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QEP Resources, Inc. *(QEP)*

Q4 2012 Earnings Call

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MANAGEMENT DISCUSSION SECTION

Operator: Greetings, and welcome to the QEP Resources Fourth Quarter Earnings Conference 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, sir. You may begin.

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

Thank you Christine, and good morning, everyone. Thank you for joining us for the QEP Resources fourth quarter and full-year 2012 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 estimated financial results, and the 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 will 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 statement disclaimer and discussion of the risks facing our business in our earnings release and SEC filings.

With that, I'd like to turn it 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 combined operations update and earnings release in which we reported fourth quarter and full-year 2012 operating and financial results; we reported year-end 2012 proved reserves; we updated operating activities in our core areas; and we updated our guidance for 2013. Chuck will provide more color on operating activities and outlook for 2013 in his prepared remarks.

Turning now to our financial results. In spite of headwinds with regard to natural gas and NGL prices, for the full-year 2012, we posted record results in a number of important areas, including EBITDA, crude oil, NGL and natural gas production, year-end proved reserve volumes and capital spending.

In comparing to the fourth quarter of 2012 to the third quarter of 2012, the story was substantially stronger financial performance at QEP Energy, our E&P business, and somewhat weaker results at QEP Field Services, our gathering and processing business.

QEP Energy reported record equivalent production of 83.9 Bcfe, up 3% from the third quarter of this year, and net equivalent realized prices that were 20% higher than in the third quarter, reflecting the rebound in prices from the middle of the year. But more importantly, the increased contribution from crude oil production in our revenue equation.

Field Services' third quarter results were lower than in the previous quarter, primarily due to lower keep-whole processing margins. From an EBITDA standpoint, we generated $1.4155 billion during the year, and the fourth quarter was the best quarter in company history. Our fourth quarter EBITDA was $391.8 million, which was $63 million or 19% higher than the third quarter of 2012 and up $1.3 million from the fourth quarter of 2011, our previous record quarter.

QEP Energy contributed $333.5 million or 85% of our aggregate fourth quarter EBITDA, and QEP Field Services contributed $57 million or about 15%.

QEP Energy's EBITDA was up $71 million or 27%, while Field Services' EBITDA was $11 million or 16% lower than their respective third quarter 2012 levels.

Factors driving our fourth quarter EBITDA include QEP Energy's production, which was 83.9 Bcfe in the quarter, 2.4 Bcfe higher than the 81.5 Bcfe reported in the third quarter of 2012. The quarter's production was 13.5% higher than the 73.9 Bcfe produced in the fourth quarter of 2011.

Of note, oil and NGL volumes accounted for 27% of our equivalent production. Oil volumes were 2.33 million barrels, up 62% from the third quarter, and NGL volumes were 1.44 million barrels, up 4% from the third quarter. Combined oil and NGL volumes were 3.8 million barrels in the quarter, up 34% from the 2.8 million barrels of combined volumes in the third quarter of 2012 and up 70% from the 2.2 million barrels of combined volumes in the fourth quarter of 2011. The step up in oil production in the quarter reflects the contribution of the oil properties we acquired in North Dakota in the third quarter.

Northern Region equivalent production was up 11% from the third quarter of 2012, driven by an 893,000 barrel increase in oil production. Southern Region production was down 5% from the third quarter, driven by an 8% decline in our Haynesville gas production but partially offset by a 13% in NGL production in our Midcontinent Division.

QEP Energy's net realized equivalent price, which includes the settlement of all of our commodity derivatives, averaged $6.17 per Mcfe in the quarter, which was $1.03 Mcfe higher than the $5.14 realized in the third quarter and $0.09 higher than the $6.08 per Mcfe realized in the fourth quarter 2011.

The higher equivalent prices reflect field-level prices that were $3.22 or 58% higher than the third quarter of 2012 and NGL prices that were $6.72 per barrel higher than the third quarter, and field-level crude oil prices that were $2.78 per barrel higher than the third quarter. Field-level crude oil revenues accounted for 44% of total field-level revenues, up 36% from the third quarter of 2012 and 27% in the fourth quarter of 2011.

QEP Energy's commodity derivatives portfolio contributed $74 million of EBITDA in the quarter compared to $90 million in the third quarter of 2012 and $66 million in the fourth quarter of 2011. The derivatives portfolio added $0.88 per Mcfe to QEP Energy's net realized price in the fourth quarter compared to $1.13 per Mcfe in the third quarter and $0.90 per Mcfe in the fourth quarter of 2011.

QEP Energy's combined lease operating, transportation and production tax expenses were $145 million in the quarter, up from $125 million in the third quarter of 2012 and $122 million in the fourth quarter of 2011. On a per-unit basis, lease operating expenses were $0.60 per Mcfe, up $0.07 from the third quarter, reflecting the increase in production from oil properties.

Transportation expense was $0.72 per Mcfe, down $0.01 from the third quarter, but production taxes were $0.40 per Mcfe compared to $0.27 per Mcfe, reflecting higher field-level prices in the quarter and more production in North Dakota, which has a relatively higher severance tax rate.

Finally, QEP Field Services' fourth quarter 2012 EBITDA was $57 million, which was about $11 million lower than the third quarter of 2012 and $30 million lower than the fourth quarter of 2011, which, due to incredibly robust keep-whole processing margins, was a high watermark for our Midstream business.

Processing margin was down $5.7 million or 16% from the third quarter as a result of a 31% decline in NGL sales volumes but 28% higher realized NGL prices, reflecting our plants operating in the ethane rejection mode.

Gathering margin was down $4.1 million or 10% in the quarter compared to the third quarter of 2012 on 8% lower gas gathering volumes, which had an average gathering fee of about $0.345 per MMBtu and slightly higher operating expenses.

We reported a net loss in the quarter of $23 million, driven by an accrual for the pending settlement of our Oklahoma class-action royalty litigation, a $58 million impairment of producing properties, offset by a $30 million gain in the mark to-market value of our derivatives portfolio.

Sequential DD&A expenses were up $23 million to $258 million as a result of increased production from our Williston Basin properties, reflected in North Dakota Acquisition. For the year, we reported capital expenditures, including acquisitions, on an accrual basis of $2.9 billion. Capital expenditures for E&P drilling and completion activities were $1.3 billion, while that equals expenditures in 2011.

Capital expenditures in our Midstream business were $171 million in the year or about $70 million more than 2011. In addition, we spent $1.4 billion on acquisitions of oil and gas properties during the year. Excluding acquisitions, our capital spending was $89 million more than in 2011. We reported a record 3.9 trillion cubic-feet equivalent of proved reserves at year-end 2012, a 9% increase from 3.6 Tcfe we reported at year-end 2011.

Crude oil and NGLs comprised 33% of total equivalent reserves, up from 24% at year-end 2011. And proved developed reserves accounted for 54% of total proved, about the same as last year. We had 314 Bcfe or 52 million barrels of oil equivalent of proved reserves as a result of the North Dakota Acquisition and 410 Bcfe of proved reserves as a result of development activity in the Uinta Basin and in Pinedale. And we lost reserves in Haynesville as a result of lower gas prices.

The standardized measure of future cash flows for year-end 2012 proved reserves was $3 billion, down from $3.5 billion last year. And the before-tax value at year-end 2012 was $4 billion compared to $4.8 billion last year.

With regard to our balance sheet, at the end of the year, total assets were $9.1 billion and shareholder equity was $3.3 billion. Total debt at the end of the year was $3.2 billion, which was a 1.2 times (sic) [2.1 times] (9:59) multiple of our trailing 12-months' EBITDA pro forma for the acquisition. Our debt at the end of the year consisted of $2.2 billion of senior notes, $300 million drawn under our term loan, due in 2017, and $690 million drawn under our $1.5 billion revolving credit facility that matures in 2016.

Finally, in January, we announced that the board had approved the formation of an MLP and the preparation and filing of a registration statement with the SEC for an initial public offering of the MLP's equity securities. We continue to work on that project as well as a number of other strategic initiatives, including upstream asset sales. And Chuck will discuss our thinking about those projects and our strategy to delever the balance sheet in his prepared remarks.

I'll now turn the call over to him.

Charles B. Stanley

Chairman, President and CEO, QEP Resources, Inc.

Thanks, Richard and good morning. Richard's already reviewed our fourth quarter 2012 results and full-year financial results. I'll try to add a little color, give you an update on our plans for 2013 and then move onto Q&A.

Before I do, I want to correct something I think I heard Richard say regarding our debt multiple. I think he switched the number. It should have been 2.1 times instead of 1.2 times. He's made his first mistake on a call. So, anyway, first some highlights. QEP Energy grew production 16% in 2012 to record 319.2 Bcfe on or average of 872 million cubic feet of gas equivalent per day, driven by good results across our entire operation.

Fourth quarter 2012 production was a record 83.9 Bcfe, a 14% year-over-year increase. We're making excellent progress in growing our crude oil production. QEP Energy crude oil production totaled 6.3 million barrels in 2012 compared to 3.7 million barrels in 2011, which was a 69% increase. And that growth is accelerating. Thanks, in part, to our North Dakota Acquisition, fourth quarter 2012 crude oil production totaled 2.3 million barrels, a 97% increase over the 1.2 million barrels we produced in the fourth quarter of 2011 and a 62% increase over the 1.4 million barrels that we produced in the third quarter of last year.

In total, more than half of QEP Energy's field-level revenue was from crude oil and NGL sales in 2012. And as Richard noted, the percentage of our proved reserves, represented by crude oil and NGL year-end 2012 continues to grow. For 2012, QEP Energy grew Southern Region production 5% from 2011 levels to a record 161.6 Bcfe.

Midcontinent production, driven primarily by their liquids-rich Cana, Granite Wash, Marmaton and Tonkawa plays was 49.3 Bcfe for 2012, up 7% from a year ago. Production from the Haynesville/Cotton Valley was 112.3 Bcfe in 2012. That's a 4% increase over the year-earlier period.

Southern Region crude oil and NGL production increased 35% in 2012 to a total of 3.1 million barrels, and crude oil comprised 47% of the Southern Region total liquids production. In the Northern Region, production totaled 157.6 Bcfe in 2012, a 30% increase over the year-earlier period.

Northern Region production growth was driven by a 185% increase in Williston Basin volumes, thanks, in part, to our acquisition, which closed on September 27 of last year, but also due to strong organic growth from ongoing development on our Fort Berthold acreage in the Williston Basin. Pinedale production was up 26% and Uinta Basin volumes were up 15%.

Northern Region crude oil production totaled 4.9 million barrels in 2012. That's a 71% increase over 2011. And combined, Northern Region crude oil and NGL production was 8.6 million barrels. That was up 105% from 2011 levels. In total, crude oil and NGL represented 33% of Northern Region production.

As Richard noted, QEP Energy reported total proved reserves of 3.9 trillion cubic feet of gas equivalent at the end of 2012, and that's a 9% increase over the 2011 year-end numbers. Despite relatively modest negative revisions totaling 245.7 Bcfe, we replaced 201% of our 2012 production.

Turning to our Midstream business. QEP Field Services had a good year operationally, but our gas processing business was clearly negatively impacted by the decline in NGL prices. While total NGL sales volumes were up about 3% for the full year, ethane prices declined through the year, forcing QEP Field Services to begin rejecting ethane late in the third quarter. Lower NGL prices for keep-whole processing margins, which were down 35% in 2012 to $79.4 million, compared to $121.5 million in 2011.

The impact was particularly pronounced in the fourth quarter, when keep-whole margins declined 63% from the year-earlier quarter. The decline in keep-whole margins was partially offset by a 40% increase in fee-based processing revenues, with our Blacks Fork and Iron Horse processing plants delivering 42% and 32% of those fees respectively.

While Field Services results were weaker due to the decline in NGL prices, keep-whole margin represented just 25% of QEP Field Services total Midstream margin, or 23% of Field Services net operating revenues. And while the impact of ethane rejection on NGL volumes may be substantial, because of the very narrow ethane frac spread over the past several quarters, the financial impact of ethane rejection on keep-whole margins is actually quite small.

Throughput on Field Services gathering systems grew to 506.5 million MMBtus in 2012, up from 495.4 million MMBtus in 2011. Field Services gathering margins declined about 7% in 2012 to $172.1 million, primarily due to the cancellation of a third-party processing arrangement. You'll recall that we entered into a short-term interruptible processing arrangement with a third party to process growing Pinedale volumes prior to the startup of the Blacks Fork II plant in 2011.

Revenues from this arrangement were reported as other gathering revenue in order to keep our QEP Field Services processing revenues segregated in our financial reporting. And those other gathering revenues associated with this special processing arrangement totaled $33 million in 2011. And the gathering expense line included $10.8 million associated with the make-up gas for this contract. Excluding the impact of cancellation of this contract, our gathering margins actually increased 6% year over year.

Turning back to QEP Energy activity, we gave you a lot of details on our current drilling activities and results in our release yesterday, so I'm not going to repeat all that information. Greg's already pointed you to the slides on our website. In North Dakota, we currently have seven rigs working in the Williston Basin. Four of the rigs are working on our newly acquired South Antelope properties, up from two at end of the year. All four of these rigs are skiddable rigs that are equipped for pad drilling. Two are placements for the non-skid-capable rigs that we inherited when we closed on the property back in September.

We were able to staff two of the new rigs with crews from our recently released Pinedale rigs. These are teams of drilling hands that have worked together for quite some time and have a great record of safe and efficient execution for QEP at Pinedale. We plan to add one more rig, bringing the total to five at South Antelope by midyear.

Since our third quarter call, we've made good progress on our filings with the North Dakota Industrial Commission for approval of increased density drilling on our South Antelope property. Our plans are to develop the acreage from an average of two four-well pads per 1,280-acre spacing unit; typically, with four Bakken and four Three Forks horizontal wells per 1,280-acre spacing unit.

During the quarter, we completed and turned to sales two new QEP-operated Three Forks Formation horizontal wells on the new South Antelope property. The performance of both of these wells matched our pre-drill expectations, with average 24-hour initial production rates of 2,175 barrels of oil equivalent per day, and we forecast estimated ultimate recoverable reserves on these wells of a little over 1 million barrels of oil equivalent.

We've made changes in the well design at South Antelope that we believe will allow us to deliver $11 million gross completed or lower well costs going forward on this property. See Slides 6 and 7 in the slide deck for more detail on South Antelope.

On our Fork Berthold acreage, we completed in turned to sales nine new wells during the fourth quarter, four Middle Bakken wells and five Three Forks wells. Seven of these wells were on or adjacent to the Independence Pad in the northwest corner of our acreage, and all of them had excellent 24-hour IPs of 2,400 to 2,900 barrels of oil equivalent per day. There were two wells that we are drilled on the eastern edge of our acreage, and those had lower IPs, around 900 barrels of oil equivalent a day. And that's not surprising, given their location toward the margin of the – or the pinch-out of the Bakken/Three Forks on the eastern part of our acreage.

During the quarter, we were able to deliver completed well costs on the reservation at a gross average cost of about $11 million, and that's a total cost, drilled, completed, equipped and turned to sales. These numbers are in line with or better than the completed well costs for outside operated wells in the same area. We currently have three wells running on the Fort Berthold acreage. You can see Slide 8 for the location of the wells that we completed during the fourth quarter for additional details.

You may have noticed in our release yesterday that we reported some Brent crude oil derivatives. To add some diversity to our Williston Basin crude oil markets, we've also entered into a Brent-based physical sale contract for 8,000 barrels a day. That's an important sort of market diversity focus for us to get exposure, not just out of LLS, but out of other markets.

Turning to Pinedale, we completed 102 new wells during 2012. We currently have four rigs running at Pinedale, three drilling QEP working interest locations and another rig that's drilling on acreage where we operate but we have only an overriding royalty interest. See Slide 9 for details of Pinedale.

In Uinta Basin, we continue to make good progress on our Red Wash Lower Mesaverde liquids-rich gas play. During 2012, we completed 37 new wells in this play. We currently have a seven-well pilot program underway to evaluate the viability of 10-acre well density for full-field development. We have two rigs currently working in the Uinta Basin. See Slides 10 and 11 for more details.

In the Midcontinent Division, during the fourth quarter, we finished drilling, and over a year in, we were in the process of completing and turning to sales eight new 100% working interest QEP-operated development wells in the core of the liquid-rich portion of the Cana Shale play, where we're focused on drilling up our leasehold on 80-acre density.

Net production from this pod of eight wells is currently about 40 million cubic feet of gas equivalent per day, and about 40% of that production volume is liquids. We have eight additional 80-acre density wells on a nearby section that are scheduled for completion in late April or early May. We have a 75% working interest in this group of wells. See Slide 12 for more details.

In the Granite Wash, we participated with a small working interest in six outside operated horizontal Kansas City Lancing wells during the fourth quarter. We also drilled a QEP-operated Cherokee Formation horizontal well during the quarter, and it was cased and awaiting completion at year end.

We also had a QEP-operated Caldwell zone horizontal well that was drilling at year end. Both of these wells are currently being completed. All of these Granite Wash wells in the various horizons target liquids-rich gas and crude oil. Slide 13 gives more details.

Finally, as you know, we ceased drilling activity in the Haynesville Shale play early in the third quarter of last year. To take advantage of the contango in the forward gas price curve, we elected to defer completion of the last five wells we drilled and cased in the Haynesville until early this year. While gas prices are still relatively weak, the six-month strip today is about 25% higher than it was when we chose to defer these completions. So it was the right decision. Those wells are now completed and are turned to sales. Slide 14 has details.

While we're talking about the E&P business, I think it's worth spending a moment on how ethane rejection impacts our financial and operational results. Just a reminder, when we extract NGLs from the gas stream, the gas shrink volume in cubic feet doesn't decrease as much as the volume of extracted liquids, on a six-to-one basis increase is reported natural gas equivalent production.

So when we leave ethane in the gas stream, the total gas equivalent volumes produced decreases by about 7% for both Pinedale and in our Red Wash Mesaverde play. But here's the interesting part. While $0.01 a gallon swing on ethane frac spread triggers ethane rejection, ethane rejection has de minimis impact on our financial results because remember, we're still selling those ethane molecules. We're just selling them in the natural gas stream for natural gas prices instead of extracting them and selling them as a separate product.

But remember that ethane can have a noticeable impact on reported production volumes. That's why it's important to keep in mind this concept when you're thinking about revenue and value versus reported production volumes.

At Field Services in January, we completed construction of the Iron Horse II processing plant. It's a 150 million cubic-foot-per-day cryogenic gas processing plant that's located in Uinta Basin of Eastern Utah. We began commissioning and start-up the plant in late January and early February, and it is making liquids as of this morning.

About half of the capacity in this new plant is contracted to a third-party producer under a fee-based processing arrangement, while the other half was processing QEP Energy's gas volumes from the Red Wash Lower Mesaverde play under a fee-based arrangement.

At our Backs Fork (sic) [Blacks Fork] (25:21) complex in Western Wyoming, construction continues on our 10,000 barrel-a-day expansion to our existing NGL fractionation facility. The expanded facility is designed to provide additional options for marketing purity propane, iso and normal butane and gasoline-range products to what are oftentimes premium-value local, regional and national markets. And we can access these markets either via truck or from our expanded rail-loading facilities at the plant. We currently expect the new fractionator to be in service toward the end of the second quarter of this year.

Now let's look forward to the remainder of 2013. You'll note we haven't significantly altered our capital allocation from our initial guidance that we gave last year. We've allocated about 53% of QEP Resources forecasted capital program to a higher return – to the highest-return project in our portfolio, which is our Bakken/Three Forks crude oil development. This program assumes we ramp up to an eight=rig drilling program on the Wilson Basin assets by midyear.

At Pinedale. we anticipate running three rigs on QEP working interest locations, down from a peak of six last year. We also have one additional rig at Pinedale that's drilling wells for our former affiliate, Wexpro.

Pinedale will get roughly 14% of the QEP Resources capital allocation in 2013. The Granite Wash play in the Midcontinent, along with the Cana, Tonkawa and Marmaton programs will receive we see about 17% of QEP Resources total capital, driven in large part by the high level of anticipated non-operated drilling activity in this plays. While the Uinta Basin will attract about 6% of total capitals, we continue development of the Lower Mesaverde liquids-rich gas play and Green River Formation oil development.

We expect Field Services capital investment to decline in 2013, as we complete the Iron Horse II plant early this year and the Blacks Fork fractionator expansion around midyear. Slide 3 and 4 will give you some additional detail on the capital allocation.

As I said last quarter, we view that this is a pivotal year for QEP, as we dramatically shift the production mix from one dominated by natural gas to one that is more balanced between natural gas, oil and NGLs. For 2013, we forced overall – we forecast overall production growth on a six-to-one basis to be modest at about 4%. But crude oil production will likely grow about 70% over 2012 volumes, and NGL volumes will be up over 30%. And as we've indicated previously, with no drilling activity in our Haynesville division, we forecast that dry natural gas production – just from that area, alone – will decline about 30%, from about 110 Bcfe in 2012 to about 75 Bcfe in 2013.

As a result, we think that our dry gas volumes at QEP Energy will be down about 10% in 2013 compared to last year. While we don't run our planning process or manage our business for absolute production growth target, we do realize that some of you focus on production growth. I would argue, as I did last quarter, that to properly value each component of the production stream, a 20-to-1 natural gas-to-liquids equivalency ratio is a more appropriate way to look at our production volumes and that of all of industry, for that matter. And if you do that, QEP's year-over-year production growth for 2013 would be a little over 20%.

I'd also like to state – just clear up a little confusion over the comments I made in last quarter's earnings call regarding our debt reduction plans. While we're engaged in a process to reduce our debt levels and leverage ratios, we do not have an absolute goal for proceeds or debt multiple in mind within a defined time period. Long term, as we've said many times to most of you on this call, we're most comfortable at a modest leverage ratio of about one point times debt to EBITDA. But we're committed to doing what's best for shareholder value creation. And if that means it takes us a little longer to get to that level, we're entirely comfortable in that scenario.

As I discussed last quarter, we've identified some upstream assets for divesture. That process is underway. We have data rooms open. We'll have more details on that process and any results in our next quarter call.

So in summary, despite some continued challenges in the natural gas markets, we believe that QEP, through continued investment in our high-quality E&P portfolio and in our complementary Midstream business, is well positioned to drive profitable growth long term for our shareholders 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 to the Q&A portion of the call, I want to remind you of the status of our Field Services business. On January 7, 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've 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, Christine, let's open the line for questions.

QUESTION AND ANSWER SECTION

Operator: Thank you. We will now be conducting a question-and-answer session. [Operator Instructions] . Thank you. Our first question comes from the line of Brian Corales with Howard Weil. Please proceed with your question.

Brian M. Corales Q
Analyst, Howard Weil, Inc.

Good morning, guys.

Charles B. Stanley A
Chairman, President and CEO, QEP Resources, Inc.

Hey, Brian.

Brian M. Corales Q
Analyst, Howard Weil, Inc.

A couple questions on the Bakken. Chuck, I think you talked about getting to $11 million or potentially below. Can you talk about where you're seeing the cost trends, and kind of what's the major effect? And how low – I mean can you get to $10 million, or where do you see the cost side going?

Charles B. Stanley A
Chairman, President and CEO, QEP Resources, Inc.

Good morning, Brian. Well when you said $10 million, Jim Torgerson started nodding his head, so I'm going to say $9 million or less. So thank you for that. I'll send you a gift card in the mail. No...

Brian M. Corales Q
Analyst, Howard Weil, Inc.

I love food.

Charles B. Stanley A
Chairman, President and CEO, QEP Resources, Inc.

So the – I think several key avenues to driving down completed well costs, obviously, drilling cycle time is one way that we can do it. And moving to pad drilling exclusively, both on the South Antelope property and continuing to do it on the Fort Berthold property. We minimize the time between TD on one well and spud of the next well using skid-capable rigs. We've spent some time, what seemed like a long time to me, identifying and moving in the right rigs and getting experienced crews to man those rigs, all of which help on the drilling cycle time side.

In addition, with pad drilling, we'll achieve some efficiencies around completions by being able to stimulate multiple wells back to back. So we'll minimize de-mobe costs on frac crews. There's also additional savings as we move to full-field development, especially on South Antelope, because of the compact nature of the property, a contiguous acreage position that we've acquired. Just logistics, moving equipment, moving frac water, handling, flow-back water, all of those things which add to the cost of the completed well, will be minimized. And so I'm optimistic that with the team of talented folks we have in our drilling/completion shop that we'll be able to put strong pressure downward on costs. And that's ignoring any inputs as far as day rates – rig day rates, additional savings that we have in terms of completion services, et cetera. That's just talking about our abilities and our track record of being able to drive down costs through increased efficiency and lowering cycle times.

Brian M. Corales
Analyst, Howard Weil, Inc.

Q

And just a further Bakken question. You talked about getting Brent hedges on – are you railing most of your crude? And can you maybe talk about your realizations; what you've seen, I guess, maybe fourth quarter and what you're likely going to see in 2013?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

The answer is, we have multiple markets for our crude. Some of it's being railed; some of it's going by pipe. We're getting a mixture of Clearbrook and LLS. And now, starting in January – late January, Brent related pricing. The average realizations, I don't have that number in front of me, Richard, for the fourth quarter.

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

A

$84.07 a barrel, fourth quarter.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

$84.07 a barrel for the fourth quarter.

Brian M. Corales
Analyst, Howard Weil, Inc.

Q

Okay. And one more and I'll hop off. You talked about four-well pads – two four-well pads per drilling unit. Could you – or y'all plan to test, go – down-spacing further? I think some other operators are doing that or have done that. And just kind of curious on your thoughts there.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

We may. We don't have any plans to pilot any closer together now. Although I would tell you that we have de facto done that to the east on the reservation where we have drilled some fan-shaped pads because of the configurations of the pads and the lake bottom. So we have drilled wells that at the toe are well more than 80-acre space. But at the heel, the closest portion before the vertical part of the well, they are very close together because they all emanate from the same pad and have drilled out in a radial pattern from that pad.

We're looking at the performance of those wells to see if we can see signs of interference. Obviously, it's very difficult to determine exactly where in the wellbore we're seeing interference or if we're seeing interference at all. But that is an example where we have drilled on closer density.

From our original modeling of the acquisition on South Antelope and our analysis of oil in place versus recoverable oil, we think that the right well spacing is four wells per reservoir, per 1,280-acre spacing unit. But obviously, we remain open-minded about increased density beyond that.

I should also point out, while we're talking about pad drilling, that obviously, it introduces some lumpiness in the production stream as we bring additional wells on line. So there'll be a delay while we drill four wells, case them and then get the rig out of the way before we can start completion operations. I just want to remind everybody that it's not going to be a well-by-well, instantaneous delivery of production as we go forward with full-field development on the South Antelope property.

Brian M. Corales
Analyst, Howard Weil, Inc. Q

All right. Thanks, guys.

Operator: Our next question comes from the line of David Tameron with Wells Fargo. Please proceed with your question.

David R. Tameron
Analyst, Wells Fargo Advisors LLC Q

Morning. Chuck, you mentioned the Bakken. Did you say you've already swapped out all the rigs, and you have that process complete? Or is that still ongoing?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc. A

We have now seven rigs operating, three on the existing Fort Berthold property, four on the South Antelope property. We have one more to go. The rigs that we have operating there now are all rigs that we want to keep, and we're looking for an eighth rig.

David R. Tameron
Analyst, Wells Fargo Advisors LLC Q

Okay. So you plan – you'll be at eight rigs?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc. A

By midyear.

David R. Tameron
Analyst, Wells Fargo Advisors LLC Q

No, that's fine. The – and I don't know if, Richard, if you mentioned this – did you mention a PV-10 number? And if so, can you repeat that? And if you didn't, could you give us one?

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

Yeah. The SEC standardized measure was $3 billion. The pre-tax SEC value is $4 billion.

David R. Tameron
Analyst, Wells Fargo Advisors LLC Q

Okay. Chuck, you mentioned the ethane rejection, the 7% up – or the 7% decrease in absolute BOE type. Can you – given you've been known – someone called you Professor in the past – can you give us a 60-second basic 101 lecture on how that math works, the mechanics of it?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

Probably rather than being professorial on the call, what we can do is post an example calculation on our website. And then if you have questions, either Greg Bensen or I or Perry Richards would be happy to walk you through the math.

But it's relatively simple. If you think about it in terms of the MMBtu value of ethane, when you take a barrel of ethane out of the gas volume, that barrel, on a six-to-one ratio, when you convert it back to Mcfs is greater than the shrink or the physical reduction of the Mcf when you extract it. So when we go into ethane recovery mode, we see – and fortuitously, it's the same at Pinedale as Uinta, even though the composition of the barrel is slightly different between the two. You see about a 7% increase in reported volumes on an Mcfe basis when you go in to ethane recovery or, conversely, a 7% shrink when we're rejecting ethane. The number of BTUs that we're selling doesn't change.

So it's – as I've said in my prepared remarks, a $0.01 change – if we just had two assets, the Uinta Basin, Mesaverde and Pinedale, a $0.01 change in ethane prices could result in us making an economic decision to either sell the ethane as a separate product or to sell it as natural gas. And it, alone, could have a 7% impact in our reported production volumes on an Mcfe basis.

And the key point there is, I think, some people forget that when we go in to ethane rejection mode, we're still selling those BTUs. We're just getting natural gas prices for them instead of a separate product, which we would be extracting and selling, hopefully, for a higher value. There's another benefit. You use a little bit less fuel in your processing plant when you're running in ethane rejection mode than in recovery mode. But you also give up a slight amount of propane recovery when you're running the plant warmer in rejection mode.

But make sure, when you're updating your models and you think about rejection, that you don't just take out those MMBtus and not give us credit for selling them as natural gas. We just don't – and we struggle to forecast ethane going forward as far as whether we're going to be in recovery or rejection. And we can make that decision on a – literally, on a daily basis. Today, the plants are running in rejection mode.

Seasonally, we may see some strengthening in ethane prices as we go through the year. We just haven't been able to forecast it. And, therefore, we're just cautioning you, as you think about production volumes that they could swing fairly significantly. But the economic impact of that production volume swing is de minimis.

David R. Tameron
Analyst, Wells Fargo Advisors LLC

Q

Okay. And what have you guys assumed for your – or what should we assume is baked in your guidance for 2013 for ethane rejection?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

That we're in rejection all year.

David R. Tameron
Analyst, Wells Fargo Advisors LLC

Q

All year. Okay.

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

A

Been in recovery all...

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

Oh – I'm sorry – recovery all year.

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

A

Yeah.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

Recovery all year. Sorry.

David R. Tameron
Analyst, Wells Fargo Advisors LLC

Q

Okay. Okay. I'll let somebody else jump on. I'll jump back in the queue if I have a follow-up. Thanks.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

Thanks.

Operator: Our next question comes from the line of Brian Singer with Goldman Sachs. Please proceed with your question.

Andre Benjamin
Analyst, Goldman Sachs & Co.

Q

Thank you. This is actually Andre Benjamin on behalf of Brian. Good morning, guys.

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

A

Hi, Andre.

Andre Benjamin
Analyst, Goldman Sachs & Co.

Q

First question. During the fourth quarter, you drilled two wells in the Northeast and Central Western edges of the acquired Southern Antelope/Bakken acreage. The slides indicate you're currently drilling two in the middle of that acreage now. After those two are done, do you think the acquired acreage is effectively de-risked? And where do you actually plan on concentrating your drilling activity in the Fort Berthold versus Southern Antelope part of the acreage over time?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

So if you'll refer to Slide 7. So, first of all, there are wells – producing wells across the entire South Antelope acreage, most of which targeted the lower of the two producing horizons, the Three Forks, simply to say – to make sure that all the leases were So in my mind, the Three Forks is pretty much completely de-risked. It's all, obviously, held by production. And even though we only have a handful of producing wells on our acreage producing from the Bakken, there are a number of producing wells around the periphery. And each of the Three Forks wells, each of the producing wells on our acreage drilled through the Middle Bakken on its way to the ultimate target in Three Folks, so we have well control on the Middle Bakken.

Going forward, Andre, our plan is to set up – where you see that cluster of blue stars along that section line or that unit boundary – and drill wells to both the north and the south from pads, and basically go through a very orderly development of our acreage, starting in the middle and sort of working our way out to the south and to the north as we drill from four-well pads going forward.

And then on the Fort Berthold side, we will continue to – if you turn to Slide 8, you can see the location of currently drilling wells. And we're going to just continue the orderly development of our acreage starting in the north and coming around the eastern boundary of our acreage and back down to the Southwestern Panhandle.

Andre Benjamin
Analyst, Goldman Sachs & Co.
Q

Thank you. And then how should we think about drilling activity in your dry gas plays if gas prices were to stay right at the $4 MMBtu? Given the focus on Bakken and growing liquids, how quickly could we see you allocate some capital to those plays? And would you add hedges at that level?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.
A

So two questions. First, the true dry gas asset in our portfolio is the Haynesville. We've said before that we think it takes a $4.50 per MMBtu gas price or higher to support a full development program there. And one of the keys that – the way I think about it, the real decision is – it's not a decision just to add a rig back to the Haynesville. In order to get the economies of scale, we probably need four or five, maybe even six rigs running in the Haynesville to get the economies of scale necessary to keep completed well costs down.

So it's really a $300 million or $400 million capital allocation decision that we would need to make. And for the foreseeable future, certainly, this year and likely next year, it would be tough, in my mind, for us to pull capital away from things like the Williston Basin and some of our more liquids-rich gas plays and allocate to dry gas in the Haynesville.

Relative to your question on hedging or using derivatives to protect gas prices, it's an asset-by-asset decision. Obviously, we can look at the Pinedale well economics and begin to put some additional hedges on that will give us very acceptable returns on invested capital for new Pinedale wells, even if, on the current forward curve we have not been super-aggressive in doing so. Although we have a portion of our production already hedged. Haynesville, more difficult because it's a – in my mind, on the bubble. As I've said, we're not currently allocating any capital there. So we probably think a bit longer about layering on additional hedges in the Haynesville at current prices.

Andre Benjamin
Analyst, Goldman Sachs & Co.
Q

Thank you.

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

A

Thanks, Andre.

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

Folks, good morning.

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

A

Hi, Dan.

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

Q

If we could turn to the balance sheet, by my model, I show leverage not increasing over the balance of 2013; in fact, leverage decreases under a certain scenarios – and again, it's just my model. But assuming I'm correct, does that potential reality put less pressure on the company to pay down debt incurred last year with the Williston Basin acquisition? That is, do you become more comfortable with the current leverage position, knowing that it can decrease on its own? And then related to that as a follow-up, what might that mean for use of proceeds from the modernization of either the upstream or Midstream assets?

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

A

Hey, Dan, it's Richard. And I think your model's – depending on what metric you're using to define leverage, your model's probably right. We're showing, including the capital over-spend and interest and dividends that we're incurring additional indebtedness through the year, but EBITDA is growing. And our expectation is the production reserves growing, if the metrics stay roughly flat to where they were at year end. I think with regard to how comfortable we are living at the 2.1 times debt multiple of EBITDA, I think the agencies have been very constructive in their commentary to us that our ratings under aren't any pressure. It's more a management desire to have some capacity on the balance sheet to find future acquisitions if they make sense.

With regard to what we're going to do with asset sales proceeds, I think that if we are pleasantly surprised in terms of what the upstream process looks like, you may see some redeployment of capital or some additional capital pushed toward the higher-return projects this year. So I think that's sort of a fluid situation that we'll have much better visibility on as we get to the first quarter results call in a couple of months.

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

Q

Okay. And then on the subject of upstream monetizations, what data rooms are open today for what assets?

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

A

Dan, this is Chuck. As I've said in the previous calls, I'm disinclined to talk a lot about what we're doing in the upstream because I don't want to condition the market, either from a seller perspective or buyer perspective and, certainly, from an investor perspective, until we're further into it. We've got a couple of data rooms open, and you guys have your network of contacts. You probably know what they are. But I'd just like to let the process run its course and see what kind of offers we get in and whether or not we view those offers as acceptable. And when we have something to talk about, we'll – if it's material, obviously, we'll press release it. And we'll certainly talk about it in the next call.

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

Understood. And then, if I could, the expectation on the next redetermination of the revolver now that the 2012 PDPs have been booked?

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

Yeah. Hey. Dan, it's Richard. The revolver's a corporate revolver. It's unsecured. There is no borrowing base redetermination. The $1.5 billion commitment stays out there to maturity. So we don't go through that semiannual borrowing base redetermination process.

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

I've got it. Okay. Got it. Got it. That's all I have. Thank you.

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

Thanks, Dan.

Operator: 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. I have a follow-up to David Tameron's question on the ethane recoveries in the 2013 guidance. The first one is, what is your ethane price assumption that's embedded in your 2013 guidance? And second question is, if I'm thinking about this right, if you assume similar ethane recovery rate as today, your NGL production volume would decrease, and your gas volume would go up. But the overall production on an equivalent basis would go up because of the shrink. Is that correct?

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

Hsulin, our assumptions about the $0.26 or so a gallon, $0.27 a gallon, which was the forward curve at the time we set the guidance, as I said, ethane prices have been very volatile and, obviously, it's not just the ethane price that you need to think about. You need to think about natural gas prices because, obviously, it's the frac spread that drives the decision whether to recover ethane or sell the molecules as natural gas. And your – the second part of your question? I'm not sure I followed you.

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

So in your guidance, you mentioned that you're assuming full ethane recovery. Right?

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

Right.

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

So if you assume rejection as you are seeing today, how would that impact...

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

So the volumes at the two main assets that we're processing that we have access to deep-cut processing that we're processing, we can see roughly a 7% decline from Pinedale and a 7% decline fortuitously from the Red Wash plant. And it's what, eight to 10 Bcf or so of swing in reported volumes on an Mcfe basis on whether or not those plants are running in recovery or in rejection. So yeah, as I said in the prepared remarks, it can be a material swing, a wild swing in my mind in reported production volumes but have a de minimis impact on the financial statement because you're still selling those molecules; you're just selling them as a separate product.

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

Right. No, I understand that. Okay. Sounds good. And then another question is regarding – well, I know you mentioned you can't really talk much about the Midstream, the MLP. But can you generally talk about the tax strategy regarding how you can minimize the – around the Midstream MLP? Or is that not – or you can't really talk about it?

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

Well, I think, Hsulin, we've stated in the past that we think we have a number of different tools to manage any kind of tax gain, whether it's an E&P asset sale or a Midstream transaction, whether that's an NOL carryforward, specifically, with regard to the MLP, whether there's repatriation of previous two years' capital investment. So in terms of managing what we describe as tax leakage around any gain on sale – tax booking on sale, we've got a couple of different things that we're looking at. And so we've talked about the – trying to manage the tax leakage. And I think we've got some tools at our disposal, but that's probably as much details I can give you.

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

Okay. No, that's fine. And then are you still pursuing a Midstream financial partner?

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

I'm sorry? Say it again.

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

Are you still pursuing a financial partner for your Midstream assets?

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

Well we've looked at a whole range of opportunities; whether that's sale, private transaction, public transaction. So I guess the answer is yes, that we never close the door to any opportunities. But certainly, that's not the primary focus right now.

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

Okay. Got it. And then my last question is, can you give us an update on Sussex play in the Powder River; what you're seeing in terms of permitting and what your plans are for 2013?

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

Our current view is that, well, the permitting situation hasn't changed, the industry's still struggling to get any permits there. And we haven't been successful in getting any APDs approved, nor have any of the offset operators. So our current plans don't include any capital allocated to the Powder River Basin for 2013.

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

Okay. Got it. Great. Thank you very much.

Operator: [Operator Instructions] 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, Chuck, a couple of questions, still in the Bakken. First, wasn't sure if this was in your prepared comments, but first quarter commentary on South Antelope, how many wells or completions or pads that you intend to bring on? And if you have to repeat yourself, I apologize. And second is, I don't think Bakken weather's been all that big an issue year to date. And if you can sort of comment on that and the near term outlook.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc. A

Well I'm not a weather man. I'm a geologist, which I think the relative reliability of predictions are about the same. But the weather has been actually fairly good – I'm looking down at Jim Torgerson. I mean, compared to two years ago, when there were just horrendous issues with snow, and then in the spring with the snow melt and break-up, so far, we haven't seen any major issues. It has been cold. It is the wintertime, and we are actively completing wells – fracking wells as we speak, but those wells are on the reservation. I haven't given – I didn't give in my prepared remarks a quarterly forecast of well completions. We just – I want to avoid doing that.

I think what we'll do is once we get our operation up and running – and we're just now ramping up our operations on South Antelope – you'll begin to see a pace of well deliveries. And one of the things we did was we didn't pick up five rigs all at once so that we have, in essence, five pads at a time coming on. We've tried to stagger the rigs that we've picked up so that we don't have that phenomenon going on. So I think any prediction I'd give you right now is going to be dependent on us hitting our operational strides. But we just – we deliberately avoided doing that.

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

Okay. And final one for me. The Iron Horse and Black Forks, what does that do for EBITDA in the quarter for margins, et cetera? What do you think the impact could be as these plants come on?

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

So Iron Horse II, which starts up – it basically started now – will have a – basically a one-month impact on EBITDA. And Perry, what's the EBITDA from the fees from that plant for a full quarter, roughly?

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

A couple million dollars.

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

So about $2 million a quarter of impact for a full quarter. And then on the fractionator, it's – one of the things I think that you need to think about on the fractionator is, it's not an entirely new stream of revenue. It is an arbitrage between Mont Belvieu pricing for the various liquids products and local and regional pricing or rail-borne pricing for those products elsewhere in – either in the Rockies, for things like butane into the refiners, or propane by rail to other parts of the country where there are, many times, premium markets relative to Mont Belvieu.

So we haven't given a forecast on EBITDA there, and it's going to be relatively difficult to do so because of the volatility in not only the underlying product pricing but also in the relative differentials between Southwest Wyoming and Mont Belvieu going forward. We built it on historic pricing relationships for propane, butane and gasoline fraction products, which are substantial at certain times of the year. And we believe that the project will generate strong returns over its life.

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

Subash, it's Richard. Let me just make sure you understood what Chuck said on the Iron Horse II plant. Typically, we're trying to set the fee structure on those plants that they're a four-to-five year payout so that the $75 million investment, that plant's going to generate about $15 million-ish of EBITDA a year. So Chuck gave you a number that, I think you might have said a couple million bugs per month.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.
A

Yeah.

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

So just – it's about $1 million to – the $1 million...

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.
A

I'm sorry. I said the quarter I mean.

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

Per quarter, yeah.

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

So, anyway, okay. Just wanted to make sure you got that right.

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

Okay. So it is a couple million dollars per quarter.

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

Per month.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.
A

Per month.

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

Per month. Okay.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.
A

Right.

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

That more like it. Got you. Okay. Thank you.

Operator: Our next question comes from the line of Tim Rezvan with Sterne, Agee. Please proceed with your question.

Tim Rezvan
Analyst, Sterne, Agee & Leach, Inc.

Q

Hi. Good morning, guys. I had a follow up on the Bakken, not sure how much color you can give, but can you talk – broadly speaking on this 70% year-over-year growth you're assuming, kind of how many net – can you give us some clarity on the net wells you're looking to get hooked to sales. And then possibly on the production of those wells because you've announced a couple of pretty strong batches of wells over the last couple of quarters?

A

Yeah, 70-80, I think in terms of gross wells and our working interest is obviously pretty high, probably average is 80%, so 70-80 gross completed wells, and there be a mixture of wells on the South Antelope and on the Fort Berthold reservation. Again, I've tried to avoid giving asset level production forecast; but just a reminder once again, the growth is going to be lumpy, it's going to come on not only on the reservation but also on the South Antelope properties on a pad-by-pad basis. The average number of wells per pad is four.

So, just remember that outside of our Williston Basin asset, we don't have a lot of crude oil production growth, so the dominant driver for the production growth that we've given as we stated – we talked about high 60s, low 70s year-over-year crude oil production growth is coming from these two assets.

Tim Rezvan
Analyst, Sterne, Agee & Leach, Inc.

Q

Okay, that's helpful. Thank you.

A

Thanks.

Operator: Ladies and gentleman, at this time we have reached the end of the question and answer session. I would now like to turn the floor back over to Mr. Stanley for closing comments.

Charles B. Stanley
Chairman, President and CEO, QEP Resources, Inc.

I'd like to thank you all for calling in today and for your interest in QEP. We're going to be on the road next week for some meetings in the North East, and we'll also be in attendance at several upcoming conferences, so look forward to seeing you in person soon.

Operator: Ladies and gentlemen, this does conclude today's teleconference. You may disconnect your lines at this time. Thank you for your participation. And have a wonderful day.