

Corporate

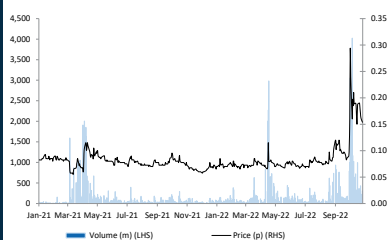
Current price **0.155p**

Sector **Oil & Gas**

Code **BOIL.L**

Listing **AIM**

Share Performance



% Change	1m	3m	12m
BOIL.L	+76.8	+92.2	+105.1

Source: Thomson Reuters, Allenby Capital

Share Data*

Market Cap (£m) **28.7**

Shares in issue (bn) **18.50**

52 weeks (p)	High	Low
	0.29	0.06

Financial year end **31 December**

Source: Company Data, Allenby Capital. * post-placing

Key Shareholders*

Hargreaves Lansdown	21.63%
Interactive Investor Services	13.63%
HSDL Nominees Ltd	10.38%
Barclays Direct Investing Nominees Ltd	5.64%
JIM Nominees	5.60%

Source: Company Data, Allenby Capital. *pre-placing

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Baron Oil plc (BOIL.L)

Chuditch a world class project

Baron Oil's Chuditch gas/liquids project offshore Timor-Leste is evolving as world class and is in the final stage of de-risking pre-drilling. Following completion of the large-scale 3-D seismic reprocessing exercise by TGS-NOPEC, a leading geophysical specialist and evaluation work by Baron, the gas resource base has been significantly increased and now easily has critical-mass for LNG feedstock. Furthermore, sub-surface imaging has greatly improved. Baron has described the reservoir characteristics for the Chuditch-1 discovery in terms of porosity (storage), permeability (flow) and gas saturation as being of 'good quality'. The reservoir evaluation consultants, ERCE, have been commissioned to independently assess resources to SPE PRMS standards. Drilling is being targeted for late 2023. Baron should be in a strong position to secure a Chuditch farm-in partner given the scale and relatively low risk of the project, rigorous project appraisal, potential access to infrastructure and burgeoning interest in Asian Rim gas-LNG projects.

- Chuditch project:** Chuditch lies in the Timor Sea 185 km south-east of the Timor-Leste coast, 400 km north-west of Darwin and 120 km north-east of Santos's Bayu-Undan condensate and gas field. The ownership of the Chuditch PSC is Baron 75% and the Timor-Leste NOC 25%. The Chuditch project was originally based on the Chuditch-1 discovery made by Shell in 1998 in the regionally prolific Jurassic Plover sandstones. The well, however, was never flow tested. In addition to the discovery, the Chuditch-SW prospect and the Chuditch-NE and Quokka leads have been identified on 3-D seismic.
- Chuditch resources:** Following the TGS 3-D seismic reprocessing exercise, Baron's best case estimate of recoverable gas at Chuditch is 3.63 tcf (605mm boe), up 24% on prospective resources using 2-D legacy seismic. The evidence points to the gas being relatively dry. For perspective, Santos's Barossa field 300 km north of Darwin also in the Bonaparte Basin is reported to have 4.5 tcf of gas and 50mm barrels of liquids.
- Chuditch PSC terms and drilling:** The Timor-Leste regulatory authority, ANPM, has recently granted a six month extension to Year 2 of the Chuditch PSC. Year 2 will now expire on June 18, 2023 by which time Baron will need to make a drill or drop well commitment. The extension will provide extra time to complete technical work and secure a farm-in partner. In the third and final phase of the PSC post June 18, 2023, Baron will need to make a final investment decision (FID) on an appraisal well which will target the Chuditch-1 discovery structure. Initial well design has been undertaken while locations are being evaluated using 3-D seismic. Drilling will occur in relatively shallow water of around 70m. The well will be deviated from vertical with a TD (total depth) about 3,000m. We believe it will take about 42 days to drill/test and cost approximately US\$24m.
- Chuditch risks:** Chuditch is a relatively low-risk project geologically. This reflects that it is based on a discovery in a regionally prolific reservoir formation. Shell put the geological chances of success (GCOS's) at 100% for Chuditch-1. We believe that this assessment is well supported by the results of the TGS 3-D reprocessing exercise. Significantly, Baron believes that Chuditch-1 has sufficient critical-mass for independent development.

Year End: 31 December

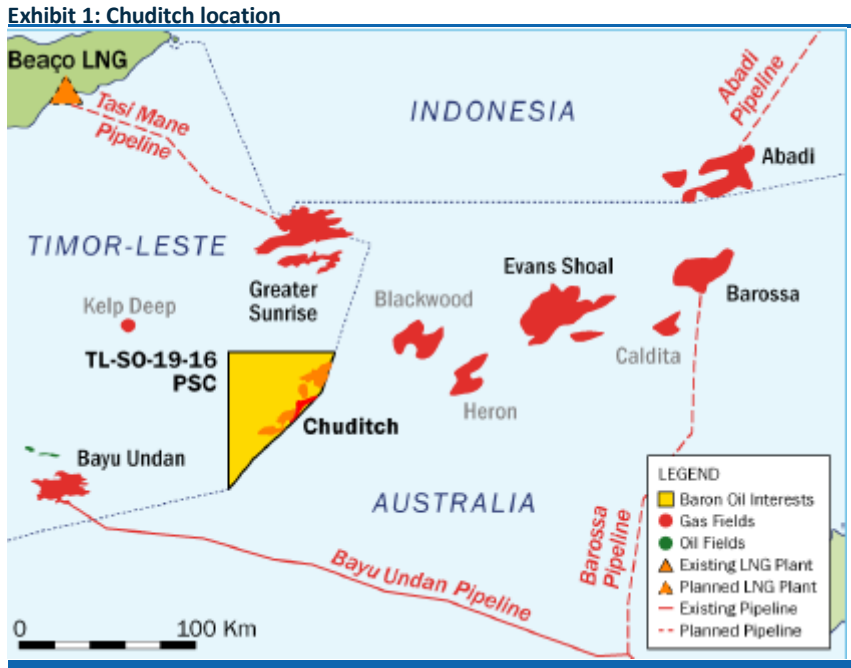
(£'000)	2019	2020	2021	2022E	2023E
EBITDA	(442)	(710)	(1,321)	(1,367)	(1,500)
NET CASH/(NET DEBT)*†	347	1,190	1,650	5,299	2,379

Source: Company; Allenby Capital. Allenby Capital acts as Nomad & Broker to Baron Oil plc (BOIL.L).

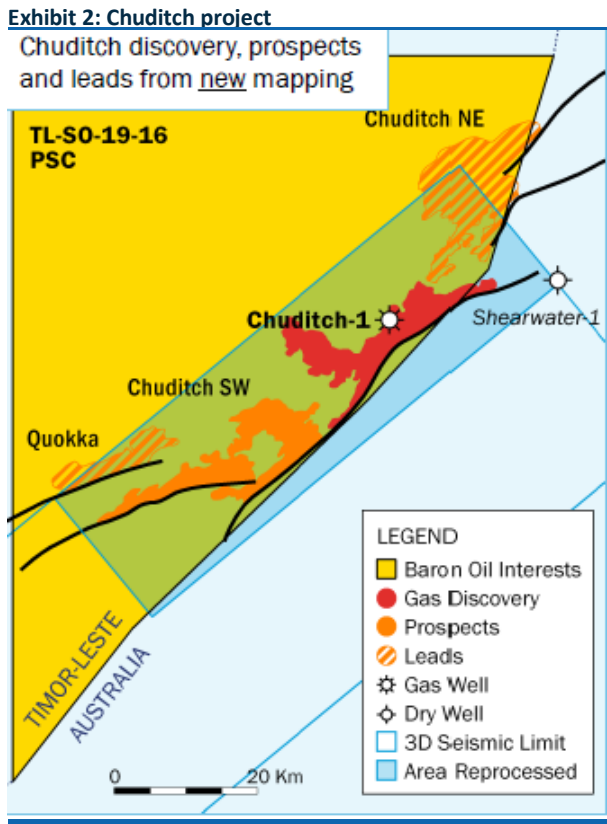
*Excludes project Bank Guarantees. † includes £5m (gross) placing.

Equity Research

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



Source: Company data

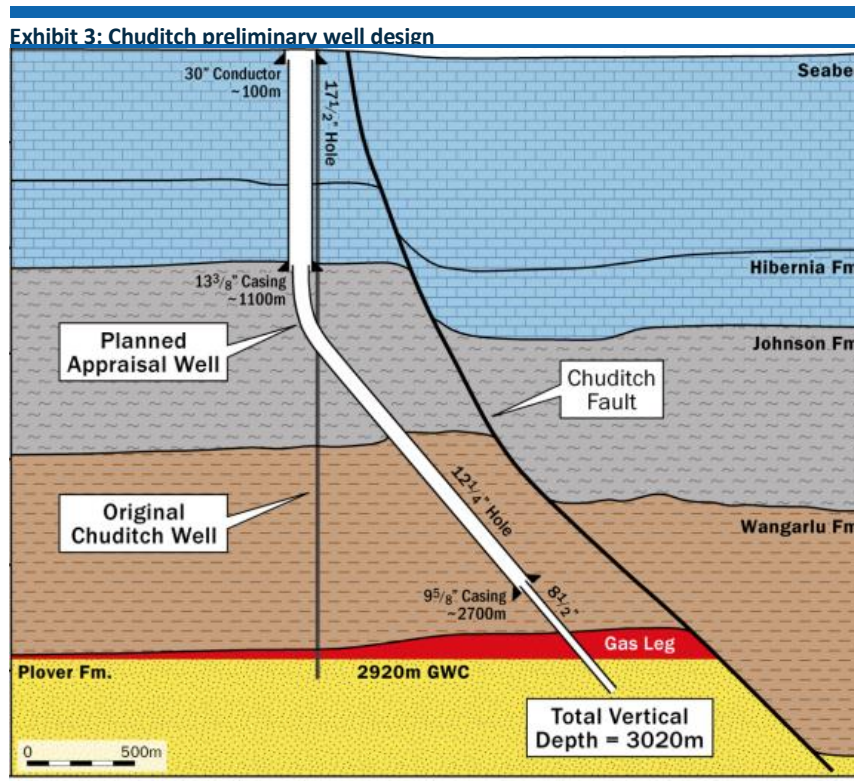


Source: Company data

Chuditch drilling plan

Arguably the earliest that an appraisal well can be drilled is Q1 2024: Baron’s current plan is to drill an appraisal well into the Chuditch-1 structure close to Shell’s original

discovery. This constitutes a variance compared with Baron’s earlier strategy which was to drill back-to-back appraisal and exploration wells. Baron is of the opinion that with the vastly improved imaging available following 3-D seismic reprocessing, that proving extra volumes with an exploration well is no longer required. According to Baron, the well cost, including testing, will be about US\$24m. We believe the lead time from FID to spudding the well will be 9 to 12 months. In our view, the earliest a well could be drilled is the first quarter of 2024 bearing in mind the lead time for securing a rig, well planning, permitting, OCTG (oil country tubular goods) procurement and rig mobilisation. Much will depend on when a farm-in partner is secured.



Source: Company data

Targeting Plover sandstone reservoir with 1.35 tcf potential: The planned well will be deviated with the deviation occurring from about 1,100m.TD (total depth) will be about 3,020m. The aim is to target what Baron believes is an up-dip gas zone which was missed by Shell’s original vertical well. According to Baron, this could have a gas column >100m against 25m for the discovery well. The well will target the Jurassic Plover sandstone formation which provides a regionally prolific gas reservoir throughout the Bonaparte Basin which underlies the Timor Sea. Baron’s best estimate of recoverable gas resources at Chuditch-1 is 1.35 tcf. This would provide sufficient critical mass to supply a standalone LNG plant. Significantly Baron is now of the view that Chuditch is very much a dry gas play which contrasts with Santos’s Bayu Undan field to the southwest which historically has provided substantial quantities of condensate.

Exploration wells possible on Chuditch SW and NE in late 2024: Assuming a success case for Chuditch, we think it likely that Baron or a joint-venture partner operator would want to test the Chuditch-SW prospect and Chuditch-NE lead. Initially this would probably necessitate shooting more seismic particularly over the latter which has only been partially

covered so far. The earliest exploration drilling could be undertaken would be late 2024 in our view.

Chuditch positives

Baron has proffered several positives in terms of commercialisation for the Chuditch project as follows:

- The existence of a PSC which precludes the need for complex negotiations with a host government.
- The licence is wholly within the jurisdiction of Timor-Leste so there are no cross border issues.
- The Timor-Leste government is highly supportive of the project.
- Chuditch has excellent critical mass with resources similar to other large scale projects in the region.
- Chuditch has excellent reservoir quality in terms of porosity, permeability, gas saturation and net to gross pay.
- Shallow water location with an average depth of about 70m implies compatibility with the use of jack-up rather than more expensive semi-submersible rigs.

Exhibit 4: Chuditch preliminary resource estimate

Status	Previous Resource Estimates Probabilistic Best Cases ¹ Gross Attributable to Licence (bcf)			Current Provisional in-house Deterministic Best Case Estimates ² Gross Attributable to Licence (bcf)			% Increase*
	Gas-in-Place ¹	Recovery Factor	Prospective Resource ¹	Gas-in-Place ^{2,3,4}	Recovery Factor	Recoverable Gas ^{2,3,4}	
Chuditch-1	951	75%	713	1,800	75%	1,350	89%
Chuditch W	540		405	Merged into Chuditch-1 discovery		n/a	
Chuditch N	473		355	Not present on improved data		n/a	
Chuditch NE ⁵	1,293		970	1,950	67%	1,300	34%
Chuditch SW	642		482	1,150	50%	575	19%
Quokka ⁵	Not evaluated			600	67%	400	n/a
Aggregate	3,899	75%	2,924	5,500	65.9	3,625	24%

2021 Prospective Resource Estimates versus October 2022 Recoverable Gas Estimates
 Volume estimates use definitions and guidelines set out in the 2018 Petroleum Resources Management System prepared by the Society of Petroleum Engineers (SPE PRMS 2018)
 Not SPE PRMS 2018 compliant
 Condensate yield not included
 Rounded deterministic technical best cases (in BCF)
 Chuditch NE & Quokka: partial 3D coverage

Source: Company data

Farm-in partners and medium-term development

Chuditch gas-LNG project necessitates a JV partner: Given the heavy requirement of capital and technical resources for a major gas-LNG project and the risks involved, Baron will need to secure a farm-in partner to undertake development of Chuditch. Baron has indicated that the farm-out process is ongoing and ‘remains in talks with multiple potentially interested parties.’

Santos is the most obvious candidate: We continue to be of the view that the most obvious route to development would be a joint venture with Santos (STO:ASX), the second largest domestically listed E&P concern in Australia. This reflects several factors as follows:

- Santos is familiar with operating in the Timor Sea given that it operates the Bayu-Undan gas field about 120 km to the southwest of Chuditch and is engaged in the development of the Barossa field 300 km north of Darwin.
- Santos operates the LNG plant at Wickham near Darwin that is the only such plant conveniently situated for a prospective Chuditch development. Furthermore, the Darwin plant needs feedstock given the near depletion of Bayu-Undan and potentially considerable delays in bringing on-stream Barossa due to an aboriginal challenge to the project on the Tiwi Islands. Santos is undertaking an upgrade of the Wickham plant that will extend its life by at least 20 years.
- Chuditch could, in principle, be relatively easily tied-in to the existing Bayu-Undan-Darwin pipeline. The tie-in would probably be c 100-150 km.
- Santos has a de facto joint-venture with the Italian major, ENI, for operations in the Timor Sea. Collectively, if not independently, these two companies have the engineering resources and capital raising capability to undertake large scale gas field development.

FLNG

Application of FLNG technology a possibility: Baron has advanced the idea of undertaking a FLNG (floating liquefied natural gas) development at Chuditch. A closely related alternative would be a platform based project. FLNG technology is relatively new and so far, has had limited application and in some cases has encountered technical challenges. The key ones have been Shell’s Prelude vessel on the NW Shelf off the coast off Western Australia and Petronas’s Satu offshore Sarawak, Malaysia. Recently an ENI led consortium has commenced operations with its Coral-Sul vessel offshore Mozambique. The vessel was constructed by Samsung Heavy Industries and is operating in ultra-deep water of 2,000m.

Highly specialised vessels capable of converting gas to LNG: FLNG technology involves producing LNG on a highly specialised vessel at sea before it is transferred to carriers for onward shipment. The vessels also have natural gas processing facilities to remove impurities and liquids storage capacity.

FLNG vessels are costly at possibly around US\$10bn----- The key advantage of FLNG technology is the ability to unlock remote, relatively small fields in theory economically. There may also be environmental advantages over land based facilities in terms of a smaller footprint. The disadvantages are very high operating and capital cost and safety issues related to working in a very confined space. Operating in adverse weather conditions may also pose challenges. Conventional FLNG vessels are large scale and contain highly specialised technology. Few shipbuilders have the necessary manufacturing capability, capital costs are probably in excess of US\$5bn and lead times are likely to be considerable and measured in years. Both Shell’s Prelude and Petronas’s Satu FLNGs are

reported to have cost about US\$10bn. ENI’s Coral-Sul FLNG vessel is reported to have cost US\$4.7bn and took 38 months to construct.

----but there is an alternative based on Hybrid FLNG technology: Hybrid FLNG technology is in the throes of development to address the manufacturing and economic challenges of conventional large scale FLNG technology. The essence of the hybrid technology is to apply a downsizing approach and may involve the conversion of an existing vessel.

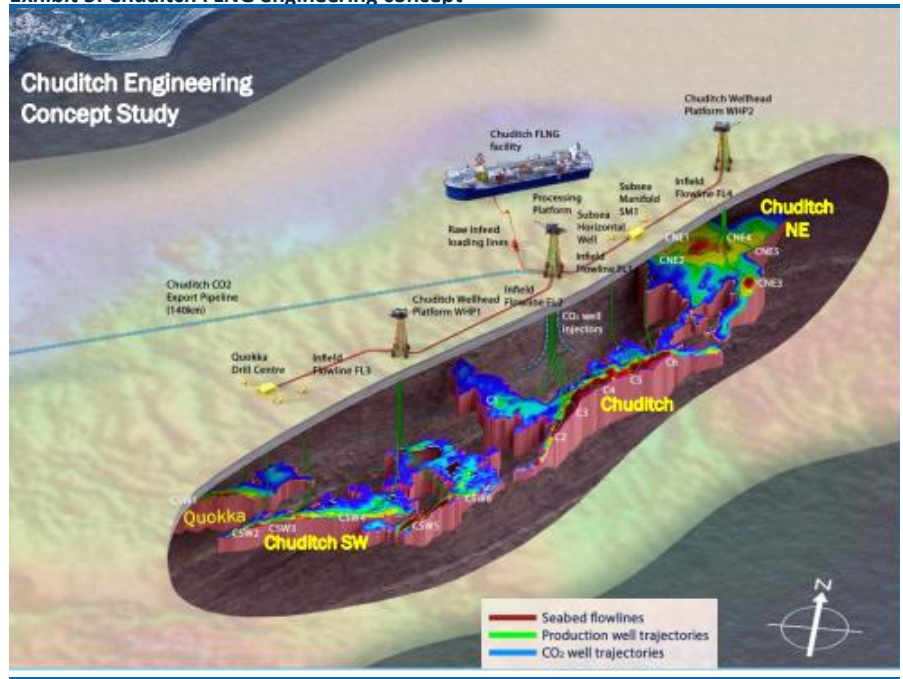
Santos has all the infrastructure in place: Note, the great beauty of the Santos solution is that much of the infrastructure including the LNG facility is in place. Interestingly, Baron has given an estimate of when a prospective Chuditch field development could come on-stream. It is suggesting by 2028 without defining the development route. In our view, a five to six year lead time would not be surprising.

Hybrid FLNG development plan

Phased Chuditch development plan: Baron has presented an initial development plan for Chuditch based on applying FLNG technology. It sees development taking place in stages starting with Chuditch-1. Conceptually the plan would be to have a platform linked to six seabed well heads. The platform would then be tied back to a FLNG vessel where LNG and gas processing would take place. Subsequently LNG would be loaded onto tankers and transported to market. As noted above, a variation on the theme would be to operate processing operations from a large platform. Subsequently the remaining fields could be brought on-stream but all linked to the central FLNG vessel. Baron plan calls for first gas in 2028 and production to plateau at 300 mmscf/d.

The phased development of the Chuditch field has the virtue of spreading the financial cost over several years. Baron has intimated that by applying Hybrid FLNG technology first stage development involving Chuditch-1 could conceivably cost about US\$1bn assuming current construction/fabrication economics. Any cost estimates at this stage are however extremely tentative.

Exhibit 5: Chuditch FLNG engineering concept



Source: Company data

JKM LNG prices

Spot market

JKM is the Asia LNG benchmark: The JKM (Japan, Korea Marker) is the LNG price benchmark for NE Asia (China, Japan, Korea and Taiwan) and is of critical importance for the economics of any prospective natural gas-LNG project in the Timor Sea. Monetisation of the natural gas necessitates conversion to LNG and delivery to international markets. Theoretically, modest quantities of gas could be shipped by pipeline to Australia while larger shipments could be made in due course to Timor-Leste, assuming development of a domestic petrochemicals industry. There are however major technical challenges in piping gas to Timor-Leste in the form of the Timor Trough. This lies about 100 km off the Timor Leste east south coast and is up to 3,000m deep. We think that the Timor Trough effectively precludes investment in a pipeline connecting Timor Sea gas fields with Timor-Leste.

JKM has ranged between \$25 and \$76/mm Btu in 2022: The JKM quote has fluctuated sharply in 2022 pretty much in tune with the European TTF benchmark. Throughout the year the JKM has been trading at historically elevated or even at times unprecedented levels. The year started with the JKM trading at about US\$25/mm Btu (US\$150/boe) The trend was strongly upward through the first eight months with the JKM hitting an all-time high of US\$76/mm Btu (US\$456/boe) in late August. This was driven by the very tight availability of LNG internationally stemming from the sharp reduction in pipeline gas from Russia to Europe and an outage at the Freeport LNG. In practice, there has been little or no spare LNG capacity available globally in 2022 at a time of buoyant demand.

Weakening trend since August-----: Since end August, JKM spot has weakened considerably with prices more than halving to approximately US\$33/mm Btu (US\$198/boe). This coincides with an unwinding of gas supply fears in Europe and subdued demand in China. The former largely reflects softening demand and replenished inventories ahead of winter while the latter stems from weak economic activity. We believe JKM prices could once again trend higher in the coming months stemming from the onset of winter conditions, the possibility of a complete cessation of Russian pipeline gas supplies to Europe and the absence of surplus LNG capacity. Russia, note, currently supplies about 9% of European demand via Turkey and has indicated that supplies will cease if the EU's price cap proposal is implemented. Large exporters in the Middle East, including Qatar, have suggested that they will not break long term contracts with Asian buyers to supply Europe.

-----but prices still elevated historically: The 2022 JKM price range of broadly US\$25/mm Btu to US\$76/mm Btu is considerably above the historical range. Taking the period 2015 to 2019, for example, the range was broadly US\$4.2/mm Btu to US\$15.0/mm Btu. We believe the LNG market internationally will remain tight probably through 2025 given the following:

- A lack of planned new capacity additions and high utilisation rates.
- The partial insulation of Russian LNG capacity.
- The strategic reorientation of European supplies from Russian pipeline gas to LNG.

Post 2025 some loosening in the LNG market is possible given major planned expansion including in Qatar (North Field East expansion project), Canada (Shell led T1 consortium based at Kitimat BC) and Mozambique (ENI and Total projects) We suspect, however, that new capacity additions will be insufficient to offset the loss of Russian pipeline capacity to Europe. Russia, note until 2021 was the world's largest exporter of pipeline gas and has the world's largest gas reserves at about 25% of the total.

Forward curve

Front end of the curve trending higher through early 2024 US\$40/mm Btu---: The LNG forward curve arguably has more relevance for a long lead time natural gas-LNG project such as Chuditch than the spot market. At the front end, the JKM forward curve is trending upward with the price rising from US\$31.3/mm Btu for December deliveries to a high of US\$40.1/mm Btu in January 2024. This is consistent with our view that the LNG supply/demand balance is likely to be tight near-term.

Exhibit 6: JKM LNG forward curve



Source: CME Group. Note, forward curve as of October 25, 2022

-----but subsequently pronounced backwardation-----After early 2024, the JKM forward curve swings to marked backwardation abstracting from seasonal influences with near-term prices higher than for the more distant dates. By end 2025 the curve is down to US\$21.1/mm Btu. At the backend of the curve in the third quarter of 2027 forward prices are close to US\$5/mm Btu (US\$30/boe). This is in-line with the low end of the range for spot prices between 2015 and 2019. The backwardation in the JKM forward curve post 2024 is symptomatic of a pronounced loosening of the supply-demand balance. This presumably reflects the anticipated influx of new capacity from mid-decade. We believe, however, prices of around US\$5/mm Btu are implausible assuming anything like the current cost structure.

-----with the price dropping to US\$5/mm Btu at back end of the curve: A price of US\$5/mm Btu would not come close to covering variable cost in which case production would cease. Capacity expansion would also be choked off.

Back end of the curve implausibly low: Based on our understanding of the LNG cost structure gas-LNG projects are likely to require an LNG price assumption of comfortably over US\$12/mm Btu for viability. In our view this is a more likely outcome in the second half of the 2020's than US\$5/mm Btu.

Profitability

LNG producers highly profitable in 2022 based on spot prices of about US\$50/mm Btu: Based on an average JKM price of around US\$50/mm Btu in the year-to date LNG producers should have been highly profitable in 2022. It needs to be remembered

however that there have been significant cost pressures due especially to energy and logistics.

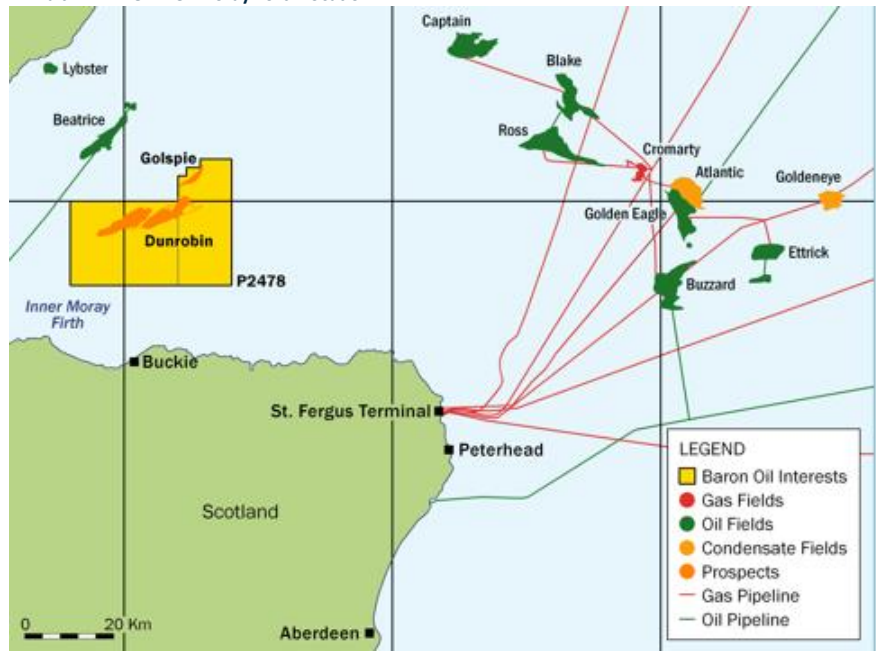
Cash costs could be around US\$10/mm Btu: Cash costs at current economics could be around US\$10/mm Btu based on industry commentary, for a medium-scale LNG facility such as Santos Wickham drawing feedstock from the Timor Sea. This comprises perhaps US\$3/mm Btu for gas lifting, processing and pipeline operating costs and US\$7/mm Btu for LNG liquefaction and transportation (cif cost of insurance and freight). The last mentioned will depend on the shipping distance and ship charter rates which are sensitive to diesel costs and ship availability. Including capital costs, it is conceivable that LNG fully accounted costs are comfortably over US\$12/mm Btu presently. As for other medium to large energy facilities with sizeable fixed costs, unit costs will be heavily dependent on facility utilisation.

Inner Moray Firth licence P2478

Licence ownership and location

Licence interest of 32%: Baron Oil’s second active project concerns UK licence P2478 in the Inner Moray Firth. The licence contains the Dunrobin and Golspie prospects. Baron increased its interest in the licence from 15% to 32% in October 2021 following a farm-in agreement with the other members of the P2478 consortium in exchange for financing the reprocessing of legacy 2-D and 3-D seismic along with various technical studies aimed at de-risking and identifying drilling locations. AIM-listed Reabold Resources (RBDR.L) is the operator of P2478 with a 36% interest. The third member of the consortium is Upland Resources (UPL.L) which has a 32% interest.

Exhibit 7: P2478 Inner Moray Firth location



Source: Company data

Dunrobin prospect: The P2478 focus of attention is the Dunrobin oil prospect. This lies approximately 30 km south of the now defunct Beatrice field and 50 km south of the northern shore of the Moray Firth. Compared with the southern shore Dunrobin lies about 25 km to the north. Golspie lies about 10 km northeast of Dunrobin. The project is now at a critical phase as evaluating the reprocessed seismic nears completion. The intimations from Baron concerning the findings on prospectivity have been highly positive.

Geology

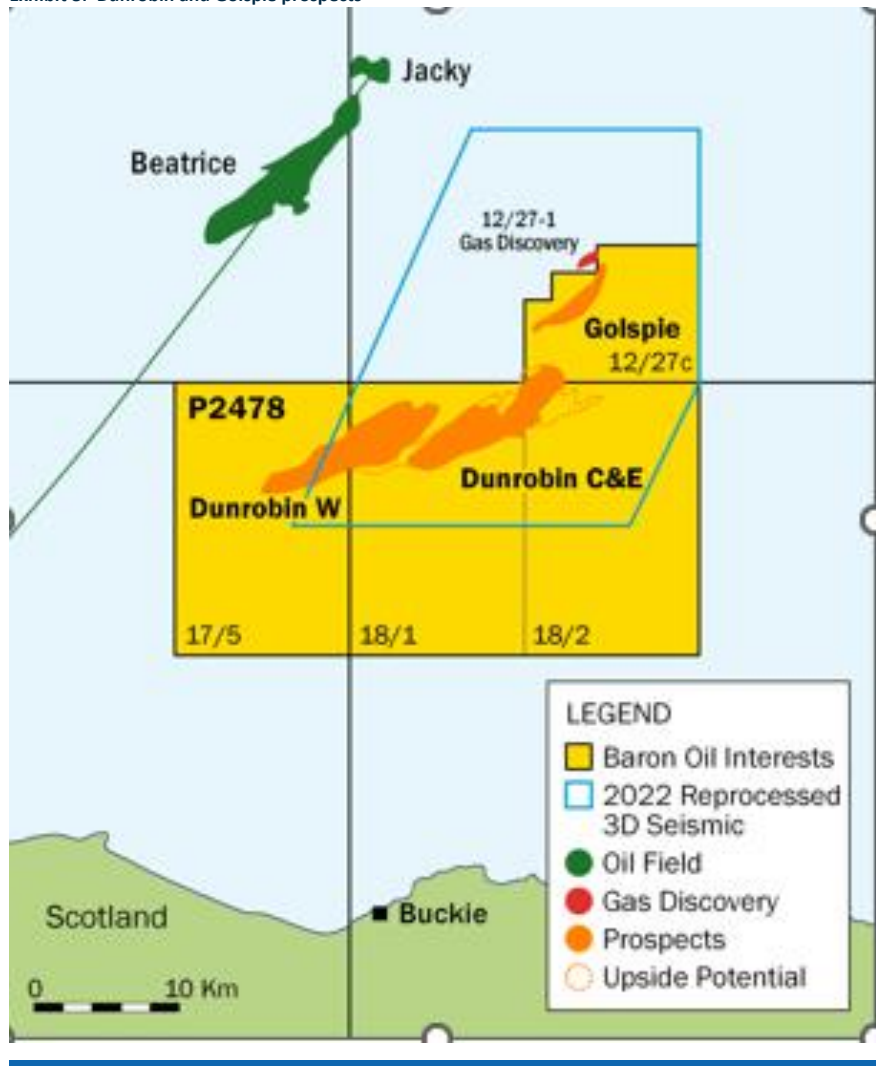
Part of prolific North Sea rift system: The Moray Firth is part of the Mesozoic (252-66 Ma) North Sea rift system, one of the world’s most prolific oil and gas provinces. Rather than the SW-NE trending grabens of the Central and Northern North Sea, the Moray Firth is characterised by an east-west structural trend. To date the only major development in the Inner Moray Firth has been the Beatrice Field which came on-stream in 1981 and produced oil from Jurassic sands until 2017. At the time of development recoverable resources, according to industry sources, were put at 162mm barrels, implying a medium-sized field. Development activity in the Moray Firth has been far more intensive in the outer zone close to the boundary with the SW-NE trending Central Graben.

Dunrobin identified using 3-D seismic: The Dunrobin prospect was originally identified using legacy 3-D seismic and consists of three large, rotated fault blocks. There is a proven

working petroleum system both locally and regionally with the Beatrice field being an obvious nearby analogue. Reservoir targets are initially the Jurassic and Dunrobin sandstones. Significantly, Reabold has identified a potential deeper Triassic sandstone reservoir.

In early 2021 the P2478 joint-venture partners received the results of technical studies from a 'large European E&P company' under a work sharing agreement signed in 2020. This enhanced understanding of the local geology and corroborated the consortium's positive view of Dunrobin's prospectivity.

Exhibit 8: Dunrobin and Golspie prospects



Source: Company

Seismic reprocessing and evaluation

Final phase of evaluation of reprocessed 3-D seismic: Legacy reprocessed 2-D and 3-D seismic covering the bulk of the northern half of the licence and including the Dunrobin and Golspie prospects was delivered to Baron for evaluation in July 2022. Baron is now in the final stages of the evaluation process and is scheduled to release its findings by end 2022. The cost of the work programme to Baron has been capped at £160,000.

Possibly relatively heavy oil: Some initial tentative comments have been made by Baron. Not surprisingly perhaps the seismic image has improved thereby increasing understanding of the sub-surface. Geochemical studies also point to a petroleum specification capable of development. Given however the relatively shallow depth (low temperature) of the reservoir at approximately 660m it is thought by Baron that the oil could be towards the heavy end of the spectrum with an API of perhaps 20-25°. It should be noted that oil of this grade is produced elsewhere in the North Sea.

Resources

Jurassic sandstone reservoir possibly >100mm barrels: Baron has indicated that its best estimate for recoverable resources from the Dunrobin Jurassic reservoir is c 100mm barrels. Furthermore, it has suggested that Dunrobin may be one of the last remaining prospects in the UK sector of the North Sea of this scale. Interestingly, Reabold has provided a more bullish estimate of mean prospective resources from the Jurassic at 173mm boe. Reabold has assigned a GCOS (geological chance of success) for Dunrobin of 34% which constitutes a moderate level of risk pre-drilling. For Golspie Reabold's assessment of mean prospective resources is 22 boe while the GCOS is put at 42%. We would expect risking to improve post seismic reprocessing and evaluation.

Potentially deeper Triassic reservoir: Reabold has also made a tentative assessment of the recoverable resource potential in the Triassic reservoir. Its estimate is 40mm boe. Given the greater depth of the Triassic, Baron believes that oil from this source maybe lighter than from the Jurassic sandstones. Conceivably the Dunrobin prospect has very significant exploration potential compared with Baron's c 100mm barrel resource estimate.

The road ahead

Drill or drop decision by July 2023: Under Phase A of the P2478 licence a drill or drop decision is required by July 2023. An exploration well to test the Dunrobin prospect will cost about £8m gross, according to Baron. The modest cost vis-à-vis most other North Sea projects reflects several factors including the following:

- Easy access to the shoreline and the Aberdeen oilfield services hub.
- Shallow water at around 75m depth which enables low-cost jack-up rigs to be used.
- Shallow drilling depth of approximately 660m which implies a short time to TD (total depth) of probably <20 days. An exploration well will test both the Jurassic and Triassic formations.

Following the expected completion of the technical studies in the coming weeks the next key task will be to obtain a CPR (Competent Persons Report) on the Dunrobin project. We think this might be released late in the first quarter of 2023.

Farm-in partner

Drilling possible late in Q2 or early Q3 2024: Baron has indicated that its preferred strategy for pursuing the exploration, appraisal and development of Dunrobin is in conjunction with a farm-in partner prepared to offer a significant element of carry. We understand that the farm-out process has commenced but presume that there will be no firm commitments until the CPR is available. Assuming that a well decision is made in the affirmative by the July 2023 deadline, we believe that the earliest Dunrobin could be drilled would be late in the second quarter of 2024. This lead time is required for permitting, well design work, procurement of OCTG (oil country tubular goods and other materials, site surveys and preparation, rig procurement and rig mobilisation.

Industry backdrop for farm-ins has improved: In considering the ability of Baron or other members of the P2478 consortium to obtain a farm-in partner it is important to note that the industry backdrop has improved considerably over the past year or so. This reflects the following:

- Markedly more attractive petroleum industry economics stemming from a surge in prices.
- Greater concern in government with energy security and boosting domestic capacity. This may translate into fewer permitting issues.
- Attractive windfall tax breaks for those prepared to invest in the North Sea.

If no farm-in partner is forthcoming or the terms are unacceptable, we think it possible that Baron and Reabold may be prepared to finance a Dunrobin well. Presumably much will depend on the results of the 3-D seismic data evaluation.

Why is Dunrobin interesting?

- An easily accessible project
- A very significant prospective resource base with upside.
- Prospect mapped on high quality reprocessed 3-D seismic
- Proven petroleum system
- Moderate risk level pre-drilling
- Relatively low drilling costs
- Proximity to Beatrice pipeline

Financials

Comfortably financed near-term: At the end of June 2022 unencumbered cash stood at £2.37m well up on the £1.65m at end December 2021. Cash flow was bolstered in the first half of 2022 by a £1.51m net equity raise in late April and the release of the Bank Guarantee on Peru Block XXI following the relinquishment of the licence. The latter raised £0.12m. Abstracting from these two factors there was an underlying cash outflow for the period of £0.91m or £152,000/month. The outflow was split £0.51m operations and £0.40m project related.

Forecast unrestricted cash of £1.05m at end 2022: As of end October 2022 we estimate that Baron's cash position was about £1.45m. We would normally see this as comfortable for financing near-term expenditure needs. In the coming months, however, the rate of spend is likely to increase driven mainly by growing project related commitments. Over the 15 months to end 2023 Baron has suggested potential project-related and G&A spending of £3.35m or £223,333/month on average reflecting the following:

- Chuditch project related expenditure £1.4m. This mainly refers to residual work evaluating the reprocessed 3-D seismic, reservoir engineering and EIA studies, compilation of the Competent Persons Report, well design and planning work and project farm-out work.
- Chuditch Bank Guarantee £0.6m. This takes into account extending the Bank Guarantee from December 1, 2022 to August 1, 2023. In future the Bank Guarantee will be owned 100% Baron Oil rather than being shared with SundaGas Pty Ltd.
- Dunrobin project work on licence P2478 Inner Moray Firth £0.25m. The work programme includes finalising the evaluation of reprocessed 2-D and 3-D seismic, modelling the outcome of geochemical studies, evaluating the secondary Triassic reservoir target, compilation of the Competent Persons Report and farm-out work. Note, a drill or drop decision is required on Dunrobin prospect by July 2023.
- New venture evaluation and preparation work including for the UK 33rd Offshore Round £0.2m.
- G&A outlays of £0.9m. In our income statement forecast we have used a considerably higher £1.5m for forecast G&A in 2023 reflecting the fact that this cost category in Asia is incorporated within Chuditch project costs. Underlying G&A costs in our view are likely to rise significantly in 2023 driven by a combination of inflationary pressure and rising levels of activity within the organisation associated with project development. A manifestation of this is the opening of the Dili office in Timor-Leste in 2022.

To finance the next 15 months forecast spending and allow for contingencies on project work Baron has recently raised £5.0m gross or £4.65m net in new equity. The raise was undertaken at 0.12p/share which has increased the shares in issue by 4.17bn to 18.50bn. For 2022 as a whole, we look for a cash inflow including share issues of £3.6m. This would leave the unrestricted cash position at 2022 year end at £5.3m. Excluding share issues and movements in restricted cash, there would be an underlying cash outflow in 2022 of £2.0m. This is split operations £1.2m and project related expenditure £0.8m.

Based on the work programme outlined above plus G&A we would look for a financing requirement in 2023 of about £2.9m. This should be very well underpinned by the cash position post the recent raise. At end 2023 we forecast unrestricted cash of £2.4m.

It should be noted that the above excludes any allowance for prospective drilling work at either Chuditch-1 or Dunrobin on P2478 in the Inner Moray Firth. Both are major projects with the former requiring a particularly large near to medium term financing commitment given an appraisal well cost of around US\$25m. Farm-in partners are currently being sought ideally offering free-carry terms. Expenditure commitments on both projects for the second half of 2023 or possibly 2024 may therefore be unknown for several months.

Exhibit 9: Summary income statement

Year-end December (£'000)	2016	2017	2018	2019	2020	2021	2022e	2023e
EBITDA	-700	-510	-549	-442	-710	-1321	-1367	-1500
Exploration & evaluation expenditure	-739	-109	-1526	-160	-145	-218	0	0
Intangible asset impairment	-356	-1837	-1360	-1047	57	-28	0	0
Receivables impairment	73	43	-54	16	74	-7	0	0
Deconsolidation of Colombia	31	831	0	0	0	0	0	0
Administration expenses	-700	-510	-549	-442	-710	-1321	-1367	-1500
(Loss)/profit on exchange	1131	-508	130	-41	-157	22	0	0
Other operating income	319	21	83	0	0	89	0	0
Operating loss	-241	-2069	-3276	-1674	-881	-1463	-1367	-1500
Associated undertaking	0	0	0	0	-44	331	0	0
Finance cost	-35	-8	-10	-1	0	-2	0	0
Finance income	101	19	6	1	5	7	0	0
Loss on ordinary activities before tax	-175	-2058	-3280	-1674	-920	-1127	-1367	-1500
Income tax credit/(expense)	-113	519	785	0	0	0	0	0
Loss on ordinary activities after tax	-288	-1539	-2495	-1674	-920	-1127	-1367	-1500

Source: Allenby Capital; Company

Exhibit 10: Summary balance sheet

Year-end December (£'000)	2016	2017	2018	2019	2020	2021	2022e*	2023e*
Non-current assets								
Property, plant and equipment	3	0	0	0	43	34	34	34
Intangibles	1325	1260	66	5	18	2736	3506	4926
Goodwill	0	0	0	0	0	0	0	0
Other	0	0	0	0	151	0	0	0
Total	1328	1260	66	5	212	2770	3540	4960
Current assets								
Trade and other receivables	2070	18	503	49	376	54	54	54
Cash	5231	3992	1838	472	1311	2509	6630	3710
Other	0	0	0	0	0	0	0	0
Total	7301	4010	2341	521	1687	2563	6684	3764
Total assets	8629	5270	2407	526	1899	5333	10224	8724
Current liabilities								
Trade payables	1054	195	594	64	58	620	720	720
Taxes payable	1502	812	23	7	16	12	12	12
Debt	0	0	0	0	0	0	0	0
Total	2556	1007	617	71	74	632	732	732
Non-current liabilities								
Lease finance					29	19	19	19
Total					29	19	19	19
Total liabilities					103	651	751	751
Net assets	6073	4263	1790	455	1796	4682	9473	7973
Net cash/(debt)	5231	3992	1838	472	1311	2509	6630	3710
Shareholders' equity								
Share capital	344	344	344	482	1107	2896	4626	4626
Reserves	5729	3919	1446	-27	689	1786	4847	3347
Total equity	6073	4263	1790	455	1796	4682	9473	7973
Total equity and liabilities	8629	5270	2407	526	1899	5333	10224	8724
Shares in issue end year (m)	1376	1376	1376	1926	4426	11584	18500	18500

Source: Allenby Capital; Company. * reflects £5m placing.

Exhibit 11: Summary Cashflow

Year-end December (£'000)	2016	2017	2018	2019	2020	2021	2022e*	2023e*
Loss attributable to controlling interests	-32	-1539	-2495	-1674	-920	-1127	-1367	-1500
Depreciation, amortisation and impairments	331	2	1360	1047	-57	28	30	30
Share based payments	0	41	33	0	81	286	0	0
Finance income	-101	-19	-6	-1	-5	-7	0	0
Associates					44	-29	0	0
Tax benefit	113	-519	-785	0	0	0	0	0
Foreign exchange translation	-1319	512	-73	-4	-52	19	0	0
Other	-257	-347	0	0	0	-302	0	0
Operating cash flow before working capital	-1265	-1869	-1966	-632	-909	-1132	-1337	-1470
Receivables (increase)/decrease	-440	2052	-485	454	-4	-1	0	0
Tax paid	71	-4	-53	0	0	0	0	0
Payables (decrease)/increase	-692	-859	400	-546	-6	557	100	0
Net cash flow from operating activities	-2326	-680	-2104	-724	-919	-576	-1237	-1470
Acquisition of intangibles	-493	-298	-66	-1047	-527	-2649	-800	-1450
Cash previously not available now released	0	2674	0	0	0	0	0	0
Sale of intangible assets	1784	0	0	0	0	0	0	0
Other	183	19	6	1	-6	-9	-472	0
Share issues	0	0	0	408	2295	3694	6158	0
Net cash flow	-852	1715	-2164	-1362	843	460	3649	-2920
Opening cash	3010	2158	3873	1709	347	1190	1650	5299
Closing unrestricted net cash/(debt)	2158	3873	1709	347	1190	1650	5299	2379
Project Bank Guarantees	3073	119	129	125	121	859	1331	1331
Net cash/(debt) as per balance sheet	5231	3992	1838	472	1311	2509	6630	3710

Source: Allenby Capital; Company. * reflects £5m placing.

Risks and challenges

Chuditch largely de-risked geologically pre-drilling: Following a positive outcome to the TGS-NOPEC seismic data reprocessing and evaluation, the Chuditch project and particularly the Chuditch discovery structure would seem to have been largely de-risked geologically. Arguably there may be some residual risk surrounding the ERCE resource estimate but we think it would be surprising if this seriously de-railed the project. The Dunrobin project in the Inner Moray Firth, however, has yet to be de-risked sufficiently prior to making a drilling decision.

Short lead time to complete technical work and secure a farm-in partner: We consider the major risk surrounding Chuditch relates to the relatively short lead time to June 18, 2022 under the terms of the PSC to complete the technical work and secure a farm-in partner. We regard eight months or so for these tasks as tight particularly given that a prospective partner would probably need visibility on the SPE PRMS compliant resource data before making a drilling commitment and FID. We believe that post FID planning for an appraisal well on Chuditch-1 will probably take a minimum of nine months and possibly a year. Assuming Chuditch-1 appraisal drilling corroborates findings from the 3-D seismic evaluation work, which seems likely in our view, exploration drilling will be required to test Chuditch-NE and Chuditch-SW. We think this would probably need to be undertaken in conjunction with a PFS for the whole project.

Financing requirement ideally requires a free-carry farm-in partner: Spending requirements over the 18 months or so subsequent to the Chuditch appraisal well FID could therefore be substantial. The key question is how this might be financed. The ideal solution would be through a free-carry farm-in. The terms on which such an arrangement might be made are unknown at this stage. Alternatively, a free-carry farm-in might not be available. A prospective partner might only be prepared to offer terms which require Baron to make a significant capital contribution and by implication accept a degree of project and financing risk.

Share price performance and valuation

Share price performance

Price surge in late October-----After having trended flat for much of the past year at around 0.08p/share, the Baron Oil share price has recently surged. On October 21 the stock hit a spot high of 0.358p and closed at 0.29p which approached a three-year high. At the recent high the stock was valued at £40.6m. Interestingly, the equity raise in April 2022 was transacted at 0.06p/share. Since the October 21 peak the stock has weakened with a decline to about 0.16p/share. This left the valuation at £23.6m.

-----**driven by positive announcement on the Chuditch project:** The proximate cause of the price surge was a positive announcement on October 18 concerning the Chuditch project. This referred to the PSC being extended by six months, the upgrading of the gas resource and the progress being made in upgrading the imaging and modelling. The October 18 statement it appears began to allay fears concerning the ability of Baron, very much a junior albeit one well-endowed with technical resources, to advance what is a major energy investment. Not altogether surprisingly after the meteoric rise, the stock weakened reflecting in part the market awaiting new developments and in part the possibility of a share raise. We think the next major influential announcement will be an independent assessment of the Chuditch resource base. The results could be announced in early 2023 and should assist in paving the way for securing a farm-in partner.

Valuation

Risked sum of the parts calculation based on the two projects: Our Baron valuation methodology continues to be based on a sum-of-parts calculation where the parts are the projects. Currently there are two, Chuditch and the Inner Moray Firth licence P2478 Dunrobin prospect. For each project the key components of the valuation are the net resource base, a risking factor which takes into account our assessment of commercialisation at this stage of development and a valuation quotient expressed in US\$/boe. We also adjust working interests for anticipated farm-ins for the first stage of appraisal/exploration. In valuation terms Chuditch is by far the most important of the two projects.

Chuditch valuation quotient raised from US\$1.0/boe to US\$1.3/boe: For Chuditch we upgraded the valuation quotient from US\$0.5 to US\$1.0/boe in June 2022 to reflect surging commodity prices, progress on the TGS-NOPEC seismic reprocessing exercise and related evaluation work and growing interest in large scale energy projects. Given the recently announced upgrade to Chuditch resources based on evaluation work using the reprocessed 3-D seismic data and the advanced stage of project modelling, we now propose raising the project valuation quotient to US\$1.3/boe. We are leaving the valuation of the Dunrobin prospect unchanged at US\$0.5/boe reflecting the still early stage of the project.

Valuations assume free-carry farm-ins in exchange for 50% of Baron project equity: Two points should be noted concerning the resource used for valuation purposes. Firstly, in the case of Chuditch we have assumed that Baron will seek a free-carry farm-in and that this will necessitate conceding 50% of the equity in the project. Its working interest will, therefore, drop from 75% to 37.5%. The balancing 25% is owned by the Timor-Leste national oil company (NOC). For Dunrobin we have also assumed a 50% concession on working interest from 32% to 16% for free-carry terms. The second point to note on the resource front for Chuditch concerns liquids. Our previous resource estimate had included an allowance for liquids. Given that Baron has now said that Chuditch is a dry gas play we have removed liquids from our new estimate. Our risking factors (probability of success) for Chuditch and Dunrobin are 53% and 48% respectively. The former is a composite and reflects the previously used probabilities of 100% for the Chuditch-1 discovery, 40% for Chuditch SW and 20% for Chuditch NE and Quokka.

Valuation upgraded from US\$110m to US\$160m-----We are upgrading our absolute risk adjusted valuation for Baron from US\$110m to US\$160m. This translates into £143m at an exchange rate of £1=US\$1.113. The increase in sterling of 63% reflects three key factors as follows:

- An increase in the net risked resources for Chuditch from 106mm boe to 120mm boe to take into account the resource upgrade.
- An increase in the Chuditch valuation quotient from US\$1.0/boe to us\$1.30/boe.
- A change in the exchange rate assumption from £1=US\$1.25 to £1=US\$1.113

-----**with the latter translating to 0.775p/share**: Using 18.500bn shares outstanding, the new absolute valuation translates into 0.775p/share. This compares with 0.61p/share previously.

Success case

Post a successful Chuditch PFS----Near to medium-term, we would define a success for Chuditch as the planned appraisal well on Chuditch-1 resulting in test production consistent with the present resource estimate. We would expect this to be followed by a pre-feasibility study and possibly exploration wells to test the Chuditch-NE and Chuditch-SW prospects. A successful pre-feasibility on this basis would then probably lead to an FID (final investment decision) for the commercialisation of the project.

-----**a valuation of US\$5/boe could be plausible**: As we have noticed previously, a large scale natural gas project in close proximity to pipeline infrastructure and potentially linked to Santos’s Wickham LNG plant is likely to be a valuable asset. Assuming JKM (Japan-Korea-Marker) prices in real terms of at least US\$15/mm Btu which would probably allow comfortable headroom above cash costs of perhaps US\$10/mm Btu we believe such a project could sell for around US\$5/boe post the pre-feasibility stage.

Exhibit 12: Baron Oil risked and diluted valuation summary

Basin	Project	Working interest %	Net risked				Valuation quotient \$/boe	Un-risked valuation \$m	Risk adjusted valuation post farm ins		
			Net un-risked resources bcfe	mean resources boemm	Risking factor %	mean resources boemm			Absolute \$m	£m	p/share
Bonaparte	Timor-Leste	37.5	1359	227	53	120.0	1.3	294.5	156.0	140.2	0.758
	Chuditch										
Moray Firth	UK P2478	16.0	117	19.5	36	7.0	0.5	9.8	3.5	3.2	0.017
	Dunrobin/Golspie										
Total			1476	246.1		127.0		304.3	159.5	143.3	0.775

Source: Allenby Capital.

Notes: Working interests have been adjusted for anticipated farm-ins for the first stage of appraisal/exploration.

Risking factors are based on Baron Oil estimates in the case of Chuditch and Reabold for Dunrobin/Golspie.

The risking factor for Chuditch is a composite for the probabilities of success given by Baron for the project’s discovery, three prospects and a lead.

P2478 valuation includes both Dunrobin and Golspie prospects based on gross prospective resources of 100mm and 22mm barrels respectively.

The shares in issue used in the per share calculation is 18,500.3bn and reflects the £5.0m placing.

Exchange rate: £1=\$1.113

Share price catalysts

We continue to see plenty of scope for influential news flow in the coming months. Key examples are potentially as follows:

- ERCE's estimates of Chuditch resources to SPE PRMS (Petroleum Resource Management System) standards. This is an internationally recognised standard for providing reliable and consistent classification and estimates for hydrocarbon resources. We believe Baron might be in a position to report ERCE's findings in early 2023.
- Selection of a Chuditch joint-venture partner. We believe an announcement on this front might occur at about the same time as the release of ERCE'S resource estimate.
- Announcement of an appraisal well commitment at Chuditch. As we have noted, a decision will be required by June 18, 2023 to be in compliance with the PSC terms.
- FID (final investment decision) on a Chuditch appraisal well possibly during the third quarter of 2023.
- Drilling of the Chuditch appraisal well possibly in the second or third quarters of 2024.
- Release of the Dunrobin reprocessed 2-D and 3-D seismic data evaluation report. This is scheduled for release by end 2022 and should provide an indication of the resource base possibly to SPE PRMS standards.
- Release of the Dunrobin CPR possibly late in the first quarter of 2023.
- Announcement of a Dunrobin farm-in partner possibly late first or early second quarter of 2023.
- Drill or drop decision on the Dunrobin project probably in late June 2023. We presume it will be drill in which case the FID should occur at about the same time.
- Dunrobin well spudding possibly late second or third quarter of 2024.

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