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PRESENTATION

Operator

Good morning. My name is David and I will be your conference operator today. At this time, I would like to welcome everyone to the QEP Resources third-quarter earnings call. All lines have been placed on mute to prevent any background noise. After the speaker's remarks, there will be a question-and-answer session. (Operator Instructions). I would now like to turn the call over to Mr. Richard Doleshek. Sir, you may begin your conference.

Richard Doleshek - *QEP Resources, Inc. - President and CEO*

Thank you, David, and good morning, everyone. This is Richard Doleshek, QEP Resources' Chief Financial Officer. Thank you for joining us for our third-quarter 2011 results conference call. With me today are the usual suspects -- 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 of Investor Relations.

The third quarter marked the beginning of our second year of operations as an independent company since being spun off from Questar Corporation on June 30, 2010. We had a number of important accomplishments in the third quarter including starting up our Blacks Fork II gas processing facility, producing over three quarters of a billion cubic feet equivalent per day in our E&P company and putting in a new five-year $1.5 billion revolving credit facility in place.

In terms of reporting our third-quarter results we issued a combined operations update and earnings release yesterday in which we reported third-quarter and nine-month 2011 results, reported third-quarter 2011 production of 70.7 Bcfe, 55% of which came from our properties in our Southern region and 15% of our production was crude oil and natural gas liquids. We updated operating activities in our core areas and we increased 2011 EBITDA guidance to be in the range of $1.315 billion to $1.35 billion. We increased production guidance to be in the range of 270 to 274 Bcfe and modestly increased our capital guidance to about $1.35 billion, still in line with projected EBITDA.

As a reminder, in conjunction with our spinoff from Questar last year, we distributed Wexpro Company to Questar. Accordingly, we have recast our historic result to treat Wexpro as discontinued operations. In addition, we have recast QEP Field Services results including revenues, volumes, to reflect Questar Gas as an unaffiliated company. Therefore QEP's reported period-to-period results are comparable to each other and we would be happy to provide additional information about this during Q&A.

In today's conference call we are using a non-GAAP measure, EBITDA, which is defined and reconciled to net income in our earnings release. In addition, we will be making numerous forward-looking statements and we remind everyone that our actual results could differ from our estimates for a variety of reasons, many of which are beyond our control and we refer everyone to our more robust forward-looking statements disclaimer in our earnings release.

Turning to our financial results in comparing the third quarter of 2011 to the second quarter of the year, the story was stronger performance at QEP Energy, our E&P business, and slightly weaker performance at QEP Field Services, our Gathering and Processing business. QEP Energy reported sequentially higher natural gas, crude oil, and NGL production, and reported net realized equivalent prices that were slightly lower quarter to quarter.

Field Services results were marginally lower than the previous quarter due to a variety of factors, startups, shakedown, NGL line pack, etc. related to the operations at the Blacks Fork II plant.

Our third-quarter EBITDA was $353.7 million which was $17 million higher than in the second quarter and up 19% from the third quarter of 2010. QEP Energy contributed $267 million or 76% of our aggregate third-quarter EBITDA and QEP Field Services contributed $85 million or about 24%. QEP Energy's EBITDA was up $20 million while Field Services EBITDA was $2 million lower than respective second-quarter levels.

For the first nine months of the year, our EBITDA was just shy of $1 billion which was $[154] million higher than a year ago in spite of net realized gas prices that were 16% lower than 2010. QEP Energy's contribution was $757 million, which was $73 million or roughly 11% higher than the first nine months of 2010. And QEP Field Services contributed $233 million which was about $82 million or 54% higher than the first nine months of 2010 and $29 million more than its full-year EBITDA in 2010.

Factors driving our third-quarter EBITDA include QEP Energy's production which was 70.7 Bcfe in the quarter, or 9% higher than the 64.7 Bcfe reported in the second quarter of 2011. The quarter's production was 15% higher than the 61.7 Bcfe produced in the third quarter of 2010. Of note, NGL volumes were 894,000 barrels, up 127% from the second quarter of the year, benefiting from the start-up of the Blacks Fork II plant.

QEP Energy's net realized equivalent price which includes a settlement of all of our commodity derivatives averaged $4.94 per Mcfe in the quarter which was 2% lower than the 505 per Mcfe realized in the second quarter of 2011 and 3% lower than the $5.10 per Mcfe realized in the third quarter of 2010.

QEP Energy's commodity-driven portfolio contributed $45 million of EBITDA in the quarter compared to $37 million in the second quarter of 2011 and $68 million in the third quarter of 2010. The derivatives portfolio added $0.63 per Mcfe to QEP Energy's net realized price in the third quarter compared to $0.57 per Mcfe in the second quarter of 2011 and $1.11 per Mcfe in the third quarter of 2010.

QEP Energy's combined lease operating and production tax expenses were $64 million in the quarter, up from $60 million in the second quarter of 2011 and up from $52 million in the third quarter of 2010. LOE was up 9% and production taxes were up 4% in the third quarter of 2011 compared to the second quarter. Per unit LOE metrics were flat quarter to quarter at $0.54 per Mcfe and we are flat with the third quarter of 2010 at $0.54 per Mcfe as well.

Finally, QEP Field Services third quarter of 2011 EBITDA was $85 million which was 2% lower than the second quarter of 2011, but 74% higher than in the third quarter of 2010. Gathering margin was down $4 million or 8% in the quarter compared to the second quarter of 2011 due to reduced volumes associated with the short-term third-party gathering processing arrangement. Gathering volumes were up about 4% to 1.38 trillion BTUs per day, processing margin was flat to the second quarter of 2011 on 5% higher fee-based processing volumes, 14% higher average processing fees, 7% lower NGL sales volume and marginally lower NGL sales prices and shrinkage expense that was sequentially $1.1 million higher.

Net income from continuing operations for the quarter was $101.5 million, up 9% percent from the second quarter 2011, influenced primarily by sequential EBITDA growth. Changes in non-cash charges were roughly small between the two quarters. DD&A expenses were up $2 million in the quarter compared to the second quarter of 2011. Exploration impairment and abandonment expenses in aggregate were flat in the quarter compared to second quarter of 2011.

Our provision for income taxes was $5 million higher in the quarter compared to the second quarter 2011 due to higher pretax income although we continue to expect that we will not be a cash income tax payer in 2011.

For the nine months of the year, we reported capital expenditures on an accrual basis of just over $1 billion. Capital expenditures for E&P activities were $939 million, including $41 million on property acquisitions and capital expenditures in our Midstream business were $68 million in the first nine months of the year. We are increasing our capital budget slightly for 2011 to about $1.35 billion and Chuck will have more comments about our capital program in his prepared remarks.

Our balance sheet has grown about $0.5 billion since year-end. We reported total assets of $7.3 billion, net PP&E of $6.3 billion and common shareholder equity of $3.3 billion and total debt of $1.6 billion.

We ended the quarter with $510 million drawn under our $1.5 billion revolving credit facility which was up $10 million from the [amount stated] at the end of the second quarter. In our new credit facility, in August we entered into a new five-year $1.5 billion revolving credit agreement with a group of 19 financial institutions. Conditions in the bank market had improved significantly since the summer of 2010 when we amended our previous facility. In our new facility, we have fewer restrictions, and we have lowered our borrowing cost by 75 basis points and reduced our commitment fee by 17.5 basis points.

The credit agreement contains an accordion feature which will allow us to increase the size of facility to $2 billion and also contains a provision to extend the maturity by two one-year periods. We appreciate the support of the banks and believe we timed the market pretty well.

I will now turn the call over to Chuck.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Good morning. Richard has already reviewed the key financial results for the quarter, so I'll try to add some color to the release, give you an update on our plans for the remainder of this year and then briefly touch on our plans for 2012 and move on to Q&A.

Let me draw your attention to the slides that we posted on our website at QEPRes.com that our Company released yesterday. I will refer to the slides as I walk through the operational details.

Since our last call QEP has completed and turned to sales 13 new Company-operated Haynesville Shale wells. All are very strong with initial rates in line with our previously announced results. QEP operated gross completed Haynesville well costs have averaged $9.1 million in 2011, down from an average of $9.3 million last year.

Other than one section where we recently acquired operatorship, our lease saving activity is now complete on QEP-operated land. And we've commenced drilling 80-acre density pilot well programs in several areas on our acreage.

We currently have six rigs running in the Haynesville play, but now that our leases are saved, you shouldn't be surprised to see us dial back activity going forward. Slides three and four will give you additional details on our Haynesville acreage and on drill times.

At Pinedale, we have completed and turned to sales 89 new wells so far this year and our completion and drilling team has continued to deliver industry-leading completed well costs. Our average gross completed well costs this year are under $3.8 million. We are on track to deliver a total of 100 to 105 completed wells during 2011 at Pinedale.

As we noted in our release, QEP Energy Pinedale production volumes and revenues benefited significantly from the start-up of Field Services Blacks Fork II processing plant in the new fee-based processing arrangement that was effective on the 1st of August. Results from the first two quarters of operation, as Richard mentioned, under this new agreement will be impacted by partial periods for obviously for the month of August as well as allocation of liquids volumes both in Field Services and in energy for line pack. And a period of time where we received Conway pricing for NGLs, we are now receiving Mont Belvieu pricing.

Also note the significant economic impact on recovering liquids from Pinedale Gas at QEP Energy. We have been able to book additional reserves, as we noted in our release, 47.2 million barrels of liquid. Minus the 93 BCF of natural gas reserves associated with the shrink that is lost in the processing of the gas. So this had the impact of reducing field level DD&A at Pinedale by about $0.21 per Mcfe. We currently have four rigs running at Pinedale. You can refer to slides five and six for more detail.

In the Anadarko Basin, Woodford or Cana Shale play we completed and turned to sell four new wells since our last call all with good results. Cana well costs as we described in previous decisions with you very widely across the play. Gross completed well costs in the deepest gas prone portions of the play have ranged from $8.9 million to $9.5 million while recent wells drilled in the shallower liquids-rich portion of the plate have ranged from $7.5 million to $8.5 million.

We currently have two rigs running in the play and we are concentrating our activity in the liquids-rich portion. That is the area that is shown in green on the map on slide seven. We will soon be turning our attention to an infill development drilling program, most likely on 80-acre density in this core area.

Turning to the Williston basin in North Dakota, as you no doubt saw yesterday in our release, we have developed a substantial backlog of standing wells that are waiting on completion. Some of the delay was caused by the drilling of a number of recent wells from two and four well pads which meant we couldn't complete any of the wells on an individual pad until we moved the drilling rig off. This exacerbated scheduling problems in an already tight pumping service environment.

We now are working through the backlog. We recently completed three wells that have just started flowing back and we have 10 more wells that are either currently being completed or waiting on completion. We should work off this backlog as we move through the fourth quarter. It is important to note, I think, that in spite of these delays, QEP's third-quarter Williston basin production was up 55% versus the second quarter of this year.

Last quarter we described plans to ramp up our activity in the Williston to five rigs late this year or early next year by placing two additional drilling rigs on our first 10 well Bakken Three Forks pad. We have decided to delay that ramp-up for now.

First, pressure pumping service issues that cause significant completion delays have also driven a continuous upward spiral in completed well costs. Despite significant improvements by our team in driving down drill times, we have seen recent gross completed well costs for QEP operated long laterals in both the Bakken and Three Forks wells come in at an average gross completed cost of $9.7 million. That is up over $1 million from what it was early this year. We don't like this cost trend frankly and we especially don't like it in the face of softer crude oil prices.

Second, we need much better visibility on the timing of well completions. There is nothing more frustrating than seeing a growing inventory of drilled and cased wells that were standing waiting on completion due to delayed or rescheduled frac dates. We had hoped this problem would be resolved by now, but it isn't. And we are loathe to add more rigs until we are certain that it will result in a proportionate increase in completed wells.

Finally, we are really encouraged by the strong results from our first two Three Forks wells that we've completed on our 90,000-acre leasehold, but we had expected to have a couple more key Three Forks wells completed and producing before we commenced drilling from our first 10 well pad, especially wells targeting at Three Forks. We are just now getting those wells completed and we would really like to see them produce for a while before we commenced pad drilling and are basically committing ourselves to drilling five wells in a row from that first 10 well pad.

I refer you to slide 8 for more details on our Bakken/Three Forks play.

At our Granite Wash/Atoka play in the Texas Panhandle since our last call, we have turned three new QEP-operated wells to sales all with strong results. The first well, the Puryear 827H was completed in the deeper, drier Atoka launch in early August and it produced at a peak rate after processing of 231 barrels a day of oil and NGL plus 8.7 million cubic feet a day of dry gas.

The second well, the Puryear 137H, also targeted the Atoka. It was completed in mid-September and had produced at a peak rate of 284 barrels of oil and NGLs plus a 9.5 million cubic feet a day of dry gas.

The third well, the Huff 724H, was completed in the shallows of the Granite Wash zones, the Caldwell, and that is the liquid -- one of the most liquid-rich zones and it came online in early October. It produced at a peak rate of 1,234 barrels a day of oil and NGLs plus 2.9 million cubic feet a day of dry gas.

In addition to these results, we currently have two QEP-operated horizontal wells, one each in the liquids-rich Caldwell zone and Cherokee zone that are waiting on completion. Well cost in this play have averaged $6.5 million to $8.5 million, depending on the depth and the relative location on our acreage position. Refer to slide nine for more details.

On the exploratory front, we have recently completed our first Marmaton formation exploratory horizontal well in Oklahoma. The initial results from this well looks strong. The well came on a little over 1,000 barrels a day of oil and it is in the early stages of clean-up. From the early results it appears to be as good as or better than the best wells that have been drilled in the play by offset operators. Our second Marmaton well was down cased and will be completed this week or sometime this weekend.

We'll have more data on these wells and more color on the play in our Analyst Day presentations that we will be making on November 14.

In that meeting we will also update you on our plans for horizontal oil-directed drilling in the Powder River Basin in Wyoming where you will recall we are targeting a number of tight sands and we are planning on drilling our first operated Sussex horizontal well early next year. And of course, we will also review with you our early-stage development plans for our liquids-rich Mesa Verde play in Red Wash unit in the Uinta Basin. And also the associated processing Mid-Stream opportunities around that emerging play.

Let me turn to Field Services. QEP Field Services had a great third quarter. The successful start-up commissioning and loading of our Blacks Fork II plant obviously had a significant impact on the results of the quarter. It should also continue to do so in the future.

The plant is really performing quite well, better than design, and we couldn't be happier with the superb execution of both our contractors and our Field Services teams who brought this plant online early and got it up and running without any issues.

In case you missed it, we issued on September 29 a release and a set of slides that detailed the operating and financial impacts of the new Blacks Fork II plant and the Blacks Fork complex. On both Field Services and QEP Energy, I would encourage you to take a look at the slides. They provide a lot of detail. You can also find the release and slides on our website and they should be right there on the home page.

On a macro front, NGL prices remain strong, ethane prices in particular, surprisingly strong. And as we reported yesterday, we have taken advantage of that strength to hedge an additional portion of our forecasted NGL production stream for the remainder of this year and also for 2012. We continue to monitor that market and we may take additional risk off the table as we deem appropriate.

As Richard noted, with better visibility we have raised our full-year 2011 EBITDA and production guidance. We now expect our production to range between 270 and 274 Bcfe up from our prior guidance of 265 to 269 Bcfe. And with Blacks Fork II coming on and our continued focus on capital allocation of to oil and liquids-rich plays, we believe QEP Energy should exit 2011 with oil and NGL comprising about 20% of net reduction volumes, up from about 11% for the full year of 2010.

With the increased production and continued strong performance in Field Services we now forecast our EBITDA could range from $1.3 billion to $1.35 billion. That is up from our previous guidance of $1.275 billion to $1.325 billion.

We gave you the main drivers in the release yesterday on what is driving that and Richard has already commented on it. As we continue to notch the efficiency gains in our core areas except of course in the Bakken, we have seen an increase in the number of completed wells and obviously the completed well costs are coming down, but the well count is going up both in the Haynesville and in the Pinedale play. We are still struggling with well cost in the Bakken, but that has driven a $1.35 billion capital budget, slight increase over our previous budget. Most of that increase is due to the increase in the number of Pinedale wells as I mentioned and Haynesville wells that are waiting on completion, as well as higher outside operated well costs in the Haynesville play.

We have also accelerated capital deployed in the Williston Basin to build a water gathering system to reduce operating costs for our wells producing from the Bakken and Three Forks.

I know many of you turned in today to get some color on our plans for next year. Unfortunately, as was the case last year, this call precedes our Annual Fall Board Meeting where we discuss our plans for 2012. As a result we didn't give any 2012 capital investment production or EBITDA guidance in our release yesterday. I can't front run the Board's decisionmaking process so I can't give you any details on our plan here today other than to make some general philosophical comments about our planning process which, if you've listened to us in previous calls, should sound very familiar to you as well as to the folks in our organization.

Number one, we plan to live in and around our forecasted EBITDAX for next year. We continue to focus on the allocating capital to the highest return projects in our portfolio. I have given you some hints about the way we're doing that. We are pushing more capital to liquids-rich plays and dialing down capital allocated to dry gas plays. We are focused on maintaining operational efficiencies not only in our drilling and completion operations, but also in our production operations and as we've described focusing on allocating capital to build out liquids-gathering infrastructure and other infrastructure to continue to drive down lease operating expense.

We believe we can through this capital allocation process continue to deliver profitable production growth.

So what does this mean? Our base case plan for the next year fits in with all these criteria. Even with these prices we think that we can still propel midteens growth in production and EBITDA over our five-year planning horizon. I can also tell you that from our pre-Board planning meeting when we get the management team of QEP together, both our management team and our team of talented asset managers are excited about the future potential of your Company and about our ability to drive profitable growth from our portfolio of high-quality assets.

In the current commodity environment we think there are very few companies in as good a position as QEP to continue to deliver significant growth while living in and around EBITDA. With that, David, let's open the lines for questions.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions). Brian Corales with Howard Weil.

Brian Corales - *Howard Weil - Analyst*

Good morning. Congratulations on the quarter. On the Bakken, you talked we've seen cost increase, I guess for everybody. Do you have any signs that that is going to slow down in the coming quarters?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

We have not seen any signs of a plateauing or a decline in cost so far. Intuitively, you would think that as the service industry responds to the rig count that there would be a decline in costs as the infrastructure catches up with growth. The rig count has continued to increase and frankly I think that the pumping service sector has lagged the rig count and that is what has led to we and a lot of other operators seeing an increase in the completion costs.

And, you know we are watching and hoping for that, but we haven't seen any yet and hence our reaction in not adding a couple of additional rigs to the drilling fleet out there only to build a larger inventory of standing wells. So as we see the service companies respond we can make appropriate adjustments real time.

One of the comments that the folks that work for me have said is that they think that there is enough horsepower in the basin, but that it is being poorly utilized due to logistical problems, getting proppant into the field, crew moves and then operator inefficiencies and scheduling frac dates, all of which is contributing to tightness in supply of pumping services and, hence, the spiraling well cost. We can manage our own activity but we cannot manage the activity of the other operators in the basin that are contributing to it obviously.

Brian Corales - *Howard Weil - Analyst*

And maybe just switching to the Haynesville -- I mean, you kind of made some comments it sounds like activity may decline next year, you are currently at six rigs. Is this a place that you would stop altogether or what is an ideal in a low commodity price environment, an ideal level of rig count?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

We haven't finalized our decision. As I said, I don't want to front run our discussion with our Board. I can tell you that it is highly unlikely we will run six rigs next year. I think it's reasonably likely that we won't go to zero. But I think we can dial down substantially there.

There are some things that we really want to answer and the primary question is, what is the appropriate well density to develop our Haynesville reservoir. And to do that we need several sections, multiple sections of pilot wells that we drill and complete and put online so that we can watch the production behavior over an extended period of time. And it is our intention to drill those wells. We are already drilling one pilot section right now. We have several others planned across our acreage that we think there is enough variability even in the small footprint of QEP-operated acreage, that we need to sample a couple of different areas in order to get a good feeling.

So with that said, I would expect a substantial pulldown. We'll give you all those details when we do our Analyst Day after we have had that conversation with our Board. But a substantial pulldown in the rig count.

One of the things we are unable to forecast, we have had conversations with our partners, but we yet don't have a very clear understanding of what our direct offset partners are going to do with their activity in the play. And that is a wild card in forecasting outside operated capital. We would likely want to participate in wells drilled in and around the periphery there because even at current prices, the economics are attractive.

Brian Corales - *Howard Weil - Analyst*

Okay. Then, one final question. Is it how much acreage do you have in that western Oklahoma and the Marmaton and some of the other zones?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well, it varies by zone. We have got 30,000 plus acres in the Marmaton. We've got other zones that are prospective in which we are still assembling acreage. I had rather not give a lot of details on it. We'll put some maps up in our Analyst Day presentation which will give you a general feel for the inventory in each of the separate plays. As you note there are multiple liquids rich gas and oil plays in the play in the region that we are pursuing.

So, some of them are stacked, some of them are sort of all set. So, by giving you an acreage number, I really need to do it on a play-by-play basis and I'm just not ready to do that right now.

Brian Corales - *Howard Weil - Analyst*

All right, thank you.

Operator

Brian Singer of Goldman Sachs.

Brian Singer - *Goldman Sachs - Analyst*

Good morning. Chuck, as you shift towards liquids, do you expect that you could still generate I think as you said midteens production growth? Or is there a sacrifice of the absolute production growth rate in exchange for higher valued production mix? I guess can you have your cake and eat it too?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

As we model it out, obviously a big component of our production volumes is 80% of it is dry gas, but the growing liquids volume helps mitigate some of the decline in dry gas production as we shift capital to the liquids-rich plays. If you look over the five-year planning horizon and we -- I look at it over a five-year horizon, because quarter to quarter, you'll see variability as we have delays in well completions and things like that -- we think we can continue to drive midteens production and EBITDA growth.

Will it be a perfect linear trajectory? No, it will be a bit lumpy. But obviously the benefit of new processing that is coming on, our focus on liquids-rich gas in the Uinta, and in other plays, should help drive that growth and allow us to continue to deliver in the teens production and EBITDA growth over the five-year planning horizon.

Brian Singer - *Goldman Sachs - Analyst*

Where would the liquids percentage of the total get you five years out when you think about that horizon?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

It moves into the -- from 20% this year out, next year it doesn't move dramatically. Because think about it; we will exit at 20% this year. Next year we will average 20 -- a little over 20%. In five years, I don't have the number on the top of my head, but it increases significantly over that time period.

Brian Singer - *Goldman Sachs - Analyst*

Thanks and then another big picture question here. We have seen a number of split-ups in Midstream assets, from E&P assets, really going back to the QEP spinoff. Now that Blacks Fork II is online, can you talk to the strategic importance of the Midstream business and adding liquid exposure and the sustained base of EBITDA versus the potential benefits of more independent structures?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

It's the same question from last quarter. We are looking at our Midstream business and thinking about obviously the evaluation of that business inside QEP Resources versus in some other structure. We continue to discuss it internally and with our directors. We haven't made any decision on a forward approach.

Obviously the benefit of the ability to control the infrastructure, prebuild infrastructure to connect wells timely, maximize the diameter of gathering pipes to avoid high line pressures on new wells as they come on in places like the Haynesville are attributes that argue for at least maintaining control of the Midstream infrastructure. Now does that mean we have to own it 100% or is there some other vehicle that we can use? Obviously, those are questions that we are continuing to ponder and discuss with our Board.

But as I said, we haven't made a definitive decision on what is right at this juncture.

Brian Singer - *Goldman Sachs - Analyst*

Last little question and potentially a bit of a repeat from the last one, but is there a gas price threshold below which you would dial down the rig count in the Haynesville or the other way to say it would be is there some gas price where you would be comfortable with the rig count that you have now that acreage is held?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

At 450, the Haynesville wells that we are drilling generate very good returns and I think everybody focuses on the prompt gas price. If you look at the forward strip, our wells generate quite good returns. Obviously, we can manage some of that commodity exposure by hedging out on the forward strip to protect the activity.

That being said, I mean we are opportunity-rich and capital-constrained so as stewards of capital, we will tend to move capital around to the higher return plays in our portfolio which are the more liquids rich plays in the Rockies and in the Mid-Continent.

Do I anticipate running six rigs at the current price out there? No. If gas prices went up to $5.00, would I reconsider that? Maybe. But it really depends on the other opportunities and how they stack up on a return basis.

I think it's important to realize that the activity level out there has obviously driven our efficiencies significantly and we are focused on doing everything we can to maintain those efficiencies and maintain the expertise and the skill set, some of which we can move around from one play to another and preserve. But it takes a while to ramp back up from one rig or no rigs to eight rigs or 10 rigs in a play.

So you lose some of the efficiencies that you've embedded in the organization right now and on the ground in the drilling completion shop and it takes a while to get those back. And that is part of what is driving our decision-making forecast on allocation to the Haynesville and all of our other plays.

Brian Singer - *Goldman Sachs - Analyst*

Great, thank you.

Operator

Subash Chandra of Jefferies.

Subash Chandra - *Jefferies & Company - Analyst*

So on Pinedale, Blacks Fork, trying to get an understanding of how much of the growth sequentially was Blacks Fork-related, how much of that was so-called organic?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well, I view Blacks Fork II as organic liquids production growth. I mean it was liquids that we were producing from an asset QEP Energy was producing from an asset, that we were selling as methane molecules because of our inability to extract the liquids. So as far as the way I think about it, we are now capturing value from that gas stream that arguably we should have been capturing several years ago. So that was part of the driver.

Richard Doleshek - *QEP Resources, Inc. - President and CEO*

Almost 490,000 barrels of NGLs came out of Pinedale in the quarter that was directly related to Blacks Fork II.

Subash Chandra - *Jefferies & Company - Analyst*

Got you. So there was -- shouldn't have been any dry gas benefit, right? There should have been almost a dry gas negative, but even the dry gas volume growth was fairly strong so trying to get an understanding of what that looks like in Q4.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Actually, Pinedale had about a 3 almost 4 BCF increase second quarter or the third quarter. So increased completion activity, so yes there was probably some shrinkage that you didn't see. So again, we were Mcf not BTU volumes. So there wasn't a lot of that that you'd see quarter to quarter.

Subash Chandra - *Jefferies & Company - Analyst*

In the Cana, the slides sort of Q3 versus Q2 has a tier 1 acreage reduced, sort of what was the thought process behind that and what that might mean for drilling activity if anything? And secondly was that you went to a sequential decline, was that sort of a one-time item? Sort of what was going on there?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

So, on the Cana, you are correct. If you compare the outline of the tier 1 from the previous IR slides to the one we released yesterday, you'll see it has contracted some. What we have done is just tighten the area around the thick part of the Cana Shale. It is the area where we have seen the most consistent well results and where we are focusing our current drilling activity.

The tier 2 area is still viable. But I will tell you that the results have been less consistent. When you move into the area where the Cana is less than 100 feet thick, we've seen some very good wells completed and turned to sales and some not-so-good wells completed and turned to sales. So from a predictability standpoint and therefore a risk standpoint, we have tightened our view of what we think is core tier 1 acreage. And that is what is shown in that revised number. Second --?

Subash Chandra - *Jefferies & Company - Analyst*

And Chuck, just to follow up on the tier 1 then so if you are focusing your one and that is I guess I don't have it right here in front of me I think something like 20,000 -- 30,000, 31,500 acres now. So I think you can sustain, I guess the math would be to sustain the two rig program there for quite some time with 30,000 acres. Is that pretty fair?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Absolutely. And you could arguably sustain an even higher rig count. That area and in particular the green area inside the tier 1 is an area where returns are still quite good even at current gas prices. And it stacks up quite well in our portfolio of investment opportunities.

We are at the point now where we are ready to start development. Most of the activity to date has been one well per section to save leases and to develop some control across the acreage, especially as you move up, dip into the oilier portion of the play. There are enough wells drilled and you can see it from that slide, slide seven, across that core area now I think everyone feels very comfortable with the geology and the reservoir and predictability of well results.

So now it is time to set up on individual sections and start developing the reservoir in an orderly fashion. Just like the Haynesville, we are trying to avoid creating a bunch of pressure sinks in the reservoir that would cause long-term completion problems where we have wells interfering -- older wells being either damaged or interfering with the efficiency of fracing new wells. So we are moving beyond the acreage-saving activity in the core now and into development mode.

Second question on the Uinta sequential production. We do not have any rigs running in the Uinta Basin right now. So what you're seeing basically is the organic PDP decline in that asset. And you have been seeing it for the better part of the year.

Subash Chandra - *Jefferies & Company - Analyst*

Okay. And I will ask the, I guess, 2012 question again. Because as we look at the base here of the growth assets and Pinedale is going to sustain growth I would imagine, but then some of the other growing assets -- Cana, Haynesville, and Bakken -- I mean two of the three I think you signaled today wouldn't sort of be in growth mode.

So back to the 20 -- the midteens growth rate question. It sounded to me like you thought that it's very achievable on a five-year basis as you sort of kickstart new plays to make up for plays that you are differing from or eliminating. But the lumpiness, you said there was lumpiness. I just wasn't quite sure where that left us on an annual basis or quarterly basis?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

It will be both. You will see lumpiness on a quarterly basis. We still have lumpiness in the Rocky Mountains, in particular Pinedale, because as you remember from previous calls, we slow down -- we stopped that completion activity at Pinedale. Sometime about now in fact it is snowing in Pinedale as we speak. And as soon as the weather gets too cold to operate efficiently, we shut down fracing out there and we will do that sometime late November, into December just depending on when the cold weather hits.

So that will introduce quarter-to-quarter lumpiness although we hope we will be able to make up for that through the spring and the rest of the year next year.

I don't want you to misread what I said. In particular, the comment you made about the Bakken and the Cana, we think we can continue to grow production in the Bakken and the Cana and do so quite significantly. The Bakken don't focus on rig count so much as number of wells that we can complete and turn to sales. Our drilling efficiencies and drill times have come down substantially in the Bakken. And so, our well delivery system shouldn't be simply a focus on rig -- on absolute rig count, but on the number of wells we can drill and complete and turn to sales.

Same in the Cana. We are able to get the wells down quicker and we'll be able to deliver production growth there through efficiency and drill time. In the Uinta Basin, you've noticed that the sequential decline there and it is because we haven't been allocating capital to that area, but we I did mention that we will be talking about an increase in activity in Uinta Basin, focus on liquids-rich gas, and I'll also point out that in drilling to that Mesa Verde target, which is a stacked series of liquids rich gas-bearing sands in the Mesa River formation.

We are also drilling through the old Red Wash oil field where there is over 600 million barrels of oil in place, a loosely spaced grid of old producing wells and with our infill drilling that we are going to do out there, we will see that reservoir over and over again and it is like many other complex stacks and reservoirs that we think there is opportunity to find additional oil reserves and increase oil production there as well.

So there's lots of opportunities and lots of levers to pull. I am not concerned about growth next year or into future years. I only warn on lumpiness because we don't forecast quarter to quarter. We don't give quarter-to-quarter guidance because we do have seasonally impacted operations, particularly in the Rockies. And when we give production guidance for the year, we have had a pretty good track record of being able to meet that guidance or exceed it.

Subash Chandra - *Jefferies & Company - Analyst*

Final follow-up for me. Chuck, you've mentioned Bakken Cana, would you throw the Haynesville in that category too? Better efficiency, production growth on lower CAPEX?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Yes, I mean it will be somewhat better. A lot of the production response to drilling dollars in the Haynesville is directly related to the working interest we have in this section. So -- that we are drilling -- and so this year and previous quarters, we have had six rigs running in the play. And sometimes those rigs have been drilling on sections in which we had a very small working interest. We actually did a deal with one of our partners in which we went out and drilled some wells with remarkably low working interest in order to keep our efficiencies up, because we were able to drill and complete the wells for over $1 million less than their completed well cost and we still had an interest in it. We thought it was a mutually beneficial thing to do.

Whether or not we are able to continue to do that next year is still an open question. I would focus more on total capital. We will reduce our capital in the Haynesville and we won't see the dramatic growth in production that we've seen out of the Haynesville this year in 2012. But again I am not concerned about being able to put up significant growth next year.

Subash Chandra - *Jefferies & Company - Analyst*

Terrific, thank you very much.

Operator

William Butler, Stephens.

William Butler - *Stephens Inc. - Analyst*

Great quarter, guys.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Thank you.

William Butler - *Stephens Inc. - Analyst*

Just not to beat a dead horse here, but just think talking broadly again on the five-year sort of growth buoys. That is within -- spending within cash flow run around there, correct?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Yes within EBITDAX. So we think about EBITDAX as sort of our available cash to invest. And over that time period, when we model it out, we see the Company continue to delever over time. And that is, I think, a pretty unusual result.

Richard Doleshek - *QEP Resources, Inc. - President and CEO*

Yes, delever on a debt multiple of EBITDA.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Right, actually. Right.

William Butler - *Stephens Inc. - Analyst*

Thank you for that clarification. And in the Pinedale, the amount of completions that you had this quarter, was that sort of held back awaiting the Blacks Fork's just for both the capacity and for the ability to get the NGL uplift? Or that is pretty one-time step change, correct? And why was that I guess, one more detail?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well no. I don't -- it is sort of a normal pace of completion. Basically, William, we have one frac group dedicated to us and it's a conveyor belt from whenever they are able to start up in the spring. And I think this year were able to get out in what, Jay, May -- I'm sorry March?

Jay Neese - *QEP Resources, Inc. - EVP*

Early March.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Early March. So from early March onward we have been utilizing one frac crew. As you will recall we are drilling from pads at Pinedale. We work on multiple wells at the same time while we are fracing and so we are able to drive well delivery basically with that frac crew. They run 24 hours a day, seven days a week and they just move from well to well or pad to pad.

So there is nothing unusual about the pace of completion so that you shouldn't read anything into just this quarter.

William Butler - *Stephens Inc. - Analyst*

But like you had indicated, probably more of a seasonal thing. I mean it just gets stronger through the summer.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Yes, right. And we have our dimension that we are planning on picking up some additional rigs at Pinedale later on this year to continue to drive growth in that production volume to load not only the brand-new Blacks Fork II plant, but the Blacks Fork I plant which is part of the processing complex and continue to drive liquids production growth through our Midstream business.

William Butler - *Stephens Inc. - Analyst*

And lastly, going back to the Bakken with sort of the deferral of adding the rigs, can you give a little more detail on the timing of these other two- and four-well pad completions you've got and I think you had previously said on that 10-well pad, you are anticipating bringing it on mid-next year and so where does that slide to now?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well it depends on when we get some visibility around the availability of pumping services. We have -- don't get hung up on just the 10-well pad. We have a number of other pads from which we can drill. We likely won't put two rigs on that 10-well pad with our existing three rig active drilling plan because that's basically sticks two of the three rigs on one pad for six months. So we will leave that pad, the 10-well pad for two additional rigs to occupy.

We have a number of other pads that we can drill from that will allow us to continue to drive growth and, obviously, since they are not 10-well pads, we'll get those wells online quicker, assuming some breakthrough in the pressure pumping services sector that allows us to more efficiently complete the wells. So I'm not concerned about delivering growth there. In fact, I would think we might actually be be able to do a little better than we would having two rigs stranded on a 10-well pad going forward.

William Butler - *Stephens Inc. - Analyst*

What do you think it takes to get either time or critical mass to get the efficiencies you're used to in places like the Pinedale and Haynesville to sort of get that level of economies of scale going in the Bakken?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well, I think first it takes the service sector -- the pumping service sector, in particular -- catching up with the rig count. You've watched the rig count in the Bakken continue to climb over time, and there's just been a dramatic lag in the service -- in the pumping service side -- catching up with it. Once it does, then it will take some time for the service sector to get more efficient in delivering those services and operators to become more efficient and utilizing the service system. How long does that take?

It probably took a year in the Haynesville. Once we sort of saw the rig count peak, before we saw the service sector level out and be able to reliably provide services, so it's a hard question to answer not knowing where the rig count is going in the Bakken. Now from our own perspective, we think we can be pretty efficient to the extent that we can get the services on the ground on our location. So, we know how to complete these wells and we can do it efficiently as soon as we have the services available to do it with if that answers your question.

William Butler - *Stephens Inc. - Analyst*

It does. I appreciate it. Thank you, that is all I had.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Thanks.

Operator

David Heikkinen. Tudor, Pickering, Holt.

David Heikkinen - *Tuder, Pickering, Holt & Co. Securities - Analyst*

Just thinking about the Bakken and the Haynesville and your focus on returns, can you talk about what well costs you would target before you would start ramping activities at current oil price? Or in conjunction is there an oil price at the current $9.7 million Bakken cost that you would slow activity?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

I think when we saw oil prices in the $85 range we were becoming concerned about the margins basically at $9.5 million, $9.7 million and $85 oil. There wasn't a lot of cushion left in our returns.

If you look at a typical Bakken well at $9.5 million at $80 oil, is generating a low 20% IRR and that doesn't give you a lot of cushion especially for delays, mechanical upsets, things like that. That is assuming that you can drill the well, get the rig off of it and timely completed and turn it to sales and you start tracking capital as we have this past quarter, it really does ding the return. So that has been our concern is the volatility of NYMEX crude oil prices concerns about widening basis differential in the Williston, and also just our inability to get wells timely completed and turned to sales.

At current prices, we are comfortable continuing to invest in the program assuming we can work off the inventory and keep the inventory of standing wells at a more normal level.

David Heikkinen - *Tuder, Pickering, Holt & Co. Securities - Analyst*

That is kind of one well in front of each rig. It would be a normal type level.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well, one or two. It depends on some pads. We will have a couple of wells stranded under the rig while we drill and case the last well. But, yes, one or two wells is more comfortable than where we are today with -- at one point we had 13 or 14 in front of 2.5 rigs basically.

David Heikkinen - *Tuder, Pickering, Holt & Co. Securities - Analyst*

Then in the Haynesville, the non-operated Haynesville well costs are considerably more than your operated costs. Can you answer the same question of gas price or well cost, where you would either nonconsent or not participate? Could you just talk about that in the Haynesville?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well we have in the past nonconsented some wells in the Haynesville where we have seen well cost in excess of $11.5 million, and under any reasonable gas price scenario it just doesn't make sense. There are some strange things in the Haynesville Shale play that most people are not aware of and one of them is in Louisiana, even if you nonconsent a well, you are still liable to pay the royalties on the gas production stream from that well, which makes us more likely than not to participate in a well even if it is marginally economic. Because we are still on the hook to pay the royalty even if we are not participating in the well with a working interest. So we have to pay the lease owner our share of the royalty on a unit basis.

So that is a vagarity that I don't think many people are focused on in the Haynesville and it's to my knowledge unique to Louisiana. I don't think there is any other state that has that issue. Something that obviously we would like to see fixed, but until it is fixed, we are sort of along for the ride in some of these wells.

I will say that the majority of the wells, offset wells that are being drilled by other operators or one operator that is pretty efficient and has told us that they are focused on driving down their costs. And we think there are some things they can do to do that they should make the economics more palatable to us.

David Heikkinen - *Tuder, Pickering, Holt & Co. Securities - Analyst*

Okay, thanks, guys.

Operator

Hsulin Peng of Robert Baird.

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

Good morning. Great quarter, everyone. Just a quick follow-up question on the Bakken. You had mentioned the 4,100, the flow rate in the third quarter, I was wondering if you have a even the backlog of 10 wells, do you have a target at 2011 exit rate for the Bakken?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

I don't have the number at my fingertips. But we have sort of guided to a 20% liquids versus gas production rate. I don't have an exact exit rate for the oil production from the Bakken for the year.

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

Also the 20% -- 20% liquids mix for 2012. Do you -- is that predicated on not adding additional rigs in the Bakken as well? Can you get there without adding additional rigs in the Bakken?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Yes, we can.

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

Okay. Then the second question is the Haynesville, given that you are restricting your flow rate there to improve the EUR, I was wondering if you can give us an update on what you are seeing for the EUR trend currently?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well, we have given you some data in our past IR materials and in last quarter's operations release slide deck where we showed you the relative performance, both in flowing pressures and in estimated EURs for a family of four wells that QEP operated that we drilled and completed compared to the performance of what I would call more unconstrained flowbacks by two other operators.

And what we see is, I'll make some general observations. I think first of all, we believe that constrained flowbacks will ultimately result in higher EURs and better longtime well performance. And that data shows it I think in two ways.

The most dramatic is that it shows in our family of four wells that even after they produce 3.5 Bcf of gas they were flowing at an average rate or average pressure rather of about 4,000 pounds compared to the other offset operators of wells that were at half that pressure or less. And flowing pressure is ultimately going to correlate to ultimate recovery. Because at any given production rate to have a well that is flowing at double the pressure of an offset well is telling you that you are still remaining in contact with more of the reservoir effectively draining more of the reservoir than the wells that were flowed back hard.

The biggest thing that will drive ultimate recovery in EUR forecasting in the Haynesville is the assignment of a B factor and the B factor is the hyperbolic exponent that we assign to the -- when we forecast their production from these wells. And one of the slides that I have the distinct advantage that the listeners don't have a -- seeing some of the slides that we are putting together for the analyst day. But one of the slides will show in the Analyst Day is the sensitivity of the hyperbolic of ultimate recoverable reserves per well in the Haynesville to the assignment of the hyperbolic exponent in the decline curve.

And one of the things you'll see from this slide that I happen to be looking at right now is that there is a broad range of hyperbolic exponents that you can assign to a well with even a couple of years of production history that drives a wide range of EUR results. We are currently using what 0.3, right, for hyperbolic exponent. Some other operators have used hyperbolic exponent is closer to 1, 0.8, 0.9.

So if you take our typical 0.3 hyperbolic exponent on a typical well in our core area, that gives us the 6 to 6.1 Bcfe EUR. If we take that same data, the same production data and we assume a 0.9 hyperbolic exponent, the EUR of that well, forecasted EUR of that well jumps over 10 Bcfe, 10.7 Bcfe.

Both assumptions or both reserve assignments don't violate any of the existing production data and it kind of gives you a feel for the range of possible outcomes. And, oh by the way they also -- the 10.7 or 10.5 Bcf high-end EUR doesn't violate the gas in place assumptions and recovery factors. You still get reasonable recovery factors of gas in plays in a section with eight wells drilled in the Haynesville.

So there is still a lot we don't know about the Haynesville reservoir and its long-term performance. The constraining wells are showing us that we are continuing to stay in contact with a lot more reservoirs. We have seen wells now that have accumulated over 50% of our assigned EUR of 6 plus or minus Bcfe which makes us very comfortable that we probably won't be negatively revising the reserves assigned to our PDP.

There is upside and we will show you that graphically in our Analyst Day presentations.

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

I am looking forward to the Analyst Day. Thank you.

Operator

(Operator Instructions). Drew Venker, Lazard Capital Markets.

Drew Venker - *Lazard Capital Markets - Analyst*

What is the potential level of activity in the Marmaton going forward if you continue to have success? Could you run a couple of rigs there next year?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

We have a couple of rigs running there right now between the Marmaton and the Tonkawa and, yes, if we see the results that we have seen from our first well and the second well that shows look good although shows don't make money. But just looking at what offset operators have been putting up for results and knowing our inventory, a couple of rigs next year is reasonable.

Drew Venker - *Lazard Capital Markets - Analyst*

And when do you plan to start drilling again in Red Wash? Is that next year?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

It will be late this year or early next year.

Drew Venker - *Lazard Capital Markets - Analyst*

Thanks, that is all I had.

Operator

(Operator Instructions). Jay Yannello of [Skiden Capital].

Jay Yannello - *Skiden Capital - Analyst*

Good morning. There has been some real extreme volatility in your stock price with the help of double leverage, triple leverage ETF's and high frequency in trading and all of that, all that stuff. And while I realize you can't front run the Board meeting, do those daily moves affect the choice that the Board may consider? In other words, I realize that you want to unlock the most value for the long term, but there is also some -- what could argue as pretty amazing short-term opportunities and, basically, are all things on the table for this meeting?

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

I think we have a pretty open-minded Board and we try to have and a great Board with a lot of industry experience. I haven't added up the accumulative experience, but it's got to be, without making them sound old, over several hundred years of experience that sits around the table. I think that our Board and certainly our management team are all about creating value for shareholders, short-term and long-term, and so with that comment I guess everything is on the table.

We think about things carefully though and don't and try not to make instantaneous decisions in reaction to one day vol chart. I happen to be -- I've looked at the volatility just in the independent E&P space and it's amazing to me how volatile everybody's stock is, not just QEP's, but you see wide trading ranges through intraday and over one month or a one-week period. A lot of times without any rational explanation, I mean, commodity prices have moved dramatically.

Certainly during the day or during a week we don't see any dramatic changes in our view of the world or our activity or results yet we see wild swings in stock price and in volumes. And it very well it could be driven by the high-frequency trading and leverage, but it -- we have to run the Company mindful that we have long-term assets. We have what we think is a great inventory to drive growth in our upstream business, a great midstream business and we are focused on creating value for shareholders and not overreacting to instantaneous changes in the stock price.

Jay Yannello - *Skiden Capital - Analyst*

Okay, thank you.

Operator

(Operator Instructions).

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Well, David, it sounds like we don't have any more callers waiting in the queue.

Operator

No, sir. There are no additional questions in queue at this time.

Chuck Stanley - *QEP Resources, Inc. - EVP, CFO and Treasurer*

Okay, well, thank you all for calling in today. We look forward to seeing you at our Analyst Day in New York on November 14. And as always feel free to call Scott Gutberlet if you have follow-up questions and thank you all for your interest in QEP.

Operator

Ladies and gentlemen, this does conclude today's conference. Thank you for your participation. You may now disconnect.
