Cairn Energy PLC

Full Year Results 2018

12 March 2019

Transcript

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Simon Thomson: Morning, everybody. Welcome to Cairn's results presentation. I'm Simon Thomson, Chief Executive, with me are James Smith; CFO, Paul Mayland; COO and Eric Hathon; Exploration Director.

So as is in the usual way, we've got a presentation that we'll walk you through this morning, we'll be very happy to take questions at the end. It's being webcast, so there'll be microphones available, so if you do have a question, please, for the sake of those listening, state your name before asking the question.

I'm sure everybody has been in this room before, but just in case, in the event that the fire alarm goes off, you can see the clearly signed exit there, and the assembly point is outside in the square.

Before I turn to the first slide, I just want to say a few words on India. Obviously, you will have seen our announcement yesterday concerning the timing of the arbitration award. There's probably not a great deal more that I can add today, but there's a couple of things that I do want to emphasise.

The first thing, obviously we clearly understand that this is frustrating for shareholders. The timing is outwith our control, and the timing has changed. But secondly, and importantly, that's the only thing that's changed. So we remain just as confident in terms of the outcome of this arbitration as we have been right the way through.

There is a revised timing in respect of the outcome, but it remains a significant value driver for us, and nothing has changed in that respect.

Now I want to just move onto the value that we see in the underlying business, so if you turn to that first slide. A couple of words on the company, where it sits in terms of its strategic delivery today. As you know, our mantra is to create, to add and to realize value, and we believe that a differentiator has been our willingness to look at returns to shareholders. Whether through buybacks, special dividends, whatever ... in delivering that mantra.

Obviously, five years ago or so after the last cash return, we set about rebuilding the company to offer a balanced business. We wanted to have something that gave shareholders significant upside potential in terms of our drilling programme backed by balance sheet strength, and we believe that that is what we have today.

If you look at this slide and starting from the top left here, our production from our North Sea assets, obviously underperformance at Kraken counted by outperformance at Catcher, provides all of the cash flows we require to meet our commitments.

Those cash flows are generated in a company that has significant balance sheet strength and financial flexibility, so that allows us to redeploy those cash flows in our exploration activity, whilst at the same time, retaining the flexibility to be able to follow up on our developments and consider any accretive new venture activity.

When you look at the sustainable investment in the exploration programme, we're really excited about what we see in front of us this year. The programme, which Eric will talk about in more detail, is seeking to access around about one billion barrels of gross resources.

And at the same time, we continue to look at bringing in, re-ranking our new venture portfolio. The company continues to focus on what is the best prospect to drill, that changes through time obviously, and we're looking at 2020, 2021, 2022. All of those have to satisfy our strict investment criteria to be bought into the company.

You then look at the follow on from exploration success, and we've got two home-grown developments in Nova in Norway and SNE Senegal. Both of those give us the ability to not only sustain but enhance cash flow generation out into the medium to longer term.

When you tie all of that back together, coming back to the point I made at the beginning, we believe where we sit today; we do offer significant upside potential. Whether through the drill bit or portfolio management, and we have been active portfolio managers in the past. We continue to desire to be so in the future.

If you look at the next slide, as you can see, it's going to be a busy year for us. So, there are a large number of wells ... there's seven wells drilling in this programme in 2019, five of them operated by Cairn, so that's where we want to be in terms of the balance of Cairn’s operated activity. As I say, Eric will talk about that in more detail.

Also, there is a lot of other activity in terms of contingent well planning for future years, ongoing seismic and data acquisition. Then we look at our development activity. Again, Paul will touch on all of that, but the key messages are they're both progressing on track, and they're both making excellent progress.

Nova fabrication is ongoing now in terms of the facilities required to be added to the platform and the tieback, and it remains on schedule for first oil in 2021.

Senegal, you'll have seen various announcements from Woodside, now the operator, following a successful transition from us, the ESIA that was submitted has now been approved. The exploitation plan that was submitted now has technical approval leading towards FID in the mid-year, which as I say, Woodside have reconfirmed, remains on target.

And also, as you'll have seen from their announcements, there's multiple FEED work ongoing and again, Paul will touch on that.

It's an exciting year for us; there's a lot that we believe we'll be able to come back to you with in terms of potential upside in the portfolio. We're working hard on that. So we're looking forward to coming back to you; on exploration drilling results, coming back to you on progression of the developments and the Indian resolution.

With that, I'll hand over to James.

James Smith: Thanks Simon, morning everyone.

So in the next few slides, I'll take you through key results for 2018, and then I look forward to the year ahead. First of all, an overview of the current funding position. Cash flows during 2018 took us to a year-end cash position of $66 million. In terms of working capital, at the balance sheet date, we had an oil sales receivable of $39 million relating to 2018 production and remaining outgoings of $30 million relating to 2018 Capex, so a small net positive cash working capital position.

The $575 million North Sea Reserve Base Lending facility was drawn $85 million at year-end, and during last year we extended the maturities of that facility out to 2025 in order to incorporate the Nova field development into that facility. Following that, all, or close to the full facility amount is now available to draw.

In Norway, we continue to use an Exploration Financing facility, which effectively prepays the tax rebate on exploration activity accumulated during the year, so drawings under that are usually roughly equal to the rebate that's been accumulated during the period.

Looking forward to the future capital programme, work on our Project Financing facility for SNE is now well-progressed. We've been working both with the Senegal government and our joint venture partners on structuring, as well as with a core group of expected lenders regarding capacity, terms and work on both of those streams is now well-progressed in readiness for a formal launch, so that we can close in conjunction with FID in mid-year.

And finally, to reiterate Simon's point, whilst we remain confident of the validity of our $1.4 billion arbitration claim against India, the timing does remain uncertain, and we, therefore, maintain a business plan that is fully funded without those proceeds taken into account.

Looking at some of the key figures for 2018, as we'd already guided at the beginning of the year ... production of 17,500 barrels a day gave revenues of $396 million on an average realised crude rise of $68 a barrel.

Average Brent prices during the period were approximately $71 a barrel so that obviously indicates strong price realizations, both for Catcher and Kraken crude, helped in part with global outages of heavier crudes across the slate.

So with average production costs of $20.5 a barrel, that gave operating cash flow from production of $229 million excluding that $39 million receivable that I mentioned earlier.

In terms of the Income Statement, we posted an impairment on our Kraken field carrying value based on currently constrained production levels, which lead to an operating loss of $182 million. As we'd already partly recognised in the mid-year 2018 results, during the year, the Indian income tax department sold the shares in Vedanta Ltd. that they had seized from us, which lead to a derecognition of the value of those shares and a P&L loss after tax of $1.1 billion.

Moving on to the guidance for this year, we anticipate production in the range of 19-22,000 barrels a day as we'd already guided in January before the Flowstream take, and an average production cost of around $20 a barrel.

The middle of that range and prevailing oil prices that would give operating cash flow for this year for more production of around $300 million.

And as you can see, we've hedged just over a third of those expected volumes with floor prices in the mid-to-high $60 Brent.

Looking now at a reconciliation of cash flows during the year, the opening cash position at the beginning of 2018 was $87 million, operating cash flows from oil production during the year, $229 million. We drew $85 million on the RBL facility and $37 million on the Exploration Finance facility in Norway to take us to the top of the chart there.

Capex on the two producing fields of %105m was $35m on Kraken. Drilling, which is ongoing, and $70m on Catcher for the completion of the FPSO at the beginning of the year, and development drilling during 2018, which has now concluded on the field.

Capex on the SNE and Nova fields, last year, was $59 million bringing Nova into the development phase and SNE into FEED phase, and then an exploration cash outflow of $121 million represented a net of tax programme of $88 million, being principally the four wells in the UK, Norway region, Tethys, Raudosen, Ekland and the Agar-Plantain discovery as well as planning for this year's Mexico campaign. Then at the end of the chart there, new ventures costs admin expense, which includes India costs and financing expense, which includes the refinancing of the RBL facility and purchase of own shares gave a year-end cash position of $66 million.

Looking now to Kraken Capex guidance for the year, $25 million of development expenditure on the producing assets relate mainly to the completion of the DC4 drilling on in the early part of this year. On NOVA $65 million relates to the start of work on the modifications and the new module required at the host platform. And in Senegal that $40 million relates to pre-FID costs only. So effectively the pre-FID and FID activity that's currently ongoing. On the exploration front, we expect four wells in the UK, Norway region this year, which Eric will come on to talk about. That's Presto, which is currently drilling total $25 million.

The core part of the expenditure this year will be on the three out of the four wells we have planned in Mexico, with total net cost of $85 million. And then across the rest of the portfolio, we have data acquisition programmes on some of the new positions we've acquired, for example, in Cote d'Ivoire, in Suriname as well as earlier stage activity across the rest of the portfolio and some pending new venture initiatives. So overall a very active capital programme for the year, but at $300 million, one which is comfortably funded from our expected operating cash flows. And in addition, as I mentioned, we have substantial undrawn debt facilities. So just to conclude on the key points, we've strengthened our balance sheet flexibility during the year by bringing NOVA into the RBL facility and extending debt maturities.

Whilst we have taken an accounting impairment on Kraken those rebased assumptions are aligned with the production guidance we'd already given and are also aligned with the bank. So we don't expect any significant funding impact on the capacity from Kraken. It's really just the accounting treatment of the rebased guidance we'd already given. As mentioned, our capital treatment programme for the year is roughly in line with operated cash flows expected during the period, and therefore we would expect net debt to remain stable through to the end of 2019.

We're working towards implementation of the Project Financing for the SNE development anticipated with FID in the middle of this year and there and as well as across the rest of the asset base. We continue to be active portfolio managers to maximise value and optimise capital allocation. And on that note, I'll hand over to Paul.

Paul Mayland: Thanks, James. Good Morning everyone. I'll start by giving you an update on our two production assets and then move on to the positive progress we've seen regarding no developments before concluding our preparedness for our 2019 exploration programme. At which point I'll hand over to Eric.

So the production is a story of two different halves, but overall across the two assets they are delivering our targets starting with the reservoirs, wells, sub-sea, and FPSO continue to outperform field development plan expectations.

We had anticipated a field with 22 wells delivering 50,000 barrels of oil per day and today we are delivering 66,000 barrels of oil per day through the facility with very strong uptime at well above 90% from 18 wells, and its early days in terms of assessing water flood performance in these re-mobilised and injected sands, but we've incorporated a small upward revision of a few million barrels gross as part of our year-end reserves reporting process at the 2P or proved plus probable level.

Equally important the 1P or proved reserves on Catcher have grown 50% since and the 3P reserves reported in remain valid today. Satellite and infill opportunities are emerging, and we expect to high grade the best opportunities for 2020 when a rig will return to drill a firm Varadero well. Kraken is a slightly different story. However, we have a much clearer reservoir picture today then compared with six months ago, and reservoir voidage has started to improve, which was a significant issue during 2018.

As we outlined in September, we conducted a programme of reservoir surveillance and well testing across the existing 11 producers and 10 injectors and we can now bracket the initial field performance of 18 months into three phases: a few select wells resulting in initial higher water cut than expected for the field. This was followed by water breakthrough in other wells more consistent with expectation, and over the last five to six months we've seen increased stabilisation with the water cut essentially flat over this period. However, the increased level of water being produced from the field has resulted in us developing reliable history matches for our reservoir simulation models and generating new forecasts.

And this process has unfortunately resulted in a downward revision of reserves on the field by approximately 19% as reported today. Kraken last year produced 30,000 barrels of oil a day. And this year we estimate 30 to 35,000 barrels of oil per day. With an increase from the current levels of production expected when the DC4 wells, 2 new producers and one injector come on stream. This will signal the end of the current joint venture approved capital drilling programme. Our main focus for 2019, therefore, relates to FPSO performance, and we're working with the operator EnQuest and the contractor Bumi on short and longer-term initiatives to improve both the uptime and the reliability of the facility.

If we move on to our developments then, Firstly onto Nova in Norway, we are very much in the execution phase, fabrication of templates, manifolds, umbilical and subsea trees are well underway. Final planning for the Host Platform, Gjøa, for the shutdown associated with the Nova works, is ongoing and the West Mira rig is in transit to Europe to complete its acknowledgment of compliance before it commences work on the Norwegian Continental Shelf. Initially, it's likely to drill some exploration wells for operator Wintershall before commencing, the Development Programme of development drilling next year for Nova. Recently, in February this year, we also saw the submission of two further satellite development plans, tied back to the same host to Gjøa, which when approved by the NPD are likely to have, a positive impact on the Nova life and therefore economic field.

So that's good news for us moving forward and good news for utilisation of existing infrastructure in Norway. So next up is obviously the SNE field in Senegal and, during 2018 we made considerable progress on this half a billion barrel oil and gas field. After extensive public consultation and technical review by the authorities, the environmental and social impact assessment of the plan development was approved in January. The Exploitation Plan has also been technically approved subject to finalisation of the FEED studies and presentation of the final field development costs to the government. As you are aware, the subsea front end, engineering and design or FEED as we call it is with the subsea integration alliance at Schlumberger, Cameron and Subsea Seven and the FPSO feed as with MODEC. Both well-established service providers in West Africa.

We also anticipate complete award of the drilling contracts and the drilling services in the next couple of months. And we anticipate that with the incorporation of pricing from these contracts, along with the goods contract already awarded in conjunction with a sharpened focus on the well scope which you will already have seen it has gone from 26 wells to 23, will result in us being below our target capex of $3 billion for phase one.

These work streams, running in parallel with the ongoing joint venture or Project Finance outlined by James, position the project well for a Final Investment Decision in mid-2019. As a brief reminder, the upper S 400 and S 500 reservoirs, hold in aggregate 3.6 billion barrels of oil with around 500 million barrels expected to be produced over several phases of development.

A Final Investment Decision, the operator expects to move around 230 million barrels, draws into 2P reserves, associated with the first phase and further phases of oil development are anticipated to come on stream anywhere between two and four years after first oil to sustain the plateau production and to maximise recovery.

Finally, our wells and supply chain team have also been busy during 2018 to position us as a company to execute our 2019 exploration programme. We believe that we can build on the strong HSE culture and performance which during 2017 and 2018 was incident free across our operated wells programme. We are pleased to have secured competitive pricing, for the Transocean Arctic Rig for Norway, the Maersk Developer for Mexico, which incidentally was Shell’s floating rig of the year in 2018.   And Stena who we've worked closely with before for the supply of Dawn for our high impact well in the UK Chimera, and on that exciting note and with a backdrop that our projects are progressing well. I'll hand over to Eric.

Eric Hathon: Thank you, Paul. Good Morning everyone. As I've shared with you before, we continually work and, as Simon said to high grade our portfolio. Looking for high impact opportunities primarily in frontier and emerging plays. Our focus is always value, not simply geography and we're always mindful of the path to commercialisation. Now towards the end of my presentation, I'll touch on how we're maturing some of the new place we have entered.

But my primary focus today is on our really exciting 2019 drilling programme. As Simon and Paul said, this year we'll drill up to seven wells in three different countries, five of them operated. And that clearly demonstrates Cairn's ability to operate effectively across multiple jurisdictions. We expect to remain active drilling in Mexico, the UK, and Norway into 2020 while we mature future targets in the balance of our portfolio. In Norway, the Equinor operated Presto well spud March 1st, and as I speak is drilling ahead. It's targeting Cretaceous Sands, which are stratigraphically trapped.

And while it's a somewhat higher risk strat play as you can see it as targeting very material volumes and more importantly as a potential to further de-risk and emerging play where Cairn has similar prospects along trend in offset acreage. We expect results for this well in early April and then Lynghaug and Godalen in the Norwegian Sea are both Cairn operated and, will be drilled back to back in the second half of the year. And by drilling back to back they share costs, mob, demob and therefore makes it a more efficient programme overall. Lynghaug is testing Triassic sands and Goodall Jurassic sands and once again the discovery on either will set up a new play trend in board of existing production where Cairn has follow on opportunities.

Then our attention will turn to the UK; we'll drill the Chimera prospect. And we recently welcomed Suncor as a partner in this block. Chimera is a stratigraphically trapped oil sand target with the potential to be highly material to shareholders. And this prospect was identified and modelled in 3D data with state of the art processing. And it was at largely invisible on older vintages of data. So if successful, we've identified a new play type in a very mature area. And again, all of these prospects have the potential to be standalone developments. But the beauty of working in mature areas in the North Sea and Norwegian sea is even with more modest volumes; they can be tied back to existing infrastructure. So our ranges of commerciality are much wider, which is one of the attractive things here.

Turning to Mexico, I'm very pleased to be starting our drilling programmes in both block 7 and 9 where we're targeting a gross mean of over 500 million barrels of oil, in proven oil-prone basins, which actually remains under-explored. So intense pay drilling on two wells in block 9 this year, both operated by Cairn and one well in block 7 where ENI operates. Drilling will commence in the second half of the year. And it's good to point out that, of course, we've mentioned before the Zama well discovery which sits just east of our block 9 and now the Murphy operated well on the eastern edge of block 5 has been reported today as a discovery.

So good follow through, read through for our activity. So we look at the Alom prospect - this is targeting multiple tertiary solid shallow marine sands in what we call a typical upthrown fault block play. And we do see indications of direct hydrocarbon indicators on the seismic, which is always a risk reducer. And another attraction here, the Alom prospect happens to be in the shallowest water of any of our prospects in our portfolio at only 140 metres of water.

The Bitol prospect will be a deep well drilling over 5,000 metres of rock, and it will test all of the tertiary targets that I've identified in the Sureste basin. So these are stacked targets, and we can assess all of them with one well bore, which again is quite economical and effective. And this will be our deepest well in the 2019 campaign and will take roughly 60 days to drill.

Now both Bitol and Alom are attractive targets and both provide the capability again of being standalone developments. In block 7 the joint venture is still finalising the initial drill target, and we expect to have that imminently. But as you can see from this geo-seismic section, there are multiple targets and block both faulted four way closures as well as three-way closures up against salt. And that salt does make a very effective seal. Prospect volumes are again quite healthy and well above the minimum required for development. We do anticipate another fairly deep well here with a depth of again of about 5,000 metres and taking a couple of months to drill. And finally, as you can see from the map both here and in block 9, we have multiple prospects that have significant follow on potential success, either to be additional standalone developments or very lucrative tiebacks.

So overall we're very excited to begin drilling in Mexico in this oil prone basin.

So I just want to leave you with, we have a robust drilling programme in 2019, and we see it continuing into 2020 again with the large operated component, which has always been one of our drivers. In our other leasehold, we continue to mature the target set. We acquired over 4,000 kilometres of 2D seismic and block 61 offshore Suriname this January. We've already started to receive the first products, and they look very crisp and exciting. We plan to acquire 2D seismic with the operator, Tullow, onshore Cote d'Ivoire in the second half of this year and we will commence a high resolution 3D seismic survey over SNE field in the environs in Senegal.

So this will provide more precise targeting for development wells. It would create a baseline for future what we call 4D seismic, and we'll further mature potential other exploration targets. Now just say 4D seismic the way that works. Once a field you have this baseline survey, and once the field comes on production, you're able to shoot additional seismic surveys which can help you identify bypass pay. So it becomes extremely valuable in later life in the field. So we're quite excited for that as well.

Offshore Ireland, we have commenced a farm down process on on our blocks as we always knew we would after the acquisition and a receipt of the new 3D seismic. And we've hosted multiple companies in our data room and in fact we've been approached by more companies to come in.

And finally we continue to look to high-grade other opportunities into our portfolio so that we're always looking for the very best and highest value opportunities and that will continue both through 2019, 2020 and beyond.

And with that, I'll turn it back over to Simon.

Simon Thomson: Thanks, Eric.

So in summary on the last slide you can see, and as I think, hopefully, we've demonstrated, there's multiple opportunities for value creation within what we believe is a sustainable business offering.

On India, we will let you know as soon as we receive an update from the panel, but the key message is, we remain absolutely confident of our position in the arbitration, and nothing has changed in that respect. As Eric's just outlined, we've got a really exciting programme of wells we're already on the first one. So we're looking forward to reporting the outcome of that programme to you during the course of the year.

We look at the portfolio management, mature developments, as Paul has outlined our developments are moving forward well, they're on track, and I think the key point to reiterate is that we are, have been and will continue to be active portfolio managers in respect of what we have currently within the portfolio and the business.

We are, as Paul as mentioned, very focused on delivering operational excellence. We're operating five wells this year. We will seek to ensure that we continue that track record of safe discipline focused operation to continue that excellent record and sustainable value creation. At the end of the day, as I said at the beginning, our mantra is to create, to add and to realise value for shareholders. And that is what we will remain focused on doing. With that, like to handover for questions, straight away.

Werner Riding (Peel Hunt): Just moved straight to Kraken and the reserve downgrade. In your statement, you cite three reasons. Two of them are above ground, one of them's a below ground challenge, and it's the below ground one, which to my mind seems the most important around increased water cut. So Paul I just wondering if you could elaborate a little bit more on the water cut issues. How many wells, what the percentage of water cut is and why as well the variance lies between you and EnQuest as to why you would as non operator take a very significant downgrade and impairment on your financials and they're not. So what are the differences between you?

Paul Mayland: Essentially I will comment two ways as to why we are taking the reserves downgrade. And basically why we're doing it now. So firstly, obviously heavy oils quite different from light oil. Water was always expected in this field in every well quite early on. So that, we should have that in our minds and mainly because it's a viscous oil field, so the displacement of oil by water was always going to be less efficient than in a light oil field. The facility has been built to handle process, reinject the produced water. However, what is clear today is that the displacement of oil by water is not as efficient as we had originally expected in the Field Development Plan.

So consequently, we are producing a level of water today, which is higher than what we had in the FDP now. So why have we actually decided to take the downgrade. We said back in September that we were going to carry out a programme of reservoir surveillance and well testing. The wells, both the production wells and the injection wells are performing very strongly. So we've got continuous production from the whole length of the lateral or the horizontal section. We've got very good injection across the horizontal injectors. It's a line drive, and that's all performing really well. We've produced a meaningful volume of oil.

So we've produced, 30,300 million barrels of oil from this field at the year-end 2018. And we've updated, and history matched our reservoir models and generated a new production forecasts from them. We knew that we're producing, even if you take out the FPSO performance we know we're producing at an oil rate about 20% below the FDP. So if we had readjusted for, the poorer performance than we expected on the FPSO, the surface or above ground as you've described it. We might have produced 40,000 barrels of oil a day. That's 20% lower than the target oil volume associated with the reserves in the FDP. And when we put all of those factors together, we believe at this time as a prudent move to readjust our reserves to reflect current performance and to do it now.

Werner: Has the field life been shortened?

Paul Mayland: No, the field life is not materially shortened. This was always going to be, a situation where you're going to be producing a lot of fluids, both oil and water for quite a long period of time. That was the basis of the FDP. That was the basis of design. We've got this huge water handling capacity built into the system and we come on to, we need to obviously get it performing a little bit better. But the longevity of the field hasn't materially changed. So it's more of a sort of, lowering the production levels, over that period versus the original FDP.

Werner: Okay, thanks. And then just so I understand the differences between you and EnQuest why you've chosen to downgrade, and they haven't as operator? Where are the differences between you?

Paul Mayland: I think it's probably best just to comment on what Cairn has done. So each oil company will estimate their own reserves, these obviously include the production forecasts that we've discussed, the oil price assumptions and obviously forecasts of operating and capital costs and without assumptions, which we believe are reasonable, we arrive at the P50 or the proved plus probable scenario that we're validating today.

Sasikanth Chilikuru (Morgan Stanley): Going back to Kraken again. You're talking about production profiles. If you were to look beyond 2019 and 2020 and a little bit beyond that, what, how do you see the profile going? Is it going to be stable? What's the new peak? Is it down to 35,000 barrels per day or you find it declining or remaining stable from 2019 levels?

Paul Mayland: Obviously we've got three wells so we're just in the process of drilling that we've got the last week or two at Kraken, the Transocean Leader, and we'll have two new producers and one injector online. So obviously with that we will bring the rates up during 2019 higher than they're producing today. But then as we've seen in other wells, we expect that we'll have water breakthrough as expected and then basically there'll be this gradual sort of build along the fractional floor so that, the field will continue at little, low decline rates to continue to produce, but in decline for quite a period of time.

Sasikanth: And I had a question on capex for the 2019 you're $300m excludes the proposed FIDs Senegal costs. Just wondering whether there was a range on that, what could we expect for this year?

James Smith: We'll give that guidance, in conjunction with FID, I mean the number, so you're right the capex guidance we give for Senegal for this year is all pre FID. So on taking FID, there will be additional capex in the balance of this year. We don't expect that to be a huge number. Obviously, the bulk of activity will be in 2020 and 2021, leading through to first oil in 2022.

Michael Alsford (Citi): On India, just to clarify, obviously you've given this new guidance on when you expect perhaps resolution. Could you just clarify, is that what the panel has told you is when you should expect the outcome to be published or is that your best estimate? Why then and not later or earlier would be helpful. And then just secondly on to James maybe on the Project Financing for SNE could you give a little bit more colour as to how you're looking to structure it? I guess given the funding from the government's perspective in terms of their share of the capex, but also you've got smaller minority partners. How confident are you to be able to get to a Project Financing that will be fit for all concerned parties?

Simon Thomson: That first point is driven by a lack of guidance from the panel, and therefore, along with advisors, given the amount of workload that they have, a practical estimation of time, but James will to touch more on that.

James Smith: As we said in the announcement yesterday, the panel has confirmed that they are still not in a position to give us specific guidance as it were. So taking that into account, given where we are now in March, and taking into account the advice we received and what we know about the other commitments and so on.

We've really wanted to give guidance that it's not as imminent as expected, and therefore back end of the year is our best estimate.

On Project Financing, as we guided previously, something around 50%, we'd be targeting better than that, leverage on senior secured debt in a Project Financing Facility for the joint venture, is the target.

The government clearly has the right and one we expect them to take up to increase their stake from 10 to 18% and the project. And, so there will be other sources of capital that, the partners, ourselves included as well as the other non operating partners will be accessing in order to fund the balance of the non-senior debt element. And there are a number of options which we are looking at ourselves and, I know which other joint venture partners are looking at to find the balance.

Michael: Would you expect this to the launch on the senior debt portion?

James Smith: Senior portion, it's been, given the scale of the financing, being relatively unprecedented in Senegal, it's been a relatively long preparatory phase as we mentioned earlier last year we were kicking off the process. That preparatory phase is now pretty well advanced, so it's been both in terms of structuring and legal questions, that arise in Senegal when we're working with a joint venture group and the government of Senegal has been, very actively engaged in this process. So that's on the one side.

And then, from late last year, we've done a market testing launch with a core group of expected lenders and commercial banks. In terms of capacity and initial feedback on a term sheet. We've now got that which again is very positive feedback. And so we're now getting ready to launch a formal banking case with a wider group of lenders. And on that it's really been about, tying down, a cost basis for that case. Well enough defined cost basis for that case and clearly where we are now with contracts with, we're pretty much ready to go on that.

Al Stanton (RBC): A couple of questions unrelated, one on Kraken and the other on portfolio management. Firstly on Kraken, what is the partnership's assumption about future capex? Is, today's reserve downgrade the assumption that the capex finishes at the end of this year and there's no further wells? And how does that view differ to what the operator might do or could afford to do? And then portfolio management, it seems to be selling at the moment. If I had $1.6b or $1.4b coming back to me, I wouldn't be issuing new shares at any time, particularly soon. So I'm wondering whether the overhang of the Indian arbitrage situation is preventing you from doing more material deals. Faroe is the obvious example, but is there something you should be doing that you can't or won't do while you wait for the money to come back from India?

Simon Thomson: Let me touch on that one first, no, is the answer. As you know, five years ago when this hit us, we immediately discounted India from any future planning in the business. And, and as a result, what we see today is a sustainable business offering. If you have something that you believe is value accretive for shareholders and you have $1.4 billion alongside it, it increases your flexibility about how you might want to bring that into the portfolio.

If you think there's a good, if there's the right transaction to do, but if it's the right transaction to do and it's accretive, and it's the right thing for shareholders, then the lack of Indian money would not stop us from finding a way to do it. Then the point is though, in our view, which is why we haven't done anything to date and, but we do look at stuff, it's got to be accretive in the sense of what we currently have in our portfolio. So we do consider things. But, as I say, at the end of the day, we'd have to be coming back to we believe that and can we justify the shareholders that it's a better thing to do than sticking with what we've currently got. So, I don't feel constrained other than obviously it's great if you have a lot of money sitting in your bank account. But if in that happy position when it comes, just to reiterate our desire is to make a significant return to shareholders.

Paul Mayland: I think it's fair to say there are both in the field and near field opportunities, at Kraken, the infield ones will be a function of further optimisation associated with, the flood pattern, and understanding of that as to how to optimise it and potentially where best to place infield wells and particularly on the west side. So separate accumulations are the near field opportunities.

I mean essentially we are still maturing those, with a view that they could be, 2020 opportunities. Some of those wells could be drilled from existing infrastructure, and there are spare slots on the manifolds. Some need may require new infrastructure. None of that is as yet committed. Because obviously the first or the initial Field Development Plan, a programme of capital has essentially been coming to a conclusion. And those resources that we would describe there, we would move into reserves potentially at the point that we sanction those investments.

Al: Do you feel you're on the same page as the operator in terms of the future development?

Paul Mayland: Yes, I think so. I think we've got a common view on what those opportunities are, and the timeline to mature them and potentially, the range of recoveries associated with those, those additional wells. But it's still very much work in progress.

Chris Wheaton (Stifel): A few questions if I may. First of all James please, on the Project Finance, would you expect to have to offer a parent company guarantee to get the Project Finance settled or, or would you assume that the securing of the debt against the project is sufficient guarantee for the lending banks?

James Smith: So it will be, we anticipate there'll will be a fairly typical Project Finance structure i.e. that debt service, the repayment and the service of the debt will be ringfenced to the assets secured on the assets and, in that sense, non-recourse. Typically, the sponsors will provide a parent company guarantee, completion guarantee if you like during the development phase. So, the joint venture parties would typically sit there with, some recourse for project execution but then effectively repayment of the debt is non-recourse.

Chris: Would that include any additional spend you might have to cover for your partners if I can pick-up on the question about paying portion of the government share for example?

James Smith: No.

Chris: The other question was on exploration, for Eric, what's your actual committed exploration spend over 2019 and 2020? You've got an awful lot of activity going on, and you've got some committed wells across 19 and 20. Could you tell me what the minimum commitments you've got in cash terms is over the next two years?

Eric Hathon: This year we're sitting at $85m, Mexico is $25m net, in Norway, UK. So that's spells out 2019, 2020, say up to another seven wells. So, one of those will be in Mexico, the majority will be Norway and possibly UK. So I can't give you a firm number. It'll be less because Mexico will be less and Norway is post-tax cheaper. So it will be something in that range. But I would expect a little bit less in 2020. But you never know because we constantly look to optimise our portfolio. So if other things come in and they make sense, and we can afford them if they’re accretive we'll figure out how to do them. But I suspect it won't be overly dissimilar.

James Hosie (Barclays): I've got a question on the Project Financing for Senegal. Can we just clarify, you talked about 50% debt funded, would you be able to drawdown for 50% of the costs from day one or would you have to put the equity share of the spend be sort of front end loaded?

James Smith: Your question is about drawings under the facility?

James H: So when you start drawing the facility, will you be able to draw on the facility for 50% of development costs from day one or we you have to basically put the equity component up front into the development spend?

James Smith: Well there are points about the term sheet that I wouldn't want to negotiate live on this line. But clearly, we will at the point of taking FID, need to be in a position for ourselves as much as for the banks, with a very clear picture of what the overall funding plan is for our stake.

James H: On your Reserve Based Lending facility will SNE always be excluded from that given its could be funded from Project Finance?

James Smith: No. The capacity under the RBL facility is now available to draw for general corporate purposes. So we're not constrained on what we draw that for.

James H: But, the RBL facility size is that independent of SNE?

James Smith: So, yes. The RBL facility has three borrowing based assets in it – Catcher, Kraken and Nova. And we're putting together a separate financing for SNE, but we can draw under the North Sea facility to fund any part of the portfolio.

Alwyn Thomas (Exane): Just to follow up on SNE, are you still looking at potentially farming down the asset. Is that still a consideration as a separate process from, the Project Financing or are you happy with the current equity stake post the Government dilution?

Simon Thomson: I think we've said this before, we're happy with the current stake. And we've certainly designed it so that we can move forward with the current stake, right the way through the development. By the same token when people have asked us that before. So we'll look at around FID, we may, depending on everything else, look at selling down some of that stake. I think the important thing is we will be staying in Senegal, we've got a commitment to that project we think is a very attractive project. But obviously, depending on what the market looks like, if there's an attractive offer sitting in front of us and that's something we want to redeploy then we'll think about it. But, we designed it so we can set the current equity level if we want to.

James Thompson (JP Morgan): Just coming back to India, obviously, the arbitration panel said they're not ready to give you some guidance. So what's brought you to the end of 2019 kind of estimate? What are the sort of details behind it that have led you to that decision? What do you think is, the variance around that? Because obviously, it's a very big event, the market looking for some sort of confidence around it. So some sort of guidance that would be helpful.

James Smith: As we set out in the, recounted the history in the announcement yesterday, when the main merits hearings were originally scheduled for August of last year, the panel indicated to us, that the whole process having been reasonably protracted by then, they would seek to issue the award as expeditiously as possible, after those hearings. That's the only guidance that we've received and not obliged to give us any guidance at all. So on that basis, we clearly expected that they would be able to, make progress, significant progress on the award during the second half of last year.

What's become clear, at the end of last year and again, just over last weekend in correspondence with the tribunal is that because of the number of procedural matters that have been brought before them, since last August, they have spent a significant amount of time ruling on those and dealing with those and significantly less time progressing the award. So, we don't know where they are with the award, but we know that they're significantly less progressed and they then they'd hope to be. we also know that they're busy arbitrators with other tribunals coming up in front of them and so on. So when we take advice on the matter, taking all that into account, the estimate is that it's not going to be before the back end of this year.

James: In terms of Mexico, what are the kind of main risks here? These are pretty deep, and they look relatively complicated wells, so just to understand a little bit more about some of the uncertainties.

Eric Hathon: The main risks obviously overall is the lack of penetrations. I mean there aren't a whole host of wells in the immediate vicinity to look to for reservoir properties. But the ones that have kept us confident that down to the depths we're looking at, we'll have good producible reservoir. I mean it's an oily basin. So source and maturity is not an issue. Hydrocarbon migration is always a question. And then seal, as I showed, some of these are fault traps. So faults seal though you can estimate it until you drill the well, you never know for sure. So we're quite encouraged by source rock, which is one of the key elements, you know the hydrocarbons are there. We see migration into most of the prospects that have been drilled today and the wells that we have access to have shown reasonable reservoir.

Speaker: Going forward, what is the process and when do we sort of wait until the back end of this year and then you get an update and maybe somewhere 2020, or will you be requesting updates on a quarterly basis to see if you can get more visibility?

James Smith: As I said, the tribunal don't feel they're in a position to give us that guidance at that point. They have committed to update us, with regard to their progress. That’s a fairly clear position that they've stated to us over last weekend, which we announced yesterday. So, there probably isn't much merit in continuously writing to them asking if there's an update. But obviously, we're confident they'll update us when they can.