Cairn Energy

Half-Yearly Results 2018

Tuesday 11th September 2018

Simon Thomson, Chief Executive Officer

Good morning everybody. Welcome to Cairn's half yearly results presentation. I'm Simon Thomson, Chief Executive. With me are James Smith, CFO, Paul Mayland, COO and Eric Hathon, Exploration Director. So, as in the usual way we've got a presentation to run through with you this morning. I'm very happy to take questions at the end. It is being webcast so there will be a microphone available, if you have a question please state your name before asking it.

I'm sure most if not all of you have been in this building before, but if a fire alarm goes off there's an exit sign there, there's an exit here and the muster point is out in the square in front of the building.

Turning to the first slide. This presentation today demonstrates continued and consistent delivery of Cairn's strategy to create, add and realise value for shareholders from a balanced portfolio.

So, cashflows from the Kraken and Catcher fields provide our core funding for reinvestment in the development projects to ensure the sustainable funding in the long term through cashflow generation, but also sufficient funding to invest in our exploration activity. And we, as we will come on to summarise, have an exciting programme, multi-year material exploration drilling.

So, as you know both EnQuest and Premier have recently updated on the Kraken and Catcher fields, and James and Paul will provide further updates from us. But I do want to say just a few words on the developments, which again Paul will summarise in more detail.

If you look at Nova, we took FID earlier this year. We expect the PDO approval shortly. And as a reminder, that's a field that will produce 10,000 barrels a day net to Cairn in 2021, and fits very well with the decline profiles of Kraken and Catcher.

And in Senegal we've made really strong progress through the first half of the year. So, tenders are in and being evaluated. We have submitted the evaluation report and the environmental impact assessment. The formal financing will be launched next month, project financing, and James will talk a little bit about that. And also later this month we will submit the exploitation plan for approval by the government; we're targeting approval by the government by the end of this year and FID in 2019.

The majority of the development planning work has already been delegated to Woodside and we anticipate formal transfer of operatorship to Woodside over the next month or so.

The first oil date is narrowing to the centre of guidance, and if you remember we've given guidance between 2021 and 2023, and that aligns also with the partner's comments in terms of first oil.

And I think important just to remember that at plateau this will provide up to 40,000 barrels a day net to Cairn at current equity interest, so potentially a very large store of value for us in the future.

If we turn to exploration in the bottom here, we've again had a very, very busy first half, both in terms of preparation and enacting of the current drilling programme, but also in making additions to the portfolio. So, over the rest of this year and until the end of 2019 we'll drill up to 11 wells. We're targeting 700 million of barrels unrisked net to Cairn. Those wells will be a combination of UK, Norway and Mexico. We're currently in two wells, Ekland and Agar-Plantain, one operated by Cairn, the Ekland well, and we anticipate results for those wells towards the end of this month.

And in Q4 we'll spud the Stjerneskudd well in Norway. That's an Equinor operated well. And I think at a 30% Cairn equity interest and 160 million barrels oil equivalent it's a good example of how we've transitioned the portfolio we originally acquired way back when with smaller equity interests and less material prospects, to large material potential value upside in the portfolio. And there are a number of those occurring through the course of the next 12 to 14 months.

If you look at the additions to the portfolio, Eric will summarise those, but the important point I'd like to say is they've been a long time in the planning. So, they fit completely with what we've been trying to rebuild over the last five years in terms of a continuous stream of exploration drilling potential going out over the next few years. So, we see them as feed stock. Of course not every prospect is going to be drilled, there will be an internal ranking process, but those with the highest value will rise to the top.

And it's also I think important to stress that they've had to pass our strict hurdle rates to be included in the portfolio, but we do see them as a great store of potential value for the future.

Just to touch on India, we've had the final hearing of the arbitration; that was in the last couple of weeks of August. The terms of the hearing are legally privileged so there's not a great deal that we can say other than we obviously confirmed that we were confident pre-hearing in terms of our legal position, and I can confirm we remain as confident, if not more confident, post-hearing of our legal position. And we anticipate that there will be a judgement from the panel towards the end of this year and we look forward to that judgement.

I guess all of this is carried out against a backdrop of continued focus on managing the portfolio, on retaining balance sheet strength and on capital discipline.

And on those subjects I'll hand over to James.

James Smith, Director of Finance

Thank you, Simon, and good morning everyone. So, in the next few slides we'll look at the cashflows from the first half, the current balance sheet position and then onto review of the forward capital programme.

So, looking first at the key figures from the first half of the year, revenues from oil sales were $172m on an average realised oil price of $67 a barrel, that's net of hedging costs of around about 90 cents a barrel. And that generated operating cashflow relating to the period of $112m on production from Catcher and Kraken net to Cairn of 14.4 thousand barrels a day, with an all-in production cost of approximately $24 a barrel.

As you can see from the slide our hedging position out over the next 12 months or so covers about 7,000 to 8,000 barrels a day, about a third of our expected production base, using low-cost collar structures with floor prices that have been steadily improving as we've implemented that hedging strategy. And we would expect to continue with that hedging structure along similar lines as we roll the programme forward.

Production for the second half of this year is expected to be in the range of 20,500 – 22,000 barrels a day. And with those production rates and uptime more stabilised we will expect to see that all-in production cost come down to around about $20 a barrel in the second half.

Turning to the balance sheet position at the half year. Cash at 30th June was $75m, and there was a receivable for production during the period that was paid for post-period end of $55m, and that's what's been included in the operating cashflow number of $112m that I just mentioned.

The current Norwegian tax receivable relating to exploration expenditure undertaken in 2017 and 2018 of $62m is roughly equal to that which we've drawn under the Norwegian exploration financing facility that we've put in place to advance those tax rebate cashflows.

Drawings under our North Sea reserve base lending facility at the mid-year was $65m. And we've recently executed an agreement to extend the maturity of that facility, that $575m facility from 2021 to 2025, and that will allow us to fully incorporate the Nova development into the borrowing base and to continue to maximise funding, headroom and flexibility.

Looking forward out into the longer-term sustainability of our producing asset base, on SNE work with government and partners is well underway to launch a project financing with potential lenders in Q4 of this year following submission of the exploitation plan. And that will be in readiness for funding close and availability roughly in conjunction with FID in the middle of next year.

And then lastly, as Simon has mentioned, the final hearings of our Indian tax arbitration concluded recently in the The Hague and we continue to expect a positive outcome in due course. But importantly our long-term business plan remains fully funded without taking into account the expected proceeds from successful enforcement of our claim against India.

Turning to the next slide, we've set out in more detail the cashflows from the first half of the year. The opening cash position was $86m, and cash inflows during the period were $57m of operating cashflow, $29m of drawings under the exploration financing facility in Norway, and as mentioned $65m of drawings under the RBL facility.

Outflows during the period: $61m of ongoing development spend on producing assets at Catcher and Kraken, $25m of pre-development spend on the SNE and Nova projects, and $59m of exploration expenditure, which included the Tethys and Raudåsen wells earlier in the year in Norway and ongoing earlier stage exploration across the portfolio. So, taking into account GNA, finance cost and FX adjustments of $17m during the period the closing cash position was $75m.

Looking now at the capex guidance for the full year, $135m of expenditure on the two producing assets will effectively see the completion of this stage of field development and the conclusion of development drilling programmes on both fields. Formal government approval for the development plan, the PDO on Nova is expected shortly, as Simon has mentioned, and on that basis we forecast $45m of development spend on Nova during 2018, out of a total $200m net to Cairn to take that project to first oil in 2021 as previously guided.

$30m on SNE in Senegal will take us through to entry into feed expected later this year, which Paul will come on to talk about in a moment.

On the exploration side activity this year continues to focus on drilling in the UK and Norway region, as well as preparation for commencement of an expected extensive drilling programme in Mexico next year, and the addition of new ventures which we've announced both today and earlier in the year of Mauritania, Suriname and Cote d'Ivoire.

So, as you can see the expected net of tax exploration spend for the full year currently stands at $120m.

So, in summary then a continued healthy balance sheet position, together with the establishment of our production base, puts Cairn in a strong position to continue to invest in the long-term sustainability of that production base, but also in an active and material exploration programme, with a strong new ventures pipeline.

And on that point I'll hand over to Paul.

Paul Mayland, Chief Operating Officer

Good morning ladies and gentleman. I'll talk through the performance and progress on our production and development assets, and we'll start with Kraken and Catcher. The picture obviously shows the offloading of the crude package from the Kraken FPSO.

You'll have no doubt received the recent feedback on the performance of Catcher and Kraken from the respective operators' half year results. We will try to give our own colour on the asset performance of each.

Catcher is performing slightly above FDP, field development plan expectations, producing around 60,000 barrels a day fairly consistently, and the FPSO has produced at levels of up to 70,000 barrels a day for short periods.

Reservoir and well performance appears strong as we continue the full commissioning of the remaining systems and iron out a few final issues with the FPSO contractor.

In H1 we produced at an average rate of around 27,000 barrels a day, but expect to exit at about double that rate in the second half.

Drilling is nearing completion, with the ENSCO 100 rig operating on well number 18, the final well versus 22 original anticipated in the field development plan.

There is likely to be some additional infill and satellite wells on the field, and the operator is working hard with the joint venture to mature those opportunities for 2020.

Kraken performance is an improving picture but slightly below the FDP expectations. Although we reached 50,000 barrels a day in Q1 we are now consistently producing at stable rates between 35,000 and 40,000 barrels a day with much improved and more consistent voidage replacement as the water injection system is performing more reliably.

We are likely to exit 2018 at these sorts of levels due to deferred drilling on DC4, planned well tests and water cuts slightly higher than expectations. In H1 we produced at an average rate of 30,700 barrels a day, due to the voidage replacement challenges, planned maintenance in March and the overall FPSO uptime being lower than originally anticipated.

We've been running the boilers and power generation on crude to help reduce diesel consumption, which should help bring opex in the second half slightly lower than in the first.

Subsea work at Drill Centre 4 is nearing completion, which will allow the Transocean Leader semi-submersible rig to return later this month to drill and complete the remaining three wells for this phase of the development. Additional potential remains predominantly on the west of the field, and we are likely to pursue these opportunities in 2020.

Moving on to Nova. Back in March we were posed several questions regarding the commercial arrangement for the Nova development. As we predicted, and with the support of the Ministry we were delighted to reach a mutually acceptable commercial arrangement between the Nova and the Gjøa partners to facilitate the processing of oil and gas from the Nova field. This $1.2bn project was the first to have its PDO successfully submitted on the Norwegian continental shelf in 2018, and we expect approval very shortly. It will develop approximately 80 million barrels, produced at a plateau rate of up to 10,000 barrels of oil equivalent net to Cairn, and generate significant levels of cashflow for Cairn in the period 2021 to 2023 when we anticipate being in the execute phase of the SNE development project in Senegal.

This will be the third subsea development by operator Wintershall on the NCS and we'd like to commend them on reducing costs between concept select and sanction by 30%.

So, moving on to SNE and our oil and gas project in Senegal. We have made significant strides forward in 2018, and achieved several of our planned milestones already. It has been particularly encouraging the level of engagement and support from the respective ministries, and Petrosen, the national oil company, in respect of this, the first offshore oil and gas project in Senegal. We have submitted the environmental and social impact assessment in June, which was quickly followed by a copy of the evaluation report, which I have today here.

We have received positive responses through a tender process for the subsea FPSO drilling rig and oil field tubulars. Evaluation is ongoing, having shortlisted several suppliers already in certain select areas.

The fundamental philosophy of a phased development remains unchanged. And although we have presented a window from 2021 to 2023 for first oil the base case is now narrowing to 2022. And this slide captures the flavour of the project that was set out in the evaluation report.

We currently envisage three phases of oil and gas development: phase one, which focuses on the 500 series reservoirs and a core area of the 400 series will develop up to 240 million barrels of 2C resources. Gas is likely to form part of this first phase, most likely one to two years after first oil.

Phases two and three see a natural expansion of the core subsea infrastructure, and potentially some facility enhancements, with each incremental phase developing around 120 to 130 million barrels. This is obviously further being refined, and the detail of the final plan will be contained in the exploitation plan or development plan which is being prepared in consultation with ourselves by our joint venture partner, Woodside.

We are targeting submission of this plan by the end of September. The PFC then allows for a three-month review period from submission before approval, so we would expect to receive this by year end or early New Year. There has already been good engagement on the project. There's a high level of interest in-country, and a joint venture aligned on targeting first phase capex of below $3bn.

The supporting finance plan is well under way, and as mentioned by James, will formally launch shortly after submission of the exploitation plan.

And finally transfer of operatorship is likely to complete by year end, with the arrangement already well understood, and Woodside already working with the support of the joint venture under a development delegation agreement.

So, in summary, we are seeing an improving production and facility performance on Kraken and Catcher. We have sanctioned Nova. And we are putting the foundations in place for an excellent oil and gas project in Senegal that has the potential to be a long-life, cash-generative asset in our portfolio.

And on that note I'll hand over to Eric.

Eric Hathon, Exploration Director

Thank you, Paul. Good morning everyone.

So, the focus on exploration today, as Simon said, is very much growth in our exploration portfolio. We've added attractive opportunities which have the potential for significant impact for Cairn.

We are growing the portfolio just as we have consistently said we would do, and we've expanded our play diversity and we're high grading our portfolio to pursue the very best opportunities.

We have the skills and capacity to move into new areas and in mature plays in a wide variety of geologic settings. We are not constrained by geography or play type. Also we're maintaining fiscal discipline while we pursue these compelling projects. As I've said before, our goal is to be capitally constrained, not opportunity constrained.

The common elements which drive our hunt for new opportunities include: good fiscal terms; plays which could be transformational in scale; a clear path to commerciality; and the ability to monetise if we choose at an attractive valuation; and of course working with excellent partners in our pursuit of high-impact exploration.

So, you can see here the most recent additions we've made: offshore in Mauritania, onshore in Cote d'Ivoire, as well as our recently awarded block in Suriname.

Now, our focus remains predominantly on frontier and emerging plays with significant impact potential. But we're also very active in the UK and Norway where we continue to identify and capture high quality opportunities with shorter cycle times.

Our farm-in to the Plantain prospect in the UK North Sea is a good example of that, and that well is drilling as we speak.

So, look, our focus in exploration remains on good fiscals, good rocks and a clear path to commerciality.

So, on the next three slides I'm going to just do a brief review of our expanding exploration portfolio, and I'm just going to hit the near-term highlights.

In Latin America and Mexico we expect approval of our exploration plans in both Block seven and nine next month. And we're on track to drill in both blocks in 2019, including our first operated wells in Mexico.

In Suriname we signed the PSC with the government in June, and we're preparing for 2D seismic acquisition, which we hope to kick off at the end of this year or early next year. And this block at almost 12,000km² is the largest block offshore Suriname.

Now, if we turn to Africa. In Senegal, as Paul said, definitely our focus is on development of the SNE field, but we do continue to mature potential tie back opportunities. These could include the FAN discovery, the SNE North discovery – which you'll remember actually found oil below the oil water contact of SNE field – and the Spica prospect. So, the focus here is to be prepared for any potential E&A activity when a rig comes back to the field.

In Cote d'Ivoire we have returned to onshore exploration with our partner and operator Tullow Oil. We have a 30% working interest in seven blocks that are targeting a continental rift play analogous to the world class discoveries that were made in Uganda and Kenya, plays discovered and built by Tullow Oil.

Now, a significant benefit here is a clear path to commerciality, with oil and gas pipelines in close proximity, oil refineries nearby and a deep water port with the facility to ship oil.

So in Mauritania we have now announced a 3D seismic option with the operator Total in their C7 block. So we had the right to acquire up to a 30% working interest upon a well decision following completion of the seismic programme and full geological and geophysical interpretation.

This is a very innovative deal for us at a modest cost in an area which is seeing significant interest and where majors have recently paid signature bonuses in excess of $70m, so we're quite happy with this opportunity.

Now I'd like to turn to Europe where as I said, and Simon said, we have two wells drilling in the UK and we have a further well in Norway to spud in the fourth quarter.

Now both the Cairn operated Ekland well and the Plantain well operated by Azinor had some issues in the shallow hole so we're a bit behind schedule but now both wells are moving forward and we expect results by the end of this month. And at Plantain we do have the option to assume operatorship after the well results are digested and evaluated.

In Norway Equinor will spud the Stjerneskudd prospect late in the year and this is quite a significant prospect for us with a mean gross volume of over 160 million barrels and where we have a 30% working interest.

Now my final slide is really a summary of our exploration programme over the next three and a half years. Hopefully as you can see we have a very busy 2019 ahead of us following a six well programme in 2018. And to reiterate what Simon said this will be 11 wells in the next 16 months, so we're going to be busy.

We'll be testing prospects in Mexico, as I said, including our first operated wells and our first operated well in Norway and a significant well test in the Barents Sea.

Again as Simon said we're targeting over 700 million barrels net unrisked to Cairn between now and the end of 2019. And we are on track to drill ten wells in the UK and Norway by the end of 2019 which is exactly what we told you we would do back in January. And in the out years as you can see we have significant optionality in our drilling programme.

Of course some of these opportunities will be matured and drilled, others will not. Look that's the fluid nature of exploration and managing a prudent portfolio.

So we now have a robust exploration portfolio which we believe will contribute significantly to our net asset value growth. And we have multiple operated assets which will give us flexibility both in attracting partners and reducing capital exposure.

Meanwhile we do continue to search for additional compelling opportunities with which to further upgrade our portfolio of opportunities. And with that I will turn it back to Simon.

Simon Thomson

Okay thanks, Eric. So as you can see we're on plan. Our production is sustainable over the long-term through developments already within the portfolio. We're funded to pursue those developments, to ensure that long-term cashflow generation but also to continue to invest in a material programme of exploration drilling over the next few years.

Balance sheet strength and capital discipline remain absolutely core to everything that we do and that allows us to actively manage the portfolio at a time of our choosing. So we believe we're well placed to deliver on the model that we've been building over the last few years, we feel it's in the right place, we look forward to coming back to you with the results of exploration drilling, of progress on our developments and obviously of the outcome of India and pursuing generally the strategy of creating, adding and ultimately realising value for shareholders.

With that I'd like to hand over for questions.

Question and answer session

Question 1

Analyst, RBC

Good morning. A couple of areas to focus on if I may. First of all on Senegal you talk about gas, which you have mentioned before but you've been a bit more specific about having to include that as part of the Phase 1, could you give a bit more colour as to what commercial arrangements you need to put in place to make gas…how are you going to make the gas work? What infrastructure do you need to put in, what kind of volumes you might look to exploit in the first phase, and what kind of gas price you'd need?

Paul Mayland, Chief Operating Officer

Some context first, so there is a fairly significant gas resource in the greater SNE area. Really that comprises three elements. So there's the associated gas which is fairly modest. There's the volumes of gas cap, gas lying directly over the oil which wouldn't be exploited until really towards the end of the field. And then there's the fairly significant volumes of non-associated gas which are in separate reservoirs. So in totality if you're looking at something around 2 TCF of potential sales gas.

Obviously we've still in discussions with the government and with Senelec, the electricity power generator in country, and I think it's too early to start talking about the details of the commercial arrangements but there's good engagement. There seems to be a desire to bring gas from this project post first oil and we would anticipate, as I said, that that may come to fruition a couple of years after first oil.

Analyst, RBC

Should we assume a material capex, because obviously you've got a big capex in first oil but then another, not insignificant, capex event to get first gas, or is that the wrong way to think about it?

Paul Mayland

That's probably the wrong way to think about it. I mean the volumes in terms of offtake we're looking at are around 60 million standard cubic feet of gas initially. So we're probably only looking at one or two satellite wells and a pipeline into Dakar.

Analyst, RBC

That's clear. And just also on Senegal given the maturity of the project are you getting more reverse enquiries on Senegal, more engagement in Senegal in general from the wider industry?

Simon Thomson

In terms of interest in the asset itself? Continuing I would say and obviously as you move towards greater certainty and FID that is when from an industry perspective things are de-risked. So as we said previously we have the capability to take this through at the current equity level if we choose to but a natural time should we decide to take any equity off the table would be more around FID. But yeah there continues to be interest in the project.

Analyst, RBC

Just one last one, on Mexico given the change of government how are you seeing the CNH working and you were talking about approvals you need for your exploration next year, how are the actual mechanics of government working underneath whatever the presidency?

Simon Thomson

Positively.

Eric Hathon

We've had no reduction in forward progress so far. So we remain confident that we'll move ahead and get our wells drilled.

<u>Question 2</u>

Analyst, Morgan Stanley

I had a couple of questions on project financing essentially. The dispute between FAR and Woodside does that hamper your discussions on project financing at all or does that need to be settled before you move ahead with that? Are you still looking at a 50% debt to equity ratio on project financing?

James Smith, Director of Finance

So on the second part of the question I think work is significantly progressed in getting ready to launch this financing with potential lenders. The resource base has been independently audited. We're finalising the process of cost estimates, an independent review of cost estimates that will feed into the exploitation plan and ultimately the banking cases. So on that basis I think the prior guidance of around about 50% target leverage remains about right; bearing in mind both the nature of the project and it lends itself to leverage in terms of the fiscal terms and so on, reasonably fast payback from particularly the cost recovery process but also obviously Senegal is a new country for project financing of this scale. So weighing those two things together I think that guidance remains current.

In terms of the arbitration between FAR and Woodside relating to the previous sale of an interest by Conoco to Woodside, that is a dispute between those two parties, it's at the side of the joint venture. The joint venture in the project is moving forward. We've been working together on preparation for project financing and we continue to plan to launch next month after the exploitation plan has gone in.

Analyst, Morgan Stanley

And just a small question on the capex. The less than $3bn capex that you allowed for Phase 1 is that still in line with the guidance that you had previously to first oil, the $2.2bn to first oil?

James Smith

Yes so we talked about net to Cairn capex to first oil of around about $800m.

<u>Question 3</u>

Analyst, BMO Capital Markets

Thanks. Just one quick question on timing around Senegal because I know you mentioned 2022 but I guess we've got a range of 2021 to 2023 still, which is quite a wide range given we're almost in 2019. So the question is perhaps you can talk around the steps that would see you actually reaching first oil in 2021? And then the key risk, what are you most worried about that could potentially push that into 2023? What's the critical path there?

Paul Mayland

I think there's obviously some commercial sensitivity because we're looking at a number of options. We're still in a tender process regarding subsea and FPSO redeployment versus conversion. So I don't really want to speak too specifically about those elements. We're obviously getting the approval process underway, getting granted the 25 year exploitation licence and delivering, certainly in the short-term from my perspective over the next six months through front end engineering and design, that's what I see as the critical line of sight that is going to potentially impact the schedule.

Thereafter, after sanction it's really about the basis of the design that we've selected FPSO being a key one.

Analyst, BMO Capital Markets

Just a quick follow up, so if we saw FID early next year would we be looking now to 2021? And if it was late next year would that be leaning more towards 23?

Paul Mayland

I would delink them, I would just basically go with our mid guidance of 2022 and the FID as we have guided before, but like in any project as I say I work to a P50 base case so there'll be opportunities to try to accelerate that and there'll be risks that potentially could delay it but our base guidance is 2022 today.

<u>Question 4</u>

Analyst, GMP FirstEnergy

I've got a question on the water cut on Kraken that you mention and perhaps you can provide some colour on this. So first around what sort of level have you reached? I was also under the impression that the water cut had stabilised since May, is this the case? And lastly is the water cut coming, you said it's a uniform situation or is it more coming from some areas? That's my first question.

Second, fairly straightforward, what sort of size are we talking about for the prospect in Mexico? Thank you.

Simon Thomson

What size are the prospects in Mexico?

Eric Hathon

We haven't put out guidance on that except to say they all are above our minimum economic field size and will be, if successful, commercial in those water depths are less than 500 metres. But we'll all have to wait and see what the results of the wells are. But we're looking forward to drilling them I'll say that.

Analyst, GMP FirstEnergy

Not even order of magnitude are we talking hundreds of millions, tens of millions, billions?

Eric Hathon

Well you can imagine in the physical environment and those water depths there'll be well in excess of 100 million barrels.

Paul Mayland

So if we just put Kraken performance in perspective there's really three factors and EnQuest as operator have discussed some of those. There's the voidage situation, the water injection system wasn't performing as well as we had hoped, so at one point we were about a million barrels deficit in terms of voidage; the amount of oil and water that we'd extracted versus what was returned to the reservoir to maintain the pressure. So that's been no doubt the dominant factor in terms of impacting production performance.

The second one is obviously the facility itself which is obviously the uptime, there's been a number of trips, some of which were unfortunately down to weather. We had the ‘beast from the east’ in March and then we had a number of facilities trips in the second quarter.

And then the third one is for a heavy oil field we anticipated early border breakthrough and that's what you've got when you've got a crude which is 100 times more viscous than the water and we were setting out expectations of around 30% water cut and we’re a bit higher than that. We’re about to go through an extensive well testing programme to try and better understand that and just think about where we want to distribute the water within the field. Just now it’s pretty uniformly being injected across the field. Should we distribute more in the north and the south versus the centre? And these are some of the plans that the operator is contemplating in terms of trying to optimise the performance of the field further.

Analyst, GMP FirstEnergy

And the 30% you're getting is it in all the wells, some of the wells?

Paul Mayland

No that's a field-wide level, that’s why we’re basically doing the specific well test now to better understand how that's distributed between the wells.

Analyst, GMP FirstEnergy

And lastly how does that compare with what you are expecting at that point of the project?

Paul Mayland

Yes so I think I've already addressed that one, the actual at a field level is slightly higher than what was originally expected.

Analyst, GMP FirstEnergy

By a lot?

Paul Mayland

No it’s 10% higher potentially.

<u>Question 5</u>

Analyst, JP Morgan

I just wondered if we could just flesh out a little bit on the exploration programme, obviously you've outlined quite a few wells over the next three to four years, just in terms of budgeting process really more than anything can you talk a little bit about how much you think you can allocate to new ventures through ’19, ’20? And how we should think about the cost of that exploration programme through 2019, 2020? Looking at potentially ten wells next year feels like it might go over $150m/$160m, just a little bit more colour on the costs and the budgeting process associated with exploration in the next couple of years would be great thanks.

James Smith

I think $150m remains the right guidance and indeed on the programme that Eric highlighted on his last slide there that is the expectation for next year.

Now that's a guidance on average, it's always lumpy of course. It'll depend in part on exactly how many wells in Mexico come into next year versus 2020 but that guidance is about right.

And then obviously beyond next year the commitments are relatively small but we like to think that the pipeline that can deliver prospects and wells is relatively strong. So there's quite a lot of flexibility around that. But in terms of planning $150m remains the right guidance.

Analyst, JP Morgan

Okay great and then following on from that could you talk a little bit about the exploration market in general? Clearly you've been able to access quite a few different areas over the last short period, is it becoming more competitive? Are you at risk of paying signature bonuses and things like that in the interim? A little bit more colour there would be great.

Eric Hathon

I'm not sure it's become more competitive because we never saw it become significantly less competitive. I think even through the downturn the competition was more robust than lots of people anticipated. I will say we are seeing now increasingly activity by, especially the majors and super majors, others are moving in. So I think everyone is recognising now as the time if you're going to ramp up activity to do it with sustained product price as we've seen it.

But we'll remain fiscally disciplined and we've been able to capture opportunities, as you've said, and we've been fortunate in that way and we're going to remain within guidance and do the right things and not overpay.

Simon Thomson

I think just to pick up on that, Eric used the example of Mauritania and other signature bonuses but you look at Mexico and the subsequent bid rounds after we established our position in blocks seven and nine and there are a number of areas that we were potentially interested in but the signature bonus from our perspective was too high to contemplate in terms of the allocation of capital going forward. So we remain disciplined in terms of the approach and if there's things where people are prepared to put a lot of cash up front then that's their call.

<u>Question 6</u>

Analyst, Jefferies

I'd like to understand the specifics of the exploitation plan in Senegal versus a final development plan at some point in 2019. Can you just give us an idea of what you lay down? Is it well counts or is the exploitation more a framework?

Paul Mayland

No, actually the evaluation report is more of the framework and the exploitation plan is very much a field development plan, but it envisages the life of the field so it has several phases set out but obviously with a natural focus from the government and obviously from the partners' perspective on what the first phase looks like. So as a comparison we're already looking at probably one or two fewer wells in the phase one exploitation plan than what we submitted in the evaluation report and that's really just because within that framework there's a little bit of optimisation that's gone on and we're probably looking at more like 24 wells rather than 26. And I'm sure by the time we actually execute it as we've done on Catcher we started with 22 wells anticipated in the FDP and we've executed 18, there might be 19 or 20.

On Kraken we envisaged 25 and it looks like we're going to drill 24. But it sets out very clearly the core subsea infrastructure and the overall architecture, all of the flow assurance is done and obviously the facilities bases of design are specified in a generic way which will be then detailed, depending on who we select for feed.

Analyst, Jefferies

So in summary then by the end of the year if Senegal approve that exploitation plan that's a very clear technical development plan?

Paul Mayland

Yes.

Analyst, Jefferies

And is the approval of that plan therefore connected to the operatorship of Woodside? You talked about around the end of the year for Woodside. Do they want to see that approved before they take that up?

Simon Thomson

No. As I said earlier on the operatorship in some senses is already happening in terms of the transition because of the amount of work that's been delegated to Woodside and so we anticipate it will formally happen next month probably.

It's not connected as such so the government is approving from the point of view of the JV the development of the field rather than the operator itself. But we anticipate that will happen ahead of it.

Analyst, Jefferies

And then secondly I feel we should touch on India a bit more Simon regarding the continued government sell down of the Vedanta stake and how that ties in to, let's assume, a successful decision out of The Hague?

Simon Thomson

Yes it's a cash claim so from our perspective the selling of the shares doesn't make any difference to the amount that we're claiming but James I don't know if you want to comment on it?

James Smith

I mean the two are not linked so our claim for compensation under the treaty outlines why we think the treaty's been breached and assuming we're successful in demonstrating those breaches then the compensation claim is to return us to the position we would have been in January 2014 but for the actions of India. And obviously we haven't had access to those shares during all of that time. We were about to sell them for just over $1bn in January 2014 so it's that plus the other losses we've suffered during the period that is the claim. So what they do with the shares in the interim doesn't affect the nature or enforceability or finality of the claim.

Analyst, Jefferies

And so recovery of a cash claim would go via what mechanism?

James Smith

Well the award, assuming it's in our favour, when it's issued will set out the terms on which India is required to meet that compensation claim. We envisage that the compensation claim will be characterised in a monetary amount and that that will be the amount due to us under the sovereign treaty from India with payment terms set out by the tribunal.

Question 7

Analyst, Barclays

Just on the project finance for SNE who's actually responsible for leading that? Is it yourselves or is it Woodside as the next operator or is it something that the JV does together?

And then are you pursuing alternatives to project finance say more conventional RPL lending?

James Smith

The base plan is very much around the project finance facility that all four joint venture partners can participate in. And the preparation for that has been there's a subcommittee appointed which has been meeting very regularly, as I said work is well progressed in readiness to launch. And that is really a partnership of the government, the four partners and the bank and legal advisers that we've appointed. So it's been all of those parties working together.

Analyst, Barclays

And is it export credit, is that the avenue you're going down with this?

James Smith

We envisage that ECAs may well play a role alongside commercial banks.

Concluding comments: Simon Thomson

Thanks for coming we look forward to reporting well success in due course. Thank you.