Cairn Energy Preliminary Results 2016

Wednesday 8 March 2017 – 9am presentation

Simon Thomson, Chief Executive

Good morning, welcome to Cairn's results presentation. I'm Simon Thomson, Chief Executive. With me are Paul Mayland, COO, Richard Heaton, Exploration Director and James Smith, CFO.

As the usual way we've got a presentation to run through with you this morning and we'd be very happy to take questions at the end. It's being webcast so if you do have a question there'll be microphones to be passed around, and please state your name before asking your question. There aren't any scheduled fire alarm practices so if an alarm does sound you can see that the exit is to the rear and the mustering point is out in Lincoln's Inn Fields.

Turning to the first slide. Over the last year we have seen positive progress across our assets and operation and that leaves us well placed for continued delivery of our balanced business offering. That business offering is underpinned by three core pillars. The first, near term production and future development options. As you've seen from the announcement this morning both Kraken and Catcher are on track and significantly under budget and we're looking forward to first oil from Kraken in this first half.

In addition, and Paul will touch on this, we now have line of sight on Skarfjell through Concept Select and we're looking at FID at the end of the year. And as a reminder, we've got a 20% interest in there, it's a hundred million barrel field, a home grown discovery, and will add to our strong cash flow position in the future.

In terms of the second pillar, our exploration portfolio continues to offer significant growth opportunities. We remain really excited about Senegal and about the options for further exploration success that we see in Senegal, and Richard in the presentation will outline a number of the prospects that we see as drilling candidates, and of course, as you'll have seen from the announcement, we've already added another well to the programme, VR-1, we're already on location on that well, it's a dual objective appraisal and exploration. We hope that will be the first of a number of wells to be added into the sequence.

But in addition, we've expanded our position in the Atlantic Margin and in the Barents, as you will have seen we've taken on a couple of farm-ins in Ireland, one of which gives us exposure to a high impact well this summer, and in the Barents we have moved forward and taken more acreage and some of that acreage is as operator for the first time in that part of Norway. So a number of exciting things moving forward in the portfolio to generate more in the way of longer term growth opportunities.

And the third pillar really underpins all of that delivery, our financial flexibility. So we're funded not only for delivery of all of our commitments, but also for further growth within the portfolio, whether in Senegal or elsewhere. Cash resources at the end of last year were $335m and undrawn facilities peaked at availability between $350m and $400m, but in addition, as you will see, and as James will describe we've entered into a number of financing of facilities that ensure that we retain that financial flexibility and that we're able to deliver a line of sight on continued exposure to exploration upside in the portfolio.

And I think an important point, the Indian dividends, a sign of progress in our tax dispute situation which in itself is moving forward. As you will be aware we've lodged our statement of claim, India have now lodged their defence, and a final hearing has been fixed for January 2018. So progress in the arbitration itself, but also as a result of that progress, confirmation of the release of the dividends, $51m. And all of that added to the cost savings that we've seen across the Group ensure that we have enhanced financial flexibility.

Moving on to the next slide, and just a brief few words on Senegal where we can report continued success in the rapid appraisal of the Senegal field. It's worth remembering that we've now drilled seven wells in three years, so following the two basin open discoveries at the back end of 2014, now five successful appraisal wells. In the 2015/16 drilling campaign, which was the second phase of drilling, the four appraisal wells which were all completed ahead of schedule and under budget helped establish the current 2C resource base of just under 500 million barrels and the oil in place of just under three billion barrels. And also allowed us to commence the development planning.

We're now in the third phase of drilling, utilising the Stena DrillMAX at an attractive rate but it's more than the rates, the rig is performing extremely well, we have a very flexible contract as you know as we've earlier disclosed and we're very pleased with performance. In fact we're already two weeks ahead of schedule in being on location on the VR-1 well.

And all of that ongoing success does provide us options for commercialisation. So what we see are a number of milestones that are potential value-defining events, whether that's Concept Select, FID or First Oil. And I think that's important when you move on to the next slide and confirmation of Cairn's business model. Our options for commercialisation can be built within our existing model, we don't need to go anywhere else to achieve that. So Kraken and Catcher on plateau, 25,000 barrels a day, sufficient to fund our future exploration activity but also to reinvest in sustainable cash flow generation from within the portfolio.

Skarfjell is an example of that. Senegal is also a potential example of that. But those projects also give us the flexibility to either be developed or to be partially or wholly commercialised, leaving us with sufficient production to reinvest in that future exploration and ensure a self-sustaining business model. Because at the end of the day what we want to do is to deliver further exploration upside but also select value realisation events and potential future returns.

And on that I'll hand over to Richard.

Richard Heaton, Director of Exploration

Thank you Simon, and good morning everybody. I'm going to start off really explaining a little about the wider strategy, look at the wider portfolio, but actually spend most of my time explaining Senegal, and particularly the latest operational results before I hand over to Paul. And of course as Simon has set out what we're trying to do is create growth, create the story through exploration, that's long been our strategy, continues to be so. Our current portfolio is one that is based around a geological theme around the Atlantic Margin, that provides you with some commonality of the geology and the plays that you're looking at, all part of the splitting apart of the Continent of Pangea that helps us hone our skills. It also allows us within that very wide area to have a mixture of basins of different risks, mature, emerging and frontier basins, and of course our team has had success there so it knows what success looks like and it's a strong exploration team.

We've built a good portfolio, a good platform, we still need to build more, and I'll come on to the latest building that we've been doing very recently in Ireland, but it is part of a wider approach. Of course we've got good acreage position, we've got good resources in Senegal and elsewhere, we've obviously got the two fields and in terms of the production that will come on in a 2P number, that allows us to keep exploring, keep looking for things, keep a sustainable model. Everywhere we're looking to build good positions, where if we have success in exploration, you can continue to build, and that requires obviously a strong technical position, like the technical attractiveness of the basin, but also good fiscal terms to make sure that it's always got value.

We've been building a portfolio across this time, Simon's talked about the Barents position that we have been building and we've now got operatorship in Norway, including in the Barents, we continue to apply in licencing rounds there and take part in drilling, also in the UK, obviously more mature, we've got positions in Morocco, Malta, we've been building in Ireland, and I'll come on to that in a little while, but we spend most time of course in Senegal. It's a strong platform: we are looking to add.

We have added in Ireland, this is entirely in line with our strategy, we've been in the basin in the Porcupine for some time now, staring out in the north Spanish Point area, last year we picked up 16/18 Licence Option which was a very competitive round last year, over 40 companies bid, we bid for quite a number and this was the one we were awarded. What we've announced today is that we're farming into the area to the south, 16/19, we'll take operatorship and 70% there, Europa were awarded that licence. We'll be shooting seismic this summer.

And then to the south further on, FEL 2/14, the Providence operated licence, the well Druid/Drombeg is drilling there, it's a very large prospect. We like this basin, we think technically it's got all the elements for hydrocarbon discovery, many wells had shows, reservoir seems to have been the issue for most of these, but it's got good data, it's a very large prospect, we see perhaps a P mean of 600 million barrels but there is some phase risk there at Druid and underlying it, Drombeg, about a 250 million barrel mean prospect size. So this is a big hitting well, very important, we're taking a 30% interest and that will be drilling later this summer so very exciting, entirely in line with our strategy.

I'll now move to Senegal, obviously we've been there now since our discoveries in 2014 and been very active, we have a growing story. SNE field is where we've undertaken most of our activities and indeed I'll come on to explain the most recent of those shortly. Just to remind you, our 2C, so that's our proven and probable resource estimate by our auditors, ERC, that's a 473 million barrel feature. So that's the anchor project and of course there is a good deal of exploration around that.

I'm going to focus first on that exploration. We have a large licence area here, over 7,000 square kilometres, but we always saw that three were multiple plays in this basin. We've started to test those. What we're about to do in the VR-1 well is test this yet more with more explorations and as Simon said, that's on location today and will start its activity today. What you can see is once the anchor project of SNE is established there's a whole raft of prospects around the area which can be tied back, they have great value. Our job, as part of a three year evaluation programme, that we're conducting across the whole block, is to try and secure as much of that value as we can before February 2019 in a series of drilling phases. We're in that second phase now, it's a pretty exciting place to be, it's very unlikely that with the first two wells ever drilled in this part of the basin that we've found all the hydrocarbons that there are going to be, every well so far has been a success and it looks very exciting.

The VR-1 well is actually a dual objective well, so it is an exploration well, and if you can recall the SNE-1 well which was the second well we drilled, that was the discovery well of SNE field, it at the time was a dual objective well. It found the sands in the upper levels and that was a success, it didn't work at the deeper carbonate level and when we now map that it's no wonder, it's probably outside of closure, certainly a long way down dip and our new depth conversion shows that the crest of these Aptian carbonates is where we're drilling it now at VR-1. It's a multi-target carbonate play, we saw in the well we drilled at SNE-1, we did see reservoir, we saw seals, we saw hydrocarbons in the rocks there, residual hydrocarbon, so it's clearly a working system.

And here we have multiple layers, multiple seals and the consolidated geological success, about 30% overall. Each layer is much riskier than that but together there's a degree of independence.

The beauty of this well is it's right beneath the SNE field but at the very far western edge of it. So where we drill this well, we're five kilometres west of the line of wells that we've been drilling in SNE, SNE-1, 3, 5 and the Bellatrix well. So it's a good appraisal, well away from that line and it's focused mostly on the lower reservoirs where we've seen them. They're the better quality reservoirs, they will be very susceptible we expect good water flood behaviour and good recoveries and so it's important in gathering this data point this far away to support what would be access to the easy oil in the first phase of any development in SNE.

So a pretty exciting well, we're well ahead of schedule as Simon has said on the drilling, so this can be very effectively and efficiently drilled, gather a lot of new information, both to help us with the SNE development and also obviously any further development of deeper oil underneath the main field.

It's not the only well we may drill, that's been confirmed, but clearly with the well and rig programme that has now three firm wells but still a further six individually exercisable options with a very efficiently performing rig then the Joint Venture is very keen to make sure that we explore the whole of the licence. And a couple of examples, some of which I've described before. This was known as the Sirius prospect, we're calling it SNE North now, more than likely in our view that actually has the sort of oil water contacts, the same contacts that we see in SNE will stretch to the north here. This target will look mostly at the upper reservoirs, we've even got some further reservoirs we've found with gas bearing in a number of the wells in SNE now, it's possible that they're gas bearing here. It's also possible at this location that they may have some underlying oil as an oil rim. So a multi-target well, again very valuable to be added in as a satellite to any SNE core development.

And then a further well, this is exploring again into the slightly deeper water, the deeper plays. The FAN-1 well was our first well in Senegal, that was a discovery, it had a long column of hydrocarbons, a series of columns, but the net reservoir there was not so good, perhaps only 20, 30 metres, but as you come slightly shallower the same plays may develop much better reservoir characteristics. We will drill some of the same sorts of rocks that we saw in FAN-1 so to some extent it's helping appraise a wider area. But essentially this is an exploration target where you've got mostly new sand input points, new FANs, new layers, it's a multi-target well, we're just firming up a potential location and obviously with both these, Sirius or SNE North and the FAN South locations something the Joint Venture will be voting on very soon.

Finally I'm going to talk here about the very latest results. SNE-5 and 6 are part of an interference test pair that the Joint Venture has long wanted to conduct to demonstrate the connectivity in the upper reservoirs or 400 series sands as they're called. They are the bulk of the oil in place but when we saw the test results on SNE-3 last year, then it showed us that there were connectivity issues to be resolved by further interference testing and that's what we're conducting now. We can see that wherever we flow these reservoirs they flow at tremendous flow rates. They're very solid flow rates, but the pressure drops. What we saw in SNE-3 after testing indicates that the connectivity of those reservoirs is not as good as the lower 500 series ones that we tested in SNE-2.

And so SNE-5, finished that well just the other day, again very solid test results here and the key is not the headline rate of four and a half barrels a day, which is great, it's the length that you can produce these reservoirs and see fairly modest declines in pressure. The importance of doing both 5 and 6 together is that we can start to understand the way that the sands are connected, not just the level of flow from them.

We've added in, in the second part of the flow, a further reservoir which was slightly higher sand. That has never been tested before, and that added a very significant amount to the flow rate as well. So this was a very useful result.

What we can see in the reservoir, and there's some complicated diagrams, but essentially this is a core taken from one of the upper reservoirs, very high quality sand. We got lots of data from that. We're integrating that with a very complex series of 3D seismic images, and you can see trends in this seismic running both in this direction, but also in an orthogonal direction across. And our expectation from placing wells 5 and later 6, is that we've got good flow rates from this well. We have flow rates from SNE-3. We'll come back and drill SNE-6, and what we'll observe is how the things connect by giving a big flow rate for about 10 days from SNE-6. We'll observe the results in SNE-3 where we've put pressure gauges down, and also in SNE-5. And we think they'll preferentially move to SNE-5 if our reservoir model is right based on this sort of seismic and core data.

And that'll be important for how we place the development wells, what direction we put them in. They will be horizontal wells for development, or near horizontal, not the vertical wells we see here, to connect up huge amounts of sand and get very high flow rates. Wells are probably the largest part of the cost of any development, and so the fewer wells you can put in the more profitable any development will be.

I will pass over to Paul who will explain just how we may go about doing the development.

Paul Mayland, Chief Operating Officer

Thanks, Richard. Good morning everyone. I'll provide an update on our operations and also our developments, and we'll start with Senegal.

Firstly on the drilling operations. We have been pleased with the results of SNE-5, both the logs and the tests, as described by Richard, but also the overall drilling and testing performance. The operations have been conducted incident free, and very low non-productive time, and overall a significant improvement compared to prior wells. And an illustration of that is shown on the diagram in the top right where the red dotted line is the original discovery well, SNE-1, which went down into the underlying carbonates and that was the last well in the four well programme conducted across Morocco and Senegal in 2013 and 2014.

The black line is the SNE-4, which was our last well drilled in the previous campaign, which was drilled just down to the clastic sandstone reservoirs. And the purple line shows obviously the performance on SNE-5 and the DrillMAX drill ship. And although they look similar times, obviously we've actually conducted the drilling operations effectively in two to three weeks, so that really is the equivalent time compared with the prior wells which were a similar evaluation. But then subsequently we conducted about three weeks of testing. And so we're very happy with the performance. We were effectively halving the prior times in terms of drilling and evaluation.

It's also worth mentioning that obviously we will incorporate that into the development well planning. A lot of that will be directional work rather than vertical. But the overall performance is good. We're also delighted to have Woodside on-board within the Joint Venture, that's working well, and overall we plan to play to the respective strengths of both companies. An FPSO solution, as described previously, has been endorsed by the Joint Venture as the most appropriate solution to take this project forward, and we're developing the overall contract strategy. And as a sign that we're moving forward with pace in terms of our development planning in 2017 we plan to conduct further metocean data gathering and conduct an extensive geotechnical seabed survey across the SNE area.

As Richard has described, clearly the results of the remaining exploration and appraisal wells will determine the overall scale and phasing of the SNE anchor project, as we describe it. We remain on track with the previous timelines that we outlined as early as post-discovery in 2014, which should see us on a journey to deliver first oil in the window of 2021-2023.

Now what are the next steps there? Really we're going to finalise the concept select this year, and formally plan and prepare to submit the evaluation report, which will formalise the end of appraisal. And then relatively quickly thereafter, in 2018 we would anticipate to finalise and submit the Exploitation Plan following completion of a competitive FEED exercise, and then take final investment decision. The targeted production rate and the timeline for first oil remains unchanged at this stage, as described in the diagram 100-120,000 barrels a day plateau rate, and first oil in that window described there. So that's our situation in Senegal.

It's probably worth just touching on quite a good publication which was made by the OGA about project execution, before we move on to the North Sea, last week. There were three things that were mentioned in it: clearly defining the project scope prior to project sanction; keeping the project as simple as possible; and improving the cooperation between the companies and the stakeholders. And obviously that is very high priority for us in Senegal, and to some degree we've seen the success of those ingredients in our North Sea projects.

If we put it in some sort of context, Kraken and Catcher, the above slide shows a list of projects ranked by size as we broadly saw them in 2012/2013 when we first entered them and the current status is also shown and described below for each project. And we are pleased overall that Kraken and Catcher have actually progressed really well both on an absolute and a relative basis and we're really encouraged that over the next 12 months we will see both projects come on-stream and ramp up to plateau production.

So firstly Kraken. I think you're relatively familiar with this project operated by EnQuest. Target first plateau rate, 50,000 barrels a day. The drilling and completion has gone well, and all of the subsea work, particularly last year, went very smoothly, such that we're ready for first oil. As EnQuest have announced earlier this year the FPSO is now on location, it's moored, all the risers are pulled in and commissioning is ongoing. And commendable to EnQuest, working with us we've managed to deliver $700m of gross project capex savings compared to the FID case in 2014. And a few good pictures shown in the diagram there.

In terms of Catcher, making steady progress there as well. We target first oil before the end of the year. Plateau production is 50,000 barrels a day. And the drilling also has gone really smoothly on the three accumulations, which are Catcher, if you remember rightly, Burgman, and Varadero, that collectively form the Catcher project. The reservoir quality, and in particular the productivity and injectivities of those wells, have either met or exceeded expectations. And there is a strong correlation between reservoir quality or permeability and recovery factor, so we're naturally quietly encouraged about how these fields are going to perform. But we're not getting ahead of ourselves. The FPSO is still progressing well. It's in the Singapore yard, and we expect that to depart later this year.

And a similar story in terms of savings. Premier and the partnership, working together with the service companies and overall performance, has resulted in a $650m gross project saving compared to the FID number. And last year in 2016, we made a small discovery called Laverda, and that licence has been extended with the option of possibly developing that via the Catcher infrastructure as a tie back.

Lastly, as Simon mentioned, but no means least, the Skarfjell project in Norway, which fits well within our overall portfolio, and is likely to see the commercialisation on organic resource discovered by Cairn in 2012 with our Joint Venture partners in Norway. The Joint Venture have selected a tie back as the best economic solution, and it was close run with some other options. We're working together to deliver a well-defined project with a low breakeven price, and we'd anticipate further cost reductions associated with this project in 2017 as we look to move it forward in what still remains a relatively weak market. This is a core area for Cairn we hold multiple licences, as shown in the diagram on the right, and we would expect to participate in one to two exploration wells a year in this area.

So in summary, Senegal is making good progress as we move through appraisal and into the final stages of Exploitation Plan preparation and subsequently FID. The UK North Sea projects are drawing close to first production, and we anticipate Skarfjell will move forward to FID by the end of this year.

At this point I will hand over to James.

James Smith, Chief Financial Officer

Thanks Paul, and morning everyone. So on the next few slides I'll set out the funding position that effectively underpins that investment programme that Richard and Paul have outlined.

As you've already heard, 2016 was really characterised by strong execution both on our UK developments and also on the Senegal appraisal, and the outturn of that is clearly costs being significantly under the original guidance during last year. In addition to that strengthening we've added further sources of funding to increase flexibility, which I'll come on to talk about in a minute.

2017 is clearly going to be an important year as we move into cash flow generation closing out that cycle in the regeneration of the business. And when that cash flow comes on-stream they are high margin barrels, as we guided previously Kraken all-in opex will be about $14 a barrel on plateau.

Looking out beyond the end of this year over the next 12-18 months, clearly there are a number of catalysts both in terms of valuation, but also in terms of further strengthening the robustness of the balance sheet. So by 2018 we'll reach plateau production in the North Sea from Catcher and Kraken, 25,000 barrels a day. We'll be taking Skarfjell through final investment decision next year. And clearly, as Paul has talked about, Senegal will also be moving into its Exploitation Plan in that year as well. And we have the financial flexibility, as you've seen with today's announcements, to be looking at new ventures and further exploration as well.

So looking first to last year's cash flow. The opening cash position was $603m. You can see the most substantial numbers on this page relate to the Senegal appraisal activity and the Kraken development. The Senegal appraisal programme was four wells last year, that $105m was effectively the original budget for the three committed wells. We expanded that programme to be four wells effectively for the original cost estimate of three.

Then on Kraken a similar story. The original cost estimate for last year for Kraken was $200m net to us, and clearly delivering at 125, which was really mostly to do with savings and the release of contingencies rather than deferrals, so true savings as it were is a pretty significant achievement for the Joint Venture.

Other items on the page across the UK and Norway and International, that's two wells in the UK and Norway, and earlier stage exploration activity across the rest of the portfolio. The all-in underlying cash G&A number, about $12m, in line with guidance, and you can see net against this $36m Norwegian tax rebate received at the end of the year that gave a closing cash position of $335m.

Looking forward now to this year and the capital programme. Starting off, there's a $37m effective working capital position at year end, so that's cash outflow this year for activity that was undertaken last year. That predominantly relates to Kraken activity which obviously carried on over the year-end. In terms of the UK developments, as we've already talked about the savings we anticipate $55m this year on Catcher, taking it towards first oil. That's a reduction of $45m net to us on the guidance we gave six months ago at the mid-year 2016 results.

And on Kraken a similar story, $95m. That is a $75m reduction in the original guidance we gave through to the end of 2017. And those savings result from effectively successful subsea installation on both fields which enabled us to release the contingencies and allowances related to that work stream. Drilling efficiencies, so the run rate on drilling, has been significantly lower than originally budgeted, and there's also some FX effect in there for the sterling costs.

Senegal, $95m. That includes the three wells, so both of the interference test wells that Richard was talking about, plus VR-1 appraisal and exploration well that we're now on location with. That compares with an original guidance of $85m for just the two wells. So again three wells largely for the original anticipated cost of two. And included in that number is also various pre-development planning and study activities that'll be carrying on to take us to the Exploitation Plan submission in 2018.

The International E&A number there includes $30m for the Druid/Drombeg farming that we announced this morning, and that, together with seismic activity and other early stage exploration activity across the UK and International portfolio, represents effectively the total of the committed capex through to the end of this year.

And the final bar there you'll see we've included $50m, which represents a two further potential exploration wells subject to Joint Venture agreement in Senegal. As Richard has alluded to, notionally those could be SNE North and FAN South, and that $50m represents the two wells net to us.

On this slide we're looking at the sources of funding that underpin that capital programme and as Simon already alluded to, we have strength and diversified those sources of funding during the last few months. So the only cash position, as I mentioned, $335m. Our reserve based lending facility, which we put in place in 2014 to underpin the Kraken and Catcher developments, remains undrawn. That's a $575m headline number facility. We expect at peak for it to be available in the range of $350-$400m to fund those projects, with approximate availability by the end of this year of $210m. That's really driven by the capex programme on the fields, so it's effectively a project financed facility where availability is shaped to the capex programme. Hence the availability stepping up through time.

We expect to receive during the year $26m Norwegian tax rebate in respect of exploration activity undertaken in the country in 2016. And we've recently put in place a $500m NOK facility, that's roughly $60m, to finance those tax rebates against future activity in Norway, to effectively create a more efficient financing base for exploration activity in Norway.

We also announced this morning, as you will have seen, a FlowStream financing. This relates really to the 4.5% stake that we acquired in Kraken from first oil early in 2016 for notional consideration. So its $75m against a royalty or stream against that 4.5% interest that we acquired, and that stream will step down to 1.35% once FlowStream has achieved a 10% return on that $75m financing. Their only recourse is to that production interest, and as I said it's effectively for us a clever way to finance that 4.5% acquisition which was for notional consideration, and the proceeds here are significantly more than the capex associated with that interest.

As Simon already said, we have through the international arbitration process on the Indian tax dispute, now confirmed that the dividends that have not been paid to us to-date from Cairn India on instruction from the Government of India, are no longer frozen. That's recent news that's come through, through the process of tribunal, and we're therefore clearly applying to Cairn India for those to be paid as soon as possible.

And the final line on the page clearly relates to operating cash flow which will come on-stream during Q2, and forecasting at the forward curve oil price of $52 for this year we expect that operating cash flow to be about $90m from Kraken only. That doesn't include Catcher which we expect to come on-stream towards the end of the year.

And with that, I'll hand back to Simon to conclude.

Simon Thomson

Thanks James. So, in conclusion therefore in terms of strategic delivery we have near-term production and future development options within the portfolio, and as you’ve seen we’re very comfortable with the progression of activities in relation to those. Our assets offer significant growth opportunities. We’re obviously very focused on Senegal and excited by the continued exploration upside we see on the acreage.

And we’ve increased our financial flexibility, that’s to reinvest in the existing portfolio, but also to consider new venture activities that satisfy our strict screening criteria, and Ireland is an example of that.

And I guess just finally looking at the picture on the right, we retain the flexibility and the desire to put ourselves in a position where we can at an appropriate time effect value realisations and potential future returns to shareholders, because that is our ongoing business model.

So, it’s going to be a busy year ahead and we’re looking forward to it. And with that I’ll hand over for questions.

<u>Q&A</u>

<u>Question 1</u>

David Round, BMO Capital Markets

The first question, I'd just like to understand what's driving the schedule changes in Senegal, and why specifically VR-1 has moved to the top of the list. I guess your partner put out a list of prospects last month; I didn't get the impression it was a high priority back then.

And two quick ones. Just in terms of contingency on Catcher is there anything left? And also I noticed the development capex on the UK developments had come down a bit from I think it was 170 to 150; is that just phasing?

Simon Thomson

On the point about partners, as is always the case people have different views on exploration upside and the acreage, and that's for each person to come forward with their views. But Richard, let me hand over to you in terms of the schedule.

Richard Heaton

I think obviously at the time that we had to commit to the rig the partnership was able to confirm that we needed an interference test. That's always going to be two wells and that was the two firm wells in the programme.

I think we also knew that we were going to conduct some exploration activity, but it took a wider discussion to understand what the key aims of that were. And so once that's been confirmed then it makes sense for us all to move the schedule a little bit, and it's more efficient for us to do so. We get a double hit with this well whereby it's really confirming some of the lower risk elements of the SNE field at the same time as exploring a potential oil field right underneath that development.

So, there will be an impact on development from both of those points, and in fact additionally it gives us rather more time to evaluate the full pressure test results from SNE-5 to ensure that what we do in SNE-6 is optimised. And that's rather than having to do it so quickly.

We still gather data even today from SNE-3 that we did last year because we have gauges down there. And as we understand how pressures are moving around in the field from all that information it helps us to understand how better to potentially develop the field.

James Smith

On the North Sea developments the numbers we showed on the chart there were a comparison to the last formal guidance we gave, or detailed guidance we gave in August 2016, but you're right, there is further reduction from the pre-close announcement we gave in January.

You also asked about contingencies. Overall those reductions are a mixture of contingency release as subsea installation has been complete, and it's complete or substantially complete on both projects now, and then also a reduction in the overall drilling costs. Clearly the all-in drilling cost is a number of services in addition to the rig rate, and we've just seen those come down significantly. So, it really is a true saving on both of them.

You asked whether there was contingency remaining on Catcher. There is contingency remaining although a substantial part of the original contingency related to subsea work which is now complete and therefore that's been unwound.

<u>Question 2</u>

Nathan Piper, RBC

A couple of nit-pick questions but maybe a bigger one first. You talk about realising value in SNE; is there some sort of pressure on you to realise value in the next 12 months before operatorship naturally passes to Woodside? I guess the other way of putting it is you will obviously have most value in your stake in SNE with the operatorship than without it, so does that provide some pressure to try and do something sooner rather than later?

On the VR-1 well is there a bit of upside from the lower SNE reservoirs in the well that you're drilling there? After the depth conversion I think things were higher so would that be able to confirm some of that?

Then the other one was on FlowStream. I think FlowStream announced a $200m deal with you, I'm not sure if you knew that, but maybe could you give a bit more colour as to what the wider deal with FlowStream could be?

Simon Thomson

On the first one no, there's absolutely no pressure in terms of realisation. And I think that's the important point and why we're labouring the point on financial flexibility: we always want to be in the position where we have the option to realise value but no obligation. We've been in Perth with Woodside, Paul led a team, it was a very good, established already, working relationship. I think they're very pleased with the way that we're going about the exploration and appraisal. They see the value add that we have in there, and that may well continue. So, no pressure at all.

Richard Heaton

On VR-1 yes, by drilling so far to the west, we haven't yet drilled that far, and our depth conversion can move things up and down, so we're choosing a position that says look, this is what we expect. It will confirm at least the 2C number. But you do need to know whether it could go up, it could also come down, but it's a very important fact to actually nail because it does have an impact on how you develop a field. You need to know that before you start. These reservoirs are the best quality reservoirs and we're aiming to try and water flood them. You need to know where to put the wells to make sure you do that water flooding and that's why it's so important.

James Smith

And on FlowStream what we've agreed is the $75m financing that I talked about, which is effectively ring-fenced to that 4.5% in Kraken that we acquired during last year, plus an option on up to a further $125m financing which would be in respect to a royalty across both Kraken and Catcher at our option and subject to various consents. You can read about that in the financial review in the Preliminary Results today.

We're very pleased that they wanted a headline with the appetite to do a bigger deal with us, and clearly that's flexibility for the future. But what we intend to draw for now is that $75m against the 4.5%.

<u>Question 3</u>

Robin Haworth, Stifel

Just a question on India, I'm just wondering if you could talk through exactly what the discussions were and if it's the arbitration that led to the dividends being released if you could please?

And just to follow up on reservoir, how do you see horizontals? Clearly you're planning horizontals for the development of SNE; I was just wondering if you could talk about whether you need to drill one of those horizontals in the appraisal phase and how that might fit in the current appraisal campaign? Can you do that in 2017 for instance?

James Smith

On the dividends first of all, I guess it is not necessarily a comment on the wider case, but it is an indication of the helpful forum of the international arbitration. Effectively we had a view, or at least our legal interpretation was that the dividends should no longer be frozen. That was not something that was easy for us to establish in country with the tax department given that there was an ongoing freeze on CIL paying them, and so we sought clarification on that matter through the international arbitration. And India gave that confirmation through that forum. So, that's the sense in which it came through the international arbitration.

Paul Mayland

On the horizontal wells or the high angles through 75 to 85 degrees through the reservoir section that's probably our base case plan for water flooding and particularly the upper reservoirs. It is an option. We've obviously got a number of options and it's something that we're discussing with the partnership. Woodside have drilled quite a number of these long laterals in the northwest shelf field, so clearly they're technically comfortable with being able to execute this.

We've always had this, as Richard described, the two firm wells which is anchored around the interference test, exploration opportunities that we would slot in accordingly, and that's what we've done. And also there's a consideration, as you've described, of a high angle well. But I think both ourselves and the partnership would really want to look at the value of that information and see if drilling such a well was actually going to change the decisions associated with the development plan and what it's going to de-risk before we allocate capital to conduct such a well.

Robin Haworth

Could you do it in 2017?

Paul Mayland

If we were to execute it we would aim to do it in 2017. So, it would probably be after the exploration wells are drilled.

<u>Question 4</u>

Stephane Foucaud, FirstEnergy

A few questions please. Coming back to the VR well, the deeper target is a carbonate, so arguably riskier, Mauritania has been difficult etc. So, taking this into consideration I guess one of the important factors to drill the well is the lower, higher quality sand, which could appear to be a bit of a change of strategy on why to drill this well so I was wondering if this was because you felt you need that well to support the development plan or perhaps Woodside coming in is a slight different view? So, I wonder whether you could provide a bit of comment on that?

The second question; is Woodside now confirmed in the partnership? Is there still risk associated with it or legal discussion or anything like this? And if that's the case could there be potential change in the partnership?

And lastly a question on the resources at SNE. I think the gross number talks about 473, but the 40% talks about 203, so it seems to be something like a ten million barrel difference when you adjust the 473, multiply by 40% compared to the 203 you're showing. So again I was wondering whether it's because you have increased more things since the Equipoise report has been made or if there was anything else, or it's maybe a calculation?

Simon Thomson

I'll answer the Woodside point and then you can come onto the other points, Richard.

From our perspective there is no issue. Woodside are a partner. We're working extremely well with them. We think they're a great value-adding partner. As I say, we've established a good relationship.

One of our partners has a dispute with an outgoing partner, and I'm not sure where that's got to, but from our perspective and from the government's perspective Woodside are adding value, and they're moving forward and there are no delays as a result of that.

Richard Heaton

A couple of points, I'll pass on to Paul for some of it, but I think on the numbers the 473 is ERC's number, they independently assess that, that is just the oil portion. The numbers that we've been quoting they're ours so it will be slightly different, or they're very close, but also the BOEs also involve the associated gas as well so that's why there'll be some difference there.

In terms of the VR-1 well I think it's the lower reservoirs that are the easy part of the field to develop because we're very confident that they will be the most valuable oil because we expect less wells to be able to extract the greater proportion of oil because they're water floodable. That's really why that is an important element to secure and that's why this well is an important well to drill at this point, because the first phase of development will likely be aimed at the easiest and most valuable oil.

Paul Mayland

Just building on that there are obviously a number of parameters that are not just technical that we consider in terms of looking at the most optimal development. And obviously bringing up the 1C number has a number of advantages. But we shouldn't dismiss that VR-1 is targeting this carbonate play which is riskier in terms of exploration risking, but it's the oil field, potentially under the oil field, and so before we put subsea infrastructure in place, which just now is targeting the upper and clastic reservoirs which obviously extend over a large area, we really need to know if there's anything worth pursuing below it before we put subsea templates for example in a number of slots and so forth. So, instead of necessarily extending the field in a real sense we need to know does it extend vertically, in this case downwards. So, it's quite an important well in that regard from the development planning, and that's one of the reasons we were quite keen to put it in the slot now, and then we'll go back to do SNE-6.

Question 5

Elaine Reynolds, Edison

I'd like to ask a question about SNE and upper zone. You've seen much better deliverability from the SNE-3 and 5 wells but a lower rate in the 2 well. Can you talk about the distribution of those sands to the north and south of the field? So, south SNE-2 is in the north. And what is the split you see between the upper and lower zones in terms of resources?

And also I'd like to ask another question about the Porcupine Basin. The 30 million that you're intending for this year for Druid and Drombeg does that equate to the 30% working interest or is it an additional amount? And now that you're going to be drilling Druid and Drombeg how does that impact on your plans for Spanish Point?

Richard Heaton

I'll try and take Senegal first. We've now drilled seven wells in the SNE field and effectively every time that we've drilled it we've been able to see the same reservoirs effectively. We've collected a large amount of data. And we've got multiple reservoir layers in there; we've very simply divided them into two fundamentally different ones which we've seen every time: the lower ones, which we're starting to call the 500 series, and the upper ones the 400 series.

The proportion of oil in place, just because of the shape of the field, is more in the upper reservoirs. And therefore the key for us, having seen the different flow rates in SNE-2, that did a test of the lower reservoirs that flowed at 8,000 barrels a day, so that was clearly an excellent test. It was a very small interval we tested then in the upper reservoirs, it was just a few metres. And of course it flowed but it was literally from one or two metres of reservoir. At that time of course that was the first test we had conducted.

When we went to SNE-3 we deliberately aimed at the upper reservoirs and we conducted a couple of tests there. High flow rates. The sand quality is good. In fact the sand quality we see right across the field, including as you go north to the Bellatrix, which is the most northerly appraisal well, sand quality isn't really an issue. We can see connectivity in terms of correlation from well to well. But individual sand bodies that's the issue that we're trying to address with this interference test.

We have very high quality seismic data, and we can see the different shapes of sands running in two directions really, as I pointed out on the slide there, and it's trying to understand those features that we can identify on the seismic data what do they relate to in terms of the way that the oil and fluids will move when we start to develop the field: will they move in a preferential direction and in each reservoir layer, because we can see multiple layers, the patterns are different in each layer. So, we have to understand that.

Now, we cored many of those wells last year. We've got over 600 metres of core all the way through this reservoir from pretty much across the field. It's a huge database to integrate all that data at various different scales, including this latest interference test data that we will pick up from 5 and 6.

So at the moment we haven't given a specific figure as to what proportion is going to be developed from each reservoir. That will be something that comes out following this latest round of appraisal as we build our reservoir models specifically for the development plan, for the first phase of development, and at that point we may be able to say more about what the proportions might be.

Simon Thomson

Paul, do you just want to touch on the Spanish Point?

Paul Mayland

The cost question was really, it's not the well cost, and I don't know if James wants to add to this, but it's obviously the back cost, the well cost including our promote and a level of contingency.

James Smith

Yes, the deal was effectively for a three for two carry, subject to a cap on the overall well cost. It's a bit more complicated than that, but simplistically we're paying 45% of the well cost for the 30% interest.

<u>Question 6</u>

Sanjeev Bahl, Edison

Just two questions please. Firstly on FlowStream, the implied cost of capital of that facility I guess is well in excess of 10%, so I'm just trying to find out was there an option to extend the RBL to cover the additional 4.5% of capex for the first oil stake or whether there are other sources of finance available? Because that seems relatively high compared to the other facilities you have in your debt portfolio.

The second question was really on cost guidance for Senegal. I think in the past you've mentioned $10 a barrel life of field opex, which still seems relatively low compared to similar sized analogues. Maybe Catcher and Kraken are on the smaller size. But I'm just trying to understand whether your thoughts on opex have changed at all or whether FPSO lease rates are just exceptionally low at the moment?

Paul Mayland

Just on that obviously the FPSO lease rate which will dominate the opex profile had a big bearing on what size of FPSO we're building, which is still under discussion. So, I think we've actually guided in the past with a range, which was obviously what I'd prefer at this stage, and whilst we're still basically determining what is going to be the scale of the project.

And obviously the other thing, which is the length of the period, so the length of the term of the FPSO lease clearly that will also have a bearing on the absolute value of the lease. So, those are the key parameters and that's what we're in the process of trying to determine.

James Smith

Just to add on that briefly before I go onto your question about the FlowStream deal. The guidance we gave of $10 a barrel was for all-in opex at plateau rate of 120,000 barrels a day as an indicator. So, life of field I guess it might be a little bit higher than that. And of course, as Paul said, you may well structure a lease with a purchase option and it will depend on the term and so on. So, it's sort of guidance for a plateau rate at those levels that we gave six months ago.

On FlowStream yes, the RBL effectively is structured to include sanction development assets that we have or that we acquire, so of course the 4.5% would have automatically rolled into that. I guess the cost of capital is relative to the risk that they're taking so FlowStream is taking full field and price risk in terms of the return it gets for that, so we have designed it around a 10% return that then automatically significantly steps down that royalty, and effectively caps it out with a further step down. But we felt that that was a reasonable return relative to the effectively project equity risk that they're taking, and that it was a neat way to ring-fence the financing to an asset or an interest in an asset that we'd acquired during the course of last year and also that was useful to diversify our financing base.

<u>Question 7</u>

Alwyn Thomas, Hexane BNP Paribas

Just a question on M&A. Your name has been mentioned in connection with a few asset deals in the North Sea or assets for sale, can you give an update on what you might be looking for and how you intend to fund those sorts of deals?

Simon Thomson

Yes, we're looking for value not volume, number one, so that maybe rules out a number of things that you might read about us. We're more interested in particular in assets. And really at the end of the day, as you've seen, we're comfortable with the balance that we have at the minute in terms of the portfolio, the balance of balance sheet strength, production from Catcher and Kraken and then a stream of exploration activity.

Obviously if there is opportunity to enhance that on either side – we've seen Ireland as an example on the exploration side – but also on the production side then we'll look at that. But we would look at that from the perspective: one, what is the value of those barrels, do they pass our strict investment criteria; and two, what we want to avoid is falling into a trap of being over-geared for acquisitions and so on. We're not interested in doing that.

Closing Comments – Simon Thomson

Any other questions? If there aren't just one thing before we finish. This will be the last year that Richard will be sitting in front of you. And whilst I'm delighted with Eric Hathon who will be replacing him, very sad to be seeing Richard go. I've been working with him for over 20 years and he has been nothing but a joy to work with and loyal and a great value-add for Cairn.

So, please would you join me and show your appreciation for him. ((Applause)) Thanks very much.