OVERVIEW:
Co. reported 2Q16 profit of $2.9m or $0.02 per diluted share.
Good day, and welcome to the Murphy Oil Corporation second-quarter 2016 earnings conference call. Today's conference is being recorded. I would now like to turn the call over to Ms. Kelly Whitley, Vice President of Investor Relations and Communications. Please go ahead.

Kelly Whitley - Murphy Oil Corporation - VP IR & Communications

Good afternoon, Jake. Good afternoon, everyone. 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 in the investor relations section of our website as you follow along with our webcast today. John will begin by providing a review of the second-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 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 the 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, CFO

Think you, Kelly, and good afternoon, everyone. Murphy’s consolidated results in the second quarter of 2016 were a profit of $2.9 million, with $0.02 per diluted share. The competitive result in the second quarter of 2015 was a net loss of $73.8 million, which equates to $0.42 per diluted share. Murphy’s earnings were well above expectations, driven by strong oil prices in the second quarter and strong production from our Eagle Ford and Permian Basin development programs.

The company also reported a strong balance sheet and liquidity position, with cash and cash equivalents of $2.3 billion and $5.1 billion of available credit under credit agreements.

In terms of outlook, we expect to continue to see strong production growth in the second half of the year, driven by our ongoing development programs. We also expect to see continued improvement in our financial performance, driven by strong oil prices and improved operational efficiencies.

I will now turn the call over to Roger for his update.

Roger Jenkins - Murphy Oil Corporation - President and CEO
share. The improvement in 2016 net results included income tax and other benefits on dispositions of two former assets, including the Company's 5% interest in Syncrude and the midstream gas processing plants that service the tougher and tougher West areas in Eastern British Columbia.

Excluding discontinued operations, continuing operations had a profit in the second quarter of 2016 of $2.9 million as well and $0.02 a share. That compares to a loss in the second quarter of 2015 from continuing operations of $89 million, or $0.51 per diluted share.

Second-quarter results from continuing operations in 2016 included net income tax benefits of $88.9 million from sale of Syncrude and Montney midstream assets. These were mostly non-cash tax benefits related to reductions in liabilities for future taxes owed on both of these disposed assets. I'll come back to these taxes and discuss them further in a moment.

Adjusted earnings, which amend our GAAP numbers for various items that affect comparability of results between periods, was a loss of $62.4 million in the second quarter 2016, compared to an adjusted net loss of $83.1 million a year ago. The improvement in adjusted results in the 2016 quarter was primarily attributable to lower cost per production, exploration and administrative activities, but these were partially offset by significantly lower oil and natural gas sales prices compared to one year ago. Our schedule of adjusted earnings is included as part of our earnings release, and amounts in this schedule are reported on an after-tax basis with a separate table as to the pretax and income tax impacts by area of operation.

I now want to discuss further the Canadian transactions in the second quarter. The sale of Montney midstream assets was structured so that no cash taxes would be payable on this transaction. The Company had previously recorded deferred tax liabilities for future taxes that were expected to be paid associated with these assets. And due to the structure of the transaction, the previously estimated future taxes will now not be paid. So, therefore, in the second quarter the Company reversed these recorded tax liabilities and accordingly recognized the deferred tax benefit of approximately $21 million.

The Syncrude sale was a taxable transaction, however. It did qualify for capital gain treatment rather than ordinary tax treatment. Therefore, the tax rate was one-half of the standard statutory rate and equated to 13.75% rate rather than a normal full rate of 27.5%. The overall net tax benefit of $68 million on the Syncrude disposition was mostly attributable to the reduced capital gain rate applicable to the transaction. Cash taxes apply to capital gains rate to the transaction in the amount of approximately $6 million, while deferred tax benefits were approximately $128 million to reduce future taxes payable, which had previously been accrued at the full tax rate.

The Company completed its entry into the Kaybob Duvernay and liquids-rich Montney areas during the second quarter. The initial spend upon closing the joint venture was $206.7 million. Plus, the Company committed approximately another $171 million of future carry for the seller over the next four to five years of operations.

The Company’s cash flow from operations during the second quarter was $70 million. The quarter was impacted by paydown of accounts payable owed to vendors and the semi-annual interest owed on outstanding debt borrowings. Since the second quarter was skewed by the timing of these cash payments, I think it is best to look at the six months year to date for understanding.

Our first-half 2016 cash flow totaled $113 million, and this included payments for canceled deepwater drilling rig contracts of almost $262 million. In the past years, these costs would have been included as investing activity spend under the category of capital expenditures. However, since a decision was made to cancel these contracts without drilling, these costs have been recorded as cash outflows from operating activities in 2016. Looking at the first six months without these one-off rig payoffs, operating cash flow would total $375 million. And annualizing this amount for a full year for pro forma purposes for 2016, operating cash flow would amount to approximately $750 million over the full 12 months, again, excluding the rig payments.

The Company’s second-quarter 2016 lease operating expense was lower by approximately $2.50 per barrel of oil equivalent compared to one year ago. Beginning in the second quarter of 2016, our average LOE costs include the new tariff associated with Montney-area gas plants that were sold. Although these assets were sold above book value, for accounting purposes the gain has been deferred. Starting in the second quarter 2016, a recorded gas processing cost is reduced to recognize a portion of the deferred gain on the asset sale, and the remainder of this gain will be recognized over the 20-year throughput commitment term.
The Company's second-quarter 2016 average realized sales price for crude oil production was $44.42 per barrel sold, lower by $12 per barrel or 21% compared to the same period in the prior year. Natural gas prices also were weaker in quarter two, compared to the prior year's quarter with average North American gas price realizations of $1.35 per thousand cubic feet, drop of $1.07 per MCF for a decline of 44%. Realized oil indexed natural gas prices offshore fell 14% to an average of $3.29 per MCF due to the declining global crude oil prices.

With crude oil prices improving during the second quarter of this year compared to the first quarter, the fair value of the Company's open crude oil derivative contracts fell. Therefore, overall Company revenue in the quarter was reduced by $59 million related to a lower mark-to-market fair value per open crude oil contracts. Although this revenue reduction is recorded in the second quarter, the impacts of the change in the fair value of these open contracts is not reflected in the average realized sales prices reported for the quarter, as here, only the actual cash received on contracts that matured during the period are included in the average realized sales prices. Our EBITDA and EBITDAX balances in the second quarter were hurt by well over $3 per barrel for the mark-to-market decline in crude contract value.

For the remaining six months of 2016, the Company has WTI-based oil price hedges for 25,000 barrels per day at a WTI average price of $50.67 per barrel. Additionally, the Company has forward sales contracts for Canadian natural gas in the amount of 99 million cubic feet a day at an average ACO price of CAD3 per thousand cubic feet over the remainder of 2016. And we also have future Canadian gas hedges covering $59 million a day, CAD2.81 per thousand cubic feet for the period of 2017 through 2020.

At the end of the quarter, June 30, 2016, Murphy's long-term debt amounted to $2.44 billion, which equates to 32% of total capital employed, and net debt amounted to 28.5% of the capital employed. Both gross and net debt ratios were significant improvements from one quarter earlier. As of quarter-end, we had total cash and invested cash of almost $400 million and no outstanding borrowed balance on our revolver that matures in June of 2017. We paid our revolving debt balance off in the second quarter using the combined net cash proceeds of approximately $1.15 billion from the Syncrude and Montney midstream dispositions. The Company is working closely with our banking syndicate and expects to reach an agreement in the near-term on a new revolving credit facility.

That concludes my comments, and I will now pass it over to Roger.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Thank you John. Good afternoon, everybody, and thanks for listening to our call today. Looking back in the second quarter 2016, it's a pivotal quarter for Murphy's. It marks the continued repositioning of the Company. We were able to close our two previously announced key divestitures, our interest in Syncrude, as well as our natural gas processing plants and pipeline servicing our tougher Montney assets.

The proceeds amounted to $1.15 billion, as John mentioned. This allowed us to repay all the borrowings on our revolver and retained almost $400 million of cash on the balance sheet. As we closed on our new -- we also closed our new North American unconventional play entering the Kaybob Duvernay and Placid Montney at a low-cost upfront entry of $207 million.

The new asset competes well with any recent North American transaction, as we were able to acquire a low-cost entry point on any measure of 2P dollar resource or acreage. We believe that our current diversified asset mix, as oil-weighted, serves as the base in which we will be able to recalibrate production and respond to possible lower-for-longer commodity prices.

During the quarter, we had an exceptionally low capital spend of $108 million that's primarily due to timing. This does not include the previously mentioned joint venture purchase. This slow rate is not indicative of a quarterly run rate, as we do plan to spend $620 million over the course of 2016 as originally planned and announced in February.

We are also maintaining our annual production guidance when adjusted for asset sales and purchases. We are also continually lowering cost structure. LOE was down 23% from quarter-two 2015 and G&A down approximately 15% from quarter-two 2015 as well.
Second-quarter production was 168,600 BOE per day, slightly lower than our guidance range when adjusted for sales and purchases. As you recall, we stay that for its planned maintenance across many of our assets, which is common in quarter two for our Company, as well as natural production declines. And Eagle Ford Shale was there were no wells planned, nor were any brought on in the second quarter.

Further impacting our second-quarter production was the divestiture for Syncrude, wildfires in Western Canada, and other third-party infrastructure and facility curtailments. We expect that our third-quarter production will be flat as compared to second quarter, with third-quarter guidance in the range of 167,500 to 169,500. The guidance takes into account a long-planned 10-day turnaround at the tougher Montney area at over 2,400 barrel equivalent per day.

The capital program for 2016, as I mentioned, is maintained at $620 million, plus an additional $207 million attributable to our purchase in the Kaybob and Montney areas. Spending for the first half of the year was roughly 40% of our planned annual CapEx.

Both annual and third-quarter production incorporates the production associated with newly acquired joint venture of Kaybob and Placid and divestiture of our interest in Syncrude as previously announced. With these inclusions, our annual guidance range has not been changed.

Lease operating expense for second-quarter 2016 was $8.36 per BOE, showing a reduction of over 23% from the second quarter of 2015, a reduction of over 9% for the full year of 2015. Our second-quarter 2016 LOE was slightly higher than quarter one due to production volumes being lower, as I just mentioned. All lease operating expenses noted here exclude Syncrude.

We have also made good progress in reducing our G&A costs over the past 12 months due to strategic restructuring and workforce reductions of approximately 35%. Second-quarter G&A is approximately 15% from second-quarter 2015. And, more importantly, we have been able to decrease G&A costs by 23% from first quarter of 2015, when we began implementing deliberate cost-reduction measures.

We continue to reposition our portfolio. Our current assets are more streamlined and concentrated than when we became an independent E&P Company almost three years ago. However, remaining true to our history, we are still a global, diversified, oil-weighted E&P Company that generates stable cash flow from long-lived conventional reserves primarily in Malaysia that are oil-weighted and priced to Brent, along with SK gas being priced with oil.

We have good positions from ground -- grassroots efforts, pardon me, and three premier North American unconventional plays that provide us short-cycle growth opportunities following our low-cost entry point. We continue to review our portfolio and will act when opportunities present themselves.

In our offshore Malaysia business, we are producing a 56,000 BOE per day during the quarter, with natural gas production from [Cerouac] registering $96 million a day. During the third quarter, we are planning a top-side installation in south access satellite platform. The wells were drilled earlier this year and expected to start producing in the fourth quarter. This top-side installation will allow us to maintain our current SK Oil production throughout the year and at maximum capacity.

As part of the improved oil recovery project in Kikeh, we installed a surface jet pump system during the quarter, now with a successful installation of the system resulting enhanced production. We will be installing an electrical submersible pump later this year. Further, we are planning a long-term gas lift project for this deal as well.

The Gulf of Mexico production in the second quarter was approximately 16,600 barrel equivalents per day at 83% liquids. The Kodiak well resumed production mid-quarter and is currently producing over 12,500 barrel equivalents per day gross. Options are currently being evaluated to comingle into an upper zone but expected to further enhance rates as well as an offset well opportunity. This project has been very successful for us.

Murphy holds a large acre position in Southern Australia's Ceduna basin, where we have seismic commitments only. Previously, we have acquired and evaluated sizing across our acreage and are pleased with the prospects we have seen. We feel this area could be greatly derisked by drilling that will take place in adjacent blocks, where BP and Statoil plans to spud the first of two wells this fall.
In the Eagle Ford Shale, second-quarter production was 47,500 equivalents per day. As planned, there were no new wells brought online this quarter. However, we did complete eight wells that are online in the current quarter. These wells are completed ahead of plan to synchronize completion schedules with offset operators and require the offset wells to be shut in.

In addition to these eight wells which are now flowing, there are 22 wells currently scheduled to be brought on during the second half of the year including two [Austin CHOP] wells: one in Carnes, and the other testing our most western acreage in Catarina. We continue making strides in decreasing drilling and completion costs as we average $4 million per well across the play, which is 25% below the [$5 million] per well in the second quarter of 2015.

We still have significant running room ahead for us here, with over 2,000 potential locations in the Eagle Ford Shale. Our reserves are oil-weighted at roughly 90%. The asset is very meaningful to Murphy's future preserved production cash flow.

Over the past several months, we have followed progress on two prior completed Carnes wells employing high-concentration sand fracks, allowing us to use a more aggressive choke technique. We’ve employed this technique on formal wells recently and planned -- and are on plan for more in the third quarter. Initial results are impressive with a 15% higher EUR and 30% higher IPs and offset wells. As stated prior, we shut in offset wells during the completion operations. After we brought these offset wells back online, we experienced an uplift in production from those wells. We look forward to bringing you updates as we move this technique across more of Carnes and into our Tilden area and also Catarina areas later this year.

We are further testing our stacked zone potential that exists across our acreage position. We are testing a new Austin chalk well along with three Upper Eagle Ford wells in Carnes in our latest high-concentration sand completion program. We also completing a new Austin chalk well in the Catarina area.

In Canada, our tougher Montney asset produced over $197 million a day for the quarter. There were 10 wells brought online during this quarter including two wells that tested extended laterals and increased proppant per lateral for -- in the completion phase. These wells are currently cleaning up with encouraging initial results. Look forward to bringing you updates in the third-quarter call.

As stated earlier, we closed the sale of our Montney natural gas processing plants early in the quarter. After including the new tariff associated with the sale, we expect well break-even costs for a 10% return to be $1.65 US ACO. And LOE for the second quarter was $0.63 per MCF, which includes the new tariff associated with monetizing Montney processing plants and pipeline. The greatly reduced drilling and completion costs and higher URs enable us to easily manage the new tariff and take advantage of monetization by deploying the proceeds into higher-returning assets. In terms of further enhancement, a long-term hedging program out to 2020 is part of our ongoing strategy.

We closed our previously announced joint venture in the Kaybob Duvernay and Placid Montney area mid quarter. We are just getting started on our operatorship with the Kaybob asset and are moving forward with development plans for the rest of the year and planning 2017. This time, we are completing a full oil pad in the condensate area of the play, and we anticipate drilling these wells very late this quarter or early next. We are also picking up the rig and plan to drill a four-well pad in the lateral area in quarter four and hope to have two wells drilled by year-end.

Our plan in the Kaybob area is to increase lateral links over time to 9,000 feet and pump fracks with 2,000 pounds per foot of sand, which we feel will lead to higher rates in the area of the play and offer upside for Murphy and our partner.

In the Placid Montney, we are a nonoperating partner at 30% working interest. The current plan is to drill 12 wells this year where drilling has already begun. The first padded well is anticipated to flow late this year.

As we close our call today, there are some takeaways. Murphy continues with our plan to reposition the Company and stabilize production and ultimately grow production as oil prices recover. This significantly reduced our 2016 capital program to $620 million as previously announced, and have recalibrated our annual production to 173,000 to 177,000 range after accounting for asset mix changes. Our key plays continue performing well in Malaysia and especially in North America unconventional onshore assets where we have significant upside.
We remain focused on our cost structure, and we’re proud of our plan to not issue equity in the price collapse earlier this year. And also during this time, we have been able to further strengthen our balance sheet by lowering debt levels.

I would now like to open it up for your questions. And thank you.

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**QUESTIONS AND ANSWERS**

**Operator**

(Operator Instructions) Paul Cheng, Barclays.

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**Paul Cheng - Barclays Capital - Analyst**

Several quick questions. I think from time to time, people are looking at your dividend. And I think last time you were mentioning that you guys will revisit it in August. Any kind of conclusion that you have come?

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

Thanks, Paul. Our dividend has been historically a long part of our commitment to long-term shareholders here at Murphy. Our dividends are viewed by the Board each quarter as common practice. It’s always been our practice also to review our annual dividend policy at our August Board meeting, which is scheduled for next week.

We will review our current financial outlook under various price levels and different options of capital allocation, and we’re going to present this to the Board and discuss it with them next week and announce it at that time.

**Paul Cheng - Barclays Capital - Analyst**

Do you -- at this point, at the management standpoint, do you believe that -- it looked like that your balance sheet situation is quite robust at this point or much improved. So, the need for any dividend cut is -- in theory is not as urgent as what it was six months ago. Don’t know whether you agree on that comment.

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

That would be getting ahead of the Board, Paul. And when you are in a chair like this, you stay in this chair by not getting ahead of your Board.

**Paul Cheng - Barclays Capital - Analyst**

Okay. That’s fair. On the Duvernay asset, can you give us some comparison on that asset that so far you learned compared to Eagle Ford?

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

We’re really pleased with it. It’s been a big transition. We have to take over the operations of the asset that currently has production. We are in a phase of doing that and plan to do so here very quickly. We are completing the four wells and are discussing the -- and being able to influence the completion with our partner. These are wells drilled prior. Probably it only -- 4,000 feet type laterals, and we want to get this lateral linked up and
get the sand up like we have been seeing recently in the Eagle Ford. We also see success at higher sand pumping with our friends in Encana and others in that play. And we want to hit the ground (technical difficulty).

Paul Cheng - Barclays Capital - Analyst
Hello? Hello?

Operator
We're experiencing a temporary interruption in today's call. Please hold the line.

Hello? Hello?
We're experiencing a temporary interruption in today's call. Please hold the line.

Everyone, we're still experiencing a temporary interruption in today's call. Please remain online. We will be resuming momentarily.

And once again, everyone, please remain online. We will be establishing the moderators' line once again. Please remain online, and we will start here momentarily.

And ladies and gentlemen, we are experiencing a temporary interruption in today's call. Please remain online. We will be starting momentarily. And in the meantime, I will feed music to the audience. When we restart, I will remove the music. Thank you.

(standby music)

And once again ladies and gentlemen, we are experiencing a temporary interruption in today's call. Please remain online. We will be resuming today's conference momentarily.

(standby music)

Ms. Whitley, please go ahead.

Roger Jenkins - Murphy Oil Corporation - President and CEO
It's Roger, everyone. Sorry about that. We have severe weather here in El Dorado today, and I went into a total blackout here. So I will go back answering Paul's question if everyone is back on the line.

Paul, Duvernay -- very pleased about that moving into longer laterals, taking over operatorship, more sand volumes, similar to Encana that are performing well in the play. And very looking forward to operating this asset. Like we say, we are drilling our first pad in the play in short order. and are completing four previously drilled wells today with our partner working together and moving forward as operator. And also pleased with our Placid Montney area as well.

Paul Cheng - Barclays Capital - Analyst
(inaudible) if I could, two final questions. One, I think in the past that you are talking about a total production runway for Eagle Ford. Since then, you have raised the total EUR for the area significantly. And now we also have heard that some number falling around -- talking about operate the gross 100% reduction of, say, 20,000 barrels per day by 2020 to 2021. So I just want to see whether you can confirm are those still a good number or whether those have changed.

And last question is that under what criteria -- or what is the criteria you would look at before you reconsider raising your CapEx.
Roger Jenkins - Murphy Oil Corporation - President and CEO

First on production, Paul, we have some of the new wells -- we've got four of the eight wells just brought on completed with these new techniques. They are doing very well. And our guidance for the quarter would have that in it, and I would say we'd be a little light on our fourth-quarter guidance as to more of those wells coming on. We have a big third quarter of well adds in Eagle Ford Shale. So, hold back on increasing the fourth quarter at this time. We'll do this thing one quarter at a time.

I'm not sure about your question about the 20,000 barrels over a certain period of time. Murphy is quite confident that when oil recovers into a near $60 level that we can achieve single-digit production growth in our Company and be free-cash-flow. We are very confident in that because of the three unconventionals we have and our very strong offshore base that we have. And I'm not sure if that calculates into the number that you have, but that's how we --

Paul Cheng - Barclays Capital - Analyst

The 20,000 barrel per day is talking about the Duvernay asset?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Oh, yes. That is still confirmed, and I think that we are building a ground-floor field development plan from grassroots up there, Paul, with the lateral-link sand, all the -- we are about to review that and move forward with that. And as I look at the -- probably some additional capital there for 2017 than we originally planned and I believe we would be well on to that number that you mentioned, yes. But that's Duvernay-only specific. So we want to replace the Syncrude production with the Duvernay as fast as we can living inside cash flow CapEx parity, Paul.

Paul Cheng - Barclays Capital - Analyst

All right. Thank you.

Operator

Ryan Todd, Deutsche Bank.

Ryan Todd - Deutsche Bank - Analyst

I guess like it's the (inaudible) with a little bit of a -- if we start with maintenance CapEx, I think Roger, in the past you have talked -- and maybe as a follow-up to the last question, you've talked about -- something about your ability to hold production flat to 2016's exit into 2017 potentially around [$800 million], [$100 million] a year of spend. Given your -- is that correct? Given your ability to do more with less this year, is that still the right number, or has that number come down?

Roger Jenkins - Murphy Oil Corporation - President and CEO

I think it would be on the lower end of what you just said, Ryan.
Ryan Todd - Deutsche Bank - Analyst
Okay. And then I guess as we think about cash allocation, I think there's been some concern that, despite a relatively intriguing Duvernay asset, you may be limited in your ability to allocate material CapEx direction in the near-term. I guess can you talk about priority of the capital allocation into 2017 and where the Duvernay fits in the pecking order there?

Roger Jenkins - Murphy Oil Corporation - President and CEO
We really have a lot of things to choose from in onshore. If you look at individual well economics today, our top two places would be our Catarina and Carnes area, probably over 40% with current May 25 strip prices. Duvernay light oil in the mid-30s there. And our Placid Montney also in the low 30s.

We're going to be probably moving -- we are just reviewing our capital for next year, but it's going to be a significant capital in there to build this production base, as I just answered the question for Paul. And we're in the middle of doing our 2017 plans, but this is going to -- our unconventional is going to be a lot of our CapEx there, Ryan, as you anticipate. And very pleased with the places I have to allocate capital. I wanted to have more competition for capital allocation. I'm going to do so, and we're going to be getting this CapEx up in Duvernay Shale to see what we have there pretty quick.

Ryan Todd - Deutsche Bank - Analyst
Okay. Thanks. I will leave it there.

Operator
Ben Wyatt, Stephens.

Ben Wyatt - Stephens Inc. - Analyst
I'll do a -- if I can have a follow-up here to the Duvernay question that was asked, as you guys get after it here in the back half, just trying to get a sense of maybe the pace of progress or the pace of change in how you guys complete wells. I believe I saw on the slide deck where you are going to start out at 2,000 pounds a lateral foot. I think people have gotten as high as about 3,500 pounds per lateral foot. Just curious how you guys are thinking about that for the back half of 2016. Do you just kind to stay at a pretty standard completion technique?

Roger Jenkins - Murphy Oil Corporation - President and CEO
We're going 2,000 on our operated area and working with our partner on their operated area. First step is to get the longer laterals and do that. It's my view, Ben, from the information that I have that 1,000 pounds per foot is quite common there now. There's been very few people stepping to the 2,000. I have not personally heard of a 3,500-pound-per-foot lateral.

But just like all things, we are taking over the operatorship, hiring those personnel into our Company, get our praxis in the field, drilling our first pad starting in October, November. Then we have to work on how long it takes to tie in wells and go through the field development plan of near infrastructure versus leased timing versus the best wells in the G&G and the best for capital allocation. We're in the middle of doing all that right now. I'm very pleased with this ground-floor buildup result. We'll be reviewing that in more detail quickly.

So, I think that we're going to start at the 2,000 pound per foot and go from there. And I think there will be a lot of information from that and the flow-back techniques and various other things that are critical to plays. But our experience of hundreds of wells in the Montney and the Eagle Ford...
and all types of experimentation around slick water and sand volumes will bode us well to move in here and really get off the learning curve very quickly, run by one single leader in all of our onshore business.

**Ben Wyatt - Stephens Inc. - Analyst**

Got it. Very good. Appreciate that. One more here. Maybe jumping over to the Eagle Ford, you guys have done a great job of lowering costs. Even this year, you guys have put downward pressure on costs and, I believe, just going around and drilling single, one-off wells. Is there more room there on the cost side of things, especially as you guys get back to pad development, or have you kind of squeezed all you can out of that?

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

Well, I keep thinking that it’s flattened on the drilling side, but we continue to improve. And you are right; we have had a lease maintenance CapEx here, and that leads to some of these timing issues on capital in the second quarter, and that’s why that capital was phased in that way. And that’s what the outcome is.

But we just drilled a record well last week. We drilled a well in Catarina over 12,000 feet in four days. I can tell you that’s incredible performance. And we -- so we haven’t even gotten into full back-pad drilling mode again, and I just see big upside. There’s discussions about service costs and large service players and that going up, et cetera, over time. But in the old operation days, it’s a day’s business. You have to be on wells less days no matter the cost, and really doing well there right now.

**Ben Wyatt - Stephens Inc. - Analyst**

Very good. Roger, I appreciate it. Thanks for letting me ask a couple.

**Operator**

Ed Westlake, Credit Suisse.

**Ed Westlake - Credit Suisse - Analyst**

Just wanted to get into a little bit of the well costs in the US in some of the new areas. Obviously, the Canadian dollar has come down as well, industry is doing better. So maybe just on the top of Montney, just any updates on well costs and well performance in terms of the UR there.

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

Our tougher -- the tougher Montney that we have, we’re looking at costs below CAD5 million right now total. And EUR is there. We have said previously that we want to get to 10 to 12 BCF wells there. We just did our first big high pumping of Sandwell, and we are pleased with the results there and think we’re going to get there.

**Ed Westlake - Credit Suisse - Analyst**

Right. And then in the Duvernay, these -- sort of 2,000 pounds plus longer laterals in Canadian. Where do you reckon those are going to come in?
Roger Jenkins - Murphy Oil Corporation - President and CEO

The current wells that we are doing, we inherited the wells from our partner. They are completing them. And they are currently using a -- you’ve got to keep in mind we just started working there over the last month. So they’re using a CAD9.5 million, which is $7.2 million kind of a charge there. And we know that these fracks went very well and are under the current completion cost of CAD5 million, which adds up to that number. And we are looking to drill and complete our own wells in the Kaybob light-oil area in the Northern condensate area of what we own for around CAD7.9 million going in is our goal, which is $6 million. And we’ve been really lowering costs in our Montney, which is 60 miles away from here. Learned a lot about that. Pad drilling, fracking, et cetera. And we believe we can drive these costs down to that level. We’re going to set a goal to do that, and I believe we’ll execute that.

Ed Westlake - Credit Suisse - Analyst

Okay. Thanks very much. And then I just wanted to -- I was listening, but just confirm that you feel that the underlying cash flow based on the first-half oil prices and ex-Syncrude, I guess, for the core portfolio in the first half of the year was closer to $3.75 if I understood that correctly, adding back the lease accounts -- I'm sorry -- the rig lease expenditure, how you've done that.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Yes, that's right. And, when you take out -- factor out the one-off cost of paying off the rigs, that we accrued those costs in the fourth quarter of 2015 but paid them in 2016. So you exclude that during the [$375 million] type number for the first six months for operating cash flow.

Ed Westlake - Credit Suisse - Analyst

Right. And then -- okay, that's helpful. Thanks.

Operator

Roger Read, Wells Fargo.

Roger Read - Wells Fargo Securities, LLC - Analyst

I think most of it has been said. But I guess maybe one thing to explore here -- you've done the asset sales. Originally we thought maybe a little more aggressive on the asset side in the lower 48. Recognize valuations may have gotten away a little bit there. But is there anything else that looks particularly interesting at this point other than the obvious if somewhere in Texas that you might want to grab?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Probably not out of there. We do have very active business development team at Murphy involved and always repositioning. I don't believe we are in the mode of doing a lot of shrinking right now. We want to keep what we have, but we're not against selling and buying and things of that nature.

We have a very active team that looks both at all of the plays in and around where we are working, and we are seeing some more data rooms and different choices there. And we look at them and study them and -- but we have a pretty high threshold to have strip price return at Murphy here, and we are real proud of our entry costs that we have in our three plays that we have.
Roger Jenkins - Murphy Oil Corporation - President and CEO

Thanks for that. And then thinking about the offshore, I know you don’t want to do a whole lot of exploration right now. But we’ve seen a number of companies sell offshore or attempt to sell offshore and, in some cases, walk away from what were at one time called discoveries. So was wondering, are you seeing any value? Or is it just far too early in the process or oil prices need to be higher to make something happen in the offshore if you decided to go that direction?

Roger Jenkins - Murphy Oil Corporation - President and CEO

No, we are very excited about these opportunities. We do have a very strong execution team in the offshore to operate any kind of facility or drilling wells anywhere in the world at any time. And we look at these opportunities. I believe that with the Deepwater rigs and the mergers of things like Technip and FMC, and you see Cameron and [Summerjay], et cetera, will lead to opportunity for lower costs there in a new starting point of a development, if you will. And we are poised to look at that where some others who may not have that ability or have no team or ability to look in Deepwater kind of leave that behind. So, many of those, and we would be looking at those on occasion. But we are pretty selective on it.

Roger Read - Wells Fargo Securities, LLC - Analyst

Okay. Thank you.

Operator

Paul Sankey, Wolfe Research.

Paul Sankey - Wolfe Research - Analyst

Most of the cash flows in Q2 were really low. Is there a particular -- were there any kind of one-off issues with that? I guess what I’m thinking is if we are in Q3 with a lower price, is there reason to think that cash flows would be stronger?

Roger Jenkins - Murphy Oil Corporation - President and CEO

I will let John answer that. But we have just a real payment of our accounts payable during the quarter, Paul. We don’t -- we feel confident in our total yearly projection. I will let John speak to that.

John Eckart - Murphy Oil Corporation - EVP, CFO

Yes, we did have some items, Paul, that hit in the second quarter that were accrued in prior periods, and that includes a significant amount of interest costs. Some of our restructuring costs were paid even though they were accrued for last quarter. So there’s a number of things that lag, if you will. Some of the cost reductions on our LOE are now -- in fact, we are seeing continue going down over time. But we have still paid for some of those in the second quarter. So it’s a timing matter as to when these bills catch up with the payments. So I don’t see anything in particularly worrisome with it, and it should balance itself out over time.

Paul Sankey - Wolfe Research - Analyst

Understood. Could you give us a sense for the scale of that? Or are you pointing us towards the full year -- is there guidance for the cash flow (multiple speakers)?
John Eckart - Murphy Oil Corporation - EVP, CFO

Well, I mentioned earlier, Paul, that we -- on a pro forma basis, the $750 million, when you annualize the six months, doesn’t seem crazy. In fact, we might be a little north. We'd be a little north of that on our internal projections. Again, subject to whatever prices do to us, and maybe they won't hold up very well. But we'll see.

But interest (multiple speakers) -- for example, interest in the second quarter was $40 million that we paid on our notes. So it's -- that comes in a lumpy fashion because we pay it semiannually instead of monthly or quarterly. So the things of that nature -- $10 million -- $9 million plus were the restructuring costs and things of that nature that were paid this quarter.

Paul Sankey - Wolfe Research - Analyst

Understood. That’s helpful. Thank you. What was the price assumption, you used the strip for the 750?

John Eckart - Murphy Oil Corporation - EVP, CFO

Yes.

Paul Sankey - Wolfe Research - Analyst

The $50 or around $50.

John Eckart - Murphy Oil Corporation - EVP, CFO

That’s correct.

Paul Sankey - Wolfe Research - Analyst

Understood. So it was definitely a one-off kind of thing this quarter. I get it.

Roger Jenkins - Murphy Oil Corporation - President and CEO

We have a pretty cautious EUR here. We think this is going to improve over time. But in certain portions of our light area, we are probably close to 700 equivalent type EURs that are around 80% liquids. In other parts of the more eastern area of light oil, approaching 500,000 equivalents, with around 80% liquids there. In the condensate, approaching 800 equivalents at 55% liquids. And then down in the Placid Montney, like 750 with 31% liquids, but we actually see around 42% at this time. So if you take those EURS and get into our ultimate cost of wanting to drill the wells for [$6.50] to [$6], I think it will lead to some pretty high rate of returns here. And we also have the infrastructure in place. We have adequate infrastructure built to handle a couple of years of growth here. And like I said earlier in the call, building our ground-floor field development plan, we are going to review it in September. And we liked it when we bought it and we love it when we own it now.
Paul Sankey - Wolfe Research - Analyst
Got it. What pricing dips do you get given the infrastructure position?

Roger Jenkins - Murphy Oil Corporation - President and CEO
We are using just current strips in there. That would be probably a little more conservative to the current strip when we make that assessment.

Paul Sankey - Wolfe Research - Analyst
Understood, but there's not a need to discount that against the (multiple speakers).

Roger Jenkins - Murphy Oil Corporation - President and CEO
We're going to build our facilities in a way to uniquely pull out the NGL and the condensate and the light oil, and we actually get a premium to WTI here. In the first quarter, it was a little bit below the premium due to the shut-in of the -- all of the mining which you are very familiar with. And -- but this is a nice situation. The WTI is definitely not a discount.

Paul Sankey - Wolfe Research - Analyst
Understood. Thanks, Roger. Have a good afternoon.

Operator
Guy Baber, Simmons.

Guy Baber - Simmons & Company International - Analyst
I just wanted to make sure I understand some of the earlier comments, so just a follow-up here. But is the general framework we should be thinking about is that you can grow in the single-digit percentage rate off your 2016 exit production base, which would be in the mid-160,000 barrel-a-day range assuming oil is near $60 a barrel? Is that the point at which you would consider growing? Do I have that correct?

Roger Jenkins - Murphy Oil Corporation - President and CEO
I would say that -- I'm not sure if oil will be in the $60s in 2017 right now. So if it's in the $50s, it would be more stabilizing in next year, and that's our goal. And then look to grow, let's say, a year from now when oil, we hope, approaches $60 again. It's all about cash flow and the CapEx and the oil price, Guy, as you know. But we have modeled a $60 flat price forever in our business that shows, post a year from now, we can start having 4% to 5% production growth with these type prices, and we believe in it confidently.

Guy Baber - Simmons & Company International - Analyst
And is the framework -- or is your primary objective still to spend within your cash flow and dividend? So, not outspending?

Roger Jenkins - Murphy Oil Corporation - President and CEO
Yes.
Guy Baber - Simmons & Company International - Analyst
Okay. Thank you. Appreciate it.

Operator
Brian Singer, Goldman Sachs.

Brian Singer - Goldman Sachs - Analyst
I wanted to see how you’re thinking about the block H expansion. As costs have come down globally, does that impact how you think about timing and incremental capital? Can you just give us an update there and how -- if that is above and beyond your growth and free cash flow metrics that you just laid out?

Roger Jenkins - Murphy Oil Corporation - President and CEO
That is not going to be a very large CapEx for us. I do not have that off the top of my head, as it has been moved out. Our partner, Petronas, is building a floating LNG ship in Korea. Due to capital cutbacks earlier in the year across all industry, because every NOC -- they have delayed that ship. It’s partially built today. It sits in Korea. And it will be coming to us around 2020 to 2021, I believe is the latest.

And we have to drill four or five wells there and do the tieback of pipelines. Naturally, if deepwater costs persist at this level, it will be much lower than we ever envisioned. This is a gain, Brian. It’s a $50 Brent gain, to give you the type of gas price to have nice returns here. This would be in our long-range plan program, but would be out in the -- we have agreed with them to delay it, and it’s in our assessment. And it’s a long way to 2020 from now in my life. So, that’s the game plan there, and it would count in the numbers I was just talking about with Guy on the phone.

Brian Singer - Goldman Sachs - Analyst
Great. Thank you. And then my follow-up is on decline rates. Can you give us an update on where you see your corporate decline rate and how is that -- how you see that evolving, particularly in some of the shale areas that have received less capital over the last year and probably seeing some moderation?

Roger Jenkins - Murphy Oil Corporation - President and CEO
We are about a 15% company, Brian. Today, I think it’s not -- as we come more shale-focused in the Company, if you look at something like the Montney, we believe that a year-one well is around 20%. A year-two of that well is 17%, and year-three, around 14%. So, not a large decline there. And of course, Eagle Ford would probably look at our current spending and growth plans around 20% in the first year, 17% in the second and 14% in the third. That’s based off of, as you know more than anyone, the timing of first-year, second-year, third-year shale wells of a declining decline rate, if you will. And we are reorganizing around that and feel good about the decline rates I just described.

Brian Singer - Goldman Sachs - Analyst
Great. Thank you very much.
Luana Siegfried - Raymond James & Associates, Inc. - Analyst

Hi, this is Luana Siegfried in for Pavel. Thank you for taking the question. It's a very quick one for me. I know it can be a little bit too early, but if you could share your expectations for the production ramp-up in Kaybob and Montney. And also any ballparks here for the incremental CapEx going forward, that would be great. Thank you.

Roger Jenkins - Murphy Oil Corporation - President and CEO

Our Duvernay is going to go to around $50 million for the rest of the year and a big growth in CapEx there. Around $40 million this coming quarter. And it's a little bit too early to get into our 2017, but if we are able to get our capital in a near-200 range, we can get that to 14,000 barrels next year.

Luana Siegfried - Raymond James & Associates, Inc. - Analyst

Okay. Thank you so much.

Sean Sneeden - Oppenheimer & Co. - Analyst

John, maybe for you, can you talk about the credit facility refinancing process at this point? I guess with nothing drawn on the facility, how are you guys thinking that it's impacting the negotiations? I guess specifically, are you guys thinking that you might be able to keep that facility unsecured, or can you give us any guidance on how to think about that?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Sean, we are working it. We are very close to having it completed. It is going well. I think we are pleased with where we are at. And I think really we will announce that here in the next couple of weeks, I think, or so if all goes -- continues to go the way we are working it. So I think we are in good shape on it. And I think at that -- other than that, I would probably just need to not say much else. We're really happy with the progress thus far with it.

Sean Sneeden - Oppenheimer & Co. - Analyst

Would it be fair to characterize it as not really adding any additional complexity to your capital structure as it stands today?

Roger Jenkins - Murphy Oil Corporation - President and CEO

Well, I guess we will just talk about that later on. But overall, our projections, Sean, in terms of your other question, were that based on cash flow of strip prices and our spending plans, we should be able not to draw down on it. And our plans are to do that as little as we can with the ups and downs of the daily cash ins and cash outs. So our plan is to keep it as low as we can keep it. And for the rest of the year, that is quite low, we believe.
Sean Sneeden - Oppenheimer & Co. - Analyst
Right. That’s fair, and I appreciate the -- what you can share there. If you don’t mind, just two quick housekeeping questions. I guess one on the Eagle Ford, LOE has ticked up a little bit sequentially on a unit basis. So was that just due to the drop-off in production or was there any kind of one-time items associated there?

Roger Jenkins - Murphy Oil Corporation - President and CEO
That would be primarily that. You are correct, Sean.

Sean Sneeden - Oppenheimer & Co. - Analyst
Okay. And then just kind of bigger picture, how should I be thinking about differentials on gas as you guys ramp up in the Duvernay?

Roger Jenkins - Murphy Oil Corporation - President and CEO
We are seeing some very high differentials now in the $0.95 range, something to that effect. But in the forward curves that are out every day, those diffs are coming down. We do see -- we are looking to do some more hedging volumes now at CAD3 through 2020. And we’re seeing the differentials tighten in 2017, 2018, 2019 to back to like a more traditional 70% to 75% number. There is also some ability to hedge some of those differentials which we are exploring. And we see that getting tighter. We see good news in storage today impacting that, and pleased with how that’s going. But mostly pleased in our lower LOE, our lower drilling costs, and building how this tariff and blended in with the Company to do really well. So, that’s the main thing: got to have those assets.

Sean Sneeden - Oppenheimer & Co. - Analyst
Right. That’s helpful. And just to be clear, that $0.95 differential, is that Canadian you are talking about?

Roger Jenkins - Murphy Oil Corporation - President and CEO
I believe that’s USD. I’m sorry, I just was looking on my computer, and I don’t have it right in front of me right now.

Sean Sneeden - Oppenheimer & Co. - Analyst
Okay. Thank you.

Roger Jenkins - Murphy Oil Corporation - President and CEO
Okay. Any -- there’s no more questions in our queue. That’s all our call today. We appreciate everyone calling in. Appreciate you staying with us during this power disruption. And we will be speaking to you next quarter when it’s football season. Looking forward to that. Take care.

Operator
And with that ladies and gentlemen, this does concludes today’s call. Let me thank you for your participation. You may now disconnect.