Company Note

Update

25 March 2021

Baron Oil plc (BOIL.L)

Chuditch interest increased, financing underpinned

In a positive move, Baron Oil has announced a restructuring of the ownership of the high-impact Chuditch natural gas project in the Timor Sea. Baron's indirect interest rises from 25.0% to 63.75%. In exchange, Baron will finance a $3.5m work programme through to the drill or drop decision in November 2022. Financing has been underpinned by the recent £3m equity raise. Baron has effectively acquired an incremental 228mm boe net of un-risked prospective resources for a nominal 1.5 cts/boe. Following the announcement in February that ANPM, the Timor-Leste government agency had granted an extension for the Chuditch licence and the recent equity raise, appraisal work on the project is now poised to commence. The initial phase concerns the reprocessing and evaluation of legacy seismic data. TGS, a leading geoscience specialist will be appointed for the task. Assuming satisfactory evaluation results, Chuditch should advance to the farm-out phase in late 2021. This would be a prelude to drilling in 2023.

- **Chuditch PSC:** Chuditch lies in the Timor Sea 185 km south east of the southern Timor-Leste coast and 400km north west of Darwin. Geologically Chuditch lies towards the northern frontier of the Bonaparte Basin, an established hydrocarbon province. Chuditch lies about 120 km north east of Santos's Bayu-Undan giant condensate/gas field (recoverable reserves 967mm boe). Following the restructuring, the Chuditch PSC ownership is: Baron Oil 63.75% (indirect), Singapore-based SundaGas Pte Ltd 11.25% and the Timor-Leste NOC 25%. The operator is a jointly owned SundaGas/Baron company.

- **Resource base:** The Chuditch project is based on a discovery made in 1998 by Shell in Jurassic Plover sandstones, a regionally prolific reservoir formation. The resource base appears substantial based both on the original discovery and on the joint-venture's evaluation work. Prospective resources have been estimated by SundaGas at to 3.52 tcf or 587mm boe gross. Natural gas liquids could provide upside given the prevalence of wet gas in the Bonaparte Basin. Baron believes that the juxtaposition of several prospects and leads in the vicinity of the Chuditch discovery could be pointing to one large continuous accumulation. This would have profoundly positive implications for project economics.

- **Work programme:** The initial phase of the Chuditch work programme involves reprocessing and evaluating a minimum 800 km² of 3-D and 2,000 km of 2-D seismic. The work will take approximately 12 months and cost around $1.6m. It should provide the final stage in the geological de-risking process and assist in identifying drilling locations. In addition, the work programme involves outlays of a further $1.9m in 2021/22.

- **Valuation:** We have upgraded our Baron absolute valuation reflecting higher attributable resources following the Chuditch change of ownership. Partially offsetting this has been a reduction of working interest in Chuditch for a free-carry farm-in. We have assumed a 50% concession on project equity for this purpose. Our risked sum of the parts absolute valuation rises from £21.8m to £25.4m. On a per share basis the risked valuation post the recent raise is 0.244p. This is close to the diluted 0.243p given in our January 8, 2021 report which assumed a share raise for the forecast 2021/22 financing requirement.

Year End: 31 December					
(£'000)	**2018**	**2019**	**2020E**	**2021E†**	**2022E†**
EBITDA	(549)	(442)	(460)	(510)	(612)
NET CASH / (NET DEBT)*	1,709	347	1,276	1,427	0

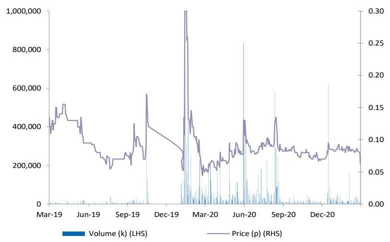
Allenby Capital acts as Nomad & Broker to Baron Oil plc (BOIL.L). * Free cash definition † pro forma

Please refer to the last page of this communication for all required disclosures and risk warnings.

Corporate

Current price	**0.063p**
Sector	**Oil & Gas**
Code	**BOIL.L**
AIM	**AIM**

Share Performance



	1m	3m	12m
BOIL.L	-25.9%	-23.6%	20.0%

Source: Thomson Reuters, Allenby Capital

Share Data (post placing)		
Market Cap (£m)		**6.6**
Shares in issue (bn)		**10.43**
52 weeks (p)	High	Low
	0.14	**0.05**
Financial year end		**31 December**

Source: Company Data, Allenby Capital

Key Shareholders (pre placing)	
Hargreaves Lansdown	12.31%
Interactive Investor Services	10.87%
Jarvis Investment Management	9.68%
HSDL Nominees	9.14%
Barclays Stockbrokers	5.80%

Source: Argus Vickers, Allenby Capital

Peter J Dupont

0203 002 2078

p.dupont@allenbycapital.com

www.allenbycapital.com

Equity Research

Chuditch PSC and SundaGas background

The operator of the Chuditch PSC (production sharing contract) and the holder of the licence is SundaGas Banda Unipessoal Ltd which is owned 100% by SundaGas (TLS) Pte Ltd. The latter in turn is owned by Singapore-based SundaGas Pte Ltd and Baron. SundaGas Banda Unipessoal was granted the Chuditch PSC in December 2019 by ANPM, the Timor-Leste oil and gas regulatory body. The Chuditch licence is for three years and was initially due to expire in December 2022. Importantly, a one-year extension was granted in late February 2021 to allow for circumstances beyond the control of the SundaGas/Baron joint-venture which delayed work on the project. The most significant problem was gaining access to the legacy 3-D seismic.

SundaGas Pte Ltd was incorporated in 2016 and is owned 50:50 by the CEO Dr Andy Butler and the Executive Director Paul Ebdale. The objective was to create a SE Asia focused oil and gas exploration targeting low-risk projects in proven hydrocarbons basins. Chuditch falls into this category. SundaGas has a headcount of six oil and gas industry professionals all with considerable experience in technical and commercial capacities working for high profile E&Ps such as ConocoPhillips, Hess and Serica Energy SE Asia. Paul Ebdale had previously founded the SE Asia-Pacific focused TSX-listed Mitra Energy. This has subsequently evolved as Jadestone Energy and was redomiciled to AIM in March 2020 where it trades under the symbol JSE. As of mid-March 2021, Jadestone's market capitalisation was about £314m. Dr Butler and Paul Ebdale have been involved in multiple farm-outs. The latter brought a major development project in Vietnam into Jadestone.

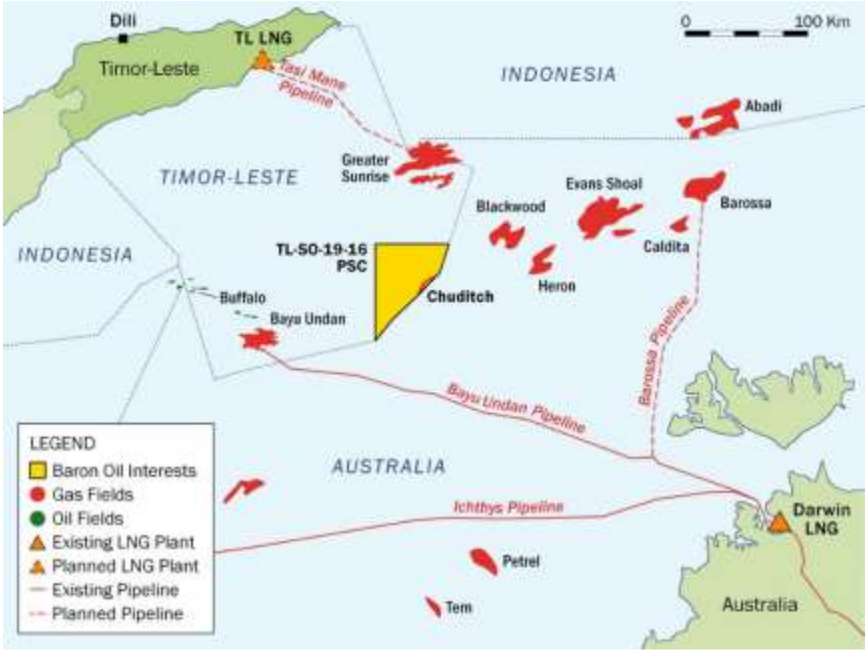
Baron Oil's interest in the Chuditch PSC project stems from its shareholding in SundaGas (TLS). Originally the interest was 33.33% and reflected consideration for support given to SundaGas in their application for the Chuditch PSC. Importantly, in March 2021 it was announced that Baron would be substantially boosting its interest in SundaGas (TLS) to 85.0% following its decision to finance the first phase of the Chuditch development programme to November 2022. The residual 15.0% is owned by SundaGas Pte Ltd. The cost of the programme is $3.5m the core of which is the TGS reprocessing and evaluation of legacy 2-D and 3-D seismic data. This will be undertaken in the UK by TGS and will cost $1.6m and take about a year. The balance of the expenditure programme comprises other sub-surface studies, a number of overhead items, including costs related to licence commitments, payments to the operator and G&A.

The Chuditch ownership structure is as follows: SundaGas (TLS) 75%, the Timor-Leste NOC (national oil company), Timor Gap 25%. Baron's indirect interest via SundaGas (TLS) is therefore 63.75% while SundaGas Pte Ltd has an indirect interest of 11.25%. Note, Timor Gap is free carried for expenditure purposes through to the development stage.

PSC terms

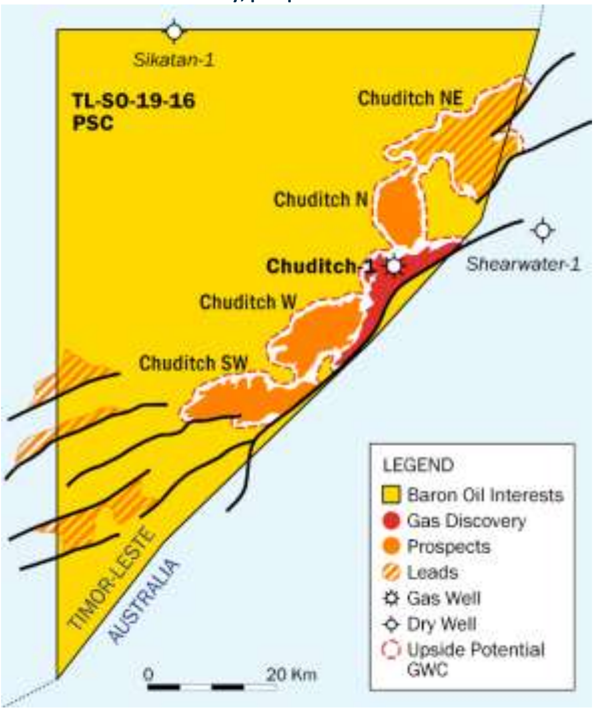
The key requirement of the Chuditch PSC is to reprocess and evaluate the 800 km of 3-D and 1,200 km of 2-D legacy seismic available on the licence within the first two years of the PSC. Subject to satisfactory results from the seismic reprocessing, the PSC calls for an exploration or appraisal well to be drilled in year three, effectively 2023. A drill or drop decision is therefore required before the end of 2022. Note, that given the requirement for a hefty input of both financial and technical resources drilling is unlikely to be undertaken without the involvement of a farm-in partner providing free-carry terms.

Exhibit 1: Chuditch project regional setting



Source: Company

Exhibit 2: Chuditch discovery, prospects and leads



Source: Company

Potential farm-in partners and development programme

Farm-in partners

Assuming positive results from the seismic reprocessing and evaluation study, the Baron-SundaGas joint-venture will focus its attention on securing a farm-in partner. As we have noted on previous occasions, the most obvious candidate is Santos Ltd, Australia's second largest oil and gas producer and arguably the most influential operator in the Bonaparte Basin. The suitability of Santos as a partner reflects the proximity of its 26-inch pipeline from the Baya-Undan field to the Santos operated LNG plant at Wickham Point near Darwin. In principle, we believe a prospective Chuditch field development could easily and cost effectively be linked to Santos's 26-inch pipeline. As far as we are aware, there are no major physical obstacles to overcome. Significantly, the Wickham Point facility needs new feedstock supplies to replace declining output from mature gas fields of which Baya-Undan is the key example.

Excluding Santos and Woodside Energy, the two leading Australian oil and gas producers, we think the most likely farm-in partners for a prospective Chuditch development project are East Asian oil energy companies and possibly utilities. In the former category could be Korea based SK Energy, the Japanese operators INPEX and Mitsubishi Energy and the Chinese major CNOOC (assuming no Australian involvement in the project). Interestingly, SK Energy is a 37.5% joint-venture partner in Santos's 62.5% owned and operated Barossa gas field project in the Bonaparte Basin. SK also has a binding agreement with Santos to acquire a 25.0% interest in the Baya-Undan field and Wickham Point LNG facility.

The utility candidates might include the likes of Tokyo Gas, Kansai Electric, Osaka Gas and JERA. Santos, note, is finalising an agreement to sell a 12.5% interest in Barossa subject to a FID. The key requirements potential partners are ready access to capital and engineering resources. Western energy companies that have been active in SE Asia in the past such ConocoPhillips, Hess, Total and ENI are unlikely to be farm-in candidates this time around. This reflects withdrawals from SE Asia and/or scaling back of exploration and development activity. A corps of Australian mid-tier oil and gas companies could also be farm-in candidates. These include Oil Search, Beach Energy, Karoon Energy, Senex Energy and Carnarvon Petroleum.

Free-carry farm-in terms

To secure a farm-in partner for Chuditch offering free-carry terms for future spending Baron and SundaGas will need to concede equity in the project. At this stage the amount of the concession is unknown but we believe based on experience elsewhere it could be 50%. Much, of course, will depend on the results of TGS's seismic reprocessing and evaluation exercise.

Development programme

The PSC requirement to drill in 2023 probably implies securing a farm-in partner by early 2022 bearing in mind the lead time required for well planning. We believe the minimum lead time for such tasks as securing and mobilising a rig, well design and procurement of OCTG (oil country tubular goods) supplies is around six months. Drilling activity in the region suggests that securing a rig should not be an issue.

Previous intimations from Baron have been that the plan is to drill back-to-back in 2023 one appraisal and one exploration well. Drilling costs are believed to be modest in the Chuditch licence area at around $12m on a dry hole basis. Keeping costs down are relatively shallow water at significantly less than 100m and hence the use of jack-up rigs, the ready availability of rigs in SE Asia and a moderate TD (total depth) objective of less than 3,000 m. Assuming drilling yields encouraging results in terms of key parameters such as flow rates, reservoir permeability and well EURs, the next phase in development would be the FEED (front end engineering and design). This is effectively a feasibility study which may also be combined with further appraisal drilling. We would expect the FEED to be undertaken in 2024/25 and to be followed by the FID (final investment decision) and the EPC (engineering procurement and construction).

The most probable development route would involve production wells tied into a central gas gathering and processing facility. Ideally this would be linked to Santos's pipeline to the Wickham Point facility at Darwin. An alternative development strategy would be to establish a FLNG (floating LNG) facility at Chuditch with an onboard LNG processing capability. We believe, however, this is an unlikely strategy given the acute technical difficulties Shell has encountered on its Prelude FLNG facility in the nearby Browse Basin. Assuming a liquids rich resource a FPSO (floating production, storage and offloading) facility will need establishing at Chuditch for processing and storage. Such a facility is planned at Santos's Barossa project. Given the scope and scale of a potential Chuditch development project, we think it unlikely that it would be on-stream before 2026 and in all probability, 2027.

Bonaparte Basin exploration and development activity

The Bonaparte Basin covers about 270,000 km² and mainly lies to the north of the coast line of Australia's Northern Territory and Western Australia in the Timor Sea. The northern boundary is the Timor Trough while in the west it adjoins the Browse Basin and in the west the Money Shoals Basin. The Bonaparte Basin stemmed from rifting associated with tectonic activity between Cambrian and Cretaceous periods (500-60mya). Successive periods of uplift and erosion have resulted in deep sedimentation which host major hydrocarbons reservoirs particularly in Middle Jurassic sandstone formations.

Exploration has been undertaken in the Bonaparte Basin since the late 1960s. The most significant developed discovery to date has been the giant Bayu-Undan field which was estimated to have recoverable reserves of gas and condensate of almost 1bn boe. ConocoPhillips made the discovery in early 1995. Production at Bayu-Undan commenced in 2004 using a FPSO to process the liquids. In 2006 natural gas shipments commenced along the 500 km pipeline to Darwin.

Interestingly, the Bonaparte Basin contains several undeveloped discoveries. These include Barossa (Santos), Petrel (Neptune Energy/Santos), Tern (Engie), Greater Sunrise (Woodside/Timor Gap) and Chuditch (SundaGas/Baron). Barossa has been undergoing a FEED study which is expected to lead to an FID imminently. Given the approaching depletion of the Bayu-Undan field based on the existing well infrastructure, Santos needs new sources of feedstock for its Wickham Point LNG facility. Barossa provides a ready source of new supply relatively close to Wickham Point which can also be linked into the Bayu-Undan to Darwin pipeline. Significantly, Santos announced in early January 2021 the go ahead for a $235m infill drilling programme at Bayu-Undan which will add over 20mm boe of gross reserves and production.

GDF Suez (Engie) had previously investigated a possible FLNG project at Petrel but decided not to undertake a FEED study in 2014. Subsequently, Neptune Energy has conducted a 3-D seismic data gathering and evaluation study over Petrel. The Woodside operated Greater Sunrise project is based on a discovery originally made by Shell in 1974. According to industry sources, the resource base is substantial at over 1bn boe but there is a conflict over how Greater Sunrise should be developed between Woodside and the NOC, Timor Gap. The most obvious technical solution would be to link Greater Sunrise to the Bayu-Undan to Darwin pipeline and the Wickham Point LNG facility. The alternative strategy based on a pipeline to an onshore LNG facility Timor-Leste has the engineering challenge of overcoming the Timor Trough which in places is up to 3,000m deep. Daunting costs along with the engineering challenges are believed to preclude a pipeline link between Greater Sunrise and an onshore Timor-Leste LNG facility.

LNG market

Supply-demand balance

According to Shell, world LNG demand in 2020 was 360 mm tonnes, marginally up on the 358m tonnes of the previous year. In a generally down year for conventional energy this rated as a strong performance. Demand overall was supported by buoyant growth in China, India and other smaller Asian markets which broadly offset weakness in Japan, RO Korea and most of Europe and Mexico. LNG, note, is very much an Asia centric market accounting for about 70% of world demand. Historically, Japan has been the largest LNG market but according to industry forecasts is likely to be overtaken by China by mid-decade. In 2020 Chinese LNG demand was 67mm tonnes or 19% of the world total.

During the course of 2020 world, LNG demand was strong at the beginning of the year but as for other hydrocarbons fell sharply in the second quarter as the covid pandemic intensified. Demand, however, recovered sharply in the second half of 2020 as the Chinese economy and other Asian economies regained upward momentum. In the fourth quarter demand was given a further boost by seasonally cold conditions in much of northern Asia.

Overall, the market appears to have been in supply surplus in 2020, although this was probably more muted than might have been expected due to falling production in Australia and particularly in the second quarter in the US. Australia was hit by ongoing technical and unplanned maintenance issues at three major facilities, Chevron operated Gorgon and Wheatstone and Shell operated Prelude FLNG (floating liquefied natural gas). US LNG availability was sharply reduced in the second quarter of 2020 by uneconomic netbacks as LNG prices plunged. Since the second quarter of 2020, US LNG exports have rebounded reflecting strengthening economics as prices trended higher. In 2020 we also believe that production was down in the mature gas producing provinces of Indonesia and probably Norway given an unplanned outage due to a fire at the Hammerfest LNG facility. Offsetting the areas of weakness in 2020, we believe, were the Middle East and Russia.

Industry sources including Oslo-based energy consultants Rystad Energy, are suggesting that LNG demand globally will increase to about 580mm tonnes by 2030 and 700mm tonnes in 2040. On this basis, growth would average 4.9% pa between 2021 and 2030 and 1.9% pa between 2031 and 2040. Growth is expected to be largely driven by Asian markets and is a function of both rapidly growing economies and fuel substitution in support of emission reduction programmes. The latter includes the increasing use of blue hydrogen (hydrogen sourced from natural gas using carbon capture and storage technology) in difficult to decarbonise applications.

Near to medium term world LNG supply, including projects already under construction or in the pipeline combined with unutilised capacity, appears adequate to meet demand. Rystad and others, however, are suggesting that to satisfy the 2030 demand projection new projects with a capacity of 104mm tonnes will need initiating by 2026. Significantly, in late February 2021 the LNG industry leader, Qatar, announced the go ahead for its $30bn North Field expansion. In the first phase this will boost Qatar’s capacity by 33mm tonnes to 110mm tonnes. The second phase which is currently undergoing a FEED study will increase capacity to 126mm tonnes.

Rystad expects the new Qatar capacity to come on-stream by 2028/29. Further capacity expansion projects are being contemplated in the Middle East particularly in Saudi Arabia, UAE and Iran. Elsewhere, capacity could be brought on-stream by 2030 in the US (mainly expansion of existing capacity) and Russia (Yamel peninsula). Following large gas discoveries in recent years offshore east Africa this could conceivably become a major new source of LNG, although given the lead times to establish facilities we could be looking at post 2030 before they are operational.

Although conceptually there are probably more than enough LNG projects at the conceptual and planning stages, there will is likely to be a significant rate of attrition particularly due to financial constraints. The depletion curve on existing fields is also a factor to bear in mind. We believe a prospective Chuditch gas field development ideally connected to the Wickham Point LNG facility should be in a strong competitive position by virtue of the following:

- Low production costs given relatively shallow water
- The existence of an established LNG processing facility
- The relatively short distance to the markets of East Asia
- Established infrastructure

LNG prices

The LNG benchmark price in the key East Asian market is the Japan-Korea-Marker (JKM). Over the past 12 to 15 months this has been on a proverbial roller-coaster ride. In early 2020 the JKM based on S&P Global Platts data was trading at just over an historically subdued $5/mmBtu cif (cost of insurance and freight or delivered to the port of entry) reflecting mild early winter weather in northern Asia and high inventories. Late in the first quarter and during the second quarter of 2020 the JKM came under heavy pressure as covid-related restrictions on economic activity sharply depressed demand. Late in the second quarter the JKM was trading at an all-time low of under $2/mm Btu, a clearly unprofitable level even on a cash basis.

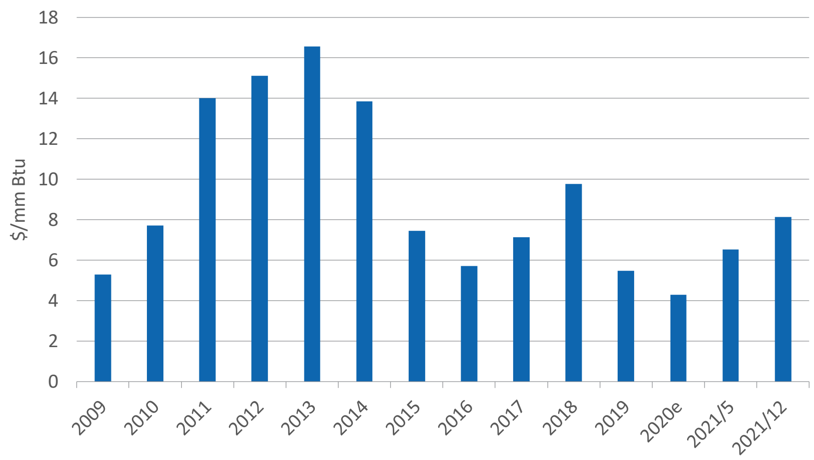
During the third quarter the trend reversed so that by late September the JKM was back to around $5/mm Btu. The drivers were, a firmer demand backdrop as the Chinese economy came back on-stream and constrained supply stemming from facility outages particularly in Australia and the backwash of production cutbacks in the US. The trend continued to firm in the fourth quarter of 2020 driven by un-seasonally cold conditions in northern Asia, firming economic activity, continuing supply constraints and a rundown of inventories.

By end 2020 the JKM was trading at about $10/mm Btu. The average for 2020 as a whole was about $4.3/mm Btu, down 22% on the previous year and at least an 11-year low. During early to mid-January 2021 the JKM spiked to an unprecedentedly high of about $33/mm Btu. The spike reflected extreme weather conditions in northern Asia and severe supply constraints both for LNG and piped gas from Kazakhstan into China.

The spike gave way to a sharp decline in late January which left the JKM trading at around $8/mm Btu at end month. The abrupt reversal in the trend reflected a return to more normal weather conditions and an easing of supply constraints. As of mid-March, JKM spot, based on S&P Global Platts data, was trading at around $6.5/mm Btu. The forward curve shows prices of $6.53/mm Btu for May deliveries and $8.13/mm Btu for December deliveries. Looking out through the middle and back end of the Platts curve into 2026, the JKM marker curve trends broadly flat and ranges between $5.5/mmBtu and $8.6/mm Btu.

For investment decisions the forward curve is arguably of greater relevance than the spot price. A JKM averaging around $7/mm Btu as implied by the forward curve would, in our view, tentatively points to the potential for profitable operations for a prospective Chuditch gas field linked to a Wickham Point LNG facility. Our thinking here is that lifting, processing and pipeline costs could be in the region of $2/mm Btu while LNG processing, liquefaction and transportation might be $4/mm Btu. By-product condensate and natural gas liquids would significantly enhance project economics. Breakeven delivered prices for Qatar according to Rystad are $4/mm Btu but over $6.5/mm Btu for US LNG producers. Note, compared with the US Gulf Coast the distance to East Asia ports of entry from Darwin is considerably shorter. Unlike for shipments from the Gulf Coast there are also no Panama Canal fees.

Exhibit 3: Trend in JKM price



Source: BP Statistical Review; S&P Global Platts; Allenby Capital (2020e)

Note: JKM refers to the Japan-Korea-Marker price for LNG. Prices are delivered port of entry East Asia. All prices are yearly averages with the exception of 2021/5 and 2021/12 which are forward prices for May and December 2021 respectively.

Risks and challenges

Chuditch is potentially a company maker for Baron. Involvement in a large scale offshore natural gas project linked to an LNG facility in a Far Eastern jurisdiction, however, is of necessity high-risk. At this stage we would identify four key risks as follows:

- Failure to secure a joint-venture partner on a timely basis prepared to offer free-carry terms without an unduly drastic dilution of Baron's working interest in Chuditch. In the event that a suitable partner is not secured, Baron and SundaGas will either have to finance initial drilling activity directly resulting in hefty dilution or abandon the project at the drill or drop stage. Although securing a partner is by no means certain, we think the Chuditch project has sufficient attractions in terms of its discovery status, potential scale, proximity to the Santos pipeline infrastructure and link to the Wickham Point LNG facility to attract a viable partner. The key issue perhaps is the concession that will have to be made to achieve free-carry status. Much will depend on the results of the seismic reprocessing exercise and evaluation study.

- Failure of the pending seismic reprocessing exercise to adequately de-risk Chuditch pre-drilling and to broadly verify the scale of the resource base. While possible, we believe this is unlikely given the extensive work already carried out on de-risking and the fact that Chuditch has been classified as a very significant discovery.

- Failure of drilling at Chuditch to confirm a commercial find. According to Shell the risks associated with trap, reservoir and charge were minimal but there was uncertainty surrounding the volume of gas-in-place, the liquids content and the flow rate. Note here, gas will need to flow to the surface under test and confirm a discovery which has sufficient critical-mass for commercial development. This is, of course, the acid test for all exploration projects.

- An extended period of weak commodity prices. Clearly, the weaker the LNG and by-product liquids price backdrop the greater the recoverable resource base required for development. In extremis, of course, a weak price environment could lead to the abandonment of Chuditch. We believe that for development Chuditch may well necessitate of at least a JKM of $7/mm Btu which is broadly in line with the forward curve. Condensate and natural gas liquids can possibly add some icing on the cake.

Financials

Baron has indicated that its cash position at end February 2021 was about £1m which is in line with our expectations. This together with the £3.0m gross (£2.80m net) equity raise in mid-March effectively underpins the company's financing requirements for the Chuditch project and G&A to end 2022. Our forecasts show a cash balance of £1.48m at end 2021 and a zero balance at end 2022. We have assumed that the TGS payable of $1.6m is expensed in 2021 and that the balance of the Chuditch spending programme of $1.9m is split evenly between 2021 and 2022. Our exchange rate assumption is £1=$1.40. Note, the March 2021 raise was undertaken at £0.0005/share and increased the shares in issue from 4.4264 bn to 10.4264 bn. The issue price reflected an approximate 39% discount to the level prevailing prior to the raise.

As far as the other projects are concerned, we have assumed that the planned El Barco-3X well on Block XXI in Peru goes ahead in 2021. Arguably, however, this is looking increasingly unlikely given the prevailing Force Majeure status. We have assumed a 50% farm-in for El Barco 3X and well costs of $1.2m gross.

In the case of the Corallian Energy operated licence P2478 (Baron Oil 15%) in the Inner Moray Firth, we think drilling is unlikely near-term and have removed the assumption of a well in the forecast in 2022. A drill or drop decision on P2478, which contains the large Dunrobin and smaller Golspie prospects, is required by July 2023. In April 2020 the three P2478 joint venture members signed a work sharing agreement with a 'large European E&P company' to undertake a regional technical study surrounding the licence. The results of the study were presented in January 2021 and significantly confirmed the prospectivity of the Dunrobin prospect. The joint-venture has incorporated the results into its own work programme aimed at de-risking Dunrobin prior to drilling.

Exhibit 4: Summary financials

Income statement (£'000)							
Year end December	**2016**	**2017**	**2018**	**2019**	**2020e**	**2021e***	**2022e***
EBITDA	-700	-510	-549	-442	-460	-510	-612
Exploration and evaluation expenditure	-739	-109	-1526	-160	0	0	0
Intangible asset impairment	-356	-1837	-1360	-1047	0	0	0
Receivables impairment	73	43	-54	16	0	0	0
Deconsolidation of Colombia	31	831	0	0	0	0	0
Administration expenses	-700	-510	-549	-442	-460	-510	-612
(Loss)/profit on exchange	1131	-508	130	-41	0	0	0
Other operating income	319	21	83	0	0	0	0
Operating loss	-241	-2069	-3276	-1674	-460	-510	-612
Finance cost	-35	-8	-10	-1	0	0	0
Finance income	101	19	6	1	0	0	0
Loss on ordinary activities before tax	-175	-2058	-3280	-1674	-460	-510	-612
Income tax credit/(expense)	-113	519	785	0	0	0	0
Loss on ordinary activities after tax	**-288**	**-1539**	**-2495**	**-1674**	**-460**	**-510**	**-612**

Balance sheet (£'000)							
Year end December	**2016**	**2017**	**2018**	**2019**	**2020e**	**2021e**	**2022e**
Assets							
Non-current assets							
Property, plant and equipment	3	0	0	0	0	0	0
Intangibles	1325	1260	66	5	657	2957	3786
Goodwill	0	0	0	0	0	0	0
Total	**1328**	**1260**	**66**	**5**	**657**	**2957**	**3786**
Current assets							
Trade and other receivables	2070	18	503	49	49	49	55
Cash	5231	3992	1838	472	1401	1427	0
Other	0	0	0	0	265	265	265
Total	**7301**	**4010**	**2341**	**521**	**1715**	**1741**	**320**
Total assets	**8629**	**5270**	**2407**	**526**	**2372**	**4698**	**4106**
Current liabilities							
Trade payables	1054	195	594	64	64	100	120
Taxes payable	1502	812	23	7	7	7	7
Debt	0	0	0	0	0	0	0
Total	**2556**	**1007**	**617**	**71**	**71**	107	127
Net assets	**6073**	**4263**	**1790**	**455**	**2301**	**4591**	**3979**
Net cash/(debt)	**5231**	**3992**	**1838**	**472**	**1401**	**1427**	**0**
Shareholders' equity							
Share capital	344	344	344	482	1107	2607	2607
Reserves	5729	3919	1446	-27	1194	1984	1372
Total equity	**6073**	**4263**	**1790**	**455**	**2301**	**4591**	**3979**
Total equity and liabilities	**8629**	**5270**	**2407**	**526**	**2372**	**4698**	**4106**
Shares in issue end year m	1376.4	1376.4	1376.4	1926.4	4426.4	10426	10426

Source: Company and Allenby Capital. * pro forma

Exhibit 5: Summary financials

Cash flow statement (£'000)							
Year end December	**2016**	**2017**	**2018**	**2019**	**2020e**	**2021e***	**2022e***
Loss attributable to controlling interests	-32	-1539	-2495	-1674	-460	-510	-612
Depreciation, amortisation and impairments	331	2	1360	1047	0	0	0
Share based payments	0	41	33	0	0	0	0
Finance income	-101	-19	-6	-1	0	0	0
Tax benefit	113	-519	-785	0	0	0	0
Foreign exchange translation	-1319	512	-73	-4	0	0	0
Other	-257	-347	0	0	0	0	0
Operating cash flow before working capital	-1265	-1869	-1966	-632	-460	-510	-612
Receivables (increase)/decrease	-440	2052	-485	454	0	0	-6
Tax paid	71	-4	-53	0	0	0	0
Payables (decrease)/increase	-692	-859	400	-546	0	36	20
Net cash flow from operating activities	-2326	-680	-2104	-724	-460	-474	-598
Acquisition of intangibles	-493	-298	-66	-1047	-652	-2300	-829
Cash previously not available now released	0	2674	0	0	0	125	0
Sale of intangible assets	1784	0	0	0	0	0	0
Other	183	19	6	1	-265	0	0
Share issues	0	0	0	408	2306	2800	0
Net cash flow	**-852**	**1715**	**-2164**	**-1362**	**929**	151	-1427
Opening cash	3010	2158	3873	1709	347	1276	1427
Closing net cash/(debt)	2158	3873	1709	347	1276	1427	0
Peru licence commitment guarantees	3073	119	129	125	125	0	0
Net cash/(debt) as per balance sheet	**5231**	**3992**	**1838**	**472**	**1401**	**1427**	**0**

Capital expenditure	**2016**	**2017**	**2018**	**2019**	**2020e**	**2021e***	**2022e***
Chuditch Timor Leste 33.3% (2020), 100% thereafter					520	1821	679
Block-XXI Peru 100% (2020), 50% thereafter					100	429	100
P2478 Inner Moray Firth 15%					30	50	50
Colter Wessex Basin 8%					2	0	0
Total					**652**	**2300**	**829**

Source: Company and Allenby Capital. * pro forma

Valuation

We continue to use risked sum of the parts methodology for assessing valuation. Chuditch is overwhelmingly the key constituent part. Our valuation retains the same valuation quotient and risking factors for the project as previously of $0.50/boe and 33% respectively. Chuditch, however, receives a boost from the sizeable increase in resources following the change in ownership of SundaGas (TLS). On a risked basis diluted for reduction in working interest from 63.75% to 32.0% to allow for a prospective Chuditch farm-in, the resources used for the valuation are 63.0mm boe against 49mm boe previously. For the other projects the risked resources and working interest assumptions are unchanged from the earlier calculation.

The key innovation that we have applied this time to the valuation calculation is diluting the ownership interest for a prospective free-carry farm-in at Chuditch to undertake drilling and long-term project development. As indicated above, we have assumed 50% of the equity in the project will have to be conceded based on experience elsewhere. Our new absolute valuation is $35.6m or £25.4m (£1=$1.40) which is an upgrade from the £21.8m (£1=$1.30) given previously. On a per share basis the valuation on the new number of shares outstanding post the raise is 0.244p. This compares with a fully diluted 0.243p given in our January 8, 2021 report. Note, previously we had diluted for an anticipated share raise to finance the work programme and G&A in 2021/22.

Exhibit 6: Baron Oil risked and diluted valuation summary

		Working interest	Net un-risked mean resources		Risking factor	Net risked mean resources	Valuation quotient	Un-risked valuation	Absolute		Risk adjusted valuation post farm ins
Basin	**Project**	**%**	**bcfe**	**boemm**	**%**	**boemm**	**$/boe**	**$m**	**$m**	**£m**	**p/share**
Bonaparte	Timor-Leste Chuditch	32.0	1129	188.1	33	62.9	0.5	94.1	31.4	22.5	0.215
Sechura	Peru Block-XX1	50.0	65	10.8	33	3.6	0.5	5.4	1.8	1.3	0.012
Moray Firth	UK P2478	8.0	94	15.6	30	4.7	0.5	7.8	2.3	1.7	0.016
Total			**1288**	**214.5**		**71.1**		**107.3**	**35.6**	**25.4**	**0.244**

Source: Allenby Capital

Note: Working interests have been adjusted where appropriate for anticipated farm-ins for the first stage of appraisal/exploration. Adjustments have been made to Timor Leste, Peru Block-XXI and Inner Moray Firth P2478.

Risking factors are Allenby inhouse probability estimates of commercialising projects at this stage.

The Chuditch risking factor is a composite of 40% for the discovery and prospects and 20% for the lead.

The shares in issue used in the per share calculation is 10.4264 bn. The per share calculation includes the proposed March 2021 raise.

Exchange rate: £1=$1.40.

Share price catalysts

We see two key potentially influential share price catalysts over the next year or so. These are positive news concerning progress, firstly, on the TGS seismic reprocessing and evaluation study and secondly, on securing a farm-in partner for Chuditch. We think ground-breaking news on these fronts is unlikely before the third quarter or indeed the fourth quarter of 2021. Although of less relevance than Chuditch, a decision to go ahead with the drilling of El Barco 3X well in Peru could also be a catalyst for the share price.

Disclaimer

Allenby Capital Limited ("Allenby") is incorporated in England no. 6706681; is authorised and regulated by the Financial Conduct Authority ("FCA") (FRN: 489795) and is a member of the London Stock Exchange. This communication is for information only it should not be regarded as an offer or solicitation to buy the securities or other instruments mentioned in it. It is a marketing communication and non-independent research and has not been prepared in accordance with the legal requirements designed to promote the independence of investment research, and is not subject to any prohibition on dealing ahead of the dissemination of investment research. The cost of Allenby research product on independent companies is paid for by research clients.

This communication is for the use of intended recipients only and only for distribution to investment professionals as that term is defined in article 19(5) of The Financial Services and Markets Act 2000 (Financial Promotion) Order 2005. Its contents are not directed at, may not be suitable for and should not be relied upon by anyone who is not an investment professional including retail clients. Any such persons should seek professional advice before investing. For the purposes of this communication Allenby is not acting for you, will not treat you as a client, will not be responsible for providing you with the protections afforded to clients, and is not advising you on the relevant transaction or stock. This communication or any part of it do not form the basis of and should not be relied upon in connection with any contract.

Allenby uses reasonable efforts to obtain information from sources which it believes to be reliable. The communication has been prepared without any substantive analysis undertaken into the companies concerned or their securities, and it has not been independently verified. No representation or warranty, express or implied is made, or responsibility of any kind accepted by Allenby its directors or employees as to the accuracy or completeness of any information in this communication. Opinions expressed are our current opinions as of the date appearing on this material only and are subject to change without notice. There is no regular update series for research issued by Allenby.

No recommendation is being made to you; the securities referred to may not be suitable for you and this communication should not be relied upon in substitution for the exercise of independent judgement. Neither past performance or forecasts are a reliable indication of future performance and investors may realise losses on any investment. Allenby shall not be liable for any direct or indirect damages including lost profits arising from the information contained in this communication.

Allenby and any company or persons connected with it, including its officers, directors and employees may have a position or holding in any investment mentioned in this document or a related investment and may from time to time dispose of any such security or instrument. Allenby may have been a manager in the underwriting or placement of securities in this communication within the last 12 months, have received compensation for investment services from such companies within the last 12 months, or expect to receive or may intend to seek compensation for investment services from such companies within the next 3 months. Accordingly, recipients should not rely on this communication as being impartial and information may be known to Allenby or persons connected with it which is not reflected in this communication. Allenby has a policy in relation to management of conflicts of interest which is available upon request.

This communication is supplied to you solely for your information and may not be reproduced or redistributed to any other person or published in whole or part for any purpose. It is not intended for distribution or use outside the European Economic Area except in circumstances mentioned below in relation to the United States. This communication is not directed to you if Allenby is prohibited or restricted by any legislation or registration in any jurisdiction from making it available to you and persons into whose possession this communication comes should inform themselves and observe any such restrictions.

Allenby may distribute research in reliance on Rule 15a-6(a)(2) of the Securities and Exchange Act 1934 to persons that are major US institutional investors, however, transactions in any securities must be effected through a US registered broker-dealer. Any failure to comply with this restriction may constitute a violation of the relevant country's laws for which Allenby does not accept liability.

By accepting this communication, you agree that you have read the above disclaimer and to be bound by the foregoing limitations and restrictions.

Research Recommendation Disclosure

Peter J Dupont is the author of this research recommendation and is employed by Allenby Capital Limited as an Equity Analyst. Unless otherwise stated, the share prices used in this publication are taken at the close of business for the day prior to the date of publication. Information on research methodologies, definitions of research recommendations, and disclosure in relation to interests or conflicts of interests can be found at www.allenbycapital.com. Allenby Capital acts as Nomad and joint broker to Baron Oil plc.

Allenby Capital, 5 St Helen's Place London EC3A 6AB, +44 (0)20 3328 5656, www.allenbycapital.com