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Range Resources Corp. (RRC)

Q1 2017 Earnings Call

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MANAGEMENT DISCUSSION SECTION

Operator: Welcome to the Range Resources First Quarter 2017 Earnings Conference Call. This call is being recorded. [Operator Instructions] Statements contained in this conference call that are not historical facts are forward-looking statements. Such statements are subject to risks and uncertainties which could cause actual results to differ materially from those in the forward-looking statements. After the speakers' remarks, there will be a question and answer period.

At this time, I'd like to turn the call over to Mr. Laith Sando, Vice President, Investor Relations at Range Resources. Please go ahead.

Laith Sando

Vice President, Investor Relations, Range Resources Corp.

Thank you, operator. Good morning everyone, and thank you for joining Range's first quarter earnings call. The speakers on today's call are Jeff Ventura, Chief Executive Officer; Ray Walker, Chief Operating Officer; and Roger Manny, Chief Financial Officer.

Hopefully you've had the chance to review the press release and updated investor presentation that we've posted on our website. We'll be referencing some of the those slides this morning. We also filed our 10-Q with the SEC yesterday. It's available on our website under the Investors tab, or you can access it using the SEC's EDGAR system.

Before we begin, let me also point out that we'll be referencing certain non-GAAP measures on today's call. Our press release provides reconciliations of these to the most comparable GAAP figures. In addition, we've posted supplemental tables on our website to assist in the calculation of these non-GAAP measures. The supplemental tables also provide calculated natural gas differentials for the upcoming quarter and detailed hedging information for all products.

With that, let me turn the call over to Jeff.

Jeffrey L. Ventura

Chairman, President & Chief Executive Officer, Range Resources Corp.

Thank you, Laith. Improving pricing differentials driving expanding margins is the theme of the first quarter and what we believe will be a continuing theme for Range in 2017 and 2018. Coupling the enhanced margins with the lowest PUD development cost for any of our oil or gas peers, we calculate our unhedged recycle ratio as approximately 3 times.

The story is ratified by independent work from well respected firms and analysts, with one such report included in our new presentation. It examines recycle ratios across the Delaware Basin, Midland Basin, the SCOOP/STACK play, the Bakken, the Eagle Ford and the Marcellus. This work includes a number of very high quality oil and gas companies. Based on this analysis, Range has one of the top recycle ratios of any company whether oil or gas and in any basin. We believe this is a key indicator of long-term success driving above average profitability in a normalized price environment or strengthened stability in the down cycle.

Moving back to margin expansion, improving price differentials for natural gas, NGLs and condensate are expected for 2017. A full year of transportation on our Gulf Expansion Phase 1 pipeline project and a full year of contribution from our near to market North Louisiana assets are resulting in our natural gas differential for this year improving to approximately NYMEX less $0.30. Later this year, we're expecting Rayne/Leach Xpress at their Southwest and Rover Phase 2 pipelines to commence operations. These transportation projects should result in further improvement in our 2018 differentials.

Per barrel NGL pricing for 2017 is projected to be 28% to 30% of WTI. A full year of Mariner East plus NGL sales from North Louisiana are the main contributors for the increase in realized price. Looking forward to 2018, fundamentals suggest that higher demand for ethane and propane from the petrochemical sector and exports can improve our pricing differentials further next year.

Our condensate pricing differential per barrel for 2017 is projected to be WTI less about $5.50. This is driven by a full year of our new marketing agreement for Marcellus condensate and a full year of North Louisiana condensate sales. Importantly, this pricing differential represent a 40% improvement over our 2016 condensate differential. This improvement in pricing across gas, NGLs and condensate coupled with one of the lowest cost structures in the industry, has resulted in the margin improvement we're seeing in the first quarter and are projecting for the full year. Capital efficiency in 2017 will continue to improve as we're targeting over 9,000 foot laterals in Pennsylvania and we're driving down the cost of drilling complete wells in North Louisiana. Ray will discuss our operational highlights next and provide more detail on our plans.

With the first quarter in the books, 2017 is shaping up to be a good year for Range. Importantly, we expect our class-leading recycle ratio in 2017 to continue into 2018 and beyond as Range is one of the few companies in the industry with a decade plus of high quality drilling locations. We have a resource potential of approximately 100 Tcfe as compared to our year-end proved reserves of 12.1 Tcfe. Our resource potential does not include the highly prospective Utica, which will drive our ratio of resource potential to proved reserves even higher.

As shown on slides 23 and 24, in the southwest portion of the Marcellus, Range has the highest estimated ultimate recovery per foot, lowest finding and development costs and lowest breakeven costs. We have a high quality asset position in North Louisiana and as shown on slide 13, we've made significant progress adding value since the acquisition was announced last May. Looking forward, Range remains well positioned to drive value for years to come.

I'll now turn the call over to Ray to discuss our operations.

Ray N. Walker, Jr.

Chief Operating Officer & Executive Vice President, Range Resources Corp.

Thanks, Jeff. Production for the first quarter came in at 1.93 Bcf equivalent per day, and guidance for the second quarter is flat to the first quarter of 2017, or 1.93 Bcf equivalent per day, and we remain on track for annual growth of 33% to 35% as the company's production growth is weighted towards the back half of the year.

Before walking through operations, I'd like to spend a few minutes on our production growth for the rest of 2017 and how this sets us up for 2018. In Appalachia, we brought to sales in the first quarter less than 20% of our expected wells for the year, so growth in the back half of the year should look really good. In North Louisiana, we expect to bring to sales 29 additional wells in the second half of 2017, also providing solid growth in the second half of the year. We delivered on our expected production for the first quarter of 2017 in both Appalachia and North Louisiana.

And in Terryville, we expect wells going forward will generate better growth than the group of wells turned to sales in the first quarter. To illustrate, let's compare and contrast our first quarter activity with our expectations going forward. As discussed on the last couple earnings calls, 18 of the Terryville wells brought to sales in the first quarter were drilled prior to the acquisition, many of them over a year ago. As result of completing such a large swath of wells at one time, which was 27 during the first quarter, and because of the location of many of these wells, approximately 40 million cubic feet equivalent per day of offset production was shut in to minimize the frac hits.

The shut-in production does not come back all at once, but will come back throughout the year via flatter declines. Going forward, we're planning a more balanced approach both in terms of activity and planning the well locations to help minimize the impact on offset production. As discussed before, we've implemented a completely different flow-back in early production protocol. The wells will now be opened up under designed, constrained conditions, allowing the use of more cost effective facilities and the minimization of expensive flow-back rental equipment. We believe this will improve the overall project returns.

What it means is, that we won't see the initial 30-day rates that you would have seen in the past. And we've changed production operations in the field. In addition to a different approach to flow-backs, we're also implementing Range's safety, facility and production protocols. One example is eliminating production of the annulus. This practice, while common in some areas, is not the preferred practice with the equipment that is currently in place. These design and operational changes resulted in cutting back production by approximately 30 million cubic feet equivalent per day for the year. Of course, this simply curtails production, and we expect to get that production back via a flatter decline.

In the first quarter, we also tested some meaningful step-outs in Terryville that will help to further delineate and de-risk our well inventory. Some of these wells were in areas perceived as the edges of the field due to poor historical results. While the results from the new wells are early, they are very encouraging and are in part the result of improved targeting. With lower drilling and completion costs, the encouraging early well results and the ability in the future to incorporate better mapping and seismic, we believe these areas hold significant potential.

As part of that same process of better understanding the field's ultimate potential, the first quarter included wells that had been drilled pre-acquisition in some of the Pink horizons. Completing these wells will provide us a better understanding of the resource potential over the coming years.

Going forward, we'll continue to be focused on the Upper and Lower Red, while occasionally drilling other horizons and extension wells to optimize our full development plans. This is similar to our approach in Appalachia, that is, focusing on the Marcellus while unlocking the Utica and Upper Devonian opportunities over time.

So while the first quarter was a great quarter operationally and financially, we're really looking forward to the second half of this year, as we continue to build on our operational successes in both North Louisiana and Appalachia.

Hitting on some of the operational highlights for the quarter, we'll start with Appalachia, where we're directing approximately two thirds of our capital spend. We continue to make great strides in unit cost reductions, improving well performance and capital efficiency.

I'd like to take a few minutes now and walk through some updates on the drilling side in Appalachia. Our team has now drilled the longest Marcellus lateral in Pennsylvania and three of the top four longest laterals in the entire basin. In the first quarter, we drilled three laterals over 15,000 feet and seven laterals over 10,000 feet. We're achieving a 67% increase in daily lateral footage drilled versus a year ago.

Combining our drilling performance and planning efforts, our average lateral length drilled this year will be approximately 9,000 feet. These improvements can be attributed to four things. We've upgraded our rig fleet to higher horsepower and higher pressure rated equipment. We've adopted and greatly improved the efficiency of our rotary steerable tools. The team has redesigned our current mud systems, and a real focus on key performance indicators that trigger real and measurable success. And two final things on the drilling side, we've accomplished all of this while narrowing our lateral target to a 10-foot window, at the same time drilling faster while lowering cost from last year on a per foot basis by over 30%. And it's been almost two years since the team has had to sidetrack a wellbore. Needless to say, we're really proud of their accomplishments.

On the completions, facilities, water and production front, we're continuing to innovate and improve efficiencies and cost. We're fine tuning frac designs and zipper frac operations, and I expect we'll continue to do so for years ahead. Even with some forecasted pressure on service costs, our cost per stage and our cost per foot of completed lateral should continue to improve throughout 2017.

Facility costs should continue to improve and LOE continues to trend in the right direction. Any way you look at the data, Range has the lowest well cost, including facilities, of any operator in the southwest portion of the basin, and we expect those costs will continue to improve. One significant and unique advantage that we have is the extensive network of existing infrastructure in pads. We're planning for approximately a third of our 2017 wells on existing pads, with as much as half of our wells in 2018. This will drive down our costs significantly, by as much as $200,000 to $500,000 per well.

On the well performance side, we continue to improve completion designs and see impressive results. As an example, I want to highlight a couple of liquids-rich pads that we brought online during the first quarter. In the wet area, we brought online a three-well pad with average lateral length of 7,186 feet, completed with 37 stages per well that produced net-to-sales under designed constrained conditions at a max 24-hour rate of 35.3 million cubic feet equivalent per day per well.

In the super-rich area, we have a four-well pad with average lateral lengths of 10,772 feet completed with 54 stages per well, but have only been able to put two of the wells to sales so far. The reason why is that they're some of the best liquids rich wells in the basin. Those two wells have averaged over 31.4 million cubic feet equivalent per day, each well, or over 62.8 million cubic feet equivalent per day combined with 69% liquids, again under designed constrained conditions net-to-sales for a max 24-hour rate.

As those two wells decline, we'll be adding the other two wells to sales as capacity frees up in the system. It's important to point out that this pad is near the planned Harmon Creek processing plant in a lightly drilled super-rich area. And we have plans to develop additional wells and pads in this area going forward.

Clearly, these two pads illustrate the quality of our low risk, long lateral inventory in Appalachia in the dry, wet and super-rich areas. These types of results, when combined with going back on to existing pads with existing gathering and compression infrastructure generate liquids-rich drilling economics that are among the best in the business. Like I've said in the past, we literally have thousands of these types of opportunities and I still don't believe we've drilled our best well yet.

As a quick update on the Utica, I believe it's worth pointing out the updated map in our presentation on page 44. Of particular note, we've highlighted the recent activity, including some direct offsets to our acreage currently being drilled that will clearly enhance our 400,000 net acre position further.

We'll continue to monitor those wells and other Utica activity in Pennsylvania as we go forward. Our best well remains as one of the top four Utica wells in the play. We believe it will hold flat for close to 400 days and the EUR looks to be around 3.25 Bcf per 1,000 foot. Again, essentially all our acreage is HBP'd and we believe the Utica play will play a complementary and important role in the future.

Shifting to North Louisiana, we're excited about the progress we've achieved in just a little over six months and believe we're on track to exceed our original acquisition expectations. We're in line with forecasted production and cash cost, and we're expecting solid growth in the second half of the year, while drilling and completion cost have improved further and faster than we expected. We've reduced our average all-in well cost for a 7,500 foot lateral by another $300,000 to $7.4 million while reducing drilling time, refining the target window and staying 100% in zone.

This is now $1.3 million or 15% below the $8.7 million cost last September, which obviously has a major impact on the economics. Like we've discussed, this lower cost will open up additional inventory from various horizons across our acreage positions. Our capital plan and the $7.4 million well cost in North Louisiana has baked in our forecast for service pricing increases for the year. For some services, those increases could range from 5% to 25%. However, as evidenced by our well cost, we fully expect that improvements in our operations and designs will more than offset the service price increases.

As mentioned earlier, our 2017 North Louisiana program includes drilling, delineating and de-risking our well inventory in Terryville. This plan consists of wells in the various Lower Cotton Valley intervals that will lead to an improved understanding and mapping of the reservoirs alongside the acquisition of additional science work directed at determining optimum targeting and completion design. We are acquiring additional seismic along the southwestern and southeastern portions of the field to help calibrate the reservoir mapping and well results.

During the quarter, we completed 27 wells made up of 19 Upper Reds, five Lower Reds and three Pinks. And we're producing these wells much differently than the historical practice, mainly under designed facility constraints, resulting in lower cost and flatter declines. We believe that this new approach of adopting more cost effective facilities, combined with better targeting and completions will drive the next step in development for the Terryville field.

To put some context around 2017 well activity, there are really three groups of wells. The first group is the wells that we simply call the pre-Range wells. In essence, we may have taken over operations in one phase or another, but essentially they were planned and designed using historical practices. This was 21 of the 27 wells in the first quarter, and 18 of them were drilled almost a year ago.

The second group of wells, which six of the 27 fall into this group, is those wells where Range may not have been able to pick the location or the formation, but we did have some influence in the targeting and drilling of the well. And then the last group are the Range wells, where we picked the location, formation, target and designed them from start to finish. The majority of the remaining 29 wells for the year, again which are weighted to the last half of the year, fall into this group and we've only recently begun completing the first of these wells. We're excited about what we see so far, and I look forward to updating those results throughout the year as we gather that performance data and build our reservoir models and development plans for the future.

As an update on the extension area activity, results continue to be encouraging from the two of the wells that we announced last quarter. Each of the two wells, each located in separate Terryville sized fault blocks, one to the east, and one to the west of the Vernon Field have cumulative production to-date of approximately 1 Bcf each. As a result, plans are underway to offset each well with another horizontal well.

Additionally, in the extension area, we have two pilot holes, one partially completed lateral that we're currently testing and we'll be starting a couple of new vertical wells designed to test multiple targets on an individual basis. This allows us to determine reservoir and rock properties while performing specific diagnostics to identify the best lateral targets. With over 400 Bcf per square mile and up to six target intervals, the potential is large. Again, we remain focused on Terryville while methodically testing and delineating the extension areas over time.

In the Marcellus, we're continuing to improve returns through lower cost and improved well performance and we continue to develop our extensive inventory of core locations with longer laterals. In North Louisiana, we're ahead of our acquisition case and believe we'll continue to make progress going forward. We're on track for our production growth guidance for 2017 and 2018 is shaping up very well.

Now, I'd like to turn the call over to Roger to discuss the financials.

Roger S. Manny

Chief Financial Officer & Executive Vice President, Range Resources Corp.

Thank you, Ray. The first quarter of 2017 builds upon the excellent fourth quarter of 2016 with further improvements in top line growth, cost control, margins and bottom line net income and cash flow. Net income on a GAAP basis for the first quarter was $170 million, while earnings using common analyst methodology, which excludes non-cash derivative mark-to-market entries and non-recurring items was $61 million.

Cash flow for the first quarter was $258 million, 2.5 times the first quarter of last year's $99 million figure. Cash flow per fully diluted share was $1.05, 78% higher than last year's per share figure of $0.59. EBITDAX for the first quarter of 2017 was $303 million, compared to last year's $135 million amount. First quarter 2017 cash margin, at $1.47 per Mcfe, was almost double that of last year's cash margin at $0.77.

One notable achievement in the first quarter of 2017 was that for the first time since 2014, Range was solidly profitable without any contribution from our hedge book, with our unhedged recycle ratio approaching 3 times and continued margin and capital efficiency improvements projected, future quarters should be much more like the past two quarters than the preceding seven.

Moving to the expense performance for the first quarter, all of our expense results came in at or below guidance. Detailed expense guidance for the second quarter of this year may be found in the earnings release.

Turning to the balance sheet, like last year, we ended the first quarter with less debt than we entered as our spending outflows were less than our cash inflows. Our debt-to-EBITDAX leverage ratio, calculated using a first quarter annualized EBITDAX, was 3.1 times and our book debt-to-capitalization ratio is 40%.

Additional hedges were selectively added during the first quarter to be already well established 2017 and 2018 hedge positions and we initiated our first hedge on 2019 production. Presently, over 75% of our 2017 natural gas production is hedged with an average floor price of $3.22 an Mmbtu. Additional hedges were added to our oil and NGL book during the first quarter as well. Full disclosure of our hedge price and volume positions maybe found in the 10-Q, earnings release and Range website.

The first quarter of each year has historically been a strong one financially. The reason for this first quarter strength is usually the peak of winter weather and the resulting strong demand and higher prices for our products. In 2017, the story is very different. This winter we experienced the second warmest first quarter in 30 years, based on gas weighted heating degree days, and the second warmest first quarter in 123 years based on average temperature.

However, our first quarter cash flow of $258 million was roughly the same as our cash flow for the first quarter of 2014, a year when we had the coldest first quarter in 30 years. The reason that our first quarter financial performance in the second warmest winter in 30 years is on par with the coldest winter in 30 years is a result of capital-efficient growth and the improved transportation, marketing and cost control measures Range has been working on for the past 10 years. The margin improvements we are seeing from our relentless cost control, the capital efficiencies from technology and the quality of our rock, combined with the marketing uplift from our unique natural gas and NGL marketing projects, have made Range's financial performance much more durable regardless of the weather.

Now Jeff, back to you.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.

Operator, let's open it up for Q&A.

QUESTION AND ANSWER SECTION

Operator: Thank you, Mr. Ventura. [Operator Instructions] Your first question comes from the line of Dan McSpirit with BMO Capital Markets.

Daniel Eugene McSpirit
Analyst, BMO Capital Markets (United States)

Q

Thank you folks. Good morning. Touching on differentials here, a big theme no doubt, and maybe picking up where Roger left off in his prepared remarks. How much of the improvement in differentials in your mind is unique to the company based on moves made in pricing molecules outside the Appalachian Basin say versus how much is based on developments general to the industry? Asking here in an effort to get a better sense of really what's sustainable.

Laith Sando
Vice President, Investor Relations, Range Resources Corp.

A

Yeah Dan, this is Laith. I think it really gets back to the approach that we've taken with marketing to move our molecules and have the flexibility of having production in-basin as well as moving gas to the Gulf Coast, the Midwest, and the Southeast. So in the first quarter, you'll notice that we came out with a positive $0.01 differential. So, despite having the warmest winter in the last 130 years like Roger mentioned, we still have some of the capacity that gets us to premium markets despite having no winter. And as we move towards the end of 2017, with some of the transport that we have coming online, you'll have 90% of our gas being sold to markets better than what we're typically seeing in Appalachia.

Daniel Eugene McSpirit
Analyst, BMO Capital Markets (United States)
Q

Okay. Great. Thank you. And just as a follow-up to that, just addressing the Terryville cost reduction, what's behind the cost reductions to-date? And what drives the reductions going forward here? I'm just trying to get a sense of how much the company's scale explains the improved capital efficiency in the field versus simply cutting fat that was in the prior operator's system, if you will.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.
A

Yeah, Dan. This is Ray. And that's a great question. And last quarter, we went through a whole litany of examples where they had increased drilling time, employed new downhole mud motors, more aggressive bit designs. We essentially changed out the drilling team. We brought in a gentleman that, Scott Chesebro, who is extremely talented and knows as much about high pressure, high temperature drilling as anybody, around and so he has really reshaped our whole program there. We've recently for example drilled a curve in one of these wells in 24 hours, and the average last year was 86 hours.

So it's just a continual litany of things like that that we've been able to do. We went from, in the series of wells that we fracked in the first quarter we had planned, because in the past they had averaged about eight stages a day or a little bit less, and so we planned for about eight and ended up averaging 12 to 15 stages a day.

So I think it's been a lot of that. It's been a lot of using Range's purchasing power, just simply because of the size and scale that we bring to the table. And then I think as we go forward with a more balanced approach and we kind of smooth out the activity levels and we plan where the wells are a little bit better, as we go forward we won't go through these very variable up and down cycles of activity levels going forward. And I think that will help improve cost as we go forward.

Daniel Eugene McSpirit
Analyst, BMO Capital Markets (United States)
Q

I appreciate the answers. Have a great day. Thank you.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.
A

You bet.

Operator: Your next question comes from the line of Holly Stewart with Scotia Howard Weil.

Holly Barrett Stewart
Analyst, Scotia Howard Weil
Q

Good morning, gentlemen.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.
A

Good morning.

Holly Barrett Stewart
Analyst, Scotia Howard Weil

Q

First, maybe Ray, you gave a lot of detail on Terryville and the well results during the quarter, which I think explains the production that we saw in 1Q. But given these dynamics and the fact that you got 29 more wells which are all Range designs, can you maybe help us think through the volume for Terryville for the rest of the year and maybe how that sequential progression goes throughout the quarters?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Sure, Holly. And basically the high level answer is the next 29 wells are going to be a lot better than the first 27. And of course to understand that, you have to compare and contrast a lot of that. And I went through in my remarks and talked about how 21 of the 27 wells were actually wells that were pre-Range. 18 of those were actually more than a year old. So in a lot of ways, we had very little influence on how those wells were picked, where they were, what they were targeted in and so forth.

And then six of the remaining wells, which was the full group of 27, were wells that we took over in one phase or another. We didn't get to pick where they were, but we may have been able to refine the target or different phases – took over in different phases of operations. And some of those wells, we're testing other horizons and different things like that. So we're learning a lot. We've changed a lot of production facility. We've changed a lot of the early flow-back procedures. We're really focused on project returns instead of just 30-day IPs.

I don't think the previous operator did anything wrong. I think it was just different, and I think we've got a much different approach and as we implement that approach, I think what we've done in these first six or seven months that we've had it under our belt, which again is not very long, but I'm real proud of what the team's accomplished and I think you'll begin to see the results of that going forward. We've shot a lot of 3D seismic. We've done a lot more mapping. We're starting to build reservoir models and we'll be able to place a lot of wells in some of the areas where we've seen really good results. And I think, bottom line, the next group of wells will be a lot better, and that's part of how we get there for the production growth for the year.

Holly Barrett Stewart
Analyst, Scotia Howard Weil

Q

Okay. Perfect. But any attempt to sort of break down Terryville versus Appalachia in that growth number?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Appalachia is – we only had about 20% of the wells to come online this year. I think I would attribute some of the changes in Appalachia to – a lot of it is timing, a lot of it is the team is making really great progress in drilling longer laterals. And you're going to start seeing some of the wells that we've talked about being on existing pads start to domino in the last half of the year. And as we've ramped up activity with the new budget and everything that started in January, a lot of that activity starts domino-ing six to nine to 12 months later, depending on if it's an existing pad or whatnot.

So, essentially we're getting really solid growth from both areas. In Appalachia, there's just a lot of timing that's going to come forward in the second half of the year. I'm really, really excited about some of the recent stuff we've done because since we've now HBP'd our acreage, one of the things that the team has really focused on is some of the very, very best areas. And the two examples I gave in my prepared remarks are certainly extremely impressive. I mean, those are some of the best economics out there, dry, wet, or super-rich.

But there were three more pads that I could have talked about that were 25 million, 26 million, 16 million a day equivalent type constrained rate conditions again. Which I think as you see us do more of that, focus in great areas, long laterals, existing pads, we're going to see really strong growth in the second half of the year out of Appalachia, just like we're going to see I think stronger growth out of North Louisiana. And we're really still solid on our production annual growth targets.

Holly Barrett Stewart
Analyst, Scotia Howard Weil

Q

Yeah. Okay. Well, maybe switching gears to Appalachian for the follow up, you mentioned a lot of infrastructure constraints, adding the Harmon Creek plant, the downtime at Houston, and then the new gathering systems. Can you just maybe talk about the timing of these things and how it sort of impacts the near term volume?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

The MarkWest plant, it's something that – what they're doing there is the original cryogenic plant was about 30 million a day plant, and they are basically going to use that spot and put a new generation 200 million a day plant. So, again it's building a lot of infrastructure for our growth in the coming years. In order to do that, they have to take the whole plant down for day or two to reroute a bunch of power and do different things there. I won't get into too many details. Also part of that, the de-ethanizer will be down for about a week. And so while that will impact our second quarter some, it won't even be a blip in MarkWest's infrastructure. I mean they've gotten so huge now. So it's something we knew about, we forecasted. It's been built into our annual growth plans for some time. So, we're pretty pleased with that.

The new wells up around the Harmon Creek, the future site for the Harmon Creek processing facility, we need to get up there and start drilling wells in preparation for that. We have some basic backbone of the infrastructure up there, but just like our position in southwest Pennsylvania is really, really large. We're far from having all the infrastructure built out, and so as we move to the north, and so forth, you're going to see us add more and more of that infrastructure in compressor stations, the restructure and compressor stations, the processing plants and so forth. And I think the exciting thing is is that could be potentially some of the best rock in the whole core up there. So we're pretty excited about that.

Holly Barrett Stewart
Analyst, Scotia Howard Weil

Q

Great. Thanks guys.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Thank you.

Operator: Your next question comes from the line of Neal Dingmann with SunTrust.

Neal D. Dingmann
Analyst, SunTrust Robinson Humphrey, Inc.

Q

Gentlemen, say, question first just guys, I looked, noticed about the – this is more about sort of allocation of activity in northern that, noticed that northern Marcellus, kind of the drop we've seen year-over-year and sequentially. Could you just talk about kind of rig allocation or activity allocation? Should we expect kind of similar? And I know now you're kind of blending the whole Appalachian together, but as we look particular to northern Marcellus, how should we think about that for the next remainder of the year?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Yeah, it's a good question, Neal. We did combine all the operations in Pennsylvania into our southern Marcellus division, or what was previously called that, and it's now we just refer to it as Appalachia. You're right in that we have over the last several years put less and less capital up there as the differentials have been really tough. It's good rock, it's just hard to sell the gas when you've got those kinds of discounts in place up there.

So, we have put it all under one team. It will be much easier to allocate capital with that team up there. They'll put it in their whole mix of assets that they've got across Pennsylvania. I think that they're likely to find some new things. Any time to get a fresh set of eyes looking at project, they're likely to come up with new ideas and they'll put their grass roots plan together going forward and if it competes economically with the projects in southwest PA, then we'll fund it going forward. But at this point, they literally just took it over in the last month. So, I think it will be some time before we see anything happen up there. The good news is it's HBP'd, so we're not really rushed to do anything.

Neal D. Dingmann
Analyst, SunTrust Robinson Humphrey, Inc.

Q

No, great flexibility there. And then, Ray, just one follow-up, as far as looking at the level of the change that seems like, or encouraged I should say, about the changes in Terryville, when you look at kind of your new pressure management, how should we think about, you did mention, it's not a surprise that the IPs might be a little bit lower. But how should we think about sort of that cumulative production over, I don't know, either the first six, nine or 12 months as you sort of dial that in versus what the previous team had?

Alan W. Farquharson
Senior Vice President, Reservoir Engineering & Economics, Range Resources Corp.

A

Well, I think what we have – this is Alan, Neal. I think what we have in the appendix portion of the book, we have some type curves associated for both the Upper Red and Lower Red. And I think what you see in those forecasts is a lower initial rate coming through. And so we would expect to probably with the wells, with the 29 wells going forward that Ray talked about, that we've had our design and everything in there, we would expect those well performance to kind of look somewhat similar to that. I don't have the exact page. I think if you look at -

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Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

46, 47

Alan W. Farquharson
Senior Vice President, Reservoir Engineering & Economics, Range Resources Corp.

A

47 and page 47 in the book kind of gives you an idea of what it would look like. Probably what we would see, is you probably won't be starting at that peak rate. You'd probably have to slide that out about 15 days or some for wells to kind of, for wells as they come on, they kind of increase productivity for a little bit. So I would expect it's going to look something similar to that, so a little bit lower rate overall. Similar for the Lower Red that's also in the book as well.

Neal D. Dingmann
Analyst, SunTrust Robinson Humphrey, Inc.

Q

But overall, Alan, your returns, I guess the way you now are position that, it certainly appears to me like on an EUR return basis, they are a bit better despite that initial little bit lower rate, correct?

Alan W. Farquharson
Senior Vice President, Reservoir Engineering & Economics, Range Resources Corp.

A

Yeah, I think that's fair to say.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.

A

With the lower well costs.

Alan W. Farquharson
Senior Vice President, Reservoir Engineering & Economics, Range Resources Corp.

A

With the lower well costs.

Neal D. Dingmann
Analyst, SunTrust Robinson Humphrey, Inc.

Q

Okay. Great add. Thanks, guys. Good color.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Thank you.

Operator: Your next question comes from the line of Ron Mills with Johnson Rice.

Ronald E. Mills
Analyst, Johnson Rice & Co. LLC

Q

Good morning, guys. Just one quick follow-up on Neal's question. Ray, is it safe to assume that part of the same or better economics despite the lower production rates is associated with the upfront costs? I think you mentioned facilities, gathering, flow-back equipment, how much is the cost savings associated with that flow-back to offset the lower initial production?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

That's a good question, Ron. We could get back to you with more exact numbers, but off the top of my head, when you're renting that expensive flow-back equipment for 30 to 60 days, it's several hundred thousand dollars, probably $0.5 million. It tops somewhere in that range. So you're saving a lot of money off the top up front.

Also like much like we've learned and done in the Marcellus over the years, you learn to optimally size your production equipment and make it more generic in nature, so you can kind of stack it, move it around, reallocate it to new wells, pull it off wells that have fallen below that and so forth. So it allows us a lot of overall project flexibility going forward. The team is doing a lot of things on the LOE side. They're doing lot of things on the salt water disposal side.

Again, we've only had it six or seven months, and gone through significant organizational changes. I think the teamwork is really coming to fruition, and you're already seeing, we've already lowered costs faster and further than we thought we would in our expectations. So, we're pretty excited about what we see. But again those well costs, we've cut a lot of the low hanging fruit, but I still think there is a lot of fine tuning that we're going do going forward over the next year. And again, we'll see I think begin to see a lot of that performance and economics really happen in the second half of this year.

Ronald E. Mills
Analyst, Johnson Rice & Co. LLC

Q

Okay great, and then moving to my question, the super-rich pad that you brought on, you talked about that being in a more lightly drilled portion of Washington County. Why was that area more lightly drilled? Does that de-risk for, in years in industry minds that that portion of the acreage and has that flowed through to kind of the resource potential you thought that area may have?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Yeah. Well again, we have a really large position southwest Pennsylvania and we sort of started in the wet area around the Houston plant and you've sort of seen our development expand from that area over the years. We drilled years ago several wells up into the northwest portions of the field and got some early indications. We have full seismic coverage. We've got a lot of information on the field and these recent wells we've gone up there, they're 10,000 foot plus laterals. They're completed with 54 stages using all of the latest technology and we've made wells that are essentially 5,200 barrels of oil equivalent per day. The wells were making over 1,000 barrels a day of condensate apiece, each well.

So I mean the bottom line is yeah, all that area is completely de-risked. And I think now, we're beginning to become more excited about drilling a whole bunch more 10,000, 15,000 foot laterals up there as we go forward, and it gives us a whole lot of confidence that helps us in sizing the infrastructure and things that are going to be developing over the years ahead. This was something that's been in our plan for many, many years going forward. It's just now really exciting to see it come to fruition and how good those extra long laterals are going to be up there.

Ronald E. Mills
Analyst, Johnson Rice & Co. LLC

Q

Great. I appreciate the answers.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

You bet.

Operator: Your next question comes from the line of Subash Chandra with Guggenheim.

Subash Chandra
Analyst, Guggenheim Securities LLC

Q

Yeah, hi. I wanted to ask about your frac protect plan in Terryville. Do you expect these offset wells to return to their pre rates, to their prior rates? And could you give us a sense of was it a mile radius or so that you saw the frac interference and how many wells might have been impacted?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Yeah, that's a great question. We're still learning exactly how far these wells will impact offset wells, but generally speaking today, I think the thoughts are around 4,000 or 5,000 foot, so about a mile. I think that to answer first part of your question, yes, that production, those wells will eventually come back, some faster than others. And so, that's what I meant in my prepared remarks, while we shut in 40 million a day, while we had all that frac activity going on, some wells come on sooner than others and some come back to where they were sooner than others and there's just a huge variation in that. So I think as we go forward, when you take a much more balanced approach in the second half of the year, you will see wells where we planned that out better to try to mitigate and minimize the amount of impacts, so we don't have to shut in as much production and a lot of those things going forward.

Subash Chandra
Analyst, Guggenheim Securities LLC

Q

Could you comment on how many wells were shut in?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

I don't know off the top of my head. I guess that's something we could, you could follow with Laith and the guys and we could get an answer, but I just don't know that answer.

Subash Chandra
Analyst, Guggenheim Securities LLC

Q

Oh, sure, sure. And my follow-up is the Terryville well cost reductions, what was in the CapEx guide? Are you, it sounds like you're overachieving the CapEx guide for the year.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Yeah. I think we were probably a little higher than where we were today. Again, we achieved it faster and further than we thought. We're going to do what we always do. We're not going to change our stripes. We're going to use that capital to optimize the plan. There is still a lot of things we want to test. A lot of the southern edges of the field we want to test, the extension areas, it's going to allow us to do more science and diagnostics in that area, help us move that plan forward faster. So, I think that's a good thing in the long run for us.

Subash Chandra
Analyst, Guggenheim Securities LLC

Q

Okay. Thank you.

Operator: Your next question comes from the line of Bob Morris with Citi.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc.

Q

Good morning.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Good morning.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc.

Q

Jeff, in your slide presentation, you highlight the three pipeline projects that are coming on in the second half of the year. Do you expect to, apart from an initial ramp-up period, fill your firm transportation capacity on those lines? And if so, is some of that moving gas from other existing lines to be more economic on these new lines, and still leaves you with some excess capacity in the system that you could fill if you continue to see better than expected well results?

And separately from that, for the industry, we're not at the 100 rigs you've always talked about that the industry needs to fill the pipe capacity, but as we get to year-end, do you see all this pipe, apart from which you're going to do, being filled by the industry?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.

A

Yeah. Let me kind of work backwards through that. In order to fill all that capacity, current rig count in Appalachia is somewhere around 64, plus or minus. I'll quote one of our competitors, Rice said they believe I think it's 125 rigs that are needed now in order to have all that filled. We've actually done our own internal work and our number is right around their number. So we think the basin basically needs to almost double the rig count in order to fill the pipes and that needs to happen almost immediately because some of those pipes are going to come on by the end of the year. So we actually believe the pipes all won't fill and there will be excess capacity in the southwest part of the play.

Of course, up in the north, far northeast part of the play, there is really no new pipe coming on this year and probably at the earliest, it's middle of 2018 or something for Atlantic Sunrise to come on up there. So one advantage of where we are in the southwest part of the play is better infrastructure, better takeaway, and it's a really important point. As those pipes come on, it will allow us to – to get to the first part of your question – to redirect some of our gas to better markets which should result in continuing to improve margins. A big part of the story this year that I think will extend into next year is margin improvement which translates into better cash flow, better cash flow per share, and coupled with that second half ramp, really helps us set up 2018.

So I think when you look at the infrastructure, the other thing – and then if you look really forward, the team's done a good job of setting up a diverse portfolio of transportation. We got a huge position where we continue to grow volumes, and as we grow volumes, then we'll have optionality whether to move some of that gas out of basin, to sell some in basin, which will ultimately really drive down, if you look forward, our transportation costs.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc.

Q

So I guess there, I guess part of my question, the corollary is that – your guidance really isn't dictated by the available pipe capacity, that it could move up given that there could be excess capacity from where you're diverting gas of existing lines.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.
A

There will be that optionality. A big part of that will be cash flow. Our spending for next year will be a function of cash flow or – at or near cash flow. So, it depends on where you think gas prices are next year, but clearly we have the inventory and ability to grow and move gas. But we'll be somewhat disciplined. We'll be disciplined in order to be at or near cash flow.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc.
Q

Okay. And then my follow-up for Ray, real quick is, Ray, you mentioned in the press release, you're drilling the two further extension wells to offset the two Terryville wells to the east and west of the Vernon Field. And your press release shows a third extension well. Is that going to be targeting the area to the north that before you had the Lower Red well that came on at about 5 million a day, which was less than the other two? But is there activity to the north of the Vernon Field part of the plan this year, also to go back to that area and see if you can get some better results up there?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.
A

We don't have anything going on right now to the north side of the Vernon Field. That third well is in a different fault block from in the first three that we've talked about. The east and the west ones are pretty encouraging. They both cumed about 1 Bcf each and so we're going to offset those two wells to the east and west. The north one, we haven't done a whole lot with and there is another fault block where that third well is, and we're right now doing a lot of testing on it. So, it's turned into more of a science well than anything at this point.

And so we've kind of got that activity going, and then we've got another area where we're going to put a couple of vertical wells in and do some real serious core-ing and log analysis and micro-seismic imaging and a lot of different things in that area to try to optimize our reservoir models and figure out what the very best target is. I mean, the good news in several of those different fault blocks, and all of those fault blocks are Terryville size or larger, so the potential is really huge. But again, we're going to take our time methodically and strategically and test each one of those as we go forward. But all those fault blocks are different and they all have tons of gas in place, so that's the exciting part of it. We just want to make sure we've got really solid plans going forward.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc.
Q

In that third fault block that you're going to test, that's east, west, or where is that?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.
A

I don't know that we've disclosed that yet. But I'm sure we'll be talking a lot more about it in the next call.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc.
Q

Okay. Great. Thank you.

Operator: Your next question comes from the line of Brian Singer with Goldman Sachs.

Brian Singer
Analyst, Goldman Sachs & Co.

Q

Thanks. Thank you. Good morning.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Good morning.

Brian Singer
Analyst, Goldman Sachs & Co.

Q

Just following up with regards to the extension wells in Northern Louisiana, you've gotten the 1 Bcfe per well over I think it's about 160 days. Can you just add some more color there and parse it with your type curve? What do you think that suggests so far regarding economics and opportunity? Obviously, you've talked to your next steps there.

Alan W. Farquharson
Senior Vice President, Reservoir Engineering & Economics, Range Resources Corp.

A

Yeah, Brian, this is Alan. We continue to plot those wells up against both the Upper and Lower Red, and they're producing kind of in line with what both those curves that are out there. That's kind of consistent with what we said on the last call when we disclosed the well results at that point in time. So, wells continue to produce similarly with what those type curves are. We're continuing to help understand where we are within the section, continue to gather a lot of data, and I think we're encouraged where we are to date to feel about going ahead and offsetting both those wells. We still like the fact that there is a tremendous amount of gas in place. There is multiple horizons out there, and of course, there is a lot of information we are continuing to glean from the production data as well as offset well performance from both vertical wells as well.

Brian Singer
Analyst, Goldman Sachs & Co.

Q

Great, thanks. And then shifting to Appalachia, Range is historically very early in signing low-cost takeaway contracts to get gas out of the region. And recognizing that the wave of new pipelines are coming on now from what you contracted a couple years ago, wanted to get your view on the strategy for growth in the next decade and whether you think it makes economic sense to be thinking about contracting now or whether your flexibility to shift capital geographically means Range down the road will depend more on local market prices and Louisiana prices?

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.

A

Brian, let me start and others can chime in. I think one thing, if you look at the next decade out, something that's I think not real well understood actually was part of internal work we've done, and I've heard other people talk about it a little bit, but not much, is the concept of sweet spot exhaustion. I think if you really look at core areas in Appalachia, but I think it's true in the Permian, the only two plays I think with more than a decade worth of true sweet spot drilling left is probably Permian and Appalachia.

But when you look in Appalachia, there is only a couple of companies that have more than a decade worth of really high quality wells. Not that a lot of people won't claim that, but when you look at the data and you look at the EURs per thousand and cost per thousand.

So I think again, I think there is only two plays that have more than a decade worth of true sweet spot drilling. A lot of the other plays will be exhausted quicker than that. So if you look in Appalachia, even early on, our thoughts were when you look at all these plays, infrastructure tends to get overbuilt with time. I mean that's true historically.

We assumed that we would get what we thought was right-size transportation early on to allow us that flexibility to grow. So, I think given the position we're in, we're in great shape as we look forward. Again, we don't think the pipes fill early on, but particularly if you look out over the next decade, there will be that optionality probably to sell gas in-basin or we'll have the ability to probably move it out, whatever is more optimum. And with that, I think that will continue to drive down unit costs with time. Again the advantage we have is just a huge inventory of high quality prospects plus we have now the optionality of drilling in Northern Louisiana or in Appalachia. So I think we're well positioned for the future.

Brian Singer
Analyst, Goldman Sachs & Co.

Q

Great. Thank you.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.

A

Thank you.

Operator: We're nearing the end of today's conference. We will go to Blaise Angelico with IBERIA for our final question.

Blaise Matthew Angelico
Analyst, IBERIA Capital Partners LLC

Q

Yeah hey, good morning guys. Apologies if I missed this early on. But just was wondering if you could talk about what specifically you're going to be changing on the completion design on those Range controlled wells in North Louisiana versus what the prior operator was doing. And then in terms of that well that is completing, is that a second quarter or a third quarter call type of event where you release production rates?

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Yeah. This is Ray. As far as completion designs, I don't want to get into too many details, but we're looking at stage spacing, the perforation cluster designs. As you can imagine, this is a sandstone. It's not a shale. There's a lot of differences involved here. We're still trying to optimize the targeting and figure out what makes sense to be. And we understand that being in the zone for 100% of the well is certainly, appears to me, making a good difference so far and we got some good examples of that.

So I think that we're doing well on that. It's going to be looking at different fluids, different proppant mixes, different perforation designs and we're far from understanding what we believe the optimum is going to be going forward. We're still working on that issue in the Marcellus, and so I think we'll have a lot of that going forward. And then, the last part of your question, I've already drawn a blank on.

Blaise Matthew Angelico
Analyst, IBERIA Capital Partners LLC

Q

Yeah, it was just in terms of that Range controlled well.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Oh yeah, yeah.

Blaise Matthew Angelico
Analyst, IBERIA Capital Partners LLC

Q

That you're just completing, just kind of timing on the production rates on that.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Yeah, we only just started completing it literally a week or two ago. There is going to be a little bit of a lull of time period until the next group of wells that we start completing. So, assuming it comes online in the next month, then we would probably want to see – I'm looking at Alan here – but probably three months plus.

Alan W. Farquharson
Senior Vice President, Reservoir Engineering & Economics, Range Resources Corp.

A

Right.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

Of production history. Because again, we've got a completely different flow-back protocol and early production protocol, and so the well we know is going to be constrained a lot longer. So, I would think it's going to be at least probably the call after next before we'll have anything that we can talk about definitively as far as EUR per 1,000 feet or anything like that. I think we'll continue to improve costs, but I think it's just going to take us some time before we can tell you much about that.

Blaise Matthew Angelico
Analyst, IBERIA Capital Partners LLC

Q

Got you. Thanks. I appreciate the time, guys.

Ray N. Walker, Jr.
Chief Operating Officer & Executive Vice President, Range Resources Corp.

A

You bet. Thank you.

Operator: Thank you. This concludes today's question-and-answer session. I would like to turn the call back over to Mr. Ventura for his concluding remarks.

Jeffrey L. Ventura
Chairman, President & Chief Executive Officer, Range Resources Corp.

Thanks to everyone for participating on the call. If you have additional questions, please follow up with the IR team.

Operator: Thank you for your participation in today's conference. You may disconnect at this time.