Q3 2010 NORTHERN OIL & GAS INC NEV Earnings Conference Call - Final

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OPERATOR: Good day, ladies and gentlemen and welcome to your **Northern Oil** and Gas 2010 third quarter release conference call. At this time, all participants are in a listen-only mode. (Operator Instructions) As a reminder, today's conference call is being recorded. I would now like to introduce your host for today's conference call , Michael Reger, Chairman and Chief Executive Officer and Ryan Gilbertson, President. You may begin.

MIKE REGER, CHAIRMAN AND CEO, **NORTHERN OIL** & GAS INC NEV: Good morning, ladies and gentlemen. My name is Mike Reger, I'm the Chairman and Chief Executive of **Northern Oil**. I'm here with Ryan Gilbertson, our President. We're excited to welcome you to the third quarter 2010 earnings call for **Northern Oil** and Gas.

Before we begin this morning's call, you should be aware that certain statements made during this call may contain forward-looking statements that are based upon management's expectations, estimates, projections and assumptions that involve certain risks and uncertainties. We encourage you to review the various risk factors relating to our business which are available in our annual report on Form 10-K for the fiscal year ended December 31, 2009 and other reports we have filed with the SEC. These forward-looking statements relate to our future plans, objectives, expectations and intentions. Our actual results could differ materially from those contemplated by these statements partially as a result of the various assumptions relied upon in making such statements.

For those of you who are joining us to learn about **Northern Oil** and Gas for the first time, I would like to take a moment to explain our operational strategy in the Bakken and Three Forks play. As a non-operator, we participate in wells on a heads-up basis in proportion to our leasehold interest in drilling units. At any time a well is permitted, all parties controlling leasehold interest within the drilling unit are automatically included in the well.

As such, **Northern Oil**'s leasehold interests are included in any well drilled within drilling units containing our interest. As an example, if we control 160 acres in a 640-**acre** drilling unit we would own 25% of any well drilled in that unit and participate heads-up with a 25% working interest. When a well is drilled in that unit we then pay our 25% share of all expenses and receive 25% of all crude oil and natural gas sold from that well. We do not farm out our interest or dilute our working interest in any way. We participate for our proportionate working interest without the infrastructure and overhead costs of our operating partners. We believe capital is most efficiently deployed through this strategy due to the substantial discount for which nonoperated leasehold interest can be obtained. With that background in mind, I would like to now turn the call over to **Northern Oil**'s President, Ryan Gilbertson, to review our financial results for the quarter.

RYAN GILBERTSON, PRESIDENT, **NORTHERN OIL** & GAS INC NEV: Thanks, Mike. This is Ryan Gilbertson speaking, President of **Northern Oil** and Gas. Today we announced record quarterly production volumes, record quarterly revenues and record operating income, excluding the impact of unrealized hedging losses. Our production volumes for the third quarter of 2010 were a quarterly record of 250,000 barrels of oil equivalent or BOE. This represents a 45% increase compared to the second quarter of 2010 and a 182% increase compared to the third quarter of 2009. These results exceeded our previous guidance of 30% to 35% quarter-over-quarter production increases and represents our 11 consecutive quarterly increase in production.

Third quarter 2010 production consisted of 96% crude oil and approximately 4% associated natural gas. We exited the third quarter of 2010 with production volumes of approximately 3,400 barrels of oil equivalent per day. During the third quarter of 2010, production was added from approximately 5.75 net wells. We have maintained a 100% success rate drilling in the Williston Basin, Bakken and Three Forks play since the Company's inception.

Revenues from the sale of crude oil and natural gas including settled hedges for the third quarter of 2010 were $16.3 million which represents a 36% increase compared to the second quarter of 2010 and a 236% increase compared to the third quarter of 2009. During the third quarter of 2010 our average realized price for crude oil was $69.64 per barrel, which included a $3.22 per barrel gain due to the settlement of our crude oil derivative hedges. This compares to an average of $70.98 per barrel realized price in the second quarter of 2010, which included a $1.83 per barrel gain due to the settlement of crude oil derivative contracts. And an average of $58.44 per barrel realized price in the third quarter of 2009, which included a $3.38 per barrel loss due to the settlement of derivative contracts.

Our reported production expenses for the third quarter of 2010 were $1,084,000, or $4.19 per barrel on an accrued basis, compared to $521,000(Sic-see press release) or $3.30 per barrel in the second quarter of 2010 and $236,000 or $2.45 per barrel in the third quarter of 2009. The higher production expense is generally a result of more mature wells in the Northern portfolio and the general maturation of **Northern Oil** 's production.

Depletion expense for the third quarter of 2010 was $3.7 million or approximately $15.00 per barrel compared to $2.6 million of $15.00 per barrel in the second quarter of 2010, or $935,000 or $10.56 per barrel for the third quarter of 2009. General and administrative expenses net of share based non-cash compensation for the third quarter of 2010 were $899,000, compared to $718,000 in the second quarter. The slight increase was primarily driven by increased personnel and field level infrastructure costs.

For the third quarter of 2010, our net income was $987,000 or $0.02 per diluted share. Our net income excluding unrealized non-cash mark-to-market hedging losses was $4,961,000 or $0.10 per diluted share. Which represents a 42% increase over net income, excluding unrealized mark-to-market hedging losses of $3.5 million or $0.07 per diluted share for the second quarter of 2010.

We define adjusted EBITDA as net income before interest expense, income taxes, depreciation, depletion and amortization, accretion of abandonment liability, pretax unrealized gain or loss on commodity risk instruments and non-cash expenses relating to share-based payments. Our adjusted EBITDA for the third quarter of 2010 was $12.7 million, or $0.24 per diluted share. Which represents a 32% increase over adjusted EBITDA of $9.7 million or $0.19 per diluted share in the second quarter of 2010. Net income excluding unrealized mark-to-market hedging gains and adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to GAAP is included in our accompanying financial tables found later in this release.

Our management believes the use of non-GAAP financial measures provides useful information to investors to gain an overall understanding of current financial performance. Specifically, we believe the non-GAAP results included herein provide useful information to both management and investors by excluding certain expenses and unrealized commodity gains and losses the management believes are not indicative of our core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring our performance. We believe that we are providing investors with financial measures that most closely align to our internal measurement processes.

For the third quarter 2010, our capital expenditures relating to exploration and development activities approximated $103 million for the nine months ending September 30. To be clear, that's $103 million year-to-date. And they're expected to approximate $132 million for the entire year, based on wells currently drilling and expected to be spud by 2010 year end.

As of November 5, 2010, we are participating in the drilling or completion of 91 gross Bakken or Three Forks wells, for an aggregate 10.72 net wells drilling awaiting completion or completed. Of those wells, five net wells are drilling, but have not yet reached total depth. An additional five net wells have been drilled to total depth and are awaiting completion and the remaining seven net wells are undergoing fracture stimulation to commence productions. As of November 5, we have spud approximately 23.68 net wells during 2010. We now expect to spud approximately 25 net wells by the end of 2010, up from previous guidance of 24 net wells. We expect to increase production volumes by 30% to 35% in the fourth quarter of 2010 as compared to the third quarter of 2010.

Year-to-date through September 30, 2010, we have acquired approximately 38,864 net acres for an aggregate price of $42.2 million, or an average price of $1,086 per **acre**. We expect to continue to opportunistically acquire acreage throughout the remainder of 2010 and into 2011. Based on 2010 and anticipated 2011 activity and assuming drilling activity within the Williston Basin continues at its current pace, we expect to average approximately 6,500 barrels of oil equivalent per day in production for 2011. I now turn it back to Mike Reger.

MIKE REGER: Thank you, Ryan. The third quarter was our best ever in terms of production volumes, adjusted EBITDA and key acreage acquisitions. The value of our nonoperated franchise is best illustrated by the fact that 80% of our acreage that we acquired in the third quarter has already been drilled or is currently drilling. We have become a clearing house of sorts for nonoperated interest in the Bakken and Three Forks play and our deal flow in nonoperated interest continues to accelerate. We believe that we are well positioned to remain focused on the best areas of this rapidly advancing play and turn our acreage to production quickly and efficiently. We look forward to further success in 2011 as we continue to gain critical mass and participate with the many skilled operators driving technology and growth in this premier oil play. We now turn it over to questions and answers and we thank you for your time.

OPERATOR: This concludes our overview of today's quarterly financial results. We will now entertain questions from our covering analysts. Our first question comes from Derrick Whitfield with Canaccord.

DERRICK WHITFIELD, ANALYST, CANACCORD: Good morning, guys. And congrats on a solid quarter and 2011 outlook. Could you share with us your thoughts on current service tightness in the basin and comment broadly on what your larger operators are experiencing in spud to sales times and what your expectations are as we look out into 2011?

RYAN GILBERTSON: Yes, thanks, Derrick. This is Ryan speaking. Thanks for the kind words, for joining the call today. You know, we've generally seen a continued tightness of service assets in the play and we've sort of seen that plateau over the last quarter or so. We still remain at 90 days spud to sales on average. Different operators have varying access to services. There are many operators with dedicated frac crews, some that don't have dedicated frac crews and at this point there probably still exists a disequalibrium between drilling rigs and completion services. So, we do expect that to remain the case, certainly we expect to see completions slow down a bit in the winter as usual. It's just economically disadvantageous to continue ahead at the same completion rate. But in general service tightness hasn't been a problem and we see this play continuing to build ahead.

DERRICK WHITFIELD: Got it and then in thinking about sort of current weld costs could you offer any color on what you're seeing with AFE's by general area and spreads you're seeing between AFE's and the actuals?

RYAN GILBERTSON: Sure many well, the one trend that we've definitely seen is actuals coming in well under AFE's and we're fortunate to be working with some of the best operators in the play that continue to deliver at costs under their AFE's. In general, for 640-**acre** units we see an average of about $4.8 million. For 1280's we're seeing a range of anywhere from $5.5 million to $7 million in some cases. We're generally more highly weighted towards 640's due to our activity east of the Nesson Anakline and in our Slawson operated Windsor area so our average well cost generally remains lower than the average across most of the play. As we get into 2011 and we start to develop more of our position west of the Nesson we'll be involved in more 1280-**acre** units and therefore higher well costs but in general those are the ranges that we're seeing right now.

DERRICK WHITFIELD: Terrific. And then moving over to your leasing activities, in the third quarter you guys effectively bought wells that were being drilled with your acreage adds. How much more opportunity do you see out in the market using that approach?

RYAN GILBERTSON: Well, Derrick, I think that what we saw in the third quarter with regard to the amount of acreage we're buying immediately falling under the bit is really indicative of the opportunity that we continue to see out there. And although most of this basin has been primarily leased up, as these rigs slide through the field, record rig about of 156 in North Dakota, you know, they're effectively spraying out AFE's in front of them and those AFE's and those opportunities to acquire acreage immediately to spud are generally coming to Northern first. And the franchise that we've built in the field has allowed us to get the first, in many cases only look at these opportunities and although there may not be many primary leasing opportunities, with the rig count and the drilling activity levels robust as it is right now, we continue to expect to see this opportunity be around for quite a while. In fact, the opportunity in front of Northern to acquire interests, minority interest in wells is as great as it's ever been and we expect that to be the case into 2011. Lot of opportunity out there.

DERRICK WHITFIELD: And just one last question, if I could. Any thoughts on the Goblin 126 well? As I recall, that was your first 320-**acre** well in the Windsor area.

RYAN GILBERTSON: That's right. **Northern Oil** owns about a 45% working interest in the Slawson operated Goblin. It is a 320-**acre** unit and certainly we've seen many operators move toward proving the concept of down spacing and we'd expect that trend to continue. That was a great well in the loop and we expect to participate in a number of additional down spaced units into 2011. You know, certainly, if 2010 has been the year of delineating and defining productivity in the Three Forks, 2011 should be the year that really gives the street an idea of how tightly down spaced this play can actually get and we think there's quite a bit of opportunity there and we look forward to participating in more infield wells as we move ahead.

DERRICK WHITFIELD: All right. Thanks. Great quarter. I'll hop back in queue.

RYAN GILBERTSON: Thanks, Derrick.

OPERATOR: Our next question comes from Peter Kissel with Howard Weil.

PETER KISSEL, ANALYST, HOWARD WEIL: Hey, guys, how are you? Couple quick questions.

MIKE REGER: How are you?

PETER KISSEL: Good, thanks. Mike, you mentioned there's still a lot of opportunity in terms of acreage acquisitions and I was just wondering if you could elaborate on that a little bit more, kind of what areas of the play are you seeing the most opportunity, what are you seeing in terms of pricing for both operated and nonoperated positions and then lastly, what plays, if any, are you looking at outside the Bakken at this point using your core competencies as a land man?

MIKE REGER: Thanks, Pete. You know, one thing that we're continuing to see is additional opportunities and an acceleration of the lease acquisition opportunities. Operated units in the Bakken play are very hard to come by. However, minority interests in these wells that are being drilled at a record pace continue to accelerate. So we continue to see more opportunities as Ryan just mentioned as the AFE's volume continues to increase. If you can just imagine the number of AFE's that are sent out ahead of the rigs that are currently drilling in the field. We continue to see our disproportionate share of nonoperated interests as they arrive on people's desks. So we usually get the first and in most cases only look at those AFE's, just because of the franchise we built as a nonoperator of scale. And then what was your second question, Pete?

PETER KISSEL: Just kind of what areas of the play you're seeing the most opportunity and then pricing and then any areas outside the Bakken?

MIKE REGER: Right. Yes, thanks. We continue to see activity even in the heart of Southern Montrail because the drilling pace is so extensive and, you know, the amount of activity and the cost associated with that activity really generate opportunities for us. So we see the entire play at all times. We see a tremendous amount of activity now, west of the Nesson as well, now that the rig count has increased out to the west. Still, a disproportionate number of rigs are on the Anakline and east of the Anakline and we see a lot of our interest grow there. To answer your last question and that's really an important question to answer. **Northern Oil** and Gas has a competitive advantage in the Williston Basin. We had a time and place advantage in the Williston Basin and, therefore, we're going to continue to be 100% committed to the Bakken and Three Forks play. We're going to stick to our knitting and we're going to keep executing on the exact plan we set out to execute which is the Bakken and Three Forks play and building the nonoperated Bakken and Three Forks program of record.

PETER KISSEL: Got you. Okay. Thanks, Mike. And then one quick one other quick question here. Ryan, you mentioned earlier that you're expecting to see a slowdown of completion activity in the winter which is normal. But I was just wondering given the backlog of completion jobs right now are you getting the indication from some of the operators they may be willing to suck up the additional half million or so cost for completion in order to catch up a little bit or do you still think they're going to delay those completions until the spring?

MIKE REGER: You know, I'll be honest with you, Pete. We don't know the answer really to that question. I mean, you know, the first thing is there's more crews coming to the basin. The second question is that there really an economic question that relates to completing wells in the winter and it's not economically efficient to complete a well during the coldest three months of the year. It's better to wait. That typically has been offset in the past by larger backlog that's sort of needed to be worked through. How that's going to work this winter I'm going to have to be honest with you and say we don't know the answer to that. The nice thing about **Northern Oil**'s production is as it grows and becomes more mature, we're less dependent on the chunkiness of new wells coming online to be able to maintain our production level and very accurately guide going forward. So the general aging of production has been a good thing and the noise that will sort of occur around production and completions throughout the winter should affect Northern much less this year than it has in past years. But basically it's a wait and see for us.

PETER KISSEL: Got you. Thanks for taking my questions, guys.

MIKE REGER: Thanks, Pete.

OPERATOR: Our next question comes from Josh Silverstein with Enerecap Partners.

JOHN SILVERSTEIN, ANALYST, ENERECAP PARTNERS: Good morning, guys. I was hoping - -

MIKE REGER: Hey, Josh, how are you?

JOHN SILVERSTEIN: Good, good. I was hoping to get a little bit more clarity surrounding the production guidance for next year, you know, if you guys had a net spud count for the amount of wells next year?

RYAN GILBERTSON: Yes, thanks, Josh. This is Ryan speaking. You know, we haven't published a net well spud count for 2011. Couple of different pending issues we're working through right now and that's something we hope to address fairly shortly. We're honing in on a pretty tight range but the nice thing is, 2011 production is primarily going to be driven by the wells that have been put on line and spud during 2010. So as we begin to dial in what we look like in 2011 with additional wells are going to have much smaller effect on production than the wells we actually have put online and plan to put online here in 2010. So we feel like we've got a pretty tight range around that 6,500, just based on the drilling activity that will be confined as spud in 2010. And at this point, although we're getting close, we're just not quite ready to make a prediction on 2011 based on a couple of different issues pending.

JOHN SILVERSTEIN: Okay. And then I was curious also if you have kind of a ballpark idea of what the working interest might be for next year? Obviously, you know, you guys seem to be increasing that every quarter and also an idea of where the bulk of the 2011 wells will be drilled if that's going to be in county or maybe out into the Western extensions?

RYAN GILBERTSON: Sure. Well, the nice thing is as we've seen this play evolve, operators have generally been drilling their larger working interest sections first and moving toward their lower working interest section and that works conversely for us. So we've seen our average working interest grow from 6% to 8% to sort of 8% to 10%, to where it sits right now which is 12% per well that we're in. And as we look into 2011 we'll probably see that grow to 15% to 17%. It's just sort of growing proportionately to the inverse of the operator's interest declining and with regard to where we see most of the activity in 2011, we're still going to be very highly focused in the east Nesson area, as we complete the Windsor drilling program and start with the infill program there east of the Nesson but we'll see that shift a little bit more towards the west. If we had to put sort of numbers on it we're probably about 50/50 in 2011 east versus west of the Nesson. Unfortunately, we continue to see these west Nesson wells come online impressively. The operators over there have done a great job of cracking the code on the play and we see those wells get better and better. So we'll participate again on both sides of the anti-kline and as we look at 2011 we'll do what we've always done which is we'll basically let the play take us where it will. We don't need to be pioneers. We don't want to strike out into any new directions. We're happy to just exploit our advantage once areas are proven up and the technology continues to expand this play.

JOHN SILVERSTEIN: Great. That's helpful. And then just lastly from me, on the LOE front you mentioned the jump to about $4.19 per barrel this quarter which was a big jump from the last quarter, mostly due to the mature wells being put on artificial lift. Going forward into next year, you know, with more wells becoming more mature, but the significant increase in the production that you're having, any feel as to where the trend in LOE may go?

RYAN GILBERTSON: Yes, Josh, the trend in LOE will definitely be higher. We expect it to plateau at around $5 a barrel when we forecast out the average age of the production as we get into 2011. There's really going to be two drivers to LOE and the first is if you're drilling in an area where there's water in the formation, you've got significant disposal costs. That's going to increase your LOE. We typically don't experience that right now which is why our lease operating expense traditionally has been lower than some of the other operators in the play. The main driver for us will be the maturing and the stabilizing of the production. Most of the costs at the wellhead level are fixed and being amortized across few barrels is going to make it a larger number of course per barrel. So the trend should be higher. We expect it to plateau around $5 and creep up there over the next couple of quarters.

JOHN SILVERSTEIN: Great. Thanks.

OPERATOR: Our next question comes from Peter Mahon with Dougherty & Company.

PETER MAHON, ANALYST, DOUGHERTY & COMPANY: Good morning, guys. Thanks for taking my questions. My question has to do with the exit rate and kind of understanding how that might develop over the course of the quarter. If we look back to the June quarter, you guys said that it exited at a rate of 2,700 BOE per day. And we ended the quarter at just under 2,800. Now, you have guided for or you said that the exit rate in the September quarter was 3,400. I was hoping you could maybe give us some clarity around how many of those wells that are awaiting completion might get completed in the fourth quarter and how that might impact the development of the rate throughout the quarter, the December quarter.

RYAN GILBERTSON: Sure. Well, with regard to what will be completed in the quarter, approximately half the wells in our drilling are completing as we expect to complete within Q4 so that's the addition of another five net wells from where we sit right now. With regard to the rate, we expect to exit the year at a run rate of about 5,000 barrels a day based on what we currently estimate. And one thing is that as we've got a number of wells coming online, as we sit here today we have I believe 26 net wells producing. And if you think about adding five wells, 10 wells in the next quarter or two, you know, it still is a significant amount of early stage production.

When we talk about a run rate, we really mean more of a sort of stabilized rate. Certainly there's going to be days right now where our production is going to fluctuate 1,000 barrels or more from one day to the next as well as are coming online so when we sort of target that exit rate we try to sort of tone down and dampen that volatility and come in with a more stabilized rate. So there is still a little bit of noise around it. As the production base again continues to become more stable that number will become more stable. If from where we sit right now, today we exited the last quarter, Q3, at about 3,400 barrels a day. Expect to grow that rate to about 5,000 barrels a day at the end of the fourth.

PETER MAHON: Okay. Great. Thanks. And my second question has to do with your hedging and I just wanted to kind of get a feel for, you know, how many -- what's your comfort level with your hedged volume right now and kind of maybe where you think that might head as you -- in the first half of 2011?

RYAN GILBERTSON: Sure. Based on our new guidance right now of approximately just under 2.4 million barrels of production in 2011, we sit just under about a third hedged. We've said in the past and we continue to believe that the appropriate hedge ratio for us at these levels of wellhead return should be about 50% going out a year. We anticipate growing that 2011 hedge level from about 31%, 32%, up to about 50% as we finish out the year here. It's important for us -- it's less about making a call on the direction of the commodity and more about ensuring the cash flows as we go through another period of development. And so for us, our hedging is really a function of two things. Our cash demands in the future, and the level of rate of return we're achieving at the wellhead level.

In many cases our rate of returns are into the triple digits and we're more than happy to lock in those returns at these levels, especially given the robust level of drilling and cash demands going forward. To us, hedging is really a matter of leverage and we've always been fairly leverage averse. You'll see that Northern is now in a 24 month period swung through two periods. One period of extreme, extreme growth in drilling and another period of almost a complete stopping of drilling. We've seen this rig count go from 12 to 90 to 20 back to 150 and we've always plowed ahead in whatever circumstance and part of that has been our hedging profile and lack of leverage. So we continue to maintain take attitude as Company. Expect to see us about 50% hedged going out about a year, 25% hedged going out two years for the foreseeable future.

PETER MAHON: Perfect. Thanks, guys and great quarter.

RYAN GILBERTSON: Thank you.

OPERATOR: Your next question comes from Neal Dingmann with -- one moment. With Wunderlich Securities.

NEAL DINGMANN, ANALYST, WUNDERLICH SECURITIES: Good morning, guys. Nice quarter. Just a quick question. You're still looking pretty hard in the Bakken as far as acquiring some private acreage and will you continue to expand that position going forward?

MIKE REGER: Sure, you know, great question, Neil. We continue to be an aggressive acquirer and we continue to be most importantly an opportunistic acquirer and when we raised capital back in April, if we would have announced to the street, we're going to acquire 40,000 acres at about $1,100 an **acre**, a meaningful percent is going to go to the bit in the first six months it would have been considered a great acquisition. The fact is, that's exactly what we did. We just did it approximately 200 acres a day throughout the entire year. That's where we see the value right now. So it's where we're going to focus our acquisition dollars. We're always looking at bigger acquisitions. But certainly we've seen some prints out there, $**7,000**, $8,000, $10,000 an **acre**. We're just not paying that. We're paying a small fraction of that for these nonoperated interests and the only knock on them, is they're nonoperated. They're going to be drilled quickly and they're in delineated defined core areas with key operators. So we're buying the best stuff in many cases $0.15, $0.20 on the dollar. And as long as we see that opportunity continue to exist in its current form that's where we're going to focus our dollars and our activity and absolutely, yes, we are still continuing to acquire with both hands as this field continues to present us with opportunities.

NEAL DINGMANN: Thanks for the color. One follow-up, I guess. Are you looking at anywhere else maybe the Nybrera or anywhere else outside of the Bakken or are you still going to focus on that core area.

MIKE REGER: We're definitely not going to leave the Bakken. The Bakken is our home. It's where we've got our competitive advantage. We're not interested in looking at any plays outside of the Bakken. It's where we'll stay for a long time.

NEAL DINGMANN: Great. Thanks, guys.

OPERATOR: Our next question comes from Marshall Carver with Capital One Southcoast.

MARSHALL CARVER, ANALYST, CAPITAL ONE SOUTHCOAST: Yes, good morning. Couple of questions. On the 2011 guidance you said you didn't want to give a lot of -- you said you had a range on the number of wells drilled. Could you elaborate any on that? Was that -- could you give us the high end, the low end and just wondering if you could give us some extra color on either the dollars to be spent on drilling or the number of net wells to be drilled next year?

MIKE REGER: Yes. Thanks, Marshall and thanks for jumping on. We're just not really in a position to give the guidance right now. We expect to be able to soon. For us, it's just an issue of working through a couple of different pending situations to most accurately and correctly dial that in. So we really can't give any more color as far as 2011 drilling although we hope to be in a position to do so very shortly.

MARSHALL CARVER: In terms of the production guidance, would you -- is there some potential down side to that if whatever you hope will happen doesn't happen or how should we think about that or is this sort of a -- you've done a great job of setting expectations and then coming and exceeding them at least the last few quarters. How should we think about that 2011 guidance? Is that a -- you put the production number out there but wondering how we should think of that versus expected CapEx?

MIKE REGER: Well, I'll tell you what, in reality, the 2011 numbers, again, primarily a function of 2010 activity. So we think there's potentially some upside to that number. Everything that we're sort of modeling here is based on rig count. I mean, the change in rig count is what's going to drive our activity from the development standpoint. If you remember back to the early part of 2010, we came into this year anticipating drilling 12 wells, 12 became 15, then it became 18, then 24, now 25 and that's directly correlated to the rig count. So, you know, there should be very little if any down side to that production number because it's primarily based on what's already happened here in 2010. And as we look forward into 2011, you think about sort of 90 days spud to sales, we've still got a lot of 2010 production that's waiting to come online or 2010 spud that's waiting to come online. So really looking out a year, it's more a function of the capital and the dollars we've allocated in the previous year than in that particular year so there shouldn't be a great amount of variance in 2011, even if there is a great amount of variance in production. One way to look at that is there's been a massive increase in our 2010 drilling activity but our production numbers have generally come in line with what you all have forecast. So what that's telling you is that although we're spudding more wells, it doesn't have immediate impact on production. It has an impact on production a quarter, two quarters, three quarters down the line so 2011 is really settling of what we've increased in 2010.

MARSHALL CARVER: Okay. That's helpful. And on the debt front, you clearly have been debt averse and have one of the best balance sheets out there. As you move forward, how should we think about your thoughts on debt as you get -- as production ramps up, I would think your borrowing base would increase and you would certainly be able to use more debt. So how should we think about that? Are there any key debt metrics that you watch and you want to make sure you don't go over those levels? How should we think about that heading forward?

MIKE REGER: Sure. Well, thanks, Marshall. There's two metrics that we've always used and said and we're maybe a little old fashioned compared to some other companies out there. But we don't believe in a leverage ratio currently of more than 0.5 times debt to EBITDA. Or more than $5 per barrel of proven reserves in borrowing. Now, we've never really pushed those limits. I take that back. We did push them once. We were using leverage in March of 2009 which was the appropriate time. And we'll continue to use those covenants to govern what we do going forward. We certainly have the ability to expand our credit facility significantly, given year-end 2010 reserves. We generally believe that the appropriate use of equity capital has been to expand and grow our position and do it accretively. And the use of cheap debt capital into high rate of return projects does make sense. So we'll continue to monitor that situation going forward and as we feel there's an appropriate use for debt, we're not afraid to employ it.

MARSHALL CARVER: Okay. And one final one. You gave some LOE guidance heading forward. In terms of G&A, how should we look at that over the next few quarters?

MIKE REGER: Well, we generally should expect cash G&A to remain sort of plus or minus 10% from the current levels. It's going to fluctuate based on things that are happening in any specific quarter and the number being under $1 million a quarter in cash G&A, it's subject to 10 or 20% increases or decreases, just based on any sort of events we may have encountered in the quarter. So you generally should expect the cash component of G&A to remain relatively constant. In general, G&A including non-cash G&A you could probably build in an increase there. We have made a couple of different staff additions here and we'll see some slightly increased personnel costs and by slightly I sort of budget 10 to 15% as we go through 2011. But in general, you shouldn't expect a large, large change in the cash component of G&A.

MARSHALL CARVER: And that's 10 to 15% over 2010 and 2011? Or that's not a quarterly number, that's a year-over-year; correct?

MIKE REGER: Correct.

MARSHALL CARVER: Okay. That's helpful. And thank you. Great results.

MIKE REGER: Thank you, Marshall.

OPERATOR: Our next question comes from Marty Beskow with Northland.

MARTY BESKOW, ANALYST, NORTHLAND: Nice job on hitting all the operational targets for the quarter. Most of the questions have been asked already but just kind of drilling into some of the detail, you mentioned how your working interests you expect to increase. How much of that increase is driven by your increased exposure to Slawson versus just working interest in general for other operators that are not Slawson?

MIKE REGER: You know, Slawson continues on a working interest basis to be our largest partner and we expect that to continue through 2011. We just recently received word that Slawson has applied for six wells per unit spacing in the loop area and that's been approved. So we're going to see significant down spacing and activity which will keep our percentage of wells with Slawson fairly high. On a gross well basis, we're exposed to a lot of different operators but that happens to be our most potent working interest area. In general, we'll see our interest sort of grow with the play and in some of the best areas but Slawson will remain a very important part of our drilling program going forward.

MARTY BESKOW: Could you give us a little bit more color regarding the acreage costs? You spent about $1,350 an **acre** in the third quarter which is higher than it has been in the past. How much of that would you say is driven by increase in market prices and how much relates to the quality of the acreage? And maybe even how much just related to the timing of how soon an AFE is attached to that ache correct?

MIKE REGER: It's primarily related to the market. We've seen definite increase in the cost of acreage. There's no question about it. We believe we're still so far away from any kind of inflection point where the economics meaningfully change, you know, I'll walk you sort of through a metric that we use internally. Let's assume that a great Bakken well, good Bakken well is going to make 800,000 barrels. Let's assume that a sort of Bakken light well to steal another operator's phrase is going to make 400,000 barrels. Pretty conservative numbers on both cases. Take 20% off of those for royalties and you come up with 320,000 barrels, 640,000 barrels which means if you're drilling on a 640-**acre** unit, for every $1,000 you pay you're paying $1 toward your finding and development costs.

Therefore, the swing from $1,000 to $1,500 is moving your F&D by $0.50. It's a non-meaningful swing. So the trend in acreage prices is higher. It's going to continue higher. We're certainly not going to see it dip off, all things remaining equal. Oil prices will -- acreage prices will go higher. We're going to probably see that average start to push up toward $1,500 an **acre** based on the opportunities we're seeing right now.

But the market just in general seems to react fairly slow to the opportunities. So the change in general has been driven by higher market prices. The quality of the acreage we've been acquiring hasn't really changed. We generally continue to target the marquee acreage and the delineated area of production and we'll continue to do the same thing going forward.

MARTY BESKOW: And as far as CapEx guidance you mentioned $29 million that you anticipate for fourth quarter. Now, is that pretty much the cash related piece related mostly to drilling?

MIKE REGER: Well, what it basically means is that we'll sort of have accrued those kinds of expenses for wells expected to spud in 2010. So, you know, in general, what's happened is our drilling CapEx for the year is going to be about $50 million higher than we initially expected which, you know, you all knew by last quarter when we announced our increase in drilling. So we sort of maintain the financial flexibility again to stick with increases or decreases in drilling and the 132 is basically a forecast of where we'll come in this year on drilling CapEx.

MARTY BESKOW: Okay. And that does not include any assumptions towards acreage or use of shares to buy acreage, is that correct?

MIKE REGER: Sorry, I couldn't hear that.

MARTY BESKOW: Now that doesn't include any effect for acreage acquisition in the fourth quarter or use of shares for the fourth quarter?

MIKE REGER: Correct.

MARTY BESKOW: Okay. All right. Thank you. Very nice quarter.

MIKE REGER: Thanks, Marty.

OPERATOR: I'm not showing any further questions at this time.

MIKE REGER: All right. Thank you very much. Again, third quarter was our best ever in terms of production volumes, adjusted EBITDA and key acreage acquisitions. We appreciate everybody's interest in the Company. Thank you for joining the call to all of our analysts and please feel free to reach out to us if you have additional questions. Thanks again for your time and appreciate your interest.

OPERATOR: Ladies and gentlemen, this does conclude today's presentation. You may now disconnect.

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