl	$70	$85	$100	$115	$130
WACC	**8%**	55	115	172	227	276
	10%	45	100	**153**	204	249
	12%	37	88	137	184	226
	14%	29	77	123	167	206

Source: Jefferies estimates

Strong cashflow generation

ENQ is highly cash generative

ENQ is highly cash generative. Even with up to $384m of development cost carries payable on Kraken (assuming 167mmbbl gross 2P, and hence full carry), and assuming the company pays cash tax from 2015 onwards, under our $100/bbl long-term crude forecast we estimate ENQ will deliver positive post-tax, post-capex free cashflow for the vast majority of the 2013-2020 period. By 2018, our numbers indicate the company could deliver excess free cashflow of over $600m as Kraken reaches peak production.

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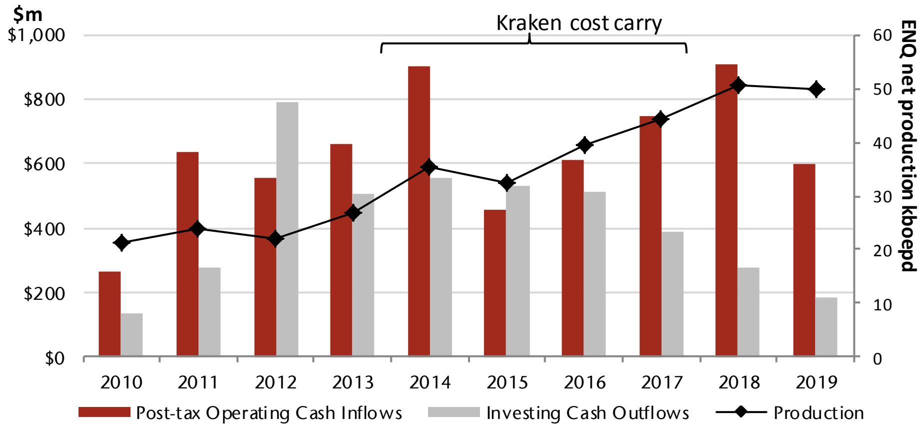
We do not expect ENQ to pay cash tax until at least 2015

ENQ's active redevelopment work on its core production assets has generated substantial capital allowances, so much so that the company is not expected to pay cash tax until at least 2015. Planned capex on the Alma & Galia and Kraken projects, plus any further new sanctioned development capex, has the potential to extend this period further; however, for now we assume ENQ will begin paying cash tax in 1H15.

Chart 5: ENQ delivers excess post-tax, post-capex cashflow despite Kraken cost



Source: Jefferies estimates, company data
Assumes ENQ pays cash tax from 2015 onwards.

At present our forecasts assume that ENQ does not need to rely heavily on its debt facility, i.e. we assume the company can fund its development plans with existing net cash balances ($92m at the end of 1H12) and forecasted operating cashflow. However, ENQ still has a substantial funding buffer through its recently-negotiated $900m revolving credit facility with a consortium of British, continental European and US banks. The facility gives ENQ an immediately committed $525m borrowing base, with a further $375m extension available – the initial term is three years, which can be extended by a further year by each of ENQ and the lenders (i.e. up to five years total). It is encouraging to see the quality of both ENQ's core portfolio and development assets validated by the debt markets.

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Possible M&A target from majors and NOCs

We believe ENQ offers an interesting M&A angle, and is likely to be on the radar of both the majors and national oil companies (NOCs). North Sea M&A activity has increased in the past 1-2 years, and in our view ENQ remains a genuine acquisition target as long as its shares continue to trade below consensus valuations (currently at a 21% discount to SoP).

We believe ENQ's 100%-oil, 100%-UK, production-heavy portfolio makes it an attractive M&A target

The key features of ENQ's portfolio that we believe would be attractive to a larger predator are:

- **A 100% oil portfolio.** ENQ's production and development assets are entirely oil-focused, which in the current oil price environment offers significantly better value than gas exposure.

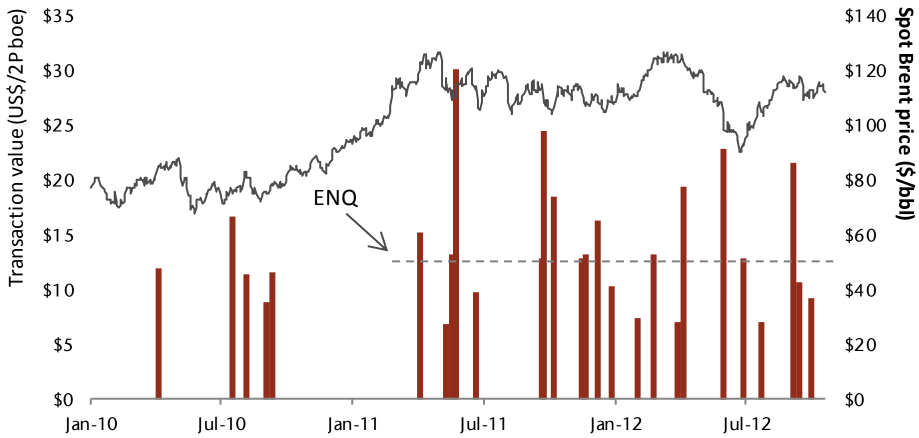
- **UK-only assets.** The North Sea is a well understood hydrocarbon province with little geopolitical risk, in our view. While there has been some unpredictability around UK oil & gas taxation in recent years, going forward we believe the risk of further tax hikes is low as the UK government looks to encourage further investment in this mature basin (as demonstrated by the recently-introduced brownfields allowance for redevelopment assets). The UK focus of ENQ's portfolio is likely to be more attractive to an NOC looking to hedge domestic energy demand, rather than the majors who have typically been recycling capital out of smaller North Sea assets.

- **Low exploration risk.** Only 1% of our ENQ SoP relates to exploration activity. This lowers the risk element of any potential acquisition, which we think would be attractive for a predator looking to secure established UKCS production rather than exploration exposure.

- **Material production outlook.** The onset of the Alma & Galia and Kraken developments (we estimate first oil 4Q13 and 4Q15, respectively) is expected to lift ENQ's net output to c.50kbopd by 2018. This level of production is material to all but the largest predator, and provides a compelling argument for any acquirer looking to secure a large production base in the North Sea.

We are also encouraged by the value of recent North Sea M&A deals, which have averaged $13.7/boe of 2P reserves since 2010 (ENQ's current EV/2P boe multiple is $12/boe, excluding Kraken's resources). In the event of any approach for the company we expect ENQ would command a premium given its low risk, oil-focused asset base – even at the average deal metric, we estimate ENQ would be worth 132p/sh, 11% above the current share price.

Chart 6: Recent UK M&A multiples typically higher than ENQ's $12/boe



Source: Thomson ONE, Jefferies estimates, company data

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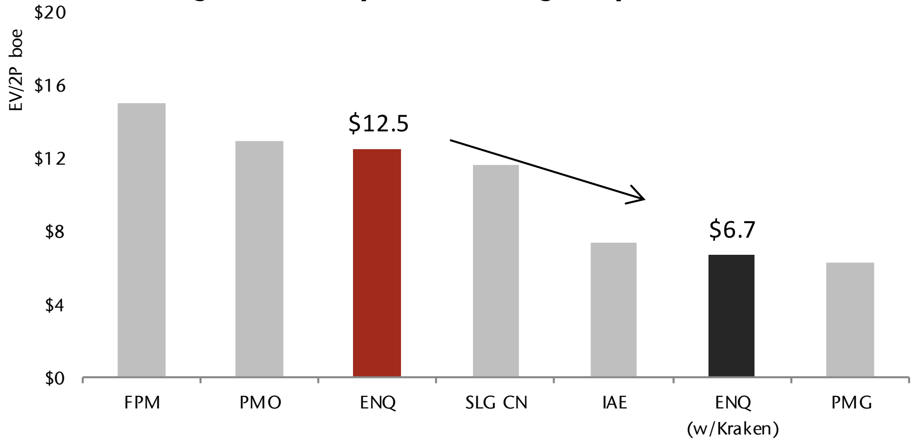
Including Kraken's 2P reserves (up to 100mmbbl) puts ENQ among the cheapest North Sea E&Ps

If we include Kraken, ENQ looks even cheaper. Using GCA's independent 167mmbbl 2P reserve estimate, once Kraken's FDP is approved (expected 1H13) we believe ENQ could book up to 100mmbbl of net 2P reserves, which when added to ENQ's FY11 year-end reserves would lift its total net 2P base to 215mmbbl. At the recent average North Sea M&A multiple of $13.7/boe, this would imply ENQ is worth 240p/sh, 99% above the current share price.

Chart 7: Including Kraken's 2P puts ENQ among cheapest North Sea E&Ps



Source: Jefferies estimates
Assumes GCA's estimated 100mmbbl of Kraken net 2P reserves added to ENQ's 115mmbbl FY11 reserves.

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ENQ's growth engine: two North Sea developments

Kraken and Alma & Galia could add up to 119mmbbl and 34kbopd...more than doubling the size of the business

ENQ's proven ability to generate significant operating cashflow has given management the flexibility to invest in two major UKCS development projects that we believe will deliver a step change to the company's reserves, production, and cashflow. Together, the **Kraken** heavy oil project (secured through corporate M&A and farm-ins) and the **Alma & Galia** development (picked up in the 26th UK licensing round) could add up to 119mmbbl to ENQ's net 2P reserves and up to 34kbopd of net incremental production by the end of the decade – potentially doubling the size of the business in terms of reserves and produced barrels.

We value ENQ's 60% stake in Kraken at $596m (47p/sh, risked at 90% CoS), and its 65% stake in Alma & Galia at $461m (36p/sh). In aggregate these two assets comprise 54% of our total ENQ SoP, which is why in this note we highlight their contribution to ENQ's long term production and reserves as a key value driver for the shares.

Table 3: Kraken and Alma & Galia are ENQ's key medium-term development projects; combined value 83p/sh

Asset	Block	Fluid	W.I. %	Partners	2P Gross	2P Net	Est. First Oil	Peak Output (kbopd)	NPV ($m)	NPV (p/sh)	Breakeven Oil ($/bbl)	Comments
Kraken	9/2b	Heavy Oil	60%	Cairn Energy (25%), First Oil (15%)	167	100	4Q15	55	596	47	$65	ENQ will fund up to $384m of Cairn/First Oil's development costs. Heavy oil allowance.
Alma & Galia	30/24, 30/25	Oil	65%	KUFPEC (35%)	29	19	4Q13	20	461	36	$62	Redevelopment picked up in 26th round. High water cut (95% in Alma). KUFPEC to carry ENQ for up to $182m. Small field allowance.

Source: Jefferies estimates, company data
Kraken assumptions use GCA's 167mmbbl 2P estimate.

The Kraken and Alma & Galia projects add sustainability to ENQ's production outlook

The impact of the two projects on ENQ's production profile, in particular, represents an important shift in how we feel the stock is perceived by the market. One oft-cited bear argument against the company was that its mature, high-decline assets meant there was little long-term value in the company. However, with Kraken and Alma & Galia estimated to lift ENQ's output to c.50kbopd by 2018, we think the company is in a strong position to re-invest the considerable cashflow spun off from these assets into new developments, extending the plateau further.

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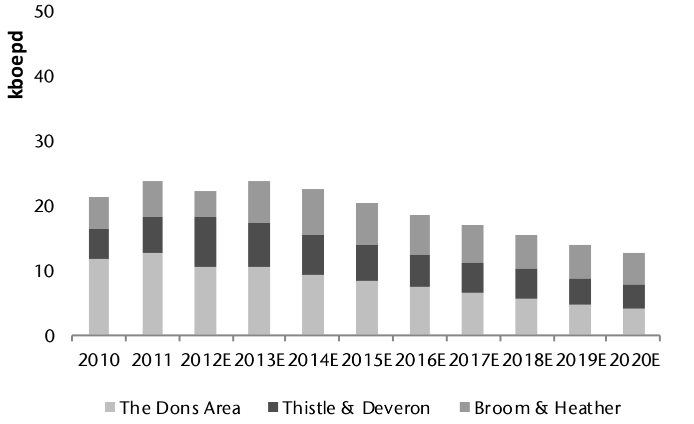
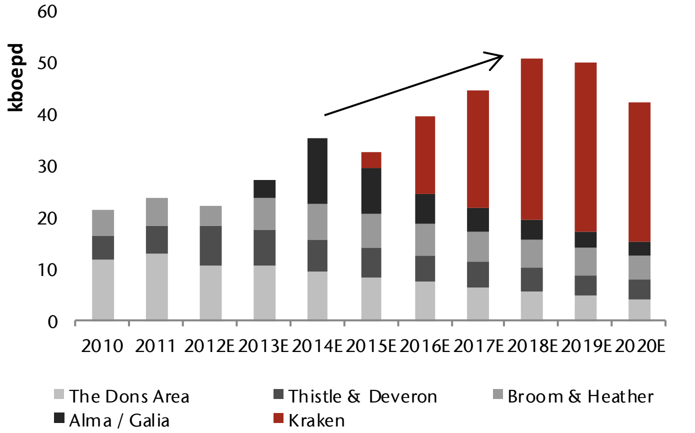
Chart 8: ENQ has moved from steady production decline…



Source: Jefferies estimates, company data
Forecast production profile excluding Alma/Galia and Kraken

Chart 9: …to visible output of c.50kboepd by end of decade



Source: Jefferies estimates, company data

Kraken: a low risk heavy oil development, 47p/sh

Kraken to be ENQ's cornerstone asset by the end of the decade

EnQuest's 60% stake in Kraken is worth $596m, or 47p/sh, to our ENQ SoP, and by the end of the decade we believe the field will be the company's cornerstone production asset. Our Kraken valuation includes adjustments for partner development costs that ENQ will fund as part of the farm-in arrangements with Cairn/Nautical and First Oil; inclusive of this cost carry we estimate the field is breakeven at around $65/bbl. We have risked Kraken at a 90% CoS pending the approval of the field FDP, due to submit 1H13.

EnQuest secured its Kraken position through three transactions in early 2012 – a takeover of Canamens (20%), and two farm-ins on similar terms to Nautical Petroleum (25%) and First Oil (15%). The deal – funded entirely through ENQ's existing resources (cash, operating cashflow, and debt facilities) – gives ENQ operatorship of the asset and represents a material uplift to the company's long-term production profile and reserve base, adding an estimated 33kbopd to net production by 2019.

Table 4: ENQ's path to 60% operated stake in Kraken

			Consideration			
Vendor	**Date**	**Stake**	**Initial**	**Deferred**	**$/bbl**	**Details**
Canamens	09-Jan-12	20%	45	45	$2.69	Second $45m payment subject to FDP approval, due early 2013.
Nautical Petroleum	24-Jan-12	25%	0	240	$5.75, $2.40 post tax	$150m development carry, with additional $90m payable if 2P reserves > 166mmbbl. Includes operatorship, surrounding acreage and earn-in option for 45% of Ketos discovery.
First Oil	26-Apr-12	15%	0	144	$5.75, $2.40 post tax	$90m development carry, with additional $54m payable if 2P reserves > 166mmbbl. Deal includes 15% of adjacent 9/6a and 9/7b blocks.

Source: Jefferies, company data
Assumes Gaffney Cline-estimated 2P reserves of 167mmbbl gross provided to Nautical Petroleum. A recently revised CPR by GCA attributed 172mmbbl of 2C resource to Kraken.

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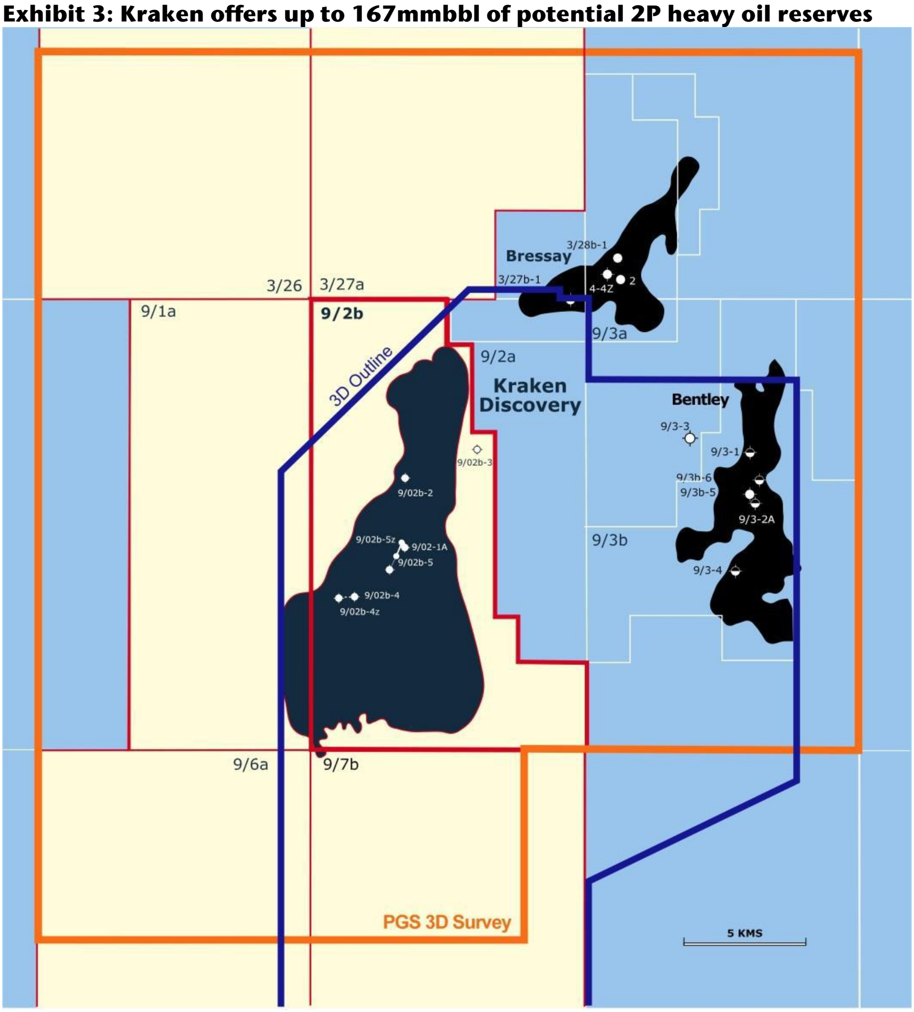
Kraken's crude is heavy (14-15°API), but its viscosity is easily manageable with a conventional development

The Kraken field is a large, three-way dip closed structure located on the East Shetland Platform in Block 9/2b of the Northern UKCS. To date, five wells and a sidetrack have been drilled on the field, identifying a commercial heavy oil accumulation in a high quality Heimdal III sandstone reservoir with no OWC observed to date. Kraken's crude is heavy (14-15° API); however, its viscosity (162cP) is considered manageable under a conventional development plan and is easily in the range of heavy crudes currently being produced commercially on the UKCS (e.g. the Captain field at 19° API and 88cP has produced c.250mmbbl since 2001). There is good appetite for North Sea heavy oil – production from the region has declined from 250kbopd at its peak to c.100kbopd today, with NW European refineries offering a straightforward route to market for new developments. As such, we expect Kraken's crude will receive a tight discount to Brent of 5% over the field's lifetime.

Exhibit 3: Kraken offers up to 167mmbbl of potential 2P heavy oil reserves



Source: Nautical Petroleum

The most recent appraisal well on Kraken, the 9/2b-5Z sidetrack, indicated excellent reservoir porosity (38%) and oil saturation (90%) with strong correlation to seismic data. Using an open-hole gravel pack completion and ESPs, the operator Nautical Petroleum delivered a maximum stabilised flow rate from Kraken of 4,550bopd with no sand or formation water produced – more than sufficient for a commercial heavy oil development. Also encouraging is that Kraken's Heimdal III reservoir is underlain by shale, and the fact that no OWC has been observed to date suggests the field's aquifer support will be via an edge-water drive. This should allow ENQ an additional degree of

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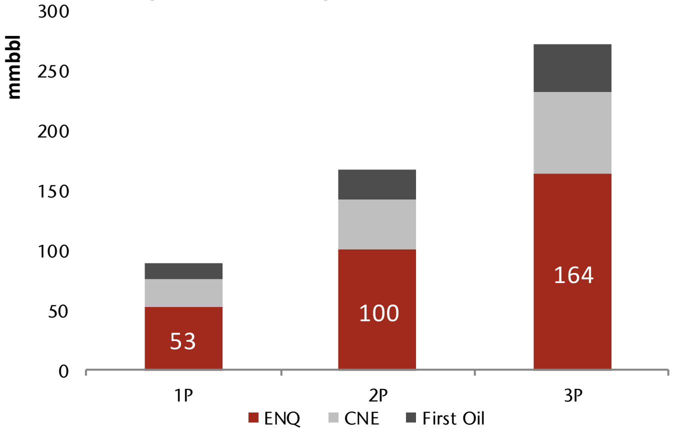
produced water control, and should allow a more efficient development design through fewer water injectors and delayed water breakthrough.

Kraken independently estimated at 172mmbbl of 2C resource

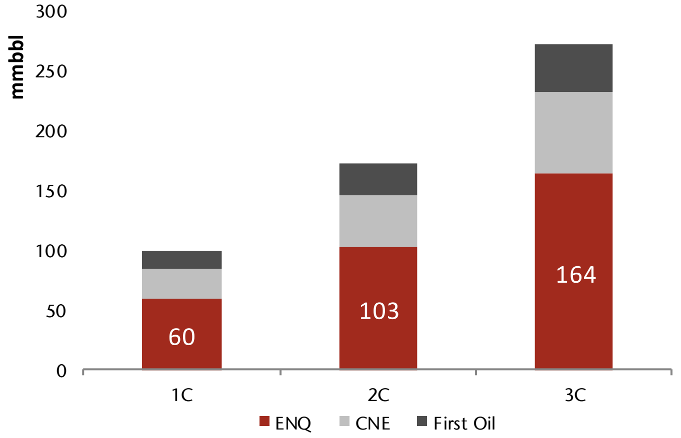
Following the results of the successful 9/2b-5Z sidetrack, Gaffney Cline provided an independent reserves opinion to Nautical Petroleum that credited Kraken with 167mmbbl of 2P reserves, taking into account the capex/opex assumptions in the draft FDP. Subsequent to this, following ENQ's acquisition of a third tranche of Kraken (from First Oil), an updated CPR from Gaffney Cline revised the independent estimate for Kraken to 172mmbbl of 2C resource. In our view, the change in classification from 2P to 2C does not necessarily mean Kraken has become more risky, only that the exact development plan is still unconfirmed. In conjunction with Kraken partners Cairn Energy (25%, recently acquired through a takeover of Nautical) and First Oil (15%), ENQ is aiming to reach FDP submission in 1H13 – we estimate first oil from the field in late 2015.

Chart 10: Original GCA CPR gave Kraken 167mmbbl 2P…



Source: Gaffney Cline, Jefferies, company data

Chart 11: …which has since been revised to 172mmbbl 2C



Source: Gaffney Cline, Jefferies, company data

Kraken development assumptions

At present we model the Kraken development in two phases, in line with the draft development plan detailed by former operator Nautical Petroleum in late 2011. Our current forecasts (which are subject to change based on ENQ's FDP) make the following assumptions:

- The development design includes a leased FPSO with oil processing capacity of 60kbopd and total costs of $450k/day. We assume $20/bbl variable opex.
- Gross capital costs amount to c.$1bn for Phase I (split evenly between drilling costs and topside facilities) and c.$500m for Phase II (mainly drilling costs), or around $12/bbl over the life of the project. Nautical's 2011 development plans suggested Phase I will look to exploit the lower risk eastern flank of the field, installing two drill centres and an 8+6 producer/injector design; Phase II will target Kraken's western side, delivering a third drill centre and using an 8+8 well concept.

We factor the maximum $384m development carry in our Kraken valuation

- In our Kraken DCF we have captured the impact of EnQuest's development cost carry agreements with Cairn (via Nautical) and First Oil. Based on the deal structure, these will reach up to $384m based on GCA's independent 2P reserve estimate of 167mmbbl, which in practise effectively means ENQ will bear 100% of Kraken's development costs from when spending begins in 2013 until around 1H17, in our view.
- Our forecasts assume first oil from Kraken in 4Q15, ramping up gradually to peak gross production of c.55kbopd in 2019 once Phase II is fully onstream. At

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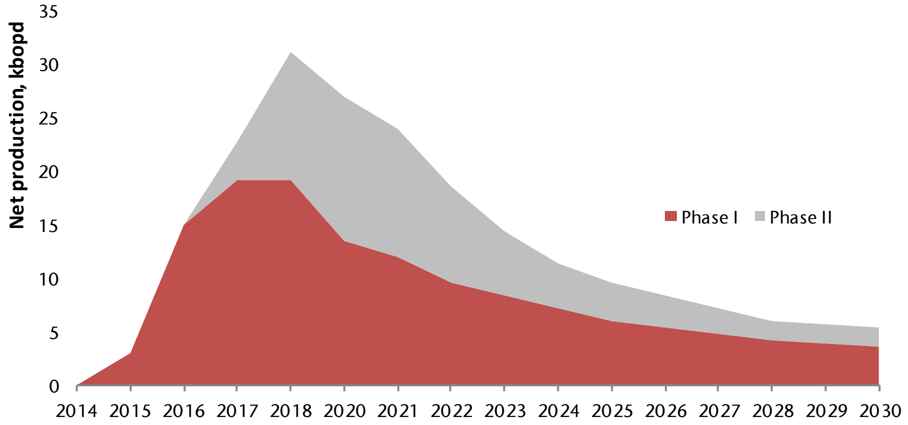
this point Kraken will be the dominant asset in ENQ's portfolio, contributing close to 70% of group production based on our current forecasts.

Kraken eligible for the UK's £800m heavy oil tax allowance

- As a heavy oil development, Kraken allows its partners to offset part of their liability for supplementary charge through the UK's £800m heavy oil field allowance (ENQ can exploit 60% of this). The field falls well within the allowance limits of API gravity below 18° (Kraken is 14-15°) and viscosity exceeding 50cP (Kraken is 162cP).

Chart 12: Estimated Kraken production profile net to ENQ, 2014-30E

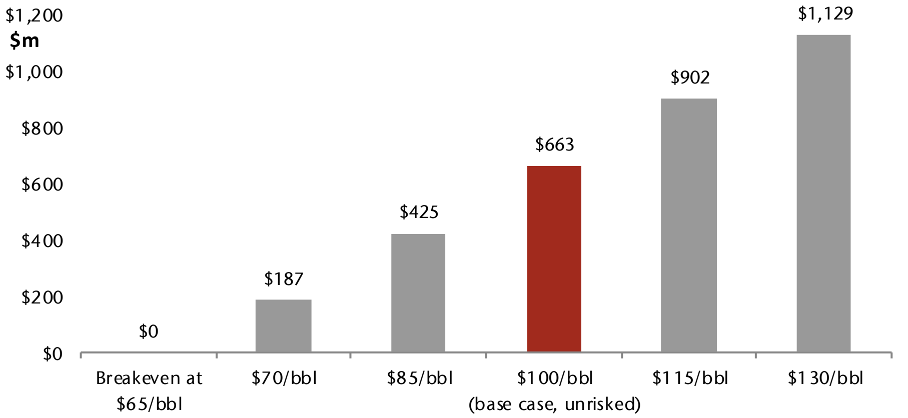


Source: Jefferies estimates, company data

We estimate Kraken breaks even at $65/bbl

Despite Kraken being technically a heavy oil asset, it remains a fairly conventional development – the FPSO-led design, low well density and helpful reservoir characteristics (low viscosity and edge-water drive) mean the project is unlikely to be unusually expensive, even for heavy oil. On a standalone basis we estimate the field breaks even at $55/bbl, suggesting that Kraken will remain economic in all but the most bearish of oil price scenarios. However, inclusive of the maximum $384m development cost carry with Cairn and First Oil, we estimate ENQ's stake in Kraken is economic only when Brent prices are in excess of $65/bbl.

Chart 13: Kraken breakeven at $65/bbl including partner carry, worth $596m (47p/sh) in risked base case



Source: Jefferies estimates
Includes maximum $384m cost carry.

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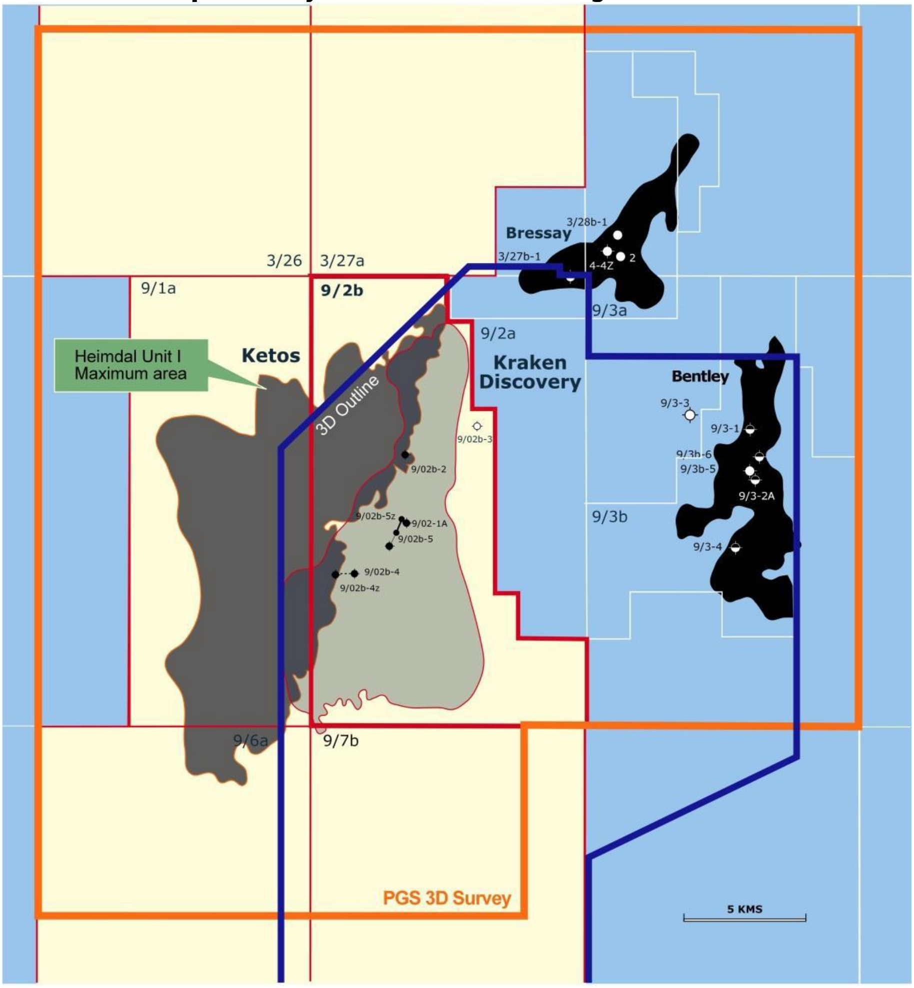
ENQ has option to farm in to 45% of Ketos by funding a two-well appraisal programme

Ketos – upside potential for Kraken area, worth 2p/sh to our SoP

As part of the Kraken farm-in agreement with Nautical (now part of Cairn Energy), ENQ gained an option to earn a 45% stake in Block 9/1a which contains the Ketos discovery. To secure a position in Ketos, ENQ must fund up to 90% of gross drilling costs for two appraisal wells; however, this is capped at 45% of Cairn/Nautical's pro rata costs for the first well ($15m gross) and second well ($20m gross). **At present ENQ has no firm plans to drill a well on Ketos**; however, we believe drilling is possible later in 2013.

Exhibit 4: Ketos potentially offers c.20mmbbl of high-value resource



Source: Nautical Petroleum

Ketos – an estimated c.20mmbbl Heimdal I structure to the west of Kraken

Ketos is a Heimdal I accumulation lying to the west of the main Kraken reservoir, where Nautical observed oil-bearing sands in the deeper interval when drilling its second Kraken appraisal well. Initial estimates suggest that a portion of Ketos could lie within Block 9/2b, meaning ENQ may already have 60% exposure to part of the accumulation. With existing 2D and new 3D seismic data suggesting the reservoir could extend much further to the west, we believe Ketos offers some significant upside potential – c.20mmbbl based on Nautical's prospective resource estimate.

Potential for tieback to Kraken means Ketos offers high value barrels

In our view this resource is particularly high value – given Ketos's proximity to Kraken, we believe any commercial discovery could be tied into the existing Kraken development fairly cheaply through subsea tiebacks. Our 2p/sh valuation of Ketos assumes a per-barrel value of $10/bbl, above than the $7/bbl we use for Kraken (including the cost carry). With ENQ owning 60% of Kraken and up to 45% of Ketos, in the long term we would expect ENQ and Cairn to equalise their interests across the two blocks; our view is that ENQ is more likely to increase its stake in Ketos than trim its exposure to Kraken.

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Alma & Galia: a classic example of ENQ's strategy

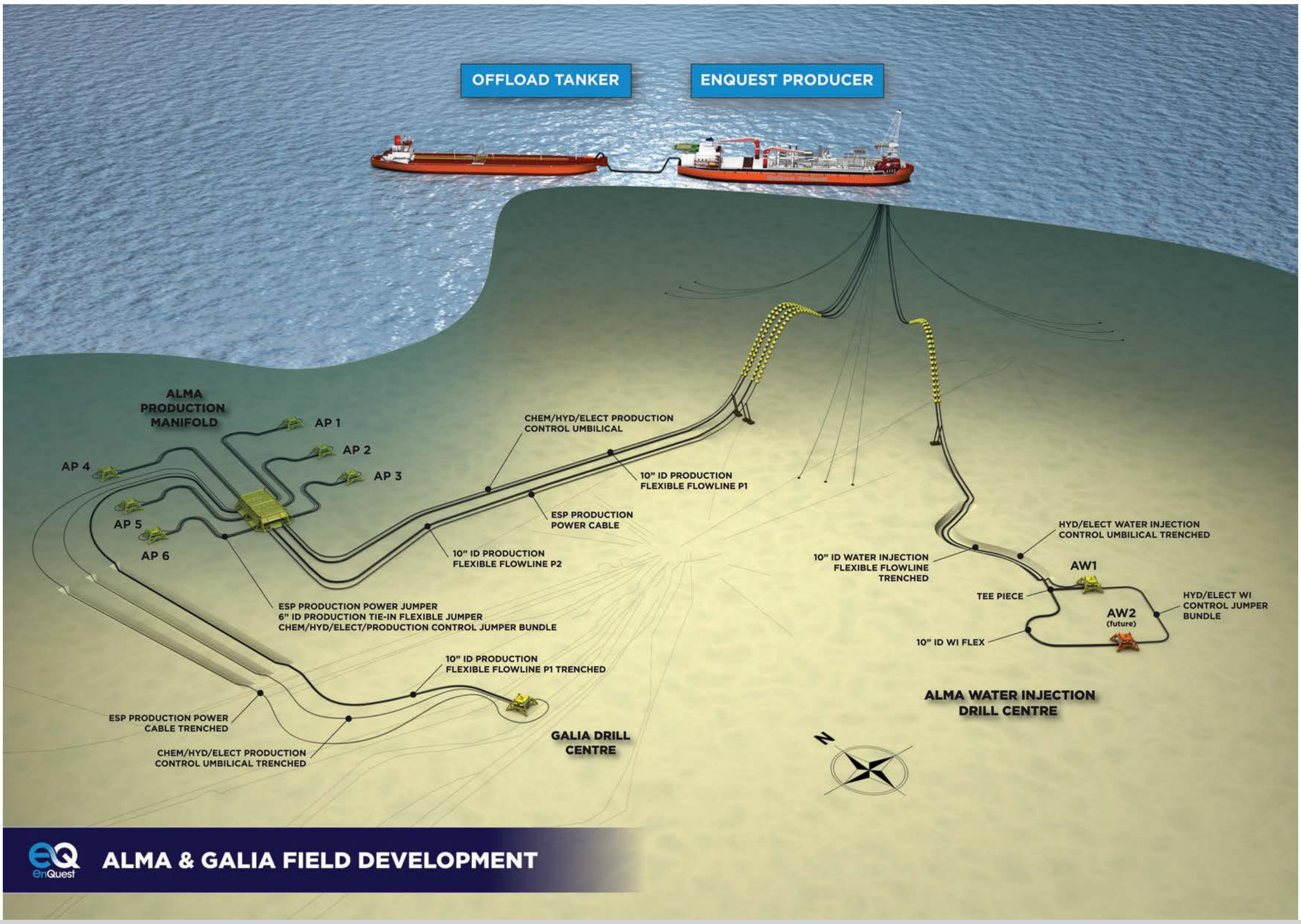
EnQuest's 65% stake in the Alma & Galia hub development is worth $461m, or 36p/sh, to our SoP. While the high expected water cut makes the project relatively expensive, it remains economic under all realistic oil price scenarios (i.e. long-term Brent >$62/bbl) and provides the primary engine of ENQ's production growth over the next three years.

Alma & Galia is a classic example of ENQ's exploitation strategy

ENQ's redevelopment of the Alma & Galia fields is a classic example of the company's North Sea strategy, i.e. leveraging its technical and operating expertise to deliver value from mature or undeveloped assets that are (a) too small for the majors and (b) outside the funding capacity of smaller players. The company secured 100% of Blocks 30/24 and 30/25, formerly known as Argyll/Ardmore and Duncan, in the 26th UK licensing round for close to zero cost, and by the end of 2011 had an FDP approved that credited ENQ with 29mmbbl of 2P light oil (38° API) reserves. During this time ENQ also sold 35% of the asset, crystallising $182m of value less than two years after the initial licence award.

Alma & Galia will feature a purchased FPSO – the EnQuest Producer, formerly the Uisge Gorm – linked to two producing drill centres (seven producers) and a water reinjection site (two injectors). The facilities will be tailored to cope with the field's high water cut, with the EnQuest Producer currently being refitted to manage up to 57kbopd and 114kbwpd, and provide water reinjection capacity of up to 95kbwpd. This is relevant for the Alma field in particular, where ENQ management believe the redevelopment can extract a further 21mmbbl by taking the field to up to 95% water cut (70% under the former operator).

Exhibit 5: Alma & Galia development to add 29mmbbl of 2P reserves and 20kbopd peak production (gross, ENQ 65%)



Source: EnQuest

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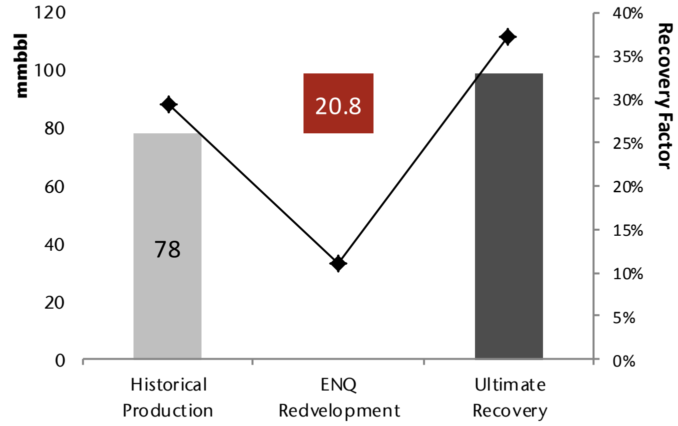
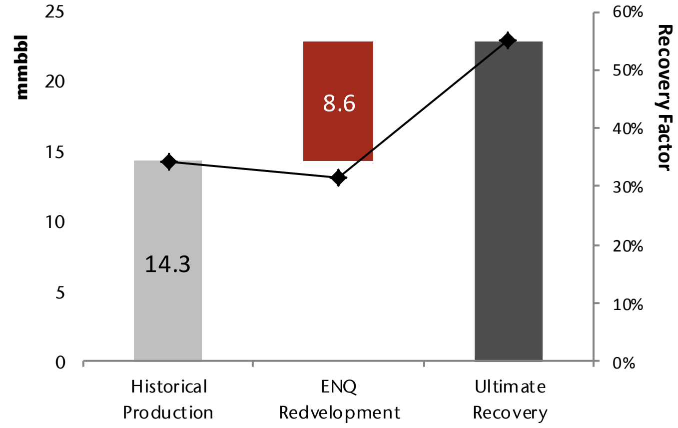
ENQ has contracted the Ocean Princess semi-sub to batch drill three wells on the site; drilling is currently underway. The company will deliver enhanced recovery from the fields by utilising proven technology – variable-speed ESPs, better surface water-handling kit, and reprocessed seismic – which allows more effective sweeping of attic oil within the reservoir. Over the next decade ENQ plans to deliver 20.8mmbbl of gross reserves from Alma and 8.6mmbbl of gross reserves from Galia.

Chart 14: Alma to deliver 21mmbbl incremental reserves



Source: Jefferies, company data
Rf % based on incremental and total recovery

Chart 15: Galia adds 9mmbbl to ENQ 2P reserves



Source: Jefferies, company data
Rf % based on incremental and total recovery

KUFPEC farm-down captures value and shows NOC interest in the North Sea

In May 2012, KUFPEC farmed in to 35% of Alma & Galia at $17.2/bbl – a good deal for ENQ

In May 2012, ENQ farmed out a 35% stake in the Alma & Galia project to the Kuwait Foreign Petroleum Exploration Company (KUFPEC) in exchange for KUFPEC's share of past costs since January 2012, and up to $182m as a future development carry for ENQ. KUFPEC's total investment is likely to reach $0.5bn inclusive of the Kuwaitis' pro rata share of future development costs. We estimate a $175m lump-sum cash payment is received in 2H12 as a payment for ENQ's back costs, with the remaining development carry utilised over 2012-14. On a per barrel basis the deal represents $17.2/bbl, towards the top end of recent UKCS M&A multiples and an excellent result for ENQ, in our view.

M&A activity by NOCs wanting entry into the North Sea is a key upside risk for ENQ

KUFPEC's re-entry into the North Sea also demonstrates the desire by large NOCs to gain material, typically non-operated stakes in producing assets in geographies with low geopolitical risk. We believe potential M&A by NOCs remains a key upside risk for ENQ given its oil-dominated, UKCS portfolio of production and development assets.

Alma & Galia development assumptions

We model the Alma & Galia development based on the purchased FPSO design and relatively expensive opex over the life of the field. Our forecasts make the following assumptions:

- Total capex of $1bn over the life of the field, weighted heavily to the key drilling phase over 2012 ($580m) and 2013 ($200m). This equates to average capex of c.$35/bbl over Alma & Galia's productive life. Our forecast is broadly in line with management's revised $1bn capex estimate provided at the time of the KUFPEC farm-in.

- Average lifetime opex of $39/bbl, though due to the fixed cost component we expect this will be significantly lower (c.$23/bbl) when the field is at its most productive over 2014-15.

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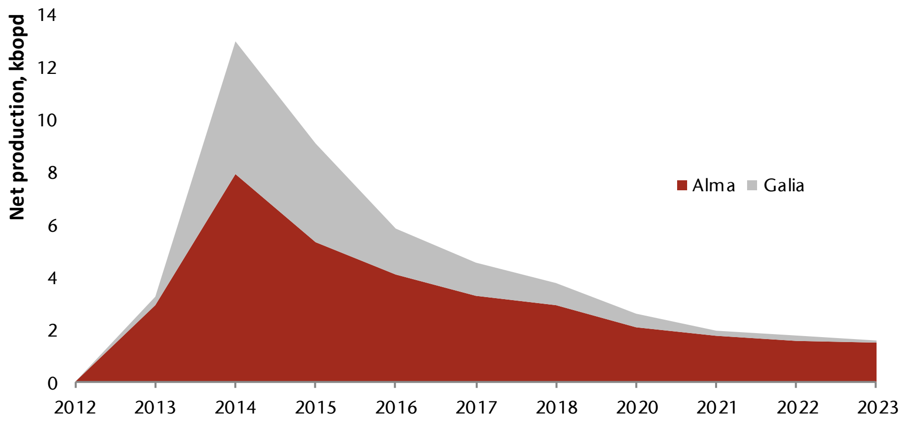
- We assume first oil from Alma & Galia in 4Q13, with gross output peaking in 2014 at 20kbopd (13kbopd net to ENQ's 65% stake). At its peak, Alma & Galia will comprise around 37% of ENQ's group output based on our forecasts; however, this tails off fairly rapidly as the fields decline and Kraken is brought onstream later this decade.
- The Alma & Galia hub development is eligible for the UK's small field allowance, allowing its partners to offset up to £150m of supplementary charge liability (ENQ can access 65% of this). As part of the FDP, ENQ was permitted to classify Alma & Galia as individual small fields and hence use the allowance to reduce its tax exposure on both assets, despite them being developed in tandem. Following the extended allowances announced in the 2012 UK Budget, the combined 29mmbbl hub development comfortably falls within the threshold for the allowance.

Chart 16: Estimated Alma & Galia production profile net to ENQ, 2012-23E



Source: Jefferies, company data

Although ENQ picked up the Alma & Galia fields very cheaply (i.e. at nominal cost in the 26th UK licensing round), with gross development capex now expected to reach close to $1bn the hub remains relatively expensive (c.$35/bbl lifetime average capex) given that gross recoverable reserves sit at 29mmbbl. This high expenditure relative to recovered resource is indicative of both (a) ENQ's approach to squeezing every last drop of value from mature or underdeveloped fields, and (b) the overall maturity of the UKCS.

We estimate Alma & Galia breaks even at $62/bbl

We estimate that the project breaks even at $62/bbl, even with the positive impact of the small field allowance. In other words, the Alma & Galia hub is economic in the current crude price environment, but has less headroom if we encounter any sustained weakness in Brent crude prices going forward.

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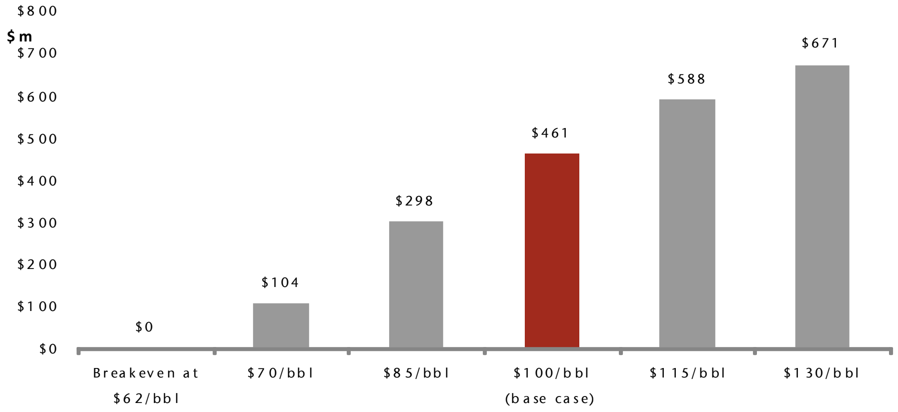
Chart 17: Alma & Galia breakeven at $62/bbl, worth $461m (36p/sh)



Source: Jefferies estimates

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Mature producing assets

ENQ's strategy is to own material, operated stakes in UKCS production hubs (e.g. The Dons, Heather & Broom, Thistle & Deveron, and the upcoming Alma & Galia), where it can drive cost efficiencies through shared infrastructure and maximise recovery from its mature assets. Since ENQ's IPO in 2010, the combination of high oil prices (Brent average $102/bbl since IPO) and active in-fill drilling has maintained strong cashflow from these fields; however, rising decline rates mean ENQ's mature portfolio is becoming less valuable.

We value ENQ's producing assets at $935m, or 74p/sh

Together we value ENQ's core producing assets at 74p/sh, or 48% of our total SoP.

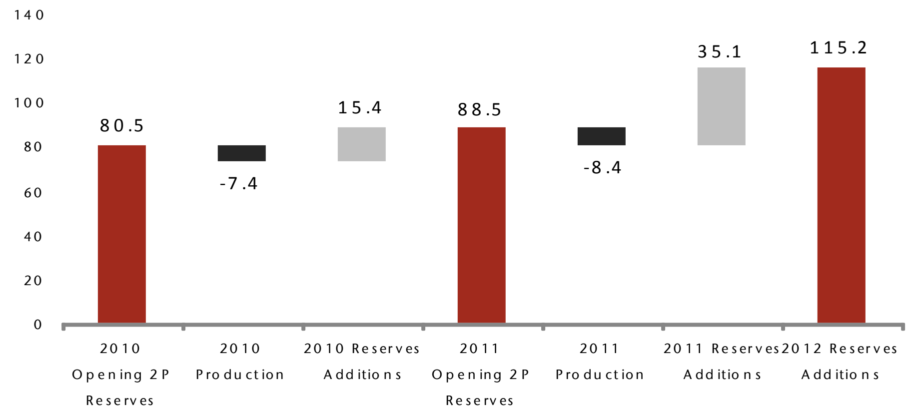
Table 5: ENQ's mature producing assets worth 74p/sh to our SoP

	Block	ENQ W.I. %	Net 2P mmbbl	$/bbl	NPV $m	NPV p/sh
The Dons Area	211/18a, 211/13b	West Don 63.45%, Don SW 60%	26	$21	538	42
Thistle & Deveron	211/18a, 211/19a	99%	25	$7	169	13
Heather & Broom	2/4a, 2/5	Heather 100%, Broom 63%	19	$12	229	18
TOTAL			**70**		**935**	**74**

Source: Jefferies estimates, company data

The company has been successful in replacing its produced barrels through in-fill drilling and new developments, due primarily to a strong in-house technical team. ENQ delivered 10% growth in 2P reserves in 2010, and the sanction of Alma & Galia in late 2011 lifted its 2P reserve base by 29mmbbl – a reserve replacement ratio of 418%. While we do not expect this level of growth in 2012, once Kraken's FDP is approved in 2013 ENQ's reserves could see another major leap as the company potentially gains up to 100mmbbl of additional net 2P reserves.

Chart 18: ENQ adds 35mmbbl 2P reserves in 2011; reserve replacement >400%



Source: EnQuest

Management guidance suggests 2012 group production is likely to dip slightly from 2011 output of 23.7kbopd, with **ENQ's FY12 net output expected to lie between 20-24kbopd; we forecast 22.2kbopd**. This small y-o-y decline reflects the maturity of

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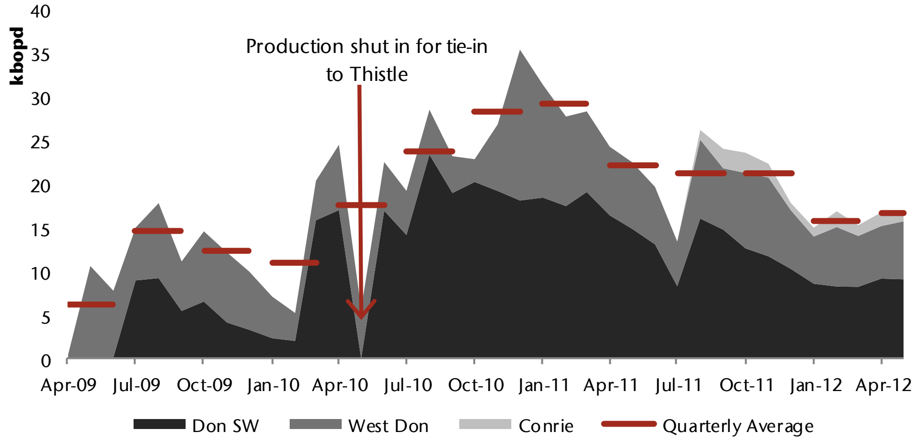
ENQ's producing portfolio, and is essentially a short-term lull before the step change in production that we expect when the Alma & Galia and Kraken developments are brought onstream in 4Q13 and 4Q15, respectively. **ENQ's early production guidance for 2013 sits at 23-28kbopd (we are at 27kbopd)**; over the medium term, we expect a net production CAGR of 14% over 2010-14.

The Dons

Ongoing development drilling is planned for The Dons Area over 2012 in order to arrest the decline of this set of fields. To date the Dons have been the cornerstone of ENQ's production (c.53% in 2011), but in our view will become marginalised once ENQ's larger developments begin producing over the next 2-3 years. With around 25mmbbl of net 2P reserves remaining the fields are still material to ENQ; however, given the in-fill drilling required to capture this residual oil we believe investment in the field offers diminishing returns. That said, the recently-introduced UK brownfields tax allowance (£250m for non-PRT paying fields) may offer ENQ an opportunity to capture more of this resource economically.

The Dons are worth 42p/sh to our ENQ SoP valuation. The key risk to our numbers is the unpredictability of the fields' decline rates.

Chart 19: The Dons Area production history



Source: DECC, Jefferies

Thistle & Deveron

ENQ's 99%-owned Thistle & Deveron fields provided 5.4kboepd (23%) of net group production in 2011, the fields' highest output in a decade. Some issues around power generation hindered the performance of water injectors onsite; however, a newly-commissioned 30MW turbine is due onstream late 2012 and is expected to boost injector performance. Two wells were planned for 2012 – the DEV-1 producer (completed in 1H12) and the ESP-supported Area 6-P1 – which we expect will lift output from the fields to over 7kbopd in 2012.

The Thistle & Deveron hub is worth 13p/share (9%) to our ENQ SoP valuation. While the field is ultimately liable for the UK's higher PRT tax regime, its decommissioning liabilities (excluding new developments) remain with its previous owner, i.e. ENQ faces minimal abandonment costs for this asset.

Heather & Broom

The Heather & Broom hub contributed 5.5kbopd (23%) to ENQ's group output in 2011, a significant y-o-y move of +20% due to slightly increased ownership (ENQ upped its Broom stake by 8% to 63% in July 2011) and better than expected well performance.

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ENQ will begin a nine-well in-fill drilling programme in 4Q12, which we estimate will increase net production from the hub by 1-2kbopd over 2012-14.

We value ENQ's stake in Heather (100% WI) and Broom (63% WI) at 18p/sh (12% of our SoP) – obvious risks are delays, performance issues, of higher-than-expected costs from the upcoming drilling campaign.

Crawford & Porter

ENQ assumed operatorship of Crawford when it acquired a 32% stake in the field from Fairfield Energy (private) in May 2011, taking its total position to 51%. The Fairfield deal included a development cost carry of up to £34.85m ($56m, or $6.50/bbl based on estimated gross 2P reserves of 26.8mmbbl).

A decision on the Crawford & Porter project is expected in 2013; however, given the complexity of the Crawford reservoir (highly compartmentalised with poor historical productivity) we believe ENQ will be examining a variety of development designs – potentially including hydraulic fracturing or multilateral wells – to optimise the field's value. We believe the project is likely to be developed as two fields, Crawford and Porter (a separate shallower Tertiary formation), meaning ENQ will be eligible for the small field tax allowance.

We value Crawford & Porter at 4p/sh. Given the uncertainty about FDP timing, for now we include the asset as a risked development – once ENQ formally selects a development design we will model the project explicitly.

Key risks

Oil price exposure

ENQ is highly levered to the oil price through its 100%-oil portfolio, meaning that any sustained weakness in global crude prices will negatively impact both our valuation and cashflow outlook. We note that ENQ's two key developments, Kraken and Alma & Galia, both have breakeven prices above $60/bbl, meaning that in the event of a major collapse in the oil price these projects would be at risk.

Development delays and cost overruns

With the large Kraken and Alma & Galia developments forming such a central part of ENQ's expected growth over the next decade, any delays to these projects or cost blowouts would have materially negative consequences for our overall ENQ SoP valuation.

Poor performance from producing assets

At present, ENQ's mature producing assets are an important source of both value (48% of our SoP) and operating cashflow. If these assets deteriorate faster than expected, or if planned in-fill drilling fails to arrest their natural decline in production, we see downside risk to ENQ's valuation and medium-term cashflow profile.

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Shareholders & Management

Amjad Bseisu, CEO

In April 2010, Mr Bseisu was appointed CEO of EnQuest when it was spun out of the Energy Developments division of Petrofac. Earlier in his career he was a founding non-executive director of Serica Energy and Stratic Energy, and in 1998 founded the operations and investment business for Petrofac, working as CEO of Petrofac Energy Developments International Ltd. Mr Bseisu holds a BSc (Hons) degree in Mechanical Engineering and an MSc and D.ENG degree in Aeronautical Engineering, and is also non-executive chairman of Enviromena Power Systems, a developer of solar services in the Middle East.

James Buckee, Non-Executive Chairman

Mr Buckee was appointed as non-executive Chairman of EnQuest in 2010, after retiring from Talisman Energy, Inc. in 2007 where he had held the roles of President and CEO since 1993. His career includes a number of senior roles with BP, including President and COO of BP Canada, Planning Manager for BP Exploration in the UK, VP of Development for BP Alaska, and operations manager for BP Norway. Mr Buckee is a non-executive director on the board of Cairn Energy, and holds a BSc (Hons) degree in Physics and a PhD in Astrophysics.

Jonathan Swinney, CFO

Mr Swinney joined the Board of ENQ in 2010, prior to which he had been working as head of mergers and acquisitions for Petrofac since 2008. His experience includes managing director within the corporate broking team at Lehman Brothers, and corporate broking experience at Credit Suisse First Boston. He is a qualified chartered accountant and solicitor.

Nigel Hares, COO

Mr Hares was appointed to ENQ's Board in 2010. Prior to his COO role at ENQ he worked as executive vice-president, international operations, for Talisman Energy, heading international operations in NW Europe, Africa, SE Asia, and Latin America. His experience also includes 22 years with BP, working in various engineering roles in the UK, Abu Dhabi, Norway and Alaska. Mr Hares also held positions of production and pipeline superintendent, manager of petroleum engineering, and manager of reservoir studies for Middle East, Europe and Africa.

Table 6: Significant ENQ shareholders

Shareholder	% stake
Amjad Bseisu	8.8%
Baillie Gifford	5.4%
Ayman Asfari	4.1%
Swedbank Robur AB	4.0%
Montanaro Asset Management	3.1%
No. of shares on issue (m)	802.7

Source: Thomson ONE

ENQ has a main market London listing and is a member of the FTSE 250.

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Faroe Petroleum (FPM LN): Initiating coverage at Buy, 240p/sh PT

We commence coverage of Faroe Petroleum with a Buy recommendation and 240p/sh price target. Faroe is a self-funded, exploration-focused E&P with assets primarily located in Norway and the UK. Although the company appears fairly valued based on Core NAV (0.85x versus peer group at 0.88x), we believe risked upside from its exploration assets and management's proven ability to create value by recycling production cashflows into the drill bit makes Faroe attractive relative to many of its North Sea peers.

Faroe's strategy is to grow production and cashflow from its 25mmboe core portfolio, and recycle this cash into an active, high-impact exploration programme that currently offers up to 84% unrisked SoP upside over the next 12 months. **Underexplored regions in the Atlantic Margin, Norwegian Sea and Barents Sea are the main focus of Faroe's long-term growth**, with the company's footprint in these regions offering investors exposure to Faroe's material working interests and favourable tax terms.

In-fill development drilling is underway across several of Faroe's producing assets, which **management expect will deliver FY12 production of 7-8kboepd (Jefferies estimate 7.7kboepd)**. We believe Faroe is fully funded to complete this redevelopment programme and its wider E&A campaign over the foreseeable future. Operating cashflow (estimated at £141m and £185m in 2012 and 2013, respectively) and debt financing ($250m committed RBL facility, plus a NOK1bn exploration facility) provide enough headroom to fund Faroe's scheduled capex, in our view, with current cash balances of £71m (post-East Foinaven) providing a solid buffer during active development drilling.

Norway's recent giant offshore discoveries and its underdeveloped acreage make **Faroe's Norwegian exposure the most exciting part of the portfolio, in our view**. The company's success in recent licensing rounds – winning operatorships and partnering with several blue-chip players (e.g., OMV, Total, Repsol) in its new acreage – reflects its strong reputation in the region. Perhaps the biggest advantage, however, is Norway's oil & gas fiscal terms, which allow Faroe to reclaim 78% of unsuccessful exploration costs and hence take more material stakes in these high-impact exploration prospects.

Key newsflow for Faroe over the next 12 months focuses on: (a) **six E&A wells** (North Uist, Spaniards East, Rodriguez South, Darwin, Novus, and Butch SW) offering a combined 150mmboe of net unrisked resource with up to 84% unrisked SoP upside; (b) the successful completion of in-fill drilling activity in Faroe's producing portfolio; and (c) the results of the UK's 27th offshore licensing round, where we expect Faroe will have focused its attention on increasing its footprint in the West of Shetlands area.

Valuation

Our sum-of-parts valuation of Faroe Petroleum is 239p/sh, implying a P/SoP multiple of 0.64 times versus the North Sea peer group on 0.67 times. Our 180p/sh Core NAV comprises full-field NPV-10 valuations of Faroe's core production assets using our $100/bbl long-term Brent forecast, with upside value provided by 59p of risked exploration assets.

Risks

Faroe's exploration and appraisal activity presents the biggest uncertainty for investors, and with c.25% of our SoP valuation exposed to E&A we see ongoing risks around the commerciality of these assets. Commodity prices below our long-term $100/bbl Brent and $9.14/mcf UK NBP gas forecasts present a downside risk to our Faroe valuation. While we see little funding risk for Faroe in the medium term due to its solid cash balances, operating cashflow and debt facilities, the future availability of suitably-priced acquisition or development opportunities is not guaranteed.

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Exhibit 1: Faroe Petroleum SoP summary

Region	Asset	Hydrocarbon	FPM W.I. %	Resource Size (mmboe) Gross	Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV p/sh	Unrisked p/sh	SoP Upside %
Producing assets	**Key assets**											
United Kingdom	Blane, Schooner, Topaz, East Foinaven	Oil/Gas	Various		7	100%	7	23	162	48	48	
Norway	Njord, Brage, Ringhorne East	Oil/Gas	Various		18	100%	18	23	419	125	125	
							25		**581**	**173**	**173**	
Development assets												
UK - West of Shetland	Glenlivet	Gas	10%	50	5	60%	3	4	12	4	6	1%
UK - West of Shetland	Tornado	Oil/Gas	7.5%	47	4	40%	1	4	6	2	4	1%
UK - Central North Sea	Perth	Oil	8.4%	41	3	80%	3	9	25	7	9	1%
Norway - Norwegian Sea	Fogelberg	Gas-Cond	15%	68	10	50%	5	5	24	7	15	3%
Norway - Southern North Sea	Butch	Oil	15%	45	7	75%	5	6	31	9	12	1%
							17		**99**	**29**	**47**	**7%**
2012-3 Exploration & Appraisal												
UK - West of Shetland	North Uist	Oil	6.3%	213	13	28%	4	8	31	9	33	10%
UK - Central North Sea	Spaniards East	Oil	8.4%	30	3	20%	1	8	4	1	6	2%
Norway - Norwegian Sea	Rodriguez South	Oil/Gas	30%	117	35	18%	6	5	30	9	50	17%
Norway - Barents Sea	Darwin	Oil	12.5%	450	56	10%	6	5	29	9	85	32%
Norway - Norwegian Sea	Novus	Oil	50%	70	35	15%	5	5	27	8	53	19%
Norway - Southern North Sea	Butch SW & E	Oil	15%	50	8	25%	2	6	12	3	14	4%
							23		**132**	**39**	**241**	**84%**
Further drilling												
UK - West of Shetland	Freya	Oil	50%	27	14	30%	4	8	33	10	33	10%
UK - West of Shetland	Fulla	Oil	50%	12	6	58%	3	8	29	8	15	3%
Norway - Southern North Sea	SE Tor	Oil	10%	16	2	40%	1	6	4	1	3	1%
							8		**66**	**20**	**51**	**13%**

Valuation Multiples				
FPM share price	153p	No. of Shares	212.4	m
Core NAV	180p	Market Cap.	£324	m
P / Core NAV	**0.85**	Enterprise Value	£241	m
P / SoP	**0.64**	2P Reserves	25.4	mmboe
Upside to SoP	56%	**EV/2P boe**	**$15.02**	**/boe**

FPM Core NAV	$m	p/sh
Producing Assets	581	173p
Development Assets	99	29p
Cash / (Net Debt)	131	39p
G&A	-151	-45p
Decommissioning Liabilities	-57	-17p
Core NAV	**603**	**180p**

FPM Sum of Parts Valuation	$m	p/sh
FPM Core NAV	603	180p
2012-13 Exploration & Appraisal	132	39p
Further Drilling	66	20p
Sum of Parts	**801**	**239p**

Source: Jefferies estimates

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Exhibit 2: Faroe Petroleum financial summary

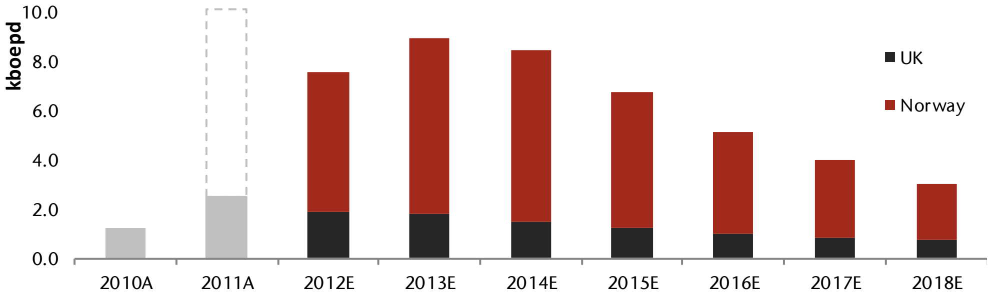
P&L		2010A	2011A	2012E	2013E	2014E
Revenue	£m	15	80	164	178	167
Cost of Sales	£m	-20	-52	-86	-97	-92
Exploration Writeoffs	£m	-14	-42	-76	-40	-18
G&A	£m	-7	-10	-12	-13	-13
Other	£m	0	40	2	0	0
Pre-tax Operating Profit	£m	-25	16	-8	27	44
Net Finance Income/(Expense)	£m	-1	-2	-1	-5	0
Pre-tax Profit	£m	-26	14	-9	23	44
Tax	£m	6	33	18	-6	-12
Net Profit incl exceptionals	£m	-20	47	8	16	31
EBIDAX	£m	7	73	159	145	48
EV/EBIDAX	x	33.3	3.3	1.5	1.7	5.0
No. of Shares	m	212	212	212	212	212
EPS	p	-13	22	4	8	15
DPS	p	0	0	0	0	0

Cashflow Statement		2010A	2011A	2012E	2013E	2014E
Cashflow from Operations	£m	16	42	141	185	92
Cashflow from Investing	£m	-47	-42	-225	-148	-69
Cashflow from Financing	£m	118	-22	26	-25	-25
Net Change in Cash	£m	87	-22	-58	12	-2

Balance Sheet		2010A	2011A	2012E	2013E	2014E
Cash	£m	132	112	51	63	61
Exploration Assets	£m	103	100	136	169	166
Prod'n & Devel. Assets	£m	10	105	189	228	247
Long Term Debt	£m	0	0	-11	14	39
Provisions	£m	-61	-99	-132	-224	-231
Shareholder Equity	£m	181	231	240	257	288
Gearing: Net Debt(Cash)/Equity	%	-73%	-48%	-26%	-19%	-8%

12-month Catalysts	FPM WI %	CoS %	Risked NAV $m	Risked NAV p/sh	SoP Upside %
North Uist	6%	28%	31	9	10%
Spaniards East	8%	20%	4	1	2%
Rodriguez South	30%	18%	30	9	17%
Darwin	13%	10%	29	9	32%
Novus	50%	15%	27	8	19%

Production Summary		2010A	2011A	2012E	2013E	2014E
FPM production WI	kboepd	1.2	2.5	7.7	8.9	8.5



SoP sensitivity to Brent & WACC						
	LT Brent $/bbl	$70.00	$85.00	$100.00	$115.00	$130.00
WACC	8%	209	231	253	275	297
	10%	197	218	**239**	259	280
	12%	186	206	225	245	265
	14%	176	195	213	232	251

Assumptions		2010A	2011A	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58

Source: Jefferies estimates

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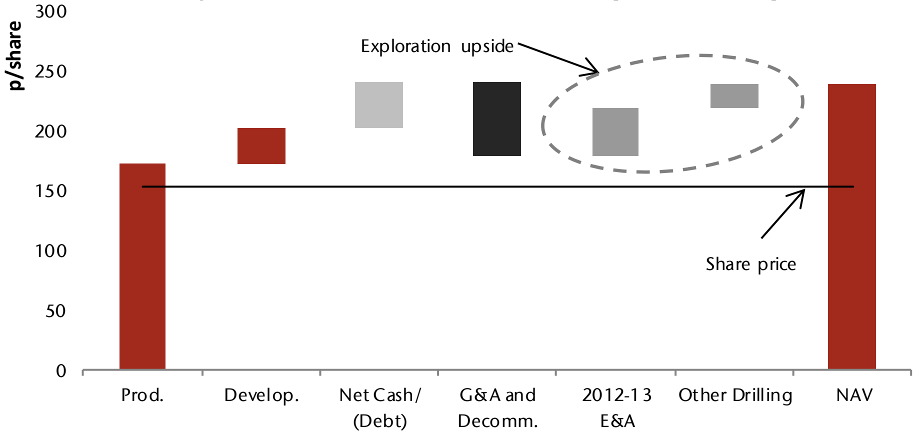
Valuation

FPM's high-impact exploration campaign could deliver 84% unrisked upside to our 239p/sh SoP valuation

Our sum-of-parts valuation of Faroe Petroleum is 239p/share, placing the shares on a 36% discount to our SoP. The shares look relatively fairly valued at 0.85x (sector average 0.88x) our 180p/sh Core NAV, which includes minority stakes in a set of producing assets in the UK and Norway; however, we believe the real reason for owning Faroe is its exploration portfolio. The company's drilling strategy focuses on high-impact wells in underexplored regions in Norway and the Atlantic Margin, where Faroe will chase 150mmboe of net unrisked prospective resource across six wells due to complete in the next 12 months. Together these wells could deliver 84% upside to our SoP on a fully derisked basis.

With FPM fully funded to complete its planned E&A programme, our 240p/sh price target is set broadly in line with our SoP. With 57% upside to this target we commence coverage of FPM with a Buy rating.

Chart 1: FPM fairly valued vs. Core NAV; offers 84% upside from exploration



Source: Jefferies estimates

While much of Faroe's core value is priced in, we believe the real upside lies in its exploration portfolio – a set of high-impact wells led by a strong management team in underexplored regions of the Barents Sea and West of Shetland regions. With a drilling success rate averaging c.50% since 2009, plus a strategic shift into Norway that brings tax benefits, in our view Faroe offers some of the best exploration value in the North Sea E&P sector.

Table 1: Faroe's 12 month E&A catalysts chasing 150mmboe of net prospective resource

Region	Asset	FPM WI %	Gross (mmboe)	Net (mmboe)	CoS %	$/boe	NPV $m	Risked NPV p/sh	SoP upside %
UK - West of Shetland	North Uist	6%	213	13	28%	8	31	9	10%
UK - Central North Sea	Spaniards East	8%	30	3	20%	8	4	1	2%
Norway - Norwegian Sea	Rodriguez South	30%	117	35	18%	5	30	9	17%
Norway - Barents Sea	Darwin	13%	450	56	10%	5	29	9	32%
Norway - Norwegian Sea	Novus	50%	70	35	15%	5	27	8	19%
Norway - Southern North Sea	Butch SW & E	15%	50	8	25%	6	12	3	4%
TOTAL			**930**	**150**			**132**	**39**	**84%**

Source: Jefferies estimates, company data

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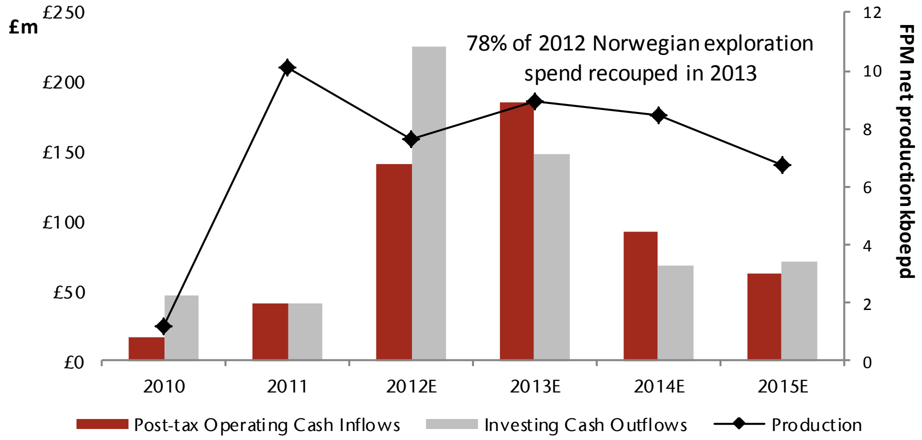
FPM funded for upcoming E&A and development capex through operating cashflow and debt facilities

Faroe funded for all foreseeable E&A and development capex

We believe Faroe is sufficiently funded to complete its planned redevelopment programme and E&A campaign over the foreseeable future. The company's operating cashflow (estimated at £141m and £185m in 2012 and 2013, respectively) and debt financing ($250m committed RBL facility, plus a NOK1bn exploration facility) provide enough headroom to fund all the company's scheduled development and exploration spending, on our forecasts. In addition, Faroe's current cash balances of £71m (post the acquisition of East Foinaven) provide a solid buffer during times of active development capex (e.g., the Norwegian in-fill drilling programme over 2012-13),

Chart 2: Faroe's cash, OpCF and debt facilities sufficient to fund capex



Source: Jefferies estimates, company data
2011 data shows 10.1kboepd economic production; actual accounting production was 2.5kboepd.

Production outlook

After the eight-fold jump in Faroe's net economic production (from 1.2kboepd to 10.1kboepd inclusive of a full year contribution from the new assets) that resulted from the Petoro asset swap in 2011, the medium term outlook for Faroe's output is highly dependent on the success of in-fill development drilling at the Njord, Brage, Ringhorne East, and Schooner fields. This work programme is targeted mainly at arresting the natural decline in the fields and maximising recovery from what are, in some cases, quite complex reservoirs – e.g., the Njord field is highly segmented and relies on constant in-fill drilling to access new fault blocks.

Faroe's management expects 2012 production of 7-8kboepd; we estimate 7.7kboepd.

Faroe's **management has given guidance for 2012 net production of between 7-8kboepd (Jefferies estimate 7.7kboepd).** This represents a material step up from Faroe's 2.5kboepd effective production over 2011 (which includes a part year contribution from the Petoro assets); however, when compared to the assets' actual 2011 output (10.1kboepd) reflects a y-o-y decline. We expect redevelopment work on the current portfolio will drive production growth over 2012-13.

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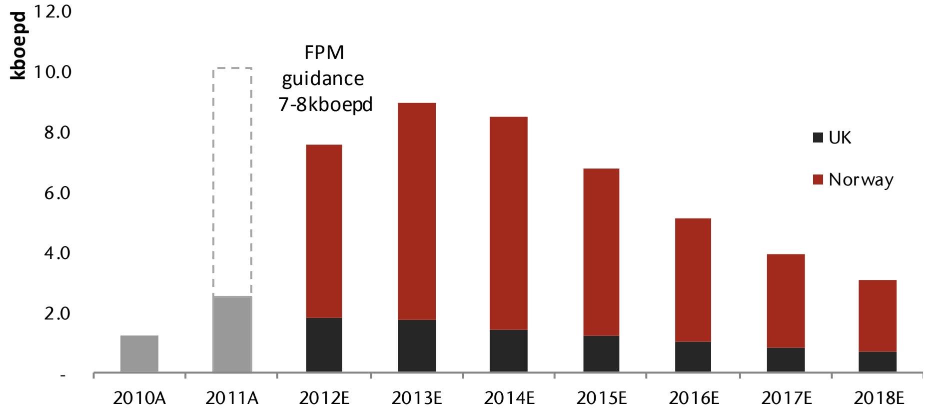
Chart 3: Redevelopment drilling drives 2012-14 production growth



Source: Jefferies estimates, company data
2011 data shows 2.5kboepd accounting output and 10.1kboepd economic output.

Oil price forecast

Our field NPVs of Faroe's producing assets use our $100/bbl Brent and $9.14/mcf UK NBP long-term price deck. Our oil price outlook is below both the current one-month forward price and the 2012 peak of $125/bbl. In our view this forecast represents a level that OPEC (and in particular Saudi Arabia) is willing to defend, and is supported by the marginal cost of non-OPEC supply. Sustained global economic weakness presents a key downside risk on the demand side.

Table 2: Sensitivity of our FPM SoP valuation Brent crude prices (p/share)

	LT Brent price $/bbl				
WACC	**$70**	**$85**	**$100**	**$115**	**$130**
8%	209	231	253	275	297
10%	197	218	**239**	259	280
12%	186	206	225	245	265
14%	176	195	213	232	251

Source: Jefferies estimates

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FPM's key medium-term catalysts include six E&A wells, in-fill development drilling, and a UK licensing round

Medium term catalysts include wells, developments, and licensing rounds

We believe the most value-sensitive pieces of newsflow for Faroe over the next 12 months are:

- **Six-well E&A programme in the UK and Norway.** Faroe's visible drilling catalysts include results from the North Uist, Spaniards East, Rodriguez South, Darwin, Novus, and Butch SW wells. Together we estimate these six results offer up to 150mmboe of net unrisked resource potential in the next year, and could add 84% to our SoP valuation if fully derisked.

- **Successful in-fill development drilling.** Planned in-fill wells at several of Faroe's production assets (e.g., Njord, Brage and Ringhorne East) are not typical catalysts for such an exploration-biased company. However, extending and enhancing the productive life of these fields offers better medium-term cashflow generation, which in turn gives Faroe the funding firepower to maintain its active exploration campaign.

- **UK license awards.** Another important catalyst for Faroe will be results of the 27th UK offshore licensing round, where results are due in 4Q12. As an exploration-focused business, securing new acreage via license awards is a crucial means of growing and improving Faroe's drilling portfolio. We believe Faroe's focus in the current bid round will have been on the Atlantic Margin/West of Shetland region, where management will seek to add new blocks in the area to (a) complement its existing assets, and (b) take advantage of the UK's new £3bn tax allowance for developments West of Shetland.

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Faroe's strategy: recycling production cashflows into high impact exploration

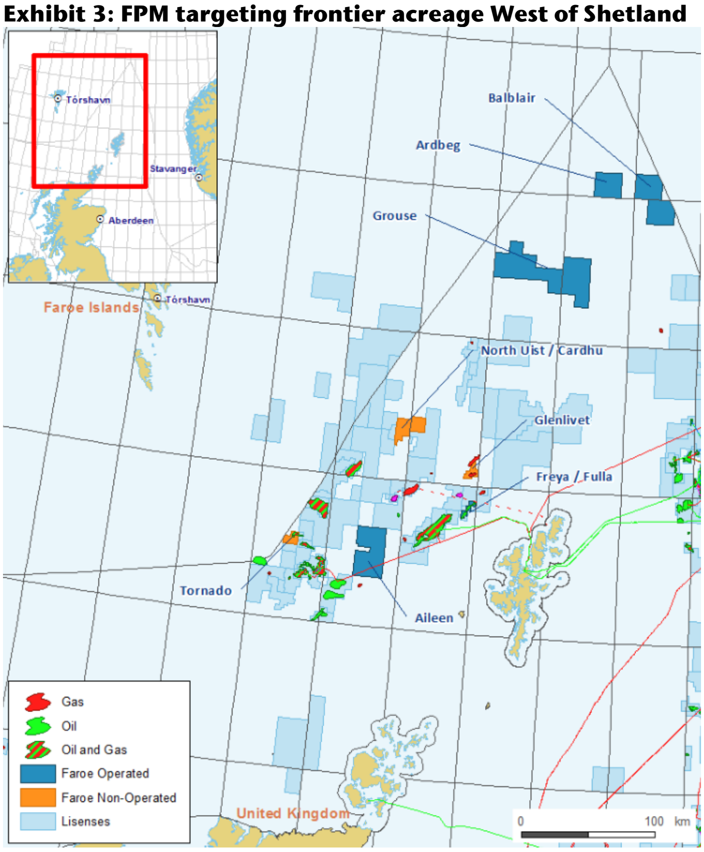
Faroe's producing assets are effectively a funding source for its high-impact exploration portfolio

Faroe has enjoyed some meaningful growth in its production and reserves over 2011-12; however, the modus operandi of the business continues to be a **self-funded explorer**. The producing assets, while expected to deliver £141m and £185m of operating cashflow in 2012 and 2013, respectively, are effectively just a source of funding for the real growth engine of the business – Faroe's exploration portfolio.

Management aim to drill five material E&A wells per year

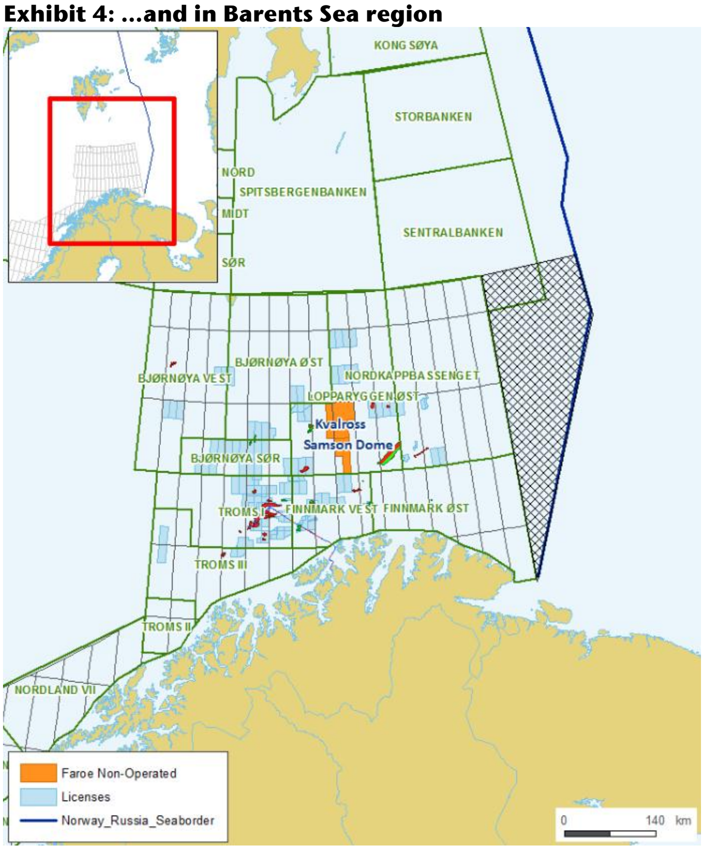
This exploration activity is mainly targeted at frontier regions (West of Shetlands in the UK, and the Barents Sea in Norway), plus near-field drilling primarily in the mature Norwegian Sea and North Sea. Management's rule of thumb is to drill around five material exploration and/or appraisal wells each year, which we estimate will cost on average £5-10m per well net to Faroe after the Norwegian tax rebate.

Exhibit 3: FPM targeting frontier acreage West of Shetland



Source: Faroe Petroleum

Exhibit 4: …and in Barents Sea region



Source: Faroe Petroleum

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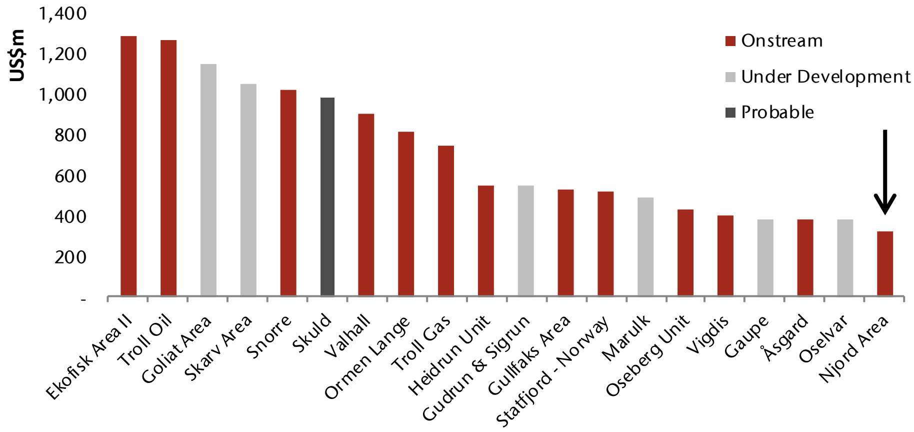
Optimising production portfolio is key to maintaining FPM's self-funded exploration model

Faroe's self-funding exploration model means that the performance of its producing assets is a key driver of how actively the company can execute its exploration campaign. Maximising production (and hence cashflow) from these assets reduces Faroe's future dependence on its cash balances and debt facilities, allowing management to allocate more capital to maturing new prospects and drilling more wells. Optimising its production portfolio is therefore a high priority for the company. For a business that is not traditionally a major developer, its 7.5% share of the Njord Area redevelopment is material – the project features in the Top 20 largest Norwegian developments (by capex) in 2011/12.

Chart 4: Faroe's Njord project makes Top 20 Norwegian developments in 2011-12



Source: Wood Mackenzie

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Norway the focus of Faroe's growth

Johan Sverdrup and Skrugard prove world class discoveries are still available in Norway

A combination of attractive fiscal terms, recent major discoveries and massively underdeveloped acreage has driven a sharp uplift in Norwegian exploration, and as an existing producer & explorer in all Norway's major hydrocarbon basins we believe Faroe is well placed to benefit from continued interest in the region. Major finds such as Skrugard/Havis (515mmboe discovered in the Barents Sea by Statoil in 2011) and Johan Sverdrup (ex-Aldous/Avaldsnes, 1.7-3.3bnboe discovered in the Norwegian North Sea by Statoil and Lundin in 2010/11) have proven that world-class oil & gas discoveries are still available in Norwegian waters.

Faroe's Norwegian E&A portfolio offers 135mmboe of net prospective resource over the next two years

We believe Norway will be a significant driver of growth for Faroe, both from the mature North Sea basin and the underexplored, higher impact Norwegian Sea and Barents Sea. A Norwegian asset swap in 2011 delivered a step change in Faroe's group production and reserves and offers further organic upside though ongoing in-fill development. In addition, Faroe has material stakes in several potentially high impact exploration prospects offshore Norway that will target 135mmboe of net prospective resource over the next two years.

Table 3: Faroe's 2012-14 Norwegian exploration programme targets 135mmboe of net prospective resource

Prospect	Approx. Timing	Region	FPM WI %	Gross mmboe	Net mmboe	CoS %	NPV $m	NPV p/sh	SoP Upside %
Rodriguez South	1Q13	Norwegian Sea	30%	117	35	18%	30	9	17%
Darwin	1Q13	Barents Sea	12.5%	450	56	10%	29	9	32%
Novus	3Q13	Norwegian Sea	50%	70	35	15%	27	8	19%
Butch SW & E	3Q13	North Sea	15%	50	8	25%	12	3	4%
SE Tor	Unknown	North Sea	10%	16	2	40%	4	1	1%
Total Norway Exploration				**703**	**135**		**101**	**30**	**73%**

Source: Jefferies estimates, company data

Licensing round success reflects Faroe's reputation

Faroe was awarded seven new blocks in the latest Norwegian APA licensing round

With Norway now the major focus for Faroe's long-term growth, in our view, it is encouraging to see management successfully using licensing rounds to build up the long-term drilling portfolio. Norway has two routes to accessing new acreage – the annual APA ("awards in pre-defined areas") licensing round, which focuses on blocks close to existing infrastructure, and the bi-annual Norwegian Licensing Round which awards blocks in more frontier locations. Faroe gained three licenses in the 2010 APA round, with a further Barents Sea block awarded in May 2011. However, the most recent round saw a big step-up for Faroe, with the company gaining seven new blocks (three of which are operated) in the 2011 APA awards with stakes ranging from 20% to 75%.

Table 4: Faroe enjoys successful 2011 Norwegian APA licensing round

Region	Prospect	FPM WI %	Partners
Norwegian Sea			
Halten Terrace	Novus	50%, operator	Centrica (40%), Skagen 44 (10%)
Halten Terrace	Aerosmith	20%	OMV (30%, operator), Repsol (20%), Centrica (20%), Skagen 44 (10%)
Norwegian North Sea			
NNS	Oksen	20%	Det Norske (40%, operator), Noreco (20%), Bayerngas (20%)
NNS	Shango	20%	Total (40%, operator), Centrica (20%), Det Norske (20%)
NNS	Darling	20%	Bridge (40%, operator), Concedo (20%), Centrica (20%)
Egersund Basin	Epsilon	75%, operator	Noreco (25%)
Egersund Basin	Lola	50%, operator	Noreco (25%), Edison (25%)

Source: Faroe Petroleum

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Faroe's licensing round success shows it is a credible, able explorer and a desirable partner

In addition to filling Faroe's pool of longer-term drilling opportunities, it also highlights that Faroe is increasingly considered to be a credible, able explorer that both the Norwegian government and industry partners want to work with. Partnering with blue-chip players like OMV, Repsol and Total highlights the quality of the new acreage, and also provides a set of natural buyers of Faroe's stake should it wish to farm down its position post any E&A success.

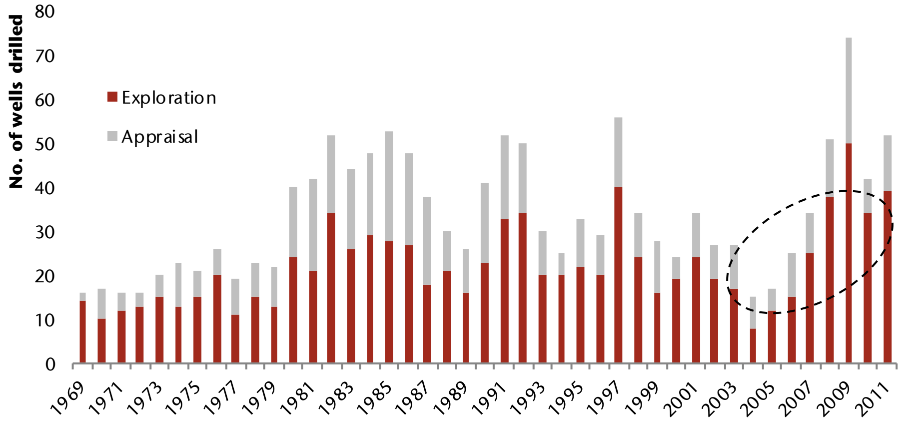
Norway's fiscal regime offers huge benefits for explorers

One clear advantage to Faroe's active Norwegian exploration campaign is the local fiscal terms. Introduced in 2005, **Norway's current regime allows companies to claim back 78% of their unsuccessful exploration expenditure in cash** in the year after drilling, limiting explorers' financial exposure through the drilling process and providing a significant incentive to invest in Norway. The flipside is that once commercial discoveries are made producers face a 78% tax burden on their oil & gas revenues; however, with giant discoveries (e.g., Johan Sverdrup) still being made offshore Norway the risk-reward of Norwegian drilling remains very attractive.

Norwegian fiscal terms essentially transfer exploration risk from E&Ps to the government

The regime essentially transfers part of the exploration risk usually borne by the E&Ps to the Norwegian government. One way of thinking about this is that the government is prepared to part-fund (and hence incentivise) exploration in Norwegian waters in anticipation of any commercial discoveries being subject to Norway's very high 78% oil & gas tax once they enter production. In other words, Norway is prepared to wear the short-term cost of unsuccessful exploration in exchange for the long-term tax revenues of large oil & gas discoveries.

Chart 5: Norwegian tax rebate drives material uplift in drilling activity



Source: Wood Mackenzie

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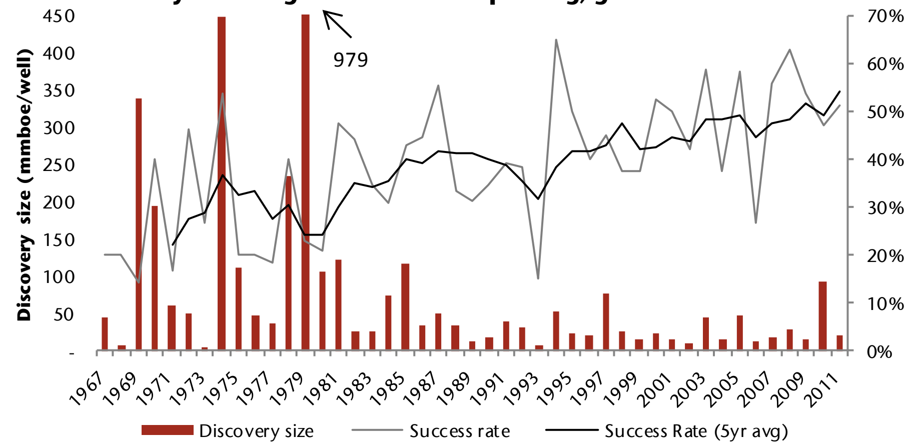
Chart 6: Norway's drilling success rates improving; giant discoveries still rare



Source: Wood Mackenzie

Norway's exploration rebate allows Faroe to hold more material stakes in Norwegian exploration assets

The direct impact on Faroe of the supportive Norwegian tax regime is that it can hold larger stakes in its exploration prospects, and therefore have a more material exposure to the wells, than comparable assets in other geographies. Compare Faroe's interest in its UK exploration assets North Uist (6.3%) and Spaniards East (8.4%) with the Norwegian wells Rodriguez South (30%), and Novus (50%).

Norway's tax rebate on unsuccessful exploration also minimises Faroe's financial exposure to its riskier activities, which is meaningful when we estimate Faroe's pre-rebate exploration expenditure will reach £110m in 2012 and £80m in 2013. Shareholders' **exposure to exploration in Norway is leveraged even further by Faroe's NOK1bn (c.£110m) Norwegian exploration debt facility**, which allows Faroe to borrow up to 75% of its net exploration expenditure in any given year – this debt is then repaid once the tax rebate is received in cash the following year.

Is the 2011 Petoro deal a signal of Faroe's future strategy?

2011 asset swap with Petoro gives Faroe a raft of benefits; may hint at model for future growth strategy

We believe Faroe's 2011 asset swap with Petoro AS, the manager of Norway's state-owned oil & gas assets, may hint at the company's future strategy for creating value from its Norwegian and UK portfolio. In this transaction, Faroe traded its 30% stake in the undeveloped Maria discovery (27mmbbl net to Faroe) for interests in four smaller Norwegian producing fields, delivering a step change in both Faroe's 2P reserves (+14mmbbl) and production (+7.6kboepd). The deal also gave Faroe a raft of additional benefits, including:

- **Organic upside from the producing assets** – Faroe is now pursuing an active in-fill drilling programme on the Njord, Brage, and Ringhorne East fields that we estimate could lift Faroe's Norwegian production to over 7kboepd in 2013.
- **Avoiding £250m of development capex** on Maria, which we estimate would have required Faroe to either farm down its stake or raise new capital.
- **Tax efficiency**, with Petoro transferring £45m (NOK400m) of tax balances to Faroe.
- **Avoiding significant decommissioning costs** – as part of the transaction, Petoro retained its liability for the traded assets' abandonment costs, estimated at £67m.

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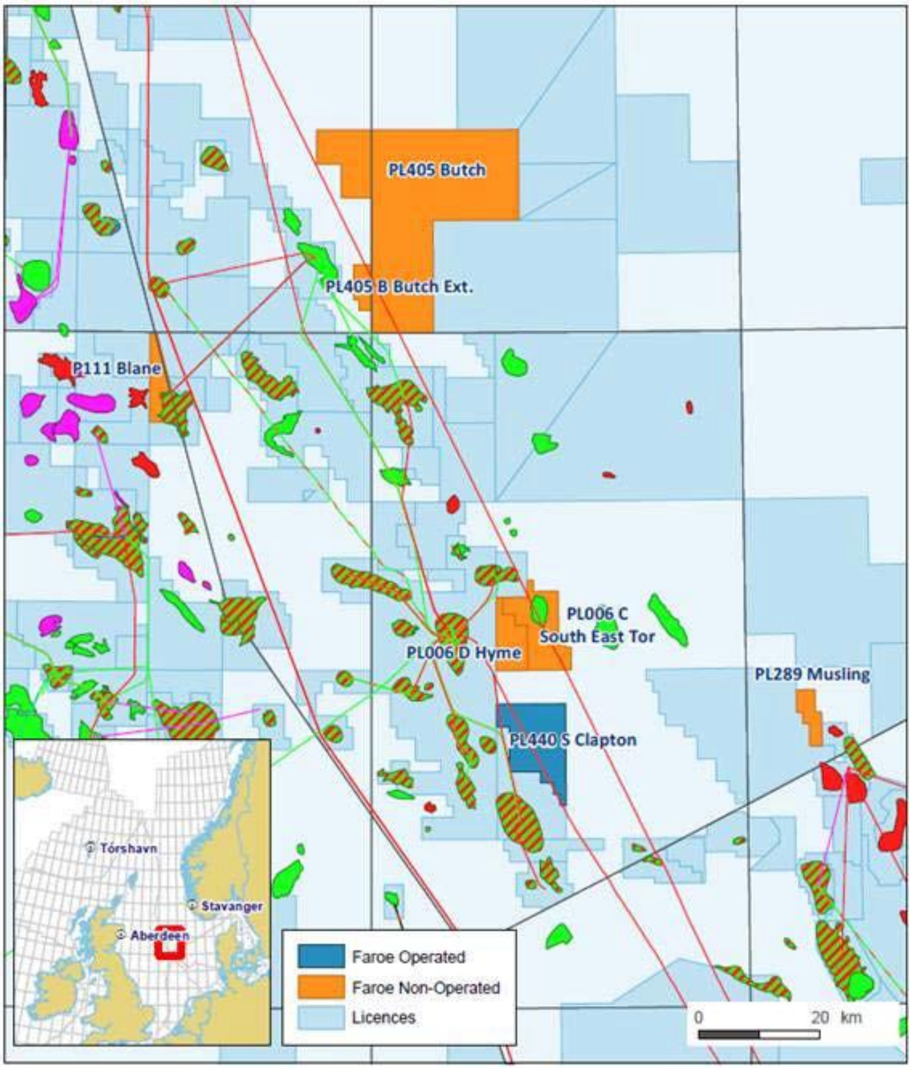
Faroe's model of recycling production cashflows into an active, high-impact exploration portfolio leaves little room for significant development expenditure. As a result, **we believe Faroe will look to replicate the success of the Petoro deal in future swap-type transactions in both Norway and the UK**, ideally trading the fundamental resource value of its pre-development discoveries for the certainty of production cashflow and reserves. This is a form of M&A that is distinct from the classic asset- or corporate-level transactions commonly seen in the North Sea; these types of asset swaps are tailored specifically to Faroe's desire to simultaneously capture value from discoveries, avoid development capex, and secure cashflow streams from producing assets.

Butch field a candidate for another swap deal?

We believe the Butch field is a potential candidate for an asset swap

One asset that we believe Faroe may be grooming for another Petoro-type swap deal is **Butch**, a Centrica-operated oil discovery made in October 2011 in the Norwegian North Sea. The discovery opened up a new play type, encountering light oil in an Upper Jurassic (Ula) reservoir with material further upside in a large salt dome structure to the southwest. Initial recoverable resource estimates are 30-60mmbbl (4.5-9mmbbl net to Faroe's 15%); we expect an ultimate reserve base at the top end of this range would be necessary to make a Butch swap deal attractive to any potential buyers.

Exhibit 5: Butch offers up to 60mmbbl gross resource with further SW upside



Source: Faroe Petroleum

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Faroe to drill Butch SW and Butch East prospects in late 2013

Based on the estimated reserves base we are comfortable that Butch is likely to be commercial, especially given its proximity to infrastructure servicing the Ula, Tambar and Gyda fields to the southwest. The initial 8/10-4S discovery well and its two sidetracks have sufficiently derisked the main Butch feature and other prospects across the block – Faroe expects to drill the standalone SW and E prospects (combined 3p/sh, 25% CoS, 50mmboe gross) in late 2013 using the Maersk Guardian rig.

Risks

Exploration & appraisal risk

With around 25% (59p/sh) of our Faroe SoP exposed to exploration or appraisal assets, the uncertainty around these assets' commerciality (i.e., from sub-commercial volumes, low flow rates, funding risk, etc.) presents a significant downside risk to our Faroe valuation.

Commodity prices

Our DCF valuations of Faroe's producing assets use a long-term price deck of $100/bbl and Brent and $9.14/mcf UK NBP – any weakness in commodity prices below these levels will negatively impact our Faroe SoP.

Acquisition growth risk

With Faroe's business model relying heavily on management's ability to successfully recycle cash from its producing assets into new exploration opportunities, the availability of suitably-priced assets is fundamental to maintaining the company's overall growth. Any shortage of value accretive deals creates uncertainty in the sustainability of this strategy.

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Shareholders & Management

Graham Stewart, Chief Executive Officer

Mr Stewart was a founder of Faroe Petroleum in 1998, and held the role of Non-Executive Chairman until his appointment as Chief Executive in December 2002. He has over 20 years' experience in oil & gas technical and commercial roles, previously holding the position of Finance Director and Commercial Director with Dana Petroleum from 1997 to 2002. Prior to this he has held positions with Schlumberger, DNV Technica and the Petroleum Science and Technology Institute. Mr Stewart holds an honours degree in Offshore Engineering from Heriot-Watt University and an MBA from Edinburgh University.

Iain Lanaghan, Group Finance Director

Mr Lanaghan joined Faroe Petroleum as Group Finance Director in May 2009. He has a broad range of experience gained in the energy, transport and service sectors, including roles as Group Finance Director of FirstGroup plc, Finance Director of Powergen International and Group Finance Director of the oil and gas services business Atlantic Power Limited. In addition to a traditional financial background he has extensive experience of financings, M&A and disposals. Mr Lanaghan is a Chartered Accountant, having qualified with KPMG in London and Frankfurt.

Helge Hammer, Chief Operating Officer

Mr Hammer joined Faroe Petroleum in 2006 from Paladin Resources, where he was Asset Manager and Deputy Managing Director. Previously he worked for Shell for 13 years as a Reservoir Engineer, Team Leader and Business Manager in Norway, Oman, Australia and Holland. Mr Hammer holds a degree in Petroleum Engineering from NTH University of Trondheim and in Economics from Institut Français du Pétrol in Paris.

Table 5: Significant FPM shareholders

Shareholder	% stake
Dana Petroleum (KNOC)	22.6%
Blackrock Investment Management	12.2%
Scottish & Southern Energy plc	5.1%
Artemis Investment Management	4.9%
Aviva Investors	4.2%
GLG Partners	4.1%
No. of shares on issue (m)	212.4

Source: Company Data

Two notable shareholders on Faroe's register are Dana Petroleum (effectively KNOC) with 22.6% and Scottish & Southern Energy with 5.1%. Both these industry players appear comfortable in leveraging Faroe's portfolio, for different reasons – KNOC to further diversify its global oil & gas production portfolio and hedge domestic energy demand, and SSE to gain upstream gas exposure as a hedge against its gas-fired downstream generation and supply operations.

We believe KNOC's significant 22.6% shareholding presents the risk of an overhang should it wish to divest part (or all) its stake. At present we consider the register to be fairly stable; however, in the long term we cannot rule out KNOC's ultimate exit strategy being an attempt to take over the entire company.

Faroe Petroleum is listed on London's AIM market.

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IGas Energy: Assuming coverage with Buy, 85p/sh price target

While not technically a North Sea E&P, IGas Energy's onshore UK portfolio is subject to many of the same industry dynamics as the offshore players. Following the acquisition of Star Energy in 2011 and the Singleton oil field last month, IGas is expanding its onshore UK footprint in regions where it has existing conventional oil & gas acreage, effectively creating regional hubs with the potential for tax and operational synergies. In addition, IGas is a leading player in the underexploited UK unconventional gas market, where we see the potential for significant value upside from its coal bed methane and shale resource base. Our 85p/sh price target (unchanged) is struck at a 15% discount to our risked SoP valuation, and with 14% upside to this target we maintain our Buy rating. We also transfer primary coverage of IGas from Laura Loppacher to Matthew Lambourne.

The unconventional assets (CBM and shale gas) are where we see the most material upside in IGas's portfolio. The company owns 1.8Tcf of contingent CBM resource across licenses spanning 1,556km^2 – pilot production testing is currently underway at the flagship Doe Green CBM site, and we believe derisking this resource by delivering commercial flow rates from the DG-3 and DG-4 wells (currently dewatering) would be a key milestone for the company. Perhaps more material is IGas's shale resource, which following recent drilling at the Ince Marshes site IGas believe could offer gas-in-place potential at least twice the previous 4.6Tcf high case estimate. IGas is currently in the process of securing a farm-in partner with prior shale gas experience to help unlock the shale potential of its licenses through further E&A drilling.

IGas recently expanded its conventional portfolio by acquiring production and development assets from Providence Resources (Buy, 950p/sh PT) for $66m ($8.25/boe 2P+2C). The deal includes 100% of the **Singleton oil field** (5.3mmbbl 2P) and 50% of the neighbouring Baxter's Copse and Burton Down discoveries. IGas will debt-fund the deal, with the company currently in advanced discussions with lenders. For now we have not factored the acquisition into our IGas SoP pending greater clarity on the debt financing terms and ability to close the deal – management expect these to be completed by the end of the year.

Valuation

We value IGas Energy at 98p/sh using a sum-of-parts methodology and our $100/bbl Brent, $9.14/mcf UK NBP long-term commodity price assumptions. Our Core NAV includes IGas's onshore conventional oil & gas portfolio acquired from Star Energy in 2011 – we value these core assets at 46p/sh based on the fields' 2P reserve base less IGas's current net debt. We also include risked development upside from the Star Energy assets (13p/sh), CBM portfolio (33p/sh) and shale gas potential (2.2p/sh). IGas currently trades at 0.76x SoP, marginally above the North Sea E&P sector at 0.67x.

Risks

Commercial viability of unconventional assets unproven. IGas's unconventional CBM and shale assets remain unproven on a technical and commercial basis. Technically recoverable volumes may be less than expected and costs may make the projects unviable. Costs and production may vary materially from our current estimates.

Onshore UK development challenges. IGas must operate in a strict environmental and planning permission environment. Failure to access appropriate drilling/operations sites could impair its ability to ramp up drilling/production.

Commodity prices. IGas's value is highly sensitive to assumed oil and gas prices which may vary materially from Jefferies long-term price deck of $100/bbl, $9.14/mcf long term.

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Valuation

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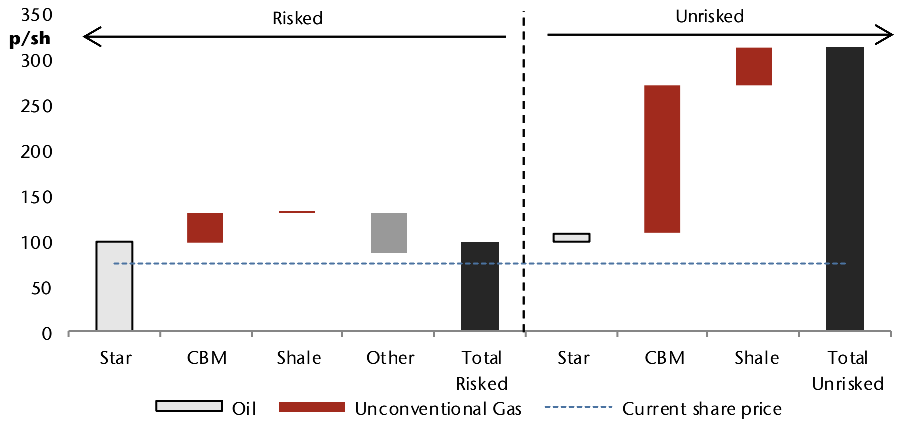
Our 98p/sh risked SoP includes Star Energy plus risked value for IGas's CBM and shale upside

Our 98p/sh SoP also includes risked development upside from the Star Energy assets (13p/sh) and CBM portfolio ("Phase 1", 6p/sh), plus value for the remaining CBM assets (28p/sh) and shale potential (2.2p/sh). IGas currently trades at 0.76x SoP, marginally above the North Sea E&P sector at 0.67x. Our 85p/sh price target is set at a c.15% discount to SoP, and with 14% upside to this target we retain our Buy recommendation.

Chart 1: Breakdown of our 98p/sh IGas Energy SoP



Source: Jefferies estimates

Singleton acquisition expected to be neutral to Core NAV, slightly accretive to risked SoP.

For now we have not factored the Singleton/Baxter's Copse acquisition into our IGas SoP pending greater clarity on the debt financing terms and ability to close the deal – management expect these to be completed by the end of the year. Our existing risked SoP is outlined below. If the deal completes, we believe it will likely be approximately neutral to our core SoP of 46p/sh and slightly accretive to our risked SoP of 98p/sh given the synergies with IGas's existing assets.

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Table 1: IGas Energy: detailed SoP valuation (excluding Singleton)

Prospect	WI	Size (mmboe)	CoS	$/boe	US$m	p/sh risked	p/sh unrisked	uplift
Producing assets								
Star assets 2P	100%	9.5	100%	26.1	247.8	85	85	0
Total producing assets		**9.5**	**100%**	**26**	**247.8**	**85**	**85**	**0**
Developing assets								
Star 15% > 2P for 5 years	100%	0.3	70%	57	11.8	4	6	2%
Star "chase the barrels" (inc gas)	100%	4.0	50%	12	24.7	9	17	12%
CBM Phase 1	100%	29.6	50%	1.15	17	6	12	8%
Total Developing assets		**34**		**3.1**	**54**	**18**	**35**	**22%**
Exploration assets								
CBM full	100%	268	15%	2.0	80.1	28	184	213%
Bowland shale	30%	125	5%	3.4	6.4	2.2	44	57%
Total exploration assets		**393**		**2.2**	**86**	**30**	**228**	**270%**
Cash					15.1	5.2	5.2	
Debt					(130)	(45)	(45)	
Warrant exercise proceeds					12	4	4.1	
Core sum of parts					**132.5**	**46**	**46**	**0%**
Star only sum of parts					**169.0**	**58**	**68.6**	**14%**
Total sum of parts					**198**	**98**	**313**	**291%**

Source: Jefferies estimates

Unconventional gas offers material upside

Proving commercial flow rates at Doe Green key to derisking IGas's 1.8Tcf CBM resource

The unconventional assets – coal bed methane and shale gas – are where we see the most material upside in IGas's portfolio. IGas currently owns 1.8Tcf of 2C contingent **CBM** resource across licenses spanning 1,556km^2, with pilot production testing underway at the flagship Doe Green site. The DG-3 and DG-4 CBM wells are currently dewatering, and we believe derisking this resource by delivering commercial flow rates at Doe Green would be a key milestone for the company. We value IGas's CBM assets at 33p/sh, comprising a moderate risk Phase 1 (6p/sh) that we estimate will capture up to 10% of the current CBM resource base, plus a riskier full-phase valuation of the remaining 1.6Tcf of IGas's CBM resource (28p/sh). If fully derisked, we see up to 165% upside to our SoP valuation from the CBM assets.

Shale gas resource offer substantial value upside; farmdown process underway.

IGas's **shale gas** resource remains an area of significant upside, but also carries a number of uncertainties. After successfully encountering shales with high total organic content (1.6-3.7%) at its Ince Marshes site, IGas believes the gas-in-place potential may be at least twice its previous high case estimates of 4.6Tcf. The potential extends across a number of IGas's assets in Cheshire, Flintshire and Staffordshire, covering a total area under licence of 1,455km^2 (360,000 acres). IGas is currently in the process of securing a farm-in partner with prior shale gas experience to help unlock the shale potential of its licenses through further E&A drilling. We currently value IGas's shale assets at 2.2p/sh, heavily risked to account for risks around farm-down dilution and the ultimately recoverable resource (due to uncertainty of GIIP, recovery factor, flow rates, and surface constraints).

Singleton – a synergistic UK onshore acquisition

Acquisition of Singleton oil field delivers tax, cost and operational synergies with IGas's conventional oil & gas portfolio

IGas recently expanded its onshore UK footprint by acquiring production and development assets from Providence Resources for $66m. The deal includes 100% of licence PL240 (containing the 5.3mmbbl 2P Singleton oil field) and 50% of PEDL233 (containing the Baxter's Copse and Burton Down discoveries). IGas will debt-fund the deal, with the company currently in advanced discussions with lenders.

The $66m purchase price implies $8.25/boe of 2P+2C resource, which in our view is a fair price at $100/bbl. We believe Singleton offers IGas a number of operational, cost, and tax

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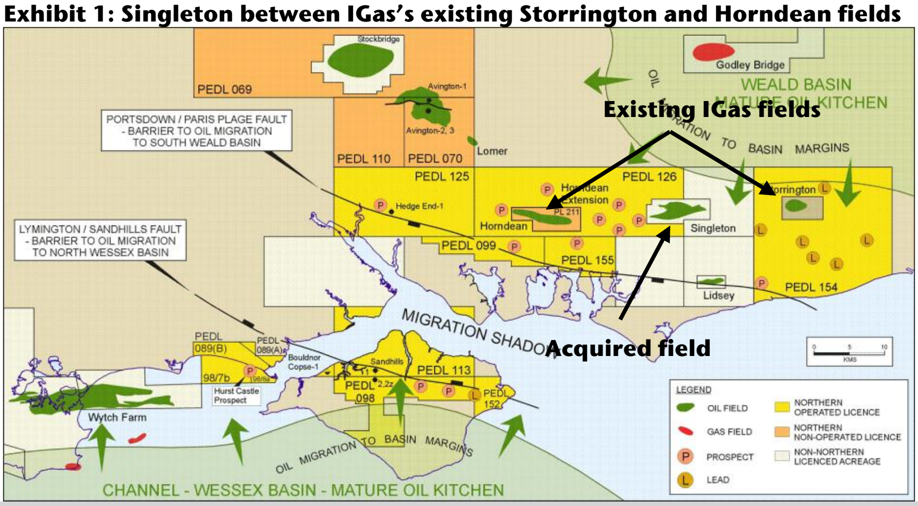
synergies with its existing onshore UK conventional assets (see map below). To date IGas has managed the sale of crude from Singleton through its Star Energy operations, meaning that IGas has a good working knowledge of the field's production history.

Exhibit 1: Singleton between IGas's existing Storrington and Horndean fields

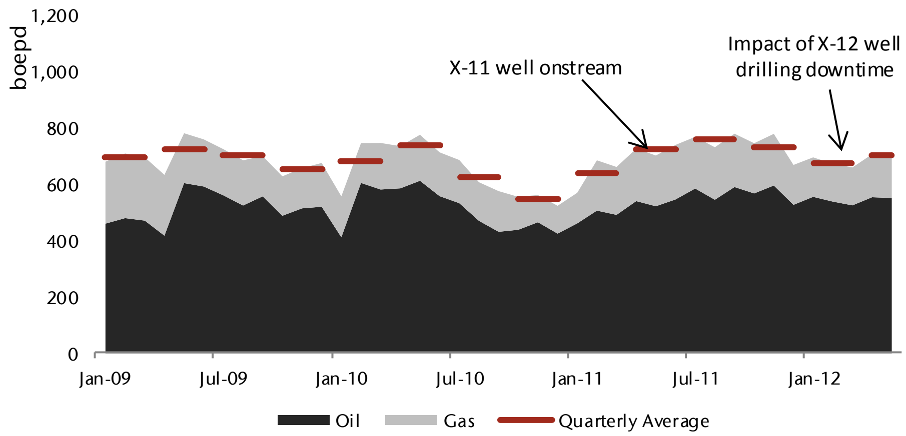


Source: Providence, Jefferies

Long-term growth potential from Singleton's underexploited oil resource (just 4% Rf to date).

Output from the **Singleton** field is modest, with production currently running at 530bopd (plus 170boepd of associated gas, which at present is flared ahead of planned investment in gas-to-wire infrastructure). However, we believe the field offers IGas some long-term growth potential – just 4.3mmbl of the field's 107mmbbl OIIP (i.e., 4% Rf) has been extracted since production began in 1986. Mechanical difficulties associated with the drilling of the latest X-12 multi-lateral well means production is not expected to see the material uplift anticipated by the previous operator – as a result, Singleton's output is forecast to fall to 485bopd in 2013.

Chart 2: Singleton production performance modest but steady, 2009-present



Source: DECC, Jefferies

Additional in-fill drilling to maximise field recovery is possible once IGas takes control of the asset; however, pending the results of the debt financing there are no immediate plans to invest significant capex. The adjacent **Baxter's Copse** oil discovery (50%) provides additional upside to the Singleton field. Baxter's Copse was initially drilled by Conoco in the early 1980s, and offers 5.4mmboe of gross resource that would most likely be developed using similar horizontal drilling techniques as Singleton.

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Ithaca Energy (IAE LN): Initiating coverage at Buy, 180p/sh PT

We commence coverage of Ithaca Energy with a Buy recommendation and 180p/sh price target. Ithaca offers a low risk exposure to a growing portfolio of producing oil & gas fields and development assets in the UK North Sea. This core portfolio gives Ithaca substantial cashflow and the funding capacity to chase further appraisal and development opportunities without exposing investors to exploration risk – a unique feature in the North Sea E&P space. At 0.65x our SoP valuation the shares look fairly valued versus the North Sea E&P sector at 0.67x; however, we believe Ithaca remains an interesting low risk option for investors to balance exploration risk elsewhere in their portfolios.

The 53mmboe **Greater Stella Area development (91p/share) is Ithaca's primary medium-term growth driver**; we expect the new hub to add c.15kboepd (net) to Ithaca's production profile when it is brought onstream in 2014. The $1.1bn GSA project will be developed using a floating production unit acquired from Petrofac, and will initially develop two fields – Stella and Harrier – with the potential to tie in future fields at low cost. The economics of the project are enhanced by the UK small field tax allowance.

Ithaca is entering a period of significant cashflow generation, and over the next two years will enjoy the twin benefits of (a) a step change in production from the new Greater Stella Area hub, which we believe could quadruple Ithaca's current output to c.22kboepd, and (b) a period where the company pays no cash tax due to its substantial tax loss position. We estimate **the company will deliver around $800m of post-tax operating cashflow over 2013-14 (more than Ithaca's current market capitalisation)**, with the company currently trading on a 2014 EV/EBIDAX multiple of just 0.7x.

Ithaca is in a very strong funding position, and in our view can comfortably fund its planned development and appraisal programme with existing cash and debt facilities. Following the recent Cook/MacCulloch acquisition Ithaca has $73m (18p/sh) of available cash, and in June 2012 negotiated a fully underwritten, senior secured $400m debt facility with BNP Paribas. We believe this is an excellent result that adds third party endorsement of the quality of both Ithaca's producing assets and its development portfolio.

The company is a **potential target for North Sea M&A activity**, in our view – Ithaca's low risk portfolio, solid balance sheet and oil bias are all attributes that are attractive to acquisitive NOCs and independents. Despite a number of unsuccessful approaches earlier in 2012, we believe Ithaca will remain on the radar of North Sea predators so long as the shares trade at a discount to recent deal multiples (IAE trades at $7.4/boe of 2P reserves versus 2010-12 transactions averaging $13.7/boe).

Valuation

We value Ithaca Energy at 180p/share on a sum-of-parts basis. This includes full field NPV-10 valuations of Ithaca's producing portfolio and committed developments, including the Greater Stella Area which at 91p/sh forms 51% of our overall SoP. Ithaca's strong funding position means we see no dilution risk from farmdowns or new equity raisings, and as such our 180p/sh (53% upside) price target is set in line with our SoP.

Risks

Ithaca is, by its nature, a fairly low risk enterprise relative to other UK E&Ps; however, the company still faces downside risk from lower-than-expected long term commodity prices (we assume $100/bbl Brent and $9.14/mcf UK NBP). In addition, Ithaca's dependence on successfully executing its development projects to extend its group production profile means that any development delays or cost overruns will have a negative impact on the company's overall valuation.

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Exhibit 1: Ithaca Energy valuation summary

Region	Asset	Hydrocarbon	IAE W.I. %	Resource Size (mmboe) Gross	Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV p/sh	Unrisked p/sh	Upside %
Producing assets												
UK - Central North Sea	Athena	Oil	23%	26	6	100%	6	32	192	47	47	
UK - Central North Sea	Beatrice & Jacky	Oil	Various	5	2	100%	2	9	25	6	6	
UK - Northern North Sea	Broom	Oil	8%	5	0	100%	0	14	11	3	3	
UK - Central North Sea	Cook	Oil/Gas	41%	15	6	100%	6	21	109	27	27	
UK - Central North Sea	MacCulloch	Oil	14%	10	1	100%	1	21	27	7	7	
UK - Southern North Sea	SNS Gas Assets	Gas	Various	3	1	100%	1	4	4	1	1	
							18		**368**	**90**	**90**	
Development assets												
UK - Central North Sea	Greater Stella Area	Oil/Gas	55%	53	29	100%	29	14	375	91	91	0%
UK - Central North Sea	Hurricane (appraisal)	Oil	55%	5	3	50%	1	10	13	3	6	2%
UK - Central North Sea	Scolty/Crathes/Torphins	Oil/Gas	10%	18	2	60%	1	8	9	2	4	1%
UK - Northern North Sea	Heather South West	Oil	13%	7	1	60%	1	8	4	1	2	0%
							32		**401**	**98**	**103**	**3%**
2012 Exploration & Appraisal												
							0		**0**	**0**	**0**	**0%**
Further drilling												
							0		**0**	**0**	**0**	**0%**

Valuation Multiples				
IAE share price	118p	No. of Shares	259.3	m
Core NAV	180p	Market Cap.	£305	m
P / Core NAV	**0.65**	Enterprise Value	£258	m
P / SoP	**0.65**	2P Reserves	55	mmbbl
Upside to SoP	53%	EV/2P boe	**$7.37**	**/boe**

IAE Sum of Parts Valuation	$m	p/sh
Ithaca Energy Assets	770	188p
Cash / (Net Debt)	73	18p
G&A	-58	-14p
Decommissioning & Cost Carries	-46	-11p
Sum of Parts	**739**	**180p**

Source: Jefferies estimates

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Exhibit 2: Ithaca Energy financial summary

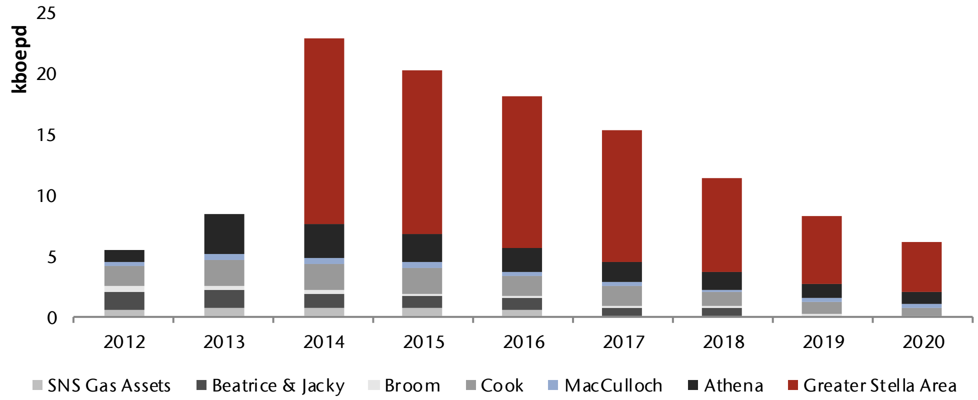
P&L		2010A	2011A	2012E	2013E	2014E
Revenue	$m	135	129	188	287	687
Cost of Sales	$m	-61	-95	-86	-72	-238
Exploration Writeoffs	$m	-1	-1	0	0	0
G&A	$m	-6	-6	-5	-6	-6
Other	$m	-8	11	19	0	0
Pre-tax Operating Profit	$m	58	38	116	210	443
Net Finance Income/(Expense)	$m	0	-1	-2	-7	-9
Pre-tax Profit	$m	58	37	114	202	434
Tax	$m	4	-1	-41	-125	-269
Net Profit incl exceptionals	$m	62	36	73	77	165
EBIDAX	$m	60	39	119	218	581
EV/EBIDAX	x	6.9	10.6	3.5	1.9	0.7
No. of Shares	m	162	263	263	263	263
EPS	cps	33	14	28	29	63
DPS	cps	0	0	0	0	0

Cashflow Statement		2010A	2011A	2012E	2013E	2014E
Cashflow from Operations	$m	89	103	135	219	582
Cashflow from Investing	$m	-66	-192	-204	-317	-102
Cashflow from Financing	$m	0	-10	-4	144	-8
Net Change in Cash	$m	23	-99	-72	46	473

Balance Sheet		2010A	2011A	2012E	2013E	2014E
Cash	$m	196	112	23	68	541
Exploration Assets	$m	18	23	40	40	40
Prod'n & Devel. Assets	$m	259	570	711	1020	983
Long Term Debt	$m	0	0	0	150	150
Provisions	$m	30	166	214	342	613
Shareholder Equity	$m	459	507	582	659	824
Gearing: Net Debt(Cash)/Equity	%	-43%	-22%	-4%	12%	-47%

12-month Catalysts	IAE WI %	CoS %	Risked NAV $m	Risked NAV p/sh	SoP Upside %
Hurricane (appraisal)	55%	50%	13	3	2%

Production Summary		2010A	2011A	2012E	2013E	2014E
IAE production WI	kboepd	4.5	4.4	5.0	8.4	22.9



SoP sensitivity to Brent & WACC	LT Brent $/bbl	$70.00	$85.00	$100.00	$115.00	$130.00
WACC	8%	140	168	196	223	251
	10%	127	153	**180**	206	232
	12%	116	141	166	191	215
	14%	106	129	154	177	200

Assumptions		2010A	2011A	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58

Source: Jefferies estimates

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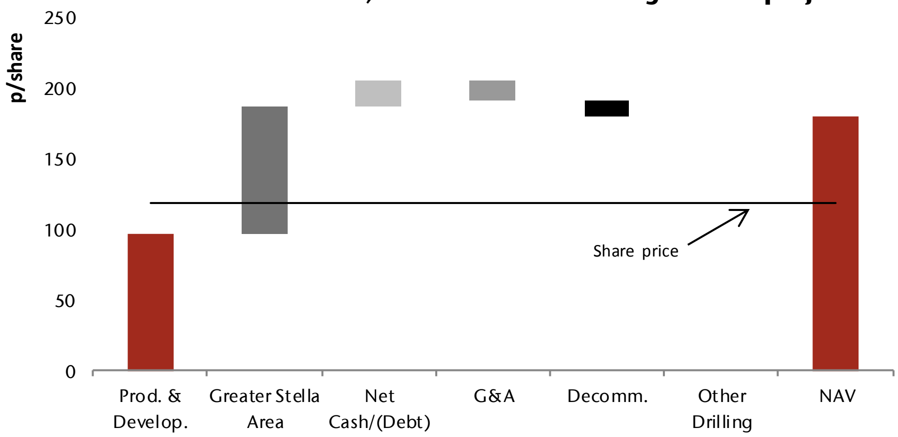
Valuation

Greater Stella Area is key to the medium-term success of IAE's low-risk portfolio

Our sum-of parts valuation of Ithaca Energy is 180p/sh, placing the company at a 35% discount to our SoP. The vast majority of our SoP valuation consists of Ithaca's producing assets and development projects, which we value using a long-term commodity price deck of $100/bbl Brent and $9.14/mcf UK NBP spot gas. The company has no risked exploration prospects, meaning our Core NAV and overall SoP valuations are equal. Ithaca's stake in the Greater Stella Area development is worth 91p/sh, or 51% of our overall valuation, which highlights the importance of this project to the business – however, as the chart below illustrates, we believe the market is only pricing in a small portion of the project's value.

Chart 1: IAE trades at 0.65x SoP; market still discounting the GSA project



Source: Jefferies estimates

Ithaca's appeal lies in its under-appreciated cashflow generation and organic growth potential

Given Ithaca's low-risk, production-heavy portfolio, it is unsurprising the shares trade at a P/SoP multiple of 0.65x, i.e., fairly valued relative to the North Sea E&P peer group (0.67x). However, in our view the appeal of the company lies in its underappreciated cashflow generation and organic growth potential, rather than high impact exploration-driven value upside. We believe Ithaca is attractive as a low risk North Sea oil & gas exposure with some M&A potential, and should appeal to investors wishing to offset exploration risk elsewhere in their portfolio.

Ithaca is fully funded for all its planned development and appraisal investment, meaning we see minimal dilution risk from farmdowns or new capital raisings. As such, we set our price target in line with our SoP valuation, and **with 53% upside to our 180p/sh target we commence coverage of Ithaca Energy with a Buy recommendation**.

Cash(flow) is king

We expect significant cashflow growth as Ithaca's production is estimated to quadruple over 2012-14

While Ithaca's production and cashflow have been modest in recent years, with the Athena field now onstream and first oil from the Greater Stella Area hub conservatively assumed to be 1Q14, we expect a significant ramp up in Ithaca's net operating cashflow in the next couple of years. As shown in the charts below, this cashflow growth will be accentuated as Ithaca enjoys the dual benefits of (a) a step change in production from the new GSA hub, which we estimate could more than quadruple Ithaca's output from an estimated 5kboepd to c.22kboepd over 2012-14, and (b) a period over 2012-14 where the company pays no cash tax due to its substantial tax loss position.

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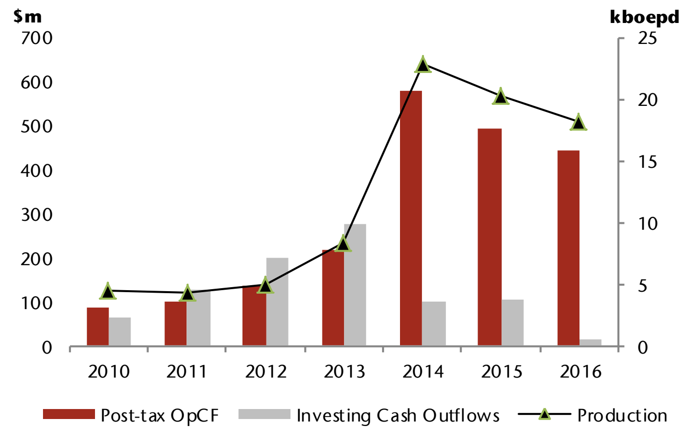
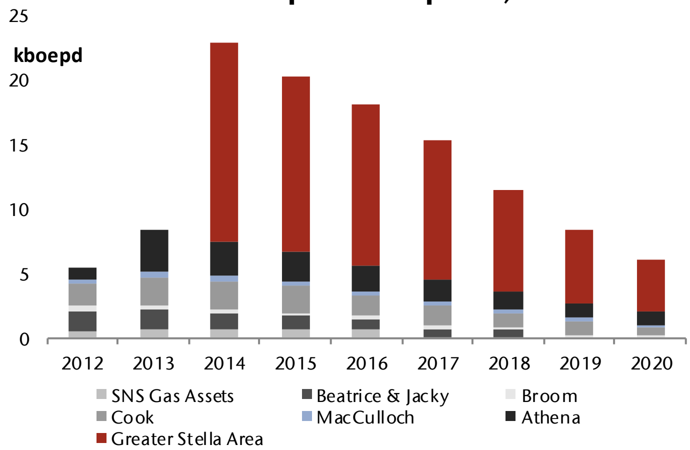
Chart 2: GSA hub delivers significant cashflow in 2014



Source: Jefferies estimates, company data

Chart 3: Forecast Ithaca production profile, 2012-20E



Source: Jefferies estimates, Wood Mackenzie

Ithaca trades at just 0.7x 2014 post-tax operating cashflow

This visible jump in cash generation presents a compelling valuation argument – using EBIDAX as a measure of post-tax operating cashflow, Ithaca trades on a 2013 EV/EBIDAX multiple of 1.9 times, which drops to just 0.7 times 2014 EBIDAX. Even if we assume a material drawdown of debt to part-fund Ithaca's upcoming GSA project costs, the shares still trade at just 1.1x 2014 EV/EBIDAX. Put another way, we estimate Ithaca will generate around $800m of post-tax operating cash over 2013-14, versus its current market capitalisation of c.$500m.

Ithaca funded for all visible development spending

Fully funded for all planned development & appraisal capex through cash, debt, and operating cashflow

Ithaca is in a very strong funding position, and in our view can comfortably fund its planned development and appraisal programme with existing cash and debt facilities. The company ended 1H12 with $112m (27p/sh) of available cash, and in June 2012 negotiated a fully underwritten, senior secured $400m debt facility with BNP Paribas – an excellent result, in our view, that adds third party endorsement of the quality of both Ithaca's producing assets and its development portfolio.

We believe Ithaca's combined cash and debt resources give it the flexibility to complete the Greater Stella Area project (and other planned investment, including the Hurricane/Helios wells) without requiring new external capital. Our forecasts suggest the greatest dependence on the new debt facility will be in 2013, when capex costs on the Greater Stella Area project are likely to reach $250m net to Ithaca – we expect the company will draw down $150m of its debt facility in 2013. We understand the balance of Ithaca's new debt facility (c.$250m) will be used to seek new North Sea acquisitions, with the company most likely chasing discovered, undeveloped resource that fits well with Ithaca's core strategy. **The recent acquisition from Noble Energy of an additional 13% in the Cook field, plus a 14% stake in the MacCulloch oil field (combined $38.5m at $11.3/bbl 2P), are good examples of Ithaca's appetite to further expand its portfolio of producing North Sea assets.**

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Ithaca offers genuine M&A potential

Ithaca's portfolio ticks lots of M&A boxes

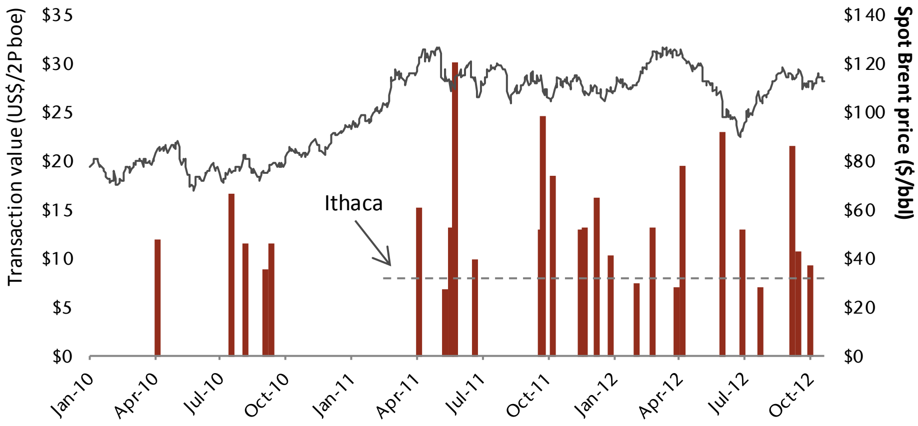
Ithaca fits many of the criteria sought by predators looking to enter or expand their position in the North Sea – a solid and (growing) cashflow profile, derisked development assets, limited exploration risk, and an open shareholder register. The company also offers low decommissioning liabilities and a healthy tax loss position, enhancing the financial mechanics of any acquisition.

The appeal of Ithaca to potential buyers was highlighted by a confidential, non-binding approach for the company early in 2012, with several other unsolicited offers subsequently received. We suspect these approaches were from both NOCs and large independents. Overall market conditions meant that no deal with any party could be agreed on suitable financial terms; however, we think Ithaca will remain on the radar of these potential buyers until general market conditions improve.

Recent North Sea M&A multiples imply Ithaca is worth 203p/sh, 73% above the current share price

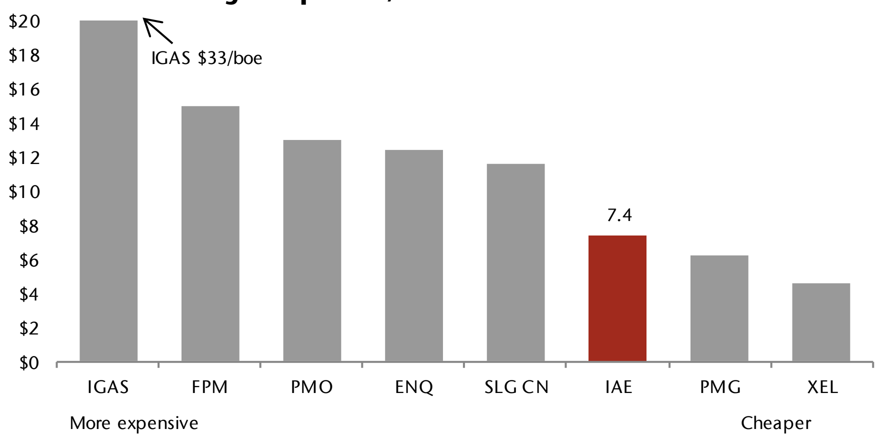
We believe M&A activity is a key value catalyst for the company so long as Ithaca continues to trade at a substantial discount to recent North Sea transaction multiples (shares are currently at \$7.4/boe of 2P reserves, versus the 2011-2 average of \$13.7/boe). At this average deal metric, we estimate Ithaca is worth 203p/sh, a 73% premium to the current price.

Chart 4: Recent North Sea M&A multiples well above Ithaca's \$7.4/boe



Source: Jefferies, Datastream, company data

Chart 5: Ithaca looking cheap on EV/2P boe metrics



Source: Jefferies estimates, company data
Note: XEL EV and 2P reserves taken from publicly available data.

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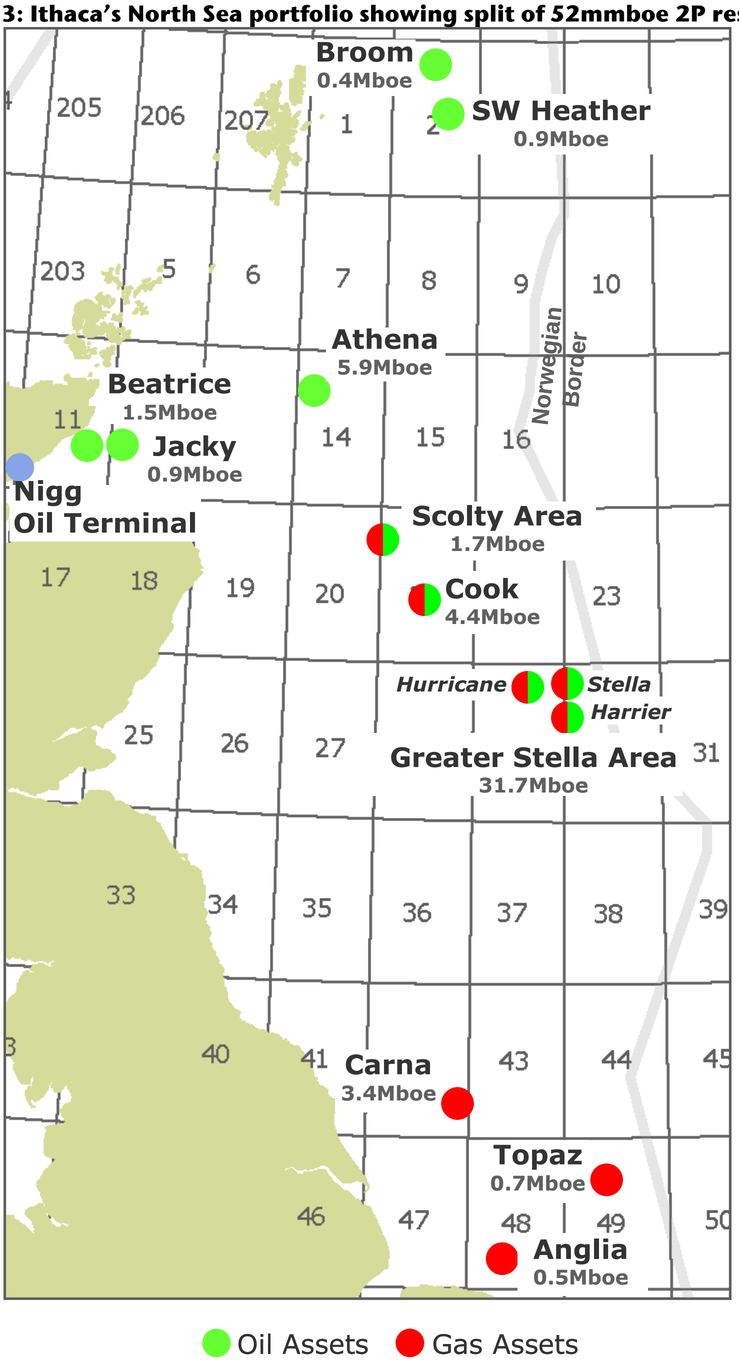
Ithaca chasing maximum growth for minimum risk

Ithaca's focus on diversified production and development, with no exploration exposure, is unique among North Sea E&Ps

Ithaca lacks the high impact exploration catalysts of some other North Sea E&Ps, instead offering a low risk exposure to a growing portfolio of producing fields and development assets. These core assets have given Ithaca the cashflow and funding capacity to chase further appraisal and/or development opportunities without exposing investors to any exploration risk – a unique feature in the North Sea E&P peer group.

Exhibit 3: Ithaca's North Sea portfolio showing split of 52mmboe 2P reserves



Source: Ithaca Energy, Sproule
Shown prior to IAE's acquisition of Cook & MacCulloch from Noble Energy, Oct 2012

The company's strategy is to deliver attractive cashflow generation by diversifying its North Sea production base, which it achieves through:

Cook/MacCulloch acquisition illustrates Ithaca's appetite for producing North Sea fields

- **Acquisitions.** Ithaca has typically acquired modest, often operated stakes in mature North Sea fields, where it can utilise its technical skill set to extract maximum value from these declining assets. One recent example is Ithaca's purchase of a further 13% stake in the Cook field and 14% of the MacCulloch field, bought from Noble Energy in October 2012 for $39m and delivering Ithaca c.1.1kboepd of oil & gas production and 3.4mmboe of 2P reserves. To date, management have shown no real preference for hydrocarbon type or asset location on the UKCS when building Ithaca's portfolio; however, there is a distinct oil bias to Ithaca's production over the medium term. We expect further acquisition activity as Ithaca looks to deploy is substantial post-GSA cash resources on either asset- or corporate-level transactions.

Development likely to be Ithaca's major growth driver over medium term

- **Developments.** Recently Ithaca's growth has been driven by development activity, with the 26mmbbl (gross) Athena project commencing production in 1H12 and the 53mmboe (gross) Greater Stella Area hub due onstream in 1Q14 – together we estimate these projects could quadruple Ithaca's net production (to c.22kboepd) over just two years. We see development activity being the major growth engine for Ithaca over the medium term, with management increasingly looking to exploit UK tax incentives for new developments in addition to competing for mature North Sea assets in an active M&A market.
- **Licensing rounds.** Securing new acreage or undeveloped fields through licensing rounds will be an important route to growing Ithaca's North Sea footprint, in our view. As the company moves towards hub-style projects (e.g., the Greater Stella Area), acquiring blocks adjacent to existing hubs will give Ithaca the opportunity to tie back these assets to existing infrastructure – a high value strategy. In the current UK 27th licensing round (results due 4Q12), Ithaca submitted four applications (three as operator) for new acreage, which we suspect will be predominantly located near its existing assets.

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Flagship project – Greater Stella Area

Greater Stella Area hub is consistent with overall North Sea trend towards hub developments

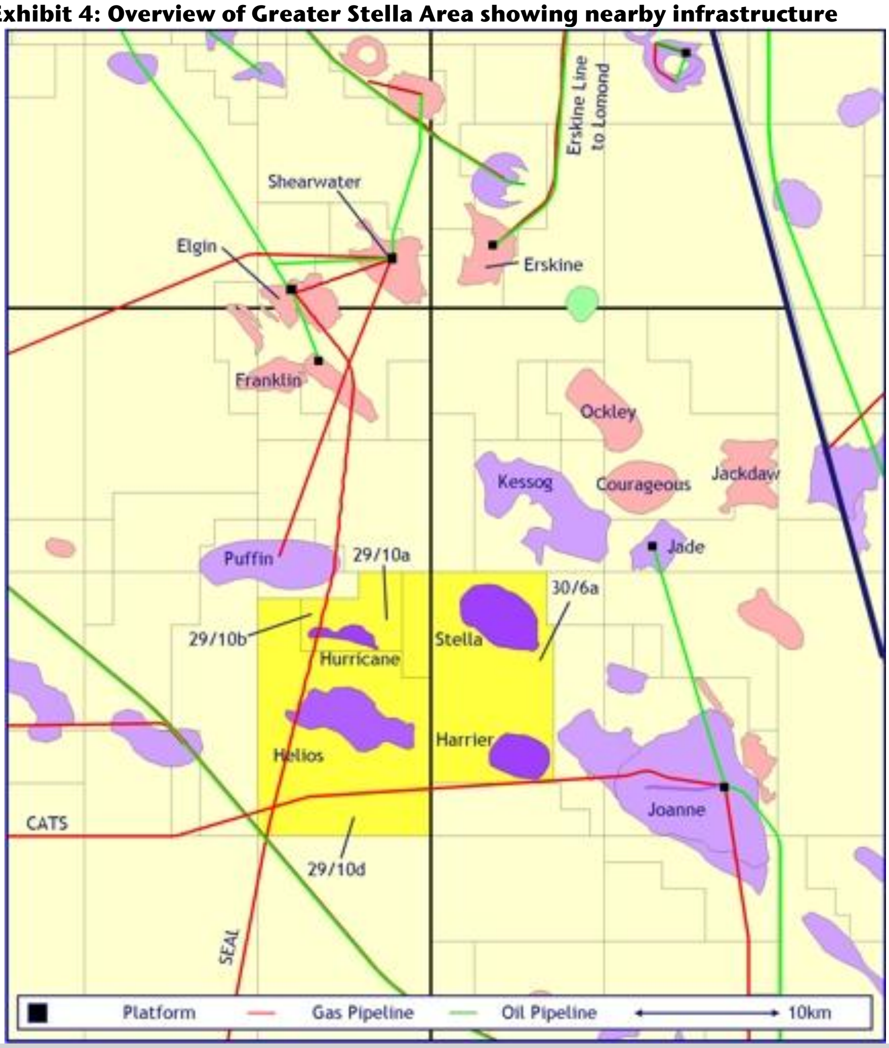
Ithaca's key growth project is its 54.66%-owned/operated Greater Stella Area hub development in the UK Central North Sea, which at 91p/sh is the largest component of our SoP valuation. Ithaca's move to develop this hub is consistent with a theme we are seeing across the North Sea, i.e., E&Ps developing clusters of assets in tandem in order to maximise efficiencies from shared contractors, infrastructure, and tax allowances.

Stella and Harrier fields form 53mmboe core of hub; potential upside from Hurricane and Helios appraisal assets

The Greater Stella Area hub will initially comprise two fields – **Stella**, which contains both gas-condensate and light oil within two reservoirs (Palaeocene and Upper Cretaceous), and **Harrier**, which contains gas/condensate in the Upper Cretaceous chalk interval. Together the two fields offer 53mmboe of gross 2P reserves (29mmboe net to Ithaca), with further upside potential from the successful appraisal of the **Hurricane** (5mmboe gross, 3p/sh risked) and **Helios** discoveries. The current hub development plan is independent of these appraisal assets – should Hurricane and/or Helios prove commercial, the ability to tie back their wells and sub-sea infrastructure to the GSA hub means we believe they will offer very high value incremental barrels. Note that because Helios does not currently have an estimated drill date, nor have management given any guidance on its resource potential, we do not currently include Helios in our Ithaca SoP.

Longer term we also see the potential for Ithaca to acquire nearby fields to add to its GSA hub, most likely as part of a JV with its existing GSA partners Petrofac and Dyas.

Exhibit 4: Overview of Greater Stella Area showing nearby infrastructure



Source: Ithaca Energy

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Ithaca's stake in the Greater Stella Area development hub worth 91p/share

We value Ithaca's stake in the Greater Stella Area at 91p/sh ($375m), or approximately 51% of our total Ithaca SoP valuation. With Ithaca having received FDP approval in 2Q12 and the development now underway, we assume a 100% CoS and have built a full-field DCF model of the combined Stella and Harrier hub. We conservatively assume first oil/gas from the hub in 1Q14. For now we treat the Hurricane appraisal well as a separate risked component of our SoP valuation – we value Hurricane at 3p/sh.

Table 1: Breakdown of Greater Stella Area contribution to our Ithaca SoP

Asset	IAE W.I. %	Gross 2P (mmboe)	Net 2P (mmboe)	CoS %	$/boe	NPV $m	Risked NPV p/sh	Upside %
Stella & Harrier	54.66%	53	29	100%	14	375	91	0%
Hurricane	54.66%	5	3	50%	10	13	3	2%
Total		**58**	**32**			**388**	**95**	**2%**

Source: Jefferies estimates

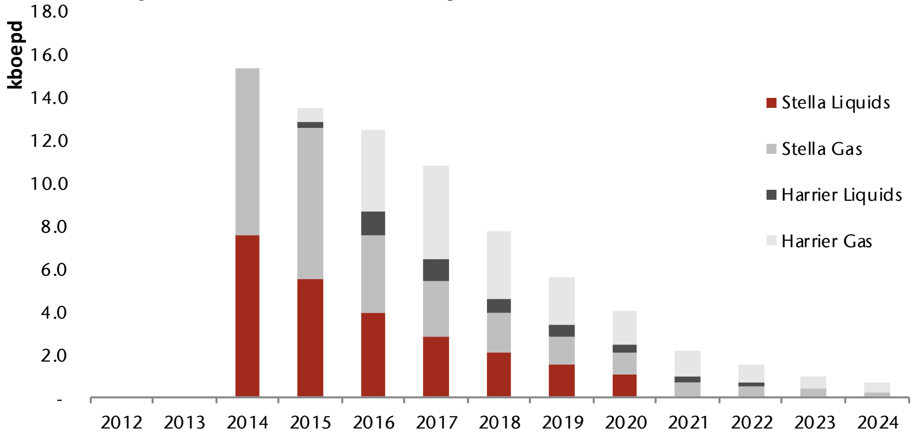
Stella and Harrier fields each eligible for UK's small field allowance, enhancing Ithaca's tax relief

The Greater Stella Area development is **eligible for the UK's small field allowance**, which allows owners of small fields to offset up to £150m of liability for the 32% supplementary charge. We understand the Stella and Harrier fields will be treated as individual assets (despite being developed in tandem) for tax purposes, greatly enhancing the hub's economics. We anticipate future additions to the hub (e.g., Hurricane) will also be treated as unique fields, giving Ithaca an additional long-term tax incentive.

GSA: $1bn+ production hub kicking off in 2014

Ithaca will develop each of the Stella and Harrier fields separately, with development works currently underway and expected to ramp up significantly in 2H12/1H13 – we conservatively estimate first production in 1Q14. The Ensco 100 heavy duty jack-up rig has been contracted for drilling the hub. Each segment will involve subsea tiebacks to the FPF-1 floating production unit, which will be refitted to handle up to 38kbopd of oil and 85mmscfpd of gas. Stella will require up to five wells with artificial lift; Harrier is expected to require two wells. Ithaca expects to process the produced hydrocarbons onboard the FPU before they are exported via new 10" pipelines to shore – Wood Mackenzie estimate the development will use Teesside (gas) and the Forties system (oil) infrastructure. As discussed above, tying in any further commercial fields (e.g., Hurricane) to the GSA will be incremental to this development plan.

Chart 6: Projected Greater Stella Area production, 2012-24



Source: Jefferies estimates, company data, Wood Mackenzie

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We estimate total gross capex for the Greater Stella Area project will reach c.$1.1bn ($650m on Stella and $420m on Harrier), with Ithaca exposed to $580m between 2012-15. The bulk of this cost is expected to be spent in 2013 once major drilling works and pipeline construction begins; we anticipate Ithaca will utilise up to $150m of its debt facility to fund this investment.

GSA to be developed using a central floating production unit; Ithaca/Dyas own 80% of vessel (acquired from Petrofac)

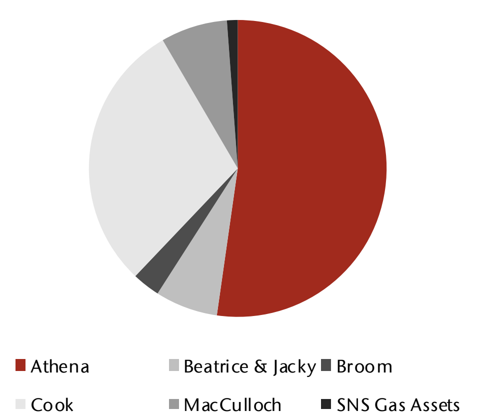
As part of the development, Ithaca and its partner Dyas have acquired an 80% stake in the refitted FPF-1 floating production unit – the core of the Greater Stella Area hub. The vendor, Petrofac, will receive a 20% interest in the Stella and Harrier fields (adding to its existing 20% stake in Hurricane and Helios), to be effected by an earn-in mechanism once the GSA begins producing in late 2013. Importantly for Ithaca, **once the Greater Stella Area ceases production (we estimate 2024 excluding Hurricane) the partners have the option to sell the vessel back to Petrofac** on a depreciated value basis ($127m for first five years of production, declining thereafter). For now we do not account for this resale option in our valuation of the GSA.

Producing assets in decline

We value Ithaca's producing portfolio at 90p/share

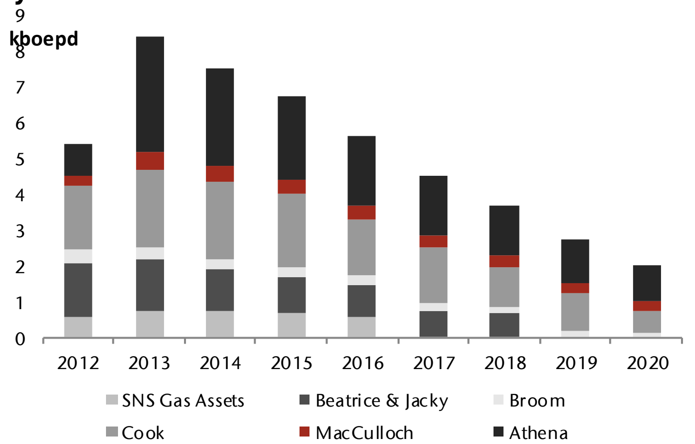
Ithaca's 18mmboe (net) core producing portfolio includes a diverse set of oil & gas fields across the UK North Sea. To date, management have shown no real preference for hydrocarbon type, location, or operatorship of the assets; however, there is a distinct oil-bias to Ithaca's production over the medium term. Together we value the producing assets at $368m, or 90p/sh. Given the age of some of these fields (in particular, Beatrice & Jacky and the Anglia/Topaz gas fields in the SNS) we do not see material production from these assets beyond the end of the decade, which places additional importance on the successful execution of the Greater Stella Area and its contribution to Ithaca's overall production.

Chart 7: Athena dominates Ithaca's production portfolio (% of SoP)



Source: Jefferies estimates

Chart 8: Current Ithaca Energy producing assets exhausted by 2020



Source: Jefferies estimates, company data, Wood Mackenzie

Athena output hit by production issues in 2012; minimal long-term impact

Ithaca's Athena development (26mmbbl, 6mmbbl net to IAE's 22.5% WI) was brought onstream in May 2012, and is the most valuable asset in Ithaca's current producing portfolio (we value Athena at 47p/sh, or $192m). While the field's surface facilities are operating in line with expectations (the BW Athena FPSO is delivering crude to the onshore Nigg oil terminal via shuttle cargoes on the Betty Knutsen tanker), during 2012 Athena faced some production difficulties in one of its four production wells due to a downhole blockage in the P1 producer. Although management deemed a workover well unnecessary, the impact of downtime from this well during the year has restricted Athena's output to c.10kbopd, around 7kbopd short of potential production. With the P1 producer now back onstream we assume production returns to 15kboepd in 1H13; management expects the well will still ultimately produce its full reserves despite the production tubing blockage.

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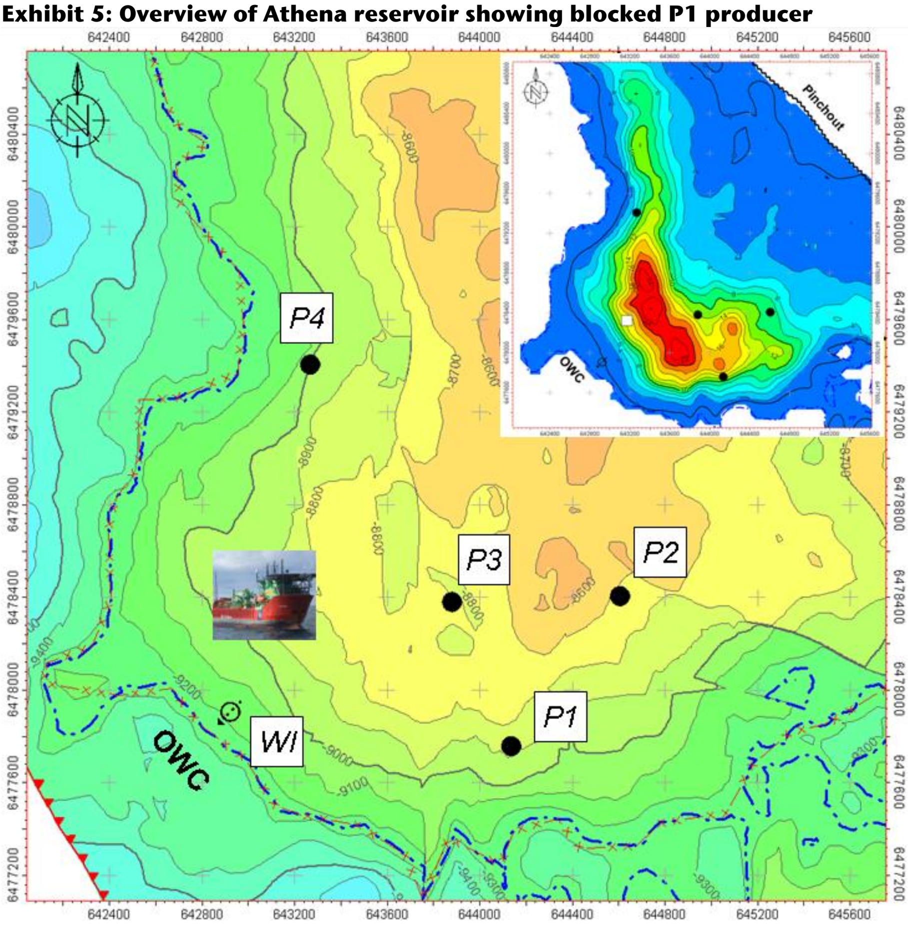
Exhibit 5: Overview of Athena reservoir showing blocked P1 producer



Source: Ithaca Energy

Risks

Development risks

Ithaca's production and development-only strategy means the company is not exposed to exploration risk. However, its reliance on successfully delivering new projects on time and on budget presents some risks – any development delays or cost overruns will have a direct impact on our overall Ithaca valuation. With the Greater Stella Area forming 51% of our total Ithaca SoP, completing this project without any major issues is very important, in our view.

Commodity price risk

Ithaca's diversified production portfolio means it is exposed to movements in both the Brent crude and UK spot gas price. We assume long-term prices of \$100/bbl and \$9.14/mcf for these commodities, respectively – any ongoing weakness in oil & gas prices will negatively impact our full-field DCF valuations and our overall Ithaca SoP.

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Shareholders & Management

Iain McKendrick, Chief Executive Officer

Mr. McKendrick joined Ithaca as COO in February 2008, and was appointed CEO in December 2008. His experience is predominately in the United Kingdom Continental Shelf, but also includes periods of business development roles in Colombia and the USA. Prior to joining Ithaca he has held senior leadership positions with TOTAL as Joint Venture Manager UKCS, and as Vice President, Business Development and Strategy in Houston. He holds a Bachelor of Law Degree and Diploma in Legal Practice from Aberdeen University.

Graham Forbes, Chief Financial Officer

Mr. Forbes joined Ithaca in March 2010. His 19 year oil & gas career has included roles with ExxonMobil, where over 5 years he worked on many operational and acquisition based projects for the company, and with First Oil/Group where he joined as finance director in 2002 and took up the position of chief director in 2007. Mr. Forbes graduated from the University of Aberdeen with an MA (Hons.) in accountancy, and gained his chartered accountant qualification through the PWC training scheme.

Nick Muir, Chief Technical Officer

Mr. Muir joined Ithaca in February 2006, and has over 25 year's technical experience in the oil and gas industry. His career includes roles with Elf from 1986, working in exploration-focused roles in both the UK and globally, and in ENI's exploration team in Ireland and West of Shetland. In 2000, Mr. Muir joined Enterprise focusing on the Central North Sea, and post its acquisition by Shell held the role of Exploration Commercial Lead for the North Sea over 2003-2006. He graduated in geology from Edinburgh University and later completed a Master's degree in geophysics at Imperial College, London.

John Woods, Chief Development Officer

Mr. Woods joined Ithaca in 2006, and has 28 years of Petroleum Engineering and Development Management experience in the North Sea. His career includes 13 years with Amerada Hess in London and Aberdeen, plus time in the North Sea service sector with Helix RDS and Wood Group Engineering. He has a Bachelor's degree from Leicester University.

Mike Travis, Chief Production Officer

Mr. Travis has over 28 years of offshore and onshore experience in the oil industry which has been acquired in the North Sea and challenging international locations. He has held key leadership positions throughout his career in all aspects of Production and Development projects including asset management, project management, drilling and operations. Mr Travis has previously been employed by BP, LASMO, Venture Production and more recently by Premier Oil.

Table 2: Top Ithaca Energy shareholders

Shareholder	% stake
JP Morgan AM UK Ltd.	5.4%
I.A. Michael Investment Counsel Ltd.	5.2%
EdgePoint Investment Group Inc.	2.5%
Hesperian Capital Management	1.6%
Norges Bank Investment Management	1.5%
No. of ordinary shares on issue (m)	259.3

Source: Thomson ONE

Ithaca Energy is listed on London's AIM market and Canada's TSX exchange.

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Parkmead Group (PMG LN): Initiating coverage at Buy, 15p/sh PT

We commence coverage of Parkmead Group with a 15p/sh price target and Buy rating. Parkmead is a small but rapidly growing NW European E&P with assets in the UK North Sea and onshore Netherlands. The company has been very acquisitive in the last year, securing stakes in Southern North Sea gas assets from XTO and Sorgenia, a North Sea oil development via the takeover of DEO Petroleum, and several Dutch production licenses from Dyas BV. We see attractive growth potential from Parkmead's existing portfolio (especially the Perth oil field) and new acquisitions, with two exploration wells and the UK's 27th licensing round providing near-term value catalysts.

Parkmead's cornerstone asset is its 52% stake in the Perth oil development in the UK Central North Sea, acquired as part of the DEO transaction in May 2012. Perth offers 21.5mmbbl (net) from its initial FPSO-based development phase, with further upside possible from a 14.4mmbbl (net) second stage, the Spaniards East appraisal well (drilling, 30mmbbl gross, 13% WI carried by PMO), and other neighbouring assets which may ultimately comprise a wider Perth hub development. Parkmead recently received FDP approval for Perth – an important milestone, in our view, that should see the market begin to price in the field's 2P reserves. We value Parkmead's stake in Perth at 13p/share.

Another potentially valuable piece of Parkmead's portfolio is its Southern North Sea gas acreage – seven blocks containing the Platypus field, the 47/10-8 discovery, and the Possum, Pharos, and Blackadder prospects. Together these **SNS gas assets offer up to 1.3Tcf of gross in-place resource in a known, prolific gas province, and if commercialised could merit a new hub development** or tie-back to a larger field nearby. Recent testing at Platypus has proven commercial flow rates, and with the Pharos prospect due to spud in 2013 we think the Southern North Sea will be a key area of focus for Parkmead in 2013. In aggregate we value the company's SNS gas assets at 2p/share.

As a predominantly development- and exploration-focused business, **we believe funding will be a key issue for Parkmead as it executes its planned drilling programme over 2012-14**. Management expect that a recent £8.5m equity placing and £8m shareholder loan facility will be sufficient to fund Parkmead's upcoming capital commitments; however, with a portion of the placing proceeds being used to fund the acquisition of Dyas's Netherlands assets we think it likely Parkmead will require new external funding to complete is planned drilling programme. We assume a new £20m debt facility is drawn in 2013 to fund Parkmead's share of upcoming well costs.

Upcoming wells at **Spaniards East and Pharos provide Parkmead investors a pair of important drilling catalysts**, with the results of the 27th UK licensing round offering further newsflow over 4Q12. Our 15p/sh price target is set at a 25% discount to our SoP to reflect uncertainty around funding, and with 16% upside to this target **we commence coverage of Parkmead with a Buy rating**.

Valuation

We value Parkmead at 20p/share on a sum-of-parts basis, placing the shares at 0.65x our SoP versus the North Sea E&P peer group at 0.67x. The majority of our valuation is Parkmead's 52% stake in Perth, which we value at 13p/sh assuming an 80% CoS.

Risks

Parkmead's funding capacity is a key medium term uncertainty as the company advances its appraisal and development campaign, particularly at the Perth and Southern North Sea gas assets – we expect new debt, farmdowns and potentially dilutive equity raisings will be the likely sources of funding. In addition, our Parkmead valuation will become more sensitive to operational issues (delays, costs) as it moves selected assets into development.

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Exhibit 1: Parkmead Group SoP valuation summary

Region	Asset	Hydrocarbon	PMG W.I. %	Resource Size (mmboe) Gross	Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV p/sh	Unrisked p/sh	Upside %
Producing assets	**Key assets**											
Netherlands Onshore	Brakel, Geesbrug, Grolloo, W.e.A.	Gas	15%		4	100%	4	11	11	1	1	
							4		**11**	**1**	**1**	
Development assets												
UK - Central North Sea	Perth (Phase 1)	Oil	52%	41	22	80%	17	9	155	13	16	16%
UK - Southern North Sea	Platypus	Gas	15%	14	2	75%	2	5	7	1	1	1%
Netherlands Onshore	Ottoland & Papekop	Oil	15%	15	2	50%	1	12	14	1	2	6%
							20		**177**	**15**	**19**	**23%**
2012-13 Exploration & Appraisal												
UK - Central North Sea	Spaniards East	Oil	13%	30	4	20%	1	8	6	1	3	10%
UK - Southern North Sea	Pharos	Gas	20%	58	12	30%	4	4	14	1	4	14%
UK - Southern North Sea	Possum	Gas	15%	12	2	30%	1	4	2	0	1	2%
							5		**23**	**2**	**7**	**26%**
Further drilling												
UK - Central North Sea	Perth (Phase 2)	Oil	52%	28	14	25%	4	8	30	2	10	37%
UK - Southern North Sea	47/10-8	Gas	20%	12	2	20%	0	3	2	0	1	3%
UK - Southern North Sea	Blackadder	Gas	20%	50	10	10%	1	3	3	0	3	13%
							5		**34**	**3**	**13**	**52%**

Valuation Multiples				
PMG share price	13p	No. of Shares	761.6	m
Core NAV	15p	Market Cap.	£98	m
P / Core NAV	**0.85**	Enterprise Value	£99	m
P / SoP	**0.65**	2P Reserves	25.1	mmbbl
Upside to SoP	55%	EV/2P boe	**$6.22**	**/boe**

PMG Sum of Parts Valuation	$m	p/sh
Parkmead Group Assets	245	20p
Cash / (Net Debt)	-1	0p
AUPEC subsidiary	31	3p
Faroe Petroleum Investment	10	1p
G&A	-45	-4p
Decommissioning & Cost Carries	0	0p
Sum of Parts	**240**	**20p**

Source: Jefferies estimates

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Exhibit 2: Parkmead Group financial summary

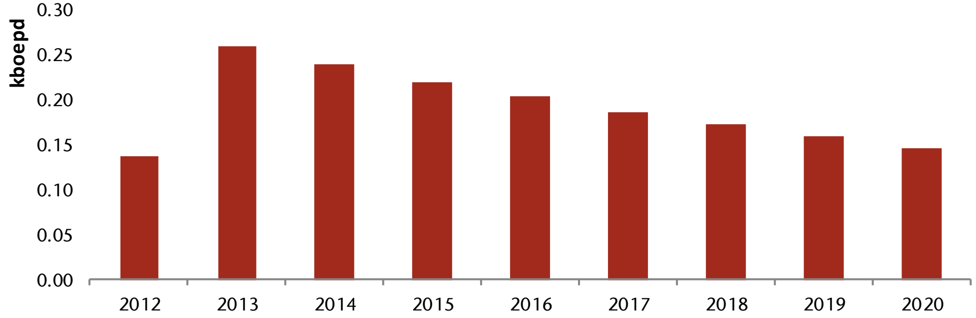
P&L		2010	2011	2012E	2013E	2014E
Revenue	£m	2	4	4	6	6
Cost of Sales	£m	-2	-2	-1	0	0
Exploration Writeoffs	£m	0	0	0	0	0
G&A	£m	-2	-5	-6	-6	-6
Other	£m	0	0	0	0	0
Pre-tax Operating Profit	£m	-2	-3	-3	-1	-1
Net Finance Income/(Expense)	£m	1	0	0	-1	-1
Pre-tax Profit	£m	-1	-3	-3	-1	-2
Tax	£m	0	2	0	0	1
Net Profit incl exceptionals	£m	-1	-2	-3	-1	-1
EBIDAX	£m	-2	-4	-4	-2	-2
No. of Shares	m	522	606	762	762	762
EPS	p/sh	0	-1	0	0	0
DPS	p/sh	0	0	0	0	0

Cashflow Statement		2010	2011	2012E	2013E	2014E
Cashflow from Operations	£m	-3	-1	-2	-2	-2
Cashflow from Investing	£m	1	2	-8	-12	0
Cashflow from Financing	£m	0	0	14	19	-1
Net Change in Cash	£m	-2	1	4	5	-4

Balance Sheet		2010	2011	2012E	2013E	2014E
Cash	£m	0	1	5	11	7
Exploration Assets	£m	0	0	4	15	15
Prod'n & Devel. Assets	£m	0	0	4	4	4
Long Term Debt	£m	0	0	5	25	25
Provisions	£m	0	0	-1	-3	-5
Shareholder Equity	£m	9	9	15	14	12
Gearing: Net Debt(Cash)/Equity	%	-3%	-14%	-1%	107%	150%

12-month Catalysts	PMG WI %	CoS %	Risked NAV $m	Risked NAV p/sh	SoP Upside %
Spaniards East	13%	20%	6	1	10%
Pharos	20%	30%	14	1	14%
Possum	15%	30%	2	0	2%

Production Summary		2010	2011	2012E	2013E	2014E
PMG production WI	kboepd	0.0	0.0	0.1	0.3	0.2



SoP sensitivity to Brent & WACC

	LT Brent $/bbl	$70.00	$85.00	$100.00	$115.00	$130.00
WACC	8%	21	21	21	21	21
	10%	20	20	**20**	20	20
	12%	19	19	19	19	19
	14%	18	18	18	18	18

Assumptions		2010	2011	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58

Source: Jefferies estimates

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Exhibit 3: Map of Parkmead's UK Central North Sea assets

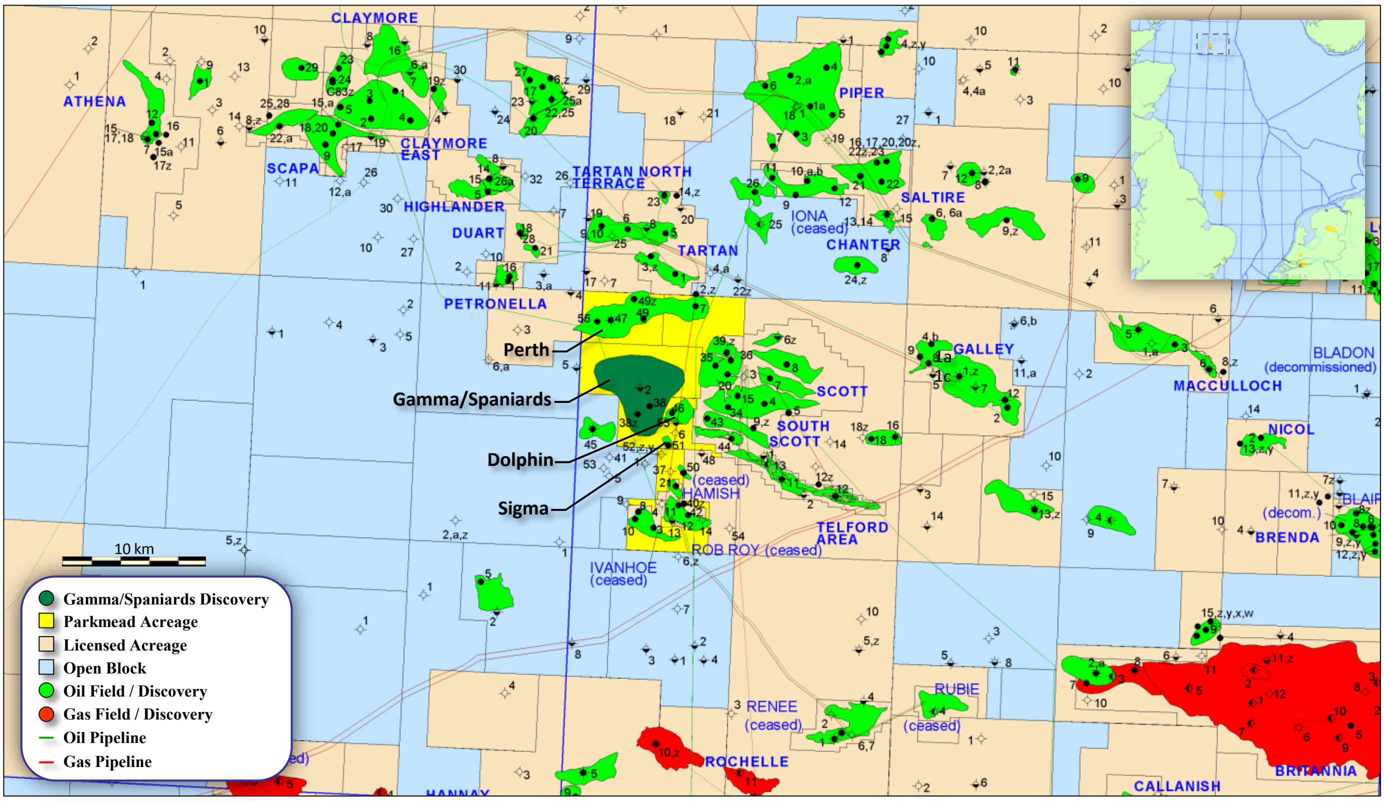
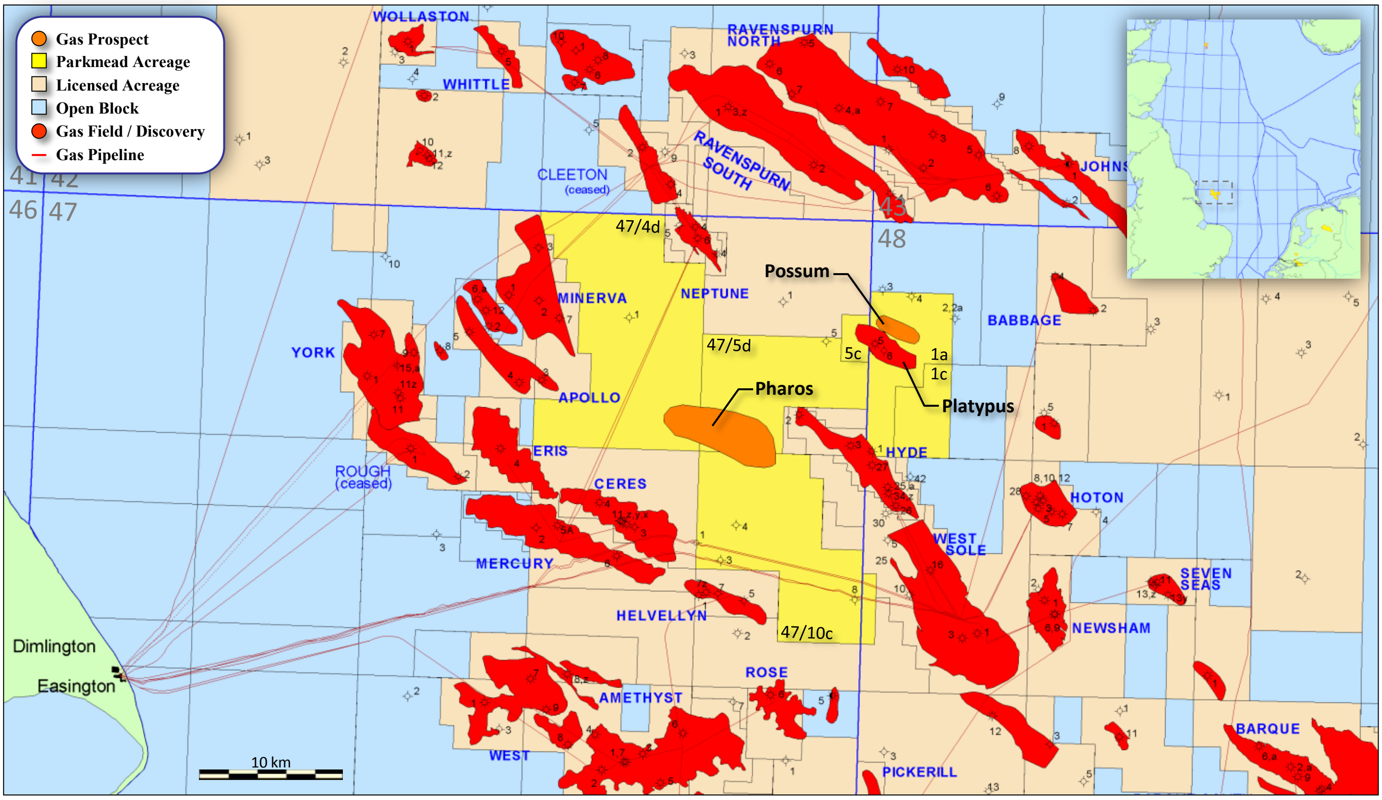


Exhibit 4: Map of Parkmead's UK Southern North Sea assets



Source (both): Parkmead Group

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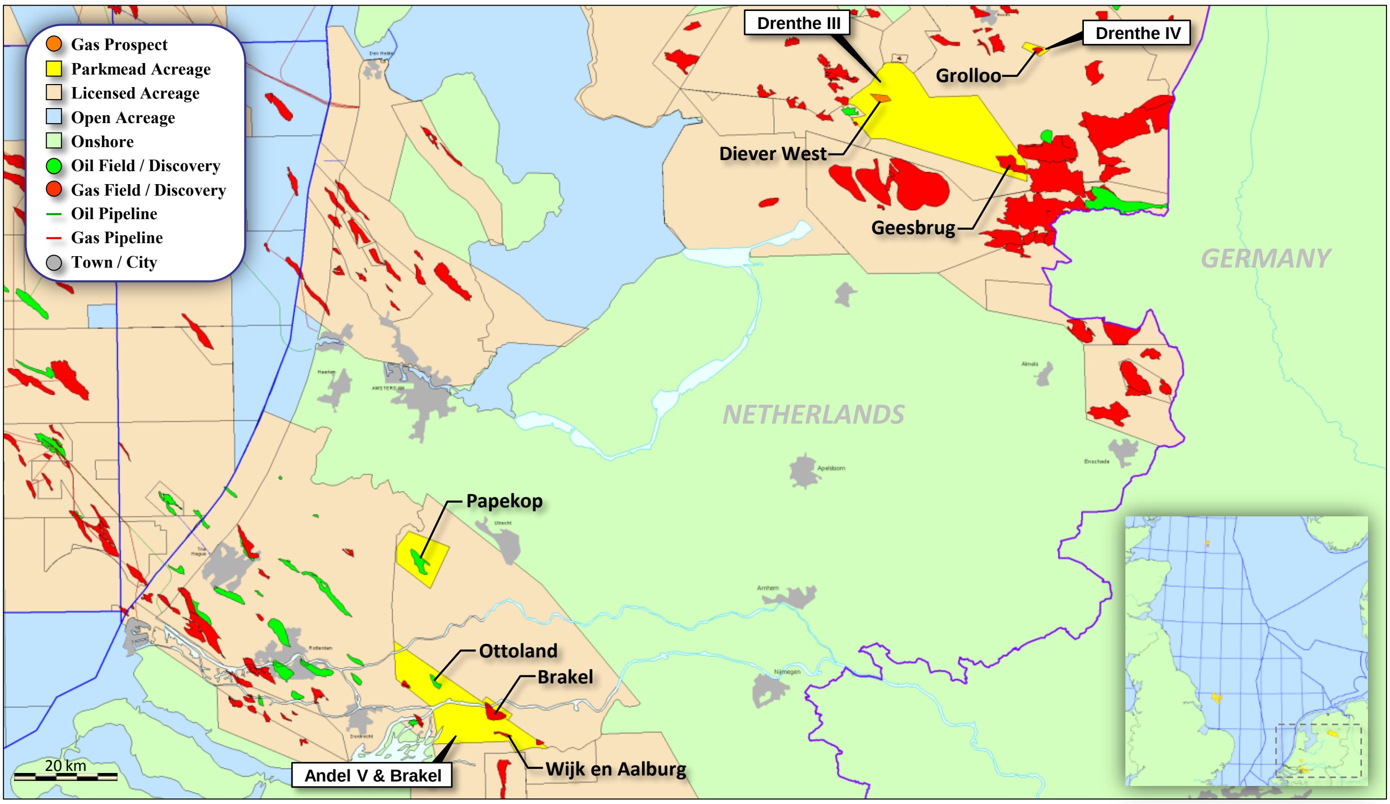
Exhibit 5: Map of Parkmead's onshore Netherlands assets



Source: Parkmead Group

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Valuation

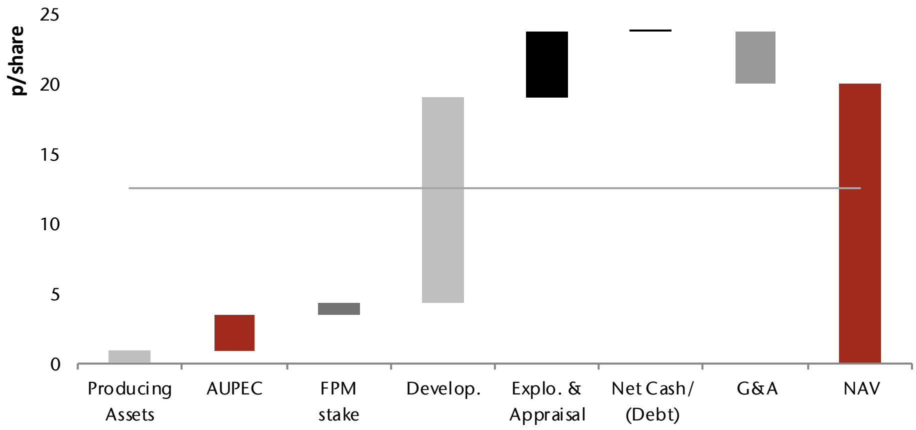
Perth field dominates our 20p/sh Parkmead SoP valuation

We value Parkmead Group at 20p/share on a sum-of-parts basis, placing the shares at a 35% discount to our SoP. Our valuation is dominated by Parkmead's development assets, and in particular the company's stake in the Perth oil field which we value at 13p/sh. A recently-approved FDP and possible further appraisal work at this UK field are important milestones that, in conjunction with new funding, we believe will see the market begin to price in some value for Parkmead's 21.5mmbbl of Perth's 2P reserves.

PMG looks cheap at $6/boe versus North Sea E&P peer group at $10/boe

The shares look especially cheap based on EV/boe multiples, due mainly to Parkmead's 52% stake in Perth. Based on Parkmead's overall 25.1mmboe 2P reserve base, we estimate the company trades at just $6/boe, a considerable discount to the North Sea E&P sector on c.$10/boe. Based on the average 2010-12 North Sea M&A multiple of $13.7/boe, we estimate Parkmead's overall 25.1mmbbl net 2P reserve base would be worth $343m or 28p/sh, a 121% premium to the current share price.

Chart 1: Breakdown of our 20p/sh Parkmead SoP valuation



Source: Jefferies estimates

Parkmead's interest in several onshore producing gas fields in the Netherlands makes a small (1p/sh) contribution to our SoP, with risked E&A activity (predominantly gas prospects in the UK Southern North Sea) forming 5p/sh, or 23% of our valuation. One small but interesting element of our SoP valuation is Parkmead's 2.1% stake in fellow North Sea E&P Faroe Petroleum (Buy, 240p/sh PT), which in our view could prove to be a useful funding source going forward. We intend to mark-to-market Parkmead's FPM stake whenever we update our Parkmead SoP; at current levels we estimate the position is worth $10m, or 1p/sh.

PMG's subsidiary AUPEC contributes 3p/sh to our SoP

We also include 3p/sh ($31m) of value for Parkmead's wholly-owned subsidiary, AUPEC. AUPEC is a petroleum economics consultancy that merged with Parkmead in 2009, and has its origins at the University of Aberdeen. AUPEC provides advisory and valuation services to the global oil & gas industry, and in the last 25 years has advised over 100 governments, NOCs, majors and independent E&Ps. AUPEC delivered £3.7m of revenue in FY11 – we do not assume any material increase in AUPEC's revenue going forward.

Management has strong pedigree in North Sea value creation

Parkmead Group: 15p price target, Buy recommendation

The company's management, led by CEO & Executive Chairman Tom Cross, has a strong pedigree in using developments and acquisitions to grow (and create value from) North Sea oil & gas portfolios. The sale of Dana Petroleum (of which Mr Cross was CEO) to KNOC in 2010 is a clear example of the scale that a North Sea portfolio can reach, and we believe Parkmead management's relationships and experience in the region put it in good stead for growing this much smaller business rapidly.

We see significant organic (Perth appraisal) and inorganic (future M&A) growth potential in Parkmead's portfolio; however, at present we believe there are some question marks about how Parkmead will fund this growth. A fairly active E&A programme planned for 4Q12-2013 could command material cash resources (we estimate up to £15m net to PMG over this period) that are as yet unsecured. Over the long term we think the company will require additional debt, farmdowns and possibly dilutive equity raisings to fund its future growth, which is why we have set our PMG target price at a 25% discount to our SoP to capture this risk. **With 16% upside to this 15p/share target price, we commence coverage of Parkmead with a Buy recommendation.**

Spaniards East (10% upside) and Pharos (14% upside) provide E&A catalysts over the next 12 months

Medium term catalysts include two E&A wells and the 27th UK licensing round

The recent growth in Parkmead's portfolio means that investors are now exposed to a variety of near-term catalysts. We expect two E&A wells – Spaniards East (oil) and Pharos (gas) – will be drilled during the next year, with further appraisal drilling possible on the Perth development later in 2013. We also expect Parkmead to have participated in the ongoing UK 27th licensing round, most likely bidding for selected blocks close to its existing assets. The Spaniards East well spudded recently, with results expected later in 4Q12.

Table 1: Parkmead's 2012 catalysts

Asset	Timing	PMG W.I. %	Resource Gross (mmboe)	Resource Net (mmboe)	CoS %	$/boe	NPV $m	NPV p/sh	Upside %	Comments
Spaniards East	4Q12	13%	30	4	20%	8	6	1	10%	Testing Upper Jurassic prospect down-dip of Gamma discovery.
27th UK Offshore Licensing Round	4Q12									Opportunity to secure new UKNS acreage, most likely near existing assets.
Pharos	2013	20%	58*	12	30%	4	14	1	14%	Structural trap in Rotliegendes sands with large areal extent; potential 0.5Tcf gas-in-place.

Source: Jefferies estimates, company data

* = assumes 70% recovery factor from 500Bcf estimated gas-in-place.

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Parkmead's funding unclear beyond near-term drilling calendar – we assume £20m new debt in 2013

Near term drilling funded through equity placing and loan facility; new debt facility likely required to avoid potential funding shortfall beyond 2013

With Parkmead moving into an active period of appraisal and development drilling in 2H12-2013 (including the Spaniards East and Pharos wells), the requirement for effective capital management is increasingly important. Management believe that a recent £8.5m equity placing, plus an £8m shareholder loan facility, are together sufficient to fund Parkmead's share of its upcoming capital commitments. However, with a material portion of the placing proceeds being used to fund the €7.5m acquisition of Dyas's Netherlands assets, we see the potential for Parkmead's funding position to become stretched over the next two years, particularly if the company wishes to accelerate its development of the Perth area and/or the Southern North Sea gas assets.

As a result, in our forecasts we assume Parkmead can secure up to £20m of lending against its Perth development (21.5mmbbl 2P reserves) to help fund this project, freeing up some capital for E&A spending elsewhere in the portfolio. We assume this new debt is drawn in 1H13 ahead of drilling the Pharos and Possum exploration prospects (we estimate net costs of £3m each) and potentially a single Perth appraisal well (we estimate £6m net to Parkmead).

Farming down PMG's 52% Perth stake could be one route to funding this development

We believe one possible funding solution for Perth, in particular, is for Parkmead to farm down its 52% stake (and potentially also operatorship) in exchange for a development carry. We suspect Parkmead would have no trouble finding a potential farm-in partner willing to invest in commercial, discovered North Sea oil reserves – many cash-rich E&Ps have shown the desire to gain acreage and production through the acquisition route.

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Parkmead's growing portfolio offers exciting North Sea opportunities

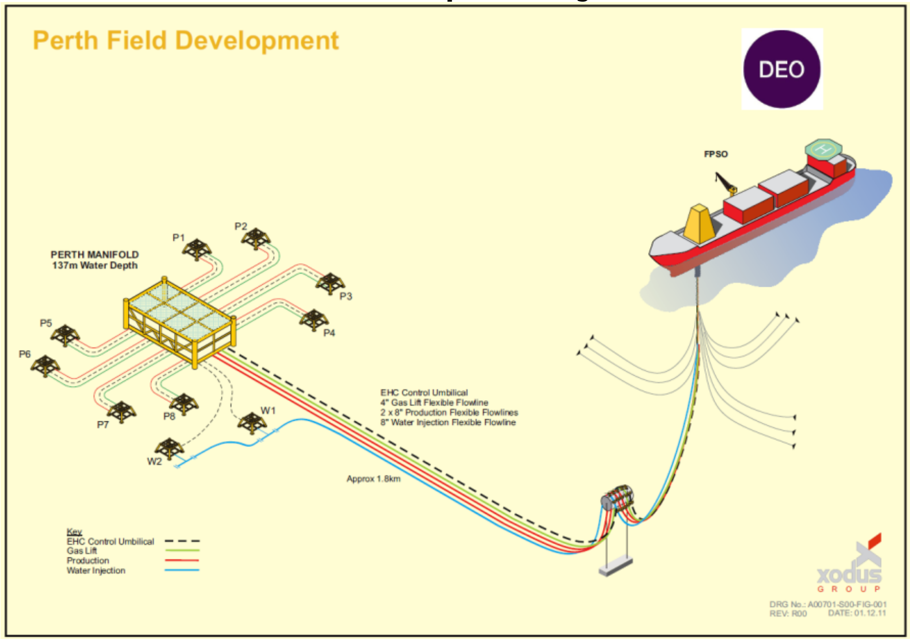
Parkmead's UK and Dutch footprint has grown rapidly in recent months, primarily as the result of acquiring portfolios from DEO Petroleum (UK North Sea) and Dyas BV (onshore Netherlands). In the last year the company has amassed a small but diverse portfolio of assets, including onshore Netherlands gas production, a mid-size UK North Sea oil development with significant step-out potential, and several Southern North Sea gas prospects that we believe could warrant a multi-field gas production hub. In this section we elaborate on what we believe are the key assets in Parkmead's portfolio.

Perth oil field key to Parkmead's growth

The Perth oil development is Parkmead's cornerstone asset, offering 21.5mmbbl of 2P reserves

The cornerstone asset in Parkmead's portfolio, in our view, is its 52% operated stake in the **Perth** oil development in the UK Central North Sea (partners include Faroe Petroleum with 35% and Atlantic Petroleum with 13%). The field was discovered in 1992 and is a combined structural/stratigraphic trap in Upper Jurassic Claymore sands, offering Brent quality (31°API) crude with high levels of CO_2 and sulphur.

Exhibit 6: Potential Perth FPSO development design



Source: DEO Petroleum

Parkmead acquired Perth through the DEO transaction announced in May 2012, and the field recently received FDP approval from DECC for the development of its first phase (plan was submitted September 2011). **We believe Perth's FDP approval was an important milestone for Parkmead**, and once development funding is secured we think the market will begin giving PMG credit for the field's 21.5mmbl of net 2P reserves, in our view. Based on the average 2010-12 North Sea M&A multiple of $13.7/boe, we estimate Parkmead's overall 25.1mmbbl net 2P reserve base would be worth $343m or 28p/sh, a 121% premium to the current share price.

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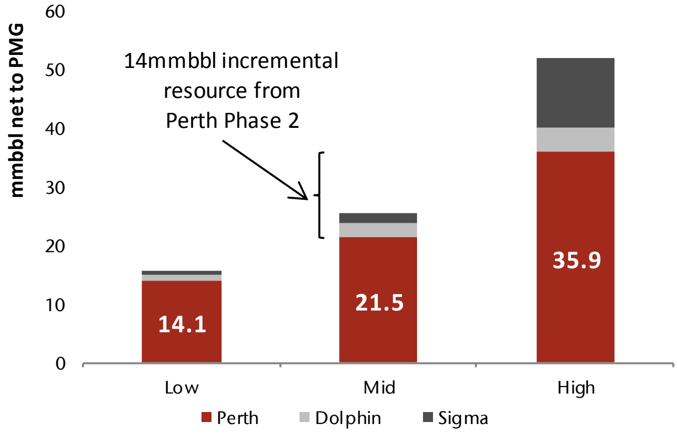
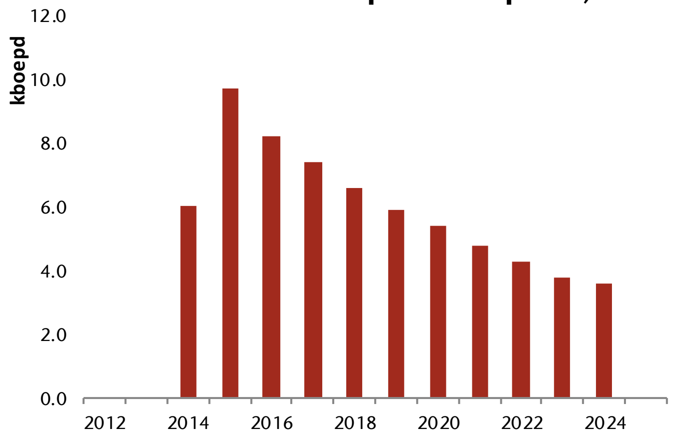
Chart 2: Estimated immediate Perth area resources



Source: Parkmead Group

Chart 3: Possible Perth Phase 1 production profile, 2012-25



Source: Wood Mackenzie, Jefferies estimates

Perth (Phase 1) valued at 13p/sh assuming an 80% CoS

We value Parkmead's stake in Perth at 13p/share, assuming an 80% CoS. Our valuation implies the development is worth $9/bbl (discounted), which we believe is fairly conservative given Perth will use an FPSO-led development design and will be eligible for the UK's small field tax allowance. The field offers further value potential through future development phases that will aim to capture up to 14.4mmbbl of further resource from Parkmead's existing portfolio; any additional commercialised barrels will benefit from existing infrastructure and will therefore offer higher value to Parkmead. We value this second stage of Perth at 2p/share, which also includes step out potential from the small Dolphin and Sigma oil discoveries to the south.

Spaniards East appraisal result due in 4Q12

Parkmead to be carried through 30mmbbl Spaniards East well in 4Q12; we value the prospect at 1p/sh.

As part of the DEO acquisition, Parkmead also acquired a 12.62% interest in the Spaniards oil discovery and **Spaniards East** prospect, located to the south of Perth. The Spaniards East well – which spudded in mid-October 2012 with a result due late-November 2012 – will test a Jurassic target down-dip of the 15/21a-38Z (Gamma) discovery made in 1989, which flowed 2.7kbopd of 25°API crude. Spaniards East offers 30mmbbl of gross prospective resource based on operator Premier Oil's (PMO LN, Hold, 415p/sh PT) mid-case estimate. Parkmead has no financial exposure to the first Spaniards East well as its costs will be fully carried by Premier Oil. We value Parkmead's stake in the Spaniards East prospect at 1p/sh, risked at 20%.

Perth and Spaniards discoveries offer potential for a hub development, in our view

A successful Spaniards East appraisal well presents Parkmead the opportunity to create a Perth hub development, in our view. When combined with the Dolphin and Sigma assets also on Parkmead's acreage (which are likely to be too small to be commercial on a standalone basis), we believe a Perth/Spaniards hub could offer Parkmead material exposure to what could be a 100mmbbl+ (gross) North Sea oil development.

Neighbouring sour oil discoveries offer long-term tie-in potential

Note that this upside is based solely on what Parkmead already owns – management believe undeveloped prospects close to Perth offer up to 902mmbbl of combined STOIIP potential. Perth is located in a neighbourhood of relatively sour oil accumulations (including Lowlander, Ardvreck and Alexandria, plus PMG's Spaniards, Dolphin and Sigma discoveries) with underdeveloped local infrastructure, the result of the industry typically ignoring this more technically challenging, high H_2S Central North Sea region. However, once a Perth FPSO is in place the economics of many of these surrounding fields could be improved substantially – **we believe some of these fields will be on Parkmead's radar for potential future M&A activity**.

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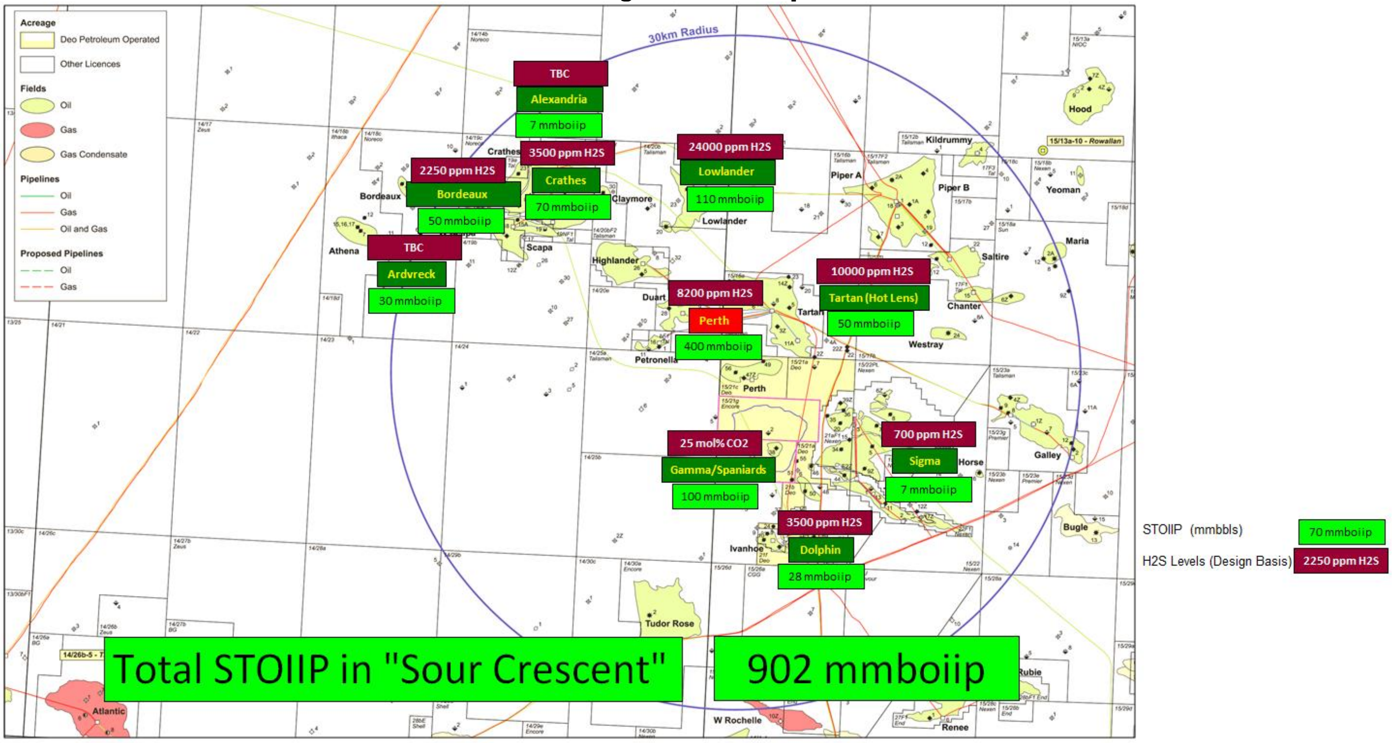
Exhibit 7: Sour oil accumulations near Perth offer long-term tie-in options



Source: Parkmead Group

Potential UK Southern North Sea gas hub

In November 2011 Parkmead acquired stakes in several UK Southern North Sea assets – the **Platypus** gas field and adjacent **Possum** gas prospect, both acquired from ExxonMobil subsidiary XTO UK, and the **Pharos** gas prospect acquired from Sorgenia UK. These assets are located in a prolific gas producing region of the SNS, and are all structural traps within Rotliegendes-age sands. Management consider historical drilling success rates in the area to be very good, which we believe is positive as we approach an exploration well on the 500Bcf gas-in-place Pharos prospect in 2013.

Table 2: Parkmead's Southern North Sea gas assets offer up to 1.3Tcf of gross in-place gas potential

	Partners	PMG WI%	GIIP (Bcf)	Gross (Bcf)	Gross (mmboe)	Net (mmboe)	CoS %	Risked (mmboe)	NPV ($m)	NPV (p/sh)	SoP upside %
Platypus	KNOC (59%, operator), First Oil Expro (11%), CalEnergy Gas (15%)	15%	180	84	14	2	75%	2	7	0.6	1%
Possum	KNOC (59%, operator), First Oil Expro (11%), CalEnergy Gas (15%)	15%	100	70*	12	2	30%	1	2	0.2	2%
Pharos	KNOC (50%, operator), Sorgenia UK (15%), MPX North Sea (15%)	20%	500	350*	58	12	30%	4	14	1.2	14%
Blackadder	KNOC (50%, operator), Sorgenia UK (30%)	20%	430	301*	50	10	10%	1	3	0.3	3%
47/10-8	KNOC (50%, operator), Sorgenia UK (30%)	20%	100	70*	12	2	20%	0	2	0.1	13%
TOTAL			**1,310**	**875**	**146**	**28**		**7**	**29**	**2.4**	**32%**

Source: Parkmead Group, Jefferies estimates

*** = assumes recovery factor of 70% from stated GIIP estimates**

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Parkmead recently completed a 3,100ft horizontal appraisal well on the Platypus field (estimated 2.1mmboe net 2C resource), delivering 27mmscf/day from a 3,100ft horizontal section within the reservoir. This level of productivity appears sufficient for a commercial development, and the well has been suspended for use as a future producer – we use a 75% CoS for Platypus to reflect that the asset has been derisked over the appraisal process.

Platypus/Possum/Pharos fields possible candidates for a gas hub

Given that Parkmead's SNS gas assets are all located in adjacent blocks, we again see the potential for a combined hub-type development should the Possum and (especially) the larger Pharos prospects be deemed commercial in addition to the successfully appraised Platypus field. Developing these fields in tandem would offer more attractive economics relative to three standalone projects, particularly if the smaller Platypus and Possum fields could access the UK's small field tax allowance – we think this is likely based on their currently estimated resource potential. The fields also offer the option to be tied back to much larger nearby gas fields, including Babbage or West Sole.

Netherlands gas fields offer production & cashflow

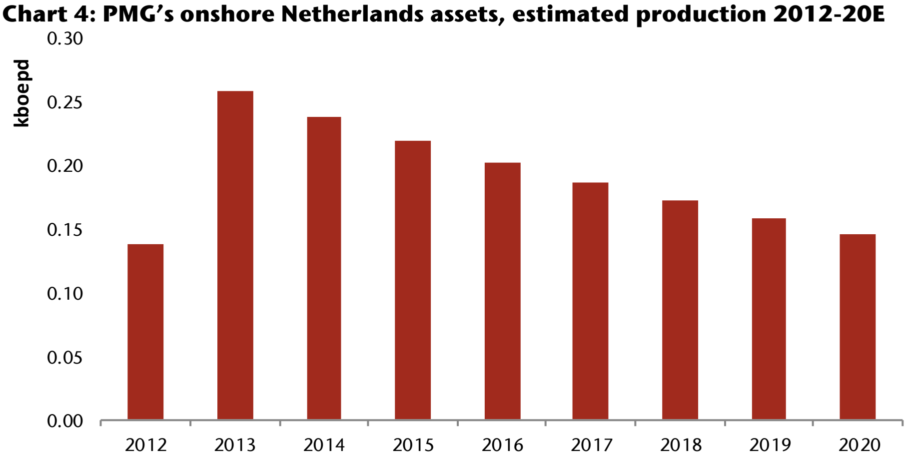
Acquisition of Dyas BV gives PMG stakes in four onshore Netherlands producing fields

Parkmead diversified its portfolio further in March 2012 by acquiring a portfolio of onshore Netherlands oil & gas assets from Dyas BV. The portfolio included stakes in four production licenses containing four producing gas fields and two oil developments

- 15% in the Andel V Production License contains the **Wijk en Aalburg** and **Brakel** producing gas fields, plus the **Ottoland** oil development.
- 15% in the Papekop Production License which contains the **Papekop** oil development
- 15% in the Drenthe III and Drenthe IV Production Licenses, containing the **Geesburg** and **Grolloo** producing gas fields

Consideration for the deal was an upfront cash payment of €4.5m (approx. £3.6m), with a €3m (approx. £2.4m) contingent payment payable upon first oil sales from the Papekop development. The deal was announced concurrently with Parkmead's £8.53m equity placing, of which a portion of the proceeds was used to finance the initial payment to Dyas.

Chart 4: PMG's onshore Netherlands assets, estimated production 2012-20E



Source: Jefferies estimates

Dutch production assets contribute c.250boepd and approx. £1m of free cashflow per annum

The acquired assets give Parkmead immediate exposure to 3.6mmboe of net 2P reserves (from the producing Andel V and Drenthe III/IV licences), 2.3mmboe of contingent resource from the planned Ottoland and Papekop oil developments, and approximately 250boepd of net production in 2012. We estimate the producing assets will deliver around £1m per annum of free cashflow over the medium term. Further in-fill drilling is expected at the Geesbrug field over 2013, with new compression facilities planned for the Brakel field in 1H13 – we believe this investment has the potential to lift recovery rates from Parkmead's Dutch assets over the medium term.

We value Parkmead's 15% stake in the onshore Dutch producing assets at $11m, or 1p/share. At present we value the Ottoland and Papekop oil projects as risked development assets, worth 1p/sh to our Parkmead SoP.

Risks

Funding risk

As a small, predominantly development- and exploration-focused business, we believe one of the key issues that Parkmead will face in growing its business is the availability of funding. Although management believe Parkmead can manage its near-term spending though both existing resources (£8.5m cash raised through a recent equity placing, plus an £8m shareholder loan facility) and carried exploration (e.g., its 12.6% carried interest in Spaniards East), in the long term we believe Parkmead may have to use new debt, dilutive equity raisings or farmdowns to fund its share of development costs. When setting our target price we capture this dilution risk in a 25% discount to SoP. Our forecasts assume a new £20m debt facility is drawn in 2013 to cover near-term expenditure.

Development delays and higher-than-expected costs

As Parkmead moves into a period of active development across its portfolio (the Ottoland and Papekop oil projects onshore Netherlands, plus the Platypus gas hub and Perth projects in the UK North Sea) the contribution of these assets to the company's overall value will increase markedly. Any delays or higher-than-expected costs in bringing these projects to completion will directly impact both our and the market's valuations.

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Shareholders & Management

Thomas Cross, Executive Chairman and Chief Executive Officer

Mr Cross is a Chartered Director and Petroleum Engineer. His career includes senior positions with Conoco, Thomson North Sea, and Louisiana Land & Exploration, and he also held the role of Director of Engineering at the UK Petroleum Science and Technology Institute. Prior to establishing the Parkmead Group, he was the founder and Chief Executive of Dana Petroleum plc until its acquisition by the Korea National Oil Corporation for c.$3bn in 2010. Mr Cross is a former Chairman of BRINDEX, the Association of British Independent Oil Companies and is a Fellow of the Institute of Directors. He chairs AUPEC, a global advisory group on energy policy and economics, and has also served as a Chairman of the Society of Petroleum Engineers.

Donald MacKay, Chief Financial Officer

Mr MacKay has over 30 years' experience in the energy sector and has extensive international work experience having worked in South East Asia, the Middle East and Africa as well as the US and the UK. He has been Managing Director of Aupec Limited since 2001, prior to which he held senior international finance and operational positions with Unocal Corporation (now part of Chevron). He is a Chartered Accountant.

Table 3: Parkmead Group major shareholders

Shareholder	% stake
Thomas Cross & affiliates	25.5%
David Rose	6.0%
Alexander Kemp	4.0%
Niall Doran	3.9%
David Mills	3.5%
YF Finance	3.1%
No. of ordinary shares on issue (m)	761.6

Source: Parkmead Group

Note that in aggregate Parkmead's senior management team own approximately 37% of the company's issued capital. We view this positively given that management is very closely aligned with Parkmead's performance; however, in our view this large cornerstone holding could present some liquidity issues in the long term.

Parkmead Group is listed on London's AIM market.

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Premier Oil (PMO LN): Assuming coverage with Hold, 415p/sh PT (+10p)

In light of our wider North Sea E&P sector initiations, in this note we focus on the outlook for Premier Oil's North Sea portfolio. The region comprises a material portion of PMO's reserves, production and value, and is home to a number of PMO's key medium-term development projects (Catcher and Solan) and exploration prospects (Luno II and Lacewing). Small revisions to our model have increased our SoP valuation slightly from 484p to 486p/sh and our target price from 405p to 415p/sh; our Hold recommendation remains unchanged. We also transfer primary coverage of Premier Oil from Laura Loppacher to Matthew Lambourne.

Premier has shown an appetite to grow both organically and inorganically in the North Sea. The company is a **proven North Sea consolidator** (see the acquisitions of EnCore Oil in early 2012, Oilexco in 2009, Wytch Farm and Solan in 2011, and Bream in Norway in 2012), and has been an active participant in both Norwegian and UK offshore licensing rounds. In the latest (27^{th}) round, Premier applied for 15 licenses, 10 of which were as operator – we expect these license awards to be announced in 4Q12.

In July 2012, Premier farmed into an operated 60% stake in Rockhopper's (RKH LN, Hold, 300p/sh PT) **Sea Lion** and surrounding fields in the Falkland Islands for $1bn (comprising a $231m immediate payment, a $48m exploration carry, and a $722m future development carry). The deal represented $4.70 per 2C barrel according to Gaffney Cline resource estimates, or $3.61/bbl on a discounted NPV-10 basis. We estimate PMO will ultimately earn an unrisked IRR of 20%, which we believe is appropriate for the operational risks of the project.

PMO offers a number of positive catalysts over the remainder of 2012, including E&A well results from Spaniards East (2p/sh, 1% SoP upside), Cyclone (7p/sh, 3% SoP upside), Luno II (5p/sh, 4% SoP upside) and Lacewing (2p/sh, 2% SoP upside), plus results from the upcoming 27^{th} UK licensing round (due 4Q12). The market will also be eagerly awaiting an update on PMO's 2012 production, where planned maintenance shutdowns and development delays recently led management to trim guidance from its previous 60-65kboepd estimate to 60kboepd. **We forecast PMO to deliver average 2012 production of 59kboepd, slightly below management's guidance**.

Valuation

Our SoP valuation of PMO has increased slightly from 484p/sh to 486p/sh. This change incorporates the impact of PMO's 1H12 results, explicit full-field NPVs of the Catcher and Solan developments, plus formal value for PMO's investment in RKH's Sea Lion. The shares trade at just 0.84x our 438p/sh Core NAV and 0.76x our 486p/sh SoP, a discount that we believe reflects the market's attitude towards PMO's ability to meet production guidance and its unremarkable exploration track record. While PMO looks undervalued versus its North Sea peers (average 0.88x Core NAV and 0.67x SoP), we believe the market requires more comfort in PMO's production and exploration before the discount is closed.

We set our PMO price target at a 15% discount to our SoP valuation to reflect these uncertainties, and with 13% upside to this revised 415p/sh target (was 405p/sh), we retain our Hold recommendation.

Risks

In our view the key near-term risks for PMO are (a) failure to meet its 60kboepd FY12 production guidance, and (b) lack of material success in its remaining four-well 2012 E&A drilling campaign. We also believe development delays and cost overruns present an increasing threat given PMO's growing exposure to developments (e.g., Sea Lion, Catcher, Solan).

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Exhibit 1: Premier Oil SoP valuation summary

Region	Asset	Hydrocarbon	PMO W.I. %	Resource Size (mmboe) Gross	Resource Size (mmboe) Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV p/sh	Unrisked p/sh	SoP Upside %
Producing assets	**Key assets**											
UK North Sea	Balmoral, Wytch Farm, Huntington	Oil/Gas	Various		124	100%	124	13	1586	192	192	
South East Asia	Chim Sáo, Natuna Sea Block A	Oil/Gas	Various		132	100%	132	12	1631	197	197	
Middle East, Africa & Pakistan	Zamzama, Qadirpur, Kadanwari	Oil/Gas	Various		41	100%	41	8	324	39	39	
							297		**3541**	**428**	**428**	
Development assets												
UK - Central North Sea	Greater Catcher Area	Oil	50%	84	42	100%	42	14	596	72	72	0%
UK - Central North Sea	Carnaby	Oil	50%	30	15	75%	11	17	192	23	31	2%
UK - West of Shetland	Solan	Oil	60%	39	24	100%	24	13	309	37	37	0%
UK - Central North Sea	West Rochelle	Oil	50%	10	5	90%	5	8	37	4	5	0%
Falkland Islands	Rockhopper - Sea Lion & surrounds	Oil	60%	383	213	84%	178	5	835	101	121	4%
Norway - Norwegian North Sea	Froy	Oil	49%	53	26	50%	13	3	39	5	9	1%
Norway - Norwegian North Sea	Bream	Oil	20%	27	5	90%	5	8	39	5	5	0%
Norway - Norwegian North Sea	Grosbeak North	Oil	10%	50	5	75%	4	6	23	3	4	0%
Vietnam	Chim Sáo & Dua upside	Oil/Gas	53%	20	11	80%	9	10	85	10	13	1%
Indonesia	Block 'A' Aceh upside	Gas	42%	100	42	80%	33	3	100	12	15	1%
Indonesia	Benteng-1	Gas	30%	76	23	40%	9	5	50	6	15	2%
							332		**2305**	**279**	**327**	**10%**
2012-13 Exploration & Appraisal												
UK - Central North Sea	Spaniards East	Oil	28%	30	8	20%	2	8	14	2	8	1%
UK - Central North Sea	Cyclone	Oil	70%	30	21	35%	7	8	60	7	21	3%
Indonesia	Matang	Gas	42%	40	17	10%	1.7	5	9	1	11	2%
Norway - Norwegian North Sea	Luno II	Oil	30%	120	36	20%	7	6	40	5	24	4%
UK - Central North Sea	Lacewing	Oil	20%	58	12	15%	2	8	14	2	12	2%
Vietnam	Ca Voi (Block 121)	Oil	40%	100	40	10%	4	6	23	3	27	5%
UK - Central North Sea	Bonneville	Oil	50%	10	5	25%	1	8	10	1	5	1%
Indonesia	Kuda/Singa Laut	Oil	65%	100	65	35%	23	5	116	14	40	5%
Vietnam	Silver Silago	Oil/Gas	30%	100	30	20%	6	6	37	5	23	4%
							54		**323**	**39**	**171**	**27%**
Further drilling												
Vietnam	Cá R?ng Đo	Oil/Gas	45%	40	18	50%	9	8	68	8	16	2%
Pakistan	Badhra-7	Gas	6%	12	1	30%	0	4	1	0	0	0%
Pakistan	Badhra K32	Gas	6%	7	0.4	30%	0	4	0	0	0	0%
							9		**69**	**8**	**17**	**2%**

Valuation Multiples				
PMO share price	367p	No. of Shares	523.6	m
Core NAV	438p	Market Cap.	£1,922	m
P / Core NAV	**0.84**	Enterprise Value	£2,436	m
P / SoP	**0.76**	2P Reserves	296.3	mmboe
Upside to SoP	32%	**EV/2P boe**	**$12.99**	**/boe**

PMO Core NAV	$m	p/sh
Producing Assets	3,541	428p
Development Assets	2,305	279p
Net Cash / (Debt)	-813	-98p
Admin. & Decommissioning	-847	-102p
PV of Rockhopper development carry	-558	-67p
Core NAV	**3,628**	**438p**

PMO Sum of Parts Valuation	$m	p/sh
PMO Core NAV	3,628	438p
2012-13 Exploration & Appraisal	323	39p
Further Drilling	69	8p
Sum of Parts	**4,020**	**486p**

Source: Jefferies estimates, company data

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Exhibit 2: Premier Oil financial summary

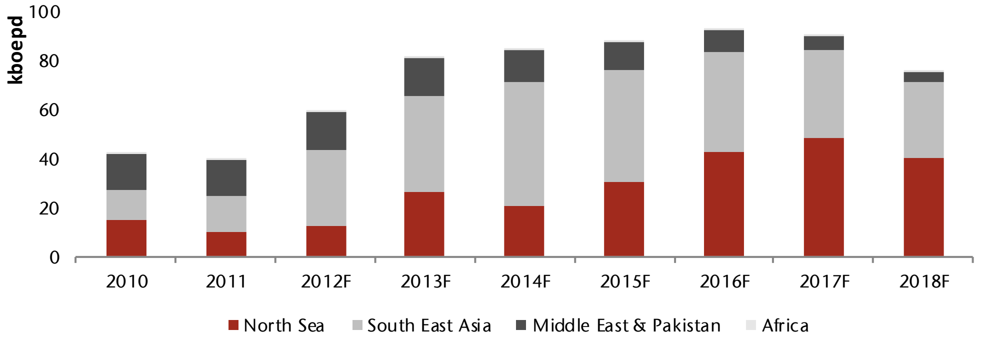
P&L		2010A	2011A	2012E	2013E	2014E
Revenue	$m	764	826	1487	1943	1805
Cost of Sales	$m	-531	-415	-680	-813	-806
Exploration Writeoffs	$m	-87	-211	-157	-129	-129
G&A	$m	-18	-26	-29	-32	-32
Other	$m	0	0	0	0	0
Pre-tax Operating Profit	$m	128	175	621	969	838
Net Finance Income/(Expense)	$m	-27	-34	-114	-151	-167
Pre-tax Profit	$m	101	141	507	818	670
Tax	$m	29	30	-238	-501	-451
Net Profit incl exceptionals	$m	130	171	269	317	220
EBIDAX	$m	411	522	851	1183	917
EV/EBIDAX	x	9.4	7.4	4.5	3.3	4.2
No. of Shares	m	464	467	524	524	524
EPS	c	28	37	52	61	42
DPS	c	0	0	0	0	0

Cashflow Statement		2010A	2011A	2012E	2013E	2014E
Cashflow from Operations	$m	436	486	676	1164	964
Cashflow from Investing	$m	-451	-773	-1098	-1179	-1006
Cashflow from Financing	$m	65	295	215	0	0
Net Change in Cash	$m	50	8	-207	-15	-41

Balance Sheet		2010A	2011A	2012E	2013E	2014E
Cash	$m	300	309	100	84	43
Exploration Assets	$m	311	316	577	660	746
Prod'n & Devel. Assets	$m	1733	2258	3271	3836	4238
Long Term Debt	$m	-685	-1037	-1411	-1562	-1729
Provisions	$m	-473	-565	-591	-591	-591
Shareholder Equity	$m	1130	1324	1958	2275	2495
Gearing: Net Debt(Cash)/Equity	%	34%	55%	67%	65%	68%

12-month Catalysts	PMO WI %	CoS %	Risked NAV $m	Risked NAV p/sh	SoP Upside %
Spaniards East	28%	20%	14	2	1%
Cyclone	70%	35%	60	7	3%
Matang	42%	10%	9	1	2%
Luno II	30%	20%	40	5	4%
Lacewing	20%	15%	14	2	2%

Production Summary		2010A	2011A	2012E	2013E	2014E
PMO production WI	kboepd	42.8	40.4	59.0	81.3	84.6



SoP sensitivity to Brent & WACC	LT Brent $/bbl	$70.00	$85.00	$100.00	$115.00	$130.00
WACC	8%	338	434	525	624	714
	10%	314	401	**486**	577	661
	12%	290	372	450	535	612
	14%	269	345	417	496	568

Assumptions		2010A	2011A	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
US Henry Hub	$/mcf	4.41	3.97	2.67	3.98	3.98
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58

Source: Jefferies estimates, company data

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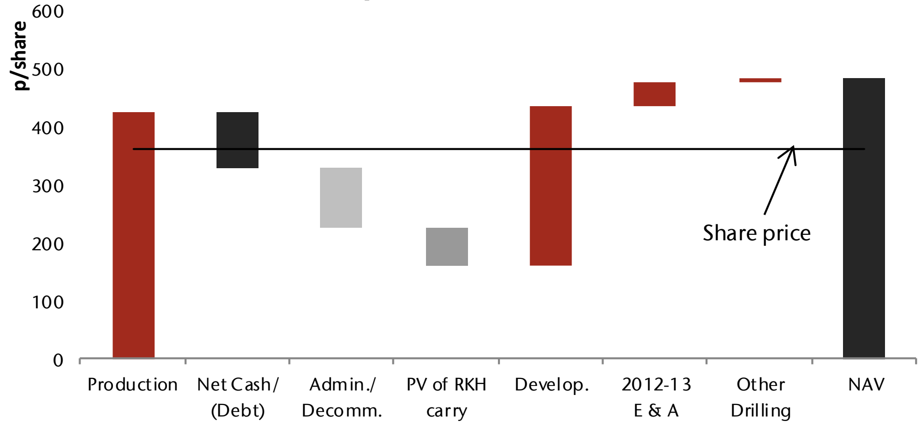
Valuation

We have made a small number of changes to our Premier SoP valuation to incorporate the recent 1H12 results and to include explicit valuations of several assets for the first time. Our 486p/sh SoP valuation (up from 484p/sh) now includes full-field NPV-10 estimates for PMO's Catcher (72p/sh) and Solan (37p/sh) developments, and we have also factored in PMO's recent farm-in to a 60% stake in Rockhopper's Sea Lion development in the North Falkland Basin – we include this asset at 101p/sh for PMO's 60% stake, offset by a substantial development cost carry.

Chart 1: Breakdown of our 486p/sh PMO SoP valuation



Source: Jefferies estimates

PMO trades at a discount to Core NAV; we believe this reflects the market's concerns about PMO's exploration performance and production guidance

At current levels PMO trades at 0.84 times our 438p/sh Core NAV and 0.76 times our 486p/sh SoP valuation, a discount that we believe captures some scepticism by the market towards PMO's ability to (a) meet its production guidance, and (b) deliver material resource and valuation upside through the drill bit. PMO's exploration track record has not been stellar, and in our view the company will require multiple successes from the current campaign to trim this market discount. In addition, we believe the market will need to regain some comfort in PMO's production guidance – meeting management's 60kboepd target for FY12 would be a good start – if PMO is to trade closer to its Core NAV.

This discount is apparent when we compare PMO to its larger, more globally-oriented peers, where its trades towards the lower end of the sector in terms of P/SoP (mid-cap sector average 0.81 times). Relative to its smaller, North Sea peers, however, PMO is one of the more fully valued names, trading above the sector average 0.67 times SoP. In our view this reflects the riskier nature of the North Sea E&P portfolios, which tend to be overweight development assets and in some cases carry material funding risk.

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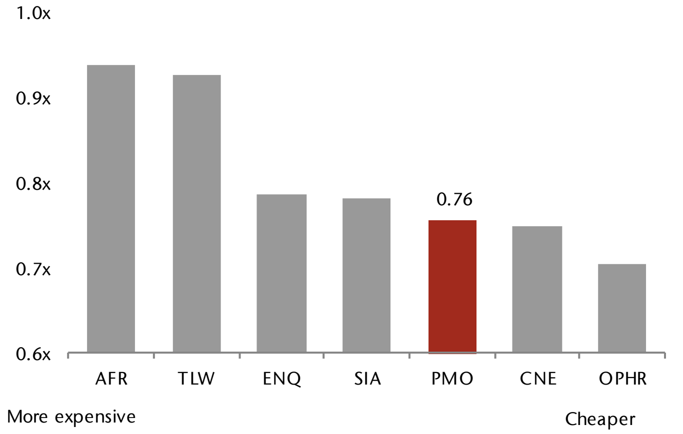
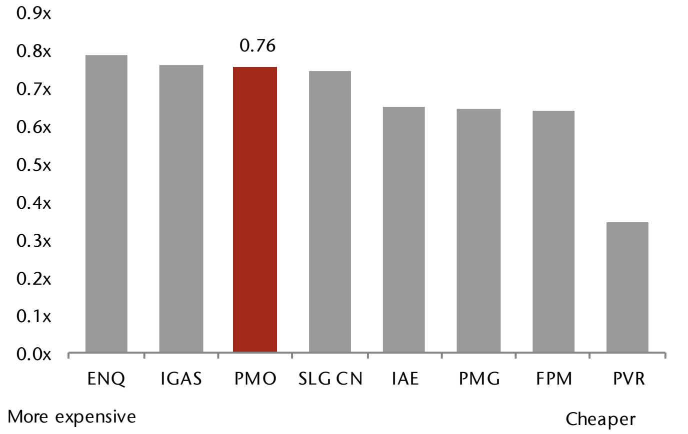
Chart 2: PMO looks cheaper versus mid-caps on P/SoP...



Source: Jefferies estimates

Chart 3: ...than against the North Sea E&Ps



Source: Jefferies estimates

To capture the uncertainty in PMO's near-term production performance and its longer-term exploration track record, our 415p/sh price target is struck at a 15% discount to our SoP valuation (i.e., +2% from our last published 405p/sh PT). Our price target remains at a small discount to our 438p/sh Core NAV, which implies that **we believe any risked value upside from PMO's E&A portfolio is offset by the risk of its core producing and development assets failing to meet management's expectations**. With 13% upside to our new target we retain our Hold recommendation.

Achieving FY12 production target a key milestone...and a key risk

Premier began 2012 with guidance for average FY12 production of 60-65kboepd, with an expected exit rate of 75kboepd as the Huntington and Rochelle developments are brought onstream in 4Q12. However, the impact of the temporary suspension of production from Kyle field (stripping out 1.8kboepd) and the later-than-expected start at Huntington mean that management now expect FY12 output to fall at the low end of this range (revised 60kboepd guidance at the 1H12 results).

We forecast PMO FY12 production of 59kboepd, slightly below management's 60kboepd guidance

We continue to see risk that Premier does not meet its revised 60kboepd target. With YTD production running below 60kboepd (58.4kboepd over 1H12, and this rate estimated to have fallen further in 3Q12 due to planned maintenance shutdowns), Premier relies on a substantial bounce in 4Q production to hit its benchmark. Based on reported 1H output, and assuming PMO produces in line with its 60kboepd target in 3Q12, **we estimate average 4Q output of at least 63.2kboepd is required for PMO to avoid missing FY12 guidance**.

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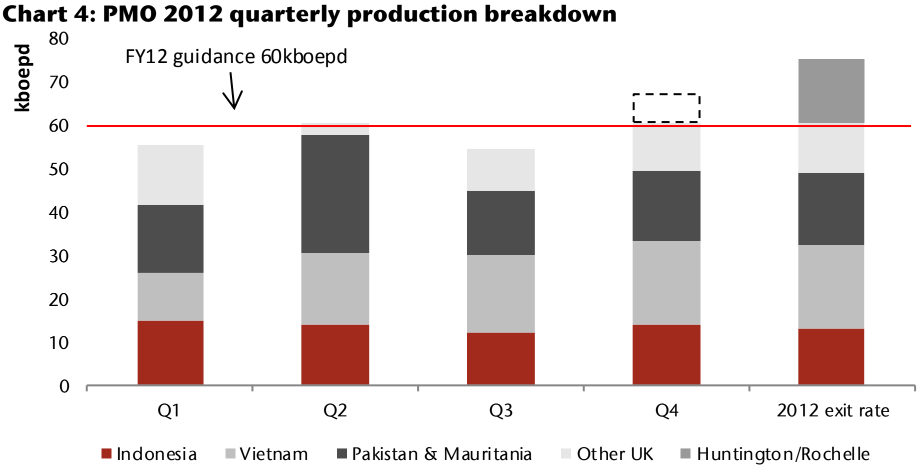
Chart 4: PMO 2012 quarterly production breakdown



Source: Premier Oil, Jefferies estimates

Some of this 4Q12 upside will be driven by Premier's new Huntington (40% WI, light oil) and Rochelle (15% WI, gas) developments, expected onstream in December 2012. While their initial production is unlikely to make a meaningful contribution to overall FY12 output, management expect they will drive a 2012 exit rate of 75kboepd, and put Premier in a position to grow FY13 production to c.80kboepd.

We forecast PMO to deliver average FY12 production of 59kboepd, slightly below management's 60kboepd guidance.

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Premier's North Sea assets

North Sea developments and exploration provide an important source of PMO's medium-term growth

North Sea an important driver of PMO's growth

Premier's North Sea business is a significant element of the company's production (23% of 1H12 output), reserves (42% of FY11 net 2P), and value (we estimate 47% of our asset value). The region is an important source of Premier's medium-term growth, with new developments at Huntington, Catcher, and Solan expected to lift production to over 100kboepd by 2016/17. In addition, high impact wells in Norway (Luno II in 4Q12 and Myrhauk in 2014) aim to test the same Jurassic play type as the wildly successful 1.7bnbbl+ Johan Sverdrup discovery in the Norwegian North Sea.

Table 1: PMO North Sea portfolio offers 245mmboe risked net resource; valued at 358p/sh

Country	Asset	PMO W.I.%	Gross (mmboe)	Net (mmboe)	CoS %	Risked (mmboe)	$/bbl	NPV $m	NPV p/sh	SoP upside %
Producing assets										
UK	Balmoral, Wytch Farm, Huntington	Various		124	100%	124	13	1,586	192	0%
Development assets										
UK	Greater Catcher Area	50%	84	42	100%	42	14	596	72	0%
UK	Carnaby	50%	30	15	75%	11	17	192	23	2%
UK	Solan	60%	39	24	100%	24	13	309	37	0%
UK	West Rochelle	50%	10	5	90%	5	8	37	4	0%
Norway	Froy	49%	53	26	50%	13	3	39	5	1%
Norway	Bream	20%	27	5	90%	5	8	39	5	0%
Norway	Grosbeak North	10%	50	5	75%	4	6	23	3	0%
2012-13 Exploration & Appraisal										
UK	Spaniards East	28%	30	8	20%	2	8	14	2	1%
UK	Cyclone	70%	30	21	35%	7	8	60	7	3%
UK	Lacewing	20%	58	12	15%	2	8	14	2	2%
UK	Bonneville	50%	10	5	25%	1	8	10	1	1%
Norway	Luno II	30%	120	36	20%	7	6	40	5	4%
TOTAL NORTH SEA				**328**		**246**		**2,961**	**358**	**14%**

Source: Premier Oil, Jefferies estimates

Wider and deeper – PMO targeting known plays in current drilling campaign

The medium-term focus of Premier's North Sea drilling campaign is to exploit known play types in the region, both by broadening well-understood plays into new areas (e.g., testing Tay sands in the 30mmboe **Cyclone** prospect, due to be drilled in the UK Central North Sea in 4Q12), or by examining underexplored, deeper fairways such as the high-impact **Luno II** prospect in Norway. Luno II is PMO's largest exploration catalyst in the next 12 months, and will test a 120mmbbl+ Jurassic target adjacent to Statoil/Lundin's giant 1.7bnbbl Johan Sverdrup discovery.

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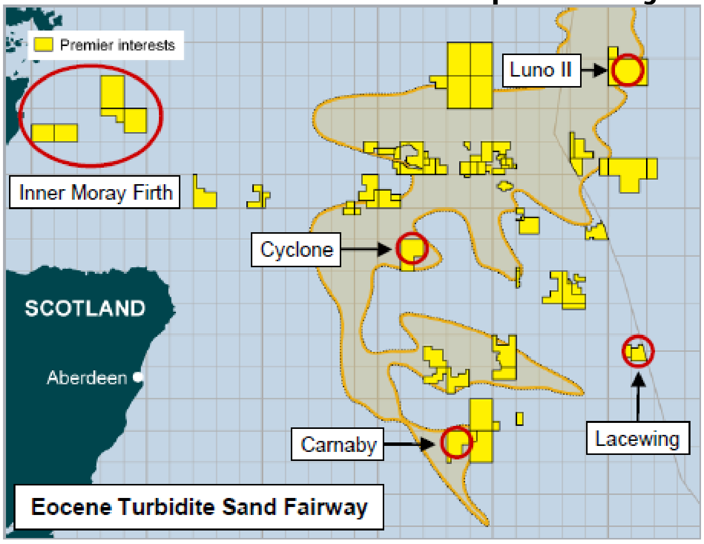
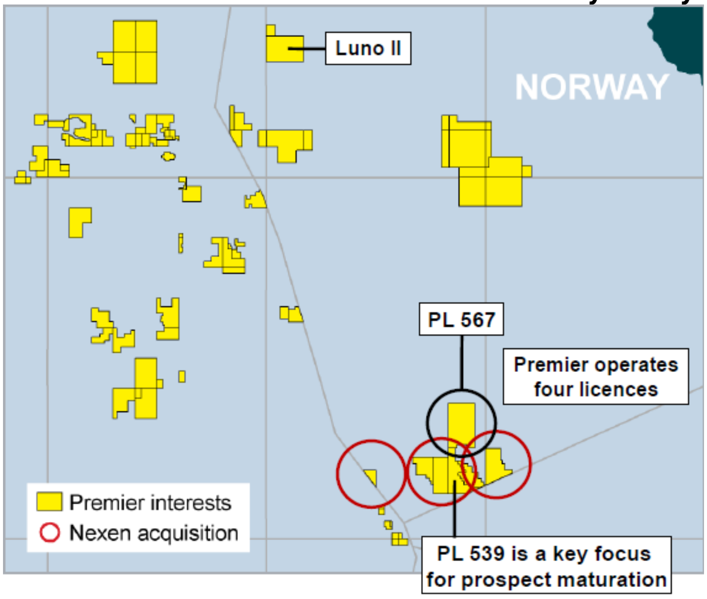
Exhibit 3: PMO's 2012-14 UK North Sea exploration targets



Source: Premier Oil

Exhibit 4: Luno II and PL539 focus of PMO's Norway activity

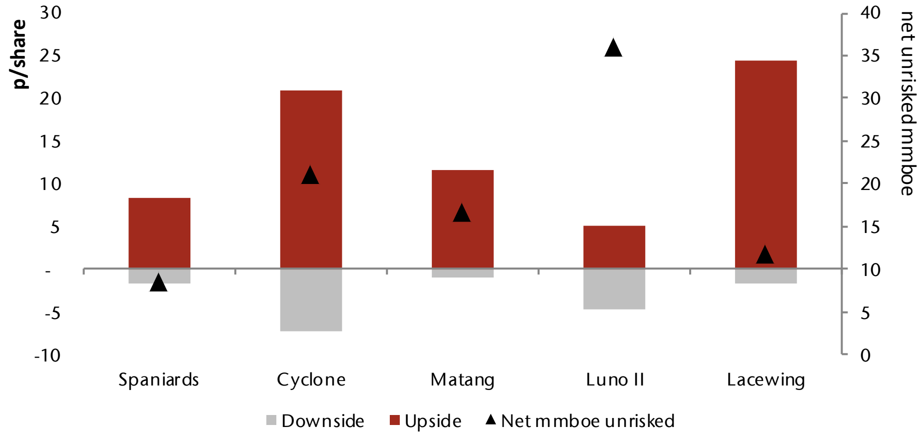


Source: Premier Oil

Five medium-term E&A wells to target 94mmboe of potential net resource, 59p/sh (12%) unrisked upside

PMO has up to five E&A wells planned for the next six months, targeting a total of 94mmboe of net unrisked resource (20mmboe risked). Together we estimate these wells offer up to 59p/sh (or 12%) unrisked upside to our SoP valuation; conversely, in the event of a complete failure in all these wells we would strip 17p/sh (3%) from our valuation, plus drilling costs.

Chart 5: Highlights of Premier's 6-month E&A pipeline



Source: Premier Oil, Jefferies estimates

Premier is also excited about its newly acquired acreage in the Norwegian North Sea, acquired from Nexen in 2011 for $5.5m. The acreage focuses on Jurassic plays at the edge of the Mandal High, where management see unrisked prospective resource potential of 250mmboe+. Gaining most attention among these at present is the 40%-owned **Myrhauk** lead in license PL539, which PMO aim to drill in 2014 – this long window is due to the current tight rig market offshore Norway. At present we do not include any risked value for Myrhauk in our SoP valuation.

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Encounter Oil deal: Longer-term potential to change Premier's UK exploration outlook?

Premier has partnered with EnCounter Oil, the former management of EnCore (which PMO acquired in early 2012) to team up in new North Sea exploration opportunities. Premier will have a right of first refusal on all new ventures identified by EnCounter. In exchange, Premier will effectively fund EnCounter's G&A expenses for two years and carry EnCounter for 10-20% of equity in any new exploration/appraisal opportunity.

EnCounter Oil arrangement could improve market sentiment towards PMO's exploration track record

The EnCounter exploration team has had notable exploration success in the North Sea (including Catcher, Cladhan, Breagh (gas) and Buzzard). If this relationship can turn around Premier's UK North Sea exploration campaign, which has had disappointing success rates of late, we believe this could improve negative market sentiment towards Premier's UK exploration program – in our view, a key reason that Premier has traded at a discount to its peers. However, given the upcoming 27th UK licensing round and the scarcity of available North Sea rigs, we expect it will be at least 2H13 before this partnership results in the drilling of new prospects – while we view the deal positively, we do not expect it to be a material share price driver in the near term.

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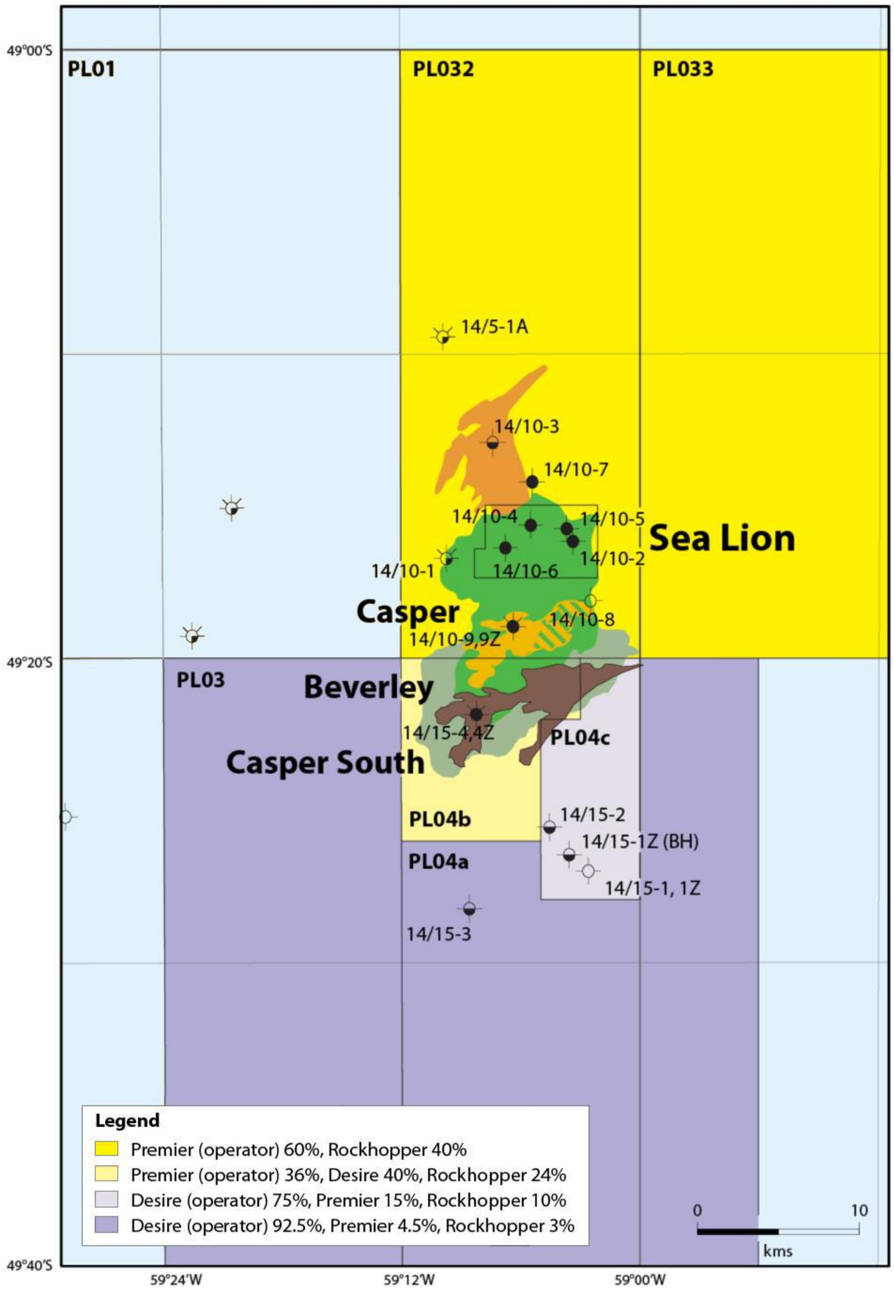
Farm-in to Sea Lion development

PMO's recent investment in Rockhopper's (RKH LN, Hold, 300p/sh) Sea Lion development in the North Falkland Basin presents a significant source of future reserve and production growth for the company. For now we have included this investment in our PMO valuation as a risked 60% stake in the asset based on our standalone RKH SoP valuation, adjusted for the initial cash payment and development carry. **We value PMO's stake in Sea Lion and its surrounding assets at $835m (101p/sh), offset by our estimated PV of PMO's development carry ($558m, or -67p/sh)**. We intend to explicitly show our detailed forecasts of Sea Lion's contribution to PMO's production and capex profile in an upcoming note.

Exhibit 5: Map of Premier's new interests in the Sea Lion area



Source: Premier Oil

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Deal terms: 60% farm-out, $231m cash, $722m development carry, $48m exploration carry, financing facility available. Premier took a 60% operated interest in the Sea Lion project, although Rockhopper state they will continue to have sub-surface lead. In addition to the upfront cash, Premier will carry the development up to $1.8bn and exploration up to $120m (effective $722m/$48m carry of Rockhopper's interest). Rockhopper will have the option to draw financing from Premier with an effective 15% interest (first trigger point to utilise at FDP).

Fair value paid. Premier paid $4.70/bbl on an undiscounted basis. Using Premier's forecasted capex profile for the carry, we estimate the NPV10 value of the $770m development and exploration carry is $558m, implying a discounted value of $3.61/bbl. We estimate this will allow Premier to earn a 20% unrisked IRR at $100/bbl, which we believe is appropriate for the risks inherent to the Sea Lion project.

Development. Premier will take over operatorship of Sea Lion in late October 2012. We believe any possible pre-development E&A is unlikely until 2014, with. FDP submission targeted for 1H14 and first oil currently forecast for 2H17. Premier estimates total capex of $5bn, which is in line with the $5.1bn we assume in our Rockhopper forecasts. We believe Premier brings valuable skills to the development such as experience with FPSOs and waxy crude developments (e.g., Chim Sao).

Exploration: Falkland Islands plus AMI for South Africa, Namibia and Southern Mozambique. Premier will carry $120m gross capex for the Sea Lion area, estimated to cover three wells in the North Falkland Basin including most likely Berkeley (29mmbbl prospective), S2 (50mmbbl prospective) plus one other. PMO will also have an area of mutual agreement in the South Atlantic conjugate margin of South Africa, Namibia and Southern Mozambique.

Deal financing. We estimate Premier can finance the short-term cash requirements from existing cash/debt facilities. However, total development capex, carry and possible financing for Rockhopper will be very material for a company of Premier's size (up to $5bn development capex vs. c.$3bn market cap). We estimate much of the development capital (including the carry) will be spent in 2015-2017. Premier believes it will be generating c.$2bn cash flow in 2015 at 100 kbopd and $100/bbl. We believe Premier will have the flexibility to accelerate or slow down development capital spend in a lower oil price environment.

Material addition to Premier's long term production. Premier estimates peak gross production from Sea Lion of 80-85 kbopd, implying 48-51 kbopd net or a 50% increase on Premier's post-Catcher target of 100 kbopd. In our RKH forecasts we estimate 70kbopd peak production (in line with Gaffney Cline's forecast), implying 42 kbopd net incremental. The timing of first oil from Sea Lion, and the shape of Premier's overall production profile (e.g., date of Catcher first oil) will determine the overall impact of this deal on PMO's output.

Government approval received, deal completed mid-October. The Falkland Island Government has approved the assignment of part-ownership and operatorship of the Sea Lion block to PMO. The deal completed on 19 October 2012.

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Providence Resources (PVR LN): Initiating coverage at Buy, 950p/sh PT

We commence coverage of Providence Resources with a Buy rating and 950p/sh price target. Providence has gained much attention of late, due primarily to its successful appraisal of the Barryroe oil field in the Celtic Sea – Ireland's first ever commercial offshore oil development. As an early mover in the immature Irish oil & gas industry, we believe Providence offers significant further resource potential at Barryroe plus a fully-funded set of visible, very high impact exploration catalysts that could deliver unrisked value many times the current share price.

We recognise that our bullish stance on PVR follows a period of very strong share price performance (+223% in 2012). However, in our view this value has been delivered solely by appraisal success at Barryroe, and does not capture the significant further upside potential from Providence's 2012-13 E&A campaign. **At current levels, we believe the risk-reward balance of Providence's exploration portfolio still lies firmly in the investor's favour**, particularly going into wells at Dunquin and Dalkey Island that could be transformational for the company.

The centrepiece of Providence's portfolio is its 80% stake in the Barryroe light oil field, located off the southern coast of Ireland. Successful appraisal drilling over 2011-12 has demonstrated that **Barryroe is larger, more productive, and more valuable than previously thought**, with management assessing P50 oil-in-place volumes in excess of 1bnbbl from the main Basal and Middle Wealden intervals, nearly triple the previous estimate. The quality of Barryroe's oil and reservoir, plus its high estimated flow rates, mean that Providence can produce more oil from the field in less time with fewer wells – we think this bodes very well for an updated CPR due in 4Q12 where we expect Barryroe to be credited with at least 200mmbbl of recoverable resource.

High impact exploration forms the bulk of PVR's catalysts over the next 12 months, where we are most excited about the Dalkey Island (1Q13, 250mmbbl gross, 50% WI, 10% CoS, 54% SoP upside) and Dunquin (2Q13, 1.7bnboe gross, 16% WI, 10% CoS, 86% SoP upside) wells. The scale of these prospects has not escaped the majors, with Providence partnering with ExxonMobil, ENI, Repsol, and PETRONAS to drill these wells. With Dalkey Island and Dunquin offering unrisked value of £11/sh and £18/sh, respectively, success at either prospect would be transformational for the company.

Valuation

We value Providence at 1,903p/sh on a sum-of-parts basis, with 1,325p/sh (70%) of this valuation contributed by the Barryroe development. Our 950p/sh price target is struck at a 50% discount to our SoP to reflect future farmdown dilution within PVR's development portfolio. However, with the shares trading at just 0.49 times our Core NAV (North Sea peer group at 0.88 times) we believe Providence's development and dilution risks have been overpriced, essentially giving investors a free hit at several high impact, very high reward exploration catalysts.

Risks

Providence's high weighting towards development assets means that any delays in bringing these projects to market, or any cost overruns, will negatively impact our overall PVR valuation. Farmdown dilution is a key uncertainty that we aim to capture in our target price – we see ongoing risk that PVR will ultimately sell stakes in its development assets at a discount to consensus valuations. We also see risk around PVR's exploration assets, which by their very nature are highly uncertain – we have taken an especially conservative stance when risking these assets in our SoP valuation.

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Exhibit 1: Providence Resources SoP valuation summary

Region	Asset	Hydrocarbon	PVR W.I. %	Resource Size (mmboe) Gross	Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV p/sh	Unrisked p/sh	Upside %
Producing assets												
							0		**0**	**0**	**0**	
Development assets												
Celtic Sea	Barryroe	Oil	80%	209	167	75%	125	11	1347	1325	1766	23%
							125		**1347**	**1325**	**1766**	**23%**
2012-3 Exploration & Appraisal												
Irish Sea	Dalkey Island	Oil	50%	250	125	10%	13	9	116	114	1145	54%
Atlantic - South Porcupine Basin	Dunquin	Gas-Cond.	16%	1716	275	10%	27	7	186	183	1829	86%
Atlantic - Main Porcupine Basin	Spanish Point	Gas-Cond.	32%	100	32	50%	16	7	108	107	213	6%
St. George's Channel	Dragon	Gas	88%	35	31	30%	9	6	51	50	168	6%
							65		**462**	**454**	**3355**	**152%**
Further drilling												
Celtic Sea	Hook Head	Oil	73%	20	15	30%	4	9	41	40	133	5%
Atlantic - Main Porcupine Basin	Burren	Oil	32%	66	21	40%	8	8	65	64	160	5%
							13		**106**	**104**	**293**	**10%**

Valuation Multiples				
PVR share price	660p	No. of Shares	64.4	m
Core NAV	1345p	Market Cap.	£425	m
P / Core NAV	**0.49**	Enterprise Value	£384	m
P / SoP	**0.35**	2P Reserves	0	mmbbl
Upside to SoP	188%	EV/2P boe	na	

PVR Sum of Parts Valuation	$m	p/sh
Providence Assets	1915	1883p
Cash / (Net Debt)	64	63p
G&A	-36	-36p
Decommissioning Liabilities	-7	-7p
Sum of Parts	**1935**	**1903p**

Source: Jefferies estimates

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Exhibit 2: Providence Resources financial summary

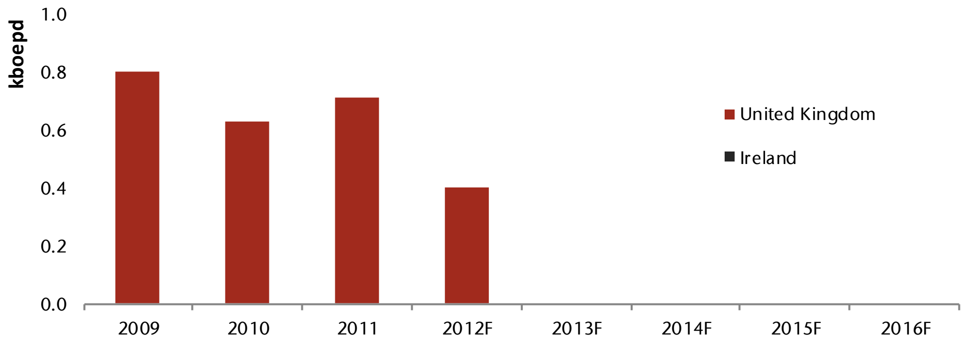
P&L		2010A	2011A	2012E	2013E	2014E
Revenue	EURm	11	14	12	0	0
Cost of Sales	EURm	-5	-4	-5	0	0
Exploration Writeoffs	EURm	-1	-7	0	0	0
G&A	EURm	-4	-3	-5	-5	-5
Other	EURm	0	0	-30	0	0
Pre-tax Operating Profit	EURm	1	0	-27	-5	-5
Net Finance Income/(Expense)	EURm	-7	-5	-2	1	0
Pre-tax Profit	EURm	-6	-5	-30	-5	-5
Tax	EURm	-4	-5	-4	1	1
Net Profit incl exceptionals	EURm	-42	-14	-33	-4	-5
EBIDAX	EURm	4	9	-26	-5	-5
No. of Shares	m	33	50	64	64	64
EPS	EURc	-125	-28	-52	-6	-7
DPS	EURc	0	0	0	0	0

Cashflow Statement		2010A	2011A	2012E	2013E	2014E
Cashflow from Operations	EURm	3	0	5	-5	-5
Cashflow from Investing	EURm	-10	-18	12	-28	-16
Cashflow from Financing	EURm	16	28	8	0	0
Net Change in Cash	EURm	8	9	25	-33	-21

Balance Sheet		2010A	2011A	2012E	2013E	2014E
Cash	EURm	9	19	44	11	-10
Exploration Assets	EURm	10	36	46	74	91
Prod'n & Devel. Assets	EURm	58	46	0	0	0
Long Term Debt	EURm	83	30	0	0	0
Provisions	EURm	22	29	34	33	33
Shareholder Equity	EURm	-24	8	55	51	46
Gearing: Net Debt(Cash)/Equity	%	nm	454%	-87%	-29%	14%

12-month Catalysts	PVR WI %	CoS %	Risked NAV $m	Risked NAV p/sh	SoP Upside %
Dalkey Island	50%	10%	116	114	54%
Dunquin	16%	10%	186	183	86%
Dragon	88%	30%	51	50	6%

Production Summary		2010A	2011A	2012E	2013E	2014E
PVR production WI	kboepd	0.6	0.7	0.4	0.0	0.0



SoP sensitivity to Brent & WACC						
	LT Brent $/bbl	**$70.00**	**$85.00**	**$100.00**	**$115.00**	**$130.00**
WACC	**8%**	2040	2040	2040	2040	2040
	10%	1903	1903	**1903**	1903	1903
	12%	1778	1778	1778	1778	1778
	14%	1665	1665	1665	1665	1665

Assumptions		2010A	2011A	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58
USD/EUR forex	$	1.32	1.39	1.35	1.35	1.35

Source: Jefferies estimates

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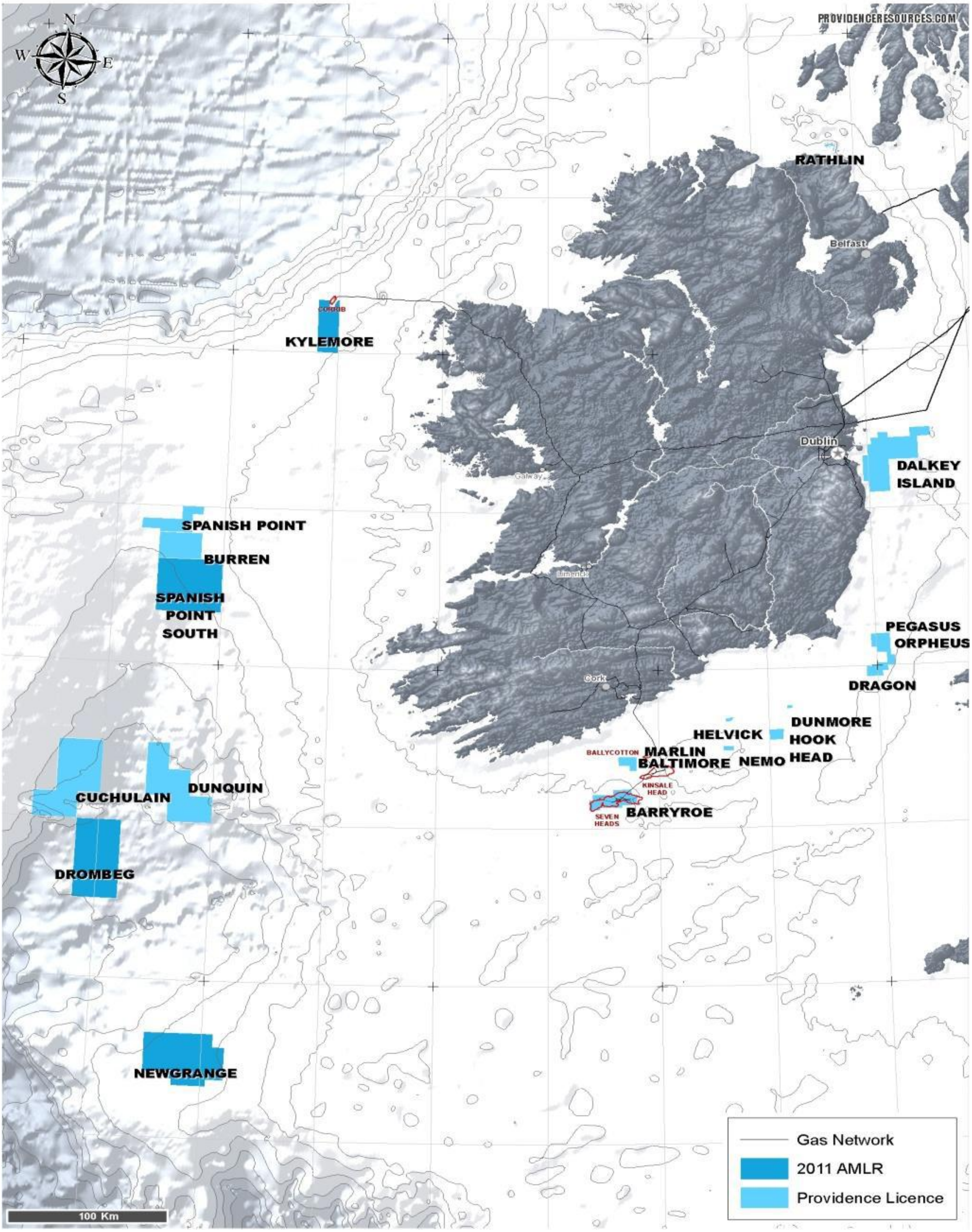
Exhibit 3: Overview of PVR's licenses, showing positions in Atlantic Margin, Celtic Sea, Irish Sea, and Rathlin basins



Source: Providence Resources

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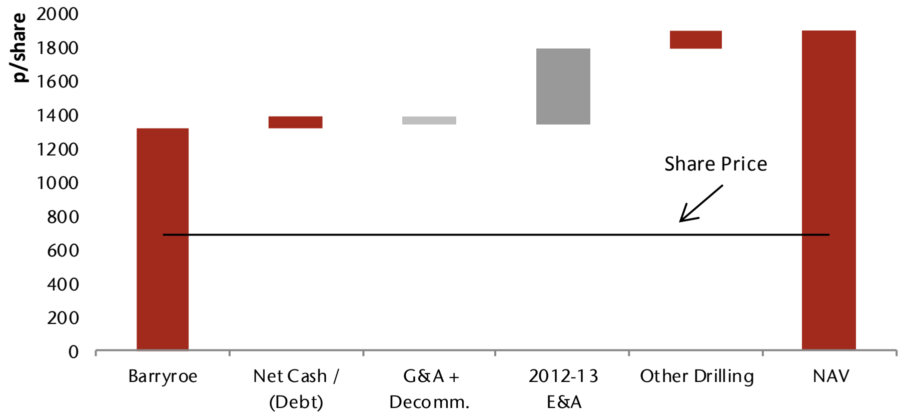
Valuation

PVR trades at just 0.35x our £19/sh SoP valuation; we believe market is overpricing development and funding risks

We value Providence at 1,903p/sh on a sum-of-parts basis. The shares trade at just 0.35 times our SoP, a substantial discount to the North Sea peer group (0.67 times) that we believe is unwarranted given the potential value of Providence's cornerstone Barryroe development asset. Although we expect Providence will face some dilution as it farms down, sells assets, or raises capital to fund its exploration and development programme, in our view the market is overpricing this risk. Our 950p/sh price target is struck at a 50% discount to SoP to reflect PVR's dilution risk, and with 44% upside to this target we commence coverage of Providence Resources with a Buy rating.

Chart 1: Breakdown of our 1,903p/sh PVR SoP valuation



Source: Jefferies estimates

Risk-reward balance still lies in investors' favour, despite PVR's strong FY12 performance

We recognise that our Buy recommendation on Providence follows a period of very strong share price performance (+223% in 2012). However, in our view this value has been delivered solely by incremental appraisal success at Barryroe, and does not capture the significant further upside potential from Providence's 2012-13 E&A campaign. At current levels, we believe the risk-reward balance of Providence's exploration portfolio still lies firmly in the investor's favour, particularly going into wells at Dalkey Island (1Q13) and Dunquin (2Q13) that could be transformational for the company.

Catalysts: Barryroe updates and high impact 1H13 wells

Over the next 12 months Providence will deliver several drilling and operational catalysts that we believe offer unrisked upside potential that is many multiples of the current share price. Newsflow from the ongoing appraisal of the Barryroe field will focus on (a) an **updated CPR** due to be published in 4Q12, where we see the potential for Barryroe's last-published 59mmbbl recoverable resource to increase by at least as much as the recently upgraded STOIIP (+180%), and (b) the outcome of the **farmdown process** in 1H13, where PVR aim to sell a portion of its Barryroe stake to a larger partner who will operate the field and carry PVR through the development stage.

Dalkey Island (£11/sh upside) and Dunquin (£18/sh upside) offer very high impact exploration catalysts in 1H13

We also look forward to Providence's very high impact exploration wells planned for 1H13. The company is exposed to c.2bnboe of gross prospective resource in two wells – **Dalkey Island** and **Dunquin** – whose resource potential has been endorsed by the majors and offers material value potential (we estimate £11/sh and £18/sh unrisked, respectively).

Table 1: PVR 2012-13 catalysts

Asset	Timing	PVR W.I. %	Resource Gross (mmboe)	Resource Net (mmboe)	CoS %	$/boe	NPV $m	NPV p/sh	Upside %	Comments
Exploration										
Dalkey Island	1H13	50%	250.0	125.0	10%	9	116	114	54%	Partnered with PETRONAS, securing foreshore license a key risk.
Dunquin	2Q13	16%	1716.0	274.6	10%	7	186	183	86%	PVR costs capped at $12m, third party validation from partners ExxonMobil, Repsol, and ENI.
Spanish Point	3Q13	32%	100.0	32.0	50%	7	108	107	6%	PVR costs capped at $20m, risks around offshore gas-condensate development.
Dragon	4Q13	88%	35.0	30.6	30%	6	51	50	6%	Farmdown process currently underway.
Appraisal										
Barryroe CPR	4Q12									Uplift to 2C resource (last estimate 59mmbbl) should match or exceed 180% uplift to STOIIP.
Barryroe farmdown	4Q12/ 1Q13									Securing partner to operate field in exchange for development cost carry removes funding risk while maintaining material stake (we estimate 30-40%).

Source: Jefferies estimates, company data

Oil price assumptions

As with all our E&P valuations, our Providence SoP uses a long-term Brent crude price assumption of $100/bbl, below both the current one-month forward price and the 2012 peak of $125/bbl. In our view this price deck represents a level that OPEC (and in particular Saudi Arabia) is willing to defend, and is supported by the marginal cost of non-OPEC supply. Sustained global economic weakness presents a key downside risk on the demand side.

Cash position – PVR funded until end 2013

PVR sufficiently funded to complete its 2012-13 drilling programme

Our forecasts suggest that Providence is sufficiently funded to complete its planned 2012-13 drilling campaign through existing cash balances and the proceeds of the recent Singleton sale. The total cost of the remaining four-well 2012-13 programme is estimated to reach c. €44m, though this number could increase in the event of any drilling delays. We estimate that, even in the worst case scenario (i.e., total failure of the planned exploration campaign) Providence should still be left with approx. €11m of cash at the end of 2013. Beyond this, we expect a rapid burn rate on PVR's cash as it funds drilling costs on the remainder of its exploration portfolio. Note that if PVR can farm down its Barryroe stake (see below) for cash consideration, this could push out its funding requirements significantly.

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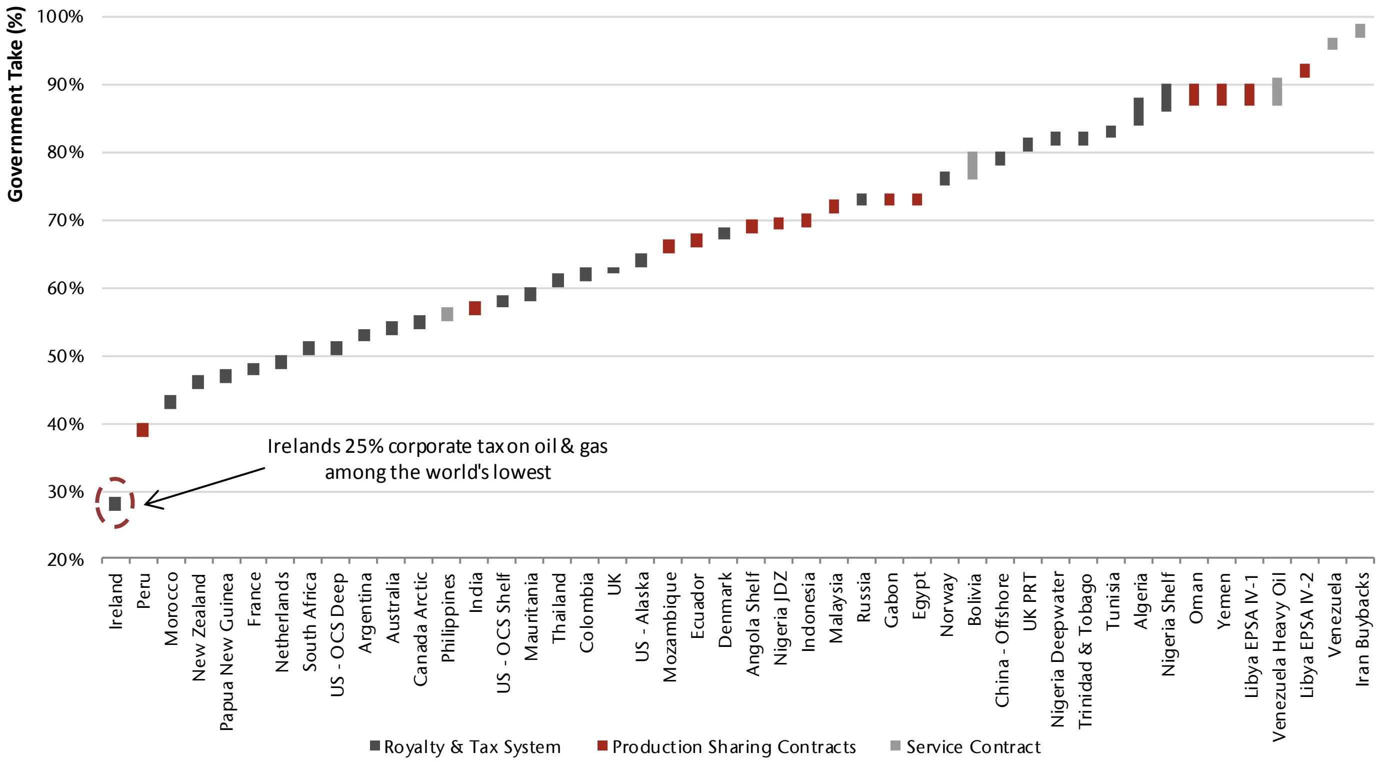
Irish oil & gas taxation

As an early mover in Ireland we believe PVR is well placed to benefit from the country's attractive fiscal terms

To date, Ireland has not been widely viewed as a leading, or even attractive, region for investment in oil & gas. A lack of commercial discoveries, underdeveloped infrastructure and a high operating cost environment have meant Ireland has not kept pace with its UK and Norwegian neighbours in exploiting its hydrocarbon resources, despite Irish fiscal terms being among the most lenient in the world. With just 25-40% corporate tax on oil & gas revenues (dependent on field size), and the ability to write off 100% of eligible capex in the year it is incurred, Ireland's government take is around half that levied by the UK (62%, or up to 81% for PRT-paying assets) and Norway (78%).

As an early mover in Ireland we think Providence is well placed to benefit from the relatively attractive fiscal terms; however, in the long term we see the potential for adverse moves in Ireland's fiscal terms as the country looks to capture more value from an expanding petroleum industry.

Chart 2: Providence Resources well placed to benefit from Ireland's relaxed oil & gas fiscal regime



Source: Journal of World Energy Law and Business

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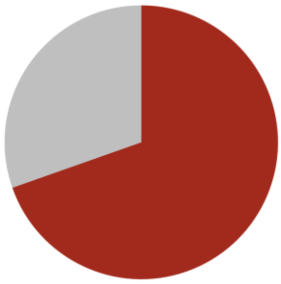
Chart 3: Barryroe worth £13/sh, or 70% of our PVR SoP



Source: Jefferies estimates

We use a more conservative 20% recovery factor for Barryroe than management's 27% average

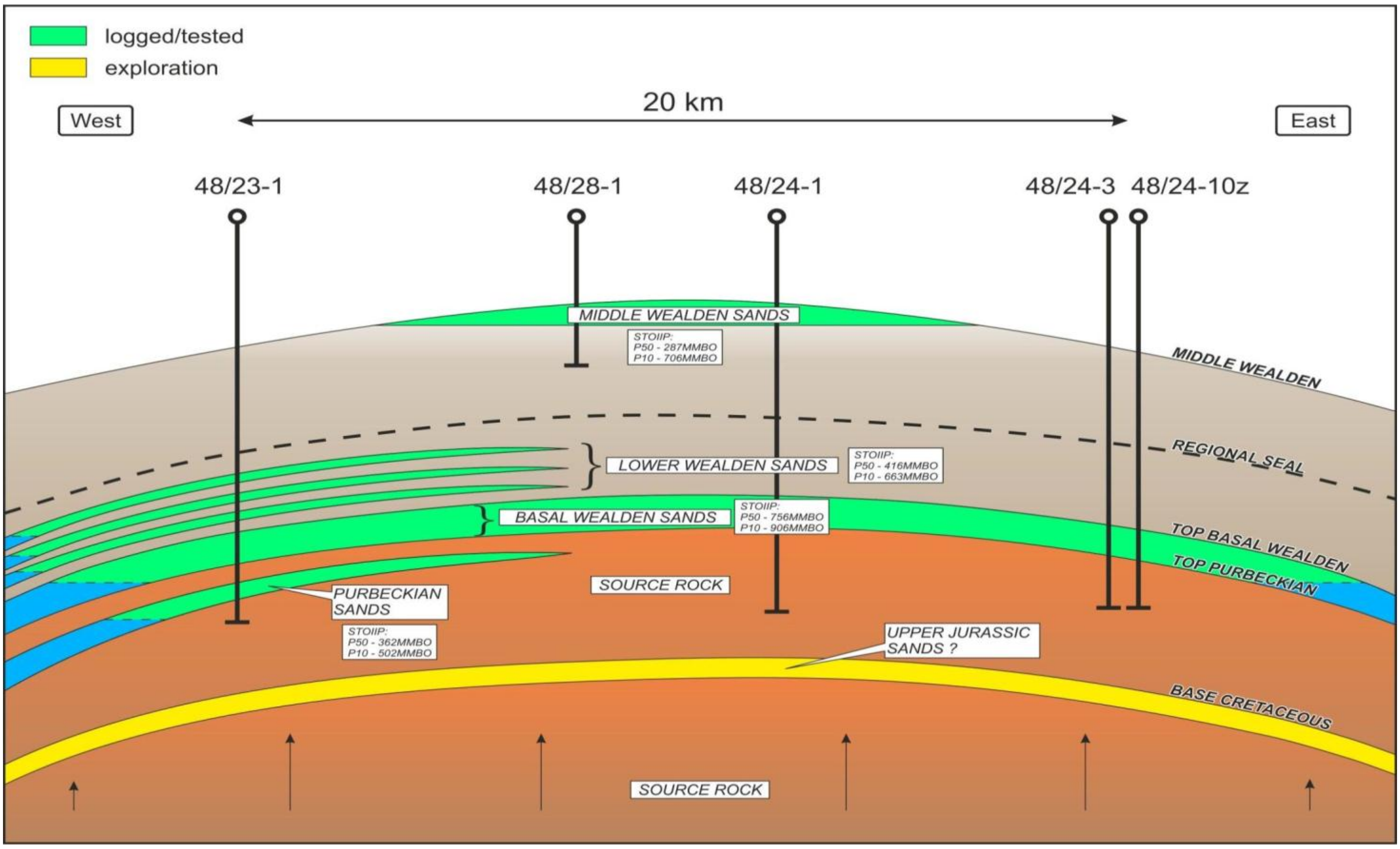
Barryroe

The Barryroe light oil accumulation is the cornerstone of Providence's portfolio. The field (PVR 80%, Lansdowne Oil & Gas 20%) lies around 50km off the southern coast of Ireland in the Celtic Sea, and after a very active period of appraisal during 2011-12 Barryroe is set to be a large (potentially 200mmbbl+ recoverable) commercial development – Ireland's first ever offshore oil project. We value Providence's 80% stake in Barryroe at 1,325p/sh (risked at a 75% CoS), or 70% of our overall PVR SoP.

The evolution of understanding of Barryroe has been rapid. A raft of testing from the 48/24-10Z appraisal well (completed in March 2012) has demonstrated that **Barryroe is larger, more productive, and more valuable than previously thought**. A recent static volumetric assessment by RPS indicated Barryroe's oil-in-place volumes had increased to 1.043bnbbl (P50), a significant 180% uplift over RPS's previous 373mmbbl P50 estimate from 2011. Further analysis also identified additional oil-in-place in the Lower Wealden (416mmbbl STOIIP) and Purbeckian (362mmbbl STOIIP) intervals; however, since these require further appraisal we have not yet included these intervals in our Barryroe valuation.

Management recently estimated recovery factors from the Basal Wealden interval of 17-43% (Middle Wealden 16%). As we detail below, for now we conservatively assume Barryroe delivers an overall average recovery factor of 20% from the increased 1bnbbl+ OIIP estimate (Basal and Middle Wealden), suggesting unrisked gross 2C resources of 209mmbbl (previously estimated at 59mmbbl P50 prior to the 48/24-10Z well). We intend to revise this estimate once the updated Barryroe CPR is published in 4Q12.

Exhibit 4: Barryroe, showing Middle Wealden and Basal Wealden sands, plus Lower Wealden and Purbeckian upside



Source: Providence Resources

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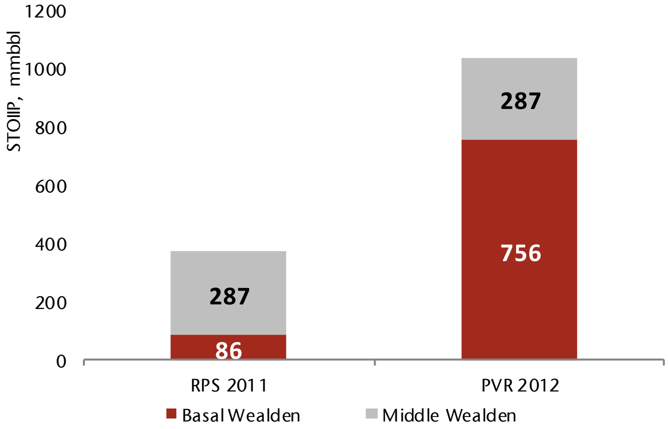
Barryroe getting bigger – upgrade to STOIIP

Prior to the recent appraisal drilling, the focus of Barryroe's potential was on its shallower Middle Wealden interval. In 2011 RPS credited this part of the field with 287mmbbl of P50 oil-in-place, with a further 86mmbbl estimated within the deeper Basal Wealden – note that estimated resource from this basal sandstone was limited to the area immediately adjacent to the 48/24-1 well. With these two intervals now representing an estimated 1.043bnbbl P50 OIIP, in our view there is significant upside to Barryroe's recoverable resource, due to be updated in 4Q12.

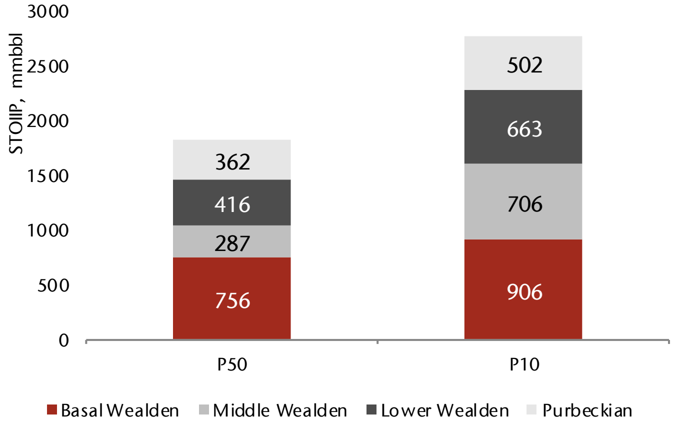
Providence also recently reported in-place volumetric estimates for the Lower Wealden and deeper Purbeckian sands, which added a further 416mmbbl and 362mmbbl of STOIIP, respectively. However, since these two intervals require further flow testing and appraisal drilling, they are not included in Providence's dynamic modelling process ahead of the Barryroe CPR.

Chart 4: Basal Wealden delivers 180% uplift in Barryroe's overall P50 STOIIP



Source: RPS, Providence Resources

Chart 5: 1.8bnbbl STOIIP inclusive of Purbeckian and Lower Wealden intervals…not included in our Barryroe NAV



Source: RPS, Providence Resources

The primary reasons why Barryroe's oil-in-place number increased so materially versus previous estimates, and why the field could potentially offer significantly higher recoverable resource potential, are:

Barryroe is larger than previously thought…

- Barryroe's basal sandstone reservoir covers **a much larger areal extent than previously thought**, with 3D seismic inversion showing the reservoir is well developed right across the 240km^2 survey area. Very little of this basal reservoir was included in RPS's original OIIP estimate, which means that inclusive of the Basal Wealden section Barryroe should see a material uplift in its recoverable resource.

…with no OWC observed to date…

- **No oil-water contact has been observed** in any of the five wells drilled in the region to date. Pressure data from the 48/24-10Z well suggests the OWC is deeper than first thought, meaning potentially more recoverable oil over a larger area.

…offering high quality, light, mobile oil…

- Testing has shown that the **oil and reservoir quality** in both the Middle Wealden and Basal Wealden sections are much better than expected. An independent assay by Shell confirmed Barryroe contains light (43° API), sweet crude with c.17% wax content – better than Providence's pre-drill estimate and mitigating a key development risk. The mobility of Barryroe's oil is also encouraging, with testing indicating low viscosity (just 0.68cP) and a good GOR (800scf/bbl).

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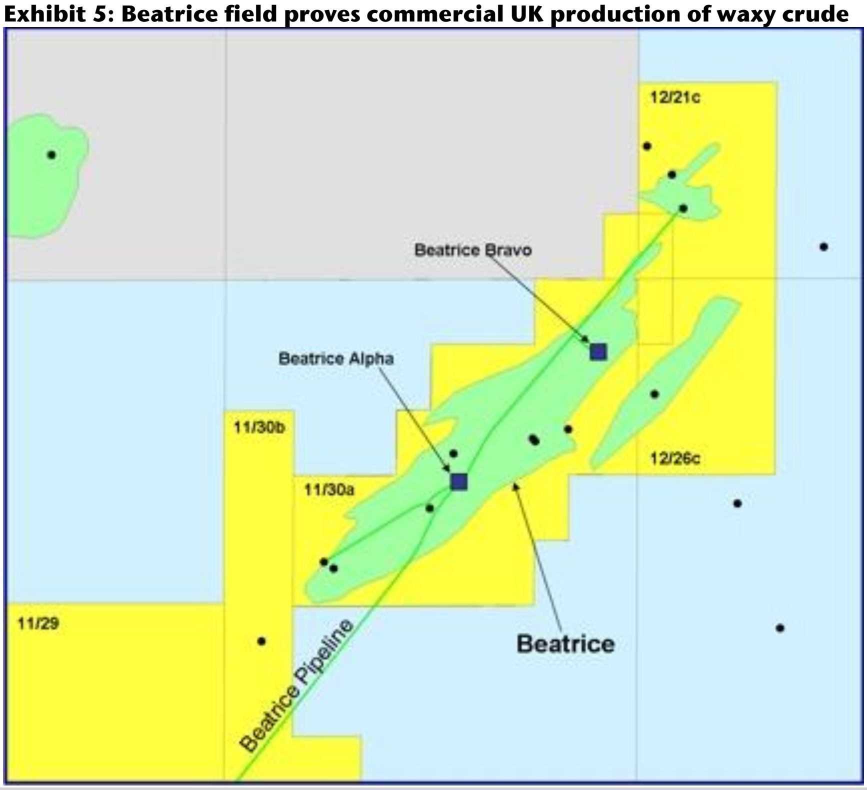
...meaning PVR can produce more oil in less time with fewer wells.

- The Basal Wealden section potentially offers **very good productivity rates**. Modelling by Schlumberger suggests that a 1,000ft horizontal well in this deeper reservoir could deliver initial natural productivity of 12.5kbopd, versus the 3.5kbopd rate observed in the 48/24-10Z vertical well. This modelled rate could improve further with the use of artificial lifting kit, with management flagging potential full-field output of up to 100kbopd per platform. In essence, this strong flow rate estimate means Providence can produce more Barryroe crude in less time with fewer wells.

Beatrice – an important local analogue for waxy light oil

Appraisal success at Barryroe has invited comparisons with other waxy light crude fields that have reached commercial production. The nearest yardstick, in our view, is Talisman's **Beatrice** development (485mmbbl STOIIP) in the Moray Firth, currently being leased to, and operated by, Ithaca Energy (Buy, 180p/sh PT). Beatrice lies in similar water depths and at a similar distance to nearby infrastructure as Barryroe, and with its light waxy crude being sold at the Brent price is supportive to Barryroe's economics.

Exhibit 5: Beatrice field proves commercial UK production of waxy crude



Source: Ithaca Energy

Beatrice – a waxy light oil analogue in the UK – has recovery factors that are encouraging for Barryroe

Since it commenced production in 1981 Beatrice has produced around 174mmbbl of oil (c.3mmbbl of 2P reserves remain), with an attractive recovery factor to date (36%) despite the crude having c.17% wax content (similar to Barryroe). No pour point depressants are added to the produced oil, meaning Beatrice's crude must be exported in heated vessels to maintain fluidity. This is encouraging for the commerciality of Barryroe – while the Irish field has a higher pour point (27°C) than Beatrice (24°C), the high mobility of its crude means we think a Barryroe development design involving multiple horizontal wells and ESPs could deliver significant productivity, particularly from the Basal Wealden reservoir.

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Table 2: Comparison of Barryroe and Beatrice waxy light oil fields

		Barryroe	Beatrice
STOIIP	mmbbl	1043	485
Initial Recoverable Oil	mmbbl	?	174 (3 remaining)
Recovery Factor	%	?	36%
Gravity	°API	43	37.8
Pour Point	°C	27	24
Wax Content	%	17%	17%
GOR	scf/bbl	800	126
Initial Production	kbopd/well	12.5*	4
Peak Production	kbopd	?	55
Water Depth	m	50	56

Source: Providence Resources, BP, Wood Mackenzie, Jefferies
*** = Schlumberger estimates Barryroe could deliver 12.5kbopd unassisted flow rates from 1,000ft horizontal well in the Basal Wealden.**

How big could Barryroe be?

The magnitude of the upgrade to Barryroe's oil-in-place estimate (+180% to 1.043bnbbl in the main Basal and Lower Wealden intervals) highlights the impact that the Basal Wealden has on the potential scale of the field. Aside from the fact that a higher oil-in-place figure implies higher recoverable oil, the recent appraisal programme highlighted several new factors that mean Barryroe's ultimate recovery from the enlarged in-place volumes could potentially be better than previously thought, including:

- **Low viscosity.** Barryroe's crude tested at just 0.68cP (less than water), indicating very good in situ mobility of the oil. Under reservoir conditions this means that the oil will "out run" water in the formation, a property that lends itself very well to using waterflood recovery techniques.

- **Lack of faulting.** A primary pre-drill risk was that the Basal Wealden reservoir was heavily faulted, with this lack of connectivity making recovery difficult. However, with the appraisal programme showing that fault density in this lower section is much lower than anticipated, Providence's management are now confident that a more continuous reservoir, combined with horizontal wells, should markedly improve recovery from this part of the field.

Barryroe's high quality crude and reservoir offers upside risk to our £13/sh risked valuation of the asset

The chart below shows Barryroe's potential resource base at a range of recovery factors, and our valuation in each case based on Providence's current 80% stake. Overall we think **the quality of Barryroe's crude and reservoir presents upside risk to the field's ultimate recovery**, particularly from the larger Basal Wealden interval. However, for now we assume Providence can achieve a 20% recovery factor from the field, i.e. 209mmbbl gross 2C resource – note this is a more prudent assumption than management's estimated 27% average recovery across the Basal Wealden (31% Rf) and Middle Wealden (16%) intervals.

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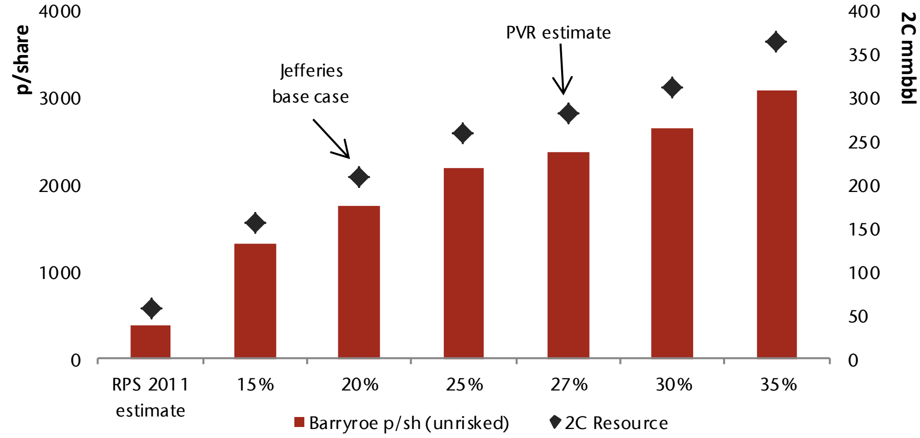
Chart 6: Potential unrisked Barryroe value and 2C resource at various recovery factors



Source: Providence Resources, RPS, Jefferies estimates

Barryroe development & valuation assumptions

Barryroe's key pre-drill risks – reservoir continuity and flow rates – have been mitigated

The results of Barryroe's appraisal programme have led Providence to reassess its development options in light of the new Basal Wealden resource and much improved productivities across the field. The key risks prior to the 48/24-10Z well were the high pour point of the crude and reservoir continuity; however, both of these issues have been derisked though (a) a lower-than-expected wax content of 17%, and (b) fault density within the basal sand being relatively low compared to the overlying Seven Heads field, respectively.

Under our simple, single field model for an Irish fixed platform development, assuming crude is sold at Brent, we value a typical offshore oil project at $15/bbl undiscounted. Clearly the final Barryroe development solution will have a big influence on this number – a horizontal well design will likely involve fewer but more complicated (expensive) wells, and it is unclear yet whether Providence will use artificial lifting immediately or rely on natural lift in the early stages of Barryroe's life. We also must account for the 4.5% profit share payable to San Leon Energy as part of a deal where PVR increased its Barryroe stake prior to the 48/24-10Z well.

Barryroe: 1,325p/share

We value Providence's stake in Barryroe at 1,325p/sh, or a significant 70% of our overall PVR SoP. Pending a firm field development plan, we risk Barryroe at a 75% CoS in our SoP valuation. We expect this valuation to tighten up significantly once we have further details on Barryroe's recoverable resources, ultimate development plan, and the results of the upcoming farm-down process (see below). The matrix below shows the sensitivity of our Barryroe valuation to both the field's recovery factor (we use a conservative base case assumption of 20%) and undiscounted per-barrel value (base case $15/bbl).

Table 3: Barryroe valuation sensitivity

	NPV $/bbl				
Rf %	**$ 10.00**	**$ 12.50**	**$ 15.00**	**$ 17.50**	**$ 20.00**
15%	923	1154	1385	1615	1846
20%	1231	1539	1846	2154	2462
25%	1539	1923	2308	2692	3077
30%	1846	2308	2769	3231	3693
35%	2154	2692	3231	3769	4308

Source: Jefferies estimates
Rf % reflects average recovery factor across all Barryroe intervals

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We expect PVR will farm down its 80% Barryroe stake to approx. 30-40% in exchange for a full development carry

Providence likely to farm down Barryroe in 2013

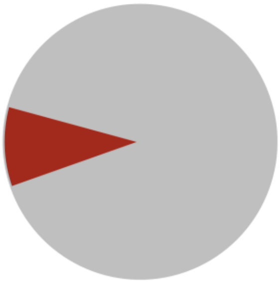
The development capex required to bring Barryroe to commercial production will likely be in the billions of dollars; too expensive, in our view, for Providence to fund at its current 80% working interest. As a result, and in order to bring an experienced operator and developer into the partnership, **we believe Providence will aim to farm down a substantial portion of its Barryroe stake** in exchange for a full cost carry through the development process. The size of the field (we estimate 200mmbbl+ recoverable) means we think Barryroe will be of interest to many large oil & gas companies, especially those keen to exploit Ireland's unchallenging fiscal regime – a data room is expected to be opened later in 4Q12/1Q13.

We expect Providence will want to retain a material stake in Barryroe, meaning that the preferred partner will be a company for whom Barryroe is a high priority development. A residual 30-40% ownership for Providence seems sensible to us; however, given that the field is still in the early stage of its life, and with significant development derisking still to be completed, in our view Providence is likely to face some dilution in any farmdown. With our $15/bbl undiscounted valuation of Barryroe as a benchmark, divesting a 50% operated stake at $5/bbl (i.e., deal value of $0.5bn+) does not seem out of the question.

To capture the dilutive impact of this farmdown – which can be extrapolated across all Providence's large E&A assets – we set our PVR target price at a 50% discount to our SoP valuation.

Dunquin

Chart 7: Dunquin worth 183p/sh, or 10% of our SoP



Source: Jefferies estimates

The big hitter in Providence's exploration portfolio is undoubtedly a 16% stake in Dunquin, a large deepwater gas-condensate prospect in the South Porcupine Basin, 200km to the southwest of Ireland. Volumetric estimates of Dunquin's gross potential are 1.7bnboe (P50) and 3.7bnboe (P10), with the P50 number comprising 8.4Tcf of gas and 316mmboe of recoverable light oil/condensate. **The scale of Dunquin has not escaped the attention of the majors** – Providence's partners in the well include ExxonMobil (27.5%), ENI (27.5%) and Repsol (25%), all of whom no doubt recognise that Dunquin has the potential to be a world-class offshore gas-condensate project.

What is particularly unique about Dunquin is its play type – an isolated carbonate platform in a region whose play systems are commonly based on clastics. To date, these Atlantic Margin clastic plays have not been especially successful offshore Ireland (PVR's Spanish Point and the Corrib gas discovery are two examples); however, with carbonate platforms recognised globally to offer significant oil & gas formations there is the potential for these plays to become a key part of Atlantic Margin exploration going forward. This play concept is similar to the super-giant Perla field in Venezuela (Repsol 32.5%), which is estimated to contain 16.3Tcf of recoverable gas.

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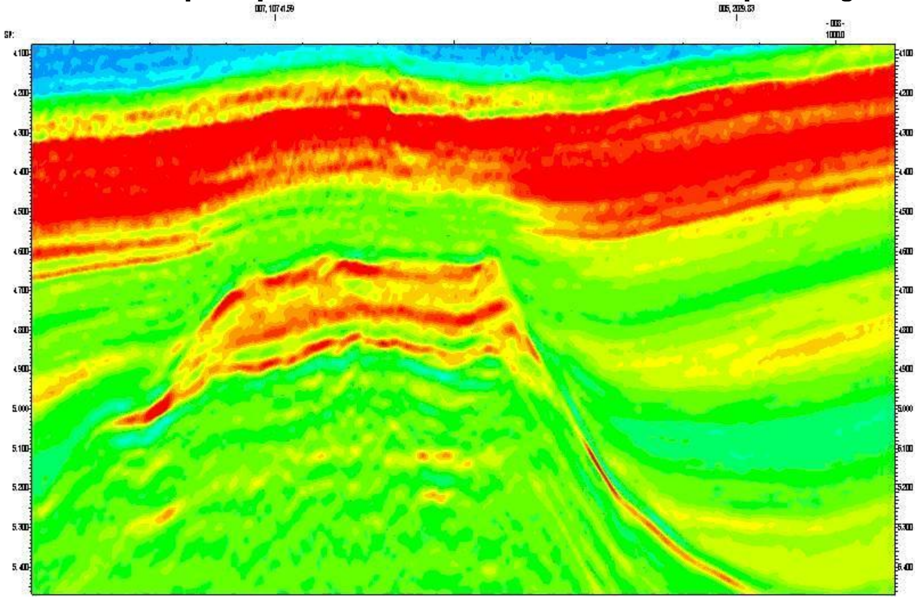
Dunquin's carbonate platform play is unique in the Atlantic Margin

Exhibit 6: Example of possible carbonate structure across Porcupine Ridge



Source: Providence Resources

Majors excited about Dunquin – ExxonMobil, ENI and Repsol all participating in the well

Pre-drill preparations at Dunquin have commenced ahead of a scheduled spud date in 1Q13 (result likely 2Q13), with operator ExxonMobil recently securing the Eirik Raude semi-sub rig for a six month contract. Providence's farm-out agreement with ExxonMobil implies that PVR's net financial exposure will be around $12m – under this deal PVR can maintain its 16% stake in Dunquin by funding 8% of the total well costs ($175m gross, with the first $25m "free"). Alternatively, PVR can trim its position to 8% and be fully carried through the next two wells; however, given the materiality of the prospect and PVR's ability to fund its share of well costs, we think it unlikely that management would opt to reduce its exposure pre-drill.

Dunquin worth £18/sh unrisked – a huge, visible catalyst within the next 12 months

Our risked valuation of Providence's position in Dunquin is 183p/sh, or around 10% of our overall PVR SoP. We have taken an overly conservative stance when risking Dunquin, assuming just a 10% commercial CoS – note this falls below the 16% GCoS estimated by Providence's partners. However, even with this cautious risking the scale of the prospect is evident in its unrisked value – **we estimate Dunquin is worth £18/sh (or over 2.5x the current share price) if fully derisked**; this clearly has the potential to be a very material catalyst within the next 12 months.

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PVR's other key assets

Outside of the two "company making" assets – Barryroe and Dunquin – that we have detailed above, Providence's portfolio includes several other assets that still offer attractive value catalysts over the next 1-2 years.

Chart 8: Dalkey Island worth 114p/sh, or 6% of our SoP

Source: Jefferies estimates

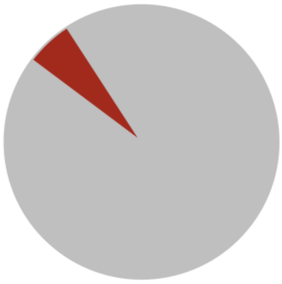
Dalkey Island

In addition to Dunquin, Providence owns a 50% stake in a second high impact exploration opportunity – Dalkey Island. This Lower Triassic oil prospect is located in the Kish Bank basin 10km offshore Dublin, and based on 2D seismic data is estimated to hold 850mmbbl of OIIP, with up to 250mmbbl of gross recoverable resource. Its proximity to shore means the planned well location will easily suit a jack-up drilling rig (25m water depth), and Providence has recently received the necessary planning foreshore licensing approvals from the Irish Department of Environment ahead of an expected spud date in 1H13.

Providence will operate the well (estimated at $12m), with the participation of major partner PETRONAS (50%) adding further validation of Dalkey Island's potential. Several analogue oil discoveries exist elsewhere in the Irish Sea (e.g., Lennox and Douglas, currently producing in the Liverpool Bay area in the East Irish Sea), and the shallow water depth and location near the Irish coast means that Dalkey Island's infrastructure requirements should not be too demanding, in our view.

We value Providence's stake in Dalkey Island at 114p/sh. While partner PETRONAS has estimated a geological chance of success of 25% for the prospect, in our SoP we have used a more cautious commercial risking of 10% to reflect that this is PVR's first foray into the basin and the fact that only 2D seismic has been shot to date. At PVR's current 50% stake a fully derisked Dalkey Island could deliver £11/sh upside to our SoP, however with PVR likely to require external financing (farmdown, equity) to participate in any development, the upside in the success case is likely to be much less.

Chart 9: Spanish Point worth 107p/sh, or 6% of SoP



Source: Jefferies estimates

Spanish Point

An appraisal well on this gas-condensate discovery is scheduled for 3Q13, where Providence (32%) and partners Chrysaor (60%, operator) and SOSINA (8%) will test a deep, overpressured Jurassic sandstone reservoir with GIIP potential of up to 510mmboe (high case). Previous testing has indicated flow rates of c.2kboepd from a single interval, with the produced fluid being a high-yield (around 190bbl/mmcf) condensate that is fairly encouraging for a commercial development – management have described Spanish Point's resource as "volatile oil" (40° API) rather than "gas condensate".

Spanish Point's location means its development will not be straightforward – the discovery lies in 350m of water around 170km off the west coast of Ireland. Early development designs have factored in up to 14 horizontal, fracture-stimulated wells, with hydrocarbons being delivered to shore via two pipelines. Providence's financial exposure to the 3Q13 well and its sidetrack is capped at $20m, secured as part of an option exercised by Chrysaor in 2011. In the event of a commercial appraisal programme we would expect Providence to farm down its current 32% position in order to fund its share of development capex, which management provisionally estimate could be over $1.4bn.

We value PVR's stake in Spanish Point at 107p/sh, risked at a 50% commercial CoS. At present we have been conservative in our estimate of the field's recoverable resource – we assume 100mmboe gross versus management's high case estimate of c.200mmboe. Providence has a number of other opportunities surrounding Spanish Point; however, of these the only one we include in our SoP is the 66mmbbl **Burren** oil discovery (64p/share, 40% CoS), which if commercial we expect would see attractive development efficiencies from shared Spanish Point infrastructure.

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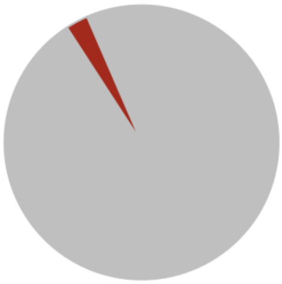
Chart 10: Dragon worth 50p/sh, just 3% of SoP



Source: Jefferies estimates

Dragon

While one of the least interesting opportunities in Providence's drilling calendar, the Dragon appraisal well could still deliver 6% unrisked upside to our SoP if it is successful once spud in 4Q13. The well will test an Upper Jurassic gas discovery made by Marathon Oil in St George's Channel in 1994, spanning the maritime border between the UK and Ireland. Recent 3D seismic work by IKON suggests in-place gas resource of up to 300Bcf, with the Dragon reservoir sands extending much further into Irish waters than first thought – up to 75% of the accumulation is estimated to lie on the Irish side of the median line (i.e., in Providence's 100%-owned and operated block SEL 1/07).

A Dragon appraisal well is expected in 2Q13, with estimated gross drilling costs of $25m. While not yet deemed commercial, Dragon appears only moderate risk – if the appraisal programme is successful a development would offer relatively straightforward tie-backs to nearby infrastructure (e.g., Milford Haven LNG in Wales). However, we understand PVR is currently in the process of farming down its stake in the asset, which we view as sensible – given the potential impact of PVR's larger prospects (e.g. Dunquin) we think capital is better used elsewhere.

We value Providence's stake in Dragon at 50p/share, risked at a 30% CoS. On an unrisked basis Dragon offers NAV upside of 118p/sh (+6%); however, we expect some mobility in this valuation depending on the outcome of the farmdown process.

Rathlin Island

Providence owns a 100% stake in an onshore license covering Rathlin Island and six offshore Rathlin licenses secured in the 26th UK offshore licensing round. The region has proven Permian/Triassic/Carboniferous reservoirs with source rock confirmed by onshore drilling (found coal and oil shales). Based on a recent airborne full tensor gradiometry survey, Providence have identified up to five "significant anomalies" within its Rathlin Basin acreage, with an exploration well possible (but, in our view, unlikely) by the end of 2013. However, we believe further exploitation of this asset will rely on a farmdown where PVR's costs are carried through the drilling process – at present we do not include any value for Rathlin Island in our PVR SoP.

Other Atlantic Margin licenses

Atlantic Margin prospects provide long-term, high-impact E&A potential

Providence added to its long term E&A potential in October 2011, when it secured two-year licenses on 22 new blocks in the Atlantic Margin. We are encouraged to see ongoing interest in this part of the world by major oil & gas companies like Repsol, adding some validation to the prospectivity of the region (and hence potential value to Providence) – the size of the prize is evident from early volumetric estimates, which suggest in-place resource volumes of up to 14Tcf at Newgrange and 228Bcf at Kylemore.

We include no value for any of these assets in our PVR SoP.

Table 4: Providence's long term Atlantic Margin E&A prospects

	Hydrocarbon	PVR W.I. %	Partners
Newgrange	Oil / Gas	40%	Repsol (40%, operator), SOSINA (20%)
Drombeg	Oil / Gas	40%	Repsol (40%, operator), SOSINA (20%)
Banshee	Oil	32%*	Chrysaor (58%), SOSINA (10%)
Kylemore & Shannon	Gas	66.6%*	First Oil (33.3%)

Source: Company Data
* = Providence operated.

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Key risks

Exploration and appraisal failure

With our Providence SoP comprised completely of E&A assets (99% including Barryroe, 29% excluding Barryroe), the underperformance or complete failure of Providence's drilling campaign presents a key downside risk to the value of the business. We have aimed to be conservative in our risking of these assets; the rank frontier nature of drilling at prospects like Dunquin means commercial success is not guaranteed.

Development delays and cost overruns

The cornerstone Barryroe development forms the bulk of our Providence SoP, meaning that the negative financial impact of any development delays or cost overruns at this project will be reflected in our overall Providence valuation. Cost overruns are a particular risk, in our view, given Ireland's underdeveloped oil & gas service industry; however, we expect this will change as the local market develops.

Adverse moves in Ireland's fiscal terms

In our view, Ireland's very low 25% tax rate on oil & gas producers is a relic from a time when the country was an unloved, underdeveloped and low priority hydrocarbon province. With Barryroe proving that several-hundred million barrel commercial oil developments are available in Ireland, we see the risk of the Irish government tightening its fiscal terms in order to capture more tax revenue from a blossoming oil & gas industry, especially given the fiscal needs of the country at present.

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Shareholders & Management

Tony O'Reilly, Chief Executive Officer

Mr O'Reilly is CEO of Providence Resources, having served on the Board since the company's incorporation in 1997. After graduating from Brown University in Rhode Island he worked in mergers and acquisitions at Dillon Read and in corporate finance at Coopers and Lybrand, advising natural resource companies. Mr O'Reilly served as Chairman of Arcon International Resources until April 2005 (including as CEO from 1996 to 2000) when Arcon merged with Lundin Mining Corporation. Prior to joining Providence he worked as CEO of Wedgwood from 2002-2005.

Simon Brett, Chief Financial Officer

Mr Brett was appointed CFO in May 2012, and has worked at Providence since 2008, most recently as Group Financial Controller. Prior to joining Providence, he held senior finance positions with Damovo Ireland Ltd. and Coca Cola Bottlers Ireland Ltd. Between 1996 and 2003, Mr Brett worked in the UK for a number of multinational companies including Johnson Wax, Sega Europe Ltd and US Can Corporation. He has a BA in Business Studies from the Liverpool John Moores University and is a member of the Institute of Management Accountants, having qualified in 1996.

John O'Sullivan, Technical Director

Mr O'Sullivan has worked in the offshore business for more than 20 years, previously with Mobil and Marathon Ireland. He holds a B.Sc. in Geology from University College Cork, Ireland, an M.Sc. in Applied Geophysics from the National University of Ireland, Galway and an M.Sc.in Technology Management from The Smurfit School of Business at University College Dublin. John is a fellow of the Geological Society of London and member of The Geophysical Association of Ireland whilst also being the Irish regional coordinator for the Petroleum Exploration Society of Great Britain.

Table 5: Significant PVR shareholders

Shareholder	% stake
Sir Anthony O'Reilly	15.5%
Blackrock Investment Management	10.9%
JP Morgan Asset Management	7.4%
Henderson Global Investors	3.9%
F&C Asset Management	3.4%
No. of ordinary shares on issue (m)	64.4

Source: Thomson ONE

Providence Resources is listed on London's AIM market and the Irish Stock Exchange.

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Sterling Resources (SLG CN): Initiating coverage at Hold, C$1.45/sh PT

We commence coverage of Sterling Resources with a Hold recommendation and C$1.45/sh price target. Sterling is a Canadian-listed E&P whose assets are primarily located in the UK North Sea and Romania, with some peripheral acreage in France and the Netherlands. The company is primarily an exploration-led business; however, we expect a period of substantial production growth over 2013-15 once the large Breagh gas field in the UK Southern North Sea is brought onstream in 1Q13. We see risks around funding in the medium-term, with Sterling currently in the process of raising external finance through farmdowns and potentially new debt – until this uncertainty is resolved, we see better value elsewhere in the North Sea E&Ps.

The 610Bcf **Breagh gas field dominates Sterling's production** and cashflow growth, in our view, with gross output expected to reach 170mmscfpd (8.5mmboe net) by the end of 2014, delivering free cashflow of c.$100m p.a. We expect first gas from Breagh in 1Q13, later than the original timing due to development delays that have added over 30% to the project's overall budget (now c.$1bn). Breagh offers future expansion potential through a second 2.7mmboe development phase, plus the appraisal of the nearby 5.1mmboe Crosgan discovery. We value the main Breagh asset at C$1.32/sh, with Breagh Phase 2 and Crosgan worth an estimated C$0.09/sh and C$0.05/sh, respectively.

Sterling's **growth potential lies firmly in the Romanian portfolio**, in our view, with the company's acreage offering near-term development opportunities (the 342Bcf Ana & Doina project) plus 403mmbbl (oil) and 1Tcf (gas) of exploration prospects in the Danube delta region of the Black Sea. A multi-Tcf discovery by Exxon/OMV in early 2012 demonstrated the prospectivity of the area, and we are encouraged by recent positive moves in the long-term Romanian gas pricing environment. We value Sterling's stake in Ana & Doina at C$0.40/sh (first gas expected 2016), with two near-term exploration prospects (Ioana and Eugenia) targeting 139mmboe and 111% of unrisked SoP upside.

In our view **the key issue that Sterling faces is funding**. Despite having sold down stakes in its Cladhan oil development and Midia block offshore Romania, and renegotiated its £105m RBL facility so far this year, management are still seeking further sales to generate external capital. We expect this can be achieved through either (a) farming down its Romanian acreage in exchange for a development carry; or (b) refinancing or replacing its existing RBL facility. We believe this requirement for new external finance, plus the uncertainty around new funding details and timing, is the key medium-term risk for investors – to capture this risk we set our Sterling target price at a c.25% discount to our C$1.90/sh SoP, and with 2% upside to this C$1.45/sh target we initiate coverage of Sterling with a Hold rating.

Valuation

We value Sterling Resources at C$1.90/share on a sum-of-parts basis, comprising full field NPV-10 valuations of the Breagh (C$1.32/sh) and Cladhan (C$0.31/sh) fields, plus risked value for SLG's development and E&A assets. Our model uses Jefferies' long-term global commodity forecasts of $100/bbl Brent and $9.14/mcf UK NBP spot gas, plus USD/CAD parity. Sterling trades at 0.75x our SoP valuation (peer group 0.67x); however, with medium term funding risks we see better value elsewhere in the North Sea E&P space.

Risks

As discussed above, we believe the key risk facing Sterling is uncertainty around the timing and method of new external funding. Sterling's expansion in Romania will present risks for both its development activity (Ana & Doina) and E&A programme (Ioana, currently drilling, and Eugenia, due to spud 4Q12). Sterling also has high asset concentration risk at present, with exposure to a single producing asset (Breagh).

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Exhibit 1: Sterling Resources SoP valuation summary

Region	Asset	Hydrocarbon	SLG W.I. %	Resource Size (mmboe) Gross	Net	CoS %	Risked mmboe	$/boe	NPV $m	Risked NPV C$ cps	Unrisked C$ cps	SoP Upside %
Producing assets												
UK - Southern North Sea	Breagh (Phase 1)	Gas	30.0%	105	31	90%	28	10	295	132	147	8%
							28		**295**	**132**	**147**	
Development assets												
UK - Northern North Sea	Cladhan	Oil	26.4%	27	7	75%	5	13	68	31	41	5%
UK - Southern North Sea	Breagh (Phase 2)	Gas	30%	9	3	70%	2	11	21	9	13	2%
Romania - Black Sea	Ana & Doina	Gas	65%	57	37	70%	26	3	88	40	57	9%
							33		**177**	**79**	**111**	**16%**
2012-13 Exploration & Appraisal												
Romania - Black Sea	Ioana	Gas	65%	94	61	10%	6	3	17	8	77	36%
Romania - Black Sea	Eugenia	Oil	65%	120	78	10%	8	5	35	16	158	75%
UK - Southern North Sea	Crosgan	Gas	30%	17	5	50%	3	5	11	5	10	3%
Netherlands - Offshore	Various	Oil	35%	36	13	20%	3	6	14	6	32	13%
							19		**78**	**35**	**277**	**127%**
Further drilling												
Romania - Black Sea	Luceafarul	Gas	50%	17	9	25%	2	3	6	3	11	4%
							2		**6**	**3**	**11**	**4%**

Valuation Multiples				
SLG share price	142c	No. of Shares	222.9	m
Core NAV	153c	Market Cap.	$316	m
P / Core NAV	**0.93**	Enterprise Value	$381	m
P / SoP	**0.75**	2P Reserves	33	mmbbl
Upside to SoP	34%	EV/2P boe	**$11.61**	**/boe**

SLG Sum of Parts Valuation	$m	C$ cps
Sterling Resources Assets	556	250c
Cash / (Net Debt)	-65	-29c
G&A	-60	-27c
Decommissioning & Cost Carries	-7	-3c
Sum of Parts	**424**	**190c**

Source: Jefferies estimates

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Exhibit 2: Sterling Resources financial summary

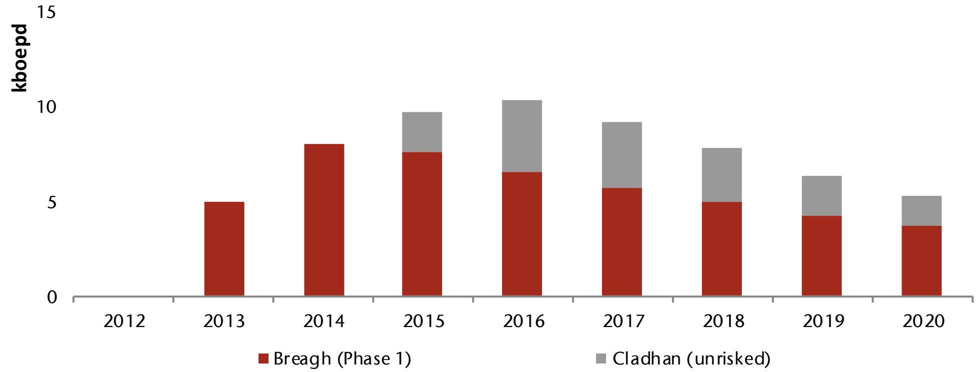
P&L		2010A	2011A	2012E	2013E	2014E
Revenue	$m	0	1	0	100	160
Cost of Sales	$m	0	0	0	-50	-77
Exploration Writeoffs	$m	-15	-24	-8	0	0
G&A	$m	-4	-3	-4	-6	-6
Other	$m	-2	-28	-5	0	0
Pre-tax Operating Profit	$m	-22	-54	-18	44	77
Net Finance Income/(Expense)	$m	0	0	-3	-8	-8
Pre-tax Profit	$m	-22	-54	-21	36	69
Tax	$m	0	0	4	-23	-43
Net Profit incl exceptionals	$m	-22	-54	-17	14	26
EBIDAX	$m	-6	-30	-9	73	123
EV/EBIDAX	x	na	na	na	8.4	5.0
No. of Shares	m	189	223	223	223	223
EPS	cps	-15	-27	-8	6	12
DPS	cps	0	0	0	0	0

Cashflow Statement		2010A	2011A	2012E	2013E	2014E
Cashflow from Operations	$m	-20	-36	-14	73	123
Cashflow from Investing	$m	-38	-161	-82	-66	-60
Cashflow from Financing	$m	-7	99	80	-8	-8
Net Change in Cash	$m	-66	-98	-15	-1	55

Balance Sheet		2010A	2011A	2012E	2013E	2014E
Cash	$m	143	50	34	33	88
Exploration Assets	$m	120	121	146	156	156
Prod'n & Devel. Assets	$m	0	167	227	254	268
Long Term Debt	$m	0	73	157	157	157
Provisions	$m	2	7	4	26	69
Shareholder Equity	$m	257	261	251	265	291
Gearing: Net Debt(Cash)/Equity	%	-56%	9%	49%	47%	24%

12-month Catalysts	SLG WI %	CoS %	Risked NAV $m	Risked NAV C$ cps	SoP Upside %
Ioana	65%	10%	17	8	36%
Eugenia	65%	10%	35	16	75%

Production Summary		2010A	2011A	2012E	2013E	2014E
SLG production WI	kboepd	0.0	0.0	0.0	5.0	8.0



SoP sensitivity to Brent & WACC	LT Brent $/bbl	$70.00	$85.00	$100.00	$115.00	$130.00
WACC	8%	195	206	216	225	235
	10%	171	181	**190**	199	208
	12%	150	160	168	176	184
	14%	132	141	148	156	163

Assumptions		2010A	2011A	2012E	2013E	2014E
Brent crude	$/bbl	79.85	111.37	111.73	100.00	100.00
UK NBP gas	$/mcf	6.25	9.17	8.92	9.14	9.14
USD/GBP forex	$	1.54	1.60	1.58	1.58	1.58
USD/CAD forex	$	0.97	1.01	1.00	1.00	1.00

Source: Jefferies estimates

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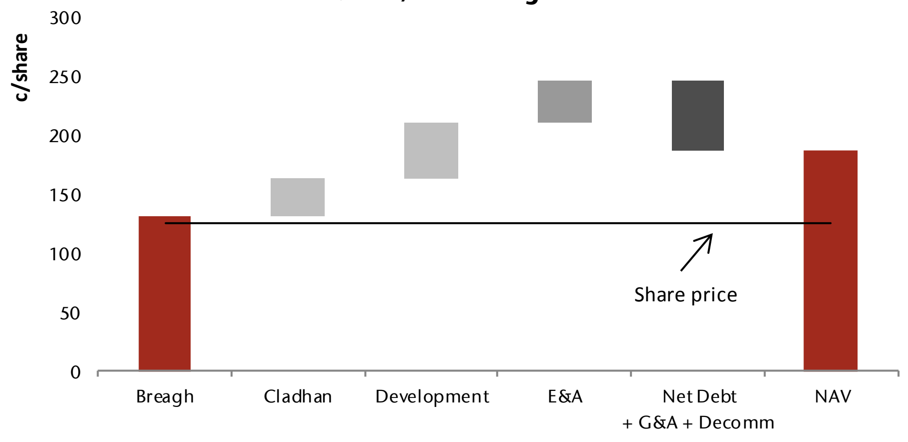
Valuation

Our C$1.90/sh valuation is dominated by SLG's stake in the Breagh field

Our sum-of-parts valuation of Sterling Resources is C$1.90/share, placing the shares at 0.75x our SoP. We have incorporated full field NPV-10 valuations of Sterling's stakes in the Breagh (gas) and Cladhan (oil) developments, which we value at C$1.32/sh (70% of SoP) and C$0.31/sh (16% of SoP), respectively. Our field valuations use Jefferies' global commodity price deck, which assume $100/bbl Brent and $9.14/mcf UK NBP in the long term, plus USD/CAD parity. Sterling offers a further C$0.38/sh of risked E&A potential, driven mainly by the Ioana and Eugenia exploration prospects due to be drilled in the Romanian Black Sea over 4Q12/1Q13 – together these two wells will target c.140mmboe of unrisked net prospective resource.

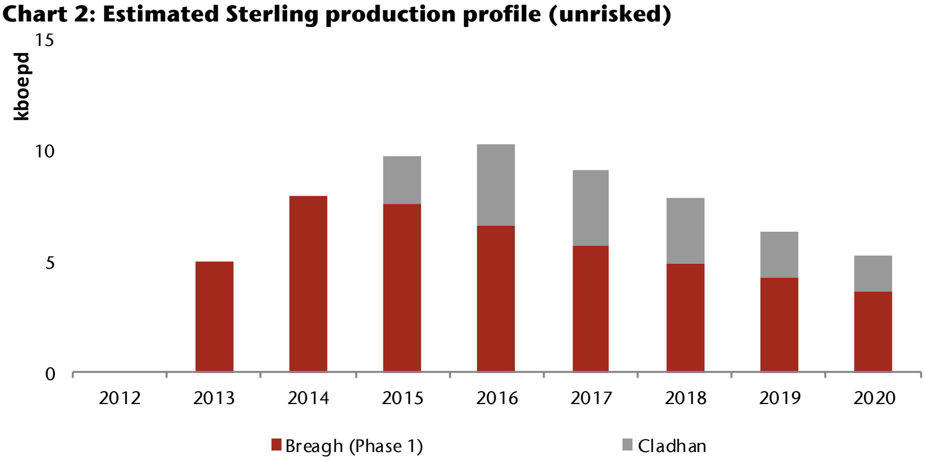
Chart 1: Breakdown of our C$1.90/sh Sterling Resources SoP valuation



Source: Jefferies estimates

Sterling's net debt at 1H12 was $65m (-C$0.29/sh), comprising a partially-drawn RBL facility against the Breagh field (we expect this £105m facility will be fully drawn by the end of 2012). Note that Sterling holds $16m in a restricted account in order to help meet the £20m minimum cash requirement required by its debt covenants.

Chart 2: Estimated Sterling production profile (unrisked)



Source: Jefferies estimates

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Jefferies

Medium-term funding concerns mean we believe SLG does not warrant a premium rating at present

The shares trade ahead of the North Sea E&P peer group in terms of P/SoP multiples (Sterling 0.75x versus sector average 0.67x), and due to the medium-term funding concerns we believe this premium valuation is not warranted at the moment. To capture SLG's financing risk (detailed below) **we set our target price at a c.25% discount to our C$1.90/sh SoP valuation, and with 2% upside to this C$1.45/sh target we commence coverage of Sterling Resources with a Hold recommendation**.

Financing a key medium term risk

2012-13 capex commitments and RBL's minimum cash requirement present medium-term funding risks...

Despite amendments to Sterling's existing RBL facility (detailed below) during 2012, and the sales of a 13.5% stake in the Cladhan field (April 2012) and a portion of the Midia block offshore Romania (October 2012), we believe Sterling faces some funding uncertainties over 2012-13. We expect the company's cashflow to enjoy a healthy increase once the Breagh field is onstream in early 2013; however, given Sterling's remaining capital commitments on the delayed Breagh field, plus a minimum £20m cash threshold imposed on the RBL facility, management has publicly stated that Sterling will require external funding later in 2012. We see two potential sources for this additional capital:

...which we think will be remedied by asset sales, farmdowns, or new debt

- **A sale or farm down of its current stake in the Midia XV, Pelican XIII, Luceafarul XXV and Muridava XXVII blocks offshore Romania**. We believe divesting part of these assets could earn either a development cost carry (as it did when farming out a 35% stake in the blocks to PetroVentures in 2007) or a cash payment (as with the recent sale of an 11% portion of its Midia block to Exxon/OMV). Sterling management have stated that the sale/farmdown process for its Romanian acreage is ongoing.

- Another avenue open to Sterling is to **refinance its current £105m RBL facility**, which management estimate will be fully drawn by the end of 2012. Possible amendments include an extension to the facility on the basis of reserve upside potential from Breagh Phase 2 (which would add c.3mmboe, or 9%, to Sterling's 31mmboe net 2P reserves at the field), or potentially a relaxing of the minimum cash requirement covenant in the RBL facility, currently sitting at £20m.

C$1.45/sh price target set at c.25% discount to SoP to reflect near-term financing risks

Until this financing uncertainty is resolved we believe a discount to Sterling's underlying value is appropriate, hence we set our C$1.45/sh price target at a c.25% discount to our C$1.90/sh SoP valuation.

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UK assets

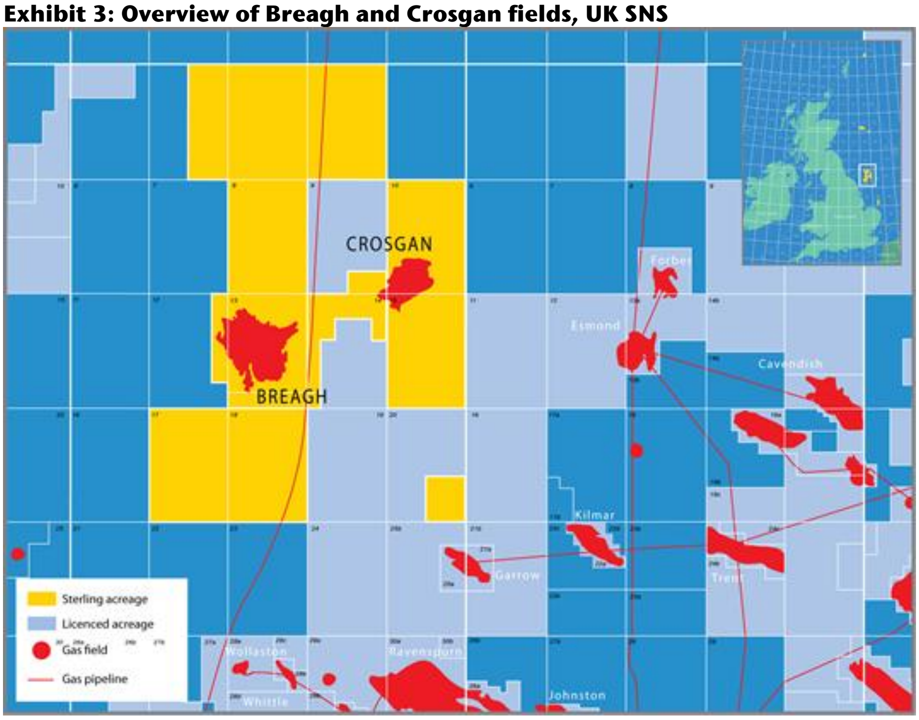
Breagh

Breagh is Sterling's core asset; we value it at C$1.32/sh

The focus of Sterling's recent investment, and the primary contributor to the company's reserves, expected production and future cashflow, is its 30% stake in the **Breagh** gas field, until now one of the largest undeveloped fields in the UK's Southern North Sea. The two-phase, RWE-operated Breagh development received FDP approval from DECC in July 2011, and management expect the field to deliver first gas in December 2012 (we assume 1Q13 to be conservative). The field's economics are enhanced by Sterling's current tax loss position, which means we do not expect Sterling to pay cash tax until at least 2016. **We value Sterling's stake in Breagh at C$1.32/sh (risked at 90% CoS), or 70% of our overall SoP.**

Breagh is a 610Bcf (184Bcf net to SLG) Lower Carboniferous reservoir located around 100km off the east coast of England. The field offers modest (2.7mmbbl gross) condensate volumes; however, in our view these offer insignificant commercial value and hence we do not include Breagh's condensate in our field NPV. A five-well appraisal programme over 2007-11 indicated flow rates of up to 17.6mmscfpd, a performance that Sterling hopes to repeat in the full field development.

Exhibit 3: Overview of Breagh and Crosgan fields, UK SNS



Source: Sterling Resources

Breagh's first phase (28.7mmboe) involves a fixed, unmanned platform ("Breagh Alpha") in the western area of the field, serviced by up to seven subsea wells being drilled by the Ensco 70 jack-up rig. Produced gas will be exported to the Teesside Gas Processing Plant via a newly constructed pipeline. The smaller second phase (2.7mmboe) is still awaiting sanction, and could include a further five wells drilled in the eastern part of the field. Sterling is still considering the design of this second stage, which could comprise either a second platform ("Breagh Bravo") or simple tiebacks to the original platform – the results of the Crosgan appraisal well (2H13) are likely to influence the scope of this second phase. Management recently delayed first gas from Breagh until the end of 1Q13; we

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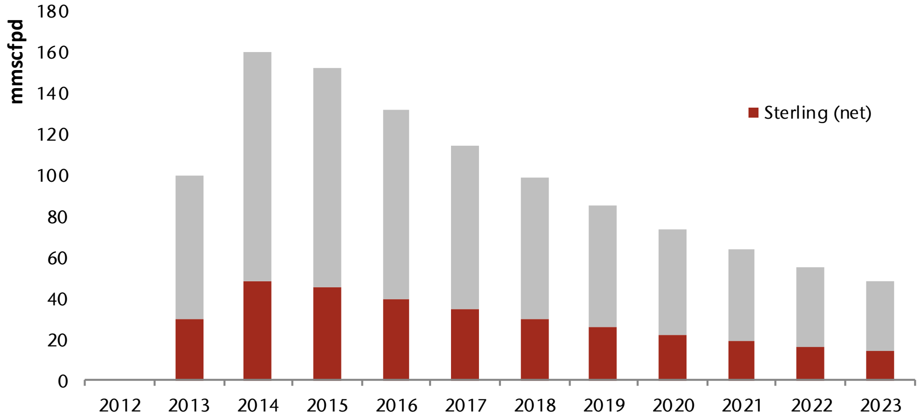
estimate Breagh will deliver gross peak output of 140mmscfpd in its first year, rising to 170mmscfpd in 2014.

Chart 3: Estimated Breagh production profile, 2012-23E



Source: Wood Mackenzie, Sterling Resources, Jefferies estimates

Breagh capex has exceeded initial budget by 30%

We estimate total gross capex for Breagh's Phase 1 of $1bn, or around $300m net to Sterling – this is around 30% higher than the operator's initial budget due to cost overruns in the TGPP pipeline construction and higher-than-expected drilling costs. Given the partners' track record of missing budgets so far, we cannot rule out the risk of further cost hikes over the remainder of the development, and to capture this uncertainty we use a 90% CoS in our Breagh valuation..

£105m Breagh RBL facility fully drawn by end of 2012

Sterling has funded its share of the Breagh capex to date (approx. $300m net) with a £105m reserve-backed debt facility with a consortium of lenders including BNP Paribas, CBA, GE Energy and Societe Generale – we expect the entire facility will be utilised to fund Breagh's development. **An important covenant of the RBL facility is the requirement for Sterling to retain minimum cash of at least £20m until the project is completed**, part of which is contributed by c.£10m of cash held in escrow. We estimate that Sterling's available cash will remain just above this threshold until Breagh is completed; however, if the company is to maintain sufficient firepower to advance with its development plans at Cladhan and in Romania beyond 2013, we believe Sterling will need to either (a) sell/farm down more of its Romanian portfolios to generate cash, and/or (b) negotiate more relaxed debt covenants,

Crosgan appraisal offers 3% SoP upside; well expected in late 2013

Crosgan appraisal well offers potential 5mmboe tie-in to Breagh development; we value it at C$0.05/sh

An interesting area of upside for Sterling's Breagh project is an appraisal well at the nearby Crosgan discovery – a 101Bcf (gross) gas accumulation found by Total in 1990. Appraisal drilling of the field by Mobil indicated flow rates of up to 8.6mmscfpd. Sterling hopes to appraise Crosgan further with a well in 2H13, with the long-term aim to tie the field in to the Breagh platform as part of the Phase 2 development. We believe the Ensco 70 rig – under contract to Sterling until later in 2013 – is likely to drill Crosgan.

We value Crosgan at C$0.05/sh, risking the field's 5.1mmboe of net resource at a 50% CoS. On a fully derisked basis, we estimate the field offers 3% upside to our Sterling SoP valuation.

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Cladhan – staying put for now

Cladhan: C$0.31/sh, risked at 75% CoS to factor in development and funding uncertainty

Sterling's second UK asset is its 26.4% operated interest in the **Cladhan** oil field in the UK Northern North Sea. A four-well appraisal programme completed in 1H11 helped delineate the Upper Jurassic sandstone reservoir, and identified gross contingent resources of 27mmbbl (7.2mmbbl net to Sterling). Sterling submitted an FDP for Cladhan in 1H12 with approval expected early in 2013; at present we estimate first oil from the field in 2015. **Cladhan is worth C$0.31/sh (16%) to our Sterling SoP valuation** – note that at present we risk our valuation of the Cladhan development at a 75% CoS to reflect the delays in reaching DECC approval and potential funding uncertainties. **Cladhan was previously earmarked by management as a potential source of funding, however following the recent sale of part of the Midia block in Romania Sterling is no longer proceeding with this sale process.** While it was up for sale, we understand Sterling had good interest from potential buyers for its 26.4% stake in the asset.

Cladhan likely to be developed using subsea tieback to TAQA's nearby Tern Platform

A number of development options are open to Sterling for the Cladhan project, including an FPSO-led design, a standalone platform, or a tieback to a nearby platform (e.g., Heather, Tern). Given the relatively modest size of the Cladhan field, and Sterling's relationship with TAQA (see below), we understand that the FDP submitted in 1H12 involves subsea infrastructure tied back to the nearby Tern Platform, operated by TAQA. This design initially involves two producers and a single water injector, with the potential to increase the well count to a 4+3 producer/injector design depending on ultimate recovery form the Cladhan accumulation. We estimate the full 4+3 development concept will incur gross capex of $600m (c.$24/bbl) over the life of the field.

Cladhan eligible for UK small field tax allowance

Cladhan is also eligible for the UK's small field allowance, allowing its partners to offset their liability for 32% supplementary charge against up to £150m of income.

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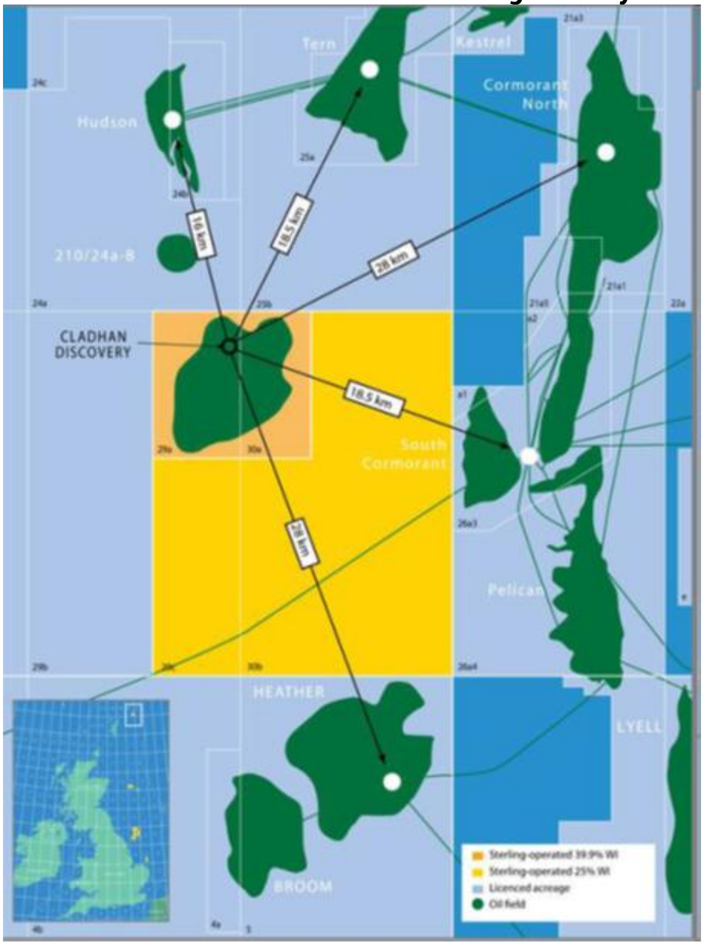
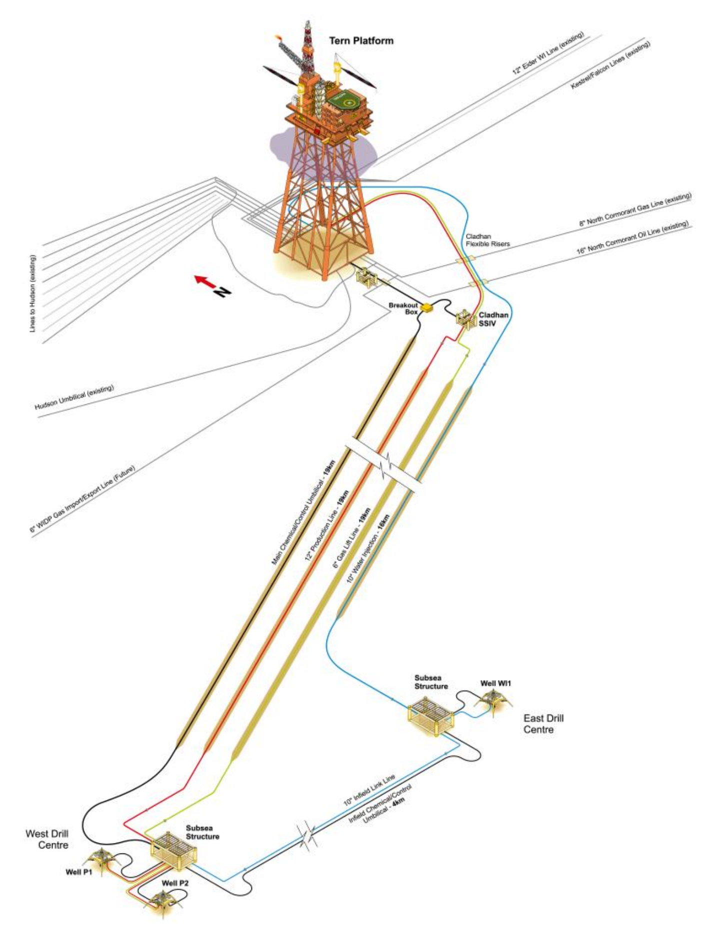
Exhibit 4: Overview of Cladhan area showing 5 nearby fields



Source: Sterling Resources

Exhibit 5: Cladhan likely to use subsea tiebacks to Tern



Source: Sterling Resources

Sterling farmed out a 13.5% stake in Cladhan to TAQA in April 2012 – a good deal at $12.8/boe, in our view

Sterling recently trimmed its position in Cladhan to reach its current 26.4% stake, divesting a 13.5% interest to TAQA Bratani in April 2012. This sale takes TAQA's stake to 40.1%. The total value of the deal was $47m, or c.$12.8/boe based on the current 27.2mmbbl Cladhan resource estimate. The sale involved an initial cash payment of $22.3m, a subsequent $4.3m payment due in 4Q12 upon Sterling reaching certain milestones, and (at SLG's discretion) a future $54m development carry (pre-tax) *or* $20.4m (post-tax) cash payment.

In our view this was a good deal for Sterling, as it:

- **Crystallised value from its Cladhan investment** at a time where Sterling required substantial cash resources to fund its Breagh gas development. Without this additional cash injection we believe Sterling is likely to have breached the covenants of its RBL facility for the Breagh project;
- Represented a solid $12.8/boe for pre-FDP contingent resources. We believe this is an **attractive valuation given that Cladhan still carries development and funding risks**, and is not dissimilar from the $13.7/boe average North Sea transaction multiple for less risky 2P reserves; and

SLG no longer proceeding with a sale of a stake in Cladhan

With Sterling's funding headroom looking tight beyond the 4Q12-1Q13 Romanian drilling programme (see below), management previously stated that they were seeking a potential sale of SLG's Cladhan stake in order to fund future growth in both the residual

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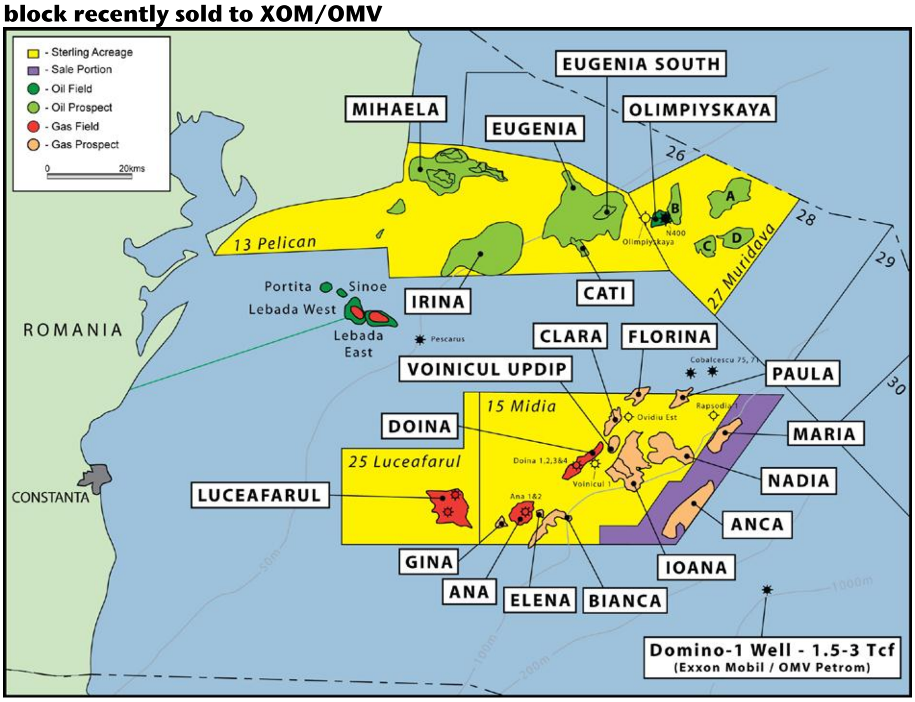
UK portfolio (including future tie-ins to Breagh) and further E&A work in Romania. However, following the recent sale of a portion of SLG's Midia Block in the Romanian Black Sea (for an initial payment of $29.25m plus future contingent payments), management will no longer be pursuing a sale of Cladhan.

Romania

Presence of industry heavyweights (ExxonMobil, OMV, Lukoil) is encouraging for SLG's Romanian portfolio

Sterling has had a presence in Romania since 2000, with its current footprint spanning both significant offshore acreage (a 65% stake in the Midia XV and Pelican XIII blocks, 50% of the Luceafarul XXV block, and 40% in the Muridava XXVII block, all in the Danube delta region of the Black Sea) and an onshore concession with unconventional (shale gas) potential. Management's focus is now on developing two existing offshore gas discoveries (Ana and Doina), and exploiting its exploration acreage in what is an increasingly prospective region. The Black Sea has attracted a number of industry heavyweights, including ExxonMobil, OMV, and Lukoil, which we think is encouraging for the future development of – and secondary market for – Sterling's assets. In fact, ExxonMobil and OMV appear to be building a position in the region following their recent acquisition of an 11% portion of SLG's Midia block.

Exhibit 6: Sterling's Romanian Black Sea acreage, showing portion of Midia block recently sold to XOM/OMV



Source: Sterling Resources

Ana & Doina development worth C$0.40/sh to our SLG SoP valuation

The planned Ana & Doina development is the key element of SLG's Romanian portfolio, in our view, with planning underway to develop the two fields' 342Bcf of gross gas resource. The project will involve a 100km pipeline to the coast where it will connect with the main Romanian gas transmission network. At present **we value SLG's stake in the Ana & Doina development at C$0.40/sh ($88m)**, assuming a $5/boe undiscounted valuation and, for now, a 70% CoS until we get more clarity on Ana & Doina's development design and timing (management expect first gas in 2016). We note

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that with part of the Romanian portfolio still up for sale to help relieve SLG's medium-term funding constraints, the ultimate contribution of the assets to our SoP is uncertain.

SLG's Black Sea E&A portfolio offers c.400mmbbl and 1Tcf of resource potential across 20+ prospects

Black Sea acreage offers 400mmbbl and 1Tcf of exploration upside

In addition to the Ana & Doina fields, Sterling's Black Sea licenses provide the company with a number of high impact exploration opportunities that could be very material. To date Sterling has identified more than 20 potential drilling targets across the oil-prone Pelican XIII block, the gas-prone Midia XV block and the Muridava XXVII block, which together offer an estimated 403mmbbl (oil) and 1Tcf (gas) of net prospective resource.

Table 1: Offshore Romania acreage offers multiple prospects (net, mmboe)

Midia Block XV (gas prone)		Pelican Block XIII (oil prone)		Luceafarul Block XXV		Muridava Block XXVII	
Discoveries	**Contingent**	**Prospects**	**Prospective**	**Discoveries**	**Contingent**	**Prospects**	**Prospective**
Ana & Doina	37	Cati	4	Oligocene Discovery*	9	A-C1	3
		Eugenia*	78			A-T North	11
Prospects	**Prospective**	Eugenia South - Eocene	4			A-T South	10
Bianca	10	Eugenia South - U.Cret.	8			B-T3	8
Clara	5	Irina	44			C-T4	10
Elena	1	Mihaela - Neocomian	21			D-T5	8
Florina	8	Mihaela - U. Jurassic	38			A-E1 (gas)	3
Gina	10						
Ioana*	61						
Nadia	33						
Paula	6						
Updip Voinicul	3						

Source: Sterling Resources
*** = Ioana and Eugenia are the only prospects included in SLG's current drilling calendar and Jefferies' SoP valuation.**

Two-well drilling programme in 4Q12 will target the Ioana and Eugenia prospects – expected to cost Sterling $20m net.

The key near-term opportunity for Sterling is a two-well drilling programme targeting the **Ioana** (drilling underway) and **Eugenia** prospects in 4Q12, with potential unrisked SoP upside of 111%. Sterling has contracted the GSP Jupiter jack-up rig to drill the wells (91m and 55m water depth, respectively), which we understand are both fairly quick (25-30 days) to drill. Sterling's drilling costs will be part-carried through the first well, Ioana, meaning total cost exposure of c.$7m; the Eugenia well is estimated to cost Sterling around $13m. We value the 61mmboe (net) Ioana gas prospect at C$0.08/sh, and the 78mmbbl (net) Eugenia oil prospect at C$0.16/sh. We assume a 10% CoS for each well.

Table 2: SLG's near-term Black Sea exploration offers 111% unrisked upside

Asset	Fluid	SLG W.I. %	Gross (mmboe)	Net (mmboe)	CoS %	$/boe	NPV $m	NPV C$ c/sh	SoP upside %
Ioana	Gas	65%	94	61	10%	3	17	8	36%
Eugenia	Oil	65%	120	78	10%	5	35	16	75%
Total			**214**	**139**			**52**	**24**	**111%**

Source: Jefferies estimates, company data

Offshore Romania already attracting interest…and success…from the majors

It is encouraging to see Sterling invested in what could be a very prolific hydrocarbon region offshore Romania. In February 2012, ExxonMobil (partnered with OMV Petrom) discovered gas in the Domino-1 exploration well – the first deep water (1,000m) well ever drilled in the Black Sea – encountering 70m of net gas pay, with Exxon estimating gross resource between 1.5-3.0 Tcf. Domino is located around 35km to the southeast of Sterling's Midia block, which management believe has derisked its prospects in the licence (including the upcoming Ioana well, currently drilling with a result expected in November 4Q12).

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The recent acquisition by ExxonMobil/OMV of an 11% portion of SLG's Midia block (containing the Maria and Anca prospects) adds further validity to the region's potential, in our view – this deal offers SLG an immediate payment of $29.25m, plus further payments of up to $48.75m contingent on discoveries and production from the block.

We believe the interest from the majors bodes well for Sterling's position in Romania – with Exxon/OMV potentially spending "several billion USD" in the region, in our view Sterling is well placed to benefit from increased rig activity and infrastructure.

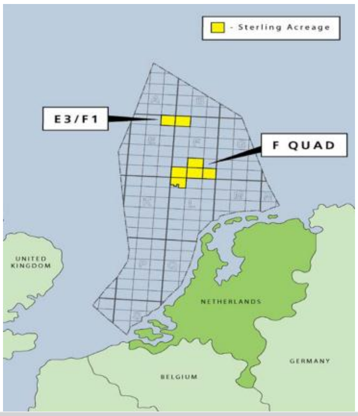
Macro considerations

Sterling is expanding its Romanian presence at an interesting time for hydrocarbon producers. After a period of particularly low gas pricing – caused by the country importing the majority of its gas from Russia via Gazprom, which vastly undercut domestic production – recent legislation has called for the liberalisation of Romania's gas market. This effectively means there is now significant incentive for domestic gas producers to invest in new production that can take advantage of pricing that is likely to approach current European levels of $8-9/mcf. Notwithstanding Romania's current weak macroeconomic environment, this **gas price liberalisation is expected to be fully enacted by 2016, right around the time when the Ana & Doina development is expected to come onstream**.

Other assets

Aside from the primary UK and Romanian assets, Sterling's portfolio also extends into France, the Netherlands, and elsewhere in the North Sea. Of these assets the appraisal opportunities offshore Netherlands are the only assets we includes in our Sterling SoP valuation – until we have further details on timing and scope of the UK and French prospects we think it prudent to omit them from our valuation for now.

Exhibit 7: SLG offshore Netherlands blocks



Source: Sterling Resources

Sterling's Dutch assets offer appraisal and exploration potential

Sterling's portfolio offshore Netherlands includes 35% interests in five blocks that to date have delivered four oil discoveries – Barkentijn, Brigantijn, Korvet and Fregat – plus a couple of blocks further offshore (E3/F1, 50% WI) that offer exploration potential. Past testing of the discoveries have demonstrated flow rates between 2-4kbopd, with RPS estimating net contingent resource of 12.6mmbbl. Sterling has also been credited with a further 19.6mmbbl of prospective resource; however, we do not yet include this in our valuation.

We value Sterling's Dutch contingent resource at C$0.06/share (3% of SoP). Further appraisal work is required to advance these assets; however, in our view the Netherlands acreage will be a lower priority (in terms of funding resources and management's time) for Sterling than its UK and Romanian production and development assets.

Onshore France present large unconventional gas opportunities

Sterling has positions in the Aquitaine and Paris basins onshore France – in particular, the 40%-owned Audignon gas prospect offers 144Bcf unrisked prospective resource. Management have previously indicated that Sterling would acquire 3D seismic data on its licences in 4Q12/1Q13 – we believe this will be subject to the outcome of Sterling's ongoing funding decisions. We do not include any value for Sterling's French assets in our SoP.

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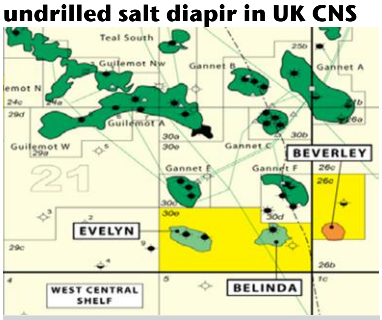
Exhibit 8: Beverley – the last undrilled salt diapir in UK CNS



Source: Sterling Resources

Beverley – Central North Sea acreage focuses on exploiting salt diapir play

In our view, one of Sterling's most interesting long-term opportunities is its 60% stake in the Beverley prospect in the UK North Sea. Beverley is the last undrilled salt diapir in the Central North Sea, and has some very encouraging analogues – the Gannet B, Gannet C, Kyle and Banff discoveries all share the same salt diapir play type. Furthermore, management believe that Beverley's location near the Evelyn and Belinda discoveries bodes well for a potential hub-style development if all three fields are deemed commercial.

Sterling's partners have suggested a well will be drilled by 2015; however, with a very long lag until any possible drilling and no firm well in Sterling's calendar we currently attribute no value to Belinda.

Risks

Development delays and cost overruns

Sterling has already faced significant delays and cost overruns at its cornerstone Breagh gas development – the field will now cost upwards of £620m and we estimate will not be onstream until 1Q13, substantially more expensive than the £485m estimated at the time of FDP approval in July 2011. In our view, future delays and higher-than-budgeted costs in its other assets will negatively impact our Sterling valuation.

Funding risks

As detailed above, some clarity on funding is a risk for Sterling over the medium term. In order to meet its current RBL covenants and continue to fund its E&A and development programme, management has stated Sterling will require additional external funding – sourced via either farming down its Romanian acreage or extending its RBL facility. Until we have some clarity on this funding situation we believe a discount to our SoP valuation is appropriate.

Exploration risk

With a sizeable inventory of exploration prospects offshore Romania, and a number of appraisal opportunities in both Romania and the UK, much of Sterling's medium-term growth relies on successful drilling campaign across these two key geographies over 2012-14. Unless Sterling can avoid risk through farmdowns/carried exploration, we think worse-than-expected drilling results from these wells could restrict growth in Sterling's portfolio and negatively impact both cash balances and our SoP.

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Shareholders & Management

Mike Azancot, President & Chief Executive Officer

Mr Azancot has 30 years of broad experience in the global E&P sector, and has held senior management positions with Occidental, LASMO and PetroKazakhstan in the North Sea, China, Indonesia and Kazakhstan. He is a qualified petroleum engineer (Master of Engineering) specialising in upstream business optimisation.

David Blewden, Chief Financial Officer

Mr Blewden has extensive international experience in oil and gas financial management, corporate finance and energy investment banking. From 2008 until 2010 he served as CFO of PetroSaudi International, a private company backed by the Saudi royal family. Prior to this, his career has included roles as CFO of African Arabian Petroleum Ltd., senior financial positions at Yukos Oil Company, and energy investment banking roles at Citigroup, UBS, Chase Manhattan and Schroders. Mr Blewden holds a BA (Hons) and MA in Natural Sciences from Cambridge University, England.

John Rapach, Chief Operating Officer

Mr Rapach has over twenty-five years of operations experience in both offshore and onshore environments. He is an industry renowned specialist in the preparation of reserve assessments, well testing, field development and performance enhancement.

Table 3: Sterling Resources top shareholders

Shareholder	% stake
Vitol Holding BV	12.4%
Ingalls & Snyder LLC	11.3%
Sprott Asset Management	10.9%
Blackrock Investment Management	4.1%
RBC Global Asset Management	3.0%
No. of ordinary shares on issue (m)	222.9

Source: Thomson ONE

Sterling Resources is listed on Canada's TSX-Venture Exchange.

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Fairfield Energy (private)

As part of this North Sea E&P report we also highlight a key unlisted player in the region – Fairfield Energy. Fairfield owns stakes in some of the same assets as E&Ps within our North Sea coverage universe, and is therefore a useful yardstick for comparing production and reserve forecasts, development progress, and exploration outlook with the listed players.

Asset summary

Fairfield's assets span the majority of the UK North Sea, and are fairly well diversified across production/development, oil/gas, and operated/non-operated fields. The company's preference is to hold high equity stakes in its assets (particularly those that Fairfield operates), and to own fields which offer further appraisal and development upside potential. Across its core assets Fairfield owns net 2P reserves of 39.7mmboe, and has exposure to a further 65.7mmboe of net contingent resources.

Table 1: Fairfield Energy asset portfolio

Region	Asset	Fairfield WI%	Gross Resource (mmboe)	Net Resource (mmboe)	Partners
Producing assets					
UK - Northern North Sea	Dunlin Area	70%	41	29	Mitsubishi (30%)
UK - Southern North Sea	Clipper South	25%	26	7	RWE (50%), Bayerngas (25%)
Development assets					
UK - Northern North Sea	Crawford & Porter	20%	27	5	EnQuest (51%), Valiant (29%)
UK - Northern North Sea	Darwin	50%	89	44	TAQA Bratani (50%)
Exploration & Appraisal					
UK - Northern North Sea	Dunlin Area Upside	70%	15	10	Mitsubishi (30%)
UK - Southern North Sea	Ensign Flank	50%	85	43	Bayerngas (50%)
UK - Southern North Sea	Glein	50%	22	11	Bayerngas (50%)
TOTAL			**304**	**149**	

Source: Jefferies, company data

At present Fairfield's only producing assets are the Dunlin Area and Clipper South; however, pending upcoming development approvals this could be boosted by new contributions from the Crawford & Porter and Darwin developments potentially onstream by the end of the decade. FY11 group production was 2.8kboepd (see below); Wood Mackenzie estimate this could exceed 7kboepd in 2012 depending on asset performance.

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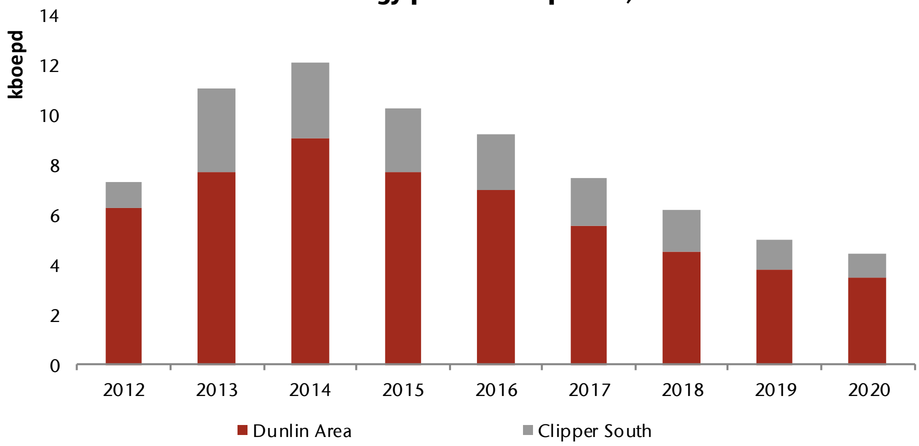
Chart 1: Estimated Fairfield Energy production profile, 2012-20



Source: Wood Mackenzie

The Dunlin Area

The bulk of Fairfield's reserves (28.6mmbbl, or 72% of total 2011 2P barrels) are sourced from its 70% stake in the Dunlin cluster of fields. This group of assets includes the mature Dunlin, Dunlin SW, Merlin, and Osprey producing fields across Blocks 211/18, 211/23 and 211/24 in the UK Northern North Sea. Overall, Dunlin production averaged 2.8kbopd in 2011, a 50% y-o-y decline due to much-reduced water injection during the year (Dunlin's water injection is driven by power imported from Shell's nearby Brent Charlie platform, which temporarily ceased power exports in 2Q11). Alongside resumption of Dunlin's water injectors, Wood Mackenzie estimates a planned work programme during 2012 will boost the cluster's output back to c.9kbopd by 2014.

All the Dunlin Area fields produce through the "Dunlin Alpha" concrete-based gravity structure, with crude exported via pipeline to the Cormorant A platform and on to the Sullom Voe terminal. **The cost of decommissioning this 340,000 tonne structure once the Dunlin fields have ceased production is a key uncertainty when considering the value of Fairfield**. At the end of 2011 Fairfield carried a $372m decommissioning provision for its producing assets (the Dunlin Area and Clipper South).

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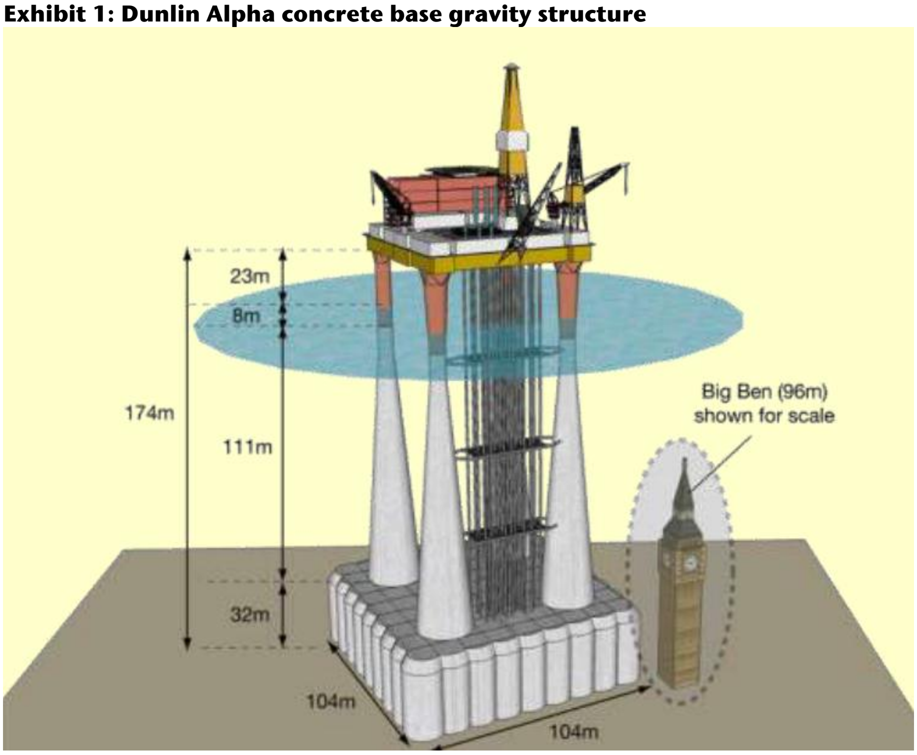
Exhibit 1: Dunlin Alpha concrete base gravity structure



Source: Fairfield Energy

Clipper South

Fairfield's newest producing asset is a 25% stake in the RWE-operated Clipper South gas field in the UK's Southern North Sea. The field will exploit a 156Bcf (gross) tight Rotliegendes sandstone reservoir, and has been developed using multiple fracture-stimulated horizontal wells to overcome the reservoir's low permeability (typically <1mD) – this type of completion is typical among tight gas fields in the Southern Gas Basin.

Fairfield benefited from £30m of development carries paid by new partners RWE and Bayerngas to earn their respective 50% and 25% stakes; following these cost carries, Fairfield utilised debt financing (a £37.5m facility with Credit Suisse) to fund its share of remaining capex. Fairfield reported first gas from Clipper South in August 2012, with initial gross flow rates hitting 43mmscfpd – once a further four producers are drilled over 2013-14 management estimate flow rates could exceed 80mscfpd.

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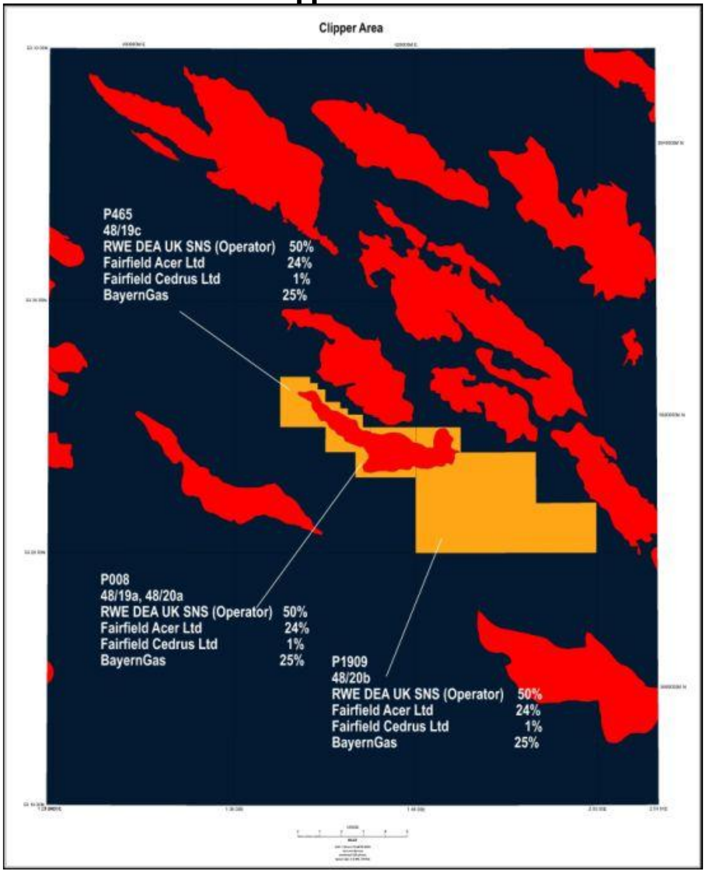
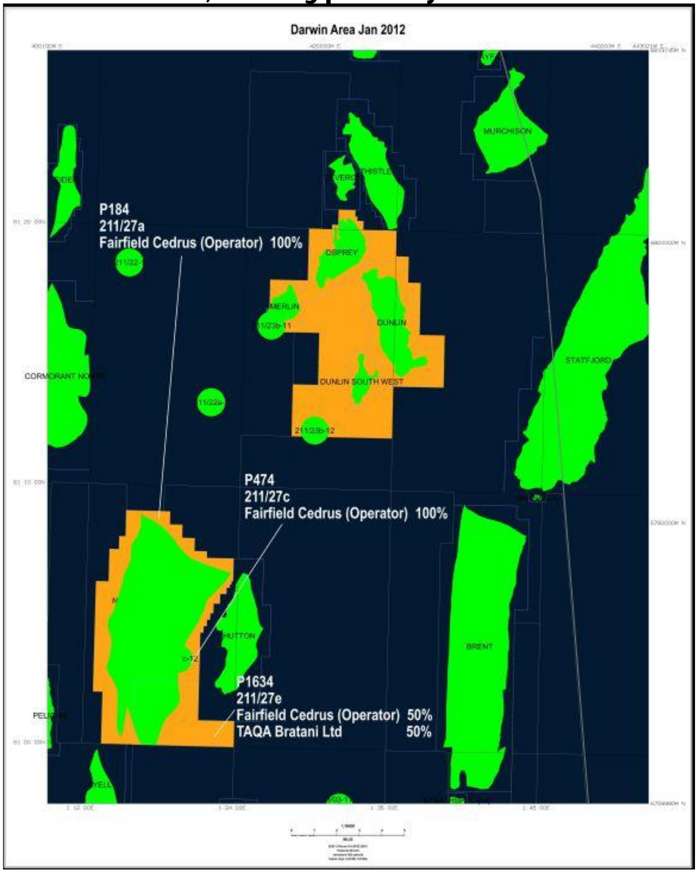
Exhibit 2: Overview of Clipper South area



Source: Fairfield Energy

Exhibit 3: Darwin, showing proximity to Dunlin cluster



Source: Fairfield Energy

Darwin

The key development asset in Fairfield's portfolio is Darwin, an 89mmbbl (gross) Northern North Sea oil development held in a 50:50 JV with TAQA Bratani. Darwin – which spans Blocks 211/27a, 211/27c, and 211/27e – is effectively the southern end of the retired NW Hutton field, and was acquired by Fairfield through both an acquisition from BP in 2009 and through the 25th UK licensing round.

Fairfield is evaluating potential development options for Darwin, including a fixed platform, an FPSO-led development, or by tie back to the nearby Cormorant (14km) or Dunlin (29km) platforms. At present, Fairfield expects first oil from Darwin as early as 2018.

Crawford & Porter

Crawford is a 27mmbbl (gross) oil redevelopment project in the Northern North Sea, targeting Jurassic Hugin, Triassic, and Tertiary reservoirs. The development will include both the Crawford and Porter fields, which are likely to be classified as a single accumulation for tax purposes (they will remain eligible for the UK small field allowance, in our view). Crawford is a highly compartmentalised reservoir whose heterogeneous nature means low overall permeability – this presents material development risks, in our view, and as such we think any development will most likely involve multiple horizontal wells to try and intersect as many of the compartments and higher-permeability zones as possible.

At present the project operator, EnQuest, is considering a variety of development options, with a decision expected in 2013 (i.e., first oil is unlikely before 2014). Fairfield will be carried for up to £34.85m of its development costs after farming down a 32% interest to EnQuest.

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Decommissioning

With Fairfield exposed to such a significant decommissioning liability, particularly on the Dunlin Alpha platform, the UK's tax legislation can have a material impact. Fairfield's decommissioning provision at the end of 2011 was $372m; essentially the present value of expected decommissioning costs less the NPV of those field's cashflows over their remaining life.

Small E&Ps hit by requirement to post capital against future abandonment
Past UK legislation stated that previous license owners could be liable for decommissioning costs, should the current partners default. Buyers of assets are often required to post security against future decommissioning costs, thereby reducing the availability of capital for investment elsewhere. This has especially hurt smaller E&P companies, where capital is scarce, and has also adversely affected market liquidity. As a result, the UK asset market has become increasingly polarised over recent years, with buyers seeking growth assets while many mature asset sales have either stalled or traded at a discount to market valuations due to large abandonment liabilities. This is a key reason why we believe Fairfield would find it difficult to divest its stake in the Dunlin Area if it wanted to, and potentially a contributing factor to Fairfield's failed IPO in 2010 (see below).

2012 budget added contractual certainty to abandonment tax relief boosting asset liquidity
In 2012, the UK Government committed to creating certainty on the tax relief available for abandonment expenditure, with companies now legally bound to receive 50% tax relief on decommissioning costs should they be forced to pay these costs due to a creditor defaulting. This essentially halves these companies' "securitisation" requirements and releases half of the capital companies had been putting aside (via provisions) for decommissioning costs, allowing reinvestment in North Sea (development or M&A). Unsurprisingly, this has been welcomed by the industry and should improve asset liquidity and increase the number of companies able to buy assets. Note that this still precludes smaller companies from operating mature assets, as the size of the investment required to maintain old facilities could still deter buyers.

Funding summary

By definition, the funding structure of a private entity like Fairfield is less clear than it is for publicly listed E&P companies. Fairfield attempted a London IPO in June 2010, when media reports suggested it tried to raise up to £330m on a full company valuation of up to £720m (source: Daily Telegraph). The float was abandoned in July 2010, however, due to adverse market conditions.

Fairfield is capitalised primarily through "investment strips" – essentially a preference share stapled to an interest-bearing instrument – that have first claim to Fairfield's assets in the event of liquidation. Coupons on the interest-bearing portion of the strips are 8% p.a. for the first five years, and 14% pa thereafter. These investment strips are typically issued whenever Fairfield requires new capital.

So far in 2012, Fairfield has raised (a) $150m of new capital from its existing shareholders (completed in April 2012), and (b) received a $150m equity commitment from Riverstone Holdings, with an option for Riverstone to subscribe to a further $200m of new equity alongside existing Fairfield shareholders. Alongside existing cash-on-hand of $32m at the end of 2011, in aggregate these funds exceed Fairfield's estimated $150m+ capex programme at Dunlin and Clipper South over 2012-13.

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EnQuest (ENQ LN)

Buy: 155p/sh Price Target

Scenarios

Target Investment Thesis

- Kraken and Alma & Galia completed on time and on budget, adding up to 119mmbbl and c.35kbopd, potentially doubling the size of the business.
- ENQ fully funded from current cash, debt, and operating cashflow to complete all planned developments.
- Able to access significant UK tax allowances on its small field and heavy oil developments.
- **SoP: 153p/sh, Core NAV: 144p/sh**

Upside Scenario

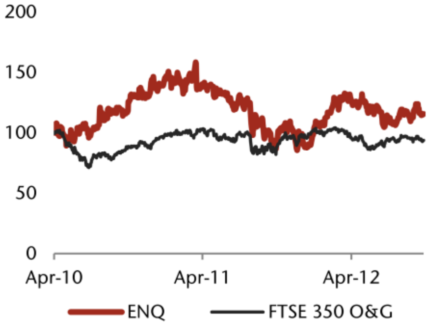
- Sustained Brent crude prices above our $100/bbl long-term forecast
- Successful appraisal drilling at Kildrummy (4Q12) and Ketos wells (not firm, 2013).
- M&A activity – ENQ's 100% oil portfolio and low political risk make it attractive to predators, especially NOCs.
- **SoP: 180p/sh**, +49% upside from current share price.

Downside Scenario

- ENQ misses 2012 production guidance of 20-24kbopd (Jefferies estimates 22kbopd).
- Weaker-than-expected Brent crude environment (base case $100/bbl) and/or rapid decline at the mature Dons, Thistle & Deveron, and Broom & Heather hubs.
- Development delays and/or cost overruns at Kraken and Alma & Galia.
- Complete failure of E&A programme.
- **SoP: 115p/sh**, 5% downside from current share price.

Long Term Analysis

ENQ share price performance index



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	**$100/bbl**
LT UK NBP spot gas price	**$9.14/mcf**
$/£ forex	**1.58**
Discount rate	**10%**

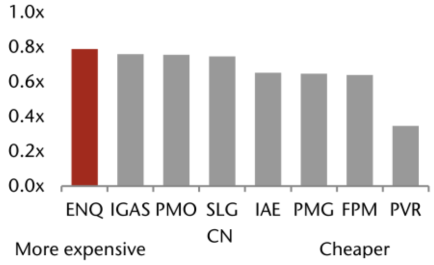
Other Considerations

ENQ is currently 100% UK focused, however we cannot rule out the company seeking assets in other geographies if suitable opportunities are scarce in the UK.

ENQ's CEO, Mr Amjad Bseisu, currently owns c.9% of ENQ shares.

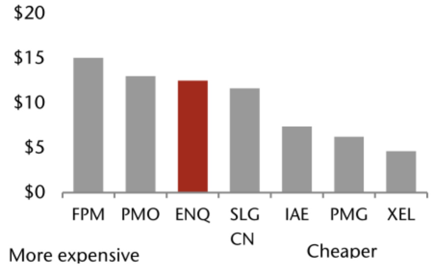
Peer Group

North Sea E&Ps – P/SoP



Source: Thomson ONE, Jefferies estimates

North Sea E&Ps – EV/2P boe



Source: Thomson ONE, Jefferies estimates

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- Appraisal well result from Kildrummy (4Q12, 12mmbbl, 60% WI, 50% CoS, 2% upside to SoP).
- Results of 27th licensing round due in 4Q12; ENQ expected to have bid aggressively throughout the North Sea.
- Kraken FDP approval expected 1H13.

Company Description

EnQuest is a 100%-oil, 100%-UK E&P company that was created in 2010 as a merger of the UK North Sea portfolios of Lundin Petroleum and Petrofac's Energy Developments division. Since then ENQ has added substantially to its portfolio through acquisitions (both corporate-level and asset-level) and licensing rounds, and now reports 2P reserves in excess of 115mmbbl and annual production of over 20kbopd. ENQ's strategy is to use its strong technical team to exploit undeveloped assets and maximise recovery from its mature fields; the company favours hub-style developments due to their lower costs and scale benefits. ENQ is listed on London's main market and is a member of the FTSE250 index.

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Faroe Petroleum (FPM LN)

Buy: 240p/sh Price Target

Scenarios

Target Investment Thesis

- FPM's self-funded exploration model offers reliable cashflow and high impact UK and Norwegian exploration upside.
- Exploration wells carried at our assessed geological and commercial chance of success.
- FPM can exploit attractive Norwegian and UK fiscal terms, encouraging exploration and development of marginal fields.
- **SoP: 239p/sh, Core NAV :180p/sh**

Upside Scenario

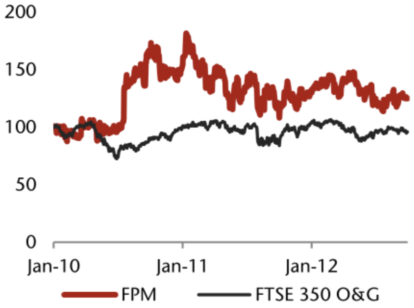
- Multiple exploration successes from high impact wells (especially North Uist, Darwin and Novus).
- Better-than-expected Brent price relative to our $100/bbl long-term forecast.
- FPM successfully replicates 2011's Maria swap deal with Petoro, trading undeveloped resource for producing assets – we believe Butch is a possible candidate.
- **SoP: 300p/sh**, +97% upside from current share price.

Downside Scenario

- Complete failure of FPM's exploration campaign.
- FPM misses management's 2012/13 production guidance of 7-8kboepd (Jefferies estimate 7.7kboepd).
- Brent crude prices endure sustained period below $100/bbl.
- **SoP: 140p/sh**, -8% downside from current share price.

Long Term Analysis

FPM share price performance



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	**$100/bbl**
LT UK NBP spot gas price	**$9.14/mcf**
$/£ forex	**1.58**
Discount rate	**10%**

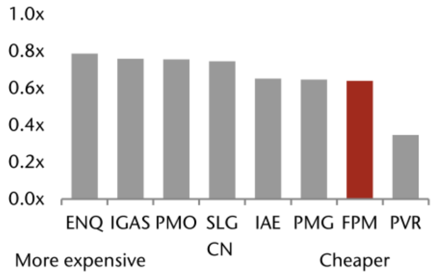
Other Considerations

FPM is part owned by the Korea National Oil Corporation (KNOC, 23%) and Scottish & Southern Energy (5%).

Faroe's strong balance sheet includes £103m of available cash at 1H12, a $250m committed RBL facility, and a NOK1bn facility allowing Faroe to debt-fund its Norwegian exploration drilling.

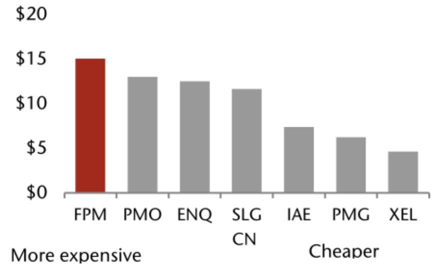
Peer Group

North Sea E&Ps – P/SoP



Source: Thomson ONE, Jefferies estimates

North Sea E&Ps – EV/2P boe



Source: Jefferies estimates, company data

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- Six 2012-13 exploration wells at North Uist, Spaniards East, Rodriguez South, Darwin, Novus and Butch SW, targeting a total of 150mmboe with combined SoP upside of 84%. Next well: Spaniards East.
- Successful in-fill drilling at Njord, Brage, etc. lifts group production to 8.9kboepd in 2013.
- UK's 27th offshore licensing round (results due 4Q12), where we expect FPM will have looked to expand its footprint in the West of Shetland area.

Company Description

Faroe Petroleum is a self-funded, exploration-biased E&P company with a focus on Norway and the UK. The company's modus operandi is to deliver steady and growing cashflow from its 25mmbboe core portfolio, and recycle this into high-impact exploration in regions where it has good geological understanding and operational experience. The Barents Sea (Norway) and West of Shetlands (UK) areas are a particular focus and offer FPM exposure to underexplored basins and favourable tax terms. FPM is listed on London's AIM market.

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Ithaca Energy (IAE LN)

Buy: 180p/sh Price Target

THE LONG VIEW

Scenarios

Target Investment Thesis

- Ithaca is fully funded from current cash, debt, and operating cashflow to complete all planned developments.
- Significant cashflow generation – estimated $800m of post-tax operating cashflow over 2013-14 (more than current market cap).
- Greater Stella Area development able to exploit UK's small field tax allowance, offers further hub potential.
- **SoP: 180p/sh, Core NAV: 176p/sh.**

Upside Scenario

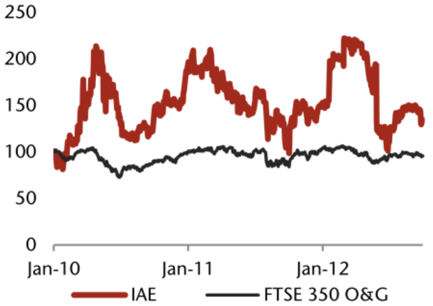
- Successful appraisal of Hurricane and Helios wells extends reserve potential of Greater Stella Area (currently 53mmbbl).
- Further M&A activity following abandoned approach for company in early 2012.
- Strong oil price environment; Brent enjoys sustained period above $100/bbl.
- **SoP: 220p/sh**, +87% upside from current share price.

Downside Scenario

- Delays and/or cost overruns at cornerstone Greater Stella Area development.
- Faster than expected decline at Ithaca's mature Beatrice & Jacky fields.
- A weak Brent environment where crude prices remain consistently below our $100/bbl forecast.
- **SoP: 130p/sh**, +11% upside from current share price.

Long Term Analysis

IAE share price performance



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	**$100/bbl**
LT UK NBP spot gas price	**$9.14/mcf**
$/£ forex	**1.58**
Discount rate	**10%**

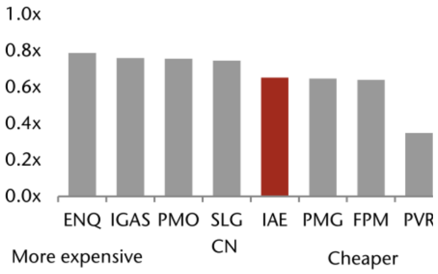
Other Considerations

Potential for Ithaca to expand into similar geographies, e.g. Norway, to replicate successful UK strategy.

Ithaca's funding capacity includes $112m of available cash at 1H12 plus a fully underwritten senior secured $400m facility with BNP Paribas.

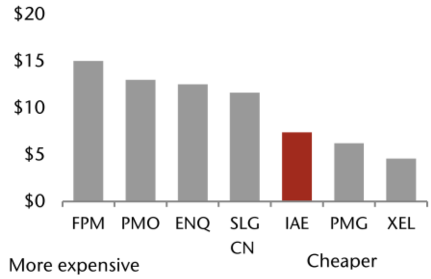
Peer Group

North Sea E&Ps – P/SoP



Source: Thomson ONE, Jefferies estimates

North Sea E&Ps – EV/2P boe



Source: Jefferies estimates, company data

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- Results of UK's 27th licensing round (due 4Q12), where we expect Ithaca to have bid for acreage close to its existing assets.
- Hurricane appraisal well results (due 4Q12) could potentially derisk Helios prospect and add reserves to GSA development.
- Development decision on ENQ-operated Scolty/Crathes development expected in 2013.

Company Description

Ithaca Energy is a UK-focused E&P with an emphasis on production and development – it has minimal exposure to exploration assets. The company's model is to secure discovered, undeveloped UK resource through either acquisitions or licensing rounds, and then take these assets to production. Ithaca offers substantial cashflow generation and is fully funded for its project pipeline through existing cash and debt. Ithaca trades on London's AIM market and Canada's TSX exchange.

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Parkmead Group (PMG LN)

Buy: 15p/sh Price Target

THE LONG VIEW

Scenarios

Target Investment Thesis

- Perth oil field is PMG's cornerstone asset; recent FDP approval confirms a near-term development project with potential for a 100mmbbl+ hub in the long-term.
- Onshore Dutch assets provide modest cashflow and development opportunities.
- PMG successfully secures £20m+ debt facility in 2013.
- Exploration carried at our assessed geological and commercial CoS.
- **SoP: 20p/sh, Core NAV: 16p/sh.**

Upside Scenario

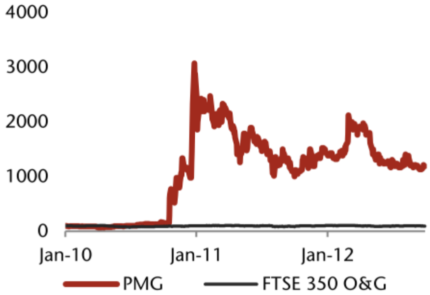
- E&A success derisks Spaniards East and/or Pharos wells, supporting local hub developments.
- Parkmead continues to grow portfolio through accretive M&A activity.
- Commodity prices exceed our long-term forecasts ($100/bbl Brent, $9.14/mcf UK NBP).
- **SoP: 29p/sh**, 125% upside from current share price.

Downside Scenario

- Complete failure of planned E&A programme.
- Lack of new funding (i.e. no new debt in 2013) puts growth on hold; PMG forced to farm down Perth at dilutive price.
- Sustained weakness in commodity prices versus our long-term forecasts.
- **SoP: 10p/sh**, -22% downside from current share price.

Long Term Analysis

PMG share price performance



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	**$100/bbl**
LT UK NBP spot gas price	**$9.14/mcf**
$/£ forex	**1.58**
Discount rate	**10%**

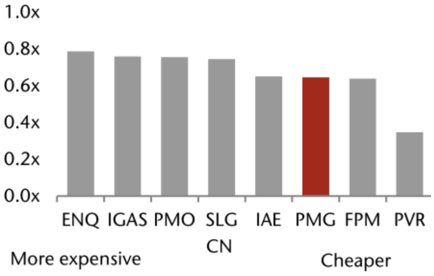
Other Considerations

In aggregate, PMG's senior management owns c.37% of issued capital – a strong alignment of management's interest but possibly presenting liquidity issues in the long term, in our view.

Parkmead owns a 2% stake in Faroe Petroleum (Buy, 240p/sh PT).

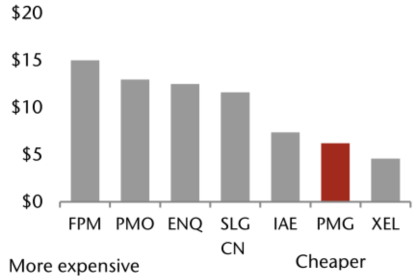
Peer Group

North Sea E&Ps – P/SoP



Source: Thomson ONE, Jefferies estimates

North Sea E&Ps – EV/2P boe



Source: Jefferies estimates, company data

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- Near-term E&A well results from Spaniards (drilling, 30mmbbl gross, 13% WI, 10% SoP upside) and Pharos (2013, 58mmboe gross, 20% WI, 14% SoP upside).
- Results of UK's 27th licensing round (expected 4Q12).
- Successful negotiation of new debt facility in 2013 (we assume £20m).

Company Description

Parkmead Group is a small but rapidly growing NW Europe E&P. Since November 2011, Parkmead has completed four M&A transactions, giving the company onshore Netherlands production, a large UK North Sea oil development, and several Southern North Sea gas assets. The company is currently funded through a recent equity placing and shareholder loan facility. The management team (which together own c.37% of PMG's capital) are predominantly ex-Dana Petroleum, giving the company extensive experience in the North Sea. Parkmead is listed on London's AIM market.

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Premier Oil (PMO LN)

Hold: 415p/sh Price Target

Scenarios

Target Investment Thesis

- Risked sum of parts with chance of success (CoS) based on assessed geological and commercial chance of success on its portfolio.
- Huntington, Catcher, and Solan projects come onstream as planned, allowing PMO to reach 80kboepd in 2014.
- PMO delivers FY12 production of 59kboepd, slightly short of 60kboepd guidance.
- **SoP: 486p/sh, Core NAV: 438p/sh**

Upside Scenario

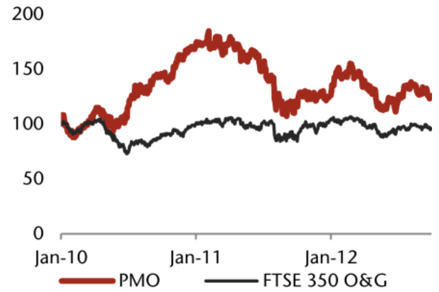
- Sustained Brent crude prices above our $100/bbl long-term forecast
- Developments come onstream on time, on budget, no development risking applied, meaning PMO's medium-term production target of 100kboepd is met.
- **SoP: 580p/sh**, +58% upside from current share price.

Downside Scenario

- Complete failure of E&A programme.
- North Sea production assets continue to suffer from unplanned outages, increased costs.
- Weaker-than-expected Brent crude environment (base case $100/bbl)
- Material development delays on Huntington, Catcher, Solan, Sea Lion.
- **SoP: 300p/sh** , 18% downside from current share price.

Long Term Analysis

PMO share price performance index



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	$100/bbl
LT UK NBP spot gas price	$9.14/mcf
$/£ exchange rate	1.58
Discount rate	10%

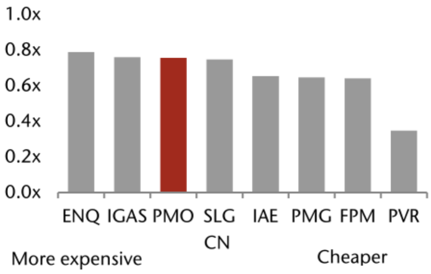
Other Considerations

Increased focus on developments means capex profile estimated to reach c.$5bn over 2012-17.

Key risks include missing production guidance due to development delays, plus failure of exploration programme.

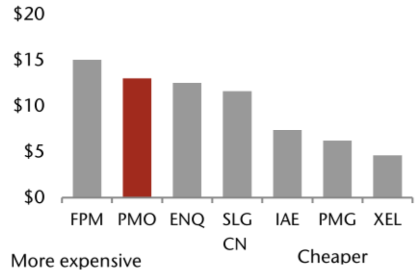
Peer Group

North Sea E&Ps – P/SoP



Source: Jefferies estimates

North Sea E&Ps – EV/2P boe



Source: Jefferies estimates

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- Hitting guidance of 60kboepd 2012 production (Jefferies estimate 59kboepd).
- Numerous exploration wells over 4Q12-1H13, including Spaniards East (drilling, 30mmbbl, 1% SoP upside), Cyclone (4Q12, 30mmboe, 3% SoP upside) and Luno II (4Q12, 120mmboe, 4% SoP upside).

Company Description

Premier Oil is a FTSE 250 full cycle oil and gas exploration and production company headquartered in London. The company's core assets are in the North Sea (UK and Norway), SE Asia (Indonesia and Vietnam), the Falkland Islands, and the Middle East (Pakistan). The company has significant production and cash flow which it uses to fund its ongoing exploration and development program. The company also looks to pursue selective acquisitions in its core areas and new geographies – notable deals include Oilexco in 2009, EnCore Oil in 2012, and the farm-in to the Sea Lion blocks in the Falkland Islands in 2012..

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Providence Resources (PVR LN)

Buy: 950p/sh Price Target

THE LONG VIEW

Scenarios

Target Investment Thesis

- Barryroe field confirmed as a commercial 200mmbbl+ oil development; PVR successfully farms down its 80% Barryroe stake in exchange for development carry.
- Favourable Irish fiscal terms maintain status quo.
- Conservative risking of PVR's high impact exploration wells (Dunquin, Dalkey Island, and Spanish Point).
- **SoP: 1903p/sh, Core NAV: 1345p/sh.**

Upside Scenario

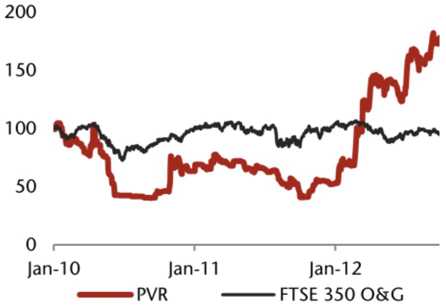
- Multiple exploration successes across PVR's high impact wells (Dunquin 1.7bnboe, Dalkey Island 250mmbbl, Spanish Point 100mmboe).
- Better-than-expected recovery factor from Barryroe field, currently estimated at 20% .
- Brent crude prices exceed our $100/bbl long-term forecast.
- **SoP: £25/share**, +279% upside from current share price.

Downside Scenario

- Development delays and/or cost overruns at cornerstone Barryroe field, or failure to conclude suitable farm-in agreement.
- Complete failure of PVR's exploration portfolio.
- Weak commodity price environment with Brent crude consistently trading below $100/bbl.
- **SoP: 350p/sh**, -47% downside from current share price.

Long Term Analysis

PVR share price performance



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	**$100/bbl**
LT UK NBP spot gas price	**$9.14/mcf**
$/£ forex	**1.58**
$/€ forex	**1.35**
Discount rate	**10%**

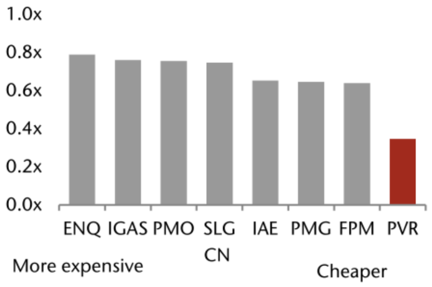
Other Considerations

We believe the participation of major oil & gas companies ExxonMobil, Repsol, ENI and PETRONAS endorses the materiality of Providence's exploration acreage.

Ireland's fiscal terms are currently among the best in the world for E&Ps; further industry success may see the Irish government increase oil & gas taxation.

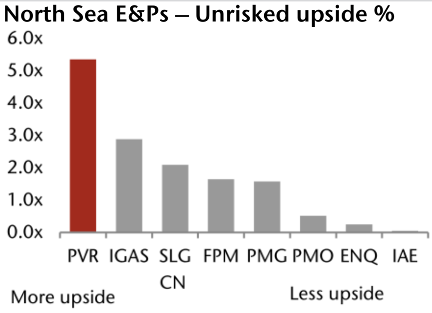
Peer Group

North Sea E&Ps – P/SoP



Source: Thomson ONE, Jefferies estimates

North Sea E&Ps – Unrisked upside %



Source: Jefferies estimates, company data

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- Updated CPR for Barryroe, PVR farming down its current Barryroe stake from 80% to c.40%.
- Dalkey Island exploration well (£11/sh unrisked, 1Q13, 250mmbbl gross, 50% WI, 10% CoS, 54% upside to SoP).
- Dunquin exploration well (£18/sh unrisked, 2Q13, 1.7bnboe gross, 16% WI, 10% CoS, 86% upside to SoP) being drilled with ExxonMobil, ENI, Repsol.

Company Description

Providence Resources is an Ireland-focused E&P company with stakes in a number of high impact exploration prospects and development assets. The bulk of Providence's value lies in its 1bnbbl+ oil-in-place Barryroe oil development in the Celtic Sea, enhanced by a set of high risk, very high reward Atlantic Margin exploration wells where PVR is partnered with blue-chip companies including Repsol, ExxonMobil, PETRONAS, and ENI. Providence is listed on London's AIM market and the Irish Stock Exchange.

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Jefferies

Sterling Resources (SLG CN)

Hold: C$1.45/sh Price Target

THE LONG VIEW

Scenarios

Target Investment Thesis

- Breagh gas field onstream late 1Q13, ramping production up to 170mmscfpd by 2014.
- Funding uncertainty continues to weigh on the stock.
- Ana & Doina development offshore Romania provides opportunity to gain material position in Black Sea and exploit positive local gas price environment.
- **SoP: C$1.90/sh; Core NAV: C$1.53/sh**

Upside Scenario

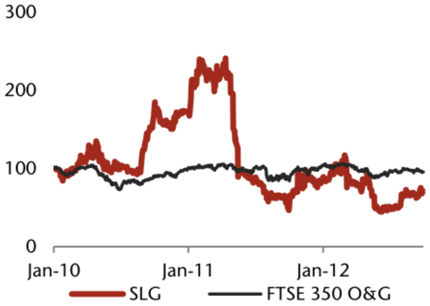
- Funding situation resolved successfully with no dilution to current portfolio; RBL facility renegotiated in 4Q12 with favourable terms.
- Success in Romanian exploration campaign (Ioana and Eugenia drilled 4Q12/1Q13), derisking SLG's other Black Sea prospects.
- Strong gas price environment good for Breagh economics.
- **SoP: C$3.00/sh**, +111% from current share price.

Downside Scenario

- Dilutive farmdowns of Romanian portfolio in order to fund upcoming drilling campaign; worsening of terms in existing RBL facility.
- Failure to deliver exploration success offshore Romania.
- Commodity prices weaker than expected, UK NBP spot gas trades consistently below our $9.14/mcf forecast.
- **SoP: C$0.80/sh**, -44% downside from current share price.

Long Term Analysis

SLG share price performance



Source: Bloomberg, Jefferies estimates

Long Term Financial Model Drivers

LT Brent crude price	**$100/bbl**
LT UK NBP spot gas price	**$9.14/mcf**
USD/CAD forex	**1.00**
Discount rate	**10%**

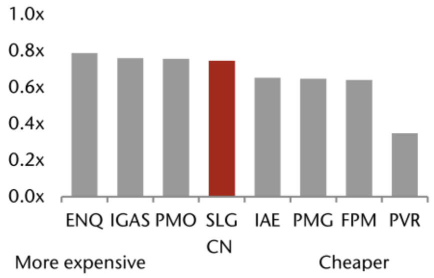
Other Considerations

Peripheral acreage in the Netherlands, France and UK Central North Sea offers long-term E&A potential, not part of SLG's immediate plans.

Current £105m RBL facility likely fully utilised by 1Q13, requires £20m minimum cash balance.

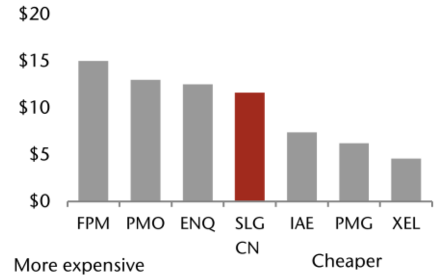
Peer Group

North Sea E&Ps – P/SoP



Source: Thomson ONE, Jefferies estimates

North Sea E&Ps – EV/2P boe



Source: Jefferies estimates, company data

Recommendation/Price Target

Ticker	Rec.	PT
ENQ	Buy	155p
FPM	Buy	240p
IGAS	Buy	85p
IAE	Buy	180p
PMG	Buy	15p
PMO	Hold	415p
PVR	Buy	950p
SLG	Hold	C$1.45

Source: Jefferies estimates

Catalysts

- A decision regarding funding is expected in 4Q12, potentially involving the sale or farmdown of Sterling's Romanian acreage.
- Successful completion of Breagh gas development (we expect first gas in late 1Q13).
- Ioana (C$0.08/sh, 36% unrisked SoP upside) and Eugenia (C$0.16/sh, 75% unrisked upside) exploration wells due to spud in Romania in 4Q12.

Company Description

Sterling Resources is a Canadian-listed E&P with assets in the UK North Sea, Romania, the Netherlands and France. The company is primarily an exploration-led business, however its production and cashflow are expected to see strong near-term growth as its Breagh gas field is brought onstream in 1Q13. A variety of exploration prospects in the Black Sea provide drilling catalysts over 2012-14 in a region that has seen large exploration success by the majors. Sterling is listed on Canada's TSX-Venture exchange.

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Company Description

EnQuest is a fully funded, 100%-oil production and development business operating solely in the UK North Sea. Its core strategy is to acquire undeveloped oil resources through farm-ins or licensing rounds, and use its strong in-house technical team to execute in-fill drilling programmes and hub-style developments that maximise recovery and minimise costs. EnQuest is highly cash generative, with much of its excess cashflow recycled into new development projects in the North Sea – two of these (Kraken and Alma & Galia) are expected to double ENQ's reserves and production by the end of the decade.

Faroe Petroleum is a self-funded E&P operating in the UK and Norway. Its recent focus has been on reinvesting production cashflows into underexplored frontier regions in the West of Shetlands and Barents Sea, where it aims to exploit similar plays to other giant discoveries made by the industry in 2011-12. Faroe benefits from favourable fiscal terms in the UK and especially Norway, where it can hold high working interests in its licences and share the financial risks of exploration with the Norwegian government.

IGas Energy is a small cap oil and gas exploration company headquartered in London, UK. Its assets are onshore UK including producing oil fields and unconventional gas exploration/appraisal, including Coal Bed Methane and shale gas. IGas completed the acquisition of Star Energy in December 2011, providing it most of its current production and all of its independently certified 2P reserves.

Ithaca Energy is a low risk oil & gas production and development business operating in the UK North Sea. Recent development activity at its cornerstone Athena and Greater Stella Area assets is expected to quadruple group production by 2014, making Ithaca highly cash generative. The company is well funded through operating cashflow and secured debt (currently undrawn), which when combined with its low risk portfolio makes Ithaca a potential M&A target, in our view.

Parkmead Group is a small but rapidly growing NW Europe E&P with assets in the UK North Sea and onshore Netherlands. The company has completed several M&A deals since inception, giving it meaningful exposure to a number of SNS gas prospects and a material operated stake in its cornerstone asset – the Perth oil development. Parkmead's shares are tightly held by management (37%), who formed Parkmead after successfully selling Dana Petroleum to KNOC in 2010.

Premier Oil plc is a growing FTSE 250 oil and gas exploration and production company with current interests in nine countries around the world. Premier Oil''s target is to deliver growth by building three quality businesses, in the North Sea, the Middle East/Pakistan and South East Asia, which together deliver 100,000 of oil per day from around 400 million barrels of reserves.

Providence Resources is unique as an E&P focused almost entirely on Ireland. Its portfolio is dominated by the 1bn+ barrel Barryroe oil development in the Celtic Sea, which should provide much of Providence's newsflow over 2012 via an updated CPR and farmdown decision. Providence is also partnered with several global oil & gas majors in two very high impact exploration prospects – Dunquin and Dalkey Island – that are due to be drilled offshore Ireland in 2013 and would be transformational for the company. Providence is headquartered in Dublin.

Sterling Resources is a Canadian-listed E&P with assets in the UK North Sea and Romania. Its UK portfolio centres on its Breagh (gas) and Cladhan (oil) development projects, which each have follow-on additional potential – first production from Breagh and Cladhan is due in 2013 and 2015, respectively. Sterling's Romania assets are very prospective, with its Ana/Doina gas fields due to be developed shortly, with several other high impact oil and gas exploration prospects due to be test over 2012-14. Sterling also owns some minor onshore unconventional assets in Romania.

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			IB Serv./Past 12 Mos.	
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