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QEP Resources, Inc. (QEP)

Q2 2013 Earnings Call

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MANAGEMENT DISCUSSION SECTION

Operator: Greetings and welcome to the QEP Resources Second Quarter Earnings Conference Call. At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. [Operator Instructions] As a reminder, this conference is being recorded.

It is now my pleasure to introduce your host, Greg Bensen, Director of Investor Relations for QEP Resources. Thank you, Mr. Bensen. You may begin.

Greg Bensen
Director-Investor Relations, QEP Resources, Inc.

Thank you, Brenda, and good morning, everyone. Thank you for joining us for the QEP Resources Second Quarter 2013 Results Conference Call. With me today are Chuck Stanley, Chairman, President and Chief Executive Officer; Richard Doleshek, Executive Vice President and Chief Financial Officer; Jay Neese, Executive Vice President and Head of our E&P Business; and Perry Richards, Senior Vice President and Head of our Midstream Business.

If you have not done so already, please go to our website, www.qepres.com, to obtain copies of our earnings release, which contains tables with our estimated financial results and a slide presentation with maps and other supporting materials.

In today's conference call, we will use a non-GAAP measure, EBITDA, which is referred to as adjusted EBITDA in our earnings release and SEC filings and is reconciled to net income in the earnings release and the SEC filings.

In addition, we'll be making numerous forward-looking statements. We remind everyone that our actual results could differ materially from our forward-looking statements for a variety of reasons, many of which are beyond our control. And we refer everyone to our more robust forward-looking statements disclaimer and discussion of the risks facing our business in our earnings release and SEC filings.

With that, I'd like to turn the call over to Richard Doleshek.

Richard J. Doleshek

Executive Vice President, CFO and Treasurer, QEP Resources, Inc.

Thank you, Greg, and good morning, everyone. In terms of reporting our results, yesterday, we issued a financial and operating results news release, in which we reported second quarter 2013 operating and financial results, we updated operating activities in our core areas, and we updated our guidance for 2013. Chuck will provide more color on our operating activities and our updated guidance for 2013 in his prepared remarks.

Turning now to our financial results. We picked up a little momentum in the second quarter, while we continued to be challenged by weather, mainly rain and wet surface conditions in the Williston, and we continue to sell lower volumes of NGLs as a result of weak ethane prices. We generated $389.5 million of EBITDA in the second quarter, which was within spitting distance of record EBITDA level.

In comparing the second quarter of 2013 to the first quarter of the year, our results were driven by strong financial performance at QEP Energy, our E&P business, and improvements at QEP Field Services, our gathering and processing business. QEP Energy reported the equivalent production of 77.9 Bcfe, essentially flat from the first quarter but higher net price realizations about 2.5% higher than the first quarter. Field Services second quarter results were higher than in previous quarters due to higher gathering and higher processing margins.

From an EBITDA standpoint, the $389.5 million generated in the second quarter was $14.5 million or 4% higher than the first quarter; and $53 million or 16% higher than second quarter of 2012. QEP Energy contributed $332 million, or 85% of our aggregate second quarter EBITDA; and QEP Field Services contributed $58 million or about 15%. QEP Energy's EBITDA was up $8.4 million, or 3%, while Field Services EBITDA was up $5 million or almost 10% in respect of first quarter levels.

There was a little bit of noise in the Field Services EBITDA but still an improvement from the first quarter. Of note, if you remove the impact of our derivative settlements in their respective quarters, we generated $35 million more of EBITDA in the second quarter than the first quarter of this year.

Factors driving our second quarter EBITDA include QEP Energy's production, which was 77.9 Bcfe a tenth of a Bcfe lower than the 78 Bcfe reported in the first quarter. And the quarter's production was 2% lower than the 79.6 Bcfe produced in the second quarter 2012. A year ago natural gas comprised 80% of our net production compared to 73% in the current quarter. Oil volumes were 2.39 million barrels, up 11.5% in the first quarter of the year. And NGL volumes were 1.12 million barrels, up 1%.

Natural gas volumes were down 3% from the first quarter of the year and down 11% from the second quarter of 2012, driven by decline in production in our Southern region. Oil volumes were up 82% or 1.08 million barrels from the second quarter of 2012. And NGL volumes were down 14% or 183,000 barrels from the second quarter.

QEP Energy's net realized equivalent price, which includes the settlement of our commodity derivatives, averaged $6.47 per Mcfe in the quarter, which was $0.16 higher than we realized in the first quarter and a $1.34 higher than the realized in the second quarter of 2012.

The higher equivalent price reflects field level gas prices that were $3.83 per Mcfe or $0.45 higher, field-level NGL prices that were $41.32 a barrel or $4.32 a barrel lower and field level crude oil prices that were $87.31 a barrel or $3.50 barrel lower than their respective levels in the first quarter of the year. Field-level crude oil revenues account for 44% of total field-level revenues, which was about the same as in the first quarter of the year but up 37% in the second quarter of 2012.

QEP Energy's commodity derivatives portfolio contributed $31 million of EBITDA in the quarter compared to $50 million in the first quarter of the year and $117 million in the second quarter of 2012. The derivatives portfolio added $0.40 per Mcfe to QEP Energy's net realized price in the quarter compared to $0.64 per Mcfe in the first quarter of the year and $1.47 per Mcfe in the second quarter of 2012.

QEP Energy's combined lease operating and transportation expenses were $105 million in the quarter, up from $97 million in the first quarter of the year and up from $99 million in the second quarter of 2012. On a per-unit basis, LOE was $0.59 per Mcfe up $0.06 from the first quarter. Transportation expense was $0.76 per Mcfe, which is up $0.04 from the first quarter. And just a reminder, our LOE is typically lower than the first quarter of the year as a result of how we manage our field activities in the winter in the Northern region.

Finally, QEP Field Services second quarter EBITDA was $58.3 million, which is about $5 million higher than the first quarter of the year. Processing margin was up $3.5 million or 13% from the first quarter of the year as a result of 108% higher NGL sales volume, which include additional volumes from the new Iron Horse II plant but 21% lower realized NGL prices because we did recover some ethane in the quarter.

Gathering margin was up $3.8 million or 10% in the quarter compared to the first quarter of the year on marginally lower gas gathering volumes. But the increase in gathering margins associated with other gathering revenues, which include water handling and condensate sales.

We reported net income attributable to QEP of $178 million in the quarter, driven by a net $100 million gain on assets sales and $84 million gain in the mark-to-market value of our derivatives portfolio. Sequential G&A expenses were down $5 million, primarily as a result of reversing some bad debt expense we took in the first quarter, lower restructuring costs and negative swing in the mark-to-market value of stock-based compensation. We expect that G&A will pick back up somewhat in the third quarter.Sequentially DD&A expenses were down $4 million to $250 million.

For the first half of the year, we reported capital expenditures including acquisitions on accrual basis of $740 million. Capital expenditures for E&P drilling and completion activities were $697 million. And capital expenditures in our Midstream business for the first six months were $30 million. In addition, we also reported $22 million of acquisitions. If you exclude acquisitions, in total, we spent about $718 million in the first half of the year, which was about $47 million less than our six months EBITDA.

With regard to our balance sheet, at the end of the quarter, total assets were $9.4 billion; shareholders equity was $3.4 billion; and total debt was $3.4 billion, which is about a 1.2 times multiple of midpoint of our 2013 EBITDA guidance. Our debt at the end of the quarter consisted of $2.2 billion of senior notes, $300 million under our term loan due in 2017 and $888.5 million drawn under our $1.5 billion revolving credit facility.

In June, we closed the two assets sales that we mentioned at subsequent events in our first quarter 10-Q. We recorded a gain on sales of about $103 million and have about $140 million of cash proceeds from those transactions on the balance sheet at quarter end. If you assume, we applied all that cash to pay down debt, our net debt multiple of midpoint EBITDA guidance would be just under two times. In addition, yesterday we reported that we had entered into an agreement to sell several non-core properties in our Southern region for approximately $66 million, and we expect to close that transaction before the end of the third quarter.

Finally, in May, we filed a registration statement with the SEC for initial public offering of LP units for midstream MLP. We filed three amendments to that registration statement in July. We continue to push that project along.

With that, I'll now turn the call over to Chuck.

Charles B. Stanley

Chairman, President and Chief Executive Officer, QEP Resources, Inc.

Thank you. Richard's already hit the financial highlights. So, I will briefly touch on some operational results for the second quarter and our plans for the remainder of 2013 before we move on to Q&A.

As Richard noted, we are making a great progress driving the share of liquids as a percentage of our total production volumes. Crude oil was up 12% from last quarter and 82% from the second quarter of 2012. Crude oil represented 18% of total QEP production in the second quarter, up from less than 10% a year ago. And combined crude oil and NGL volumes represented 27% of QEP Energy production in the second quarter, up from 25% in the first quarter and 20% of total production in the second quarter of 2012.

We are now well underway with pad-based development on our Williston Basin oil assets, and we remain on track to achieve at least 70% year-over-year increase in crude oil production volumes in 2013. I'd note that a lot of the growth in crude oil volumes is coming in the back half of the year and in particular in the fourth quarter, as the pace of well completions catches up with the number of rigs that we've added in the Williston Basin during the first half of the year. Now we can get into more detail on that in Q&A. But clearly, growing oil production is having a significant positive impact on our financial results.

QEP Energy delivered adjusted EBITDA of $332.1 million in second quarter that was up 3% from the first quarter and 25% from a year ago. If we strip out the proceeds from the settlement of derivative contracts during the period, the higher margin crude oil production growth is even more obvious. QEP Energy EBITDA was up 10% for the first quarter of this year and 101% from the second quarter of 2012. We are clearly focused on profitable production growth.

Now, let me give you a little more color on our operational results from the second quarter and our plans for the remainder of 2013. And as I do so, would you please refer to the slide presentation that's accompanied our release yesterday afternoon.

In North Dakota, we're making steady progress on development of our Bakken and Three Forks oil properties. Recall that last year, we closed the acquisition of South Antelope property in late September. And toward the end of the year, we shifted away from single well development to pad development on the property. We swapped out the two rigs that the previous owners were using for skid-capable rigs, and as each new rig arrived it moved on to and started drilling on a multi-well pad.

As a reminder, our development plans for South Antelope, the newly acquired property call for an average of eight long lateral wells per 1,280-acre spacing unit, with an average of four wells drilled in each of the two reservoirs, the Three Forks and the middle Bakken reservoirs. We will develop most of the units with four-well – with two four-well pads.

Pad drilling is helping us drive down well costs by reducing the time and associated cost of rig moves and mobilization and demobilization costs associated with completion crews and equipment. The pad development will also enable us to share some production facilities in gathering lines on the properties.

It's important to note that we're not able to complete any of the wells on a pad until all the wells – all four wells have been drilled and cased by the drilling rig and then the drilling rig is moved out of the way, and that can take four to five months depending on the cycle time. Before you get first production from the spud of the first well. So pad development obviously will introduce some volatility in our production growth profile.

We tried to manage the arrival of each new rig to stagger the delivery of each new multi-well pad. So, while there will be some volatility in the production growth going forward, we remain on track to grow crude oil at least 70% in 2013. We're making good progress on drilling completion efficiencies and are continuing to drive toward a targeted year-end gross all-in that includes pad construction all of the facilities, drill complete, equipped and turned to sales, all-in well costs of $10 million or under.

We've been quite pleased with the well results at South Antelope. Back in early June, we've released some results from a number of recent well completions, including the first two QEP-operated middle Bakken wells that were drilled by us on our South Antelope property. These wells were important in that the previous owner had concentrated their development activity, drilling one Three Forks well per spacing unit in order to save all the leases on the property.

We knew the Bakken was present. We've seen it on logs. We had core through it. But we didn't have a modern state-of-the-art long lateral Bakken completion on our acreage. Our first two QEP-operated Bakken completions with post-processing 24-hour IPs of over 4,500 BOE per day, confirmed the middle Bakken is, every bit is good and perhaps even better than we had modeled in our acquisition evaluation.

In total, we completed and turned to sales, six new wells during the second quarter on South Antelope, there was four Bakken and two Three Forks wells, and a production performance of all these wells, that we completed during the quarter and in prior quarters, since assuming operations continued to meet or exceed our forecast with an average first 30-day production rate of about 1,300 barrels of oil equivalent per day.

We currently have six rigs working on South Antelope, you'll recall that we guided for five rigs, that's one more than last quarter. In response to some challenging pad construction conditions over to the east on the Fort Berthold Reservation caused by very wet spring, we decided to temporarily move one of the three rigs that was working on the reservation over to South Antelope to give the ground some time to dry out. So as a result we have six rigs running today at South Antelope. See slide six for a remainder of the location of South Antelope in the Fort Berthold acreage; and slide seven, for the location of six wells that we completed and turned to the sales during the quarter.

Turning to the Fort Berthold acreage, which we completed and turned to sales, nine new wells during the quarter, five middle Bakken and four Three Folks wells. Four of the new wells are on a pad that's located in the northwest corner of our Fort Berthold acreage block and all four of them came on with excellent rates with an average 24-hour IP of over 3,000 barrels of oil equivalent per day gross processing.

An additional five wells were completed on the second pod of the 10-well Independence Pad, which is located about 4 miles to the east and the average per well initial 24-hour rate for this group of wells was a little over 2,100 barrels of oil equivalent per day, post processing. You can see slide eight for the locations of these wells and for additional information on our Fort Berthold acreage.

On the infrastructure side, the third party gathering system operator on the Fort Berthold Reservation continues to make progress, and their water-gathering system is moving about 75% of our produced water. We are significantly reducing LOE as a result. As a result, we are now saving about $5 a barrel moving that portion of the produced water by pipe versus trucking it.

Additional gathering system upgrades are in progress and that should allow us to move the remainder of our produced water and flow-back volumes by pipe by the end of the summer or early fall. We continue to make good progress on well costs on the reservation as well. We are targeting a $10 million or lower gross completed well cost by year-end, but I would remind you that on the Fort Berthold Reservation because of our acreage configuration under Lake Sakakawea on average, we're drilling a longer lateral than we do over on South Antelope. So we would expect that the completed well costs would remain slightly higher than that of South Antelope.

As I stated earlier, we have two rigs running on the Fort Berthold Reservation. Field-level crude oil prices for all the QEP Energy dominated by our oil volumes in the Williston Basin declined a bit from the first quarter, due in part to the narrowing Brent WTI and WTI LLS basis. Our company wide average field level crude oil price during second quarter 2013 was $87.31 per barrel versus an average NYMEX price of $94.05 per barrel or about a 7% discount to WTI. For comparison first quarter 2013 field level prices for crude oil were $90.81 a barrel, or about a 4% discount to WTI. And of course field level prices are stronger than they were a year ago in both absolute terms and as a percentage of WTI. For reference, in the second quarter 2012, our average field level price of $81.90 a barrel versus the average NYMEX price of $93.29 a barrel or about 12% discount to WTI.

Turning to Pinedale, due to favorable weather conditions we go to off to an early start completing wells at Pinedale. And at the end of the second quarter, we had a total of 57 new producing wells completed and turned to sales for the year, including 35 wells that were completed in the second quarter. QEP has an average 74% working interest in the new wells that have been completed to date. We are on track today to complete about 110 wells at Pinedale for the year and that includes 29 wells that we operate for another operator that used to be affiliated with QEP in which we only have an override, so there will be 29 wells that have a minimum volume impact on our production volumes in the second half.

Note that due to continued low ethane prices and high natural gas prices, net to the well frac spreads for ethane remain negative, and we can continue to run all of our gas processing plants in the Rockies with the exception of intermittent operation of ethane recovery down in Uinta Basin and ethane rejection mode and we can get into more detail in Q&A on that.

As we have told you previously the ethane rejection results in 7% to 8%reduction in the Mcfe or Bcfe production volumes at Pinedale, but because of lower ethane prices the rejection has very little impact on our financial results. We currently have three rigs running for QEP and another QEP operated rig that's currently drilling wells for that other operator in which we have only a small overriding royalty interest, i.e., no working interest in those wells. The fourth rig will begin drilling on QEP working interest locations toward the end of this month, and we plan to continue to run all four rigs at Pinedale through year-end. Slides 9 and 10 show details for Pinedale. In the appendix of our current IR slide deck has a great slide that shows the details of the production volume impact of ethane rejection and recovery.

In the Uinta Basin, we continue to make good progress on our Red Wash Lower Mesaverde liquids-rich play – liquids-rich gas play. At the end of the second quarter, we have one rig active in the Mesaverde, drilling on a Pinedale-style multi-well pad. As is the case with all of our pad-drilling operations, we have a number of wells that are drilled and cased and that we cannot access until the drilling rig is moved out of the way. We've completed and turned to sales eight wells – eight new wells in the first pod of wells on that pad, and we're continuing to evaluate the early production performance to help us to determine the ultimate well density and drainage pattern in this lower Mesaverde play. As a reminder, we are rejecting ethane in Uinta Basin too, and it has a negative impact on reported gas equivalent volumes on the Mesaverde play of 7% to 8%.

At the end of the quarter, we also had one rig running in the Uinta Basin, actively drilling horizontal and vertical oil wells in the Green River formation. Slides 11 and 12 show more details on our Uinta Basin activities.

Turning to the Midcontinent, during the second quarter, we completed and turned to sales eight new QEP-operated wells in the core of the liquids-rich portion of the Cana Shale play. In addition to operated activity, we also participated in a number of outside operator wells that were in progress drilling or waiting on completion during the quarter. We dropped our last QEP-operated rig in the Cana play for the time being, as we continue to focus on allocating capital to higher return crude oil projects. See slide 13 for the location of recently completed Cana wells and for other details on the play.

In the Granite Wash, we completed two new QEP-operated horizontal wells, and we participated in four additional outside-operated horizontal wells that were completed during the second quarter and all had solid results. These wells all targeted crude oil and liquids-rich gas horizons in the various washes in the Granite Wash section. Slide 14 gives additional details.

And then finally, there were no new completions in the Haynesville down in northwest Louisiana in the second quarter, but we are participating with a small working interest in seven wells that are drilled by other operators in the Haynesville play. Slide 15 gives the details.

At Field Services, we started up our new 150 million cubic foot a day Iron Horse II cryo plant in the Uinta Basin early in the first quarter of this year, and the play continued to run smoothly in the second quarter. We did, however, recover some ethane in the second quarter, and we can get into details on that because I want you to understand the impact of some performance testing that we did that distorts our second quarter numbers some. Richard can give you the details on that.

About half the capacity of this new Iron Horse plant is contracted to a third-party producer under a fee-based processing arrangement, while the other half is available to process QEP Energy's gas volumes from the Red Wash Lower Mesaverde play, and that arrangement between QEP Field Services and QEP Energy is also fee based.

Most of the gas volume currently going through the Iron Horse II plant was previously being processed in our refrigeration plant that we call Stagecoach. So while the net change in fee-based processing volumes was small, we did experience a 10% increase in average fee-based revenue in the second quarter compared to the prior year period. Field services also completed construction and started up its new 10,000 barrel a day NGL fractionation facility at the Blacks Fork complex in western Wyoming. This facility will provide additional options for marketing purity propane, iso and normal butane and gasoline range products to what are often times premium-value markets both locally and regionally, via truck and then of course across the U.S. buy our expanded rail loading facilities at the plant. The rail loading facilities are still under construction, should be finished up sometime – late in the third or early fourth quarter this year.

So, now if we look forward – we view 2013 as a pivotal year for QEP, as we continue to dramatically shift the production mix of QEP Energy from one dominated by natural gas to one that's more balanced. We remain on track to increase crude oil production by at least 70% this year compared to 2012 levels. And natural gas volumes are likely to decrease 10% or so in 2013 as we allocate capital to higher return oil projects, and most if not all of that gas production decline is being driven by declines in the Haynesville absent new drilling and completions.

Despite the sale of over $200 million in producing properties and associated reserves that we announced yesterday, we've reaffirmed our production guidance for the year. Our focus remains on growing high margin crude oil production. And we are on track to grow QEP crude oil volumes by at least 70% over 2012 levels. With that I'll turn it back over to Greg.

Greg Bensen
Director-Investor Relations, QEP Resources, Inc.

Thanks, Chuck. Before moving onto the Q&A portion of the call, I want to remind you the status of our Field Services business. On January 7, we announced that in addition to evaluating the strategic alternatives with respect to certain of our Midstream assets, we plan to form a master limited partnership, or MLP, and have filed a registration statement with the SEC in the second quarter of 2013. As we have initiated the registration process, our remarks about the MLP on this call will be limited, and we will not provide any detail on the Midstream business beyond what we have historically disclosed.

With that, Brenda, let's open the line for questions.

QUESTION AND ANSWER SECTION

Operator: Certainly. At this time, we'd be conducting the question-and-answer session. [Operator Instructions] And our first question comes from the line of Brian Corales with Howard Weil. Please proceed with your question.

Brian Corales
Analyst, Howard Weil

Q

Good morning, guys.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Hi, Brian.

Brian Corales
Analyst, Howard Weil

Q

Can you talk about where your Bakken production is currently?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Current volume is a little over 20,000 barrels equivalent a day. And it's heading up. I think, Brian, there were some – we probably didn't do an adequate job communicating our, the shape of the growth in our production curve in the Williston Basin generally. As I said in my prepared remarks, we've moved in a number of rigs in the first half of the year, but they had no impact on production volumes because they are all sitting on pads drilling multiple wells, and we see that production volume response really starting a little bit in the second quarter, but it's really backend loaded. And so I would caution you guys as you model our production volumes into the third and fourth quarters to not assume sort of a linear increase in production in the second half. It will tend to be, as I said, backed loaded. We forecast about an 18% growth in Q3 and a 31% growth in Q4. So I guess if I was a spin doctor, I'd say to you that – that means that our exist rate is probably higher than most of you've modeled in your model going into 2014, but it's not a linear – if you just do a linear extrapolation, be about 24% increase across the second half, so it's kind of a big hockey stick if you will into the third – between third quarter and fourth quarter.

[Operator Instructions] Thank you and our next question comes from the line of the Eli Kantor with Iberia Capital Partners. Please proceed with your question.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC
Q

Hi, good morning guys.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Good morning, Eli.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC
Q

Can you talk about the Wilson IP rates that you announced in June, looks like 24 hour rates were significantly better than previous results, just wondering what was the driver of improvement there?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Well, I think the – in general the strongest results were obviously on the south Antelope acreage. The big wells were the middle Bakken wells that we announced, and obviously it's a reflection and confirmation of what we recognized and analyzed when we made the south Antelope acquisition last year. It's good rock; it's over pressured. The quality of the production performance is directly related to that rock quality in both the middle Bakken, but also in the Three Forks, both reservoirs put up some of the best well resultsin the basin, and just as a reminder we forecast EURs in the middle Bakken on the South Antelope properties slightly over 1 million barrels of oil equivalent and slightly under 1 million barrels of oil equivalent for the underlying Three Forks.

So they're just good wells, and it's supporting our geological and engineering analysis of the South Antelope property. Maybe I should also – just as I think about it, the completion techniques that we're using just a – to remind everyone, we are using sliding sleeves. We average about 30 stages. The wells that we put up earlier in the middle of the year were generally smaller sand volumes or smaller profit volumes somewhere around 2 million to 2.5 million pounds of sand. We've now – we're now experimenting with larger proppant volumes in more recent wells. I think we've got some either slated or we've just recently pump some as large as 5 million pounds of sand. We're looking for that point of diminishing result and diminishing returns, as we increase the sand volume.

We have not seen any material difference between the Three Forks wells that were drilled and completed by the previous owner on South Antelope, using a cemented liner and plug and perf completion design versus the recent wells that we have drilled very close by in which we've employed sliding sleeves and similar size jobs but 30 stage jobs sliding sleeves versus the cemented liners.

The other observation that I would make realize that we are using a hybrid proppant design dominated by sand, with a tail end of either resin coated sand or ceramic proppant. And we have a good family of wells in the Three Forks that we can compare performance. The previous owner, not only designed their completions with cemented liner and plug and perf but they also pumped 100% ceramic proppant in each of those wells. So it's been a great natural laboratory to compare early well performance and longer term well performance and frankly we struggled to see any significant difference. Now that doesn't mean that in certain parts of the basin where rock quality may not be as good, where geology is different that there may be a material difference between sliding sleeve and plug and perf cemented liner completions, we just don't see it in the area where we are operating.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC

Q

One of your peers in the basin has reported a significant improvement in well productivity by using slick water based fracs, is that a design that you guys have looked at?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Yeah, we use again in addition to the proppant design, we use a hybrid completion fluid design as well with a combination of gel and slick water as we get into higher proppant concentrations, we tend to add little gel toward the end of the jobs to place the terminal portion of each frac stage, but and it also sweeps the sleeves and keeps the sleeves from malfunctioning as well.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC

Q

Okay. Moving over to the Uinta, it looks like you dropped one of your two lower Mesaverde rigs, are there plans to reallocate that capital elsewhere?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Yeah. Generally, we're pulling capital away from the lower Mesaverde for the time being while we let these wells perform and wash the well performance to help us determine the ultimate, not only well density spacing but also the pattern that we drilled the wells into avoid frac interference. And frankly, we need to see some history on these wells to make sure we understand the interference pattern, and we can design a plan and development going forward. So it's – as we pull capital out, we've – it's generally headed to the oil plays and especially to the Williston.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC

Q

Okay. Last one from me, just on the Cana, you guys had looked at potentially selling that asset earlier this year. It sounded like you had pulled it off the market. Any change in thoughts there?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Well, it's an asset that we've thought about selling and obviously if a buyer made an offer that was acceptable to us, we would divest of it. When we look at any of our properties, we look at the PV of developing the property ourselves and holding it in our portfolio versus the PV offered to us by a buyer, and of course the buyers offer is risk-free with respect to execution and commodity prices, et cetera. So we take that into account. But to date, the offers that we received have not met our threshold to consider transacting. Gas markets change, perceptional of property changes, so it might happen, it might not. I'm not going to predict what the future will hold for the Cana.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC

Q

Okay. Thanks very much. Nice quarter.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Thank you, Eli.

Operator: Our next question comes from the line of Brian Gamble with Simmons & Company. Please proceed with your question.

Brian D. Gamble
Analyst, Simmons & Co. International
Q

Good morning, guys.

Eli J. Kantor
Analyst, IBERIA Capital Partners LLC
Q

Good morning Brian.

Brian D. Gamble
Analyst, Simmons & Co. International
Q

I wanted to follow-on on your comment about what you are seeing currently in those middle Bakken wells. You expected them to be good and they were. Is your expectation from what you've got as far as data across your new acreage there, is it consistent across – would you expect to see those same sort of flow rates, as you're moving forward?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Yeah, the geology looks pretty well behaved from the wireline logs that we have across the Bakken, and we just have a handful of cores. There has been a few outside operated wells around the periphery of our acreage, and they too look very similar as far as well performance. And I guess, I would caution you that as always, IP is not what we really look at. We look at 30-day, 60-day, 90-day, 120-day performance, and obviously as we get enough production history on the well to forecast EUR, that's what really matters.

We're in fact internally struggling with maximization of first-day rate versus risk of flowing back portion of the proppant that we've placed in the fractures, and from our experience in other plays like the Haynesville, we think not getting too aggressive on flow back on these wells maybe advisable.

So, as we go forward, we may in fact chock back on these wells a little bit if the initial – for the initial flow back to avoid any long-term damage to the reservoir. So, I think it's pretty well established from us and from all the other operators that, in fact, I've got a plot here of IP versus EUR and the R-squared about 0.3. It starts to – the cluster starts to tighten around, the distribution starts to tighten and by the time, you get to 90 days, there is about a 75% or 80% correlation coefficient. So, I think it's very dangerous to just look at IP's, and we're still very happy with the well performance and is pointing us toward the wells that we assume when we made the acquisition about a million barrels – little over a million barrels almost 1.1 million barrels of oil equivalent.

Brian D. Gamble
Analyst, Simmons & Co. International
Q

Yeah. I would agree with that definitely. And then when you look at, to that point, you raised your average EUR just based on the current or recent Three Forks wells, looked like it was off from 990 to right over a million. Does that speak any sort of trend as you are moving in a certain direction from your Three Forks wells or was that just?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

No. I mean.

Brian D. Gamble
Analyst, Simmons & Co. International

Q

Which happen to fall above the tight curve?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

No. I mean we just do the math right. We just – we looked at our – at the reserves that we had signed the wells we had in our production history to feel comfortable and the average is what we reported. So, I wouldn't read too much into a slight bump in EUR. It's just – it's the statistics of the recent wells that we put on. There is some variability in the Three Forks across the acreage, but it's generally again as good as if not better than we had assumed in the acquisition model.

Brian D. Gamble
Analyst, Simmons & Co. International

Q

Great, and one more from me on the discussion about the Cana divestment. Obviously active before, it seems like you're not as active now. Does the – do the other packages that are out there on the market. We've seen several announcements from different guys, not all Cana, but seem to be all Midcon properties over last few months. Has that changed the landscape, are there new people potentially looking that could come in or how has that changed your thinking just based on your assets in the area?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Well. I think there are a handful of new buyers who are emerging. Some of them are still working on their funding. There are – obviously the private equity sponsored companies have a – maybe a more constructive long-term view on gas properties versus oil properties and that's typically what we've seen in the data rooms and in interest levels. So, I think that this summer, the first quarter and second quarter and into the summer, the market was pretty full of property divestitures and the inventory seems to be coming down some, as we move into the end of the summer. So we'll see, we've had several inbounds from new people that didn't originally participated in the data room and process, so you never know. One of them may get to our magic number.

Brian D. Gamble
Analyst, Simmons & Co. International

Q

It's a great color. I appreciate it.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Thanks Brian.

Operator: Our next question comes from the line of Dan McSpirit with BMO Capital. Please proceed with your question.

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Thank you, folks. Good morning.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Hey, Dan.

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Assuming the current pace of drilling and assuming current development spacing. In what period do you drill the last well on the South Antelope and Fort Berthold leasehold and what period does production peak from these same areas?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

So, in aggregate we've finished everything by sort of the end of 2015, production peaks a little earlier on the South Antelope property, it peaks in sort of late 2014. We got more locations on the Fort Berthold Reservation than on South Antelope. And of course we are consuming the locations on South Antelope more rapidly because of the current rig count and rig allocation.

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Okay, great. And at what price – what gas price does the Haynesville begin to compete on returns with the Fort Berthold operation?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Let me think about that for a minute Dan. It's got five in it, let me ask this question, at what oil price should I compare? At current oil prices?

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Yeah, please.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

<A>: If I sort of take the forward curve, we would need a five handle on gas to start to think, even think about allocating capital away from the Fort Berthold Reservation and back toward the Haynesville. But keep in mind, the Haynesville is the driest, lowest return gas project in our portfolio. There are other places that we would allocate capital in our gas portfolio before we got to Haynesville.

Mesaverde and the Uinta Basin additional drilling in Pinedale and some other properties that we have in the MidCon, including the Cana, which as you know has a significant liquids component that helps boost returns. So, it's not just a dry gas play. The Haynesville is the tough one because as we learned, when we were actively drilling with six rigs in the Haynesville, you really need to have a decent program there, multi-rig program, five or six rigs running in the play in order to get the kind of economies of scale that allow us to drive down or hold down completed well cost.

And that's not a – an immaterial capital allocation decision, it's probably $400 million of capital that we would need to divert on an annual basis from some play to the Haynesville in order to fund that level of activity. So, it's a major shift in capital allocation. And looking at the forward curves of oil and gas today, I struggle to see that happening in the next year or two.

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Okay. Great. And then, one more if I may. If you could remind me of the decline rate on the base natural gas production and how is that expected to change over time?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

It's about – we're forecasting about a 10% year-over-year decline this year in base natural gas production. And it's driven by an over 30% decline in the Haynesville. And that's not base. If I step back, I'm sorry that is our forecasted decline in gas production versus last year. And so that includes drilling activity because all of our gas producing areas Pinedale, Uinta et cetera are up year-over-year with the exception of Haynesville. So, when I think about a Haynesville, the Haynesville with mid 30%s first-year of decline with no drilling activity going on and no completion activity going on. And then of course we're growing gas production in the other areas. If we look at our corporate average and I can't, I don't have the number in my head or on any other paper in front of me for our just our gas wedge, but our corporate average first-year PDP decline is in the high 20%s, 27% – 28%. And I don't think it's dissimilar, Dan, between oil and gas. It might be a little steeper on the oil side because of all the new Bakken wells we're bringing on. But it's probably a reasonable proxy for both oil and gas.

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Okay. Great. And then, I will ask one more. Chuck, the stock price, the performance continues to lag the group I guess to put it politely. What do you think the market is missing here?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Well, we ask ourselves the same question, Dan, I think the thing that, that I sense is that the market is waiting for execution on South Antelope and obviously it's toward the back end of the year. We put another element of uncertainty into the equation with the announcement of the formation of an MLP, so the market is waiting for us to execute on that. There has been debate about the value of our Midstream assets in an MLP. So, I think that those two things are probably the – the two that we hear most from investors when we're on the road talking to our shareholders.

Dan E. McSpirit
Analyst, BMO Capital Markets (United States)

Q

Very good. Thank you.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Thank you.

Operator: Thank you. Our next question comes from the line of Duane Grubert with Susquehanna Financial. Please proceed with our question.

Duane M. Grubert
Analyst, Susquehanna Financial Group LLLP

Q

Yes. Kind along the same lines of thinking, maybe five-year planning wise, you guys had made a pretty good commitment to the Uinta as sort of the next big project. And obviously you're going to focus on the Bakken near term here. But what kind of science work and what kind of other work can you do on the Uinta in the meantime that doesn't necessarily involve drilling a lot of wells. Uinta looks like that you are going to still – is going to be material after the [indiscernible] (46:17)?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

That's a great question Duane. One of things that we have focused on is taking some full hole cores and doing special core analysis on this cores because one of the things that we learned is that the wireline log data from the Mesaverde section – lower Mesaverde section is being dramatically distorted by the presence of clays in some of the sands. And we had been under the false impression that the Mesaverde section in Uinta Basin unlike the Mesaverde section up at Pinedale had some wet reservoirs interspersed through the sand packages. The core data that we've collected over the past six months and the analysis that we have done suggest that we've been leaving behind a large percentage of the section thinking it was wet when in fact it's gas bearing.

We took oil base cores, we've done – we tagged the drilling fluid with a marker so that we could differentiate between invasion of drilling fluid and native hydrocarbon and all of that data points to some very exciting – a very exciting change in our interpretation of the wireline log data that suggests that the whole section is gas, at least the lower half of the section is gas charged and we don't have to surgically complete these wells. We can pretty much look at the logs and pick the sands and not worry about free water production. That has significant ramifications because you could it fundamentally change the EURs of these wells.

The current pad, I'm sorry pod of wells that we're drilling will be completed using this new data that we've derived from the cores and that's – I think that's an important data point to watch over the next couple of quarters because, if that is true, then our whole sort of drilling plan and development of this asset changes dramatically. And just to put a final point on it, early on we struggled, Dwayne, and I know you're reservoir engineer, so you'll get this. There was a very low correlation between net pay calculated on the logs and well performance, and we couldn't understand why. We'd have high EUR wells that had very little net pay and vice versa. And we originally rationalized that we were fracking away from the wellbore into sands that we couldn't see on the logs. It may be.that what's going on is that we were seeing contribution from sands that we were counting as wet that we're actually flowing into the well, just because of frac height growth. So it's a very interesting data, we've got now several data points. We're going to – I'm sure that I'm going to be bombarded by the technical team to take even more cores, so if they're listening in I guess you got me. So that's the story on the Unita. So there's a lot of science to do and of course on production reservoir engineering side watching these wells that we've completed to see if we see either direct or indirect interference between the wells at different spacing is an important part of this strategy as well.

Duane M. Grubert
Analyst, Susquehanna Financial Group LLLP

Q

And I guess just a one follow-up to that. Since you guys have a minority interest in a lot of that program, are you working with other owners out there? Is there sort of a consortium that's doing the same sort of work, or are you trying to gain a competitive advantage [indiscernible] (50:14)?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

So, Duane actually in the Red Wash unit, we're 100% working interest owner. We operate all of the stuff that we're working on. Around the periphery to the south and the northern part of the Natural Butte's unit and Shapeda wells unit, we have a smattering of acreage, but our acreage is concentrated in a 100% working interest QEP operated block. That being said all the acreage out there is tightly held by Anadarko EOG, us and handful of other operators, right in that neighborhood. And so there has been some cooperative sharing of core and core analysis and well data between the operators because we all benefit from sharing the science.

Duane M. Grubert
Analyst, Susquehanna Financial Group LLLP

Q

Great. Thank you very much.

Operator: Thank you. [Operator Instructions] Our next question comes from the line of Subash Chandra with Jefferies. Please proceed with your question.

Subash V. Chandra
Analyst, Jefferies LLC

Q

Yeah. Hi, good morning. At the risk of making too much of IPs and I know how you feel about that, but just looking at the second quarter completion reports on the Bakken, look like there was a wider choke but pressures look pretty strong. At the risk of trying to sound like a reservoir engineer, I mean, is that a testament to the inability to actually produce these wells more flush? Or were you saying earlier that you still run the risk of pulling some proppant in?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Yeah. I mean, Subash, the wider chokes are a direct indication of the reservoir support. It's really a question of how much velocity you have down hole and whether or not we run the risk of pulling in proppant. We also worry a bit – we developed a view in the Haynesville that hard flow back, if you will, higher initial flow backs, and of course we could never go down there and observe it directly, but the higher initial flow backs had a detrimental effect on long-term well performance in that that it may – and we speculated that maybe we were doing something to the near wellbore either compacting the prop fracture or not completely connecting the well up to the full length of the prop fracture by having preferentially inflow from either the near wellbore part of each of the frac stages or perhaps having preferential inflow from the best frac stages in the well, and not cleaning up the rest of the wells. So from that thought process, we have been debating internally managing that early flow back and so that's why I've made the comment I want to make sure that folks don't look at results in the third quarter or fourth quarter and say oh now their wells aren't as good because first of all I won't pay any attention to the IP's, and second we may manage those IP's in order to avoid reservoir damage.

Subash V. Chandra
Analyst, Jefferies LLC

Q

Okay, great. Thank you. Secondly, so when you were talking about your internal forecast for South Antelope, I just want to get the numbers right, so you are thinking about Q4 slightly over 30,000 BOE per day?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Yeah, hang on, I've got – I think I have got that number here, if you'll just give me a second, actually we can follow-up with you with that number, I don't have it right in front of me, Subash, it's a little under 31,000 barrels a day.

Subash V. Chandra
Analyst, Jefferies LLC

Q

Okay. Okay. Yeah.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

And they kind of put – it, to put it in context, we are planning on completing 70 wells this year and we only had 27 completed by the end of the first half. So that should also help you with the shape of that production growth curve.

Subash V. Chandra
Analyst, Jefferies LLC

Q

Okay, I'm sorry Chuck, could you just repeat those last numbers?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

We are planning on 70 wells total for the year, 70 QEP operated wells, obviously we have an interesting number of outside operated wells. We had by the end of the second quarter first half of the year 27 completed.

Subash V. Chandra
Analyst, Jefferies LLC

Q

Okay.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

That means, so geologist's math that means we got 43 to go, if I didn't slip a decimal.

Subash V. Chandra
Analyst, Jefferies LLC

Q

All right. Okay. That's – I think that's layman's math too. KKR, I mean this is just third party evidence in the Haynesville, but KKR and EXCO, they're going back in, they're drilling. I don't think they're drilling core-core. EXCO had exhausted that. But just given your comments earlier on the Haynesville, have you ever – have you given thought to that. I mean, I don't think KKR are dumb folks notwithstanding that there are bunch ex Jefferies people?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

I won't comment on the latter part of your statement, but – well as far as the joint venture you mean or you talking about just that they're doing it and we're not?

Subash V. Chandra
Analyst, Jefferies LLC
Q

Yeah. I guess, they jumped into this with a 75% interest with EXCO on the – on this new acquisition that EXCO made in the Haynesville. And I guess they have some sort of – they have a model – an internal model that suggests that they can – at current gas prices get away with it and earn a good to exceptional return and do you see that angle or?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

So – well, it's all about portfolio, right. So, the way we run our business is we look at all of the investment opportunities we have in our portfolio and we allocate capital, at least we try to allocate capital to the highest return projects in the portfolio. And clearly, when we force rank it, we run out of capital before we get to the Haynesville. Other companies might not be as fortunate to have as a high return of projects as we do in front of the Haynesville. But I'd also say with respect to that company that they have done an excellent job of driving down well cost because unlike the rest of us who pulled out of the play, they kept drilling, and they have continued to perfect their well design. And obviously well costs are a huge driver in returns. It's very sensitive – the Haynesville is very sensitive to completed well costs, and it's even more sensitive to the shape of the natural gas curve, I mean, if you look in the appendices of our IR deck, you can see how steep the return sensitivity is versus NYMEX gas price. And so, some might take a view that while the gas price is wrong, it's going to be up $0.50 or $1 over the next 12 months to 18 months. And with that kind of view, I could see how you could continue to allocate capital and aggressively develop the Haynesville. We have better places to put our capital.

Subash V. Chandra
Analyst, Jefferies LLC
Q

Okay. Good answer. Thank you.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Thanks, Subash.

Operator: And our next question comes from the line of Hsulin Peng with Robert W. Baird. Please proceed with your question.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets
Q

Good morning, everyone.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Hey, good morning.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets

Q

Good morning, everyone. So my first question is regarding the drilling inventory that you talked about in South Antelope. So, I was wondering, can you elaborate more on how many – what is your number well per unit assumption because I think you guys are doing mostly four well per pad right now? Have you looked into the deeper ventures or down spacing potential for South Antelope?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

That's a great question. And I should have added that to my answer, earlier. Thanks for reminding me. This is – the inventory and runway is based on the assumptions Hsulin, that we only drill four wells in each of the two reservoirs per 1,280-acre spacing unit. So, four middle Bakken wells and four First Bench Three Forks wells. We're still working to evaluate the two additional opportunities, the first being increased density and we're doing some increased density both reservoir engineering work as well as will do some piloting work. And then, the second piece is evaluating other potential reservoirs in the sequence and that work is ongoing as well. So it has the potential to materially impact that inventory, both in terms of in-fill and with respect to additional reservoirs.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets

Q

Okay. Great. That's good color. And then secondly on your the third asset sale agreement now you enter into, maybe I missed it, but did you say what assets those were?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

No we didn't. We did not, Hsulin, and I would prefer not to identify the asset until the transaction is closed. We gave you the dollar amount and it's about $66 million I recall of proceeds, and we will give you more color around that asset once the deal is closed.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets

Q

Okay. And how about in terms of the three combined asset sale, can you tell us what the associated production is with those asset – those sales?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Yeah. For the first half it's immaterial right because the two that have closed, really close toward the end of the first half. If we look at it on a full, for the remainder of this year run rate, a couple of Bcfe roughly of production, and I'm sitting here looking at Rich. I can't remember the ratio of gas to oil. But it's an oilier mix; they were oilier properties. So a couple of Bcfe of impact in the second half of the year.

Richard J. Doleshek
Executive Vice President, CFO and Treasurer, QEP Resources, Inc.

A

But Hsulin, you won't see it. We didn't change our guidance because of the two that we've closed and then one that we're going to close. So you can kind of calibrate that if we had a five Bcfe range and sort of in that zip code and still be – to still be inside guidance.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets

Q

Okay. Got it. And then in your, in the Field Services processing volume I noticed that it went up meaningfully in the second quarter, and I think you alluded to some making of novelty during second quarter. Is that – and I'm not quite sure whether you guys still are trying to but?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Let us help you with that. Richard [indiscernible] (61:15) because what I don't want to have happen is folks start taking the second quarter number and multiplying it by two for the second half of the year because there are some anomalies in there. So Richard can give you some color on that.

Richard J. Doleshek
Executive Vice President, CFO and Treasurer, QEP Resources, Inc.

A

So with Iron Horse plant being completed, we actually ran that plant in all phases of recovery. And I would say the real increase associated with that processing activity is probably 150,000 barrels in the quarter. We produced about 100,000 barrels of ethane in conjunction with some things that we're doing that we really don't expect to be recovering. So if you took the 709,000 barrels in the second quarter, backed off 110,000 barrels of ethane. We also had some accrual changes that we're doing as a result of that plant coming on. So I think if you think about sort of good run rate for the third quarter, it's going to be somewhere between 450,000 barrels and 500,000 barrels, as you worked and noise out of the system with bringing that new plant on and some of the things that were doing to just test that plant, get it fully up and running and doing some other custom processing for other people.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

So do you see an impact on volumes and – but it's going to be on a heavier part of barrels going forward. It's just because of the increased recovery efficiency of the cryo plant. Even when it's running in ethane rejection mode, it does a better job of extracting the propane and heavier liquids out of the gas stream than the old refrig plant did.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets

Q

Okay. Got it. And then, I guess last question in the interest of time. It's regarding your CapEx. So, you mentioned that you're trying to get the Bakken well cost to I think $10 million by year-end. So, I was wondering what is currently building your CapEx and would you potentially increase, if you assume the same CapEx amount, would you consider increasing the number of well count or would you keep your well count and then reduce CapEx? And then also, just a quick question about that the $30 million CapEx decrease in your Midstream, what is that attributed to?

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

A

Okay. So on the first question, Hsulin, we got a declining – a forecasted decline in the completed well costs in the second half of the year that drives the CapEx number. What really drivers an increase in CapEx and an increase in well cost or well count in – particularly in the middle Bakken is just getting – middle Bakken and Three Forks is just getting better and better in the cycle time both drilling and completion cycle time, which would increase the number of wells that we can deliver to production by year end, and it would also by necessity increase the CapEx if we're just completing more wells. So the guidance right now assumes that number that I gave earlier about 70 total wells completed for the full year and roughly 43 wells in the second half. And there's a lot of folks focused on doing better than that and that might result in an uptick – a slight uptick in capital – CapEx in the second half, if we can just get more wells completed.

On the $30 million reduction at Field Services, that's a reflection of pushing out the new processing plant that we'd talked about, we've been talking about for several years, down in the Uinta basin into next year and that's really a direct reflection of the desire to get some more production data on the lower Mesaverde play, and make sure that when we go in to start development, we understand exactly how to develop the reservoir. But that's – that's the, we'd anticipated earlier when we set guidance, well, this time last year when we started thinking about guidance for 2013 that we would be ordering a lot of equipment and vessels for that plant during 2013 and it slipped into 2014.

Hsulin Peng
Analyst, Robert W. Baird & Co. Equity Capital Markets
Q

Okay. That sounds good. Thank you guys.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.
A

Thank you.

Operator: It seems there are no further questions at this time I would like to turn the floor back over to Mr. Stanley for closing comments.

Charles B. Stanley
Chairman, President and Chief Executive Officer, QEP Resources, Inc.

Thank you Brenda. In summary, we're excited about QEP's future. We continue to make great progress in shifting our production mix towards higher return crude oil and liquids rich gas production from our existing asset base, and with our recently acquired Williston Basin assets we're now poised to accelerate crude oil production volumes and drive a profitable growth from our portfolio of high quality assets in 2013 and beyond.

I'd like to thank you all for calling in today. And thank you for your interest in QEP. And we look forward to seeing you all soon. Have a good day.

Operator: Ladies and gentlemen, this concludes today's teleconference. You may disconnect your lines at this time, and thank you for your participation.