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Hess Corporation (HES) CEO John Hess on Q3 2019 Results - Earnings Call Transcript

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Q3: 10-30-19 Earnings Summary

Press Release *10-Q* *Slides*

EPS of $-0.32 misses by $-0.01 | Revenue of $1.51B (-17.12% Y/Y) misses by $-2.91M

Earning Call Audio

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Hess Corporation (NYSE:HES) Q3 2019 Results Earnings Conference Call October 30, 2019 10:00 AM ET

Company Participants

Jay Wilson - Vice President of Investor Relations

John Hess - Chief Executive Officer

Greg Hill - President, Chief Operating Officer

John Rielly - Senior Vice President, Chief Financial Officer

Conference Call Participants

Devin McDermott - Morgan Stanley

Roger Read - Wells Fargo

Doug Leggate - Bank of America

Brian Singer - Goldman Sachs

Bob Brackett - Bernstein Research

Scott Gruber - Citigroup

Jeanine Wai - Barclays

Arun Jayaram - JPMorgan

Paul Cheng - Scotia Howard

Jeffrey Campbell - Tuohy Brothers

Michael Hall - Heikkinen Energy

Muhammed Ghulam - Raymond James

Operator

Good day ladies and gentlemen and welcome to the third quarter 2019 Hess Corporation conference call. My name is Andrew and I will be your operator for today. At this time, all participants are in a listen-only mode. Later, we will conduct a question-and-answer session. [Operator Instructions]. As a reminder, this conference is being recorded for replay purposes.

I would now like to turn the conference over to Jay Wilson, Vice President of Investor Relations. Please proceed.

Jay Wilson

Thank you Andrew. Good morning everyone and thank you for participating in our third quarter earnings conference call. Our earnings release was issued this morning and appears on our website, www.hess.com.

Today's conference call contains projections and other forward-looking statements within the meaning of the federal securities laws. These statements are subject to known and unknown risks and uncertainties that may cause actual results to differ from those expressed or implied in such statements. These risks include those set forth in the Risk Factors section of Hess' annual and quarterly reports filed with the SEC.

Also, on today's conference call, we may discuss certain non-GAAP financial measures. A reconciliation of the differences between these non-GAAP financial measures and the most directly comparable GAAP financial measures can be found in the supplemental information provided on our website.

Now, as usual, with me today are John Hess, Chief Executive Officer, Greg Hill, Chief Operating Officer and John Rielly, Chief Financial Officer.

I will now turn the call over to John Hess.

John Hess

Thank you Jay. Welcome to our third quarter conference call. I will provide a strategy update, then Greg Hill will discuss our operating performance and John Riley will review our financial results.

We continued to execute our strategy of disciplined capital allocation, focusing only on low-cost, high-return opportunities. We had another strong quarter, delivering higher production and lower capital and exploratory expenditures than our previous guidance. Our portfolio with Guyana and the Bakken as our growth engines and Malaysia and the deepwater Gulf of Mexico as our cash engines is on track to deliver industry-leading performance in terms of financial returns, cash flow growth and a portfolio breakeven below $40 per barrel Brent by 2025.

A key part of our strategy is maintaining a strong balance sheet and liquidity position. With $1.9 billion of cash on our balance sheet at the end of the quarter, we are in a strong financial position to fund our high-return growth projects across a range of prices. As a result of strong execution throughout the portfolio, we have reduced our full-year 2019 capital and exploratory expenditures guidance by further $100 million to $2.7 billion.

Earlier this month, Hess Midstream Partners announced plans to convert to an Up-C structure and acquire Hess Infrastructure Partners, including its oil and gas midstream interests, water services business, outstanding economic general partner interest and incentive distribution rights in Hess Midstream Partners. Upon completion of this transaction, which is expected in the fourth quarter, Hess Corporation will receive approximately $275 million in cash and will own approximately $134 million units or 47% of the new Hess Midstream consolidated entity valued net to Hess at approximately $2.85 billion as of last night's close. Cash proceeds will be used to fund our world-class investments in Guyana and the Bakken where we plan to invest more than 75% of our capital expenditures over the next five years.

Turning to Guyana. On the Stabroek Block where Hess has a 30% interest and ExxonMobil is the operator, gross discovered recoverable resources are estimated at more than six billion barrels of oil equivalent with multibillion barrels of future exploration potential remaining. In September, we announced a 1fourth discovery on the Block at the Tripletail-1 well located in the Turbot area approximately three miles northeast of the Longtail discovery. The well encountered approximately 108 feet of a high-quality oil-bearing sandstone reservoir. Subsequently, additional hydrocarbon bearing reservoirs have been encountered below the previously announced Tripletail discovery. Tripletail is still under evaluation and will further underpin the Turbot area as a major development hub.

During the quarter, drilling and appraisal activities were completed at Hammerhead with encouraging results, including a successful drill stem test. These results are being evaluated for potential future development. Also, drilling and evaluation activities continue on the Ranger 2 well with the objective of appraising the Ranger oil discovery.

In terms of our developments, the Liza Phase 1 development is now targeted to start up in December and will produce up to 120,000 gross barrels of oil per day utilizing the Liza Destiny floating production storage and offloading vessel or FPSO, which arrived in Guyana on August 29. The Liza Phase 2 development is also progressing to plan and will use a second FPSO, the Liza Unity with a gross production capacity of 220,000 barrels of oil per day. First oil is expected by mid-2022. Planning is underway for a third development at Payara, which will use an FPSO with gross production capacity of 220,000 barrels of oil per day and first production from Payara is expected in 2023.

We are also seeing positive results from our focused exploration program in the deepwater Gulf of Mexico, where we have acquired 60 blocks over the past five years for approximately $120 million to pursue high-return infrastructure led and hub class prospects. Yesterday, we announced the successful oil discovery at the Esox-1 exploration well in Mississippi Canyon, which encountered approximately 191 feet of net pay in the high-quality oil-bearing Miocene reservoir. Hess is the operator and holds a 57.14% interest. We expect to commence production in the first quarter of 2020. Esox will be a low cost tieback to the Tubular Bells production facilities and is expected to generate strong financial returns. We also plan to spud the Oldfield well by the end of the year. Kosmos is the operator and Hess has a 60% interest in this prospect, which is located approximately six miles east of the Esox-1 well.

Moving to the Bakken. Our transition to plug and perf completions has been very successful and we are seeing the expected uplift in initial production rates, in estimated ultimate recovery and most importantly in value. Net production in the Bakken is on track to reach approximately 200,000 barrels of oil equivalent per day by 2021. We then plan to reduce our current six rig program to four rigs, which will enable us to maintain production of approximately 200,000 barrels of oil equivalent per day, resulting in material free cash flow generation across the range of prices.

Now, turning to our financial results. In the third quarter, we posted a net loss of $205 million or $0.68 per share, compared to a net loss of $42 million or $0.18 per share in the year ago quarter. On an adjusted basis, we posted a net loss of $98 million or $0.32 per share, compared with adjusted net income of $29 million or $0.06 per share in the third quarter of 2018. Compared to our third quarter 2018, our financial results primarily reflect lower realized selling prices, which were partially offset by reduced exploration expenses.

Third quarter net production averaged 290,000 barrels of oil equivalent per day, excluding Libya, up from 279,000 barrels of oil equivalent per day in the year ago quarter. For the full year 2019, we are raising our guidance for net production to approximately 285,000 barrels of oil equivalent per day, excluding Libya, up from our previous guidance range of 275,000 to 280,000 barrels of oil equivalent per day. Third quarter net production in the Bakken averaged 163,000 barrels of oil equivalent per day, up 38% from 118,000 barrels of oil equivalent per day a year ago. For the full year 2019, we are raising our guidance for the Bakken net production to approximately 150,000 barrels of oil equivalent per day, up from our previous guidance range of 140,000 to 145,000 barrels of oil equivalent per day.

In summary, our strategy of disciplined capital allocation and a focused portfolio of assets is achieving positive results and uniquely positions our company to deliver increasing and strong financial returns, visible and low risk production growth and significant free cash flow.

I will now turn the call over to Greg for an operational update.

Greg Hill

Thanks John. I would like to provide an update on our progress in 2019 as we continue to execute our strategy, starting with production. In the third quarter, net production averaged 290,000 barrels of oil equivalent per day, excluding Libya, which was above our guidance range for the quarter of 270,000 to 280,000 barrels of oil equivalent per day. Based on this strong year-to-date performance, we are increasing our full year 2019 net production guidance, excluding Libya, to approximately 285,000 barrels of oil equivalent per day compared to our previous guidance range of 275,000 to 280,000 barrels of oil equivalent per day. We expect fourth quarter production to average approximately 300,000 barrels of oil equivalent per day on the same basis.

In the Bakken, third quarter net production averaged 163,000 barrels of oil equivalent per day, significantly above our guidance range of 145,000 to 150,000 barrels of oil equivalent per day and nearly 40% higher than the year ago quarter. Compared to the second quarter, net oil production was up by 12% as a result of continuing strong performance from our plug and perf completions. Natural gas and NGL volumes were also higher in the third quarter as a result of increased gas capture from the startup of the Little Missouri 4 gas plant in late July and the decline in NGL prices during the quarter, which increased our entitlement from gas processing contracts operating under percentage of proceeds agreements in the Bakken.

During the third quarter, we brought 33 new wells online and over the fourth quarter, we now expect to bring online between 55 and 60 new wells. For the full year 2019, we expect to bring online approximately 155 new wells, which is slightly below our original guidance of 160 wells, primarily due to weather related issues earlier this year. For full year 2019, with stronger well performance more than offsetting fewer new wells coming online, we now forecast Bakken net production will average approximately 150,000 barrels of oil equivalent per day compared to our previous guidance range of 140,000 to 145,000 barrels of oil equivalent per day. In the fourth quarter, Bakken production is expected to average approximately 165,000 barrels of oil equivalent per day. This modest increase from the third quarter reflects the back-end loaded completions program, contingency for winter weather and our expectation for seasonally higher NGL prices, which may reduce our entitlement from percentage of proceeds contracts.

In the third quarter, our average drilling and completion costs were $6.7 million per well, down to 8% from $7.3 million in the first quarter. Through the continued application of lean manufacturing, we expect to achieve further cost reductions as we progress towards our targeted drilling and completion costs of $6 million per well. Overall, we remain firmly on track to deliver net production of 200,000 barrels of oil equivalent per day by 2021 while continuing to drive down well costs.

Now moving to the offshore. In the deepwater Gulf of Mexico, net production averaged 59,000 barrels of oil equivalent per day in the third quarter, reflecting planned maintenance and downtime associated with Hurricane Barry in July, which reduced third quarter net production by approximately 6,000 barrels of oil equivalent per day. The gradual ramp-up of the Llano-5 well in which Hess has a 50% working interest has been underway since July when the well was first brought on production. The well is approaching its peak rate, with current production at approximately 8,000 net barrels of oil equivalent per day.

Our infrastructure led exploration in the Gulf of Mexico is also proving successful. Yesterday, we announced an oil discovery at the Hess operated Esox-1 exploration well in which Hess holds a 57.14% interest. The well encountered approximately 191 feet of net pay in high-quality light oil bearing Miocene age reservoir. Planning is now underway to tie back to the well into an existing slot at the Tubular Bells production facility during the first quarter of 2020. We also plan to spud another infrastructure led exploration well by year end on the Oldfield prospect approximately six miles east of Esox-1 in which Cosmos is the operator and Hess has a 60% interest.

Turning to Southeast Asia. Net production averaged 60,000 barrels of oil equivalent per day in the third quarter, reflecting the completion of a successful two week planned shutdown for maintenance activities at the joint development area.

Now turning to Guyana, where exploration success on the Stabroek block continues and development activities are progressing to plan. Last month, we announced an oil discovery at the Tripletail-1 well located in the Turbot area approximately three miles northeast of Longtail discovery. Tripletail-1 is our fourth discovery in 2019 and brings the total number of discoveries on the block to-date to 14. The well was drilled in 6,572 feet of water and encountered approximately 108 feet of high-quality oil-bearing sandstone reservoir. Drilling operations and evaluation are ongoing with additional hydrocarbon-bearing reservoirs encountered below the previously announced discovery. Following completion of activities at Tripletail, the Noble Tom Madden drillship will next drill the Uaru-1 prospect located approximately 10 miles east of the Liza-1 well. Also on the block, the Stena Carron drillship is currently conducting well operations on the Ranger-2 appraisal well, which includes an extensive logging and quarrying program. Following Ranger-2, the rig will move to the previously announced Yellowtail-1 discovery to conduct a production test. A fourth drillship, the Noble Don Taylor is expected to arrive in Guyana in November and will drill the Mako-1 exploration well, located approximately six miles south of the Liza-1 well.

Turning to our Guyana developments. The Liza Phase 1 project is now targeted to achieve first oil in December. The Liza Destiny FPSO with a gross production capacity of 120,000 barrels of oil per day arrived in Guyana on August 29. Drilling of the Liza Phase 1 development wells by the Noble Bob Douglas drillship is proceeding to plan and subsea installation is nearly complete. Liza Phase 2, sanctioned in May of this year, will utilize the Liza Unity FPSO, which will have a gross production capacity of 220,000 barrels of oil per day and will develop approximately 600 million barrels of oil. The hole is nearing completion and is expected to sail to the Keppel yard in Singapore by year-end where the topside modules will be installed and the vessel commissioned. Development drilling of

Liza Phase 2 will commence in the first quarter of 2020 with first oil expected by mid-2022. Pending government approvals, a third development at Payara is planned to utilize an FPSO with a gross production capacity of 220,000 barrels of oil per day and is expected to achieve first oil in 2023.

In closing, our execution continues to be strong. In 2019, we are on track to deliver higher production on lower capital and exploratory expenditures than previously guided. Our offshore cash engines continue to generate significant free cash flow. The Bakken is on a strong capital efficient growth trajectory. Our Gulf of Mexico exploration program is proving to be successful and Guyana continues to get bigger and better, all of which position us to deliver industry-leading returns, material free cash flow generation and significant shareholder value.

I will now turn the call over to John Rielly.

John Rielly

Thanks Greg. In my remarks today, I will compare results from the third quarter of 2019 to the second quarter of 2019. We incurred a net loss of $205 million in the third quarter of 2019, compared to a net loss of $6 million in the second quarter of 2019. On an adjusted basis, which excludes items affecting comparability of earnings between periods, we incurred a net loss of $98 million in the third quarter of 2019, compared to a net loss of $28 million in the previous quarter.

Turning to E&P. On an adjusted basis, E&P incurred a net loss of $34 million in the third quarter of 2019, compared to net income of $46 million in the previous quarter. The changes in the after-tax components of adjusted E&P results between the third quarter and second quarter of 2019 were as follows.

Higher sales volumes increased results by $63 million. Lower realized selling prices decreased results by $66 million. Higher DD&A expense decreased results by $48 million. Higher cash cost decreased results by $24 million. All other items decreased results by $5 million for an overall decrease in third quarter results of $80 million.

Turning to midstream. The midstream segment had net income of $39 million in the third quarter of 2019, compared to $35 million in the second quarter of 2019. Midstream EBITDA before non-controlling interest amounted to $133 million in the third quarter of 2019, compared to $127 million in the previous quarter.

Turning to corporate. On an adjusted basis, after-tax corporate and interest expenses were $103 million in the third quarter of 2019, compared to $109 million in the previous quarter.

Now to our financial position. At quarter-end, cash and cash equivalents were $1.9 billion excluding midstream and total liquidity was $5.7 billion including available committed credit facilities, while debt and finance lease obligations totaled $5.6 billion. As John Hess mentioned, we will receive approximately $275 million in cash upon completion of Hess Midstream Partners' acquisition of Hess Infrastructure Partners, which is expected to close in the fourth quarter of this year. In the third quarter of 2019, net cash provided from operating activities was $443 million or $543 million before changes in working capital and items affecting comparability. Cash expenditures for investing activities were $721 million in the third quarter.

Now, turning to guidance, first for E&P. In the third quarter, our E&P cash costs were $12.13 per barrel of oil equivalent including Libya and $12.75 per barrel of oil equivalent, excluding Libya, which beat guidance on higher production than forecast. We project E&P cash cost, excluding Libya, in the fourth quarter to be in the range of $12.50 to $13.50 per barrel of oil equivalent and full-year 2019 cash cost to be unchanged at $12.50 to $13 per barrel of oil equivalent.

DD&A expense in the third quarter was $17.67 per barrel of oil equivalent including Libya and $18.79 per barrel of oil equivalent, excluding Libya. DD&A expense excluding Libya is forecast to be in the range of $17.50 to $18.50 per barrel of oil equivalent in the fourth quarter and $18 to $18.50 per barrel of oil equivalent for the full year, which is at the lower end of previous guidance. This results in projected total E&P unit operating costs, excluding Libya, to be in the range of $30 to $32 per barrel of oil equivalent for the fourth quarter and $30.50 to $31.50 per barrel of oil equivalent for the full year of 2019.

Exploration expenses, excluding dry hole costs, are expected to be in the range of $70 million to $75 million in the fourth quarter with full year guidance expected to be in the range of $190 million to $195 million, which is down from previous guidance of $200 million to $210 million. The midstream tariff is projected to be approximately $250 million for the fourth quarter and full year guidance is expected to be approximately $725 million. The increase in fourth quarter tariff expense compared with the third quarter is due to an anticipated increase in midstream volumes during by increasing third-party throughput with the ramp up of the Little Missouri 4 gas processing plant in North Dakota.

The E&P effective tax rate, excluding Libya, is expected to be an expense in the range of 0% to 4% for the fourth quarter and for the full year. Our crude oil hedge positions remain unchanged. We have 95,000 barrels of oil per day hedged for the remainder of 2019 with $60 WTI put option contracts. We expect non-cash option premium amortization to be approximately $29 million for the fourth quarter. Full year E&P capital and exploratory expenditures are now expected to be approximately $2.7 billion, down $100 million from previous guidance. The reduced spend reflects efficiencies across the portfolio but primarily in the Bakken, where we have reduced well costs and the number of wells expected to be completed for the year, while being on track to exceed our original production guidance for the year.

For midstream, we anticipate net income attributable to Hess from the midstream segment, excluding specials, to be approximately $55 million in the fourth quarter and approximately $165 million for the full year. For corporate, for the fourth quarter of 2019, corporate expenses are estimated to be in the range of $25 million to $30 million, with full year guidance unchanged at $110 million to $115 million. Interest expense is estimated to be in the range of $75 million to $80 million for the fourth quarter with the full year guidance unchanged at $315 million to $320 million.

This concludes my remarks. We will be happy to answer any questions. I will now turn the call over to the operator.

Question-and-Answer Session

Operator

[Operator Instructions]. Your first question comes from the line of Devin McDermott, Morgan Stanley.

Devin McDermott

Good morning. Congrats on the strong results today.

John Hess

Thanks Devin.

Devin McDermott

So my first question is actually on the Bakken. And it's been one of the strong points in the portfolio each quarter so far this year, despite some of the weather headwinds. So it's a bit of a two-part question. The first one is, one of the areas of strength on production this quarter was on the higher gas and NGL volumes and you mentioned that part of that was the Little Missouri 4 plant startup and part of that was the POP contracts, some of which reverses into the fourth quarter. I was wondering just how you are thinking about with that reversal, the normalized oil mix going forward and as a rule of thumb on how we can think about the sensitivity around those POP contracts? And then the second part of the question is stepping back, as you think about this transition to plug and perf and how it's gone relative to the expectations, it seems like the results have been beating at least the guidance that you laid out at the Investor Day last year, particularly on cost side. So what opportunities have you found to drive down costs so far and what opportunities do you see going forward to further cut cost out of the system and improve returns there?

John Hess

Okay. Let me take your first question. So yes, you are right. This is a really good thing. The volumes in the third quarter due to higher midstream capture. So the first thing I want to say that is it's not a reservoir issue at all. There is no material change in the GOR at the wellhead. I think it's important to note that in the third quarter we had very strong oil production growth. So, it was 12% increase versus the Q2 level. So, the oil is doing great.

And as you mentioned, the higher natural gas and NGL volumes amounted to about 7,000 barrels a day and that was due to two things. First of all, the increased capture from the Little Missouri 4 gas plant that came on in July. And then secondly, as you mentioned, the higher gas and NGL entitlement under our POP contracts. Now how those POP contracts are going to perform in the future is obviously going to be a function of NGL prices. Seasonally, in the fourth quarter, we lowered our expectations for those typically because NGL prices are higher with the weather.

Now as we look forward, I think what we can say is that we expect that the Bakken oil percentage is going to average approximately 60%, low-60s on a go forward basis. Now, one other thing I will say is, if NGL prices stay low, there is a chance that it will actually be higher than the 200,000 barrels a day as a result of additional POP volume. So this is all a very good thing.

Now, on your second question in terms of performance of the Bakken wells, you are right. Extremely pleased with the performance of the team, both not only on the productivity side. So the plug and perf is, on average, exactly on track with what we expected. The 15% uplift in IP180s, the 5% uplift in EURs, well on track for that. But the second thing I am really proud of the team on is their performance on the cost side.

Recall, we started the first quarter of the year at $7.3 million a well. Second quarter, we came in at $7 million a well. And the third quarter, we came in at $6.7 million a well. Now all of that is lean manufacturing gains primarily. We are also doing some technology things where we ran some fiber-optic in the wells that allowed us to reduce our stage count and that also led to our lower well cost.

Now we are marching our way towards the $6 million a well that we talked about at Investor Day and if we are successful in achieving that $6 million well cost, it's going to add a further $1 billion to the NPV of the Bakken. So we are well on track from a productivity standpoint and a well cost standpoint.

Devin McDermott

Great. So pretty impressive improvement there. And just one more, if I may, is actually on the Gulf of Mexico. And I think it's been a strong area of the portfolio that probably doesn't get as much attention as it may be should. And you mentioned you picked up 60 new blocks over the past few years there and we had the Esox discovery announced yesterday. And at a high level, how should we think about the Gulf of Mexico and the role of the portfolio going forward in terms of investment level, production profile and also the cadence of the exploration here over the next few quarters and into 2020?

John Hess

Yes. Sure. So obviously, it's a very important part of the portfolio, strong cash generation. We have outstanding capability there, not only in terms of exploration but also project delivery. So the way we think about the Gulf of Mexico is, think of it as being relatively flat at about 65,000 barrels a day over the next several years. And we are confident that we can keep it at that level really through a combination of high-value, short-cycle exploitation projects and infrastructure-led exploration.

A couple of examples of that. Obviously the Llano-5 well, which we talked about in our opening remarks, still ramping but producing 8,000 barrels of oil equivalent per day, net to us. And then in terms of ILX, the Esox-1 discovery, which we are very pleased with the outcome of the well, 191 feet of light oil-bearing high-quality Miocene reservoir, exceeding our pre-drill expectations. And the thing I would say about Esox is, this is not your typical tieback in terms of size. This is a significant discovery that's going to generate very high returns and cash flow, particularly since it's tied into that existing slot and will be brought online very quickly. So discovery to first oil is a matter of a few months.

Now the evaluation of that well, the result is still ongoing. And we intend to provide further updates including a resource estimate, production rate, et cetera early next year after we have some dynamic production data. But I really wanted to highlight Esox, because I think it's a great example of what we think we can do in the Gulf in the short term and the next well up, which is similar to Esox is the Oilfield ILX well.

Now beyond that, we will need a new hub to keep it flat or grow it. And as we have acquired those leases over the past five years that John mentioned in his opening remarks, we see some 25 leads and prospects in there. So we have got a fairly healthy inventory.

John Rielly

And you can assume it for capital planning purposes, this would be within our long term capital plan and probably have two wells a year. It might be infrastructure-led, hub class, all infrastructure-led, all hub class, but about two shots on goal a year.

Devin McDermott

Perfect. Thanks so much.

Operator

Your next question comes from the line of Roger Read with Wells Fargo.

Roger Read

Yes. Thanks. Good morning.

John Hess

Good morning.

John Rielly

Good morning.

Roger Read

I guess maybe you kind of answered one of the questions I was going to ask. If we think about CapEx next year with fewer wells this year in the Bakken and then the Esox development, do we have any thought process at this point on 2020 CapEx, whether maybe the bias is to the upside with those two factors, maybe more wells in the Bakken as a catch-up? And then anything in the Gulf?

John Rielly

No. Roger, this was all part of our plan. Now, we will give guidance for 2020 in January. But kind of I mentioned it on the last call and consistent with our Investor Day, we expect our capital and exploratory spend for 2020 to be approximately $3 billion. And it's going to be exactly what we said back in that Investor Day. We are only investing in that high-return, low-cost opportunities like Esox that you just mentioned in order to grow that free cash flow in a disciplined and reliable manner.

But our capital really through 2025, 75% of forward spend is going to be allocated to our world-class assets in Guyana and the Bakken and everything you talked about now with wells, we do expect to be more efficient in the Bakken, because as with lean, we will reduce the cost, we will get maybe more wells in 2020 verses 2019. But that's all factored into that $3 billion spend that I mentioned.

Roger Read

Okay. Great. And then the commentary about the Llano-5 well kind of ramping up and looking at Guyana starting production in December of 2019, what's the right way we should think about how that field will start up? I know you are not the operator. But is that a phased kind of say thing? We are going to be pretty careful with the wells? Or there is enough understanding that we should think about those, I think it's eight wells in total just kind of coming on in rapid succession.

John Rielly

No. I think you should assume a three to four month ramp in production. We want to get a lot of dynamic data, including some potential build-ups along the way. So this was all designed to slowly ramp the wells up and see what we have got going on the reservoir. First well is in the reservoir. That's not uncommon in deepwater to do that.

John Hess

And I think another point that needs to be made is the production ramp-up from first oil discovery to production in five years is industry-leading performance and we are very proud of the job. The joint venture is done, specifically ExxonMobil as our operator in bringing that forward and that's going to auger well for our future developments as well.

Roger Read

Great. Thank you. I will leave it there.

Operator

Your next question comes from the line of Doug Leggate, Bank of America.

Doug Leggate

Hi. Yes. Good morning. That was a good effort. Good morning everybody. I guess, John, maybe I could kick off, John or Greg, just kick off with Guyana. We have been on Ranger now for quite a while and I just want to make sure I am not reading too much into your language, John, about difference between evaluate with the intention of appraising. Can you just give us any early prognosis that you have currently? And I guess, Greg specifically, the thing I guess we are all watching here is you were planning a flow test, as I understand it. What has been the conclusion of pressure communication with the Ranger-1? Because I guess that's going to be the key thing here is whether or not we have got compartmentalization or whether we have got a viable development. Anything you can share there? And I have got a follow-up, please?

Greg Hill

Yes. Doug, what I can say is that on Ranger, drilling and evaluation are ongoing. As you recall, we have got a very extensive logging, coring program, et cetera on this well. But what I can say is that, however, based on the logs and core that is taken so far, we have seen encouraging reservoir development, confirmation of the presence of oil. So that's about all we can say at this point in time. So stay tuned. There's a lot of operations ongoing on the well.

Doug Leggate

Maybe just press you a little bit on this, Greg. Is there anything that's disappointed you on Ranger?

Greg Hill

Not to-date.

Doug Leggate

Okay. My follow-up is also Guyana-related because obviously, we are going to see a change in reporting here in terms of how the earnings and cash flow are going to flow through. I am just wondering, John Reilly, if there is any help you can give the street in terms of how this is going to play out? Because you will obviously have to report tax associated with this. But as we all know, there is no tax. So is there any way you can -- how are you going to navigate this going forward, because it is going to be such a large part of the portfolio of cash flow going forward? Because headline earnings, if I am not mistaken, are going to be kind of all over the place when this thing comes online. So any help you can offer? And I will leave it there. Thank you.

John Rielly

Sure, Doug. And really what I will do is on the January call that we gave the forecast for the year, that's when we will give some more detailed explanations on this. But you are exactly right. So the way that contract works after the cost recovery, the profit oil, they split for the government and the working interest owners. And the government out of its profit oil pays for the taxes of the working interest owners. So what that requires us to do is record a tax. So we will have a tax line associated with our Guyana production and then what you have is up above in revenue essentially additional barrels being recorded to offset that tax. So the revenue line up above will offset that tax line.

Now we will lay that out as we get through the year and I will get through the full forecast, we get Exxon's numbers and then put it together with all our numbers, I will lay out what the tax rate looks like for next year. It can be a little more specific about Guyana. But you are exactly right. Whatever taxes that show up there do not affect the bottom line cash flow from our Guyana production.

Doug Leggate

Okay. I know it's going to be complicated, but I appreciate the answers. Thanks, fellows.

Operator

Your next question comes from the line of Brian Singer, Goldman Sachs.

Brian Singer

Thank you. Good morning. Two Guyana bigger picture questions. The first is, can you broadly speak to how you see the cost structure of future projects evolving? You benefited from the dearth of international project sanctions and low oil services activity? Now oil services companies on the margin are highlighting some inflection in international activity. How do you see cost evolving for future projects, the efficiency side of the equation versus the service cost outlook?

John Rielly

If you look at the deepwater offshore service sector, it continues to be over-supplied, given the extended period of low activity. And as you mentioned, I think also the industry's focus on efficiency and simplification and standardization continues to drive unit cost down. So as a result, we expect to see minimal cost inflation on that front.

Brian Singer

Great. Thanks. And then my follow-up is on the gas condensate discoveries at Haimara and Pluma. Can you just talk about any update there on the process of determining the timing, if at all, of development? And how you would see the rates of return there relative to the other options?

Greg Hill

No. I think these reservoirs will be developed, but certainly they won't be part of the first five FPSOs that we have discussed getting us to the 750,000 barrels a day in 2025. So it will be after that. But they are still very good reservoirs, very good fluids. So they will be developed at some point.

John Hess

And our exploration and appraisal program that we are doing this year, last of which is Tripletail, which is still under evaluation, is going to give us more granularity to sort of give guidance on what the fourth and fifth ship or potentially a sixth ship in that southeastern

Turbot Hub area. So I would think next year we can give more clarity on the phasing of the fourth and fifth ship and future ships potentially thereafter.

Brian Singer

Great. Thank you.

Operator

Your next question comes from the line of Bob Brackett with Bernstein Research.

Bob Brackett

Hi. Good morning. I had a question around the commissioning of Liza Destiny. Does the Noble Bob Douglas drillship, what does it do as you get toward commissioning? Is that going to get repurposed? Will that stand by to drill further wells?

John Rielly

No. It will stay there and just finish out the drilling of both producers and injectors for the Liza Field.

Bob Brackett

So the initial ramp will be a partial set of injectors and producers and then drilling will continue during that kind of three to four month ramp?

John Rielly

Yes, it will.

Bob Brackett

Okay. That makes sense. That's all I had. Thank you.

Operator

Your next question comes from the line of Scott Gruber, Citigroup.

Scott Gruber

Yes. Good morning.

John Rielly

Good morning.

Scott Gruber

I may have missed it earlier, but any color you can provide on Bakken wells you brought online in 4Q?

John Hess

In terms of basically, the Bakken program in general continues to meet all expectations. We are on track for the 15% on average IP180 increase due to the plug and perf. We are on track for the 120,000 to 125,000 barrels of oil of IP180. So basically all on track. There was nothing remarkable necessarily about the third quarter. Now, we did have lower wells online, but they did outperform in the third quarter.

Scott Gruber

Got it. And just as you consider Bakken CapEx for next year, it sounds like this year there's a lot of general process improvement and efficiency improvement. But as you think about Bakken CapEx next year, do you anticipate incorporating service cost deflation and any color on order of magnitude?

John Rielly

So to your point, Scott, we are not seeing pressure on costs in North Dakota. And obviously, with the decline in the rig count, that helps from the cost standpoint. So at this point right now what we are more focused on is, as Greg said earlier, are just driving our lean manufacturing and continuing to drive down those well costs with our goal of getting to a six million D&C well. So when you are looking at capital next year, we will have some reductions baked in for our efficiencies for those well costs, not really for cost deflation or anything like that, just our lean manufacturing, offset by with our efficiencies, there will be more wells that gets drilled next year, just again as we get better and better drilling the plug and perf. So that's kind of how we are laying out the program for next year. And remember, as John has mentioned earlier, it's six rigs for 2020.

Scott Gruber

Got it. Appreciate the color. Thank you.

Operator

Your next question comes from the line of Jeanine Wai with Barclays.

Jeanine Wai

Hi. Good morning everyone.

John Hess

Good morning.

Jeanine Wai

Good morning. The Bakken, it's outperforming this year and you just increased the full year production guide. So I just wanted to follow-up from some of the prior questions. So could this outperformance potentially bias the plan to level load at that 200,000 barrels a day? And I think I heard you say earlier in the call that it could be higher than 200,000 barrels a day, but I think that was more related to your NGL contracts. So I guess, if you think about achieving your target, could you do it on less wells and less CapEx? Or would you rather kind of let things float and have higher production and maybe kind of higher free cash flow? And I know there's a lot of moving pieces, but kind of similar to what other people have been saying, there's been, a lot of your recent activity suggests that you have a lot of other opportunities in the portfolio. And I also think there are some infrastructure considerations on that 200,000 a day. So I wanted to check in on that to see if that's a limiting factor.

Greg Hill

Yes. Well, first of all, let me say there is no infrastructure constraints at all for us to make it to the 200,000 barrels a day. We are still on track to deliver 200,000 barrels a day in 2021, a six-rig program next year and then after that we will drop the rig count to four and as you suggested in your remarks, we will then hold that production flat for a number of years at 200,000 barrels a day. And as a result of dropping four rigs, we will be generating significant free cash flow, $800 million to $1 billion of free cash flow, once we drop the rig count to four. So it becomes a very significant cash flow generator for the company.

We do get asked why not go higher than 200,000 barrels? If you look at the infrastructure required to build for a bigger peak, it doesn't make economic sense to do that. So the right thing to do from an overall value standpoint is hold it at 200,000 barrels a day. And you are right, the POP contracts are going to ebb and flow with prices. And what I mentioned was, if NGL prices stay chronically low, we could be above 200,000 barrels a day as a result of those additional NGL volumes that we would capture.

Jeanine Wai

Okay. Great. That's really helpful. And my follow-up, again, it's on the Bakken. There's been a lot of talk about well cost reductions and performance. In terms of the base production, we have heard commentary from other operators that making sure that your base is performing well is some of the highest return on CapEx dollars you can spend. So is better performance on the PDPs a component of what's going on with the higher Bakken production?

Greg Hill

It is. I mean, the base continues to hang in there achieving or beating expectations. So we see no problems in the base production. And then, of course, you have the new wells which you are doing much better with the plug and perf design. That's how we are continuing to overachieve in the Bakken.

Jeanine Wai

Okay. Great. Thank you for taking my questions.

Greg Hill

Thank you.

Operator

Your next question comes from the line of Arun Jayaram with JPMorgan.

Arun Jayaram

Yes. Good morning. Greg, I was wondering if you could give us your thoughts on whether the oil mix in the Bakken should hold relatively flat in the fourth quarter versus the third quarter? And it sounds like you still remain comfortable in terms of the 2021 outlook of 200 MBOE per day with a low 60% oil mix. Is that correct?

Greg Hill

Yes, we do. Yes, we are very confident in that number. As I said, probably what's going to effect fourth quarter mix again is the NGL pricing. Does that go up or down? Because always, when this oil volume, always when this gas percentage fluctuates in the Bakken, it's purely due to the midstream, it's increased gas capture and it's POP contracts. That's the only thing providing really the variation. If I look at wellhead GORs, those are staying the same. So, it's purely a midstream issue and the result of how we consolidate our volumes on the balance sheet.

Arun Jayaram

Okay. But at the 165, you would assume it pretty similar to the guide, I believe?

John Rielly

Yes. And again, it all does depend on the NGL pricing as we go forward. So we have estimated NGL prices going up. So it will be a little bit less from the POP contracts. But yes, just as Greg said, we believe we can keep this low-60 with, kind of call it, a normalized NGL price. But I guess the point I think Greg was trying to point out is, is you don't need to focus really on that, right. Our oil production was up 12% quarter-on-quarter. It's going really strong. Everything is going really well in the Bakken from an execution standpoint and a reservoir standpoint. And we will get fluctuations on the gas and the NGLs just due to pricing and gas capture.

Arun Jayaram

Great. Thanks a lot. And then just my follow-up. Liza-1 is coming online a bit early. I was wondering if you could help us better understand how long the ramp would be to full productive capacity at 120. And also, John, maybe you could give us some thoughts on the operating costs. Once you do get the capacity, I think you did lease the vehicle -- the vessel, pardon me. So I was just wondering if you could give us maybe some broader thoughts on op costs as well per barrel.

Greg Hill

Yes. Again, Arun, I think you can assume a three to four month ramp on Liza-1 to get to the 120. And again, that's not uncommon for first wells in field in a deepwater reservoir, because you really want to see how those wells are performing. You will gradually increase the chokes. You may do some shut-ins to get some build-ups. You really want to understand the dynamic nature of the reservoir, again not uncommon at all in deepwater.

John Rielly

And then, Arun, as far as the cost per barrel that will produce, obviously we will get the full guidance as we go out in January. So we will obviously have the ramp, right. So you will have a higher cost per BOE as we are doing the ramp here. Then as it moves on, you are right, we have it leased here for a period of time, which is adding $3-ish per barrel on the cost. So it will be above $10 cash cost per BOE on Phase 1 here on the ramp until that FPSO, which the plan would be later on to be purchased, which would drop that $3 off the op cost and move it to the DD&A line. But this will be a good low-cost addition to our portfolio. So again, it's part of this plan. The Phase 1 will begin to take down our cash cost. Phase 2 will even do it more as we get the bigger ship and more production on at that point.

Arun Jayaram

Great. So the cash cost excluding the leasing cost would be $6 to $7 per barrel. Something like that?

John Rielly

No. It will be a little bit higher than that number. So it will be a little bit above the $10. So you can do let's just call it around $12-ish in that type of range and then you can drop just to a little bit under 10 after the FPSO is purchased. But we will give full guidance as we move into next year.

Arun Jayaram

All right. That's super helpful. Thanks.

Operator

Your next question comes from the line of Paul Cheng with Scotia Howard.

Paul Cheng

John, at some point that by 2022 when Liza-2 come on stream, I would suppose that either 2022 or 2023, you guys will be free cash flow. So on a longer term basis, do you have internally a target? What will be the right production growth rate and free cash flow yield combination that you may be targeting?

John Hess

Well, very much we laid this out in our Investor Day as our long term plan out to 2025. We are on track to execute that strategy, which is 20% cash flow from operations growth, 10% production growth out to 2025. We are on track. Our results this year underpin it. Our results next year that we forecast underpin it. And that's how we really look at any guidance we would say. We put out a long term strategy and we are executing it.

Having said that, as our cash engines continue to generate cash and then the Bakken starts becoming a major cash engine, 2021 and beyond and Guyana, 2022 and beyond, obviously we will be a significant free cash flow generator. We see that free cash flow compounding over time and the first call will be continuing to invest in our high-return projects. As John Reilly said, 75% of our CapEx in that $3 billion range goes to the Bakken and Guyana. But once we start to generate free cash flow on a recurring basis, our top priority will be starting to return capital to our shareholders on a consistent basis and the first priority there will be increasing the dividend.

Paul Cheng

I guess my question is that on the longer term basis that do you have a target? Like how much is the cash flow you will return to the shareholder or a free cash flow yield, say 6%, 5% per cycle? Any kind of target like that you have in mind?

John Hess

Because our free cash flow increases over time, I think the best way to look at it is the majority of that free cash flow will be returned as capital to shareholders. I think that's the best way to look at it.

Paul Cheng

Okay. And maybe this is for John Rielly. You have a target cash cost for the corporation will drop below $10 by 2021 versus right now it's like $12 to $13? And you just mentioned that Guyana is going to be, say, call it roughly $12. So what is the major component, the reduction going to be in order for you to drop that much?

John Rielly

Right. So I am going to call it to the two biggest drivers are, as I said, Guyana starts around $12. We will buyout that FPSO because as you know, that's part of the plan. That would happen in 2021. That will drop that cash cost by $3. They are going on Phase 1. So you are under $10 right there with Guyana. And then Bakken again driving up to 200,000 barrels a day is a big contributor there to drop our cash down to $10. Again, now with you got Esox coming in, very good. That's going to be a nice low-cost cash add to the portfolio, as Greg mentioned, Llano-5 ramping up. So it's really is a combination of our portfolio in total, but with the big drivers being Guyana and Bakken.

Paul Cheng

John, what is Bakken your target in 2021 on the cash costs?

John Rielly

I don't lay out a target, per se, by asset there. But as I have always said here, Bakken's cash cost is below our portfolio average right now. So the $12.75, it is below that and it's going to continue to drive down with this significant increase in production going to 200,000 barrels a day.

Paul Cheng

Do you have a number, what is the Hess Midstream total CapEx supply in 2020 and 2021?

John Rielly

No. We have not put those numbers out yet. Although I would tell you when in the announcement that of the midstream transaction, they did put some guidance out for 2020, but not 2021.

Paul Cheng

Okay. Final one. This is for Greg. For Esox-1, I know that you are not going to give us some additional data early next year. Do you think this is a one-well or two-well program ultimately? And also that what's the well production and oil and gas mix which we should assume?

Greg Hill

Yes. So I think, again, evaluation of the well results are still ongoing and we will give you further updates, including resource estimate and production rate probably early next year after we have some dynamic production data. We are going to start with the first well, but we see enough hydrocarbons here that it could take another well to evacuate all that we see.

Paul Cheng

Do you have a oil and gas mix?

Greg Hill

No, not yet. We will provide that. GOR is in the 2,000 to 3,000 range in the reservoirs.

Paul Cheng

All right. Thank you.

Operator

Your next question comes from the line of Jeffrey Campbell, Tuohy Brothers.

Jeffrey Campbell

Good morning and congratulations on a solid quarter.

John Hess

Thank you.

Jeffrey Campbell

I want to return back to the Esox-1 just because it sounds like it's a really big well and maybe even two wells. And then when we put that together with the flat 65,000 barrels of equivalent per day target, it sounds like, I am wondering how that fits together. I mean, will you choke back the well to stay within the 65,000? Or will we have a period where we might have some excessive production? Because if a well exceeds expectations like Esox does, wondering also is there some infrastructure limits embedded in there some place?

Greg Hill

No, there is not. I mean, I think you can assume that Gulf of Mexico will be between 65,000 and 70,000 barrels a day, really in that range. There is no infrastructure constraints. Necessarily we won't choke back wells. We will maximize production in the Gulf of Mexico.

Jeffrey Campbell

Okay. Thanks. That makes more sense. And I had one Guyana question. I have just noted with interest that a number of these upcoming exploration wells are in the Liza Phase-1 neighborhood. And bearing in mind that's the earliest project to get sanctioned. That strikes me as interesting. And I was wondering if you could add any color on what the thinking is behind the continued exploration in this area.

Greg Hill

Sure. I think I think as we have talked about before, what we are really trying to do is delineate what I call the eastern seaboard that exist between Turbot and Liza. And we see a lot of prospectivity kind of in that whole eastern margin. So really what we are trying to do is understand all the volume we have there to inform the cadence of the future vessels. So that's really the purpose, because as you get closer to Liza, probably higher value in there just because you have a higher oil content on a relative basis than as you get closer to Turbot. So our interest is really, can we delineate as much of that stuff in and around Liza for a future vessel in that area?

Jeffrey Campbell

Right. I understand. And also you want to be capital efficient as well. So thanks very much for the color.

Greg Hill

Absolutely, yes.

Operator

Your next question comes from the line of Michael Hall, Heikkinen Energy.

Michael Hall

Good morning. Thanks for the time.

John Hess

Good morning.

Michael Hall

Yes, I guess a couple of quick ones on my end. I am just curious, given all the moving pieces around the POP contracts that we saw last quarter and then again this quarter and it sounds like there's some of that, although less assumed next quarter. How much of the increase guide in the Bakken is a function of gas capture exceeding expectations and/or POP contracts as opposed to reservoir outperformance or well timing?

John Hess

As Greg mentioned earlier, about 7,000 barrels of oil equivalent per day in the third quarter was due to a combination of the increased gas capture and the POP. So you can get a feel for that number there. Now again, we are forecasting a higher NGL price, so lower POP volumes for the fourth quarter. So you would have to bake the 7,000 in overall for the year divided by four quarters. So there's an additional 2,000 barrels a day coming in through that. And then we should get picked up a little bit more gas capture in the fourth quarter as well. So nothing specific, nothing that's driving a significant increase in the production from that, but it is a factor, as Greg mentioned.

Michael Hall

Okay. Sorry to beat that dead horse. I just wanted to be clear. I appreciate it. And then I guess just if we think about 2020, clearly as you have outlined, you have got a big ramp in free cash flow coming over the next few years. But at the current strip and with all the different moving pieces, kind of how do you see the outspend shaping up next year?

John Rielly

So, as John Hess mentioned, we have this long term strategy. We laid it out at Investor Day and we continue to execute that. And to go along with the strategy, we have a strong financial position to be able to execute that. So at the end of the quarter, we have $1.9 billion of cash on hand. As we mentioned, post the closing of the midstream transaction, we also get an additional $275 million.

And just as a reminder, we still do have the $60 WTI put options in place for 95,000 barrels a day for the remainder of the year. So we are in a really good, strong financial position to fund our program. And we do realize there is an investment program here until

Phase 2 comes on.

But looking forward now, we have got production from Guyana starting up in December. So we are going to be picking up some cash flow there now in Guyana. And as you mentioned, Bakken is becoming significantly cash flow generative. And by 2021, as Greg mentioned, $800 million to $1 billion of free cash flow.

So we will use that cash flow from operations, along with the cash on the balance sheet to fund the Guyana investment program through Liza Phase 2. And when Phase 2 comes on then Guyana is generating free cash flow. So all of our assets are generating free cash flow at that point. So we feel we are in a good position to execute that.

Michael Hall

Okay. But specific to 2020, I mean just to kind of help us think about next year, any figures you can provide?

John Rielly

No, nothing specific. Obviously, commodity prices are going to move. And so as we get into January, we will give more guidance on where our production is from that standpoint. We will be using our cash flow from operations, some of the cash on the balance to fund it. But again, we feel we are in a good position to get through to Phase 2.

John Hess

And also, depending upon market conditions, we will certainly look at adding to our hedge position for 2020 that really is going to look to protecting the downside. We think that's prudent and we are just being disciplined about how we think about that.

Michael Hall

Okay. Thank you.

Operator

Your next question comes from the line of Pavel Molchanov, Raymond James.

Muhammed Ghulam

Hi guys. This is Muhammed Ghulam, on behalf of Pavel Molchanov. Thanks for taking the question.

John Hess

Thank you.

Muhammed Ghulam

First of all, do you have any update on the exploration plans for Suriname? Are you guys still planning to drill there in 2020?

John Hess

Yes. So as you recall, there's two blocks in Suriname. So let me talk about each one separately. So in Block 42, we believe there is excellent potential there and a second exploration well is currently being planned for 2021. So there will be nothing on Block 42 in 2020. Recall, Kosmos is the operator there, Hess has a 33.3% interest as does Chevron as well as Kosmos. So third, a third, a third.

On Block 59 in Suriname, recall the operator is ExxonMobil there. And what's going on there is the operator's nearing completion of a 2D seismic acquisition on the block. Following that, the data will undergo processing. Then we will shoot a smaller, more focused 3D survey in and around any prospectivity that's identified. And so the first exploration well will likely be spud in 2022 on that block. And the other partners are Hess and Statoil each, with a third again.

Muhammed Ghulam

Okay. Understood. And this one is kind of, well, I know you guys don't focus as much on this segment, but can you guys talk a bit about Libya? What's going on there and what are the next steps, if there are any?

John Hess

Yes. Look, our production continues in Libya. Obviously, there is significant civil unrest there. So giving more clarity, other than that is a hard thing to do. It's a cash generator, not that material. But at the end of the day, operations continue but it's subject to disruption based upon political unrest. And so far it's been fairly stable.

Muhammed Ghulam

Okay. Understood. That's all from me. Thanks.

Operator

Thank you very much. This concludes today's conference. Thank you for your participation. You may now disconnect. Everyone have a great day.