Company: **Dragon Oil plc**
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Operator: Welcome to the Dragon Oil plc 2013 interim results conference call. At this time, I would like to turn the conference over to your host today of Dragon Oil. Please go ahead.

Emad Buhulaigah: Good morning, ladies and gentlemen. I am Emad Buhulaigah, General Manager of Petroleum Development. I'll present together with Hussain Al Ansari, our COO, the operational results and Tarun Ohri will give you an overview about our financial results.

First I would like to welcome you all to our analyst call today and we will start by moving to page number 3. We'll talk about first half 2013 key operational highlights and the first six months of this year we grew production by 15% against the same period in last year, to 73,600 barrels of oil per day (bopd). We also reported early in July that the average gross production in June was 75,800 barrels per day. We completed six wells, including one sidetrack, and we are preparing the Zhdanov A platform for drilling, which is due to commence later this year. Tenders are ongoing to award contracts to construct up to four platforms, the Gas Treatment Plant (GTP), the crude oil storage tanks and another 30-inch trunkline. We spent about US$150 million on infrastructure and drilling during this period.

Moving onto slide number 4, talking about gross production, a number of factors contributed to production growth in the first half of 2013. As we mentioned, we drilled six new wells. Two wells were worked over during the same period, one sidetrack and one cleanup. We did artificial lifts in two wells, that is jet pumps application, and overall performance of the field was stable thanks to management of wells' performance through regular pigging and wax cutting.

Moving to slide number 5, it shows the drilling results for this half of the year. The initial flow rate from single completion wells from the Lam 28, wells 178, 179 and 182 were between 1,600 and just under 2,000. Two of these wells were stabilised at a rate of 2,000 a couple of weeks after the completion, after the wells were cleaned out and some of the drilling residue removed. So these results were within our expectations, as well as the flow rates from single sidetrack on Lam 28 151A. The results from Lam 21 wells 180 and 181 came in below our expectations. But we expect to return to these wells later with some work to improve the rates. One of them was suspended due to high gas pressure, which the rig was not able to take care of. So we will bring another rig to take care of that well again.

Moving to page number 6 and talking about infrastructure, I will turn it over to my colleague Hussain Al Ansari to give you an overview on the infrastructure.

Hussain Al Ansari: Good morning, everyone. Let's talk about the infrastructure highlights. Basically Zhdanov A platform is being installed as we speak and hopefully we would be commencing drilling in the fourth quarter of this year. Zhdanov platform B is assembled/fabricated at our yard. It's almost finished; we're ready to load it out. On the new platforms, we have done a technical evaluation of the bids and we are ready to open the commercial bids – two of them are with the state agency for approval, then we should be able to award those very soon.

The construction of the new storage tanks or tank farm, we are just about to award the contract and for our 30-inch pipeline, the tender is ongoing. On the 12-inch pipelines, existing pipelines that come onshore, we have started rehabilitating them – that means we are changing part of them to prolong their useful life. All this above is to create a network of oil and gas transportation, which is flexible and we can flow from one to another so we can optimise the production from the field. Under the abandonment and decommissioning work, we plugged and abandoned a third well this year.

Emad Buhulaigah: Okay, I'll take over again. This is Emad Buhulaigah. Going into rig deployment, and in terms of rig availability, we have one jack-up rig drilling on Lam C as we speak. That is Elima, previously called Iran Khazar. The Land Rig number 1 or NIS rig is on scheduled maintenance and being prepared to commence drilling on Lam 22 platform. Land Rig 2 is coming soon to start drilling from Zhdanov A platform, and Land Rig 3 is delayed till first quarter next year and expected to commence drilling from Zhdanov B platform in the middle of 2014.

Caspian Driller rig is currently in Kazakhstan undergoing commissioning and we expect it to arrive to our block at the end of this year. And we signed recently an MOU with BKE Shelf for two drilling rigs, and those are both jack-up rigs. We'll use them for a period of three years. First, we'll start with Neptune for nine months, and this rig is already in the Caspian Sea and we expect it to be available in the third quarter of this year. The second jack-up rig from BKE is Mercury rig, it's coming at the end of 2014, and we will use it for the remainder of the three years then.

Moving to page number 8, on secondary oil recovery, the pilot water injection project on Lam 75 platform started earlier this year. And initial results are expected, as we said earlier, in previous notes, within six months. The second pilot water injection project is planned for Lam 13 area in the next few months as well, and Lam main area will be the focus of the water flooding in the long term. This section of the reservoir has been producing for a number of years and is more likely to benefit from secondary recovery techniques, which will prolong the life of the wells by maintaining the pressure in the reservoir and then increase the recovery by pushing the oil from the injectors towards the producers.

Moving to page number 9, on marketing of crude oil, we sell our share of crude oil production via Baku. Earlier, we struck an agreement with SOCAR in terms different from the previous agreements that we had in previous years. There is a fixed dollar discount to SOCAR to transport our crude to refineries in the Mediterranean Sea, but there are also Brent price fluctuations, which have an impact on the overall discount achieved due to the fact that the pricing period does not coincide with the reporting period. Our estimate is that discounts may range between 14% and 21% over the life of the marketing arrangements that we have, which will expire by the end of 2014, depending on the oil price, Brent price. This takes into account the fixed discount and fluctuation in Brent price.

The priority is to have a secure route to market for all Dragon Oil crude oil production, which is what the Baku route represents. However, we constantly review alternative routes, which are via Russia or Kazakhstan to China. When we looked at the alternatives at the end of 2012, those two routes could take partial volumes of our crude oil production. We hope that with time, these hubs will be developed enough to handle more volumes.

Moving to page number 10, on gas monetisation, the tendering process for an engineering procurement, installation and construction project for the Gas Treatment Plant is ongoing, with technical bids currently under evaluation. The intention is to award the contract in the last quarter of this year. The construction phase is likely to take two to three years after the contract is awarded. So we expect this plant to be ready by 2016.

On the diversification front, first in Tunisia, which we are farming in with Cooper Energy, testing of the well that we drilled in Bargou exploration permit is to commence imminently, probably today or tomorrow. And testing is expected to take between 4-8 days with initial results available thereafter and more analysis to follow. The first phase will be to allow oil to flow naturally. If there is no flow then it is planned to introduce acid into the well bore to stimulate the flow. And if it doesn't flow from this current section, there is also a contingency plan to drill further towards more fractured part of the reservoir.

In Iraq Block 9, as you know, the operator is Kuwait Energy, they are currently sourcing a drilling rig to enable spudding of an early well. That is a well that will be drilled before we finish the de-mining and do the seismic, because we have indications from across the border that there is an extension of that field into our block. The overall scope of work in that block is to de-mine the block and do the seismic survey and then perform exploration drilling of the prospects in that block. The consortium wants to progress faster and is seeking to de-mine a part of the block and drill an early well.

In Afghanistan, we have agreed on the consortium partners' holdings in two blocks and who will operate in each one of those blocks. For both blocks, we agreed on the same stakes while we'll operate the Sanduqli block and the Turkish partner will operate the Mazar-i-Sharif block. We are now awaiting the final approval by the authorities. We already initialled on the contract.

Investment in people and communities, which is an important role for our company in the host country, and here we're talking about Turkmenistan. We continue to invest in our people and we are hiring more talent and developing existing talent at the Group. The polyclinic that you know about has been completed and the facilities are currently being handed over to the local authorities, and we will continue to come up with ideas and programmes to help in securing better relationship with the host country.

Now I will hand it over to Tarun to talk about the financial results.

Tarun Ohri: Thank you, Emad, and good morning, ladies and gentlemen. I'll just take you through the financial highlights and at the end of it, we'll probably have Q&A and let you ask all the questions you'd like to.

Going over the highlights, production growth Emad has talked about. The Brent in the first half of 2013 averaged about US$108 and our realised price was US$86 a barrel. The provisional discount we stated was 20% but the discount we forecast based on the actual pricing is likely to be about 18%.

The interim dividend is 15 US cents a share and as declared previously, our dividend policy relates to performance of the company and the cash flows, and we expect the dividend to grow modestly in 2013 over 2012, and the dividends are split between interim and final. And the final dividend would be declared in 2014, based on performance, and we expect there to be a modest growth on the overall dividend for 2013. And if you notice that previously we ramped up our dividend from 14 US cents to 30 US cents, so there has been a ramp-up of dividend from the maiden dividend in 2010 and in 2011 to 2012. In 2012, we had a 50% increase in the dividend payout and as guided previously, we expect a modest growth going forward.

The net cash generated from operations was US$220 million and we have over US$200 million held as receivables at the end of the first half of the year, and we expect the cash flow to be generated from operations to be strong, and we'll be able to self-finance our capital expenditure as we have done in the past.

We expect our capital expenditure this year to range around US$450 million. This is at the back of projects we'll be able to finalise and award, which include two platforms and other infrastructure projects, which will be awarded, and the contractors will be able to ramp up progress on these projects before the end of the year. Spend in Tunisia has been about US$24 million, with Iraq about US$7.5 million on account of the signature bonus, and Afghanistan we have not spent any money to date.

Going to the results summary, if you look at our revenue, it was lower by 16% and that's because of the entitlement barrels and the realised oil prices. These are the two main components, which comprise the revenue. Our entitlement was down to 44% as compared to 49% previously, and this was on the back of lower-than-expected spend of capex. We spent only US$149 million on capital expenditure in drilling and infrastructure and as mentioned, we hope to ramp this up in the second half of the year.

The realised price was US$86 as compared to US$102 a barrel, and this is on account of a generally lower Brent during the period. Brent price in the previous comparable period was US$112 and in this half of the year it was US$108. There has been a lot of volatility of oil price in the first half of the year. In the first quarter, the Brent averaged US$113 and it came down to US$102 in the second quarter. So there has been a substantial amount of volatility. We expect an about 18% discount in the first half of the year and a discount is an absolute number and it increases when the oil price decreases and vice versa. So this is a function of what terms we have and the limited opportunities we have to export our cargos, there are various other alternatives we are looking at and we hope that post the end of the agreement, we'll have alternative routes, which will enable us to diversify marketing of crude oil. And obviously at this point in time, none of the alternatives can take our volumes entirely. As explained earlier, the realised price is impacted by the volatility of the Brent during the pricing period, and this pricing period, part of which extends outside of the reporting period, so that leads to the provisional pricing we have built into our financial reporting systems. The discount was revised recently, as you all have probably noticed. It's been widened from the earlier guidance to 14% to 21% and the spread was widened based on the actual realised price in the two quarters. In the first quarter, the discount was at the top end of the range. In the second quarter, the discount was to the bottom end of the range, and we expect this to be the range where the crude oil, our discount would sit or trade till the end of the agreement.

Going to the next slide, 18, we have cost of sales of US$151 million. Our field operating costs have remained in line with the previous guidance. Our field operating costs range between US$4 and US$5 a barrel and they have been stable with respect to costs in Turkmenistan. Our depletion costs have also remained the same. And the change in the cost of sales is because of our lifting position mainly.

Our finance income has fallen by 44% and this is on the back of lower yields we have realised on our deposits. The average cash balance we held in 2013 was about US$1.7 billion as compared to US$1.6 billion in the previous half year. The yield was 0.7% as compared to 1.2% and this is dependent on the general low interest rate environment and we balance our cash portfolio amongst various banks, some of them international banks and some of them local banks in the UAE.

On slide number 19, we look at the cash flow for the first half of the year. We have generated about US$220 million from operations, interest received on deposits of about US$6 million down from the previous number of about US$10 million, capital expenditure of US$182 million is a cash outflow and this has led to the closing balance of about US$1.6 billion. It's roughly in line with what we had previously and that is after our capital expenditure and other operating payments we've had this year.

With regard to the balance sheet, we maintain a strong, healthy balance sheet, cash and term deposits total about US$2.1 billion out of which close to half a billion dollars is A&D funds set aside for abandonment and decommissioning activities. That's about US$474 million to be precise, money held in A&D funds.

Going to the next slide, 21, there's a breakup of our capital expenditure in 2013, the first half. We spent US$149 million as compared to US$208 million last year, and 63% is on drilling expenditures, which was comprised six wells including one sidetrack, and the workovers, which were completed, including artificial lift systems and other projects in the drilling programme. The infrastructure was 37% with most spend on the Zhdanov A and Zhdanov B platform and additional slots, to give us flexibility in our operations, we've got additional slots in various platforms on the Lam field.

So with that I hand it over to Emad to go over the outlook.

Emad Buhulaigah: Thank you, Tarun. Going into the outlook for the rest of this year, we plan to complete six more wells, including one sidetrack, and we reiterate our production growth target at the lower end of the 10-15% growth on average. We expect to have sufficient drilling capacity with up to five drilling rigs, operational for part or all of 2014 and 2015 to enable us to reach our targeted production level of 100,000 barrels in 2015. Our anticipated capital expenditure on infrastructure and drilling is estimated at US$450 million; for 2013-2015, the estimated capital expenditure for infrastructure and drilling in the Cheleken Contract Area to remain at US$1.5 billion.

Moving into page 24, continuing with the outlook, we have have discussed gas monetisation earlier and we are also looking at alternative buyers for the gas following the development of the GTP.

As for our diversification strategy, we continue our search for exploration and development assets and have a strong cash balance to execute deals if the fit is right.

With that I come to the conclusion of our presentation. We will be happy to answer your questions now.

Alexander Holbourn, Bank of America Merrill Lynch: Good morning, all, and thanks very much. Just three questions. The first is on the steady decline rates that we've seen in well productivity over the last two and a half years. Just wondering if you could comment on the two wells that you made an announcement on this morning that came in below expectations, on well 181 and 151A, and why they came in below. And then just potentially linked to that, wondering what the latest is on sand intrusion issues and the benefits of the gravel pack completions that you've been testing on some of the wells. Thanks very much.

Emad Buhulaigah: Okay, thank you. This is Emad. On Lam 21 180 and 181, that part of the reservoir came to be below our expectations in terms of reservoir quality and reservoir thickness, and for that reason on well 181 the rate came out to be around 1,000 and on well 180 we encountered high pressure zone, gas zone. And for that reason, and since our drilling rig was not capable to handle that kind of pressure, we suspended the well until we get a more powerful rig to continue with that well.

151A sidetrack was a rig completion into another part of that field and we did a short string, because that section of the reservoir has a short oil column, the production rate became as you have seen, with the water low cut and thicker zones.

The sand issues are under control and we've experimented with expandable screens and that was successful, and we're going to try also with the gravel pack in one or two wells, and we will continue to install the mesh wires, which is the mesh wire screens in our wells. And as we've mentioned earlier, in earlier announcements, that we've installed de-sanders on some of those platforms that have wells without sand control completion.

Alexander Holbourn: Thanks very much. And as a result, do you think that you'll be able to offset the decline that we've seen in productivity over the last couple of years?

Emad Buhulaigah: Yes. We, as I keep mentioning in each of these occasions, that the reservoir is not like a layed cake. It has its variations all over, it's not uniform, so you would expect normally from any reservoir in the world that you will have different productivities and different sand qualities all across the reservoir.

Gerry Hennigan, Goodbody: Good morning, just if you can maybe comment in terms of distribution routes, you seem to be suggesting that potentially next year you would be in a position to use one of the alternative routes. Where are you with regard to those negotiations and when would you be in a position to outline that to the market? And will it be a case that you will still use the route to Baku and Azerbaijan and potentially maybe have some of your distribution growing possibly through the Chinese pipeline? And then also maybe in Tunisia, obviously your partner there, Cooper Energy is suggesting this morning that the drilling commenced last night. Can you give us an indication that assuming that it is, you get a successful outcome with regard to the rate you're looking for from this, what the follow-on potential is here and what sort of resource estimates you're actually targeting in the permit?

Emad Buhulaigah: On your first question about the routes, we are committed to SOCAR for the next year and this year, and as to alternative routes, we've explored the alternative routes and we've been in discussion with the entities there, and the only issue is that they cannot take the whole volume. And we don't have experience with them or we haven't tried those routes. So what we are planning to do is to try with the limited volumes through these routes and confirm their capabilities and any risks associated with those routes.

On your second question as to the Hammamet-West number 3, we're going to test the well as we mentioned, without acid and maybe with acid, and look at the production rates and the quality of crude and so on, and composition, and then decide on future actions. If the rate and the quality are considered commercial then we will go into a field development plan phase and then go through the developments that will include some delineation wells.

Gerry Hennigan: But just to confirm, do you think there is other potential, assuming you get an economical rate here, there is other follow-on potential to target thereafter in Tunisia?

Emad Buhulaigah: Well, the target will be dictated from the results – what we do is we take the rate and then we take it through economic analysis of how much potential that reservoir might have and so on, and decide whether it's commercial or not. It would require facilities and infrastructure.

Gerry Hennigan: Okay, and one other question with regard to the discount to Brent to Azerbaijan, maybe this is more for Tarun. Given that it's worked out a quarter in arrears, Tarun, will there be a restatement of H1 results post Q3 in terms of recognition what the actual discount is, or how do you apply that?

Tarun Ohri: Yes, Gerry, as earlier stated, the discount rate is a function of Brent as well as the absolute number. And we expect that the oil price might be above the threshold limit and below the threshold limit for equal number of days, and we'll be able to hit the midpoint between that range of 14-21%; that's our expectation going forward.

Farid Abasov, Standard Bank: Good morning, I have three questions from my end. The first question is actually on your production growth guidance for next year and for 2015. It looks like you are more certain providing 15% growth rather than a range and I was wondering what is that certainly underpinned by given the fact that there is still uncertainty on the Zhdanov performance and also obviously there is different productivity from different parts of the reservoir. So is it the extra drilling capacity that you have to maintain that flexibility of increasing the number of wells to be drilled to deliver that growth? Second question is: could you please provide the breakthrough between Zhdanov and Lam wells for the 2014 and 2015 to be drilled? And my third question is on the gas negotiations with Turkmenistan. I think given the fact that you are already progressing with the GTP, you must have a price in mind, or at least could you give us any kind of guidance on the pricing going forward? Thank you.

Emad Buhulaigah: On the production growth, we have reiterated that we will reach our 100,000 in 2015. And as to the drilling during those two years, the remaining two years, we are looking at 20-25 wells per year. And on the rigs, the more rigs become available and the platforms to drill from, the faster we will reach our target. And on the quality of the reservoir related to productivity of the wells in different regions or areas of the field, these are all built into our plans, as to how much we expect from different areas of the field.

Your second question related to Zhdanov versus Lam. The drilling in Zhdanov, we are putting the Zhdanov A, which has 16 slots, and we will be drilling these slots by a jack-up and land rig. They cannot be on the same platform at the same time. So we would expect to have that platform drilled in three years, and the rest of the wells are going to be in Lam.

Going to your third question related to gas negotiation and gas price, that is the question that we are negotiating about with the Turkmen government, and the volumes. And those will be reported when resolved.

Caren Crowley, Davy: Good morning, gentlemen, two questions for you. Just with respect to production growth year to date, what's your feeling with respect to reserves upgrades? Do you think you're on course to produce another reserve upgrade at the end of this year? And the second question relates to Lam 21. You talked earlier on during the call about performance from wells drilled on that platform being below expectations and I see that you're going to drill again from that platform in the second half of the year and I'm wondering whether the wells yet to come will target better sections of the reservoir in that area or have your initial production rates for those upcoming wells been revised downwards after the two wells you drilled from Lam 21 in the first half of this year.

Emad Buhulaigah: Thank you, Caren. On your first question regarding the reserves upgrade, we have in our plan to drill in areas where we don't have actual information or real information on the reservoir quality, reservoir thickness, oil thickness and water contact and so on. And with that, we are hoping to upgrade our reserves, from P2 to P1.

And on your second question related to Lam 21, as I said earlier, we are not dealing with the layed cake, so whatever we have in our models related to the reservoir quality in Lam 21 where we drilled 180 and 181 was different from our models and for that reason, it was not expected. However, we have to drill in all the areas in the reservoir to cover all the reserves so that we recover the maximum of the reservoir, regardless of the reservoir quality or the expected productivity of the wells. When you go into a reservoir to develop knowing the boundaries and the contact, fluid contacts and so on, you have to drill the whole thing, regardless of the quality of the reservoir, so that you would recover the oil in that reservoir. I hope this answers your question.

Caren Crowley: Yes, thanks, Emad. If I could just return to the reserve upgrades, do you think the success to date, be it its early days, with artificial lift may produce a reserve upgrade in terms of recovery rates higher than already they audited for?

Emad Buhulaigah: Yes, on the water injection, for sure it's going to increase the reserves. On artificial lift, it would increase it but not as much as the water injection.

Dominic Lewenz, VisorCapital: Good afternoon, gentlemen, just two quick questions if I could. Firstly I think you're looking at spending about US$300 million in the second half of the year. Could you give us some rough breakdown by quarter of how you would expect that to be and what might be the key uncertainties about it? And secondly just in terms of the marketing routes, is there anything you could say more specific about which routes you're looking at and would my understanding be correct that from the end of 2014, you might still look at having an option via Azerbaijan? Thank you.

Emad Buhulaigah: Okay, on your second question because I didn't get the first one, on the marketing routes we are looking at Kazakhstan and Russia, and there are some terminals there that can take crude. Can you repeat the first question? I didn't get it.

Dominic Lewenz: The first question was you're looking at spending I think US$300 million on capex in the second half of the year. Could you give some guidance in terms of how that will split down by quarter and what might be the uncertainties in that? I'm assuming a lot of the infrastructure in there is quite blocky.

Emad Buhulaigah: Well, on the second quarter expenditure, of course part of it is going to be drilling and the rest is going to be on infrastructure. We have a number of projects ongoing including Zhdanov A, Zhdanov B and there we're going to award tank farm and also we have some other projects including the crane barge and so on. These will consume part of this $300 million.

Anish Kapadia, Tudor Pickering Holt: Good morning, I've got three questions please. One of the recurring themes we've seen when you've reported over the last six months and over the last few half year results is that there has been slippage in the infrastructure contract awards and also times of arrivals of drilling rigs. So I'm just wondering what is the risk to your production target if you do continue to see slippage in these things? Second one is to do with the IP rates. If we look at the average IP rates over the last 12 months, around 1,500 barrels per day, that's versus I suppose a historical IP rate of 2,050 barrels per day. I'm just wondering if you could explain in a little bit more detail why these IP rates are going down, if it's just that you've drilled out the best locations. And I suppose more importantly, give some guidance on where you'd expect average IP rates to be going forward over the next few years for the field as a whole. And then the final one, in particular on Lam West, so what I've understood in the past is that Lam West, you've got thick sands, you've got better water support. So I think what we have seen in the past was wells' IP at about 3,000 barrels per day but it looks like the Lam 28 wells have been significantly lower than that 3,000 barrels a day. I'm just wondering if you could explain why we've been seeing that at Lam West.

Emad Buhulaigah: Okay, thank you for those questions. On the contracts and rigs slippage and so on, and delays, part of this is the process of going through the tenders and approvals with the state agency and Turkmen government and getting the contractors mobilised and so on. And the same issue can be said about rigs. If we are taking the rig that is a new rig from China or whatever, we're facing the same issues with the delays in delivery of the rig and so on. However, all these are built into our plans, otherwise we wouldn't have met our production targets even at the lower end over the past years.

On your second question on initial production rates, we give guidance as to what is the range of rate that we expect from our wells. However, depending on where we have available slots on platforms, whether they are in Lam West or Lam Main or wherever, where we drill will dictate how much rate we produce from the well. If it is Lam West, Lam C or Lam 28, we would have good production rates with the productivity because well quality and thickness and the aquifer support are all helping. On other parts of the field, we would expect lower than the rate that we produce from Lam West. And each particular area has its own reservoir characteristics and aquifer support and so on that would dictate the rate that we will produce. These are all built into our models. So we use simulations models also and we just finished an updated model after all the drilling updates and the new geology that was developed based on those updates, we built a dynamic reservoir simulation model for the field, and we use those models to forecast our production from drilling in different areas of the field. And of course, the reservoir simulation model is not like a spreadsheet where you assume same reservoir quality or a simplified reservoir quality factor. The reservoir simulation models will account for all kind of parameters related to the reservoir and the wells to be drilled in the reservoir.

Okay, you asked about Lam West and how Lam 28 rates are not as in the past, and this is related to the reservoir pressure support in that area. It's not 100% aquifer-supported, so you would expect that rates will decline as there is well pressure decline through the depletion from that area. I think this should answer your question, I hope that I have answered your question. If there is anything to clarify, go ahead please, Anish.

Anish Kapadia: Yes, just in terms of a little bit more detail, so for the Lam West wells, what would be the range of expected IP rate and then for the more mature part of the field, what's the kind of range of IP you would expect?

Emad Buhulaigah: Well, let me tell you something. What we have in mind now, we haven't drilled any horizontal wells or high productivity wells in Lam field to date, and what we're looking at now is at using available drilling and completion technologies to increase the production rate from our wells. And depending on the economics, we might go into some of those new technologies that will give us high productivity wells and, for example I'm looking for a well that might produce 5,000 bopd or more. So the production rate of the well also depends on the type of well, between different horizontal, multilateral, long string would give you higher productivity.

Ritesh Gaggar, GMP: Hi, just a couple of questions, firstly on 2013 production, since you have deferred 2-3 wells from 2013 into 2014 due to delay in rig schedules, and also given that the two recent underperforming wells have been flagged today. Are you still confident of meeting your guidance of at least 10% in 2013? And that's the first question then another one for Tarun maybe on crude pricing. It looks like there is a big fixed cost component as the discount increased when Brent came down this year in the second quarter. Can you provide some sensitivities of the pricing discounts around a couple of Brent levels, if not the pricing formula maybe around US$95-100, 105 or 110 Brent. Thank you.

Emad Buhulaigah: On the certainty of meeting our targets, we are certain, pretty certain that we will meet our target production for this year, and for the coming years based on the rig schedules and platforms, plus as I said, we've built in some contingencies. Tarun?

Tarun Ohri: On the Brent pricing and the discount on the Brent, due to commercial sensitivity of the agreement, we do not disclose the exact terms. We know it's an absolute number and you can sort of track how the discount varies with the average Brent price and figure out what the number is, but we don't disclose the number.

Ritesh Gaggar: Right, no worries. Just one more question on the Hammamet West well in Tunisia, I mean the costs have exceeded your pre-drill estimates. Now in case of successful commercial discovery, does it impact your previous estimate of a low-cost development, or this was just a one-off increase in your costs?

Emad Buhulaigah: This is a one-off increase in our costs.

Ritesh Gaggar: And this is mainly because of the BOP issues and putting in the liners, that deviated a little bit from your original plan?

Emad Buhulaigah: No, no, it's related to the pricing of services and rigs. And also related to the rig performance itself. It was not as we anticipated.

Ritesh Gaggar: Right. Now, then definitely we'll wait for the flow test results and possibly you guys looking to increase your stake as Cooper might be decreasing, but it will be interesting anyhow to track this over the next week in terms of the flow rate.

Emad Buhulaigah: Yes, sure. We will have to wait until we see what the results of the test are.

Gerry Hennigan, Goodbody: Yes, just one or two other follow-up questions if I can. On the enhanced recovery programme, particularly the water injectivity, what proportion of the Lam field, Emad, do you expect that to be rolled out over and what sort of timeframe are we talking about here? And then maybe for Tarun, if you can just talk about the cash balance at the moment, I know you're obviously maintaining a cash balance for diversification but how close are you to any sort of deal flow there, or if you can give us some sort of idea in terms of the level of activity you're seeing in the market at the moment or potential opportunities.

Emad Buhulaigah: On enhanced oil recovery, what we have is currently Lam well 75 injection and we are expanding into Lam 13 and moving into a third one soon. And the results will be coming in within a year, because when you inject into those wells, you don't see the results right away; it's not like inflating a balloon or a tyre. It takes its time to go through the reservoir and the rocks and so on, until it reaches the end – which is the producer, from the injector to the producer. So, and then if it's a big reservoir so you need to inject a big volume related to the size of the reservoir to see a change in the reservoir pressure. So, but as I mentioned, we are doing also simulation and so on to see the impact, however the proof of the pudding is the actual field. So by the time we finish with the surveillance programme, with those pilots whereby we collect data and information from surrounding wells related to pressure and saturations and so on, to find out the effectiveness of that process. If it proves successful then we will be looking at two alternatives. Either we do a full field water injection or we go by the same strategy, go into platform by platform. And that all depends on the economics, which we will be doing after we get the data and the results of this water injection.

On the second question, I'll turn it over to Tarun.

Tarun Ohri: Yes Gerry, about the cash balance we hold, obviously the use is for the capital expenditure programme in Turkmenistan as well as acquisitions. We have a lot of prospects in the pipeline, the new business ventures team are looking at assets, and we expect to pick up exploration assets as well as we are still focused on development assets through our portfolio which would enable us to diversify into development assets as well besides the exploration portfolio we already have.

Job Langbroek, Davy: Just want a quick follow-on if I may. I'd just like to just think about your dividend policy for a moment and the dividend you announced today, or the policy for the full year. Tarun, am I correct in understanding that in your introduction earlier on, you suggested that the dividend numbers in the first couple of years were to get to a certain level and that's why we saw the chunky size of the dividend, and from now on it'll be a relatively conservative policy going forward. And then you might just address when you said that the dividend depends on cash flow and performance, whether you can just give a little bit more detail or colour on cash flow and your thinking about cash flow and dividend please.

Tarun Ohri: Yes, thank you. As I stated earlier, our dividend policy is flexible and allows the Board a lot of latitude in terms of determining the level of dividends going forward, which should be based on cash availability, on acquisition opportunities as well as performance, basically the oil price. So there're lots of factors, which play into the ultimate determination of dividend going forward but as our dividend policy stated, we are looking for a modest growth going forward. It's going to be conservative and not as aggressive in terms of ramp-up of dividend we've seen in the last 2-3 years.

Tobias Lindemann, Adelphi Capital: Hello, gentlemen, thanks for your presentation. A few of my questions have been answered already; I have just one more. Can you comment a little bit on the rig costs of the rigs you have running at the moment compared to the new ones you are taking on from Shelf, the Neptune and the other one coming in 2014. Is there a significant difference in price or is that roughly the same?

Emad Buhulaigah: No, there is some difference in price but the new rigs are going to be more powerful and will have the capability to drill oil-based mud, with oil-based mud, which will give it a faster rate of penetration and more smooth operation.

Alexander Holbourn, Bank of America Merrill Lynch: Thanks very much, hi again. Just on the new alternative completions that you're considering, I'm just wondering what specific types you were looking at. And obviously you mentioned horizontal wells but also other types of completion. When as well are you likely to test each of those? And specifically on the horizontal wells, do you believe that it's a production rate of somewhere north of 5,000 barrels a day that's necessary in order for them to be economically viable? Thanks a lot.

Emad Buhulaigah: Yes, there are different types of completions, as you know, currently in the market include multilaterals, smart completions with down hole chokes and valves and you know, whatever other jewellery, and the conventional horizontal well. And what we are looking at are the simplest and most cost-effective, because some of those completions are very expensive in relation to the productivity that you expect and the production, the cumulative production that you would get from the well. So it depends on the economics, as I mentioned earlier; we will be looking at the cost versus rate that we get from different completions.

Alexander Holbourn: And so on your expectations for horizontal wells, you believe that a production rate increase to north of 5,000 barrels a day would be necessary for them to be economically viable?

Emad Buhulaigah: No, no, for horizontal wells, planned horizontal wells, a lower rate will be economical. Lower than 5,000 bopd but what I'm looking for is a well that will produce 5,000+ horizontal.

Alexander Holbourn: Okay, and when are you looking to test some of those completions?

Emad Buhulaigah: We are working on some now, depending on when we get the material required for a specific completion.

Kingsley Jibunoh, FirstEnergy: Good morning, gentlemen. My question is in regards to the capital expenditure over 2013 to 2015. If I heard you correctly, you'll be spending US$1.5 billion over the next three years and I wanted to know the split between drilling expenditure and infrastructure spend. So how much is drilling roughly and how much is infrastructure?

Emad Buhulaigah: Yes, okay, of the US$1.5 billion expenditure over the next three years, we expect to spend about US$0.5 billion each year, which would be roughly split equally between drilling and infrastructure. And obviously this expenditure excludes the expenditure we have towards the Gas Treatment Plant, which will be separate, over and above the US$1.5 billion.

Kingsley Jibunoh: Okay, the Gas Treatment Plant expenditure, how much is that? Do you have an estimate for the cost?

Emad Buhulaigah: Yes, we don't have an estimate now. We expect it to be around US$200 million.

Kingsley Jibunoh: Could I also ask a follow-up question? How much roughly does each of the development wells cost in the Cheleken Contract Area?

Emad Buhulaigah: The well cost is dependent on the type of the rig you use and what is the type of the platform and the depth of the well, and this would range between US$10-$15 million for a well completed with the land rig and between US$18-$22 million for a well, which is completed by jack-up.

Emad Buhulaigah: Okay, thank you, ladies and gentlemen, for this session and hopefully we will get to you again with better results and more growth in Dragon Oil.