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QEP - Q2 2014 QEP Resources Inc Earnings Call

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OVERVIEW:

QEP reported 2Q14 net loss attributable to QEP of $92.3m and adjusted net income of $67.9m or $0.38 per share.

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PRESENTATION

Operator

Greetings, and welcome to the QEP Resources second quarter earnings conference call. At this time, all participants are in a listen-only mode. A brief question and answer session will follow the formal presentation.

(Operator Instructions)

As a reminder, this conference is being recorded. I would now like to turn the conference over to your host, Mr. Greg Bensen, Director of Investor Relations. Thank you, sir. You may begin.

Greg Bensen - *QEP Resources Inc - Director of IR*

Thank you, Latanya, and good morning, everyone. Thank you for joining us for the QEP Resources second quarter 2014 results conference call. With me today at Chuck Stanley, Chairman, President, and Chief Executive Officer; Richard Doleshek, Executive Vice President and Chief Financial Officer; Jim Torgerson, Executive Vice President and Head of our E&P Business; and Perry Richards, Senior Vice President and Head of our Instream Business. If you've not done so already, please go to our website, www.qepres.com to obtain copies of our earnings release which contains tables with our financial results and the slide presentation with maps and other supporting materials.

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

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

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Thanks, Greg, and good morning, everyone. I'd like to begin with a quick review on our progress on some key strategic initiatives, then I'll briefly touch on some operational results for the quarter and then finish with our plans for the remainder of 2014. I'll then turn it over to Richard who will review our second-quarter financial results as well as our 2014 guidance assumptions before we move on to Q&A.

Over the past several years, we've been successfully executing on our strategy to transition QEP into a more balanced and focused portfolio of E&P assets with an emphasis on growing higher-margin crude oil and liquids-rich gas production while divesting of non-core assets to better focus our human and financial capital. In the second-quarter 2014, we made great progress on our strategy. Let me touch on a few highlights of the quarter.

First, we posted record EBITDA. Our record EBITDA was driven by record quarterly production which included 67% increase in higher-margin crude oil volumes from last year. Second, we continue to make great operational progress in the crude oil basins of the Williston and Permian with the daily production increases of 15% and 16% respectively over the first quarter of this year. We continue our technical innovation and the new innovation, and we are now unveiling an exciting new horizontal development approach for the lower Mesaverde play there.

We also improved our balance sheet and operational focus through upstream asset sales and the sale of a 40% interest in Green River Processing to our affiliate QEPM, which closed on July 1, and we also made substantial progress on the separation of QEP Field Services from QEP Resources. Let me elaborate a bit on that last point.

In December of last year, we announced plans to unlock additional value for our shareholders by fully separating our Midstream business, QEP Field Services, including its ownership in QEP Midstream Partners, from QEP Resources. When complete, would believe this separation will better position both our E&P and our Midstream businesses to compete and thrive in their respective business environments. We are pursuing multiple avenues to achieve the Midstream separation ranging an outright sale of the business to a straight spinoff of the business to QEP shareholders. To prepare for the possibility of a straight spin or various spin merged transaction structures, we filed a Form 10 in the SEC in the second quarter as promised.

Last quarter, we also told you that we had finalized a confidential information, or SIM, that contains asset-level operational, commercial and financial information for QEP Field Services. The confidential information memorandum was distributed to interested parties shortly after our first quarter call. We received very strong indicative offers, and we are currently in the second and final round of that process and expect to receive final binding offers in the next few weeks. The range of proposed potential transactions includes various merger of combination structures, offers to purchase QEP Field Services for cash, and several other alternative transaction structures.

So, what are the next steps in the separation process? After receiving the final offers in the second round, we will either choose to pursue one of the proposals and then proceed toward the negotiation and execution of a definitive transaction agreement, or we'll decide to proceed down the path of a straight spinoff at Field Services.

Our ultimate objective is maximization of shareholder value and the continuation of profitable Midstream operations is part of a viable, competitive midstream industry. We expect to reach a final decision on the right path forward in the third quarter, and we hope to complete the separation before the end of this year. In the meantime, we'll continue to maximize value for both our E&P and Midstream businesses.

To this end, on July 1, we closed on the sale of a 40% membership interest in Green River Processing LLC to QEP Midstream Partners for gross proceeds of $230 million. Green River Processing owns our Blacks Fork and Emigrant Trail processing assets in southwestern Wyoming. By selling a membership interest in Green River at a valuation that was well about QEP's EBITDA multiple and below that, a few EPMs, this transaction will be accretive to both entities.

To further focus our E&P asset portfolio, we closed on the sale of certain non-core E&P priorities, primarily in the Midcontinent region, for total proceeds of approximately $702 million before post closing adjustments. Combined with the proceeds from the Green River Processing drop-down, these transactions go a long way toward offsetting the $942 million purchase price of our Permian basin acquisition. As a reminder, we structured the recent purchases -- purchase of the Permian assets and the recent sales of non-core E&P assets as a reverse 1031 exchange, meaning we will be able to transfer the tax basis from the divested assets over to the newly acquired Permian assets.

We have additional non-core Midcontinent assets to market that we hope to sell before year-end, including our acreage located in the Woodford SCOOP play. Our remaining Midcontinent assets have aggregate net production of approximately 21 million cubic feet of gas equivalent a day. Assuming that the sales are all completed by year end, we will have completely exit the Midcontinent region, and the result will be a much more focused upstream portfolio. Just to give you a feel for this, we're trading 70 -- 2,769 gross wells in the Midcontinent at the end of the year -- last year 2013, with an average working interest of about 30% for approximately 300 wells in the Permian basin with a 94% working interest and a much stronger growth profile.

I believe the sale of our Midcontinent assets to invest in the Permian was the right strategic decision for us. The second quarter was our first full quarter operating our Permian properties, and our team continues to make great progress with the assets. We currently run seven rigs, and we completed two horizontal wells and several vertical wells since taking ownership back in February with very encouraging results. I'll go into more detail in a few minutes on the Permian.

In total, our strategic initiatives, including the Permian acquisition and the sale of non-core E&P properties, and the drop-down of our Green River Processing interest to QEPM have left us with a more focused asset portfolio with higher growth potential and higher operating margins, and we'll have a strong balance sheet to help fund future growth.

Clearly, we've made substantial progress transforming QEP into a more focused and balanced upstream Company by optimizing our upstream portfolio, and we are well along the path of maximizing shareholder value through the separation of our Midstream business. I'm equally pleased with the ongoing performance of our business this quarter. Our asset managers delivered record EBITDA, record oil production, record oil revenue, and record total production, which was up 8% from the prior year on a 6 to 1 basis, and on a 20 to 1 basis, it was up over 31%. As a result of this ongoing performance, you'll note that we raised our full year 2014 crude oil NGL and total production guidance.

Now, let me give you a little more color on our operational results by area, more detail on our plans for the remainder of 2014. As I do so, you can refer to the slide presentation which accompanied our release yesterday afternoon.

In Williston basin, we currently have seven rigs running down from -- down one from last quarter due to improvements in drilling efficiencies. Our spud to TD times continue to come down an average of 18.6 days in the second quarter compared to an average of 26.2 days in 2013. That's nearly a 30% improvement and is consistent with operational improvements that our team has delivered in the past in other areas.

At the end of the second quarter, all seven rigs in the Williston were working on our South Antelope acreage. Completion activity increased in the Williston basin in the second quarter of this year with 31 gross QEP operated wells completed and turned to sales during the quarter. And that compares to 14 in the first quarter and 26 in the fourth quarter of last year. We expect to average 20 to 25 gross QEP operated completions per quarter in the Williston for the remainder of 2014.

We continue to evaluate the potential for increased well density on our acreage. The results of our recent pilot test and those of nearby operators are encouraging for potential down spacing and/or infill drilling in the future.

In addition, we recently made a dramatic shift in completion methodology, which we think offers additional upside. In the past, we have been placing between 3 million and 3.5 million pounds of proppant in a typical long lateral Bakken or Three Forks well, but in recent wells, we've placed approximately 10 million pounds of proppant, and we're doing it through bore entry points or more perf clusters. From the data that we've analyzed, we believe that this increase in estimated -- this will result in an increase in estimated recoverable oil and will generate a return of over 50% at $90 flat crude oil prices.

Incremental costs for this completion design vary from one $1.3 million to about $2.5 million, and it really depends on our ultimate selection of appropriation method, whether we use sliding sleeves or plug and perf. The increase in profit volumes and entry points is obviously putting upward pressure on well costs. But we expect that we should be able to offset most of this with our increased drilling efficiency. As a result, our 2014 capital budget in the Williston basin is basically unchanged from last quarter of about $920 million, or roughly half of our 2014 planned capital expenditures.

I'd also note that the larger frac jobs will slow down the pace of well delivery in the second half, so keep that in mind as you digest our production guidance. You can see slide 6 through 8 for more details on the Williston base operations.

Turning to the Permian. We have made great progress in five months after closing on the acquisition the end of February. Since closing, we've increased drilling activity on our acreage from two to seven rigs with five of those rigs drilling vertical wells and two drilling horizontal wells. We plan to add a third horizontal rig soon.

Remember, we've got some science to do to evaluate the horizontal potential of some of the target intervals, and this is accomplished through our vertical well program. Once the collected the data from our vertical wells, we plan to shift our emphasis to horizontal development.

Our plan at the time of acquisition was to ramp the six rigs by the end of 2014. Clearly, we've made better progress on that schedule than planned, and the team is now focused on accelerating the transition to horizontal development.

Production from initial QEP operated vertical and horizontal wells is tracking performance that is in line with our expectations. We completed one horizontal Wolfcamp B well in the second quarter, and it's performing quite well with a maximum average 30 day rate of -- average rate 637 BOE per day.

We've also recently completed a horizontal Wolfcamp D well, and it's still cleaning up after stimulation. We plan to continue drilling horizontal wells in the Wolfcamp B and D, and we'll also test a Spraberry horizontal later this year. Our vertical development program's also performing quite well with an average maximum daily rate of 359 BOE for the wells that we've completed in the second quarter.

Overall, we're very pleased with our Permian basin acquisition. Our long going reservoir evaluation work coupled with reports of strong initial well performance from horizontal wells drilled by nearby operators continues to affirm the quality of the acquired properties. Combining these early results with the substantial progress we've made in offsetting the acquisition cost with non-core E&P asset sales, it's abundantly clear to me that making this acquisition was the right strategic move for QEP.

Excluding acquisition costs, as a results of the faster ramp up and rig count, we now plan to invest about $340 million, or about a 10% increase from our last quarter estimate in the Permian basin. Slides 9 and 10 show you more details on our Permian basin properties.

At Pinedale, production volumes increased 21% compared to the first quarter due to the typical seasonal response as we resumed completion activities in the middle of the first quarter and due to more of our first half 2014 completion activity being concentrated in areas where we, QEP, has a high working interest.

It's important to note that even though ethane frac spreads were near breakeven during the quarter, propane margins remained strong, and as a result of better propane recoveries and ethane recovery mode and approved NGL price environment, led us to recover ethane throughout the quarter. We've also adjusted our 2014 production guidance to reflect that we will likely continue recovering ethane for the full year.

For the second quarter completed and turned to sales 35 new wells at Pinedale, and at the end of the second quarter, we had 50 gross Pinedale wells with QEP working interests that were drill cased and awaiting completion, and the average work interest in those wells was 70%. We anticipate running four rigs at Pinedale throughout the remainder of 2014, and we should complete somewhere between 110 and 115 wells during the year. And of that 110 to 115 wells, there are 10 wells in which QEP is the operator, but we have only a small overriding interest.

We'll continue to get more -- while we continue to get more efficient at Pinedale, we increased our capital budget by about $40 million from last quarter to $310 million total due to some additional non-operated working interest that we picked up from other parties. Slides 11 and 12 show the details of our activities at Pinedale.

In the Uinta basin, we continue to make a good process on our Red Wash lower Mesaverde liquids-rich play. Last quarter, we talked about some early results from a fundamentally different well design that we think could radically alter the economics in the way we approach development of this asset. This new design is a horizontal development approach targeted at that specific interval in the lower Mesaverde. We've drilled and completed three wells so far using this technique, and we are nearing completion of our fourth well. We have learned some very valuable lessons along the way, but our initial results on these wells indicate that a horizontal development approach will improve the economics in the play and allow us to more efficiently unlock the value of this substantial asset.

With multiple Tcfe of probable reserves in our 100% working interest, 87% in our acreage position, clearly this project represents not only a significant growth opportunity for QEP Energy, but also for our Midstream business. We currently plan to invest about $80 million in the Uinta basin, and that's up about $15 million from the last quarter. Slide 13 and 14 show the details of our Uinta basin activity, and included in there is a type log for the Mesaverde section identifying the interval that we are currently targeting for horizontal development. I'd also point out that the slide shows other potential horizontal target intervals within the Mesaverde and underlying formations.

Let me turn quickly to the Haynesville. While we don't have any operated rigs running in the Haynesville currently, we have seen a big increase in outside operated well proposals that we expect to generate good returns. We've elected to participate in those well proposals, and as a result, we have increased our 2014 capital budget for the Haynesville to $80 million. We expect this relatively modest investment will help stem the production decline that we've seen in the Haynesville. It won't offset it, but it will certainly slow down that decline.

And then finally, we've allocated about $20 million that's barely visible on the bar chart in the slides that we've provided to you. About $20 million to some exploratory drilling this year to test some new play concepts in our portfolio.

Turning to Field Services. EBITDA was down compared to the second quarter of 2013. Richard will give you more detail on the moving pieces in the quarter, but the decline was primarily due to an increase in G&A related to transactions, bad debt expense, a cost of QEPM being a public Company, as well as the timing of recognition of certain of our deficiency payments that come in throughout the year and did not -- they came in the first quarter and distorted first quarter results, and we did not have any in second quarter.

Late in the first quarter, Field Services commenced construction on a new project to add capacity through the de-bottlenecking our Vermilion gas processing plant which is located in southwest Wyoming. The de-bottlenecking project expanded the inlet processing capacity of the Vermillion cryo plant from 43 million cubic feet a day of raw gas to approximate 57 million cubic feet a day. The total capital cost for the project, gross capital cost is about $11.7 million within a net capital cost to QEP of about $8.3 million. We started off the expanded plan about a week ago, and it should be operating at full capacity in the next few days. We plan to invest $75 million in field services projects in 2014, and that includes our capital investments at QEPM.

I'm very proud of our accomplishments so far in 2014. we've closed on multiple transactions, and we've made a substantial amount of progress on our key strategics initiatives, all while delivering solid results from our underlying business and improving our position for future growth. I believe we are well-positioned to continue liquids -- growing liquids volumes in 2014 and beyond. And while we expect our natural gas production volumes to decline again this year, we believe that continued capital allocations of higher return oil projects will lead to strong crude oil production growth and corresponding growth in EBITDA.

As we look forward to the end of this year, we expect to emerge as a more focused and balanced E&P Company with a deep portfolio of high return investment opportunities capable of delivering superior returns in a variety of market conditions. With substantial footprints in two premier US oil plays and a deep inventory of low-cost liquids-rich gas projects, including our Uinta basin horizontal program, we are confident that our portfolio can support multiple years of profitable growth.

We are also well along the path of separation of our Midstream business from QEP Resources, and we're excited about the value creation opportunity that this separation transaction presents for our shareholders. We look forward to updating you on our continued progress as we reach important additional milestones in the weeks and months ahead. With that, I'll turn the call over to Richard.

Richard Doleshek - *QEP Resources Inc - EVP & CFO*

Thank you, Chuck, and good morning, everyone. With Chuck having discussed our strategic and operational highlights for the second part of the year, I'll provide you with some color about our financial results before we go to Q&A.

For the second quarter, we generated record $401 million with adjusted EBITDA. If we include the public's 42% share of QEP Midstream Partners results, we would've reported $408 million of EBITDA. The $401 million of EBITDA generated in the second quarter was $15 million higher than the first quarter of the year and $11 million higher than the second quarter 2013.

QEP Energy contributed $373 million, or 93% of the aggregate second quarter EBITDA, and QEP Field Services contributed $29 million, or about 7%. QEP Energy's EBITDA was up $41 million from the first quarter of 2014, driven by a 20% increase in oil volumes, a 20% increase in NGL volumes and a 9% increase in natural gas volumes from the first quarter of year's volumes.

Our field level and prices were down about $0.17 per Mcfe for the first quarter, and our realized losses from our commodities-driven portfolio were about the same as the first quarter. Excluding realized losses on the commodities-driven portfolio, QEP Energy's EBITDA was up 11% from the first quarter of 2014 to about $407 million.

QEP Energy's second quarter production was 83.9 Bcfe, or 10.2 Bcfe higher than the 73.7 Bcfe reported in the first quarter. Oil volumes were 4 million barrels, up 669,000 barrels from the first quarter levels. The Permian basin properties contributed 418,000 barrels of oil compared to 140,000 barrels in the first quarter.

Oil volumes in the Williston basin were 2.8 million barrels, up 311,000 barrels, and gas volumes were 48.6 Bcf, an increase of 4.1Bcf due to the seasonal increase in Pinedale, offset by a 1.3 Bcf decline in Haynesville. NGL volumes were 1.9 million barrels, up 318,000 barrels in quarter.

Our guidance for 2014, effective as of July 1 of the year, which includes adjustments from the Granite wash and Woodford-Cana asset divestitures, forecasts natural gas lines to be about 165 to 175 Bcf. This is a quite slight decrease from last quarter due to a change in our assumption regarding ethane rejection, i.e., we're going to leave it in the gas stream verses recovering ethane and selling it in NGL stream.

Our forecast for oil volumes is 14.7 million to 15.2 million barrels, an increase from our previous guidance and up about 46% from 2013 at midpoint. Our guidance for NGL volumes for the year is 6 million to 6.3 million barrels, the midpoint of which is about 28% from 2013 assuming that we'll remain in ethane recovery for the remainder of the year. In total, we are increasing our equipment production guidance by about 4% from last quarter.

QEP Energy's combined lease operating and transportation expenses were $132 million in the quarter, up from $121 million in the second quarter and up from $105 million in the second quarter of 2013. On a per unit basis, leased operating expenses were $0.71 per Mcfe, and transportation expense was $0.86 per Mcfe, or $1.57 per Mcfe for the two items combined. Our guidance for leased operating and transportation expenses for 2014 is unchanged at $1.50 to $1.65 per Mcfe for full year 2014.

QEP Field Services second quarter EBITDA was $29 million, which was down $24.2 million from the first quarter, and let me give you some color about that decline. In the second quarter, there were $1.2 million of deficiencies -- of deficiency revenues recorded while in the first quarter there were $10.5 million of deficiency revenues. As you all know, deficiency revenues are lumpy throughout the year.

NGL sales were $10.2 million lower in the quarter as a result of lower volumes and lower individual product prices. In addition, as a result of a new NGL transportation contracts, we make some changes in how we report transportation expense.

Finally, Field Services general and administrative expense was $4.3 million higher than the first quarter, due primarily to bad debt expense and professional services associated with the asset drop to the MLP. Gathering margin was up slightly from the first quarter as increased volume and average gathering rate were offset by a decrease in deficiency revenues. Although there was some noise in the Field Services reported results this quarter, our outlook for the business is essentially unchanged, and we anticipate adjusted EBITDA of approximately $80 million for the second half of 2014, which is consistent with the first-half number, including the impact of the EBITDA that was sold through the agreement with processing transaction with the MLP.

Sequential G&A expenses were up $7.6 million, primarily the result of a charge for bad debt expense, the non-cash impact of a change in the mark-to-market value of our equity compensation plans, and expenses associated with the replacement of many of our corporate IT systems. I'm happy to report that we did go live with our new enterprise resource playing system, or more simply, our accounting system, in the second quarter, and were up and running with significantly fewer hiccups than we expected. The team really did a great job.

So, as a result of these and other impacts in the first half of the year, our guidance for G&A expenses for 2014 was increased. We think G&A expense for the full year will be in the range of $225 million to $235 million.

We reported a net loss attributable to QEP of $92.3 million in the quarter, including $51.1 million of unrealized loss on derivatives and a $201 million loss on asset sales. Excluding the unrealized loss in non-recurring items, QEP reported adjusted net income of $67.9 million, or $0.38 per share, as compared to the first call consensus meeting of $0.33 per share.

Capital expenditures on accrual basis for EP drilling completion activities were $761 million for the first half of the year, and capital expenditures in our Midstream business were $37.6 million, and acquisition expenditures were $949 million. If you exclude acquisitions, our capital spending was in line with our EBITDA in the first half of the year. Excluding acquisitions, we are forecasting the midpoint of 2014 capital spending to be about $1.775 billion for QEP Energy, about $75 million for QEP Field Services, and about $15 million for corporate.

With regard to our balance sheet, at the end of the quarter, total assets were $10.6 billion and total debt was $3.9 billion, but we had $702 million in cash on the balance sheet. As you recall, we structure the Permian acquisition and the sales of the various non-core E&P properties through a reverse like kind exchange, and the bulk of the asset sales occurred on June 30. It was a complicated transaction to unwind.

We weren't able to affect all of the steps of the exchange due to the cash in hand and pay down debt on June 30, hence, the cash on the balance sheet at the end of quarter. However, on July 1, we took that cash and $230 million of proceeds from the sales of the 40% increase of Green River processing to QEPM, which closed on July 1 and paid down the outstanding balance under our revolving credit facility to $165 million. So, on July 1, our total debt was just under $3 billion, which is about 1.9 times multiple of our annualized first half 2014 EBITDA. So, we made good progress, it just wasn't at the end of the quarter.

With that, Latanya, we would like to open the line for questions.

QUESTIONS AND ANSWERS

Operator

Thank you.

(Operator Instructions)

Tim Rezvan, Sterne Agee.

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

Good morning, folks. Thanks for taking my questions. First, can you clarify that -- how many completions per quarter we should expect in the back half in the Bakken? I didn't catch that number.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

I think it's 20 -- 20 to 25. Tim, as I said in my prepared remarks, with the change in completion design, larger proppant volume, and potentially moving to plug and perf -- we are still not convinced that moving to plug and perf is the right answer. We're doing some studies on sliding sleeves that we believe don't show a material difference between sliding sleeve and plug and perf, at least in the area where we're operating. But if we do go to plug and perf, it will slow us down.

Obviously, it just takes longer to stimulate the well and then drill out the plugs. But also, keep in mind that the offset wells will have to be shut in longer, so it will have an impact on production volumes. But 25 is probably a good quarterly number to use for Q3 and Q4.

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

Okay. Thank you for that.

And then, I know you touched on this a bit in your prepared comments. I understand you have a six-well pilot that's been producing testing downspacing. We've heard other operators talk about success, especially in the reservation area. What is holding you back from quantifying this information, given the long-term bear thesis on your limited inventory?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Well, we want to make sure that we have enough production history on the wells to confirm our reserve forecast, and to verify that -- there is going to be some interference, but verify the level of interference that's impacting production volumes. It clearly is going to cut the average EUR on the infields, and the question is how much.

So far, for the duration of our pilot test, we've seen very minor interference, and encouragement. We'd just like to watch it a while longer before we pound the table. And the real question for infill for us will be, for example, in South Antelope, can we go from four wells per spacing unit per reservoir to eight? And that will be a profound answer, and one that -- we can extrapolate from the pilot we have, but we really need to go do it and make sure that the results hold up in a full eight well per spacing unit test.

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

Do you think that's information you may be able to quantify by the end of the year as you --?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We'll certainly have more production history on our pilot that will give us more comfort.

The other thing I'd point out is: Over in Fort Berthold, we have pseudo increased density spacing on -- in several of our spacing units where we didn't drill parallel wells. You'll recall: In the northern part of our Fort Berthold acreage on the northwestern corner, we have some, what I would call hub-and-spoke geometry wells where we drilled out under the lake. And because of topographical reasons, we couldn't drill the wells parallel to each other north to south.

So, we have some wells that are spaced. At the heels, they're spaced very close together. And so, we do have some production performance information from those wells. And again, I think that the results are encouraging for increased density.

The thing that is the next sort of, I think, step in the evolution -- the next step in the evolution of future enhanced production and future upside on our properties in the Williston is not only increased density, but also the larger completion size. Because we think the empirical evidence is very convincing that these larger completions will increment reserves and, ultimately, well performance. In part, I think it's due to getting much more rock volume stimulated in the near wellbore, which we think will enhance recovery and will probably lead to the need for increased density.

Looking at some of the offset operators who have recently completed some large stimulated rock volume wells adjacent to us, there's strong evidence that marrying the larger fracs with increased density or well spacing will result in more recovery of oil in place. And that's the thesis that we're operating under right now.

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

Okay. I appreciate that color.

And then just to clarify: Are 100% of your wells now being completed with these larger completions?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Yes. 100% are being completed with some variation of the completion designs that I mentioned. Right now, we're using larger -- roughly 10 million pounds of proppant -- more entry stages. We're increasing the number of entry stages and cluster spacing, and looking for an optimization. There is obviously an optimization around increased cost versus increased recovery. But, yes, everything we're doing now is the larger size.

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

Okay. Thank you.

One last one: On the Midstream, you seem to be giving more color on the possibility of a sale there. If you do choose a potential partner, and go to negotiate, at what point do you think that would be announced to the public? Is it possible we may not hear by the end of the quarter?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Well, Tim, as I said in my prepared remarks, we have a process underway. We are in the second round. We are expecting final offers within the next several weeks.

Depending on the nature of those offers, we should be able to clearly identify our preferred proponent, and then it's a matter of negotiating mutually acceptable transaction documents before announcement. I can't imagine it's going to run through the end of September. We are targeting to have news out before the end of the quarter.

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

Okay. That's very helpful. Thanks for all the answers.

Operator

David Heikkinen, Heikkinen Energy.

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

Good morning, guys. And Chuck, you've talked in the past about the economic benefits of the integration of the Midstream and the E&P business, particularly on some of your Rockies assets. As you think about heading forward, how does the separation of the businesses impact your plans on capital spending and things like the acreage additions you had because of some non-consents, it sounds like, in the Pinedale? How will that change the economics of the decisions and your overall business plan?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

That's a great question, David. First of all, as you know, we have always run our Midstream business as a stand-alone business. And we've put in place, from the beginning, commercial gathering and processing arrangements between our E&P entity, QEP Energy, and Field Services, that were arm's length. They were market-based rates that we were charging between Field Services and Energy.

If you've been watching our behavior over the past several years, we have been diligently converting the handful of cheap hole processing arrangements we had, where we were shifting the liquid volumes to Field Services under keep hold processing arrangements. We restruck all of those arrangements so that they are all fee-based now. And our liquid revenues and exposure to the commodity is where it should be, which is in the E&P company.

So, when I think about the impact of a separation, I see very little economic change with respect to our investment decision making and the economics of drilling wells in the Rockies, in areas where Field Service currently -- Field Services currently serves as our gatherer and processor. Because we ran economics on places like Pinedale, based on E&P company netbacks and E&P company returns. And if Field Services was processing gas on a keep-hold basis for one of our partners, and making additional return on the liquids recovered in that gas stream, that was upside for the Midstream company, but we didn't include it in our economics and in our decision-making process for drilling wells in the E&P business.

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

As you think about the -- that's a perfect answer.

So, the Midstream business benefit and predictability of fee income just ties to the growth rate. And one of the things that we're looking at was the guidance now on QEPM, and then your outlook of $80 million of EBITDA in the back half of the year. Can you talk about how growth in that Midstream business potentially shifts? Or does it shift as you separate the Business and no longer have a sponsor?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

I think that the activity upstream of the Field Services and QEPM systems is driven by pretty compelling economics. And to the extent that we are making decisions today to invest E&P capital in these assets, we would continue to do so going forward. So, I don't see a change in trajectory of growth and throughput on Field Services' systems going forward.

In fact, in places like the Uinta basin where we're very encouraged with the results that we've seen from our early horizontal development activities there. There's a tremendous growth opportunity for Field Services because we'll have to build an entirely new gathering [de-hi] compression system, and we'll also have to also build additional processing capacity as volumes ramp in the area.

In addition to that, just remember, David, that all of these areas are dedicated to Field Services. So, any activity that goes on in the area, they will benefit from going forward.

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

That was a perfect segue into the growth in the horizontal program. As you think about the three wells, and that uplift in both NGLs through the contract term, taking the liquids at QEP, and then just the uplift in productivity in the Uinta. Can you talk about how you think about that opportunity to unlock this multi-Tcf potential in the Uinta (multiple speakers) or growth it could be?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Well, obviously, we're very excited. We're taking a measured approach to make sure we understand the horizontal well performance. And everyone, I think, is probably -- we've talked about it. There's one well that has been on now for almost a year, and it was a partial completion, and the performance of that well is quite encouraging. We've got a second well that now has a decent amount of production history.

We're forecasting EURs -- and you're an engineer, you know how difficult it is with short time period, especially when the wells are exhibiting relatively modest decline. But we're forecasting EURs on these wells in the 10 Bcfe-plus range right now.

At current well costs, current AFE, we are looking at low- to mid-20%s returns b-tax, and right at 20% return after tax. We think, given the history of our drilling and completion shop's ability to drive down cost, that, as we continue to work on well design and bit selection, that we can continue to -- I'm looking at Jim Torgerson, he's nodding. I don't know if he's falling asleep or agreeing with me (laughter). If we can continue to drive down costs.

Just to give a little more color, now that we're talking about horizontal development here. We are targeting the sand-rich interval in the Neslen, and there's a slide in the slide deck that shows that interval on logs. And one of the things that we found is -- it's a very difficult interval to drill. It's very abrasive, and it tends to grind up drill bits as we are grinding up rock. One of the things that we're trying on the latest well that we're drilling is actually undershooting the sandiest section, and drilling in a silty interval where it's not as abrasive in an attempt to improve penetration rates and bit durability, and we'll see how that works.

The performance of these wells is also quite strange, because they do not decline. They do not exhibit this typical unconventional hyper -- initial high rate and then rapid decline. They're quite reminiscent, at least from the few wells that we drilled in the lower Cotton Valley and northwest Louisiana, to those wells, in that they clean up and then they stay at a relatively constant production rate for some time, especially the more recent ones that we've completed.

So, we've got a lot of reservoir modeling work to do as well, but we're very excited about the Pinedale-like inventory and Pinedale-like repeatability of this play. We don't think that just this one interval, the current interval that we're targeting, is the only interval that we can develop using this technique.

The big focus today is on working on our well design, getting our well costs down to drive even better returns going forward. But obviously, when you can put on 10-million-a-day wells, you can very rapidly increase production volume here. We're working on our plans going forward, and then we'll update you as soon as we have a formalized plan. Obviously, this will require additional rigs and additional infrastructure to make it into a rapid growth machine.

David Heikkinen - *Heikkinen Energy Advisors - Analyst*

Thanks, guys.

Operator

Brian Corales, Howard Weil.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Brian? Oops, I think Brian is not there. Operator, can we go to David?

Operator

Brian, your line is live.

Brian Corales - *Howard Weil Incorporated - Analyst*

-- hear me?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Brian, are you there?

Brian Corales - *Howard Weil Incorporated - Analyst*

Hello?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Can you hear us, Brian?

Brian Corales - *Howard Weil Incorporated - Analyst*

I can hear.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Okay, you are live.

Brian Corales - *Howard Weil Incorporated - Analyst*

Okay. Sorry about that. The follow-up on the Uinta: Are you all testing these other zones in the near term, or is it just potential down the road?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We may test one in the near future; the Blackhawk would be the next one that we would test. They're similar. We can see them -- as is noted on the slide that we included in the deck -- we can see them contributing production in vertical wells, so we know that they are gas charged and valid targets. Our focus to date has been on trying to figure out how to drill and complete in one. And we figure if we can do that, that knowledge should be transferable to the other intervals.

Brian Corales - *Howard Weil Incorporated - Analyst*

Okay. And then just switching tunes to the Permian, what are your thoughts on, one, adding acreage -- and the future horizontal wells -- we've seen the neighboring wells, some better rates. Are you all doing anything differently on the completion side, on the next few horizontal wells that you all plan?

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Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We're continuing to, obviously, study the completion designs that others are using, and we're working on ours as well. I think our Wolfcamp B IP was comparable to some recently reported rates around us.

A lot of the well performance is directly impacted by the fluid volumes that you pump, and obviously, it takes longer to clean these wells up. These wells don't hit peak rates for 30 days, or more in some instances. So, we're continuing to tweak that as we go forward.

And also, I would point out that this first well was a 75-foot lateral -- 7,500-foot lateral, so you want to make sure, as you are comparing all set well results, that you are comparing apples to apples. Because some of the offset wells are 10,000-foot laterals.

Brian Corales - *Howard Weil Incorporated - Analyst*

Right, okay. Thanks, guys.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Thank you.

Operator

David Tameron, Wells Fargo.

David Tameron - *Wells Fargo Securities, LLC - Analyst*

Good morning. Congrats on the production in the quarter.

Chuck, you talked about -- obviously, about the midstream. I want to come back to it one more time. I know preference ultimately means: what adds the most value and what has the most dollars. One, do you care to give us your preference? And then two, what other considerations are you thinking about in terms of -- if all the bids come in equal, what would be your preference, or what else are you thinking about?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Look, David, I think that the ultimate goal here needs to be the maximization of shareholder value. And so, it's premature for me to talk about preference until we see final offers. We had very strong indications from a number of folks; we've invited a subset of those back in for a second round.

As I mentioned in our call -- the prepared remarks -- there's a variety of transaction structures that have been proposed by this subset of folks who are in the second round. And we've got a team of advisors who are going to help us think through -- us and the Board think through which transaction -- which individual proponent and which transaction structure we think generates the most value for our shareholders.

David Tameron - *Wells Fargo Securities, LLC - Analyst*

Okay. Let me ask one more, just on that. The tax rate -- if you were to do an outright spin -- or I'm sorry, outright sale -- can you do anything -- I assume this has a fairly low cost basis on it. What can you do to protect -- or is there anything you can do to protect the tax side of things, and would you care to venture out, like a effective tax rate on a potential sale?

Richard Doleshek - *QEP Resources Inc - EVP & CFO*

Hey, David. It's Richard. We absolutely have tools in our toolkit for managing the tax leakage, and it expands over a multi-year sort of process. So, you'd have, obviously, a pretty high cash tax leakage in your first year, and you'd be able to carry back future NOLs back to the transaction year.

We play sort of an interesting game right now trying to minimize our alternate minimum tax payments. And so, whether you expense IDC, your capitalized IDC, and how you use those IDC benefits is pretty complicated. We've got folks helping us think that through.

But if you look at the MLP last year IPO, our effective tax rate on that sale was in the 10% to 15% range. And again, we were able to use operating losses, A&T credits, et cetera. It's really hard; if you look at it just on the transaction year to get the complete picture, you have to look at how we're going to carry back net operating losses. So, without having a good number to give you, that's the guidance we put out there for you.

David Tameron - *Wells Fargo Securities, LLC - Analyst*

Okay. That's helpful. Let me switch over to the forward guidance. If I back out -- and Greg, we talked a little bit about this last night. But when I start thinking about third and fourth quarter, if I back out the Midcon sale, it looks relatively flattish. Chuck, I know the first quarter was probably too low, second quarter probably too high. But even so, I would think you'd see a little more ramp in the second half there. Just to ask it bluntly: Are you sandbagging, or what's going on?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We're putting guidance out that we feel comfortable that we can meet. And as I said, David, we don't know yet how much impact switching out to these larger completions is going to have on our pace of well delivery up in North Dakota.

It's not just the -- don't think about it just in terms of bringing new wells on. Think about it in terms of how much production we may have shut in around those new wells as we stimulate them. So, we're trying to build some cushion in for that. We hope it's not as bad as we've built, but we want to make sure that people aren't getting too far out over their skis, and projecting the ramp in completions.

And in the Permian, we brought in a number of new rigs. We're still getting our feet under us in the Permian. And we know that, from our experience in the Williston, that there's a learning curve that we come up in a new basin, and it takes us a little while to hit our stride. And that's another piece.

And then, our first half of the year in the Haynesville, we had a -- we worked on some wells down there, and we got some, basically, no-cost or low-cost production volume out of those wells in the first half of the year that flattened the Haynesville decline a bit. It didn't stop the decline, but it slowed the rate of decline for a while. It was a one-time benefit, and now we expect those wells will go back on their normal decline. And as a result, the second half is not going to be as good as the first half in the Haynesville, at least on the existing proved developed producing wells.

Now, as I mentioned in my prepared remarks, we are participating in a number of outside operated wells, but most of those wells probably won't be online until late in the year. So, they'll have an impact, but it will be on 2015, not 2014 production.

David Tameron - *Wells Fargo Securities, LLC - Analyst*

Okay. And last question: If you go through with -- presuming you get an influx of cash from the Midstream separation, just remind me again, what your thought is for that? Are you looking at more Permian acreage, or what's the use of proceeds?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Well, we'll cross that bridge when we get there. We don't know yet whether the transaction involving the Midstream business is going to be for cash or whether it's going to be a spin merge or what the structure will be. As we figure out the right answer for shareholders, we'll have more color around that.

David Tameron - *Wells Fargo Securities, LLC - Analyst*

All right. I'll let somebody else jump in. Thanks.

Operator

Brian Gamble, Simmons.

Brian Gamble - *Simmons & Company - Analyst*

Good morning, guys. I wanted to start in the Williston. You mentioned, when you were rolling through the incremental costs of the proppant. What are we looking like for total well cost there? I know you mentioned the IRR, but if you roll all the way to 10 million pounds of prop -- maybe it depends on exactly what's going into those proppants -- maybe you can detail the sand and ceramic content of it. But what does that ultimately look like from a well cost standpoint?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

I mentioned -- just a straight increase in proppant volume and additional perf clusters probably adds $1.3 million, $1.4 million to the well cost. If we go full load, cemented liner, plug and perf, when you add in additional rig time, workover rig time or coiled tubing time, and additional time to pump the frac jobs with wireline and plug and perf, you potentially add $2.5 million to $2.7 million to a well. We think that, for the most part, we can offset the midpoint of that with our increased efficiency.

We were seeing well costs going down. And what we've determined is that it's in our best interest from a return perspective to add that additional cost. And so, we basically are -- we haven't raised our capital budget for the year because we think we can offset the additional costs of these bigger frac jobs with efficiency gains in drilling and, therefore, not raise our capital budget. So, these are $10 million to $10.5 million wells.

Brian Gamble - *Simmons & Company - Analyst*

Great. And then, the mix there of prop you're using at the 10-million-pound level? Is that --?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

It's all sand. We are not using any ceramics.

Brian Gamble - *Simmons & Company - Analyst*

Great. And then, on the Permian side of things, you mentioned the third horizontal coming in soon, and that's quicker than previously expected. Are we going to continue to see that ramp? Was does the end of the year rig count look like? Are we looking maybe slough off one of the verticals and add another horizontal by year end?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

That would be the right general direction. Exactly when we do that -- I don't have the rig schedule in front of me. But the key here is that we need more vertical well data to fully evaluate the horizontal potential. And as we gather that data, we can slow down and stop our vertical development and shift to all horizontal. And so, you're right, directionally, on the shift from vertical rigs to horizontal rigs.

Brian Gamble - *Simmons & Company - Analyst*

When you say complete development mode up there, that means no verticals left? When you are completely done with the data, you don't need to drill (multiple speaks) and won't be drilling these verticals?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We may have one rig or maybe two rigs drilling verticals for quite a while.

Brian Gamble - *Simmons & Company - Analyst*

Okay, so there is some verticals later on in the well? Great.

And then, on the -- back in the Uinta, talking about the horizontals -- three wells so far. The rest of the year, how many more are we thinking? You mentioned the ones that you might put into the Blackhawk interval. How many more Neslen wells are we expecting?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We'll probably have the one well that we are getting ready to complete, and another well by year end, but it will be over at year end and into the first quarter, I would think, before it gets online.

Brian Gamble - *Simmons & Company - Analyst*

That sounds good. Appreciate it, guys.

Operator

Matt Portillo, TPH.

Matt Portillo - *Tudor, Pickering, Holt - Analyst*

Good morning, guys. Just a quick question -- a follow-up on the Bakken. In terms of the upsized fracs, is that baked into your guidance, or how have you guys risked that?

And then, a second question alongside that is: It sounds like you've -- given the activity, all this has been allocated to the Antelope area so far. But I was curious if you've tested upsized fracs in Fort Berthold?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

I'll answer the second question, first. We have not yet, but we plan to do it soon.

And then on the assumptions around upsized fracs -- we have held our IPs constant. In other words, we have seen, from offset operators with larger frac jobs, an increase in IP and a sustained higher production volume over the first 12 months or more. Really, about all we have is 12 months of production history from these wells.

But until we have a family of wells that we have stimulated ourselves, and watched the production performance for some time, we're reluctant to raise our assumed rate until we have our own actual well performance. The guidance is based on our historic estimated IPs and rates, and so there's upside there from the bigger frac jobs, if, in fact, we see similar performance to offset operators.

Matt Portillo - *Tudor, Pickering, Holt - Analyst*

Great. And just a quick follow-up on that. As we think about the information you guys provided today, it's based on the early production data you've seen so far, and maybe some of the offset completions you've seen by other operators. But a lot of that's been heavily risked in your assumptions on incremental improvements through rates of return, and also on your production guidance?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

That's correct.

Matt Portillo - *Tudor, Pickering, Holt - Analyst*

Perfect. And then, a second -- two other quick questions. In the Uinta, I was wondering if you could provide us maybe some color around the horizontal well cost? Or if you have a targeted well cost that you may be looking to achieve? And I'll have one quick follow-up after that.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

They are all over the map. Our current AFE is about $14.8 million. We think that we can drive it down below that. The key, as I mentioned earlier, is hopefully with undershooting this very abrasive sand-prone interval and fracking up into it, we can improve our penetration rates and really cut down our completed well costs. That's part of the strategy here for pushing the economics up, is to drive down the drill times and, therefore, well costs, because this is a very abrasive interval.

Matt Portillo - *Tudor, Pickering, Holt - Analyst*

Great. And my last question -- just in regards to the Haynesville. Are you guys evaluating at all any re-frac opportunities or participating in non-operated re-fracs? We've seen some fairly encouraging results early on, but a fairly limited data set from industry. So, just curious how you guys are thinking about that.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We're watching it like everybody else is. We have obviously a team of people that are following the Haynesville, and we've obviously got re-frac candidates. It's very interesting early results. We would agree with you. We just need to see more production history to convince ourselves that it's not just flush production from ballooning a rock up. But so far, they look quite interesting.

Matt Portillo - *Tudor, Pickering, Holt - Analyst*

Thank you very much.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Thank you.

Operator

Dan McSpirit, BMO.

Dan McSpirit - *BMO Capital Markets - Analyst*

Thank you, folks. Good morning. How should we look at the relationship between EBITDA or cash flow to capital spending beyond 2014, as the Company potentially allocates more capital to the Permian basin, and proceeds from the asset sales come in the door? And what might that mean for leverage here going forward?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Well, we're trying to run a business which lives in and around cash flow. This year, we have an outspend, and I think you should've expected that. We sort of telegraphed that as we ramped up activity in the Permian. And as a result, cash flow from the assets lags the initial flush investment as we ramp up activity and ramp up the well-delivery machine.

Going forward, we like to live in and around EBITDA. And that's been our philosophy in running the Company for some time.

I think that, as far as leverage, I'll let Richard talk to you about our general view of leverage and balance sheet strength and liquidity.

Richard Doleshek - *QEP Resources Inc - EVP & CFO*

Hey, Dan. Generally, we're trying to run on a leverage level less than 2 times debt multiple of EBITDA. And so, if we have a couple hundred million dollar outspend versus EBITDA this year, with the EBITDA growth we see next year and probably that same level of outspend as we continue to ramp up in the Permian, that would ultimately result in a decrease of leverage because that's a 1-to-1 ratio.

I think, just keep in mind, 2 times or less is where we want to live. And we're probably going to have a bit of an outspend next year. We haven't put formal guidance together yet, but we probably won't breach through that 2 times just with developing our own properties.

Dan McSpirit - *BMO Capital Markets - Analyst*

Great. And as a follow up, if I may, maybe more for modeling here, would there be much change expected in the -- maybe in the first year decline rate on the Williston basin, producers in the middle Bakken wells fracked or completed with this new and improved technique?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

What we see is a bulk shift in the production curve on the wells that have been online a year or so. So, you see a sustained higher rate on the 30-day, 60-day, 90-day, 120-day, 365-day cumulative rate, Dan. And you can go out with drilling info and look at -- isolate those wells that have been online. And we waited and watched those wells for some time until we saw the, what I think is, very convincing 12-month production history.

What are there, Jim, probably 20 wells -- 15 or 20 wells that have got a year on them now. And some of them are stand-alone wells that are in an unstimulated block of rock, but there have been a number of wells that have been drilled on tight density that all exhibit this -- it's really a bulk shift. It doesn't look like it fundamentally changes the shape of the decline curve, the B factor or terminal decline rate. It simply shifts the whole thing up on IP; and that results in a substantial amount of incremental oil being recovered over the first 12 months of production.

Dan McSpirit - *BMO Capital Markets - Analyst*

Okay, great. And then, lastly here, what's the base decline rate on the Haynesville shale operations?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Before we perturbed it in the first quarter and into the second quarter, it was about 34%, 35% -- right in that range.

Dan McSpirit - *BMO Capital Markets - Analyst*

Got it. Thanks again.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Thank you.

Operator

Andrew Coleman, Raymond James.

Andrew Coleman - *Raymond James & Associates - Analyst*

Great. I made it in just under the bell. Thanks for taking my questions. And the first one was just another different take on Tameron's one from earlier, which is that -- can you quantify an approximate ethane rejection uplift in the second quarter or how much it might be in the third and fourth quarters?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

We don't make any money on ethane. We make $0.01, we lose $0.01 on a daily basis. What we do though, when we run the plants and ethane recoveries, we recover more propane. And that has basically allowed us to make a slightly higher margin per barrel of recovered liquids than we would make if we let the ethane go down the line and didn't recover as much propane.

It was significant in the first quarter. It's still positive this quarter. You tell me what liquids prices and gas prices are going to be for the rest of the year, and I'll tell you what we're going to make. But it's slightly better than letting the ethane go down the line and not getting full propane recovery.

Andrew Coleman - *Raymond James & Associates - Analyst*

Okay, all right. I can follow up with Greg and I'll give him a couple scenarios, and then we can check what's in there.

Second of all, with the extra activity for the Haynesville, do you have a sense what the decline might slow to? Are we talking about 5 to 10 wells, or are we talking about more than that being drilled?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

No, it's a $50-million, roughly, increment in our capital budget. It's not going to impact 2014 production materially, if at all, because of the timing of well completions, but it will have an impact on 2015.

The average working interest that we are participating with is -- it varies, anywhere from a few percent up to about 20% of these wells that are getting drilled. But they're being drilled by operators who are basically infilling full sections. The wells are being drilled and cased, and they are being left standing while the whole section is being drilled up, and then they'll all be completed at once. When they all come on, it's going to have a positive impact on our decline. But we don't have full visibility on when that's going to happen.

Andrew Coleman - *Raymond James & Associates - Analyst*

Okay. All right. And then, you mentioned the SCOOP sale. That's the last of your non-core stuff. With that coming at some point, and then if you get cash from Midstream, would it be possible to see much debt payment as a result of that? Or would you look to put -- apply most of that back into organic [options with that] cash?

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

First, let me clarify, Andrew, the SCOOP is in the market, but the remaining assets, the Arkoma and other assets that we have are not yet in the market. We have additional assets beyond the SCOOP in the Midcon that we plan to sell, and we hope to get those deals done late this year. They may slop over into next year.

The proceeds from those sales will go to repay debt, likely, but it's going to be --the timing on close is going to be late this year for most of the assets.

Andrew Coleman - *Raymond James & Associates - Analyst*

Okay. Thank you very much.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Thank you.

Operator

At this time, I would like to turn the call back over to management for closing comments.

Chuck Stanley - *QEP Resources Inc - Chairman, President & CEO*

Thank you all for your interest in QEP. We're going to be attending a number of conferences coming up through the remainder of the year. We look forward to seeing you all in person.

Operator

Thank you. This does conclude today's teleconference. You may disconnect your lines at this time, and have a great day.