Company Name: Pioneer Natural Co
Company Ticker: PXD US
Date: 2016-04-26
Event Description: Q1 2016 Earnings Call

Market Cap: 27,061.64
Current PX: 165.36
YTD Change($): +39.98
YTD Change(%): +31.887

Bloomberg Estimates - EPS
Current Quarter: -0.492
Current Year: -1.447
Bloomberg Estimates - Sales
Current Quarter: 700.778
Current Year: 2956.692

Q1 2016 Earnings Call

Company Participants

- Frank E. Hopkins
- Scott Douglas Sheffield
- Timothy L. Dove
- Richard P. Dealy

Other Participants

- John A. Freeman
- David Kistler
- Arun Jayaram
- Doug Leggate
- Neal D. Dingmann
- Charles A. Meade
- Scott Hanold
- Evan Calio
- Ryan Todd
- Brian Singer

MANAGEMENT DISCUSSION SECTION

Operator

Welcome to the Pioneer Natural Resources First Quarter Conference Call. Joining us today will be Scott Sheffield, Chairman and Chief Executive Officer, Tim Dove, President and Chief Operating Officer, Rich Dealy, Executive Vice President and Chief Financial Officer, and Frank Hopkins, Senior Vice President of Investor Relations.

Pioneer has prepared a PowerPoint slide to supplement their comments today. These slides can be accessed over the Internet at www.pxd.com. Again the Internet site to access the slides related to today's call is www.pxd.com. At the website, select Investors then select Earnings and Webcasts. This call is being recorded. A replay of the call will be archived on the Internet site through May 20.

The company's comments today will include forward-looking statements made pursuant to the Safe Harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described in Pioneer's news release on page 2 of the slide presentation, and in Pioneer's public filings made with the Securities and Exchange Commission.

At this time for opening remarks, I'd like to turn the call over to Pioneer's Senior Vice President of Investor Relations, Frank Hopkins. Please go ahead, sir.

Frank E. Hopkins

Good day everyone and thank you for joining us. I'm going to briefly review the agenda for today's call. Scott will be the first speaker. He'll provide the financial and operating highlights for the first quarter of 2016, another quarter which saw the company deliver solid execution and outstanding performance. Scott will then review our latest plans for 2016 in the face of continuing commodity price uncertainty. After Scott concludes his remarks, Tim will review our continuing strong horizontal well results and capital efficiency improvements in the Spraberry/Wolfcamp. Rich will then cover the first quarter financials and provide guidance for the second quarter of 2016. And after that, we'll open up the call, as always, for your questions.

So Scott, I'll turn the call over to you.

Scott Douglas Sheffield

Thank you Frank. Good morning. Slide number three, financial and operating highlights. We had a first quarter adjusted loss of $104 million, or $0.64 per diluted share. What's more important is that the company hit record production again, first quarter 2016, 222,000 barrels of oil equivalent per day, 55% oil. So we're well along our movement from 52% to 56% oil from 2015 to 2016. Way above Pioneer's guidance range of 211,000 barrels a day equivalent to 216,000 barrels a day equivalent, an increase of 7,000 barrels a day equivalent, or 3% versus the fourth quarter of 2015.

Oil production is up 10,000 barrels of oil per day, or 9% versus the fourth quarter 2015, obviously driven by the growth of the Spraberry/Wolfcamp horizontal drilling program. What's also a milestone for the company, our gross production in the Spraberry/Wolfcamp fields exceeded 200,000 barrels a day equivalent for the first time, and total field production has exceeded and surpassed 1 million barrels of oil equivalent per day, and still growing, probably the only field growing in today's environment in North America.

We placed 55 horizontal wells on production in the Spraberry/Wolfcamp field during the first quarter. All wells benefited from completion optimization, which Tim will give you a lot more detail. Continuing to realize significant capital efficiency gains in the field, both with the optimization program, longer lateral lengths and increasing and enhancing well productivity. Drilling and completion efficiencies and cost reduction initiatives are still driving down cost per lateral foot.

What's also more important, again, reducing our combined production costs, and G&A expense for the quarter versus the fourth quarter of 15%. We continue, over the next several quarters continue to see continued improvement in regard to those numbers.

We also added the recently Targa-operated Spraberry/Wolfcamp gas processing plant of 200 million a day. It's online, essentially it's up to about 120 million a day. That came from other plants, which reduced their intake in those other plants, so there's plenty of room for the next two years or three years for additional capacity. Pioneer, just to remind people, we do own 27% of this system.

Increased oil and gas derivative coverage for 2017. We've already released these numbers, and we'll talk a bit more about it, moving our all hedges up primarily 50% for 2017.

Slide number four on our outlook. We plan to maintain our 12 horizontal rigs in the North Spraberry/Wolfcamp field based on favorable returns in the area. We are currently operating 12 horizontal rigs in the north and two rigs in the south. The two rigs in the south will be terminated by the end of June. As I have mentioned on previous calls, our partner [indiscernible] (5:20) will look more at a $50 oil price to reinitiate any rig activity at that point in time.

This activity level is expected to deliver production growth of 12% plus, which we've raised up from 10% plus in 2016, and will allow the company to continue to progress its completion optimization program. The higher forecasted growth rate reflects the improving Spraberry/Wolfcamp well productivity.

We are keeping our planned capital expenditures the same for both drilling activity and vertical integration spending at $2 billion for 2016, $1.85 billion for drilling, and $150 million for vertical integration, systems upgrades, and field facilities.

We get asked all the time, we put the comment in here, the Pioneer expects to add 5 to 10 horizontal rigs when the price of oil recovers to $50 a barrel, and the outlook for oil supply-demand fundamentals is positive. So what do we mean by this? What's ideal? The strip in 2017 has moved up to above $47, $47.50 for oil. Today's price is close to $44. So if we see the strip in 2017, for instance, get up to $50, and we see inventory starting to decrease, which gives us confidence in the supply-demand fundamentals. We know the supply side is dropping. U.S. should see a significant drop in the third quarter on U.S. shale, probably a good 400,000, 500,000 barrels a day just in that quarter, in the third quarter, especially as reported by the EIA. And so what's ideal? We don't want to add them all at the same time, we would like to add a few at a time. So I know Frank gets asked the questions a lot, so that gives you a little bit more flavor in detail.

Going to slide number five, on our hedge position. Obviously, we are almost fully hedged for 2016. For oil, we moved our hedges up from 20% to 50% for 2017. The detailed hedges are in the back. We would like also to continue to move that number up in 2017 over time, as we see the oil price continue to move up in 2017.

We did a little bit more gas hedging for 2017. It's up to about 25%, still about 70% for 2016. That leaves a very strong investment-grade balance sheet. I think we are one of only six or seven companies that Moody's rates investment-grade now. The forecasted cash flow enables the company to grow production, and fund its expected capital program through 2017, without increasing debt. Our cash on hand and liquid investments, at $2.5 billion end of first quarter, includes proceeds from the successful equity offering in early January. Also includes $940 million that will fund our July 2016 and March 2017 senior note maturities. An additional $0.5 billion will come in July 2016 from our Eagle Ford midstream sale business that we did in 2015. Pro forma net debt to 2016 operating cash flow of 0.4 times. At the end of the first quarter, we had a debt to book of 10%.

Going to slide number six. No change in our capital program. I think the only change on this slide is the fact that the star is moving around on the rainbow chart. It's up to $1.4 billion. If the strip holds the rest of the year, it'll be up closer to $1.5 billion. So that gives us an extra $100 million to $200 million of cash that'll be added into our coffers by the end of 2016.

Slide number seven. Obviously again reminding people we did increase our production growth forecast from 10% plus to 12% plus. So that takes us up to 229,000 barrels a day equivalent for 2016. Still keeping oil at 56% oil, up from 52% due to our well productivity in the Spraberry/Wolfcamp. Our oil growth has gone up from 20% to 24% plus. Again, expect continued production growth over the 2016/2018 period. Obviously it'll depend on the pace of the commodity price recovery.

I'll now turn it over to Tim to get into more detail on our optimization program.

Timothy L. Dove

Thanks, Scott. I'll turn now to slide eight. And I think it's safe to say our completion optimization campaign in the northern part of the Spraberry/Wolfcamp continues to show very impressive results. Toward that end, I'd point you to the graph on the top left. This is a Wolfcamp B graph which shows all of the wells that have been completed utilizing our optimization campaign since the mid-part of last year, mid-2015. That's a total of 68 wells. What you see in the blue curve is an average of all of those wells in terms of their early production, and you can see it's pretty clear that blue line far exceeds the million barrel BOE type curve shown below. In fact, we would calculate that the early production range would show about a 35% improvement compared to that curve. So that's obviously extremely positive from the standpoint of our completion testing.

And then if you look to the top right, the Wolfcamp A, we see similar results although realizing it's a substantial smaller sample size, with only 13 wells since the mid-part of last year. I think it's really too early to call what the ultimate uplift will be for the Wolfcamp A, but for the time being the chart would easily show a 20% improvement compared to the million barrel type curve. Lower Spraberry Shale, again, a relatively smaller sample size, 16 wells in the same timeframe.

Early results again, but we are showing improvement. We calculate it is more about 10% over the million barrel type curve currently. But suffice it to say, on the 97 wells that we have performed completion optimization on through the end of the first quarter, we'd see significant improvement. 42 of those wells of the 97 wells that is, were placed on production in the first quarter, and have seen similar productivity gains as had been in the case in the prior couple of quarters. And now it's the case that these 97 wells provide a baseline for further testing that we're doing in 2016. And I'll talk more about that in a couple of slides.

On slide nine, we see similar results in the Southern Wolfcamp area, from the standpoint of the completion optimization, where we've tested about 22 wells through the end of the first quarter. You can see in the graph on the left the effects of the Wolfcamp B again, in this case about a 25% improvement over that million barrel type curve on 21 wells since the fourth quarter last year. And then similarly on the Wolfcamp A an improvement of about 25%, in this case above the 800,000 BOE type curve which we tend to see in the south. Of course, that's only one well in the Wolfcamp A on the bottom right graph, but nonetheless, it's also encouraging.

Turning now to slide 10, this is the slide in which we show a little bit more detail on how these completion designs have adjusted through time. If you look at the left-hand part of the slide, you see our basic initial design of fracs during the period 2013/2014, which is early days in terms of the play, and it generally had us with probably no more than 1,000 pounds of sand per foot, 30 barrels per foot of fluids, 60 foot cluster spacing, 240 foot stage spacing. And the idea there was long half-length fracs was the initial design concept to reach out and touch rock far away from the well bore.

As we move forward into 2015, the second half of 2015, to the first quarter, we've now put these 97 wells on production in the north, 22 wells in the south. It's the subject of really more of the same, which is 1,400 pounds. You can see on this graph 36 barrels of fluid and so on, tighter cluster spacing. Of course, that does cost money. That's what gets us to about the $7.5 million to $8 million well cost based on the 9,000 foot lateral, the additional $500,000 coming from this frac design.

But in essence, the frac design that we put in place, and we now see the results for, becomes the new standard design, and really the new base case that we're testing the further optimization techniques that we're employing this year. We're going to see more results as we go. There's an 80-well campaign underway to really substantially increase the proppant utilization in some cases up to 2,000 pounds per foot, and in some cases over 50 barrels per foot of fluid, and even down to 15-foot cluster spacing.

And so we really are pushing the design envelope right now to hopefully be able to reach some sort of optimal stage here by the end of this year in terms of how to complete these wells at least from the standpoint of utilization of current technology. And the additional amount of fluid and proppant and so on does add about $500,000 to $1 million per well, and I think we believe that the optimization will actually have a positive payout, but stay tuned on that because we really won't see much data on this till we get into the second through the fourth quarters. As you can see, as depicted from a cartoon standpoint, what we are trying to do is now design completions to allow more rock near the well bore to be contacted. It also will allow us theoretically to more tightly space the wells and optimize recoveries.

So I think this is an action that we have been planning on for some time. We have this well underway as we speak, and hope to see some positive results going forward. We'll certainly know much more in the next few quarters. This is really one of the critical reasons that we mentioned in regard to maintaining our 12-rig campaign because we really need to continue our further understanding of this completion optimization business, so that we're ready when we accelerate our drilling campaign, when things improve in terms of commodities to do so in an optimal fashion.

Turning now to slide 11. Another area where we've been successful in adding value is extending laterals, in this case beyond 10,000 feet. We placed a couple of our longest laterals on production in the first quarter, 11,000 feet and 13,000 feet of perforations, each of which was the subject of completion optimization. Of course, those wells being longer laterals are out and roughly $10 million each. Early data looks very encouraging. As shown here on the graph on the bottom, you see on the green line the two most recent wells, the longer lateral wells, as compared to wells that were drilled prior to those which had shorter laterals.

So in the case of the 23 wells you see on the blue curve, you see below that 13 wells, which are on the gray curve. And it's pretty clear to see that the longer laterals are in fact contributing really substantial improvements over the earlier predecessors which were more or like 9,500 foot laterals and 7,000 foot laterals. So I think it's pretty clear we continue to see a very strong correlation between lateral length, perforated lateral length, and well productivity and we continue to see that as we look forward. I would say we'd do the calculations over 60% or so of our acreage is amenable to based on the leasehold configurations, over 10,000 foot lateral drilling.

Turning now to slide 12. This is an update essentially from the slide that we shared with you last quarter. It shows now a 32% decrease from the year-end 2014 till the first quarter in terms of our drilling and completion cost per foot. We still are at a point where we think we can reduce this going forward. The easiest way to explain it is we still are under old drilling contracts with a very high day rates in the mid $20,000s, where today's rates are probably more in the mid teens. So we'll continue as those contracts roll off to see reductions, not considering the fact we're also going to be continuing to try to optimize regarding completions.

And one of the major areas where we see cost reduction opportunities has been in our frac fleet efficiency where we really measure that in terms of the number of feet that are completed per day by each fleet, and in this case we've seen the average Pioneer pumping services fleet increase substantially from about 800 feet per day of lateral section completed to about 1,200 feet per day during the first quarter. That translates directly into speed of the job as well as in addition the cost reductions that come from time. And really what it amounts to is we're getting more wells POP faster and that's simply another component of outperformance when it comes to production. And it certainly, of course further helps to reduce costs and improve our overall drilling economics.

Turning now to slide 13. Activity continues to be focused on the north where our plans are essentially unchanged from where we were last quarter, and Scott mentioned the fact we'll be drilling with the 12 rigs in the north with about 230 wells to be put on production. Our mix of wells still is predominantly Wolfcamp B and Wolfcamp A. The mix essentially remains the same. What was now the – what was prior of course the standard completion technique is now subject to the new optimization campaign, I mentioned earlier. And if we look at this from the standpoint of the 2015 optimization campaign, we're still in that $7.5 million to $8 million cost per well assuming 9000 foot laterals. In addition to which to the extent the optimization is completed on those wells in the new style of optimization we add another $500,000 or $1 million per well.

One advantage we have in this field is a tremendous opportunity presented by low LOE. Because these are very high volume wells, and they typically run $3 to $5 per BOE in terms of at least operating expense. When you add taxes on you have a very favorable $5 to $7 total cost to operate these wells. That's one of the reasons you'll – Rich will comment on this, but you continue to see our LOE per BOE reduce through time is simply because as we add more of these horizontal wells into the mix it just drives down our averages in terms of LOE.

The economics still look good. I think they're still conducive to our drilling activity, and certainly with regard to where prices are today, it would exceed 30% IRR. It's probably in the neighborhood of approaching 40%. And it also, of course, allows us to progress our completion optimization campaign and be ready to optimally move ahead when we think we get to price, our message is to accelerate drilling.

And then on slide 14, the outstanding well performance I've been talking about in the Spraberry/Wolfcamp area is driving strong growth, and actually with production exceeding our forecast once again, it has led us, in this field, to increase our guidance for the rest of the year, and actually, the total year now is 167,000 BOE compared to an earlier forecast of 162,000 BOE. First quarter production was very strong. Scott has already touched on a lot of these numbers, but in this field particularly we had 149,000 BOE per day, almost 70% oil, and increased about 9% since the fourth quarter of last year.

We did put 55 wells on production this quarter; 42 wells in the north, 13 wells in the south. And you can see on this slide the mix of wells. Again, it's very similar to the mix of campaign of 2016 in total which is predominance on Wolfcamp A, Wolfcamp B wells. Once again, production in the quarter benefited from the completion optimization, longer laterals, POP timing due to efficiency gains, and everything we've been talking about in the prior slides.

Looking forward, we are increasing the growth rate of the field to about 33% this year. It had been at 30%. Again, just reflecting on these productivity gains, and we will be POPing, it is estimated about 60 wells in the second quarter, that compares to 55 wells in the first quarter. We are utilizing choke management in some areas, and what that leads to is a situation where 24-hour IP rates and even in some cases 30-day IP rates can really have less meaning when we are optimizing the use of the infrastructure in the area without overbuilding water capacity for peak production. What we're doing, of course, is we're pumping with more fluid.

We're also just by choice completing more wells near existing infrastructure, and what that has the effect of doing is filling up our water handling capacity, and so what we do is we choke the wells back typically for a couple of weeks, can be two weeks to four weeks, in order to basically allow them to produce, and not overfill those facilities, and at which point in time we would basically full produce the wells. But again, as I said, one of the main aspects of this to consider is I think it's the right economic decision, but at the same time it will cause IP rates in some cases to appear a bit odd because of the curtailment of the wells in certain areas. I think we'll see a little bit less of this going into the next quarter, simply because where we're choosing to complete the wells in the quarter.

So overall, I'd say it's a stellar quarter for the company from an operational standpoint, and it sure sets us up well for a strong 2016 from the standpoint of our full-year results.

And with that, I'm going to pass it to Rich for his review of the financials for the quarter, and also his outlook for the second quarter.

Richard P. Dealy

Thanks, Tim. I'm going to start on slide 15, where we reported a net loss attributable to common stockholders of $267 million after-tax, or $1.65 per diluted share. That did include noncash mark-to-market losses of $111 million after-tax, or $0.69. And then you can see on the slide here, included unusual items, aggregating a $52 million loss or $0.32 per diluted share, principally related to impairments, one in the West Panhandle field and one in Alaska where we held a royalty interest and some unproved acreage. Those were mainly due to lower commodity prices at the end of March.

We also took a charge of $10 million associated with the early termination of 10 drilling rig contracts that we're not going to use prior to their expiration, and so that was just a cost-saving decision to do that. So after adjusting for the unusual items, as Scott mentioned, we are at $104 million loss, or $0.64, principally attributable to the lower commodity price environment that we're dealing with.

If you look at the bottom of slide 15, where we show Q1 guidance versus results. Scott talked about the outperformance on production. And then if you look at really the rest of the items, they were either on the positive side of guidance or within guidance throughout there, so I won't go through each in detail, just to say that it was a really good quarter. The company's cost structure continues to come down, and so other than the backdrop of commodity prices, really excellent results.

Turning to slide 16, looking at price realizations in more detail. As you guys all know, it was a tough quarter on pricing. Oil prices for the company were down 26% to $28.09. NGLs were down 15% to $10.33 per barrel, and gas prices were down 12% to $1.79. Fortunately for the company we were well hedged, and so we were mitigated by our derivative portfolio, which brought in about $217 million of incremental cash flow from our derivatives. Hopefully the first quarter was the low point as commodity prices have strengthened some in the second quarter, and so hopefully we've seen the bottom and future quarters will show better realizations.

The one other item I'd point out at the bottom on our NYMEX differential for oil for the first quarter, you can see it was up a little over a dollar, the differential. That's predominantly due to Eagle Ford condensate sales. In the last year, if you recall, we were exporting about 20,000 gross barrels a day of condensate. That contract expired at the end of the year, and so we had a few minor spot sales in the first quarter, but principally got domestic pricing. And so that caused our differential to go back up. We do have, or expect to see improved pricing in the second quarter with improved domestic pricing under new contract.

Turning to slide 17 on production costs. All of the asset teams, as Tim talked about, have really done a great job on working to lower their cost structure and improve our margins. You can see that production costs were down 17% in total from Q4 to Q1. Base LOE was down 20% quarter-on-quarter, principally related to lower costs on chemicals, electricity, contract services, and just efficiency improvements that the operations guys are doing to really help with margins. So overall, production costs continue to trend lower, and plus as Tim mentioned, we are adding more horizontal wells to the mix of wells with an average of $5 to $7 per BOE of production costs, which will help continue to drive these costs down.

Turning to slide 18, looking at the company's balance sheet. We have excellent liquidity with net debt at the end of the quarter of $1.1 billion. That's net of cash on hand and our liquid investments about $2.5 billion. We're still expecting to get the $500 million in July from our Eagle Ford midstream business sale that we did last year that'll come in July. Undrawn credit facility of $1.5 billion is still completely unused. As you're aware, we have pre-funded our 2016 and 2017 bond maturities, and so that's in the $2.5 billion of cash on hand, and so no near-term maturities. We've got that all taken care of.

And during the last 60 days or so, we have been affirmed by Moody's, S&P and Fitch, so obviously recognizing the company's strength of our balance sheet. So overall, I'd say excellent balance sheet, well-positioned to increase activity levels when oil prices improve, as Scott and Tim both talked about.

Turning to slide 19, and switching gears to second quarter guidance. We are forecasting production of 224,000 to 229,000 BOEs per day for the quarter. The rest of the items here are really consistent with first quarter results, so rather than going through each of those in detail, I'll let you read through those. But consistent with what you would've saw from first quarter actual results.

So with that, why don't we stop there, and we'll open up the call for questions.

Q&A

Operator

Thank you. [Operator Instructions] We'll take our first question from John Freeman with Raymond James. Your line is open.

<Q - John A. Freeman>: Good morning, guys. Terrific quarter.

<A - Scott Douglas Sheffield>: Thanks, John.

<Q - John A. Freeman>: First question I had, obviously given a lot of the efficiency gains that Tim, that you talked about, you brought online significantly more wells than you originally expected in the Spraberry/Wolfcamp in the first quarter, but yet the full year guidance still says to expect the same 230 wells on production. So maybe if you could just speak to, is there any reason to expect those efficiency gains to not continue?

<A - Timothy L. Dove>: Yeah, John, I'd say first of all, we did, because of the efficiency, complete a few more wells, really a handful, probably 10 more wells than we had planned in the quarter. Most of those were near the very end of the quarter as you might expect, just the way the timing works, and so they don't have much of an effect on the first quarter results as they will have more of an effect in the second quarter. But as to the bigger picture, I think we're going to see continuous optimization gains across the board. It has to do with all the things I mentioned regarding the completion optimization campaign on the one hand, but then also mixing in longer laterals. We're going to have 10 to 20 long lateral wells here in the mix for 2016 as well. So I think it's going to be more of an all of the above. I think you're going to see continuous gains, and I think you'll see us, hopefully, continue to outperform.

<Q - John A. Freeman>: Okay. And then just last question for me. On the two wells that you did that averaged about the 12,000 foot lateral, I just wanted to verify that the only difference between those wells and the others on that slide 11 is just the lateral length? They didn't benefit from this, I guess, for lack of a better version, the 3.0 optimization plan that you're going to do on these 80 wells? Like, that was just straight lateral length longer versus the others?

<A - Timothy L. Dove>: Yeah, essentially that's correct. If you saw what I mentioned in there, it was the, what we now call the baseline optimization, not the 2016 version which we'd compare them exactly with all the rest of the wells that were drilled prior.

<Q - John A. Freeman>: Perfect. Great quarter, guys. Thanks.

<A - Timothy L. Dove>: Thanks, John.

Operator

Thank you. And we'll move next to Dave Kistler with Simmons & Company. Your line is open.

<Q - David Kistler>: Good morning, guys. Great work. Looking at the increased production or the impressive production beat that you guys delivered and kind of building on the last question, can you break down a little bit of what the benefit was of weather versus additional completions versus well productivity in terms of what drove that beat? I'm guessing from the answer you gave previously, it's primarily well productivity versus additional wells POPed, but any added color you can give on that would be helpful.

<A - Timothy L. Dove>: Okay, Dave. Yeah, the weather was not a factor. We were fortunate this year as compared to – you recall some of our prior years with ice storms and gosh, who knows what? We were really hammered two years out of the last three years, but this year we got lucky, and had good weather. So it's not weather. And I already mentioned the fact that we had let's say 10 additional completions. Really it's semi-immaterial for the first quarter because they were late in the quarter. So it has all to do with well productivity. And this has to do with the fact that the graphs I showed really depict the fact that we're producing better wells and better initial rates. And when you have better initial rates than what you had planned in the forecast, then you're going to exceed and that's what's happening.

<Q - David Kistler>: Great. So the way to view that is definitely much more secular in nature, not just a temporal item?

<A - Timothy L. Dove>: >: I think we're going to continue to improve is what I'd say.

<Q - David Kistler>: And then following up also, last quarter you'd guided to shut-ins as a result of fracking offsetting wells. When you guys kind of think about that going forward, will there be kind of a continued impact from fracking offsetting wells, or should we actually look towards maybe even a slightly larger uptick associated with not doing that going forward?

<A - Timothy L. Dove>: Yeah. So the way to think about that is we did in fact shut in almost exactly the number of wells and barrels that we had planned in the first quarter, substantially more than we had shut in in the fourth quarter. So despite that, our production exceeded. That said, I think our second quarter numbers look lower in terms of shut in offset production. It's just simply a matter of the mix of wells and where they're being drilled and completed. It just so happens in the second quarter we haven't got as many offset issues as we had where the wells were chosen for the first quarter. So I would anticipate that number to come down somewhat.

<Q - David Kistler>: Okay. Appreciate that. And then one last one. When you talk about adding incremental rigs, kind of five rigs to 10 rigs, and staging them in, can you talk a little bit about how you sit with respect to personnel to handle that ramp-up and maybe specifically with the tool pusher, the effective driller on each one of those rigs?

<A - Timothy L. Dove>: Actually we've had the good fortune of hanging around with some of our drilling contractors the last few days, and they are ready to add rigs and they're getting pinged upon right now by industry, as you might expect, to start potentially adding rigs. And they would make the case that if you were talking about a handful of rigs like we are, let's just say five rigs to 10 rigs, that's no problem at all. It's when we start to have a major acceleration where they would have issues because what they've done, of course, is to keep most of their management and supervisory personnel. They don't have to really rebuild staff. There's quite a few people who are available to come back to work, it's just a matter of making that happen.

So I don't think a small number of rigs that we're really talking about today is that material of an issue. As for us, of course, we have this advantage that's associated with having Pioneer pumping services, Pioneer well services. We have our own people ready to go complete our own wells, and work on our own wells. And so we won't miss a beat, and I think our drilling contractors will be there with us in good shape at least for this first tranche.

<Q - David Kistler>: Great. Well, I appreciate the added color. Fantastic work, guys.

<A - Timothy L. Dove>: Thanks Dave.

Operator

Thank you. We'll move next to Arun Jayaram from JPMorgan. Your line is open.

<Q - Arun Jayaram>: Yeah, good morning, gentlemen. I wanted to talk a little bit – or ask you a little bit about the new guidance. You raised your overall guidance by 2%, and oil by 4%. And I'm just trying to understand the magnitude of well productivity gains that you've assumed in your new guidance because it is the same number of wells. You guys have talked about seeing 10% to 35% improvements in well productivity, but what is in the new guidance?

<A - Frank E. Hopkins>: Arun, basically what we've done is we've pushed up some of the productivity, if you want to call them EURs, internally, on wells in certain areas based on results that we've seen now, not only for the first quarter but the past two quarters. I get the question all the time, when are we going to raise our type curve and the answer is give us a couple of more quarters. Let us get some more data. I think you've heard Tim and Scott say that we think we'll have a pretty good understanding of the Wolfcamp B by the end of this year, where we'll certainly be in a position to do that. Wolfcamp A and Lower Spraberry Shale, it might take you into next year just because of the timing again of getting enough data. We're trying to not get too far out in front of this, but we also recognize that we do have to provide you with some reasonable estimates of where production is going to go based on our actual results.

<Q - Arun Jayaram>: Okay. That's helpful. That's helpful. Just a second question perhaps, Tim, in terms of lateral lengths, you've been drilling wells kind of in the 8,200 foot and 9,200 foot range. You've obviously announced some results on the wells beyond 10,000 foot. Have you had any conclusions on what you think the optimal lateral foot could be in terms of drilling in some of the wells in the Sale Ranch? You think that could be applicable to other parts of your acreage position outside of Martin?

<A - Timothy L. Dove>: Well, you're going to see different well results in all different areas. So the Sale Ranch happens to be one of our really good areas, so I don't think you would necessarily say that that's going to be the same exact result everywhere we drill, but I think what you'll see is the same sort of upticks on lateral drilling or lateral extensions.

The way we look at it is where we are today, unless you stay out to 13,000 feet, is probably the economic limit in realizing if you're talking about extended reach drilling, it can be tens of thousands of feet longer than that. The issue is these are wells in which we're pumping very large fracs, so you have hydraulic limitations out at the toe where you're not going to be able to necessarily get off as an effective frac.

And we think we're still pretty close to linear in terms of the relationship between lateral lengths out to 11,000 feet to 13,000 feet and productivity of the well. In other words, one-to-one payout, and we know the economics are strong from that standpoint. But I think we're almost at the limit in terms of the fact that even though we could drill longer wells, completing them becomes a hydraulic issue. And so I think that's probably about where we're going to stop, but the more 13,000 footers you can do the better is kind of our current view. So that means what we'll be trying to do is configure leasehold where we can to get out to 12,000 feet, 13,000 feet by doing acreage swaps and other trades.

<Q - Arun Jayaram>: Great. My final question, perhaps for Scott. Scott, you talked about when you get confidence around $50 you could increase your Permian activity by five rigs to 10 rigs. What about the Eagle Ford? At what oil price would you contemplate adding or restarting activity in the Eagle Ford?

<A - Scott Douglas Sheffield>: Yes. We have stated when oil gets to $50, which is an equivalent to the condensate price that we would get, so if WTI gets to $50, we would look at restarting Eagle Ford. So we'll have to make a decision at the time if we add 10 rigs, for instance, in 2017, do we take two of those rigs and put in Eagle Ford, for instance? We do have partners there we have to get approvals on, but I could see us add a couple of rigs in Eagle Ford as a portion of that 10 rig add.

<Q - Arun Jayaram>: Okay. That's very helpful. Thanks a lot.

Operator

Thank you. And we'll take our next question from Doug Leggate with Bank of America. Your line is open.

<Q - Doug Leggate>: Thanks. Good morning, fellas. I'm looking at slide 12, Tim, and obviously very substantial improvement in the cost per foot, but kind of flattened out in the last quarter or so. I'm just wondering if you see – are we getting to the limits of the improvement now, or do you think that's got further to go? And I've got a couple of follow-ups, please.

<A - Timothy L. Dove>: I think if you're certainly looking as an eyeball test, it would say it's flattened out somewhat. It has to do, of course, with the mix of wells we're drilling and where they are and so on. But we still have other areas where I think we can reduce our costs. We have, as I already mentioned, contracts that are peeling off from the standpoint of drilling contractors over this year into next year. And so coming off of what would've been mid $20,000s day rates into mid-teens is going to be a substantial effect for us. And there's other ancillary things that we're doing as well at the margin.

I think we can reduce our tubular somewhat from this point on as well, at least marginally, maybe 5%. But I think a lot of it will be not just the cost per se from existing contracts and existing supplies but rather continuing just to improve and this has to do in our case with reducing nonproductive time as an example and we're splitting up both drilling and completions into small pieces to make sure we can optimize. And so I think you'll start – you'll see us continuously improve, but I think we are reaching more of a flat spot in the curve relative to where we were. You can see dramatic increase – or decreases in the early stages of what you would expect, and now we're sort of reaching more of an asymptote but with a small decline going forward.

<Q - Doug Leggate>: Okay. Thank you for that. Your comments, Tim, about the choking back for water management, and so on, materially enough, that you mentioned it in the slide deck. I'm just wondering if you could help us understand what that could mean for flattening out decline rates, for example in the areas where you're doing that. I mean, is that just kind of a one-off to deal with this water infrastructure issue, or is it something that could become more of a policy for Pioneer going forward?

<A - Timothy L. Dove>: It's 100% today related to water, so we're not trying to effect EURs or wells by choking them back. We don't think there's actually any effect from choking the wells back would amount to typically two weeks to four weeks while this substantial water flow back period occurs. And so I think essentially what we're trying to do is optimize infrastructure. We could haul off this water but it's such a huge volume of water it creates a logistics problem and it's a minimum of 250 per barrel to do so.

And to go build bigger facilities, we all know the conundrum presented by that, which is we could actually build bigger facilities, and they'd only be used for two weeks while we would basically see a decline in the initial production of the well both in terms of water and oil. And so this we think is optimal, it's simply just slightly choke back the wells until the facilities can handle the volumes considering the volumes are substantially higher. I think we'll see less of an effect on this as we get into the second quarter, as I mentioned, simply because we'll be drilling in different areas that won't have as close to existing infrastructure. Of course, that will require infrastructure build-out so there's no free lunches in this infrastructure business.

<**Q - Doug Leggate**>: Thanks, Tim. Last one for me, if I may, and, Scott, I apologize for laboring the topic about what oil price you put rigs back to work, but it seems to be topic du jour. I just want to make sure I understood properly. So you're looking more at the strip than anything on the spot, it sounds like and I'm just curious is that – you add a rig, let's say tomorrow, when would you expect production contribution given your pad drilling? And I'll leave it there. Thanks.

<**A - Scott Douglas Sheffield**>: Yeah, I think we're down to spud-to-POP of 120 days to 130 days, so we used to say six months, so it's down in the four months to five months range. So when we add rigs it'll take four months to five months, and it's a bigger picture for the industry. I think the industry is going to – we just can't become a big shale swing producer like OPEC thinks just because of the combination of leverage, the amount of people we had to get back to work. It's going to take the industry a good year-and-a-half, two years to get production growing again, once it starts back up.

<**Q - Doug Leggate**>: [indiscernible] (44:20) Thanks, Scott. I appreciate the time.

Operator

Thank you. And we'll go now to Neal Dingmann from SunTrust. Your line is open.

<**Q - Neal D. Dingmann**>: Good morning, guys. Say, I just got a question, I know there's a couple of packages, one – or at least one or two large floating around the Midland. Your thoughts about looking at some of these maybe at least to fill in acreage. I know you certainly don't have any cost of inventory issue, so I'm thinking more, Scott, about just filling in acreage. Are these things that you all are looking at?

<**A - Scott Douglas Sheffield**>: Yes. Our standard is still to look at anything that's contiguous next to our acreage that will extend our laterals. So far we're only spending $10 million, $20 million a year but if we see something that will definitely improve our laterals from 5000 feet to 10,000 feet to 12,000 feet, we'll definitely look at it. The prices people are paying are still fairly strong. So we'll just have to evaluate and see as these deals come through our system.

<**Q - Neal D. Dingmann**>: Okay. Okay. And, Scott, for you – maybe for you or maybe for Tim. I'm just looking at that slide eight. I want to make sure where it does show kind of beating all those type curves in the northern Spraberry and Wolfcamp. And especially I'm just looking at that Wolfcamp B, talking about that 35% improvement. Is that pre sort of all the additional proppant, the longer laterals, and all these other things you've already done? I'm just trying to get a sense of that certainly shows strong in all three of those curves, particularly in the Wolfcamp B. I'm just wondering is that before some of these other things you've just now started doing?

<**A - Timothy L. Dove**>: Yeah, so I would simply say if you look at the completion optimization campaign slide, if you consider what we used to do in 2013 and 2014 is 1.0, it's really the 2.0 case where all those wells were completed using various completion optimization techniques, but they did not include any what we call 3.0, which is 2016 campaign.

<**Q - Neal D. Dingmann**>: Wow. Okay. So there's really room to – I guess the last question I had then, how much until you have the confidence, I mean again, certainly a million barrels is already great EUR. How much more would you have to see or how much more just timing in our data would you have to see to decide to even take those type curves a bit higher?

<**A - Frank E. Hopkins**>: Hey, Neal. This is Frank. Again, I'll just sort of repeat what I said earlier. I think when you get well into the second half of this year – I don't know whether it's third quarter or fourth quarter, but in some cases the results we have are only – we've only got 90 days of results but everything is looking positive. So give us a couple of more quarters, certainly on the Wolfcamp B, and I think we'll be able to declare an increased level, a new EUR, whatever you want to call it there, and up the EURs we're building into our forecast. And then with respect to the Wolfcamp A and the Lower Spraberry Shale, we'll be getting a lot more data over the second half of this year, but our data set is not nearly as extensive as we have with the Wolfcamp B. So we're probably looking sometime into 2017 till we get enough confidence there that we want to just declare – I call it declare a victory.

<**Q - Neal D. Dingmann**>: Certainly. Certainly. Makes sense, Frank. Thanks a lot. Go ahead.

Operator

Thank you. We'll move next to Charles Meade from Johnson Rice. Your line is open.

<**Q - Charles A. Meade**>: Good morning, Scott and Tim and to the rest of the team there. I wonder if I could ask a question about the completion optimizations, and how far things might go. One way of looking at it is that you could spend a million bucks to bring on – or for an increment as small as 100,000 barrels and that would still benefit your F&D. And I'm curious, how close is that to the way you guys are analyzing it? And what might be left out of the picture when we look at it that way?

<**A - Timothy L. Dove**>: I think that's exactly the right math when you consider, Charles that our F&D costs for this part of our business horizontal Wolfcamp/Spraberry drilling is roughly about $10. And so $10 is a good F&D costs, but I think what we're really finding is that the increments we're talking about are substantially more than 10%, as we're showing in some cases where they're 25%, 35%. The real question is as we get to a point here in the 3.0 model that I was referring to, we're already down to 15-foot cluster spacing.

I don't really know how much closer you can get clusters, but it's not much closer than that. And I think you're at a point where even pumping proppant, even though we're 1700 pounds to 2000 pounds of proppant, you see some plays where they've gotten to 2500 pounds, 3000 pounds. So we maybe have a little marginal ability to move more that direction. But I think the more of the same model is something we're really testing in 2016. You're going to see improvement, I think, out of a lot of those techniques. The issue is going to be once you get past there, and you can't really do more of the same because you're limited by space or volume or physics, what do you do there? Then you're probably more into new technology applications, which are a little bit unclear today.

<**Q - Charles A. Meade**>: Right. Yeah, I remember you mentioned that earlier in your prepared comments, Tim. And if we could stick on that, your new iteration of the completion design, you talked about the 80 wells in the back half or in the remainder of this year. Is there going to be any shift in the mix of those wells versus what we've seen to-date, or should we still expect two-thirds, three-quarters Wolfcamp B will this newest completion design?

<**A - Timothy L. Dove**>: Yeah. I don't anticipate that the mix of optimally completed wells will change compared to just the totality of the program.

<**Q - Charles A. Meade**>: Great. Thank you for that.

<**A - Timothy L. Dove**>: Thank you, Charles.

Operator

Thank you. We'll move next to Scott Hanold with RBC Capital. Your line is open.

<**Q - Scott Hanold**>: Thanks. Good quarter, guys. If I could refer to page 10, Tim, just to clarify, so on, I guess, version 3.0, specifically from our seats what should we be looking at in terms of relative productivity to make this an economically feasible plan to move forward with? Certainly you're seeing a nice 10% to 35% increase, or I guess even just on the Wolfcamp B 35% increase on version 2. Is that the type of increment that you'll need to make that decision on a go-forward basis, or what should we look for?

<**A - Timothy L. Dove**>: I kind of refer back to Charles' question in the sense that version 3.0 has us adding somewhere between $500,000 and $1 million per well. You use a $10 F&D costs, you better feel pretty good that you're getting that kind of percentage increment as well, which is on a well cost basis probably in the neighborhood of 10%. So you better feel like you're getting at least a 10% bump or you probably wouldn't proceed, but so far our bumps have been substantially higher. Remember back to the Eagle Ford Shale, we stopped when we were at a point when we were generating 15% to 30% increments but we're not stopping here.

And the other thing that occurs to me in that question is we're not even talking about spacing. What happened in this field was we began by looking at 500 foot to 600 foot spacing. We had situations where we had what we thought was too much well interference at a time we were drilling larger half-length wells on the completions. That was really kind of a 1.0 model. And since then, we now find we're completing the wells with more near well bore rock stimulation. That allows for the potential for tightening spacing. So we're now actually testing down to again down to 500 foot to 600 foot spacing where we had blown it out to 900 foot to 1000 foot for that concern regarding interference. So now you're talking about substantial incremental improvements in overall EURs from selected field areas. So in other words, your recovery rates go up. So we're not even referring to that, but behind the scenes that's also going on. We just don't have any data yet to show you, but it's just another thing on the list to hopefully essentially increase EURs.

<Q - Scott Hanold>: Yeah. So just to clarify there, 2.0 assumes somewhere 500 foot to 600 foot. I know it's early, but is that what you're referring to?

<A - Timothy L. Dove>: 2.0 – 1.0 is I'd say we tried down to 500 foot to 600 foot. We saw interference in some wells back in 2013/2014 to the point we were concerned about it, and thought we might be overstimulating the rock, and therefore moved out to 800 foot to 900 foot spacing, some cases 1000 feet. And some of the more recent testing we're doing now, we're moving back to 500 foot to 600 foot because we think that the more near well bore rock stimulation campaign is presented by the 3.0 case will allow us to do that. So when we're talking about the moving back to 500 foot to 600 foot is actually a 3.0 scenario.

<Q - Scott Hanold>: Okay. Understood. So of those 80 wells that you're drilling, they will likely be 500 foot to 600 foot, if I'm hearing you correctly. And could I also ask you can you give us a sense – are you looking at doing Wolfcamp A, Bs Lower Spraberry all at once or how are you orientating these wells?

<A - Timothy L. Dove>: Well, we still continue to use, on the last part of your question, the drilling a bunch of Wolfcamp Bs. You can see the predominance of the wells being drilled, and then with the waiting period following up with Wolfcamp A, and then it's just going to continue to be the plan. And so I would see that going forward as well.

<Q - Scott Hanold>: Okay. Thank you.

Operator

Thank you. We'll take our next question from Evan Calio from Morgan Stanley. Your line is open.

<Q - Evan Calio>: Hey, good morning, guys. A couple of follow-up questions on your rig deployment comments. Is $50 is the threshold that relates to your ability to hedge, $50 on the downside? What percentage of 2017 do you need to hedge at those levels in order to add rings? Is there a trigger level there?

<A - Scott Douglas Sheffield>: We have historically, Evan, gone up to 75% to 85%, so it will be somewhere in that range. We're not going to give out what hedge position we're going to put in because there's too many people hedging in the market in this day and time, but obviously it'll be hedges trying to collect as close to $50 as we can.

<Q - Evan Calio>: Right. And that hedge would then allow you to add the first rigs, I guess as the first five cold stacked rigs. Is the next five rigs then up for the 10 rigs based upon oil price oil price in F&D outlook?

<A - Scott Douglas Sheffield>: No. The entire five rigs to 10 rigs is based on the strip getting to $50 for 2017, and also believing that the fundamentals are strong, such as inventories are declining. We would not like to add – it's not ideal to add 10 rigs at once. We'd like to add two rigs or three rigs one month, two rigs or three rigs the next month, two rigs or three rigs the next month. And so we'll probably have a phase-in time period.

<Q - Evan Calio>: Great.

<A - Scott Douglas Sheffield>: And we could – we'd like to also maybe do it later this year, so if we can achieve those fundamental goals and also the oil price goal.

<Q - Evan Calio>: Great. Any range on vertical integration CapEx increase under a five rig to 10 rig addition program from the $150 million this year?

<A - Scott Douglas Sheffield>: I don't think...

<A - Timothy L. Dove>: Our fleets can handle it right now.

<A - Scott Douglas Sheffield>: Can handle it, so I don't think there will be an increase.

<Q - Evan Calio>: Great. Maybe last for me, if I could. Could you guys discuss any technical challenges that remain to wider deployment of longer lateral versus your 9,500 foot standard design? And what percentage – I appreciate the levels for 2016, but what percentage of those longer laterals could be in your 2017 program? Thanks.

<A - Timothy L. Dove>: Yeah, I think the only technical hurdle is the one I mentioned which has to do with the fact that the longer laterals present more of a completion issue than they do anything else. Realize you get far out in the well bore you have hydraulic issues that may be a limiting factor in terms of how well the completions are pumped at the toe. Also, remember we are using still a plug and perf model here for how these wells are completed, and so your drill-out campaign becomes much more difficult especially if you're using coil or what have you at that length.

So it really becomes more mechanical on the completions than it does the drilling. I don't really see us out testing much more in terms of lateral length than out there to the 12,000 feet to 13,000 feet. But as I mentioned, we have probably over 60% of our acreage today is amenable to plus 10,000 foot drilling. We're going to have 15 wells, probably 10 wells, 15 wells, 20 wells that are out past 10,000 foot. We've got some work to do to really configure some more of our leasehold to add that other 40% for long laterals as well.

<Q - Evan Calio>: Great. So some higher number in 2017, but we'll stay tuned for that.

<A - Timothy L. Dove>: Yeah, we're heading that way. That seems to be the right economic decision to get as long lateral out there as we can, and so I would see us pushing in that direction.

<Q - Evan Calio>: All right. Appreciate it, guys.

Operator

Thank you. We'll take our next question from Ryan Todd with Deutsche Bank. Your line is open.

<Q - Ryan Todd>: Great. Thanks. Good morning, guys. Maybe just one follow-up question maybe on the other side of the rig acceleration. I know you've talked a lot about when you would add rigs, but if we think about on the higher side, what are some of the limits in terms of how much additional capital you'd want to deploy? I think in the past you've talked about a 1.5 times leverage as kind of high end of a target. If you think about how much capital you could eventually push into the market, is balance sheet metrics still kind of a limiting factor? Is it – are there infrastructure limitations or bottlenecks that we should be aware of, or how are you thinking about your additional to deploy, whether it's five rigs or 10 rigs or 15 rigs or more?

<A - Scott Douglas Sheffield>: Yeah, five rigs to 10 rigs first is cash flow. We're going to have a strong cash position by the end of 2016 obviously and then going into 2017, I do expect oil prices to continue to move on up past $50 towards $60 going into 2018. And so we'll continue to add rigs. Our cash flow starts getting to a number close to $2 billion plus, you start talking about those types of numbers, so we can start paying for ourselves our rig costs and we'll use the balance sheet. I think it's probably even more important, and I think other companies will probably lower their targets. Too many companies were at 2, 2.5 to 1, and they got caught with this downturn and they're up to 4 to 5 to 6 to 1. And so it's probably even more important for the company to keep this debt-to-cash flow at 1.5 to 1 as a limiting factor going forward.

<Q - Ryan Todd>: Great. I appreciate that. And then maybe, I mean over the medium term it probably feels like a ways away at this point, but you've talked in the past about eventually wanting to target cash flow neutrality in the medium term. Is that still a medium term outlook? Is that a long ways away for us to worry about at this point, or how do you think towards long-term managing to that target?

<A - Scott Douglas Sheffield>: Managing – say again.

<Q - Ryan Todd>: Managing to a cash flow neutral position.

<A - Scott Douglas Sheffield>: Yeah, I think if oil prices get back up to $60, and we don't see a – we see a very small increase in service costs, it depends on how many rigs are being added, that the company can grow within its cash flow at that point in time. Once we spend our cash flow, get production up and assuming some small increases in service costs, I think the company can live within cash flow at that point in time.

<Q - Ryan Todd>: Great. Congrats, guys. I'll leave it there.

Operator

Thank you. We'll take our next question from Brian Singer with Goldman Sachs. Your line is open.

<Q - Brian Singer>: Thank you. Good morning. To follow up on a couple of the topics from earlier, first on the longer laterals. What percent of your northern acreage could you today apply 10,000 foot laterals? And can you give us some sense of your expectations for the magnitude of acreage swaps you think we could see this year and then how much have a greater percentage of your acreage that could open up to longer laterals?

<A - Timothy L. Dove>: Well, I think I've already mentioned, Brian, that about 60% of our current acreage would be amenable to 10,000 foot laterals or more today. We're doing acreage swaps essentially every day or close to it. We have internal goals in that regard. I remind you that one of the more recent deals we did had us swapping out 1200 acres, and this is acreage for acreage with no cash changing hands and we added 210,000 feet of laterals. So it's basically – I think it will be easily something we would look at as a goal to add 2 million feet of laterals as a goal for 2016, and this is just stacking onto our existing acreage position.

<Q - Brian Singer>: Got it. And the 60% is northern or total at Permian acreage?

<A - Timothy L. Dove>: I'm speaking more northern right now because that's the only place we're doing any drilling.

<Q - Brian Singer>: Got it. Okay. And then if and when it does make sense to start adding 5 to 10 rigs, would the completions associated with the new rigs all be the version 3.0 and would you characterize the wells drilled as more development mode in areas that are all fully tested for the zones you – for the Lower Spraberry A and B, or would there be more delineation drilling testing new zones in portions of your acreage, testing spacing, et cetera?

<A - Timothy L. Dove>: Well, I'm first going to just tell you this we only have an 80-well campaign going right now on 3.0. So we're not going to make further decisions on the expansion of the use of 3.0 until we understand whether it's working. And if so at what sort of economic basis that it's working. So to the extent we were to add new rigs, we'd have to kind of hold off and see how 3.0 works. If we think 3.0 works well, then we would absolutely add it to every single well. It would be part of the 5 to 10 rig adds. In terms of the zones, the way I think about this, when I consult with our geo team, we should know with the plethora of data we have vis-à-vis the Wolfcamp B and the 3.0 campaign going on in the Wolfcamp B this year, we should pretty much be at a point we will be in full development mode on Wolfcamp B at an optimal completion by the end of this year.

But in the case of the Wolfcamp A and then further to the Lower Spraberry Shale, we just don't have as much data. So it might be into 2018 before you can really say we are in development mode at the optimal way these wells are to be completed. So I think it's going to be a staggered approach. You can't get all the data every – today on every single zone at the speed in which we're drilling, but we're trying to accumulate it as fast as we can. But I would think Wolfcamp B ready by the end of the year to be on full development mode, A and Lower Spraberry Shale into 2018 and 2019.

<Q - Brian Singer>: Great. Thank you.

Operator

Thank you. And this does conclude our Q&A session for today. I'd like to turn the call back to Scott Sheffield for any closing remarks.

Scott Douglas Sheffield

Again, we thank everyone for taking their time out. Again, reminding people that we had a great quarter. Looking forward to the next quarter, and continuing with our outstanding performance. Thank you.

Operator

And this does conclude today's conference. Thank you for your participation. You may disconnect at any time.