Co. reported 3Q16 net loss of $16.2m or $0.09 per diluted share.
CORPORATE PARTICIPANTS
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PRESENTATION
Operator

Good afternoon, ladies and gentlemen, and welcome to the Murphy Oil Corporation third-quarter 2016 earnings conference call. This call is being recorded.

I would now like to turn the call over to Kelly Whitley, Vice President, Investor Relations and Communications. Please go ahead.

Kelly Whitley  Murphy Oil Corporation - VP of IR and Communications

Good afternoon, everyone, and thank you for joining us on our call today. With me are Roger Jenkins, President and Chief Executive Officer; and John Eckart, Executive Vice President and Chief Financial Officer.

Please refer to the informational slides we have placed on the Investor Relations section of our website as you follow along with our webcast today. John will begin by providing a review of third-quarter financial results, highlighting our balance sheet and strong liquidity position; followed by Roger, with an operational update and outlook, after which questions will be taken.

Please keep in mind that some of the comments made during this call will be considered forward-looking statements, as defined in the Private Securities Litigation Reform Act of 1995. As such, no assurances can be given that these events will occur, or that projections will be attained. A variety of factors exist that may cause actual results to differ. For further discussion of risk factors, see Murphy’s 2015 annual report on Form 10-K on file with the SEC. Murphy takes no duty to publicly update or revise any forward-looking statements.
I now turn the call over to John for his comments.

**John Eckart - Murphy Oil Corporation - EVP and CFO**

Thank you, Kelly, and good afternoon to everyone on the call. Murphy's consolidated results in the third quarter of 2016 were a net loss of $16.2 million or $0.09 per diluted share. The comparative result from the same quarter in 2015 was a net loss of $1.6 billion or $9.26 per diluted share. The prior-year quarter included a pre-tax impairment charge of $2.3 billion associated with oil prices that were weakening a year ago.

Excluding the impairment in the prior year, operating results in the 2016 third quarter were improved compared to 2015, due to lower operating expenses and lower administrative expenses that more than offset lower oil and gas sales prices. Excluding discontinued operations, continuing operations had a net loss of $14.6 million in the third quarter or $0.08 per diluted share.

Adjusted earnings, which normalize our quarterly results for various items that affect comparability between periods, was a net loss of $31.7 million in the third quarter of 2016, compared to an adjusted net loss of $124.5 million a year ago. This improvement in adjusted results in the 2016 quarter was primarily attributable to lower cost for production, exploration, and administrative activities. But these were partially offset by somewhat lower oil and natural gas sales prices compared to last year.

Our third-quarter 2016 lease operating expense -- excluding Syncrude, which has been sold -- was lower by approximately $0.44 per barrel of oil equivalent compared to a year ago. We have continued to bring down our operating costs due to efficiency improvements, aggressive rebidding of services, and one-time benefits from operated and non-operated fields.

Our third-quarter 2016 average realized sales price for crude oil production was $44.64 per barrel sold, and that’s 3% lower than the same period in the prior year. Natural gas prices also were weaker in quarter three, compared to the prior year's quarter, with average North American gas price realizations of $1.96 per thousand cubic feet, a drop of $0.46 per MCF or a decline of 19%.

Realized oil indexed natural gas prices, offshore Sarawak, fell 20% to an average of $3.01 per MCF due to a decline in global crude oil prices between periods. For the remaining three months of 2016 we have WTI-based oil sales contracts that hedge 25,000 barrels per day at a WTI average fixed price of $50.67 per barrel.

Additionally, we have forward sales contracts for Canadian natural gas in the amount of 99 million cubic feet per day, at an average AECO fixed price of CAD3 per thousand cubic feet over the remainder of 2016.

For subsequent years we also have WTI contracts for 18,000 barrels per day in 2017 at an average price of $50.60 per barrel. Plus we have Canadian gas forward sales contracts covering 99 million cubic feet a day at CAD2.89 per thousand cubic feet for 2017; plus $9 million cubic feet a day at CAD2.81 for 2018 through 2020. As previously announced, in the third quarter we reduced our quarterly dividend from $0.35 per share to $0.25 per share, thereby reducing our annualized distribution by approximately $69 million per year.

At September 30, 2016, Murphy’s long-term debt amounted to $2.97 billion, representing 36.9% of total capital employed. Excluding cap leases, total debt was $2.8 billion. Net debt at the quarter-end amounted to 29.5%. Also as of quarter-end, we had total cash and invested cash of $871 million and no outstanding borrowed balance on our revolving credit facilities, providing us ample liquidity for the future.

We currently anticipate that fourth-quarter oil sales volumes will be approximately 13,000 barrels per day below our average daily production. This is due to the periodic timing of offshore oil liftings primarily for our operations in Malaysia.

The lifting schedule calls for four liftings from offshore storage facilities during the first week in January. Three of these occur in the first two days of the new year. And these account for the noted reduction in sales volume in the fourth quarter compared to production.
In August, we successfully completed a new, $1.2 billion, three-year unsecured credit facility, and also issued $550 million of eight-year notes at a coupon rate of 6.875%, with these notes maturing in 2024. Further details regarding these financial transactions may be found in our 8-K reports filed with the US Securities and Exchange Commission on August 12 and August 17.

And that concludes my comments. I'd like to now turn it back over to Roger.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Thank you, John, and good afternoon everybody, and thanks for listening to our call today. We had a solid quarter operationally across our business. The legacy offshore fields achieved just over $30 per BOE cash margin. And our onshore business achieved continued success, employing high sand concentration fracks in the Eagle Ford Shale and Tupper Montney. Furthermore, we brought on our first full well pad in our new Kaybob Duvernay asset, and are encouraged by the early results.

On the expense side, we continued lowering our cost structure. During the quarter our capital expenditures were $172 million; and year to date are $429 million, in line with our 2016 previously announced capital expenditure program of $620 million.

As John mentioned, we were also successful in obtaining our new unsecured revolver and issuing a new bond, which allows for continued flexibility, ample liquidity, and continued preservation of our balance sheet. We also adjusted our dividend while remaining top-quartile dividend yield. We believe that our current diversified oil-weighted asset mix serves as a foundation which will be able to recalibrate production, forming a new base in which to grow in the future.

Third-quarter production was just over 169,800 barrel equivalents per day, which exceeded the high end of our production guidance. The higher third-quarter production is largely attributable to better-than-planned performance and facility uptime in Sabah, Malaysia, as well as offshore Canada and the Gulf of Mexico. We expect our fourth-quarter production will be in the range of 162,000 to 164,000 barrel equivalents a day.

Our fourth-quarter guidance takes into account the following: a planned 10-day shut-in at Kikeh and Siakap North-Petai fields in Malaysia. And also in Malaysia, a planned two-day shut-in at our Sarawak oil and gas field where we changed out our field base FSO.

These two major shut-ins account for nearly 5,000 [of] equivalents of production this quarter from downtime and risked well recovery. Both of these major shut-ins have now been completed on time. And we are very pleased with the recovery, especially in the Kikeh wells in the facility following the first major shut-in in the field's nine year history. As expected, we will have some field declines, [site] impact, and small field shut-ins across our business, as well as positive production impacts in our Canadian business from quarter to quarter.

The capital program for 2016 is maintaining at $620 million, as I just said. However, there's a change in allocation as more capital is being allocated toward our Eagle Ford Shale business at the end of the year where we have placed additional wells online. The fourth-quarter production guidance is 162,000 to 164,000 due to impacts of our shut-ins, as I previously discussed. And our annual production range has been tightened to 174,000 to 175,000 equivalents per day, within guidance, post- divestitures and purchases announced earlier this year.

Our lease operating expense for the first nine months of 2016 was $7.83 per BOE, showing an 18% reduction in same period a year ago. Our quarter-three LOE was $7.65 as compared to $8.09 per BOE in quarter-three 2015. All LOE expenses noted exclude Syncrude.

We also made good progress in continuing to reduce our G&A costs over the year. Third-quarter G&A is down approximately 24% from the first quarter of 2016. More importantly, we've been able to decrease G&A by 36% from the first quarter of 2015 when we began implementing deliberate cost reduction measures.

Our current assets are more streamlined and concentrated than when we became an independent E&P company three years ago. However, remaining true to our strategy, we'll still maintain a global, diversified, oil-weighted E&P company. We have built positions from grassroots efforts in three premier North American unconventional plays that provide short-cycle growth opportunities following our low-cost entry points. We
continue to review our portfolio, and will act when opportunities present themselves. We generate free cash flow from our [long-lived] offshore conventional fields that are oil-weighted and priced to Brent.

In our offshore Malaysia business, we have produced over 39,000 barrels of liquids per day during the quarter, with natural gas production from Sarawak at 116 million a day. We successfully installed a second platform in our South Acis Field as part of the original field development plan. The resource size of the field has doubled since it came online in December of 2013.

As part of the improved oil recovery project at Kikeh, we installed a surface jet pump system which is in the first -- which is our first of three planned improved oil recovery projects for the field. Over the course of the next couple of years, we will install an electrical submersible pump, followed by a gas lift project on our Kikeh spar.

In the Gulf of Mexico and East Coast Canada, production for the third quarter was 25,000 barrel equivalents a day at 89% liquids. Subsequent to quarter-end, the Kodiak Field received gain -- Kodiak Field recently gained approval to co-mingle production between reservoirs, and expect the additional zone to be online by year-end. We have maintained our offshore capabilities and continue its focused evaluation in the Gulf of Mexico, Vulcan, and Ceduna Basins of Australia, Malaysia, and Vietnam. We believe their offshore execution ability serves as a competitive advantage and allow for assessment and entry into discovered resource opportunities that could -- that we could access through expanding alliances with other operators.

In Eagle Ford Shale, third-quarter production was just over 46,000 barrel equivalents per day comprised of 87% liquids. The 23 new wells brought online in the quarter included two Austin Chalk and four Upper Eagle Ford wells. In the fourth quarter, the Company expects to bring online 17 new wells, including to Austin Chalk wells and two Upper Eagle Ford wells. The fourth-quarter online wells is an increase of 10 from previous guidance, with the majority planned for very late in the quarter. Due to timing, they will have minimal impact on 2016 production.

We continue making strides into accretion drilling and completion costs as we averaged $4.3 million per well across the entire play, which is 18% below the $5.3 million per well in the third quarter of 2015. We drilled pacesetter wells in both our Karnes and Catarina areas. The spud to TD for Karnes is 7.9 days versus 13 in 2015, a 39% reduction; and Catarina was 7.3 versus 9.3 in 2015, a 21% reduction.

We still have significant running room ahead for us there, with over 2,000 potential Eagle Ford Shale locations. Our reserves are oil-weighted at roughly 9%. This asset is very meaningful to Murphy’s future reserves, production, and cash flow.

We have continued to employ high sand concentration fracks over this last quarter which have continued to yield higher IP rates and enhance type curves. In our Karnes area, recent IP rates have been up to 50% higher. We see one-year cumulative oil rates over 35% higher than our older vintage wells.

In our Catarina area, recent IP 30 rates have exceeded the type curves by up to 17%. We’re now forecasting increased EURs of high sand concentration fracs, and are in the evaluation phase as to the EUR increases.

In the quarter, we completed our second Austin Chalk well in the Karnes area to test the boundaries of the Austin Chalk [resource]. And the first Austin Chalk well is completing what I describe as a wildcat test in our Catarina areas. Both wells are flowing and still in the cleanup phase, and we will bring more information on our fourth-quarter call.

In Canada, our Tupper Montney asset produced about 119 million a day for the third quarter. We are pleased with the performance of our recent extended lateral high sand concentration wells that were brought online in the second quarter. The results are compelling and are trending toward our 10 to 14 Bcf type curve. These results, coupled with our continued lower drilling and completion costs, continue to support our ongoing field development plan. We have reduced our drilling days and costs in the Montney by approximately 30% since 2014.

As John spoke earlier, we have taken on additional hedges for 2017 through 2020 as part of our strategy to lock in the terms, given our low breakeven and PV at natural gas prices of CAD2.10.
In the Kaybob Duvernay and Placid Montney, production is over 3,100 equivalents for the quarter at 44% liquids. In Kaybob Duvernay, our four-well pad was brought online in the gas condensate area during the quarter, and was previously drilled by our partner.

Two of these wells have an average effective lateral length of 4,150 feet, and the other two have an effective lateral length of 2,665 feet. While these lateral lengths are well below our future development plan, the pad is flowing in excess of 2,100 barrel equivalents per day with nearly 70% liquids after flowing for only 40 days utilizing our conservative choke management approach. Initial results look encouraging, as the wells are trending along type curve an accounting to effective lateral lengths.

With the two varying exposed stimulated horizontal sections, we can tie lateral lengths to flow performance. We've been very impressed with the condensate to gas ratio, as the wells are maintaining a stabilized CGR of near 500, which is higher than our originally assumed number.

We further expect that as we move up of the learning curve in this play, we will continue to refine completion techniques based on the first operated production flowbacks. We'll be drilling our first operated new two-well pad in the fourth quarter in the gas condensate region, with production online in first quarter of next year. Drilling and completion costs for this two-well pad are expected to be $5.6 million per well.

The average lateral length for these wells is near 4,500 feet. They were previously permitted by our partner and are limited by lease boundary shape. We will be implementing a similar completion zone [as we have] done in Eagle Ford Shale, which includes pumping fracks of 2,000 pounds per foot.

Moving forward, we’re working a plan in the Kaybob area to increase lateral lengths over 9,000 feet, and continue to pump fracks at 2,000 pounds per foot, and tweak spacing of stages, et cetera, which will lead to higher rates in this area of the play and offer upside for Murphy. Over time, we’ve been very successful at lowering our drilling and completion costs in the Eagle Ford and Montney, and expect we will do the same in the Duvernay play over time.

In our non-operated Placid Montney, four wells were drilled, and eight more are planned for this winter. Four of these wells will be completed late in the year, and the remainder online in 2017.

As we close our call today, here’s some takeaways. We’re pleased with our overall results this year. As we move forward, we’ll focus on our continuing well efficiencies, improving cost structure, and preserving our balance sheet. Our high-cash-margin offshore assets provide the cash flow required to ramp up on new unconventional assets in the Duvernay, as well as unlocking value on the Eagle Ford Shale and Montney businesses.

As you can appreciate, oil and gas prices have been very volatile over the past two years. However, we believe prices are stabilizing. We're in the middle of our internal budgeting process, with the goal of maintaining cash flow neutrality, including our dividend. We have many great opportunities across our assets, as we do every year; and we will be releasing our 2017 guidance and CapEx in late January. I look forward to discussing those with you at that time.

This concludes our opening remarks. I’d like to open it up for your usual questions and we’ll go from there. Thanks.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions). Paul Cheng, Barclays.

Paul Cheng - Barclays Capital - Analyst

In Canada, for Duvernay and Montney, is your activity level that we should assume next year is primary in the sand project, testing out in the placing, or that you are going to increase the commercial development also? How should we (multiple speakers)?
Roger Jenkins - Murphy Oil Corporation - President and CEO

We are trying to -- we obviously have a lot of options for both, or all three of those concepts, Paul. We're in the middle of determining that now. I would like to have, at this time, probably a focus on the condensate region; but test black oil and further areas of gas condensate, as well, or volatile oil areas like Eagle Ford Shale and one of the reasons we went into the plays. We feel we have all three there: high-rate, high EUR, gas condensate, very successful volatile oil areas. And very, very high issue for Murphy as to return in the black oil, should that prove successful, which we applied no value to that acreage when we purchased this asset.

So, working on that. It's a tough call. But we're going to be spending capital in all three of those areas to both delineate and build up production primarily for 2018 out of that asset, Paul.

Paul Cheng - Barclays Capital - Analyst

And any rough preliminary estimate that how many rig you end up that are going to run up there for 2017? And what may determine then -- that whether it is going to be higher or lower subsequently?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Oh, we're going to be in the one- to two-rig range in there, for sure. And we also have Montney, where we're going to spend some level of capital maintaining that production. It's going very well economically for us, too, some of the higher economics in the Company. And we're going to be in there all year, drilling with a rig to two rigs at this time for sure, Paul.

Paul Cheng - Barclays Capital - Analyst

But what may trickle you to have a higher number of rigs, then? And is it just (multiple speakers)?

Roger Jenkins - Murphy Oil Corporation - President and CEO

As we look at our budget, we will be allocating capital across the different parts of our North America onshore business. And that will be one of those questions that we have when we're in the middle of doing right now, Paul.

Paul Cheng - Barclays Capital - Analyst

Well, maybe can I ask it in a different way? Let's say --.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Paul, are you going to ask me ten questions until you get to the budget?

Paul Cheng - Barclays Capital - Analyst

No, no, no. I'm just trying to understand the [fourth] process. That when you decide to increase your CapEx, what would be the first area you are going to allocate the CapEx to? Is it going to be Eagle Ford, or it's going to be up in Canada?
Roger Jenkins - Murphy Oil Corporation - President and CEO

That’s a hard call, at this time. I think we need to -- we’re just establishing our field development plan in our new asset. We just really started operating the field in August up there. And we have a permitting process in Canada that’s longer than in Eagle Ford. And we are in the middle of doing that, and setting up pads with this long lateral length, and planning that. We’re going to step into longer lateral lengths earlier there than we did in Eagle Ford, for sure.

Very short notice; you would probably go to Eagle Ford over that. But it will depend on the outcomes. This well -- we are very happy about the results, very happy about what we planned and what we’re seeing, very happy about the CGR. Really nice wells to drill coming up this quarter that are next to some very high performing wells, some of the better performing wells from our partner. And all that will take into account some flexibility as to our field development plan, the pad layouts that we have, the areas in which we receive permits. Comparing that back to Eagle Ford [then]. I’m glad to have the ability to move between them pretty easily, Paul.

Paul Cheng - Barclays Capital - Analyst

All right. Thank you.

Operator

(Operator Instructions). Roger Read, Wells Fargo. You may have us on mute. We aren’t able to hear you.

Kyle Rhodes, RBC.

Kyle Rhodes - RBC Capital Markets - Analyst

Roger, you just touched on my first question; but can you remind us of where you are in the permitting process in terms of getting those longer lateral wells on the schedule for 2017? Did you have to re-permit all of Athabasca’s shorter lateral wells? Where are we in that process?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We’re just started in August and September. This is a unique area in which there are no drilled uncompleted inventory of kind in the whole entire play. We just completed the only four uncompleted wells we had, and they had two permits in which we’re fixing to drill. And we are starting over with the kind of wells we want, various options of shorter and longer lateral design, across black oil, volatile oil, and condensate. And we’re not going to be held back by that. We have a plan, and are out executing optionality around that as we speak.

Kyle Rhodes - RBC Capital Markets - Analyst

Got it. So in terms of timing on the next spud behind the two-well, is that something we should expect, early 2017?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Yes.

Kyle Rhodes - RBC Capital Markets - Analyst

Okay, great (multiple speakers).
Roger Jenkins - Murphy Oil Corporation - President and CEO

But we’re going to be drilling them starting in November. We have drill two wells and complete them, and flow them back. And we are very conservative on our choking of these wells. But we may have it for our first call. It will be very close.

Kyle Rhodes - RBC Capital Markets - Analyst

Great. Appreciate that. And I understand that you guys don’t want to get into the budget too much here. But any kind of high-level color you can give us on capital mix, and how you guys are thinking about capital allocation for 2016? And then maybe which regions we would expect to see growth from, 4Q 2016 to 4Q 2017?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Really prefer not to get into all that now. I have a lot of optionality around that. Real pleased about the capital allocation alternatives I have from a DPI perspective. And we’re going to be spending a lot of money in our onshore business. And we also have some very nice high-return projects in our offshore business, such as the gas lift project in Malaysia. It’s probably some of the highest rate of return we’ve seen in a while. And various types of spend like that; and not massive offshore spend, but we’re going to have some offshore spend; and we’re in the middle of getting that all allocated up right now.

Kyle Rhodes - RBC Capital Markets - Analyst

Great. And then just one final housekeeping one for me. What’s the expected net impact to Murphy from the co-mingling of the added zone at Kodiak?

John Eckart - Murphy Oil Corporation - EVP and CFO

It’s probably a couple thousand barrels a day.

Kyle Rhodes - RBC Capital Markets - Analyst

Great. I appreciate it, guys.

Operator

Peter Kissel, Scotia Howard Weil.

Peter Kissel - Scotia Howard Weil - Analyst

A quick question on the Eagle Ford. You’ve been doing a lot there. And I’m just curious to see if you have an update on the inventory that you’ve put out before. Roger, I think you mentioned 2,000 roughly locations. But with some of the bigger completions, does that take down some of the traditional inventory that you have highlighted? On the flipside, does the Austin Chalk or the Upper Eagle Ford maybe increase it?
Roger Jenkins - Murphy Oil Corporation - President and CEO

We have all that in those numbers -- some 2,800 locations, and that's a lot of inventory, I feel, for our size company. And that latest location count through various spacings would account for these lateral lengths. We're expanding our lateral lengths in Catarina primarily. Still have a lot of 5,000, 5,500 wells in Karnes, because of the shape and the prior wells drilled there. So, a big expansion of longer laterals are primarily located in Catarina. And that well count that we've been talking about would have all that in it. And our Upper Eagle Ford locations are very similar to what we've broke out in a prior slide deck. And those would be maintained at this time.

Peter Kissel - Scotia Howard Weil - Analyst

Got you, okay. And then one other thing you have mentioned several times in the prepared remarks, and one of the more impressive things, is some of the cost reductions that you have seen. Have we reached the end of the cost reductions here, and is it more of an efficiency gain game? Or how are you thinking about that here?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, we've been really very proud of our efforts of my team here on this. And it's a misnomer that it's all about bidding. It's really 75% efficiency, and a lot of work around chemical costs globally, and exact amount of chemicals and doing a lot of research around that.

So, our savings is 75% efficiency, and 25% re-bidding of services. What we're trying to do in OpEx -- and I think there's not massive improvement left for us. But in our big businesses like Eagle Ford, it was up a little bit this quarter due to some timing of some artificial lift and some workovers of rods and things of that nature.

But what our goal here is to be a $7.50 player through 2018 in this new business, Eagle Ford Shale, that we've built in the last five years. So our goal is to get there by the end of 2018. I believe we will be. In our offshore business, with these shut-ins will go up next quarter as well. But overall I'm pleased with the recovery of the Kikeh field. Very pleased, in fact, because that was quite risky for us to shut that big field in like that. And, in general, happy there.

And then really what we want to be is a $9 BOE total company, long-term. And I think that would be a very successful company to be with our higher-cash-margin, oil-weighted portfolio we have. And that's where we are wanting to be. And the Eagle Ford at $7.50, and the Company at $9, and that's not off of where we are now. So I see that as a good plan, and where we're going to be.

Peter Kissel - Scotia Howard Weil - Analyst

Great. Thanks, Roger. That's helpful. One quick last one for me. In terms of the portfolio, obviously it's been a pretty active year in terms of acquisitions and divestitures. But how are you thinking about it going forward?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We don't really have a lot of non-core things. Our heavy oil would stick out as my goal of being an unconventional-only North American player. And that would be the only thing that I consider not on that path at this time.

Peter Kissel - Scotia Howard Weil - Analyst

What about acquisitions, Roger?
Roger Jenkins - Murphy Oil Corporation - President and CEO

We are very active looking at various things in both offshore and onshore. I think one of our advantages, we have the teams and ability to look at both. And we very, very much know the North American onshore space. And also looking globally, as well, in the offshore for certain areas where we could really believe that there will be a lack of competition for fields that are discovered in certain countries. And we have the ability to execute and evaluate those, and real pleased with what I'm seeing and hearing in that situation.

Peter Kissel - Scotia Howard Weil - Analyst

Got you. Thanks again, Roger.

Operator

Pavel Molchanov, Raymond James.

Pavel Molchanov - Raymond James & Associates, Inc. - Analyst

About a year ago, you farmed into the new Vietnam block. Can you confirm that you have not had any activity there to date? And if not, any sense of what the plans might be for 2017?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We've been working through a partnering arrangement there, and a field development plan process that's a little slower than we're used to in Malaysia. But we're very, very, very senior at working in that region, and understand what we're doing there.

We would see activity in there next year and the drilling of a well, highly likely at this time. And we're very happy about that project, and very happy about the running room in that block, and continuing to progress that just a little slower pace than we had desired. But it fit into our capital reductions this year that we had anyway.

So looking to get back in there next year, going with that; and the field development plan process and the resource remains positive, in my view, very positive.

Pavel Molchanov - Raymond James & Associates, Inc. - Analyst

And if I can also ask about the Kaybob. It's obviously not as much of a household name as the Eagle Ford for most operators. Have the results you've gotten to date, over the last six months or so, have they met your original expectations when you did that asset swap?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, we only brought on four wells. And the other wells were drilled by the prior operator, quite overflowed for well over a year. When we bought the play, we had EUR assumptions for volatile oil, gas condensate, and black oil; black oil which we put very little value, if any. And we've, since that time, broken this field into many EUR curves, which would be normal in shale operations, which we are very experienced at doing.

And if you were to tie this up with the lateral length of the kind of wells we want to drill and the -- what we're seeing from a linear concept between -- it is an advantage to have a short and longer well; we can see how they flow, side-by-side, actually. And we're real happy about the EURs you
assumed, real happy about what we assumed when we purchased it. And this is going to be about lowering drilling costs. And we're going to lower drilling cost just like we did in all our other plays, and will add a lot of value here for the Company.

Pavel Molchanov - Raymond James & Associates, Inc. - Analyst
All right. Appreciate it.

Operator
Edward Westlake, Credit Suisse.

Edward Westlake - Credit Suisse - Analyst
Just on the Montney, obviously well done on the completions. You've got a massive resource base there. What are the steps you have to take to get that gas production up and out to market?

Roger Jenkins - Murphy Oil Corporation - President and CEO
Well, we have TCPL agreements that can get us out of there at 200 million a day for some time. The plants are flowing that on a net basis, when I say the 200 million. Naturally it's a capital allocation decision probably coming up late next year into early next year, if we want to expand in that play and work with midstream partners to build additional gas plants there. And we are now seeing very, very high EURs; very, very good economic returns. And we have that on our long-range plan list of positive capital allocation alternatives in the Company.

And we've also been very active at hedging. Probably Murphy has never been a big hedging outfit. But up there, we are getting into the 50% of production range to protect these returns. Real happy about our operations, the uptime, the operating expenses, the EUR per well. And all those things are going well, and we lock in anything north of $2.10. We're doing very well. And the DPI of these wells are very strong.

So, we have set up and covered here to be able to handle these lower gas prices and are profiting from that, delivering free cash flow in that business every year. And we'll continue to do so. And we have a big decision to make if we want to expand it, because we certainly have the subsurface ability to do so.

Edward Westlake - Credit Suisse - Analyst
And just to make sure I heard you correctly, that decision will be late 2017; so CapEx, so maybe 2019 (multiple speakers)?

Roger Jenkins - Murphy Oil Corporation - President and CEO
No, it won't be a -- it will be an issue around working with midstream partners. We are very happy with the midstream partner that we have. And it will be about drilling wells for that person to execute that buildout, if you will. It will be a decision. It won't be a capital constraint for those periods of time, if you catch my drift. They have to build a plant. We have to then drill the wells to meet the plant schedule, the permitting, and all those various things, if we want to do that.
Edward Westlake - Credit Suisse - Analyst

Yes, so we’ll just watch the infrastructure guys there. And then on the Duvernay, obviously it’s still early days. Given your experience, when do you think you’ll have drilled enough wells to really get to the point where you can move to a development plan? It feels like, again, that’s not next year; it’s probably into 2018.

Roger Jenkins - Murphy Oil Corporation - President and CEO

We have a field development plan now. It’s just a matter of deciding, as to Paul’s question, where we allocate the capital. We do not see any reason why we’re not going to be successful and work here, because we have so much acreage and so much optionality around different acreage that we own. It’s just a matter of delineating and getting going.

I consider us in field development plan mode every day there. And there will be certain areas that would improve or go further down the list, and we’ll -- through next year, or a year from now, we will be setting up for what we’re going to do in 2018.

The goal here is to replace to production the higher margin that we sold in Syncrude. And I see us well on that ability, and happy with the costs, operating expenses and all that. And real pleased about how that’s going. We’re hitting this ground running pretty hard. With our experiences in Eagle Ford, in Montney, and what we learned about going to higher sand and going to longer laterals early is really helping us here relocate a lot of staff around building up that ability; doing things quicker, and while still maintaining some of the Murphy conservatism that we have.

Like in flowback; you know, these wells are flowing only on 14, 16 choke. So, real happy about how that’s going right now. Thank you, Ed.

Operator

Roger Read, Wells Fargo.

Roger Read - Wells Fargo Securities, LLC - Analyst

Sorry about that earlier, but it’s been one of those kind of days. Eagle Ford Shale and CapEx: I want to understand in general -- and I know you are hesitant to give us a specific CapEx number for 2017. But as you think about whatever the right oil price may be -- use the strip as an example today -- and the cash flow you would generate, should we presume you are aiming for cash flow neutrality after CapEx and dividends? Is there a desire to build a cash balance? I know not necessarily a necessity, but maybe a preference, as we try to think about it.

And then as you think about an incremental dollar -- obviously a lot of discussion here about Canada. But where does the Eagle Ford Shale fit in in all that, given you’ve talked fairly optimistic scenarios there in terms of well costs and the Austin Chalk as well?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We do desire cash flow neutrality with our dividend as a corporation. And working around that right now is an overall basis for us. In Eagle Ford, CapEx is going to going up. Production will not continue to decline. It will be flattened or slightly growing is the current plan. Real happy about that. It’s the best -- these downspaced wells in Catarina are some of the top in the Company. And it’s a matter of capital allocation around -- we could put all the capital in there if we would like.

But our Duvernay Shale, we have to delineate this black oil, volatile oil, condensate. And we have to also prove that we can lower costs. And the only way to prove you can lower costs is to drill some pads. You have to drill those pads aggressively with longer laterals.

So it’s going to be one of those kind of calls, Roger. [We make] production what you want it to be, if you put all the capital in the best IP type wells, which lead to the better returns, mostly -- usually.
But we have a new unconventional shale business that has zero DUCs in it. So that’s not that common. And we have that as a capital allocation decision, but we absolutely have to get in there and drill some wells. And our Eagle Ford will be there for us, and it’s doing really, really well.

**Roger Read** - Wells Fargo Securities, LLC - Analyst

And along those lines -- and I apologize again, because I have been on and off the call. But have you given a CapEx number for Canada for the Duvernay, or at least some broad guidance on what we should think about for next year?

**Roger Jenkins** - Murphy Oil Corporation - President and CEO

No, I have not.

**Roger Read** - Wells Fargo Securities, LLC - Analyst

Got to wait till January?

**Roger Jenkins** - Murphy Oil Corporation - President and CEO

There’s nothing wrong with waiting till January. It's just 90-something days away, Roger.

**Roger Read** - Wells Fargo Securities, LLC - Analyst

(laughter) You're asking Wall Street for patience, Roger. That’s always a challenge.

**Roger Jenkins** - Murphy Oil Corporation - President and CEO

Well, you know. It will be what it will be.

**Roger Read** - Wells Fargo Securities, LLC - Analyst

All right. Appreciate your time. Thank you.

**Operator**

Arun Jayaram, JPMorgan.

**Arun Jayaram** - JPMorgan - Analyst

My first question, Roger, is just on the income statement. You had a pretty meaningful decline in G&A: sequentially almost it is $12 million. Anything unusual in that number? Or is that a good run rate, going forward? Because you were at $74 million in the first quarter, and you’re at $56 million this quarter.
Roger Jenkins - Murphy Oil Corporation - President and CEO

It’s a good run rate for us. We’ve had unfortunately some reductions in staff earlier in the year. And now those costs, special items for that, are behind us. We are doing very well on not just employees, but lowering G&A and G&A focus on our Company in general. And I think that’s a good run rate number, what we’re hoping to have next year or better. And that’s where we’re headed there; greatly improved in that situation.

Arun Jayaram - JPMorgan - Analyst

So that’s a permanent reduction? Okay, great. My second question just regarding the high density completions in the Eagle Ford. On the charts on page 12, it looks like you guys have been doing this for well over a year. I just wanted to -- if you could note is -- have the bulk of the completions over the past year been using those high density completions? Or are you shifting -- has it been more of a mix? And then going forward, you could benefit from a well productivity standpoint?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We have only had probably four wells flow for over a year, and the others have flowed about 90 days. And are now moving to it almost exclusively in Karnes and Catarina. And Tilden as well, which is a big, large acreage area for us. Of course the technology works there as well. So, we do not have still massive amounts of data on that. But we’re very happy with what we’re doing, and we know it’s working in the industry here. And we show a long-term example, but that doesn’t mean I have dozens of wells at that. But I’m real happy about how this is going. This Catarina area is very prolific for us; very low cost; and doing very, very well, too.

Arun Jayaram - JPMorgan - Analyst

Okay. And my final question is just thinking about A&D activity. We have seen -- primarily a lot of the transactions have been in the Permian, but we have seen some things in the Gulf of Mexico, as well as the Eagle Ford. How are you thinking about A&D activity? Could Brazil be an opportunity? Perhaps just give us you where you are seeing some opportunities for perhaps Murphy to participate in.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, in all three of those places, for sure. We see one in Eagle Ford this week, and some acreage surrounding our Catarina area north and south there. Of course, an inch is as good as a mile in some of these plays sometimes. And the offshore business, you know we are an offshore company from the old days, and we look at opportunities there. And in Brazil, we are very excited about Brazil. We see them with needing companies like Murphy to develop fields that they have discovered prior, and these fields would have some level of delineation to them. There will be a market in there for super majors after the very, very large fields.

We will be going after the smaller ones and things in which we operate. We do operate smaller FPSOs, TLPs, you name it. We operate everything globally, and have been, and can do this very well. We’re very, very good at it. And we’re going to be looking at those opportunities down there real hard.

Arun Jayaram - JPMorgan - Analyst

Okay. Thank you, sir.

Operator

Sean Sneeden, Oppenheimer.
John, maybe for you: LOEs were down pretty nicely in the quarter. Could you just bridge us from the roughly $8.36 per BOE in Q2 to the $7.65 in Q3?

So, Sean, we had -- and particularly in our operations in Malaysia, we had some one-off items this quarter with [see cap]. So our operator had been given us a number of projections of what our LOE was to be. And after a period of time, it became obvious that they were not going to run that high, so we adjusted for that. And so there's a little bit of benefit in there associated with that. So, it's just a truing-up case, if you will, that benefits the third quarter.

Okay. And so, would that imply that Q2 would be a more appropriate run rate to think about going forward, everything else being equal?

I think it will be difficult to quite be as low as it has been; or it was in third quarter, probably a better way to say it. Those third-quarter benefits probably won't repeat.

Okay, that's helpful.

But let me have a comment on that. Our Kikeh recovery, our risk recovery, this Kikeh downtime is a big deal for us. And this is a real, live, in our face right here, this is recovery. So this is taking place as we speak, and it's going very well. And having those wells recover back to their rate and losing that risk in the guidance can be very instrumental in this OpEx over there. And that's a big part of that business over there is to get this field back going after not shutting in for a long time; nine years; ever. We pride ourselves in less turnarounds than anyone else in the industry. This is the highest performing FPSO in the world, and we have that thing back on now. And that's going to impact us, and it's very positive for us.

That makes sense, and that's helpful. The second question is how do you guys weigh taking out your 2017 bonds versus maybe using the, let's call it, $800 million of cash on the balance sheet for D&C or bolt-on deals?

Yes Sean, we evaluate that continually. And we kind of like it both ways. We like having the cash; we also like to take it out. So it's one of those that we're studying. We can, at times, probably make some economic sense. It makes some economic sense to take a piece of that stuff out early. But we're just evaluating and haven't made a call on it yet. We've had other priorities to worry with. But we do analyze it routinely. And there are opportunities out there to do so, at least in the small chunks, if we so chose to do so. We have not considered yet a full takeout opportunity.
Okay, that's helpful. And then are you guys generally comfortable with those bonds becoming a current liability in December, just given the level of cash you have?

Roger Jenkins - Murphy Oil Corporation - President and CEO
Yes.

John Eckart - Murphy Oil Corporation - EVP and CFO
Yes, I am.

Okay. That's helpful. Thank you very much.

Ryan Todd, Deutsche Bank.

Maybe I'll follow up on some previous comments from earlier this year. I think you've spoken in the past about -- at least maybe into $50 oil and about 2017 volumes holding flat at 4Q 2016 levels, if I've got that roughly right. Maybe this is quibbling over details.

When I think about where volumes go from here, is that inclusive of the shut-in volumes in Malaysia, because they're a little bit lower than we would have expected in Q4? Is that based on what a normalized run rate would be, assuming Kikeh is back up and running? And is it still realistic to think -- is that still an accurate way to think about your volumes of stabilizing at these levels and then looking to grow from there?

We have all the optionality around doing what we want to do on that with our capital. Like I spoke to earlier in the call, we have to consider big unconventional asset that's new that we're happy about, that we need to work on as well, that will need a ramp up. And I think that third to fourth quarter in there is a good description of the goal there. And in the capital allocation options around that versus other things will be the focus of our budgeting, which we are working on now.

So you're right; the fourth quarter is pulled back by a one-off shut-in here that's been planned for well over a year, and has done very well with the recovery of that. So that would be the way I'd describe it at this time.

Okay. And are we likely to see any exploration -- any offshore exploration in 2017?
Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, it gets back to that same old question about the production and the capital. And of course, we have opportunities there in many of them. I do not see it as a big capital allocation. And it is, again, one of the options I have on the table at this time that we’re really working on, as to capital allocation between Duvernay; our Eagle Ford Shale; offshore projects that have very, very high rates of return on existing facilities, and concepts of that in our business as well.

Ryan Todd - Deutsche Bank - Analyst

Okay (multiple speakers).

Roger Jenkins - Murphy Oil Corporation - President and CEO

That’s why it takes till January, Ryan.

Ryan Todd - Deutsche Bank - Analyst

All right. I’ll leave it there, Roger. Thanks.

Operator

Brian Singer, Goldman Sachs.

Brian Singer - Goldman Sachs - Analyst

A couple questions on the Eagle Ford. The first is can you talk about the trajectory as you begin to ramp or get more wells online in the Eagle Ford, of what the impact would be to how we should look at the oil mix in the Eagle Ford? And then I’ve got another follow-up after that.

Roger Jenkins - Murphy Oil Corporation - President and CEO

We’re looking now at that being slightly higher than it was this year than flat. We want to have a flat production business there long-term that delivers free cash. And we have model to do so, and real happy to do so.

As to the oil amount, you really ask a lot of questions on that issue. We are an oil-weighted company in there and very, very high oil-weighted. And in our comparisons from quarter to quarter, you have many, many issues going on there. You have some old historic wells in which they would have some level of GOR creep, I guess, to them.

But primarily what this is about is drilling our core acreage. And when we only drill 50 wells and we used to drill 150, we are drilling them near our facilities and capturing more gas than we used to capture. And we used to drill more on the peripheral parts of the field with multiple rigs running, and we were flaring some of that gas and we were not gathering all that gas. We’re gathering more gas and we’ve cut back on a lot of new wells that we used to drill. And a 1% or 2% change off of that is not a long-term factor. And we’re very comfortable with the 89% type liquids in that business in which we also enjoy very little NGLs in our business.

And our long-range plan, and all of our PVT, and all the work from our 800 wells are not leading to a collapse in our liquid volumes in the Eagle Ford Shale at all.
Brian Singer - Goldman Sachs - Analyst

Great. Thank you. And then the follow-up is just on the capital cost side. Specifically as you are talking to some of the services companies about getting more aggressive from a completions perspective, at a minimum can you talk about the feedback that you are hearing, and your expectations for cost trends as you go into 2017?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, we're real happy about where that's going. Keep in mind that in a business like Eagle Ford Shale, before you get involved with the service companies, is that we have -- we're looking at 7.9 days to drill a Karnes well now. It used to be 13 in 2015. A Catarina well used to be 9.3 and now it's 7.3, so we have lowered drilling per field. In East Tilden, 60%; Catarina, 75%; Tilden, 47%; Karnes, 85%. That's just from the last five years. And in the last two, incredible continuation of efficiency here on the wells.

From a service perspective, we have a frac crew lined up for the entire year, and are out bidding for spot crews as we need. They are about 50% less than they were in 2014 to accomplish these services. We feel firm about the contract that we have to deliver our fracturing services in Eagle Ford. We have a rig there that doesn't expire for some time, into late next year. And we are seeing spot rigs in there for $15,000 a day to add additional rig. And then we'll probably go to a couple rigs in that play.

And I'm happy with the procurement and the bidding structure that we have to go through 2017 and able to maintain our costs. And that's not one of our main concerns in our budgeting at this time.

Brian Singer - Goldman Sachs - Analyst

That's great. Thank you for the color.

Operator


Paul Sankey - Wolfe Research - Analyst

I had a specific and a general. The specific: you seem to be a little bit coy about the Duvernay. Can you just talk a little bit more about — I know you said it's in line with your expectations. But we see this as a differentiated area for you. Could you just remind us why you are differentiated there and what the outlook is for activity? I know that you have partly addressed some of these questions earlier in the call, but if you could just be again more specific on Duvernay, that would be great. Thanks.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Oh, I'm not coy about it at all. I'm real happy with the EUR curves we're seeing, well like — there are many, many wells in the Eagle Ford Shale or across the plays in North America that deliver around 450,000 to 500,000 barrels. And we're looking very positive toward doing that and tying up a very one barrel per feet of horizontal length there. So it's going well, and those are the type of EURs we anticipated coming out of the well; only flowed the well for 40 days; still have the well on a very low choke.

So I'm happy about how much it cost to frac it. I'm happy about where we're headed to drill the next two wells, and how that will incredibly add value to us. And the CGR is a big deal. 100 units in that game is big, and we have drawn some lines as to what we thought CGR would be, and it's better. And we just have limited data. It only flowed for 40 days. But from what I'm seeing, I'm real happy about how we evaluated it, and very happy about how the well is performing. I just have four wells. In the Eagle Ford, I have 798 or something like that.
From a differentiated perspective, we purchased the asset for a known dollar per foot that's quite low. Massive (technical difficulty)

Paul Sankey - Wolfe Research - Analyst
No.

Roger Jenkins - Murphy Oil Corporation - President and CEO
What's that?

Paul Sankey - Wolfe Research - Analyst
Sorry, I thought my phone had hung up. Excuse me.

Roger Jenkins - Murphy Oil Corporation - President and CEO
Don't start hollering at me, Paul. I'm barely making (multiple speakers).

Paul Sankey - Wolfe Research - Analyst
I beg your pardon, Roger. We fell off the call earlier, and I thought it was you that hung up.

Roger Jenkins - Murphy Oil Corporation - President and CEO
No. So, I feel we're very differentiated there, because we're in a very low entry point across incredible amount of acreage. We can delineate black oil, volatile oil, and we can always go into the gas condensate area, which has been de-risked by peers, and doing very well there. And I see this as a very unique opportunity for us.

But just like everything else, we have to get in there, get capital in there. And if the EURs are the same -- we have some very prolific EURs coming, on next well, for example; higher than we have in Eagle Ford. So the EUR, from a BOE perspective, I'm very happy about.

And we just got to get the drilling costs lower and I'm really excited about being able to do it, because I've done it everywhere else we've been. And have the same people supervising it, same team, and we're going to do it.

Paul Sankey - Wolfe Research - Analyst
Thanks for that complete answer, Roger, and apologies again. I thought my phone had hung up. That was the -- no. The other question I had was you mentioned about essentially something along the lines of breakeven, without being specific. I wondered where do you consider now the oil price breakeven for you guys to be, I guess ex-growth? And what are your aspirations for what would be an appropriate or attractive level of growth for you to achieve beyond that? And at what price do you think you could achieve that? Thanks.

Roger Jenkins - Murphy Oil Corporation - President and CEO
I'm not sure on the breakeven question, as that would change my budget as to what I'd do. I don't think of it that way. I think of our Company as a $50 type -- or, let's just say, the strip for 2017 and a $60 company going forward. $60 flat that would be escalated, like many peers use that type
of number. And we desire to be a single-digit production growth company; feel we can do that with the assets we have for certainty, and deliver free cash.

And that’s the long range plan that I have in front of me, and that’s what we're working to obtain. And feel good about that. Like everyone else, I would need oil to go up from where it is today. And then when it does, Murphy will be very well positioned with the assets that we have.

Paul Sankey - Wolfe Research - Analyst

Right. Apart from the clients abusing me for the no, there's one asking a specific question about where your maintenance capital would be. Do you think -- would it be around flat for 2017 and 2018, or is that number moving?

Roger Jenkins - Murphy Oil Corporation - President and CEO

No. We've said 850 to 950 in the past. And the issue will be the new unconventional game we are in with no DUCs there, which is at ground zero, which is not easy to do inside that. But we have an ability to move capital around for different production areas, back to Ron's question a few minutes ago. And that would be about the same as in the past. And it gets back to working on our budget and what we want to do about the new unconventional asset and high rate of return specific projects in the offshore, which are not enormous capital. But every capital amount is precious now, more than ever before. So, that 850, 950 number I said in the past is maintained, in my view.

Paul Sankey - Wolfe Research - Analyst

Thank you very much, Roger.

Operator

Ben Wyatt, Stephens.

Ben Wyatt - Stephens Inc. - Analyst

I know we've covered a lot today, but did want to just bring up Australia. Recently BP announced that they are kind of, at least for the time being, stepping away from southern Australia. Just curious if that's changed you guys' thinking on the asset at all, or if it has just removed a data point and some news flow that you guys were expecting to see here in the near term?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, it's a very one-off, strange occurrence, I will say, because there's been enormous capital spent by that party, and they still have a very large commitment there. So I'm not sure what's going to happen with that for them. We're a totally different situation. To our east there is a very large acreage position that Chevron holds, also with drilling commitments that are quite large, and rigs to be moved there, et cetera; also in the blocks next door to us, which BP has left. And Statoil remains their partner, which they farmed in with the VP at the time. So it's a very unique circumstance. I just know that we have some very large prospects and many of them on our block.

It would be preferable for Murphy for someone to drill next door. But I feel that in things like this that there will be a well drilled down there by some of these folks at some period of time. And we will be there to take advantage of that at that time. And all I know is the blocks we have and the data we have and the prospectivity that we have is very good. And in the short term, it's hurtful for them to pull out. But, overall, this is a long-term game, and we're in this thing for a very low amount of capital.
Ben Wyatt - Stephens Inc. - Analyst

Very good. Well, that’s it for me. Again, thanks for squeezing me in.

Operator

That concludes today’s question-and-answer session. Mr. Roger Jenkins, at this time, I would like to turn the conference back to you for any additional or closing remarks.

Roger Jenkins - Murphy Oil Corporation - President and CEO

No, just thanks for everyone calling in today. I thought we had a good call. I answered many questions. And we’ll move forward and speak to you in the new year. And appreciate it, and thank you all.

Operator

That concludes today’s call. Thank you for your participation. You may now disconnect.