Co. reported 2Q17 consolidated loss of $17.6m or $0.10 per diluted share.
CORPORATE PARTICIPANTS

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PRESENTATION

Operator
Good day, and welcome to the Murphy Oil Corporation Second Quarter 2017 Earnings Conference Call. Today’s conference is being recorded.

At this time, I would like to turn the conference over to Kelly Whitley, Vice President, Investor Relations and Communications. Please go ahead.

Kelly L. Whitley  Murphy Oil Corporation - VP of IR & Communications
Good morning, Andrew. Good morning, everyone, and thank you for joining 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 that we have placed on the Investor Relations section of our website as you follow along with our webcast today. John will begin the call by providing a review of the second quarter financial results, highlighting our balance sheet and strong liquidity position, followed by Roger with second quarter highlights and operational update of which questions will be asked afterwards.

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 2016 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 W. Eckart  Murphy Oil Corporation - Executive VP & CFO
Thank you, Kelly, and good day to everyone. Murphy Oil’s consolidated results in the second quarter of 2017 were a loss of $17.6 million, $0.10 per diluted share. That compares to net income of $2.9 million, $0.02 per diluted share in the same quarter a year ago. Excluding discontinued operations, our continuing operations had a loss in the second quarter of 2017 of $17.4 million, also $0.10 per diluted share. Our adjusted loss, which adjust our GAAP numbers for various items that affect comparability of results between periods, was a loss of $19.1 million, $0.11 per share in the second quarter 2017.

Our schedule of adjusted loss is included as part of our earnings release and the amounts in this schedule are reported on an after-tax basis. Our balance sheet continues to show low leverage with ample liquidity and manageable debt maturities. At June 30, 2017, our total debt was $2.9 billion or 37% of total capital employed, while net debt was 27% of capital employed and amounted to $1.83 billion. At the end of the second
quarter, we had no outstanding borrowings under our $1.1 billion revolving credit facility, and cash and invested cash balances totaled $1.1 billion at quarter end.

Following the December 2017 bond maturity of $550 million, Murphy does not have further debt maturities until 2022. Our oil and natural gas revenue for the quarter totaled $509 million. That’s a 24% increase from the same quarter in 2016. In order to underpin our cash flow, we hedge a portion of our oil and forward sale a part of our natural gas production. At the end of the quarter, we had 22,000 barrels per day of oil hedged at $50.41 per barrel WTI for the second half of 2017. On the natural gas side, we had 124 million cubic feet per day forward sold at AECO at CAD 2.97 per MCF, for the balance of this year and as well, we had 59 million cubic feet per day at AECO at CAD 2.81 per MCF for 2018 through 2020. We’ve also a contract for 20 million cubic feet per day at Chicago Citygate priced at $3.51 per MCF for the period of November ’17 to March of ’18.

That concludes my comments. And I will now -- Roger will now present a review of the company’s operations.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

Thank you, John. Good morning, everybody, and thanks for listening to our call today. In second quarter we produced 163,000 barrel equivalents per day, caused a balance mix between onshore and offshore production, with the onshore business producing 51% liquids and our offshore business producing 71% liquids.

For the quarter, the company invested $201 million in capital projects, which is in line with our 2017 capital budget of $890 million. The conservative balance sheet management, ample liquidity, cash on hand will continue to build positive financial momentum as we progress through the year. Our diverse asset base provides a competitive margin and our $18 EBITDA per BOE for the second quarter. We continue to maintain our top quartile dividend yield in this challenging commodity price environment, while paying our way and living within our cash flow.

Operationally, we’re successful accomplishing all of our 2017 goals. We’re progressing our Kaybob Duvernay appraisal plan and we’re pleased with our above planned early results. In the Eagle Ford Shale play, we continue to cost-effectively capture additional resource by using our cube multi-dimension completion design. In our Tupper Montney asset, we committed to bring forward value by accelerating long-term growth for additional takeaway commitments.

In our offshore assets, we’re continuing to execute on highly economic production optimization projects and enhance our exploration portfolio. In Malaysia, we’re achieving stable high-margin production, implementing innovative projects, such as surface jet pumps and dry treatment of gas with subsea equipment. In Vietnam, we drove the discovery well in the Nam Con Son Basin. In the Gulf of Mexico, we continue to progress evaluation of our Mexico deepwater Block 5, which is near a recently announced major discovery.

And now a look at the second quarter in more detail. Production in third quarter is expected to be in the range of 156,000 to 158,000 equivalents per day. Third quarter production guidance is below our second quarter actuals due to preplanned downtime work at our Sarawak oil and gas fields and our non-operated Terra Nova field in Eastern Canada, as well as the loss of the non-operated Kodiak well in the Gulf of Mexico, which is awaiting repair work. There’s also planned downtime at the Keyera processing plant at Kaybob Duvernay. This temporary production outages are approximately 10,000 barrel equivalents per day are partially offset by new wells we’re planning to bring on the North American Onshore business and better performance in offshore totaling approximately 4,000 equivalents per day.

The annual 2017 capital budget is being maintained at a $890 million. The full-year 2017 production guidance has been tightened to 163,000 to 167,000 equivalents per day with North American Onshore production [set to] increase by over 15% from fourth quarter 2016 to fourth quarter 2017, as a result of continued ramp up of activity in our onshore and [traditional] business as we progress through the year. Our teams continue to be focused on creating substantial cost efficiencies that have and will continue to lead toward lower operating expenses and data analytics is one of the tools that helps us do that. Our use of data management is one of the reasons we see the lowest level of quarterly operating expenses per BOE in over a decade.

In our offshore operations, we have 9 [unmanned] platforms in Sarawak which utilize high-frequency data capture curation and visualization which enables remote natural gas platform operation from an offshore central facility, which minimizes operating complexity, manning requirements...
and cost. The use of data analytics allows [valuable] decisions to be made regarding [treatment] quality, specifications volumes and chemical management.

In our Eagle Ford Shale business, we've established a 24-hour remote operating center in Houston. We've had this center for some time that enables us to monitor every well and facility in real-time. We use the data-driven pipeline management systems that utilizes data and dashboard, incorporates real-time information, and enables intelligent decision making and specific key performance indicators for monitoring our pipeline operations. Optimizing activities based on database analytics has aided in lowering OpEx at the Eagle Ford Shale over 15% from the past year. We've also reduced downtime about 50% over 18 months in using this 24-hour day operating center.

In our offshore business, we produced 77,000 equivalents in the second quarter with 71% liquids. And our offshore Malaysia business Block K and Sarawak produced over 34,000 barrels equivalents per day during the quarter with natural gas production from Sarawak averaging 113 million per day. Our Malaysia assets are very steady cash flow generating business and we continue to make great strides in lowering operating expenses in that region. Our Malaysia business delivered almost $112 million of free cash flow this quarter.

In the Gulf of Mexico and East Coast Canada, production for the second quarter averaged over 22,000 equivalents per day with 91% liquids. Our Kodiak field has been shut-in since early June due to an issue with the downhole tubing string component, and we expect it to come back online prior to year-end.

In Vietnam, we drilled an oil discovery at the CT-1X (inaudible) in Block 11-2 and we're evaluating this discovery with our partner. Following the discovery, the second exploration well on the block was delayed in order to plan for a location of further testing of the interval discovered in the CT-1X well. The second well in the plan named CM-1X will be drilled later in this quarter. In the Cuu Long Basin, we're working with our operator on Block 15-1 LDV discovery for sanction next year, as well as planning an additional exploration well.

During the second quarter, we signed an application for 35% working interest in the adjacent 15-2 Block as operated. But we will ultimately target a feature similar to our successful LDV project in the adjoining block.

In Australia, we're positioned in 2 promising exploration areas, the Ceduna and Vulcan Basins. (inaudible) our Ceduna acreage is having significant exploration, recoverable resource potential with 5 Tier 1 leads of over 300 million barrels equivalent identified and 50 leads overall. We have no remaining commitments on our block. We're pleased to see the nearby leaseholders reorganize their well commitments to facilitate drilling in this exciting, untested basin.

In the Vulcan Basin, we're maturing multiple leads in the Murphy-Developed Jurassic Play Fairway, we believe that these shallow water high-margin prospects hold up to 200 million barrels equivalent on each location. In the deepwater of Mexico Block 5, we continue to progress through the drilling approval process, with plans to start our first exploration well in late 2018 and early 2019. We continue to mature multiple leads and see prospectivity of up to 1 billion barrels of recoverable oil potential on our block. I'm particularly encouraged by the shallow water Zama discovery recently announced by, Talos, Premier, Sierra. This discovery well is located approximately 15 miles south of our deepwater Block 5, with prospective Miocene section in Zama mapped onto our block.

These are examples of high-impact exploration opportunities that allow us to take advantage of our considerable in-house offshore expertise. We believe in maintaining global exploration and replenishing our portfolio as we are now in exploration sweet-spot at the bottom of this extended cycle.

At Eagle Ford Shale, second quarter production averaged near 46,000 equivalents a day at 87% liquids. Over 19 new wells brought online of which 2 in Austin Chalk, 1 in Upper Eagle Ford Shale and 16 in Lower Eagle Ford Shale, primarily in our Tilden area. During the second quarter, we completed 11 wells using new slickwater completion style with tighter cluster spacing, and higher concentrations of finer mesh sand, we call Generation 5.0. Of these 11 wells, 8 outperformed their pre-drill IP30 estimates by over 30%. As a result of these positive outcomes, we've continued to use this completion style more widely across the field, which leads to additional resource recovery over the long term.
In the third quarter, we plan to bring 24 Eagle Ford Shale wells online, of which 14 in our Karnes and 10 in our Catarina area. These additional wells are in our core areas and we will drive production increases to year-end. We continue to operate Eagle Ford Shale very efficiently with improving operating cost and continuation of drilling pace-set wells in the play.

Stacked pay potential exists across the majority of our Eagle Ford acreage. We’re progressing our new development optimization program called Cube Design with a 4 to 5 well pad layout. Each well is drilled, will target either lower Eagle Ford or Upper Eagle Ford or Austin Chalk. We expect to gain efficiencies by employing this Cube Design by minimizing our offset frac heads and enabling us to accelerate production. For example, in Karnes, the cube style development in 4 different pads in the second quarter, we’re able to successfully test down spacing of our Lower Eagle Ford wells, 250 feet. For the second half of this year, we’ve started to test down spacing, now focusing on the Catarina area. We continue to be pleased with Austin Chalk execution where 2 new wells are brought online in the quarter. One well is drilling in the conventional landing zone, while the other is drilling in the higher landing zone. The well that’s drilling in the higher zone outperformed pre-drill estimates by over 45%. As compared to the other well, that utilized the conventional landing zone and performed in line with pre-drill expectations.

We signed 2 additional Austin Chalk wells over the last 2 years. In Canada, our Tupper Montney asset produced 204 million (sic) [cubic feet] a day for the second quarter. Early in the quarter, we brought 5 wells online, 3 in Upper Montney, 2 in the middle. All the wells are exceeding expectations with projected ultimate recoveries on trend to be an 18 BCF per well type curve. Our new 10,000 foot lateral high-sand concentration wells continue to validate outstanding sub-service performance in our multi-branched Montney asset. Our development plan has been to drill-to-fill strategy that will allow growth with additional available processing capacity of [80 million a day] by late 2019.

Murphy is taking the first step in bringing forward additional value in our Montney asset by committing to long-term volume expansion, TransCanada, for an additional 200 million capacity, we expect to be available in late 2020. To implement this expansion we executed a FEED contract with Enbridge for additional processing capacity planned for the project to be sanctioned in the first quarter of 2018. The project will have full cycle returns upward of 30% and bring value forward in this low-cost long-life asset with solid subsurface deliverability. Our full cycle breakeven -- remain below $2 per MCF Canadian AECO with current royalties of approximately 3% to 5%.

In our Kaybob Duvernay asset, production for the quarter averaged over 3,500 equivalents, which is an increase of 24% from the previous quarter to 58% liquids. We brought 2 new wells online with a 04-32 two pad in oil window, they’re significantly outperforming pre-drill expectations. We also brought 3 new wells online early in the third quarter at 11-18 pad. These wells on the boundary of the oil and condensate window. These 5 wells are the first wells drilled and completed in [pulling] Murphy well-designed at this time.

As part of our ongoing dynamic field appraisal, each of these 5 wells was completed with different completions designs and flow-back plans in order to help us determine the best forward path for our play development. We’re pleased with our progress in delineating and appraising the play. Similar to the Montney, we also have lower royalties in the Duvernay which are (inaudible) near 5%. The lower royalty with low-cost entry will allow for very low [full] cycle well economics.

The 04-32 2-well pad in the oil window was brought online in the second quarter. The 04-32C well was drilled with a lateral length of over 7,400 feet and completed with slick water frac of 3,000 pounds per foot sand concentration. The well significantly outperformed its type curve with a peak rate of over 2,000 barrel equivalents per day and an IP30 of approximately 1,800 equivalents per day with 75% liquids. [We will use current] public data. The well appears to be the best well in this region. 04-32D was drilled with the lateral length of over 8,000 feet and was completed with a gel frac at 2,000 pounds/well [sic] sand concentration. This well is also outperforming its type curve with an IP30 of over 900 barrel equivalents with 75% liquids. The 05-29 pad also continues to flow on trend with its pre-drill type curve 665,000 equivalents, which is 70% liquids, as well as stimulated with only 1,000 pounds per foot of sand and gel (inaudible) slickwater treatment with much larger cluster and stage spacings compared to our current well plans. This well was [started to plan] for over 4 months. This year we’ll drill 16 wells and complete 10 in the Duvernay, as we progress through our 2017 plan, we shifted our well sequencing. We expect to bring the wells online in Kaybob west and drill wells closer to existing infrastructure and processing capacity with (inaudible).

We’re progressing our 2017 plan and we’re pleased with our execution. We’re executing our top quartile EBITDA for BOE metrics, which is a benefit of our diverse asset base. With conservative balance sheet management and ample liquidity, we’re building positive financial momentum. Onshore assets continue to outperform (inaudible) employ higher sand concentration fracs for longer lateral wells. We’re progressing our Kaybob Duvernay...
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appraisal plan and we're encouraged of our strong early results. In offshore assets, we continue to execute on highly economic production optimization projects and enhance our exploration portfolio. We remain focused on evaluating both onshore and offshore opportunity as we position the company to grow long term. This concludes our remarks today. I'd like to open up the phone lines now for your questions. Thank you.

QUESTIONS AND ANSWERS

Operator
(Operator Instructions) Our first question comes from Arun Jayaram with JP Morgan.

Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst

I was wondering if you could either help us think about your initial read of your Duvernay results. Looks like some of the wells are outperforming your type curve. So I just wanted to maybe if you can give us some baseline on where D&C costs are today. What kind of EURs do you need to see to, where you're [hurdling] kind of EUR and what do you think these most recent or your early completions are tracking towards in terms of an EUR basis, pardon me.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

Arun, this year, we drilled these wells. We've been very successful at understanding and managing, and drilling very long-lateral wells. As a matter of fact, this week, we just drilled a well almost over 9,000 feet for around USD 2.5 million. So we've been very successful and consistently drilling the wells below $3 million, the longest laterals ever drilled up in that region. Unfortunately, some of our wells, we've had a problem with casing failure that had to be repaired and some of our wells had to do with some corrosions, some pipes stored inappropriately. That has caused us some setbacks in the timing of the completion. And those costs, when neutralized out which are one-off [current is with 50s] cost of these wells, they're around $10 million. We've yet to have pad -- we pad drilled 3 wells together, but the completions are all extremely different. So yet to set up water management infrastructure, we've yet to go to full pad drilling and get into a motion of manufacturing, if you will. We feel very confident of that, over time, lowering these costs by 30% to 40%, which we've done in all our plays, Montney and Eagle Ford, where we drilled thousands of wells. And we see that getting into the -- our goal of $6.5 million. We see that fully in range. I've seen the drilling greatly improving of late. Like I said, with actual data. And that's going to lead to some really nice full cycle, again, economics here, breakeven process around $40 in this play due to our low-cost entry, lower royalty and improved -- moving to pad development. The EURs will be various across the play. We've [proved up] pretty solid, it's around 900 EURs in some of the volatile oil condensate regions. We're working around 600,000 EURs in our more northern part of Kaybob West. We consistently seen this perform, saw this 05-29 perform at a very low frac volume for a long time. And if you look at the EURs in Eagle Ford, this is similar to that or larger than that. But the royalty is much, much less. So this is a value creating thing, low entry, old Murphy strategy at work and working through it and we're very pleased with what we're doing.

Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst

Great. That's helpful. My second question, Roger, as you have now secured some midstream or takeaway in the Montney, can you talk about capital allocation to that place. And where are you kind of moving capital as the Montney looks like it's going to take an increasing part of the pie on a go-forward basis.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

All of our capital plans for the last couple of years have included our drill-to-fill strategy. We have some peers that flow to some of our facilities to date, both the Tupper main and Tupper West. These 2 -- these 2 strong gas peers have -- will be pulling off some of the capacity between now and late 2019. So we're going to be replacing that and that's always been planned. The new bring forward values to actually add on top of that original
plan, another $200 million a day into a situation where we could continue to add $200 million increments if we choose to do so. The cash flow from this asset with the infusion of around $100 million above the cash flow of the asset only will allow us to get to this new $200 million and can expand from then on with the cash flow provided by the asset. And this very low AECO breakeven price, with that ability of free cash to build is going to be very much accretive for us to bring forward this cash now.

Operator

And our next question comes from Ben Wyatt with Stephens.

Benjamin James Wyatt - Stephens Inc., Research Division - Senior Research Analyst

Roger, I'll hop over to the Eagle Ford, if we can. You guys had some commentary on the new completion design over there. Just curious, if that was all tested in Tilden or if you were able to go to other assets in the Eagle Ford and try that? Just trying to get a sense of how confident you are in this completion design? How portable it is to the other Eagle Ford assets?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

We see it to be real portable. For the quarter, let me get my sheet here. For quarter 2 -- in the -- in the quarter -- let me see here, had the wrong page here. In the quarter 2 wells we delivered. Let me just go ahead and answer the question. I'm fairly confident of the answer. It's very portable and can be moved between Tilden and Eagle Ford, Karnes pretty easily. I'd say the wells are around 50-50, around where we experimented both in Tilden and Karnes area and made both of them very helpful.

Benjamin James Wyatt - Stephens Inc., Research Division - Senior Research Analyst

Got it. Good stuff. And then maybe just now thinking kind of on the offshore international, you guys are clearly excited about that. It seems like costs are really coming down and are competitive now. Just curious if you guys could -- if we think out to maybe next year, maybe how that -- how the budget looks, how that capital is allocated, maybe as a percentage of the total budget, like I said, as we think about '18?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

I would imagine exploration spending for drilling wells would be like 7% to 10% of the budget because that's similar cost-to-date of 30% to 40% of the budget. So it's very inexpensive to participate in these opportunities. We've completely changed our exploration team over the last several years. Total different strategy, we're bidding in places that have a lot of competition with a lot of success. Our partner in our block is the same partner of the major successful block in Mexico and we're going to drill 2 to 3 wells next year for sure. And targeting to drill in Mexico in late year, working through the permitting process they have and very excited about where we're working, who's following us around, where we're working. Our partnership levels, our working interest, not at a high working interest and more -- have more opportunities and it's going really well for us.

Operator

Our next question comes from Paul Cheng with Barclays.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Roger, in Eagle Ford, I think, your last estimate is you have about 800 million barrels of resource still remaining. What will be the sweet spot on longer term? Are you still looking at just 50,000 barrel per day or that is going to be 60,000 or 70,000? I mean, how should we look at it longer term?
Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

The -- of course, we're not -- we're revitalizing our budget and long-range plan. I'm also pleased with that. But I think when you think about that business next year around, 47, 48 business, probably get into the low 50s for '19 and '20 and then [all go up] into the high 50s in '21, '22 and probably staying at that level.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

So it would be somewhere between 50 to 60, you believe in this, for you.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

Yes.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

And do you actually have a preliminary outlook for 2018 CapEx reduction?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

No, Paul. It's not even time for your conference yet, Paul. And I won't say -- and I won't say it there either. We're -- let me just make a statement about that. We're like anyone else here as late and around where we work and we have very successful wells on our onshore business, too. And we're increasing EUR per-well, we're doing very well with that. Increasing IP30 per well. We're ahead of where we were a year ago on that. Our offshore asset, especially in Malaysia, are holding up better than we thought a year ago. And we're progressing our new Block H LNG project is coming along nicely with that situation, so solid long term. So is our gas business, it's going well for us. And with that backdrop, we of course will be reworking our plans and looking at oil prices, et cetera. I'd say (inaudible) high level WTI in a 48 to 49, 2018, 2019 number, keeping our debt levels the same as they are today and ending up around, you know $52 in 2022. We still deliver our single-digit 7% to 10% CAGR there, paying our dividend. And we're happy about where that's positioned. And we will have the ability to do that and we're working toward finalizing, and working through those plans over the next few months.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Roger, if we're looking at unit now in CapEx. Looks like in Duvernay you're going to spend more money, in Eagle Ford probably not, in Montney, in the Canadian gas, you're probably spending more money for the growth. So should we assume that the CapEx is going to up at least for next year, maybe by a couple hundred million dollars?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

We're working toward trying to get to $1 billion. Yes.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Okay. On the -- I just want to clarify that based on your press release, so should we assume by the -- towards the end of 2020, your Canadian gas will be roughly about 500 million cubic feet per day?
Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

That's exactly where it will be.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Okay. Two final ones, real quick. Do you have a pre-drilled resource estimate you can share for CT-1X discovery? And so far, do you see if it's any different than that number?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

What we have here is a series of very small fault blocks. We probably have 10 million to 12 million barrels discovery where we originally drilled, the well we announced today. This is shallow water jack-up territory, very similar to some of our Sarawak field that we put online. Been very, very successful there. And we're drilling another fault block of a similar size. There's around 4 other of these fault block opportunities. These are around $8 million net to Murphy to drill these wells, very inexpensive, very low F&D, very low breakeven. There's another discovery by another party in the southern part of this block, a large gas discovery that goes into our block. It's possible, we would work with that party in the development or that -- or sell to that party or monetize into capital allocation. But we want to do several of these smaller fields at this time. And we're really happy, this well had a lot of pay in it over several hundred feet of pay in a very small fault block and made us change our drilling position to where we are today and it's just a small, very high-margin shallow water business that we've been very successful at running in Malaysia for a long time. For over 10 years.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Great. Final one. Malaysia Block K floating LNG or flexible LNG. Are we still looking at the 2020 start-up? Or that has been changed?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

No. It's maintained.

Operator

(Operator Instructions) We'll take our next question from Muhammed Ghulam with Raymond James.

Muhammed Ghulam

This is Muhammed on behalf of Pavel. My first question is regarding Vietnam. The discovery you announced there earlier today, I guess last night. How much future activity do you anticipate before you can assess the resource base present within the country?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

Well, we have 2 blocks there. We have the Nam Con Son Basin and the Cuu Long Basin. Nam Con Son is a block we've had for a few years. We have 4 to 5 similar sized opportunities. So what we're drilling today, our well, recently was discovery in a small fault block area. It's just a matter of time to gather smaller fault blocks, which we've done very successfully before in our shallow water business. In our 15-1 business, we see this field that we've discovered as a near 100 million barrel discovery gross recoverable resource. We're working with our partners toward the final (inaudible) development and sanction. It's a very nice opportunity of an exploration well next door to that. And now, a new opportunity of a similar feature
bringing onto a new block that we just picked up in an application with PetroVietnam. We have yet to hit a water level on our field that we've discovered in 15-1. I see this is as low-risk, low-cost exploration, could be very positive for us in a region where we've been very, very successful, very, very well known for operating and building cost structure ability. And so we can, I believe we can build a solid offshore business in shallow water Vietnam.

Muhammed Ghulam

Second one is about CapEx. We've seen various operators reporting that service costs increases have subsided over the past few months. What are you seeing in your portfolio?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

We, of course, have seen some completion cost, but then we made it through half the year without as much impact on that. It's coming more to bear, primarily in the Eagle Ford Shale, nowhere else in our business are we seeing it, primarily around frac-ing, probably talking around 20% increase in our completion cost for the wells. Drilling has hung in there very well. We continue optimization and ability to drill pace set of wells, primarily in Catarina where we actually drilling wells for barely $1 million in only 4 days, 4.5 days in some situations. Our total CapEx, we have reflects, the rest of the year, these costs have been -- completions going up. We've managed that through CapEx efficiencies in some of our artificial lift and electrification projects and other projects that we have in the Eagle Ford. They would stand by our CapEx for the year and actually deliver a few more wells in Eagle Ford than planned. And I'm pleased with our handling of that situation. Canada, we're not seeing a problem with it. And this is more about efficiency in Canada, lining up to do the same completion repeatedly. And we will then have a nice situation there where our ability to lower days to the efficiencies is just getting started.

Muhammed Ghulam

And last one for me. Can you talk about your Australian operations and what your plans are for the country? And what's going on over there right now?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

Well, we have some very nice exploration blocks, a very small team that works on that in our company. They are true experts around these 2 regions. We have all of our 3D seismic shot in our Ceduna Basin, fully loaded in our workstations, enormous prospects here, very large prospects. We just need some drilling to go in the area and we're hoping that super majors nearby will go through with their plans if they reorganize, which is very positive for us. Vulcan Basin, no well commitment, seismic, very inexpensive, built a very nice business there, ground floor, grassroots, old style exploration with a very experienced team that worked in this region for another major company. And we will be looking to drill there probably in the '19 to '20 time frame and be monitoring what goes on in the Ceduna Basin during that period. So it's probably a 20-20 plus kind of deal for that. But I'm very pleased with the prospectivity we're seeing right now.

Operator

And it appears there are no further questions at this time. I'd like to turn the conference back over to our speakers for any additional or closing remarks.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director

No, we have nothing left today. This was a nice call. We appreciate everyone calling in. And I look forward to talking to you later this fall. Thank you. Appreciate it.
Operator

This concludes today's conference. Thank you for your participation. You may now disconnect.