EDISON

Hurricane Energy

Pioneering fractured basement

Initiation of coverage

Oil & gas

Hurricane Energy is an E&P company focused on fractured basement in the UK, where it has de-risked its 207mmboe Lancaster field with a successful horizontal appraisal well (flow rates of c 10mb/d constrained by surface equipment). Management is now envisaging an Early Production System to answer remaining uncertainties and reduce upfront capital requirements. The company is currently seeking a farm-out to fund an EPS, targeting first oil in late 2017, with full field production five years later. While the farm-out market is currently subdued, Lancaster may attract interested parties due to its high well deliverability and relatively simple development scheme. Furthermore, success at Lancaster could lead to a wider de-risking of basement plays – opening up a much larger resource base. In these circumstances, our RENAV of 45p/share could have considerable upside, although we note that the terms of the farm-down and performance of any EPS are critical.

Year end	EBITDA* (£m)	PBT* (£m)	Operating cash flow (£m)	Capex (£m)	Net (debt)/cash (£m)
12/13	(5.2)	(12.0)	(4.4)	(6.9)	14.0
12/14	(8.5)	(9.0)	(4.7)	(36.5)	15.9
12/15e	(5.0)	(5.1)	(5.0)	(7.4)	3.5
12/16e	(5.0)	(5.1)	(5.0)	(7.4)	(9.0)

Note: *EBITDA and PBT are normalised, excluding intangible amortisation, exceptional items and share-based payments.

EPS needed to de-risk fractured basement play

Fractured basement reservoirs rely entirely on fractures for porosity and permeability as the matrix (granite) offers little or no permeability. Production from fractured reservoirs has been known to decline significantly once major fractures are drained. The extent, density and good connectivity of Lancaster's fracture network should ensure more sustained output from horizontal wells; however, only a longer test can demonstrate this. Hurricane is proposing an EPS to test longer-term production rates, which could lead to a FID on a full field development (FFD).

Financing is key to unlocking value

With many farm-out deals progressing slowly, we think the market is penalising unfunded E&P assets indiscriminately. However, we estimate that an EPS would require little capital (<$200m) to get to first oil. Revenues from the EPS would also help fund a significant portion of the $2.3bn capex needed for an FFD.

Valuation: 45p/share RENAV with upside

Our RENAV of 45p/share is based on a risked valuation of Lancaster, assuming successive farm-outs as the main funding route. There is upside to our unrisked field NPV of c $1.2bn if well productivity is better than expected; reducing the current 11-well count (as per the CPR) to eight would add c 11%. In addition to our risk factors of 59-53% applied to the EPS and FFD, we have incorporated our estimated WI dilution in a farm-out process. Technical progress on Lancaster would help de-risk Hurricane's other discoveries and prospects.

12 June 2015

Price	**17.75p**
Market cap	**£112m**
	US$1.52/£
Net cash (£m) at 31 December 2014	15.9
Shares in issue	633.1m
Free float	81%
Code	HUR
Primary exchange	AIM
Secondary exchange	N/A

Share price performance

%	1m	3m	12m
Abs	3.4	8.3	(40.8)
Rel (local)	1.5	11.3	(39.5)
52-week high/low		51.3p	12.0p

Business description

Hurricane is an E&P focused on UKCS fractured basement exploration. It owns 100% in three licences, including the 207mmboe Lancaster discovery where it drilled an appraised well in 2014. It is currently engaged in a farm-out process to fund an Early Production System (EPS).

Company next events

Farm-out	2015/16
FDP submission	Late 2015
Updated CPR	Following FDP submission
EPS first oil	Late 2018 (Edison assumption)

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Edison profile page

Hurricane Energy is a research client of Edison Investment Research Limited

Investment summary

Company description: Fractured basement pioneer

Hurricane Energy (HUR) is an AIM-listed E&P company founded in 2004 to explore for UK Continental Shelf (UKCS) basement plays in the West of Shetland. Fractured basement is considered an unusual reservoir in the UK, but has been producing for decades around the world. Hurricane's main asset is its 100%-owned 207mmboe Lancaster oil discovery. The field was substantially de-risked by a 1km horizontal appraisal well drilled in mid-2014, which demonstrated commercial flow rates during a 78-hour test (5,300b/d natural flow, 9,800b/d with an ESP, both constrained by surface equipment). Despite the well success, several unknowns remain, chiefly long-term production rates. Hurricane plans to sanction an Early Production System (EPS) with first oil targeted for late 2017 to address these uncertainties and generate cash, paving the way for FID on a full field development (FFD) after two years of production. It is currently looking to farm out some or all of the group's assets to secure capex funding for the Lancaster EPS, which we estimate at less than $200m to get to first oil in late 2018.

Valuation: RENAV of 45p/share, with significant upside

Our RENAV valuation of 45p/share is based on our risked value assessment for an EPS and FFD at Lancaster. In addition to our usual geological and commercial risking, we have attempted to quantify the likely dilution incurred in a phased farm-out process with a cost carry. Importantly, if Hurricane can succeed in de-risking the basement play concept in the UK, it has numerous other assets in its portfolio. Although development of these lies too far in the future to include in our RENAV, 250mmboe of additional 2C and 437mmboe of P50 prospective resources is a material resource base.

Our Lancaster unrisked valuation of just under $1.2bn is based on conservative assumptions of a late 2018 EPS start-up (one year behind guidance) and estimates from the November 2013 CPR on well count (11 wells) and costs, which do not reflect last year's successful appraisal well. Higher flow rates and recovery per well compared to the CPR's assumption would decrease the well count – for instance, moving to eight wells would increase our unrisked NPV by c 11% to c $1.3bn.

Financials: Farm-outs and financing are key

Hurricane has £16m ($24m) of cash on its balance sheet as of end-2014. Hurricane is funded for ongoing activities outside drilling until end-2017 on our estimates, but requires farm-outs or debt/equity financing to fund an EPS and likely a full field development as well. We estimate an 11-well development would cost $2.3bn to get to first oil from the FFD in 2024 with a purchased FPSO, or $1.2bn with a leased FPSO. Capex requirements drop significantly when netted against revenues from an EPS. To minimise dilution, Hurricane could seek debt funding and notably reserve-based lending, which should become available after start-up of an EPS. Another option would be to turn to a contractor group for financing.

Sensitivities: Long-term production test needed to de-risk

- **Geological:** fractured basement is seen as an unusual play in the UK, although basement reservoirs elsewhere have been producing for decades. To raise confidence in the project's viability, a long-term production test is required. Uncertainties include the ability to drain oil from below structural closure (where 63% of the 2C resources are located), long-term flow rates and water/gas breakthrough. Conversely, there is upside if well productivity and recovery factors are better than estimated in the 2013 CPR, which seems likely based on the 2014 well results.

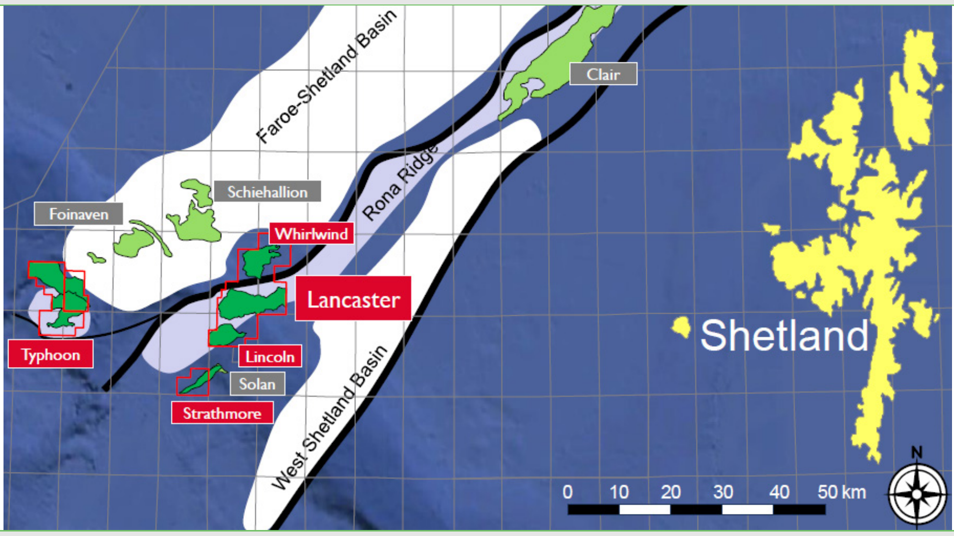
- **Funding risk:** Hurricane requires external funding for an EPS and full field development. However, its 100% WI puts it in a position of strength in farm-out negotiations.
- **Oil/gas pricing:** Lancaster's valuation is sensitive to long-term oil prices. Divergences in oil price views between Hurricane and potential farminees might create delays in the farm-out.

Fractured basement pioneer

Hurricane was founded in 2004 to explore for UKCS basement plays and holds 100% of three licences West of Shetland. It was awarded the first licence, P1368 in the 23rd Offshore Oil and Gas Licensing Round in 2005. The company is currently focused on developing the 207mmboe Lancaster discovery, which was successfully appraised with a horizontal well in 2014, achieving a natural flow rate of 5,300b/d and a maximum stabilised flow rate of 9,800b/d with an ESP of 38^{o} API oil, both constrained by surface equipment.

Other assets include the 179-205mmboe Whirlwind discovery, together with basement prospects Lincoln and Typhoon and sandstone discovery Strathmore. The assets sit along the same basic trend and are mainly located around 85km to the south-west of BP's Clair Field on the Rona Ridge, a major NE-SW trending basement ridge between the Faroe-Shetland basin containing Foinaven and Schiehallion (also BP-operated) and the West Shetland basin. To put the size of these discoveries into perspective, the average North Sea exploration target in 2014 was just over 30mmboe according to the Oil & Gas UK Activity Survey 2015.

Exhibit 1: Hurricane asset locations



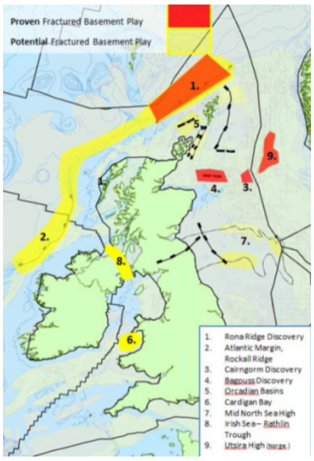
Source: Hurricane Energy

Hurricane is the first company to actively pursue the fractured basement play in the UKCS. While still considered unusual here, basement plays have been developed all over the world, with production histories going back as far as the 1940s and 1950s. The closest analogues are the Bach Ho field in Vietnam and recent discoveries in Yemen.

Exhibit 2: Global basement activity - fractured basement fields in production

Source: Hurricane Energy

Exhibit 3: UK fractured basement



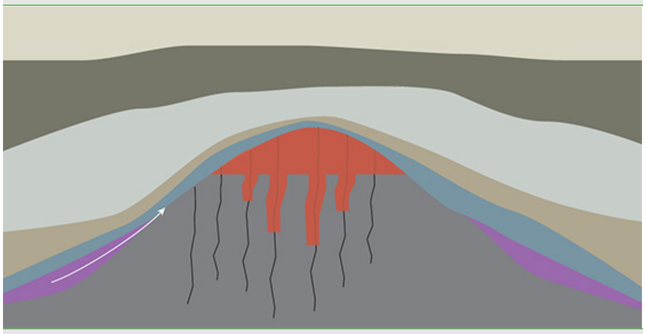
Source: PILOT/DECC

In recent years the UKCS fractured basement play has been recognised by PILOT, a taskforce comprised of DECC and industry, as a key underexplored play. The trend is believed to extend from the Rona Ridge out into the Atlantic Ridge, but is also present in other areas of the UK North Sea, for example in Premier's Bagpuss discovery in the Moray Firth and EnQuest's 2014 Cairngorm discovery.

Fractured basement reservoirs are crystalline rock underlying the sedimentary overburden which exhibit fractures relating to cooling, tectonic processes and fluid movement. As the rock is hard and brittle with low matrix porosity and permeability, oil storage and mobility entirely depends on the fracture network. The extremely long geological history of the Lancaster Field, including numerous tectonic events, has led to the generation of an extensive and extremely well-connected fracture system.

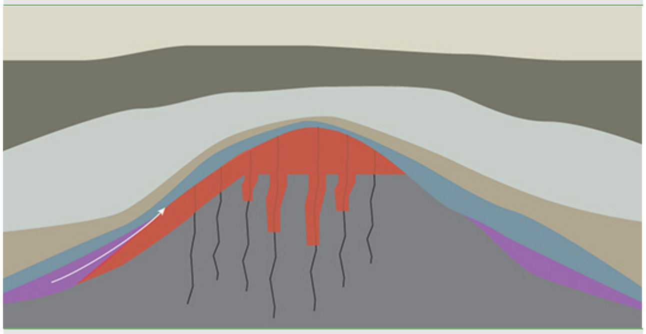
The oil-producing rock forces out hydrocarbons that move up the flank and into the basement through the fracture network. Oil can be found outside structural closure as it backfills down through the highly permeable fracture network. In the basement there is no permeability in the rock, so the oil cannot escape. Hurricane call this the "jellyfish" model.

Exhibit 4: Jellyfish model



Source: Hurricane Energy

Exhibit 5: Oil can also accumulate in the flanks



Source: Hurricane Energy

Hydrocarbon volumes in such reservoirs can therefore be significantly larger than suggested by a traditional mappable closure, but are highly dependent on the fracture distribution and connectivity. An understanding of the fracture network is therefore essential to understanding the reservoir.

Focus on Lancaster

Hurricane's most advanced asset is the Lancaster discovery, which is estimated to contain 2C resources of 200mmbbls of oil, and 207mmboe including gas. The field was originally discovered by

Shell in 1974 when its 205/21-1A well found oil shows in basement core. Despite the interval testing water with only a trace of light oil at that time, Hurricane subsequently assessed this as being due to formation damage and felt there was potential in the reservoir. Since 2009, the company has drilled three wells on the field, culminating in the 205/21a-6 horizontal appraisal well in 2014, which successfully produced 5,300b/d (natural flow) and 9,800b/d (aided by an ESP) of 38° API oil, constrained by surface equipment. Hurricane now plans to develop the field using a phased approach utilising an Early Production System (EPS) followed by a Full Field Development (FFD), and is currently looking for a farm-in partner to provide funding.

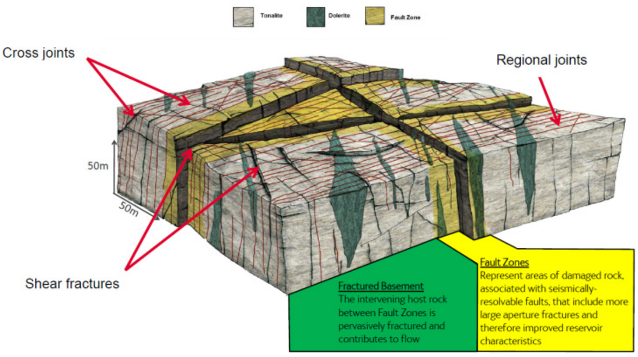
Exceptionally fractured reservoir

Sitting in 150m of water, the basement reservoir in Lancaster is 2.3bn years old and has been substantially uplifted, by around 1.5km, so that it sits at a shallow depth of around 1,000m subsea. The source rock is the world class Kimmeridge Clay, while a thick Cretaceous mudstone provides a robust seal. The reservoir is classified as a Type I fractured reservoir, meaning that the fractures provide storage capacity and fluid pathways with very little porosity/permeability in the matrix. Hurricane model the reservoir as consisting of:

- **fault zones** containing seismically resolvable faults with large fractures and improved reservoir characteristics; and
- **'fractured basement'** (referred to in the CPR as 'pseudo-matrix'), which is pervasively fractured and contributes to flow.

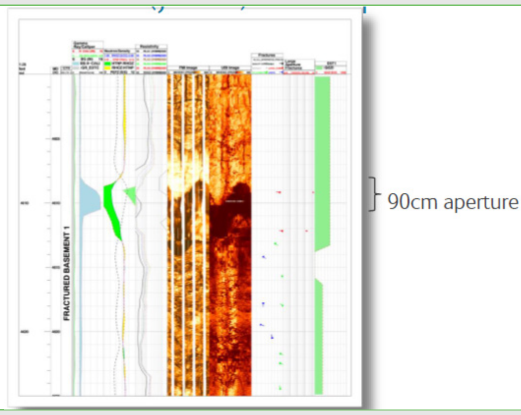
The rock is exceptionally fractured with a well-connected feeding system. Fracturing is dense and can have apertures of up to 1m (see Exhibit 7).

Exhibit 6: Conceptual reservoir model



Source: Hurricane Energy

Exhibit 7: Fracture example from Lancaster 205/21a-4Z



Source: Hurricane Energy

By comparison, the analogue Bach Ho field in Vietnam is believed only to be fractured in the fault zone region, with none in the fractured basement zone as identified in Exhibit 6. This is due to the fact that the rock, at 70m years old, is substantially younger than in Lancaster at 2.3bn years old, and so has undergone much less fracture-inducing movement throughout its history.

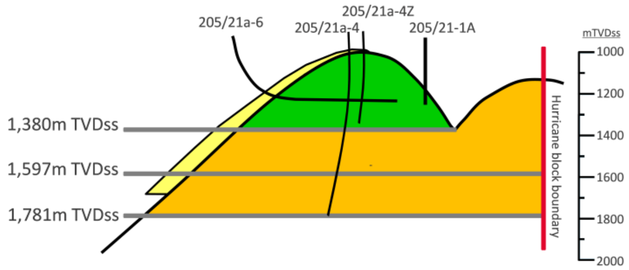
With an understanding of the fault fracture distribution being crucial to correctly targeting wells to access production, Hurricane has focused on modelling the faults in Lancaster using manual fault interpretation from seismic and automated fault interpretation known as ant tracking. The results from the 205/21a-4, 4Z and 6 wells have been proven to match the resulting model and have given confidence that the company is correctly modelling the fault distribution across the field.

Volumes: Structural closure and more

As previously mentioned, the volumes of hydrocarbons trapped in fractured basement reservoirs can exceed the volume that is trapped in the mapped structural closure. For Lancaster, the 2013

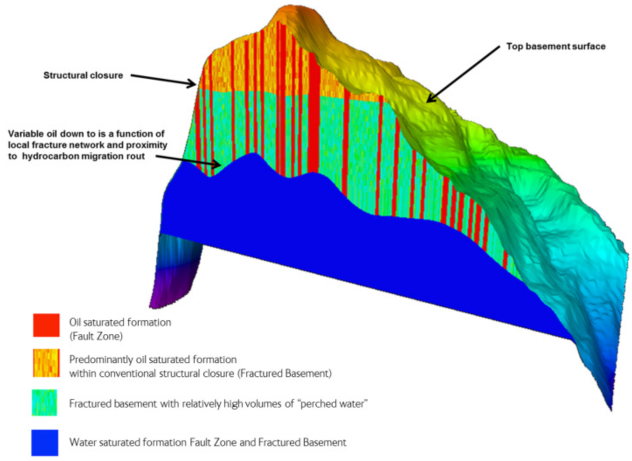
CPR from RPS Energy estimated that the recoverable volume in structural closure is 61mmbbls, with a further 139mmbbls located below this and in the eastern structure to give a full field oil volume of 200mmbbls in the 2C case. Full field recoverable oil resources in the upside 3C case are estimated at 437mmbbls.

Exhibit 8: Lancaster full field volume



Source: Hurricane Energy

Exhibit 9: Lancaster variable oil down to (ODT)



Source: Hurricane Energy

Evidence of the presence of oil below the 1,380m true vertical depth subsea (TVDss) spill point comes from the 205/21a-4 well. A modular dynamics tester (MDT) sample recovered oil from 1,475m TVDss, while oil was recovered when two swabs occurred at 1,597m TVDss. Post-well analysis also recorded oil in cuttings from the TD of the well at 1,781m TVDss. These depths formed the basis of the low-to-high ranges estimated by the CPR, with the base case taken as 1,597m. However, it should be noted that the oil water contact (OWC) across the field is expected to be variable as it is determined by the local fracture network and proximity to the hydrocarbon migration route (see Exhibit 9). The CPR has addressed this by modelling greater water saturations (S_w) in the fractured basement than in the fault zones, particularly below structural closure where the S_w is modelled at 50% for the base case. This model will need refining, but will not be resolved without drilling a deeper well to investigate.

Conservative recovery factor in CPR

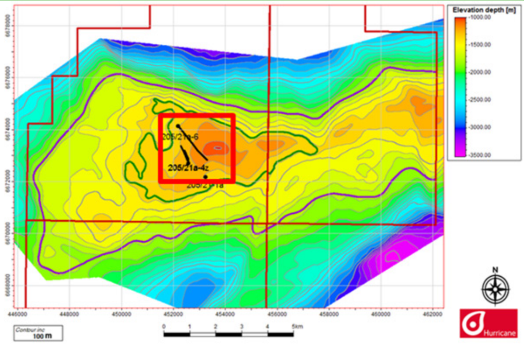
In estimating contingent resources for Lancaster, RPS has assumed an average recovery factor (RF) of 19% for the full field volume based on an RF of 30% for the structural closure volume and 16% for the resources below the spill point. We believe there is scope for the recovery factor to be higher, although this will only become evident once longer-term production performance can be analysed.

Recovery factors from fractured basement reservoirs typically fall in the 30-50% range with, for example, the La Paz field in Venezuela achieving 39% recovery and Zeit Bay in Egypt reporting 54%. Lancaster's closest analogue, Bach Ho in Vietnam, has a recovery factor of 44%. Given that production in Bach Ho is believed to be entirely from the fault zone with no contribution from the fractured basement, it would be reasonable at this stage to expect that recovery from the more extensively fractured Lancaster could be at least as great, if not greater.

Horizontal well 205/21a-6 objectives achieved

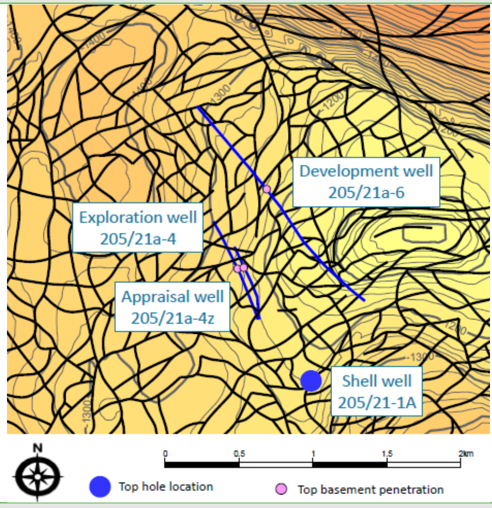
Before drilling the horizontal well 205/21a-6 well in 2014, Hurricane had drilled the exploration well 205/21a-4 in 2009, followed by the 205/21a-4Z sidetrack in 2010. These wells had established that the Lancaster reservoir contained a light 38^{o} API oil in a highly permeable reservoir, which had flowed at a maximum rate of 2,885b/d through a compromised well test, as well as confirming the company's understanding of the fault distribution.

Exhibit 10: Lancaster field



Source: Hurricane Energy

Exhibit 11: Lancaster wells



Source: Hurricane Energy

This also highlighted some issues that would need to be addressed before drilling a 1km horizontal section appraisal well. The key learning points were:

- **minimising losses:** it is common to experience fluid losses into the reservoir when drilling through fault zones and this can lead to formation damage and well safety issues. From the 4 and 4Z wells, Hurricane established that the best way to manage this was to use a viscosified brine as the drilling fluid, as this minimised losses and allowed drill cuttings to be removed from the wellbore; and
- **wax inhibition:** Lancaster crude contains wax between 8.4-13.5% wt and this had dropped out in the 4Z well and contributed, along with drill cuttings, to significant formation damage in the well. Wax inhibition chemicals were used in the horizontal well to avoid this.

Well 205/21a-6 was successfully drilled and tested in 2014. In summary, Hurricane de-risked Lancaster and the basement play and demonstrated that it was able to improve on the earlier wells and deliver commercial rates from a horizontal well.

The 1km horizontal section was drilled on time (73.5 days including testing) and within budget (£36.7m, $56m) and encountered the fractures as forecast. The well flowed at 5,300b/d naturally and tested at 9,800b/d with no water produced using an electrical submersible pump (ESP), both constrained by surface equipment. The well test analysis established that formation damage was minimal and demonstrated the excellent deliverability of the reservoir through high rates achieved with a limited drawdown. More specifically, the pressure build-up analysis pointed to a well productivity index of c 160stb/d/psi, implying that rates of up to 19,200b/d could be achieved with a moderate 120psi drawdown.

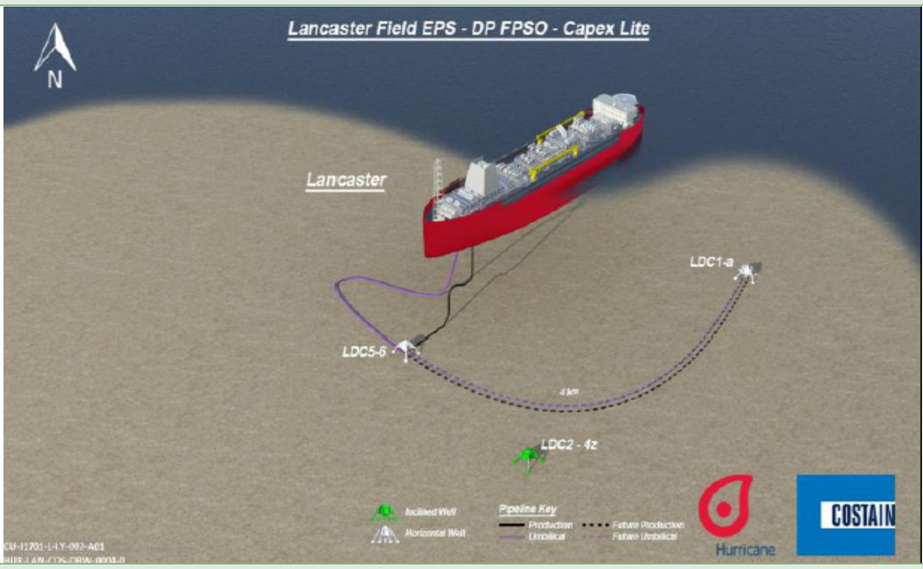
EPS to address remaining risks

While the horizontal well test established commercial rates from Lancaster, there are still some key risks that need to be addressed before Hurricane will commit to a full field development. To address these issues, the company is planning to carry out an EPS. The company's 'EPS Capex Lite' scenario would involve producing from initially just one horizontal well, most likely the existing 205/21a-6 well which is currently suspended and ready to be completed as a producer, connected to a small-size FPSO or possibly local infrastructure.

A second well could be drilled after around six to 12 months of production from the first well, and could be financed largely through cash flows generated from the first well.

The second well's location is yet to be determined and will largely depend on production history from the first well. One option is to drill the second well on the other side of the structural closure to limit interference with the 205/21a-6 well and gather more geological data (see Exhibit 12). Alternatively it could be drilled closer to the first well, which would minimise costs but possibly answer fewer questions about reservoir performance over the full aerial extent.

Exhibit 12: Lancaster 'EPS Capex Lite' with a dynamically positioned FPSO and two wells



Source: Hurricane Energy

Export would be via an FPSO capable of handling 20,000b/d, which would give an average daily rate of 12,000b/d taking into account flaring limits and assuming 80% availability. Hurricane's current reference case for the EPS is based on an FPSO solution, although other alternatives exist including the use of existing facilities. Such facilities could include Premier's Solan or BP's Schiehallion, the two fields most closely located to Lancaster. In our view, an FPSO solution would give Hurricane more flexibility and could potentially start up earlier.

The company believes that a decision could be taken on full field sanction after around two years of EPS production. In addition to the two producing wells, Hurricane would like to drill a deep appraisal well and install gauges in the existing 4Z well to allow reservoir surveillance during the test.

The EPS objectives are to establish the following:

- **Well production profiles and long-term commercial rates:** Well 205/21a-6 demonstrated commercial rates from Lancaster over a short well test, however there is uncertainty as to how the reservoir will behave over a longer time period. Production from fractured reservoirs has been known to decline as major fractures are drained and flow switches to the matrix, or in the case of Lancaster to the smaller fractures in the fractured basement zone. With the fractures in Lancaster being much more extensive and larger than typically seen in a fractured reservoir, there is a lack of comparable data from existing fields. Hurricane is evaluating the long-term potential with reservoir modelling, but only more sustained production from the EPS will be able to demonstrate this.
- **Water movement and production:** early water breakthrough can occur in fractured reservoirs, particularly if managed sub-optimally by either producing at excessively high rates or implementing an incorrect secondary recovery technique. Hurricane's management is well aware of this and is planning to address the issue by continuing to gather data with the EPS, positioning the wells in the crest of the field and producing with low drawdowns. However, the

facilities will be designed to handle high water cuts from first oil in case water unexpectedly breaks through early.

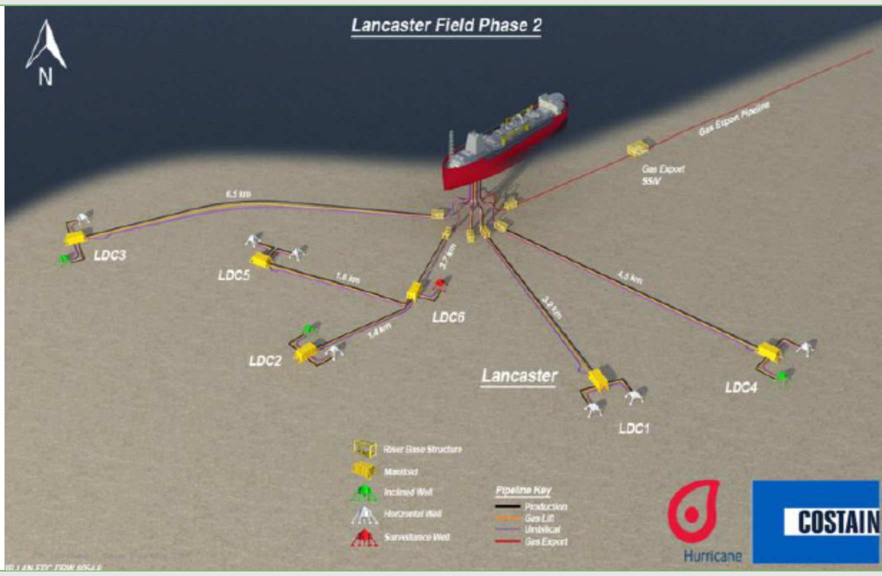
- **Effective drainage from below structural closure:** the producing wells will be located in the crest of the field, but Hurricane believes they can still drain hydrocarbons from below the structural closure. The pressure build-up analysis from the horizontal well test shows the well is connected to a large volume, which gives the company confidence that this will be possible; however, this can also only be established over a longer period of production.
- **Gas breakthrough:** the bubble point of the fluid is only just under 300psi below the initial reservoir pressure. Hurricane plans to manage this in the same way as the water breakthrough management, ie by maintaining a low drawdown during production.
- **Aquifer support:** the presence of active aquifer support can only be established with longer-term production.

Development concept: FPSO

The 2013 CPR proposes a full field development of 11 wells split across two phases with six wells in Phase 1, including the existing 4Z and 6 wells, and a further five wells in Phase 2. Based on the CPR, but dependent on the results of the EPS, we have assumed that the field would be fully developed with the same well stock of 11 wells; however, this will be phased differently, with the initial two wells from the EPS followed by an additional nine wells once the full field development is sanctioned. Under this scenario we assume that production from the EPS will commence in late 2018, with the full field online from 2024. Our first oil assumption of late 2018 for the EPS is somewhat conservative as it is one year behind company guidance ("late 2017") and is in line with the CPR assumption, which applies to a much larger six-well Phase 1.

In line with the CPR, to meet this full field start-up date, development drilling would commence after the first two years of the EPS, as the company estimates it can drill only two wells per drilling season due to difficult winter conditions in the West of Shetland area. A further two wells will need to be drilled post start-up to reach the necessary 11-well stock. The first of the development wells to be drilled will be the two wells on the flanks of the field, so that performance from these outlying areas can be assessed and any resulting design changes incorporated early in the process if necessary.

Exhibit 13: Lancaster full field development schematic



Source: Hurricane Energy

For the full field development, the FPSO would be capable of handling 75,000b/d. This would allow spare capacity on top of the expected throughput from Lancaster of 45,000-50,000b/d, thereby giving room for a potential future tieback from Lincoln and/or better than anticipated Lancaster reserves and production. Gas would be used to provide power and utilities on the FPSO and any surplus would be exported. During the FFD gas may also be used for gas lift and potentially to heat the flowlines (to deal with the waxy nature of the crude), although other more energy-efficient flow assurance solutions are also being considered.

Economics of a Lancaster development

We have built a detailed Lancaster DCF model using the 2013 CPR and company guidance, and have modelled an EPS and a full field development separately as they will be determined by two distinct investment decisions. We estimate that the full field project based on 11 wells would be worth just under $1.2bn, based on a 12% WACC and $80/bbl Brent long term.

On our estimates reflecting the 2013 CPR and recent company guidance, an EPS would cost around $190m to get to first oil with one well (compared to guidance of under $150m). This would rise to c $380m in total including the cost of drilling and tying in a second well, which we estimate could be entirely funded by cash flows generated from the first well. A one- or two-well EPS would be profitable on a standalone go-forward basis with a 42-45% IRR.

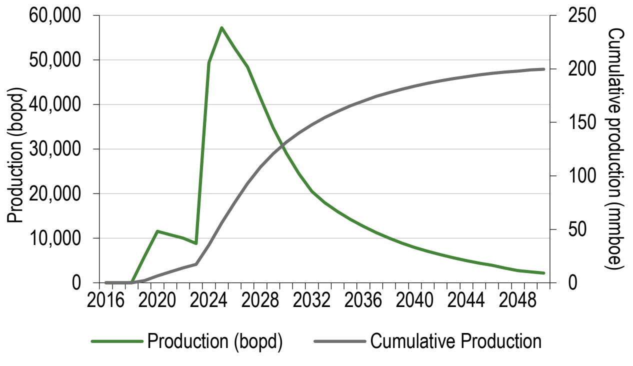
Including a purchased FPSO, we model $2.6bn of development capex (ex-decommissioning) for a full field development including the initial two wells, of which $2.3bn will be spent to get to first full field production and positive free cash flow in 2024. These figures drop to $1.5bn and $1.2bn respectively with a leased FPSO. We base our modelling on the 2013 CPR, with a few tweaks to reflect the results of last year's appraisal well, the current environment and company guidance:

- Development well costs of $55m on average, similar to the 2014 well cost. This compares to a range of $75-94m in the CPR as we assume faster drilling times (67 days, as the horizontal wells will be 1km long rather than 2km) and lower rig rates given the current rig downcycle ($345k/day vs the CPR's $400k/day).
- Pipeline capex of c $710m, higher than the CPR's $445m as Lancaster will likely require heated flowlines.
- Average IP rates of 6,000b/d in year one and declining thereafter, and ultimate recovery per well of 18mmbbls, broadly consistent with the CPR's assumptions. We highlight that there could be upside to initial production rates and recovery per well given the results of the 205/21a-6 well, which flowed at 9,800b/d with an ESP. We model peak production of c 12mb/d from two EPS wells from 2019 to 2023, rising to 57mb/d in 2025 when nine new wells will be brought on-stream.
  - Hurricane has indicated that the first EPS well could produce at high rates of 10-12mb/d for six to 12 months without damaging the reservoir, and could then be choked back to 6mb/d once another well is brought onstream. For simplicity purposes, we have conservatively modelled similar production profiles for all wells.
  - Hurricane's recently disclosed 'first pass' simulation results, using data from the 2014 horizontal well and the CPR reservoir properties, indicate that flow rates of 10,000b/d could be sustained for several years before entering decline. These preliminary results, coupled with the actual horizontal well results (which implied no barriers to flow within the reservoir) highlight the potential for improvements in production rates compared to the CPR and our assumptions.
- We use the new supplementary tax charge of 20%, cut from 30% in the March 2015 UK budget, on top of the 30% corporate tax rate. We factor in $362m (£239m) of tax losses reported at end-2014. We assume that Lancaster is eligible for the proposed investment allowance from the March 2015 budget, whereby the amount of profit exempt from the

supplementary charge will equal 62.5% of capex incurred from 1 April 2015 onwards. The investment allowance adds c 11% to our Lancaster NPV in the purchased FPSO case and 6% in the leased FPSO case.

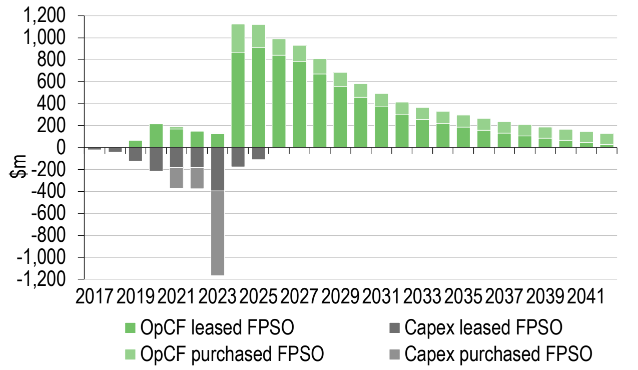
We have modelled Lancaster's cash flow/capex profile assuming the larger 75mb/d FPSO for the full field development is either purchased (for $1.16bn) or leased (for $500k/day), as shown in Exhibit 15. We find that a leased FPSO would yield a higher go-forward IRR (47% vs 35%) and a broadly unchanged NPV. We examine the implications of the FPSO lease-vs-buy choice later in this report.

Exhibit 14: Lancaster production profile and cumulative production



Source: Edison Investment Research, company data

Exhibit 15: Lancaster cash flow profile, in purchased and leased FPSO scenarios



Source: Edison Investment Research, company data

Further assets to be de-risked

Beyond Lancaster, Hurricane has a number of other discoveries and prospects in the area, the majority of which are fractured basement reservoirs (see Exhibit 16). Technical progress on Lancaster would arguably de-risk to some extent the Whirlwind, Lincoln and Typhoon basement reservoir discoveries and prospects. These assets could potentially be included in a larger farm-out deal together with Lancaster.

Exhibit 16: Hurricane asset overview

Asset	2C resources (mmboe)	Prospective resources - best (mmboe)	Status according to CPR	Comments
Lancaster oil, of which:	200*	53	Development pending	Fractured basement discovery. To be developed with 11 wells tied to mid-sized ship-shaped FPSO.
- structural closure	74			
- below structural closure	126	52		
Whirlwind - average case	192	85	Development unclarified	2010 discovery by HUR. Fractured basement with overlying limestone reservoir. Uncertainty on fluid type.
- Whirlwind oil case	205	90		
- Whirlwind gas condensate case	179	80		
Strathmore	32		Development on hold	1991 discovery. Sandstone reservoir. Could be tied back to Premier's Solan field or Lancaster.
Lincoln	0	150		Undrilled prospect. Fractured basement reservoir. Seen as analogue to Lancaster. Tie-back to Lancaster (9km away).
Tempest/Typhoon	26	149		Tempest is a 1981 discovery. Sandstone reservoir. Typhoon is a basement flank prospect.
Total	**450**	**437**		

Source: Company data, Edison Investment Research. Note: *Lancaster also contains 7mmboe of 2C gas resources. 74mmbbls of Lancaster 2C resources within structural closure includes the East accumulation and Commodore sandstone.

- **Lincoln prospect (basement):** Lincoln is located 9km to the south-west of Lancaster, with a similar fractured basement reservoir that sits around 500m deeper. The prospect is estimated to hold P50 prospective recoverable resources of 150mmstb, and the main risks are expected to be the effectiveness of the trap and seal. Hurricane believes that Lincoln has similar characteristics to Lancaster and as a consequence they could be developed together, producing into the same FPSO. As such, it is considered to have the highest priority of the assets surrounding Lancaster.

- **Whirlwind discovery (basement):** Whirlwind sits some 12km to the north of Lancaster and holds 2C contingent resources of 205mmboe in the oil case. Although structurally similar to Lancaster, it is around 2,000m deeper. The fractured basement appears to have a similar fracture density and is additionally overlain by the oil-bearing Valhall formation limestone. Hurricane drilled the 205/21a-5 well on the structure in 2010, although the 2011 well test was unable to establish the reservoir fluid type, as flow from the well was not stabilised and it was not possible to obtain a representative fluid sample. The well was suspended and can be re-entered and side-tracked at a later date to allow appraisal of the discovery, particularly to establish whether the hydrocarbons are a volatile oil or gas condensate.
- **Typhoon prospect/Tempest discovery (basement):** Typhoon and Tempest are located further away from the other Hurricane assets to the south-west of Foinaven in deeper waters of around 450m. Typhoon is primarily a basement prospect, while the potential in the overlying Jurassic sandstones is known as Tempest. Typhoon has P50 prospective resources of 149mmboe, although it carries a significant upside of more than 1bn barrels in the P10 case. This is because it is believed to be a flank accumulation, where oil has built up deep down the flank of the structure (Exhibit 5). Oil samples recovered from the 1981 204/28-1 well drilled on structure by BP indicate the presence of heavy oil, although lighter oil was established in down flank wells 204/23-1 and 204/22-1. Hurricane believes that this points to the possible presence of lighter oil in the flank accumulation; however, this can only be established by drilling an exploration well. The company has a commitment to drill a well on the prospect and must have a rig contracted by the end of June 2016; otherwise it will have to relinquish the licence unless an extension is granted.
- **Strathmore discovery (sandstone):** Strathmore is an undeveloped oil field located 20km to the south-west of Lancaster. The discovery contains 2C resources of 32mmbbls in Triassic aged sandstones. With no fractured basement in the discovery, it is not currently considered part of Hurricane's core portfolio, but could be developed through a tie-back to neighbouring infrastructure, particularly Lancaster.

Management

Hurricane's management has extensive experience in the oil and gas business, and its CEO has significant expertise in the characterisation and evaluation of fractured reservoirs.

Dr Robert Trice (CEO) is Hurricane's founder and has over 25 years' oil industry experience. He has a PhD in Geology from Birkbeck College (University of London) and gained the bulk of his geoscience experience with Enterprise Oil and Shell. He has worked in field development, exploration, well site operations and geological consultancy. Robert has published and presented on subjects related to fractured reservoirs and exploration for stratigraphic traps.

Nicholas Mardon Taylor (CFO) has worked in the oil industry for over 30 years. Nicholas has held senior finance roles within Total, and FD roles at Saxon Oil, Carless and Alkane. Nicholas has been with Hurricane since its creation in 2005 when he was the company's first CFO.

Neil Platt (COO) has more than 20 years' experience and has worked for Amoco, BG and Petrofac. He has worked in engineering, commercial and management roles including production asset manager (NSW) for BG and VP for project delivery in Petrofac Production Solutions. Neil joined Hurricane in 2011 and was appointed to the board in 2013.

John Hogan (non-executive chairman) has over 35 years' experience. He spent almost 20 years with LASMO where he was MD North Sea between 1989 and 1993, followed by seven years on the board as COO. Since 2000 he has held a number of chairman and non-executive roles in the energy sector.

Sensitivities

- **Geological risk:** although last year's 205/21a-6 appraisal well was highly successful and flowed at commercial rates, there remain a number of uncertainties to be addressed by an EPS. Uncertainties include the ability of horizontal wells in the structural closure to drain oil from below structural closure (where 63% of the 2C recoverable resources are located in Lancaster), long-term production rates and water/gas breakthrough. Hurricane has indicated it would take around two years of EPS production to better understand the reservoir and commit to a full field development. Conversely, there is significant upside to economics if well productivity and recovery factors are better than reported in the CPR.
- **Funding risk:** Hurricane is not funded for further appraisal wells, an EPS or full field development. The company is considering various funding options and is in farm-out discussions. In the absence of further drilling, Hurricane is funded for its ongoing business until end-2017, on our estimates. Its 100% operated working interest in its licences means it is in a position of strength and should be able to retain at least a high minority share in the licence. Given the size and attractiveness of the asset, in our view it is possible that a Lancaster farm-out could progress faster than other UK North Sea farm-outs.
- **Delays:** there is no certainty that Hurricane's proposed development concept for Lancaster will be retained by a potential farminee, which could lead to delays if it is reworked by Hurricane's partner(s). It is not unusual for majors farming into assets to devise their own development scenarios. In particular, any changes that would increase development complexity and cost would be unwelcome for Hurricane, notably if it leads to greater dilution.
- **Oil/gas pricing:** while short-term fluctuations do not affect the assets' fair value, their valuation is very sensitive to long-term oil prices. Divergences in views on long-term oil prices between Hurricane and potential farminees could create delays in the farm-out process.

Valuation

Traditionally, we value oil companies with an asset-by-asset NAV derived from detailed DCF modelling. Our valuation includes production, development and contingent resources, while exploration is valued only if the company has a plan and resources to drill in the next 18 months.

We apply a risking to this value, which aims to take account of geological, technical and commercial (development and funding) uncertainties. For unsanctioned projects, we typically apply a maximum commercial risking of 65%, and de-risk them over time. For exploration, in the event of success, companies like Hurricane may not be fully funded for the appraisal and development phase. Our standard assumption is therefore to apply a 50% risking on top of the geological risks to account for commercial and funding issues. For projects with marginal economics (ie where estimated returns are fairly close to the cost of capital), we reduce this commercial risking further to c 33%.

For commodity pricing, we assume $80/bbl long term for Brent (from 2018 onwards), while we use c $7/mcf for UK gas prices, inflated at 2.5% pa from 2015 onwards.

Quantifying potential dilution in a farm-out

Given the importance of Lancaster in Hurricane's valuation, we have attempted to quantify the probable dilution in Hurricane's working interest as it seeks farm-outs to fully carry development capex, assuming an FPSO buy-out. We think a potential farm-out would take place in two stages: a first farm-out deal to fund the EPS, followed by a second farm-out to fund the FFD. We assume that the farminee would carry the entirety of the EPS costs (c $190m gross to first oil) in the first stage; then depending on the outcome of the EPS, it would have an option to carry Hurricane in a full field development at the same working interest. Below we explain our methodology in some detail:

- We assume that a farminee would aim for a c 20% all-in investment return including the capex carry, compared with the project's 35-47% go-forward IRRs. A lower IRR for the farminee vs the project's underlying IRR is justified by the entry costs to be borne by a later-stage entrant into an asset that has been discovered and partially de-risked.
- We calculate that Hurricane would need to farm out 66% of the asset in exchange for a full cost carry to allow the farminee to reach its target IRR. This would leave the company with a 34% working interest after a two-stage farm-out. It is worth noting that if a one- or two-well EPS proves inconclusive and a full field development is not sanctioned, the farminee's investment returns would still be 19-25%, broadly meeting our assumed hurdle rate of 20%. In other words, the farminee's risk/return profile would remain acceptable even if an EPS does not lead to a full field development.

Dilution would be much reduced with a capex-light FPSO lease option

From Hurricane's perspective, we believe it would make more sense to push for an FPSO lease option during the FFD rather than an FPSO purchase. As previously outlined, we estimate that gross capex of $1.2bn would be needed by 2024 to reach full field plateau production with a leased FPSO, well below the $2.3bn required in the purchased FPSO case. This has two main consequences: firstly, we estimate project returns would be comfortably higher with a leased FPSO at 47% vs 35%. Secondly, leasing an FPSO would considerably maximise Hurricane's retained working interest in a second farm-out, as a farminee's assumed target IRR of 20% would be achieved with lower dilution.

Using the same methodology as above, we estimate that Hurricane's post-farm-out working interest in an FPSO lease scenario would be 52%, around 1.5 times the working interest in an FPSO buyout case.

We note that the dilution scenarios outlined above assume that only the Lancaster licence is farmed out. However, Hurricane is also looking to farm down its other assets, which if included in a broader farm-out deal would presumably reduce dilution in Lancaster.

In Exhibit 17 we show a sensitivity of Hurricane's post farm-out working interest in Lancaster using a range of target IRRs applied by the farminee in the farm-out process, and flexing our base case capex by +/- 20%. This analysis shows that while the lease-vs-own FPSO issue is generally less relevant for the well-funded majors, we believe it is an important issue for a small E&P in Hurricane's position of attempting to minimise dilution in a farm-out.

Exhibit 17: Hurricane's WI in Lancaster post farm-outs

		Farminee's target IRR		
	$bn	15%	20%	25%
			Purchased FPSO case	
Capex to	1.87 (-20%)	53%	43%	33%
positive FCF	2.34	45%	34%	23%
	2.81 (+20%)	37%	26%	14%
			Leased FPSO case	
Capex to	0.95 (-20%)	67%	60%	52%
positive FCF	1.18	60%	52%	43%
	1.42 (+20%)	53%	44%	35%

Source: Edison Investment Research

Our conservative RENAV valuation offers upside

Our core NAV includes net cash on the balance sheet as of end-2014 of £16m ($24m), minus the present value of two years' worth of general and administrative costs. We do not yet include Lancaster in our core NAV, as we generally classify resources as "core" only once they are in production, development or close to being sanctioned with a relatively high degree of certainty (usually with a CoS of >50%).

We use our usual development risking for unsanctioned projects of 65% for the early production system, and 59% (or 90% of the EPS risking) for the full field development. Although Lancaster is classified as contingent resources by RPS Energy and thus has a 100% GCoS under industry (SPE) guidelines, we have applied a 90% GCoS to reflect remaining uncertainties such as flow rates, water cuts and drainage of volumes below structural closure. Our total CoS (GCoS x CCoS) is therefore 59% for the EPS and 53% for the FFD.

In our base case valuation, we have assumed that the FPSO is purchased (as per company guidance) despite better investment returns and lower dilution in a leased FPSO scenario for Hurricane. There would be upside to our base case RENAV if the leased FPSO route were chosen. Our RENAV of 45p/share includes the risked Lancaster early production system and full field development, and would be closer to 55p/share with a leased FPSO development.

Exhibit 18: Hurricane Energy valuation summary – purchased FPSO scenario (reference case)

				Recoverable reserves			Net risked	Value per share	
Asset	**Country**	**Diluted WI**	**CoS**	**Gross**	**Net**	**NPV/boe**	**value**	**Risked/**	**Unrisked/**
NOSH: 633.1		**%**	**%**	**mmboe**	**mmboe**	**$/boe**	**$m**	**share (p)**	**share (p)**
Net (debt)/cash 31 Dec 2014		100%	100%				24	3	3
SG&A (two years)		100%	100%				(13)	(1)	(1)
Core NAV							11	1	1
Contingent									
Lancaster EPS - two wells	UK	34%	59%	31	11	13.3	84	9	15
Lancaster FFD (post-EPS)	UK	34%	53%	169	58	11.2	344	36	68
RENAV					**69**		**439**	**45**	**84**

Source: Edison Investment Research, company data. Note: NPV/boe calculations assume a farm-out with full capex carry for Hurricane.

Exhibit 19: Hurricane Energy valuation summary – leased FPSO scenario

				Recoverable reserves			Net risked	Value per share	
Asset	**Country**	**Diluted WI**	**CoS**	**Gross**	**Net**	**NPV/boe**	**value**	**Risked/**	**Unrisked/**
NOSH: 633.1		**%**	**%**	**mmboe**	**mmboe**	**$/boe**	**$m**	**share (p)**	**share (p)**
Core NAV							**11**	**1**	**1**
Contingent									
Lancaster EPS - two wells	UK	52%	59%	31	16	13.3	127	13	22
Lancaster FFD (post-EPS)	UK	52%	53%	169	88	8.5	391	40	77
RENAV					**104**		**528**	**55**	**100**

Source: Edison Investment Research, company data. Note: NPV/boe calculations assume a farm-out with full capex carry for Hurricane.

At this stage, we do not include the possible value from other discoveries and prospects, as there is no clarity on when appraisal/exploration wells will be drilled and how they will be funded. We believe that wells are likely to be drilled beyond our usual 12- to 18-month horizon. This "blue-sky" exploration/appraisal portfolio is worth a further 17p/share of risked upside on our estimates. We stress that we have not conducted the same detailed dilution analysis for other discoveries and prospects as for Lancaster, and as such may overestimate their commercial chances of success.

Exhibit 20: Hurricane Energy valuation summary – exploration/appraisal portfolio

Asset	Country	Diluted WI	CoS	Recoverable Reserves Gross	Net	NPV/boe	Net Risked value	Value per share Risked/ share (p)	Unrisked/ share (p)
		%	%	mmboe	mmboe	$/boe	$m		
Discovery - on hold or unclarified									
Whirlwind	UK	100%	13%	192	192	1.6	42	4	31
Strathmore	UK	100%	10%	32	32	1.2	4	0	4
Long-term exploration upside									
Lincoln	UK	100%	7%	150	150	4.0	40	4	62
Tempest/Typhoon	UK	100%	8%	175	175	3.4	47	5	61
Lancaster prospective resources	UK	100%	5%	53	53	5.8	15	2	32
Whirlwind prospective resources	UK	100%	8%	85	85	2.3	16	2	20
Long-term exploration upside					**687**		**165**	**17**	**211**

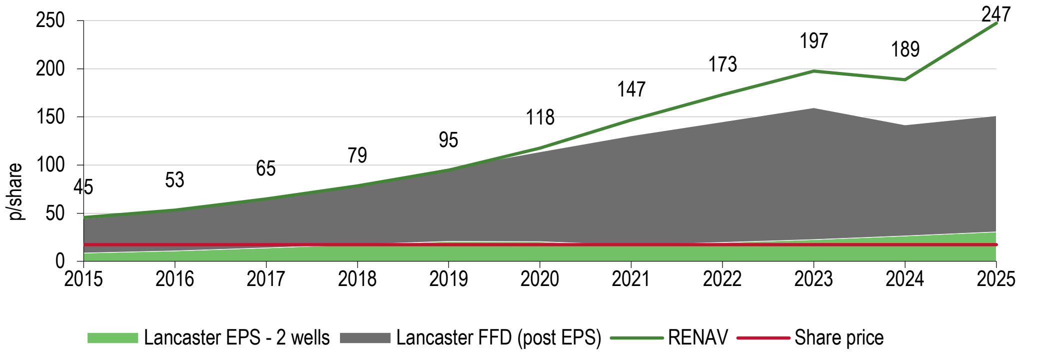
Source: Edison Investment Research, company data. Note: Lincoln includes conventional and unconventional volumes with a combined GCoS of 13.2%. For Tempest/Typhoon we use the 16% GCoS that applies to the flank prospective resources of 149mmbbls, as 2C contingent resources of 26mmbbls are too small to be developed standalone. For Whirlwind, we show the arithmetic average of the oil case (205mmboe) and the gas/condensate case (179mmboe). NPV/boe calculations include capex. We have not conducted the same quantified farm-out analysis to estimate post farm-out working interests for exploration/appraisal assets.

Rolling NAV shows value accretion over time

While a snapshot valuation is informative, it is also useful to see how the value could progress over the coming years as the Lancaster EPS and FFD developments progress, the project is further de-risked and first production nears. We can evaluate how NAV will evolve over time, modelling the Lancaster project including development capex from 1 January 2016, 2017 etc and net debt/cash evolution. In addition to the natural NPV accretion that arises from getting closer to first production, we gradually de-risk the EPS by 2019, and the full field development by 2024.

This analysis shows that our RENAV of 45/share grows at 19-22% CAGR to 2020-25 based only on Lancaster moving forward. Excluding any de-risking of the project and just based on natural NPV accretion and cash generation, the returns are c 11-15%.

Exhibit 21: Hurricane RENAV over time



Source: Edison Investment Research. Note: Lancaster FFD assumes purchased FPSO case.

Sensitivities

Below, we illustrate the sensitivity of RENAV to oil prices and discount rates. Every $10/bbl change in the long-term Brent price moves our RENAV by c 12%, using constant chances of success. We note this analysis does not take into account possible cost/capex reductions if lower oil prices are sustained, which would likely dampen NPV sensitivities.

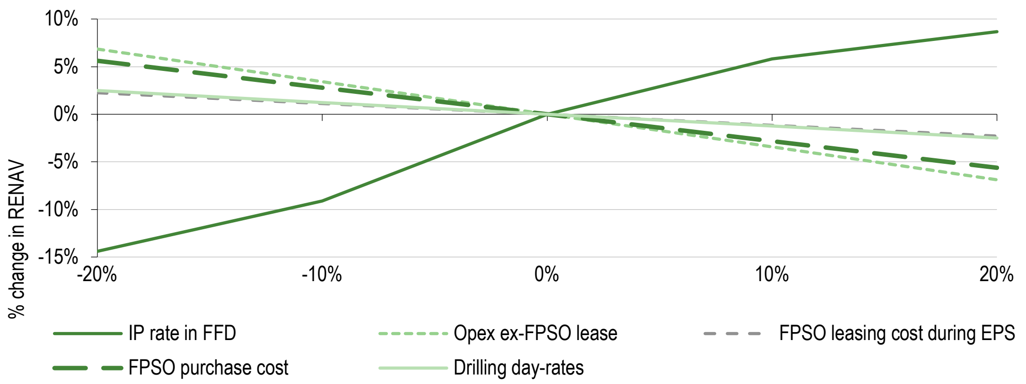
Exhibit 22: Sensitivity of RENAV to oil price (p/share)

		Long-term Brent oil price ($/bbl)				
		60	**70**	**80**	**90**	**100**
Discount rate	**10%**	42	49	56	63	70
	11%	38	44	51	57	63
	12%	34	40	45	51	57
	13%	31	36	41	46	51

Source: Edison Investment Research. Note: CoS for Lancaster is fixed at our base case, not dynamic. In reality, changes in oil prices would alter the project's NPV/IRR, and hence the level of dilution in a farm-out.

In Exhibit 23 below, we show sensitivities to +/-10% changes in well initial production (IP) rates and costs, including operating costs, FPSO leasing day rates and drilling day rates. RENAV is most sensitive to well productivity and unit opex, and less sensitive to FPSO costs and drilling day rates.

Exhibit 23: Sensitivity of unrisked Lancaster NPV to well productivity and costs



Source: Edison Investment Research

Among non-macro parameters, the most important sensitivity is well productivity and recovery per well. Higher commercial flow rates would lead to a reduced well count – for instance, moving to 8,000b/d instead of 6,000b/d would mean only eight wells instead of 11 are needed to produce 200mmbbls. It would reduce capex and improve investment returns accordingly, thus minimising dilution, particularly in a purchased FPSO scenario. To illustrate this, we show the impact of a reduced well count on capex, post farm-out working interest (which drives our CoS) and ultimately RENAV.

Exhibit 24: Sensitivity to IP rates – better economics should mean less dilution

IP (bopd)	EUR (mmboe)	# wells in FFD	Dev capex (purchased FPSO)	Dev capex (leased FPSO)	Lancaster unrisked NPV (purchased)	WI post farm-out	RENAV (p/share)
4,000	11.9	17	3,208	2,051	875	15%	20
6,000	**18.2**	**11**	**2,626**	**1,469**	**1,190**	**34%**	**46**
8,000	24.5	8	2,335	1,178	1,308	42%	56
10,000	30.8	6	2,141	984	1,321	46%	61

Source: Edison Investment Research. Note: WI and CoS are dynamic, not fixed. Dev capex excludes decommissioning costs. Assumes purchased FPSO case.

In the event only volumes in the structural closure (74mmbbls) were recovered, we estimate that our RENAV would fall to 23p/share, all else being equal. Conversely, in an upside case where only eight wells were needed, our RENAV would rise to c 56p/share. In the 3C contingent resource case (437mmbbls), our RENAV would rise to 109p/share.

Low implied EV/2C valuation points to upside in farm-out

Hurricane is currently trading on an EV/2C of $0.3/boe, or $0.7/boe based on Lancaster 2C resources alone. Generally speaking, the oil and gas industry ascribes considerably more value to assets in farm-out deals than equity markets, with the stock market discount anywhere from 50% to 80% of values paid by industry. Given the fairly unique nature of Hurricane's fractured basement asset portfolio, recent North Sea transactions unfortunately offer few insights for investors to benchmark Hurricane's valuation. We highlight Faroe's September 2014 sale of the Glenlivet gas discovery to Total in the West of Shetland, executed at $3.3/boe of 2P reserves, around 10 times above Hurricane's current implied EV/2C valuation. UK E&P peer Xcite Energy currently trades on $1.0/boe of 2P+2C resources from its Bentley heavy oil field located east of Shetland. This points to considerable potential upside for Hurricane once a farm-out is announced.

Financials

Hurricane has just under £16m (c $24m) of cash on its balance sheet as of end-2014, down from £38m at end-June 2014 as it spent c £22m on the 205/21a-6 appraisal well (out of a total of £37m) in H214. If the company does not drill any further wells at its current 100% working interest and spends £5m a year on G&A and geological studies, it would be fully funded for up to three years (ie until end-2017) on our estimates. In its 2014 annual report dated 1 May 2015, the company states it is funded for G&A for "at least the next 12 months".

Hurricane is therefore in a position of strength to farm down its interest in Lancaster and other assets, with 100% ownership of its licences and no rush to issue equity to fund well commitments (other than the Tempest/Typhoon commitment well). It is currently in farm-out discussions, having opened a dataroom in early October 2014, and has seen "considerable industry interest" in both Lancaster and its other assets. As previously indicated, we estimate that HUR would be able to retain at least a high minority stake in the licence after a two-stage farm-out process.

One of the key advantages of an EPS is that it would move some contingent resources into 2P reserves (although it is unclear how much it would be allowed to move into reserves), and thus allow Hurricane to seek reserve-based lending (RBL) to help fund the full field development. Debt funding would reduce Hurricane's WI dilution during a second farm-out, and possibly entirely obviate the need for a second farm-out if it chooses the capex-light FPSO leasing option. Other funding sources include equity, and financing from the contractor group.

Below we show sensitivities to Hurricane's RENAV if we factor in access to an RBL facility equivalent to c 10-20% of the gross capex requirements in the full field development phase. Access to RBL funding should allow Hurricane to retain a greater share of the Lancaster licence.

Exhibit 25: Hurricane RENAV assuming RBL funding used in full field development

Reserve-based lending facility ($m)	WI farmed out (%)	WI retained (%)	RENAV (p)
Purchased FPSO case			
No RBL	66%	34%	45
250	58%	42%	49
350	55%	45%	52
450	53%	47%	53
Leased FPSO case			
No RBL	48%	52%	55
150	42%	58%	56
200	40%	60%	57
250	38%	62%	58

Source: Edison Investment Research

EDISON

Exhibit 26: Financial summary

£ '000s	2012	2013	2014	2015e	2016e	2017e
Dec	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS
PROFIT & LOSS						
Revenue	0	0	0	0	0	0
Operating Expenses	(7,216)	(5,151)	(8,489)	(5,000)	(5,000)	(5,000)
EBITDA	(7,216)	(5,151)	(8,489)	(5,000)	(5,000)	(5,000)
Operating Profit (before amort. and except.)	(7,216)	(5,333)	(8,584)	(5,095)	(5,095)	(5,095)
Exploration expenses	(9)	(534)	0	0	0	0
Exceptionals	0	(8,792)	0	0	0	0
Other	0	0	0	0	0	0
Operating Profit	(7,225)	(14,659)	(8,584)	(5,095)	(5,095)	(5,095)
Net Interest	444	(6,671)	(441)	41	20	0
Profit Before Tax (norm)	(6,772)	(12,004)	(9,025)	(5,054)	(5,075)	(5,095)
Profit Before Tax (FRS 3)	(6,781)	(21,330)	(9,025)	(5,054)	(5,075)	(5,095)
Tax	(18)	(23)	19	0	0	0
Profit After Tax (norm)	(6,790)	(12,027)	(9,006)	(5,054)	(5,075)	(5,095)
Profit After Tax (FRS 3)	(6,799)	(21,353)	(9,006)	(5,054)	(5,075)	(5,095)
Average Number of Shares Outstanding (m)	462.8	480.2	621.4	633.1	633.1	633.1
EPS - normalised (p)	(1.5)	(2.5)	(1.4)	(0.8)	(0.8)	(0.8)
EPS - normalised and fully diluted (p)	(1.5)	(2.5)	(1.4)	(0.8)	(0.8)	(0.8)
EPS - (IFRS) (p)	(1.5)	(4.4)	(1.4)	(0.8)	(0.8)	(0.8)
Dividend per share (p)	0.0	0.0	0.0	0.0	0.0	0.0
Gross Margin (%)	NA	NA	NA	NA	NA	NA
EBITDA Margin (%)	NA	NA	NA	NA	NA	NA
Operating Margin (before GW and except.) (%)	NA	NA	NA	NA	NA	NA
BALANCE SHEET						
Fixed Assets	131,207	138,141	177,653	184,994	192,335	206,276
Intangible Assets	131,077	137,681	177,308	184,744	184,744	184,744
Tangible Assets	0	330	215	120	7,461	21,402
Investments	130	130	130	130	130	130
Current Assets	22,780	41,265	17,409	5,014	1,553	1,553
Stocks	0	0	0	0	0	0
Debtors	390	1,098	1,553	1,553	1,553	1,553
Cash	22,390	40,167	15,856	3,461	0	0
Other	0	0	0	0	0	0
Current Liabilities	(810)	(42,709)	(1,487)	(1,487)	(1,487)	(1,487)
Creditors	(810)	(16,564)	(1,487)	(1,487)	(1,487)	(1,487)
Short term borrowings	0	(26,145)	0	0	0	0
Long Term Liabilities	(4,000)	(4,764)	(7,281)	(7,281)	(16,235)	(35,271)
Long term borrowings	0	0	0	0	(8,954)	(27,990)
Other long term liabilities	(4,000)	(4,764)	(7,281)	(7,281)	(7,281)	(7,281)
Net Assets	149,177	131,933	186,294	181,240	176,165	171,070
CASH FLOW						
Operating Cash Flow	(6,307)	(4,424)	(4,677)	(4,959)	(4,980)	(5,000)
Net Interest	0	0	0	0	0	0
Tax	0	0	0	0	0	0
Capex	(33,066)	(6,944)	(36,542)	(7,436)	(7,436)	(14,036)
Acquisitions/disposals	0	0	0	0	0	0
Financing	28,527	3,533	16,783	0	0	0
Dividends	0	0	0	0	0	0
Net Cash Flow	(10,846)	(7,835)	(24,436)	(12,395)	(12,415)	(19,036)
Opening net debt/(cash)	(32,888)	(22,390)	(14,022)	(15,856)	(3,461)	8,954
HP finance leases initiated	0	0	0	0	0	0
Other	348	(533)	26,270	0	0	0
Closing net debt/(cash)	(22,390)	(14,022)	(15,856)	(3,461)	8,954	27,990

Source: Edison Investment Research, company data. Note: Assumes no farm-outs, ie Lancaster EPS funded at 100% WI by Hurricane for illustrative purposes.

Contact details	Revenue by geography
Hurricane Energy The Wharf, Abbey Mill Business Park Godalming United Kingdom +44 1483 862 820 www.hurricaneenergy.com	N/A

Management team

CEO: Dr Robert Trice	CFO: Nicholas Mardon Taylor
Dr Robert Trice is Hurricane's founder and has over 25 years' oil industry experience. He has a PhD in Geology from Birkbeck College (University of London) and gained the bulk of his geoscience experience with Enterprise Oil and Shell. He has worked in field development, exploration, well site operations and geological consultancy. Robert has published and presented on subjects related to fractured reservoirs and exploration for stratigraphic traps.	Nicholas Mardon Taylor has worked in the oil industry for over 30 years. He has held senior finance roles within Total, and FD roles at Saxon Oil, Carless and Alkane. Nicholas has been with Hurricane since its creation in 2005 when he was the company's first CFO.
Chief Operations Officer: Neil Platt	**Non-exec Chairman: John Hogan**
Neil Platt has more than 20 years' experience and has worked for Amoco, BG and Petrofac. He has worked in engineering, commercial and management roles including production asset manager (NSW) for BG and VP for project delivery in Petrofac Production Solutions. Neil joined Hurricane in 2011 and was appointed to the board in 2013.	John Hogan has over 35 years' experience. He spent almost 20 years with LASMO, where he was MD North Sea between 1989 and 1993, followed by seven years on the board as COO. Since 2000 he has held a number of chairman and non-executive roles in the energy sector.

Principal shareholders	(%)
Crystal Amber Fund	9.8%
Taheh International Holdings	9.6%
Artemis Investment Management	7.6%
Blue Investments 2 LP	5.9%
Awal Bank	5.5%
Matopos Holdings	4.6%
Robert Trice	4.0%

Companies named in this report

Hurricane Energy, BP, Premier Oil, Shell, EnQuest