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Range Resources Corp. (RRC)

Q3 2017 Earnings Call

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MANAGEMENT DISCUSSION SECTION

Operator: Welcome to the Range Resources Third Quarter 2017 Earnings Conference Call. All lines have been placed on mute to prevent any background noise. Statements made during 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 would like to turn the call over to Mr. Laith Sando, Vice President of Investor Relations at Range Resources. Please go ahead, sir.

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

Thank you, operator. Good morning, everyone, and thank you for joining Range's third 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 a chance to review the press release and updated investor presentation that we've posted on our website. We'll be referencing some of 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 on 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, and thanks to everyone joining us on the call today. As we approach the close of 2017, Range is nearing a very important and exciting point in the company's Marcellus development. We are clearly at an inflection point in what has, in essence, been a decade-long commissioning of the largest gas field in the country.

Range has been a leader in finding and developing the Marcellus play and now is in a position to capture additional value. Major projects, such as LNG facilities, power plants and the like, have long construction periods of capital-intensive work. For Range, this commissioning phase is nearing an end, with the last of our three natural gas infrastructure commitments slated to come online by early 2018.

The culmination of this build-out provides Range substantial deliverability of gas, NGLs and condensate to markets across the U.S. and internationally. This infrastructure will enable us to continue developing our Marcellus inventory in an increasingly capital-efficient manner.

The portfolio of takeaway projects that Range has secured over the last decade enables us to move natural gas production of almost 2 Bcf per day to meet our customers' growing demand, both outside and within the Appalachian Basin. The completion of this infrastructure foundation in concert with a high-quality inventory we believe will deliver strong returns on capital for many, many years.

For Range specifically, as a result of this infrastructure, we expect continued improvement in our realized natural gas prices as a result of gas transported into higher-priced markets and improved local pricing. Based on strip pricing, we expect that improvement could result in a corporate natural gas differential to Henry Hub of only about minus $0.15, or better, for 2018, offsetting increased transport costs in 2018.

We also see positive market conditions on the NGL side as well, with fundamentals coming back into balance due to increased domestic use and significant exports. Range has participated in the market improvements, as evidenced by our higher reported NGL price realizations and guidance.

Looking at ethane first. Range's ethane portfolio continues to accomplish two important goals for us. One, we're increasing cash flow versus leaving ethane in our gas stream. And, two, we can meet natural gas pipeline specs even with substantial growth. In fact, we're extracting and selling such a significant percentage of our ethane that Range could theoretically double its wet gas production from current levels, leave all the additional ethane in the gas stream and still have no problems meeting pipeline spec. That's an enviable position to be in as one of the largest NGL producers in the country and it provides us of the flexibility of finding additional ethane agreements in years to come that are cash flow accretive.

On the propane side, as the only producer with capacity on Mariner East 1, we continue to sell almost all of our propane production into international markets. So far this year, the Range team has been able to realize Mont Belvieu-plus pricing. Again, an enviable position among NGL producers as we have the ability to see how the

Appalachian NGL market continues to develop with projects like Mariner East 2, in-basin steam crackers and other projects and make decisions about the additional transactions based on the economic benefits to Range from those transactions rather than operational constraints.

As a result of the projects Range has in place and the improving fundamentals in the NGL market, we're projecting that Range's NGL realizations as a percent of WTI will reach the highest levels that we've seen in several years for the fourth quarter of 2017. Based on strip pricing, we expect our 2018 realizations to be in the 30% to 32% of WTI range, despite a very backwardated 2018 strip that we believe have the potential to improve.

Operationally, I'm pleased that the Range-designed and drilled wells in North Louisiana are performing well, and we expect to get similar strong results from the wells we're bringing on line in the fourth quarter and going forward. In Pennsylvania, the long laterals we're drilling are also performing well, and we continue to drill some of the best wells in the company's history, which Ray will cover here in a minute.

Regarding capital allocation, our expectation is that we'll allocate additional capital to the Marcellus to utilize the additional firm takeaway capacity coming online. Both areas of operations have seen recent drilling success, but using North Louisiana cash flow to fund additional Marcellus drilling will drive better overall corporate returns next year as we optimize capacity, and it demonstrates one of the benefits of having two high-quality resource plays.

For 2018, we have not yet finalized our budget and, as a result, we will not give formal guidance at this time. What I can say is that, at strip pricing, we would expect to spend at or slightly below our projected cash flow. This will result in volumes sufficient to satisfy our transportation commitments on the pipelines coming into service during 2018.

Beyond 2018, when our transportation commitments are satisfied, we will have more flexibility to achieve moderate growth in production while spending less than cash flow and de-levering our balance sheet in the current commodity price environment. To the extent that commodity prices improve from current levels, it's our current intention to use the excess cash flow to reduce leverage rather than accelerate growth.

Looking at the balance sheet, we're committed to reducing our debt to EBITDAX to less than 3 times as swiftly as we can and, in the longer term, we will strive towards an investment-grade profile. In order to reduce leverage, we're pursuing various asset sales, which includes our remaining Mid-Continent properties in our Northeast Pennsylvania assets. In addition, we will look at ways to pull forward value on some of our acreage that we would not otherwise develop in a timeframe that drives our valuation.

By efficiently allocating capital to our best projects and spending below cash flow, Range can de-lever over time, given the quality of our inventory. The magnitude and timing of this method to reduce debt is clearly very sensitive to commodity prices. However, given our peer-leading recycle ratio, Range's capital efficiency, our growth per dollar spent should remain among the best in the industry. While we're proud of that metric, we're equally focused on improving our leverage metrics.

Many of our stockholders have been loud and clear that they expect the industry to rapidly focus on the next stage of the shale play development, which is focusing less on growth metrics, and instead focusing on return on capital, cash flow and returning cash to shareholders when it makes sense.

We agree. We think it's right for Range and our investors as well, and this fits well with our current stage of development in the Marcellus. I think it's also worth pointing out, for the last decade, Range has been one of the very few E&P companies with its executive compensation tied to debt-adjusted per-share metrics and not absolute growth targets. In addition, this year Range added a drilling rate of return metric to our compensation. We think this clearly evidences our board's and management's commitment to return-based metrics.

We have deployed or redeployed billions of dollars of your capital and, in doing so, we achieved a strong position in one of the best shale basins in the world. Going forward, we expect Range's combination of assets and infrastructure will permit the flexibility to continually optimize returns from drilling capital, balance sheet improvement and returns to shareholders.

What distinguishes Range is both a very high quality and a very large inventory. We have core locations that will last for many years beyond that of most other companies. As gas demand continues to grow with time and if gas trades more like an international commodity, Range will have plenty of high-quality inventory, which we believe will create significant free cash flow and shareholder value over the long term.

I will 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 third quarter came in at 1.99 Bcf equivalent per day, which is a little over our guidance of 1.97 Bcf equivalent per day. And guidance for the fourth quarter remains at 2.17 Bcf equivalent per day, resulting in annual growth of 30%. Organically, this represents about 10% year-over-year growth.

This expected $200 million a day ramp of new production coming online during the fourth quarter fits well with our anticipated incremental pipeline capacity, expected improving pricing differentials and sets us up well for 2018, consistent with Jeff's description of next year and beyond.

Looking at some of the operational highlights for the quarter. We'll start with Appalachia and bring you up to speed on some exceptional well performance from seven different Marcellus pads spread across our acreage position in southwest Pennsylvania.

Starting in the super-rich area, we reported a seven-well pad last quarter with an average lateral length of 10,685 feet completed with an average of 54 stages per well. At the time, we reported five of the seven wells were flowing to sales with strong results.

The remaining wells were brought to sales in the third quarter, generating an average IP per well for the seven wells of over 30 million cubic feet equivalent per day, or 5,000 BOE per day per well being greater than 70% liquids.

These wells continue to be high condensate producers, with the pad producing over 5,000 barrels per day of condensate for over 30 days, which was a main driver behind our 21% quarter-over-quarter increase in condensate production for the company.

The wells have been transitioned to permanent production equipment, which by design constrains the wells and, after 90 days of production to sales under these constrained conditions, are performing well above the type curve on a normalized basis.

Also in the super-rich portion of our acreage, we completed two four-well pads turned to sales in the third quarter. The average lateral length for the eight wells is 9,652 feet completed with an average of 49 stages per well.

The average IP from the two pads were both greater than 40 million cubic feet equivalent per day per well and more than 60% liquids. One of the pads came online early in the quarter. And after 90 days to sales, again under constrained conditions, continues to perform significantly above the normalized type curve.

Moving to the east in our wet gas area, I want to update you on a three-well pad turned to sales last quarter near the Houston plant. Having been online for about 180 days and under constrained conditions, the wells are performing 77% above the wet area type curve on a normalized basis. These are clearly outstanding wells and highlight improved well productivity from an area that we began drilling over a decade ago.

Also in the wet gas area, we recently completed a five-well pad and a six-well pad with average lateral lengths of 11,416 feet averaging 58 stages per well. We're currently flowing the wells under constrained conditions through our permanent production equipment, with two wells still cleaning up on flowback. And the average IP per well on each pad was over 30 million cubic feet equivalent per day with over 50% liquids.

Moving further to the east, to the dry gas area. On the last call, we discussed a four-well pad in our dry gas acreage with average laterals greater than 11,000 feet. At the time of the last call, this pad had maintained a flow rate of 100 million a day for 40 days. Updated numbers show this pad maintained 96 million a day for 99 days, with production at the end of the third quarter still well over 80 million a day for the pad. These are incredible results. And we're presently offsetting this pad and expect to bring the new wells online by the end of this year.

All of the pads I just discussed are pointed out on a new slide on page 9 in our updated presentation on the website. These highlighted pads are a reflection of the quality and repeatability of our asset, our large de-risked inventory and our exceptional team in Appalachia. I believe they also reflect our technical team's ability to significantly improve well results by incorporating Big Data analytics and, therefore, applying the appropriate completion strategies and technologies.

Range currently holds four of the top-six highest reported rates to sales in the entire Marcellus play. We literally have thousands of these types of opportunities left to drill across our acreage position, representing many years of value-creating development.

We continue to make improvements in operational efficiencies across the board in Appalachia. Let me go through some quick examples comparing the third quarter of this year to the third quarter of last year.

On the drilling side, we drilled one well in the third quarter of 2016 that was greater than 10,000 feet of lateral length. We drilled 19 wells greater than 10,000 feet in the third quarter of this year. The average drilled lateral length in the third quarter of 2016 was 6,171 feet. The average in the third quarter of 2017 was over 11,700 feet, representing a 90% increase.

Importantly, drilling costs per lateral foot in the third quarter of 2016 was $302 and in 2017 is $202 per foot, which is a 33% decrease. This means we drilled 90% longer laterals at 33% less cost per foot than a year ago. And five of the company's top-10 longest laterals were drilled in the third quarter of this year.

The completions team successfully completed 1,730 fracs stages in the third quarter, which is a record amount of stages representing 31% more stages than the previous record while only utilizing three frac crews.

Year-to-date, lease operating expenses in Appalachia are 15% lower on a unit basis as compared to the same time period last year. Water sharing agreements with outside operators and the redeployment of production facilities have been large contributors to saving millions of dollars by reducing our capital cost and operating expenses and are a key part of our strategy to compete in what is currently a difficult commodity business.

While it's early and we're still working on the plans for 2018 budget, in Appalachia we believe the average lateral length of wells put to sales next year will be over 10,000 feet versus an average of greater than 9,500 feet for the second half of this year. The mix of dry wells versus wet wells is expected to be slightly higher in 2018, and we should be approaching around 50% of our wells on existing pads versus around 30% this year.

Again, it's early, and this can change throughout the year as the team optimizes our plan, as they always do, striving for the best economics and more capital-efficient operations. I'm pleased to report that the permitting process has run very efficiently these past few months and we don't foresee any issues with permits going forward. Our team, along with the Pennsylvania DEP, has done a tremendous job getting us back on track.

Shifting now to North Louisiana. Our plan for the remainder of the year remains consistent, focusing on Terryville while strategically testing and delineating the extension areas. In Terryville, we've made great strides in improving cost while driving operational efficiencies and we're continuing to delineate the stacked pay potential of the field. In Terryville, we announced the first three wells located, designed and executed totally by the Range team in early September.

The two Upper Red wells have averaged 30-day rates to sales of $25.8 million and $20.7 million public feet equivalent per day, respectively, with lateral lengths of 7,427 feet and 6,827 feet. Both were completed with typical fluid intensity and both wells are in line with the type curve, as expected. A good example of the stack pay potential at Terryville is the Lower Deep Pink well on that same pad, which is a 7,400-foot lateral completed with 25 stages. The well averaged 20.2 million cubic feet equivalent per day for 30 days for sales and is the best Pink interval well drilled in the field to-date. We have more wells planed in this area for 2018 and beyond.

We did not bring any new wells online during the quarter after these three. On the last call, we were hopeful that we would have had a couple of more Terryville wells to discuss on this call, but the frac crew showed up a few weeks later than we had predicted. We just started the flowbacks on two Upper Red wells and are in the very early stages of cleaning these wells up. Currently, we have three frac crews working and this activity will, of course, drive the big ramp in production during the fourth quarter as the remaining 2017 wells will be coming online in November and December.

In the extension area, we currently have work going on a three new fault blocks that look promising. We recently finished completing a well in a new fault block to the north of Driscoll Field, which is south of Terryville. The lateral was completed in three phases to study different completion designs and to get detailed information in order to model the reservoir. The early production data is very promising, with peak 24-hour production rates on a normalized basis being over 3.5 million per day per thousand-foot of lateral.

Also the horizontal wells offsetting our early extension area horizontal test [ph] in separate salt (20:50) blocks to the east and west of Vernon Field are underway, with one rig drilling and the other rig moving in next week. We expect to see production from these two wells late this year or early next year.

Switching to marketing. By the end of the first quarter of 2018, Range will have incremental gross transportation capacity of 900 million a day out of southwest Pennsylvania, with over 70% reaching the Gulf Coast, which currently receives near NYMEX-based pricing.

These projects include TransCanada's Leach and [ph] Rain (21:29) Xpress Projects and Enbridge's Tetco Adair Southwest Project, which are both projected to be in service prior to year-end, and then Energy Transfer's Rover Project, which should reach full completion by the end of the first quarter of 2018. When all of these are online, Range will have the ability to transport greater than 90% of its production out of southwest Pennsylvania to markets which we believe will continue to provide better pricing.

Of the additional capacity, Range plans to immediately fill more than half by, first, rerouting our existing local production and then, second, we'll be sending volumes from the fourth quarter production growth to these projects. By the end of 2018, we should essentially reach full utilization of our transportation.

Importantly, these additions to Range's portfolio reduce basis volatility, especially during seasonally weak months and should increase the predictability of Range's corporate natural gas differential going forward.

As it relates to the near-term macro for natural gas, the in-service of these Appalachian projects does not always mean that production will immediately increase to fill the new capacity. I understand that this has been the case in the past, when capacity additions were anywhere from two-tenths of a B per day all the way up to a close to a B per day, and the industry seemed to immediately fill those new pipes.

However, with between 13 Bcfs per day and 14 Bcfs per day of new capacity additions happening between now and the end of 2018, we believe industry cannot support the production increases equivalent to the capacity added from these projects in southwest Pennsylvania, especially given where the strip is today combined with sweet spot exhaustion. Unless we see a significant uptick in rig additions, we think the Basin will see significant displacement of gas from local markets over the next few quarters as production has simply moved to better markets rather than an instant wave of new production.

Moving to liquids. Range reported NGL pricing of 35% of WTI during the third quarter, which, for Range, is the highest realization as a percent of WTI in several years, primarily led by the increases we've seen in propane prices both domestically and internationally.

Propane prices slowly increased throughout this past summer and achieved multi-year highs in September as inventories versus the five-year average remained below normal, especially when adjusting for current demand and export levels based on days of storage. Slower than expected domestic propane supply growth and strong export demand have continued to pull storage down. That, coupled with low stocks in Asia ahead of winter and the start-up of additional PDH plants in the last part of 2017 and into 2018, should keep U.S. and global propane prices elevated into next year.

As the only producer with propane capacity on Mariner East 1, Range has been exporting the majority of its propane out of market since early 2016. By doing so, we've been able to capture above-Mont Belvieu prices in Europe and Asia and expect to see opportunities to replicate this success in the future.

Looking into 2018 and 2019. As additional NGL projects start up in Appalachia over the coming quarters, Range is well-positioned to benefit financially, as local NGL supply is sent out of Basin, improving local liquids pricing. Range will have the optionality of selling both internationally and taking advantage of improving local markets.

As a result of these anticipated improvements to NGL pricing, we expect to see a percent of WTI differential for Range's fourth quarter NGL price of around 35%. And though still early, 2018 appears to be at a much better starting point than how 2017 began. Again, we believe this will be a unique advantage for Range as one of the largest NGL producers in the U.S.

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. In the third quarter, revenues and cash flow were higher than the prior quarter and significantly higher than the third quarter of last year. We hit our marks on production and total costs were in-line with guidance.

Natural gas, NGL and oil revenues, including cash-settled derivatives, were $524 million or 47% higher than the third quarter of 2016. Third quarter cash flow was $204 million, 66% higher than last year. Year-to-date cash flow totaled $656 million, a 108% increase from year-to-date 2016. Third quarter EBITDAX was $251 million and year-to-date EBITDAX totaled $794 million.

Fully diluted cash flow per share for the third quarter was $0.83, 22% higher than the third quarter of last year. Year-to-date cash flow per fully diluted share was $2.68, 46% higher than year-to-date last year.

As cash revenue is growing faster than cash costs, our MCFE cash margin for the third quarter was $1.09, which is in-line with the second quarter and a 33% improvement over the third quarter of last year. With strengthening NGL prices and new pipeline capacity coming on later in the fourth quarter and early next year, we anticipate noteworthy improvement in our cash margins going forward.

Net income adjusted for non-cash and non-recurring items, using common analyst methodology, was $12 million, while GAAP net income was a loss of $128 million due to several extraordinary expense items. On the recurring item expense side, direct operating unit cost expense came in $0.02 above guidance due to higher work-over costs, while production taxes came in $0.01 over guidance due to higher-than-anticipated ad valorem and severance taxes, including the Pennsylvania Impact Fee. Other unit costs were below or in-line with guidance.

On the non-recurring expense side, we had a bit of noise in the quarter. First, we took $73 million in proved property impairments to the Mid-Continent cost center as we prepared our remaining Mid-Continent properties for an active sales process. $9 million of this total represents an exploratory dry hole expense also booked to the Mid-Continent cost center.

Second, under successful efforts accounting, leases that we did not anticipate renewing upon expiration in future periods must be impaired in the current quarter. As a result, we impaired a total of $43 million of unproved properties in the third quarter as we have begun to rightsize and further high-grade our anticipated 2018 leasing activity.

Turning to the balance sheet. As Jeff stated, we are intently focused on bringing down our leverage below 3 times over the near term, with additional reductions to follow. We have active asset sales process underway. But as usual, timing of these sales is difficult to predict. Until sales are consummated, our liquidity remains ample, with over $600 million in committed availability and no long-term debt maturities until 2021.

The third quarter was an active quarter for our hedging program, with additional 2017, 2018 and 2019 volumes hedged across most all of our products. In particular, we added significant hedge positions to our projected 2018 natural gas production. The specifics of these new hedges are too numerous to mention, but are detailed in the earnings release, 10-Q and supplemental tables found on the Range website.

In summary, third quarter was solid and steady. We hit our marks and look forward to the fourth quarter, which should bring higher production, improving margins and an excellent base to build from in 2018.

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] And your first question comes from the line of Ron Mills with Johnson Rice.

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

Q

Morning, guys. Hey, Jeff. Just as you talked about the generalities of 2018, I know you can't talk specifics, but curious if you could just provide a little bit more description by how you may think about capital allocation between the Marcellus and Louisiana and maybe anything that may cause you to change that allocation thought process?

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

A

Okay. Great question, Ron. We haven't finalized our 2018 plans yet, but let me try and come at it from a little different angle to see if I can help frame it a little bit.

As you know, we have additional firm transportation coming on in Appalachia into 2018. And it makes strong economic sense to utilize as much of that capacity as we can as quickly as possible.

A good portion of that capacity, more than half, will be immediately used by simply redirecting volumes out of the current local sales to better markets. Also, we have flexibility in how we can allocate capital. And by allocating additional capital to the Marcellus, we expect to fully utilize the new capacity by the end of next year.

To do so will only require corporate growth of approximately 10%. At current strip prices, we believe we can achieve that 10% year-over-year growth while spending less than cash flow. That's a great starting point for 2018 because, theoretically, any increases in commodity prices or proceeds from asset sales could go straight to paying down debt, and we would still fill our new firm capacity. And I'll reiterate that at current strip pricing, spending within cash flow is embedded in our plans going forward.

The important thing to note is that we're in a very good position coming into 2018. We feel we're on track in north Louisiana, as you've seen with our recent wells, and we continue to drill phenomenal wells in Pennsylvania with longer laterals.

Hopefully, that provides a little context. And we're looking forward to providing a full update later this year or early next year.

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

Q

And then I just want to follow-up, just as it relates to Louisiana. As your Upper Reds are now tracking your curve, can you provide a little bit more details maybe, Ray, on the Deep Pink and your early thoughts from that well? And how development of that zone could fit into the Upper Red?

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

A

Well, sure, Ron. Clearly, that Pink well is the best well in the field to-date from that interval, and we're going to continue to study that. We're definitely making plans to offset it, of course. And I think we'll do some wells in 2018 and 2019 and beyond in that area again.

We think there's several cases throughout the field where there's some stacked pay potential like that. It's hard to talk about until we've tested them and fracked them and completed them and so forth, but we're very encouraged with that.

We're also very encouraged that the Upper Red wells are right on track. We've got I think 16 more to put online in the fourth quarter that we have really good expectations for. And we look forward to reporting on all of that as we get some of that production history probably at the next call in February.

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

Q

Great. Thank you so much.

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 Bob Brackett with Bernstein.

Robert Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC

Q

A quick follow-up on the 2018 capital allocation. You mentioned in some of your prepared comments a focus on dry gas. Is the idea there that gives you the biggest volume to fill that new takeaway capacity?

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

A

Well, I think that what I said was I think right now the plans are really early, so this is not formal guidance by any means. But in the current plans that we're putting together, it looks like our mix of dry gas versus liquids and super-rich gas will be slightly higher. But I think that's more of a timing at looking at what's available as far as existing pads to drill on and capacity in the gathering systems at the compressor stations and so forth and so on rather than just trying to optimize.

Now, given that everything else is equal, clearly, we would drill the dry gas well to create more volume faster and the economics are still a little bit better there also. So, it's sort of all of that worked in together. But right now, it does look like it will be slightly more dry than next year, but, again, that probably will change. It always does.

Robert Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC

Q

Okay. Gotcha. And then a quick follow-up on north Louisiana. As you move south to Driscoll Field, it looks like that Cotton Valley interval gets awfully thick. Do you think that, number one, are there multiple zones in, say, the Red there? And, two, will the cost of those wells rise? Is it more over-pressured? Any thoughts?

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

A

Well, it's a great question, Bob. And, yes, you're exactly right. As you go deeper into the Basin or south of Terryville, we do see a good thickening reservoir. And, in fact, on slide 11 in our presentation is a cross section that illustrates that very fact.

You go from a focus on Upper Red in Terryville around 100 Bs per square mile to some of the areas down in Driscoll and around Vernon are close to 400 Bs per square mile. You go from one pretty much identified target in the Upper Red to where the Upper Red down in the southern part of the Basin there might have three targets in it. The Lower Red, Vernon Field is primarily a Lower Red development, so that has about three targets in it.

And so, like we talked about on the last call, we've got a couple of vertical tests going and we're going to go slow and be very strategic and thoughtful about what's the best way to approach these fault blocks, but, again, we're very encouraged. We've announced another encouraging result in this new fault block to the north of Driscoll Field, so we've got three fault blocks now that look very encouraging and we're going to look forward about talking about the results of some more tests in those wells as we get into next year.

Robert Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC

Q

Thank you.

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

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

Q

Good morning, guys. And just looking, Jeff, at that slide on page nine, obviously, some fantastic results, particularly on those two in the four-well pad, over 41 a day, and then that four-well pad over 40 a day. I see the lateral lengths there.

Can you talk about, is there anything else special on those wells that, as far as the surfactant, or just the fluid that you did on those, those obviously, stuck out a little bit. I didn't know if you had any more color around those.

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

A

Yeah. Neal, this is Ray. And I'll fill in that one and Jeff can add some color, too, or Alan. But, clearly, I think the biggest change is that we've continue to optimize our reservoir models and we continue to look at things like targeting, cluster, perforation cluster placement, the amount of proppant that we're putting in there, fluid, injection rates.

Again, we present to the public three type curves: super-rich, wet and dry. But the reservoir team up there and the completions team has about 30 different models that they're working on at any one given time. So I think it's just a refinement of that.

I think another big influence, really, really big influence, over the last three, four years, has been basically, as we've incorporated the Big Data analytics and starting to look at a whole slew of different variables and using machine learning. And what's important is, taking that machine learning and then doing predictive analysis with it and doing some things that weren't necessarily apparent to an old frac engineer like me, for instance, things that were totally different. And clearly, it's paying off.

If you go back and look at my remarks in the last conference call where I talked about we had some areas that were over 4 Bs per 1,000-foot, clearly all these wells we just talked about. And the slides that illustrate the fact that it's across the whole position; it's not just any one particular area. And we literally do have thousands more of these to do and the lateral lengths are getting longer and the teams are getting better and we're using more predictive analysis in analytics and so forth.

And so, I think this is a trend you're going to continue to see and we look forward to updating all these economics and curves and costs and everything, like we always do about first of the year, so I think we'll come out with that probably in February. And we're pretty excited about what we see going forward. The economics are looking really, really good.

And I think it's a great timing, like Jeff talked about in his remarks, that we're at that point where all of these big projects are reaching commissioning. We said we don't have any more big projects coming online. We believe there's going to be a very viable market there locally and we're going to be able to take advantage of that. And I think is a strategy that we've been 10 years putting together and it's coming to fruition. And I'm, for one, really glad to see it.

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

A

And just add a little bit. I think Ray and Dennis and really the entire team that we have working on that technically are just doing a great job of continuing to drive performance up.

But the other thing at a higher level, and just – and Ray said it, but it's an important point when you look at that slide on page nine, we have a big blocky position in the core part of the play. And there's a lot of advantages to that, and particularly now that we have all that infrastructure in place. It just demonstrates, that slide, coupled with where we've been trending over time that that position is high-quality across northeast, southwest and the center part of it. We have a big blocky position that enables us to continue to drill longer laterals, continue to drive efficiencies and experiment.

And, again, Ray said it earlier, we think the cores of these plays are defined. And the key is what company has core, and you're going to start at some point to see that sweet spot exhaustion. Range will have plenty of inventory to drive well beyond that and to continue to drive efficiencies.

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

A

One more point I wanted to just emphasize again is the pad number five on that map is a pad right by the Houston plant. For those of you that have followed us for a long time, the Discovery Marcellus well was basically right by the Houston plant there. And, of course, we built some of those early systems there. And those wells have been really good from decades – from a decade ago, and that system has been packed for years without the ability to add anything to it.

That pad has been online for 180 days and it's almost 80% above the type curve on a normalized basis. And if you look at the IPs, it stacks up well and it's a 30% shorter lateral on average than most of the other ones in there. So we're really, really excited about the potential locations that we see going forward. And I think that's a great example that we don't want to over gloss it.

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

Q

Great details, guys. And then just one follow-up if I could. Ray, you and Roger mentioned about, obviously, the focus on getting that debt down to about 3 times and getting it to investment-grade. Being cognizant of not having that 2018 plan out there, would that entail trying to get to that – I'm just trying to look at the general overall activity with given prices today, given your hedges and given the plant capacity coming on. Would that mean would you potentially accelerate or think about going the other way as far as trying to bring that leverage in line?

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

A

Let me start. But when would you look at leverage, and, in fact, that might have been noticed that I gave originally and then the answer to Ron's question initially, the important part is we think to fill pipes requires approximately 10% growth, which we think we can do at current strip price. And we can do that, get 10% year-over-year growth, spending less than cash flow.

In addition to that, we have active asset sale underway. So it's really a combination of those two things, of that asset sales coupled with the ability to fill pipes and get growth below cash flow that would drive delevering.

The pace of that then depends on where oil and gas prices and liquids prices end up coupled with the speed of the asset sales. And we know with asset sales it's important to find the right buyer, to be patient. It was important for us in Nora. And sometimes it's hard to predict that exact timing, but we have those things in place and the ability to do that.

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

Q

Thanks, Jeff. 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 Dan McSpirit, BMO Capital Markets.

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

Q

Thank you, folks. Good morning. Just wanted to revisit your remarks on transport costs and the commissioning phase coming to an end here. When exactly do transport costs peak at $1.20 per M? And what's the progression in unit costs from that point forward? Asking really in an effort to get a better sense of whether the capacity additions are truly a competitive advantage here and what that means for margins and recycle ratios going forward.

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

A

Dan, this is Laith. Looking at the transport costs, that will peak at a time when Rover comps on. So if you're looking at that being sometime in the first quarter, it would peak around first or second quarter. And then how quickly we drive that down will simply be dependent on the growth numbers that we've got for 2018, which we'll come out with probably early next year.

But it sets us up really well, like Ray had mentioned, it gets 70% of our gas headed to the Gulf Coast. And you start to see the benefit of that additional transport really in the fourth quarter. And our fourth quarter differentials improve to $0.28 from $0.51, which we saw in the third quarter. And then looking forward into next year, it improves further to $0.15. So, a massive improvement in differentials, which, to your point, serves to offset that increased transport.

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

Q

Okay. Thanks. I appreciate the answer there. North Louisiana DNC costs, a question on that. Wild Horse WRD as well as MRD, that was acquired, stated completed well costs well above the $7.4 million that the company now estimates. What explains the difference in your view? That is, are there any above-ground costs not included in your estimate? Or if the comparison is really apples-to-apples, then what inefficiencies do you think have been squeezed out since taking over operations that would explain the lower costs here?

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

A

Well, it's a great question. And I think when we first looked at the deal, over a year ago, it was at $11.3 million, or I can't remember exactly, but over $11 million well cost. And we predicted early on we could get down to $8.7 million, close to $8 million I think in the acquisition, S-4, or whatever it's called. And essentially, we've been able to get it down to $7.4 million for a 7,500-foot lateral.

I think a lot of that is people. We brought on board Scott Chesebro, who has a world of experience in high-temperature high-pressure drilling and has optimized some big drilling programs for some big operators in a lot of different basins. So it was a big focus on changing out the team and the people. It was a big focus on implementing some new technologies, new motors, new bits, new mud systems. A lot of that on the drilling side.

And then the completion side, I would say was more just getting back to a point where – we just do it different than a lot of them do. We weren't necessarily focused on 30-day IPs and pullback procedures similar to what they had done. So we're doing things differently. I think we're approaching the stimulation designs in execution, especially more like we do in Appalachia, 24/7 operations and a lot of different things like that.

So I think it's just an overall different long-term approach, much more focused on trying to smooth out the activity level. You can do a much better job when you have a frac crew working for you continuously, rather than bringing them in for two or three weeks and then letting them go for two months and then bringing them back and so forth and so on.

And I said early on when we announced the deal that we would really be going into 2018 before we could kind of smooth it out and do it "the Range way." And that's really where we are. I think we'll be moving into next year.

What's important right now is that we've got three frac crews running. We've basically got them fired up just in the last week or two. Everything's right on track in north Louisiana. Third quarter looked good, we just didn't put very many wells online. And so I think we're pretty pleased with what we see going forward there.

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

Okay. Appreciate it. And one last one maybe here just on asset divestitures. What more can you tell us about the contemplated divestitures of the Mid-Con and northeast PA assets, in particular timing? And use of proceeds here? Guessing that it goes right to the balance sheet.

Roger S. Manny
Chief Financial Officer & Executive Vice President, Range Resources Corp.
A

Yeah, use of proceeds to the balance sheet. We have active processes underway. We're actively working on divesting in the Mid-Continent as well as northeast PA. And like I said in my prepared remarks, we'd also consider – we've got a big acreage position in Pennsylvania, 900,000 surface acres. And in some of those stacked pay areas, if you just look at southwest PA, 1.5 million net acres when you consider not just Marcellus, but Upper Devonian and Utica.

So we have the Mid-Continent, we have northeast PA. And then to the extent somebody is willing to pay us what we think is a good value for something we're not going to get to for a while and pull some of that value forward, we'd consider that as well.

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

Got it. Appreciate it. Have a great day. Thank you.

Roger S. Manny
Chief Financial Officer & Executive Vice President, Range Resources Corp.
A

Thank you.

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

Thank you.

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

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc. (Broker)
Q

Thank you. You had mentioned that to fill the total capacity by year end next year in the northeast, that would imply corporate growth of 10%. In that 10% corporate growth, what does that imply for the Terryville growth for Louisiana?

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

A

Again, by late this year and early next year, we'll give actual more distinct guidance. But what we're saying is, this year, we allocated about two-thirds of our capital to PA and about a third to north Louisiana. We expect good results and we're having good results in both areas.

But given the new pipes coming on, we'll probably over-allocate capital to the Marcellus. Use some of that north Louisiana cash flow – again, the advantage of having two areas – to help fill pipes.

So the growth would be disproportionate to PA next year, because we'll be allocating more capital there. We'll give you more color late this year most likely, early next year, which is our typical timeframe for coming out with the budget.

....

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc. (Broker)

Q

Okay. And then in the Terryville Field in north Louisiana you took some write-offs for acreage you expect will expire. How many rigs do you need to keep running there to hold the acreage you now anticipate going forward in 2018? I think you're running, is it two or three frac crews and then how many rigs now? And how many do you need to average next year to then hold the acreage and not incur any further write-down on expirations?

....

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

A

Sure, Bob. I'll see if I can hit all those points. I think in Terryville this year, we'll probably average around five rigs. We've had up to three frac crews at different periods. But, again, they've kind of been in compressed timeframes when it's happened. So right now, currently I think we have five rigs running right now. We have three frac crews running there. I do know that for a fact.

I think next year it will – like Jeff was alluding to, I think it's probably a little less than that. And hopefully we're at more of a steady pace for frac crews, where we would average something around one crew running most of the year, but probably not all year. Appalachia activity will probably be similar to now, if not a little more.

Again, we're just formalizing those plans right now. And we'll come out with formal guidance in late this year or early next year, but that's kind of where we see it right now.

....

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

A

Yeah, Bob, this is Roger. Yeah. The expirations, again, we're taking these impairments ahead of the expirations, so these haven't actually expired. So we have a lot of optionality going forward if the drilling results or whatever changes our direction of capital.

But I would point out that when it comes to acreage, when you look at our proxy peer group, there's four of our peers that have market caps higher than Range whose total acreage positions are less than what we have in north Louisiana. So we have plenty of acreage there to move the needle for us. We're not at all concerned about that.

....

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc. (Broker)

Q

Sure. I understand that. I was just wondering how many rigs you needed just to hold what you do anticipate not expiring there, but that's good.

And then I guess just one last quick question. You said that the frac crew showed up couple of weeks late. Is that any indication that the results of just tightness in the market and that crew having to come from, say, some other place like the Permian? Or is it other factors that caused that to be late?

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

A

Yeah, there's no doubt that the activity levels were up and there's a lot of tightness. There's crews that have probably left from every basin that have hauled on to West Texas, New Mexico, over the last months. Don't expect that's going to change a whole lot. Right now, we're going through the process of putting prices together and bids and awarding contracts. And that will happen for us over the next 30 days or 60 days or so. That's part of putting our formalized plan together to present to the board in December and so forth and so on.

So I think it's definitely indication of that. And that's simply what it was, the frac crew just tied up for another operator longer than we thought and didn't get to us as quickly as we had thought when we talked about it 90 days ago. As you know, in this business things change a lot in 90 days oftentimes.

Robert Scott Morris
Analyst, Citigroup Global Markets, Inc. (Broker)

Q

Yeah, great. Thank you.

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

A

All right. Thanks.

Operator: We are nearing the end of today's conference. We will go to David Deckelbaum with KeyBanc for our final question.

David A. Deckelbaum
Analyst, KeyBanc Capital Markets, Inc.

Q

Just under the wire here. Thanks, guys. I guess I'll round out the call with maybe more of a philosophical conversation. Jeff, I wanted to understand a little bit more around your comments. Once you fill the 900 million of incremental pipe capacity coming out of Appalachia, you said a couple things. One, you want to stay below 3 times levered. But, two, that you're going to be focusing more on perhaps under spending cash flows at that point and continuing to delever.

I guess should we think about it beyond 2018 for Range, that the philosophy will be just to hold that full capacity steady unless commodities would dictate otherwise, where you'd want to significantly start ramping up capacity?

At that point, should we just be thinking there's obviously the in-Basin option to accelerate. But is the long-term plan here once you get to that full capacity on pipelines to start harvesting some free cash as opposed to even considering growth beyond that full capacity?

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

A

I think the key is, one, again, we'll come out late this year, early next year, with our 2018 plans and maybe a little clearer vision past that. But the important part is I think we're in a great position and we have great flexibility. Again, to fill the pipes next year, 10% year-over-year growth, we can do that for less than cash flow at strip pricing.

And when you look forward then, we have a lot of flexibility with no new projects coming on. Like Ray said, there's 13 Bs of additional pipeline capacity coming in just to the southwest part of the play over the next couple of years.

So, we think there's plenty of availability either to sell product in-Basin, which will help reduce and drive down our unit costs that way, or perhaps to pick some of that up and move it to better markets. But because of the high-quality position, peer-leading or one of the best recycle ratios in the business for an oil or gas company, we think we're in a great position with a lot of flexibility.

David A. Deckelbaum
Analyst, KeyBanc Capital Markets, Inc.

Q

Okay. I appreciate that. And then the comments around perhaps bringing the value forward outside of non-core assets I guess within the core. Are you considering some pruning within the core of outright sales? Or are you also considering developmental JVs or is it everything is on the table to try to maximize MPV?

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

A

Yeah, I think what we're saying is we are open and we're open-minded to what that would be. Of course, we've got the asset sales in the Mid-Continent, northeast PA. But to the extent there's some method or some opportunity out there to pull value forward, we'd certainly be open to that.

David A. Deckelbaum
Analyst, KeyBanc Capital Markets, Inc.

Q

Thanks, guys. And best of luck in Q4.

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

A

Thank you.

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

A

Thank you.

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

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

I just want to say we really appreciate everybody taking time to be on the call with us this morning. Feel free to follow-up with Laith and the rest of the team with any additional comments you might have. Thank you.

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