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Corporate Participants

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Presentation

UNIDENTIFIED PARTICIPANT: I went to thank everyone for coming here this morning. We are going to get started to talk about Appalachia. Obviously, as a play, I think that's been on the forefront of everyone's mind in the past several months.

Natural gas prices, of course, have been weak and Appalachia continues to command a premium on a lot of the pricing. There's a lot of exciting developments going on there, and companies are certainly putting a fair bit of capital work up there these days.

So we've got four presenters today. I'm going to kind of introduce them, one by one. They're going to give some thoughts on Appalachia and what their activities are. Once each presenter has wrapped up, then we're going to go to Q&A and we're going to be relying on the audience here, all you folks out there, for some great questions.

So we are going to start off with Rich Weber. He is the President and Chief Operating Officer of Atlas Energy. And with that, I'll turn it over to Rich.

RICH WEBER, PRESIDENT, COO, DIRECTOR, ATLAS ENERGY RESOSOURCES LLC: Thank you very much. I'm keeping my comments brief. When we talk about Appalachia, I think most of you here want to talk about what's going on in the Marcellus shale, or at least many of you. We have a pretty big position in the Marcellus shale.

The large circle there represents the acreage that we think is prospective for the Marcellus shale. We have about 545,000 acres in that larger circle.

We are focusing all of our efforts in the smaller egg there in southwestern Pennsylvania, principally in four counties, Washington, Green, Fayette, and Westmoreland counties. We have roughly 274,000 acres in that egg, in that smaller egg there.

We've drilled and completed 140 Marcellus wells, most of which are vertical. We've had a very extensive vertical program over the last couple of years. We have drilled most of these wells through our syndicated partnerships, which is something that we've been doing as a company for over 40 years.

Our vertical results have been very good, especially as of late. We have pioneered a process of two-staging the completion of our vertical wells. And average initial rates of production, over 2 million a day. These wells are getting EURs from our independent reservoir engineer of around 1.4 BCF. These are wells that we feel very good about and think are very commercial.

However, we do believe that the play will be primarily developed horizontally. For many reasons, including more exposure to the reservoir, as well as reduced impact on the surface. And we have begun drilling in Marcellus horizontally. We have drilled eight wells to date where we have operated, and four of those wells have been completed and are in the line as we speak.

One of those wells, the third well that we announced publicly, was one of the bigger wells completed so far in the Marcellus, and was turning the line at 10.1 million natural gas equivalents per day.

You can see our position. We steal the Scotia [wattress] map. I think they do a pretty good job of identifying where others have drilled and where our acreage is. You can see that we, again, are focused in southwestern Pennsylvania.

It's not that we don't think the rest of the play is productive. It's just that -- we are a company that has had success in the southwestern part of the state. This play requires tremendous amounts of infrastructure. The play is not uniform. That's one thing we have proven to ourselves and I think others on the panel would probably say the same thing. It doesn't mean the whole play won't be prospective.

But what you do in southwestern Pennsylvania may not be what you do in West Virginia or northeast Pennsylvania, etc.. So we've elected to really focus our efforts in the southwestern part of the state where we've had some really good results.

We are located in a very fortunate area in that there is extensive pipeline infrastructure where we are drilling and completing our wells. There are several different interstate pipeline networks running through southwestern Pennsylvania, not the least of which is represented by Equitable. Which is -- Murry is here to talk about their great assets.

And we are a good customer of Equitable, but we also have Texas Eastern, Dominion Transmission, Columbia Transmission, National Fuel Gas also has assets moving through the area. We feel like there is reasonably good takeaway capacity. There's quite a few expansion projects that are on the books right now. We feel like this is an area where the gas will move.

One of the big issues, and I know the companies on the panel will agree with me, is gathering infrastructure and gas processing infrastructure. This is somewhat limited in Appalachia. We have not had to deal with high-pressure, high-volume wells before.

And the good news is, when you can put a well in the line at 10 million a day, you are very happy. The bad news is, there are not a lot of gathering assets that can handle that kind of volume.

What we have decided to do as a company is partner with the Williams Companies. Our affiliate, Atlas Pipeline Partners, is actually closing today a joint venture with Williams. We are forming Laurel Mountain Midstream Partners, which will look to build out a high-pressure header system throughout southwestern Pennsylvania and I know that they have eyes on the rest of the play as well.

But this is a very good thing for my company in that we feel comfortable that the infrastructure is going to be in place as we grow our production in the Marcellus shale.

We show this graph just to show our acreage development. Quite frankly, we do not see expanding the actual acreage volume that we have -- the acreage totals that we have. We are more focused right now on high grading our acreage -- swapping and trading and letting some acreage expire, getting other leases.

We have plenty of acreage to drill. The most important thing is that we block it up and try to create a situation where it's economic to develop.

Did I push something wrong? Probably. Why don't we just go to Equitable? I think it's important we keep the presentations short. So thank you and I look forward to questions.

UNIDENTIFIED PARTICIPANT: Thank you, Rich. Next up we have Murry Gerber, Chairman and CEO of EQT Corp.

MURRY GERBER, CHAIRMAN, CEO, EQT CORP.: Rich can give my presentation for me. He'll do a fine job. It's good to see you all today.

Just a little bit about EQT. We are the largest Appalachian E&P but we are also exclusively Appalachian E&P, and this just shows the distribution of our businesses. Almost 60% production, 3.4 million acres in the Appalachian basin all in total.

Midstream very important to us. About 30% of our operating income, over 11,000 miles of pipeline. Rich mentioned that. We'll talk a bit about it in the context of the Marcellus, and then we have a small gas company that serves Pittsburgh -- actually, it used to be the core of the company -- called Equitable Gas that serves some customers down there.

Importantly for EQT, the resource plays we have are on firmly-held acreage. All 3.4 million is either held by production or is held in fee. The mineral rights are in fee. So we don't have lease expiry problems at all.

The Huron Berea, which you won't probably hear a lot about on this panel today, has really been where EQT has been a technology leader. It's a low-pressure shale and sandstone, and required air drilling to make it work. We drill with air, frac with nitrogen. A little sand on occasion, a little foam sometimes, but at any rate, these wells are under hydrostatic pressure, needed to be drilled with a fluid lighter than water, and we used air.

Marcellus is also a secure position. It's 400,000 acres. We are not intending to add to that at this point in time. Extensive midstream capability and capacity, I mentioned, including, importantly for the Marcellus, the Equitrans system. Equitrans is a pipeline that was once used to supply the steel industry in Pittsburgh with gas. It connects to a number of interstate pipes.

As Rich rightly identified, the big issue is not interstate pipeline capacity in the Appalachian region. You can muscle your way in and be a price taker on firm capacity on interstate pipelines. That's not a problem.

The issue is upstream from that, the high-pressure gathering system. Fortunately, Equitrans is a high-pressure system and EQT is in the process of turning that system inside out from one that is supplying the Pittsburgh steel industry to one that will be gathering high pressure for Marcellus.

It currently has 70 million a day capacity but could be expanded dramatically from that, and we are in the process of going to FERC, we'll be going to FERC this year, for some expansion and have solicited a number of customers. We've had over 300 million a day interest in that Equitrans pipeline so we will be looking at that.

Our sales growth this year is 15%. Cost structure, as I will show you, is industry-leading. Other reserves, currently in 3P, you can see the dominate of Huron Berea, coalbed methane is a big piece, and in our 3P, we have a relatively modest Marcellus.

None of our growth projections at this point include the Marcellus. That's not because we don't believe in the play. We think it's quite a good play. It's just that we don't need it to sustain more than 20% growth right now. As we drill more wells, we will be becoming more aggressive on our predictions with respect to Marcellus.

If you look at the total potential, beyond 3P, you can see Marcellus does potentially figure quite prominently, and the Huron Berea is more than doubled.

Just getting to the Huron Berea, it's been a -- kind of an interesting road here. Huron is a very thick section, and it has multiple zones for completion, multiple organic rich shales. And that sort of distinguishes itself uniquely in the Appalachian basin.

On any given spacing unit in the Appalachian area, we have about 2.5 potential locations, and that's important because the acreage is quite extensive. It covers quite a large area, but we have multiple plays that go all the way through there.

I'm going to skip a couple of things here. But this shows the technology pattern -- path that we've had. We used to drill vertical wells in the Berea. We've drilled horizontal fracture, multilaterals, to try to access those fractures. We don't need a big fracs to access them. These wells produce naturally, and now we are going into fractured multilaterals and pad drilling.

This is an example of what one of those pads look like. So this is what we're currently doing. Five wells at one level and then we are doing five wells at another level. These are multilateral wells and we are going to frac all of those wells, and hopefully this is the kind of thing that could produce, for the Huron play, very interesting results.

We are hoping to do this for about $10 million and get about 10 BCF and have first month average production of about 10 million a day. That's kind of what we are headed for.

I'm going to skip -- again, I'm going to skip a couple more. But this just shows the impact of horizontal drilling on EQT. All the drilling before the arrow was vertical and you can see what the total trajectory was and then what each individual's years of drilling was worth in terms of adding to that production. You can see that in 2008, that we really, with horizontal drilling dominantly in the Huron and Berea, have been able to add substantially and proved some pretty good growth trajectories.

And I'm just going to end with this. This is cost structure. These are public data, but you can see between Altera and EQT, we sort of lead the pack on F&D. Unit expenses, a little higher for us. Reflective of the gathering costs in the southern Appalachians. Still, though, pretty good.

And then on asset intensity, this is the amount of capital required to keep production flat. We hold up pretty well on that.

So with that, I will turn it over to Chad. Thank you very much.

UNIDENTIFIED PARTICIPANT: Thank you, Murry. Next up we have Chad Stephens, SVP. He runs the acquisition effort at Range Resources.

CHAD STEPHENS, SVP CORPORATE DEVELOPMENT, RANGE RESOURCES CORP.: Good afternoon. It's great to be here and sit on this panel with these distinguished gentlemen.

Range enjoys a partnership with Equitable in our north field. We love it down there, and the numbers and the things that Murry showed demonstrates why.

I've known Rich quite a long time. He's a great gentleman. Helped us in one of our predecessor companies, Lomak Petroleum, who has had a long-standing presence for about 30 years in the Appalachian basin, so Range and Rich have a great relationship.

My first slide, just to give some perspective on the Marcellus, shows all the various shale basins around the country. Obviously, the top three or four are the Barnett and the [forward] basin, the Woodford and the Fayetteville shales up in the midcontinent area, and then, the Marcellus Devonian.

You can see the actual Marcellus has the potential to be just tremendous. It's got potential of over 65 million to 70 million acres of development, and given that large scale across the state, it takes 10 to 12 hours to drive from the northeast part of the state to the southwest.

Range thinks we're going to need all of the Atlases and the Equitables and the Chesapeakes of the world to help build out the infrastructure, and make the play the enormous potential and provide the gas that the domestic U.S. will need. So we think that's going to be important.

What does it make to create successful Marcellus shale play? One is the right geologic model or geologic setting. We have 900,000 acres in the main Marcellus shale fairway. Like Rich discussed, we have focused on the southwest part of the play and I have a later slide that discusses the breakout of that 900,000 acres. But it's approximately 500,000 in the southwest and 400,000 up in the Northeast. And like Atlas, we're focusing on the southwest for a couple of different reasons.

But to make it a successful Marcellus shale play, the rest of those bullet points all focus on execution. You need to have the right technical team. We do, with proven shale engineers. Some of them have been brought up from the Barnett shale in Fort Worth. We have Mark Whitley, who helped discover the Barnett shale with Mitchell Energy, and he has been extremely important and instrumental in us putting together our Marcellus shale team in the Pittsburgh office, along with Ray Walker.

Ray and Mark and their relationships and experience in the Barnett shale has also helped bring up the services, the [ridge] and services that need to make the Marcellus shale successful, have the slick water fraction and the pump trucks and all the various ancillary services that were required to make the play successful.

The water source and disposal was, this time last year, was a real concern and probably a lot of misinformation has floated around, but we feel like we helped establish the Marcellus shale committee that dealt with the DEP and the other state regulatory agencies to assuage their fears about water use and of water disposal. So we've taken care of those issues.

And I think the other misperception about gas gathering and gas transportation up there is there's plenty of regional truck transportation lines to get the gas to market. The problem is, from a local perspective, building out the gathering to get the gas from the well head to those major trunk lines, and that's where we are focused on in the southwest, as well as Atlas is, is just building out that local infrastructure to gather the gas and get it to the trunk lines.

Again, this is a cartoon that just demonstrates the difference between the southwest and the northeast. And in the southwest, the very corner of the state, that gas is wet. It's about 1,400 BTU gas. Yields about 120 to 125 barrels per million.

We established a JV with MarkWest in the southwest and they built a cryogenic plants to process that gas. As you move north and east, the gas gets dry and you do not need processing.

This breaks out our acreage, again, between the southwest and the northeast. We have net reserve potentials of between 3 BCF and 4 BCF, so you can see the overall potential of -- resource potential on our acreage in southwest and the northeast total about 15 to 22 TCF.

We've recently taken delivery of two new custom-built rigs Patterson built out for us. They were designed specifically for pad drilling in the Marcellus. Are well-suited for, especially in the southwest, the agrarian, rolling hills that you find in the southwest part.

It's state-of-the-art technology. It's got -- you do not need a human up in the top of the rig to take care of the pipe. It's all automatic, and when you move the rig across the pad, it walks across the pad so, spread to spread, you're at about 16 to 18 days, which makes it much, much more efficient and cost effective.

As I mentioned, the MarkWest JV that we have, they are adding the low-pressure gathering system and the processing in the southwest. We brought on a refrigeration plant in the fall of 2008 at 30 million a day. We've recently added a cryogenic plant that brought on a total of 60 million a day capacity. And you can see, by the end of the year or early January 2010, we will be at about 200 million a day, plus we have about 150 million of firm transport on regional transportation lines to get the gas to market.

Again, just focusing on the misinformation about the water use. This slide graphically demonstrates the various uses in the state of millions of gallons of water a day for each sector or industry. Power generation all the way down to the actual Marcellus shale, and you even have, in the middle there, that other category includes recreation and golf courses. They use a lot more water than the Marcellus shale potentially will use. So this type of information that we gave the state agencies calm them down a little bit about water use in the state.

And the regulatory progress overall with the DEP, we've streamlined the permitting process and gotten it down to about 45 days on average. They've added more humans at our advice. They've increased the permit fees to help pay for the increased employment. So we've gotten the regulatory process and the state agencies to embrace the play.

I guess the most important thing that everyone here wants to know about is the economics. From our perspective, the average 3 to 4 BCF -- if you assume a 3.5 BCF well with capital of $3.5 million per well to drill, you can see at around $4 gas, you are realizing just a little over 30% rates of return and at $7 gas, you are up over 70% rates of return. So very, very robust dynamics and even in today's current gas price, we are making good rates of return.

So the Marcellus shale gives you best of class over any other shale play in the country. It's got low F&D costs. It's got positive basis differential of about $0.25 to $0.30 to NYMEX. And at attractive lease terms, low royalties of between an eighth and 25%, whereas most Haynesville and Barnett, they were having to pay in excess of 25% royalties. So it just drives your economics that much better.

So Range wants to make the Marcellus real for the Range shareholders, so our goal for exiting 2009 would be to exit it at about 80 million to 100 million a day, and double that rate in 2010 and then double it again in 2011. So that's really the bottom line is to prove up the Marcellus to our shareholders by creating material volume.

And I think that's -- I think we've already said all of that. Okay, that's it.

UNIDENTIFIED PARTICIPANT: Thanks, Chad. Next up we've got Jim Fraser. He's the SVP of their North American Division East for Talisman Energy.

JIM FRASER, SVP NORTH AMERICAN DIVISION EAST, TALISMAN ENERGY INC.: Well, it's kind of daunting to address this group. I'm going to show you production from four wells, where Atlas showed you 140 wells. So we are kind of the new kid on the block.

I've got one slide on the Corporation, and then the rest I will concentrate on the Marcellus in specific. Following our change in strategic direction early last year, we've grown our position in four unconventional plays in North America.

Over the last year, we have accumulated an additional 320,000 net acres in unconventional land, mostly in our shale areas. Our total estimated contingent resource on these lands is 30 TCF -- that's the pie chart on the right -- of which the Marcellus is approximately one-third of this at almost 10 TCFe.

So here is our slide and of course, you've seen the Marcellus before. Our acreage, which is shown in yellow on the right, straddles both north-central Pennsylvania and south-central New York. We have 793,000 net acres in the play, of which 18%, or 146,000 acres, is in Pennsylvania, and the remainder are in New York.

The map also shows the major pipelines in the area of which we have secured firm transport on TGP 300 of 200 million a day over the next 10 years.

More specifically on Talisman, in 2009 we have focused on Pennsylvania. As a regulatory environment in New York, it sorted out over the second half of the year. All of our 2009 wells will be drilled in Pennsylvania. Even without our New York acreage, we intend to grow production here to over half a BCF a day, just on the Pennsylvania acreage.

We have initiated full-scale development with pad drilling and an intense focus on drilling and completion costs. We are already observing better-than-expected results, and we estimate that the play will work at lower gas prices and our current breakeven is $3.50, as Chad just quoted.

The other two components to operate in Pennsylvania, water, both supply and disposal and well drilling permits, have been resolved for 2009.

So here's that chart of those four wells I was talking about. This is the actual day-by-day production of our first four horizontal wells. They've all have initial rates from 2.5 million cubic feet a day to almost 5 million cubic feet a day. We've also imposed some [tight] curves on here for two, four, and six BCF well reserves.

Two conclusions to be drawn from this. First, our fourth well, which is on the top, is better than our first well, and second, our target for individual well EUR of over -- of 3 BCF a day -- or 3 BCF has been exceeded. So based on this success, we currently are very encouraged and we are looking at increased spending options both in 2009 and 2010.

This slide is a waterfall chart of specifically how we have reduced well costs over the last seven months. Our first well, which is the Thomas number 1H, was drilled and completed last fall for a total of $7.5 million. That included about $1 million for pilot hole, open whole core, microseismic survey, and production logging.

Our fourth well, the Lex number 2H, was drilled and completed for $5.6 million and you can see the last well was drilled and completed for $4.3 million. That's over a seven-month timeframe.

Now I won't go through all the individual bars on that. You probably can't read them anyhow, but they are a result of several techniques -- pad drilling, the use of the pre-set rig, which drills the vertical portion of the well, an optimized water management plan, and, of course, better procurement costs through our supply management negotiations. They've all contributed to those bars to decrease the well costs.

Now, in addition to continuous improvement process, we're also using state-of-the-art technologies that everybody else is. This slide montage shows some of those. That picture in the upper left is not in the Marcellus. That's actually up in Montney Shale in British Columbia.

But from pad drilling to large multistage frac jobs to microseismic, you can see on the right hand side there, to a 24/7 operations center that we have in Calgary where we monitor our worldwide operations on a real-time basis.

In addition, we are also looking at other applications. That cartoon in the bottom right, it shows you a potential application in the Montney Shale, which is about five times as thick as the Marcellus.

So my last slide on the Marcellus is a summary slide. We believe there is high potential in the Marcellus. We have a large land base. We see potential for material production and a significant upside on both resource and reserves, and it's targeted for substantial capital investment for Talisman.

The last slide -- the last point is, of course, as other companies, we will continue to focus on improving operational excellence to achieve top tier performance with an acute focus on cost control.

So that's my prepared comments. I turn it over to Leo now.

UNIDENTIFIED PARTICIPANT: Thanks a lot, Jim, as well as everyone else on the panel. That basically concludes kind of the structured part of the Appalachian panel here.

At this point in time, we would like to turn over to questions from the audience. So, anything anyone wants to know about the Appalachia, I think this is the group to probably answer some of those questions.

Questions and Answers

UNIDENTIFIED AUDIENCE MEMBER: (Inaudible question - microphone inaccessible)

UNIDENTIFIED PARTICIPANT: The question here is just to address regulatory differences between New York and Pennsylvania. Why don't I have Jim from Talisman talk about that, since he's got a very large position up there in New York?

JIM FRASER: First off, I'm glad that somebody else had the Marcellus continuing into New York because as I said, we've got 80% of our acreage there.

The question is what is the regulatory environment in New York? Right now, the state is undergoing what they call an SGEIS, which is supplemental generic environmental impact statement process, and their first draft of that is supposed to be out this summer. It was as early as June 19. I think they have revised that to mid-summer.

And then, upon that, there will be a 90-day to 120-day comment period and after that, hopefully, that will be resolved towards the end of this year and we would like to gear up and drill some wells in New York in 2010, but it's all predicated on that environmental permit process getting sorted out the second half of this year.

As somebody else pointed out, there is a pretty firm process in Pennsylvania. You can get a permit in 45 days. Right now, you cannot get a permit to drill Marcellus horizontal well in the state of New York.

UNIDENTIFIED AUDIENCE MEMBER: (Inaudible question - microphone inaccessible)

UNIDENTIFIED PARTICIPANT: Just to repeat the question here -- it's for Equitable basically to -- EQT -- sorry, for the name change here -- to basically discuss what they think the opportunity is on the midstream side of the business.

MURRY GERBER: First of all, you rightly point out how important the midstream is and I think all the panel members have talked about this high-pressure midstream gathering being very important.

As it happens, the Equitrans system that we own extends from northern West Virginia, which is also quite prospective for the Marcellus, the high-pressure Marcellus, all the way into sort of the central Pennsylvania area. And the existing capacity on that system is about 700 million a day. Much of it is already subscribed.

Last fall, we did an open season on expanding that system. And got more than 300 million a day additional requests for taps into the Equitrans system. That's not including what EQT wants to do, which will be another doubling of that, let's say, plus or minus. So it could be a doubling the size of that Equitrans system.

It will require more capital. Fairly substantial amounts more. However, the good thing is that the right of ways are still -- are already there, and a lot of the capital involves beefing up the pipes, adding compression, adding some processing.

It's a dry system. So there would have to be processing put at the entry to Equitrans in order to get wet gas, to the extent there is wet gas in that area, in, and it will require a FERC order because it is a FERC-regulated pipeline. And for that reason, we really haven't talked much about returns yet.

We are in the process of securing precedent agreements from the various producers who have indicated interest in that pipeline and we hope to file this thing at the end of the year, and at that time you will know a little more about the extent of that opportunity.

But we think it's quite -- first of all, it's critical and it's also going to be pretty profitable, too. Generally speaking, I mean 12% on equity is what you get on investments.

UNIDENTIFIED AUDIENCE MEMBER: What is the ballpark range of how much (inaudible question - microphone inaccessible)?

MURRY GERBER: Yes, don't know yet. It depends on what happens with these precedent agreements.

UNIDENTIFIED AUDIENCE MEMBER: (Inaudible question - microphone inaccessible)

UNIDENTIFIED PARTICIPANT: Just to repeat the question here that's for Range, concerning Range's use of third-party gatherer in the Marcellus, specifically it's MarkWest in this case, and whether or not Range has any concerns about them being able to keep up with their pace of activity in the longer term.

CHAD STEPHENS: Obviously, when we first began looking at the need for processing and gathering, we went out and interviewed or discussed the opportunity with several different providers.

And we chose MarkWest for a couple of different reasons. One -- the most important, we felt like they could perform for us and focus on us, and not some other deal somewhere else.

Fortunately, along the way here, they have, one, they have performed better than we even expected. But secondly, they sold part of their JV in Pennsylvania to a natural gas partners portfolio company that's run by John Raymond. They put in $200 million into the JV to have a 50% ownership, plus they pledged an additional $200 million in the coming year or two for additional expansion.

So in terms of the balance sheet and the capital capabilities, we feel like that really helped us get over the hump, for now, for the next 12 to 24 months. MarkWest is going to focus on the southwest area where we are and with that capital they can more than meet the growth needs, expansion needs that we will have in the southwest for the next foreseeable couple of years.

In the meantime, we are going to move on to other parts of the state, other acreage that we have in the play, and that will be a different set of problems and we won't necessarily focus or use MarkWest in those areas for the gathering needs.

UNIDENTIFIED PARTICIPANT: Next question, anyone?

UNIDENTIFIED AUDIENCE MEMBER: Can you talk about the (inaudible question - microphone inaccessible)

UNIDENTIFIED PARTICIPANT: The question is surrounding the -- right now, the positive differential in the Marcellus. Obviously, there is a lot of talk about big production ramp in the next couple of years and what effect that will have on differentials versus NYMEX. Why don't we go to Rich and answer that one for now?

RICH WEBER: Well, right now in southwestern Pennsylvania, we get, depending on what type we are producing into, our biggest market is Texas Eastern, we'll get today anything between $0.20 and a $0.25 greater than NYMEX delivering into Texas Eastern. Dominion, we might get, maybe, $0.30.

But it's very possible that we could see erosion of [our] bases in southwestern Pennsylvania. You know, you -- not only do you have the increase in Marcellus production, you've also got the REX pipeline moving in.

That being said, there's quite a bit of expansion projects that I talked about in my presentation on all of these large systems. I'm pretty sure, Jeff, that there is no way we're going below NYMEX. So I don't think the exposure to us in terms of returns is really all that great. We certainly appreciate the premium we get, but it isn't like it's devastating if it eroded to zero.

UNIDENTIFIED PARTICIPANT: Why don't we have Murry answer that?

MURRY GERBER: Yes, just a (multiple speakers) little bit on what Rich said. I agree with him completely.

I think -- keep in mind that when pricing any commodity, you've got to price from the market back. And so, the main market for the gas that comes out of Appalachia is this northeastern market today.

And so, I think for all the panel members here, I'm not so sure about Jim because he is a little bit further north, but I know for the three of us, pretty much all of us have some sort of firm transportation to get to these northeastern markets.

So the question is what is New York? Because we are going to get New York minus what we are paying collectively for that capacity. The question we have is, what will REX or REX X or whatever have -- what is the impact it will have on New York City gate? I think that's a key issue.

And -- but I think all of us will then get that price minus. Now, EQT strategy with regard to that, and we've joined El Paso under the 300 line expansion, which is the first REX X, it's 300 north and then 300 back to the Henry hub so that we can sell gas anywhere on the East Coast. To take advantage, hopefully, of any dislocations there are in the markets.

But all of us, I think, are prepared to take New York minus. We just don't know what New York is going to be. I think that's really the way to think -- do you guys agree, kind of? And Jim, I'm not sure -- I'm just not sure what you're (multiple speakers)

JIM FRASER: I agree. I think it's a much more -- I think it's a bigger question for folks that are upstream of that. If you are in the midcontinent or the Rocky Mountains, I think what we're talking about here has much greater implications to producers there than it does in the Appalachian basin.

MURRY GERBER: Because they are going to get New York minus minus minus.

UNIDENTIFIED PARTICIPANT: I'm going to jump in and [turn] a question here myself then. Obviously, there's been a lot of ramp-up in activity in Appalachia recently. I'm just curious if I can get some observations in to how the service side of the industry has responded to the increased activity and the CapEx that we're seeing? Why don't we go to Chad from Range?

CHAD STEPHENS: In the Barnett Shale, the rig count this time last year peaked at about 185 to 190 rigs. And the Barnett Shale at that point had all of the necessary ancillary services, pumping services, and all the other services, to meet that rig count.

Currently, the rig count is at about 65 rigs, so there's been a huge reduction in the rig count. Some of the rigs have gone to the Haynesville shale. Some of the rigs have gone to Fayetteville. And a lot of rigs are being moved up to the Marcellus shale. I think the current rig count up there is somewhere between 40 and 50, and who knows what it will be by the end of the year but it's going to be a lot.

And we see a lot of the ancillary services that were in the Barnett servicing, those Barnett-style frac jobs, moving up through the Marcellus shale because the Marcellus shale completion techniques are very similar to the Barnett.

So at this point, we don't anticipate any huge bottleneck or shortages of services. We see the industry just transitioning and moving from the peak of the Barnett to meet the needs of the Marcellus.

MURRY GERBER: I'd like to put a little more color on that. We probably operate farther east than these other gentlemen. And not quite a year ago when we got started in northeast Pennsylvania, we -- there was only one frac company and it was a local company.

Now there is six or seven companies that are actively working up there. So they've -- whatever that multiple is -- six or seven times the available horsepower there was just seven or eight months ago.

One thing I know about service companies, they will go where the work is, and this and the Haynesville are probably the two most active areas in the U.S. right now. These service companies understand that. And they have moved their horsepower and their manpower from points west to the Marcellus.

So we don't see a real restriction at all, at least on hydraulic horsepower to pump frac jobs, which is probably the single largest cost item in the equation. So that's been a positive improvement in the last six months or so.

UNIDENTIFIED PARTICIPANT: Any other questions from the crowd, at this point? I can keep asking all day, myself here.

I've got a question here, just related to the Marcellus activity. Perhaps we can have someone address what the role of the 3-D seismic is likely going to be going forward, and how important you folks think that is in drilling horizontal wells. Why don't I have Rich make a comment? You guys recently have transitioned to doing some more horizontal drilling over there.

RICH WEBER: Well, I do think that seismic interpretation is going to become more and more important as we develop the Marcellus shale. We have not made big use, at this point, of seismic.

We have chosen to delineate our acreage substantially with vertical well bores. That's not the -- not the full answer, but it's got us a long way to understanding what kind of geo-hazards we might have and we think we've got a pretty good understanding of the fracture systems that exist.

I think as the play gets developed more east of us, and I'm not talking up where Jim is up in New York, but I'm talking about into the Allegheny Mountains where the shale is quite thick, I think there is a lot of structure as you get into the Allegheny Mountains that will require seismic to effectively drill the play.

UNIDENTIFIED PARTICIPANT: Maybe we can get your perspective as well, Chad? In terms of what you guys have done thus far?

CHAD STEPHENS: Yes, when you compare the use of seismic in the Barnett to seismic -- the use of seismic in Marcellus, it really touches on what Rich was just talking about. The Barnett was a relatively low [release] structure with these geo-hazards or [course], and they were just collapsed breccia at Ellenberger that fractured up the Barnett, and you wanted to keep your horizontal lateral away from those what they called geo-hazards.

So in the Barnett, probably 80% of the acreage in the Barnett has been shot with 3-D seismic where we'll be able to find and stay away from those geo-hazards.

In the Marcellus, the use of seismic will be important but for different reasons, and really, Rich touched on it for the most part just in terms of the sub [terras foam] belts up against the Allegheny Mountains.

As you move west over where the range is currently, it's more -- are you staying away from subtle faults and that sort of thing, not getting stuck in subtle faults and knowing exactly where your horizontal is being landed in this section, more than anything else.

UNIDENTIFIED PARTICIPANT: Murry?

MURRY GERBER: We are currently doing about an 80-square-mile 3-D, not specifically for the Marcellus, but for deeper stuff. But we are interested to see the subtle variations that we see in the Marcellus and determine whether there is something interesting there that can be exploited.

It really depends on how the Marcellus evolves. If it evolves as hotspots, and kind of dead spots, if that's what happens, I think we will all kind of want to hone in on it. Anything we can do to figure out the hotspots.

But right now, it's -- I would say it's a little too early to tell. And we don't have the same problem that Chad was talking about. The geo-hazards. At least, it seems we don't.

UNIDENTIFIED PARTICIPANT: Jim, do you want to add anything?

JIM FRASER: Yes, we are shooting 3-D as we speak. Our acreage is a pretty good couple contiguous blocks up in Bradford and Tioga counties in Pennsylvania, and we are shooting it for the geo-hazards, as somebody else mentioned.

But it does not have the same issues as the Barnett as Chad mentioned. Of course, you had some situations in the Barnett where you could actually get into significant water flow and that would essentially make your well noncommercial.

We don't see water in the bottom of the Marcellus. But we are using it to stay away from geo-hazards.

The other thing we're using it for, we don't have as much well control as some of these other gentlemen do in the southern -- southwest part of Pennsylvania, so with the new SEC rules and regulations on booking proved and developed reserves, you have to show a continuous accumulation on the horizon, and so we are hoping that this is another piece of the puzzle that the 3-D will help us answer is, how extensive is the Marcellus away from our well control itself?

UNIDENTIFIED PARTICIPANT: Anything else in the audience at this point?

UNIDENTIFIED AUDIENCE MEMBER: (Inaudible question - microphone inaccessible)

UNIDENTIFIED PARTICIPANT: So the question surrounds how much of a bottleneck processing capacity will be here in Appalachia. So why don't we start off with Rich here?

RICH WEBER: You know, not all of the Marcellus needs to be processed. Our gas, for example, in the core of where we are developing, is actually pipeline quality. We average 97% methane, about 1050 BTU. So we are delivering directly into a pipeline. So it's really not an issue for us for the bulk of our acreage.

But there are very, very productive areas in what we call the wet gas area. Our large well was in the wet gas area. And there really is limited processing capacity, with the exception of MarkWest has their facility in Washington County, at least in Pennsylvania, and we have a couple of skid packages, basically. It's a much smaller scale.

Today, I guess it is a constraint. But those who are developing aggressively in that area, and I really probably should let Chad answer that, I mean, we've got plans to create that capacity.

UNIDENTIFIED PARTICIPANT: I guess that's a good segue into Chad's thoughts on that topic.

CHAD STEPHENS: The processing problem, if you want to call it that -- it's really an upgrade. It improves your economics or boosts your economics, but the processing problem is limited to the southwestern part of the state and really in Washington County, and that's where we are doing most of our drilling right now. And it is a problem short term.

We have refrigeration and cryogenic skid plants right now operational at 60 million a day capacity constrained. We're going to add another 20 million very soon, in the next 60 days or so. And by the end of the year, we will be up at 200 million a day of total capacity for that Washington County area.

So it is somewhat of a problem, but we are addressing it and trying to stay ahead of our drilling.

JIM FRASER: We've got 40 million on skid-mounted rigs and it really depends -- skid-mounted plants. It depends a lot on what happens with the wet/dry boundary.

The only thing I would add to it is if ethane is a big component, at some point we're going to have to deal with ethane. And right now the pipeline is run -- [gas] very dry from the Gulf coast up to the Appalachian basin. Most of the ethane has dropped off in chemical plants in the ship channel, and that allows the pipelines to then add higher BTU gas when it gets up here or gets up in the Appalachian region.

If ethane becomes a big component, then at some point we're going to have to deal with that somehow. I'm not sure how -- make electricity out of it or something.

But that is not an immediate problem. That could be an emerging problem if this play grows.

Or build some chemical plants. That's how [they call it] the governor of Pennsylvania. You can build chemical plants back in Pennsylvania -- or fertilizer plants or something.

UNIDENTIFIED PARTICIPANT: I guess one more question for me over here. We will let Chad answer this point. Just thoughts on a potential severance tax being enacted in Pennsylvania. There's been a lot of discussion in the press about that. Just kind of wondering if you have any thoughts on kind of where the legislature is headed over there?

CHAD STEPHENS: Well, there's been a bill actually introduced to the state House. The state House is, as I understand it, is controlled by the Republicans. The state Senate is controlled by the Democrats.

For the most part, the Republicans and some of the Democrats do not want a severance tax, if ever, initiated -- implemented. Obviously, the governor does. He's got a budget that he's got to meet and he's having problems meeting it. So he would love to have the severance tax passed in this current legislature.

Whether that will happen or not, we don't know. We would prefer, obviously, it not. But -- because it will hinder the development of the play. Maybe at some point in the far-out future if they introduce a severance tax, once the play gets some legs, that's a different story.

But if they do implement the tax, at least the government will have some skin in the game, and they will be more embracing the play and more cooperative and try to help the play along. So, we -- we view it both ways.

UNIDENTIFIED PARTICIPANT: Murry, do you have anything to add to that?

MURRY GERBER: Just that if they do do a tax, and I agree with Chad, I think it could get killed. If they do one, we are strongly advocating for a more comprehensive solution to deal with issues like water, surface owner rights, post-production expenses, etc., etc. And if we have to get a severance tax, I hope it's constructive on those other matters as well. Because any of those issues can be troublesome.

UNIDENTIFIED AUDIENCE MEMBER: I sympathize with these gentlemen and I agree it would be nice not to have a severance tax, but looking at state budgets all around the county, I think it's inevitable that you're going to get one. Can you talk about this issue a little bit more, and how this would not [create a spend all] on your company? Or your industry? I think it's a little important -- although perhaps you don't want to, [what's the disposing content] of the tax? (multiple speakers)

MURRY GERBER: There is no prose to the tax. But I think our -- but I will say that, yes, I think Chad said it right. Skin in the game.

The local governments need to get some of this money back. I mean, we are on their roads. If there is a severance tax, we need to make sure they get that money, that it gets put on the road, so that we look like we are really -- we are. We would be contributing substantially to the local economy.

UNIDENTIFIED AUDIENCE MEMBER: So, wouldn't that help you in the long (multiple speakers)

MURRY GERBER: I think it could. But you know this -- it depends. If it's all take and no give, then Chad is right. We should just say no, as long as we can.

But if there is give and take, which -- we will see. Then I think there is a compromise that could be achieved that could accelerate the development and deal with some of these nasty issues. I hope.

But you know, these games -- they are not the same as they used to be. And just because Washington is rational doesn't mean that Pennsylvania is going to be.

CHAD STEPHENS: And to start a play this size takes an enormous amount of capital. And Range today has over $1 billion invested in the play with very little production. Very little cash flow.

We've ramped up our employment up there. We've got over 120 employees officing in Pittsburgh. We are throwing a lot of money at this play and we need to get a rate of return back, and to introduce a 6% or 7% or 8% bonus tax will mean that rate of return isn't going to last for that longer out in the future.

So it is a give and a take, and we realize that we are using the roads and the rivers, the water in the rivers, and so we want to be good corporate citizens and we have been to date. But it's -- the bottom line is is cash flow.

JIM FRASER: The other angle that we haven't talked about is, there is other alternatives for the state. There is over 2 million acres of state leasehold that, through the Marcellus shale community, which I know we all are very active on. We have encouraged the state to lease some more of that land and I've done some numbers on the back of an envelope.

And you can generate a lot more capital near term leasing that acreage than you can taxing it 5% to 6% to 7% of fairly modest production stream right now. So that's what the Marcellus shale community has pushed.

From Talisman's perspective, we, like other companies on the panel, there is other uses for our capital and we continually look at the best investment opportunities across -- in our situation, across the globe. The money, the projects that have the best returns is where the money is going to go. And if this project is hampered by a tax which doesn't exist today, that's just one more component of the economics which might take us to take our money somewhere else.

UNIDENTIFIED PARTICIPANT: Rich, do you have anything to add, just to kind of round it off?

RICH WEBER: I think it's been covered. I think the shot over the bow from the governor was just that. He wanted to spark discussion.

I think the legislature is going to kill it for this year. It may be inevitable down the road but who knows. But it's not going to be what the governor proposed.

You know, the state of Arkansas faced a very similar situation a few years ago, and passed a severance tax that nominally was a 5% severance tax. But when you really run through the math, and you figure out what which wells were exempted, and what stage of the well was exempted, etc., it was more of a 2% severance tax, which would not be overly burdensome.

UNIDENTIFIED PARTICIPANT: Do we have anything else from the audience at this point?

UNIDENTIFIED AUDIENCE MEMBER: (Inaudible question - microphone inaccessible)

UNIDENTIFIED PARTICIPANT: The question here is what are the individual companies' plans to potentially add acreage up in the Marcellus, and then what are those costs looking like today? Why don't we start on the end with Talisman, and we'll work our way this way.

JIM FRASER: Yes. I'm sure everybody will answer the question the same way. Yes, we are looking to expand our acreage position. We, as do probably everybody in this conference, think the Marcellus is in the top two or three economic plays in North America, and we truly believe that as well.

So sure, we would love to increase our holdings that. What we are doing now is we're actually rationalizing our acreage with other companies. If they have minority interests in some of our acreage and we have minority interests in some of theirs, we are swapping that acreage to kind of consolidate blocks. And I think that's, of course, a very cheap way of consolidating -- of getting something to drill.

As far as costs, I don't know if I'm going to quote you a number. I will say they are half what they were last year. And of course, that's predicated on product prices.

UNIDENTIFIED PARTICIPANT: We'll go to Chad next for any comments.

CHAD STEPHENS: Yes, as the slide showed, we have 900,000 acres and we would love all 65 million if we could get it.

But we're focused on the southwest. There are strategic pieces that we have our eye on that we want to acquire and, like Jim, I'm not going to quote an acreage price. But they have come way down.

UNIDENTIFIED PARTICIPANT: Murry?

MURRY GERBER: We've got 3.4 million acres there and we're happy with our position at this moment.

UNIDENTIFIED PARTICIPANT: Rich, to round it out.

RICH WEBER: Well, as I mentioned in my prepared remarks, I don't think we're looking to increase our investment in acreage. But we are high grading, much like Jim mentioned, rationalizing our position where -- I don't know if we will add to it, but we will substantially increase the drillable opportunities on our acreage over the next couple of years.

UNIDENTIFIED PARTICIPANT: Okay, as kind of a -- bit of a question to follow along the same line of thought here, why don't we start with Jim again and we'll kind of work our way this way. But just maybe kind of talk about how you think about ramping up your drilling activity in the Marcellus, once we get into the second half of the year and into 2010. Obviously you guys are kind of early on in your drilling up there and your costs have come down a lot. Just kind of maybe give us a look how you see this play evolving for you guys as we head into 2010.

JIM FRASER: Yes, there is no doubt. We've drilled probably fewer wells than anybody else on this panel. We've drilled -- so far in 2009, we've probably drilled about 12 wells. We've completed about half of those. I showed you the data on the first four.

Our plan in 2009 is to drill 36 wells in Pennsylvania. It doesn't sound like a lot, but they are all going to be horizontal and we started from zero. Our first well was drilled last September.

As far as 2010 and beyond, it depends on the results, quite frankly. We have to show our shareholders and our management that we can execute, and I think some of the slides we showed on our cost improvement has shown that we can execute. Our goal is to drive that cost down even more.

And we don't know what our 2010 and 2011 budget is, but there is definitely plenty of potential here and we've got a lot of acreage to develop and I would like to see our budgets going up, but I don't have a number to provide you.

Quite frankly, part of ours is to get the human resources in place. Fortunately, we had an office in Horseheads, New York with our Trenton Black River development, so we had 90 people in place there. We've added to that with some drilling and completion and some water management folks.

And so, we are having to show the organization and the outside world we can execute in 2009 and hopefully, if the results warrant, we will be ramping back up in 2010 and beyond.

UNIDENTIFIED PARTICIPANT: We'll go next to Chad.

CHAD STEPHENS: We've got two rigs running currently. We will exit 2009 at six rigs. Drilled probably 40 to 50 wells this year. Exit 2010 at probably 10 to 12 rigs, having drilled probably another 70 to 100 wells, and exit 2010 at around 200 million a day. So that's kind of our goal.

MURRY GERBER: We are -- in the Appalachian region, we are drilling 650 wells this year. And about 45 of them are in the Marcellus shale. Virtually all of them are horizontal wells. We've drilled 31 wells [to date] in the Marcellus. By the end of the year, including what we're going to do this year, we will have 70 -- 75 wells, a combination of vertical and horizontal.

We came into the year saying we were going to spend $1 billion. We are going to spend $1 billion. We just kind of traded some Marcellus for some Huron because we are drilling more horizontals now. Like Rich, we like the trends of the horizontals better than the verticals.

And then, 2010 is a sort of up for grabs, and generally pacing of the resource play, I think, is generally up for grabs.

Fortunately, EQT is in a great liquidity position. We have an unsecured revolver that expires at the end of 2011. We will have virtually no draw on that by the end of the year. We are investment grade.

So we are going to go into 2010, take the results that we've had this year in the Huron and the Marcellus plays, and then figure out where to go from there.

UNIDENTIFIED PARTICIPANT: All right, Rich?

RICH WEBER: Well, for this year we are planning 15 horizontal wells drilled and completed as well as 125 vertical wells. All of those will be funded through our investment programs, which substantially limits our own investment.

As we've talked about publicly, we are going to begin drilling the Marcellus horizontally for our own account. We've talked about a two-rig program in 2010, which would be somewhere between low side 24, maybe high side 30 wells in 2010.

So, as I mentioned to some of you in the breakout sessions, that we are staffing the company to be able to handle as much as a six-rig horizontal program in 2010, just to maintain our optionality, to be able to increase that, should we choose.

UNIDENTIFIED PARTICIPANT: Anything else out there from the audience at this point in time? I think we have a few minutes left here. I'm going to ask one last question and we'll wrap it up.

I think an issue on a lot of people's minds is going to be leasehold expiry up there. A lot of companies have got a lot of acreage. I know in Murry's case all your stuff is HBP, but maybe Jim, you can talk about hold and leasehold for Talisman.

JIM FRASER: Well, that's obviously something we look at all the time. Our acreage is not all HBP. Some of it is in New York, due to the Trenton Black River stuff.

But there are expirations over time. We've bought some of this stuff -- it's five-year term and we bought it one and two years ago, so it has some term on it. The state lease we got last fall has a 10-year term, so that's really not an issue there.

But it's just something we -- we incorporate into our development plans is we want to have the best well results, but we also want to maintain the acreage as well. So that's part of our development scenario.

UNIDENTIFIED PARTICIPANT: Chad, we'll go next to you.

CHAD STEPHENS: Probably one-third to 40% of our acreage is HBP, and the rest is either five-year term or five-year with a five-year kicker. We don't have any real acreage expiration problems until 2011. But we do have a little bit in 2010 that we will want to save, so some of our drilling is planned to save that acreage.

UNIDENTIFIED PARTICIPANT: I think I know your answer, Murry, so we'll go to Rich.

RICH WEBER: Of our acreage, there is about 25,000 acres that expire this year that we care about. And much of it, we are going to hold through drilling.

We are extending some of those leases and we are making much greater use of our unitization clauses in our leases, which allows us to unitize up to 640 acres for the wells. We have a budget right now of about $20 million for lease renewals and I think that's more than adequate to satisfy our needs for this year.

UNIDENTIFIED PARTICIPANT: Okay. I think we are probably going to end with that as we are just about out of time here. But I want to thank everyone for participating here and thanks to our panel here.

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