

**MAGNUM HUNTER RESOURCES**

**Moderator: Brad Davis  
November 9, 2011  
11:00 a.m. ET**

Operator: Good morning. My name is (Onika), and I will be your conference operator today.

At this time, I would like to welcome everyone to the Magnum Hunter Resources third quarter 2011 financial and operating results conference call. All lines have been placed on mute to prevent any background noise. After the speakers' remarks, there will be a question-and-answer session. If you would like to ask a question during this time, simply press star, then the number one on your telephone keypad. If you would like to withdraw your question, press the pound key.

Thank you. I would now like to turn the call over to Brad Davis.

Brad Davis: Thank you, Operator. This is Brad Davis, senior vice president of capital markets for Magnum Hunter Resources, and I want to welcome you to the third quarter 2011 earnings and operating conference call. We're holding this call today from the cardiac unit in the emergency room at Memorial Hospital.

So we have several people. I'm going to read some forward-looking statements real quick and then turn it over to our chairman and chief executive officer, Gary C. Evans. We have all of our senior managers and executive managers with us today on the call, so during the Q&A, we can answer most any question.

So if we get started, the statements and information contained on today's conference call that are statements of historical fact, including all estimates

and assumptions contained herein, are forward-looking statements, as defined in Section 27(a) of the Securities Act of 1933 and as amended in Section 21(e) of the Securities Exchange Act of 1934, as amended.

These forward-looking statements include, among other statements, estimates and assumptions relating to our business and growth strategies, our oil and gas reserve estimates, estimates of oil and natural gas resource potential, our abilities to successfully and economically explore for and develop oil and gas resources, our exploration and development prospects, future inventories, projects and programs, expectations relating to availability and costs of drilling rigs and field services, anticipated trends in our business or industry, our future results of operations, our liquidity and ability to finance our exploration and development activities, market conditions in the oil and gas industry, and the impact of environmental and other governmental regulation.

I would refer you to the press release and to other publications that we've processed publicly for any additional forward-looking statements.

At this point, I am going to turn it over to our chairman and chief executive officer, Mr. Gary C. Evans. Gary?

Gary Evans: Thank you, Brad. And take some of that Ritalin and simmer down.

I thank you for joining in, and we do apologize for some of the delays we've had this morning. We were first going to blame it on the Greece, but I think now we'll blame it on the Italians today. But we had the delay in getting our news release out, and we had a really difficult problem getting this conference call set up after we all dialed in about six times.

So, anyway, we're off to the races. Let me just maybe summarize here. I do have with me Jim Denny, who runs our Appalachia group. I've got also with me Kip Ferguson, who runs our Eagle Ford group. I believe Glenn Dawson is on the line. He runs our Williston group. And then up in Dallas, we've got Ron, our chief financial officer, and Don Kirkendall, who runs our Eureka midstream group.

So let me just make a few comments. Basically, third quarter was business as usual. We remain on track. And our results signify that we continue to improve our activities in all three of our unconventional resource plays. Also, our midstream activities have really kicked it in high gear, and we're consistently laying pipe in West Virginia and now moving over into Ohio to stay ahead of our competition.

Our production, which is our most meaningful tool that we look at on a daily and weekly basis, has continued to accelerate. And I take a lot of pride in thanking the division heads for all their hard work in their three areas for making sure that we are using the latest technology and tools to increase our results in all three areas.

We mentioned in the press release this morning our current production rate is around 8,400 barrels a day. We anticipate that getting up to over 9,000 barrels a day easily by the end of this month. We will have – should have no problem at all exiting at our exit rate north of 10,000 BOE.

It's also, though, important to note that because we've been so active drilling in these three areas, our reserves have increased significantly. And just to kind of put that in perspective, just in a 90-day period, from June 30 to September 30, our reserves were up 19 percent. And we expect similar additions by year end. So it just exemplifies how fast the company's moving. We have got all the acquisitions that we did earlier in the year pretty well under our belt and pretty much know how to spend our money with our resource plays and where we want to that capital to go. And so I believe that the company is on track and will be able to show some additional growth in the fourth quarter that will take us to that 10,000 BOE mark.

So I would like, at this point, to maybe give each division head an opportunity to talk a little bit about what they saw and what happened in their area for the quarter and what their plans are since the quarter and now. So, Jim, I'll let you start out.

Jim Denny:

OK. Throughout the quarter, we've maintained one rig active in the Marcellus, in West Virginia, in Tyler County. We just completed the third of

three wells on the same pad, on the (Avert Weese pad). We are now moving that rig to the (middle-born area), also in Tyler County, where we will begin a four-well pad that'll be completed sometime after the 1st of the year.

We do plan on having the three wells that we just drilled and cased and cemented on production by the end of the year. Each of those – well, two will be 16 stages, and one will be 18 stages. We continue with two rigs active in our Kentucky area, drilling a combination of (lower Huron Cleveland) and (where wells). We have drilled and cemented, cased 10 wells so far to date and our anticipation of another 10 by the end of the year.

We continue to improve our drilling techniques and our completion techniques, and we are beginning to see some of the fruits of that in that region, as indicated in the press release. We remain on track to deliver our goal of something (north) of 6,000 BOE a day from Appalachia. And, in fact, we are very near that as we speak today.

That pretty well sums up our activity, and we'll continue to be on budget, so we're not, you know, costing the company any extra capital at this point in time. So I think we have a very positive result. We've seen production increase dramatically through the year, starting out at about 2,200 barrels a day, and I think yesterday we were at about 5,900 BOE a day.

Gary Evans: Very good, Jim.

Kip?

Kip Ferguson: Thank you, Gary.

The Eagle Ford has continued to impress us along the way. Their last quarter – over the last quarter, we have changed a little bit of our frac designs, and we've added more stages to our frac, a little longer laterals. Our 20-stage frac has continued to improve (our IT rates). We currently have one rig through the quarter running, and now we have picked up a second rig. We have two (non-op rigs) running in the Eagle Ford, so we have a total of four rigs running where we have a working interest.

Through the quarter, we also have now completed our gathering system, natural gas gathering system, (casing head) gathering system, where we have all of our wells going to energy transfer, under a really advantageous agreement to capture this 1,350 BTU gas. We're getting approximately a \$3 uplift on our gas. We're quite excited about that.

We've also, in the last quarter, signed a new marketing agreement whereby we have about a \$10 premium above WTI for our oil because of the quality of our oil being equivalent to LLS. So this has really been a fantastic marketing quarter for us. And we've signed a six-month contract to gather our crude under that advantageous pricing.

We have – we just finished a (fur number two H frac). We're currently drilling plugs. We are rigging up for a (kudu number one frac) that's going to start next week. We're also – like I had said earlier, we have the four rigs running. We have two more fracs planned for later this year in December. And this – in December. We're looking forward to getting these four brand-new wells online by the year end. And I'll tell you that, right now, we're real happy with our results and looking forward to these new wells we are currently drilling.

Gary Evans: OK, Kip, thank you.

Glenn, are you able to give a view of – overview of Williston Basin?

Glenn Dawson: I am, Gary. Good afternoon, gentlemen. Glenn Dawson here, running the Williston Basin division. Activities currently have ramped up to nine rigs this week (inaudible) six or seven steady. Two (inaudible) running (inaudible) six – seven in North Dakota.

We were able to (grind out) our backlog of drilled wells (inaudible) by increasing our (inaudible) commitment (inaudible) Halliburton. So we ground that down to (16 gross), (2.2 net), and we've been able to increase production to 1,670 BOEs per day on the Q3 exit.

Saskatchewan has been robust. We have been attempting some new (fracture stimulation techniques) in Saskatchewan. We've been going to 28 states,

(cemented sleeves), (activated by the mongoose tool). We're pumping (20-ton Saskatchewan), and we were able to pump a job about (inaudible) and we (flowed that) well back at record rates. So we'll put (that well as now) into production on (artificial lift).

We have also been working on our cost structure in both North Dakota and Saskatchewan. Most recently in Saskatchewan, you know we have a battery facility that was built out last year with three miles of pipe. We're adding three miles of pipe to that program. I (inaudible) (knockout), which significantly (reduced) our operating costs (south of) \$10 (inaudible) (bringing in three-phase) power and electrification to further reduce our costs in Saskatchewan.

North Dakota (inaudible) we have pretty much gone completely to (sliding sleeves), 20 (inaudible) per two-mile well. We're primarily doing (two two-mile wells) off of (eco pads), and we have ramped our production up in North Dakota, as well as we have experienced higher IP rates, (IP 7, 30 and 60 days), to the numbers indicated in the last press release.

We are looking to add significant reserves from (Williston to Hunter) this year. We see an expansion of our proven (PDP) and (PUD) base. We've also got some exciting new developments in the Saskatchewan area. There's been some (new built) Bakken plays discovered by some majors proximal to our acreage. And we're looking at drilling a well possibly by year end or Q1 into the middle Bakken in Saskatchewan, as well. Primarily to date, we've been (inaudible) players.

We are also looking at conservation and realization (inaudible) in North Dakota, in natural gas, and natural gas liquids associated with our production, which is 1450 BTU natural gas. We're on the cusp of signing up a third-party agreement, which will bring in hundreds of miles of six-inch (trunk line) and will ultimately allow us to tie in the (gas for flaring), which is over 10 million cubic feet a day grossed, and expect to recover liquids – depending on (the plant) we went (through), in excess of 100 barrels per million cubic feet (inaudible) account.

So we haven't booked any of those reserves into our reserve report. We hope to do that in 2012.

Thank you.

Gary Evans: Thank you very much, Glenn.

And we'll now jump to our midstream section, Don Kirkendall.

Don Kirkendall: Thank you, Gary.

Eureka Hunter continued to put 20-inch gas pipeline into West Virginia, (ahead of Triad Hunter's drilling plans), most recently completing a 14-mile lateral we know as (Pursely). Triad will be drilling that in the first quarter of next year, so we have (line) ready to go there.

We've completed almost 30 miles of pipe year to date as opposed to about 13 miles for 2010. Looking into the first part of 2012, we've got two major projects for us, one being a seven-mile lateral going north to our Wetzel County wells, picking up some very strong wells that Triad has drilled there and then laying another seven- or eight-mile lateral into the (Markwest Mobely) plant facility.

On that same topic, we have recently negotiated gas processing agreements with (Markwest) to handle (Triad's) equity gas, as well as gas processing for third-party gas to be connected to the Eureka system. We've got several gas-gathering contracts in the hands of several large producers, continuing to negotiate terms on that. We expect to conclude negotiations in the first few months of 2012 and the last quarter of 2011.

The pipeline, of course, is 20-inch, 900-pound, designed to carry 250, 300 million cubic feet a day. Everything continues to go pretty much as planned.

Gary Evans: Very good, Don. Thank you.

OK, Ron, you want to give us a financial overview of results for the third quarter and nine months ended September 30?

Ron Ormand: Yes, be happy to.

So our revenue – excuse me – revenue for the three months ended September 30 increased 310 percent over the comparable quarter in 2010 to \$32.4 million. Adjusted EBITDA for the quarter was approximately \$10.4 million compared to \$300,000 in the period in 2010.

Our net income per share was reported at 1 cent per share loss. After adjusting for non-recurring and unrealized gains on derivatives, we have a 5 cent loss.

Notably, our (LOE and BOE – LOE per BOE MG and a for BOE) continue to decline, (1570 for LOE per BOE) in the three months compared to 22 last year. And (1583) in recurring G&A compared to (1981) last year.

For the nine months, our revenue was \$80.1 million, up 249 percent. And our nine months into (EBIDAX) is \$30.3 million, compared to \$3.3 million last year. You should also understand (that only) includes results for (new lock and in gas) as of April and May, respectively.

Reported earnings were 28 cent loss and recurring earnings for the nine months ended were 10 cent loss. (LOE per BOE) and (G&A for BOE) also declined and (continued to decline), and we expect that trend to continue throughout the end of the year and into 2012, particularly as we're adding on lower-cost production and selling higher-cost production.

CAPEX in the third quarter was approximately \$74.2 million, bringing our CAPEX for the year to \$170 million. Our liquidity remains very strong, \$117 million at the end of the quarter, 9/30. We expect that (our borrowing) base shall also increase, as we have added substantial reserves in the quarter, and we're currently undergoing a (re-determination) to increase our borrowing base, which (should be) out in the next 30 days.

(Our debt to cap remains) about 20.5 percent, so we're still very underlevered compared to most of the peer group. Production for the third quarter was (5270) a day, 300 percent up from third quarter 2010, 7 percent sequentially

from the second quarter. This is in – as a result of the acquisitions and our drilling efforts. However, we were impacted in the quarter by the (shut-in) conditions due to weather in Williston Basin, which also pushed back some of our completion schedule there, and also we (shut in) some of our production in the Eagle Ford (in order to reinstall) new (ESP pumping) units, which we'll going to provide, we believe, for a much better (EUR) over the long term and beneficial to do so.

The current production today is approximately 8,400 BOE (today). We expect an additional two to three net wells on by the end of this month. And we're very confident in meeting our exit rate of 10,000 barrels a day by the end of 2011.

With that, I'll turn it back to you, Gary.

Gary Evans: All right, thank you, Ron.

Brad, I think we've kind of covered every division of the company and the financial side, so let's open up the floor or the call now to any of our listeners who wish to ask some questions. Operator?

Brad Davis: Yes, absolutely.

Ron Ormand: At this time, I would like to remind everyone, in order to ask a question, press star, then the number one on your telephone keypad. We'll pause for just a moment to compile the Q&A roster.

Your first question comes from (Sulan Ping).

(Sulan Ping): Good morning, gentlemen. First question is, can you give some more color regarding the 750 BOE per day of (shut-in)? I know you mentioned (inaudible) adverse weather, but I was wondering specifically what kind of weather condition did you experience in the third quarter? And also how many wells were impacted? Just, you know, trying to get more color there.

Gary Evans: This predominantly due to weather-related issues up in Saskatchewan and North Dakota, so I'll let Glenn kind of address the situation, because I think a

lot of people don't realize how bad it was and how there are still some issues up there. Glenn?

Glenn Dawson: Well, if you've watched CNN through March and June, you – all you have to do (inaudible) where the city was basically flooded out. Essentially what they (inaudible) in late April was a massive snow accumulation of 8 to 10 (inaudible) which is very untypical for the area. Then in May, we received seven (inaudible) rain in Saskatchewan and North Dakota, which is about what they get in a year.

So essentially, the land is very, very flat, (with some low area), and it was more (inaudible) on the ground than there was ground. And I mean water three, four, five feet deep. So essentially all of our production in Saskatchewan, North Dakota, was shut in for three months, so that accounts for the numbers we're talking about.

We've been able to restore that as the water receded, so currently we virtually have no (shut-in) in Canada and a very modest amount of production (shut-in) in North Dakota, less than 100 barrels a day. So that's the – now (inaudible) in the Williston Basin, of course, not just our company.

I hope that answers your question.

(Sulan Ping): OK, and – so can you just tell us, what's the current production rate? And what's your target exit rate (inaudible) in Williston Basin specifically right now?

Glenn Dawson: (We reported) 1,670 BOE production per day. Our current production is (inaudible) barrels a day of current (productive capacity). We are on target to make our production forecast exit. We most recently stated in (inaudible) at 2,300 barrels equivalent, and we'll be over (inaudible) on the exit this year.

(Sulan Ping): OK, so that's still on target. OK. And second question, regarding your – just trying to understand the fourth quarter production for 2011 and also think about 2012, given what you had said before. So I think – I was estimating around 9,000 (inaudible) for fourth quarter. So can I assume that you will get the full – you know, the full recovery of the 750 (shut-in) production, so that

would get it close to – I mean, I know you said the (exit rate) is 10,000 (inaudible) already 9,750 there, average for the quarter. And then 2012, you had mentioned 80 percent to 90 percent growth rate with (inaudible) 13,000 BOE per day of (exit rate). Are you – can you reaffirm that? Or how should we think about it?

Male: We have – we are not backing off any of those numbers. In fact, the production that Glenn was just referring to affected the third quarter, will not affect the fourth quarter, because it's all (on). So we don't have any issues in the fourth quarter with respect to (shut-in) production. And to take it a step further, a lot of the new wells that we're drilling in the last 30 to next 30 days, are 100 percent (owned well), so they have significant impact to Magnum Hunter both in (the table and field up) in Saskatchewan and then what Jim Denny is drilling over in the Marcellus of West Virginia.

So we feel very good. We mentioned our production is currently 8,400, expected to be over 9,000 by the end of the month, gets us an – (easy opportunity) to get to over 10,000 by the end of December, with all the new wells in all three divisions. So we're – the numbers we've given you and given the street as a 13,000 BOE a day exit rate for 2012, we are firmly reconfirming.

(Sulan Ping): OK. Sounds good. And then last question (inaudible) liquidity, I was just wondering if you can talk in general as to what you think you will need in 2012, in terms of your funding gap.

Male: We have no funding gap.

(Sulan Ping): (inaudible) liquidity. But how about just, you know, operating cash minus your \$200 million of CAPEX? How much do you think you – are you – I mean, based on your existing...

Male: Yes. Yes. Based on our existing capitalization, we have no funding gap. First off, the \$200 million in CAPEX, \$50 million of that is funded from our pipeline facility, so then you have \$150 million that's funded from our upstream facility, of which the total cash flow deficit would be somewhere

between \$30 million and \$40 million, depending on prices. Based on our current liquidity, we have sufficient capacity to cover that.

Male: Yeah, let me just make another comment there, because I'm just amazed that that's even – that question is even being asked. The reason that Magnum Hunter took the proactive effort 60 days ago to get the \$100 million term loan, (do the) \$150 million financing at Eureka Hunter, to do all the things we've done is so that we have no funding gap.

I don't know how many times I've got to say this. And I'm going to say it again. This company is fully funded without having to raise a dime of equity and a dime of additional debt to fund all its capital needs for 2011 and 2012. And, you know, if you don't understand that, please call Ron, please call Brad, please call me and I'll walk you through it. It's fairly easy math.

So we have no funding gap. And I don't know how those rumors continue to go out there in the marketplace, but they're hogwash.

Operator: Your next question comes from (Neil Dingman).

Male: Hey, (Neil).

(Neil Dingman): How you doing?

Male: Good.

(Neil Dingman): Say, first question, Gary, maybe for you or Jim, just (inaudible) Appalachian. I noticed kind of going forward you mentioned (inaudible) more activity going forward (inaudible) more (Huron-focused) versus (Weir). I was wondering if that will be the case. And just, you know, for a while, I know it seemed like the (Weir) wells had pretty solid estimates coming, with just what's going on with them, and then kind of where the focus will go.

Male: Well, you know, our focus in that – in Kentucky part of Appalachia has been to hold acreage. So we have to balance our capital dollars to make sure that we're maximizing or optimizing the acreage that we're able to hold. So that's what's drilling or compelling our minimum drilling commitment.

As commodities move or as we see – we're improving the (Weir), and our last two wells have been our best wells, then we can add to that, but the reason you're seeing that is just because we're drilling to hold acreage and that's our primary focus.

But we're looking at other ways to improve production on our existing portfolio, applying some new technologies and that sort of thing, so...

Male: You might just touch a little bit about the (Weir) wells that we've drilled and some of the issues we've had and some of the things you think you've resolved.

Male: OK. We've drilled four (Weir) wells this year. The first two we encountered considerable drilling issues having to do with – we drill these wells – or we began drilling them on air. And then the – we are not able to control the liquids, both water and condensate, to control the – to continue to drill the wells in that fashion.

So we began using fluid. And as we went to fluid, we experience (loss circulation) problems, so we had severe damage to the formation, in my opinion, on the first two wells we drilled.

We sat back, and we came up with a different plan, and the last two wells we drilled, we did a considerable job of getting – doing a combination of increasing our air by more than double and by using a misting, foaming type drilling fluid, we were able to get a full – a full 3,000-foot lateral out there.

However, when we came out of the hole to run casing, instead of the usual open flow of, say, (200 to 600 MCF), which quickly dies off, we were experiencing rates north of 3 million cubic feet a day, and we were blowing condensate all over the location. So we still had to mud up the wells to get casing in the hole, and we did not get casing all the way out to the toe. But we did a lot less damage to those two wells than we did to the first two.

And usually these wells last a couple of weeks on flowing and then we go to artificial lift. These last two – the first one that's been on production the

longest is still producing in excess of a million cubic feet a day, 1.2 million a day, almost 1.3, and 30 to 40 barrels of oil a day. So...

Male: And what are the cost of these wells?

Male: And these wells are – I think they're averaging about 1.5 million. We first – the last two were – well, one was 1.2, and the other was about 1.6, so somewhere around 1.4 to 1.5 million.

Male: So, (Neil), to answer your question and kind of make the full circle here, we're extremely excited about this (Weir). You've heard me mention it before. We're just trying to be sure that we got the right, you know, code. We figured out the best way to drill it. And we have, what, 70,000 acres of potential, so you can imagine a well that costs \$1.5 million (drill and complete) that's producing, you know, well over 1 million a day net, that makes money all day long. So we're trying to get the code right to accelerate that program, and you'll see that happen in 2012.

(Neil Dingman): Great answer, guys. And then maybe over for Kip, as far as, you know, some of the drilling that you're doing there, wondering, number one, well, everything going forward I guess for next year, will it all be pad drilling? And if so, you know, what do you think is sort of the optimal per pad?

And then I noticed on the couple wells going forward, it looked like now 20 stages kind of going to be the norm. Is that going to be the case going forward?

Male: Yeah, thanks, (Neil). You know, we are having such tremendous results on the 20 stages that the next two wells, the (fur number 2H), and the next well, which is called the (Kudu Hunter number one), are both 20 stages. And we have several wells we're currently drilling, we've moved the rigs off or moving these – we're drilling some new wells – that it looks like they might have pushed 25 to 27 stages.

So we are trying to do longer stages or more stages and longer laterals. We don't know, you know, how successful we're going to be, you know, drilling

these longer laterals, but it's certainly something that we've had tremendous success with, so we want to continue that process.

As for pad drilling and whatnot, what we're currently trying to do – you know, our acreage allows us to form 640-acre units. So we have – although we have three and, in some cases, four years left on our leases, you know, we're continuing to try to (HBP) all of our acreage, so we're continually drilling one single well in every unit.

So we – the idea is that we're finalizing all the title opinions, get all the division orders done, get the wells – one single well producing on every unit. And then we're coming back and doing typically a two-well pad for every unit, and that's going to be kind of the program that we're doing and starting kind of midyear next year in 2012.

So currently, we're just be – we'll probably just be drilling one well per unit. Now, we do see a significant savings on these pads, but I think – and the whole plan is to end up with a very nice, concise, successful area that you have fully (HBP). So that's kind of the plan today.

(Neil Dingman): Great response. And two more, if I could. One for Ron. Just, Ron, any comments on sort of the run rate on the G&A and LOE on a per unit basis, kind of as we look at the fourth quarter and into 2012?

Ron Ormand: Yeah, it's going to continue to trim down. I think fourth quarter we have around \$12 (inaudible) (LOE), around 10 to 12.

(Neil Dingman): OK. And then very last question for Gary, just wondering, Gary, what you think of, the M&A mark that's currently – are you still aggressive? Or are you – you know, got enough now for a while?

Gary Evans: Well, you know, we're constantly looking at other opportunities in all three of these areas. We just, you know, had actually a pretty big management meeting here the last few days, and approved, you know, (an acquisition of) additional leases. (And in one of our plays) we're working on a significant transaction and a second play that (would have) big impact to us.

But, you know, we're watching how we spend our capital, because, you know, our goal is to add reserves and production on a very cost competitive basis. And because our entry into all three of these plays is at such a low acreage cost, we don't want to do anything to skew that.

So it's not like we don't have plenty of properties to drill, but we're constantly looking for ways to expand our footprint, especially in areas where we think we have a competitive edge.

So with regards to the overall M&A market, we're seeing a lot of activity around our properties. We're seeing some significant values being applied. We are talking to certain parties about possible joint ventures. We're talking to parties about possible financial partners.

So we're keeping all of our options open. The beauty of where Magnum Hunter sits today is we don't have to do anything. We are fully funded and can continue to grow this production base at exponential speed, but you know the way we are. We're not complacent. So we're looking and seeking all the other opportunities that might exist out there to improve shareholder value. And that's our goal.

(Neil Dingman): Great call. Thank, you all.

Operator: Your next question comes from (Will Fitzpatrick) with (Johnson Rights).

Male: Hello, (Will).

(Will Fitzpatrick): Understanding that a lot of the drilling currently is to hold acreage, if I remember correctly, you guys were planning on (some down spacing) tests in the Marcellus or Eagle Ford. Can you give us an update on the progress on that and your general thoughts on (down spacing)?

Male: Well, first of all, I'd like to say that most of our drilling is not to hold acreage, because most of our acreage is held by production, so that's an incorrect statement. We do drill – what Jim mentioned is we're drilling some (Huron) wells, which are very inexpensive wells in Kentucky to hold acreage, but we got, what, 300,000 acres there to hold, and most of it is already held.

So I'll let you guys comment on the additional drilling he's talking about in the Marcellus.

Jim Denny: We have done some testing recently – this is Jim Denny – in the Marcellus that would tell us that we can space our laterals closer together. We have been currently keeping a spacing of at least 1,000 feet between laterals.

Our current plan certainly in Wetzel County would be to drill at 750-foot space in between laterals. So that's the extent that we're willing to go at this point in the Marcellus.

Kip?

Kip Ferguson: Yeah, in the Eagle Ford, (Will), we've been doing a lot of testing, and we have a lot of data – (bottom hole) flowing data that we have in all of our wells – or at least, actually, three of our wells, where we are using (ESP pumps).

And what we found is that there's still a tremendous amount of (bottom hole) pressure, and it continues to surprise us. And, you know, some of the modeling we've done – we've gone out, reached out to some, you know, third-party reservoir modeling companies to kind of confirm what we already think we understand, and they have confirmed that, you know, our drainage here is only somewhere around 8 percent to 10 percent per well, the volume that you're draining per well. So we're really not recovering the amount of reserves in place that you can recover.

So we have to – we either have to (down space) or do a much better job fracking. And that's one of the things you see us actually adding stages and whatnot and changing our stage spacing. We used to be at 310 feet. Now we're at 250-foot spacing between stages. We're having, you know, really good results there.

But we are looking at (down spacing), just to recover the tremendous amount of oil and reserves that are in place that we're just not getting with a single lateral, 1,000 foot apart. So there's a lot of work to do there, but we think

there's tremendous opportunity. We've heard that from other operators in some of their press releases, too, so...

Gary Evans: Glenn, do you want to comment about Williston Basin?

Glenn Dawson: I think it's pretty well understood from all the literature out there and all the operators that it's three to four wells per section in (inaudible) Bakken, which gives you eight wells per section or space unit (inaudible) 1,280 PSU, two sections (inaudible) together.

Our operations are focused on drilling one well per PSU currently, so without a year-and-a-half, we'll have all of our land matured in North Dakota. In Saskatchewan, we're already down to three wells in some section. By year end, we're going to have several sections at four wells per section, so our offset is about 1,200 feet.

We (inaudible) based on (volumetrics) that, you know, we're – as Kip mentioned, we're really only recovering probably about 10 percent to 15 percent (inaudible) that's generated in these sections. But we are down spacing in Canada.

(Will Fitzpatrick): Perfect. Thanks so much. That's all I got.

Male: Thank you.

Operator: Your next question comes from (Kim Pakinawski) with MLV and Company.

Male: Hello, (Kim).

(Kim Pakinawski): Hi. My first question is for Glenn. Glenn, the two – you said the last two wells in (tableland) averaged a 24-hour IP rate of 425 barrels a day. How does that compare – in your presentation, you have an IP 30 rate of 180. So can you tell us what the average IP rate – the 24-hour IP rate is for those wells and just compare these last two? You said you were changing some things at the completion.

And also, if you can discuss (well cost) improvements. And I just think it'd very helpful – I think a lot of people really don't get this area, and it just might be helpful to just go over the rates of return there.

Glenn Dawson: Thanks for the question, (Kim). Well, the two wells (inaudible) the first one was (frac 28 stages), normal frac, we (put it away), got a good result on it. So I would say that's typical of the better wells we've drilled in (tableland).

The last well we drilled, we made some significant changes to the completion program. We went with (27 cemented sleeves), activated by a (mongoose tool). We also changed up our frac company and we went with CalFrac, lowered our concentrations, pumped more water, (less sand). And we think that gives us better contact with the formation and better (wings).

We (had a press release the numbers) on this well. We (pulled) the well back for 13 days, which is a record flow for us. And now the well's on (rod pump) and producing, but we haven't put that number out there. I think if you look at that number that's in the press release today, you can figure out what the well (IP'd) at.

(Kim Pakinawski): OK.

Glenn Dawson: But it's significantly better completion than we've experienced in the past. So the question looms – is it a sweet spot in the rock? Or have we effectively made a (step change) in our completion technique? And it's too early to tell until we get more time on this well, and then we've got (two) currently drilling, immediately offsetting this well, (which should) be completed with similar completion techniques, and they're (inaudible) proof of whether it's a combination of the two, better fracking, sweet (spots in the rock), or whether it's just related to the completion technique. (inaudible)

Male: (Kim), to take that a step further, though, for those that don't recall what we're doing up in Saskatchewan, these are 100 percent owned (working interest) wells. Our net royalty is only 2.5 percent to the provincial government, so we have a 97.5 percent net lease. You're talking about wells that cost \$3 million, and you're talking about wells that are (IP'ing) over 500 barrels a day. So it

doesn't take a rocket scientist to figure out this is a very good area for the company.

(Kim Pakinawski): OK, great, thank you. And could you just give us a little bit more color on – you mentioned a well – successful well in the Bakken up there?

Male: We're working (inaudible) Bakken play. There has been a significant new Bakken discovery by (Hotske) just to the west of our block. We've just drilled a well on the North Dakota side, which is one mile from the Canadian border. And that well is just – has been flowing back. It was one of the ones that was fracked earlier and caught up in breakup and sat for six months. And we went in and did the last six fracs. It's just (on rod pump) now, and we're seeing some positive indications of hydrocarbon. If that well gels out, it's going to set us up for a (new Bakken exploration test) in Q4 or Q1 on (inaudible)

On (our cost side), I mean, we're really focused on driving on our operating costs down. As you know, we have (inaudible) facility in here, which I alluded to. We're adding (three miles) to that, so there's probably six new wells that are going to be gathered on it, and the potential to gather is, you know, 20 new wells. What does that do for you? Well, everything comes into our (battery). Oil and water separates (inaudible) (knockout). We have a disposal well. This is how you get your costs down well under \$10.

We're also bringing in three phase power to electrify all of our (inaudible) forward and (switch) most of the wells to electrical pump motors using diesel (gen sets) to power them until the three-phase power comes in, which should be Q1 to Q2 before (inaudible) which is (inaudible) trucking costs (inaudible)

So all we do in Canada is truck the oil. We market it ourselves. As Gary alluded to, we have the low royalty on the first 100,000 barrels of 2.5 percent on (crown lands). We've only drilled (crown land) to date. Our operating costs (inaudible) under \$10 leave us with a fairly healthy net back in this area.

We do not see a differential on crude pricing in Canada, as we manage it right into the (inaudible) trans-Canada system ourselves.

(Kim Pakinawski): OK, great. Thanks for the color. And a question for Kip. In the Eagle Ford, Kip, could you just remind me what the difference in the IRRs are with the (ESP) installed, what the improvement is? And also, if you could just give us some more color on that contract for your – you said you have a six-month contract. When would you renew that? What are the volumes that that contract is on? Is it on all the oil? And if you could just talk about that going forward.

Kip Ferguson: Yeah, sure. We – the (ESPs) have been – it's something that we've been kind of experimenting with. And, you know, it's really – an (ESP) pump can really flow incredible rates and pump incredible rates. But what we like to do is try to manage those rates and, you know, kind of keep it the best efficient rate for the formation itself.

And the plan with (ESPs) is, once the well quits flowing, which is anywhere from five to nine months, what we try to do is put the ESP in the hole. We use it sometimes to – like, help it kick off, for one instance, the (fur number one), you know, it – we ran the (ESP) for 18 hours, and then it kicked off flowing for 35 days. So I mean, we kind of just kind of use it to kind of keep the well stimulated and flowing. It's a real efficient, real effective method to continue to artificial lift these wells.

But also, too, there is an operational, you know, method that we use with the (ESPs) to kind of maintain a rate that works the best for these wells. And so we're kind of still experimenting with that. We're having (inaudible) we're happy with it. We've been flowing, I think, one well over 100 days with (ESP), and it's really working really well.

So the plan is to have the wells produce 100,000 barrels of oil within the first 12 months to 18 months of their life. And this, obviously, drives the IRR, you know, substantially.

Male: And, (Kim), that 100,000 barrels, the reason that's a key for us, is that achieves well payout. So if we can speed up the time it takes to get that 100,000 barrels by adding these (ESP) pumps, we obviously can have payout quicker and therefore can develop the properties faster.

And so that's really the whole concept. And we stole it, really, from the Bakken area, where Glenn's at, because (inaudible)

(Kim Pakinawski): Right, yeah, I recall.

Male: ... (ESPs) – that's just kind of their natural business motive, is once they drill the well, they'll go to (ESP) and then go (to rod pump). So I think Kip here has tried three different designs of (ESPs). We've been told we're one of the first, maybe the only company in the Eagle Ford that's using the (ESPs). You know, and we have a well doing 150, 200 barrels a day, and you take it to 400, 500 barrels a day. That's not a bad deal.

(Kim Pakinawski): Right.

Male: The beauty of the new technology and these pumps is that we can control them from our office. So we literally can have an engineer sitting there monitoring and saying, "Turn the pump on, turn it off," you know, and watch what's going on.

So efficiency is really what it boils down to, is being more efficient and getting that oil out of the ground faster and, therefore, getting payouts quicker.

(Kim Pakinawski): OK, great. And do you have 30-day rates yet on the (Sable Hunter) and the (Orex Hunter)?

Male: I do. I do have 30-day rates.

(Kim Pakinawski): Would you care to share them?

Male: Well, they're posted on our website, actually.

(Kim Pakinawski): Oh, they are? OK, I didn't see them.

Male: (inaudible) there's a (inaudible) (IR presentation) that has some (inaudible) information in it that will be up this morning or (inaudible)

(Kim Pakinawski): Oh, OK. Yeah, because I looked at the last one, and I didn't see the rates.

Male: No, that was October. We need to – we've got the November one up.

(Kim Pakinawski): OK. Can you tell us what the rates are? Or do I have to wait for the posting?

Male: Yeah, we'll tell you right now. Just hold on one second. He's digging it out.

Male: (inaudible) very fast.

Male: (inaudible)

Male: (inaudible) yeah, OK, so the (Sable Hunter) 30-day rate was 455 barrels of oil a day, BOE a day. And the (Orex well) was 626 BOE a day.

(Kim Pakinawski): Terrific. OK, great. And then I don't want to leave (Jim) out, so one very quick question for (Jim). Why did – and you might have said this before, and I forget the answer, but why was the (Roger Weiss 1002)? Why did you drill a vertical well?

Male: This was – when we first drilled our first horizontal, it was the (1001). And the (1002) was set out to be our second well. And when we got in there, we found that the surface casing was so askew that we (would have had tremendous torque) and drag, so we abandoned trying to drill the horizontal almost immediately to save some dollars.

So then we drilled our second horizontal. And then when we came back, we drilled our third horizontal on that property. And then we drilled the vertical, was the only thing we really could do, down to recover the reserves that would be sitting between those three horizontals...

Male: Yeah, it was a well basically – one of our first wells last year that we screwed up. We made the decision we wanted to make good wells, so we backed up, drilled a new one, (left the hole) there, and Jim was going to make something out of it, so he just (inaudible)

(Kim Pakinawski): OK.

Male: Yeah, that's right. It was efficiency and the fact that it was cheap.

(Kim Pakinawski): OK. Great, thanks for answering all my questions.

Male: You're welcome.

Operator: Your next question comes from (William Butler) with (Stevens).

Male: (Mr. Butler), how are you, sir?

(William Butler): Just fine. This question's for Kip. Again, on the Eagle Ford, can you tell us what the current production rate is, in how much production was down due to the (ESP) downtime in the third quarter?

Kip Ferguson: It's right around about 900 BOE a day right now. And what we do is, on the ESPs, one of the ideas we'll try and do is you have to rig up. We flow all the wells (naturally of casing). So some of the delays we get are – you have to move a rig in, you have to run tubing, you have to set the (ESP). We've used a couple of different designs to, one, operate the (ESP) in the style that we like to operate on efficiently. And that is temperature control in the (ESP) and operating and how we get to use these (ESPs), you know, our kind of method that we operate them at.

So the delays are – you can imagine taking three of your really good wells and taking 150 BOE a day offline. They were all about the same time. We use two different (ESP) companies. We're using Schlumberger and then (Baker central lift). So we want to kind of get two different – really good companies to help us design the best process for this.

And they both seem to be doing a really great job, by the way. One of the things that we get from these (ESPs) is real-time (bottom hole) flowing pressure, which a lot of people don't have in a lot of their wells. It's just not something common that we get that information with these (ESPs). So we're really quite excited about it. We've been able to use it to do some really great detail reservoir modeling work.

(William Butler): OK.

Kip Ferguson: Did that answer that? I'm sorry. There (were) somewhere between 300 and 400 barrels down, I would say.

(William Butler): On average for 3Q?

Kip Ferguson: Yeah.

(William Butler): OK. No, that's helpful. And then in the fourth quarter, I mean, how many wells do you expect to have down at various times and for how long to put in (ESPs)?

Kip Ferguson: Good question. The two wells right now that we'd like to run (ESP) on, sometime, you know, we're going to predict them sooner or later, is the (Sable) and the (Orex). I mean, we think the (Orex) would be a phenomenal character to run (ESP) in, because it's just high-rate. It continues to kind of level out at a really high rate. I think it's – and so we'd like to really run (ESP) on it.

But you really don't like to run (ESP) until the well quits flowing. So they kind of go – they kind of trickle on down for the next couple of months. And we're planning to run (ESP) in December. I think it's jumping the gun a little bit, but, you know, be prepared. You know? You have to get three-phase power out there. You have to get everything lined up. You have to have the (ESP) design and built to our standards.

So we might have two more on (ESP). You know, and we were fracking – we're finishing the – we're actually drilling out plugs on (the fur number two). We're fracking the (Kudu Hunter) next week. And we have two more fracs planned for December. We have two frac dates in December. So we think we're going to have four new wells online, brand-new wells online by the year end.

Male: Yeah, that's something that we should – we hadn't really highlighted, but our schedule on the Eagle Ford has ramped up a lot faster than we originally had planned. And we've also been able to get frac dates that we didn't think we would get.

So we should have four really nice, new wells online in the fourth quarter from the Eagle Ford area that would have some very nice impact on the company.

(William Butler): OK. And it sounds like barely any downtime for (ESP), so we should expect a pretty significant jump any – what should we expect out of there on average for the quarter?

Male: You know, I don't have that number for you yet, because one of the things we're looking at is, do we actually need to run (ESPs) on those wells by the end of this quarter? (That may) continue to surprise us. That (20-stage) really does help the deliverability and the decline, also. It's just not a very (hard decline) once they kind of level out.

So I don't have that exact number for you and that analysis. You know, it's something that we're constantly looking at.

(William Butler): OK, thank you. And then, Gary, I guess, to follow on your comment there, are you all seeing an abatement in – or an easing in service cost, both pressure and – or cost pressure and availability?

Gary Evans: We obviously monitor that pretty closely. And, you know, it's kind of – you would think that with the pullback in the capital markets and with commodity prices that had dropped – now they're back up a bit – you would begin to see some things.

I think we're seeing a little bit of loosening in the Eagle Ford. I know that we've had some sand issues up in the Bakken that have just surfaced over the last couple weeks. Fortunately, in the Marcellus, we do own some of our own rigs. Jim was proactive last year, earlier this year, and we bought our sand for the whole year supply, so we have it in storage.

We're just – we're monitoring it very, very closely. At one time, you know, we were thinking about putting together our own frac spread in the Marcellus. I don't think we're going to need to do that now, because a lot of new equipment is coming out of manufacture.

So what we're trying to do – I haven't seen prices go up. We've seen things moderate. We're trying to be more efficient with the auxiliary services. And we've taken the proactive approach of buying a lot of equipment ourselves, things that we have to use on every well, you know, we can pay for in a well and a half or two wells.

So we're getting storage yards and having our own equipment, because we have an equipment division. We're comfortable with that. And so every area we're trying to more and more efficient up in the Saskatchewan (table end field). As Glenn mentioned, we're expanding our water system, which saves us a ton of money, because we can transport the water ourselves and inject the water ourselves. And, of course, we have our own disposal wells (at Triad), and we use those religiously.

So all areas – you know, we're constantly trying to figure out ways that – to cut costs, because there are opportunities to do that, but it takes scale to do it.

(William Butler): Right. OK, thank you all very much. That's all I had.

Operator: Your next question comes from (Mario Veraza) with (Toohey Brothers).

(Mario Veraza): (inaudible) doing today?

Male: Hey. How are you today?

(Mario Veraza): Good, thank you. Just had a couple quick questions, one for Don on the midstream. The 250 to 300 million cubic feet a day, how should we think about that for a ramp-up next year?

Gary Evans: That's a good question, Don. Would you answer that for me, too?

Don Kirkendall: I'm sorry. How are you, Gary?

The 200 design capacity is 250, 300 million a day, is our general capacity at about 900 pounds. We're forecasting that, with some of the discussions we have with third-party producers right now, middle of next year, Q3 of next year, we should be in the 100, 120 million a day range for equity and third-party gas going over to the (Mobley) plant.

(Mario Veraza): OK.

Gary Evans: The reason it's so difficult for us to make that projection is it's just a – it's a hard question to answer. And you can imagine we're always asking that question to ourselves, is that, you know, we built (Eureka Hunter) first and foremost for our own (equity gas that Triad has). But as we continue to expand the system, more and more opportunities come about to gather third-party gas.

The ingredient that had been missing since we bought Triad in February of 2010 was that we had no way to process the gas. And so we went down several different paths of trying to resolve that problem, and we did so recently with the announcement over the last 30 days of our transaction with (Markwest hydrocarbons), which is a cradle-to-grave solution.

And it's not just being able to take that gas from the wellhead to the gathering to the processing. We have the ability to move that gas from the tailgate of those plants and also have an ethane solution. So when all that occurs, which should happen, we all believe, by June of 2012, Magnum Hunter, Triad Hunter, is going to have a price uplift in its gas of \$1.25 an MCF, because we have got this solution now resolved.

Because that solution is resolved, the third-party gas that Don and his team are trying so hard to get into the pipeline becomes so much easier because we have a complete solution today.

Male: Well, Gary, let me add one thing, though. And you kind of alluded to it. It took a company like Magnum Hunter to prove up this area from both an exploration standpoint and to build a pipe to get it out. It was a real chicken-and-the-egg thing prior to our coming along. There were no wells, because there was no pipe. There was no pipe because there were no wells. Now we're (proving at) the area that gives third parties the confidence to start drilling.

And there are very, very large companies that watch our results, and it's because of the work we're doing in these somewhat virgin areas that will

propel third-party growth. So it all becomes a function of third-party drilling, and a lot of that stems from the drilling that Triad is doing in that area.

(Mario Veraza): OK (inaudible)

Male: I'd like to make one other comment here that I want to make sure our listeners take a note of. You know, we drilled the first two Marcellus horizontal wells in December of last year in this (Weiss) area. And we were very excited that we had a couple wells doing, you know, 3.5, 4 million a day initial production.

We just offset those wells. And Jim's got wells doing 10 million to 12 million a day, same formation, just in the exact same area. What's changed? We have learned how to better drill them and complete them.

Male: Could be.

Male: And so that in itself is adding significant value to Eureka Hunter, because we have big-time wells to put into the system that we didn't – we thought it would take two to three times the drilling to get to that level. So the value of Eureka Hunter and the proactive approaches we took over the past year at the latest pipeline is really going to prove to be a significant boost to our shareholders, because when we do spend (this off), hopefully sometime mid-next year, I think people will then be able to begin seeing the true intrinsic value we've created in this asset.

(Mario Veraza): All right. Thanks. And then, shifting to the Eagle Ford, there's an operator in (Fayette County) who is testing the (Austin chalk). Do you guys have any thoughts about potentially doing that in the future?

Male: You know, we have seen – there's an operator that's (inaudible) (Austin chalk) really very close to our acreage. And I have spoke with them at a recent conference and listened to their results, and they've had good results.

We have also participated in a non-op position with some of our acreage in an (upper Austin chalk) well, which (we made a nice well), with a small working interest. We just contributed some acreage and participated for the data.

So all of these wells that we drill in the Gonzales area, we see potential in the (Austin chalk). It's not our focus. We always see it. We always know about it. But it hasn't been on the top of our exploratory and capital minds, going to drill these wells at this time.

Male: We just believe that the Eagle Ford is the (source rock) for the (chalk) and the (Buddha). And the results that we will – we are seeing in the Eagle Ford are so much better than you're going to see in the (chalk). That doesn't mean the (chalk) isn't there. It doesn't mean it doesn't have properties that should be exploited. They just don't meet our risk profile and our rate of return profit, and so therefore, if we have it, we will probably farm it out or let another party do it.

(Mario Veraza): All right. Thanks, guys.

Operator: Your next question comes from (Irene Haas) with Wunderlich Securities.

Male: (inaudible)

(Irene Haas): (inaudible) hey, good morning. I have a question for Jim, Don and Ron mainly on the Marcellus. And firstly, starting with Jim, the Wetzel County, Tyler County, you're scoring some pretty big wells, you know, 9 to 12 million cubic feet flow rate. And (inaudible) is it more than 5 BCF per day now? I'm kind of looking for the upper range. Are you hitting some 10 BCF wells? And then, you know, secondly, you know, what's the composition, you know, condensate versus natural gas, liquid and (BTU) content of the gas? And so that's first question.

The second question has to do with the 20-inch pipeline, the main line. Is it in Ohio yet? And percent completion? You know, how big is that particular (trunk line)?

Then last question is for Ron. The Eureka facility, how much is drawn? When would you start hitting the lower interest rate tranche? I suppose (it would be) mid-year next year. And then are you still planning on doing an (MLP) in 2012? And I'll stop here.

Jim Denny: OK. I think you got me first, so I'll start.

(Irene Haas): OK.

Jim Denny: The – we have done some comparisons. I mean, it's a little early in the game. I've only got, what, 30 days on the Wetzel County wells, and we are (rate restricted) there until, really, the end of this week. We're changing out some metering that will allow – give us some extra capacity.

In the (step rate testing) that we did, it looked like the (max efficient) rate's going to be around 7, 8 million a day for those wells. And we'll have the capacity to do that.

As far as where we are on our (EURs), I think all that we've been using for our current (PUDs) are about the four BCF range, so the numbers that you see currently published or the mid-year numbers at about four BCF.

I have some data that (inaudible) sharing with our board on Monday that shows – I pulled together some industry numbers by year, starting back – going back to 2005. And it encompasses about 200-plus wells. And from that, the industry has – as you alluded to, have – kind of have a range of (5 to 5.7 BCFE equivalent) on their curves.

The data that we have on all of our wells, including the original two wells, (are above) that (tight curve). Only one of the wells (has actually) come into the (tight curve). So I think – I'm anticipating that we will be able to convince our reserve engineers that there is some validity in moving our reserves for well upwards. I don't think – it's way too early for me to speculate that, you know, in the 10 BCF range, (Irene), but certainly in the 5 to 6 I think is very doable.

And you ask about condensate. We're about eight barrels per million in Wetzel County, and the (BTU content) is about (1260). The – in Tyler, in our (Weiss) area, we have been – no, I've said that wrong. I think it's more like (1225) in Wetzel County. And we – in Tyler County, on the (Weiss) wells, it's higher, and we're experiencing about 10 to 14 barrels per million in that –

on those wells. So – and the (BTU content) is about (1260) to (1280), somewhere along in there.

And as we move further to the west, we will continue to see an increase in the liquid make-up. We will be adding (JT units), now that we can safely do so on our (Roger Weiss pad), and to be followed with the (Everett Weiss). So we'll begin to see some (liquids uplift) rather shortly, but it'll be mid-next year before we see the big uplift that both Don and Gary have alluded to.

So did I answer my part of the question?

(Irene Haas): Yeah, perfect. Thank you.

Don Kirkendall: (Irene), this is Don. On the pipeline going into Ohio, we have not decided exactly what our plans will be for Ohio. We could come across the river with a 20. We're also looking at crossing with a 16. There's two – actually two places that we're looking at crossing the river in Ohio, going north from (our Pursley) – our (Middlebourne lateral), going up north toward our (Arnett well). If we do that and make that river crossing, that one would most likely be a 20-inch.

As we continue westerly with our main line, which is a 20-inch, we've looked at downsizing and coming across the river with a 16 possibly, but that decision or those decisions have not yet been made. It'll probably be later this year before we make those decisions, early next year, perhaps.

(Irene Haas): And how about the (main line) percent of completion? You know, I mean, how – exactly how long is that (main trunk) line, not the (laterals)?

Don Kirkendall: Well, we've got – coming over from (Weiss) going east towards (Dominion), there's – and then turning up north into Wetzels, that's about 16 miles right there. We still consider going over to the (Mobley) plant part of our main area, and that lateral will be laid early next year, as well as the Wetzels. Those will both be 20-inch.

And we call them laterals. They're just on a straight shot going east-west. We still consider that part of our main line, however.

(Irene Haas): OK, great, thanks.

Male: (inaudible) connection with your – yeah, connection with the (collection on the facility), we have net debt of about 25 outstanding. You know, we got some cash back when we sold the processing plant, so we have cash and then availability above that. We took down (inaudible) (31 million). So that will cover our needs through the first quarter of next year. Then we will – once we complete our milestones, you know, and draw down the remaining part of the term loan, then we go into the senior revolver.

(Irene Haas): And the senior revolver, it would require that you have some shipper on your pipeline as such, right?

Male: No, it's really more tied to completion of the laterals and cash flow.

(Irene Haas): Oh, great. And you're still planning on an (MLP) in 2012?

Male: Yes. That is our plan, probably second half of 2012, you know, as we ramp up volumes with the completion of the (Mobley) plant.

(Irene Haas): Great, thank you.

Male: We probably have – we've been on this for an hour and 15 minutes, so let's do one last question, Operator.

Operator: Your final question comes from (Dan McSpirit) with BMO Capital Markets.

Male: Hey, (Dan).

(Dan McSpirit): Good morning. Good morning. Gary, if I heard you correctly, you spoke to additional lease-hold acquisitions or acquisition and maybe a significant transaction at the top of the call. Again, if I heard you correctly, could you speak maybe to the timing of disclosure on such events and maybe the size of such deals?

Gary Evans: Well, obviously, they aren't done, so it's just speculation at this point. But we are looking at additional leases, really, in all three areas. I have meetings with

the division heads and the (land people) in those divisions all the time trying to determine which areas we want to take additional leases.

We're constantly leasing land, OK? That's – you know, you don't – we don't tell you, oh, we just leased 400 acres and 800 acres here or there. That's part of our business. But the larger (tracts) that we're talking about, you know, involve typically some cash consideration or drilling commitment. And we have two larger transactions that we're working. One, you know, we hope we'll announce here before too long.

But just – they're (step-out). They're not any kind of game-changers for the company. They're just add-ons, bolt-ons to what we're already doing. And when we get more comfortable in an area, we have some expertise because of new drilling we've done that others don't have, then we take a more aggressive approach and go try to expand our footprint. That's really what it boils down to.

(Dan McSpirit): OK, very good. And then lastly here, if I could, with respect to well costs, can you review for us currently what drilling complete costs are across the three different primary areas – that is, the Williston Basin, at least on the U.S. side, the Eagle Ford, with the (ESP), and then, lastly, the Marcellus?

Gary Evans: That's a pretty detailed question. Maybe what we ought to do is let you call Ron or Brad after the call, because that might take about 15 minutes to go through, and we can give you some specifics.

Brad Davis: (Dan), it's Brad Davis. Why don't you give me a quick call, and we'll go through that? It's actually – if you will look, the guidance that we have on that is on our IRR pages that we have for each one of the three areas. Might need to give you a little bit more detail on (tableland) versus North Dakota, but why don't you give me a call on that right after the call?

(Dan McSpirit): Will do. Thank you.

Gary Evans: All right. Thank you, everybody. Thank you for your time today. We feel like we continue to execute our business plan that we have established. We're on track and adding the production and properties. And I think everybody

will be pleasantly surprised as we continue to grow these areas and some things that we're doing a little different.

So we do appreciate your support, and it's been some very volatile times in the market. And those of you that have stuck with Magnum Hunter during that volatility are going to be richly rewarded. And our job is to make you very proud, happy shareholders. So thank you very much today. And we look forward to future reports down the road.

Operator: Ladies and gentlemen, this concludes today's conference call. You may now disconnect.

END