Co. reported 4Q16 loss from continuing operations of $62.8m or $0.36 per diluted share.
Good day ladies and gentlemen and welcome to the Murphy Oil Corporation fourth-quarter 2016 earnings conference call. Today’s conference is being recorded. I would now like to turn the conference over to Mrs. Kelly Whitley, Vice President of Investor Relations and Communications. Please go ahead.

Kelly Whitley - Murphy Oil Corporation - VP of IR and Communications

Good morning everyone and thank you for joining us on our call today. With me are Roger Jenkins, President & 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 fourth-quarter financial results highlighting our balance sheet and strong liquidity position followed by Roger with fourth-quarter highlights and 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 the projections will be attained. A variety of factors exist that may cause actual results to differ. For further discussions 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 will now turn the call over to John for his comments.

John Eckart - Murphy Oil Corporation - EVP and CFO

Thank you, Kelly and good morning to all. Murphy’s fourth-quarter results from continuing operations were a loss of $62.8 million or $0.36 per diluted share. The fourth-quarter of 2016 results from continuing operations included a $24.2 million after-tax charge associated with an expected cash settlement during 2017 for a contractually required redetermination of working interest in the Kakap Gumusut field offshore Sabah, Malaysia.

The redetermination settlement is expected to reduce the companies networking interest in the Kakap field, and this ending the approval of Petranoss. Adjusted earnings, which adjust our GAAP numbers for various items that affect comparability of results between periods, was a loss...
of $26.9 million or $0.16 per share in this quarter. Our schedule of adjusted loss is included as part of our earnings release and amounts in this schedule are recorded on an after-tax basis.

The Company’s average realized price for its crude oil production was $47.75 per barrel in the fourth-quarter of 2016. Realized natural gas sales prices in North America averaged $2.19 per mcf in the quarter while realized oil index natural gas prices offshore Sarawak averaged $3.23 per mcf. At this time, we have WTI crude oil hedges of 22,000 barrels per day at $50.41 per barrel for 2017.

We have Canadian natural gas hedges for 2017 that total 124 million cubic feet per day at AECO, and the average price of these are CAD2.97 per mcf. We have hedges for 2018 through 2020 of 59 million cubic feet per day also at AECO, and an average price of CAD2.81 per mcf. At December 31, 2016, Murphy’s total debt amounted to $2.99 billion or 37.8% of total capital employed; while net debt to capital employed was $2 billion at 29%. As of year-end 2016, we have no outstanding borrowings under our $1.1 billion revolver.

Our worldwide cash and invested cash balances totaled approximately $1 billion at December 31. That concludes my comments and at this point I will pass the call to Roger.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Thanks, John. Good morning everyone. Thanks for calling in today. Murphy closed out the year with an all-around solid quarter, with strong results from our higher than forecasted production while generating free cash flow. During the year, we took several actions to high-grade our North American onshore portfolio amidst one of the most difficult years in our industry’s history.

We believe our improved portfolio provides us with a stabilized and balanced production base that will be our foundation for growth. Together, with a solid balance sheet, ample liquidity, and top quartile dividend yield, we’re set up to be successful heading into 2017. Fourth-quarter production was 168,000 equivalents per day and full year production was 176,000 equivalents a day; both of which exceeded the high end of our production guidelines.

The strong fourth-quarter production is attributable to additional 1,500 equivalents a day and better than scheduled performance at the facility [upcom] in Sabah and Sarawak, Malaysia following our planned facility turnarounds. Approximately 1,800 barrel equivalents additional production from new wells that outperformed in our Catarina area of Eagle Ford Shale. For the quarter the Company spent $176 million in capital expenditures, bringing the full-year total to $605 million, that’s compared to $2.2 billion in 2015.

2016’s capital budget is exclusive of the $207 million we spent at the Kaybob Duvernay and Placid acquisition last year. For the full-year our keen attention on reducing cost has paid off with lowered LOE by 15% year over year and reduced G&A by 14% year over year. This is achieved through implementing multiple cost-cutting measures along with efficiency gains made across the organization. During the quarter, we expanded our exploration portfolio by entering into a successful Gulf of Mexico Farm-in and winning a block in Mexico’s recent bid ground.

With regard to our onshore portfolio, we monetized our non-core Canadian heavy oil seal asset, which closed last week leaving us with a more focused unconventional only onshore portfolio. Preliminary reserves for year-end 2016 were 685 million barrel equivalents of which crude development is now approximately 50%. The change in year over year reserves is attributable to reductions of $121 million equivalents from divestitures especially Syncrude, which alone was 113 million barrels and production of 64 million.

We added 52 million in acquisitions primarily related to the Kaybob Duvernay joint venture, along with 44 million of net positive extensions, discoveries, and revisions. This equates to reserve life index of 10.7 years. Our finding and development costs were $8.18 per boe bringing our three-year cumulative F&D cost to under $16 a barrel equivalent.

Organic replacement was 69% due to a 63% reduction in capital spending from 2017; however our average three-year replacement is 154%. Our offshore business produced over 81,000 equivalents for the fourth quarter, with 73% liquids and operating expenses of $8.84 per boe. For the full-year the offshore business produced 83,000 equivalents per day or 73% liquids and operating expenses of $8.40 per boe. In offshore Malaysia,
Block K and Sarawak produced over 37,000 barrels of liquids per day during the quarter with natural gas production from Sarawak averaging over 115 million per day.

Full-year production from Block K and Sarawak averaged 39,000 barrels of liquids per day and 106 million of natural gas from Sarawak. As planned, there were major turnarounds in the fourth quarter at our Kikeh and Sarawak facilities which cumulatively reduced fourth-quarter production by 4,900 barrels equivalents per day. Both turnarounds involved over 500 personnel and 125,000 man-hours without a single incident, a highlight of our mindful focus on safety in our Company.

In our Gulf of Mexico and East Coast Canada business, production for the fourth quarter averaged 23,000 equivalents per day of 92% liquids. The co-mingling of two zones at the nonoperating Kodiak field began this month resulting in a well now producing approximately 20,000 barrel equivalents on a gross basis. Our subsea multiphase pump project in Dalmatian field was sanctioned during the quarter. The project accelerates production as well as increased reserves in the field with a project start up expected in 2018.

During the fourth quarter, Murphy reached an agreement with Chevron to participate in drilling Hoffe Park, a Gulf of Mexico Mississippi Canyon prospect in Block 166 with a 25% working interest. Chevron drilled the well in the late fourth quarter and successfully encountered hydrocarbons. Drilling of the well went extremely well and the total cost to Murphy for the well was only $16 million.

The well has been suspended, pending determination of the appraisal plan for the discovery. Currently we see major efficiencies and cost improvements in deepwater; which we believe will place this discovery within our goal of top quartile F&D costs. We have focused our offshore capabilities on several concentrated areas.

Murphy's and it's partners are successful better in Mexico's recent deepwater auction on Block 5; the most competitive block in the bid round. Under the terms of the joint venture Murphy will be the operator with a 30% working interest. This block is located in deepwater Salinas basin covering over 1,000 square miles and water depths of 2,300 to 3,600 feet. The initial exploration program for the license is four years and includes a one well work program commitment.

In Eagle Ford Shale, fourth-quarter production average near 46,000 equivalents per day with 88% liquids. Full year production averaged near 49,000 a day with 53 wells brought online during the year. This spring Company's online operating well count is over 700. For the year we spent $233 million in the Eagle Ford, while maintaining stable production from second quarter 2016 onward which will continue over the course of 2017.

We continue driving down our operating expenses over the course of the year by adding water disposal wells and field electrification. OpEx for the full-year 2016 was down 11% in 2015. We believe that long-term, our operating expenses in Eagle Ford Shale will be in the $7.00 per boe range. We continue to optimize our completion designs which is leading to increased productivity and higher EURs field-wide. Several new wells in the Catarina area are showing encouraging results.

Now we are averaging 70% to 100% cumulative production higher than historical completions in the area, over the same time period. Our Catarina cumulative cash flows continue to show that buildings compete favorably with our Karnes area. We now have 400 lower Eagle Ford locations remaining in the Catarina area giving us multiyear inventory at below $38 breakeven price. [Area 7] wells have brought on production performing mildly expected increased type curve yielding 30 day initial production rates of 500 to 800 barrel equivalents.

In January 2017, two Austin chalk wells have gone online in the Karnes area are still cleaning up phase with encouraging initial results. And both wells producing an excess of 1,000 barrel equivalents each. In Canada, our Tupper Montney asset produced 204 million a day for the fourth-quarter and full-year production was 200 million per day. During the quarter, two wells were brought online utilizing our longer lateral, higher sand concentration design. These wells, along with previous wells using similar design, have production profiles that continue to support our increased tight curve of 10 bcf to 14 bcf per well. With some wells trending toward estimated-type curves in excess of 17 bcf to 18 bcf.

Due to efficiencies our cost continued to increase [in this play] even while driven longer laterals. Since 2014, our Montney driven costs are 30% lower now that the break even price of CAD2.05 AECO. In Kaybob Duvernay, production averaged over 3,100 barrel equivalents with 54% liquids
in the quarter. In Kaybob, the four gas condensate wells brought online during the third quarter continued to perform at or above the normalized type curve.

While these lateral links are below our future development plans, we're pleased with the results utilizing this new increase sand concentration completion design. At year-end, Murphy booked approximately 55 million equivalents approved reserves for the area, which puts us ahead of our goal to replace reserves divested from Syncrude last year.

In the fourth quarter, Murphy drilled a two-well pad, which will be brought online during the first quarter with a planned lateral length of nearly 4,500 feet. These are the first wells drilled by Murphy since taking over operatorship. And even being new to the area with a new crew, well cost $2.5 million per well. This highlights as we expected, we will be able to leverage our North American shale expertise across all plays and drive costs down quickly in this new play as we're already at the benchmark of the area on our first attempt.

Over the course of 2017, we continue to gain better understanding of Murphy’s area in Duvernay shale play and we anticipate we will set up Murphy on a clear path forward as a competitive cost player when we move to full development mode. Moving forward, Murphy will be permitting all new wells consistent with the development plans established upon taking over operatorship in which the average well length will be up to 9,000 feet per well.

In 2017, we're planning to spend within cash flow while maintaining our current dividend to preserve financial strength and liquidity. We are continuing to focus to lower-cost structure and finally we are stabilizing our production to serve as a foundation to set us up for growth in the future. As for our operating strategy in Duvernay shale, we’re favoring appraisal with the oil window in the central condensate regions over production growth. In Eagle Ford shale we’ll continue delineate multiple zones, while driving greater efficiencies across the play.

We believe this will lead to continued increases in EURs. Offshore participating in high return offshore projects primarily in Malaysia, from where we are turning expiration in a measured, way where we see many opportunities in the business at the bottom of the cost cycle. We're planning on spending $890 million in CapEx in 2017. In our budget assumed WTI oil price of $52 per barrel per the year. Again, we have natural gas prices of $3.10 per mcf.

Field development and development drilling is $755 million referencing about 85% of the total budget. Approximately 65% of the capital will be allocated toward our three onshore and conventional businesses with the majority spent in Eagle Ford and Kaybob Duvernay assets. In Eagle Ford, we plan on spending $370 million, drilling 72 wells and completing 71, as well as field development expenses. In Tupper Montney, we plan on spending $35 million, drilling six wells and completing five. The Kaybob Duvernay, we plan on spending $145 million, which includes $33 million related to the carry in our joint venture.

We will drill 16 wells and complete 11 as we are in the early stages of appraising the assets, there will be a 11 completed wells. Six will be drilled in central gas condensate area, three in the volatile oil area, and the remainder in the black oil area. We feel our measured appraisal with asset will enhance full development planning in the field.

Our offshore expenditures are focused on short cycle projects that maintain existing assets, as well as other activities that we expect will increase production in future years with high returns. We expect our first-quarter 2017 production to be in the range of 166,000 to 170,000 barrel equivalents per day. We will be able to essentially hold for full-year the production flat from our fourth-quarter 2016 adjusted for sale rate of 164,000 equivalents per day with our planned capital spend.

Full year productions estimated to be in the range of 162,000 to 168,000 and has an onshore production growing about 9% over the year. Over the next four years, we believe we can achieve production growth at a compounded annual rate between 6% to 10%. This growth can be accomplished within cash flow while generating cumulative free cash flow of around $400 million maintaining our dividend.

We believe we can do this within our existing portfolio, as this plan does not take into account future exploration success or acquisitions. Our stable offshore portfolio provides $1.7 billion of free cash flow that fuels our onshore unconventional production CAGR of 10% to 15% during this planning period.
We close today with a few takeaways. We’re growing onshore production by 9% year over year, preserving our balance sheet and strong liquidity position. We are leading EBITDA per boe producer, we’re adding reserves from M&A, leading to below $10 F&D for our Company, we’re expanding exploration portfolio at the very bottom of the cost cycle, achieving value added top tier driven and completion performance, and we’re establishing a foundation for future growth within cash flow.

This concludes our opening remarks and open it up for questions now.

QUESTIONS AND ANSWERS

Operator
(Operator Instructions)

Ben Wyatt, Stephens.

Ben Wyatt - Stephens Inc. - Analyst

How are you doing? I wanted to ask a couple questions on Canada. I guess I can start first with a tougher and the well you brought online.

Obviously, you ramped the sand volumes there any other tweaks you are going to do on wells going forward or do you feel like you dialed in how you want to complete these tougher wells going forward?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Tougher is a big asset for us. Mind-boggling amount of TCF’s there. We do have three zones there and many, many locations.

We are now, really in this play the sand is not near as high of concentration as we’re using in Duvernay or in Eagle Ford, these are only 1,000 pound a foot type fracks. We’ve never really experimented with much higher but we are onto a cluster perforation design much longer lateral wells.

Now we are always drilling wells well over 9,000 feet of horizontal up there. Just onto a good flow of lower costs, great execution, and the wells are performing ahead of expectation and they are setting up a place where we can easily keep this plant full and take on volumes from some of our peer companies that will be leaving the plant over time by drilling five or six wells per year. It’s going really well for us in that area.

Ben Wyatt - Stephens Inc. - Analyst

Got it. Very good. And then maybe hopping over to the Duvernay. Just taking a look at the tight curve you have in the bottom right on that slide, the 4-36, looks like it takes a month or so to clean up but then stays relatively flat.

How are you internally thinking about that? Does that stay flat for much longer? And also are you having to put any type of artificial lift on that pretty quick or is it flowing naturally for you?

Roger Jenkins - Murphy Oil Corporation - President and CEO

It’s flowing naturally at this time. That’s the whole deal about this play we’re trying to delineate. There’s only very limited well information in this volatile oil considering how vast and large this acreage is in this region.
You can see it on the scale. These are townships on this map. I am real pleased with the wells. These are really non-optimized.

They're only 4,100 feet linked tight curve here. And the stimulation is really not even full 4,000 feet there. To come in on an EUR in the 470s just getting started in the play and production we believe will meet up with a 470 curve that will continue out to the right.

And they're not on artificial lift. Pleased with our first foray. We just really have taken a while here to take over operatorship.

We didn't close this deal until May. These wells were drilled by our joint venture partner. We participated in the design of completion but we didn't execute the completion and we have now moved and drilled another two well pad with real, what I consider low cost for the beginning of our work.

That well is not optimized in the azimuth we would like and we're just now drilling the azimuths we want, the links we want, permits and everything set up for the much longer lateral and we're going to try to hit this play with the 9,000 foot laterals and not a start off in the 4,000 to 5,000 foot that we have done years ago and really trying to build our expertise.

We drilled thousands of wells between Eagle Ford and Montney and we know what we're doing here as far as executing in shale, but it takes time to take over, get your game planned, get your permits, deal with the long-term rig schedule, keep our rigs moving between Montney and Duvernay and our frack crews for that efficiency, driving in back-and-forth, breakup season, organizing all this, just getting going good and I am real pleased with how we are executing.

It's going to be about getting the cost down. We are very good at doing that and we're off to a good start here.

Ben Wyatt - Stephens Inc. - Analyst

Very good. Well I appreciate it. Thanks.

Operator

Kyle Rhodes, RBC Capital Markets.

Kyle Rhodes - RBC Capital Markets - Analyst

Good morning. Does Murphy see itself as a potential consolidator in Eagle Ford and curious on Murphy's views on bringing in a financial partner to help facilitate a larger transaction there?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We are like any other player with a full on business development team that look at opportunities such as that quite often. But that would depend on that cost to capital versus the cost of capital opportunities we would have at our Company. I think a lot of this consolidation in our view has been more Western of our Catarina or more in a [gassier] area near the Catarina which would be like a 33% between NGL, gas, and oil.

We are really in the high 80's here. I'm not sure if there's been a lot of consolidation in real true oil window there. And we have looked at those opportunities often and wage it against other things we can do. But purely not really interested in giving away a lot of value in our oil weighted Eagle Ford just advanced to capital at this point.

We are approached and do look at opportunities of naturally every day. We don't preclude that we're going to do that.
Kyle Rhodes - RBC Capital Markets - Analyst

Great. That’s helpful. And then hoping you could discuss Murphy’s thoughts on the potential border adjustment tax.

Specifically if you think it poses any risk to your Canadian operations and if there’s anything Murphy can do to mitigate that potential risk in the form of hedging or something else?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Everyday there’s a change coming from this administration which I believe will lead to lower regulation and many positive things for our industry. But the understanding of how that would particularly work, I do not believe Murphy will be incredibly disadvantaged. We have our crude in Asia that’s really sold in that part of the world.

Our East Coast to Canada crude has traded like a brink crude and would come into the East United States possibly. I suppose. And our production, our Kaybob Duvernay area, which is a big growth area for us, goes into Edmonton and goes into [Delumont] there and not really coming of course into the United States.

I think they will be many factors coming from this administration on many changed items over the course of the next year or so. I think it’s too early to predict what that would actually be. We just have to keep lowering our costs, keep making our production levels, keep rolling, and let our president do what he needs to do which in general will help business in America in my view, and go from there.

Kyle Rhodes - RBC Capital Markets - Analyst

Great, and then one more if I could. I believe your 2017 budget was based on $52 oil. Now we are sitting on this (inaudible), it’s closer to $55 to $56. If we do get a little stronger oil prices in 2017, where does that incremental next dollar of cash flow go?

Is it -- how does Murphy rank potential dividend increases or is this debt pay down versus growing production versus growing acreage?

Roger Jenkins - Murphy Oil Corporation - President and CEO

I would say we're not really looking to focus on a big debt pay down because that $3 increase from strip to where we are something below $100 million. I would like to look for opportunities in our Catarina area. It is a very very prolific area for us. If you look at cumulative production coming out of Catarina and compare that to some Permian cumulative production slides that are available from our peers, you find these cumulative production areas between there and Karnes to be quite competitive so that probably actually in some cases exceeding.

I would say we have -- If you are dealing with less than $100 million in capital, we would have additional opportunities in our Catarina area. We also, up in our Duvernay shale would like to complete a pad or two more of wells there. We'll end up was some ducks on the water there at the end of the year. Those type of opportunities would be first for us over dividend per share and for balance sheet.

Balance sheet is pretty strong, leverage metrics pretty strong, cash available to pay a bond due at the end of the year, cash balances even on a strip basis, keeping our cash levels in the $400 million to $500 million range easily. So I would like to do a little more drilling if we can get $3 more but the prompt month is always $52. We will go from there.

Kyle Rhodes - RBC Capital Markets - Analyst

Appreciate the color, Roger.
Good morning, Roger. Good to talk to you in 2017. Just following up a little bit on some of the expectations for production growth for 2017 and onshore and then even the guidance for higher rate of onshore growth in coming years. How should we think about that between the Eagle Ford shale and the Canadian opportunities? Clearly a lot more wells in EFS. Is that the right way to think about protection as well?

Compare back to this year, the growth will primarily be across those three plays almost evenly. CR Eagle Ford is stabilizing our Kaybob Duvernay and our Placid areas almost doubling and that’s really where the production is coming from. There’s some big drilling program in place there. It’s not like we are thinking of that.

It’s happening now. And so when I look at for the year, I will be looking at that Eagle Ford Shale slightly higher than 2016. I’ll be looking at the Montney and Duvernay combined to be somewhat higher price, almost 6,000 a day higher. So those are the primary growth areas, Roger.

Okay. Appreciate that. And then in the offshore space, you mentioned in your opening comments, probably pretty low here on the cost structure. You made the move into Mexico during the fourth quarter.

I am just curious oil above $50, obviously everybody feels a little bit better about life. But is that slowing the number of opportunities to acquire something that’s partially along the process in the offshore? Is it bringing in more bidders?

Has it made you more confident about moving forward? Has it brought more potential sellers out? Have there been any real evolution along those lines?

I do not see any increase in bidders, I can tell you (laughter). That’s how you roll when things are in that, when no one you don’t have a lot of bidders. There’s a lot of bidders in other parts of North American business I can tell you. No. They were -- we did have a lot of bidders on the round we bid including some large companies and some very successful exploration companies.

It was the most bid block in Mexico. And we had, I believe four other bidders besides our bid group. That is competition come to that and we were successful and I’m glad to have that. I just think that, that cost structure is going to be there a while.

The opportunity to enter into the ground floor exploration, it’s just changed so much in three or four years. Any type of prospect that was a decent prospect was a two-for-one promote at least three years ago. And now you’re entering into these on a ground floor basis. I strongly believe that the efficiency and the onshore drilling has driven the teams and these companies of the offshore to improve as well. These very large new rigs barely got a chance to go and we are seeing these new high-end rigs perform incredibly well.

This well would participate when it was drilled in 20-something days. That well was easily double that, two or three years ago. The rig rate here was north of 450 and our cost to drill the well was $16 million. So if you can envision drilling that well for our share being $8 million and can do that for a while ahead in my view. That’s a real positive F&D, CapEx per barrel, total business there that will rival shale without a problem.
Roger Read - Wells Fargo Securities, LLC - Analyst

Got you. Thanks for that. Maybe just one last little follow up along those lines. When you are evaluating a known discovery that a company is attempting to put on the market versus the... I don’t know if we talk about rank exploration, but let’s call it a legitimate exploration prospect, have we seen those narrow up in terms of relative risk-reward-adjustment or is it still that much more attractive to do to the exploration side relative to that entry cost and the projected drilling costs?

Roger Jenkins - Murphy Oil Corporation - President and CEO

I think that as we look at benchmarking and look at a lot of things involved in exploration, today’s time of finding cost of below $4 is pretty considered to be pretty decent or pretty good. If you look at some of the deals in the world Brazil and there’s been a lot of super major activity going to Brazil on the very, very large fields, you are in a $2.50 per dollar acquisition deal, with some type of an outcome from there of how to get that $2.50. That’s what we see there.

The exploration is not far away from that. The issue will be the timing, the delineation of each particular prospect that you’re looking to buy. That’s going to drive that entry cost. If the project hasn’t been delineated appropriately, you will be paying less. I think that just not a lot of people looking to do it, is the big issue over the comments I had about cost per barrel.

That’s where we like to fit in there. But I’ll be very clear that you can enter into an international discovered resource and you can compare that to a entry into a major shale basin where you would have three to four benches if you will and each bench making 1 million barrels each and 24 wells a section, and you drill that out around 30,000 acres, I can tell you that the breakeven is lower oil price, the payout is similar, the acquisition cost is lower, the CapEx for boe is lower, and the supply cost of the business is better, and that the MPV per boe is better, and the rate of return better.

Roger Read - Wells Fargo Securities, LLC - Analyst

So better than (laughter).

Roger Jenkins - Murphy Oil Corporation - President and CEO

It’s better or we wouldn’t be doing it (multiple speakers). I do not believe the offshore deepwater industry will turn into a VHS tape type of thing.

Roger Read - Wells Fargo Securities, LLC - Analyst

How about Betamax? I am just kidding you. Thanks, Roger.

Operator

Guy Baber, Simmons.

Guy Baber - Simmons - Analyst

Thanks very much. Good morning, Roger. I wanted to ask a little about the longer-term growth guidance that you have in your slides, which we very much appreciate. And you gave a little bit more color on the 2017 growth.

I was hoping that you could dive a bit deeper into the 2017 to 2020 CAGR that you show, but you obviously are showing very meaningful growth in the onshore portfolio. So could you just discuss a bit more the individual (inaudible) components maybe.
Because I believe previously you had been talking about Eagle Ford as perhaps a flattish to slightly up business over time. Are you more optimistic there now? And to what extent is the growth in the Tupper Montney dry gas contributing? Any color you could put around those drivers would be very much appreciated.

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

Right now we do have what I consider the Eagle Ford to be quite flat through 2020, slightly increasing from where we are for 2017, which is around 49,000 in there. And see that’s slightly maintaining a couple years and slightly trending up by 2020.

Our Montney position will go up probably around 8,000 or 9,000 boe per day because the plant has some company that will be coming out of the plant and we will be taking their place. With these high 14 to 17 bcf per e wells that breakeven at little over CAD2.00 AECO and we’ll be taking its place and then we need to see growth and plan on growth from Kaybob, Placid but a lot of CapEx going in there in the next two to three years.

Many, many different types of wells to drill. Many of the areas are near competitors that are drilling successful wells, namely in Canada, Shell, and Chevron. We have that going up the rest of the way there from an onshore basis.

**Guy Baber - Simmons - Analyst**

Okay. Great. That’s helpful. And then can you talk a little more on the topic of the Kaybob Duvernay. You mentioned it’s really important for you to get the costs down there. It sounds like you have already made some pretty impressive strides.

So can you just lay it out for us, just the type of well cost improvement that you were looking to achieve, what you have already achieved, maybe what you see is the runway in addition to maybe a reminder on the enhancements you are making on the drilling front there is well.

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

It’s going to be a year or more before we can show the improvements that we need. I think I am encouraged by the idea that we go in the middle of the field between many peers and this is third-party information that is in the slide today. And we get in there and we start off and the wells are permitted prior, we go in and we execute the wells at a normalized length and at the length they are and we’re already in the top quartile.

And are even with the quartile of everyone else who has been on the play ahead of us. That’s off to a positive direction, but we’ll be struggling from a lowering cost mode because we really only have -- we are drilling on a two well pad right now and we have one pad that’s a three well pad and the rest of our wells are single well pads or possibly two.

You really need to get to four well pads to get the efficiency of these high-spec rigs that we have contracted there, well in to 2019. We will have well costs probably approaching $9 million for these wells. $9 million to $10 million.

These wells also were -- reading across at my notes here, we were talking about 9,800 feet, 9,800 feet, 9,800 feet, 7,500 feet, 98 -- so our wells are 9,800 and two wells are almost 10,000 feet of horizontal. So these wells are almost two wells if you will under prior thoughts about shale. We believe that it’s all about days and drilling days.

We will pull these days down as we get to pad drilling and we already start off at the benchmark now and our long-term goal is to have $6 million to $7 million wells in here at 9,000 feet. And I believe we will be able to do that.
Guy Baber - Simmons - Analyst

That’s very helpful. And then last one for me. You mentioned a comment and this was discussed a little bit earlier but you mentioned the goal of adding reserves at $10 per barrel F&D to the portfolio. I was hoping you could discuss that comment a little bit more.

Is $10 a barrel F&D the type of F&D you see as sustainable for your portfolio and for that business? Are you talking specifically about some specific adds to the portfolio? I just wanted to better understand the commentary around the $10 barrel F&D.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Actually I consider even $15 to be top quartile and to think you look back over a while, you'll see that's really good F&D.

I think you have two situations here. If you look at F&D in the big onshore entry you are probably going to be talking about $12 to $13 -- talking about first quartile there too. In the offshore deals we are working on that we discussed today, we feel will be in the $10 range and I believe that over the next three to four years that, that F&D cost in offshore will be pretty firm.

It’s possible that costs increase in the onshore will drive that up, in our view. But the offshore that we are looking at as we -- it’s about return in top quartile F&D and not getting into a project that on a risk basis would not lead you to be able to accomplish that.

That’s what our new focus and exploration opportunities are. Smaller work in interest, less expensive wells, around $10 F&D that on the worst day it goes to $15 that's okay. If we determine that from a success case that we can’t get to the F&D that we want then we are moving on and not looking at that.

Guy Baber - Simmons - Analyst

That makes a lot of sense. Thanks for clarifying that.

Roger Jenkins - Murphy Oil Corporation - President and CEO

That’s a totally different view that we had a few years ago and I think we improved and one that will lead to value creation here.

Operator

Paul Cheng, Barclays.

Paul Cheng - Barclays Capital - Analyst

Hey, good morning. We’re talking about exploration program. Can you give us some sense that what consider going forward as a normal exploration program at year end. How much you're going to spend?

How many wells you're going to precipitate? And what kind of interest will that tie up (inaudible) that you can share?

Roger Jenkins - Murphy Oil Corporation - President and CEO

I don’t believe we are off on a round of getting back to the high-level of exploration spend we had before. We’re looking at consistently $100 million to $150 million that's in the plan that we outlined here today. We are looking at opportunities where if those opportunities would be helpful to us, we would participate more.
But the costs are so much lower, and the entry is so much lower, and the availability so much better, that $100 million goes a lot more in deep water than it did two years ago. Its probably similar to $300 million to $400 million actually. We would like that to be higher, but we have to have our growth plans that we have here, our value-added growth where we have really good performance in Eagle Ford.

We believe top line performance ahead in Kaybob Duvernay. We're illustrating more and more value-added creation in Montney. And so we have all that mindful of that.

We are not off into a big jump back into the $400 million exploration budget just trying to accomplish a lower working interest in the right sort of things with the lower level of exploration spend. I think we're off to a pretty good start doing that.

Paul Cheng - Barclays Capital - Analyst

And should we assume that this kind of exploration budget which seem to say somewhere in the five to six well, 25% to 30% what of interest, that kind of program? That year?

Roger Jenkins - Murphy Oil Corporation - President and CEO

No, we will have other expenses in our international offices like our Vietnam office and things of that nature, seismic. We'll probably only be drilling a couple wells a year in these working interests as our current plan. Our current plan outlined in here is not a heavily weighted exploration plan.

Paul Cheng - Barclays Capital - Analyst

I see. Okay. And this will be at least in the foreseeable future the kind of program that you have in mind?

Roger Jenkins - Murphy Oil Corporation - President and CEO

What's that? I'm sorry Paul, one more time?

Paul Cheng - Barclays Capital - Analyst

At least that in the foreseeable future, this is the kind of program you have in mind at this point?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Yes, you are right. At this time.

Paul Cheng - Barclays Capital - Analyst

Just clear on the acquisition fund for exploration, have you looked at Conoco Gulf of Mexico Deepwater program whether you have interest or not. If you're not interested is it because of the quality or because of the size of that portfolio?
Roger Jenkins - Murphy Oil Corporation - President and CEO

We looked at several months ago, I'm not sure because I don't recall exactly the outcome they had. We're not really looking to take on large exploration acreage. Looking to one-off select opportunities to drill wells with partners, are working opportunities in which we could operate which would be the best situation for us where we had the most value.

We were very interested in their project they had in West Africa which was a sale of an oil field that they had partially delineated but not interested in going to a data room and taking on massive exploration acreage from a pier. They would rather go and anticipate in wells that will be drilled and from a ground floor basis and that's much more our plan than to take on a big set of acreage and commitments from other people. That's not the plan at all at this time.

Paul Cheng - Barclays Capital - Analyst

And for the recent opinion on the Hoffe Park, any color in terms of discovery in terms of the size? Whether that's was (inaudible) type of oil and gas mix? What is there and when you're going to drill the, any kind of information you may be able to share?

Roger Jenkins - Murphy Oil Corporation - President and CEO

It's in medium water depth range of around 5,000 feet or something to that effect. It was high quality oil found there. It's not a gas well or anything like that. I prefer not to talk about the size.

We have delineation well that we had to take some seismic reprocessing from the well. We drilled near salt there and there is some salt proximity work that's being done by both parties working very well with Chevron. Enjoying working with Chevron and planning delineation. At that time we will say what comes out of it.

Obviously to move or discuss or suspend the well, you must have some idea it's above a minimum field volume which we do and the pay that was found in the well. Just tiptoeing back into this business and prefer to have things better lined up prior to quoting size and numbers on that at this time, Paul (multiple speakers). I'm real happy with the results.

It's near a lot of tie back opportunities for are three to four areas to bring to production. Some are very close to where we are drilling. A lot of successful wells in this area. Middle Miocene, Mississippi Canyon, is a very prolific reservoir and we're real happy with our partnership, real happy with the outcome. And looking forward to some more information there coming. Hopefully in the second half or later part of this year.

Paul Cheng - Barclays Capital - Analyst

So this is (inaudible), I presume and that when you (inaudible) drill the appraisal well?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We are working with them on that plan. I would say it would be at best, at the end of this year. Not at best, I anticipate it happening before the end of the year. And it won’t take long to do it.

Paul Cheng - Barclays Capital - Analyst

And just want to clarify earlier then, (inaudible) you're talking about a $9 million to $10 million per well cost in the Duvernay yet the drilling cost is $2.5 million so you implied at least until that you get into more the pad drilling that the completion cost is going to be about 70% of the total well cost save $7 million to $8 million range. I just wanted to clarify that?
Roger Jenkins - Murphy Oil Corporation - President and CEO

In Kaybob (multiple speakers)? In Kaybob area Paul?

Paul Cheng - Barclays Capital - Analyst

Yes.

Roger Jenkins - Murphy Oil Corporation - President and CEO

That's primarily completion. I don't have it written down in front of me what it is, but the drilling is probably going to be a third of it, something of that nature.

Paul Cheng - Barclays Capital - Analyst

I see. And on Eagle Ford and on the Kaybob. Kaybob I think when you initially reported it, I believe you have the press release or statement or someone else is speculating saying that the total production net to you may be 20,000 barrel per day and Eagle Ford a while ago before the downturn was talking about 70,000 barrel per day and now you just said Eagle Ford that you expect to be flat at around 50 through 2020 and only modestly. So have those numbers been changed at this point?

Roger Jenkins - Murphy Oil Corporation - President and CEO

(Multiple speakers) Paul, we cut back CapEx there from $1.1 billion a year to $200 million. I would say a lot of numbers change for a lot of peers this year. I think it's a year of maintenance CapEx person. You have asked me about it many, many times.

We barely went down in our production this year with only $200 million and we get in there and spend a little over $300 million a year. We stay flat production in an asset that's actually leading to free cash flow with any type of help on oil price before 2020. I think that's a really good deal to spend $300 million something a day on a big asset like this and keep oil around 49,000 day going into low 50s in 2020. (Multiple speakers) More oil weighted.

Paul Cheng - Barclays Capital - Analyst

(Multiple speakers) longer-term cash is available. Based on the resource and based on your portfolio Management that your overall synergy where you see that the total weight longer term for Eagle Ford could settle into, is it still at the 70 or is it now that given (multiple speakers) how you do --

Roger Jenkins - Murphy Oil Corporation - President and CEO

Our plan -- but thanks, Paul. Our plan stops at 2020. But 2021 has it going up a good bit. We're probably going to be in a plateau and back in 65 range and won't get back to the 70 again because we have other opportunities and other things that we can be allocating capital to. However, if that changes and we want to put more capital back in here we can reach back to the 70s again. But at this time probably get in the mid-60s there around 2021. That's a long time from now, Paul. Understand. How about Kaybob and Duvernay, that portfolio. I think that one point that someone was speculating is 20,000 net to you at plateau. Is there any number you can share on that? Speculating that our Kaybob would be 20,000 our share? Is that what you are saying?
Paul Cheng - Barclays Capital - Analyst

Yes.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Yes, I believe about 2020 we will be higher than that in that business.

Paul Cheng - Barclays Capital - Analyst

Final one for me. Hedging. Looks like oil already bottomed. Right now, for 2017 your oil hedge comparing to the future strip is losing money. Is there any change in your hedging strategy going forward should we assume you will continue trying to add hedge position or are you pretty much done?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Pretty much done. I wanted to have some protection from OPEC issues ahead and I want to be conservative about my US cash flow for the US cash expenses I have and the capital allocation into Eagle Ford shale and I made that call a couple months ago and here I am today with that. Not interested in that, but am very pleased with our quite aggressive hedging in the Montney where we have some nice hedge positions there. We did do very, very well in our hedging last year in oil as well. All in all the book is pretty positive for us there and this hedging in the Montney is something we spend a lot more time and focus on and we want to be heavily hedged there, well above our breakeven CAECO price and we are doing well in that regard and I am happy about that.

Paul Cheng - Barclays Capital - Analyst

Thank you.

Operator

Pavel Molchanove, Raymond James.

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

Thanks for taking the question. Just one for me maybe in two parts. A lot of your peers are also raising 2017 CapEx within 20% to 30%. Depending on where we are in the oil service supply chain, we're hearing reports of cost escalation of upwards of 20%.

Most particularly in North America but not exclusively. Given the pretty diverse asset base that you are currently at, can you walk us through the service cost inflation that is embedded in the $800 million budget kind by geography?

Roger Jenkins - Murphy Oil Corporation - President and CEO

No, I don’t have a net break down but I’ll give you my view of how we are lined up here. We are -- main thing for us to go with the US, I mean, we believe from our data that the increase in cost is primarily related to frack and casing. We have our rigs lined up to work here for us.
Our rig costs are going down because we had a co-mingled rate last year from some contract pulling together to one rig if you will, so we're actually looking at 16 to 18 long term well into 18 and have the rigs we need for a two rig budget there and pick up a third rig as needed on occasion. The main thing for us is in Eagle Ford we have around 10% per year efficiency gains. This has been quite consistent.

If you pull one day off of a well, we are right now keeping our costs flat from last year, we assume we will have this continued efficiency and I'm informed of a pacesetter well almost every week here and have been for a very long time. And then if you start looking at it all going into the frack issue, that could happen of course. We have a crew lined up for us with prices agreed to the first half of 2017.

Working with them in the second half of 2017. We have a second crew that prices are fixed for all of 2017. All of these contracts in fracturing allow for increases for sand and fuel on a documented basis. Some are limited by the market must move by 10% on that. We will work with our vendors toward doing that.

We do see there the name brand large vendors in the space. They are smaller companies. We have used many smaller companies before. The smaller companies are coming to us about work. And are willing to work at near the prices we have today.

I am not as gravely concerned about it as you might be because if I have my efficiency, times my wells, and put that against a possible increase in frack costs of 20% representing about 40% of the well, I believe I can handle that and my cash position and my balance sheet and my ability to continue to drill the program, I think is in a strong position for us. When we get into Canada, I feel we are in very good shape there. We have two high --

I think the difference to Canada to the US are the availability of very high spec rigs that walk if you will from well to well hold pipe in the Derek and drill efficiently. Especially in pad drilling which we haven't gotten to yet. We have two rigs contracted there into 2019. Probably in the 14,000 USD range.

This is very favorable. We have our fracking locked up there through the first half of 2017. We have the second crew competing well there with us. Wanting to work for us there, a smaller company.

And feel good about my situation to handle these increases. I have been through many of these collapses in my career and so has my top two operational lieutenants who know how to work with vendors here on these things and about how much work to commit and how to work with them. We have to work our way through it and it will impact all of our peers.

I think that a little bit of isolated work in Kaybob and we have to admit that Eagle Ford has lost a lot of rig count, probably Eagle Ford and then Bakkan has lost more rig count than anywhere else. It's about those service companies in that area wanting to move all of that equipment somewhere else and not have a presence there anymore. We are not seeing that today. We have a (inaudible) for the first half of the year.

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

That's helpful. Just aggregating everything, of the 24% year over year spending increase, how much is cost inflation?

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

Our cost inflation is very limited there.

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

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

Because of our efficiency. We just drilled a well in Kaybob at the top of the quartile and we are going to keep improving there. We hardly got started. And our Eagle Ford just continues to deliver. It's mostly on the drilling side because the completion days have been more complex due to more sand.

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

Appreciate it. Thank you.

Operator

Ryan Todd, Deutsche Bank.

Ryan Todd - Deutsche Bank - Analyst

Hi, good morning, Roger. A couple of follow-ups on and one on the Duvernay. How do you think about -- when you look over the next few years, about your potential ramp in the Duvernay? How do you think about limitations on your ability to ramp? Is the governor primarily going to be cash flow? Is it where the appraisal science is? Is it permitting? If cash flow has exceeded expectations to the upside, can you accelerate beyond with the current plan is in the Duvernay, or are there other reasons that would keep the pace moderate?

Roger Jenkins - Murphy Oil Corporation - President and CEO

No, of course it's a negative cash flow as we build up here but we're getting cash from our other businesses. We are pretty much neutral across our Company and our free cash flow from offshore is funding our other corporate needs. No, we are in the middle of really setting up a lot of optionality around permitting both for additional infrastructure and wells and pads and we are able to move back into if we're not successful in some areas, we can move into other gas condensate areas, leaving the gas condensate that has been very prolific by one of our peers. Leaving that off to the side we feel we can easily go in and execute there.

Just depends on these results over this year and we're setting up options to work inside that. I don't see a problem from Murphy and some type of large increase in oil price or cash flow or additional capital allocations, or some of these wells to perform above him million barrel boe type curve to we could double this from two rigs to four. I don't see that as a stretch on our Company and things of that nature.

In shale today, compared to five years ago, we used to have 13 rigs in Eagle Ford. We're doing all the work with two. There's no 10 to 12 rig plan in here anymore.

You can do a lot of work with four to six rigs. I think we could easily handle permit and work that issue if that opportunity comes to us.

Ryan Todd - Deutsche Bank - Analyst

Would you be willing to say over the plan that you have out through 2020, where do you have the rig count headed in the Duvernay. Is it by the end of that plan is it getting up there into that four to six rig?

Roger Jenkins - Murphy Oil Corporation - President and CEO

No, we're going to be two for a couple of years and moving into the four range later in the planned cycle.
Ryan Todd - Deutsche Bank - Analyst

Okay. And then maybe one on the Montney. I know in the past you have talked about the possibility of an expansion in the Montney. Maybe underpinning some expansion of infrastructure up there.

You referenced taking some of the capacity and existing infrastructure there over the next couple of years. But what's the thought process right now in terms of potential higher expansion there in the Montney?

Roger Jenkins - Murphy Oil Corporation - President and CEO

We have one facility. We're not talking about that I'm talking 30 million or 40 million increase for us to feel that type of number. It's not earth shattering especially when wells produce like we have here.

We have many, many TCF’s here and we would work with our infrastructure partner to build out plants if you will and we would look to expand and fill those plans. We are reviewing that. Probably make a decision about that at the end of the year.

Probably also looking to have a partner on that if we were to consider that. But it’s got to compete with capital with other things we are doing and that has a lot to do with how different things end up with the infrastructure price point side of Chicago, California, Dawn different things of that nature, how LNG progresses in Canada.

A lot of factors involved with that. But it definitely works economically and we have that in one of our to do lists of things to do ahead for us. We have a lot of resources in our Company and a lot of things to review and compete for capital and I think it's a good position to be in.

Operator

Ladies and gentlemen, this will conclude today’s question-and-answer session. At this time I would like to turn the conference back to your speakers for any additional or closing remarks.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Our time is up today. We've went over an hour here. We appreciate everyone calling in so we can get back to executing our plan. Appreciate all the calls and questions today and we will speak to you soon and take care. Appreciate it.

Operator

Ladies and gentlemen this concludes today's conference. We appreciate your participation.
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