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PRESENTATION

Operator

Good day, ladies and gentlemen, and welcome to the Q1 2017 WPX Energy, Inc. Earnings Conference Call. (Operator Instructions) As a reminder, this call is being recorded. I would now like to turn the call over to David Sullivan, Director of Investor Relations.

David Sullivan - *WPX Energy, Inc. - Manager of IR*

Thank you. Good morning, everybody. Welcome to the WPX Energy First Quarter 2017 Call. We appreciate your interest in WPX Energy. Rick Muncrief, our CEO; Clay Gaspar, our COO; and Kevin Vann, our CFO, will review the prepared slide presentation this morning. Along with Rick, Clay and Kevin, Bryan Guderian, our Senior Vice President, Business Development, will be available for questions after the presentation. On our website, wpxenergy.com, you will find today's presentation and press release that was issued after the market closed yesterday. Also, our Q will be filed later today.

Please review the forward-looking statements and disclaimer on oil and gas reserves at the end of the presentation. They are important and integral to our remarks, so please review them.

So with that, Rick, I'll turn it over to you.

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Thanks, David. Good morning, everyone. We really appreciate your interest in our company this morning, and today, we're very pleased to report on the highlights that you saw in yesterday's press release.

Let's get started. Let's turn to Page 2. For me personally, this is the quarter we've been waiting for since the day we started here just under 3 years ago. As we sit here today, we're seeing our vision come together in real time. It is personally very gratifying to have the bulk of our transformation under our belt and behind us. It's great to be in the thick of things in the Delaware Basin. And I'm quite pleased that our goals for oil and EBITDAX growth over the next 4 years have been very well received. We call it our 2020 vision, and really if you look back, we rolled this out in late 2014. That's an indicator of our forward-looking nature and the forethought, discipline and perseverance that we have in WPX.

Over the past few years, we've made some bold moves. It was necessary, even critical, but not really anymore. We don't have to do anything now other than firmly execute to stay on course. And our game plan remains just as attractive and as simple as it's always been: stay disciplined, grow our oil production, grow shareholder value. They absolutely go hand-in-hand.

With that, there's really just one more question: Can we keep delivering? I can emphatically say we're doing it every day. Execution is the name of the game. Our results have plenty of proof to show how our portfolio is now built for growth. In fact, we knew that we'd be out ahead of the pack. The results we're seeing today come from the planning that we did during the downturn. As others were idle and struggling to find their way, we were carving out a place, working closely with our service providers and preparing to put rigs in the air. As you know, our story isn't about 20 or 30 rigs. Our number is 10: 7 in the Delaware, 2 in the Williston and 1 in the San Juan Basin. But we're accomplishing a great deal with those 10 rigs, and we can accomplish even more in 2018 and beyond with modest incremental additions to our fleet.

Now let's turn to Page 3. When you think about our ability to execute right now, while staying opportunistic, I think this page says a lot. Let's start with our position in the Delaware Basin. It's now up to approximately 135,000 net acres after completing 2 more transactions. We closed our previously announced Panther acquisition in March. That helped our first quarter production a little bit, but most importantly, we added 900 more gross drillable locations in the most coveted E&P real estate on the planet. Our recent completions on this acreage showed just how good it really is.

We also completed an acquisition for some exploratory acreage in the western flanks of the Delaware Basin. It's a longer-term project for us, but at the same time, it's another move that has the potential to further deepen our drilling inventory and provide numerous other value-adding opportunities in the future.

But the biggest headline in this page is our oil production growth. It's on track and even a little ahead of where we thought we would be at this point. Our first quarter results reflect a subtle bump of 3% over fourth quarter, which is in line with what we've previewed during the last call, based on how pad drilling and the batching of completions affects the timing of sales. But now we're seeing oil production of 55,000 barrels per day after a nice month of first sales in April. That's fueled by the 9 wells from our CBR-22 pad, some 1-mile laterals from our Panther acquisition that are trending nicely above a 1-million-barrel type curve and extremely strong results in the Williston Basin, including one well that had a peak rate of over 3,300 BOE per day, including 2,700 barrels of oil per day. You'll hear further details from Clay in a few moments.

Since we're nearly at the midpoint of a new quarter, our 55,000 number provides a proxy of sorts of what our second quarter oil production could be when we talk again in August. Think about that. We're talking 20% growth from first quarter to second quarter on our oil volumes. Also by that time, we expect to reach a decision on our idea for our Permian Basin midstream JV that would involve our Stateline oil gathering system and plans we have for gas processing infrastructure. A lot of parties have shown interest and now we're down to a handful of finalists. We're keeping a very open mind about what's best for WPX and how we can leverage this opportunity to deliver shareholder value. We're going to make sure that what we do is right and not rush the process. The timing is on track, and we're going to weigh our options carefully.

Let's turn to Page 4. As I mentioned earlier, we closed on the purchase of approximately 18,000 acres in Culberson County during the first quarter. We refer to this as the Taylor Ranch transaction. This takes our Permian acreage to 135,000 net acres. 2 years ago, at this time, we had 0. When you look at our track record, each -- and in each case, we have transacted in a way that truly has benefited shareholders. Let me touch on a few things.

First, while this acreage is more step-out in nature than our existing fairway, other companies are starting to delineate toward this acreage, and we're closely monitoring their work. We're seeing some interesting results and our seismic that we have over the acreage suggests some intriguing potential. Recent transactions in the nearby area have gone for multiples of what we paid.

Also, this acreage is not going to take capital away from our core development that we're going to have in the Delaware, in the Wolfcamp A and X/Y. Simply put, we're talking only about 3 wells that we're committing to over the next 2.5 years. These are extremely manageable obligations. It's a risk worth taking and one that's consistent with our bias for action. I think we will have numerous value-added opportunities over the next several years with this acreage.

With that, I'm going to turn it over to Page 5 and turn the presentation and the prepared remarks over to our COO, Clay Gaspar.

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Thanks, Rick, and good morning, everyone. Our first quarter numbers and the subsequent current rate update are tangible outcomes of the restart program that began nearly a year ago. After our remarkable portfolio transformation, early last summer, we developed a disciplined and value-enhancing plan for driving shareholder value. This plan included adding additional rigs late in 2016, contractually partnering with our service providers and getting capital investment buy-in from our board for 2017 and 2018. Rick then laid out a 5-year growth plan in September, driving an emphatic stake in the ground. With today's updates, we're now seeing the initial results of our long-term plan starting to come into focus.

For the restart program, our team has rallied around 3 strategic imperatives: operational and financial discipline, value-driven growth and remaining opportunistic. For our current oil production of 55,000 barrels a day, I agree with Rick that it is a good proxy for the second quarter production. I also want to reiterate that once achieved, it's a 20% increase quarter-over-quarter and over a 40% increase from third quarter of '16. This impressive 5-year 30% to 40% oil CAGR is starting to materialize.

Our operations team continues to execute. Despite some January winter weather issues and taking over operations from Panther a little quicker than initially planned, our team delivered in the first quarter. That said, I believe it's a bit early in the year to increase full year guidance. Assuming continued momentum, I would say there is a likely increase on the next earnings call. We also still have some room for improvement. There is a significant gap between LOE for Stateline and the other Permian areas. As we build out infrastructure and apply some of the best practices to these newer less-land-dense areas, we will see the costs improve.

As we look proactively at our growth story, we've been out ahead of the market, hedging the downside on commodities and aligning with our preferred vendors to control cost inflation and also provide surety of service. Looking forward, you will hear more about us taking proactive midstream steps to provide flow assurance to our growing Permian production.

Yesterday, we announced a deal that locks down capacity for gas out of Waha to Katy, which is a great market. We're not permitted to mention the name of the company or the fee, but I can tell you I feel great about the deal we have relative to spot rates today and where we believe the market could take this differential. Again, it's much more about protecting the downside rather than trying to create value through marketing gas. This is very cheap insurance to ensure our ability to continue our oil and value growth story.

We will likely be announcing our Permian midstream JV by the next call. This is another important step to make sure that we have the right partners to run beside us as we grow this amazing asset.

Let's turn to the next slide and we can take a look at the early results on CBR-22. This is a great picture of the rigs when they were drilling the 9 wells. You will notice that we divided the drilling between 3 pads to accelerate the time from first spud to first sales. I've been talking about this spacing test since late last year, and I am excited to now show you this very encouraging early-time results.

This spacing test best -- is the best representation of full section development and the tightest spacing for upper and lower Wolfcamp A development in the Delaware Basin to date. The CBR-22 tested both vertical and lateral spacing of the upper and lower Wolfcamp A development program. Early-time results are very positive. The 9 wells, all 1-mile laterals, have been producing nearly 14,000 BOE per day with a 50% oil cut. Remember, these wells are flowing through combined facilities and we're working out start-up issues for 9 wells at the same time, so the individual rates will look better than the combined rate. Flowing pressures are also what the downhole well-to-well interaction is telling us, a lot about the spacing and helping us plan the balance of our development.

Importantly, we see little to no fracture interference between the 9 wells. This is important since early-time communication could have been a very negative result and we needed to rule that out before we got too far down the development trail. It's still too early to say that 15 is the singular right answer, but early data is very, very supportive and encouraging. Later this year, we plan to drill the X/Y wells in the CBR-22 to validate the spacing for the X/Y and its relationship to the upper A wells.

Now let's turn to the next slide and look at some recent Panther acquisition results. The well performance is very exciting. You can see why we were so encouraged to do this deal. All 4 of the wells were averaging over 2,000 BOE per day for the first 30 days of the production, with 55% oil cuts for 1-mile laterals, all 4 exceeding our 1 million BOE type curve.

Our Delaware team looked over -- took over operations from Panther on March 10, including the 2 rigs that they were running. The Delaware team has gone through -- from 3 rigs in September of last year to running 7 rigs currently. This quick transition has been very demanding on the team, but they're now making great strides in getting all of the operations to our first-class standards.

We will continue to evolve our well designs and work on our costs. We've already made vendor and logistical changes to the Panther operations that will save well over $1 million per well. When Rick talked about finding unique value on the last call, this is exactly what he meant.

Now let's turn to the next slide, and we'll talk about the continued strong results in the Williston Basin. As I mentioned on the last call, we completed our DUC inventory late last year in Williston. Now the Williston team is in steady-state mode drilling and completing wells, with 2 rigs employing the latest drilling and completion designs. As we continue to test new designs, we leverage the incredible amount of data that we have and use this to understand not just initial rates but also EURs and, ultimately, creating the most NPV from the drilling spacing unit. The Williston Basin had some winter weather challenges in the first quarter, but the team overcame those challenges and delivered a strong quarter, bringing on 3 pads with impressive results, including the Grizzly 13 well, which had a peak rate of over 3,300 BOE per day with 81% oil. The 3 pads were the Grizzly, the Caribou and the Behr. The average wells on these 3 pads -- excuse me, the Grizzly and the Caribou wells are exceeding the 850 MBOE type curve and the Behr pad is just below that type curve.

Let's turn to slide -- the next slide, and we'll update to you on San Juan. San Juan continues to impress. We got back to work drilling wells in the first quarter, and we're currently bringing on the first 6-well pad of the year. The first well achieved a 24-hour IP rate of 1,400 BOE per day with approximately 75% oil. Year-to-date, the San Juan team has installed 26 miles of pipe, including oil, natural gas and water, in preparation for the remaining West Lybrook build-out. We now have the San Juan oil growth machine up and running, and we'll see steady growth in the next several quarters.

As usual, the San Juan team set a few new drilling records in the quarter. The record for spud to rig release for a 7,500-foot lateral in San Juan is now 5.8 days, and the record for the most lateral foot drilled in a 24-hour period is 6,258 feet. These are very impressive numbers, and the team is literally just getting started on this very significant program. I'm very pleased that the San Juan team continues to find ways to improve their already impressive efficiencies. Currently, we have 58 approved drilling permits in the Gallup area, and we're nearing completion on 2 additional units encompassing 12,000 acres.

Now I'll turn it over to Kevin Vann, our CFO, so he can update you on the financials.

J. Kevin Vann - *WPX Energy, Inc. - CFO and SVP*

Thank you, Clay. I appreciate the great work your team is doing to help us meet our goals. As Rick and Clay mentioned, our execution has begun. This is critical when you're aiming for a 30% to 40% compound annual growth rate in oil volumes and EBITDAX through the year 2020. We are feeding off the execution and transforming WPX over the last 2 years and pushing that forward into our operations. It really comes down to exactly that: execution. There are all kinds of variables that our teams continually manage, from vendor ability, to rig schedules, to completion recipes, just to name a few, all in pursuit of finding efficiencies and new ways to increase the returns from the amazing portfolio of assets that we have. The progress and performance we're achieving are the direct results of our strategy, our disciplined approach, the strength in our portfolio and the tactical steps we're taking day in and day out to carry out the plan.

As we set our sights beyond our transformation, our results reflect the new reality at WPX. We're built to succeed. We have attractive opportunities across our portfolio and up and down all the horizons in the Delaware stacked pay. We're going to compete very vigorously everywhere we operate. We'll keep managing. We'll keep making tweaks to what we own, but there's no need to make wholesale changes anymore. We've already changed, and our results are already showing what's possible.

Let's turn to Slide 11 and review our first quarter results. For the quarter, at 46,100 barrels per day, our oil production is 11% higher than for the same period of 2016. The increase in our Delaware production, together with our activities of getting back to work in the Williston, drove the increase. When comparing to the fourth quarter of 2016, our oil production was up 3%. As we stated during the fourth quarter earnings call, well completions in the Williston Basin charged the fourth quarter production volumes. In fact, as Clay mentioned, our cadence of completions was faster than we anticipated, which helped fourth quarter production and kept us in front of some of the weather that rolled into 2017, setting us up for a nice start to the year. At 196 million cubic feet per day, our natural gas production for the first quarter was up 6% versus the same quarter of 2016 and slightly down compared to the fourth quarter. At 90,000 equivalent barrels per day, our production is 12% higher than the first quarter of last year and roughly flat to the fourth quarter.

For the first quarter, we are reporting an adjusted EBITDAX of $115 million, which is $16 million lower than the first quarter of last year. The reduction in EBITDAX is primarily driven by lower realizations on our commodity hedges, which was mostly offset by higher oil production and higher margins achieved on that production. Excluding hedges, net realized prices were higher in '17 than in the first quarter of 2016. We have stressed the transformation of our portfolio, and now you are seeing those results from a margin-per-unit perspective as they begin to manifest themselves through our financial statements.

For the quarter, we did see a $6 million increase in lease operating expenses due to winter-related costs in the Williston and as production from the Delaware increased. We are actively managing all the components of LOE as we grow production in the Delaware.

For the quarter, we are reporting an adjusted net loss of $59 million versus a net loss of $58 million in 2016. The decline was driven by the same factors impacting adjusted EBITDAX, but I do want to mention a couple of additional items in regards to the performance this quarter. Depreciation, depletion and amortization was $5 million favorable compared to 2016, which resulted from improved rates in the Williston and San Juan Gallup. Quite simply, we are getting better well performance at lower drilling and completion cost. These types of results are often subtle in the financial performance, but as we get more swings at the plate, our batting average continues to improve.

In addition, our G&A continues to come in line with roughly $42 million in expense for the quarter. Our organization is coming into an appropriate size for the growth trajectory we have outlined.

Our capital expenditures incurred for the first quarter totaled $280 million. Of this amount, $54 million relates to the acquisition of additional acreage in the Delaware Basin, $9 million for expenditures incurred on our crude gathering line in the Delaware and $7 million of other corporate expenditures. Excluding these amounts, our drilling and completion capital spending was in line with where we expected to be at this point in the year.

Now turning to Slide 12, just want to give a quick update on our liquidity and hedging. First, as you will see, our liquidity remains strong. In April, our borrowing base under our revolving credit facility increased to $1.2 billion following the semiannual redetermination process. We did utilize a portion of the cash that we had on hand at the end of last year to fund the non-D&C capital that I referenced on the previous slide. In addition, we utilized approximately $130 million to help fund the Panther acquisition completed in March. As Rick and Clay have indicated, the operational results from this acquisition are already exceeding our expectations. And as a reminder, the manner from which we funded this acquisition enhances our leverage profile.

Also impacting our cash position was the impact of making one of our semiannual interest payments, together with some other payments that do not affect EBITDAX for the quarter. A reconciliation of our cash position is included in appendix of the slide deck for reference.

And as we see crude oil pulling back today, I would like to remind you all of our very strong hedge book. Our hedge position for 2017 is strong. We have nearly 3/4 of our oil and natural gas production locked in at approximately $51 per barrel and a little over $3 per MMBtu. For '18, we have continued to add to our hedge position for oil with 42,000 barrels of oil hedged at $54.36. On the natural gas side, for 2018, we now have 185 million cubic feet per day hedged at nearly $3.

We layered in more hedges over the fourth quarter -- over the fourth and first quarter to further protect our cash flows during 2017 and 2018. These positions, together with services which we have contracted for going forward, help ensure the growth targets that we have established for production and EBITDA. The hedge book we have compiled for '17 and '18 demonstrates our continued discipline to managing the balance sheet and decreasing the variability of cash flows and hitting our financial targets we have outlined.

Lastly, we continue to pursue some Midland basis protection. We have executed contracts for approximately 14,000 barrels per day of Midland basis swaps for '17 at $0.57 and 13,000 barrels in 2018 at $0.94.

With the operational execution that we are now delivering, the production targets, EBITDAX growth and leverage metrics we have outlined are coming into focus. With each passing day of this execution, the ultimate goal of cash flow neutrality and net debt-to-EBITDA of approximately 2 turns becomes more evident. We here at WPX know it's real, and we're doing everything we can to manage the risk to those goals through hedging, contracting with our service providers and maintaining the relationships with our vendors. Our assets now afford us the ability to hit our goals.

I'll now turn it back to Rick for some closing comments.

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Thanks, Kevin. Great job. Really appreciate you and Clay, your respective teams as well as everyone else throughout the organization. I want to add today that WPX is a solid, sound company. We have the assets, the talent, the plan and the forceful wherewithal to make sure things happen and achieve our goals. By now most of you are familiar with the personality of this team, and you know that, ultimately, we want to be second to none.

We still have a few things to prove, and we respect that, but that's what drivers us day to day, month to month and year to year. That's another thing that defines our WPX 2.0: We're not easily satisfied, and that's how we create value.

At this time, we'll open the line for questions. Operator, I'll turn it back over to you.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) Our first question comes from Brian Corales of Howard Weil.

Brian Michael Corales - *Scotia Howard Weil, Research Division - Analyst*

I'm going to start -- I think you talked last quarter about having kind of 70% of the -- your cost profile for '17 locked in. Is that still the case? Because it seems like you're a little bit ahead of schedule. And where are you seeing the pressures? Is it just in the Permian? And what aspects?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Brian, this is Clay. I appreciate the questions. So we realize we had a lot of moving parts in the capital side of the reporting this quarter, but when you break it down, we had about $210 million in D&C capital. I think that's very much in line with -- kind of scale that up for the year, feel really good about that. I feel the -- there are some capital opportunities, and we'll see cost decrease on -- as I mentioned, in the Panther acquisition. That wasn't contemplated in the original layout. Those wells are a little bit more expensive. We'll get them back in line. But so far, I still feel really good about my remarks from the last quarter around that 70%. As I look at the inflationary environment that we will be in, especially in the Delaware Basin, I think the risks that come to mind to me are at least as much along the line of surety of service as they are cost. Let me explain what I mean by that. When we have some upset in the system, you reach out for coil tubing or some ancillary service, and if that's not readily available, that could cost you days, and that can translate into production impacts and other things. So we are really hyper-focused on that right now. I can tell you, the vendors we're working with are first class. We're incredibly happy to have those guys, having really good dialogue. And they are aligned that, as long as we are executing, they can certainly live and be profitable in the environment that we've contracted them with. So still very encouraged. Inevitably by year-end, especially for any incremental work that we're doing, we'll have to go to the spot market for that, and we'll have some pressure on that. I think originally I had laid out in line to maybe 10% adder by year-end. I think I still feel really good with those numbers.

Brian Michael Corales - *Scotia Howard Weil, Research Division - Analyst*

Right, and then maybe for Rick. I mean, we're seeing the differentials in the Bakken come down. Those well results look very good. I mean, do you see a point maybe a year out where maybe the Bakken, you're going to put more capital than you previously thought versus the Delaware? Or is it just the scale, size of the Delaware takes the cake?

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Brian, one of the true values of having a diverse portfolio like we have, it's focused, it's diverse, but it's -- is a fact of doing just what you say. We'll look at each point in time. I would tell you, Clay and Kevin, they do a nice job on capital allocation, in my mind. And at the end of the day, irrespective of the scale of any particular asset, it comes down to returns. And so, yes, if you look at those Williston results, they are eye-popping. And I can tell you that we talk about that quite frequently. So as you think about in the future years, we've talked about 2018 adding 1 to 3 rigs. So probably at this point in time we'll watch things, but that's we've talked about. But we really haven't said that they're all going to go to one basin or the other. So when you look at the returns of the Permian, they are really, really strong. I'm very, very impressed. When you look at the Bakken, very, very strong and very impressive. And when you look at the San Juan and the Gallup, those are very strong returns and low cost and nice wells, and so we do have options. And so I think you hit the nail on the head. We'll just see over time where that's at, but we really like all 3 of our assets.

Operator

Our next question comes from Neal Dingmann of SunTrust.

Neal David Dingmann - *SunTrust Robinson Humphrey, Inc., Research Division - MD*

Rick for you, or Clay. I think this is maybe for Clay. Clay, you obviously had the success in that -- over in the Delaware, where you're testing now 15 wells per section in the upper and lower As. I'm wondering how you would think about incorporating -- it seems to me that there is great Bone Springs and obviously other formation potential in that area, so how you would think about, besides that tight spacing you're already doing in the Wolfcamp, incorporating some of these other zones in there?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Yes, great question. We have to balance the development, putting oil in the tank, really turning the crank on the kind of derisked zones, think upper and lower Wolfcamp A. And I would even venture to put that X/Y in there as well. We have a lot of confidence in that zone. So those 3 are kind of certain -- they sit in one category of development. That's why that's spacing test, pushing it so early in the development, it was incredibly important because we want to make sure we're doing this right. Not over-drilling or not under-drilling, because as you well know, either one of those are kind of a onetime chance to get it right. So we've done that. We feel really good about that. You'll see those zones really fall into development mode, turning the crank, hopefully drilling a lot more longer laterals, which we're doing actively today, and you'll see those returns scale up with those longer laterals. Now you mentioned Bone Springs, some of the other zones. This year, we're going to dabble in the Wolfcamp C, probably one well; a handful of Ds; a Third Bone Spring well, and also some of the geography that we need to understand. Think of those kind of onesies and twosies really kind of framing up what we're going to be concentrating on in 2019, '20, '21. It's incredibly important that we understand that. We get some tests in the ground, and we understand the productivity, and ultimately, development and spacing and some other bigger questions so that we'll have those ready to go when we're ready to reach for them. I would say for now, we're really, really excited with what we're seeing with the Wolfcamp A, the X/Y, and we have plenty of that inventory keep us real busy on the main development mode for the foreseeable future.

Neal David Dingmann - *SunTrust Robinson Humphrey, Inc., Research Division - MD*

Great details. And then just one follow-up, maybe for Rick, just in broader terms. You all, versus -- especially versus a year ago, now have significant liquidity. Even Kevin and the guys have done a great job adding hedges all the way through '18, looks like even over 50%. So with all that backdrop, how do you foresee the ramp changing potentially if -- it looks like prices are drifting down a little bit more this morning, if we -- let's assume we stay in sort of the low- to mid-40s versus the low- to mid-50s, do you see much change in that overall plan as we exit this year and enter the next year?

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Neal, we really don't. We're really consistent with our outlook, and not that we just say something and we don't change or we go back and re-pressure test our assumptions. But every time we do, we come back to the same place. That -- we'd have to feel very strong that the crude stays -- is going to stay probably for 12 months in the low 40s -- high 30s, low 40s for us to change our outlook in '17. And as we get to the end of '17, we'll continue to look at it. But right now, that's our -- giving you somewhat of a broad range, but it'd certainly have to be in the plus/minus $40 per barrel for us to really change what we've built. If you think about our hedge position, it does give you some surety. You would have cash flow fluctuations, obviously, where the crude moves too much up over our hedge position, too much down below it. But at the end of the day, that's still our outlook.

Operator

Our next question comes from Michael Glick of JP Morgan.

Michael Adam Glick - *JP Morgan Chase & Co, Research Division - Senior Analyst*

Just a high level on Culberson County. Could you give us some more color on what you like about the geology? And is there any well control, either horizontal or vertical, in the area?

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Yes, there is a quite a bit of horizontal activity just a few sections away. Yes, there's a lot going on out there, and I just -- most of which is by private operator. So I think I would encourage you to watch some of that [state] data.

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

And I'll just add on to that. Remember, this is a very cheap option. This is us getting out ahead. We have the ability now to not just worry about kind of current year, next year. This is kind of forward-looking things that -- very cheap options. I can tell you, we have to put very minimal capital to this. In reality, industry is going to do that for us. And so we'll watch this offset operator activity. As Rick mentioned, we have some really great intel. We have some 3D seismic that we're looking at. We're excited. There's a geologic reason that we've pursued this, but I can tell you, this is in the western side of the basin. That means it's going to be gassier than typically what we're drilling today. That just means it's a little bit more of a long-dated option. Happy to have it. I can tell you it's trading, as Rick mentioned earlier, multiples of what we paid today. So it's an option well into the money that we'll exercise over the coming years.

Michael Adam Glick - *JP Morgan Chase & Co, Research Division - Senior Analyst*

Got you. And then, Clay, could you maybe give us the latest and greatest on your completion design and landing zones in the Delaware?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Yes, and as I mentioned to Neal before, we have lots of landing zones and it's -- I'll try and summarize it relatively quickly. For our development mode, which is Wolfcamp A upper, lower, and then the X/Y, I would say state-of-the-art, probably standard is 2,500 pounds per foot. I can tell you, we've pumped 3,000, we've pumped well over 4,000 pounds on jobs, and we're continuing to evaluate that. As you well know, that's not the only knob that we turn. Cluster spacing, how many -- how tight those clusters are. We're currently in the ballpark of 30-foot cluster to cluster, 4 clusters per stage. That is something we continue to evaluate. We look at size of the perforations. This is not sexy stuff that we talk about in slides and all those things. But just how much pressure drop you're getting through each perforation determines your diversion to the other zones. There's things like that, that we're really starting to fine tune on and continue to make really good progress. As we move into the D, to the other zones, it's a whole new set of trials that we need to understand, in the Wolfcamp D, in particular. That's where we've tried even significantly more sand. We've a lot more volume to touch. And so there, we're able to really put the sand to it and see if we can reach out and grab more reservoir [bock] for each well that we're drilling. So one note on the Section 22 wells. We went back to our -- essentially our prior standard, which was 2,000 pounds per foot. I can tell you there was a lot of internal debate around that. We feel like 2,500 is probably better. That's why it's current state-of-the-art. But what we needed to do and understand in the spacing test was how do we compare to the most inventory that we have kind of like-for-like. And most of the wells that we've drilled are 2,000 pounds per foot. And so that was a really important decision that we made to really understand what does well interference in this tight spacing really to do. We didn't want to change too many variables on this test. So we'll -- state-of-the-art 2,500, 30 foot per -- between clusters, and I would say we are -- still lots of room to continue to improve and work on that.

Operator

Our next question comes from Jeff Grampp of Northland Capital.

Jeffrey Scott Grampp - *Northland Capital Markets, Research Division - MD and Senior Research Analyst*

I was hoping to kind of get a high-level view for how you guys think about longer-term development in the Delaware as it relates to the CBR testing. Down the road, if you guys kind of determine that, that is kind of the right spacing and, et cetera, to go with in the Wolfcamp A, I mean, do you guys kind of go right to the larger pads and go right after it that way? Or how do you guys kind of think about balancing cycle times versus efficiencies in full field development?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Yes. Challenging dilemma, first quartile dilemma that we have. We have lots of inventory and we have lots of quality, and so that -- what you're exactly talking about is balancing that -- the lumpiness of big developments versus -- well, we're going to be drilling 15 wells per section in just the Wolfcamp A, that's a lot of wells to develop. And so this was a pretty big step to do 9 wells at one time. As I mentioned in my prepared remarks, we had 3 rigs out there. So it sped up that first spud to first sales. We're looking for ways to continue to tweak that and refine that. As we get more rigs, it becomes easier to commit to bigger pads, bigger development, kind of self-smoothes that curve. I would say, we'll continue to be 3 wells per pads, 6 wells per development phase. That'll probably be the kind of standard. And what we're finding is, we're not seeing the significant well interference even from some offset wells. As you recall on the CBR test, there was a 2-year-old-plus well that was on the west side of the spacing unit. It was kind of mislanded right in between the upper and the lower, and so we spaced a little bit further away from that one, but we were really anxious to see how this closest well is going to react to that pressure sink. I could tell you, there was no reaction. That is incredibly strong and positive news that we can come back in and develop when we come in a little bit later. And so we'll be able to hit these kind of 6 wells at a time, get them on production and then hit it again with 6 wells, and then come back, drill some X/Ys, come back in time, and then -- so we'll able to stage into this. We won't have to drill necessarily 15, plus another 4 or 6 in the X/Y, all in one fell swoop.

Jeffrey Scott Grampp - *Northland Capital Markets, Research Division - MD and Senior Research Analyst*

Okay, great color. And then for my follow-up, just curious to get your thoughts, high-level, on the C bench test that you guys are going after. Obviously, it'll be a little bit easier to answer this once you got a result to talk about. But how does that zone generally compare to the A bench result that you have and the X/Y and the D bench that you guys do have some operated results on?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

So we don't have any production on it yet. We drilled the well. We have it down. We haven't completed it. And so it's premature to talk about what we know. I can tell you what we think. I feel very assured that it's going to be oil cut somewhere between the A and the D, higher than the A, lower than the D -- excuse me, opposite, higher than the D, lower than the A, but it's also -- we know it has a lot of energy. So some of the real positives that we've seen from the Wolfcamp D is the pressure and the energy ultimately transitioning to recovery factors and EURs that we've seen in the D. We've certainly seen that in the C as well. I don't want to get ahead of ourselves on talking too much about the C as a potential target. Remember, this is a single test, probably the only one we'll drill for 2017. I think it's an important data point. We want to see, understand well cost. We want to understand productivity and then where this whole thing stacks up in our portfolio over time. So we will report that. I would guess that by the next call, we'll have some early-time data. Third quarter, we'll have really the 30-, 60-day kind of production numbers that we would like to share in a little bit more detail, but it'll be something -- I don't expect us to shift all the rigs to C or Third Bone Spring or anything anytime soon. Like I said, we're going to be hitting the X/Y and the upper and lower A really hard for the foreseeable future.

Operator

Our next question comes from Subash Chandra of Guggenheim.

Subash Chandra - *Guggenheim Securities, LLC, Research Division - Analyst*

Very -- I mean, this is a density pilot. It feels like a milestone. So I have a few questions here. And I think, Clay, you shared a ton of detail I'd like to follow up on. But kind of curious how bounded completions might vary from unbounded? It sounded like you thought you could press the proppant intensity. So I was hoping you could comment on fluid intensity, how you completed these and if you could step that up or need to? And are you looking for constructive interference rather than no interference, which is what you've experienced here?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Yes. So it's a good point because the fully bounded wells, if you notice, on the lower and the upper, we have immediate offsets, at least on one well, laterally and horizontally. And so that is -- that will be really important. We want to not kid ourselves and just do a lower Wolfcamp A bench test or just an upper. We thought it was really important to have that vertical control as well. And so we'll be watching -- and that comes out over time, but we'll be watching these wells very intensely. And for the fully bounded wells, in particular, we're going to be doing some shut-in tests probably in a few months, and we'll watch the offset production. We'll shut in the offset wells. We'll watch the bounded wells production to really kind of get a feel for how tight is too tight. Right now, when you add it all up, we're about 330 feet laterally well-to-well, kind of bird's eye view. That's pretty tight. But having that wine-rack pattern, we believe it can work. We've been through all the reservoir engineering math, the oil-in-place numbers. Those calculations check out, and now it was just putting the empirical evidence to it and making sure that we weren't seeing kind of that day 1, day 2, day 5 interference that you really can see in many other reservoirs. So very encouraging. And I'm talking to a lot of people about the encouragement around this pressure data is very, very exciting to us, and it was one of the things that we kind of needed to check that box before we could really feel great about kind of leaning on the full-blown commitment to develop at this spacing. Ultimately, we'll see what -- the finer tuning we do on completion design, as you mentioned, how much fluid we put into the wells, how much sand we put into the wells, we'll continue to tweak that. I would imagine our next spacing test -- we have a few more planned for this year. We'll vary the completion technology. We'll look at different proppant-loading and fluid-loading and see how that impacts well interference. Ultimately, you want some well-to-well interference but not too much where you're really destroying net present value.

Subash Chandra - *Guggenheim Securities, LLC, Research Division - Analyst*

And my follow-up is, you mentioned this and I can't recollect what it was relative to, but that you didn't experience a pressure sink, and if you can just kind of review that comment again? And I'm curious if you think that is -- is it too early to say that's a basin experience? Or does your gut tell you that's a one-off?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Well, we have -- so the details on that well, the -- RKI had drilled a well right at what we would consider the upper and lower interface. We have it depicted on the block diagram that we've shown plenty of times. It's all the way on the left side. That well, we spaced about 750 feet from the next closest well laterally. And so the next well laterally is about 75 feet lower. That actually sits in the lower Wolfcamp A. And so that well, in particular, was one that we were really interested in getting gauges to bottom hole and checking that pressure. And when we checked that pressure and we compared it to 5 or 6 wells over to the east, and to really what we would consider true virgin rock, the pressures were essentially the same. And so that gave us some very good indications that, that older -- couple-of-year-old well, that's a good well. I mean, this would be close to a 1-million-barrel well, didn't essentially drain the west side of our section, or even cause stringers. None of it's fully drained, but you get into kind of fast-zone, high-permeability streaks that can partially deplete part of your zone. That's where we really get into later-life completion issues, and when you're trying to stimulate these wells, and naturally you're pumping this pressure, and it's wanting to go to that pressure sink in a big way. We didn't have issues completing these wells. That was another big check for us, especially the western-most wells. They took fluid and took sand very, very well. And so your follow-up is: Does that extrapolate to the rest of the Stateline? Does it go further than that? I think Stateline being geographically and geologically very similar, I think I feel pretty good about that. I wouldn't make a blanket statement ever when it comes to our industry, because this is just more complex than ubiquitous geology. But I believe that certainly it's a very good indication and it gives us very positive feelings about doing a similar development going forward.

Operator

Our next question comes from Chad Mabry of FBR Capital.

Chad Lindbergh Mabry - *FBR Capital Markets & Co., Research Division - SVP and Senior Equity Research Analyst*

Question on the new transportation agreement out of Waha. I appreciate that you -- I respect, I guess, that you can't mention the fee associated with that, but I was just curious if you could provide any color on the kind of commitment that you provided there. And then maybe, I guess, it looks like, obviously, the main concern is getting your gas east, but any issues foreseen getting your gas to the hub?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Yes. So we'll be able to talk more about this, I think, when we do -- when we announce our Midstream Permian JV, I think we'll have -- give you a bigger-picture view of all the other midstream things we're working right now. We do have some conversations in the works to get gas to Waha. I can tell you, I'm less concerned about that. That's a shorter putt than getting gas out of Waha. I think there is -- this was kind of the last of the available capacity that really takes it at a very nominal rate. This is a roughly 10-year commitment. I feel very, very good about this low-cost insurance.

As you know, we've talked about this before, getting to Waha is checking a big, big box, but getting it out of Waha is really dependent on Mexican demand. And if the Mexican demand materializes, Waha can -- it'll relieve that pressure and we'll feel good about just getting gas there. The concern is, and I think this year it's kind of bubbling up around the industry, what if Mexican demand isn't quite at what we projected? Does Waha become that bottleneck and you -- you start to get kind of a Marcellus effect where you're getting differentials blowing out? We wanted to avoid that situation where we have significant differential blowout, and even to the point where maybe you can't move products at all, that would be the horror story. Because, I can tell you, gas is the byproduct for our Permian Basin development, and so we want to make sure that we have flow assurance for the oil product, where we're making our revenues and really making our margins. So we do have other conversations in the works to get gas to Waha. I tell you, those are a little bit easier. We are also having conservations on oil. Obviously, we got an oil-gathering facility significantly up and running. It'll be essentially full built-out by year-end. That gives us a lot of flexibility to have conversations with counterparties further downstream than that oil-gathering system. And there are significant dollars and significant flow assurance reasons for us to be involved in those conversations.

J. Kevin Vann - *WPX Energy, Inc. - CFO and SVP*

Yes, and I think, if you think about it from a commitment perspective, you are talking a 10-year deal, roughly, if the spread was never in the money, which it's deeply in the money right now, but if the spread was never in the money, you're talking about $16 million a year. But again, that flow assurance is what's critical to us in order to just make sure that we get gas out of Waha.

Chad Lindbergh Mabry - *FBR Capital Markets & Co., Research Division - SVP and Senior Equity Research Analyst*

That makes sense. That's helpful, guys. Maybe for a follow-up, if I could, switch over to San Juan. We saw a large transition announced recently. I was just curious of your thoughts on that, and maybe where you see some of those assets in the portfolio given the market out there.

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Well, what you saw with ConocoPhillips' San Juan is ConocoPhillips -- I'll kind of compare and contrast their gas position and our gas position. ConocoPhillips was predominantly in the fairway for the Mesaverde Dakota, which had, I guess, pretty nice NGLs with it. And also, it was the fairway of Fruitland coal, the very, very highly prolific coals. But over time, those have declined pretty dramatically. That transaction also had ownership in their -- 50% ownership in their big cryo plant there. So if you compare that deal with our assets, there's quite a bit of difference. Fundamentally, yes, we won't have any midstream assets there. And we also have, for the most part, dry gas on our legacy gas position, northern part of the basin. We have some nice dry Mancos potential. But we are planning on moving forward with pulling our nonoperated dry gas position together to potentially market it. And I know that we've had a lot of interest on the operated legacy gas position. So we'll just -- we'll see how that plays out over time. But in aggregate, you're talking about 80 million to 85 million a day of net gas volumes in our legacy gas. So we'll see. Obviously, our Gallup, as we've talked earlier, southern part of the basin, nice oil play and great returns. We always have inbounds on that and the Permian and Bakken and everything else. But I would say that we'll wait and see, but more than likely, you'll see us trim some branches at least on the outside operated for San Juan, the dry gas position.

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

Chad, this is Clay. I'll just add to that. You've heard this before, but we have 2 types of questions specifically on our San Juan Gallup. We have some investors interested in, "So are you going to sell the asset?" What that tells me is that they haven't really studied the well productivity and the quality and where it fits in the portfolio. The other half of the questions are, "Holy cow. Those San Juan wells are really good. What's going on there?" And so it's interesting, kind of that bimodal distribution of the Q&A. We're really pleased with the San Juan Gallup oil results. And as Rick said earlier, the capital allocation process is not a process in charity. This is, earn it. And these guys earn it every single day, and that truly does compete for returns in our portfolio, which is a pretty strong statement.

Operator

Our next question comes from Kevin MacCurdy of Heikkinen Energy.

Kevin Moreland MacCurdy - *Heikkinen Energy Advisors, LLC - Partner and Exploration and Production Research Analyst*

Congratulations on your forward thinking regarding infrastructure in the Delaware Basin. Following up on that a little bit, have you seen any issues with crude quality? And is there anything you can do to mitigate any concerns there?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

I think the -- again, being forward-thinking about handling our crude gives us a lot of flexibilities. Today, we are kind of 44 to 52 API gravity. We blended it all together. We haven't had any pushback. Hypothetically, you start drilling more Wolfcamp Ds one day, and it becomes more of the 52, less of the 40, 45 gravity stuff. You could get into a situation where you're working with the downstream oil gatherers to send it in batches. That gives us incredible flexibility. It'll be something we will have as an option if that ever manifests one day. But I can tell you, today, and the foreseeable future, we're really, really pleased with the netbacks that we're getting, and we're getting no pushback on quality considerations.

Operator

Our next question comes from Kashy Harrison of Simmons Piper Jaffray.

Kashy Oladipo Harrison - *Piper Jaffray Companies, Research Division - VP and Senior Research Analyst, Exploration and Production*

So can you update us on just what the A&D market looks like right now in the Delaware for -- specifically for acreage swaps to help you build the more contiguous acreage position in the region?

Bryan K. Guderian - *WPX Energy, Inc. - SVP of Business Development*

Sure. I think I'd just start out by saying the availability of acreage for transaction continues to surprise us. The buy-side resilience, I think, continues to surprise us as well. So near term, our focus is really what we would call kind of blocking and tackling. We have our footprint in place. We're really nicely blocked up in Stateline and some of the nearby areas there. We have some other acreage that is a little bit more one-off, but we see really nice opportunities dealing with probably 4 or 5 different trading partners in and around Stateline and, in particular, the northern part of the Texas side of our position. And we've had some great success already dealing with those folks to block up and drill longer laterals. Kind of along those lines, we are also finding that there is still some additional acreage, generally smaller tracts, some expirations, still opportunity to bolt on and add to those positions in small ways. The same is probably true up in New Mexico, although I would say that given the federal lands and some of the larger tracts that we deal with in New Mexico, that has not been as much of a focus for us recently. Looking more broadly across the basin, there are a number of fairly sizable deals that are in the market currently or that we expect to come to market. I'm going to say that they tend to be a little more fringe-y. There are a couple of deals over in the eastern side of the basin that we would anticipate being marketed this year. I won't go into names, because I don't know the exact status of those. But likewise, still I think some opportunities over on the west side of the basin. And obviously, we took advantage of one with our Taylor Ranch acquisition. And then I would expect to continue seeing some private equity monetization. I think we all realize we're probably in the seventh or eighth inning of that process. But again, the availability of acreage, as much as we think we know about the basin, things continue to come to market, but more in small packages at this point. And I think, back to sort of the theme of our story, we're going to stick to our knitting. We really like the footprint that we have. And so our primary objective is bolting on and adding efficiency to the position that we already have.

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

And I would just add just a little bit to that, Bryan, that we have a lot of small trades, stuff that's way below the radar you never hear about. In fact, we have 25 active discussions going on right now. Bryan mentioned 4 big counterparties right around Stateline, but they're our acreage. I mean, our #1 goal in land is to shore up and block up our core positions. That allows so much for infrastructure, efficiency around being able to scale up, certainly drilling the longer laterals. And so many of these deals, it might be a 640 for 640 or 320 for 320. It is mutually beneficial and helps all parties. I can tell you, sometimes, it's a 2-for-1 acreage swap, sometimes it's a 1 for 2, but those are really relatively small deals that are still very accretive to our overall portfolio. So 135,000 acres today, really happy with the position we have, incredibly happy with our entry costs and where we stand today. Last thing we want to do is do something to disrupt that and something that would be dilutive to our overall portfolio. The way we create the most value in the shortest amount of time are these relatively small deals that happen every day kind of below the radar. So we'll continue our efforts on that.

Operator

Our next question comes from Derrick Whitfield of Stifel.

Derrick Lee Whitfield - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD and Senior Analyst*

So staying on the forward-thinking theme, other than commodity prices and midstream, are there any other gating factors in the Delaware that would prevent you from ramping beyond your current activity levels?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

I'll put them in order of -- the ultimate gating factor is geology. I think we have fully checked that box, and that is no longer something I'm front-of-mind concerned about today. How we ultimately develop in spacing and some of those nuances, we'll continue to work on. But there's no question, especially where we're at in the Delaware Basin is world-class rock, and there is tons of opportunity. Second on my list would be commodity price. You mentioned that. We've been very aggressive on kind of putting that floor in place so that we can roll with these inevitable cycles of oil price. Swing today. I imagine there's a lot of our peers that are fully exposed, that are really pulling their hair out, and I can tell you it's very reassuring to have that confidence to be able to go to the team and say, "Yes, we're still doing what we're doing." Go to our key vendors and say, "Guys, we're still plowing ahead, stay with us. Let's keep moving on." That allows us a tremendous amount of leveraging and negotiating ability with some of these counterparties that have more accretive options down the road, but maybe it's a little bit more spotty on when things show up. The next thing on the list I would put is that cost. And so the commodity price hedging, our ability to ramp up to 10 rigs and run that going forward with a high degree of confidence gives us ability to lock in. We've mentioned the 70%. I still feel good about that number. We'll continue to push that, and we'll continue to work with those guys. Inevitably, there will be some sand in the gears as the whole industry picks up activity. We'll work through those things. That's what we do every day. And then the fourth thing on the list, you mentioned as well, is the midstream kind of takeaway. I can tell you, that's where we've been quietly working for the last 4, 5, 6 months, and you're seeing the first of those deals really come out. We've got a handful of other things that we're working on, the biggest of which would be the midstream JV in the Permian, and that is -- it's so significantly tied to making sure that we have a partner that can run right alongside of us and stay out in front of us on this incredible build-out. There is going to be a very significant infrastructure build-out in the Delaware Basin, and specifically to just manage our resources. We want to make sure that, that partner definitely are goal-aligned with us.

Derrick Lee Whitfield - *Stifel, Nicolaus & Company, Incorporated, Research Division - MD and Senior Analyst*

Clay, that's a very thorough response. And then switching gears, moving over to the Panther wells you guys announced for the quarter, do have a view on why those wells are considerably outperforming your expectations? Is this simply conservatism in your acquisition metrics? Or did you guys meaningfully adjust the completion design relative to what Panther was utilizing?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

I think we are -- we knew it would be good geology. We always have a touch of conservatism in how we model these things going forward. Rick has set a really high bar for any of these acquisitions, and we want to make sure that whatever we bring in is accretive to our overall story. So these wells happen to be coming on at a really interesting time as we're negotiating, as we're finalizing the deal. I think that concentration of wells coming in, really after we've consummated the deal, pretty beneficially helped the story and it was just something we wanted to highlight. I don't know that there's anything material. In fact, this is basically the Panther completion designs. So I don't think there's anything material that we changed. I would say the one thing that just going forward, the logistical work that we have and the change in vendors will materially improve the cost structure.

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

I might add that Bob Revella and his team on the exploration side, they really, really like this area for the rock. And so it's a nicely pressured area, and we just saw a lot of stack pay in there that had some great-looking [perm]. And so I think, over time, I'm fairly confident that we're going to even improve results even more, but when you start early thinking at -- we're talking about 1-mile laterals and greatly exceeding 1-million-barrel type curves. And I can tell you, the folks at Panther, their CEO, he was very open, and -- early on in the negotiations of how -- from their geologic assessment, how much quality was there. And our team who, I think, are -- in my mind, are about 4 for 4 on transactions and picking the right spots, they really like that deep stacked pay there and it is -- there is productivity running all up and down through that column. So we really look forward to developing that over the next few years.

Operator

Our next question comes from Gail Nicholson of KLR.

Gail Amanda Nicholson - *KLR Group Holdings, LLC, Research Division - MD*

I'm just looking at the Williston wells, all very good, but the Caribou pad significantly outperforming that 850 type curve. Was there anything done differently in Caribou versus the Behr and Grizzly wells?

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

No, Gail, I think those are roughly the same completion design. We are at a point where we're really doing some fine-tuning. There is a little bit of geologic difference where those sit. That particular pad is closer to some of the Emma Owner and the Mandarees that have just been historically some of the best wells that we drilled. A little bit difference in geology, but I can tell you, all of those wells, at today's current well cost, roughly $5.5 million for the drilling, the completions and facilities on the reservation, those numbers work really, really well for all 3 of those pads. So very excited about what we're seeing there, and that's a -- that team is contributing vitally to our oil growth story.

Gail Amanda Nicholson - *KLR Group Holdings, LLC, Research Division - MD*

Great. And then inventory-wise, you have ample inventory prior to the downspacing test. The downspacing test looks encouraging in the Permian. When you think about physical surface acreage, though, and -- how many rigs you think you could physically run on a surface acreage standpoint in order to kind of extract that inventory and bring value forward, assuming there is no negative commodity price environment? Let's say commodity is $70, $80.

Clay M. Gaspar - *WPX Energy, Inc. - COO and SVP*

It's a pretty staggering number. I can tell you, running 3 rigs on just one section certainly didn't bust the seams. I mean, the physical footprint of a rig is 2 or 3 acres. And so you could stack them up pretty deep, and you look -- just start counting sections, and it's a pretty amazing multiplying effect. So I don't see the physical -- the surface being a physical limit on the number of rigs. I think it goes back to -- for the foreseeable future, I'm going to be looking at Kevin to say what is the right financial investment capital spend, and that'll probably dictate rig count going forward.

Operator

There are no further questions. I would like to turn the call back over to Rick Muncrief, CEO, for any closing remarks.

Richard E. Muncrief - *WPX Energy, Inc. - Chairman, CEO and President*

Once again, we want to thank everyone for joining us today. As you can tell, this team is extremely excited about the assets that we put together and our execution. And as I mentioned in my opening remarks, this is actually the time I've been really waiting forward to -- or waiting for and looking forward to, and that is when you really saw this very distinctive ramp in production and cash flows and EBITDA growth. So stay tuned, we plan on having some very exciting quarters as we travel throughout this year. Have a great day.

Operator

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