Charles Stanley SECURITIES

Company note

21 October 2013

Oil & Gas
FTSE AIM All Share

Parkmead Group

Initiation

Buy

Price	11.5p
Price target	21.0p
12m high/low	16.3p/10.9p
Market cap.	£119m
Net cash	£14m
Enterprise value	£105m
Free float	63%
Avg. daily volume	734k
Shares in issue	1,036.2m
Company code	PMG.L

Next news	Prelims - 15 Nov 2013
Confidence in estimates	Medium
Expected movement in estimates	◄►

Adviser	Yes
Broker	Yes
NOMAD	Yes

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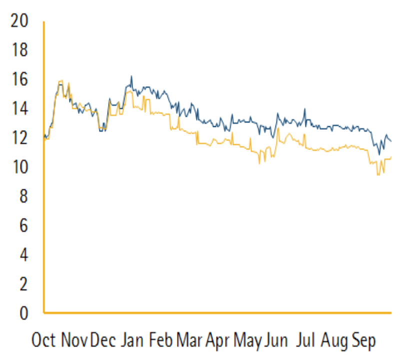
Share price performance (1 year)



	1m	3m	12m
– Price	-4.7	-2.9	3.1
– Rel all share	-10.6	-5.3	-14.1

Source: Thomson Datastream

Accelerated Dana

Parkmead is led by the highly successful entrepreneur Tom Cross, who is applying the same strategic model he used to grow Dana Petroleum from scratch into what became the largest independent oil company in the UK, before selling it to the Korea National Oil Corporation ("KNOC") for over $US 3 billion. Our 21.0p/share target price consists of a Core NAV of 16.8p/share, which reflects the value of discovered oil and gas fields, and 4.2p/share of value relating to lower visibility oil & gas assets. We believe that the company has the leadership team, the technical team, the assets and the growth trajectory to make it a pre-eminent European oil & gas company.

- **Focused team –** Management owns circa 37% of the company.
- **Just the beginning –** Since Tom Cross repositioned Parkmead as an oil & gas company it has made four asset or corporate acquisitions. The company was awarded more blocks in the 27th UKCS Licensing Round than any of its London-listed peers.
- **Undervalued –** We believe our 21.0p target price reflects the fair value of the company today, which provides 83% upside relative to the current market price.
- **Poised for value growth –** Future operational results and strategic acquisitions can reasonably be expected to grow the value of the company beyond our target price.
- **Near-term exploration catalyst –** Parkmead holds a 20% working interest in the Dana Petroleum-operated Pharos exploration target where drilling has commenced and results are expected in early-mid November. Based on our geological assessment we believe that Pharos has a one in three chance of success. If successful, we estimate the net value of Pharos to Parkmead will amount to 2.3p/share and that it will open the door for drilling the Blackadder prospect (valued at 2.2p/share assuming success). In our target price we have included 0.6p/share for Pharos and no value for Blackadder because it is conditional on the success of Pharos.
- **Production –** The company's acquisition of 10% of the producing Athena oil field (UK North Sea) through the takeover of Lochard Energy will add to base production (from the Netherlands) in FY2014 and provide a platform for future growth.
- **Political safety –** We believe that the overlap of production growth and the political stability of the UK (and the Netherlands) increases the attractiveness of Parkmead.

Key financial data

Year to June	2012A	2013E	2014E	2015E	2016E	2017E
Production (boe/d)	250	261	895	850	5,530	9,741
Production growth yoy	n.a.	4%	243%	-5%	551%	76%
Oil production / total production	0%	0%	77%	66%	79%	75%
Revenue (£m)	2.9	4.7	14.9	12.7	115.0	208.4
EBITDA (£m)	-5.5	-4.7	2.0	-0.0	79.7	153.4
Operating cash flow (£m)	-1.0	-2.1	1.1	-2.5	60.3	138.4
Brent oil price ($US/bbl)	112.41	108.67	100.75	102.76	104.82	106.91
UK natural gas price ($US/mcf)	9.23	10.40	10.83	11.16	11.49	11.84

Please see important disclaimers and disclosures on page 52

Investment case

- Parkmead is led by Tom Cross who founded, grew and sold Dana Petroleum to KNOC for over $US 3 billion. Parkmead's strategy is to replicate the successful Dana Petroleum model over a shorter time period focusing on the geographic areas that were most transformational for Dana: the North Sea and Africa. Currently, Parkmead believes that there are sufficient opportunities in the North Sea to create significant shareholder value in the mid-term, although opportunistically it might also acquire assets in Africa.
- In our opinion the strategies of junior oil & gas companies are generally dictated by their assets. However, we believe that Parkmead is exceptional in that it does have an overriding strategy that can be expected to deliver tangible returns over and above the current asset value. The company is applying a "hub" strategy, which means that it plans on strategically controlling areas in terms of i) infrastructure and ii) geological understanding, where a stronghold can be built by developing resources that have already been discovered.
- The Perth field, a sour oilfield in the UK North Sea (operated and 52.03% held by Parkmead) is the perfect example of such a hub strategy. The facilities used to produce the Perth field will be the only export route available to produce over 900mn bbls of STOOIP (STOOIP figure refers to oil in place a proportion of which would be producible) of already discovered sour crude oil. No value is ascribed to this strategic potential in our target price; however, conceptually this strategy is quite important to the Parkmead investment thesis.
- Parkmead is delivering on its guidance that it will grow more quickly than Dana Petroleum grew. Since Tom Cross repositioned the company as an oil & gas company (over the course of 2011), it has made multiple acquisitions, the most important of which have been: i) the acquisition of a 15% interest in the Platypus gas discovery and nearby prospects from XTO UK (completed in November 2011), ii) the acquisition of producing oil & gas assets in the Netherlands from Dyas B.V. (completed in August 2012) iii) the acquisition of DEO Petroleum through which the company acquired its interest in the Perth field (also completed in August 2012) and iv) the acquisition of Lochard Energy which held a 10% working interest in the producing Athena oil field in the UK North Sea (completed in July 2013). The company also has a suite of assets that it is growing from the early stages of exploration. Only four major international companies were awarded more blocks than Parkmead in the UKCS 27th Licensing Round and Parkmead was appointed operator by its joint venture partners for all its newly awarded licences, which speaks to the credibility of Parkmead amongst its peers.
- The company is producing oil & gas from its onshore Dutch assets and the Athena field, which are therefore of strategic interest due to the cash flow they are generating. We believe that from a valuation perspective, the company's most material assets are i) the Perth field in the UK Central North Sea, ii) the company's gas discovery in the Southern North Sea (Platypus) and the nearby exploration potential inclusive of Pharos and iii) the Skerryvore oil exploration prospect in the UK Central North Sea.
- Parkmead is undervalued. Our 21.0p/share target price represents what we believe is a fair price for the company today.

Risk factors

- General risks for almost all investments in the oil & gas sector primarily include: i) commodity price risks, ii) risks related to the estimation of reserves and future production, iii) risks related to capital and operating costs, iv) operational risks, v) funding risks, vi) the risk of delays, vii) the risk that regulations change adversely, viii) the risk that the taxation system changes adversely, ix) exploration risks and x) environmental risks.
- In addition to these risks, we believe investors should consider the following specific risks in relation to Parkmead: i) the Perth field is a sour crude oil field meaning that the fluids in the field have a high sulphur content which creates operating risks and challenges and ii) 80% of the current production from Athena is from wells that have both primary and backup pumps, nonetheless the risk of pump failure is a consideration.

Asset, Valuation and Target Price Summary

Oil & Gas Assets	Type	Working Interest	Total Value Net to Company (NPV10): Total USD ($mn)	Total Value Net to Company (NPV10): Total GBP (£mn)	Total Value Net to Company (NPV10): Per Share (p/share)	Risked Value: Geological Chance of Success (%)	Risked Value: Commercial Chance of Success (%)	Risked Value: Market Valuation Factor (%)	Risked Value: Combined Valuation Factor (%)	Risked Value: Contribution to Target Price Total ($mn)	Risked Value: Contribution to Target Price per Share (p/share)	Valuation Estimates: Value $/boe ($/boe)	Valuation Estimates: Total Future Production (mnboe; net)
UK Oil & Gas Assets													
Athena	Oil	10.0%	18.2	11.4	1.1	100%	100%	100%	100%	18.2	1.1	29.21	0.6
Perth Core	Oil	52.0%	149.1	93.2	8.8	100%	80%	100%	80%	119.3	7.0	6.93	21.5
Perth NW Terrace	Oil	52.0%	94.2	58.9	5.6	66%	80%	100%	53%	49.7	2.9	11.63	8.1
Perth NE Terrace	Oil	52.0%	80.8	50.5	4.8	50%	80%	100%	40%	32.3	1.9	11.71	6.9
Platypus	Gas	15.0%	15.9	9.9	0.9	100%	80%	100%	80%	12.7	0.8	6.16	2.6
Total UK Oil & Gas Assets			358.2	223.9	21.2					232.3	13.7	9.02	39.7
Netherlands Oil & Gas Assets													
Onshore Gas	Gas	15.0%	7.3	4.5	0.4	100%	100%	100%	100%	7.3	0.4	14.54	0.5
Geesbrug (2 wells)	Gas	15.0%	1.7	1.0	0.1	100%	50%	100%	50%	0.8	0.0	3.00	0.5
Ottoland	Oil & Gas	15.0%	2.1	1.3	0.1	100%	50%	100%	50%	1.0	0.1	7.70	0.3
Papekop	Oil & Gas	15.0%	8.6	5.4	0.5	100%	50%	100%	50%	4.3	0.3	11.83	0.7
Total Netherlands Oil & Gas Assets			19.6	12.3	1.2					13.5	0.8	9.57	2.1
Total Oil & Gas Assets			**377.8**	**236.2**	**22.3**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**245.7**	**14.5**	**9.05**	**41.8**
Balance Sheet and Other Adjustments													
Investment in Faroe Petroleum			8.1	5.1	0.5					8.1	0.5		
Aupec consulting business			30.0	12.5	1.2					30.0	1.2		
General & Admin (PV10, four years after tax)			(13.7)	(8.6)	(0.8)					(13.7)	(0.8)		
Cash net of equity raise and acquisition costs			25.0	15.7	1.5					25.0	1.5		
Cash assumed from option exercise			2.0	1.2	0.1					2.0	0.1		
Loans (31/12/2012; adjusted for debt-equity swap)			(3.2)	(2.0)	(0.2)					(3.2)	(0.2)		
Total			**48.3**	**23.9**	**2.3**					**48.3**	**2.3**		
Core NAV			**426.1**	**260.0**	**24.6**					**294.0**	**16.8**		
Lower Visibility Oil & Gas Assets													
UK Oil & Gas Assets													
Possum	Gas	15.0%	13.3	8.3	0.8	50%	80%	100%	40%	5.3	0.3	12.67	1.1
Pharos	Gas	20.0%	38.5	24.1	2.3	33%	80%	100%	27%	10.3	0.6	6.64	5.8
Skerryvore	Oil	30.5%	187.3	117.0	11.1	38%	80%	100%	30%	56.2	3.3	10.32	18.1
Athena 5th Well	Oil	10.0%	13.3	8.3	0.8	100%	50%	0%	0%	-	-	15.01	0.9
Blackadder	Gas	20.0%	37.0	23.1	2.2	24%	80%	0%	0%	-	-	6.27	5.9
Total UK Oil & Gas Assets			289.4	180.9	17.1					71.8	4.2	9.11	31.8
Netherlands Oil & Gas Assets													
Diever West	Gas	7.5%	1.3	0.8	0.1	51%	50%	100%	26%	0.3	0.0	5.82	0.2
Total Netherlands Oil & Gas Assets			1.3	0.8	0.1					0.3	0.0	5.8	0.2
Total of Lower Visibility Assets			**290.7**	**181.7**	**17.2**	**n.a.**	**n.a.**	**n.a.**	**n.a.**	**72.1**	**4.2**	**14.9**	**32.0**
Net Asset Value and Target Price										**366.1**	**21.0**		

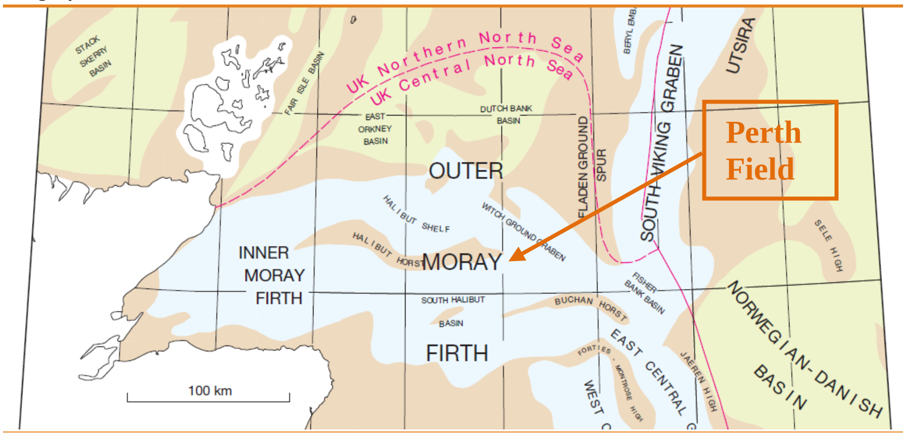
Perth

Overview:

The company holds a 52.03% operated interest in Perth

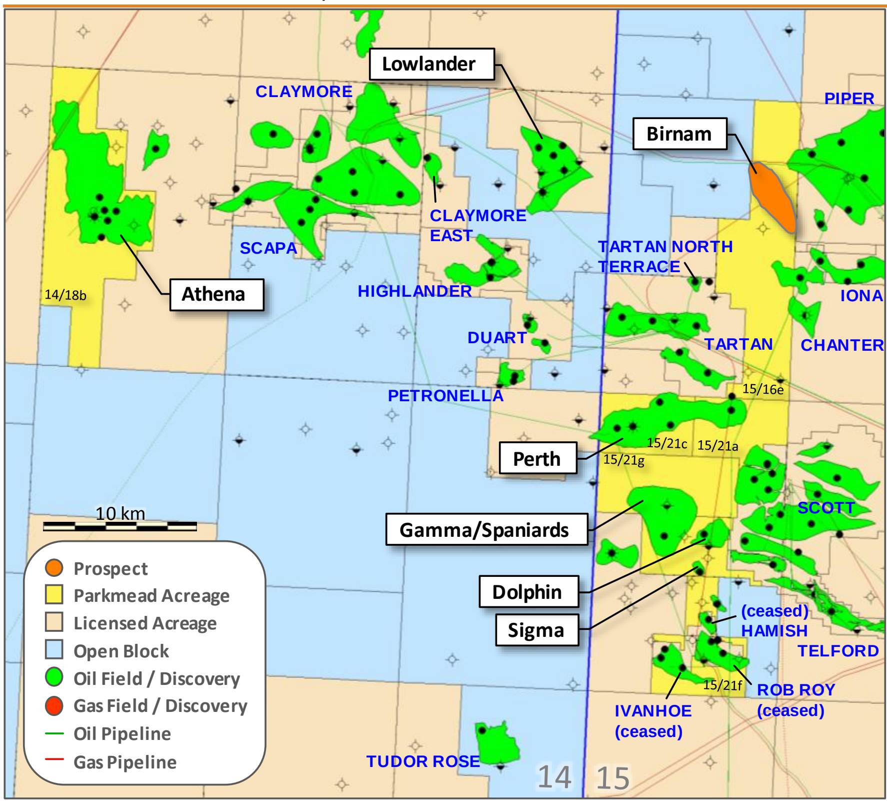
The Perth Field is in licenses P218 (Block 15/21a) and P588 (Block 15/21c) in the Outer Moray Firth of the Central North Sea. The field is located about 135km northeast from the Aberdeenshire coastline in water depths of circa 130-140m.

Geographic Location of Perth Field



Source: British Geological Survey, Charles Stanley Securities

Perth Field Location in Outer Moray Firth



Source: The Parkmead Group

The Field Development Plan for the Perth Field was submitted to DECC in September 2011 and it has been agreed in principle by DECC.

The discovery well (15/21a-7) was drilled in 1983 by Monsanto. Subsequently, four appraisal wells (and a sidetrack well) were drilled into the field by Hess the last of which was drilled in 1997. All five wells were drilled into the field's oil-bearing productive reservoir sands with two of the wells also intersecting the oil water contact, which is located on the southern margin of the field.

The field remained undeveloped due to the high hydrogen sulphide (H_2S) content of the reservoir fluids which was, and continues to be, incompatible with nearby infrastructure.

We have a lot of data to understand this field

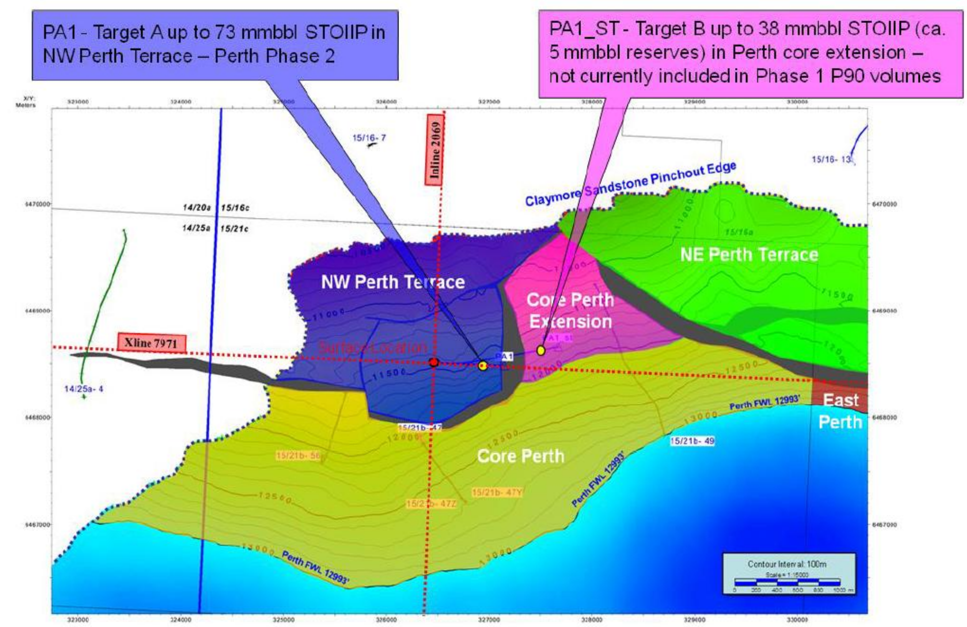
A 10-day extended well test was undertaken on one of the wells (15/21b-56). The well flowed at initial stabilised rates of up to 4,400 bbls/d, with slowly declining bottom hole pressure and production rates at the end of the test.

The field is held by Parkmead (52.03%), Faroe Petroleum (34.62%) and Atlantic Petroleum (13.35%). Parkmead operates the field.

Perth produces light oil with an API density of 30-32°. The oil is sour with high concentrations of hydrogen sulphide (6,500 ppm) and carbon dioxide (35.4% mol% in the produced gas).

The field is divided by faults that create four reservoir compartments: Core Perth, NW Perth Terrace, NE Perth Terrace and East Perth. The Core Perth reservoir extends into an undrilled area called the Core Perth Extension, which is expected to be in pressure communication with Core Perth. Core Perth has been penetrated by four wells. The NE Perth terrace is the only other oil-bearing reservoir compartment currently drilled (well 15/21a-7 was drilled near the eastern edge of NE Perth Terrace and it is not shown in the map below).

Perth Field: Top Claymore Depth Map Illustrating Reservoir Compartments



Source: The Parkmead Group

The next well drilled into the field is anticipated to commence drilling in calendar 1H 2014, subject to rig availability. This well will be a very important well because it will penetrate two undrilled segments of the field: NW Perth Terrace before being sidetracked into Core Perth Extension. The well will be suspended for future re-entry and subsequent completion to produce from the Core Perth Extension. We expect the cost of the next well to amount to $US45.3mn gross ($US23.6mn net to Parkmead). Long-lead items for the well have been ordered and authorisation for expenditure has been agreed by the license holders.

According to a resource assessment prepared by Senergy Oil & Gas, the Phase 1 development offshore Perth has proven and probable reserves of 41.3 mn bbls (gross). We have used this estimate as the basis of our valuation of Phase 1. Senergy has not prepared a best estimate (or proven and probable reserve estimate) for Phase 2. We estimate that the Phase 2 development will produce 28.8 mn bbls of oil (gross) of which 15.5mn bbls is expected from Perth NW Terrace and 13.3mn bbls is expected from Perth NE Terrace. We estimate that East Perth has a recoverable resource potential of circa 2.6mn bbls.

We believe that the two most noteworthy fields that produced from similar sands in the same area as Perth are the Claymore and Scapa fields. In our opinion, the analysis of the performance of these fields suggests that actual ultimate recovery of oil from the Perth Field could materially outperform the expectations built into our target price.

Sour Crude Oil Hub Strategy:

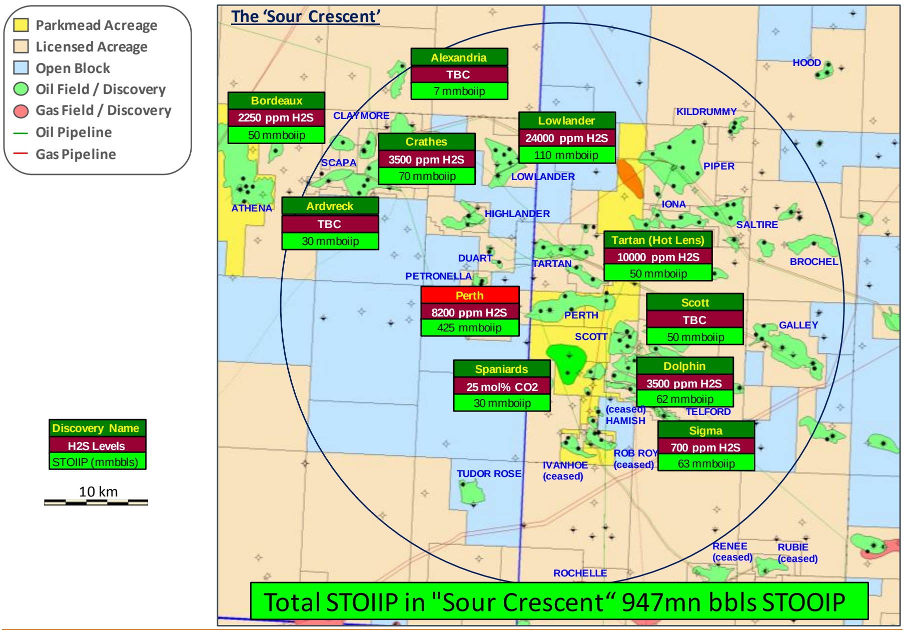
There are no existing facilities that allow for the production of sour crude oil in the area of the Perth Field; however, many sour crude oil fields have been discovered in the area. *As a technical note the Tartan field is able to produce a limited amount of low-H_2S sour crude oil but there is no material spare sour crude oil capacity in the area.*

We estimate that the present value of the bare boat charges in relation to Perth field amount to $388mn, which will be funded via fixed lease payments. We believe that a considerable amount of the FPSO maintenance and running charges are also fixed charges.

Once the fixed costs have been borne, the costs of bringing new fields onstream consist only of drilling, completing and tying in new wells, capital costs to facilitate incremental production on the FPSO and variable operating costs. This greatly increases the economic attractiveness of fields that can be brought onstream using existing facilities.

The Perth Field is located in the central area of a very large fairway of sour oilfields. Parkmead refers to the area within a 30 km radius of the Perth Field as the "Sour Crescent", which is estimated to contain circa 950mn bbls of stranded crude oil in place within discovered but undeveloped fields (85% sour crude oil). If the fields were developed, a proportion of this estimate would be recoverable, depending on the recovery rate. Parkmead believes that oil fields within the 30km radius could be produced through the Central Perth facilities.

Radius Around Perth Oil Field



Sources: The Parkmead Group

The most obvious field that could be brought into a hub development is the Lowlander field which is about 16km to the north west of the Perth Field. Faroe Petroleum (one of the Perth partners) acquired a 50% interest in the field from Talisman in February 2013 and became field operator. The remaining 50% is held by North Sea Ventures. Faroe Petroleum is undertaking a joint (Lowlander-Perth) field development study, which is expected to be completed by calendar year-end 2013.

Once suitable production infrastructure is operational it will allow for the production of nearby stranded sour crude oil.

The Lowlander Field is one of the sourest fields in the Sour Crescent and potentially three times as sour as the Perth Field. This suggests that engineering the facilities as a joint development (at least in so far as H_2S handling capabilities are concerned) would be optimal compared to designing the integration of the Lowlander field as an afterthought.

From a commercial perspective, our understanding is that a joint development concept could involve Parkmead taking an equity stake in the Lowlander field, a unitisation agreement might be reached, the Perth license holders may charge the Lowlander license holders a tariff for the use of the Perth production facilities or a cost sharing arrangement might be reached.

Parkmead currently has a 52.03% operated stake in two nearby stranded crude discoveries, namely Dolphin and Sigma, and a 12.63% non-operated stake in the Spaniards discovery. These three discoveries are located approximately six km to the south of the future Perth FPSO.

The hub strategy was proven successful by Dana Petroleum, its application to sour crude oil should be particularly compelling

Although we have not done so for the purposes of our target price, we believe that there is a strong logic that suggests Perth should be valued at a premium to the value of the oil it will produce because the field has potential to unlock considerable amounts of stranded oil due to its strategic location within the Sour Crescent.

Geology and Reservoir Characterisation:

The Perth field is a combined structural/stratigraphic trap consisting of Upper Jurassic Claymore sandstones onlapping the Tartan ridge to the north. The reservoir thickens and dips to the south.

Acquiring a high quality seismic image of the field is difficult because the top and the base of the reservoir do not give a strong seismic response. Three 3D datasets have been used to interpret the field, one was acquired in 2001 and another in 2005. The third data-set, a high density campaign undertaken by TGSNopec, was acquired in 2011/2012 with final interpretation available in 2012. The seismic data has been tied to the five Perth wells which provides support to volumetric estimates.

The performance of producing wells and water injector wells could be reduced by the existence of faults that cut across what are thought to be communicating reservoir compartments. We believe this risk would represent a worst case scenario from a reservoir risk perspective. According to Senergy, the 3D seismic images (correlated to five wells) suggest that each of the main independent reservoirs is internally unfaulted and that the risk of sealing faults is limited primarily to the immediate proximity of the main faults and to the northern extremities of the field where it thins (onlaps). Analysis of the 10-day extended well test suggests fluid communication is good within the reservoir (no faulting). We are reassured that there is a total absence of affirmative data that suggests this risk has materialised.

The oil is under saturated (with a GOR of circa 825 scf/bbl) and aquifer support is expected to be limited, thus longer-term reservoir pressure must be provided by water injection. The reservoir is suitable for water injection as proven by the injectivity test carried out on the 15/21b-47Y well, which injected water into the aquifer at a rate of up to 5,500 b/d.

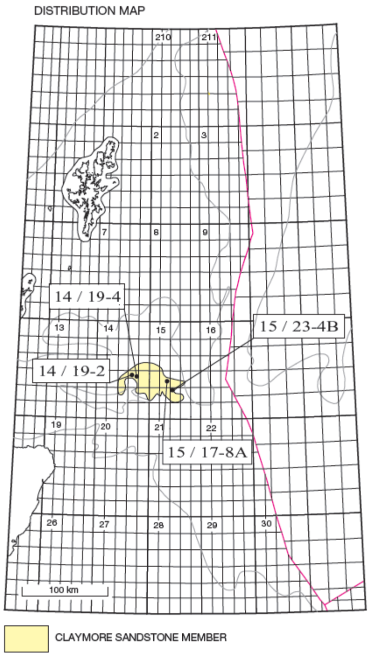
The reservoir is thought to be comprised of deep water turbidite sands sourced from the Halibut Horst (to the west and south). The reservoir is heterogenous with variable net to gross ratios (ranging from 84% to 19% in wells drilled to date). Porosity in the reservoir averages between 12%-13%. Within the net pay, permeability ranges from 10mD to 600mD. 30% of measured permeabilities in the net pay exceed 30mD. In well 15/21b-56 circa 6% of the core plugs have permeabilities in excess of 60mD and this percentage was 11% in well 15/21b-47.

The high permeability volumes (in excess of 60mD) are interpreted to result from diagenetic dissolution by acidic fluids expulsed from the underlying Kimmeridge Clay. The upward movement of these fluids appears to have been constrained by overlying mudstone horizons, creating good permeability beneath these mudstone horizons. This interpretation suggests that the high permeability streaks will be laterally extensive because the mudstones themselves are laterally extensive. The well logs also suggests that high permeability intervals are generally, but imperfectly, laterally extensive. As a base case we believe it is reasonable to assume that there is connectivity between the high permeability sands creating a network of good permeability intervals. This will be important to ensure the effectiveness of the water injection strategy and to obtain a reasonable recovery of original oil in place.

For Phase 1, our economic valuation assumes a recovery rate of 24% (based on the Senergy 2P estimates). We expect the actual recovery rate to vary from this current best estimate, perhaps materially because there is quite a bit of uncertainty, in our opinion, relating to the distribution of higher quality sands within the heterogeneous Claymore reservoir. Recovery estimates for the Claymore and Scapa fields, which also produce from Claymore sands, increased over time to 40% and 56% respectively (according to the operator Talisman Energy's most recent publicly available estimates).

We believe the extended well test eliminates much of the risk of an extreme downside case and that a moderate downside case could, if required, be remedied by operational strategies (more intensive drilling/sidetracks, increased water injection capacity etc). In our opinion, the Claymore Sands, which are not widely distributed in the North Sea, create forecasting challenges for expected ultimate recoveries and production profiles due to the variability and uncertainty of the sand qualities within that sand group. However, on balance we believe that the Perth Field's reservoir is more likely to over deliver than not relative to the expectations built into our target price.

Claymore Sands Distribution Map



Source: British Geological Survey

The senior management team at Parkmead is experienced in producing from the Claymore sands as Dana Petroleum acquired a 7.25% interest in the Claymore Field from Centrica in 1998.

Development and Production:

The Perth Field is a commercially attractive project on a stand-alone basis and we have valued it as such; however, it is possible that the field is developed jointly with Lowlander, which would further improve the economics of the field by sharing costs.

We have modelled the Perth field to produce first oil in calendar 1H 2016. We have made allowances for delays for commercial reasons relating to a joint Perth/Lowlander development.

We anticipate that the forthcoming appraisal/development well will be drilled in calendar 1H 2014, subject to rig availability.

It is anticipated that the field will be produced with a dedicated floating production storage and offloading (FPSO) vessel with a swivel turret. Once on production, crude oil will flow from a single subsea drill centre to the FPSO via a primary 8 inch flowline. A secondary 8 inch production flowline will also be installed in addition to an 8 inch water injection line, a 4 inch gas lift flowline and a control umbilical. Gas production will be utilised to power processes on the FPSO and for gas lift, any excess gas will be flared. The sour gas will be treated in an amine unit to remove the hydrogen sulphide before the gas is used for gas lift.

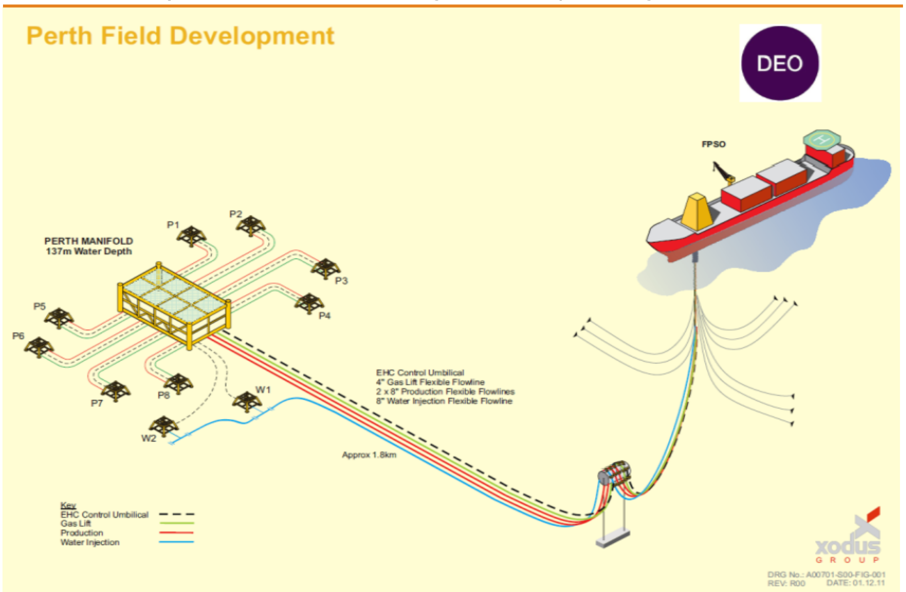
Phase 1 will produce oil from Core Perth and Core Perth Extension. Phase 1 will consist of four highly deviated wells and two water injection wells that will be drilled to penetrate the reservoir near the interpreted oil water contact (based on pressure data) at 12,993 ft tvdss.

We believe that the development concept for Phase 2 will depend on the results of the Phase 1 development. We anticipate that ultimately, Phase 2 will produce oil from NW Perth Terrace and NE Perth Terrace. We expect each of the terraces will be produced via two producing wells and one injector well (this can change if long-reach horizontal wells are drilled). We anticipate first oil from Phase 2 to start flowing two years after first oil from Phase 1.

Instead of drilling two producer wells in each of the Terraces, Parkmead is considering the option of drilling a producer/injector pair in East Perth. For the time being we believe that the combined resource potential of NW Perth Terrace and NE Perth Terrace is almost ten times greater than that of East Perth and therefore we expect that capital will be allocated in priority to the terraces in Phase 2. East Perth can always be developed at a later stage once high recovery rates are secured for the terraces. We have assumed no value for East Perth in our Target Price. Essentially we believe that most of the upside for Perth resides in the NW Perth Terrace and NE Perth Terrace.

We believe the actual development plan for Phase 2 is likely to evolve depending on the results of the Phase 1 development

Perth Field Development Schematic (Well Configuration Likely to Change)



The Parkmead Group

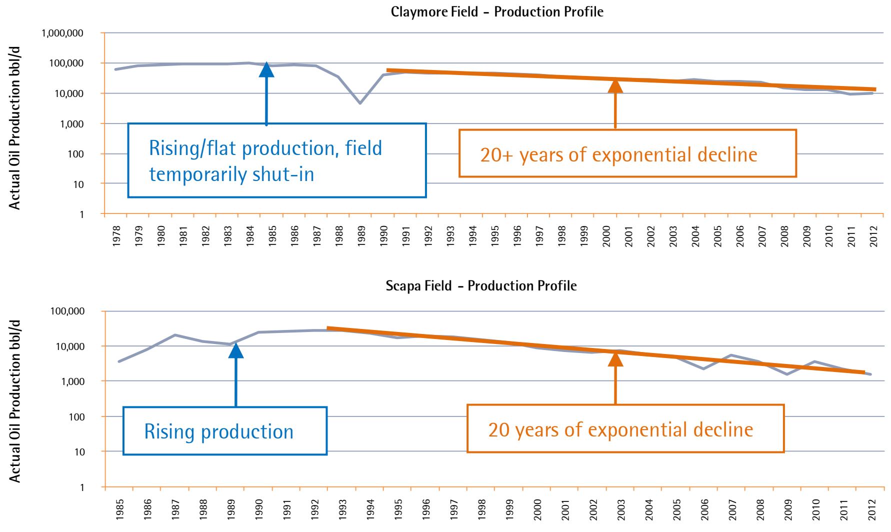
Production Profiles / Upside

Our base case valuation for Phase 1 is premised on the proven and probable production estimates established by Senergy. However, our best estimate is that production profiles will be flatter and higher than Senergy's estimates in the first six years of production and lower in the later years, which would add materially to the NPV10 of Perth, without materially changing the expected ultimate recovery from the field.

We believe that the Claymore Field and the Scapa Field have similarly heterogeneous sands deposited in the same location as the Perth reservoir sands during a similar geological interval: The Claymore Field consists of Claymore Sands of Late Jurassic (Kimmeridgian) origin and the Scapa Field consists of slightly younger Scapa Sands of Early Cretaceous (Valhall) origin.

We have assessed the decline profiles of the Claymore and Scapa fields, which provides a perspective on the challenge of forecasting decline curves for reservoirs that produce from the relevant sands: Both fields experienced very considerable and prolonged *increases* in production after first oil, as good reservoir performance encouraged more investments in the fields. After the initial period of rising production at the Claymore and Scapa fields, we conclude that the decline rates were exponential (flat decline rates) of 8% and 12% respectively.

Claymore and Scapa Fields – Historical Production Profiles



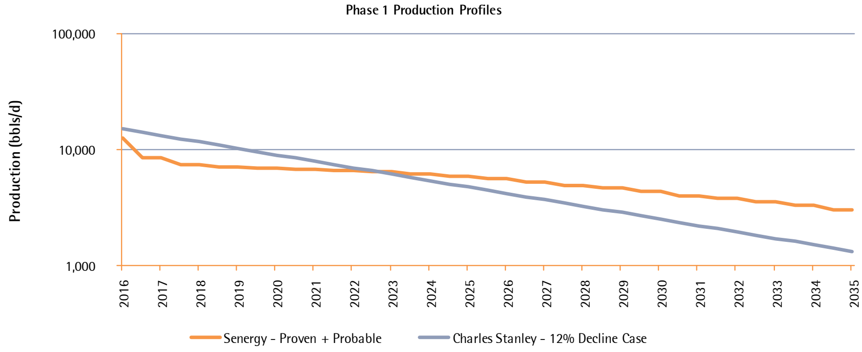
Sources: Department of Energy and Climate Change, Charles Stanley

We have modelled a scenario labelled "12% Decline Rate", which represents how we estimate the production profile to evolve. In this scenario, we estimate initial stabilised production from Phase 1 will be circa 15,800 bbls/d (averaging circa 15,000 bbs/d in the first six months of production, allowing for the cited decline rate). We have based this estimate on the production rates from the extended well test (modified downward to reflect that downhole pressure had not stabilised) and the fact that the producing wells will be highly deviated. Our 12% Decline Rate case suggests 41.0mn bbls will be produced over a 20 year period, which compares to the 41.3 mn bbl proven and probable estimate established by Senergy, also over 20 years.

We expect that it will take several months of (high) production to stabilise production rates with a constant flowing bottom-hole pressure and boundary-dominated flow, which is relevant for long-term decline curve analysis. Our analysis is based on stabilised flow rates, which we believe are most relevant from a shareholder's perspective because almost all of the value is extracted from most oil fields under stabilised flow. A short period of non-boundary dominated flow or transient flow can only add marginal value to our valuation.

The chart below shows our upside production profile compared to Senergy's proven and probable production profile (used in our base case valuation).

Phase 1 – Proven and Probable Production Compared to Upside Production



Source : Senergy, Charles Stanley Securities

Our 12% Decline Rate case increases the value of Perth Phase 1 by $US55mn, a 37% uplift in value.

The 12% Decline Rate case does not represent an upside case because it assumes only that the expected oil production (according to the 2P case) is front-end loaded, which has an NPV effect. Our analysis does not consider the possibility of higher recovery rates or an increase to the estimate of original oil in place, which we believe would be the key drivers of a real upside case.

Cost Estimates

We estimate that Phase 1 capital costs will amount to $US477mn (gross, not including the cost of the FPSO) of which 64% relates to drilling with the remainder relating to subsea facilities inclusive of installation costs. We assume that the FPSO will be leased with no upfront costs.

We expect the total gross capital costs of Phase 2 will amount to $US379mn, inclusive of FPSO upgrades ($US32mn).

We have undertaken a detailed review of the costs per well and expect that actual drilling costs will amount to circa $US49.6mn/well, which compares to Senergy's per-well estimate for Perth of circa $US44mn. We believe that if crude oil prices remain high or increase, it is likely that the costs per well will increase in the years ahead. However, we expect that such dynamics would on balance favour Parkmead due to the impact of higher commodity prices.

Including both phases, we estimate capital costs will amount to $US12.93/bbl.

We expect initial operating costs to be high (circa $US36/bbl for Phase 1) of which circa 62% will relate to bareboat lease costs for the FPSO, which excludes production and maintenance costs. We expect that high bareboat lease costs will reduce after the vessel has been substantially paid off (after circa 7 years), after which time we expect the company will exercise an option to acquire the FPSO. Over the life of the field, we estimate that the present value of the leasing costs amount to circa $US338mn (gross). We have modelled an initial cost rate for the FPSO of $US224,000/day.

Other operating costs amount to 36.7% of total operating costs. They include duty holder operating costs (19.7%, or $US69k/d), standby vessel costs (3.7%), CO_2 emissions charges (3.4% or $US0.94/bbl), insurance costs (2.8%), transportation costs (2.7% or $US0.75/bbl), diesel (2.1%), FPSO maintenance costs (1.8%) and subsea inspection costs (0.5%).

We estimate that operating costs for the combined Phase 1 and Phase 2 are only circa 18% greater than for Phase 1 alone due to the high fixed nature of the costs due to the FPSO leasing and running costs. On a per barrel of oil produced basis we estimate the operating costs of the combined phases is circa 32% lower than for Phase 1 alone.

From a tax perspective, the field benefits from a £150mn small field allowance.

Economic Analysis

We have assumed a Brent crude oil price of $US100/bbl inflated at 2.0% p.a.

We have assumed that the crude oil from Perth is sold for $US2/bbl less than the Brent benchmark price, which discount is increased by 2.0% p.a.

Perth is economically attractive on a stand-alone basis, but investors might also consider the bigger picture of the hub strategy and the potential value of owning the only facilities able to produce sour crude oil in an area with an abundance of sour crude oil – no related strategic value is incorporated into our target price

We estimate that Phase 1 (Core Perth and Core Perth Extension) has a NPV10 net to Parkmead of $US149.1mn and that Phase 2 (Perth NW Terrace and Perth NE Terrace) has a value of $US175.0mn (net). The Perth Phase 2 value consists of $US94.2mn for the Perth NW Terrace and $US80.8mn for Perth NE Terrace.

We estimate that the value per barrel is $US6.93/bbl for Phase 1, $US11.63/bbl for Perth NW Terrace and $US11.71/bbl for Perth NE Terrace.

The cited per-barrel values provide considerable support to Parkmead's Hub Strategy. The terraces, which are less economic than Perth Core on a stand-alone basis, actually have materially better per barrel valuations relative to Perth Core (+68%) due to the sharing of fixed costs.

For reference, Senergy's estimate of the value of Phase 1 amounts to $US158mn (net to Parkmead; converting their £100.0mn estimate at $US1.58/GBP). Senergy based this valuation on a $US90/bbl crude oil price (escalated at 2% p.a.). Despite our higher crude oil price assumption, our valuation is lower than that of Senergy because i) our FPSO day rate charges are 20% higher than those assumed by Senergy to reflect current market rates ii) current drilling costs are 13% higher than the assumptions made by Senergy and iii) we have assumed that first oil will occur 1.5 years later (January 2016 vs July 2014).

Based on our estimates, we believe that the NPV10 breakeven Brent crude oil prices for Phase 1 and Phase 2 are $US65/bbl and $US55/bbl respectively. Although operating costs would fall substantially if crude oil prices fell to those levels.

Athena

Overview:

The company holds a 10% working interest in Athena

Parkmead's acquisition of Lochard Energy ("Lochard") was sanctioned by a Court Hearing on 25 July 2013. Lochard's core asset was a 10% interest in the Ithaca Energy ("Ithaca") operated Athena field, whose interest is now held by Parkmead. The field came onstream in May 2012.

Athena FPSO, BW Athena – Starboard and Deck

Source : Ithaca Energy

Ithaca holds a 22.5% interest in Athena, the remaining interests are held by Dyas (17.5%), EWE (20%), Trap Oil (15%) and Spike Exploration (15%).

The field is located in the Outer Moray Firth about 135km northeast of the Aberdeenshire coastline in water depths of circa 130-140m. The field is located about 35km to the north west of the Perth Field.

Although production from the Athena field has been lower than initial expectations, the principal causes of the production discrepancy are thought to be mechanical or related to reservoir damage from drilling or completing the wells, as distinct from natural reservoir challenges. We believe that the reservoir itself is performing well to the extent that production rates of operating wells have been stable with minimal declines. Water breakthrough has been minimal (relative to initial expectations) and occurred later than expected.

Athena is generating material cash flow for Parkmead

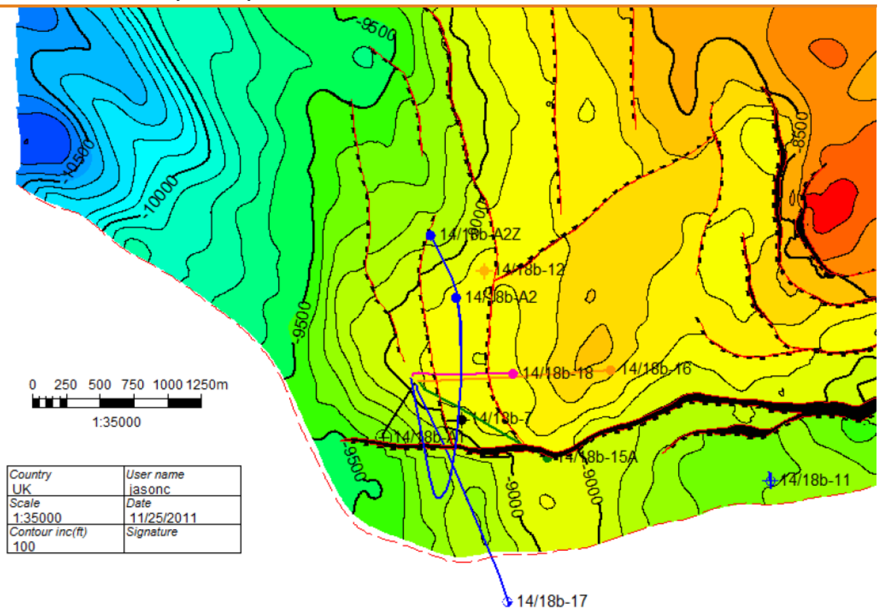
We believe that drilling at least one additional well into the field is possible because it would add incremental production and also extend the life of the field. No decision to drill more wells has been made at this stage. We estimate that from 1 July 2013 to 31 December 2014, the field will generate cash (net to Parkmead) amounting to circa $US17mn.

In March 2012, Trap Oil agreed to acquire a 15% interest in the Athena field from Dyas for a consideration of £34.5m, the deal completed on 21 December 2012. We do not believe that this is a good valuation benchmark because the field's production levels are significantly lower than anticipated.

The field was expected to come onstream at 22,000 bbls/d (gross). Ithaca Energy ("Ithaca") reported on 7 June 2012 that initial production of 22,000 bbls/d was achieved. On 25 June 2012, Ithaca reported that production had decreased to 12,000 bbls/d (gross).

Four productive wells (A2z, A3, A4 and A5) have been tied-in to the field's FPSO. Well locations are shown below (A1 is a water injection well).

Athena Reservoir (Scapa A Depth Structure) and Well Locations



Well label key
A1 = I1 = 14/18b-A1 (black) – visible to the west of the drill centre
A2z = P4 = 14/18b-A2Z (blue) – horizontal well (in reservoir between two dots)
A3 = P2 =14/18b-16 (orange)
A4 = P3 = 14/18b-18 (pink)
A5 = P1 = 14/18b-15A (green)

Source : Sproule International, Charles Stanley Securities

The A5/P1 well has produced below expectations since it came onstream. Lochard's belief was that the problem at A5 was caused by a physical blockage in the downhole completion. Remedial measures inclusive of a hydraulic intervention increased production moderately. Future investments to increase the flow rate have not been finalised (in part because the definite nature of the problem has not been established). The A3/P2 well has encountered mechanical problems and the A2z/P4 wells first and second ESPs have failed. Remedial action for the operational challenges has yet to be finalised.

Due to the mentioned mechanical failures, production has fallen to circa 7,500 bbls/d according to Trap Oil (announced 16 September 2013).

Currently, 80% of production is from wells that are operating on their first electrical submersible pump (with a second pump in reserve). Currently, the A4/P3 well is by far the most important well (circa 70% of production) and mechanical and reservoir performance suggest we can expect steady production from this well.

The company also acquired three operated promote licenses through the acquisition of Lochard which we do not believe are currently sufficiently developed to be included in our valuation.

Pump Lifespan:

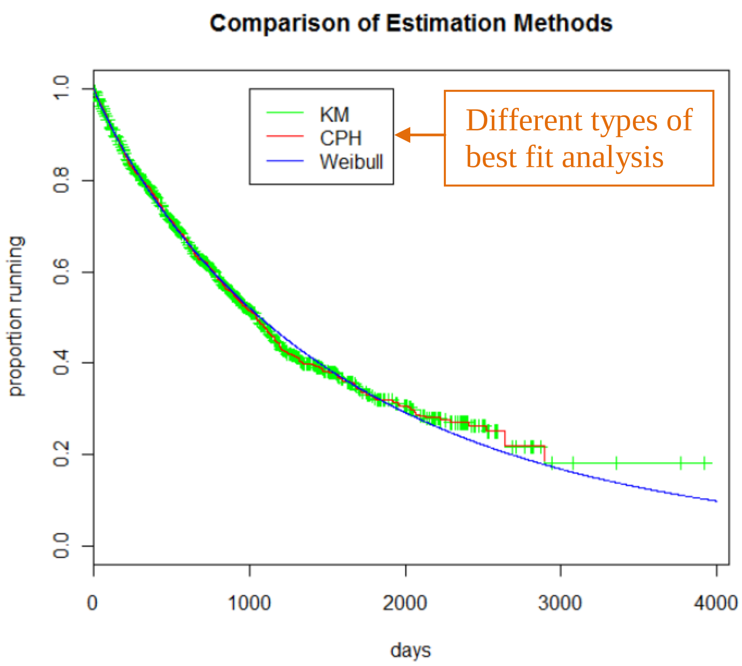
Each of the four producing wells has two electrical submersible pumps ("ESPs"), the second of which is a back-up pump.

The most important well, A4/P3, is operating on its first ESP and the A3/P2 well is also operating on its first ESP. The ESPs at the A2z/P4 well are not performing and only one of the ESPs at A5/P1 well is working.

Replacing ESPs is possible, but because the pumps are installed at the end of the production tubing a rig will be required to replace them.

Texas A&M University undertook a statistical study on the survival rates of ESPs based on data related to Chevron-operated fields globally. According to this study, the mean estimate of the run life of an ESP installation is circa 2.9 years, with tail risk favouring significantly longer run lives *(source: Electrical Submersible Pump Survival Analysis, Michelle Pflueger et al, Texas A&M University, March 2011).*

Survival Rates of Electrical Submersible Pumps



Source : Texas A&M University

It is assumed that the field is abandoned in 1H 2016 after ESP failures and natural declines render the field uneconomic. A wider investment strategy involving the drilling of more wells could create a virtuous circle by extending the economic life of the field.

The valuation in our target price assumes that no material investments are made to repair ESPs or to drill additional wells.

Royalty Arrangement:

Lochard partly funded its share of development costs for the Athena field with $US14mn advanced by Gemini Oil & Gas Fund II ("Gemini"). In addition to repaying the $US14mn provided by the fund, an additional $US14mn must be repaid. Gemini has a royalty claim on the company's share of revenue from the Athena Field. Gemini's royalty was 50% of the company's revenue from the field until the first $US14mn was repaid (in calendar 1H 2013), after which the royalty was reduced to 20% of the company's revenue. The 20% rate will be effective until the second $US14mn is paid to Gemini (we estimate this will occur in mid 2015), after which the royalty will be reduced to 5% for an indefinite period.

Geology and Reservoir Characterisation:

The field is located on a structural high between the Jura and West Scapa depositional basins (developed during rifting). The reservoir sands are Scapa sandstones of the Lower Valhall Formation (Lower Cretaceous). The turbiditic sands are thought to be sourced from the Halibut Horst to the south.

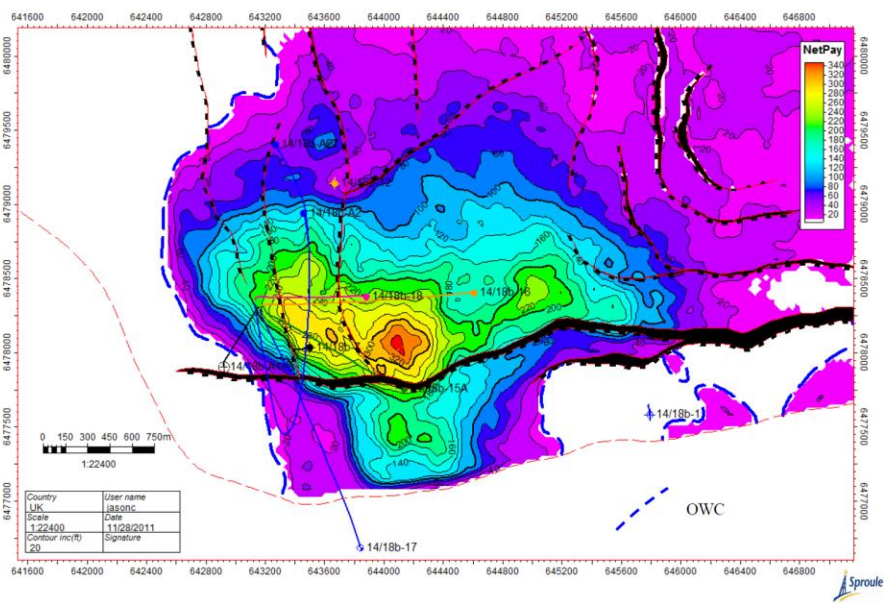
The reservoir sands pinch out into calcareous marls (stratigraphic trap) to the north. To the south, the reservoir either onlaps or is truncated against conglomerates derived from the Halibut Shelf edge. No conglomerate has been encountered in the main field although the location of the transition into conglomerates is unknown. Calcareous cementation is interpreted to increase towards the north of the reservoir, but it is not thought to be significant within the main reservoir. Within the core reservoir the sands are generally well sorted and fine to medium grained.

The field was discovered by well 14/18b-7z in 1990 (drilled by Texaco) and encountered an 82m oil column with 54m of net pay (based on a 7% porosity cut-off). A net pay map (derived by well and 3D seismic data) is provided below. The average porosity is 13%.

The average water saturation is estimated to be circa 30% and the oil water contact is at a depth of circa 2,827m.

We believe a potential target for a future well might be directly to the south of the main fault

Athena Reservoir (Scapa A Depth Structure) and Well Locations



Source : Sproule International

Oil from the field has an API density of 24-28° API and the oil is expected to therefore trade at a modest discount to lighter blends such as Brent. The oil has a low gas/oil ratio of less than 200scf/bbl and limited aquifer support means that water injection is required.

One of the reasons that we have confidence in the reservoir performance of the Athena field is that the water injection well penetrated 325 ft (99m) of high quality reservoir with excellent porosity allowing for good fluid mobility. The designed water injection rate is 22,000 bbls/d, although we believe that more water injection could be possible due to the better than expected reservoir quality penetrated by the injection well.

We believe that the reservoir section below the major fault in the net pay map is a natural target for a future productive well.

Sproule Reserves Estimate:

Sproule International Limited ("Sproule") prepared a reserves report for the field with an effective date of 30 June 2012.

According to this report, the Athena field has 17.9mn bbls of proven developed producing oil reserves (inclusive of prior production amounting to 0.3mn bbls). The report estimates that the Athena Field's proven and probable reserves amount to 26.1mn bbls (inclusive of prior production), which requires the investment in at least one more well and the effective operation of all existing wells.

Due to operational challenges with the producer wells, we do not believe that the Sproule estimates provide an accurate basis for valuing the Athena asset. However, we do believe that the Sproule reserve estimates are relevant for assessing how the field could produce if the operating conditions were optimal.

In its report, Sproule suggests that "skin damage may have developed during the completion operations, which could be the reason for current productivities being lower than those measured on initial tests."

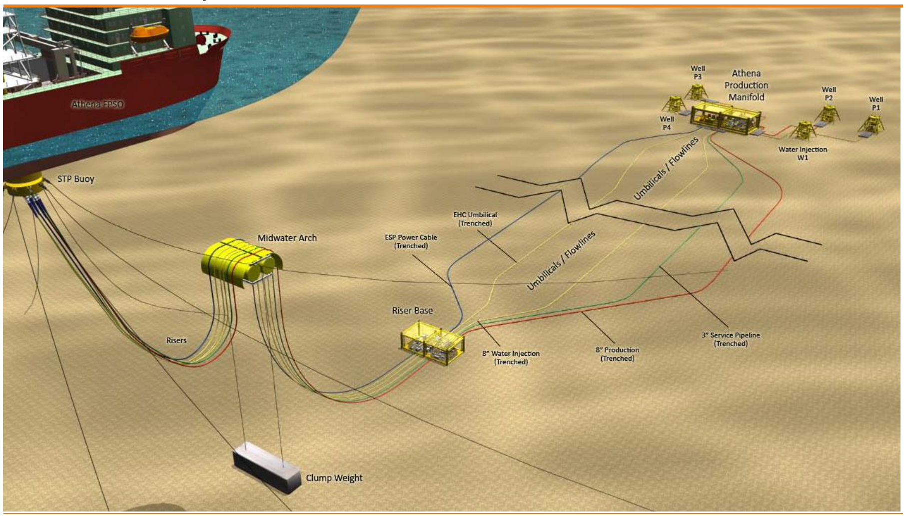
Sproule's proven and probable estimate of original oil in place is 87 mn bbls, which does not include reserves to the south of the main fault (where an additional well could be drilled). Sproule's proven and probable reserve estimate implies a 30% recovery rate. For comparison, our valuation and target price is premised on a recovery rate of only 7%, due to operational and reservoir constraints.

Development and Production:

Four oil producers were drilled, completed and tied in for production. A single water injector well near the oil-water contact (9,275 feet tvdss) maintains reservoir pressure.

The field is produced via a dedicated FPSO, which was renamed BW Athena. A development schematic is provided below.

Athena Field – Development Schematic



Source : Ithaca Energy

Two well slots remain available for additional wells.

Production Profiles:

Sproule applied a 20% p.a. exponential decline rate to its Proven Producing Developed production profile. Based purely on an analytical analysis, we believe this is too conservative. We have assumed that the decline rate flattens modestly from that rate of decline (by applying an Arp's coefficient of 0.20) to circa 18% in 2015, which we believe is still too conservative and really only of marginal significance relative to the Sproule estimate.

Under the fifth production well scenario, we assume that the dual ESP at the A2z/P4 well is replaced. We estimate a fifth well would add 8.8mn bbls (gross) of production to our estimate, of which 3.5mn bbls would come from extending the productive lives of currently producing wells.

Cost Estimates:

Our detailed cost analysis was compared against the actual operating costs for 2H 2013 (as disclosed by Lochard) amounting to $US51mn (gross) so that we have a high degree of confidence in our operating cost estimate.

Public disclosure gives us a high degree of confidence in our operating cost estimates

The cost rate for BW Athena is circa $US151k/day, which equates to 54.3% of our operating cost estimate. Other costs are made up of transport and marketing costs reflecting that the oil is sold from the Ithaca-operated onshore Nigg Terminal (15.3% or $US4/bbl), duty holder opex of 13.6% (or circa $US38k/day), operator related costs including the costs of engineering, G&G, design and planning in addition to a "catch all" amount so that our estimates fit with historical costs (6.6%), standby vessel costs (4.7%), diesel (2.7%), subsea inspection and maintenance (0.6%), and insurance and administration costs (2.2%).

We estimate that operating costs amount to circa $US32.94/bbl in calendar 2013.

In our valuation model we assume that the cost of drilling future production wells amounts to $US41mn each (gross). We base our cost estimate on the day rate for Transocean SEDCO 704 type semi-submersible rigs (circa $US373k/day), which rig was used to drill the field's most recent development wells. We assume that subsea, tie-in and FPSO upgrade costs amount to $US15.0mn per well (gross).

We assume that the cost of replacing ESPs is $US20mn for the Athena field. We estimate that the cost of the actual dual ESPs would amount to circa $US1.6mn and that the remainder of the costs would consist of rig-time (15 days of repairs/tripping per ESP + 5 days of mobilisation/deomobilisation) and lesser service costs.

Economic Analysis and Valuation:

Based on our blow-down scenario where no material investments are made in the field, we estimate that the Athena field has a value of $US18.2mn net to Parkmead (or 1.1p/share). This is the only value for the Athena field incorporated into our target price.

The Gemini royalty and a number of tax losses that are material and specific to Lochard affect any read-across of our valuation to other interest holders in the Athena field.

We are reasonably confident in our blow-down valuation because we were able to cross-check our operating cost estimates against historical costs for calendar 1H 2013 ($US5.1mn net to Lochard/Parkmead). We have also based our production profile on actual/historical data and have applied a conservative decline rate. 80% of production is coming from wells with 2 working ESPs.

Over and above our valuation, it is important to appreciate the strategic benefit of holding a producing asset which is providing cash flow that the company can deploy elsewhere.

Our target price ascribes no value to the possibility that more wells could be drilled in to the reservoir

We believe that the incremental value gain of drilling a 5th well would amount to circa $US13.3mn (or 0.8 p/share). If a fifth well is a success, further investment would be likely.

We have assumed a Brent crude oil price of $US100/bbl escalated at 2% p.a. and a $US7.75/bbl discount to Brent.

We estimate that the NPV10 breakeven price for the Athena field is circa $US50/bbl.

Southern North Sea Gas

Overview:

The company holds 15%-20% working interests in the Southern North Sea

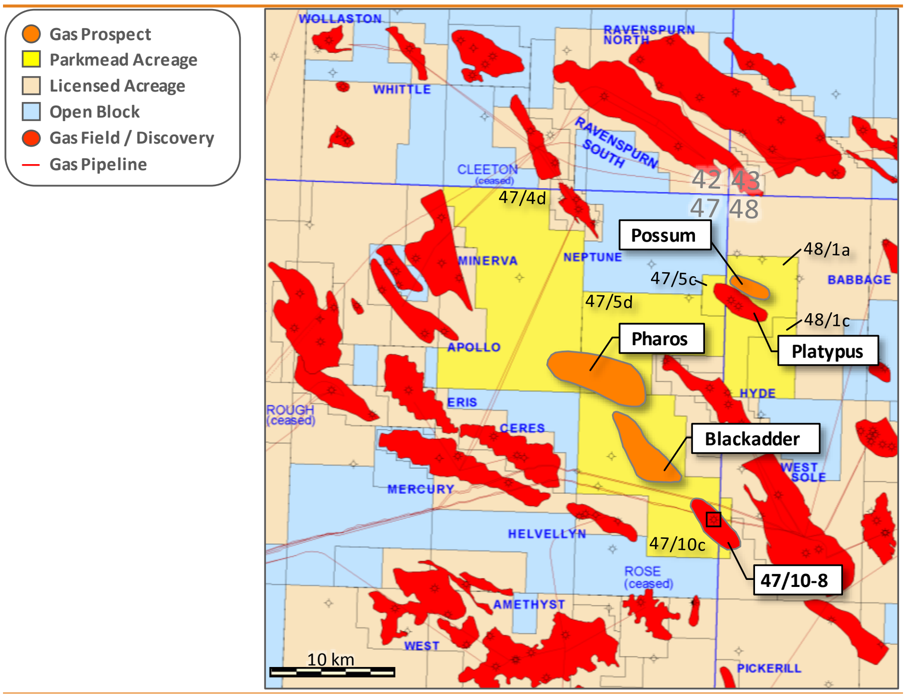
In our opinion, Parkmead has four key assets in the Southern North Sea, which consist of a gas discovery, Platypus, and three gas prospects Pharos, Possum and Blackadder. Dana Petroleum is the operator of all four of the key assets.

The exploration well for the Pharos prospect commenced drilling on 1 October 2013 and results are expected in mid-early November.

Platypus and Possum are held by Dana Petroleum (59%), Parkmead (15%), Cal Energy (15%) and First Oil (11%). Pharos is held by Dana Petroleum (35%), Parkmead (20%), Hanza (15%), MPX (15%) and Dyas (15%). The Blackadder prospect is held by Dana (35%), Dyas (30%), Parkmead (20%) and Hanza (15%).

The locations of Platypus, Possum, Pharos and Blackadder are shown in the map below.

Parkmead's Southern North Sea Assets



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Platypus:

Platypus is in water depths of 43m allowing for wells to be drilled with a jack-up rig. The discovery well, 48/1a-5 (operated by Dana Petroleum), was drilled to a measured depth of 3,367m. On 15 April 2010, Dana Petroleum announced that the well successfully encountered 66m of high quality gas bearing Lower Leman reservoir. The well was suspended for re-entry as a producer. At the time of the discovery, Dana Petroleum indicated that its initial analysis was in-line with pre-drill estimates and consistent with a gas in place estimate of 130 bcf, a proportion of which would be recoverable depending on the recovery rate.

The Platypus appraisal well, well 48/1a-6, was spudded on 11 April 2012. The well reached total measured depth of 4,320m on 19 June 2012 after drilling a 944m horizontal section within the reservoir. A drill stem test was completed which recorded a flow rate of 27mmscf/d per day (equivalent to 4,500 boe/d) on a 96/64" choke. This result increased the gas in place estimate by 13% to 147 bcf.

Ensco 80 jack-up rig performing an extended well test on Platypus

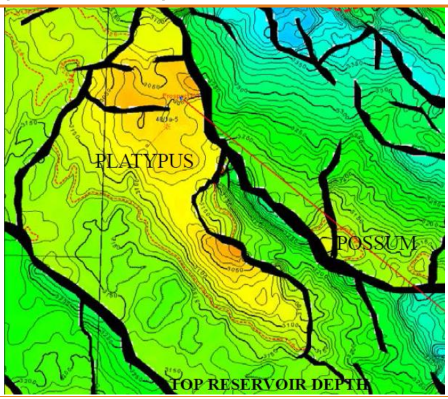
Source: Dana Petroleum

Parkmead estimates that the Platypus gas discovery contains best estimate recoverable reserves of 103bcf. Based on our economic evaluation we believe that it is a commercially viable project as a standalone project.

Possum:

Possum and Platypus have the same reservoir and trap type (fault/dip closure) as shown below:

Platypus and Possum – Top of Reservoir Depth



Parkmead

Platypus and Possum are expected to be developed conjointly. This means that the first well drilled into Possum will both confirm the existence of the field and produce the gas within it.

Parkmead estimates that the Possum prospect has a circa 50% chance of success, with the two primary geological risks relating to the presence of an effective trap and the quality of the reservoir.

According to the company, the best estimate of recoverable gas is 43bcf. The best estimate is based on the volumetric analysis that assumes that a fault cutting across the reservoir is not a sealing fault, or in other terms this assumes that the lateral extent of the field is limited to a dip-closed area. If the relevant fault is a sealing fault then the best estimate of recoverable gas would be circa two times greater than the 43bcf estimate. Assuming that the reservoir is commercial there is a circa one third chance that the fault is sealing. Therefore, we believe that coupled with the other geological risks, the larger resource estimate is too risky to be included in our target price.

Pharos:

On 1 October 2013, Parkmead announced that the Pharos exploration well had commenced drilling. We expect that it will take circa 40 days to reach target depth, after which, if successful, the well will be completed over 20 days. We expect that the well results will be announced shortly after the well reaches target depth in early-mid November.

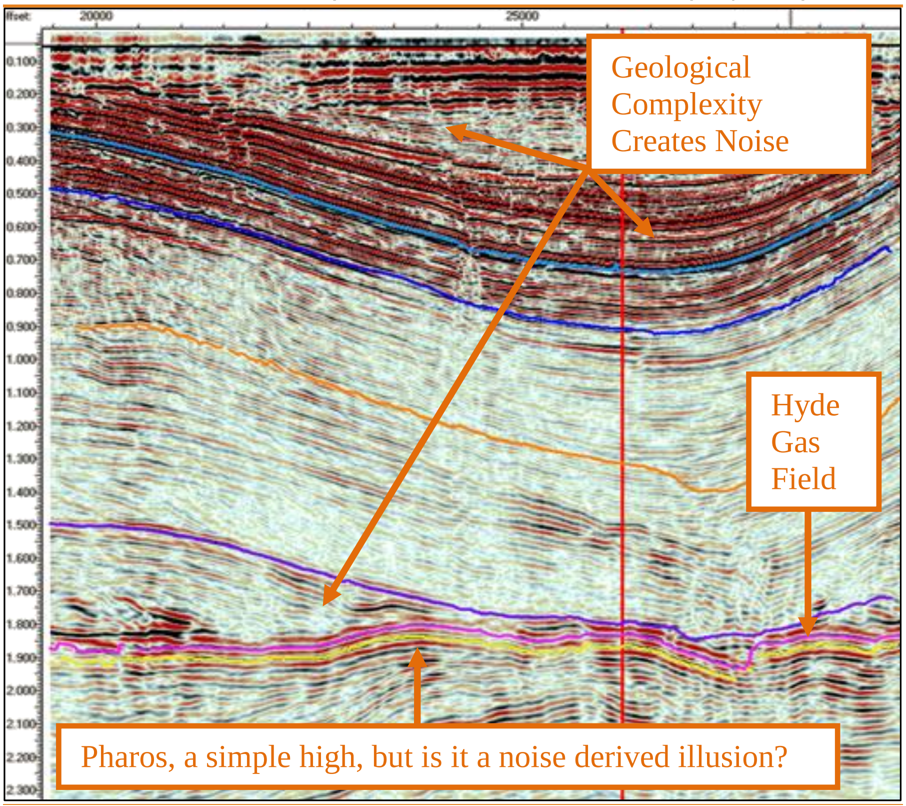
The rig that is currently drilling the Pharos exploration prospect, Noble Lynda Bossler, is shown below

In an upside scenario, Parkmead estimates that the Pharos field may contain up to 500 bcf of gas originally in place. The company's best estimate of gas initially in place is 305 bcf, of which 60% should be recoverable (182 bcf). The large range of estimates of gas in place reflects the fact that some uncertainty remains in the seismically defined volumetrics and reservoir rock properties.

From an exploration perspective, the principal complication related to the Pharos prospect is that it is overlain by relatively complex geology. These complexities distort the seismic image and therefore the top of the reservoir structure and we believe this introduces the principle source of risk for this prospect. Another geological risk is reservoir quality risk, which is in our opinion limited because i) a large number of wells have been drilled nearby which have encountered satisfactory sands and ii) the threshold of commerciality from a reservoir quality perspective will be quite low because the field would be produced by horizontal wells.

The seismic complexity above the Pharos prospect is shown in the seismic cross section below, which also shows the Pharos trapping structure, a seismic high.

Seismic Cross Section of Pharos Prospect (left scale is seismic travel time, a proxy for depth)

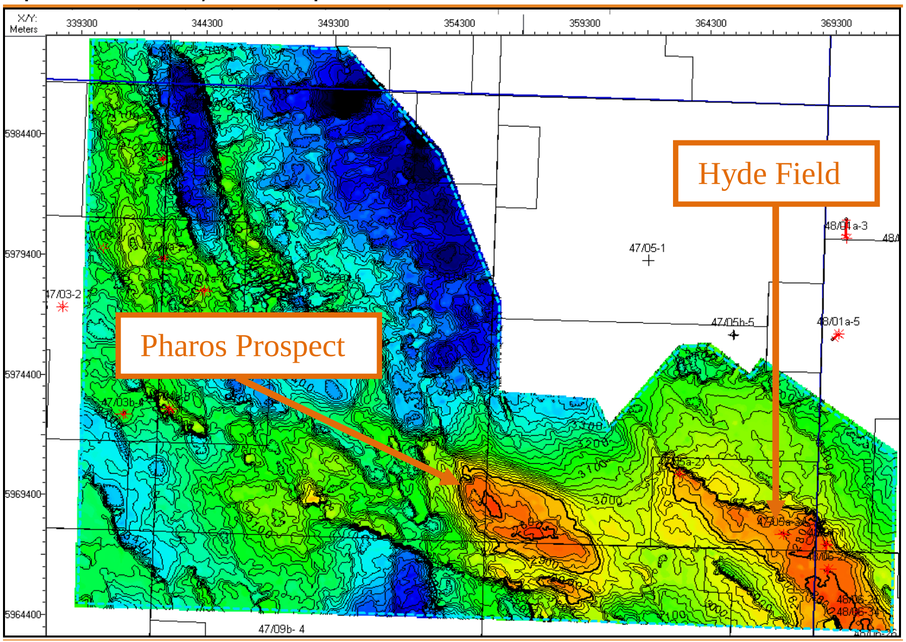


Parkmead, Charles Stanley

Pharos is a simple four way dip closure, which forms a very robust trapping structure in principal as seen in the image below. In the absence of the complex overburden, we could be absolutely certain of the high quality of the trapping structure for Pharos (a precondition for exploration success).

We like the Pharos prospect because we believe that the anticline to the right (the structure of the Pharos prospect) is unlikely to have been created by seismic noise

Top Leman, Seismically Derived Depth Structure (contour lines in meters)



Parkmead, Charles Stanley

Due to the geological complexity above the target we are reluctant to ascribe the credibility of the seismic interpretation relating to the existence of structural closure with a chance of success greater than 50%. We believe that this is conservative given i) the high degree of well control (number of wells) in the area and ii) the relief of the structure as shown in the image above (circa 183m), which would necessitate a remarkable overburden complexity to create.

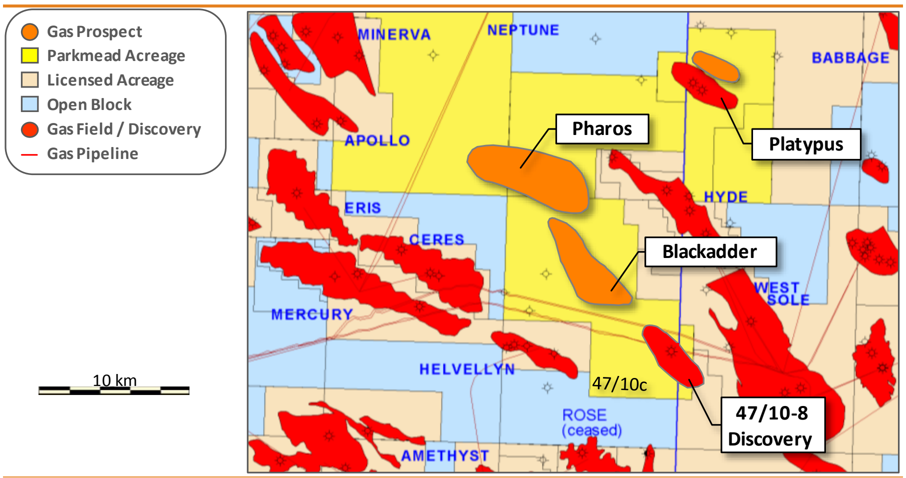
Due to the nearby well control and the low-threshold for reservoir quality given that the field would be developed with horizontal wells, we believe that there is 66.6% chance of success that the reservoir quality will be satisfactory.

Combined, we estimate that the chance of geological success is circa one in three.

Blackadder:

The location of the Blackadder prospect is shown below:

Blackadder Location



Parkmead

If Pharos is a successful discovery, then the Blackadder prospect would be a near-term follow-on prospect, with drilling anticipated in calendar 2014.

The company estimates that the Blackadder prospect may contain up to 430 bcf of gas originally in place. The company's best estimate of gas originally in place is 311bcf, of which 60% is expected to be recoverable (186 bcf).

If Pharos is developed, it is possible the 47/10-8 discovery is also developed, which is estimated to contain 86 bcf of gas in place.

Geology, Reservoir Characterisation and Background:

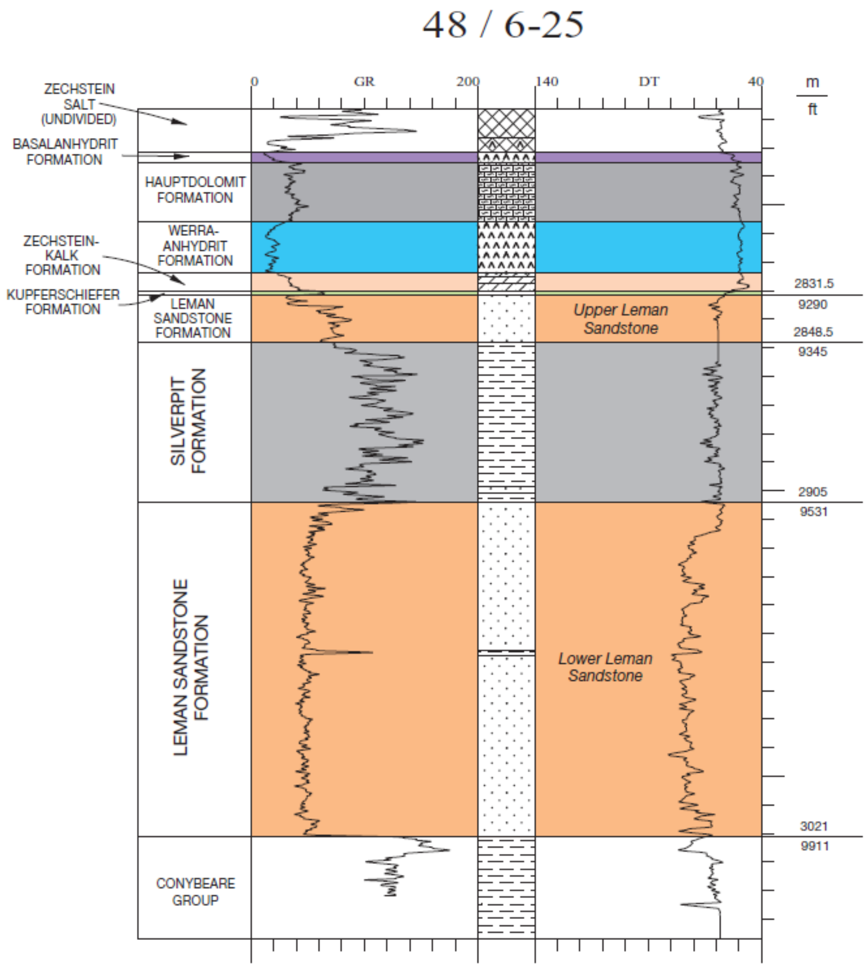
The Platypus, Possum, Pharos and Blackadder reservoir rock consists of Rotliegend, Lower Leman sands (Lower Permian). The Lower Leman is the major producing reservoir in the Southern North Sea. The sands consist primarily of desert deposits that are interbedded with mudstones *(source: British Geological Survey).*

Based on the Platypus well test production rate and the length of the horizontal leg of the appraisal well, we believe it is clear that the reservoir is relatively tight/low permeability.

We believe that the Hyde Field is probably the best analog field as it is nearby and it produces from the Lower Leman sands. The Hyde Field had permeabilities of 0.4 to 3mD in the best (aeolian) reservoir. The Hyde field was therefore developed using horizontal wells, like the Platypus field. We expect that the illite cementation in the Hyde Field is also present in the Platypus field. The Hyde field was originally discovered by BP in 1982, but the challenges of the field (low permeability) meant that first commercial production was achieved 11 years after the discovery, after 5 appraisal wells were drilled. The Hyde field was developed with horizontal wells. In the 31 years since the Hyde Field was discovered, horizontal drilling and improved completion technologies have advanced considerably, and from the very outset the Platypus field development plan included horizontal wells *(source throughout: Understanding the Performance of a Low-Permeability Gas Reservoir: Hyde Field, Southern North Sea, 1996 Society of Petroleum Engineers, R.P. Baron and A.J. Pearce - BP Exploration Operating Co Ltd.).*

The log of the well that discovered the Hyde field is shown below. The gamma ray log indicates that the reservoir is clean and homogenous and the sonic log indicates that the reservoir is homogenous. Due to the proximity of the Platypus field to the Hyde field we expect the Platypus reservoir to be a clean homogenous reservoir, which suggests production visibility should be high.

Hyde Field Discovery Well – Log



British Geological Survey

The Hyde field produced more water than initially expected due to the extremely low downhole pressures (relative to virgin reservoir pressure), which caused production issues in the reservoir and operational challenges at the surface. We believe a simple solution to this problem is to drill more wells allowing each to drain a smaller area with a lower drawdown pressure, which we have modelled.

Dana Petroleum has extensive experience producing from the Lower Leman sands in the Southern North Sea, inclusive of experience gained from the Johnston, Victor, Anglia and Babbage fields.

Production Profiles:

The company has not yet published a CPR for its Southern North Sea assets, although we expect that in due course

We have assumed that the base case recovery factor is 60% of the gas initially in place for all the fields.

We estimate that the recovery rate was circa 55% for the Hyde field, based on the most recent publicly available information we have reviewed *(R.P. Baron, 1996).* However, we believe this result can be ameliorated by drilling more wells and by applying modern drilling and completion practices that should cause less reservoir damage.

For all of the fields we have assumed a 20% initial decline rate and an Arp's coefficient of 50%, which reduces the decline rate over time. We believe that these estimates are appropriate for a tight gas reservoir in the Southern North Sea.

Development, Production and Cost Estimates:

We have assumed that the Platypus and Possum fields are developed conjointly from the same platform. We have assumed that the Pharos and Blackadder fields are developed conjointly, but that each has a dedicated platform. In reality, all of the fields might be developed in an integrated fashion, which could reduce costs relative to our estimates.

Parkmead expects that a draft field development plan for Platypus and Possum will be submitted to DECC in late calendar 2013 and that the final field development plan is expected to be submitted in late calendar 2014.

There are a number of development options for the fields inclusive of tying them into the West Sole or Babbage facilities. Dana Petroleum held a 40% equity stake in the Babbage field when it was acquired by KNOC in 2010, so the Parkmead team is familiar with developing gas fields in this area. The facilities in the area all lead to the Easington landing point via the West-Sole Easington pipeline, which has excess capacity.

We expect that a fixed platform will be installed for each of the fields, except Possum.

The table below provides the key assumptions in our economic model. We have based our cost assumptions on comparable Southern North Sea gas fields.

Key Developmental Assumptions

Field	Discovery Well (calendar)	First Gas (calendar)	Gross Future Capex ($USmn)	Future Capex/ Mcf ($US/mcf)	Gross Total Sales Gas (bcf; EUR)
Platypus	1H 2010A	1H 2016	244	2.37	103
Possum	1H 2015E	1H 2016	61	1.46	42
Pharos	2H 2013E	1H 2018	414	2.38	174
Blackadder	2014E	1H 2018	372	2.10	177

Source: Parkmead and Charles Stanley Securities

Economic Analysis:

We have assumed a gas price of 65p/therm ($US10.38/mcf), which we escalate at 2% p.a.

We assume operating costs average circa $US1.88/mcf in the first three years of production at Platypus. We estimate that the average operating cost for Platypus, Possum, Pharos and Blackadder over the lives of those fields is $US4.03/mcf.

Economic Summary

Field	PMG Net Total Sales Gas (bcf)	PMG Net Total Value ($USmn)	Value/ Mcf ($US/mcf)	Inclusion in Target Price?	% Inclusion in Target Price (%)	Value Included in Target Price ($USmn)
Platypus	15.5	15.9	1.03	Partial	80%	12.7
Possum	6.3	13.3	2.11	Partial	40%	5.3
Pharos	34.8	38.5	1.11	Partial	27%	10.3
Blackadder	35.4	37.0	1.05	No	0%	0.0

Source: Charles Stanley Securities

The higher value of Possum per mcf reflects that it will be developed from the Platypus facility for minimal incremental costs.

In our target price we have reduced the best estimate NPV10 valuation to reflect various risks (geological and commercial). Currently, we do not believe that the equity market is paying for prospects that are conditional on the success of prior exploration prospects. Therefore, we have not included any value for the prospectivity of Blackadder, which is conditional on the success of Pharos. Success at Pharos should therefore serve as a catalyst to unlock the prospective (and appropriately risked) value for Blackadder.

Netherlands Onshore

Overview:

The company holds 7.5%-15% working interests in the Netherlands

On 8 March 2012, Parkmead announced the acquisition of a portfolio of oil & gas assets in the Netherlands for €7.5mn, of which €3.0mn is payable upon the first sale of oil from one of the fields (Papekop).

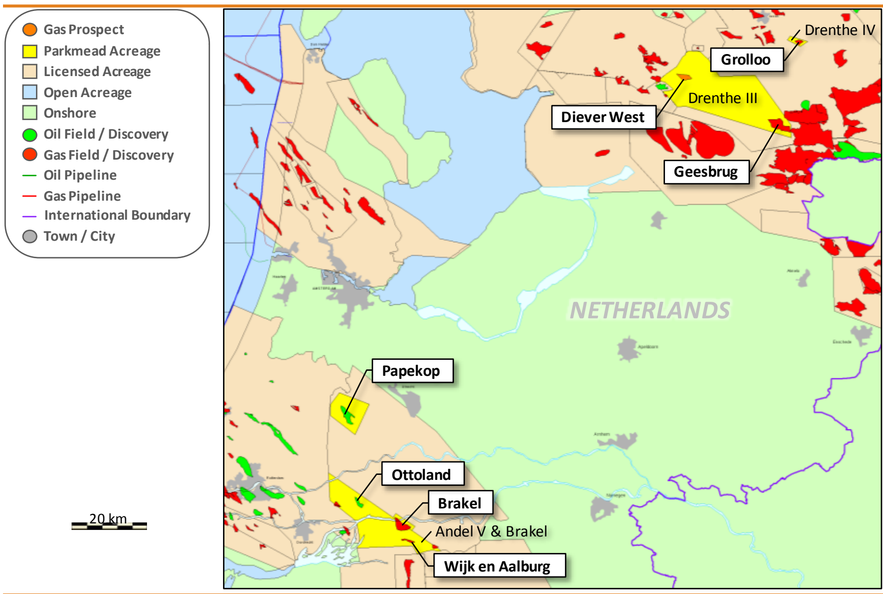
The company's Dutch assets were more material to the company when they were acquired. Due to the company's subsequent growth, the company's Dutch assets account for less than 4% of our target price

At the effective date of the acquisition, 1 January 2012, the assets were producing gas at a rate of 12,000 mcf/d (or 2,000 boe/d) of which 1,800 mcf/d (or 300 boe/d) was net to Parkmead. Currently, the fields are producing circa 1,200 mcf/d (or 200 boe/d) net to Parkmead.

We estimate that current gas production is coming from Geesbrug (48%), Brakel (30%) and Grolloo (22%). Production at Geesbrug and Grolloo has been consistent with expectations whereas production at Brakel has been less than expected.

A map of Parkmead's Dutch assets is shown below.

Locations of Parkmead's Dutch Assets



Source: Parkmead

Parkmead holds a 15% working interest in its producing assets, although the effective revenue interest is 7.5% due to a 50% royalty arrangement with NAM (a 50/50 joint venture between ExxonMobil and Shell). After cost recovery (+30%) 50% of the company's revenue is lost to royalties paid to NAM. Certain of the company's assets are not subject to the 50% NAM royalty. Of the company's key Dutch assets, we prefer assets that are outside of the NAM agreement: Papekop and Diever West.

The assets are also held by Vermillion Oil & Gas BV (45%) and Energie Beheer Nederland (40%), which is owned by the Dutch state. All of the company's Dutch assets are operated by Vermillion Oil & Gas BV.

The prior operator of Parkmead's Dutch assets, Northern Petroleum, announced on 1 October 2013 that it had entered into a binding sale and purchase agreement with Vermillion Oil & Gas BV ("Vermillion"), a wholly owned subsidiary of TSX listed Vermillion Energy Inc. (market capitalisation of circa $CDN 5.8bn) for the sale of its Netherlands operating subsidiary. The consideration for the sale will be satisfied as follows: i) Canadian $27.5mn, payable in cash upon completion, ii) a net profit interest in the Papekop Production License and iii) a net profit interest over any future production from unconventional reservoirs. The portfolio of assets sold include five producing gas fields onshore and an offshore gas field. Assuming the value of assets not partially held by Parkmead is nil, the implied transaction value of Parkmead's assets would amount to $(US) circa 8.7mn (plus the value of the net profit interests which are not immaterial). This compares to $13.8mn included in our target price. Despite the discrepancy in value we are comfortable with our valuation because we believe that the assets are worth considerably more with Vermillion as operator due to that company's ability to fund developments and its proven technical and commercial capabilities to grow production onshore continental Europe. The transaction completed on 11 October 2013. Vermillion is the second largest onshore gas producer in the Netherlands.

We believe that Parkmead acquired the assets for substantially less than the value of the producing gas assets on a blow-down basis (which assumes no material investments are made). We also recognise the strategic benefits of immediate production and cash flow for a growing oil & gas company.

The company has a clean 15% interest in the Papekop oil and gas discovery, which has not yet been developed, and it will pay a one-off bonus of €3.0mn upon first oil from that field. The company will earn a clean 7.5% interest in the Diever West exploration prospect by paying for 15% of the first well. The returns on these assets are therefore considerably better than for comparable assets within the NAM agreement.

Of the assets that fall within the NAM agreement, we believe that drilling more wells into the producing Geesbrug field is the project that is most worthy of being allocated capital because the geological risks are quite low for this development and the production history of this field is encouraging.

In our target price we have reflected i) the full value of currently producing gas wells ii) the partial (risked) value of two additional wells at Geesbrug iii) the partial (risked) value of the development of the Papekop discovery and iv) the partial (risked) value of the potential of the Diever West exploration prospect. The Dutch assets contribute less than 4% to the asset value included in our target price; however, the assets have considerable strategic value because they provide immediate production and cash flow.

Geology and Reservoir Characterisation:

The productive horizon(s) for each of the assets is provided below.

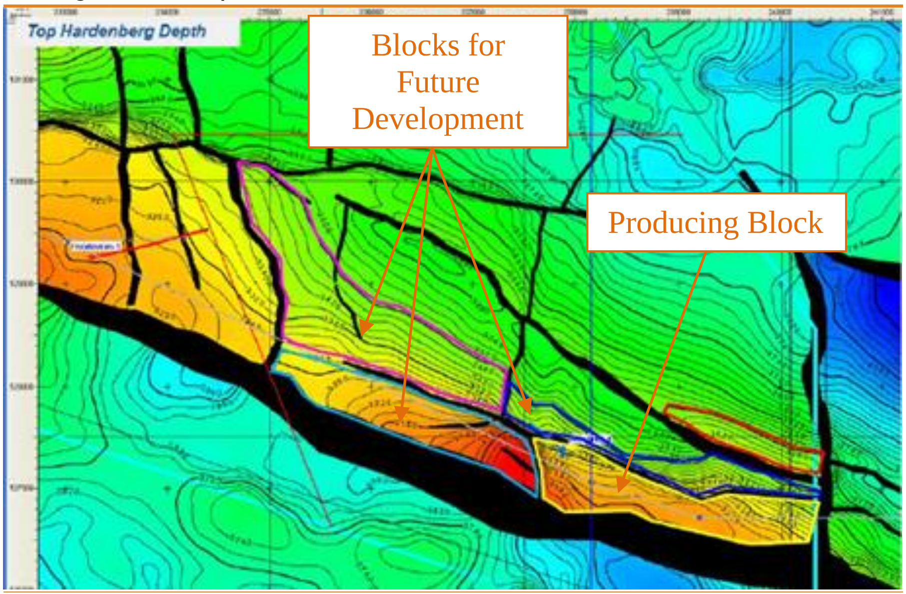
Productive Horizon by Field

Field	Productive Horizon (s)
Brakel	Lower Triassic Bunter
Geesbrug	U. Permian Rotliegend, U. C. Dalen, U. C. Hardenberg
Grolloo	Upper Carboniferous
Ottoland	Lower Triassic Bunter
Papekop	Middle Triassic Bunter
Wijk en Aalburg	Lower Triassic Bunter
Diever West	Upper Permian Rotliegend

Source: Wood Mackenzie

The additional wells at Geesbrug will involve the drilling of up to three fault blocks that are juxtaposed to the producing Geesbrug fault block. It is currently anticipated that the next well drilled into the structure will target the South East Fault Block which contains the currently producing well, which is only accessing part of the gas contained within this fault panel. Due to the reasonably good seismic quality obtained over the target (which has been calibrated against the actual productive well), the known quality of the Rotliegend and Carboniferous sands (also controlled by the productive well) and the excellent sealing qualities of the overlying Zechstein Salt, we believe that the additional wells at Geesbrug have minimal geological risks. A structural map is provided below.

Geesbrug Structural Map

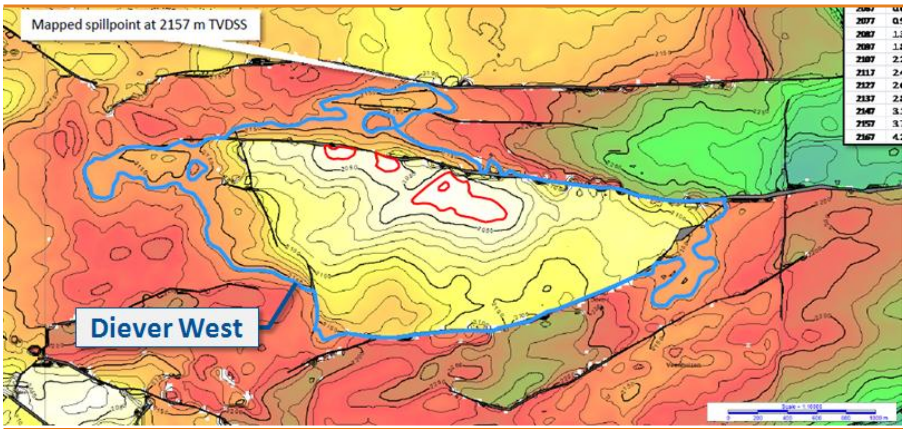


Source: Parkmead

The geological risks for Papekop and Ottoland are low as these fields have already been successfully penetrated by discovery wells. The most recent seismic interpretation of the Papekop field suggests that it is a simple structure that is entirely in pressure communication (limited faulting), which adds further confidence in the field.

The Diever West target is a classic fault and dip bounded structure. Based on seismic mapping it has 129m of relief between the crest and the spill point, suggesting that a good trapping structure can reasonably be expected, but this remains a principal risk. We believe that reservoir quality is also a source of uncertainty, but generally the prospect appears to be a relatively low risk prospect, which is not surprising given that the petroleum system onshore the Netherlands is very well understood.

Diever West



Source: Parkmead

Production Profiles:

We have assumed that the natural exponential decline rate in the Netherlands is 18% in the first year of production and 15% in subsequent years. We have assumed a 20% exponential decline for the Brakel field.

Development, Production and Cost Estimates:

In our economic model we have delayed first oil at Papekop and Ottoland by one year relative to management expectations to allow for commercial delays.

The table below provides our key developmental assumptions incorporated into our economic model.

Dutch Portfolio – Key Developmental Assumptions

Asset	Discovery Timing (calendar)	First Prod. (calendar)	Production Wells (number of)	Gross Future Capex ($USmn)	Gross Expected Recoverable Resource (mn boe)	Gross Capex/ BOE ($US/boe)
Brakel	1992A	2010A	1	n.a.	1.0	n.a.
Geesbrug	1992A	2009A	1	n.a.	1.9	n.a.
Geesbrug - 2 wells	n.a.	2014E	2	24.3	3.7	6.64
Grolloo	1980A	2009A	1	n.a.	0.5	n.a.
Ottoland	1988A	2017E	2	25.9	1.8	14.33
Papekop	1986A	2016E	2	51.3	4.9	10.52
Diever West	2014E	2016E	2	24.0	2.9	8.19

Source: Parkmead, Charles Stanley Securities

The Papekop and Ottoland oilfields also produce associated gas and as such they require investments in gas treatment, gas compression and pipelines. Current planning is premised on both fields sharing a newly built 22km pipeline.

The producing wells have all been fracture stimulated to improve flow rates and fracturing is planned for the oil field developments.

The rural population density in the Netherlands is high relative to other international petroleum producing regions and regulatory oversight can be expected to be high.

Economic Analysis:

A summary of our economic assessment of the key fields is provided below.

Summary of Economic Analysis

Field	Expected Recoverable Resource (kboe)	Net Total Value ($USmn)	Value / BOE ($US/boe)	Inclusion in Target Price?	Inclusion in Target Price (%)	Included in Target Price ($USmn)
Brakel	143	2.4	16.60	Yes	100%	2.4
Geesbrug	279	3.6	12.90	Yes	100%	3.6
Geesbrug - 2 wells	550	1.7	3.00	Partial	50%	0.8
Grolloo	78	1.3	16.64	Yes	100%	1.3
Ottoland	272	2.1	7.70	No	0%	0.0
Papekop	731	8.6	11.83	Partial	50%	4.3
Diever West	220	1.3	5.82	Partial	26%	0.3
Total	2,271	20.9	9.21			12.7

Source: Charles Stanley Securities

We estimate that Parkmead's Dutch assets contribute less than 4% to the total value included in our target price. However, the assets have strategic value by contributing immediately to production and cash flow.

Of the undeveloped assets, we estimate that Papekop has the most potential to create shareholder value because it is partially an oil field (in addition to gas), it has the best commercial terms of Parkmead's Dutch assets and it has material scale (0.7 mn boe net to Parkmead).

The net expected recoverable resource estimates (and $US/boe figures) in the above table reflect the company's working interests, not the company's revenue interests. Thus in some cases the $US/boe figures could be twice as high if they were based on the company's net revenue interest.

27th Licensing Round Assets

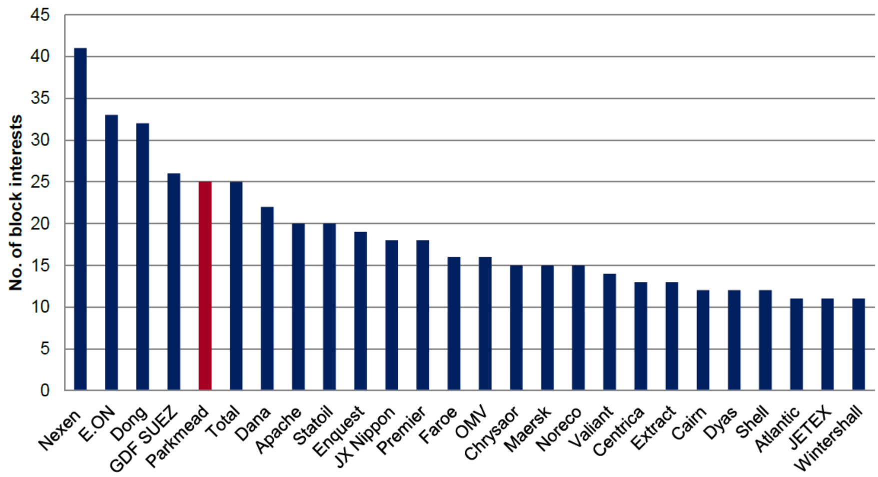
Overview:

The company holds a 30.5% operated interest in Skerryvore (a key prospect) amongst other interests gained in the most recent licensing round

In the UK 27th Licensing Round DECC awarded Parkmead six licences covering 25 blocks, which is a remarkable achievement. The chart below indicates that Parkmead was awarded more blocks than Total, Dana, Apache and Statoil, which are some of the largest and most active operators in the North Sea. Only Nexen, E.ON, Dong and GDF Suez were awarded more blocks than Parkmead, all of which are internationally significant energy companies.

The company's newly awarded blocks should create value over the mid-term as prospects are progressed. Skerryvore is the first drill-ready prospect in the blocks awarded which is why it is included in our target price. As other prospects are progressed we will assess them and as appropriate include them in our target price.

Company Rankings by Blocks Awarded in the 27th Licensing Round

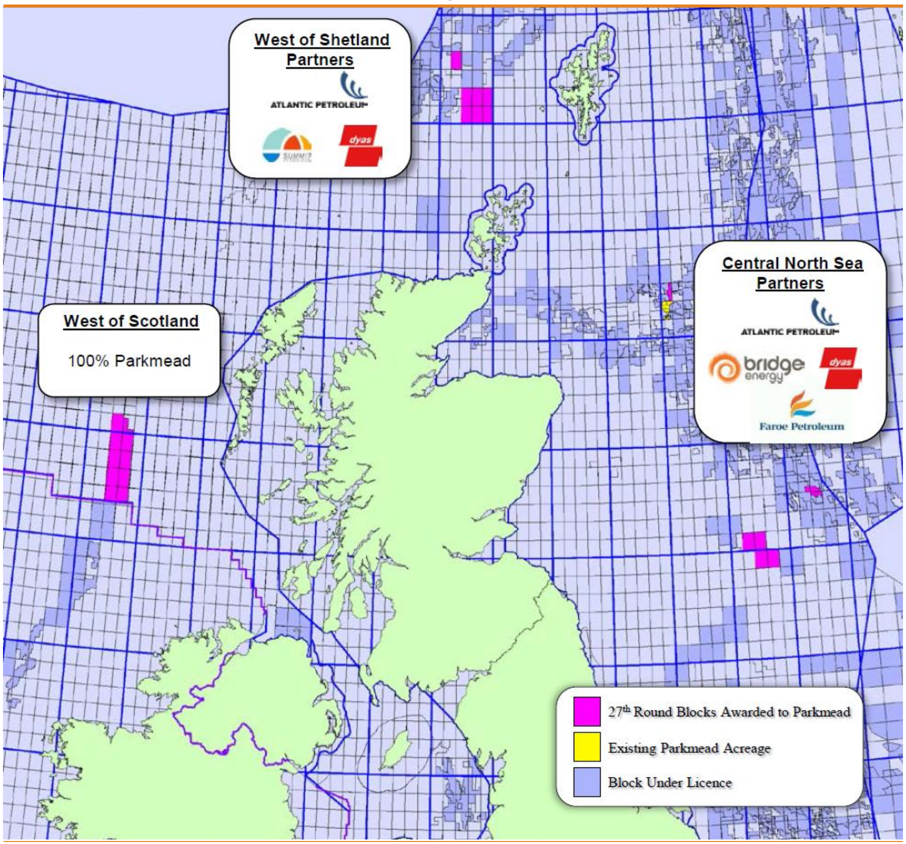


Source: Parkmead

Parkmead's standing amongst its peers is made clear by the fact that it will become nominated operator of the licenses awarded in each partnership group.

The map below shows the very significant acreage acquired West of Shetlands, West of Scotland and in the Central North Sea (in purple). The company has also applied for license blocks in the Southern North Sea, which the government has yet to award.

Blocks Awarded to Parkmead in the 27th Licensing Round



Source: Parkmead

A key point is that Parkmead is acquiring assets at the earliest stage possible. This strategy is beneficial in two ways i) it provides excellent returns on capital and ii) it reduces funding risk because instead of farming into assets (a use of funds), farming out is possible (a source of funds). Although the strategy is straightforward it is difficult to execute from a technical perspective. In this respect, we believe that Parkmead has a very strong positioning relative to peers and larger oil & gas companies based on the proven credentials of its management team.

Investing in the early stages of exploration generally involves looking for and sifting through multiple prospects, which can take several years. However, in the case of the portfolio awarded to Parkmead through the 27th Licensing round, there is already a prospect that the company has committed to drilling, Skerryvore in the Central North Sea.

The drilling of the Skerryvore prospect is the most important commitment made by Parkmead in respect of the licences awarded through the 27th licensing round. It is the only drilling commitment the company has in respect of those licenses. Other commitments are limited to modest geological work.

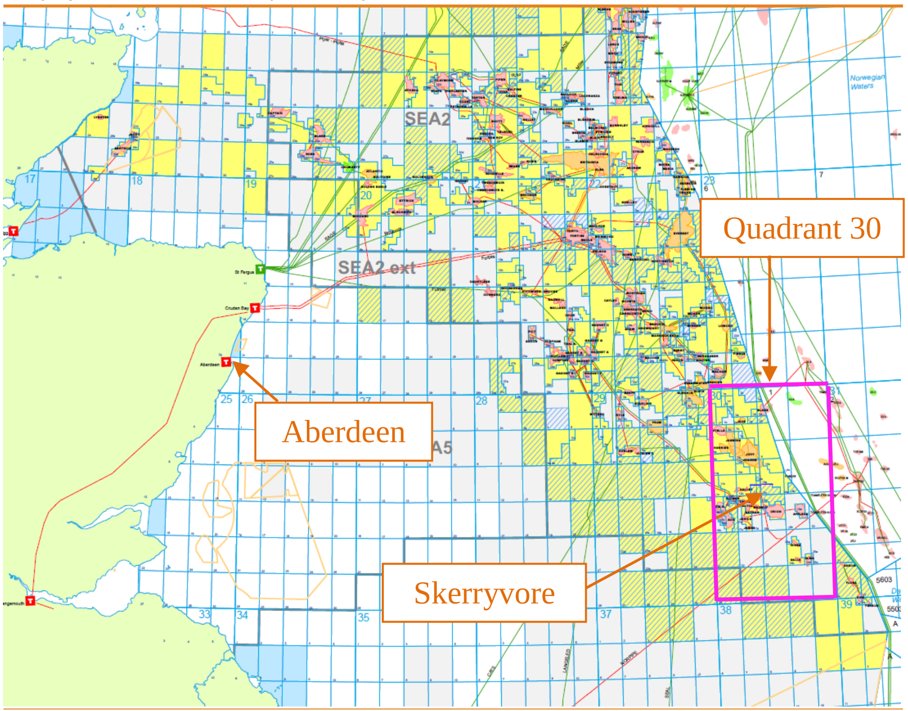
Skerryvore:

We anticipate the Skerryvore prospect will be drilled near the end of 2015.

Parkmead operates the relevant license (P2082 for blocks 30/12c, 13c and 18c) in which it holds a 30.5% interest. The other interest holders are Atlantic Petroleum (30.5%), Bridge Energy (25%) and Dyas (14%).

The Skerryvore license area is in the Central Graben area of the North Sea. The relevant license area is located in the centre of Quadrant 30 as shown in the map below, which is around 250km east of Aberdeen. Water depths in the area are circa 80m.

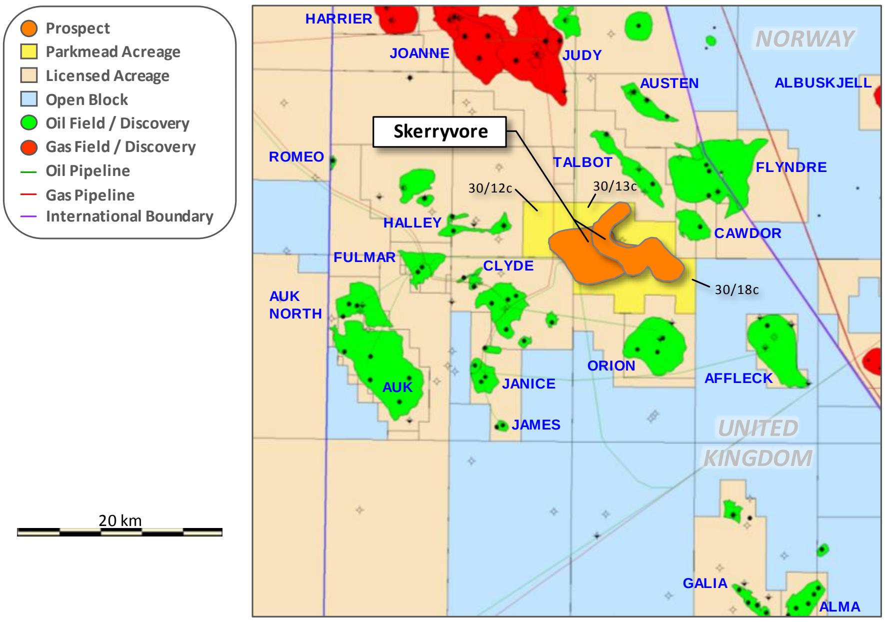
Geographic Location of Skerryvore Prospect



Source: DECC, Charles Stanley Securities

A more detailed map of the general location of Skerryvore is shown below, which indicates that there are many nearby oil & gas fields with existing infrastructure in the area.

Detailed Geographic Location of Skerryvore Prospect



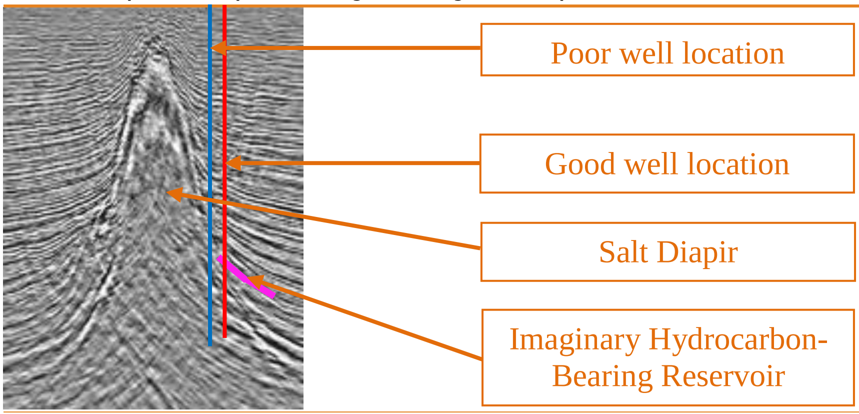
Source: Parkmead

The target is a stacked target involving prospects in three distinct geological stratas: sand in the Palaeocene (Mey Formation), chalk in the Lower Cretaceous (Ekofisk *inter alia*), and sand in the Jurassic (Fulmar Formation). We believe that the structural setting is very conducive to stacked targets, and that the possibility of “getting lucky” adds to the attractiveness of the prospect. Combined, we estimate that all the secondary targets have a resource potential that is slightly greater than that of the primary target. However, we have focused mainly on understanding the primary target and have included no value in our target price for the off chance of “getting lucky”.

The principal Skerryvore target is the Upper Cretaceous Chalk that is expected to have 223mn bbls of oil originally in place of which 30% is expected to be recoverable, or 66mn bbls, if successful. We estimate that 90% of the prospect will be within Parkmead’s block. Circa 10% of the prospect is expected to extend into a license area (P256) held by Talisman Sinopec North Sea (a joint venture between Talisman and Addax Petroleum, a 100% subsidiary of Sinopec). A unitisation agreement is likely, though we expect that Parkmead would retain operatorship of the development. In our economic model, we have assumed that Parkmead holds a 27.45% interest in the primary prospect at Skerryvore after the unitisation agreement.

The Skerryvore prospect was drilled by well 30/13-8, which did not encounter reservoir rock or hydrocarbons. It has been interpreted that the reason for the failure of the 30/13-8 well was that it was drilled too high up the structure where the reservoir had been pinched out. The Skerryvore target is on the flank of a salt dome, similar to the generic example shown in the diagram below which shows how drilling too high up a salt dome structure can miss a hydrocarbon bearing reservoir.

Generic Example of an Exploration Target Flanking a Salt Diapir

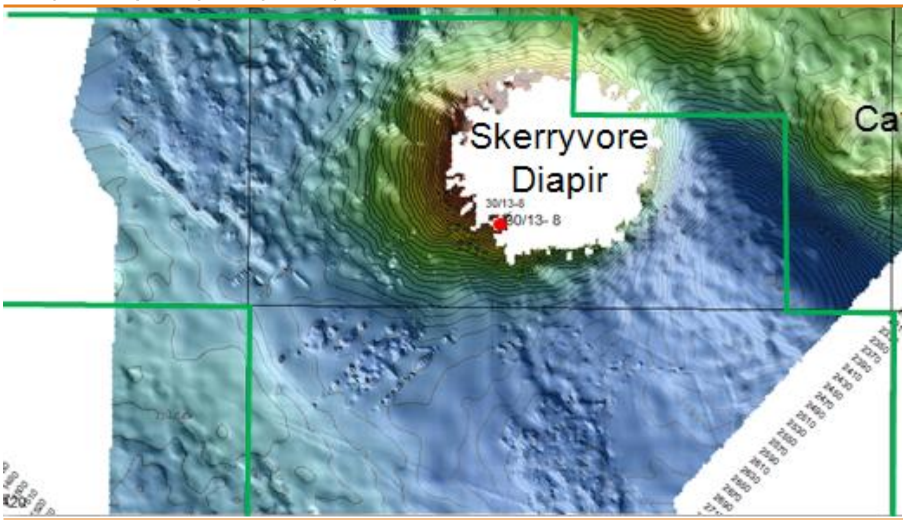


Charles Stanley Securities

Geology and Reservoir Characterisation:

The Skerryvore target is to the south west of a salt diapir. The location of the salt diapir and the 30/13-8 exploration well are shown in the map shown below.

Skerryvore Diapir (Depth: Top of Mey Sands)



Source: Parkmead

Excluding the 30/13-8 well, the closest well drilled near the structure was drilled circa 7km to the north/north-east of Skerryvore and it encountered oil. The petroleum system in the area is well understood and the regional geological risks (presence of source rock, etc) are effectively nil. However, localised risks remain, in particular reservoir quality and seal risk are the two most significant risks.

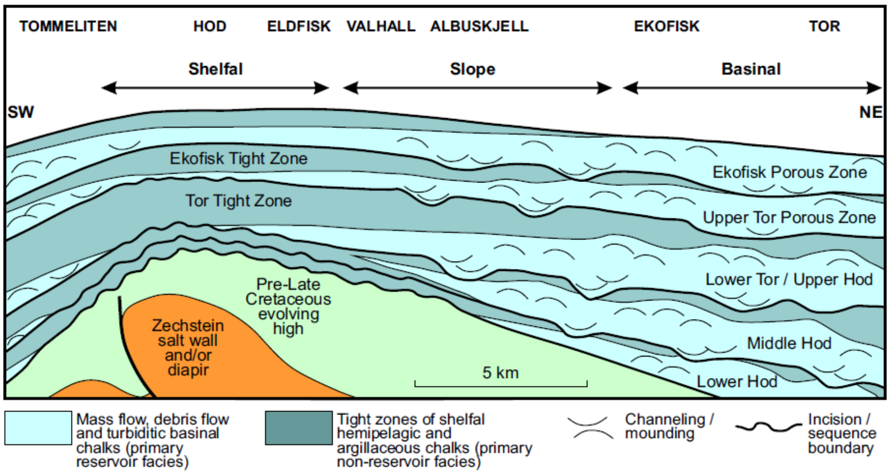
The principal target is the Upper Cretaceous Chalk. The Norwegian giant Ekofisk field is expected to produce circa 1.2bn bbls from the same horizon. This field was the first field to come onstream in Norway (in 1971), so there is a considerable body of knowledge related to this geological strata. Like for the Ekofisk field, oil for the Skeyrryvore prospect is expected to be sourced from the ubiquitous Kimmeridge Clay (Late Jurassic). Also (like the Ekofisk) field the sealing rock for Skerryvore is expected to be Palaeocene shales. The Ekofisk field's average porosity and permeability was 35% and 1.0 mD respectively. *Source: Casebook in Earth Sciences, Cretaceous and Tertiary Chalk of Ekofisk Field Area, Central North Sea, Charles T Feazal et al, 1985.*

The success of the prospect requires carbonate rocks to serve as reservoir rocks and also as sealing rocks. A multitude of nearby wells suggests that carbonates in the area are generally impermeable. Therefore, we believe that the crux of the risk relates to whether or not the reservoir rock is present (the same strata must be generally impermeable, but highly permeable and porous locally to create a good reservoir). It is thought that high quality reservoir rock resulted from the slumping of chalk from the flank of the diapir. This remobilized chalk has better porosity and permeability and forms the reservoir.

The depositional model can be appreciated from the schematic below, which shows the generic chalk play of the UK Central Graben (Source: DECC, Promote UK 2006).

The depositional model for the Skerryvore reservoir is well known in the Southern North Sea

Generic Chalk Play of the UK Central Graben



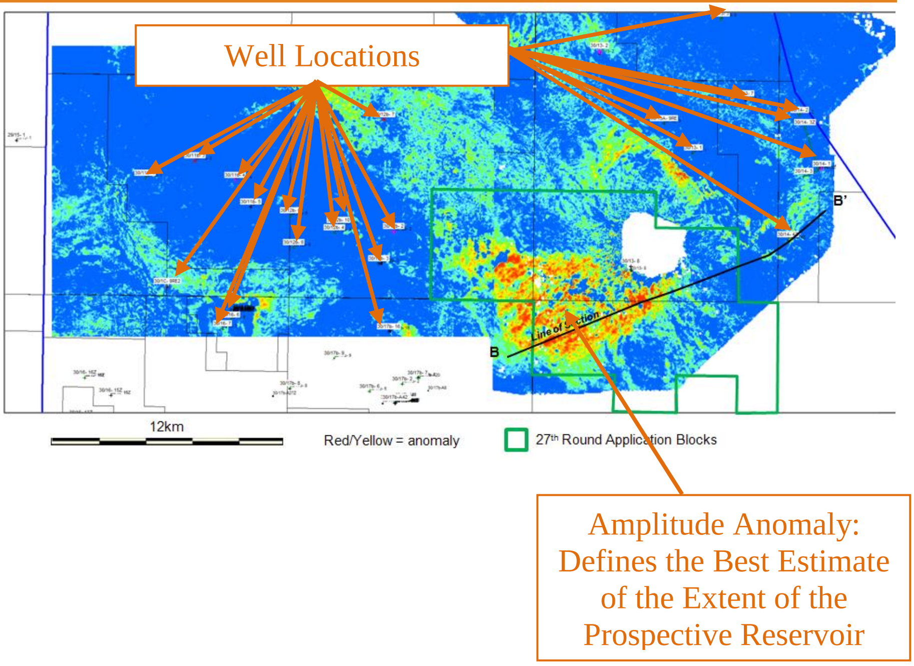
Source: DECC

In the DECC schematic above it can be seen that chalk reservoirs have been emplaced by slumping, debris flows and turbidity flows, with triggering mechanism thought to be gravitational and seismic shocks, which is consistent with descriptions provided by other sources (*Upper Cretaceous and Lower Tertiary chalks of the Albuskjell area, North Sea: Deposition in a slope and base of slope environment, N.L.Watts et al, Geology, 1980).*

The depositional model and the prospectivity of the Skerryvore prospect is supported by amplitude anomalies on the top of the prospective reservoir, as seen in the image below. DECC (Promote UK 2006) states that: "Published studies show that the magnitude of seismic reflection amplitudes can be used to predict porosity distribution within the Chalk...The difference in porosity gives rise to an acoustic impedance contrast at reservoir top and base, and the productive limits of the field are approximately delineated by the limits of the seismic amplitude anomaly seen."

Numerous well locations provide evidence that the Ekofisk can serve as a seal, but will it also serve as a reservoir where required?

Amplitude Anomalies – Top of Ekofisk



Source: Parkmead

We believe that the amplitude anomalies shown above are significant (too strong and localised to be noise). We also believe that straightforward amplitude anomalies (direct readings) are by their nature more robust than amplitude vs offset analysis (contrived analysis). Still, in the case of the Skerryvore prospect, a lot of weight has been placed on the amplitude anomalies. The geological story has been developed such that it fits the anomalies vs. a situation where the geological story exists independently of the anomalies.

Due to experience with failed wells based on seismically derived direct hydrocarbon indicators (such as amplitude anomalies) we are reluctant to assume a chance of success greater than 50% in respect of whether the amplitude anomalies have correctly identified porous/permeable rock. Although we have applied this arbitrary limit in our target price, this limit is not obvious in the case of Skerryvore given the strength of the anomalies and the very considerable experience and success of this play type in the Central North Sea.

We estimate that there is a 75% chance that the structure will be effectively sealed. Essentially, we believe that a good seal can reasonably be expected and that failure from a lack of good seal would be bad luck.

Combining the risks related to reservoir quality and seal, we estimate that the chance of geological success at Skerryvore is 37.5%.

Production Profiles:

We have assumed a decline rate of 18% in our economic model. This estimate would most likely be subject to significant revision after the initial exploration well is drilled.

Development, Production and Cost Estimates:

We believe that if the Skerryvore field has satisfactory permeability, developing the field will be very efficient due to the existence of nearby infrastructure.

The nearby Orion field was developed as a subsea satellite of the Clyde platform (both fields are now operated by Talisman Sinopec North Sea), via a 16km tie-back. The Clyde field was brought onstream in 1988 at 52.7 kb/d, so we believe there should be ample capacity on this facility now that production has fallen to 1.6 kb/d (source: DECC).

We believe that sweet crude oil (minimal sulphur) and good porosity and permeability are the most likely outcomes should the field be a success, allowing for a relatively straightforward tie-in to existing facilities.

Assuming that the field is developed with nine wells (including two water injector wells) and a subsea tie-back to Clyde, we estimate that the total capital expenditure involved in bringing the development onstream would amount to circa $US928mn or circa $US15/bbl.

We would also expect operating costs to be relatively low, given that the incremental costs of processing crude oil from Skerryvore on the Clyde platform should be minimal. A commercial arrangement would have to be agreed in due course. We believe Talisman Sinopec North Sea would be keen to extend the life of the Clyde facility and would therefore be accommodative.

We have assumed that the average operating cost per barrel over the life of the field is $US25.

We have assumed that first production is achieved in the first half of calendar 2019. In the case of success, we believe that it is more likely for first oil to be earlier than later.

We estimate the gross costs of drilling the exploration well would amount to $US47.2mn of which $US14.4mn would be funded by Parkmead.

We have assumed that a semi-submersible rig will be used to drill the exploration and development wells, although the use of a less expensive jack-up rig could possibly be envisioned (based on an expected water depth of circa 80m).

Economic Analysis

We have assumed a Brent crude oil price of $US100/bbl escalated at 2% p.a. and a $US3/bbl discount to Brent.

We have included no benefit for field allowances in our economic model due to the significant scale of the Skerryvore prospect.

In the case of success, we estimate that Parkmead's interest in the field (after unitisation) has an NPV10 value of $US187mn. This equates to $US10.32/bbl and 11.1p/share.

To reflect exploration risk (37.5% chance of success) and developmental risk (80% chance of success), we have included only 3.3p/share of value for Skerryvore in our target price.

We estimate that the NPV10 breakeven price for the Skerryvore field is circa $US50/bbl. This is the same as Athena, but Athena is a producing field (fixed costs have already been sunk). Essentially, if successful we expect Skerryvore to be a very economic oilfield.

Skerryvore has the makings of a very economically attractive resource: scale and nearby infrastructure

The attraction of a field in the political safety of the UK that should provide an NPV10 of circa $US10/bbl (inclusive of capital costs) will greatly alleviate commercial risks, which for Skerryvore should consist principally of funding risk. We believe that a successful exploration well could warrant an upward adjustment to our commercial chance of success estimate because sourcing capital to develop this field, if geologically successful, should not be problematic.

We believe that a farm-out of Skerryvore could be achieved quite easily however, we understand that Parkmead does not currently intend to reduce its equity exposure to this prospect.

Aupec Limited

Aupec Limited (Aupec) is a consultancy that resided within Parkmead, prior to Parkmead becoming an upstream oil & gas company. Aupec is a petroleum economics consultancy that has advised over 100 governments, national oil companies, majors and independents across the world, over more than 25 years.

The company was created in 1986 and was born out of academic research at the University of Aberdeen, which was led by Professor Alex Kemp OBE.

The company was incorporated as an independent limited company in 1997. Management invested in the company in 2000. In 2001 additional funds were provided to grow the company. The company merged with Parkmead in 2009.

Aupec is a leading global authority on energy economics and it has delivered expertise in respect of i) the design of petroleum taxes ii) national energy policies iii) forecasting petroleum revenues iv) institutional strengthening v) revenue management vi) the valuation of oil & gas assets and vii) economic benchmarking, inclusive of related IT capabilities.

The company counts among its clients many of the world's largest national oil companies, including Saudi Aramco, Statoil and Petrobras. Aupec also serves many of the major oil companies inclusive of ConocoPhillips, Shell, ENI, Total and BP. Additionally, the company serves a large number of smaller oil companies.

In the year ended 30 June 2012, Aupec generated revenue of £2.507mn and recorded an operating profit of £0.453mn.

We have valued Aupec at $US30mn, which represents a 7.5x historical revenue multiple.

From an expected monetary value perspective, Parkmead believes that $30mn would be a reasonable valuation for Aupec, with variability in future value dependent on i) the strength of market conditions ii) the growth outlook for Aupec and iii) the strategic benefits of Aupec for a potential acquirer.

Financial Analysis

Recently, the company issued 115.0mn shares to acquire Lochard Energy (effective 25 July 2013, based on an exchange ratio of 0.385 Parkmead shares per Lochard Energy share). The company completed a successful equity placing and debt for equity conversion in January 2013, providing finance for growth of £19.925mn. Of that amount £15.925 mn was raised via an oversubscribed placing of 130.0mn shares at 12.25p/share. In addition, 27.8mn shares were issued to Tom Cross (and affiliates) relating to the conversion of £3.4mn of loans drawn by the company from Tom Cross (and affiliates).

The company currently has debt of £2.0mn drawn from a £8.0mn loan facility agreed with Tom Cross (and affiliates). The loan is due in November 2013 (two year tenor) and it has an interest rate of 2.5% above LIBOR. The recent conversion of £3.4mn of loan into equity suggests that the loan is likely to be rolled-over indefinitely.

We suggest reviewing the sources and uses of cash in the Financial Statements section

We expect that the company will fund its projects by i) cash flow from operations ii) raising equity capital iii) raising debt capital and iv) farm-outs to other oil & gas companies. We have built financial projections going out until the end of the 2017 financial year (30 June), which are provided in the Financial Statements section. We stress the importance of assessing the cash flow statement both in terms of uses and sources of cash flow.

Due to the nature of Parkmead's intended capital programme on its key growth assets, there will be an onward funding requirement. We believe that it is appropriate to assess the funding requirements in relation to the high quality of Parkmead's assets and the management team's proven track record. Although the financial crisis has reduced the amount of equity and debt capital available for junior oil & gas companies, we believe that this anomalous period is ending. Parkmead has a proven capacity to raise equity as made evident by the oversubscribed fundraise it closed in 2013. Parkmead is in discussions with multiple banks concerning funding needs and is confident that debt funding will be available to assist with the financing of its projects. The quality of the company's assets also allows the company to consider farm-outs or in some cases asset sales. We note that currently many large oil companies have plenty of capital from operating cash flow with a shortage of high quality assets.

We have reduced the valuations in our target price by 80% for currently unfunded assets to reflect funding risk. Our perception is that this risk is abating, but that it remains an important consideration.

The company's financial reporting period ends on 30 June.

Shareholder Structure

At the date of the last annual report (30 June 2012) the company had 22.0 mn options outstanding with a weighted average exercise price of £0.0567. Circa 37% of the shares are held by management. The largest shareholders are listed below. The table reflects the recent acquisition of Lochard Energy.

We believe that Parkmead has an attractive shareholder structure: the company's management has "skin in the game", there is strong institutional support and shares are liquid, with 723k shares traded daily on average.

Significant Shareholders

Shareholders	**(mn)**	**(%)**
Tom Cross and affiliates (Executive Chairman)	250.0	24.1%
Henderson Global Investors	81.2	7.8%
David Rose (Aupec Director and co-founder)	45.9	4.4%
Fidelity Investments	35.2	3.4%
Professor Alex Kemp (Aupec co-founder)	30.6	3.0%
Other	593.3	57.3%
Total shares outstanding	1,036.2	100.0%

Source: company

Board of Directors

Tom Cross – Executive Chairman

Tom is a Chartered Director and petroleum engineer with extensive energy sector experience, spanning projects in over 20 countries. Tom has held senior positions with Conoco, Thomson North Sea, Louisiana Land and Exploration and was Director of Engineering at the UK Petroleum Science and Technology Institute. He was founder and Chief Executive of Dana Petroleum plc through until its sale to the Korea National Oil Corporation in 2010. Tom is a former Chairman of BRINDEX, the Association of British Independent Oil Companies and a Fellow of the Institute of Directors. He chairs AUPEC, a global advisory group on energy policy and has served as a Chairman of the Society of Petroleum Engineers.

Ryan Stroulger – Finance Director

Ryan began his career as a financial analyst working on oil and gas projects in the UK, Dutch and Norwegian sectors of the North Sea, in addition to numerous ventures across onshore and offshore Africa. Ryan has been a key member of the Parkmead Group Management Team over recent years. Before becoming Finance Director, Ryan served as Commercial Director. Prior to this, he served as Group Finance Manager, responsible for all aspects of Parkmead's external financing, from strategic planning through to successful execution. He has been responsible for identifying and driving forward corporate opportunities, such as the acquisitions of DEO Petroleum plc and Lochard Energy Group plc. Ryan holds a Masters Degree in Oil and Gas Enterprise Management from the University of Aberdeen and a Master of Science degree from Edinburgh University. He is a member of the UK's Institute of Directors (IoD) and he holds the Institute of Directors' Certificate in company Direction. Ryan has also been awarded the Corporate Finance Qualification by the Institute of Chartered Accountants in England and Wales (ICAEW).

Dr. Colin Percival – Technical Director

Colin has more than 30 years experience in the Oil & Gas industry, having started his career with BP where he was a sedimentologist on BP's international operations. Colin also worked on BP's Alaskan exploration programme and returned to the UK where he led a series of BP exploration teams evaluating various plays in the UKCS, which led to a number of significant discoveries. In 1992 Colin joined British-Borneo where he led their successful UK and international exploration programmes. In 1998 Colin returned to BP where he was responsible for UK Knowledge and Data Management, Licence Management and Divestment, and latterly subsurface management of BP's largest producing UK field. In 2003, Colin joined Dana Petroleum plc ("Dana") as Geoscience Manager with responsibility for the technical work on all Dana operated assets and new ventures. He joined Parkmead in March 2011, where he leads the company's exploration and technical team. Colin played a key role in the Group's success in the recent UKCS 27th Licensing Round. Dr Percival holds a first class honours degree in geology from Reading University and a Ph.D. in sedimentology from Durham University.

Philip Dayer – Non Executive Director

Philip has over 25 years of corporate finance, public company and stock market experience. He has worked with a number of prominent city institutions and advised a wide range of public companies including UK and international groups active in the oil and gas sector. Mr Dayer qualified as a Chartered Accountant and went on to gain extensive experience as Director or Head of Corporate Finance with Barclays De Zoete, Citigroup Scrimgeour Vickers, ANZ Grindlays and Societe Generale. Latterly, whilst focusing on the energy sector, Mr Dayer was Director of Corporate Finance at Old Mutual Securities and Executive Director at Hoare Govett Limited. Philip was a Non-Executive Director of Dana Petroleum plc from 2006 through to its successful sale in 2010 and is a Non-Executive Director of a number of other companies. Philip is Chairman of the Audit Committee of the Parkmead Group.

Ian Rawlinson – Non Executive Director

Ian has over 25 years' of experience in the banking and investment industries and in advising public and private companies, including working with Lazard Brothers, Robert Fleming, Fleming Family & Partners and Dana Petroleum plc. Mr Rawlinson read law at Cambridge and was called to the Bar in 1981. From 1995 to 2000 he was responsible for building and managing Flemings' investment banking presence in Southern Africa. In 2000 he joined Fleming Family & Partners, and until 2005 held various senior executive and advisory positions within this group. Ian became a Non-Executive Director of Dana Petroleum plc in 2005, serving through to its successful sale in 2010. Since 2005, in addition to his role at Dana Petroleum, he has focused on independent commercial and charitable interests, which concentrate on natural resources, the financial sector, transportation and the environment. He is a director of a number of public and private companies and is Chairman of Tusk Trust. Ian is Chairman of the Remuneration Committee of the Parkmead Group.

Financial Statements

It is known that commodity prices, acquisitions, dispositions, farm-outs, successful discoveries and unforeseen growth opportunities will evolve in ways that are not possible to predict in advance. Investors should consider that our financial estimates are for indicative purposes only.

We estimate that the company's maximum level of debt would be £158mn, which would occur at the end of the 2016 financial first half (31 December 2015). Our financial statements reflect the assumption that £70mn of that debt is repaid before the 30 June 2016 financial year-end.

Our estimate of the maximum level of indebtedness reflects that we estimate that Pharos/Possum and Perth achieve first oil on 1 January 2016. In reality it is likely that the projects will not start production at exactly the same time, which opens scope for the operating cash flow of one asset (probably Pharos) to fund for the development of the other asset (probably Perth), which would reduce the maximum amount of debt required.

Our financial statement projections reflect the assumption that Perth will be developed as a stand-alone asset. In reality, we expect that the Perth field will be developed jointly with the Lowlander field, which would i) delay the capital expenditure requirements for Perth ii) lower company's share of the capital expenditure requirements in respect of Perth and iii) increase the value of Perth to the company.

Balance sheet (£m)						
Year to June	2012A	2013E	2014E	2015E	2016E	2017E
Cash and equivalents	7.7	13.2	20.8	3.3	4.2	32.4
Trade receivables	3.3	3.4	3.2	2.7	3.9	14.7
Inventories	-	1.2	1.2	1.2	1.2	17.0
Other current assets	-	-	-	-	-	-
Investments	6.5	4.3	-	-	-	-
Long-term assets	5.5	50.2	67.2	136.5	237.9	207.8
Total assets	**22.9**	**72.3**	**92.5**	**143.7**	**247.1**	**271.9**
Trade payables	4.1	7.1	7.5	7.5	12.0	14.3
Other current liabilities	0.1	0.2	0.2	0.2	0.2	0.2
Debt	3.0	2.0	8.0	48.0	88.0	8.0
Long-term deferred taxes	0.0	1.6	1.6	1.6	1.6	1.6
Other long-term liabilities	3.5	5.3	5.3	5.3	5.3	5.3
Total liabilities	10.7	16.2	22.6	62.6	107.0	29.3
Equity	12.3	56.1	70.0	81.1	140.1	242.6
Liabilities and equity	**22.9**	**72.3**	**92.5**	**143.7**	**247.1**	**271.9**

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Income statement (£m)						
Revenue	**2.9**	**4.7**	**14.9**	**12.7**	**115.0**	**208.4**
Cash opex	(1.4)	(1.6)	(6.8)	(6.4)	(28.7)	(48.4)
G&A costs	(5.5)	(7.7)	(6.1)	(6.3)	(6.5)	(6.7)
EBITDA	**(4.0)**	**(4.7)**	**2.0**	**(0.0)**	**79.7**	**153.4**
Depreciation	(0.7)	(0.4)	(7.3)	(6.4)	(21.2)	(35.9)
Operating profit	**(4.7)**	**(5.1)**	**(5.3)**	**(6.4)**	**58.5**	**117.5**
Other	-	(0.5)	-	-	-	-
Financial expenses	(0.2)	(0.1)	(0.2)	(1.9)	(17.1)	(5.9)
Profit (loss) on investments	-	(0.0)	-	-	-	-
Income tax	0.0	(0.4)	(0.7)	(0.6)	(2.4)	(9.1)
Earnings	**(4.9)**	**(6.0)**	**(6.2)**	**(8.9)**	**39.0**	**102.5**
Minority interests	-	-	-	-	-	-
Earnings for shareholders	**(4.9)**	**(6.0)**	**(6.2)**	**(8.9)**	**39.0**	**102.5**

Charles Stanley Securities

Cash flow statement (£m)						
Earnings	(4.9)	(6.0)	(6.2)	(8.9)	39.0	102.5
Depreciation	0.1	0.5	7.3	6.4	21.2	35.9
Other	3.9	3.4	-	-	-	-
Deferred tax	0.0	-	-	-	-	-
Cash flow from operations	**(1.0)**	**(2.1)**	**1.1**	**(2.5)**	**60.3**	**138.4**
Changes in working capital	(1.5)	(3.2)	0.5	0.6	3.3	(24.3)
Cash from operations	**(2.5)**	**(5.3)**	**1.6**	**(1.9)**	**63.5**	**114.1**
Disposals	0.0	0.0	4.3	-	-	-
Investments	(2.9)	(6.7)	(24.3)	(75.7)	(122.6)	(5.9)
Cash from investments	**(2.9)**	**(6.7)**	**(20.0)**	**(75.7)**	**(122.6)**	**(5.9)**
Cash from equity raised	8.8	15.1	20.0	20.0	20.0	-
Net cash from debt capital	3.0	2.4	6.0	40.0	40.0	(80.0)
Cash from financing	**11.8**	**17.5**	**26.0**	**60.0**	**60.0**	**(80.0)**
Net change in cash	**6.4**	**5.5**	**7.6**	**(17.6)**	**0.9**	**28.2**

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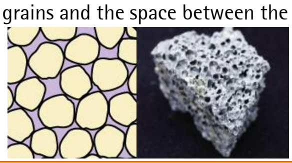
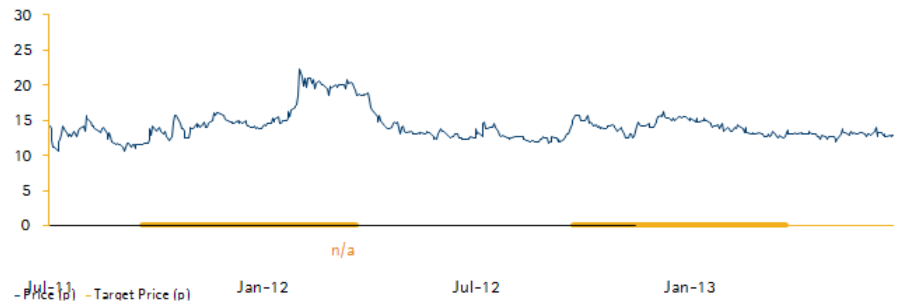
Glossary of Terms

API density	A measure of the density of oil. Brent has an API density of +/- 38°. Water which is heavier than most crude oil has an API density of 10°.
Anticline	A hill type structure (schematic and photographic examples below, one photo showing a cross section and the other showing outcrops at the surface) 
BOE	Barrel of Oil Equivalent. 1 boe = 1 bbl of oil or 6,000 cubic feet of gas (by arbitrary definition)
cf	Cubic Feet, mcf = thousand cubic feet, mmcf = million cubic feet
DECC	UK Department of Energy and Climate Change
ESP	Electric Submersible Pump
Fault	Fracture and displacement of a structure along a plane (normal fault below) 
FPSO	Floating Production Storage and Offloading Vessel
GOIP	Gas Originally in Place, refers to the amount of gas originally in the reservoir, a proportion of which will be recovered/produced depending on the recovery rate. The estimate refers to gas at surface/atmospheric conditions (after pressure/temperature adjustment are made).
GOR	Gas Oil Ratio, the amount of gas relative to oil
Porosity	The percentage of a rock's volume that is composed of fluid (gases or liquids) and not rock. Sandstone is composed of grains and the space between the grains creates porosity, other types of rocks can be porous for other reasons. 
Permeability	The measure of the ability of a porous material (rock) to allow fluid to pass through it. Permeability, rate of fluid flow, pressure, the dimensions of the rock (height and surface area) and viscosity have linear relationships. Permeability is measured in Darcies and often expressed in millidarcies (Md). The more permeability the better for reservoir rock. Permeability and porosity are correlated for most rock types.
Sour Crude Oil	Oil that contains sulphur
Sweet Crude Oil	Oil that contains little or no sulphur
STOOIP	Stock Tank Oil Originally in Place refers to the total amount of oil in place, a proportion of which will be recovered/produced to surface depending on the recovery rate. Stock tank refers to surface vs. reservoir conditions (pressure/temperature).
Stratigraphic Trap	A trap caused by the depositional environment/caused by changing rock types: pinch outs, unconformities, channel/river systems, reefs etc.
Structural Trap	A trap created by tectonic forces: bending/faulting (also created by salt diapers and other forces that change the shape of the earth/substructure)
TVDSS	True Vertical Depth Sub Sea, the best estimate of depth relative to the sea level
Velocity	The speed with which sound travels through rock (a key assumption for seismic analysis)
UKCS	UK Continental Shelf or offshore UK

Important Disclosures

Recommendation and target price history

Share price performance



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Total Coverage	Number	Percent	Banking Relationships	Number	Percent
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Add	21	11.86	Add	3	9.38
Hold	54	30.51	Hold	7	21.88
Reduce	10	5.65	Reduce	0	0.00
Sell	4	2.26	Sell	0	0.00

Charles Stanley Securities rating definitions – 12 month time scale

Buy	+20%	<	expected absolute change		
Add	+10%	<	expected absolute change	<	+20%
Hold	-10%	<	expected absolute change	<	+10%
Reduce	-20%	<	expected absolute change	<	-10%
Sell			expected absolute change	<	-20%

Date for security prices

Security prices are at the close on 14 October 2013.

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