Operator

Good day everyone and welcome to Kosmos Energy's Third Quarter 2017 Conference Call. Just a reminder, today's call is being recorded. At this time, let me turn the call over to Neal Shah, Vice President of Finance and Treasurer at Kosmos Energy.

Neal Shah

Thank you, operator and thanks to all of you for joining us today. This morning, we issued our releases regarding our third quarter earnings, which is available on the Investors page of the kosmosenergy.com website. We anticipate filing our 10-Q for the third quarter with the SEC later today.

Joining me on the call today are Andy Inglis, Chairman and Chief Executive Officer; Brian Maxted, Chief Exploration Officer; and Tom Chambers, Chief Financial Officer.

Before we get started, I'd like to mention that this conference call includes certain forward-looking statements based on our current expectations. The risks associated with the forward-looking statements have been outlined in the earnings release and in our SEC filings.

We may also refer to certain non-GAAP financial measures in our discussion. Management believes such measures are important in looking at the Company's historical and future performance and these are commonly referred to industry metrics. These measures are provided in addition to and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP and included in our SEC filings.

At this time, I'll turn the call over to Andy.

Andy Inglis

Thanks Neal and good morning everyone. 2017 has been a strong year for Kosmos. We maintained our focus on growing the value of our company and delivering superior returns to our investors while strengthening our balance sheet. We ramped our production at the TEN fields, solidified our partnership with BP in Mauritania and Senegal and acquired an exploration and production position in Equatorial Guinea that is immediately accretive.

Over the next few years three key attributes will differentiate Kosmos enabling us to continue to deliver superior returns to our shareholders. First, we build an exploration portfolio of unparalleled scale for a company of our size. Each opportunity has been accessed and evaluated using a rigorous and disciplined process resulting in four high impact quality prospects that are planned to be drilled in the next 12 months. Second in our portfolio we have a combination of defined growth opportunities from producing assets and scattered resources all of which are characterized by their top quartile full cycle breakeven cost. And third, we continue to maintain our robust financial position and strong liquidity allowing us to invest counter cyclically and grow the company at time when supply costs are lower.

We would like to update you first on our exploration portfolio which remains as strong as it ever has been. Our position of Mauritania and Senegal combined with our Suriname, Sao Tome acreage is very promising providing a program of opportunities to deliver significant success. While everyone is unlikely to be successfully in frontier exploration our goal is to deliver focused high-quality exploration program which means we will only drill the best prospects. Last week, we announced the result of Hippocampe-1 well in Mauritania.

I'll now turn the call over to Brian to discuss the results and implications of the well in more detail as well our ongoing exploration activities. Before I provide you with an update on the rest of our business.

Brian Maxted

Thanks, Andy and good morning, everyone. As we disclosed last week in the press release Hippocampe-1 was a dry haul. Our post well analysis which is ongoing suggested the well failed mostly likely due to a lack of charge access, more on this in a moment. Hippocampe-1 was a second of four independent tests designed to fully evaluate the key prospects of different fairway of the basin floor fan. Along the western outboard portion of our acreage offshore Mauritania and Senegal. Each fairway includes a different combination of reservoir and charge systems. The Hippocampe well was a significant step out from our other discoveries. Approximately 110 kilometers from Tortue and 60 kilometers from Marsouin.

Hippocampe-1 was designed to test low Lower Cenomanian Albian reservoirs charged by the deeper Valanginian, Neocomian source and the last mature part of the kitchen. Here we anticipated that lower heat flows related to our acreage further south in Senegal will present a stronger chance for liquids or oil. In several respects, our understanding of geology proved correct. Firstly, the well encountered the target intervals on prognosis and importantly the sands in the Lower Cenomanian as well as the upper Albian were exceeding our expectations in terms of both thickness and quality. This outcome extends the proven actual extent of the basin floor fan fairway nearly 200 kilometers from Hippocampe-1 to the Yakaar discovery.

Given the quality of the reservoir targets coupled with the fact that they were also buried more deeply than in other wells drilled to-date. The well outcome also extends the depth window for commercially successfully exploration. Secondly, we also encountered a lower thermal grade and test predicted pre-drill compared to our discoveries in southern Mauritania and Senegal. This is consistent with our thesis that we're more likely to find liquids and oil along the western flank of our acreage charged by the deeper source.

As I mentioned, while it's still early days in our post well fairly announces its continuing, we believe the most likely reason for finding brines on filled sands with no hydrocarbon shows in the prospect is due to a localized lack of charge migration, access from the deeper Valanginian, Neocomian source to the low Cenomanian and upper Albian reservoirs in this part of the petroleum system.

We believe this due to a combination of several factors including the presence of verticals seals, the prevailing pressure regime and the maturity of the source rock i.e. another gravity oil and liquids and not mobile as lean gas. Together these drivers may have ensured less buoyancy and coupled with greater barriers to vertical migration. Blended charge access more difficult. Our post well analysis has also focused on explaining the false positive AVO anomaly. The first we've encountered in the basin. We believe, the AVO signature at Hippocampe instead of being the highly reliable hydrocarbon predictor. It has proven to be another part of the basin, here's it is only lithology indicator. This we believe is due to differences in rock properties and seismic velocities in this part of the fairway.

While the use of AVO as an exploration tool remains valid and what continue to be an important into de-risking our prospects, it will be need to employed with greater caution going forward. This is particularly important when the two is not calibrated by approximate wells. Where we need to ensure that the geophysical attributes is supported by the fundamental geology. Turning to the forward program in Mauritania and Senegal. As a result of the independence of our prospects, primarily in relation to charge but also reservoirs our forward program remains unchanged. Our next well, Lamantin, is an independent test with a different charge model and different reservoir target and remains our best chance of finding oil in this petroleum system. The well spuded over the weekend and we expect results within 60 days. Lamantin is targeted in the younger Campanian age reservoir located uniquely above oil mature Cenomanian and Albian source rocks. It is not dependence on the deeper source and we do not expect any major virtual seals at separate at source rocks from the reservoir which should reduce migration risk.

Although this well has another significant step out, the AVO is calibrated by well approximately 20 kilometers away. Following Lamantin, we will test the Requin-Tigre prospect a super giant basin full fan located down dip of Tortue and long trend from Yakkar. The well is located in the same geological setting as Yakkar and benefit from good AVO calibration with successful offsetting wells. as we've discussed in the past, we expect the geothermal grade into this fairway to be higher and similar to that encountered in the nearby Tortue and Yakkar discoveries suggesting Valanginian, Neocomian sort rocks there to be gas mature and therefore facilitating vertical migration from the deep resort to the lower Cenomanian and upper Albian reservoir target. With 2 billion to 3 billion barrel oil test at Lamantin, the 62 cf gas thrust in Requin-Tigre we believe this basin has the potential continue to grow significantly.

To conclude, I want you to provide an update for you on the progress during the last quarter of the rest of our exploration portfolio. Turning first to Suriname, we expect to drill two exploration wells next year one in Block 45 and one on Block 42. On Block 45 we plan to test Anapie 750 million barrel oil prospect. This involves early cretaceous reservoir strapped in a structural-stratigraphic along the flank to begin on Suriname basin. On Block 42 we're in a high number of high quality prospects that we alongside our partners are evaluating for drilling next year. We plan to spud Anapie the second quarter of 2018 followed by the high graded prospect in 42 in the second half of 2018.

Recent drilling in the basin both positive and negative as proved additional validation of our geological and geophysical models. Secondly in Sao Tome last quarter, we completed the acquisition for approximately 16,000 square kilometers proprietary through these seismic. The results of the very early process seismic volumes are encouraging particularly in confirming the presence of multiple stacked reservoir plate fairways as well as number of potential large combination structural-stratigraphic traps. We expect to continue through next year to evaluate this prospectivity ahead of planned drilling in 2019.

Given we've already demonstrated the presence of the working petroleum system through something of oil in the islands as we've previously reported we continue to be very excited about this opportunity. We expect that they're maturing for drilling of the exploration opportunities in Suriname and Sao Tome in 2018 and 2019 respectively together with follow-on wells in Mauritania and Senegal well enable cost most of the inactive explorer with two or three high impact exploration wells each year through to the next decade.

In addition, we continue to actively pursue strategic new ventures for drilling in 2020 and beyond both independently as Kosmos and together in partnership with BP as part of our exploration alliance. We're strongly leveraging our leading edge knowledge, sharing new ideas, countercyclical initiatives together with the capabilities of the Kosmos big combination to identify and access new exploration opportunities and we expect our efforts to bear fruit soon.

At this time, I will turn the call to back over to Andy.

Andy Inglis

Thanks, Brian. I'll turn my focus to production growth from our existing portfolio producing assets and discovered resources. In Ghana, we've achieved two important milestones which position the assets for growth in 2018 and 2019. We recently received approval for the Greater Jubilee Full Field Development Program and also received a favorable ruling from the International Tribunal of the Law of the Sea or ITLOS in late September with regard to TEN fields. These milestones paved the way for the partnership to drill additional development wells in both fields starting 2018.

Related to Jubilee, during the last quarter has been strong averaging growth sales of approximately 100,000 barrels of oil per day. However, it is important that we received approval of the Full Field Development Program and in addition to allowing drilling to resume it extends the unit boundary to include the Mahogany and Teak fields. It establishes price for gas produced at the field after the foundation volume and it allows Kosmos to book additional reserves to the year end.

Alongside the increase and production, the Jubilee partnership continues to work on resolving FPSO turret bearing issue. We've been working hard with our partners and the government to ensure shutdowns our as completion as possible and minimize downtime. From an original shutdown of up to 12 weeks this year, the partners have now agreed to shorter shutdown of approximately four weeks of the two periods in early 2018 for stabilization of the turret.

Planning for rotation of the vessel is ongoing is expected to result in a short shutdown around year end 2018. At TEN, gross sales average approximately 60,000 barrels of oil per day during the third quarter with the existing limited wild stock. With a favorable ruling delivered by ITLOS in late September we now expect to resume drilling on the field in early 2018 to increase production levels towards the FPSO capacity.

As I discussed on our call two weeks ago, we also announced our strategic entry in Equatorial Guinea through establishing an exploration and production position. Members of our exploration team discovered the Sabre field nearly 20 years ago and as a result, Kosmos has differential knowledge of Remuni [ph] basin and a special relationship with these assets. Principe basin was opened very little exploration has taken place. We bring - our new thinking and apply modern technology to maximize the value of these assets. The producing assets Sabe and Ekume [ph] fields add additional source of low cost, high margin production the Kosmos portfolio which increases our current production by almost 50%.

Our partnership with Triton Energy allows us to focus on what we do best exploration while Triton focuses on the defined resource upside through optimizing production operations and targeted infill drilling. The assets generate significant free cash flow which enhances Kosmos strong financial position and improves our financial metrics. We acquire the asset to very attractive valuation and the transaction is immediately accretive. We expect to update you on our plans after closing later this year.

In Mauritania and Senegal work on Tortue continues and the partnership has made significant progress. I'll remind you that just one year ago we were finalizing our Farm-Out to BP which we announced just before year end and they've rapidly taken control of the project, demonstrating the importance of bringing the right partner at the right time. In late August, we completed the drill stem test or DST on the Tortue-1 well. The positive results from the DST confirm that the Tortue fill is a world class resource validating assumptions that underpin our development concepts. The well floated a sustained equipment constrained rate of approximately 16 million cubic feet per day during the main extended flow period which minimal pressure drawed out providing confidence in well designs that reach capable of producing 200 million standard cubic feet per day.

The DST results confirmed and a connected volume to well consistent with current development scheme which together with high well rate is expected to result in a low number of development wells compared to equivalent schemes. Initial now to the fluid samples collected during the test indicate Tortue gas is well suited for liquefaction given low levels of liquid and minimal impurities. The combination of how high well rates large connected volume per well together with gas well suited for liquefaction is why we believe Tortue is one of the lowest cost pre-FID Greenfield LNG projects. With regard to the ICA, that's full engagement by both governments to approve the agreement at a timely fashion aligned for FID in 2018 and first gas in 2021.

To achieve this extensive pre-FEED work is currently ongoing and approximately 70,000 man hours of engineering work have already been invested. So, in summary, we have a strong growth agenda for our producing assets recently strengthen with our acquisition in EG as well as clear path to first gas from our discovered resource in Mauritania and Senegal.

Lastly, I'd like to discuss our strong financial position through the end of the third quarter we've already delivered over $200 million of free cash flow and are on track to exceed our full year guidance of $250 million excluding the recently announced EG transaction. Our enviable free cash flow generation and solid liquidity have allowed us to invest through the cycle and take advantages of opportunities counter cyclically. Our recent entry into Equatorial Guinea is a clear example of our strategy in action.

I'll now turn the call over to Tom to discuss our third quarter results.

Tom Chambers

Thank you, Andy good morning, everyone. Our commodity prices have recently improved, our commitment to full cycle returns, financial strength and robust liquidity combined with our rigorous capital allocation process will continue to set Kosmos apart from other independent E&P operators. We plan to continue living within our means using our strong free cash flow to execute our growth plan. With regard to liquidity, we exited the quarter with approximately $1.3 billion in total corporate liquidity including capacity on our RBL and RCF facilities as well available cash.

Through the third quarter, we repaid $250 million of debt and exited the period with $890 million of net debt. We plan to continue maintaining significant headroom in both our RBL and RCF facilities by ensuring we extend the facilities between RBL amortization begins or the RCF reaches maturity. We also anticipate adding incremental RBL capacity by incorporating the EG assets once the transaction closes.

Now I'll turn to the results for the quarter. We finished the quarter with three crude oil liftings, two from Jubilee and one from TEN in line with our guidance. This generated second quarter 2017 oil revenues of $151 million, excluding $12 million of derivative settlements. When you add our revenue to our sell hedges, it reflects a realized price of approximately $55.57 per barrel sold in the quarter.

Third quarter revenues were up compared to the same quarter in 2016 as a result of lifting two more cargoes in the quarter. The third quarter, we generated a net loss of $63 million or $0.16 per diluted share, adjusting for the impact of one-time items that affect comparability, including a $27 million mark-to-market hedging loss, the company generated net loss of $37 million or $0.09 per diluted share.

On the cost side, operating expense for the third quarter was $39 million or $13.33 per barrel versus $14 million or $14.33 per barrel in the second quarter of 2017. This included approximately $36 million of regular operating expense and $7 million of cost attributed to revise operating procedures, offset by $4 million in insurance recoveries. Exploration expense for the third quarter was $37 million which included $21 million related to the difference between rate charge to the partnership and the contracted rate for [indiscernible] associated with the Hippocampe-1 well and covered under our BP Farm-Out transaction. The remaining expense was primarily attributable to ongoing seismic in geologic and geophysical costs incurred in Mauritania, Sao Tome and Suriname.

Also in the quarter, other expense net totaled $5 million most of which were non-cash charges associated with the exploration activities of KBSL. Our joint venture BP in Senegal. We've now agreed to unwind the JV, which we expect to occur in the fourth quarter allowing our activity in Senegal to be accounted for under the normal proportionate consolidation accounting method. General and administrative expenses were $20 million during the third quarter inclusive approximately $10 million of non-cash equity based compensation.

Depletion and depreciation expense for the quarter was $73 million or $25.01 per barrel consistent with the second quarter and three liftings. Taxes were a benefit of $2 million and included a deferred benefit of approximately $8 million. Hedging continues to play a key role in supporting our balance sheet, strength and environment of volatile oil prices. As of September 30, we had approximately 14 million barrels hedged from 2017 to 2019. We plan to hedge the EG volumes consistent with our strategy to ensure we deliver the projected cash flow out of that project and to lock-in payback within three years.

In summary, we continue to maintain a solid balance sheet which allows us to execute our planned work program, preserve our financial flexibility and fund our ongoing operations and growth initiatives to enhance the value of Kosmos for our shareholders.

With that, that concludes our prepared remarks and now operator we'd like to open the call for questions.

Question-and-Answer Session

Operator

[Operator Instructions] our first question comes from the line of Charles Meade with Johnson Rice. Please proceed with your question.

Charles Meade

Brian, this maybe perhaps be best for you. I recognized it's early days in the post the Hippocampe well and then we're also dealing with the limitations of this median that we don't have any visuals we can refer to, but I'm hoping that you can talk a little bit more about what you learned with the after this dry hole and how it has perhaps changed your view of the risks and the prospectivity of the basing. I recognized that all these prospects have independent risk, but at least my point of view it seems like what they share is perhaps the same size of chute and certainly you're thinking about how to high grade these prospects. So, can you just elaborate little bit on your prepared comments there?

Brian Maxted

Certainly, Charles. I'll be happy to. I think the first point to note is all of the prospectivity that we've defined in this current drilling program we see as independent and that's deliberate because what we want to do, is to test all of the elements of this petroleum system in this initial exploration phase in the out board, that's the first point to note. So, the read throughs from Hippocampe to the rest of the prospectivity limited or zero. So, as I mentioned in the prepared remarks the program isn't changing at all.

The second point to note, is this was probably our most significant step out into the basin. And whilst we've had obviously good consistency and success thus far and this was our first dry hole, one has to remember how big this petroleum system is, we're talking several hundred kilometers long and 100 kilometers wide and it is very difficult to expect a basin of that size to be perfectly confirming across its extent. So, the fact that we saw some changes in the rocks as we went outboard and further to the north and west in this basin, was no major surprise, but that was one of the reasons for drilling this well early, we felt it would give us significant information on better understanding the petroleum system itself particularly in the Northern part of Mauritania. And whilst we got all right, the objectives of there - qualities I mentioned. The one thing we didn't get right or didn't work for us was the AVO, it was our first force AVO and we're working through that right now.

We do believe we'll be able to fully understand it, we do believe it is where our question related to sonic and density variations both within the reservoir and in the enclosing shales relative to the wells that we drilled to-date and the question here will be, how do we then explain geologically those geophysical changes both stratigraphically and geographically across the base and that is part of the work program that we really just started.

And as I mentioned on the call, the next well independent in the sense - that they have different reservoir objectives and all they have different source rocks feeding them and or they're in a different geological setting and or calibrated by offsetting wells more so than Hippocampe was. So I think overall it's just an occupational how you're going to drill dry holes and often times you learn a lot more from dry holes than you do from successful wells and that is absolutely the case here and I think the results that we got are significantly enhancing our understanding of this basin which hopefully will translate through to a continuing degree of significant success across the basin where there is much more potential to touch on our last point much more potential still to test. This was a big prospect. It had big follow-on prospectivity in the area, but it was just on potential hub of many hubs that - defined across this basin and so we see significant remaining potential to test here in the next two or three years to add on to the obviously the significant resources that we've discovered and delineated to-date.

Charles Meade

Brian, that's great. Thanks for sharing. I'm sorry?

Brian Maxted

No just wanted to make sure that answers your question, Charles.

Charles Meade

It does, a lot of great detail on your elaboration there and just one small quick follow-up. You mentioned in your prepared comments that you found the lower thermal gradient at Hippocampe, was that consistent what your modeling was for Lamantin or was it just right in line better or worse.

Brian Maxted

It's absolutely right in line and consistent with the geological model that we went through in some detail after the Yakkar result actually, while we were explaining that why that was lean gas and not oil. And importantly one possible read through you could argue from Hippocampe it's confirmed the geothermal gradient that we're using in the Northern part of Mauritania that underpin the switching on/off this, the Albian and Cenomanian, Turonian source rocks in that area which are obviously the key source rocks for charging the Lamantin prospect itself.

Charles Meade

Great. Thank you, Brian.

Operator

Thank you. Our next question comes from the line of Bob Morris with Citigroup. Please proceed with your question.

Bob Morris

Andy my first question with regard to TEN, now that you've got ITLOS approval, at one point you'd talked about further expanding the facilities there to reach 100,000 barrels a day which you'd indicated have the capacity to reach, how does that play in and what is the likelihood that ultimately you can get to that sort of production level?

Andy Inglis

Yes, thanks Bob. I think the first objective for the partnership is to commence drilling to build the well stock. We intend to do that early in 2018, we're out procuring a rig to do that anticipated starting on TEN at the beginning of the year. I think the comments read around then building the well stock is ultimately to test the full capacity of the FPSO. It has a name plate capacity of 80,000 barrels a day, but we have tested at liquid throughput rates which are higher than that. So, I think the objective of the partnership will be to build the well stock and then to be able to test it at the FPSO capacity and then hopefully with successful drilling is to be able to test it beyond that. So, I think the real message is that I think there's real potential for improving production from TEN in 2018 through 2019.

Bob Morris

Okay, good and my second question is, you mentioned that the Hippocampe, AVO indicated lithology and not hydrocarbons are you're still studying that to try and understand that, but as you figure that out how likely is that to give you better insight into the AVO on the other prospects to better determine what they're indicating just given the distance to this, is there going to be from what you learn ability to high grade to better understand that AVO elsewhere across the basin.

Andy Inglis

Yes, I'll let Brian cover that and I think, there's one big message to take away from the if you like the AVO false positive is the frank that about calibration. We have in Lamantin well that is 20 kilometers away, so we feel good about the calibration on Lamantin. We really feel good about the calibration in the Requin-Tigre area given the analog setting of the Yakaar and then up the slope Tortue. So I think as a non-geologist my big takeaway in the use of tool is, is the importance of calibration and then as you step away as we did with Hippocampe maybe 80 kilometers away from the nearest calibration there is more work to be done to be able to calibrate it and therefore that is going to be the challenge now as it were, but as the basin gets drilled up, we're going to have more and more point to calibration which means the two itself will become I believe more predictable. But Brian?

Brian Maxted

I think, Andy hit the nail on the head there. It's about two things, it's about understand what drives the AVO and what we've done so far, we've been able to successfully replicate the AVO response with the rock properties and seismic losses that we saw in Hippocampe-1 and it does give a false positive in other words brine filled sand gives you a positive AVO, close to AVO response. It does improve when you put hydrocarbons into it and so there is a subtle difference which pre-drill we didn't recognize. So, there's no question the driver for the AVO here is potentially denser rock, higher seismic velocities causing a varied response that - in hydrocarbon bearing sands, but the key is to calibration and this well didn't have a calibration within 60 kilometers of it. And Lamantin has a calibration within 20 kilometers of it and Requin-Tigre is well calibrated the south by Yakaar and well calibrated to east by Tortue, where we see similar seismic velocities occurring.

So, we think at this point in time that we've got sufficient calibration in Lamantin and in Requin-Tigre for those AVOs to actually be true hydrocarbon predictors as oppose to lithology indicators.

Bob Morris

Great. Thank you.

Operator

Thank you. Our next question comes from the line of John Herrlin with Societe Generale. Please proceed with your question.

John Herrlin

Couple quick ones for Brian. Did you do any side wall cores on the sands at all?

Brian Maxted

We did John, we have enough obviously. That's a crucial piece of information that helps us to understand why are these rocks denser than we thought, they were going to be. We have got the side wall core issues, we haven't got the analysis in yet but that [technical difficulty] as you rightly point, will be an important part of our post drill analysis.

John Herrlin

Okay then with EG if I remember correctly because you're affiliated with it a long time ago after - has bought the properties they had some issues with the compartmentalization do you have any thoughts on that? I think they did Siba [ph] if I'm not mistaken.

Brian Maxted

Yes. I mean - my recollection on it. It was a long time ago, but part of the early problems were caused by not having water injection in place alongside the initial oil production and I think whilst the compartmentalization was demonstrated those compartments were large enough in off them themselves to justify individual producer injected well pads and we think there's a significant amount of overlooked potential in - unsweat or undeveloped compartments in Siba [ph] and that's one of the sources of value that we see in the project among many others.

John Herrlin

Great. And last one for me is on gas price. Are you going to be able to disclose what gas price you'll be selling for is or is gas couldn't be produced in Ghana and you don't get it report, what's the potential net back for you?

Andy Inglis

John its Andy. Post the foundation volume of 200 Bcf gross the agreed gas price is $2.35 MMBtu which on a Mcf but $2.35 on an MMBtu basis.

John Herrlin

Great. Thanks very much.

Operator

Thank you. Our next question comes from the line of Brendan Warn with BMO Capital Markets. Please proceed with your question.

Brendan Warn

I guess just if I switch to Suriname, you made a couple of comments obviously there's been a number of positive rolls from led by Exxon, you recently had Talos unsuccessful one and I think it was Apache earlier this year, can you just talk through what have you learned from both sets of rows in terms of what you'll be chasing over your drilling next year and second quarter.

Andy Inglis

Great. I'll let Brian handle that. Good question, Brendan.

Brian Maxted

Thanks Brendan. Yes, you have to think about the, as you know when we go into these basins we look for play diversity so Block 42 and Block 45 are different plays. 42 to the west is essentially a play extension of the Lisa fairway and so the recent drilling Exxon and partners have been doing in the southern part of the stone river block are directly and geographically in read through to our acreage and of course as you know we have paths involved in Block 42 as well for the primary reason of bringing that calibration into the partnership and so with that direct read through but the results are very positive, the play is working in southern part of the most recent well [indiscernible] is right adjacent to Block 42 to show that the play is working up to the borderline there's no reason it should stop working at the borderline, so a good positive direct read through.

And then when you go further east, we've had the recent Raku well that Tullow and partners drilled which is east of Block 45 in the Anapie prospect. The Anapie prospect is on the flanks on the Guyana-Suriname basin and the first point to note Raku prospect is actually on a interbasin hike [indiscernible] which is largely bold of the reservoir systems that we are chasing in Blocks 42 and 45. Not just the reservoir system but the charge systems as well and so we always struggled with understanding how the geologic story in Raku geophysical story which is part of the story that really excited the operating and art is in Raku.

There is no read through really for Block 45 or deeper Block 42 from Raku. As I mentioned in the remarks it calibrates our interpretation that we didn't expect to see reservoir in that area, we thought charge was going to be very difficult, but it was charge that's it's probably charge from either from another port or deep depth which might explain the gas condensate. So, in Anapie in Raku we have really good story which complements the strong geophysics and the AVO responses so we're hopeful that they are, the independence is there versus certainly the Tullow well and the Dependence is there versus the Exxon well. So, we remain extremely bullish and exciting about that potential that we'll drill out next year.

Brendan Warn

Okay thanks and then my second question, if I just come back to Mauritania or Mauritania and Senegal and just you already given up that - in know BP are the operator in terms of the development, but update on where the signing of the border agreements up to concept selection. Just what sort of catalyst should we be expecting before the year end or end of fourth quarter in regards to Tortue, if you can please?

Andy Inglis

Yes, sure Brendan. I'll pick that up and talk about in two parts the projects and then the intergovernmental cooperation agreement. I think on the projects BP have actually made significant progress really short period of time. It's less than a year ago, since we announced the BP Farm-in Mauritania and Senegal in that time the rounds of engineering significantly, they've spent around 70,000 man hours as I said in my remarks completing the concept select. And if you think about a project to get to first gas, you got to go through sort of four stages appraise, select which is all about the concept, define which is about the front end engineering takes it to FID, execute, first gas. So where are we in that timeline, the praise is done completed with the DST, positive results, select sort of done, BPX back to go through select, define gate by year end. They've taken all the big engineering decisions we need to do to finalize the concept for example the exact location of the break water on the border then a bunch of soil survey it allow us to be comfort into the break water is properly positioned.

So yearend we have select done that will analyze to go out to define which is about the front end engineering and some sort of pre-qualification is taking place with various vendors to enable us to do that. the define program is around sort of nine, 12 months which allows FID by year end 2018, 36 months of execute it takes you to post gas at the end of 21. So, I think all of that we're on track. I think to me it demonstrates sort of the rigor and discipline that BP brings to the project as a super major, it has helped us enormously I feel decision we made during BP, at the time we did was absolutely right.

For the intergovernmental cooperation agreement as I said in my remarks full engagement by both governments. They're aware of the need to finalize it in a timely fashion to allow FID 2018 [technical difficulty] agreements in terms of what the agreement should say, its supported by both ministries, both countries, both NOCs. But more importantly supported by both President's. Both BP and Kosmos. Have those personal assurances. It's now actually the process of getting a National Treaty approved by both governments which requires process in a sense of degree of bureaucracy across several ministries including finance, foreign affairs, etc. and I think it's honest to say given the novel nature the agreement is taking longer than we anticipated. But we have absolute engagement from both countries, absolutely engagement down from the President and it's clear that both Presidents are targeting year end to get it done so that we can therefore more forward through the FEED process.

So, a lot of progress, is it all done yet? No, but the process of having BP and they're driving it now I think it's made a huge difference.

Brendan Warn

That's great. Thanks a lot.

Operator

Thank you. Our next question comes from the line of Rafal Gutaj with Bank of America Merrill Lynch. Please proceed with your question.

Rafal Gutaj

I've got two questions both on Ghana. If I may. First one just on TEN and the 60,000 barrels a day that you achieved in the third quarter. Just thinking back to earlier in the year. I think the intentional is to keep the field running at about 50,000 barrels a day, owing to some pressure issues on the Enyenra so the question is basically, could you give us a little bit more color how you achieved that and should we expect that run rate to continue over Q4 and into Q1 ahead of further drilling. And then coming to the greater Jubilee Full Field Development Plan. I wondered if you could give us some more color now that the plan has been approved on CapEx kind of first oil and then incremental production and when we should expect that. And also, what is the associated reserve booking with that at year end 2017? Thank you.

Andy Inglis

Lots of questions there, Rafal. I think but on both hand, I think what you've seen and the improvement in the production rate is actually about an organization becoming more innovative. With actual inability to spend [indiscernible] so we've been looking at ways in which we can optimize the field looking at a different flowing bottom role pressures, different injection regimes, etc. And I think hats off to the partnership for getting the production level up to 60,000 barrels a day. We clearly, the objective is to sustain that through the fourth quarter. Again, I think the real important that is not the fourth quarter production but the ability then to start the build-up of new well stock and then the increase in production that would carry through 2018.

The loss of potential in TEN and I think we've demonstrated the performance of reservoir through being able to maintain a 60,000 barrel a day production rate in the third quarter despite the very limited well stock, that we had. On the greater Jubilee full field development program. It's too early to give you all the guidance where what we do know is that, we have a rig coming to Ghana it will initially spend time on both TEN and Jubilee. We're working with the partnership at the moment to look at bringing in the second rig in 2018 to accelerate the drilling because we see there is real potential there. So, I think, we need to conclude those conversations in the partnership and then as customary we will give you the guidance in our 4Q results in February for 2018 from all the dimensions we just talked about, which our CapEx production, reserves, etc.

I think the great opportunity there's real opportunity in both fields now given the ports that we have in drilling or awaiting the full filed development program on Jubilee and ITLOS drilling issues to now sort of get back to business and start pushing on the production rate.

Rafal Gutaj

Great. Thank you.

Operator

Thank you. Our next question comes from the line of Pavel Molchanov with Raymond James. Please proceed with your question.

Pavel Molchanov

On EG, at both Jubilee and TEN as analyst we've been accustomed to modeling your production as a function of cargos, right. Certain number of cargos each quarter. Is that going to be how it works with EG or is there going to be kind of more steady state production run rate that we can expect from quarter to quarter?

Andy Inglis

Pavel, I think - behind that is Tom. But I think you'll get by. All right we're going to give you production numbers and clearly from a cash flow perspective you want to be able to model the cash received that will give you guidance on the cargoes. Tom?

Tom Chambers

That's right, Pavel. We're going to give the fact that it will be countered for a bit differently, we're going to provide some extra details that to allow you to understand what the production is, what the cargos are, what the operating G&A expenses of the partnership? So, we're currently working our way through that and we'll have the detail for you on our next call into the - at the fourth quarter call in February.

Pavel Molchanov

Okay, just a quick follow-up on to help kind of sequence out the catalyst we should be thinking about for 2018. Requin-Tigre spuds in Q1 of 2018 and then you mentioned the two prospects in Suriname, did I miss anything that supposed to spud next year or is it just those three?

Andy Inglis

In terms of the big exploration wells, Pavel you docked obviously three big wells in 2018 from an exploration perspective. Requin-Tigre as you say spuds in 1Q, you then got most likely the Block 45 well which took you and then Block 42 to 3Q.

Pavel Molchanov

Very clear. Appreciated.

Operator

Thank you. Our next question comes from the line of David Gamboa with Tudor, Pickering and Holt. Please proceed with your question.

David Gamboa

I have two keys. First one, we thought Andy you were very clear talking about the next catalyst for the project. I just wanted to double check something with you. I think earlier this year you mentioned or it was mentioned that a potential mix range solution could be announced by mid-year and we haven't seen that yet. I was wondering what have been the delay, if you can comment around that and if you expect this to potentially be a risk toward FID at slipping into 2019 and alongside thought you, if you could give us some color around how being to pre-market the gas, how's the market at this point in time in terms of getting good price for that gas previous to first production.

And then second one, just if you could give us a sense of TEN ramp up towards the FPSO plateau and given the pressure issues that have been mentioned and the pace you expect to drill this new wells that we should expect the field to reach plateau within the first half or second half of the year. Thank you.

Andy Inglis

Yes, great. Thanks David. If I go back the Tortue questions first. The question about the Midstream solution is part of the concept select process which BP been rigorously following. One of the key decisions that phase or etc for phase praise is like define, execute the concept work was to fully work through the Midstream solution. I think we've made with BP a decision on the concept that we want to carry through into the defined stage i.e. what is the first vessel that will be used on the FLNG for the FLNG solution and so with the completion of the concept work by the end of the year, that is now done.

In terms of gas as you know, we have BP in the project one of the reason we brought BP in, is that they have the ability take Tortue gas and add it to their global portfolio. Clearly independent of that we're testing the market for other solutions that will be competitive with a BP option and going out to other potential buyers of the gas. That process is started and it actually moving long at quite a good pace actually so, it's a great thing about this partnership is it really simple partnership. Ourselves, BP national oil companies all absolutely aligned in terms of the outcome and so I think, I don't see the gas marketing being the rate defining step to get us through FID. We're well balanced in that process.

In terms of TEN ramp up, as you say we gave you full guidance when we come to our earnings in February but you should anticipate a ramp up to the fatter rates in the second half of the year rather than the first half of the year. All right.

David Gamboa

Right. Thank you.

Operator

Thank you. Our next question comes from the line of Al Stanton with RBC Capital Markets. Please proceed with your question.

Al Stanton

Brian, can I ask couple questions about Lamantin? Can we learn a bit more about the prospect? I mean the size range 2 to 3 billion barrels, it's quite wide. I was wondering what the key drivers were in terms of whether there is a base case structural trap and an upside strat trap and also as you did talking about Suriname there's been a lot of lessons learned from the sort of Ghana [ph] or and Tullow vintage worlds of the past. So is there anything you've really learned from drilling in the vicinity that is helping you more than just the AVO's. I think if your confidence on this prospect.

Brian Maxted

Hi, Al. Brian here. In terms of the range of potential size of Lamantin. It's primarily - the shape and extents of the trap and the definition of the trap is actually very good. And so, the variation in terms of potential is really driven by the internal geometry and particularly the net pay, net gross, net pay and distribution across the trap, which is quite a large trap. So that really reflects its that's uncertain really reflects to the range of volume, that we're closing for Lamantin because if you recall in this area, we're in a bit of a different reservoir system then we are further south and we're getting much more influence from the [indiscernible] river as come further north as oppose to Senegal river site which is quite well calibrated in predicting reservoir thickness and quality from the existing wells. So that's what drives the range of volumes for Lamantin. In terms of risk and the de-risk part of the AVO, two things I mean we've mentioned now couple of times one in the context of our own prospects and one in the context of the dry holes or others and it's very important to have the geological story and the geophysical story support each other.

The geophysical story in Lamantin we believe is different from Hippocampe and the reason we believe that is because we have a well about 19 kilometers away [indiscernible]. Which didn't quite get down to the Campignian primary objective, but it got into some sense several hundred meters above its horizon and so what we got is a calibration on the seismic velocities and the rock properties. The well was a dry hole it was, but it had hydrocarbon shows in it. And so, it's enabled us to calibrate geophysically the sands in a water bearing situation and then obviously compare that with the sands that we got in Lamantin-1 in the [technical difficulty] response of those and we see a clear difference.

So, unless we got a significant change in the geophysical parameters or the rock property parameters within that 20 kilometers we've much better calibrated than we were in Hippocampe. Much more calibrated in the sense we're further south in the Tortue, Teranga, Yakaar. The second point to note is, is the geological story is different. And in particular we're dealing with proven oil source rocks, you recall the deep Valanginian, Neocomian system is still speculative we're still haven't penetrated it, we know it's there, but we haven't actually penetrated it. We've actually penetrated the CT and Albian source rocks in the basin, we know that they're prone and we believe that they will mature in the drainage area of Lamantin trap. They directly underlie the Campignian reservoir and so migration which we believe was a big program in Hippocampe should not be a problem in Lamantin. And so, the geological model is quite different than Hippocampe and much more consistent and supportive of the geophysical story that we're seeing in the Lamantin prospect itself. So, for those reason.

Al Stanton

And will this will make or break the prospect?

Brian Maxted

Will make or break the Lamantin prospect for sure. We have a number of prospects along this trend some in other different reservoir system, some with other different track geometries. They have some dependency but won't necessarily be written off if Lamantin is a dry help for example. So, there will be other potential to possibly test going down the road, but this an obviously a very important well kind of play fairway area opening well in this northern part of basin which we haven't yet drilled. It is well over 100 kilometers not of Hippocampe again giving you a sense of the scale of this basin. So, an important well for us.

Al Stanton

Okay, thank you.

Operator

Thank you. Our next question comes from the line of Richard Tullis with Capital One Securities. Please proceed with your question.

Richard Tullis

Andy, going back to the EG acquisition that I guess is looking all the more attractive with each dollar uptick in Brent oil price. Are there development exploitation opportunities that could be somewhat fast tracked to keep production up or even increase from current levels next year and especially given the improving Brent oil price?

Andy Inglis

Yes, Richard if you think about the phases of what we're doing, all right. We're fully understanding the ability to bring some of near field opportunities to the existing infrastructure either through exploration, new prospects and infill drilling. To do that, we're going to shoot a new seismic survey, modern technology across the surrounding blocks SW and 21 as well as across the field. From there we will high grade the drilling opportunities which we would start pursuing in 2019 which will be a mix of those potential tie back prospects and infill opportunities and we see from the data that we have from the existing 3D and some lines across WS and 21, we see significant potential for that. But we want to make sure we've high graded it, we've done it in a very rigorous way drilling the best things first. So that's really 2018 is the dart and 2019 will be the execution. So, what has 2018 become, 2018 is really about improving the recovery of the existing developed resources. As we said on the call it's actually the fields production today is gas lift constrained, it's at a certain point on the water - can't lift any more fluid to go further, we need to increasing water injection, you got to be able to life it, so you got to be able to put more lift capacity in, how you're going to do that it's about conversion of the gas lift wells to ESPs, so that's a big focus of 2018 really is about advancing that program and that's what we intend to do.

So obviously the transition of operatorship from ourselves to the Triton-Kosmos joint venture and then it's' about getting on with optimization of the current gas lift and then the conversion of the key wells to water lifts, to ESPs that allows us to increase the water injection capacity. So, I think your comment is well made, which is hell of a good time to product. Plenty of opportunity to do it, but we're going to go through it in a sort of phase approach which is the best opportunities today driving that near term production is from increasing the lift capacity and then we're going to follow it up with the continuation of the program into 2019, so supplemented by the infill and then the near field exploration.

Richard Tullis

Thank you, Andy that's helpful and that's all from me. Appreciated.

Operator

Thank you. Our final question comes from the line of Niki Kouzmanov with Jefferies. Please proceed with your question.

Niki Kouzmanov

Maybe if we can go back on TEN, very quickly. I just wanted to confirm with you, if you have had permit to specific well locations to start treating as soon as you get the rigging early 2018 and then just in terms of gas, you talked about Jubilee gas after the foundation volumes, but what about gas from TEN including sales gas and actual production that you might need to inject. And then maybe if you can just go to more - I've seen this morning you confirmed the C18 Block farm-in there's been in media recently people talking about Kosmos maybe taking interest in deal which I think is on a different Block, but just you can give us a bit of update on what you see in C18 which you think is just out for Lamantin, for the partner side any exploration during this time, at this stage and so on? Thank you.

Andy Inglis

If we just go back to the questions around TEN, is yes, we do have very clear objectives to drill as you were the inter [indiscernible] losses around little hard on the field. We've obviously had the benefit of the over a year, of production which has allowed us to look at the dynamic response of the field, which actually the positive when you then come to high grade the drilling opportunities to identify the ones that are going to have the most impact. So, whilst negative the worse and positives by having early production, which analyses to pick the well locations which are going to have the most impact. So those well locations are well defined and which would allow us to start drilling on TEN in early in the year. So that's kind of done, the - in terms of TEN, the gas price for both associated gas and non-associated gas was agreed so there's no further work to be done on that. We have to sort of finalize the gas sales agreements on there. But in terms of pricing of that, that's already been done.

So really the optimization of the field will be about integrating the depletion planning which is ultimately about ensuring that you're maintaining the reservoir pressures through water injection and then being able to optimize the gas off take and as you know from Jubilee we didn't have the gas off take there at day one, it certainly created more challenges in creating that right balance. On Mauritania and Senegal, on Mauritania Block C18 you're correct. We finalized the farm-in, we're planning on shooting seismic in 2018. I think permits are on place in there and Brian will add a few more detail comments.

To us I think your same comment around often surrounding acreage, is that we see Mauritania as a large unexplored basin with significant potential and we're at this front end I believe the exploration program to fully define it. Let's remember we only have seven wells in the whole basin now. We have with Hippocampe, Marsouin two wells. In Tortue, four wells. In Mauritania in a huge piece of acreage. And I think that's the message that I want to leave with you about the rather get into the detail. Is that we see it as a significant basin, multiple source rocks, multiple reservoir systems and unexplored. So, what we're doing is, ensuring that we position ourselves at the front end of that entry by getting into the best acreage at the beginning which is ultimately when the strategic battle is won. So C18 is part of that. we see potential for different targets around the TF area, as well TF itself and we believe we've got differential knowledge today as a result of our drilling campaign but also of all the work we've done on the petroleum system and we aim to optimize that at the front end of this basin which is when the real value is created. So, you can expect us to continue this type of acreage build.

Brian Maxted

Yes, Niki I think just add-on to that. I mean a nail on the head again. It's a big petroleum system and it's going to continue to get bigger and I mentioned in the remarks that the result of Hippocampe well, it probably extended the exploration of commercial exploration window deeper than we previously imagined. The upper part of the exploration window is really defined by the TF area, you got to recall, remember that the TF play is actually no different many of the plays that we're pursuing in the cretaceous further out board, it's just more of a channel system as oppose to a slow basin full fan system but it's the same geological processes. So, we see potential all the way from the early part of the cretaceous all the way through to Miocene in this base, we believe the basin is going to get bigger it is going to have hiccups like Hippocampe. But overall it is going to expand in terms of its potential and the entry into C18 is a good example where we leverage in our insight and our knowledge and our capability to essentially restart the exploration program and C18 is very much for us a potential continuation of the Lamantin trend further north over the mature Albian and CT source kitchens and we saw things in there that the incumbent partner didn't see and ourselves and BP [indiscernible] formed in to that acreage now. So, it will be good follow-on opportunity for us in the event that Lamantin works.

Niki Kouzmanov

Understood. Thank you very much and just briefly on TEN, so are you expecting gas production and gas test to start soon or is that something that's going to be pushed back into 2018 as well?

Andy Inglis

The gas sales agreement needs to be finalized as I said we got a gas price, the gas sales agreement needs to be finalized. Once the gas sale agreement is finalized which is not faraway gas production in sense, gas sales will be possible.

Niki Kouzmanov

Understood. Thank you.

Operator

Thank you. There are no further questions at this time. I would like to turn the call back over to Neal Shah for any closing comments.

Neal Shah

Thank you, operator. We appreciate all of you joining us on the call today and your interest in Kosmos. If you have any further questions, please don't hesitate to reach out. Thank you very much.