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UPL - Q2 2018 Ultra Petroleum Corp Earnings Call

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PRESENTATION

Operator

Good day, ladies and gentlemen, and welcome to the Ultra Petroleum Second Quarter 2018 Earnings Conference Call. (Operator Instructions) As a reminder, this conference call maybe recorded.

I would now like to turn the conference over to Sandi Kraemer, Director of Investor Relations. You may begin.

Sandra D. Kraemer - *Ultra Petroleum Corp. - Director of IR & External Reporting*

Thanks, operator. Earlier this morning, we included in our news release results for the second quarter and updates for 2018. In this call, we will provide additional information with our prepared remark along with references to our updated investor presentation that was posted earlier today on our website.

I'd like to point out that many of the comments during this conference call are forward-looking statements that involve risk and uncertainties affecting outcomes, many of which are beyond our control and are discussed in more detail in the Risk Factors and Forward-looking Statement section of our annual and quarterly filings with the SEC.

Although we believe these expectations expressed are based on reasonable assumptions, they are not guarantees of future performance and actual results or developments may differ materially. Also, this call may contain certain non-GAAP financial measures. Reconciliation and calculation schedules can be found on our website.

I thank all of you for joining us today. With me today is Brad Johnson, our interim Chief Executive Officer; Garland Shaw, our Chief Financial Officer; and Jay Stratton, our Chief Operating Officer. Now I'll turn the call over to Brad.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Thanks, Sandi. Good morning, and welcome to Ultra Petroleum's second quarter conference call. Today, we will review the quarter's financial results and focus most of our time giving you an update on our horizontal well program, our vertical program and outline our path forward.

Ultra is in the beginning stages of developing the Pinedale Field with horizontal wells. Like other basins, such as Permian and Eagle Ford, with successful horizontal plays, the effort is no small task, and it requires a systematic and data-driven approach to successfully execute on this objective. With 78,000 net acres and an operating team that has drilled more than 2,100 vertical wells in Pinedale, we're uniquely positioned to lead this effort, but it will take time and patience as we optimize our learnings and delineate Pinedale's significant horizontal potential.

As we pursue this resource expansion, we remain focused on capital efficiency, disciplined growth, free cash flow generation and the pursuit of higher returns in order to drive sustainable shareholder returns. Even in the current gas-price environment, Ultra's vertical inventory of more than 4,000 locations gives us the foundation to generate free cash flow while we delineate the horizontal potential in a more controlled and methodical manner going forward.

I want to quickly go through some of the highlights for the quarter that we've included on Slide 4. Production in the quarter came in at the low end of our guidance range. Pace of production remained strong, but our wedge volume from new horizontal wells came in below expectations. As a result, EBITDA for the second quarter was also below expectations. Cash costs beat by $0.04, driven by lower net gathering fees benefiting from increased processing revenue.

As we outlined last quarter, we embarked on a ramp-up of horizontal activity in Pinedale based on extremely encouraging initial results. We've brought online 11 horizontal wells in the quarter, all in Lower Lance.

This effort has yielded a wealth of information about the opportunity to expand the resource potential of our Pinedale asset. It also came with more variability than anticipated. Based on results to-date, we've increased the number of intervals in the Lower Lance from 4 to 5 and further defined 2 specific target zones in each of those 5 intervals.

Later on in this presentation, Jay Stratton, our new Chief Operating Officer, will provide more details on our results and forward plans for optimizing and enhancing the horizontal program.

The existing production from our vertical well program continues to generate the revenue and cash flow to support our horizontal program. In the second quarter, our operated vertical wells posted initial average production rates of 8.8 million cubic feet equivalent per day. Since the first of the year, we've been providing updates on our expanded effort to hedge in order to provide cash flow visibility. Much of the hedging effort for 2018 is complete, and we have recently been focused on opportunities to hedge in 2019 and 2020.

With our commitment to capital discipline, we are making additional adjustments to our capital plan for 2018 to prioritize cash flow generation. While we anticipated variable results and had some encouraging results from our horizontal program, overall, the average performance of these wells in the second quarter was below expectations. And with the forward strip suggesting lower gas prices into 2019, it is appropriate to ramp down the horizontal program while we incorporate our learnings.

Fortunately, with our technical expertise and robust vertical program, we have the ability to shift rather quickly as conditions warrant. We recently dropped 1 of our 4 rigs and plan to run 3 rigs for the rest of 2018 with 2 rigs focused on verticals and 1 rig drilling horizontal wells.

Our conviction remains strong regarding the potential returns from horizontal wells in the Pinedale Field. However, as we take a systematic approach to this program, we want our shareholders to understand that, by getting new or extending play, there will be variability in our horizontal well results. The amount of data recently collected and an enhanced integrated workflow will help us in our future development and, we believe, ultimately drive significant, long-term shareholder value.

At this time, I will turn the call over to Garland to discuss our second quarter financial results and to provide an update on our hedging program.

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

Thanks, Brad. The company produced an average of 779 MMcfe per day or 70.9 Bcfe of total equivalent production in the second quarter, an increase of 6% compared to the second quarter of 2017. Production volumes include 66.9 billion cubic feet of natural gas and 667,000 barrels of oil and condensate.

Total cost of $2.30 per Mcfe, excluding stock compensation expense, were in line with the midpoint of our expense guidance. EBITDA cash cost of $0.96 per Mcfe were $0.04 lower than the midpoint of our guidance. Including our hedges, our realized revenue per Mcfe for the quarter was $2.70. Before hedges, our realized average gas price per Mcf was $2.11, which equates to 75% of the average first [in] month Henry Hub price for the quarter.

Our average realized oil price was $64.71 per barrel, excluding hedges, or 95% of the average WTI oil price for the second quarter. Our resulting EBITDA for the quarter was $122 million, which was slightly below our expectations due mainly to lower production volumes associated with new horizontal wells having average performance below our budget case.

Moving to Slide 6. The company has a very solid hedge profile in place for the remainder of 2018 and continued to add to its 2019 hedge position during the second quarter to support our operating objectives. This slide includes our total volume hedge by product for the remainder of this year and for the first and second half of 2019. For the remainder of 2018, we have both Henry Hub and Northwest ROX basis hedges in place, equivalent to over 80% of our expected gas production at a net price of $2.22 per MMBtu.

After applying our 1.07 BTU factor, we get an average hedge gas price per Mcf of $2.38. When we take our oil hedges into account, the average price per Mcfe for these hedge volumes is $2.77.

Year-to-date, our hedge program has yielded $7.7 million in realized gains. We will continue to be opportunistic in adding hedges for 2019 and 2020 to improve our cash flow visibility.

On Slide 7, you will see our outstanding debt and associated maturities. As you can see, our next major maturity won't occur until 2022. The 2022 unsecured bonds, which carry an interest rate of 6.875%, currently comprise $700 million of our debt. After those bonds come due, we have the remainder of our $975 million term loan due in 2024 and $500 million in unsecured bonds, which carry a 7.125% interest rate and are due in 2025. Our cash flows and availability on our revolver provide ample liquidity for us to cover all interest expenses and to execute on our development plans for years to come.

Now I'd like to turn the call back over to Brad.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Thank you, Garland. On Slide 8, we have a summary time line breaking down the transition to horizontal development, which Ultra has pursued over the last few quarters. We are still in the early stages of the transition, and we remain committed to taking a major and systematic approach to expanding the Pinedale Field.

Our first 4 wells drilled from 2016 to the first quarter of this year prove the prolific nature of the rock in Pinedale and its horizontal potential. After confirming the viability of horizontal drilling in the play, we set out to accelerate its development, concurrent to gathering more data along the flanks of the field.

After having tremendous success early on with 2 wells that had 24-hour IP rates over 50 million cubic feet equivalent per day, we were certainly disappointed in the some of the more recent wells. But as I mentioned before, variability should be expected in the early phases of any play, and we certainly experienced more variability than expected this quarter.

But with every well we drill, we gain additional learnings. We are expanding our technical efforts by incorporating all of our data and learnings captured to-date. This ongoing process will offer a great deal of insight into horizontal potential in Pinedale, and Ultra stands uniquely positioned to benefit from further study of the play. Our vertical well program gives us insight into the play no other operator can match, and we look forward to better understanding the horizontal potential of Pinedale and add a best on lot this expanding resource.

If you will turn now to Slide 9, you can see our updated view on the Lower Lance and how we are now subdividing this formation into intervals and zones based on what the data is showing us to-date. Through the companies' horizontal delineation, we have now designated 5 intervals within the Lower Lance: Lower Lance A through E. Inside each of these intervals, Ultra is exploring an upper and lower landing zone, which we refer to as Zone 1 and 2, respectively.

In the second quarter, Ultra focused on further delineation of the Lower Lance formation, drilling and completing 11 horizontal wells landing in 4 different zones within the Lower Lance. Four of the wells were drilled in the Lower Lance A1, 90 feet below the top of the Lower Lance formation. Four wells were drilled in the Lower Lance A2, 250 feet below the top of the formation. Two wells were drilled in the Lower Lance C1, 690 feet below the top of the formation. And one well was drilled into the Lower Lance E1, 1,290 feet below the top of the Lower Lance formation.

On Slide 10, we have a summary of the horizontal wells the company has drilled so far. Most of our horizontal wells drilled to-date have targeted the Lower Lance formation, and the best wells drilled so far are in the A1 zone, 90 feet below the top of the formation. The A1 zone is not immune to variability, but the average IP of the first 6 wells is 27.3 million cubic equivalent per day.

The first 4 wells listed in the table were all drilled east, and their average IP is 37.5 million cubic feet equivalent per day, including initial yields up to 25 barrels per million. For the rest of 2018, our activity will be focused in this zone and on the east flank.

During the second quarter, the company also drilled 4 wells in Lower Lance A2, 2 wells in the C1 and our first well in the E1 zone. The 4 wells drilled in the A2 zone, which were drilled 250 feet below the top of the formation, did not perform as well as we expected and serve to highlight how much variability there is as we delineate horizontal in Pinedale. The will wells drilled deeper during the second quarter to the Lower Lance C1 and E1 zones continue to highlight the multiple areas of pay available on our acreage, including these deeper wells, posting 2 of the 3 highest initial oil yields to-date. While they have not performed as well as the A1, we want to better our understanding of these deeper landing zones as we continue to delineate the play.

With that summary, I would now like to welcome Jay Stratton, our new COO. Jay joined our leadership team in early June, and I'm very pleased to have his experience and leadership guiding our efforts to expand and optimize the value of Pinedale.

J. Jay Stratton - *Ultra Petroleum Corp. - COO*

Thank you, Brad. It's an exciting time to be joining Ultra as the company works to optimize the development of the horizontal play and maximize the value of our robust vertical inventory. The team at Ultra has a long reputation as operator of the industry's most efficient directionally drilled pad development program. We have an extensive simultaneous operations experience with pad-based drilling of over 2,100 vertical wells, something the industry's challenged with in other basins. This experience has and will continue to translate into efficiencies as we optimize the horizontal program.

If you'll please turn now to Slide 11, I'll walk you through our horizontal development workflow. The extraordinary performance of early prolific wells drilled on the Eastern side of the field has given us great insight into what zones and completion designs can work in Pinedale. It would have been an exceptional outcome if we could have repeated that performance in many later wells without developing a more rigorous analytical approach. Delineation to poor-performing deeper zones in different areas of Pinedale has identified the importance of expanding our understanding and adding tools needed to realize the full potential of the horizontal development opportunity.

Along with 3D seismic data across our entire asset, we have an extensive knowledge base and dataset from almost 2 decades of the development experience along with a rich dataset from a past acquisition of a major operator's position. We recognize the challenge and opportunity to execute on a workflow to extend our resource and maximize the value of a horizontal development.

Illustrated on Slide 11 is a workflow progressing on many parallel paths that has been developed around our existing dataset and technology. In simple terms, our objective is to increase our understanding of the productive rock with data from our existing vertical and horizontal wells. We are also filling gaps in that data with efficient use of new technology. We are leveraging existing 3D seismic data on an inversion pilot to extend understanding of rock types further away from well control.

Our technical staff is leading the build-out of an integrated geo-cellular model with industry experts, in parallel with the numerical modeling work scope, led by a firm that has added value to the most respected, large independents in the unconventional space.

Our Big Data acquisition work scope is focused on providing the information on rock properties and fluid type to construct robust models. This will allow us to understand the range of performance and to better predict future well productivity. We will then use our deeper understanding to connect wellbores to the most productive rock. Ultra is in the early stages of optimizing our horizontal completion designs. Early completions were successful, but few design changes were attempted in later wells. We're now testing designs biased towards higher-intensity stimulations that have proven successful in unconventional plays.

Cluster density, fluid type and volume, extreme limits of entry (inaudible) and proppant loading are all being optimized. Performance is tracked with an extensive data acquisition and analytical program using different tracer types, pressure transient analysis and selective production logging. Our production performance is closely monitored with the intention of understanding the efficiency of the wells' productivity over time, including an understanding of initial stimulated rock volume, or SRV, and using rate transient analysis to understand how that SRV changes over time.

This new understanding will be recycled back into our advanced geo model and numerical simulation used for further refinement of our well performance predictions in all rock types found in Pinedale. Now that we completed our initial horizontal well targeting and acquired valuable data, we intend to do our most our rigorous testing in the simulator to build confidence in new zones before testing further potential with the drill bit.

Ultra has taken a disciplined process and data-driven approach, leveraging our existing staff with the most respected resources in oil and gas to understand the opportunities presented by horizontal drilling in Pinedale. Using this process, data from the horizontal wells drilled to-date in over 2,100 vertical wells drilled by the company, Ultra is well-positioned to unlock the full value of the asset.

Slide 12 provides updated economics for the horizontal well program going forward in the near term. We're focused on over 28,000 net acres in the immediate plank of Pinedale, where we believe we can still achieve compelling returns. We're going to further refocus our development plan on the most prolific Lower Lance A1 zone while continuing to understand opportunity in other Lower Lance zones with our horizontal tentacle workflow.

The Mesaverde and Upper Lance also offer additional upside to be unlocked. Economics of Lower Lance A1 zone have been excellent. The net gas price represents Henry Hub minus Rockies basis, and the economics include the uplift we enjoy due to the high BTU content of our Pinedale gas and the oil revenue from the associated condensate production.

In particular, with the increases in oil mix from horizontal wells, our team is working to understand oil properties and completion designs that will allow for more efficient recovery of both oil and gas. These results show strong, expected returns even when Henry Hub minus Rockies basis results in a net gas price below $2 per MMbtu.

Turning to Slide 13, we have updated our vertical well performance chart to feature average cumulative production over the last 8 years, highlighting the last 2 quarters. While we have focused a lot of this call on updates to the horizontal program, we are also extremely focused on continuing to optimize and maximize returns from our robust vertical program.

In 2007, with an increase in activity, more vertical wells were drilled on the flank than in the core. That resulted in well performance below historical averages. In 2018, as we resume a high-graded vertical drilling program, average well performance has been at record levels with activity focused in the core of Pinedale.

During the second quarter of 2018, we posted the highest average IPs in the last 7 quarters with our operated vertical wells having an average IP of 8.8 million cubic feet equivalent per day. The opportunity to high-grade these locations demonstrates the quality of the inventory and the ability to deliver strong margins even in stressed price environments. With ample inventory of high-quality vertical locations, we'll continue to execute on a solid vertical program as we expand our understanding over the horizontal opportunities.

Now I'd like to turn the call back over to Brad

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Thanks, Jay. Our capital plan continues to be driven by the following 3 objectives: first, the disciplined deployment of capital in pursuit of superior returns; second, the increased visibility of cash flow, which for 2018 has driven by a strong base of production from our vertical wells and our hedge book; and third, the continued delineation of our horizontal development.

In the near term, while we further study and refine our program, we are scaling back the horizontal effort. For the remainder of 2018, we plan to run 3 operated rigs with 1 horizontal rig that will be focused on Lower Lance A1 on the East flank and 2 vertical rigs continuing to drill across our high-graded core acreage.

Full year capital guidance remains the same at $400 million. Our pivot to horizontals last quarter actually occurred at a faster pace than we had planned. From an execution standpoint, this was positive. However, we incurred costs as part of that transition that put pressure on both our vertical and horizontal well costs.

In the second quarter, vertical wells averaged $3.6 million per well and horizontal wells cost $9.6 million. As we pivot back to more verticals and a near-term focus on horizontals on the A1 zone, we expect to drive down our well cost to previous levels. For the second half of this year, we expect to average $3.1 million for verticals and $9 million for horizontals.

Based on the lower-than-expected performance of our horizontal wells drilled in the second quarter, we are adjusting down full year production guidance to a new range of 273 to 283 Bcfe. And for the third quarter, our production guidance is 710 million to 750 million cubic feet equivalent per day. Expense guidance for the year remains on track and is summarized in the lower-left part of this slide.

Now on Slide 15, we provide detailed expense guidance for the third quarter and EBITDA guidance for the full year. For EBITDA cash cost, we estimate $0.99 per Mcfe for the third quarter and $0.98 per Mcfe for the full year. With our hedges in place, we expect price realizations for the year to average $2.81 per Mcfe. Using updated expense from production guidance, we now forecast 2018 EBITDA to be $509 million.

In summary, I would like to thank our team for their tremendous effort and execution as we moved very quickly from vertical development to a horizontal delineation program. We remain focused on taking a disciplined approach to capital allocation to drive cash flows and shareholder value. We are in the early days of expanding our resource potential in the Pinedale Field through horizontal development. We're encouraged by some of our early results.

We also remain focused and committed to our vertical program. We still have thousands of locations in inventory. This program is delivering solid returns even in the current gas price environment. We look forward to sharing with investors our ongoing progress as we continue to move our vertical and horizontal programs forward.

At this time, we will open the line for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) Our first question comes from the line of Jacob Gomolinski of Morgan Stanley.

Jacob Gomolinski-Ekel

Can you help us understand why CapEx for the year isn't going down as you reduced rig count by about 25%?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes, we're affirming our capital for the year at $400 million. We came in heavy for the second quarter as a result of higher well cost, both in our vertical and horizontal program. So as we ramp down activity, we do expect our capital burn to be reduced. But because of the capital in the second quarter, that's keeping our full year guidance right at $400 million for now.

Jacob Gomolinski-Ekel

Okay. And then maybe I missed it, but I didn't see it in early sort of the (inaudible) and out. So what CapEx was in Q2.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

We were $116 million for CapEx for 2Q.

Jacob Gomolinski-Ekel

Okay. And then maybe just on the guidance for the rest of the year. Does that incorporate the sale of the Utah asset and the 2,000 barrels a day of oil production? And maybe, if you can, just give us a sense of what the EBITDA and cash flows that was associated with that asset were?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. As an update for our Utah asset, we did, at the end of July, subsequent to quarter-end, signed a PSA selling our asset in Utah for $75 million of cash. And our forecasts for the remainder part of the year, we are incorporating Utah through the month of August, and that plays into the volumes and the expense forecasts for that asset incorporated in the overall company numbers.

Jacob Gomolinski-Ekel

Okay. So the guidance for the year or for Q3 is assuming that the asset closes at the end of August but doesn't -- you lose the production in September?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

That's what we've included in our guidance, yes.

Jacob Gomolinski-Ekel

Okay. And then maybe, I don't know, did you just have a sense of what the EBITDA was for that asset or the cash flow?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

EBITDA shown 12 months was about $18 million on a trailing 12-month basis. Just to clarify. That was for the Utah asset.

Operator

Our next question comes from the line of Marshall Carver of Heikkinen Energy.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

Yes, on the vertical well program, what is your inventory of vertical wells that are higher than 4 Bcf? I know you showed some slides a couple years ago that showed that the number of wells at 4 Bcf and then 3.5 and so on as you went forward in future years. But do you have a feel for how many wells you have remaining that are north of 4?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So a few comments on the vertical inventory. First, we -- year-end '17, our reserves were based on a relatively small PUD pool, frankly, as we were working in our development plan a combination of vertical and horizontal wells. And we had about 300 vertical wells in the PUD pool, again, a much smaller -- deliberately small case for PUDs. In the current prices, we have about 800 wells that are economic. Obviously, low prices today. I don't have a number for you on wells over 4 Bcf.

Marshall Hampton Carver - *Heikkinen Energy Advisors, LLC - Founding Partner and Director of Research*

That was actually -- the prior question was -- all my questions have been answered between me and the prior person who asked some questions.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes, as I comment about 800 wells at current economic for current prices, of course, we've got over 4,000 vertical wells in our inventory. And a significant amount of those become economic as prices would improve. And so we share some of that. The economics on our vertical slide demonstrate the economic potential of our vertical program in an improving gas price environment.

Operator

Our next question comes from the line of Sean Sneeden of Guggenheim.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Maybe just to start. Brad, can you just kind of update us on your thoughts around maintenance capital? I think previously, you're kind of thinking about a $270 million figure is just in light of future results. Is that something we should still be thinking about? Or how should we, I guess, be thinking about that going forward?

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C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

No, I think that's still a valid number. And I think last quarter, we talked a bit about maintenance capital at that level. And if the horizontal wells were delivering above expectations, we would have the opportunity to maintain flat production at lower CapEx. Or if horizontal wells -- or if we decided to maintain CapEx and have a horizontal performance contribute, then we would have the ability to grow at that level. Certainly, the second quarter results for the horizontal wells were below expectations. I think right now, to think about maintenance capital, basing that on the vertical program that's been low-risk, significant inventory, and I think that $270 million to $275 million is still a fair number.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. And that $270 million is basically on a pure vertical program.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Yes.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Yes. Got it. That make sense. And then just -- you shared the $9 million target for horizontals for second half. Can you just kind of share what that -- the line of sight that you have there? Obviously, I think as you kind of said, Q2 was a bit choppy with some of the testing of some of the deeper intervals. But can you help bridge us to kind to get into those type of numbers for second half?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. As I mentioned in my remarks, we average $9.6 million for our horizontal wells this quarter. We definitely experienced cost pressure as we were ramping up that activity. And we had shared previously and I had shared that there was an advantage for having the ability to drill horizontals and verticals off the same pad. And that was certainly the case from an execution standpoint. But we have shared equipment cost on these pads. And as we are adjusting down our activity, a large portion of our equipped costs are now being allocated to less wells. And so that's creating pressure on our costs that we're posting for the second quarter. I do expect that to go down in time as we, frankly, rightsize equipment capital on our future horizontal wells.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Got it. That's helpful. And then maybe just lastly. I think you commented that the goal here is to generate free cash flow for the balance of the year. How should we think about what you -- what the use of any kind of free cash flow generation is for? Is that debt repayment? Is it just kind of using that as a potential war chest for A&D activity? Or how should we think about that?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. Obviously, we're very focused in -- and desire to delever. However, cash right now, we have not committed it to any specific use. We want to maximize liquidity. We want to continue any incremental investments to pursue the best returns available in our portfolio. But right now, we have not committed those proceeds to any particular use.

Sean M. Sneeden - *Guggenheim Securities, LLC - MD & Trading Desk Credit Strategist*

Okay. Okay, that's helpful. And just remind me on that point. You currently are restricted from buying back any of the unsecured bonds under the term loan covenant. Is that right?

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

This is Garland. That's right. Under the term loan and the revolver, we're restricted. We have to be at 3x leverage or better in order to buy back any bond or stock.

Operator

Our next question comes from the line of David Epstein of Cowen.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

When you spoke about the maintenance CapEx of $270 million to $275 million, what production level where you thinking? You used to talk about sort of Q4 '17. Were you referring to sort of your full year '18 guidance here. That's part of it. And then as also part of it, what are you thinking in terms of vertical cost when you talk about a number? Yes, I think you talked about getting back to 3.1 for the second half of the year. Will you ever be able to get back to the old 2.9? Or does inflation and lower scale make that tough?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. Regarding maintenance capital, the numbers would be on a -- flat to 2017 volume, which would be 280 [Bs] or so. The vertical well cost, yes we -- as we were ramping up horizontal and drilling both horizontal and vertical wells on the same pad, we were mobilizing equipment to complete horizontal wells, which required higher-pressure rated equipment. And so we had oversized equipment, frankly, on the completions of our vertical wells. We knew that, but that was part of the ability and the effort and the objective to ramp up. So I do see us mitigating and reversing those costs. We've had a bit of inflation pressure, not a lot, but some over the last quarter: steel and fuel. And I think those will -- those particular items we've got built in to our forward look for costs. I do think, as we return back to much more of a dedicated vertical effort on one pad and horizontal on another, that we'll be able to revert back to those historical costs. And for now, we are forecasting 3.1, but my expectation is that we would get below 3 as we move forward. But for now, we're going to use 3.1 for the balance of the year.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

Great. And obviously, you're redirecting towards verticals a little bit. Would doing horizontals in the core, what are your current thoughts on that?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Still believe there's potential in the core. But some of the wells we drilled this past quarter, and there -- I might reference Slide 10 in our presentation, where we have the data tabulated. Ample wells -- we drilled 4 wells to the last. And a few of those were testing the core up in the A1 Zone. And those results were not that encouraging. We saw less yield, of course, as we went back to the core. And we saw higher water production. There'll always be some depletion risk potential as well as we drill back. So we're not -- we haven't ruled that out by any means and certainly haven't condemned any zone in our entire horizontal program. But just looking at the real results on Slide 10 and seeing a [lab] variability but also seeing strong results in the A1. That's where we're going to focus near term with a drill bit drilling to A1 to the east.

David Michael Epstein - *Cowen and Company, LLC, Research Division - MD and Analyst*

And so in the core, it's just you have a nice vertical column. But they're -- it's heterogeneity, for a lack of a better word, horizontally and not a high net to gross? Or is it something else?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Well, not so much a geologic contributor. It -- at least on the first few wells we drilled, we encountered higher water. And so we may have targeted zones in the core that were higher water saturation. And we certainly experienced higher water on those wells. And the overall deliverability was lower. So as we drill in the core and some of those really nice sands that we've developed are vertical wells, the balancing act there is drilling good rock but also potentially encountering some -- some level of depletion. So that's just part of the effort that is incorporated and Jay had a lot of comments about with respect to really just advancing and refining our models as we move forward with the horizontal effort.

Operator

Our next question comes from the line of Vivek Pal with Seaport.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

Most of my questions have been answered. Just a quick one for Garland. In second half of this -- in '18, do you expect to be cash flow neutral to modestly positive based on what I hear in terms of a declining CapEx for the second half?

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

So with the asset sale, we actually expect to be cash flow positive in the second half of this year.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

So it'll be $75 million plus? Or do we -- or you'll be burning a little cash operationally?

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

I don't think we'll be over $75 million.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

Okay. And I know you just mentioned it, but I just want to be clear. Say your normalized vertical well costs are about roughly 1/3 of what your horizontal costs are, right, in terms of CapEx?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

That's correct.

Vivek Pal - *Seaport Global Securities LLC, Research Division - MD of Fixed Income Strategy*

And in vertical, is it safe to assume that you can average about [8 MMcfe] per day. Is that a fair number for vertical because you've done so many?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So that was -- the 8.8 million cubic feet equivalent per day was the average of our operated wells in the second quarter. And we anticipate drilling similar quality wells for the rest of 2018.

Operator

Our next question comes from the line of Jacob Gomolinski of Morgan Stanley.

Jacob Gomolinski-Ekel

Just wanted to see if you had a sense of where current PDP value was or PV-10 value as of today given some of the wells you've drilled over the years as well as some of the production over the year so far? And maybe also what the core -- sorry, what the current corporate decline rate is?

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Sure. So on a PDP valuation standpoint, we've added wells, so our PDP base has grown through the year. And from a valuation standpoint, in reserve space, that value is going to be much more driven by trailing 12-month pricing used in reserve calculations. I think our PDP value is holding steady as we look at our numbers through the year. The -- let's see, the second question. I'm sorry the second part of your question was decline rate?

Jacob Gomolinski-Ekel

Yes.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

So from a nominal decline on our base production, first year is about 25% on PDP. And of course, due to the hyperbolic nature of the decline curves of our wells, that annual decline (inaudible) or diminishes each year. So by year 5 or 6, you're in (inaudible) single-digit percent declines. And in Pinedale, the wells and, ultimately, the production ends up in around 6% or 7% terminal decline.

Jacob Gomolinski-Ekel

Got it. And then -- that's very helpful. And on the -- it looks like you paid down about $2.5 million of term loan. I think I know the answer. I just want to confirm. Is that just the [amort] starting up? And is that just how to expect it going forward and how that'll maybe, I guess, the [lat] just impact the borrowing base? I realize we're not talking huge numbers here but just want to make sure we're thinking about it the right way.

Garland R. Shaw - *Ultra Petroleum Corp. - Senior VP & CFO*

(inaudible) current. So payment due in the next 12 months, so it's very different spot.

J. Jay Stratton - *Ultra Petroleum Corp. - COO*

Yes, it's just reclassed the balance sheet. We didn't actually paid it down yet. I don't believe that starts until June of 2019.

Operator

(Operator Instructions) And I'm showing no further questions at this time. I'd like to hand the call back over to Brad Johnson for any closing remarks.

C. Bradley Johnson - *Ultra Petroleum Corp. - Interim CEO & Director*

Okay, this concludes our second quarter conference call. I wish to thank everybody for joining us this morning. If you have any questions, please follow up with Sandi Kraemer. Thank you, and goodbye.

Operator

Ladies and gentlemen, thank you for participating in today's conference. That does conclude today's program. You may all disconnect. Everyone, have a great day.
