[SWN] - Southwestern Energy Company
Q3 2011 Earnings Teleconference
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Officers
Steve Mueller; Southwestern Energy; President and CEO
Greg Kerley; Southwestern Energy; CFO

Analysts
Brian Singer; Goldman Sachs; Analyst
David Heikkinen; Tudor, Pickering Securities; Analyst
Scott Hanold; RBC Capital Markets; Analyst
Amir Arif; Stifel Nicolaus ; Analyst
Scott Wilmoth; Simmons & Company; Analyst
Gil Yang; Bank of America; Analyst
Michael Bodino; Global Hunter Securities; Analyst
Robert Christensen; Buckingham Research; Analyst
Sue Lynn Ing; Robert W. Baird; Analyst
Rehan Rashid; FBR Capital Markets; Analyst
Michael McAllister; Sterne Agee; Analyst
Mario Braza; Touhy Brothers; Analyst

Presentation

Operator: Greetings, and welcome to the Southwestern Energy third quarter conference call. At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. (Operator Instructions) As a reminder, this conference is being recorded.

It is now my pleasure to introduce your host, Steve Mueller, President and CEO. Thank you, Mr. Mueller. You may now begin.

Steve Mueller: Thank you. Good morning and thank you all for joining us. With me today are Bill Way, our new Chief Operating Officer, Greg Kerley, our CFO, and Brad Sylvester, our VP of Investor Relations. If you have not received a copy of yesterday's press release regarding our third quarter results, you can find a copy on our website www.SWN.com.

Also, I would like to point out that many of the comments during this teleconference are forward-looking statements that involve risks and uncertainties affecting outcomes, many of which are beyond our control and are discussed in more details in the Risk Factors and Forward-Looking Statements sections of our annual and quarterly filings with the Securities and Exchange Commission. Although we believe these expectations expressed are based on reasonable assumptions, they are not guarantees of future performance, and actual results or developments may differ materially.

To begin. We posted outstanding results for the third quarter. Our earnings and cash flow were up, primarily driven by our production growth which continues to exceed our expectations. As a result, we have increased our production guidance for the fourth quarter and for the full year 2011. Total production growth was 23% during the quarter, fueled by our Fayetteville Shale which grew 21% with production of 112 Bcf. We also produced 7.4 Bcf from the Marcellus Shale and 9.6 Bcf from our ArkLaTex division.

Now to talk about each of our operating areas. We placed 132 operated wells on production in the Fayetteville Shale during the third quarter, which resulted in gross operated production reaching approximately 1.9 Bcf per day earlier this week. Overall, our operator horizontal wells had an average completed well cost of $2.8 million per well, with an average lateral length of 4,847 feet and an average drilling time of 7.8 days during the third quarter. We also placed 25 wells on production during the quarter that were drilled in five days or less. In total, we have drilled 80 wells to date in five days or less. Our average initial producing rates were approximately 3.4 million cubic foot per day, which is up 14% from the second quarter.

In Northeast Pennsylvania, we're very encouraged with what we have seen. No new wells were placed on production in the third quarter, however, we're excited that the same 17 Marcellus Shale horizontal wells in our Greenzweig area in Bradford County are currently producing approximately 110 million cubic feet of gross operated production per day, compared to 104 million cubic foot per day when we spoke to you at the last teleconference. Net production from the area was 7.4 Bcf in the third quarter of 2011, compared to 5.1 Bcf in the second quarter.

As for our activities for the rest of the year, we are currently in the process of completing a 5-well pad in Bradford County and expect those wells to come on line in November. We have also moved in a second rig and started drilling in our Price area in Susquehanna County and we expect to have first production from this area in January.

We will be drilling in Greensweig, Price and Range Trust areas throughout the rest of the year, but will not put any new wells to sales until January due to state permitting delays and the constraints of firm transportation and gathering capacity. We are planning to be much more active in the Northeast Pennsylvania in 2012 and have recently signed a contract for 2 additional rigs to be delivered in midyear 2012. These rigs will be new builds and designed specifically for our Marcellus Shale operations.

Switching to new ventures. In New Brunswick, we completed the second phase of surface geochemical sampling and the acquisition phase of approximately 250 miles of 2D data. Interpretation of both sets of data is currently underway. The next step in 2012 is to shoot more 2D seismic to help give us a better understanding of where to drill our first well.

Outside of New Brunswick, we currently have approximately 948,000 net undeveloped acres in connection with other new venture prospects. Of these 948,000 net acres, we have approximately 487,000 net acres located in the Lower Smackover Brown Dense formation, an unconventional oil reservoir found in Southern Arkansas and Northern Louisiana. We spud our first well in September, the Robertson 115-H located in Columbia County, Arkansas and it's currently drilling the lateral portion of the well. This well has a vertical depth of approximately 9,200 feet and a planned horizontal lateral length of 4,000 feet and is planned to be completed next month.

We will spud our second well located in Claiborne Parish, Louisiana as soon as the rig moves off the Robertson well. This well has a planned total vertical depth of approximately 10,700 feet and a planned 7,900 foot horizontal lateral. Our plans are to dill up to 8 additional wells as we continue to test the concept in 2012. If our drilling program yields positive results, activity in the play could increase significantly over the next several years.

In addition to the projects mentioned, we have 461,000 net acres on other ideas that we'll provide updates on in the future. This acreage total is 86,000 acres up from the second quarter, or 23%. I will now turn it over to Greg Kerley, our Chief Financial Officer, who will discuss our financial results.

Greg Kerley: Thank you Steve and good morning. We reported earnings for the third quarter of $175 million or $0.50 a share, up 9% from the prior year. Our discretionary cash flow was $473 million, which set a new record and was up 12% from the same period in 2010. As Steve noted, our earnings and cash flow were up primarily due to our strong production growth, which combined with our low cost structure more than offset the impact of lower gas prices.

Our production growth continues to exceed our expectations and as a result we've increased our production guidance for the full year to 496 to 500 Bcf equivalent, representing an increase of approximately 23% over the prior year. We realized an average gas price of $4.30 per Mcf in the third quarter, down from $4.67 a year ago. Our hedging activities helped to increase our average gas price by $0.59 per Mcf during the third quarter and for the remainder of 2011 we currently have NYMEX price hedges in place on notional volumes of 80 Bcf, which is over 60% of our expected fourth quarter gas production at a weighted average oil price of $5.21 per Mcf.

Operating income for our E&P segment was $229 million during the quarter, compared to $217 million in the same period last year. Our cost structure continues to be a key advantage for us and our all-in cash operating costs, which includes lease operating expenses, G&A, taxes other than income taxes and net interest expense, were $1.26 per Mcf in the third quarter, down from $1.31 a year ago. Our full-cost full amortization rate also declined $1.28 per Mcf in the third quarter, down from $1.31 in the prior year.

Operating income for our Midstream Services segment was $67 million in the third quarter, up 25% from the prior year. The increase in operating income was primarily due to the increase in gathering revenues from our Fayetteville and Marcellus Shale properties, partially offset by increased operating costs and expenses. Our Fayetteville gathering system achieved a significant milestone during the third quarter as the system throughput exceeded 2 billion cubic feet of natural gas per day, up from 1.7 billion cubic feet a year ago.

As a reminder, in the Marcellus we currently have firm transportation agreements in place on approximately 125 million cubic feet of gas per day. Our firm transportation increases are roughly 155 million cubic feet per day in the first quarter of 2012, then increases of 215 million in the second quarter and to 300 million in the fourth quarter of 2012.

At September 30th we had $600 million borrowed on our $1.5 billion credit facility at an average interest rate of around 2.2% and had total debt outstanding of $1.3 billion, resulting in a debt to book capital ratio of 26%, which is down from 27% at December 31, 2010. More importantly, our cash flow in the third quarter exceeded our capital investments for the first time since announcing the Fayetteville Shale project seven years ago. We continue to borrow some funds at times to drill efficiently and test new ideas, but this is yet another milestone in 2011, along with gathering over 2 billion cubic feet per day in almost 100% pad drilling in the Fayetteville.

In summary, we are very pleased with our third quarter results and the progress we've made year-to-date. Our strong operating and financial results continue to reflect the high quality of our assets and cost structure and we are well positioned to provide profitable growth and production and reserves over the next several years.

That concludes my comments, so now we'll turn back to the operator who will explain the procedure for asking questions.

+++ q-and-a

Operator: (Operator Instructions) Brian Singer, Goldman Sachs.

Brian Singer: I wanted to focus on the Marcellus Shale with some of the very strong well results that you had in the chart. Can you just kind of talk to where you think these wells would be producing on an unconstrained basis were it not for any of the pipeline issues and how you think about how those wells and how the well results will start to move around as you start to drill more in Susquehanna County?

Steve Mueller: There's really a couple of things to think about as far as the wells. If you remember last quarter we talked that all the wells were flowing against about 1,100 pounds pressure. We had not turned the compression on. Today we do have compression turned on for most of those wells and we're flowing basically against something in the mid 400 pound range. Now that compares to say Fayetteville Shale we're flowing against 100 pounds, so it's still more than is ultimately typical, but that does constrain to some degree.

The other part if you look at those curves that we have, you see that our production has been brought up fairly slowly. We have not in any of the wells brought them on quickly. We've kind of slowly ramped them up and we've kind of capped them, I think the best we've ever done is somewhere around 10 million a day. Now, what could be their ultimate, you can do some back of the envelope calculations and on an IP, if you brought it on fairly quickly, went to compression immediately, you might add between 25% and 30% to that, whether it's a 6 million a day well or 10 million a day well type number. So, that's the range.

Now, as we go forward, I think you'll see us do a couple of things. The lateral length will get a little bit longer. It looks like and we're still working on this, but it looks like more stages of fracs are better than fewer stages and today we're I think averaging about 10 to 11 stages of fracs.

You'll see that go up a little bit. So at least in this Greenzweig area, where we have information, I would expect that the future wells would be the same kind or if not a little bit better as we go through.

Brian Singer: Then a follow-up question would be just on the midstream side of the equation. Can you just give us your latest thoughts on the strategic importance and various options you may or may not be considering?

Steve Mueller: I think you're talking about Fayetteville Shale there?

Brian Singer: Yes, switching to the Fayetteville midstream.

Steve Mueller: I'll mention some of the Marcellus also, but really no change in what we were thinking before. We still are open to do something but it's probably not the right time right now. And when I say it's not the right time, we're working on 2012 budget to figure out how much capital we may need in 2012. That's not done yet. And as we look at the market, there's nothing that says you have to do it today versus maybe waiting a quarter or something. So, we keep watching it. There's value in our midstream. There's value in keeping our midstream where it's at and there's possibly value down the road of doing something with it also.

Now, I do want to mention something in the Marcellus and it's kind of related to how we look at our midstream. Our midstream is a standalone group. We signed contracts with our midstream in all the areas where they gather and we actually have them bid just like they were another company whenever we're working with them.

In the Marcellus, the one deal we have now is a company called DTE. They'll be putting in part of our gathering system because the bid frankly from our midstream wasn't as good. So we've got some of the Greenzweig area that's being gathered by our midstream, we'll have some of the other parts of it gathered by other companies and so there'll be kind of a mix in Pennsylvania.

Brian Singer: So your decision as to whether you would move ahead with it selling interest or moving to a different corporate structure with the midstream would be based on your having a specific plan of action on investing the cash or is there anything strategic that needs to kind of change in the Fayetteville itself?

Steve Mueller: You know, the Fayetteville capital is dropping this year versus last year and I think you'll see a drop in 2012 and the reason for that is we do have the backbone in. And we've always said that that was the biggest part of what we needed to do. There are some things in the Fayetteville, especially with some third party gas that we'd like to get taken care of what might give some more upside to the midstream.

But by far, the dominant thing is if you're going to bring in cash in from any direction, whether it's midstream or selling an asset or going to the market and raising it, we want to have a good reason to put that cash to work that we can ensure all of our investors that it makes more sense putting cash to work there than it is putting it someplace else. So that's going to be the key on any of it. It doesn't matter if it's disposition or midstream.

Brian Singer: Thank you very much.

Operator: Thank you. Our next question is from the line of David Heikkinen with Tudor, Pickering. Please state with your question.

David Heikkinen: Good morning, Steve. Just thinking about multi-year plans and the Marcellus and kind of where your constraints are today on the pipeline systems and kind of where things go over the next several years, can you walk us through an overall marketing plan, both transportation on the pipelines to market, as well as the midstream, as you march up activity levels beyond ‘12 and just kind of how you're thinking about where those limits and governors come in?

Steve Mueller: There’s kind of two pieces of that. Greg had given some guidance on what we've got firm for 2012. When you look at 2013, as you exit ‘12, we've got about 300 million a day of firm capacity. Through most of 2013, we have 300 million a day capacity and then right in the fourth quarter of 2013, that jumps up to somewhere around just a little bit short of 490 million a day and that’s all firm that we've got in hand today. We are working on other firm and there’s some little gaps in there. As we start looking at curves, we have to fill in some things between now and 2013 and we think there’s some small -- when I say small, maybe 25 to 50 million a day of pieces that we can fill between now and 2013.

As you look beyond 2013, most of the projects that are on pipes that’s currently in the Marcellus have been prescribed by the various companies that are out there and so there’s not a lot of firm to get beyond little pieces, and so what you have to do is have new pipe into the area. And I don't -- except for knowing that we have to have new pipe in the area, after talking to several different groups that have proposed where that pipe might go and how it might work, that’s where we’re at in that kind of process, but at 2013, we've got just under 500 million a day. The shortest contract we have for firm is 10 years. Most of these are 15. There’s 120 in there.

David Heikkinen: Okay.

Steve Mueller: So we’ve got at least for 2013 forward. From a rig count standpoint, that’s really the way we’re designing our rigs also. We've got two rigs running right now. We said we’re going to add two next year. Somewhere between four and five rigs gets you in that range that we’re talking about with what we have firm today. So you won't see us ramp up much more than that without having some other firm in hand.

David Heikkinen: Okay. And as you think about the evolution of the Marcellus in your overall portfolio and kind of in the gas market, how does this change your thoughts around how you market or where Fayetteville gas goes? I mean, do you think it has an impact just base and wide, not just Southwestern production, but what is this? I mean, the reservoir is remarkable, so how do you think about that impact?

Steve Mueller: I think we’re like everyone else. We’re trying to figure out how fast it’s going to grow and how big that impact really is for the Northeast and for the rest of the country. You're starting to see some of these contracts that actually have backhaul where these are backhauling back toward Chicago or backhauling down to the Gulf Coast, and until we get more built into the system, the system will limit how much you've got and that will kind of put a moderator, at least for the next few years, on having the issues, but as we start building out beyond 2013 as an industry, it will have to go some other place in the Northeast.

Now, how does that factor into, for instance, the Fayetteville shale? We always set the Fayetteville shale up, knowing that we'd be there for a long time and that over time, we had no idea where the best place to sell gas was. So if you remember, the way we designed it, we have the ability to send about 2 Bcf a day either to the East Coast or to the Southeast and then we've got the ability to send probably pushing about a Bcf a day to the Mid-Continent, whether that's to the Gulf Coast area or up to Chicago. And our idea all along was that over the years, at certain points of time, you can put gas one way or the other in the system.

And so that's our strategy really for any areas, to try get as much as you can to as many markets as you can, so that as it evolves over time, you can take advantage of that. The Northeast is much harder because frankly, you're in the Northeast. You're not going to get that gas to the West Coast and it does cost quite a bit to get to the Gulf Coast. So it's something for the entire industry to look at.

David Heikkinen: Okay. Thanks, guys.

Operator: Thank you. Our next question is from the line of Scott Hanold with RBC Capital Markets. Please go ahead with your question.

Scott Hanold: Yes, good morning, gentlemen.

Steve Mueller: Good morning.

Scott Hanold: Steve, could you give us your view on sort of what you think of gas prices at this point in time and structurally, what could that mean to Fayetteville activity? I mean, we've sort of been stuck in this $4 range for some time. How do you think about that when you sort of develop your plans on the Fayetteville going forward?

Steve Mueller: I think internally, $4.50 is the new $7 is the way we think about it. There is a lot of gas out there. Certainly, you've see indications on rig count when it drops below four and it stays there for a few months if the rig count is affected, but anything above four rig count seems to be holding in pretty much where it's at today.

So we're just assuming for the next few years at least that we're range bound in that $4 to $5 range and I think that's reflected in our hedges. As Greg kind of said, we've got 60% of our production hedged at $5 this year just to guarantee that our realized price will be above $4, and then as we look out in 2012 and 2013, we've got 266 Bcf hedged in 2012 with like [516] floors. We've got 185 Bcf in 2013 with [506] floors. That pretty much will guarantee, unless gas gets in the low 3's, that we'll be in the $4 price environment.

And as we mentioned in the past, our key project, the Fayetteville shale, as long as we can get $4 flat, we hit our 1.3 PBI hurdle and can stay close to cash flow and all those other neat things we need to do. So we're planning it'll be in this environment and I think we've got hedges for the next couple of years that would already pretty much tell us that we can stay in that environment. We will, when we get the opportunity, put on more hedges. We're not done there, and we're hoping for some cold spots during some of the winters coming up so we can do that.

Scott Hanold: Okay. So activity in the Fayetteville shale will be sort of steady state here over the next couple of years in this environment?

Steve Mueller: Yes, I would say at least steady state. If everyone -- kind of to remind everyone, the way we designed our Fayetteville shale this year, we designed it to basically attempt to live within cash flow and as production grows, as long as the price, gas price, stays in this environment, it'll continue to give us excess cash flow and you might see us even creep up a little bit in our drilling. We've got a lot of wells to do there, so that's the other moderator we put on Fayetteville shale.

Scott Hanold: Okay, understood. And for my follow-up, on the Smackover play, obviously, you're still drilling the wells, so probably have not much to offer on what you're seeing yet, but what should we expect in terms of information coming from Southwestern on that well result? It sounds like this could be a sort of December type of event and what we should sort of expect? Is it IP rate or some extended flow rate test or what kind of things do you plan on talking about?

Steve Mueller: Yes. As far as what we know today, we did take about 360 feet of core. We got all but about 10 feet of core, so we got a very good sampling of the entire interval with our cores. That's all in labs being looked at various different ways, but first indication -- and again, to remind everyone, we were [off-siting] a well about a mile away that had a test on it and was cored, and we didn't have the core to look at, but we had some core data. And everything we're seeing in the core to date looks like the core about a mile away, so it's confirming what we thought, even to the point where you can sometimes get indication whether there's oil or gas, and this looks oily from what we're seeing in the core. So that's where we're at as far as new information.

Then as we look forward, what we're thinking about today is a little bit different than what we were thinking in the second quarter. The second quarter, we thought we would complete the entire well, do all the stages of fracs in mid-November and certainly, by December or early January, have enough production data we could talk about the entire well. Well, we're talking -- we're thinking about doing today, and it's not completely finalized, but what we're [setting] for today is basically splitting the oil in half, completing part of it with one sets of stages between [purse] and how the [purse] -- both the stages in the [purse] a little bit different, and then producing it for a while, coming back and completing the second half.

If we do that, then you'll get some information late in the year on part of the well and how it's produced, but you won't get the whole well until after the 1st of the year, and we haven't quite finalized that, so I can't guarantee it, but I think two things to say -- once we get information, you won't see us press release probably, but the second we get a chance to get new quarterly data or year-end data, or have a conference call, we'll talk about whatever we've got on any wells that are out there, and under the rules, especially in Arkansas, we have to put that data quickly to the state if you want to sell anything that came out of that well. So the state will also have the information fairly quickly. So there's nothing confidential necessarily about the well-test data and what we're seeing in the wells.

Scott Hanold: And can you tell me -- you said you were going to split the well. Why would you do that? I mean, did --

Steve Mueller: Well, we did this early on in some of our wells in Marcellus where you don't know a lot of things. You don't know what the right frac fluid is; you don't know what the right spacing to put the fracs in the well is; and you don't know what the right spacing to put the perforations in the well. And so, one of the ways we got it to speed quickly in the Marcellus was in our first few wells, in say the toe, we put the perforations at one space in and then in the heel of the well, we put another spacing and we tested two different parts.

And so we could basically get information that would normally take you two wells to get in one well, and we're talking about doing that same thing in this well, where the fluid will be the same. The amount of sand we'd put in general per frac would be the same, but we might change the spacing of the fracs or we might change the spacing of the perforations just to see if there's a difference in how it produced to help us set up to how to complete the next well. So it's just accelerating our knowledge by trying to figure out some of the little tweaks early on.

Scott Hanold: Okay, understood, thanks.

Operator: Thank you. Our next question is from the line of Amir Arif of Stifel Nicolaus. Please state your question.

Amir Arif: Thanks, Good morning, guys. Steve, the question was on your second Smackover that you're going to do an 8,000 lateral, almost doubling the lateral length of your first well, but -- so I was just curious, is this related to what you were just talking about in terms of being able to test different things, or is that a comfort level with going ahead a; starting to do longer laterals in terms of the productive potential of the [horizon]?

Steve Mueller: It's both. We want to see what a longer lateral would do and certainly, a longer lateral gives you more ways to test it, but the other thing is there's a difference between Arkansas and Louisiana. Arkansas, under current rules, you can -- you need to keep your well within a square mile, a 640-acre section. So if you're drilling either north-south or east-west, you can only have about a 4,000-foot lateral. In Louisiana, you can put up to a 1,280-acre unit together and then you can drill a lot longer lateral. So one of the reasons for doing the Louisiana is because we drill a longer lateral to test some of these things, but the other part of it is (inaudible) that will let you do it there.

I expect that once we figure out what the right lateral length is, if it's not correct in Arkansas, we'll go back, just like we did in the Fayetteville shale, and be able to change some rules to make it the right length, but right now, the maximal lateral length in Arkansas is somewhere around 4,500 feet.

Amir Arif: Okay. Thanks. And just a second question on the Fayetteville side, your drilling efficiencies keep getting better in terms of days to drill. So as you just look at your ‘12 budget, are you thinking about keeping a similar number of rigs or 12 rigs running even if you're going to drill a lot more wells if your drilling days drop down, or are you thinking of keeping a constant number of wells and maybe moving one of the rigs to Marcellus or somewhere else?

Steve Mueller: That’s a good question and I don't have an answer, but we've got some meetings next week that can help us with that. We just have to look at where the capital is going and how the overall capital looks to figure out rig counts wherever we’re at, but if I had my preference, we’d probably just keep the rigs the same and let the well count creep up a little bit, but that decision is still to be made.

Amir Arif: Yes, and the detailed ‘12 guidance, will that come out in December or January?

Steve Mueller: Historically, sometime towards the middle of December, we do something that talks about end of the year and 2012 numbers and unless there’s something just really unusual, I would expect the same thing would happen this year.

Amir Arif: Thank you.

Operator: Thank you. Our next question is from the line of Scott Wilmoth of Simmons and Company. Please state your question.

Scott Wilmoth: Hey, guys. Fifteen percent of the budget this year is going to Marcellus. I know it's stepping up next year. Do we have any early indications of what that allocation percentage might be next year for the Marcellus? And then what are current well costs running in the Marcellus?

Steve Mueller: I don't know about as percentage of budget. I can tell you that whether it's Marcellus or Fayetteville, it's a little bit more expensive to run a rig in the Marcellus. But it's around $100 million per rig per year to drill and complete wells. So when we talk about adding two rigs in the middle of the year, that's equivalent to one running all year. So that's 100, little over $100 million of additional budget over the two rigs we're running now. So you can kind of start factoring in some dollars on that side.

As far as our well costs go, if -- I don't know yet what a typical well's going to be. But the average that we've done to date is just under 10 fracs per well and just over 400 foot lateral links, those are running about $5.5 million to drill. The one well that we had the 19 stage frac on we talked about last conference call was almost $8 million wells in that case. So that's kind of the range that we're looking at.

Scott Wilmoth: Okay. Thanks. And then just kind of following on on some Fayetteville efficiencies. Obviously, base to drill, picking down a large number of wells, I think 25 wells under five days. I think the limiting factor there is using the one bit. What can we expect for that going into 2012? Are you guys seeing something that you think you're going to be able to do this more frequently?

Steve Mueller: Well, I did a quick calculation. Nineteen percent of our wells last quarter were under five days. So that's significantly higher than it's been for any other quarter. It's creeping up. It's one of those learning curves. And we're trying to figure out where that might end up as we go out into 2012. Certainly all the indications I have is this year we guided that we'd average nine days, and we missed badly. We're going to average in the mid-eights or in the low eights this year. Next year you'll see some kind of average number less than eight days per well.

Scott Wilmoth: Okay. Thanks, guys.

Operator: Thank you. Our next question is from the line of Gil Yang of Bank of America. Please state your question.

Gil Yang: Good morning, Steve. Could you comment on it looked like the number of wells you're putting on per quarter has been sort of dropping. Is there anything in particular going on there?

Steve Mueller: No, it's just how many wells are drilled. If you think about the third quarter versus the second quarter and you're talking about Fayetteville Shale --

Gil Yang: Right.

Steve Mueller: -- we moved two rigs from the Fayetteville Shale one late first quarter, one second -- or late second quarter, and then one in -- yes, late second quarter and then one in the first quarter, up to the Marcellus. And then we had to pick up two outside rigs. And so there's about a week and a half, two weeks worth of time where we weren't drilling with the same number of rigs. And so we're down a little bit on well count.

We're actually, on number of wells in inventory, almost identical quarter-over-quarter. We usually have about 50 weeks that are in some kind of completion stage. And I think at the end of this quarter, we're almost exactly 50. At the end of the second quarter, I think we're 39 or 40. So it went up a couple wells, but it's in there at the same range.

Gil Yang: Okay. So we shouldn't expect any major change in the number of wells, Fayetteville wells per quarter going forward? It should be on the order of 130'ish?

Steve Mueller: It goes back to that how fast you drill the wells. But at the pace we're drilling right now, between 130 and 135, 136 wells is what we'll drill a quarter, and that'll be about what we complete a quarter.

Gil Yang: Okay. In the Smackover, you added 27,000 acres in the last quarter. Can you comment on what kind of acreage you're adding? Are you sort of [filling] into the -- in the holes in the existing 400,000 acres or are you sort of stepping out on the edges? And can you comment on what you think quality of the acreage is outside of the 487,000 acres that you own?

Steve Mueller: Well, the area that we're actually buying in has a lot more acreage than 487,000, and it's close to 800,000. It's actually a little over 800,000 acres that we think could be potential. Now, in that there's some people already on some acreage and then some of that gets subtracted back out. The reason you're seeing the acreage go up a little bit, and you'll see it over the next several quarters actually, is that when we announced the play last quarter, what we announced for the acreage we actually have is the acreage that we've found the landowner, we've made a deal with the landowner, we've checked title on it to make sure he actually owned it, and he's cashed the check.

There's some acreage, [another] acreage we have this quarter, an acreage we're going to have the next three or four quarters, that we found the landowner, we signed a contract with them, but we're out there doing the title work before we hand them the check, and then they cash it to have it come in and be able to put in the courthouse.

And so you're going to see it continue to go up. But it's not because necessarily we're pushing the boundaries of the play or anything, it is nothing more than it takes time to get the title work done, especially in some of the smaller tracks that are out there. So expect the acreage to go up, but some of that acreage is right in the heart of the play, or most of its in the heart of the play.

Gil Yang: Got you. Okay. And then last question is, could you just -- you went through a nice sort of summary of what you thought was going to happen to gas prices. Could you just give us an idea of the 900,000 acres in the Fayetteville? What proportion is economic at $3, $3.50, $4, $4.50 gas?

Steve Mueller: Okay. Let's start at the kind of the 900,000 acres. To remind everybody, the 900,000 acres is a little over 600,000 that we've drilled on. There's a hundred and about 60 thousand acres that's federal acreage that we now have six wells on. They're all verticals and they're cored, but there's no testing been done on those wells. And over the next several months, we'll drill another five wells on that acreage. And that's [on] a longer time frame to test and do something with. And then we have almost 150,000 acres that is in the older established part of the play that we've got, held by production for a long time, and we'll get to it when we can get to it. So when we usually talk about how many wells we have left to drill, we're only talking about what we've tested to date on 600,000 acres.

Now, as you start thinking about the economics, when I said that we needed to have $4 flat going forward, that goes with the number that we always talked about, the 8,000 net wells that we have to drill or on a gross basis, because at that net, if [everyone] needs to remember, we have 75% working interest. On a gross basis, that's almost 12,000 gross wells. That's where the $4 number comes in.

If you drop down to $3.50, that 8,000 net drops down in the 2,000 net range at $3.5. So you do drop considerable off of that. And I can't tell you what happens at $3. There's going to be some piece of that that works at $3. But it -- somewhere in the high threes, it stops dropping off pretty quick.

Gil Yang: If you go to $4.50, do you add a lot more wells, or is it still about -- it tops out at around 8,000 wells?

Steve Mueller: Yes, where you start seeing the real increase in wells is with the other acreage, it's not really with the pricing.

Gil Yang: Okay.

Steve Mueller: Because we've pretty much got the spacing we need, and almost all of our acreage, that 600,000, its economic is at $4. There's a little bit of trend stuff, and I wouldn't even guess it's 10%, 15%, that even if you went to $5, that would add to the well count. It'd be mainly the north and some of the shallow areas right around the fringe of our acreage on the north side.

Greg Kerley: And, Gil, remember that one -- the well count that Steve was talking about is to hit our 1.3 TBI target.

Gil Yang: Okay.

Greg Kerley: [Just] economic wells.

Gil Yang: And you're talking about NYMEX price?

Steve Mueller: Yes.

Greg Kerley: Yes.

Gil Yang: Yes. Okay. Thank you very much. It's very helpful.

Steve Mueller: Thank you.

Operator: Our next question is from the line of Michael Bodino of Global Hunter Securities. Please state your question.

Michael Bodino: Thank you. Good morning. Just a quick follow-up. Most of my questions have been answered. With the Laser line now in service in northeast Pennsylvania, can you give us a sense of what you expect to get completed in terms of a well count on the balance of the year in the Marcellus?

Steve Mueller: Yes. We -- where the Laser line helps us is that it sends some gas to a little bit different pipeline so we get a little bit different price. It doesn't really help us towards the end of the year on any of our take-away because we don't go into laser. Right now we're going into Stagecoach. And really, the only difference between what we're doing today and the end of the year will be Stagecoach has had some issues in September and October, and actually today has some compression issues. They did a major addition of compression in September right when the flooding was going on, and we were completely down for about five or six days, and they've had some problems since then.

But there's probably, for us, another $10 million to $15 million a day that we can get Stagecoach lines out there [worked]. We've got committed, we just haven't been able to put in [another] line. And then I mentioned we've got some permitting issues. There's a fifth compressor we need to put out on a certain site. We thought we'd have that permit by now. It looks like that'll be late in the year. If it comes sooner than that, we probably got another $15 million to $20 million a day that we could put on between now and the end of the year. But that's the only thing between now and the end of the year.

And really, the numbers Greg mentioned earlier, we assume the compressor that bump up right at the very beginning of the year, that was the compressor coming on in January was our assumption there. That's where that comes from.

So the next significant jump is when the DTE line comes in, and we'll kind of work our way up to that. But the DTE line, sometime in the second quarter.

Michael Bodino: Thank you very much.

Operator: Thank you. Our next question is from the line of Robert Christensen of Buckingham Research. Please state your question.

Robert Christensen: Steve, on this lower Smackover first well, how's the trajectory of the lateral going right now. I think you wanted to stay fairly low. Is the drilling up to your expectations as were in this lateral leg?

Steve Mueller: I'll kind of give you two comments there. The actual formation, we drilled it vertically and we did this coring. That's where formation came within 10 feet of exactly the way we had it mapped. So it was dead on that direction. And that, one of the reasons we wanted to drill through it, besides taking the core, was we wanted to land in the bottom basically 40 or 50 feet of the brown dense. We're in that. I don't know exactly how many feet we're out right now. We're out a couple thousand feet at this point, not quite 2,000 feet at this point. And so far we're right in zone and haven't had any issues.

Robert Christensen: Can you speak to Exxon's interest in the play? And I think one time you had mentioned that they had proposed a joint 3D seismic survey of their lands and yours. Any thoughts on what the (inaudible) might be doing?

Steve Mueller: I really don't have any thoughts. We're still talking about 3Ds or [doing] some seismic together. But we really haven't got an indication of any drilling that they may do. And for everyone, Exxon has a position basically east of where we're drilling, almost on the Louisiana-Arkansas border.

Robert Christensen: Could you characterize what the one or two principal risks are in this exploratory well?

Steve Mueller: I think there's two risks. The one is while the one core we have in the area shows good porosity, permeability, all the things that you'd hope to see in a core, you just don't know outside of that one core what the real characteristic of all the rock is. [You've] done [a lot] of calculations. But then you need to get some cores, need to get some other wells with a lot of data, and very well could be that there is parts of this play that don't have those characteristics and are too tight or have some issue, you can't frac them. And so the play's smaller than you think it is. That'd be one issue.

I think the other issue, you've got the brown dense. The brown dense that we're going for is 300 to 500 foot thick. Right above the brown dense is the middle Smackover. The middle Smackover's about 150 foot thick. It is a very, very tight, bright white limestone, and we're considering it the seal for the brown dense. And then above that tight limestone is the conventional Smackover that all these fields in southern Arkansas and northern Louisiana had produced oil from for all those years. That upper Smackover has very high porosity, permeability, and has water. So somehow, either it's from a fault that would go from the upper Smackover all the way down into the brown dense, or from -- it would be really strange to have a frac go that high. But somehow, if you could frac through all the brown dense, through 200 feet of tight rock, and then get into that, you could actually have water come from that upper interval.

So those are the two risks in the play.

Robert Christensen: Thank you very much.

Operator: Thank you. (Operator Instructions)

The next question is from [Sue Lynn Ing] of Robert W. Baird. Please state your question.

Sue Lynn Ing: Good morning, gentlemen. A quick follow-up question. The $5.5 million Marcellus well cost, is that – was that drilling? And the second question is are you – can you talk about the service cost trends you are seeing in Marcellus and also the availability?

Steve Mueller: Okay, your first question had to do with whether that was all end cost?

Sue Lynn Ing: Right, also with that pad drilling if you're anticipating any sort of additional savings on – from that?

Steve Mueller: Yes, all of our wells to date have had basically pad drilling. I think the fewest number of wells we've put on a pad is three, and as I said we're about ready to do a five well pad. So there's some if you want to call it cost savings, efficiencies, something from drilling two or three to a pad. Ultimately, I think you're going to have less wells per pad in Pennsylvania than you do in the Fayetteville Shale.

And the reason I say that it looks like it's going to be wider spacing. Where we talk about 40 and 60-acre space in the Fayetteville Shale, it looks like it's going to be over a 100-acre spacing here. So you won't have as much chance at pad efficiency just because you're going to have more pads and fewer wells per pad. But that's still all to be learned on that side of it.

Now as far as costs go, I've got to frame this a little bit. In the case of the Marcellus to drill an identical well in the Fayetteville Shale to that $5.5 million well in the Marcellus would probably be the high three's, $3.6 million, $3.7 million. So there's significant cost differences between Fayetteville and Marcellus. Some of those are terrain, some of those are permitting, some of those are water handling that you're – they're just different and you're not going to get around them. The other part of those are just your – the fact that the rig count has gone up so quickly in Pennsylvania and the services have been difficult to find historically.

You're starting to see the services because that rig count stayed flat for the last six or seven months, the services are starting to be more available to you. And, I think I said this in the past, this time last year if you could find frac equipment you took whatever you had and it didn't matter how good the equipment was, how bad the equipment was, you took it and went with it. Today you can actually call and 30 days down the road talk to several vendors and get frac equipment out there.

Costs are still about 20% higher than the Fayetteville Shale but they're flat really from – they've gone down a little bit from the beginning of the year, but they've been flat the last couple of quarters.

Sue Lynn Ing: Okay. Thank you.

Operator: Our next question is from Rehan Rashid with FBR Capital Markets. Please state your question.

Rehan Rashid: On the new business ventures group, the other half a million acres, what will it take to have some more open discussion with us in terms of where it's located and what the plant would be? What are we waiting for, Steve?

Steve Mueller: Yes, it's just like it was before we announced the Brown Dense Play. We need to get all the acreage we've kind of targeted for any one of those areas. And once we get the acreage put together in any of those areas and we've controlled what we think we need to control, then we'll start talking about it.

And I would expect that next year we'll talk about at least one more area at the pace we're going right now in some of the ones we're doing. And, again, that acreage isn't just one area. There's more than one area we're putting acreage together on, so I would expect that next year, the third quarter conference call we've got some acreage and you're asking the same questions about one, we're going to know about it, as well.

Rehan Rashid: Okay, okay. Back to the Fayetteville real quick. As I look at the decline curve for greater than 4,000, greater than 5,000-foot laterals, towards the backend of the decline curve I see a kind of bounce back up in kind of productivity rates, a couple hundred days down the road. Can you tell us kind of why, is that a data aberration or associated gas coming out? Any thoughts on that front?

Steve Mueller: No, I don't think – it's a good question – I think it's more a data aberration. And one of the things we do on our curves is we try and show you how many wells that go into that portion of the curve and we do it by color code. And in that top blue curve, when it starts bumping up, especially, oh, I'd say we're 400 days on. And you can see that there's only about 36 wells and it drops quickly down to one well versus the beginning of that curve has over 250 wells in it. And so I think you're just seeing the aberration of those various wells, just having only 30 versus 250.

Now I think the other part of what you were asking, though, is we do have a significant amount of what we call [absorbed] gas, and the absorbed gas comes out with a pressure drop. And the flattening you see on all of those curves, it doesn't matter which lateral links, is showing you that absorbed gas.

And in our case about 40% of our gas that we have is what we call free gas. It's in the fractures, that's what gives you the IP, that's what gives your beginning first year, year-and-a-half production. And we're probably in some of these now, we've got enough days on them, on those other curves that that flattening is -- you're actually starting to see some absorbed gas coming into the system.

Rehan Rashid: Okay. Thank you.

Operator: Our next question is from the line of Michael McAllister with Sterne Agee. Please state your question.

Michael McAllister: Good morning, guys. My question is from your comments I guess earlier in the Q&A about the type of Marcellus wells that you want to drill with longer laterals and greater frac stages, should we be using a – something higher or something closer to $7 million per well as a cost going forward rather than the $5.5 million, which is the 10-stage frac number?

Steve Mueller: I don't know the answer to that. Just, and really I'm just guessing here, and I'm guessing as much from our experience, as well as just hearing anecdotally from some of the operators around us. My guess is we're not going to end up with a 10, 11-stage average. That it'll probably be 14, 15-stage. A 14 to 15-stage well would be $6.5 million to $7 million. So I'm thinking it's going that direction, but we're still doing a lot of testing to make sure that's – that really is right or not.

Michael McAllister: So you're still going to be like in a mix for [awhile].

Steve Mueller: Yes, for awhile, we're going to be a mix. And the other thing that everyone needs to keep in mind, in Pennsylvania part of your lateral linkup is how you can put your units together. And most of the units that we have are in the 500 to 700-acre size units, which would be between 4,000 and maybe as high as 6,000-foot laterals. We do have some that are bigger, so but that also does a little bit of limitation on lateral length which also then factors back to the number of stages, also.

Michael McAllister: Okay, great. And will Southwestern be leveraging William Way's international experience?

Steve Mueller: We certainly had talked to various international operators, that they've – we get calls all the time from somebody that wants to learn about what we're doing and how we're doing. And if the right deal came along you might see us do something with someone, but it's not the primary driver of what we're doing. Our primary driver is work in North America and pick-up this acreage that we're working on and going in that direction.

So another way to answer that of that new ventures acreage that's the – we're not talking much about, none of that at this point is in Canada, and none of it's international or someplace else.

Michael McAllister: Okay, fair enough. Thank you.

Operator: Thank you. Our next question is from [Mario Braza] with [Touhy Brothers]. Please state your question.

Mario Braza: Hey, guys, all my questions have been answered. Thank you.

Steve Mueller: Thank you.

Operator: Thank you. There are no further questions at this time. I would now like to turn the floor back over to Mr. Mueller for closing comments.

Steve Mueller: Thank you. I started today saying we were very excited, and we're very excited for a lot of different reasons. We continue to make very good money in today's price environment. As I talked about, we think it's going to be around for awhile, and we believe we're one of the few operators that can really do that.

We're excited about the Fayetteville Shale, and in the case of the Fayetteville Shale we're doing pad drilling. The days are coming down. We're getting more efficient. There's more efficiencies to take out, so we're comfortable that over the next few years we can drill wells at the same cost we're doing today and continue to do what we're doing on the production and the [ER] side of that.

And I would tell you about Pennsylvania and we've shown the graphs in our presentation that we sent out, and those wells are looking really good. We do have the firm that we need to ramp-up our production. We're getting the rigs. And so we're starting to get that to go in our direction, as well.

And then when you look at the new ventures, we're drilling that first well in the Brown Dense and we're continuing to get more information in New Brunswick.

So things are working for us. We're looking forward to a really good fourth quarter and a real exciting 2012.

And, with that, I thank you for listening to our call today, and I wish you the best over the next quarter. Thank you.

Operator: This concludes today's teleconference. You may disconnect your lines at this time, and thank you for your participation.