01-May-2013

QEP Resources, Inc. *(QEP)*

Q1 2013 Earnings Call

CORPORATE PARTICIPANTS

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

Richard J. Doleshek
Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.

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

Jay B. Neese
Executive Vice President, QEP Resources, Inc.

Perry H. Richards
Senior Vice President-Field Services, QEP Resources, Inc.

OTHER PARTICIPANTS

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Brian Corales
Analyst, Howard Weil

Subash V. Chandra
Analyst, Jefferies & Co., Inc.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC

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

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

Ben Wyatt
Analyst, Stephens, Inc.

MANAGEMENT DISCUSSION SECTION

Operator: Greetings and welcome to the QEP Resources First Quarter Earnings Call. [Operator Instructions] 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 First 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, qepres.com, to obtain copies of our earnings release, which contains tables with our 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 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 our SEC filings.

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

Richard J. Doleshek

Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.

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

Turning now to our financial results. As many of you know, our first quarter is typically a weaker quarter relative to the rest of the year as a result of how we manage our drilling and completion activities during the winter in our Northern region. In addition, I'm sure you've heard our peers talk about the impact of gas processing plants operating in ethane rejection mode and the negative impact that it has on production volumes and corresponding positive impact on average realized natural gas and NGL prices. We experienced similar impacts to our operating results in the first quarter.

When comparing the first quarter of 2013 to the fourth quarter of 2012, the story was marginally weaker financial performance in QEP Energy, our E&P business, and slightly weaker results at QEP Field Services, our gathering and processing business. QEP Energy reported the growing production of 78 Bcfe, down 7% from the fourth quarter of 2012, but net equivalent realized prices that were 2% higher than during the fourth quarter. Field Services first quarter results were lower than the previous quarter, primarily due to lower processing margins.

From an EBITDA standpoint, we generated $375 million in the first quarter, which is $15 million, or 4% lower than the fourth quarter of 2012, but $24 million, or 7% higher than the first quarter of 2012. QEP Energy contributed $324 million, or 86% of our aggregate first quarter EBITDA, and QEP Field Services contributed $53 million, or about 14%. QEP Energy's EBITDA was down $10.6 million, or 3%, while Field Services EBITDA was down $2.6 million, or 5% lower than the respective fourth quarter 2012 levels.

Of note, if you remove the impact of our derivative settlements in their respective quarters, we generated $11 million more EBITDA in the first quarter of this year than the fourth quarter of 2012. Factors driving our first quarter EBITDA included QEP Energy's production, which was 78 Bcfe in the quarter, 5.9 Bcfe lower than the record 83.9 Bcfe recorded in the fourth quarter of 2012.

The quarter's production was 5% higher than the 74.2 Bcfe produced in the first quarter 2012. Oil and NGL volumes account for 25% of our equivalent production in the quarter. Oil volumes were 2.14 million barrels, down 8%; NGL volumes were 1.11 million barrels, down 23% from the fourth quarter of 2012.

Combined oil and NGL volumes were 3.3 million barrels in the quarter, down 14% from the 3.8 million barrels of combined volumes in the fourth quarter of 2012 but up 33% from the 2.4 million barrels of combined volumes in the first quarter of 2012. The lower oil production reflects the impact of converting the pad drilling on the South Antelope properties, which resulted in only one well being completed in the first quarter. And the reduction in NGL volumes from the fourth quarter 2012 reflects the impact of ethane rejection.

QEP Energy's net realized [ph] reformed (05:08) price, which includes the settlement of our commodity derivatives, averaged $3.61 per Mcfe in the quarter, which was $ 0.14 per Mcfe higher than the realized fourth quarter 2012 prices and $0.84 per Mcfe higher than what's realized in the first quarter of 2012. The higher equivalent price reflects field-level gas prices that were $3.38 per Mcf, or $0.16 higher; field-level NGL prices that were $45.64 a barrel, or $11.09 a barrel higher; and field-level crude oil prices that were $9.81 a barrel, or $6.43 a barrel higher than the respective fourth quarter levels of 2012.Field-level crude oil revenues account for 44% of total field-level revenues, which was the same as in the fourth quarter of 2012 but up from 34% in the first quarter of 2012.

QEP Energy's commodity derivatives portfolio contributed $50 million of EBITDA in the quarter compared to $74 million in the fourth quarter of 2012 and $83.5 million in the first quarter of 2012. The derivatives portfolio added $0.64 per Mcfe to QEP Energy's net realized price in the quarter compared to $0.88 per Mcfe in the fourth quarter and $1.13 per Mcfe in the first quarter of 2012. The average price of our natural gas derivatives portfolio made a step function change at year-end with 2013's portfolio having an average swap price that's about $0.33 per MMBtu lower than the 2012 portfolio average swap price.

In essence, the change in the contribution from the commodity derivatives portfolio drove the decrease in the EBITDA of QEP Energy from the fourth quarter to the first quarter as the operating activities were up about $13.6 million sequentially.

QEP Energy's combined lease operating, transportation and production tax expenses were $132 million in the quarter, down from $145 million in the fourth quarter and up from $114 million in the first quarter of 2012. On a per-unit basis, lease operating expenses were $0.53 per Mcfe, down $0.07 per Mcfe from the fourth quarter. Transportation expense was $0.72 per Mcfe, which was unchanged from the fourth quarter. But production taxes were $0.44 per Mcfe compared to $0.40 per Mcfe.

Our LOE is typically lower in the first quarter of the year as a result of how we manage our field activities during the winter in the Northern region. Finally, QEP Field Services first quarter 2013 EBITDA was $53 million, which was $2.6 million lower than the fourth quarter of 2012 and $30 million lower than the first quarter of 2012. Processing margin was down $2.7 million, or 9%, from the fourth quarter as a result of 41% lower NGL sales volumes but 10% higher realized NGL prices, each reflecting our plants operating in ethane-rejection mode.

Gathering margin was down $1.3 million, or 3%, in the quarter compared to the fourth quarter on 7% lower gas gathering volumes of $1.24 million MMBtu per day, due primarily to the declining production in Haynesville. The average gathering fee in the quarter was $0.338 per MMBtu. We reported a $4 million net loss in the quarter, driven by an $85 million loss in the March market value of our derivatives portfolio, and sequential DD&A expenses were down $3 million to $254 million.

In terms of capital expenditures for the quarter, we reported $342 million of capital expenditures, including acquisitions. Capital expenditures for our E&P drilling and completion activities were $302 million. And in addition, we reported $24 million of acquisitions, $5.5 million of which was a post-closing adjustment related to the 2012 North Dakota acquisition. Capital expenditures in our Midstream business were $12 million in the quarter. Excluding acquisitions, in total, we spent about $318 million in the quarter, which was about $57 million less than our first quarter EBITDA.

With regard to our balance sheet, at the end of the quarter, total assets were $9.1 billion; shareholders equity was $3.2 billion; and total debt at the end of the quarter was $3.37 billion, which is about a 2.25 times multiple of our annualized first quarter EBITDA. 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 $850.5 million drawn under our $1.5 billion revolving credit facility that matures in 2016.

Finally, in January, we announced the Board of Directors had approved the formation of an MLP and the preparation and filing of a registration statement with the SEC for initial public offering of the MLP's LP units. We continue to work on that project, as well as the number of other strategic initiatives, including upstream sales. And yesterday, we reported that we had entered agreements to sell several non-core properties in our Northern region for approximately $145 million and we expect those sales to close before the end of the second quarter.

I'll now turn the call over to Chuck.

Charles B. Stanley

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

Thanks, Richard, and good morning, everyone. As Richard mentioned earlier, QEP Energy crude oil production grew 75% from a year ago with crude oil representing 16% of total production in the first quarter, which is up from 10% of total production a year ago. This growth is not only coming from our new acquisition of South Antelope and development of our other Williston Basin properties, but also from other assets. For example, our Midcontinent crude oil production was up 43% from last year's first quarter.

Our crude oil volumes were down a bit sequentially from the fourth quarter. I think that may have surprised some of you. As Richard mentioned, it's due primarily to our shift to pad drilling in the Williston Basin. We could have easily drilled one well per pad, but going to pad drilling, multi-well drilling from a single pad is the right thing to do and I'll get into more of the details of the impact of that in a moment.

Obviously, pad drilling defers a number of well completions in the second quarter and later in the year when all the wells on a pad have been drilled and cased, and we can move the drilling rig out of the way. When we gave guidance, we anticipated this and we still expect to be able to achieve 70% or better year-over-year increase in crude oil volumes in 2013.We continue to focus on profitable growth over absolute natural gas equivalent volume growth. Growing crude oil production is having a significant impact on our financial results through increased EBITDA per Mcfe, even while natural gas equivalent production volumes are decreasing. While net realized natural gas prices were essentially flat compared to last year, a 5% increase in realized crude prices coupled with a 75% increase in year-over-year crude volumes resulted in a 21% increase in QEP Energy EBITDA in the first quarter of 2013 compared to the first quarter of 2012.

Let me give you a little more color on our operational results from the first quarter and our plans for the remainder of 2013. As I do, I'd ask that you please refer to the slide presentation that's accompanying our release, which was posted on our website yesterday afternoon.

In North Dakota, we're making good progress on development of our South Antelope property. Recall we closed the acquisition on the 27th of September last year. And toward the end of last year, we shifted to pad development on the property. We swapped out the two rigs that the previous owners were using for skid-capable rigs. And as those new rigs arrive, they immediately commenced drilling on multi-well pads. We currently have four rigs working on the South Antelope property and we expect to be at five rigs before mid-year.

As a reminder, our development plans for South Antelope call for an average of eight long lateral wells per 1,280-acre spacing unit with an average of four wells drilled into each of the Three Forks and Middle Bakken reservoirs. We'll develop most of these units with two four-well pads.

Pad drilling is the right thing to do to develop this property and it should help us drive down well cost by reducing the time associated with rig moves and mobilization – demobilization of completion crews and equipment. Pad development will also facilitate sharing of some of the production facilities and gathering lines.

As I mentioned earlier, some of you were surprised by the decline in crude oil volumes in Q1. It's important to note that we're not able to complete any of the wells on a pad until all the wells are drilled and cased and the drilling rig is removed. So development will necessarily introduce lumpiness as we go to pad development. It will introduce lumpiness in our production growth profile.

We tried to manage the arrival of each new rig to stagger delivery of each new multi-well pad. But we still expect to see lumpiness in the growth profile going forward. We're also making changes in well design that should allow us to consistently deliver wells at an $11 million gross completed all-in well cost or less going forward. Because of our shift to pad drilling, as Richard mentioned, we only completed in terms of sales one new South Antelope well during the quarter. The well's called the Moberg 13-17/16H and it's another Three Forks producer.

This well had a lower initial rate of about 1,397 Boe per day as reported to the state due to some temporary surface equipment constraints during the first few days of flow back. In short, you shouldn't read too much into the lower reported 24-hour initial rate as the well was producing at over 3,100 Boe a day at the end of the 24-hour flow back period, which compares favorably in both quality and performance to the other completed wells on our South Antelope acreage.

To be very clear, this was a well-specific equipment problem and not a gathering system problem, and the 30- and 60-day rates for this well were every bit as good as those of the offset wells.

See Slide 6 for a reminder of the location of our South Antelope property, and Slide 7 will show you the location of the Moberg well that we completed during the quarter.

On our Fort Berthold acreage immediately to the east, we completed and turned to sales 11 new wells during the first quarter, 6 in the Middle Bakken and 5 in the Three Forks formation. Five of the new wells were on a pod on our Buffalo 10-well pad, which is located on the far northwest corner of our Fort Berthold acreage. And all five of those wells came on at excellent rates with an average initial 24-hour rate of over 2,190 barrels of oil equivalent per day.

An additional five wells were completed on the Skunk Creek pad about five miles east of the Buffalo pad. And all of these wells were strong with an average 24-hour rate of 2,479 barrels of oil equivalent a day. The 11th well that was drilled on our Fort Berthold reservation was a single lease-saving well that was drilled near the eastern edge of the Middle Bakken reservoir and it had an initial 24-hour rate of 836 Boe per day.

On the infrastructure side on the reservation, the third-party gathering system operator has made some progress and their water-gathering system is now up and running and it's moving about 75% of our flow-back water, which is a reminder, much higher than the normal run rate of produced water, and it's moving 100% of the produced water volumes.

As a result, we're now saving about $5 a barrel moving that portion of the flow back and produced water by pipe versus trucking. As the weather improves, additional gathering system upgrades are planned over the next month or so that should allow the remaining water volumes to be collected and moved by pipe.

Field-level net back crude oil placing in the Williston also improved dramatically in the first quarter from a year ago. Thanks to our new marketing and transportation agreements, we're able to access multiple crude oil markets. So our average field-level crude oil prices during our first quarter of 2013 were $90.81 a barrel, or about 96% of the WTI average for that period. Compare that to the first quarter of 2012 when our average field-level price was about the same, $90.67 a barrel, but that was only 88% of the average WTI spot price for the first quarter of 2012.

During the first quarter and continuing into the current quarter, we've been able to deliver completed wells on the reservation at an average gross completed well cost that's all-in, drilled, complete, equipped and turned to sales of $10.8 million. We currently have three rigs running on the Fort Berthold reservation. See Slide 8 for more information on our Fort Berthold activities.

We were also able to make a successful bolt-on acquisition on the Williston Basin during the quarter. We acquired leasehold that added about 1.4 million barrels of oil equivalent in PDP and PUD reserves in spacing units which we currently operate for an acquisition cost of about $12.25 per Boe. We continue to hunt for opportunities to add additional interest around our core Williston Basin properties.

At Pinedale, we currently have three rigs running for QEP and another QEP-operated rig that's drilling wells in which we have only an overriding interest, i.e., no working interest, for a total of four rigs working at Pinedale.

Due to the favorable weather conditions, at least until this morning when it started snowing in the Rockies again, we were able to get an early start on completing Pinedale wells this spring. And in the end of the first quarter, we had 22 new wells that have already been completed and turned to sales. We plan to complete a total of about 110 wells this year, including 29 wells in which we have only an overriding royalty interest.

Due to continued low ethane prices and higher natural gas prices net to the well, ethane frac spreads remained negative and we continue to run all of our gas processing plants in the Rockies in ethane-rejection mode. As we described during our call last quarter, ethane rejection results in a 7% to 8% reduction in natural gas equivalent production volumes at Pinedale, but because of currently low ethane prices, rejection of ethane has little impact on gross revenues from our Pinedale and other Rockies properties.

And remember, we still sell that ethane in the natural gas stream, so it increases the Btu content in the natural gas revenue. Just look at the total company results as an illustration of this concept. Total NGL volumes were down about 23% quarter-on-quarter, but QEP Energy NGL revenue actually increased slightly during the period.See Slides 9 and 10 for details on Pinedale. And the appendix of our current IR deck has a great slide that shows the details of the production volume impact of ethane rejection and recovery and I think it's a great place to go if you're still struggling with the concept of why volumes go down when we go into ethane-rejection mode.

Turning to Uinta Basin, we continue to make good progress on our Red Wash Lower Mesaverde liquids-rich gas play. At the end of the first quarter, we had two rigs active in the play, both drilling on Pinedale-style multi-well pads. As is the case in all of our pad-drilling operations, we have a number of wells that are drilled and cased that we cannot complete until we get the rig moved out of the way, and we're beginning completing that first pod of pad wells in a couple of weeks and we're eager to see the results.

As you may expect, we are rejecting ethane in the Uinta Basin too, and this will negatively impact gas equivalent production volumes by the Mesaverde play by a similar volume, about 7% or 8% reduction versus ethane recovery.

At the end of the first quarter, we also had one drilling rig actively drilling horizontal and vertical wells targeting oil reservoirs in the shallow Green River formation in the Uinta Basin. See Slides 11 and 12 for more details on the Uinta Basin activities.

Turning to the Midcontinent, at the end of the first quarter, we had seven QEP-operated wells waiting on completion and one company-operated rig drilling in the core of the liquids-rich portion of the Cana Shale play in Oklahoma. We'll commence completion operations on that group of eight QEP-operated wells before the end of May.

In addition to operated activity, we've also participated in a number of outside-operated wells during the quarter. Since the end of the first quarter, the drill-out of the current QEP-operated unit has been completed and we dropped our last rig in the Cana play for the time being as we continue to focus on higher-return crude oil projects. See our release and Slide 13 for more details on the Cana.

In the Granite Wash, we completed three new QEP-operated wells and participated in five additional outside-operated wells that were completed during the first quarter with solid average results. All of these horizontal wells targeted crude oil and liquids-rich gas horizons in the Granite Wash sands. Please see Slide 14 for the details on that play. Thanks to the strong performance from the Cana and Granite Wash, Midcontinent crude oil volumes were up 43% in the first quarter of 2013 compared to the first quarter of 2012.

Finally, as you know, we ceased drilling activity in the Haynesville play early in the third quarter of last year. And as you'll remember, we elected to defer completion of the last five drilled and cased Haynesville wells until the first part of this year to take advantage of the Contango and forward gas prices. During the first quarter this year, we completed those wells and turned them to sales. Slide 15 has details.

At Field Services, we successfully completed and started up our new 150 million cubic foot per day Iron Horse II cryogenic gas processing plant in the Uinta Basin early in the first quarter. About half the capacity of the new plant is contracted to a third-party producer under a fee-based processing arrangement, while the other half of that capacity will process QEP Energy gas volumes from the Red Wash Lower Mesaverde play, and that capacity is also contracted under a fee-based arrangement.

Most of the gas volume currently going through the Iron Horse II plant had previously been processed in the adjacent Stagecoach refrigeration plant, so while the net change in fee-based processing volumes was small, we did experience a 12% increase in average fee-based revenues in the first quarter.

Construction continues on our 10,000 barrel per day NGL fractionation facility at Blacks Fork in Western Wyoming. The expanded facility is designed to provide additional options for marketing purity propane, iso and normal butane and gasoline range products to what are often times premium-value local, regional and national markets via either truck or through an expanded rail loading facility that we're constructing at the plant. We expect the new fractionator to be in service around mid-year and the financial impact of this new fractionator should be seen in improved NGL realizations.

As we announced in our release yesterday, we recently entered in two purchase and sale agreements for divestiture of some non-core properties that will result in proceeds of about $145 million. The deals cover our Powder River Basin assets and some other non-core Rockies properties. We also have several Midcontinent assets up for sale. We didn't garner any acceptable offers for the first Midcontinent asset we had on the market. A Cana Shale package and a formal sales process is over, but we continue to have conversations with several interested parties.

As I said at the outset of this process back in the third quarter of last year, we'll only sell assets where we receive offers that are at or above our whole value, which we define as the risk future value of us continuing to own and develop the assets in our portfolio. The final Midcontinent asset pack is on the market and bids are due in the next couple of weeks.

So now, let's look forward to the remainder of 2013. We view this as really a pivotal year for QEP as we continue to dramatically shift the production mix from one that was dominated by natural gas a few years ago to one that's more balanced. We expect crude oil production to increase by at least 70% this year and natural gas volumes will decrease about 10% in 2013 compared to 2012 levels solely due to the decline in our Haynesville volumes, absent any new drilling.

Yesterday, we revised our 2013 production forecast to reflect the reduction in natural gas equivalent volumes based on the assumption that our Rockies gas processing plants will continue to run in ethane-rejection mode for the rest of the year. Our focus remains on growing high-margin crude oil production and we're on track to grow QEP Energy crude production volumes by at least 70% over 2012. As a reminder, as we have shifted to pad-drilling in our key resource plays, not just in the Williston, but in other places, we have built up a significant inventory of uncompleted wells that will have a positive impact on production volumes in the second quarter and beyond.

So in summary, we're excited about QEP's future. We continue to make great progress in shifting our production mix toward higher return crude oil and liquids-rich gas plays from our existing asset bases. And with our recently-acquired Uinta Basin assets, we are now poised to accelerate crude oil production volumes and drive profitable growth in our portfolio of high-quality assets in 2013 and beyond.

I'd now like to turn the call back over to Greg Bensen for a moment before we start the Q&A session.

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 of the status of our Field Services business. On January 7 of this year, we announced that in addition to evaluating strategic alternatives with respect to certain of our Midstream assets, we plan to form a master limited partnership, or MLP, and file a registration statement with the SEC in the second quarter of 2013. As we have initiated the registration process, our comments 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: Thank you. We will now be conducting the question-and-answer session. [Operator Instructions] Our first question comes from the line of Brian Lively with Tudor Pickering Holt & Co. Please proceed with your question.

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Q

Hi, good morning.

Richard J. Doleshek
Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.

A

Hey, Brian.

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Q

Chuck, you stepped through those asset monetization updates pretty quickly. Can you backtrack a little bit, specifically on the Cana?

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

A

Sure, Brian. We marketed a package of assets, including the Cana. It was on the market about two months ago. And we got offers from several parties, but none of those offers met our internal valuation on holding the asset and continuing to develop it as part of our portfolio. We do the same sort of evaluation for assets that we hold in our portfolio as we do for acquisitions. And we had a range of values and risk outcomes based on uncertainty about future commodity prices and the pace of development, et cetera. But we just didn't get any offers that were attractive to us.

And as you saw, the asset continues to perform quite well. It was, in part, responsible for the growth in liquids production in the Midcontinent in the first quarter. So we're just not going to sell it if we can't get an attractive price.

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Q

Yeah, that makes sense. Do you have a maybe pro forma target on divestitures ex the Cana then?

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

A

No, we haven't given a dollar value there.<Q – [07KTKH-E]Brian Lively – Tudor Pickering Holt & Co. Securities, Inc.>: Okay. I'm just shifting to another topic. With the pad operations in the Williston and obviously the lumpiness you talked about, for the second quarter, do you guys have any visibility in terms of cadence or how many completions you're anticipating, both in the Antelope area and also the Fort Berthold reservation?

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

A

I think in our operations release, we talked about the number of wells at the end of the quarter that we had standing cased waiting on a completion. Obviously, that inventory will come into production as the rigs move out of the way. And I think a good way to think about it is on a typical four-well pad, from the time the rig arrives on the pad until the time it leaves, you're thinking about on average about 120 days, plus or minus 10 days, depending on operational issues and just adding a little cushion for modeling.

And then immediately after the rig leaves, we move in the completion crews and begin completing those four-well pads. So the rigs arrive throughout the quarter, so as you can imagine, several of them are on two-well pads, but for the most part, we're going to be looking at four and five-well pad well delivery going forward. So it's going to be lumpy. We're going to have a significant increase in completions from Antelope in particular during the second quarter.

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Q

Okay. And just last for me. This is completely different. But what are you guys projecting at this point in terms of the IRRs for the Pinedale?

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

A

The typical Pinedale well, even with ethane rejection, is still a mid-teens IRR at current gas prices or a little better. And there is also, obviously, economic benefit to Field Services that's not cross-counted, if you will, in the returns for the upstream business.

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Q

So you're not capturing the NGL – the incremental NGL uplift in that return?

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

A

No, the NGL uplift is in the return for the E&P company, but there's additional revenue and return that benefits Field Services from their processing fees and from their gathering fees for water, condensate and gas that are not reflected in the well returns at the field level for QEP Energy.

Brian Lively
Analyst, Tudor Pickering Holt & Co. Securities, Inc.

Q

Okay, I understand. Thanks, Chuck, for all the comments.

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

A

Thanks, Brian.

Operator: Our next 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.

Richard J. Doleshek
Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.

A

Hi, Brian.

Brian Corales
Analyst, Howard Weil

Q

To follow through on the Bakken, can you maybe talk about an average number of completions a quarter? I know it's going to vary, but to help us kind of model production going forward?

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

A

Give me a second to kind of work through the math. I mean, I think we talked about on the Antelope – I'm looking at Jay Neese here to help me with some numbers. The average number of completions for the quarter for the Antelope property...

Jay B. Neese
Executive Vice President, QEP Resources, Inc.

A

It'll probably be about five or six through the second quarter.

A

Right.

Jay B. Neese
Executive Vice President, QEP Resources, Inc.

A

And probably about the same each quarter.

Brian Corales
Analyst, Howard Weil

Q

Okay. Okay.

A

[indiscernible] (32:58)

Brian Corales
Analyst, Howard Weil

Q

Okay. And what would be a normal backlog – I mean I understand that the pad drilling and you have several wells drilling in process throughout. But what would be a normal backlog of waiting on completion and drilling? Is it what you currently reported for this quarter? Or is that a little bit higher than what you expect going forward?

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

A

Well, if you have five rigs running – I'm just going to focus on the Antelope property. You have five rigs running at any given time, there's probably two to two and a half wells trapped under each rig, up to four wells as a rig moves off. But if you think about it in terms of 5 rigs running, there's probably 10 or 12 wells at any given time that are trapped under a rig because you're going to have – each rig is going to be finishing up a four-well pad and moving, and you'll have another pad commencing but you'll be able to expose those four wells and complete them.

Brian Corales
Analyst, Howard Weil

Q

Okay. And then just one more. I'm assuming it's the Bakken realizations that were pretty strong. Oil prices for the quarter I thought were very good. What – are you still seeing that currently with the spread coming in quite a bit? Or can you talk about where your – what your Bakken realizations are looking like, say, already in the second quarter?

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

A

Well, as a percentage of WTI, they continue to be quite strong. Obviously, the overall price has decreased as a result of the overall crude oil curve sliding back some. Richard, do you have a current number for the quarter? Do you remember?

Richard J. Doleshek
Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.

A

Yeah. I think we're going to be really close to WTI on average because of the 8,000 barrel a day uplift we're getting...

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

A

From the Brent...

Richard J. Doleshek
Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.

A

Brent, offset by what happens to us in the Uinta. But we're going to be pretty close to WTI. I'd say plus or minus a few dollars.

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

Right.

Brian Corales
Analyst, Howard Weil
Q

Okay. All right, guys. Thank you.

Richard J. Doleshek
Chief Financial Officer, Treasurer & Executive VP, QEP Resources, Inc.
A

Thanks.

Operator: Our next question comes from the line of Subash Chandra with Jefferies. Please proceed with your question.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.
Q

Yeah. Hi. Good morning. First, Chuck, on South Antelope again, I was curious, the 2P reserves, how long do you think it would take to convert that 2P inventory into 1P?

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

Well, let's just make sure we're talking about proved versus probable. And at the end of last year, we booked a fairly significant portion of the reserves as probable in part because, as you'll recall, the previous owner had focused on developing the Three Forks. So while we had well control through the Middle Bakken, we only had a handful of wells on the property that were completed in the Middle Bakken, and therefore, not a lot of production data.

As we go forward with pad development and establish four-well-per-reservoir-per-1,280 spacing unit, we'll get comfortable with booking more and more of the Bakken as proved. Will we convert 100% of it this year? Probably not. We'll probably a get good ways there. But it doesn't make any more money to convert it from probable to proved. And as we get more well performance and more control across the acreage, we'll get comfortable booking it and I'm sure that our independent reserve valuators will as well.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.
Q

The $1 billion of PUD conversion dollars in 2013, I guess the majority will be at South Antelope?

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

There's a fair amount at Pinedale as well, just thinking about it, because we have a fair number of locations at Pinedale that are not booked as proved that we're drilling. And – but the vast – over 50% of our capital is going to the Bakken and a large number of locations that we're drilling, especially in the Middle Bakken reservoir, are not booked as proved this year. So probably 75% of that capital will go to development of unbooked locations.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.

Q

Okay, got it. Your 10% – I think formally you said 10% decline in dry gas volumes, has that view changed with what happened in Q1?

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

A

No. No, I mean the Haynesville decline, which is really the primary driver because we have no drilling activity there, that volume is – the performance of the field overall and the volume decline there is about what we expected. The biggest single driver in our revised guidance is strictly the roughly 7% to 8% impact of ethane rejection in the Rockies. And that's really the only thing that's changed our view from year-end to the end of the first quarter is that we're not optimistic that ethane prices are going to be high enough or the frac spread is going to be attractive enough to recover ethane. So we revised our guidance accordingly.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.

Q

Okay. And just one final one here on the asset sale. So just trying to get a sense of was the PRB sale the entirety of the $145 million? Or where would there be [indiscernible] (38:36)?

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

A

No, there were some other non-core Rockies assets that were sold in a separate transaction.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.

Q

Okay. And any sense of proportion there and...

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

A

I'd rather not get into details.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.

Q

Okay. And just one final one on that, how many buyers in total did you have for the $145 million?

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

A

There were a total of two buyers, two separate transactions.

Subash V. Chandra
Analyst, Jefferies & Co., Inc.

Q

Okay. Thank you very much.

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

A

Thank you.Operator: Our next question comes from the line of Trevor Seelye with Wells Fargo. Please proceed with your question.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC
Q

Hey, good morning.

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

Hi, Trevor.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC
Q

Hey, just a follow-up on Subash's question there. I think SM announced that they added about 40,000 acres. I think you guys had a little more of that in the Powder. Does that mean that you still have some Powder assets that you're marketing?

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

I think that the sale that we made is the entirety of our assets. And there may be a few leases that are outside of the core, but I don't – effectively, we have sold or we've entered into an agreement to sell the leases and properties that we have in the Powder.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC
Q

Okay. Thanks. And then in the Uinta, you talked about three horizontals that you completed in the quarter. Were those all Green River? And would you care to just give any color around those wells?

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

Yeah. They're completed in this very – we've talked about it in previous calls, these very relatively thin but very high-quality sands and freshwater limestones in the Green River formation, which contain oil that has never been touched by either primary development or water flood in the field area. And the wells are typically a couple of hundred barrels a day IP. They are 100,000 barrels of oil equivalent to 125,000 barrels of oil equivalent. They make 30% to 40% IRRs. They're obviously black wax because they're in the Uinta Basin. It's been a really very robust economic program for us. We've drilled quite a number of these wells and they're in reservoirs that if you just glanced at a well log, you would never think could produce 120,000 barrels or 130,000 barrels from a horizontal well. First, they're very thin. I mean in many instances, the porous interval is five or six feet thick, and we've been able to steer horizontal wells and stay in that porous zone. And they're quite predictable, at least in the areas where we've been drilling.

That's part of the program for this year. And we're, in fact, moving on one of those this morning to drill another one. But we also have a number of wells planned in the old Red Wash field. And if you'll recall back to our Investor Day in 2011, we highlighted the potential for additional development in the Red Wash field as we sort of took the field apart and put it back together and develop additional well control through the Mesaverde drilling program where we're drilling through the old oil field and into the underlying gas reservoirs.

We've identified what we think are significant opportunities for redevelopment. And we permitted wells and we'll be drilling a handful of wells, six or eight vertical wells, to evaluate some of these unproduced areas, unproduced reservoirs and unproduced areas of the Red Wash field during the rest of this year.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC

Q

Okay. Thanks. Very thorough. And can you talk about the black wax marketing there? I know that some of the refineries, there's been some expansions I think in the second quarter and can you just talk about are you guys having any issues with selling that crude there?

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

A

We're not having any issues. Obviously, black wax sells at a discount to WTI. Most of our volume, the vast majority of our volume, moves by pipeline. And you have to go back through the history of this area. These properties used to belong to Gulf and Chevron and ultimately Chevron. And so most of our oil moves on the Chevron-owned pipeline to the Chevron refinery, and it's been a relatively higher net back as a result of not suffering the additional cost of trucking. So we've been fortunate that we have a sort of physically-connected producing field to the refineries in the Salt Lake Valley. There are a number of projects underway, as you mentioned, to expand refining capacity.

There's also a project to potentially build at least an upgrader facility closer to the producing area, which would help. And there's actually some producers who are moving oil out of the sort of what I call a captive refining market in Salt Lake to other refineries on the West Coast and Gulf Coast by rail. And those – it's sort of early days for those projects, but there are opportunities to do that, not only for our E&P business but potentially for our Midstream business to be involved in that business as well.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC

Q

Okay, great. Thanks. And just last one for me. On Iron Horse II, how should we think about the volumes growing there through the year and maybe just overall how the processing volumes should grow?

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

A

Well, we've got – we haven't given asset-specific guidance. Obviously, we have a number of wells in the Mesaverde play that are on pads that are slated for completion starting in the second quarter. Third-party volumes, we don't have a clear view of their activity and their forecast. We talked to them. Their plans are in flux. But the important thing to remember about Iron Horse II is it is underpinned by minimum volume commitments, basically volumetric indemnity payments from third parties that are processing and QEP Energy actually has one with Field Services as well for those volumes.

Trevor P. Seelye
Analyst, Wells Fargo Securities LLC

Q

Okay. Thanks very much.

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

A

Thanks, Trevor.

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

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

Q

Thank you, folks. Good morning. If we could focus on the Pinedale Slide, number 9, on that slide, you illustrate the economic limit of the Pinedale. Can you refresh me on what goes into that economic-limit calculation? And what is that economic limit today?

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

A

So the economic limit at Pinedale – Dan, as you know, there's not a classical gas-water contact at Pinedale like there are in conventional fields. There's hundreds of different sand reservoirs. And what you see as you move down dip at Pinedale is a decrease in rock quality, and therefore well deliverability and ultimate recovery. And that line is basically an economic limit rather than a physical limit on gas accumulation.

So at $10 gas, the line maybe moves down dip a couple of well locations on 20-acre density. It moves up dip at $2 by a couple of well locations. And what you see drawn there is the limit at current pricing. Now, the interesting thing about this line is if you look at it, in particular on the east side, there are not a lot of wells that define the eastern limit going north on the anticline, and one of the things that we've seen is we've drilled a handful of wells along the margin is the line has moved out some. Not dramatically, but it's moved out to sweep in a couple of more locations on both the east side and the west side. And so even though we had 3D seismic here, we have a lot of well control relative to a lot places that we're operating, we're still refining that economic limit as we drill development wells going forward.

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

Q

Okay, got it. And in recognizing that we're talking about a different rock, a different reservoir, but if we were to turn to the Williston Basin and you were to apply that same calculation, is there an answer to that same question that is what is the economic limit of the Williston Basin talking about both the South Antelope area and Fort Berthold reservation [ph] profits (47:44)?

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

A

Yes. Got it. So Antelope is very clearly in a geological sweet spot. For both the Middle Bakken and the Three Forks reservoirs, it's over-pressured, high oil saturations relative to other areas, lower water saturation, so therefore lower produced water. So excellent wells across the whole acreage. So we don't see "an economic limit" there. But as you know, if you look at – if you get back at a much higher level scale, the Williston Basin has areas where well results in economics are challenged, either through total EUR of the well or through high water cuts.And if you go to our Fort Berthold acreage, as we know, because we have seen other wells drilled, we have been fortunate that we have not drilled one, but there is an eastern limit to the oil system there in both the Three Forks and in the Middle Bakken. If you look to the north of Fort Berthold along the eastern margin of the partial field, you can see a very, very clear deterioration in well performance. Not an absolute single line, but a very rapid deterioration from one horizontal well producing 300,000 barrels to 400,000 barrels of EUR, and then immediate next spacing unit having an uneconomic well that will be lucky to recover 50,000 barrels of oil.

That line has been very clearly delineated at partial. As we come down into the Fort Berthold acreage, we are delineating it, and I mentioned in my prepared remarks a well that came on at 860, 870 barrels of oil equivalent a day. That well was drilled near the – what we call the line of death on the Middle Bakken reservoir.

Because of our large leasehold – our large lease block on the Fort Berthold reservation, we have the ability to drill from the known to the unknown, so we can start on the west side of our acreage and push the limits to the east on both reservoirs. So that's what we're doing. And we don't have to drill every single spacing units to save leases. There are big leases there that allow us the flexibility to not have to go out and explore for that eastern margin.

So what you see from our well control that we have so far is a fairly well-defined line coming south, but we're not exactly sure where it goes as it goes across the southeastern quarter of our Fort Berthold leasehold. My guess is it's going to cut off part of that acreage. We're just not sure exactly where yet until we drill some more wells.

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

I understand. And then one last question from me, maybe more general, maybe more about corporate strategy. If you turn back to Slide number 3, which illustrates the company's operating areas, if we look out three to five years from now, can you comment on whether that math looks any different considering the upstream divestitures that have taken place and that may be contemplated going forward, that is, are you deeper in any one basin and maybe less wide overall?

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

We'd probably continue to focus in areas where we can put together acreage positions and assets that meet our criteria for resource play development. And that is contiguous acreage blocks where we can drive down cost through pad drilling. One of the frustrations for us in the asset that we've talked about earlier in the Northern region was our inability to block up a contiguous acreage block that would allow us to work the – what we think is a core skill set, which is pad development and resource – whole manufacturing, if you will, resource development.

The other frustration for us in the Powder River Basin, frankly, was that the Federal BLM permitting process has been at a standstill for quite a while now. And we saw no encouragement that that was going to change. So not to be able to control your own destiny is another challenge.

So as I look at opportunities, we have said we'd like to continue to look for bolt-on acquisitions in the Williston Basin. The Uinta and Western Wyoming Green River properties remain core to us. In the Midcontinent, as I said, we're not going to just give away properties in order to concentrate our efforts. And so we'll continue to look at the Midcontinent as a core area until such time as we either get an acceptable offer or we'll continue to own those properties and develop them going forward.

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

Very good. Thank you.

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

Thank you.

Operator: [Operator Instructions] 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, gentlemen. So I have a follow-up question on Bakken. I think you mentioned in your prepared remarks that the well cost target is around $11 million. And I was just wondering, can you tell us what kind of proppants are you using in that $11 million well cost? Because I remember you guys talking about a potential cost savings will be from ceramic to sand at the time of acquisition.

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

We're using dominantly sands, Hsulin, with the tail-in of some ceramic. It's a hybrid proppant mixture. If I said that our target is $11 million completed well cost, I misspoke. We're currently below $11 million. We averaged $10.8 million in the first quarter. I would hope that as we move to pad drilling and we continue to see improvements in drill times and just overall efficiency as we get a total of eight rigs running in the basin that we should be able to drive down well cost. My target is $10 million or less this year by the end of the year. It won't be instantaneous, but we're shooting for a well cost below that.

And I think it's important. We've gone back and looked at the well cost of pure play competitors in the basin, and what we see are similar well costs to the numbers that I've been discussing. And many of those wells are drilled in parts of the basin where pressures are lower, so mud weights are lighter; treating pressures are lower, so treating costs or simulation costs are less. And we don't see a big – we don't think that our costs are an anomaly. We see well costs from other operators that are similar to, if not higher, than ours, certainly, if you normalize for the drilling conditions and operating the extra pressure that we're encountering and extra drill times just because of the overpressure.

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

Okay, no, understood. And then my second question is regarding the production mix. I think on the previous call, you had mentioned around 30% liquids mix for 2013. And I was just wondering how we should think – if you can kind of help us for modeling purpose how the 25% from this quarter will evolve, especially given the ethane rejection for this year, how that will evolve to year-end.

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

Yes, so the liquid mix will change a bit because of our revision in our full-year estimate to stay in ethane rejection in the Rockies. I should point out in the Midcon, most of the plants are running in ethane-recovery mode now. There's a couple that are not, but for the most part, they're running in recovery.

The crude oil mix for the year we're thinking will be around 21%. NGL mix will be about 10%. And the remaining 70% will be gas. In the prior guidance we gave was a little bit lighter barrel, so about 19% crude oil and 13% NGLs when we assumed ethane recovery.

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

Okay. And is this a year-end target or the average for 2013?

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

That would be the production mix, cumulative volume mix for the year, if you will. So obviously, it's going to – the crude oil production is going to accelerate through the year as we ramp up activity in the Bakken.

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

Okay. Got it. And then in – also a question on your guidance. So given that you're assuming ethane rejection now, so we should – we'll get higher NGL price realization per barrel. So I'm assuming basically we'll just exclude ethane and including the other heavier NGL components. But in your guidance for EBITDA guidance, what are you assuming for that heavier component pricing?

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

Yeah, Hsulin, I'll have to get back to you. I don't have the component pricing. Greg Bensen can help you guys with that if you need the detailed breakdown. I'd point out, if you look at the pricing in the first quarter, we had a NGL barrel that was about $60 per barrel in the Northern region and $33 a barrel in the Southern region for an average of about $46 a barrel. So you can probably take that pricing relationship and drop that into your model.

It's about 50% of WTI. But you'll have to think of – as you model, you'll have to think about the change in production volume growth between the Northern and Southern region using that pricing relationship that I just mentioned.

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

Okay. No, that sounds good. I'll do that. That's it for me. Thank you.

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

Thank you.

Operator: Our next question comes from the line of Ben Wyatt with Stephens. Please proceed with your question.

Ben Wyatt
Analyst, Stephens, Inc.
Q

Yeah. Good morning, guys.

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

Hey, Ben.

Ben Wyatt
Analyst, Stephens, Inc.
Q

Just one quick question from me. But as everyone kind of talks about ethane rejection, there's not any risk with all the ethane rejection that's happening right now, no risk that so much ethane is put into the pipe that we meet the spec limits that the pipes can take on, is there?

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

A

No, not in the areas where we operate. In general, the average dew point spec is 20 degrees, and that allows full ethane rejection and still plenty of room, if you will. Cryogenic gas processing in the Rockies is a fairly recent phenomenon. And so most of the pipes in the area we're receiving gas that was either unprocessed or processed in refridge mode. And there are – go ahead, Perry.

Perry H. Richards
Senior Vice President-Field Services, QEP Resources, Inc.

A

I'll tell you, in the cryo processing, takes the dew point down to about a minus 100...

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

A

Right.

Perry H. Richards
Senior Vice President-Field Services, QEP Resources, Inc.

A

And so...

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

A

By ethane rejection, you're at...

Perry H. Richards
Senior Vice President-Field Services, QEP Resources, Inc.

A

About minus 50. It doesn't change it very much, so you're still easily meeting the dew point requirements of the pipeline.

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

A

So in certain parts of the country where pipeline blending, if you will, is an issue, i.e., your markets are very close to the producing area and relatively rich gas is being introduced with ethane rejection, you have a problem because the local distribution companies have, in many instances, tighter specs for liquid hydrocarbons or potential for liquid hydrocarbons in the system. So it becomes a problem in certain parts of the country. But in the areas where we operate, it's not a problem.

Ben Wyatt
Analyst, Stephens, Inc.

Q

All right. Very good. Well, that's all I had. Thanks a lot, guys.

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

A

Thank you.

Operator: And since there are no further questions at this time, I'd like to turn the floor back over for closing comments.

Charles B. Stanley

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

All right, everyone. Thank you very much for calling in today and for your interest in QEP. We look forward to seeing you as we are out on the road at conferences and in non-deal road shows.

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