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QEP - Q1 2012 QEP Resources, Inc. Earnings Conference Call

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PRESENTATION

Operator

Good morning. My name is Regina and I will be your conference operator today. At this time, I would like to welcome everyone to the QEP Resources first-quarter earnings conference call. (Operator Instructions). Thank you. I would now like to turn the conference over to Mr. Richard Doleshek. Sir, you may begin your conference.

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO, Treasurer*

Thank you, Regina, and good morning, everyone. Thank you for joining us for our first-quarter 2012 results conference call.

With me today are Chuck Stanley, President and Chief Executive Officer; Jay Neese, Executive Vice President and head of our E&P business; Perry Richards, Senior Vice President and head of our midstream business; and Scott Gutberlet, Director, Investor Relations.

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

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

In terms of reporting results, we issued a combined operations update and earnings release yesterday, in which we reported first-quarter 2012 financial results; reported first-quarter 2012 production of 74.2 Bcfe, 20% of which was composed of crude oil and natural gas liquids. We updated operating activities in our core areas and updated our guidance for 2012.

We reaffirmed our EBITDA guidance to be in the range of $1.35 billion to $1.45 billion. We reaffirmed our production guidance to be in the range of 305 Bcfe to 310 Bcfe and we modestly increased our CapEx guidance to be in a range of $1.35 billion to $1.5 billion, which is still in line with our projected EBITDA for the year.

As you've heard us say in the past, the current-year capital program generally has more impact on the following year's production than on the current year's production.

From a financial-reporting perspective, we continue to try to keep you on your toes. In the first quarter of 2012, we elected to discontinue hedge accounting. We believe that investors understand what is going on with the change in the mark-to-market valuations of our derivatives portfolio and we don't believe that there's any real benefit derived from the effort required to maintain hedge accounting. As a result, the entire change in the mark-to-market value of our derivatives portfolio now runs through our income statement, instead of through other comprehensive income.

In addition, the impact of subtle derivative contracts is no longer included in the revenue section of the income statement, but is now reported below the operating income line.

Also, recall that in the fourth quarter of 2011, we changed the presentation of transportation expenses. Historically, we netted transportation expenses against revenues. We are now reporting these expenses at a separate line item in the operating-expense section of the income statement, and have recast historical revenue and historical product price data to reflect the change in presentation. We'll be happy to provide additional information about the changes in how we report our financial results during Q&A.

Turning to our financial results, in comparing the first quarter of 2012 to the fourth quarter of 2011, the story was weaker financial performance at QEP Energy, our E&P business, and slightly weaker financial performance at QEP Field Services, our gathering and processing business.

QEP Energy reported marginally-higher equivalent production, which included sequentially-higher crude oil and NGL production, but lower natural gas production, which is typical as we suspend completion activities in the winter in our northern region properties. The production increase was offset by a 10% decrease in quarter-to-quarter net realized equivalent prices. Field Services' first-quarter results were marginally lower than the previous quarter, primarily due to lower ethane prices.

Our first-quarter EBITDA was $345.7 million, which was $45 million, or 11%, lower than the fourth quarter of 2011, but up $40 million, or 13%, from the first quarter of 2011.

QEP Energy contributed $261 million, or 75%, of our aggregate first-quarter EBITDA and QEP Field Services contributed $84 million, or about 24%. QEP Energy's EBITDA was down about $40 million, while Field Services' EBITDA was $3 million lower than respective fourth-quarter 2011 levels.

Factors driving our first-quarter EBITDA include QEP Energy's production, which was 74.2 Bcfe in the quarter, slightly higher than the 73.9 Bcfe reported in the fourth quarter of 2011. The quarter's production was 12% higher than the 65.9 Bcfe produced in the first quarter of 2011. Of note, while gas volumes were down 1 BCF, oil volumes were 1.2 million barrels, up 3% from the fourth quarter, and NGL volumes were also 1.2 million barrels, up 17% from the fourth quarter of 2011.

Combined, oil and NGL volumes were 2.4 million barrels in the quarter, compared to 1.1 million barrels of combined volumes in the first quarter of 2011.

QEP Energy's net realized equivalent price, which includes a settlement of all of our combined derivatives, averaged $5.47 per MCFE in the quarter, which was 10% lower than the $6.08 per MCFE realized in the fourth quarter of 2011 and $0.03 lower than the $5.50 per MCFE realized in the first quarter of 2011. The lower equivalent price reflects field level prices -- gas prices that were 26% lower than in the fourth quarter of 2011.

QEP Energy's commodities-driven portfolio contributed $83 million of EBITDA in the quarter, compared to $66 million in the fourth quarter of 2011 and $42 million in the first quarter of 2011. The derivatives portfolio added $1.13 per Mcfe to QEP Energy's net realized price in the first quarter, compared to $0.89 per Mcfe in the fourth quarter of 2011 and $0.64 in the first quarter of 2011.

QEP Energy's combined lease, operating, transportation, and production tax expenses were $114 million in the quarter, down from $120 million in the fourth quarter of 2011 and up from $99 million in the first quarter of 2011. LOE was down 2%, transportation was down 9%, and production taxes are down 9% in the quarter, compared to the fourth quarter of 2011.

And finally, QEP Field Services first-quarter 2012 EBITDA was $84 million, which was about $3 million lower than the fourth quarter of 2011 and 37% higher than the first quarter of 2011.

Gathering margin was up $2.5 million, or 6%, in the quarter, compared to the fourth quarter of 2011, due to slightly higher other gathering revenues. Gas gathering volumes were about 1.36 million MMBtu per day and the average gathering fee was $0.34 per MCF.

Processing margin was down $8.6 million from the record fourth quarter of 2011 dollars on 4% higher NGL sales volumes, but 22% lower NGL prices, offset somewhat by shrinkage expense that was sequentially $5 million lower in the quarter. Fee-based processing volumes were up 1% from the fourth quarter of 2011, while processing fees were flat.

While EBITDA was $45 million lower in the first quarter of 2011, compared to the fourth quarter -- sorry, 2012, compared to the fourth quarter of 2011, net income from continuing operations was $155.5 million higher, driven in large part by a $128 million gain in the value of the commodity derivatives portfolio.

As I mentioned earlier, on January 1 the Company discontinued the use of hedge accounting. As a result, the entire change in the value of the derivatives portfolio runs through the income statement, as opposed to other comprehensive income. The gain is a non-cash item, and we adjusted for it in our EBITDA calculation.

Sequential DD&A expenses were essentially flat at $199 million, while exploration, impairment, and abandonment expense in aggregate were $9 million in the quarter, compared to $205 million in the fourth quarter of 2011, which included a $195 million impairment of producing properties.

Our provision for income taxes was $89 million in the quarter, compared to a credit of $2 million in the fourth quarter of 2011.

And finally, interest expense was up $1.7 million in the quarter, compared to the fourth quarter of 2011, as a result of new senior notes that we issued on March 1.

Turning to capital expenditures, in the first quarter of the year we reported capital expenditures on an accrual basis of $341 million. Capital expenditures for the E&P activities were $293 million, including $1.4 million on property acquisitions, and capital expenditures in our midstream business were $47 million in the quarter. We continue to focus on directing as much capital as possible to our higher-return crude oil and liquids-rich natural gas plays, and Chuck will have more comments about our capital program in his prepared remarks.

With regard to our balance sheet, at the end of the quarter total assets were $7.5 billion and shareholder equity was $3.4 billion. Total debt at the end of the quarter was $1.68 billion, which was a 1.18 times multiple of trailing 12-months EBITDA.

In March, we issued $500 million of senior notes due 2022, and proceeds of the offering were used to reduce indebtedness under our revolving credit facility. The notes are unsecured, carry a coupon of 5.375%, pay interest semiannually in April and October, and we were pleased with the execution in the offering, which resulted in the lowest interest rate for a long-term debt issuance by the Company in recent history.

In addition, last week we entered into a $300 million, five-year term loan agreement with a group of financial institutions, which adds substantially the same pricing and covenants as our revolving credit agreement. As of today, we have no outstandings under the revolver and have $1.7 billion of borrowing capacity under our combined bank credit facilities.

I'll now turn the call over to Chuck.

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Thanks and good morning. Richard has already hit the highlights of our first-quarter results. I'll try to add some color, give you an update on our plans for the remainder of 2012, and then move on to Q&A.

First, QEP Energy grew production to 74.2 Bcfe in the first quarter of 2012. That was a 13% increase over a year ago.

But that is not the big story. As I'm sure you saw in our release, we're making excellent progress on organically growing QEP Energy crude oil and NGL production. In the first quarter, QEP crude oil and NGL production comprised 20% of total volumes. And at the field level, crude oil and NGL sales represented 50% of QEP Energy production revenues.

Crude oil and NGL production at QEP totaled 2.4 million barrels in 2012, compared to 1.1 million barrels in the first quarter of 2011. That was a 113% year-over-year increase. And crude oil, as a total -- out of total liquids production, comprised a little over 50% of total volumes in the quarter.

QEP Energy southern region production in the first quarter was up 5% from 2011 levels. The midcontinent production, basically the Anadarko basin production, driven by increased liquids-rich production in the Cana, shale, and wash plays in western Oklahoma and the Texas Panhandle and increased crude oil production in the Marmaton and Tonkawa plays, was up 20% from a year ago.

Production from the Haynesville Cotton Valley area in northwest Louisiana was essentially flat from a year ago.

Southern region crude oil and NGL production increased 46% in the first quarter of 2012 over the first quarter of 2011 to a total of 737,000 barrels. Crude oil, as a percentage of total liquids production, was 40% in the southern region.

Northern region production was up 24% in the first quarter of 2012, compared to a year ago, driven by a 37% increase in Pinedale gas and NGL production and a 51% increase in Rockies legacy production, which was driven primarily by increased crude oil production in the Williston basin Bakken/Three Forks play.

This growth was slightly offset by a decline in Uinta Basin volumes. Please note that the Uinta Basin year-over-year comparison was distorted by a positive 1.6 Bcfe prior-period adjustment back in the first quarter of last year that resulted from a change in QEP's ownership interest in a federal unit. Without that adjustment, Uinta Basin volumes were down only 4% from last year.

Keep in mind that we restarted drilling activity in our new Uinta Mesaverde play late in the fourth quarter of last year, so it's going to take a while for us to arrest decline, the underlying base decline in the properties, and turn up the volume growth.

Northern region crude oil and NGL production totaled 1.7 million barrels in the first quarter of 2012. That is a 164% increase over the first quarter of 2011. That increase was driven by a 149% increase in crude oil production from our Rockies legacy division, primarily from the Williston basin, and from NGL production at Pinedale, thanks to the startup in the middle of last year of our Blacks Fork II cryogenic gas processing plant.

Crude oil production comprised 54% of northern region's total liquids production in the first quarter of 2012.

Turning to our midstream business, Field Services had a good quarter, both financially and operationally. The Blacks Fork II plant continues to operate quite well, and as a result, the Field Services first quarter of 2012 NGL sales totaled 45.2 million gallons, or approximately 12,000 barrels a day, and that was a 63% increase over the first quarter of last year.

The average realized NGL price for the quarter was $1.07 a gallon. That's essentially flat with a year ago, but importantly, it's down significantly from the $1.38 per gallon average realized price that we had back in the fourth quarter of last year. The biggest driver in the recent decline in overall NGL prices has been the drop in the average price of ethane, which was down 36% from the average price in the fourth quarter.

Also a note that in the first quarter of 2012, we reported our first clean quarter of operational results from Blacks Fork II. That is, with no noise from line pack inventory in either QEP Energy or QEP Field Services that we experienced and talked to you about in the third and fourth quarters of last year. So for the first time this quarter, the percentage of ethane in our average NGL barrels has increased significantly relative to historic levels, and it should now be pretty stable going forward until we bring on our next cryo plant, Iron Horse II, which should start up in the first quarter of next year.

From a macro perspective, we talked about this last quarter, the decline in ethane prices appears to be the result of a near balance in supply and demand in the ethane market, exacerbated by normal plant turnarounds in the ethylene complex, which generally occur during the winter and certainly occurred during the first quarter of 2012. And that has been exacerbated by an excess of propane due to the unusually warm winter of 2011-2012 that we had, and of course, propane can be cracked and substituted for ethane in the ethylene complex, so that's added to the apparent oversupply.

The good news is we have seen some recent strengthening in ethane prices as the ethylene crackers are returning to normal service. It's important to note that the raw NGL product from our plants here in the Rockies all ends up down at Mont Belvieu, Texas, which, as you all know, is the premium market for NGLs.

As a result, even with the pullback in pricing, our processing margins remain well above historic levels.

Fuel Services gathering volumes were up 4% from a year ago, driven primarily by increased volumes on systems connected to the Blacks Fork hub, which, of course, includes the Pinedale anticline.

Blacks Fork hub volumes totaled 61.2 million MMBtus during the first quarter of 2012. That's 6% higher from the first quarter of 2011. Cotton Valley Haynesville volumes also increased about 6% to 20 million MMBtus, and this increase was partially offset by a 6% decline in Uinta Basin gathering volumes.

So looking forward to the remainder of this year, we gave you a lot of details on our current drilling activities and our results of recent wells in our release yesterday, so I'm not going to repeat that information. I'd also draw your attention to the slides that we put out on our website yesterday of the Company in our release.

As you know, natural gas prices have continued to drop, with the remainder of 2012 NYMEX price hovering around $2.38 an MMBtu. In response, we have made and will continue to make changes to our capital allocation in QEP Energy. Those changes are summarized graphically on the slide in the front of the deck, slide four, that shows our capital allocation in each of our plays.

You'll note the [dramatic] decline in capital allocated to the dry-gas Haynesville play. Today, we're down to one rig operating in the Haynesville, and we'll drop that rig this summer when it finishes drilling 80-acre development wells in the section it currently occupies. Also note that we're anticipating a significant decrease in outside operated activity in the Haynesville for the remainder of 2011.

We're now allocating 89% of our forecasted capital in QEP Energy to crude oil and liquids-rich natural gas plays. Our focus will be on driving crude oil production in the northern region, in the Williston basin, Three Forks, and the Powder River basin, Sussex, Shannon. And in the Uinta basin, Green River play is where you'll note we're picking up a third rig in the Uinta basin focused solely on drilling Green River oil wells.

In the southern region, we'll continue to focus on the Marmaton and Tonkawa plays, as well as the shallowest of the wash plays, the Missouri play in the Texas Panhandle, where we plan to drill some oil wells in the remaining part of the year.

We'll also allocate capital to liquids-rich gas plays, including our emerging Uinta Basin Mesaverde play and, of course, the Pinedale in the northern region, and to the up-dip wet portion of the Cana shale play in the southern region.

Our release gives you a lot of details on our current thinking on rig count in each of the plays and our other details. Jay Neese is here with us today, and he'll be happy to give you more color on our thoughts around individual plays and our evolving plans at QEP Energy during Q&A.

At Field Services, our plans call for investment of roughly $170 million in several major projects and a number of smaller ones. We recently broke ground on our next cryogenic gas processing plant, the 150 million cubic foot a day Iron Horse II plant, which is located in the Uinta Basin in eastern Utah. About half of the Iron Horse II plant capacity is contracted by a third-party producer under a fee-based processing arrangement and the other half will be available to process QEP Energy's growing liquids-rich gas volumes from the Uinta Basin Red Wash Mesaverde play.

We've also now sanctioned construction of a 10,000 barrel a day NGL fractionator at our Blacks Fork II complex in western Wyoming. Combined with the 5,000-barrel a day fractionator that already exists at Blacks Fork, this facility will be designed to provide additional options for marketing purity propane, normal and iso butane, and gasoline range products to premium range, local, regional, national, and sometimes we even send propane by rail into international markets, such as Mexico.

We've placed orders for major rotating equipment and vessels and we'll begin field construction on this facility in a few months. We expect that the Blacks Fork fractionator will be in service by the end of the second quarter of 2013.

And of course, an additional -- in addition to these major projects, we have a number of ongoing minor projects, including well connections and construction and expansion of our existing gathering systems, as well as we're starting work on preliminary design, engineering, and procurement activities on additional gas processing capacity here in the Rockies.

So at the macro level, we're finally seeing signs that gas-directed drilling is starting to slow down, and we've seen ourselves and other operators drop a number of rigs in dry-gas plays such as the Haynesville and other plays. Even so, we expect that the supply response will be sticky and will lag the downturn in the rig count while the inventory of standing wells that have yet to be completed is worked through.

It's too early to tell if this supply response, in conjunction with increased demand, driven primarily by increased gas burn in the electric power sector, will allow the industry to avoid forced curtailments toward the end of the injection season in the shoulder season this fall.

As a reminder, in response to our concern about this, we've been defensive on natural gas prices, and we now have about 74% of our forecasted gas production for the remainder of 2012 protected by derivative contracts, primarily fixed-price swaps.

We remain focused on allocating capital to the highest-return plays in our portfolio, which means we will continue to drive profitable growth in our oil and liquids-rich gas plays and in our midstream business for the remainder of 2012 and beyond.

And with that, Regina, let's open the lines for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions). Brian Lively, Tudor, Pickering, Holt.

Brian Lively - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Chuck, could you provide a little more color, maybe, on 2013 in the context of how the higher liquids spending impacts 2013, if not from an overall growth perspective, but maybe from a mix of liquids versus gas?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Brian, it's pretty early in the year to talk about capital for 2013. And of course, as we've said repeatedly, the capital allocation decisions we're making today, certainly by the end of the second quarter, have far more impact on production volumes and mix in the next year than they do in the current year.

We've said that we're focused on growing organically our mix of oil and NGL as a percentage of our total production, and this year we think we'll be at about 20% for the year. You can see we're making good progress there organically.

We would expect that, looking at our year-over-year trend from 2011 to 2012, we were at 14% for last year, 20% this year. Absent a major acquisition that would change that mix, we would expect a similar trajectory with the mix continuing to change maybe five percent -- 25% or so, 27% in 2013.

That being said, if we decide to radically change our allocation to gas in response to a further decline or a more structural decline in gas long term, we could see our gas production drop, and that would obviously change the relative ratio going forward.

Brian Lively - *Tudor, Pickering, Holt & Co. Securities - Analyst*

And is your expectation right now for year-end 2012 and 2013 to drop the Haynesville rig? So are you already dialing that into your, I would say, broad thoughts on what the mix looks like for 2013?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Yes, when I made that statement, we're assuming that we likely will not recommence drilling activity in the Haynesville until we see an improvement in gas prices to a zip code somewhere between $4 and $4.50, probably toward the high end of that range before we would commit the resources that restart development activities in the Haynesville.

Brian Lively - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Okay, and in the Pinedale, it looked like the working interest of around 70% was higher than it has been historically. What is sort of the normal working interest run rate for the Pinedale?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

It's low 60s working interest, and we picked up interest from several of our working interest partners and some wells as they've elected to nonconsent because of the relative economics of our investment versus that of our working interest partners who don't benefit from the liquids volumes that we extract at Blacks Fork II.

As we've said before, it makes a substantial improvement in the relative economics, and of course, our working interest partners gas is being processed by us, but it's being processed on a keep-whole basis, and we're enjoying the benefit of the liquids extracted there.

Brian Lively - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Just the last question for me, on your commentary on the -- from a macro gas perspective, it taking longer to correct -- for the supply to correct, from your own portfolio as you consider taking a rig out, your last rig out of the Haynesville, what is your expectation for your Haynesville volumes maybe over the second half and next year in terms of the decline, meaning do you think you guys, with the restricted rate programs, will be able to hold that relatively flat?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Well, certainly -- first of all, we are one of several operators that has decided, and we've convinced ourselves from the long-term well performance that restricted flowback of these wells not only results in higher-flowing pressures and higher cumulative production at any given point in the wellhead history, it certainly appears that we're going to get higher recoveries overall from these wells.

But it does, as you've observed, create a plateau period that lasts probably -- nominally six months or so from the time you first put a well on. That's observation number one. And sometimes it lasts even longer. We have some -- I mean, it's a very subtle decline, but there is a plateau period that lasts close to a year before you really see the well starting to decline.

And when the well does enter decline, it enters decline at a shallower rate than wells that have been flowed back hard and that have not been, we believe -- that have probably damaged the reservoir. So as a result, we see initial declines roughly half or in the 50%, 55% range, as opposed to a 90%-plus range for unconstrained wells.

So our aggregate production portfolio will decline at a lower rate than most of the other operators in the Haynesville and certainly a lot of the larger operators in the Haynesville who do not practice this constrained flowback.

So we think -- you know, we'll be roughly flat for the year on Haynesville production, and then we'll enter into decline next year, absent additional capital investment, and the production will come off at some rate less than 50% because, keep in mind, we have a bunch of wells now that are three or four years old that are out of the steeper part of their decline.

The industry in aggregate, I think, will still see a much higher decline than the 50% that I referenced, so there's a couple of other factors. One is how many standing wells are left to be completed in aggregate in the Haynesville. The rig count is down to the high 60s this week, I think, so the number of wells that are being drilled and cased is declining, and the inventory is being worked off as completion activity has continued in the first quarter and into the second quarter of this year pretty much at the same pace that it as in the past.

So, the inventory is down. I think -- well, Haynesville production has turned over, and I think that the decline will accelerate now that the rig count and the standing well inventory is coming off.

Brian Lively - *Tudor, Pickering, Holt & Co. Securities - Analyst*

Great commentary. Thanks much, guys.

Operator

Brian Corales, Howard Weil.

Brian Corales - *Howard Weil Incorporated - Analyst*

A question on the Bakken. You're adding a fourth rig. Is there an optimal level you're trying to get to in the Bakken for a more efficient program?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Brian, yes, we're adding a fourth rig. We hope it will -- we're going to sequence it in with the three existing rigs there.

And of course, as you know, we're drilling from pads there and are sort of constrained in when we add that fourth rig by. Making sure we put two rigs on a pad more or less simultaneously so they accomplish drilling the wells in parallel so that we don't experience an unnecessary amount of delay in getting those wells online by having staggered rig activity.

The optimum number is probably five rigs, and we're striving to get there, and we're anticipating adding a fifth rig sometime later this year. Again, we're looking at the sequencing of the rigs on the pads, keeping in mind that some pads we can physically only fit one rig, some we can fit two rigs on. So five rigs feels like sort of the sweet spot.

Brian Corales - *Howard Weil Incorporated - Analyst*

Okay, and do you have a guess right now what that would do on the cost side of the equation? Is that going to gain some -- allow costs to decline a little bit?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

We certainly hope so, Brian. We haven't seen enough pad drilling activity to really get a good handle on what economies of scale we should see.

But our experience at Pinedale and other places where we pad drill would indicate that -- I mean, there's some obvious savings. Firstly, you don't have to move the rig. You don't have to take the rig down and move it and rig back up, which should save a few hundred thousand dollars minimum.

And then, once we drill and case a number of wells and we move the rigs out of the way, our ability to work on multiple wells back to back with the frack crews is also a savings. And then, obviously, having all the facilities on one pad will reduce individual well connection costs.

So in aggregate, intuitively you would think that we should save somewhere around $0.5 million or so a well. Whether we can actually realize that is still -- the jury is still out on that.

Brian Corales - *Howard Weil Incorporated - Analyst*

Okay. And then, one question on the Uinta. You're adding the rig for the Green River. How is that develop -- and you said horizontal. Was that developed vertically prior or is that horizontally as well?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Brian, the answer is both. The historic drilling out there, so if we sort of talk about two different areas, in the Red Wash field which overlies our active Mesaverde gas development program, all of those wells are vertical.

And there's a series of stacked sands out there. Geologically, it's quite reminiscent of the geology at Pinedale where you have, in the case of the Red Wash field, in some wells 40 or 50 separate sands that are perforated and have been produced. The average is probably 15 or 20.

And so, really for the most part, the development in the Red Wash area lends itself to vertical wells because you really need to contact all of those separate sands. And so, the focus there is on increasing the well density because most of the field was developed -- the tightest density was 40 acres. There was a lot of the field that only has 80-acre or 160-acre, and a significant part of the field that only has four wells or 320-acre -- or I'm sorry, 80-acre -- I'm sorry, Brian, 160-acre -- I will get it right in a minute -- 160-acre spacing, four wells per section.

So the opportunity there is to basically increase the well density and capture a lot of the oil that hasn't been produced from the old vertical wells.

We have had in the past, and what we'll be doing is continuing to drill, a number of horizontal wells in the -- focused in the Green River formation for oil. I think up until maybe a few months ago when the aggregate industry activities sort of outpaced us, we had the most horizontal wells -- well, I think we still have the most horizontal wells in the basin, and we've probably had, up until a couple of months ago, the more horizontal wells than the rest of the industry combined in the Uinta Basin.

Our horizontal development has focused on thin sands and limestones that are a few feet thick, less than 10 feet thick, generally, and they were ignored and not perforated in the original development of portions of the field that were developed with vertical wells. So what we find is that we can drill a horizontal well in these thin sands, find virgin reservoir pressure, and find reservoir that has never been produced either in primary mode or had been swept by the poorly-designed and executed water flood in portions of the field.

So it's been, you know, a really neat sort of redevelopment activity. A lot of the horizontal wells that are being drilled have been drilled by cutting windows in the casing of existing vertical wells and then going horizontally, and we've actually done a number of them with multiple laterals, with one lateral in each compass -- in two compass directions, so two horizontal legs off of the existing vertical well. And those have been quite successful.

So we'll be doing a combination of horizontal wells and then drilling some additional vertical wells to get additional vertical well data and production around some of the areas of the Red Wash field where we don't have high-density drilling.

Operator

William Butler, Stephens.

William Butler - *Stephens Inc. - Analyst*

I had a question on the Bakken. You all had slightly higher well costs and you decided inflation there. Can you talk a little bit about the inflationary pressures you're seeing there? Is that something that is transitory or is that something you think is still solidly in the basin up there?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

It's interesting. Our well costs were below that of some of our offset -- and still are below that of some of the offset operators in the area.

The well costs are directly related to the depth, the amount of overpressure. And we are in an area which has a significant amount of overpressure, so well cost -- drilling costs are a little higher, and then treating costs are higher because we need more hydraulic horsepower.

We've seen our well costs inflate to be closer to that of our neighbors, and part of it is still inefficiency on our part, just in our inability to manage the completion activity to drive down costs, and it's economies of scale that I think that we'll start to see when we add a fourth rig.

Part of it is also we're giving you a prospective view of what we think well costs will be for the remainder of the year, and we're hearing that some constituents of the completion fluid costs may be going up in the future, and we're sort of trying to warn you that we anticipate some inflation on the completion fluid side.

But obviously, we're focused on doing things, everything we can, to drive down costs, and I think pad drilling will help and then working on multiple wells will help as well. So, we're hoping that that is transitory and we open that we can turn it the other way.

William Butler - *Stephens Inc. - Analyst*

Okay. On your well design, have you guys experimented with, given the depths and pressures where you are and small-set operators using ceramics? Is that something you all are contemplating, more or less?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

We've looked at the relative well performance of wells that have been fracked and propped with ceramics versus sand, and we've seen -- we've participated in a lot of wells operated by others.

And looking at that well performance versus ours, and looking at outside operators' well performance, ceramic proppant versus non-ceramic proppant, we have yet to be convinced that there's any material change in well performance related to the type of proppant that's used. There is certainly a good argument for increased stages, and I think you've seen that as the understanding of the reservoir has improved over time. All the operators have gravitated to increased stage count and closer stage spacing, which is probably more to blame or is the reason why we're seeing better well performance overall out of the wells that are being drilled over the past 18 months versus the early wells that were drilled.

And then, the third point is long laterals. We're drilling all long laterals, so obviously a long lateral exposes more of the well bore to the reservoir and ultimately results in higher EURs per well.

William Butler - *Stephens Inc. - Analyst*

Okay. And I noticed on your maps, you all spotted some more acreage in the Bakken now than you had previously. Is that just -- have you all acquired some smaller acreage blocks in McKenzie-Williams, or is that just stuff (multiple speakers)

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

I think it was probably there before. Maybe we made the map bigger so you could see it, but the acreage count hasn't really changed materially.

William Butler - *Stephens Inc. - Analyst*

Okay, I appreciate it. One last question on your Woodford Cana, your EURs, you tightened in the range there. Any commentary on that?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Yes, we're -- the reason that we did that is the early -- I think we used to have a range of 4.5 Bs to 12 Bs, and that was our experience over the broader play, and now we are focused in on drilling development wells in the sweet spot and the core.

So we're taking into account, A, the fact that we're drilling in the Cana where it's 275 to 350 feet thick, and two, we are drilling on 80-acre density so we're anticipating some interference between the wells on 80-acre density. But we're in an area now where there's just not as much variability in where we can predict pretty tightly what the results will be.

William Butler - *Stephens Inc. - Analyst*

Okay, and is that an area -- it seemed pretty low down on the list of where you're allocating your capital. Is that an area that if you all had a use for the (technical difficulty) that would be on sort of the divestiture block, or is it an area that we should just continue to think is part of you guys going forward?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

We think the core is very economic, especially as you move, in our slide eight there, in the light green to the dark green area, it's competitive with all the other liquids-rich shale plays around the country. We like that acreage and we don't have any plans to divest of it today.

Operator

David Tameron, Wells Fargo.

David Tameron - *Stifel Nicolaus - Analyst*

Chuck, do you guys have a -- if you think about Blacks Fork in your -- you guys gave us some run rate numbers when you first came out with this and talked about what you expected. Obviously, ethane has moved that number. Can you talk about, one, is there any way to strip out what the actual earnings contribution was from Blacks Fork on the quarter? And two, what the run rate is going forward or how we should think about that?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

I don't have the granularity to do it. We'd have to -- obviously, Blacks Fork benefits not only Field Services, but also QEP Energy. In my prepared remarks, I did point out that this is the first -- the first quarter of 2012 was the first quarter where we didn't have all the noise going on.

For instance, in the fourth quarter we had 240,000 barrels of NGLs that went into line back, so those barrels ended up going in -- being entered on the balance sheet as basically inventory, and so, of course, it sort of perturbs the reported production volumes in QEP Energy.

And so, one of the things that we've heard a lot of questions and a lot of commentary after we issued the release yesterday about the drop in realized NGL prices, and one of the things that I want to make sure everybody understands is that, as a result of the first clean quarter of operation of Blacks Fork in the first quarter, we saw a substantial increase in ethane as a percentage of our total NGL barrel. And so, just to remind everybody, Blacks Fork is generating 15,000, 16,000 barrels a day of NGLs, of which is 60%, roughly -- 59.8%, to be exact, but 60% roughly, is ethane. So that has substantially lightened the barrel and therefore driven down the average realized price of that barrel, so we had that going on just at a physical level with the lightening of the barrel.

And then, two, we saw a dramatic decline from what were just outrageously high ethane prices in the fourth quarter into the first quarter, which had the impact of driving down the realizations on that part of the barrel.

So, to get at the absolute impact just from Blacks Fork, it's probably somewhere in the $25 million to $30 million range of EBITDA, and that would be total, right? That would be for both Field Services and for Energy.

And, obviously, your view of ethane, I mean, we believe that ethane prices, we can see some strengthening. There was a lot of turnaround-related demand taken out of the market. Those crackers are coming back on. It's taken longer than it did last year for the turnarounds, for whatever reason. We're not sure.

But we have seen strengthening in the ethane price here in the past month or two, and we would think that that would continue.

David Tameron - *Stifel Nicolaus - Analyst*

Okay. That color is helpful, so appreciate that. Let me jump a couple more. Haynesville -- or just, I guess, maybe gas in general. Is there a price -- what price would you shut in gas? Sub-cash costs or what number are you talking? I know (multiple speakers)

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Obviously, if we're not generating positive cash margins. There are other questions that drive that, and part of it is reservoir related.

Some of our highest cash-cost gas production is in areas that have very low-rate wells that are on [funger lift], and we tried to shut those in a number of years ago and the results were not pretty. We never got the wells back on their original decline curve and we're loathe to lose reserves as a result of a temporary shut-in.

There are some areas that clearly are amenable to shut-ins. We've done it at Pinedale in the past, although Pinedale arguably on an economic basis is our lowest lifting cost area and the one that would be the least likely to get shut in just on a pure economic basis.

Haynesville wells, they seem to be okay, although we only have short-duration data on shut-ins of -- or of Haynesville wells, and in effect, we are managing production volumes in the Haynesville with our deliberate curtailment through the constrained flowback.

We really can't choke the wells back in the Haynesville anymore without them freezing off. They're still flowing at such high pressures that they tend to freeze off if we try to close the chokes anymore, just because of the significant pressure drop at the wellhead.

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO, Treasurer*

And David, just as a little bit of color, if you look at just the cash component of lifting costs, whether it is production taxes, transportation, and LOE, I mean, we -- none of our gassy regions that have costs in excess of $1.25. So, if you're just looking at making money on a daily flowing Mcf, we can make money all the way down to $1.00, plus or minus.

David Tameron - *Stifel Nicolaus - Analyst*

That's helpful. A couple more questions. I mean, Chuck, what do you see -- from your experience or your crystal ball, what do you see for gas prices over the next three to four months, given where storage is at? I know you guys talked about locking in some hedges. What's your view on it?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Well, I know there is a group of folks that think that we could see forced withdrawals here as we're in the shoulder between withdrawal and injection to basically bring down inventories and storage -- forced inventory reduction that's driven by tariffs in some storage facilities.

We haven't seen that effect yet, and I'm becoming more optimistic we won't see it in the spring.

The real questions then become weather, right? How hot is it? How quickly does it get hot? And how fast does the cooling load pop up to help support gas burn in the power sector? Unfortunately, we do have a great pricing advantage over even Powder River basin coal at current gas prices, so I think we'll see continued high utilization of gas in the power sector. But it really becomes a weather issue, just like gas demand in the winter is a weather issue ultimately.

I'm more concerned about the end of the injection season and the risk that, as a result of a cooler summer and less gas burn in the power sector and stickiness in the supply response, that we end up north of 4.1 Ps in storage. And I think that is still a risk, although the pundits that I read, and I am as knowledgeable as the collective wisdom of everybody I read, is that we might squeak by.

And then, there's also this argument that maybe the real capacity is not 4.1, but 4.3. I kind of doubt that, but I do think that there is a chance that we squeak by in the fall if we continue to see supply response head downward and we don't have a really cold summer.

David Tameron - *Stifel Nicolaus - Analyst*

I appreciate that. Final question for me, and since nobody else will ask it, I'll take the bullet. And you mentioned it during your opening response to Q&A. You said absent an acquisition, you know, portfolio mix is going to be this next year. Can you -- that's obviously out there, a lot of chatter about that. Can you just talk about where you're currently at in acquisitions? Are you still looking? You still have a -- I'll just leave it at that and let you answer.

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

We have a group who is charged with looking at opportunities to do bolt-ons, and obviously, all things being equal, we'd like to add more oil to the mix, although if you look at the prices of oil assets, they've been -- we've not been successful. We have made a number of unsolicited offers and we've anticipated in some auctions, and we've not been the high bidder or our unsolicited offers have not been accepted -- acceptable to sellers or owners of assets.

We're continuing to buy leases in some of the oily plays, and I think honestly, from a value-creation perspective, that is probably the -- certainly the lowest risk and probably the way you ultimately, long term, create value is by looking for new plays and then just bolting on through -- or leasing. And we're still seeing forced pooling opportunities in places like western Oklahoma, where we're picking up incremental interest in wells that we're operating and drilling through farmouts or sales in the forced pooling process.

But you know, we continue to look. As Richard mentioned in his remarks, we have got a lot of dry powder on our -- with our bank facility and revolving credit facility, and we'd like to be opportunistic.

And we're agnostic, by the way. While we talk about oil, we certainly also understand that the best time to buy natural gas assets is probably when they're out of favor, and certainly there's no one on the call that would argue that they're in favor right now. So we would also look for opportunities to buy at the right price, natural gas assets, to add to our portfolio.

David Tameron - *Stifel Nicolaus - Analyst*

All right. I appreciate it.

Operator

Brian Singer, Goldman Sachs.

Brian Singer - *Goldman Sachs - Analyst*

Chuck, it's been about five months or so since your analyst meeting where you laid out in great detail your excitement about your liquids plays. Can you assess with perhaps some greater color than in your slides how the wells that you've drilled since then are performing, particularly in the Powder River basin, but maybe you could also speak to the Green River basin, Marmaton, and Tonkawa plays, and also how the percent crude oil in those wells is looking versus your expectations?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Okay, so the Powder River basin is an easy one. We haven't drilled any wells. We have been stymied, as most of the industry has, by our inability to get permits out of the BLM office in Wyoming.

As you will recall, we stated that a goodly amount -- basically, all of our acreage in the Powder River basin has at least some federal acreage in each section, which, with a 640-acre spacing unit, requires us to get a federal APD. We've got a handful of APDs, but we don't have enough APDs to date to support picking up a rig and moving it into the basin to drill wells.

The good news is there is enough other operators in the area that are experiencing a similar problem that we may be able to [winnow] out a rig and drill a handful of wells with the permits that we have, and then let the rig go back to the operator who currently has it under contract, and we're in discussions to do just that. But we've been very frustrated with the inability to get APDs out of the BLM office.

Moving down to the Mesaverde, we have two rigs running in the Mesaverde play. The -- and by the way, before I leave the Powder River basin, the wells that have been drilled up there by other operators, we participated in some of them, with working interests around the periphery of our acreage have been quite encouraging, and we're seeing well results which would not change our view of the type curve and potential EURs that we talked to you about.

As you know, the Powder River is a pretty oily basin, so it's [donnelly] oil with some associated gas, and that play really does have an oil-type characteristic to it, as opposed to some of the liquids-rich gas plays.

Moving down to the Mesaverde, we have two rigs running on the play, and what we've seen there is basically the same results that we described to you from the handful of wells, the 20-plus wells that we had drilled in the play earlier. It is a statistical play. There is a range of well results, and our average well may be a little higher than what we showed earlier, driven by a couple of really strong wells that we completed late last year or early this year. But it, again -- there are no surprises there.

In the Marmaton and Tonkawa, we see a range of outcomes as well, not only from the wells that we're drilling, our QEP-operated wells, but from wells in which we have a working interest that are operated by others. But the well performance there has been within -- in line with our average sort of EURs that we're expecting.

Mesaverde, by the way, it's a wet gas play, although over 50% of the revenues at the wellhead come from condensate and from NGLs. The Marmaton/Tonkawa plays are really oil plays as well, very similar to the Sussex and Shannon and other plays in the Powder River basin.

And then, one play that we did not talk about in the discussion at the analyst day was the shallowest of the Granite Wash reservoirs, Missouri and Hogshooter, whatever name it goes by and whatever pasture you happen to be in, but we posted in our slides deck some recent well results. We have three wells in which we have a working interest that are operated by others that are in the process of flowing back now.

Those are oil wells. I mean, if you look at the ones that were drilled that we reported last quarter that are also in that slide deck, a couple of very strong high-rate wells that came on at very high oil rates, one over 5,000 barrels a day, one almost 3,000 barrels a day, immediately offsetting our acreage, and we have plans to follow up on that and drill wells on our operated acreage later this year.

Brian Singer - *Goldman Sachs - Analyst*

Great, thanks. That's very helpful.

And then, in a follow-up to David's question earlier, in some of the areas where you have made bids, whether they be solicited or unsolicited, have these been in areas that are where you're currently producing or you currently have a meaningful position, looking to meaningfully expand that position, or have they been more in newer areas?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Our first priority is to increase ownership in areas that we have an operating presence and we have local knowledge and arguably expertise. And so, our focus has been on trying to add to acreage positions in areas where we're currently active.

We have a new ventures group, by the way, as well that is charged with coming up with new ideas and new geologic concepts, and those guys aren't -- and ladies are not constrained to just looking in the areas where we're currently active. But the bids have been in areas where -- and offers have been in areas where we're currently active.

Operator

Hsulin Peng, Robert W. Baird.

Hsulin Peng - *Robert W. Baird & Company, Inc. - Analyst*

So a quick follow-up question to the Marmaton and Tonkawa. I was wondering, can you talk about potential for adding -- so right now, you're running one rig there. What is the potential for adding another rig, just like you are doing in the Bakken area?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Hsulin, the potential is there. What we need to do first, there has been quite a bit of industry activity in both of those plays, and we are, of course, participating in a number of wells drilled by others in sections where we have a lower working interest.

For the most part, these have been sort of first well, first section, and the results are variable. It is not a blanket reservoir, neither the Tonkawa nor the Marmaton.

So the first thing we need to do is seek control over the area to sort of be a little bit more fully mapped and understand the potential, and where I think we add additional rigs is once we are confident that our acreage is within the range of economic well results, we'll come back in and infill those sections, and that's where we can add the additional well count -- rig count, rather.

Hsulin Peng - *Robert W. Baird & Company, Inc. - Analyst*

Got it. And second quick question is for Richard. Can you comment on the G&A trend for the rest of 2012, given that first quarter was slightly higher? Do you expect that to trend back to the more historical norm?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO, Treasurer*

I think, Hsulin, the first quarter we had a couple of unusual things happen. The first being, as you know, we consolidated our Oklahoma offices into Tulsa. We took $2.7 million charge to G&A then. We have got another couple of million dollars that we will recognize over the next two quarters.

And the other piece of that is just sort of the trajectory of employees. And if you look at the first quarter of 2011's employee count to the first quarter of 2012, and think about, let's just pick a number, 50 open positions, we will see an increase in G&A on an absolute-dollar basis. On a per Mcf basis, I think it stays pretty consistent with where it has been in sort of the mid $0.30 per Mcfe range. I don't know if that helps or not.

And there are other things that come, whether that's litigation expense that is lumpy and hard to predict, and the other piece is anything that is sort of share-based is going to move with where the stock price is. And so, the deferred comp piece moves around as well.

So I'll say I think the trend ought to be consistent with where it has been, with those comments in mind.

Operator

Craig Shere, Tuohy Brothers.

Craig Shere - *Tuohy Brothers - Analyst*

I just want to try to clarify. There has been a couple of questions around the comment of, quote-unquote, all things being equal in regards to M&A and the possibility for some altering transactions. Do you see your gas mix only declining through M&A because you're adding liquids through acquisitions, or would you consider, even though you said this might be the time to be a buyer in distressed markets, would you consider divesting some of your existing positions?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Let me try to answer. I think I followed the question, so look, we don't have any plans to sell any assets, and certainly selling gas assets into the current market is sort of counterintuitive to the buy high -- or buy low, sell high sort of mantra.

The shift in liquids as a percentage of total production that I mentioned, 14% last year, roughly 20% this year, and probably about 25% next year, is based on our current run rate and doesn't assume any fundamental change in our property mix as a result of either an acquisition or a divestiture. We don't build into our forecasts, either when we give guidance or when we think about our plan.

We'd like to be opportunistic, and if we see compelling valuations on either side, on either the buy or sell side, of course we'd consider them. And we have always been pruners of our assets when we view the value of holding them to be less than the value that others are willing to pay for them.

Craig Shere - *Tuohy Brothers - Analyst*

Understood.

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

There is no programmatic or built-in assumptions in our current thinking when we talk about our production mix and future forecasts.

Craig Shere - *Tuohy Brothers - Analyst*

Understood. And second question, on Field Services I noticed, I believe, a 10% sequential decline in unaffiliated customer gathering volumes. How exposed is Field Services to the ever-growing exodus from gas E&P fields? I mean, we're even hearing of people lightening up in attractive places, maybe not the core, like the Cana, when they have got alternatives, like the Permian. How exposed are you guys from the midstream standpoint?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO, Treasurer*

Craig, it's Richard. And again, there is the contract structure for the processing business, and the gathering business in the Rockies is a little bit different from the midcontinent, and a lot of the contracts are structured as reservation charges versus throughput charges.

And so, when you look at declining volumes, that may not manifest itself at all in declining revenues or EBITDA, just because of the -- it's a demand charge versus, well, we'll just charge you for every molecule you put through the system.

So I think your comment on a macro basis is right. If you look at what some of the operators are doing in the Rockies, they are reducing their gas [restricted] activities, which should have potentially an impact on gas flowed through the system. It doesn't necessarily translate itself to reduced revenues in the systems.

Craig Shere - *Tuohy Brothers - Analyst*

And how far out are your contracts?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO, Treasurer*

They're either life of lease or 10 years, so we've got a pretty good portfolio in terms of the tenor of that portfolio.

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Craig, just to add to one of Richard thoughts, the other underlying comment is the relative economic viability, if you will, of the producing assets that are connected to our systems.

First of all, our gathering systems outside of the Haynesville are all in the Rockies, and a lot of the fields that we gather are low-decline fields, so they're older properties, or their fields like Pinedale which, you know, I would submit to you that Pinedale's economics, given the well costs and low lifting costs, are competitive with any gas field in North America. So if I'm going to gather gas and have a big component of throughput coming from any field in the U.S., I like Pinedale as a field from which that gathering volume to evolve.

Craig Shere - *Tuohy Brothers - Analyst*

Fair enough. I appreciate that.

Operator

(Operator Instructions). Brian Velie, Capital One Southcoast.

Brian Velie - *Capital One Southcoast, Inc. - Analyst*

I have one quick question. On the outside operator's activity that you mentioned in the Haynesville, it has declined, as you mentioned (technical difficulty). I know from 2011 to 2012, it dropped from about 29% to 22%. Is there any way you can kind of project what it might look like in 2013 if gas prices stay about where they are?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Boy, that requires me to have an even clearer crystal ball to look inside the heads of our partners.

You know, I think that if we -- what I can do is just look at the current rig count and look at how people are pulling rigs out of the play, and presume that at current gas prices and looking at the forward curve, that we shouldn't see a substantial change in activity.

And I would argue that we still have a ways to go in laying down rigs as an industry in the Haynesville and it wouldn't surprise me by the sort of end of the summer to see the rig count at half where it is today. I think some people are running rigs because they have a contract that's going to expire in the next few months and then they are going to lay them down, but we've just seen our outside operated activity, as far as AFEs coming in, well proposals, it's just dried up. And that is what I would presume would continue to be the case into 2013.

Brian Velie - *Capital One Southcoast, Inc. - Analyst*

Okay, thank you. And then, as a follow-up to that, with that money that you had previously spent in the Haynesville field, if it is freed up or any significant portion of what is currently being spent there is freed up, how would you prioritize your more liquids-rich targets? I know you mentioned the Bakken and I've seen some rate-of-return charts before, but with the way things stand right now, where would you go with that kind of money?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

The Bakken still makes sense. Obviously, we'd like to put capital into the Sussex and the other plays in the Powder River basin to the extent that we can gain some traction on permits.

We're seeing some structural changes, by the way, in the processing capability of the BLM, which we hope will help turn that around.

So we're adding a rig in the Bakken as we speak. It will be there sometime before the end of next month. We're contemplating adding another rig in the Bakken later on, so that that is in response to that pricing. We hope we can get some permits and increased activity in the Sussex. And I'm kind of going geographically, which also happens to be sort of return as well.

And then, we're picking up a third rig in the Uinta Basin to develop Green River oil and we will keep that rig busy for the remainder of the year. And then, we're down into the midcontinent region, and the first and highest returns in that area would be these very shallow -- shallowest of the Missouri and washes over the Texas Panhandle with these very high rate, 2,000, 3,000, 5,000 barrel a day oil wells, which pay out quite quickly.

And so, you could anticipate we'll put more capital there as we get permits and as we watch these wells that are coming online that are currently flowing back.

Brian Velie - *Capital One Southcoast, Inc. - Analyst*

That's very helpful. Thank you very much. The rest of my questions have been answered.

Operator

James Spicer, Wells Fargo.

James Spicer - *Wells Fargo Securities, LLC - Analyst*

Just a couple of balance sheet related questions. What was your revolver balance at the end of the quarter?

Richard Doleshek - *QEP Resources, Inc. - EVP, CFO, Treasurer*

At the end of the quarter, it was $101 million.

James Spicer - *Wells Fargo Securities, LLC - Analyst*

Okay, thanks. And can you just comment a little bit more on that term loan you put in place, what the rationale behind that was and what, if any, impact that has on the size of your revolver?

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

James, the term loan was our attempt to increase the size of the availability from banks without asking each one of the 19 banks to take a pro rata share increase in an accordion that we can exercise in the revolver.

So the revolver is $1.5 billion. We can take it to $2 billion, but we didn't want to put a gun at the banks' heads and say, okay, each of you guys take a pro rata share of the increase. So we said we'll do a funded facility that will sit right next to the revolver, look just like the revolver in terms of covenants and pricing, and the financial institutions that have an appetite for that kind of asset can play and the ones that don't don't have to play.

And so, that was -- the rationale was trying to offer a piece of paper that gave us more availability through the bank market, but only required the banks that wanted to have a funded asset on their balance sheet to participate. So it was sort of a hybrid in terms of exercising the accordion versus doing another capital markets issue.

James Spicer - *Wells Fargo Securities, LLC - Analyst*

Okay, that makes sense. And the size of your revolver is still $1.5 billion, then, in terms of (multiple speakers)

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Correct, and it still has the ability to go to $2 billion if we want to exercise the accordion down the road.

James Spicer - *Wells Fargo Securities, LLC - Analyst*

Got it. That's it. Thank you.

Operator

I will now turn the conference back over to management for any closing remarks.

Chuck Stanley - *QEP Resources, Inc. - President, CEO*

Thank you, Regina. Thank, everyone, for dialing in today. Thank you for your interest in QEP, and we look forward to seeing you over the next month or so as we're on the road at a variety of different conferences. So have a good day.

Operator

Ladies and gentlemen, this does conclude today's conference. Thank you all for joining and you may disconnect.