Black Hills Corp

October 6, 2014
4:00 PM ET

Jerome Nichols: Good afternoon, and welcome to Black Hills Corporation's 2014 Analyst Day being held here at the Little America Hotel and Resort in Cheyenne, Wyoming. My name is Jerome Nichols, and I'm the Director of Investor Relations at Black Hills. On behalf of our leadership team, I want to thank all of you, those participating by webcast today, and particularly those here at the hotel, for taking time out of your busy schedules to spend the afternoon with us. We hope you'll find today's sessions informative and helpful.

Slide two of our Analyst Day presentation has today's agenda. I want to note one change to our schedule. David Emery, our Chairman, President and Chief Executive Officer, will not be attending today's event. He is tending to his mother's medical situation this afternoon. Linn Evans, our Chief Operating Officer and President of Utilities, will cover Dave's sections today.

Our format today includes presentations by each of our business segment leaders. We will hold a question and answer session after each presenter. We will also have time at the end of the meeting for final questions. The webcast participants can ask questions through the chat feature of their Web player.

Our presentation today includes forward-looking information and the use of non-GAAP financial measures. You should refer to slide three of the presentation, as well as our filings with the Securities Exchange Commission, for some of the risk factors that could cause future results to differ from our forward-looking statements. Our reconciliation of non-GAAP measures is available in the appendix of our presentation materials.

As a reminder, today's event is being recorded, and a transcript and an audio recording will be available after the event at our website at www.blackhillscorp.com under the Investor Relations tab.

Our first presenter this afternoon is Linn Evans, Chief Operating Officer and President of Utilities. Linn?

Linn Evans: Thank you, Jerome. Good afternoon, and thank you very much for being here today, especially those of you who traveled to Cheyenne. I hope it's something that you really enjoy, will appreciate. Tomorrow we get to show off to you our new Cheyenne Prairie Generating Station, congratulate Mark and his team for the exceptional job they've done in bringing that in on time and on budget.

And you'll -- you're actually going to see it before the public sees it. We have a – I guess you might call it an opening ceremony coming up in a few weeks, but you'll be able to see it before they do. So, thank you for being here, and we thank you very much for those of you on the webcast for being here, as well.

Those of you who know David and know him well know how important family is to him, but you also know -- I know how important our relationships are you with. So, it was a very difficult decision in some ways for him not to be here, and he asked me to extend his deepest regrets for not being here, but you know how important family is to him as he cares for his mother today. So, we -- our prayers and thoughts are with him.

Many of you are quite familiar with the story, and some of you may not be. But, we are going to take a step, I guess, backward today a little bit with respect to going into some detail about the organization. Something that's important to us with respect to this meeting, at least from our perspective, is the chance to get to meet more of the leadership team that you're going to meet over today and tomorrow. You get to meet an outstanding group of folks and -- that lead our Company. You're going to be able to hear from their perspective, as they go a little bit deeper into the organization, with respect to strategy and our growth strategies, et cetera. So, we're real proud that they are here with us today.

And we are going to have a number of presenters, and we have a number of people in the back of the room. So, what I'd like to do is ask each person to introduce themselves by their name and title very quickly so you know who they are. We'll start at the table with Tony, and then we'll move to the back of the room.

Tony Cleberg: Good afternoon. My name's Tony Cleberg, and I'm the Chief Financial Officer.

Stuart Wevik: Good afternoon, Stuart Wevik, Vice President of Utility Operations.

Ivan Vancas: Good afternoon, Ivan Vancas, Vice President of Operation Services.

Mark Stege: Good day, Mark Stege, Vice President of Operations for Cheyenne Light, Fuel, and Power.

Mark Lux: I'm Mark Lux, the Vice President and General Manager of Power Delivery.

John Benton: Good afternoon, and my name is John Benton. I'm the Vice President and General Manager of Black Hills Exploration and Production.

Brian Iverson: In at the back of the room here, Brian Iverson, Vice President and Treasurer of Black Hills.

Rich Kinzley: Yes, Rich Kinzley, Vice President and Corporate Controller.

Leslie Hartwell: Leslie Hartwell, Administrative Assistant, Investor Relations, Treasury.

Linn Evans: Thank you. And I want to thank Leslie for her hard work in getting this prepared for today. She's done a lot to get us ready and help make this an event for you. So, thank you to Leslie.

I should also stop and thank Mark Stege a bit for the weather. This time last year, we were literally digging ourselves out of an extraordinary snowstorm, the worst that we had had in Black Hills Corporation's history in South Dakota. We literally lost our whole system for a few days -- a few minutes. We lost a lot of our customers for a few days.

So, this weather is a stark contrast to that, so thank you, Mark, for that. So, a Chamber of Commerce Day in Cheyenne.

Many of you, if not all of you, are familiar with this slide. It gives you an idea of who we are. We essentially have two operating segments. We have the utilities, which include our electric and natural gas utilities, and we have our non-regulated energy, which includes our coal mine, our non-regulated generation, and our oil and gas and our exploration company. They look at it, think we're involved in quite a few businesses. From our perspective as a leadership team, we see it that we're involved in three things. We have fuel, we have generation, and we have the electric and natural gas distribution units. So, essentially, we're well head to the burner tip, and we are coal mine to the light bulb, if you will.

So, important reason why we're here today is why Black Hills. Why are we a good investment opportunity from you from -- at least from our perspective, and we're going to talk about that. We've been talking about that for quite some time, and we'd like to talk about that more today.

From an earnings perspective, we've had six years of fantastic growth. We expect to continue that growth at above average with respect to our peers, and we're going to talk about the Mancos Shale. We get lots of questions about that. We will have a deeper dive into that today with John Benton. We think there's lots of value there. We are executing a plan that we've been talking about for a couple years. We continue to execute that plan. And to date, we have good reason to continue to execute that plan.

We're very proud of our dividend track record. It's something as a management team we're very focused on. We've had 44 consecutive years of growth with respect to the dividend. We did pull it back slightly for a couple years while we were spending lots of cash with respect to growing the business, which is important to us. We did bring it into 2013 back to more of a $0.04 per year increase, and that's where we are today. And we're very proud of the fact that we worked pretty doggoned hard for more than 10 years to get our credit ratings back to BBB. We have that with all three of our credit rating agencies, and we think that we have a -- we represent an excellent business risk, particularly given that .7 beta that we have, and we'll show some slides here in a few minutes with respect to our record on shareholder growth.

We're very focused on growth, not only focused on growth but focused on the fundamentals that allow us to grow, and that is being excellent at operating utilities and excellent with relations -- with respect to relationships with our regulators. We have a $1.3 billion capital investment plan that we are currently executing from 2014 through 2016. That's more on average than what we have spent the last several years, and it's certainly more than our depreciation.

We're going to spend some time talking about Cheyenne Prairie, and those of you here that are in attendance, and hopefully will participate in the tour tomorrow, that's our 20th generation project since 1995. So, that's essentially one every year for the last 19 years we've had a generation project ongoing. Mark Lux has been with us since then and has led, especially the last several years, those construction development opportunities for us.

We're looking for opportunity -- we've been looking for opportunities, and beginning to talk about Cost of Service Gas, something that we're going to have a -- more of a deep dive in with respect to today, and Ivan Vancas is going to lead that discussion. We've been looking for opportunities of how we marry, if you will, our oil and gas expertise with the opportunity that we have with respect to our regulatory relationships and how we can perhaps use this lower-cost environment with respect to natural gas to benefit our customers. We have plans in place. We've been visiting with our regulators, and we'd like to give you an update on that today.

I've already mentioned our disciplined approach with the Mancos oil -- Mancos Shale play. We continue to execute the plan that we've been speaking to you for about three, four years now when we launched that plan. It's on track. It's where we hoped it to be. In fact, you might even argue it's a little bit better than what we thought it might be a few years ago. So, we'll continue to work on that. We're very focused on answering two questions, proving what we have, and how do we get it out of the ground in economic rate. So, we'll be updating you on the activity in the Piceance Basin.

We're also interested -- continue to be interested in utility acquisitions. Lot of our growth that's come from the acquisition of Cheyenne Light here, we bought Cheyenne Light with literally no rate-based generation. We've had two major projects for Cheyenne Light, now completed the second, so it's giving us a great growth -- a great opportunity for growth. And the same thing is true with the Aquila transaction.

So, we continue to look for those opportunities. At the premiums being paid today, we question how smart some of those could be at the moment for us, but we are at the table looking at those as disciplined as we can. But, we are being successful with our fill-in approach with the LDCs, and we'll talk more about that, as well. We've been very successful in acquiring smaller LDCs that help us fill in our footprint and help us improve our efficiencies as an organization.

Each of you is very well aware of some of the headwinds that we have as an industry, so I won't go into any of those in any great detail. What I hope that you will take away from this time with us, in the time that you've been -- and known us for a while, is that we have, I think, a pretty good track record for adapting to change, meeting challenges head-on, getting through them quickly, protecting customers as best we can with respect to rates, and moving forward.

The greenhouse gas regulation that we're currently seeing proposed from the EPA, it will be very interesting to see how those are going to unfold. We don't know exactly how they're going to unfold because they require, as you know, state plans that are approved by the EPA. However, as an organization, we are at the table in every state with each commission, whether they be an environmental commission or a public utilities commission, and we're involved in helping them prepare and draft comments being produced to the EPA. So, that will be an interesting one for all of us to watch.

And in one respect, we think we're in pretty good shape because we have one of the most modern fleets -- generation fleets in the country. Our oldest coal plant was brought on in 1996, and everything has been built since then. So, we have a very -- low emissions with respect to everything but carbon dioxide, and we also operate relatively smaller plants in that 100 megawatt or smaller range. So, we think the combination of those positions as well as we could, but we're watching the outcome of those very closely.

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We're also cognizant of the regulatory environment that are causing customers' rates to rise. We're watching that closely. We'll show you a slide how our rates compare to our local and regional peers, and it's something that we're not -- that has not escaped us. We understand that. One of our strategies with respect to that is to invest capital where we can lower O&M expenses, something you'll see scattered throughout the slides today in our presentation. An example of that in the past has been AMI, Automated Meter Infrastructure. We are 100% AMI with respect to our electric utilities, or as high as 94%

AMR/AMI on the natural gas utilities. That's allowed us to lower O&M costs, improve operations efficiencies, and allow us to invest on behalf of shareholders.

You're going to see something today called Field Services Operations, or FSO. We've been talking about that more publicly. We'll have a deeper dive into some things that we're doing as an organization that's going to change the way we do business in the field and how we interact with our customers. We think that's going to serve us well.

With respect to delivering for shareholders, that's why we're here, to deliver energy to our customers while providing a fair return to our shareholders. We feel pretty good about our record with respect to that. We've produced a 12% annual return since -- over the last 20 years for our shareholders. We've been very close to the -- on the far right-hand slide of slide 12, and I apologize for not telling the folks where I am for those that aren't here -- so, slide 12 is where I am now. Our total shareholder return has come pretty close to equating to the S&P 500 since 2009.

I mentioned before the increase -- the annual dividend is important to us. That has been increased for 44 straight years. This management team doesn't want to be the one that stops doing that, so that's very important to us. And then, EPS as adjusted, we do adjust the figures -- the numbers with respect to how we report them to you so you can get an idea. We can take the extra (inaudible)(sensitivies) out of it so we can give you an indicative number of things that are extraneous to our normal EPS.

Many of you might be aware of these -- this kind of a slide presentation in terms of our strategic objectives. This is a document that we use primarily internal to the organization as we work to engage our employees and explain to them what our strategy is with respect to how they can help us fulfill our strategy every day. And having engaged aligned employees, not only engage but also aligned employees is very important to us. We have four buckets of goals, if you will, to help us accomplish our vision, our mission, and our values. We have profitable growth, which of course our focus on shareholders. We have valued service, focus on our customers. Better Every Day, that's our way of talking about continuous improvement, getting better every day at what we do, keeping our costs as low as we can, finding ways of reducing our expenses, and having a great workplace that has both engaged and aligned safely -- safe working employees.

With that introduction, we're going to start to roll into the utilities. This is normally where I would begin to speak. I'm pleased to have four of our five senior leadership team that manages our company. Steve Pella is responsible for our communications and our regulatory affairs is not here, but this team that will be presenting are responsible for our natural gas and our electric utilities, all of our generation. We also have corporate-wide responsibility for safety, communications, regulatory affairs, legislative affairs, and things of that nature. So, I'm very pleased to have them here, and glad to have Mark here, as well. Mark -- we have an operating VP in each one of our jurisdictions, and Mark is the Operating VP who operates Cheyenne Light on our behalf.

Here's another slide that you're probably familiar with. It has been updated with respect to numbers, but it gives you a good idea of the demographics of both our electric and gas utilities, where they are located, and how we operate those. We enjoy operating in a relatively strong economic environment through the Midwest.

We operate in essentially seven states, including those few customers that we have in Montana, but most of -- four of our states are in the top 10 with respect to unemployment, are good -- are employed -- people being employed. Still don't' know how to describe that -- but, we had relatively unemployment in four of the states that we serve in the top

10, and all of them in the top 15. There's a lot of activity going on in North Dakota. You're pretty close to that here now. But, we're seeing quite an impact on our jurisdictions with respect to what's going on even in North Dakota.

We're still experiencing decent growth. This graph gives you ideas since the beginning of the Great Recession in 2008. You can see on the far-right graph on slide 18 that our gas usage has begun to come back. 2012 was an unusually warm, if not a record warm winter, which impacted customers' use. But, you can see that our fill-in acquisitions with respect to LDCs, but primarily focusing on munis, is allowing us to grow customer count, and demand continues to grow within our region.

With that, I'd like to turn it over to Stuart and to Ivan. They're going to tag-team a little bit with respect to the next several slides. After they have presented, then I think Jerome will come up and we'll do a Q&A that'll be focused on answering your questions with respect to utilities.

Stuart Wevik: Thank you, Linn. I'm Stuart Wevik. Welcome to Cheyenne, Wyoming. As Linn mentioned, Ivan Vancas and I are going to tag-team the utilities portion. I will start off with just a brief overview. Ivan is going to talk about some recent accomplishments that really position us for the future. I'll come back and talk a little bit from a forward-looking perspective, things that we've got planned, and then Ivan will close with cost-of service gas initiative that we have.

Slide number 19, just a brief overview of our gas utilities. It gives you the relative size of our various gas utilities that serve approximately 538,000 customers across the Midwest states. Also, you'll see on the map Cheyenne Light shows up on here. I'll remind you that Cheyenne Light is our only combination utility we have, provides both electric and gas service. And the Cheyenne Light results really roll up through our electric utility business segment.

Slide 20, the same type of summary for our electric utilities. We serve approximately 239,000 customers, kind of on the far west of the Midwest region, bordering on the front range of Colorado. You can see the relative sales mix, as well as some of the other metrics in the table below. The megawatts of generation owned has been updated. That does reflect Cheyenne Prairie generating station in that mix, as well. That went into commercial operation on October 1. And then, as mentioned previously, you can see the Cheyenne Light Gas customers are included on this particular slide, as well.

Wanted to share with you on slide 21 just a little bit about where we lie in the transmission world, within the grid in the United States. Just a couple of things I'll highlight on this slide. First of all, starting with some of our generation complexes, with the completion of Cheyenne Prairie, we now have three generation complexes. At the far north part -- top of the map, small print, you'll see Wyodak printed there. Obviously that is our generation complex adjacent to the coal mine. Down in the center part, kind of in Southeastern Wyoming, is the Cheyenne Prairie, what we believe is going to be the opportunity for a generation campus, with recently completed Cheyenne Prairie. And then lastly, in southern Colorado, the Pueblo Airport generation station, really the three anchors of our system is our vertically owned generation.

And second of all, the transmission part of our business. We really have three different transmission areas. The circular bubble that straddles both Wyoming and South Dakota is known as our common use system. It's a transmission system that is jointly owned between Black Hills Power, Basin Electric, and Powder River Energy Corporation. Then again, in the central part, southeastern Wyoming, Cheyenne Light has a very small transmission system relative to the other two utilities. And then, lastly, the Colorado Electric transmission system in southern Colorado. Later we'll be talking about some specific transmission projects, and for those projects that take place in the common use system, in the Wyoming-South Dakota system in the north, as well as the southern Colorado system, those are investments that we recover through annual trackers. More to come on that later. And then, lastly, there are some black symbols on there that represent the interconnection points that we have with other providers in the region, namely WAPA, Tri-State, and PSCO.

So, with that, I will turn it over to Ivan, and he's going to cover some accomplishments.

Ivan Vancas: Thank you, Stuart. For those that are attending the webcast, we're now on slide 22. And I think Linn talked about this at the beginning of his presentation. These are the four categories that we organize our strategic goals in - Profitable Growth, Valued Service, Better Every Day, and Great Workplace. And each of the accomplishments that you see on slide 22 I'll be talking about in a little bit more detail in the upcoming slides.

The first is our Cheyenne Prairie generating station, and I think Mark Lux and his team have done an outstanding job of getting that complex in on time. We'll see that tomorrow during the field tour, and I don't want to steal Mark's thunder, but it couldn't have gone more smoothly. And we now have, as Stuart mentioned, a third site of generation, so that gives us some supply diversity. This site, along with Pueblo and our Wyoming site, are all expandable, so gives us some great optionality for additional resource needs in the future. And I'll show you a little bit of a graph about what we forecast our demand to be and what our resources are as we currently have them.

The next slide is our most recent results standing in the IEEE reliability survey. The results come out in 2014 based on 2013 data. And as you can see, several years in a row -- 2013 was no exception -- Black Hills Corporation is in the first quartile, and I would add all of our three individual utilities are in the first quartile, as well. This is a composite number. So, the investments that we're making in our transmission and distribution infrastructure, really in our generation infrastructure as well, is proving out to provide great service for our customers.

Winter storm Atlas, we were coming back from the Analyst Day meeting last year in New York and made it as far as Minneapolis when all of the Delta flights were shut down because Rapid City had, by that time I think, gotten at least 24 inches of snow. And true to form, the Black Hills family all pulled together. We had employees sleeping on the floors at night so they could be available 24 hours a day, and we began to work on service restoration and had most of our customers back on within six days. And we really, I think this time, did a great job communicating with our customers through new technologies that we'd been utilizing, like social media.

We also experienced some Colorado fires in summer of 2013, again another great example of the commitment and dedication that our employees have. Within eight days of the fires being fully contained, burned 14,000 acre -- plus acres, we had 98% of our customers back on. And I think this is another example -- both of these storms are examples of our ability to martial resources from multiple utilities that are within the Black Hills family to get our customer service back on.

A little bit about technology integration. This is our utility of the future initiative. And simply put, we are investing in technology, both upgrades and new technology, that helps us, one run the business more efficiently, drive costs out of our value chain, utilizing technology rather than people to get a lot of work done, and it also gives us the ability to be more effective in delivering our service with our customers, because it gives them new options and choices about how to interact with us and new services that might -- they might want and need.

You see some of the metrics here on slide 26 in terms of the results that we're having so far. And I'll go through a timeline of what we've got planned in the near future. Probably the accomplishment that we are most proud of is our safety improvement. Since 2010, we've had a 61% reduction in our total case incident rate. These are recordable injuries to our employees. And that's just been a phenomenal result. What that means to us is all of our -- 61% reduction in the number of injuries means more of our employees are going home at the end of every day safely as they came to work. We have a goal to be the safest energy company in the country, safest utility company in the country, and we continue to work on improvements here. And we've introduced a ninth value to our corporate values, and that's safety, and we commit to live and work safely every day.

We do our biannual employee engagement survey, had really strong results this year, 84% participation rate. That's really top quartile performance. We were better than the US norm and significantly better than the US utility norm. So, our employees are engaged in -- particularly the ones that had the most positive improvement, alignment of vision, strategy, and our work goals I think -- we think is very, very strong for our Company.

Resource planning update, I think most of you know we've been approved for a -- addition of a 40-megawatt natural gas fired combustion turbine to be completed by the end of 2016 at our PAGS (ph) location. We did issue RFPs for an all-source solicitation for up to 60 megawatts of renewables also in Colorado, plan to have those reviewed and a recommendation made by I think November of this year to the Colorado Public Utility Commission. And I think as probably all of you know, our IPP did submit bids into that solicitation, as well. So, we have a division of employees, ones that were part of the bidding process, and then another that are part of the utility evaluating those bids. And then, our next electric resource planned is due in Colorado by October of next year.

Cheyenne Light, we continue to work on our resource plan, including an option to convert the WyGen (ph) 1 PPA to ownership. By the time that option expires in 2019, we're now reviewing, as Linn mentioned, current -- or latest EPA proposal to see how that impacts the timing of that conversion. And then, finally, Black Hills Power, as well we're reviewing EPA's 111-D rules. And if necessary, we'll complete a integrated resource plan by 2015.

So, here's how we currently look in terms of our resources and our forecasted load, plus a 15% reserve margin. And as you can see, we are somewhat below in terms of resources available compared to our forecast and the reserve margin that we're required to have. Now, some of that is related to a very short period, peak seasonal need. But, over time, that peak continues to grow and becomes a base load kind of requirement. So, we continue to look at our resource availability, our resource needs as compared to how our loads are shaping up, and we make decisions as we need to to add additional capacity to make sure that we're filling our customers' needs, and we're doing that at the least cost basis.

So, with that, those are the recent accomplishments. Let me turn it back over to Stuart to talk about some other items.

Stuart Wevik: Linn mentioned the slide 31 a little bit previously. This is a slide that compares Black Hills' average fleet age versus those other investor-owned utilities within our region, as well as customer rates. And as you've heard and as you know, we've had -- Black Hills has had significant upgrades in our generation resources over the past six to seven years. And we also have to keep in mind that rates are a snapshot in time. And certainly our rates are reflective of the significant investment we've made on behalf of our customers.

But, as I look at this, I really truly believe that our customers and our company were well-positioned for the future. If you look at the jurisdiction on the far right, South Dakota, the average age of Black Hills Power's fleet is about half of what the other utilities that serve customers in South Dakota. If you look at Colorado, the average age of fleet there is about a quarter compared to the other major provider in Colorado. And then, lastly in Wyoming, Mark has got a baby of a fleet that's one-tenth the age of another utility serving customers within the state. So, again, we believe that we're well-positioned for the future in terms of cost-effective and efficient generation, moving forward.

Slide 32 is a good summary in terms of where we're at from several regulatory initiatives. Black Hills Power serves customers in two states, both in South Dakota and Wyoming. And you'll see two rate cases leading off the top of this slide. The BHP Wyoming case is approved as indicated on the far-right column with the status. Rates effective there effective October 1. The South Dakota-based case, interim rates are in effect as of October 1, again coincident with the in-service date of Cheyenne Prairie generating station. A hearing scheduled in the latter part of January on that base case.

Cheyenne Light, a couple of cases, both gas and electric. Those cases were approved earlier this year, again effective date October 1, good results there. Ivan just mentioned the Colorado Electric ERP. We also have a rate case filed in Colorado Electric. Hearing was just conducted a week or two ago on that, and we expect results on that in the first quarter of 2015. And then, lastly on this slide, Kansas Gas, for our natural gas utility in Kansas, we've got a base case in play there, as well. I believe it's been eight years since the last base case in Kansas. Hearings are scheduled in November in that particular case.

Slide 33, you have seen this before. It's an update of some of the cost recovery mechanisms and trackers that we have across all of our utilities. I will clarify one thing. On the electric utility jurisdiction half, the third column over indicates transmission. That's really transmission expense. A couple columns to the right of that is the investment tracker for transmission, just to clarify.

While there is an unchecked box in the bottom right-hand corner of the electric utility grid, that is for the CWIP (ph) rider that we've applied for with our base case in Colorado Electric, and again hope to get approval on that in the first part of '15. In the gas utilities, Linn mentioned the volatility that can come through earnings based on weather. We do have one of our four gas utilities that does have a weather normalized component to revenues there.

So, as we kind of think about where we've been and where we're going, this are -- these are some of the strategies on slide 34 that we're pursuing on a going-forward basis. The first one up there is about vertically integrated generation assets. Mark Lux and his team have proved that, again, that one of our core strengths is really cost-effectively building and operating generation units, something that we intend to leverage, going forward. The second bullet, Transmission and Distribution Growth, there are some significant projects that we'll detail out there in just a slide or two. And significant investment across both the electric and gas utilities in terms of some of the capital for some integrity projects.

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The fourth bullet down, Pursue Gas Utility Organic Growth Opportunities, we really believe that there are opportunities in and around our existing service territories, particular in our gas utilities, opportunities there around conversions, customers presently burning propane, some pipeline extensions and some other small acquisitions. And plans are in place and are being actively worked on those. Cost of Service Gas may be a new concept. Ivan is going to go through that in some more detail in just a few minutes.

I want to talk about the second bullet, really the first two bullets combined under valued service. We'll just talk both about -- first bullet really is about operational excellence, things like reliability and generation resource performance, things like that. Second bullet talks about relationships, primarily externally. I think a great example of that is right here in Cheyenne Light. Cheyenne Light's probably as dynamic of a utility that we have, looking at all seven of our utilities. And the governor of Wyoming, when he was running for election, he had a plank in his election platform. He wanted to go after data centers, go after some technology business. Wyoming is fortunate to have a strong energy-based economy, but he wanted to diversify that. And Black Hills has worked very closely with the governor's office and state and local economic development office and personnel, as well.

In terms of operational excellence, the thing that is at the top of any kind of technology-based business, including data centers, is reliability. And Mark Stege and the Cheyenne Light team have delivered very high levels of reliability, and that is a major draw. That is something that you can't fix overnight to try to bring in a data center. And that operational excellence, coupled with the great relationships between state, local, and Black Hills officials, really made the courtship and the eventual bringing of the NCAR data center, as well as the Microsoft Data Center, to Cheyenne. And for a governor that wants to grow technology, I can't think of a better anchor tenant than a Microsoft.

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Linn mentioned things with Better Every Day. You can see our goals, strategies that we have there. Finally, Great Workplace. Ivan mentioned the improvements that we have seen in safety. We are certainly pleased, but not satisfied. We've got a ways to go and several things in the works.

The last bullet on slide 34 really talks about our employees. And it's not only about retention, as this particular bullet states, but it's also about attraction. Like everybody else in the utility industry, we've got an aging workforce. And so, the attraction, the training, the retention and the engagement of great talent is something that we're very, very involved in ourselves.

Slide 35, a high-level overview of what has occurred, historic levels of capital investment, and what is planned, what's forecast the balance of this year, as well as what's planned. And you can see, in the utilities, we've got strong capital deployment in that $270 million to $290 million range. You can see the breakdown for yourself. We also added a subset, the last line on that page, that shows the tracker-eligible capital. Those are for those transmission projects in the far north and south bullets -- bubbles I talked about earlier, as well as some tracker capital that we have in place at some of our gas utilities.

The next slide, 36, identifies some of the more significant projects, both historic and planned. Obviously, Cheyenne Prairie, it's the first two bullets. That one has been recently completed, very successful project. Ivan mentioned the Colorado Electric 40-megawatt simple cycle with a projected in-service date of 2016. The next two lines, they both start with Black Hills Power, those are related to a couple of large transmission projects that are in that common use system that will be subject to recovery via the tracker mechanism that we have there.

Colorado Electric, there's a couple transmission projects there that fall into the tracker bucket. And the last one I'll mention on this slide, we've got some additional detail on this, but the northeast Nebraska pipeline, very successful venture in terms of working and leveraging relationships again. It's a 50-mile pipeline that we're building in the northern part of Nebraska.

I promised earlier we would talk a little bit more about what we call organic growth in our natural gas utilities, something that we're really excited about. The projects we've -- I've broken them into these four bulleted areas, first one being muni and LDC acquisitions. In addition to MGTC, which you've heard about, a hearing coming on that I believe in November, hopefully for approval of that. There are also a number of other smaller -- small municipal natural gas utility systems across our natural gas utility footprint.

And just like our company and our industry is experiencing some aging workforce and turnover, those municipals are, as well. So, we're finding we've got opportunities to provide services to those munis. Maybe it's helping with compliance, maintenance, things like that, and that gets our foot in the door to potentially get some bigger and better things. Could we get rid of this on the screen?

The second bullet on there, fuel conversions, volatility of the price of propane has given us great opportunity. There are pockets of customers in subdivisions throughout our service territory that we see as huge opportunity. In fact, Mark Stege here in Cheyenne Light, just within the last month they've connected up over 120 services of customers that were formerly on propane that we've converted to natural gas.

Natural gas vehicles, we've got a lot of initiatives, a lot of various programs. One area that we're focusing is on fleets, those fleets that have a daily route, they go out and about and they come back at night, delivery vehicles, refuse haulers, things like that. And then, lastly, pipeline extensions. That is really the northeast Nebraska line, the lower half of slide 37, that's a great example.

Norfolk is a relatively small city, 25,000 residents, give or take, in northern Nebraska. It has been -- it has experienced constraints with natural gas supply for many, many years. There has been a run at some legislative fixes. State lawmakers have been involved. And Black Hills, what we've done, we've pursued solutions with the transportation provider, but those were cost-prohibitive to go down one of those solution routes.

So, what we did, we worked very closely with state and local officials in trying to come up with some solutions, and we'll see the result -- some of the headlines that were in the paper. It's really a great project for that area and for that state. As mentioned, the 50-mile pipeline provides great capacity for an area that's currently underserved today. And it was a great partnership. Nucor Steel, one of the larger steel manufacturers in the country, made a $5 million Contribution in Aid of Construction, as did the city of Norfolk. So, we had a partnership in terms of bringing forth some capital to bring that project to fruition, and we expect to have that pipeline completed in late 2015.

Ivan Vancas: Thanks, Stuart. We're now on slide 38. And slide 38 is a follow-up to the technology slide that I had earlier on the presentation, and it's more of a timeline depiction showing what initiatives we have completed and then which ones we have upcoming. And the technology that we're pursuing is in part a refresh on some of the systems that have reached their useful life.

A classic example of that is our dispatching tools that we use to route our technicians. That particular application is at the end of its useful life and as we sat back and looked at whether or not we ought to replace that or enhance it, we determined that enhancing that technology was the best way to go to, one, achieve more benefits and, two, provide our employees and our customers a great user experience. That project is called FSO, Field Service Optimization, and it's scheduled to go live in November.

The purpose of these technology initiatives is to, one, improve the way that we do business, primarily by leveraging technology and reducing operating costs. So, we want that technology to do a lot of the work that our employees have done in the past. A good example is the services that we are providing and plan to provide via our website and mobile technology will actually give our customers more options surrounding when they want to pay their bill, doing a payment arrangement, whatever kinds of service that they want to transact and allow them to do that on their mobile device rather than calling in to our call center. So, we are investing capital to reduce operating expenses.

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The second thing that we're working on is a great user experience. A great user experience is really important because you want technology adoption both from the customer perspective so that they're using the tools that you're putting out there and from an employee perspective again so that they're using the tools you're providing for them to do their jobs effectively. As part of that adoption and that user experience, what we decided to do was to create a bit of a video that for both employees and customers would show the future state of the objective that we were pursuing and how the deployment of these investments might actually change the services that we provide and enhance them as well as change our employee's every day work experience.

So, we're going to show you that video now. It's only about five minutes. So, again, from what we're trying to accomplish, this is a hypothetical scenario about some future service delivery, all of which we're trying to pursue through these investments in technology.

[begin video]

Husband: Hey, you still stressed about the move?

Wife: I am, a little.

Husband: Just think how close we're going to be to your family.

Wife: I know. I'm excited to get back home. But starting new jobs while building a new house…

Husband: It's a lot. We can do it. What are you working on?

Wife: I'm getting some stuff done online. Our new energy company offers hook ups for natural gas or electric vehicles. We should put one in our garage.

Husband: Nice. Hey, while you're on there, get some information on network appliances. We can keep track of how much energy we're using. Oh, and surge protection in case of storms.

Wife: Perfect. Let's see if we can schedule an appointment. Looks like they have an opening next Friday at four. We're both available.

Husband: Book it! Hey, Louis.

Louis: Hi. How are you guys doing?

Husband: Great. Pretty excited to get moving on all of this.

Louis: Absolutely. On the screen, you should be able to see the model of your new home that your contractor provided along with the lay out for your electric and gas service.

Husband: Yeah. We see it.

Louis: You can also see the estimated cost for your new service along with the schedule date. Does that look okay? Or do you have any questions?

Wife: Well, we really don't like the look of those power lines. Could we bury them instead?

Louis: Yes. But that means we'll have to place a pad mounted transformer in your yard along with rerouting our power lines. Just a second and I can show you what that looks like. Okay. Does that look better?

Wife: Yeah. That looks great.

Husband: Our new air conditioner is already saving us a lot of money. Check this out.

Wife: Wow. That was a great idea. We should be using more of those energy saving tips.

Husband: Looks like it's going to rain tonight.

Wife: At least my flowers will finally get some water.

Husband: What's it say?

Wife: Says the power is going to be out for a couple of hours. But downtown isn't effected. Do you want to go check out that new restaurant?

Husband: Yeah. Sure. Let's go.

Wife: Okay.

Worker #1: Alright. Where are we at?

Worker #2: We have a storm rolling through the area. It caused an outage to circuit 1287. Initially we started out with 352 customers out in this area but the automated switch took place and we're only down to 26.

Worker #1: So, we've isolated the outage area to right in here?

Worker #2: That's correct. The reports are just coming in from the field. I'll put them up on the board.

Worker #1: Alright. We have a tree through a phase three line. I'll get the work request started and get over to the warehouse.

Worker #2: Alright. I'll keep you posted.

Betty: Okay. You're all set. Be safe out there.

Worker #1: Thanks, Betty!

Betty: You're welcome.

Worker #3: Luke, this doesn't look too difficult but you might want to review the job before we head out.

Worker #1: Repairs have been made. Men and equipment are in the clear. Ground's been removed. I'd like to put this circuit back to normal now.

Worker #4: 10-4. I understand you have repairs made. Men and equipment are in the clear. Grounds are removed. You are clear to put the circuit back to normal.

Worker #1: 10-4.

Waiter: Here you go. No rush.

Husband: Great. Thanks.

Wife: Perfect timing. Power's back on.

Husband: Good.

Wife: It says that a surge was detected but our surge protection kept it from causing any damage. Glad we ordered that.

Husband: Another one of my brilliant ideas.

Wife: Hey, that was a team effort.

Husband: We do make a great team.

[end of video]

Ivan Vancas: Most of the people in that video are our employees. If you look at that hypothetical scenario, a couple of things hopefully stood out to you. One is we made it really convenient for that hypothetical customer to interact with us when they applied for their new service. One, we let them do that on technology. Again, there weren't any people behind the telephone waiting for their call, one, causing delays.

Two, it's a more expensive option to do that. Secondly, we provided them with options for other products and services that they could pick and chose from that give us a potential to grow our business.

Third, if you look at the way that we detected the outage, dispatched the crews, issued the material, a lot of that took inefficiencies out of the value chain. Again, using that technology, we've invested capital and we've reduced operating expenses.

And then, finally, it gives our customers a level of satisfaction that we have multiple points of interaction with them throughout a particular transaction whether that would be paying a bill, whether it's an outage, or whether it's applying for a new service. So, investment capital to reduce operating expenses, that's a good thing for both customers and shareholders get to earn a return on that capital, and reduce our operating expenses which hopefully puts lower pressure on customer bills.

So, now let's move on to cost of service gas. On slide 39, one way to look at our utility growth opportunities is in four categories. The first one is growing customers and demand. Examples of that are Microsoft that Stuart talked about here at Cheyenne, WY. Also, muni acquisitions. We've been successful at doing a number of those and we have continued interests and opportunities that we're looking at. Natural gas vehicles, another example of ways that we can grow customers and-or demand.

Another one is replacing O&M with capital. Those are the technology investments that we talked about. We have an ability to investment capital, deploy some great technologies that allow our customers and employees to interact more efficiently and effectively and it provides really more options than we've had for both groups than in the past. Investing for reliability and capacity, the transmission and distribution projects, as well as Cheyenne Prairie generation station are all examples of investing in the infrastructure that provide us with growth opportunities.

And then the category that we're looking at now and pursuing is replacing pass through costs with capital investment. And cost of service gas is a program that we think will help us replace those capital costs with investment opportunities for our shareholders while also potentially saving our customers money over time.

This is an example of a customer's utility bill as it currently might come in the mail every month. There's a distribution cost which is associated with our infrastructure or operating expenses, return on capital, and then a big portion of that bill, ranging from 60% to 70% or more is a commodity cost and that commodity cost is very volatile and exposed to the markets. So, when there are variations in natural gas prices and we saw those last winter when gas prices spiked inter day as high as $60 and $70. That volatility gets translated to customer bills. What customers really want and what we're trying to accomplish with cost of service gas is stabilizing that commodity cost over time so that, one, it's more predictable, and then two, hopefully over time so it's also lower than the market.

We currently manage that volatility with a limited set of tools in our gas supply portfolio. We buy gas in the market for the heating season during various parts of the summer and the winter, to try a dollar cost average into the market and into gas prices. We buy some at fixed prices and we put gas in storage but storage is a seasonal option because you have to -- not only can you inject but you have to withdraw to maintain the integrity of the storage fields.

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And then we use financial hedges and financial hedges have limited benefit as well because they're only for a fixed term. You can't get them over a long period of time. We believe that with the introduction of cost of service gas or drilling and acquiring reserves, adding that to our overall gas supply portfolio will allow us to stabilize customer prices over a much longer period of time.

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Here's the way we're proposing it would work. A non-utility subsidiary of Black Hills Corporation would drill and-or acquire reserves on behalf of our utility companies. That entity would produce natural gas and sell that natural gas at a market price and then credit the proceeds for the sale of that gas to the utility companies which are a part of the program, the utilities being Black Hills utilities.

This entity would then build a utility at a cost base formula, including a return to shareholders through a long-term contract. So, in effect, we would use rate making principles as a way to price this service or this long-term hedge from the non-regulated entity to our utility businesses. And we would continue to make purchases of the physical gas and deliver it as we have in the past, albeit over time we would phase out financial hedges.

So, what this does is effectively provide gas at a more stable cost of service coupled with the fact that an ongoing drilling program would ensure that we are able to provide a stable level of supply over a long period of time.

So, just a little bit of information about the firm natural gas demand of Black Hills utilities. As you see on slide 43, 12 months as of June 2014, we burned a little over 77 billion cubic feet of natural gas and you see the break down amongst the various jurisdictions. Over time, or a long-term target is that 50% of that annual firm demand rather would come from a cost of service gas program.

A little bit more detail and a hypothetical example, let's assume that gas is selling in the market at $4.50. And we are producing gas in a cost of service program for $4. Again, hypothetically, $2.75 of that in this bar chart is the recovery of expenses, including depletion charges for that produced gas. Another $1.25 is a return on investment for the capital that we invested to acquire reserves and to drill and produce natural gas.

Then, finally, if we sell $4 gas in a $4.50 market, the $0.50 margin that we would realize on that sale would be credited to our utilities who are participating in that program. The non-regulated entity receives proceeds from the utilities essentially under a traditional rate making formula, expenses, plus a return of and a return on investment. Customers would see price stability by the credit of the proceeds that they would get from the market sales of the gas produced.

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So, this provides stability for customers and price, and it provides a much more expanded investment opportunity for the Company for our natural gas utilities than we've ever had in the past.

For those of you who follow Black Hills, it's very similar to what we have in place currently for our Wyodak Mine. As I think all of you know, our mine sits in a non-regulated entity and the coal that it mines is really for sale to primarily our utility businesses using a revenue requirement like formula just like the utilities do along with the commensurate return relative to the risk.

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So, the cost of service gas model is in effect very similar to the Wyodak model. We thought that was a good way to go because our South Dakota and Wyoming regulators recognized that very simple model to understand and really it's a model that we think would provide the lowest costs to our customers by also providing a fair return commensurate with the risk to our shareholders.

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Why is this a good idea? Our customers currently experience a lot of volatility in their natural gas bills and this provides us a way to stabilize those commodity costs over a long period of time. We are in a relatively low gas price environment. Now is the time to acquire reserves and production to stand up a program like this while gas prices are still relatively low. Hedges have their limitations. It's very difficult to find a counter party who is willing to do a hedge beyond five years and ones that do are going to price that risk appropriately because they don't own the physical commodity. So, they are taking on speculative risk.

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The central difference under this model is we would own the physical commodity, the reserves on the ground, so it provides a long-term physical hedge, not a financial hedge. We're not the only utility to think about this. I'll show you here in a minute that others have successfully implemented this model and there are a few that are about to be implemented here in the near future.

And finally and what we heard from regulators in our initial round of discussions we could utilize our E&P experience. In fact, in every jurisdiction that we have the conversation about this concept, the regulators said we understand that you understand this because you have an E&P business. And that gives us a competitive advantage over companies that don't.

I mentioned this has been done successfully. This is a map of a number of utilities that have had this model in place for a long time. Questar obviously the longest duration since the early '80s and I think if you look at their material they've saved their customers a significant among of money by utilizing a program like this as compared to buying all their gas in the market. And a number of other companies that are either in progress or complete. I've also tried to include in this diagram the percent of the annual firm demand that is included in a program like this based on those utility jurisdiction and that will be an item obviously that we'll have to work with regulators in our jurisdictions to establish. We'd like a target. We think a target of 50% makes sense. We don't want to put all of our eggs in one basket. But this is a great opportunity for us to stabilize prices over a long-term after the portfolio we think makes abundant sense.

So, what are we doing next? As I mentioned, we had initial regulator and consumer advocate meetings. We held those in the spring. We are now going through a second round of meetings with our regulators that we're describing as technical workshops where we're getting into a lot more detail about how a program like this might work, how we would structure it, and how the individual utilities would participate.

We are also evaluating properties for inclusion into the program. If you look at that map of the United States, every entity that has done this successfully has approached regulators with a specific property in hand. It's not been a concept. They've had the ability to talk about specific aspects of an acquisition. I can tell you that in our meetings with regulators, the first question that they ask after they say this sounds like a great concept is what price are you going to produce natural gas for? The only way we can answer that is to have a specific property that we're talking about.

Just in terms of potential capital investment, we think $1 to $2 per Mcfe delivered is about how much capital we would invest both in initial acquisition in an ongoing drilling program to make sure that we maintain that stable level of production over a long period of time and stabilize those prices for a long period of time.

With that, I think Stuart is going to introduce you, Mark? Oh, okay.

Jerome Nichols: Excellent. So, we covered a lot of information there on utilities and the cost of service gas model as an opportunity for the utility business. What we'd like to do at this point is just open it up for questions for our panel here. If you have a question, please wait for a microphone. Raise your hand. We'll get you a microphone and identify yourself and your firm and then ask your question.

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Pradeep Killamsetty: Thanks for the opportunity. I'm Pradeep with the John Hancock's investment group. I had a quick question on the cost of service model. You noted that you plan on using this

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program for maybe 50% of your demand. It wasn't clear to me what percent of production would equal 50%.

Ivan Vancas: 50% is what we think is an ideal level in terms of our firm utility demand. That's for both gas and electric fuel supply. That's still be worked out by regulators. It's not a decision we can make unilaterally. In terms of percent of our overall production, do you mean with reserves and production we currently own?

Pradeep: Or pro forma whatever asset you're thinking of, the program comes into play in 2016, so the way you're planning right now against random numbers, you're thinking you'd use this program to hedge out 50% of your utility demand, what would that be as a percent of your 2016 annual production?

Ivan: I think John Benton would need to answer what percent of annual production. I think the broader point to make is in a cost of service gas program we might have some of our existing resource. It might be resource that is altogether different from what we have or it might be a combination of both of those. So, we're still working out how the final portfolio that would get us to the 50% or whatever regulators would approve would be comprised. I think it's fair to say that our initial approach is going to be smaller in scale so that the regulators approve the methodology, the cost recovery, and the concept, part of our application will be to also receive approval for guidelines that we can make additional investments in acquisitions without having to come back for approval every time. We're still working out how we would get to that 50% or whatever the regulators would approve.

Pradeep: One last question. The way you produce natural gas and sell at market price and then the profits you make are for the utility. Then, it wasn't clear to me if all the gas was non-utility subsidiaries producing would be going to either sell in the market and all of that profit goes to the utility and the rest of it goes to the utility as cost of service model. It wasn't clear to me how the credits are going to be allocated -- the profits are going to be allocated. Thank you.

Brian Iverson: Brian, I think I can answer part of that. I think one of the things you need to look at, this is separate, non-regulated entity. So, it's not our E&P business that will be transacting with the utilities. That's one piece. And then when you look at the production we had last year compared to getting to 50% several times what our E&P production is. So, you really have to look at it as two different pieces. We have the E&P business but we have this other way to develop either third-parties or potentially even some of the company's E&P properties for this. So, I think the answer to your question is the entity we form for the purpose of cost of service gas will be set up and any excess over our production cost or any excess over what is paid by the utilities for the gas will be credited back to the customers and that's where they get the benefit.

Ivan: That's example right. It would be an altogether different entity from our Black Hills E&P and it would have only assets that are intended for the cost of service gas program to whatever level that our regulators are comfortable with. We have the benefit of investing capital and getting a utility-like return. And customers have the benefit of that price stability. But also the upside, if we sell into a higher priced market, we think that's a good thing. It's like power plants for the gas business. We have an opportunity to invest a lot of capital that historically we have not had an opportunity to and customers have a great opportunity to get price stability over a long period of time that they haven't had in the past.

Pradeep: Thank you. Now I understand.

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Ivan: Exactly. We're going to use John and his team's expertise to help us out and get the program going.

Mike: Mike, BMO. On this Questar service, I would imagine that the initial assets would have to come from existing Black Hills properties. And so regulators are asking what the cost of producing the gas will be and you don't know that. Initially I would think that it would come from Black Hills properties.

Ivan: Not necessarily. It could. But it could come from a small acquisition outside of our current footprint. You know, if you look at regulators' point of view in the jurisdictions that we're in, but for Wyoming, most of them are not familiar with owning and producing natural gas. So, they view this with some concern in terms of their expertise in evaluating it and we recognize that. If you look at the companies that have been successful in doing this, they have put properties in that have been proven, producing, and-or proven or undeveloped in very long-term sure fields. We think it's critically important that our initial entry in front of regulators is with a property that we have a high degree of confidence that we know what the production costs are going to be and that we know what the output is going to be. So, we will try to find a property that matches that profile.

Mike: If there is a potential risk that the regulators deny it at the end of the day are you comfortable rolling that into the rest of your -- ?

Ivan: That's exactly what we're saying in the technical workshop. We're going to make -- what we come in with will be relatively small if it's not something that's part of -- and really from a practical perspective, if we walked in with our first property that we owned you then have the additional layer of complexity of affiliate roles, it would be a lot cleaner if it was something outside of that. But, yes, if we do end up acquiring something, we would acquire something that would be commercially attractive to us as stand alone business so that if we didn't get a full subscription from our states that we would be happy to own it but 77 billion cubic feet of annual firm demand, half of that is a big number and if you walk in with a relatively low level of production I don't see that there would be a high risk that it wouldn't be fully subscribed.

Mike: When will you begin to roll this out in terms of --

Ivan: That's a great question. Our strategy has been talk early, talk often, be transparent with regulators because that's the advice we've gotten from the companies that have done this successfully. And we've been doing that. We had the initial round of meetings in the spring. We have a subsequent round of technical workshops this fall and I would say that the feedback we've got -- we asked the question, is this a valuable use of your time and the response we've gotten so far is yes, this is really helping me understand what you're talking about so that why you come in with an application, I understand what it means. Coupled with the fact that we need to have a specific property that we can have a relatively predictable forecast of the price. So, I don't have a specific date for you but obviously we'd like it to be sooner rather than later but we also want to make sure because this will be a long-term relationship with our regulators that when we do it initially and ongoing that we do it right. So, we're going to make sure that they get comfortable before we come in with a file. We promised them that we wouldn't surprise them with a filing, that we would have multiple discussions so they understood the concept before we came in the filing.

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Ivan: I assure you that it won't be before the end of the year. That much I can say.

Mike: Will it be a simultaneously filing at the same time or will you just put them through?

Ivan: We are approaching it as initially as a simultaneous filing but part of the discussions that we're hoping will help us flesh out whether a different strategy might be more effective. What we've emphasized though to all of our regulators is you can't expect to wait two or three years while the other utilities try this out and if you like it, get into the program at the prices that you saw two or three years ago. So, as gas prices go up, costs go up, and the ticket to entry will be different in the future than it is today.

Matt Davis: Matt Davis, Credit Suisse. Just a couple more questions on that. At what point would you need to actually have property in hand within the filing? Do you need to have it before you actually make the filing? Or is there some time after the initial filing has been made?

Ivan: No. it really needs to be before. Because I think we need to talk about what our forecast cost is to produce and we need to talk about what the forward curve for natural gas prices looks like and what kind of savings customers might realize. We certainly wouldn't go in with the 50% threshold in the initial filing. That's something we would ramp to as I mentioned earlier part of our filing is going to -- or our thinking currently is to ask for some guidelines that we can apply for additional drilling and-or acquisition to get us to that level without requiring a formal approval subsequent to the first one.

Matt Davis: And then this proposal is going across five different jurisdictions, so if you could just talk about the receptivity across the different jurisdictions as the responses I would assume would be different from each of the commissions or the stakeholders?

Ivan: Actually in the spring it was remarkably the same. First of all, they're not going to say to the degree that we meet with actual commissioners they're not going to signal how they would look at this because this is early conversations. We've met with commissioners. We've met with staff. We've met with consumer advocates. If I could summarize everybody's initial reaction, it was this is a great idea for long-term price stability, something we've not heard before, looks like it could work. But we have lots of questions about at what price. We have lots of questions about who takes what risk. What risks do customers take? What risks do shareholders take? And we have lots of questions about what our ability is to oversee or regulate components of this.

Matt Tucker: Matt Tucker, KeyBanc. I have a couple of questions on other topics but just a follow up on the cost of gas real quick. You've obviously talked about this before. I feel like -- my impression was it was mostly in the context of your Mancos shale program. And you talked about needing to get through the end of next year to potentially delineate that play and in the past it sounded to me like the timing for this program would kind of coincide with delineating the play. Can you talk a little about the extent to which the timing kind of depends on what you're doing in the Mancos shale and should we still consider that property would be kind of the base case for the asset that you go to regulators with?

Ivan: In terms of timing, I'd ask John to clarify this too if I get this wrong because I'm on the utility side. We think from a utility point of view makes sense to pursue this on its own track rather than waiting until we complete our drilling program in 2016 because as time goes by there's a potential for gas prices to go up and it's not as attractive when you make that filing. At the same time, we recognize that regulators would probably view the Mancos today as more speculative than a field where we have hundreds and hundreds of wells already producing. So, our initial entry into cost of service gas will be an initial entry and to maintain a certain level of production over time it will require a continuous

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drilling program. In other words you're going to have to be drilling wells pretty much annually if you get to that 50% target for whatever period of time you want to maintain that plant level production. So, when the Mancos proves out we'll take a look at how that would fit or wouldn't fit and make decisions accordingly. The great part about this is we can still pursue the strategy at E&P like we originally communicated or we have another option. Either way, we do have an option for the utilities to grow that business more than we have in the past. It's just a question of what resource we have.

Matt Tucker: That's helpful. Pardon me if I'm wrong, it sounds like this is going to be a state by state decision with the regulators. Is there a certain critical mass where if you didn't get to three or four states it wouldn't make sense? Are you going to pursue this in however many states will approve it, even if it's maybe just one or two?

Unidentified Speaker: We were asked that question in Iowa just a couple weeks ago. As we told Iowa, yes, if Iowa signed up for 50% and that was the only state, we'd be happy to produce that much gas over a long period of time. There is a certain critical mass but if you look at the individual states most of them have a firm demand large enough that it would be attractive. First point. Second point is we have been very forthright with our regulators in saying we don't want five or six models of this. We want a consistent model. So, we plan to make -- part of the purpose of having these couple of rounds or three rounds of communication is to understand what everybody's needs and concerns are so that we can address as many of those as possible. But we've been very candid that we don't want multiple versions. It's too expensive to administer or complicated, et cetera. We all get that.

Matt Tucker: Thanks. Great. Just a couple quick unrelated questions. Pardon me if I missed this but the expected timing of the results of the RFP for renewables in Colorado?

Unidentified Speaker: We have 120 day report due in November where we plan to make our recommendations.

Matt Tucker: Thanks. And then I heard a comment about UPA rules potentially impacting the potential sale of Wygen (I). Could you just elaborate on how those rules could potentially impact that?

Unidentified Speaker: Well, I think Wyoming regulators have asked could it and if so how? We need to be able to answer those questions when we make that filing. That's the only thing I was trying to convey.

Matt Tucker: Okay. Thank you.

Insoo Kimm: Insoo, RBC Capital Markets. First question just to follow up on the cost of gas program, how are you thinking about it in terms of financing the positions if you were to make them prior to filing with the commission?

Brian Iverson: I think Brian can answer that. It really depends on the size. We've typically been funding acquisitions like this at the corporate level. So, we would look at being longer-term assets as we would get to a critical mass we'd go out and issue bonds at the corporate level.

Matt Barnett: In your various jurisdictions, how is demand response, energy efficiency impacting the demand and talking about the normalization clause, how much of a push are you making in the various jurisdictions for implementing those mechanisms?

Stewart Wevik: You'll have to clarify the latter part of your question. The normalization clause?

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Matt Barnett: Weather and demand response, energy efficiency to put in mechanisms to cover?

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Stewart: Most of our jurisdictions, and it's on the regulatory tracker update slide indicates on there what states have energy efficiency type programs in place, the ability to recover costs associated with those programs. In response to your question about how much is it effecting our overall demand, I don't know if we can share -- I don't have a specific number to share on that. We don't believe it's significant at this point.

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Jerome Nichols: Alright, Chris. We'll take one more question and then we need to get rolling here and keep on schedule. Chris?

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Chris: Last one, I guess it's kind of a boring one about rate based growth, outside of the gas rate facing, I wanted to get a sense within your CapEx time horizon through 2016 I think what we can look at for total Company electric and gas rate base growth and then if you guys are willing to give any sense of what you expect for lag and where it's been maybe the past year or so?

Stewart: In terms of I think we can really only speak in terms of capital investment which was detailed for '14 forecast and years '15 and '16, budgeted as well. Tony?

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Tony: (inaudible) We're up roughly $70 million for -- most of that is --

Jerome: Very good. Let's continue down our agenda. So, next will be Mark Stege who is a Vice President of Operations at Cheyenne Light and he's going to provide a spotlight on the growth that's happening in Cheyenne. Mark?

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Mark Stege: Good afternoon, everyone. Thanks for joining us here in Cheyenne. Hopefully, you'll enjoy your visit.

What I'd like to do, turning to the next slide, is really tell you about a story of growth here in Cheyenne, a story of a community that's banded together. Part of that story is going to begin with a little bit of history, back to the 1980s.

I'm going to talk a little bit about LEADS, the economic development entity, or Laramie County Corporation for Economic Development, and the key role that LEADS has played. I'm going to talk a little bit about the core Cheyenne Lights partnership with this community to build the required and related infrastructure that meets the growth needs, the benefits of being in Cheyenne. Besides the wind resource that we have, we have many other benefits we're going to talk about, and then the impact of development on jobs and reliability.

So, if we turn to slide 51, we're going to talk about strong economic growth. If I can provide a quick orientation to this map, you'll see at the top of the page to the bottom, the line represent I-25. The one left to the right or right to left is I-80, and you can see that shaded area being the City of Cheyenne.

If we go back to the mid-'80s, Wyoming was in the middle of an economic bust. We were in tough shape. The community banded together, and in 1986 they formed LEADS, the economic development entity for the City of Cheyenne and Laramie County.

Two years later, in 1988, Cheyenne Light purchased 1,000 acres, held it for LEADS and two years later, in 1990, LEADS took this property over, and it was the formation of the first business park, the Cheyenne Business Park. It's on the right hand side in blue on the east end of town, over 900 acres.

Mid-1990s, the growth continued. We needed some capital to complete the park, so they had a capital campaign, raised $2 million of private funds and finished the infrastructure.

By 2002-2003, it was obvious the business park was growing at a rapid rate. So, the community said we need another capital campaign, raised almost $4 million and purchased 600 acres on the west side of town. It's in the light green area. It's now called the North Range Business Park, and the birth of that park was 2005.

A couple years later, the word got out that Cheyenne was experiencing a mini-economic boom. Private industry came in. Granite Peak Development came in, purchased 7,000 acres, and started their own business park, the Swan Ranch Business Park, and that's denoted in that salmon pink color.

The results -- strong economic growth. We have three business parks now that we can offer up to businesses that come in to Cheyenne.

We've highlighted just a few names here that I've just popped up, technology data centers, excuse me, have just popped up in the last five years.

We'll start with the first one, NCAR, National Center for Atmospheric Research, a federally funded supercomputer site in atmospheric research. That began operating in 2011.

The next year, EchoStar Data Center became operational in 2012. That houses the data for DISH Network, along with many other companies.

That same year, Green House Data, a local Wyoming company, began operations. They do colocation for servers, and just this year, they finished a phase two of Green House Data.

And lastly, Microsoft. In April of 2012, Microsoft announced the construction of a data center here in town.

December of 2013, they took operation of the first phase of this, which they call CY1. As soon as they finished CY1, they began construction of CY2, and that currently is being tested, as we speak.

In April of this year, Microsoft announced, again, it was going to-- it continued to expand the facility. Now they're working on CY4. They anticipate 18-month buildouts. We're anticipating somewhere mid-2015 to be operational.

The Microsoft facility provides cloud computing, and they support Xbox games.

Turning to the next slide, number 52, talking a little bit specifically about Cheyenne LEADS, again, private non-for-profit company, economic development arm for the City of Cheyenne and Laramie County. Over 300 businesses primarily fund LEADS.

LEADS facilitates economic development in Cheyenne by providing shovel-ready sites for companies willing to come in, invest capital, and bring jobs in our area. Currently, in just the two LEADS business parks, there's over 500 acres available for future expansion for companies.

Our long-standing Cheyenne Light involvement. Again, we were involved in just not the foundation and formation of LEADS, but we were also involved, and have been, in leadership roles with LEADS.

The result -- the creation of well over 4,000 jobs. In fact, it's almost 5,000 new jobs with annual payroll greater than $150 million in Cheyenne.

Big attribute. Again, Stuart talked about the governor being bullish on diversity, and, of course, bullish on Wyoming. Wyoming is a business-friendly state. There's no state corporate income tax, no state personal income tax, no inventory tax, low property taxes, and low sales tax, amongst other items.

And how do we fit into this? As a leader at the economic development and at the table, we've been instrumental in providing the necessary infrastructure to facilitate this growth.

Moving on to the next slide, what has our investment in infrastructure been? Again, same I-25 north and south, I-80 east and west, you see the three business parks denoted there.

First off, Cheyenne Light we own and operate over 37 miles of 115 transmission line. If you take a look on the screen, it's the red-dashed lines that circle the city.

We tie in to the 230 KV transmission. That's the fatter, thicker purple lines that you see crisscrossing the area. We tie in at four injection sites, so we have four 230 injection sites, put to us very favorably. So, a robust system.

Over the past few years, we've invested in numerous system upgrades and improvements, additional sub-systems, 115 transmission line, natural gas lines, and then, most recently, the Cheyenne Prairie Generating Station.

All in all -- as you can tell, it gets a little busy on this map -- but we have a very robust, highly reliable system and backbone for our customers and for the community.

Turn to the next slide. It's all about location, location, location. So, in addition to slide number fifty-- let me look here, it must be 54. In addition to being the state capital, and close proximity to the north range of Colorado, we also have two interstates, I-25 and I-80, that intersect. We have robust fiber that follows both interstates. We're served by two rails, Burlington Northern Santa Fe, and Union Pacific.

We're 90 minutes from DIA. We have the three shovel-ready business parks available for immediate occupancy, and it's all supported by a strong regional, local background and backbone.

So, turn to the next page. What are the results? Strong reliability, exceptional electrical transmission reliability. In fact three-year average, five 9s of reliability. And, as Stuart mentioned, that's the first thing that data centers look at, is high reliability.

On the distribution side, we are top quartile. In fact, last three years, we've averaged 27 minutes for [SADI] minutes.

We're connected to a strong regional transmission network, supported by numerous transmission providers, WAPA and others that are mentioned. Our 115 line is supported by four 230 injection sources, as I mentioned earlier.

We have large generators in the area supporting the transmission network, and then lastly -- Mark Lux is going to talk about the Cheyenne Prairie Generation Station and other improvements we've been partnering with this community all along.

Turn to the next slide. Talk a little bit about growth. What this is, this chart compares percentage increase to total energy sales in five-year blocks. For instance-- and then the light orange, compared to the darker color, is Cheyenne Light.

So, you can take a look. From 1995 to 2000, our increase in energy sales went up 10%. That next tranche, from 2000 to 2005, increased 4%. From 2005 to 2010, increased 10%. And from 2010 through forecasted 2015, increase 25% in energy sales.

So, if we compare 2005 when Black Hills Corp. purchased Cheyenne Light to our forecasted 2015, we're forecasted to increase energy sales by 38% over this last 10-year period of time. Compare and contrast, then, to the U.S. average, which is information provided by the Energy Information Agency.

And then lastly, turning to my last slide, preparing for the future. We're-- we're well prepared for the future. LEADS will continue to be the economic development entity for Cheyenne, and does a great job in bringing businesses to us. We'll continue to provide the facilities and infrastructure necessary to facilitate the growth.

Look at some of the recent investments in Cheyenne Prairie Generating Station. That station provides an increase in the reliability. Having a generation source right next to the load. We have energy security of supply, which is very important, and adaptability, the ability to back up renewable generation.

State-of-the-art generation results in low emissions, and lastly, room for future expansion. Mark's going to talk about this, but the site can more double in size.

So, with that, I thank you.

Jerome Nichols: Thank you, Mark. We are scheduled to take a short break here, so we're going to take just a five-minute break, so you can get up and help yourself to refreshments or anything of that nature. We're going to take just five minutes, though, because we're going to have to keep on schedule.

And we'll mute the webcast, and then in five minutes, about 3:45, we'll un-mute, and begin again.

(break)

Jerome Nichols: If we can have everybody take their seats, please, and we'll go ahead and get started here.

So, the next session is power generation and coal mining, and Mark Lux, Vice President and General Manager of Power Delivery, is going to cover those particular business segments. Mark?

Mark Lux: Well, good afternoon, and thank you, Jerome. As mentioned, my name is Mark Lux, Vice President and General Manager of Power Delivery. And in addition to being your host tomorrow to tour the small ranch east of Cheyenne called Cheyenne Prairie Generation Station, it's my privilege today to present the corporation's power generation and mining business segments.

So, for the next 10 to 15 minutes you can expect to hear about our core business focus, followed by a strategy discussion for continued profitability of each of these business segments.

Starting with slide 59, we'll begin the power generation business segment presentation first. Very simply, our power generation business is an extension of our utility business. With 269 megawatts of capacity owned, we currently have long-term power purchase agreements with our utility affiliates. Additionally, we provide operation and maintenance services for third-parties under long-term agreements, and most recently we are excited about the opportunity of entering into a long-term purchase agreement for economy energy purchases with the City of Gillette, Wyoming, a municipal in the northern Wyoming.

Our power generation business is a vertically integrated part of the corporation. We operate our utility and our independent power generation with the same core team. This management philosophy allows for efficient growth, expanding generation resources at our existing power generation sites.

By duplicating the small plant approach that was recently discussed, we are able to operate the latest technology, and diversify our generating fleet, while, at the same time, sell our energy management services, too, for ongoing profitability.

Moving next to slide 60, and at the heart of what we do is our proven record of constructing and operating power plant, safely, on schedule, and on budget. We operate a modern fleet of over 1,000-- 1,100 megawatts of diversified generation, including renewable generation. We provide energy management services to four non-affiliate utility providers, and, as an energy partner of choice, we have a proven record of constructing 1,900 megawatts of power projects across seven states.

We have above industry benchmark operating results for reliability and safety, and we have long-term energy partnerships providing energy management services to third parties.

Slide 61 shows the tabulation of our power projects, and at the bottom of this tabulation is the planned $65 million, 40 megawatt project in Pueblo. This power project is permitted and planned to come online by 2017.

Our latest project, as previously mentioned, is the Cheyenne Prairie Generation Station, and is shown on slide 62. This $222 million investment began commercial operation just a few short days ago on October 1st. It is the first combined cycle power plant in Wyoming and is jointly owned by Black Hills Power and Cheyenne Light, Fuel, and Power.

Additionally, Cheyenne Light, Fuel, and Power owns a simple-cycle unit at the site, which essentially replaced the power-purchase agreement that expired in September of this year, and led to the opportunity for the economy energy power-purchase agreement that was previously mentioned.

The Cheyenne Prairie Generation Station consists of a jointly owned combined-cycle unit and a Cheyenne Light, Fuel, and Power-owned simple-cycle unit, and both of these units are aligned with the future and pending EPA-proposed regulations. Currently the emissions from both of these plants are well below the EPA state proposed emission limits for the EPA Rule 111b for emissions of greenhouse gases.

Slide 63 provides an overview of our power plant operating metrics, compared to benchmark industry averages. We're very pleased with our continued operating results, and the great work by our operating teams of these power plants.

Additionally, we continue to be a leader in safety performance, constructing power projects on schedule, and on budget. In the last four years, our power projects constructed, shown on slide 64, were among the safest in the nation.

While the construction industry, on average, continues to have a total case incidence of 4.5, meaning 4.5 accidents per 200,000 man-hours worked, our projects continue to be in the lower quartile of the industry benchmark. Cheyenne Prairie Generating Station's exceptional record with 700,000 man-hours worked, demonstrates the ability of our team to successful execute power plant investments.

Our diversified power generation fleet is located in Wyoming, Colorado, and South Dakota, as shown on slide 65. Stuart spoke to this previously.

Slide 66 further provides a breakout of these site locations by capacity and ownership. By colocating facilities at these sites, we gain many infrastructure efficiencies, including shared staff, fuel logistic economies, and reduced operating costs.

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Moving next to our strategy discussion, you can see we focus on profitable growth by being an energy partner of choice. As demonstrated by our benchmark results, we continue to get better every day, and believe we have a competitive advantage in the utility regions we serve.

Leveraging our customer service reputation and brand, we can construct, operate, and provide energy management services as an extension of the utility business. Utilizing this competitive advantage, as depicted on slide 68, and focusing in the geographic regions we serve, we plan to capture opportunities for growth, executing three energy solutions, which are shown on slide 69.

The three energy solutions include the traditional power-purchase agreement, selling energy and capacity under long-term tolling arrangements, and two newly offered energy solutions, economy energy power-purchase agreements, and distributive energy resources for commercial and industrial loads.

The mechanics of an economy energy power-purchase agreement are shown on slide 70. The top half of this slide depicts the contractual agreement structure between power generation, on the left, and the third-party energy partner, on the right. The bottom half of this slide depicts the decisions on the left that power generation makes for the physical transfer of electric energy to be provided to the third-party energy partner on the right.

Very simply, power generation provides a long-term energy management service, whereby we share in the arbitrage difference between purchasing non-firm market energy compared to the cost of dispatching and operating the third parties generating asset.

As required for non-firm energy purchases, we utilize the third parties fast-start natural-gas-fired-generating assets as backup to purchase non-firm energy on the market at a rate that is typically less than the firm energy purchases. But dependent on the percent-sharing mechanisms negotiated for the arbitrage savings, a typical municipal with a population of 30,000 can produce operating income of $1 million to $3 million, depending on the market conditions.

The distributed energy solution is shown on slide 71. The power generation business is exploring and planning to provide distributed energy resource opportunities across the utility regions to targeted customers.

As energy prices approach parity, compared to the cost of distributive energy resources, we plan to execute agreements with commercial and industrial customers in our utility regions to provide energy management solutions, constructing, operating, and dispatching these resources owned by these new commercial and industrial energy partners.

The value proposition is merely leveraging our customer service brand, providing energy solutions in the utility geographic regions we serve. These energy solutions, micro-gas turbines, and renewable distributive energy resources for commercial and industrial loads, are vertically aligned with our gas utility demand and provide an opportunity for growth.

So, as an extension to our utility business, and utilizing our proven record and small plant approach, the power generation business segment is well positioned to be an energy solution provider to the seven-state utility regions we serve.

This concludes the power generation business segment, and we'll move next to the coal mining business segment.

Our mining business segment continues to provide low-cost fuel supply to our utility customers. To put this in perspective, as compared to today's natural gas prices, our coal sale price to our customers is over 300% less expensive -- 300% less expensive -- than gas.

So, coal mining currently sells coal to two primary customers, Black Hills Corp. affiliates and PacifiCorp. The Black Hills Corp. affiliates cost-based pricing mechanism limits our financial cash flow risk, while equally important, the current mine plan provides the lowest cost of operation to maximize margins on the market-based pricing provided to PacifiCorp.

Slide 73 is a graphical representation of the forecasted tons to be sold by our mining segment. Sales are anticipated to range from 4 million to 4.2 million tons. Although national pressure to reduce coal sales continues, our mine plan coal production forecast remains stable for the foreseeable future.

The mining business segment deserves much recognition for its safety and compliance performance over the last five years. Slide 74 lists some of these accomplishments.

I, for one, am extremely pleased with our mine's performance, operating the safest mine in the Powder River Basin. This summer we received the Wyoming Governor's Award for safety performance, and we continue to achieve excellent safety results, with awards from MSHA in 2013 for our continued five-year record without a lost-time accident.

Moving to our coal mine strategy, our engaged employees provide stable earnings with low-cost fuel supply to our mine mouth power plant customers, while maximizing profits from existing market-based contracts by controlling expenses. The mine has limited growth opportunity, so, it is important to optimize profitability by maximizing revenue and controlling expenses.

To maximize revenue, we are focused on three initiatives, shown on slide 76. Our PacifiCorp coal-sale agreement and price reopener in 2014 and in 2019, the WyGen I sale to Cheyenne Light, Fuel, and Power, which triggers wholesale price adjustments to a cost-based pricing, and asset optimization, exploring partnership opportunities to utilize our rail spur for other commodities.

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We're nearing completion of the 2014 price opener, which is recorded and effective beginning in July of this year. The price reopener has three components -- a market coal price adjustment, a cost adjustment for our rail-in storage facility, and a transportation cost adjustment.

Of the three price adjustments in the contract, the coal transportation cost is the remaining item to be finalized. The final adjustment price is expected to be profitable and favorable.

This price has escalated through five years with commodity indices, when in 2019 we have another price reopener set point, which will, then, be the final price adjustment that will remain through the term of the agreement.

Additionally, we are targeting the WyGen I transfer to cost-based affiliate pricing in December of 2015, and we continue to explore opportunities for leasing or utilizing our rail spur for other partnership opportunities, using other commodities.

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We're also focused on controlling expenses by managing our mine and effectively implementing productivity enhancements. Slide 77 provides details of these expense-control strategies, but the primary driver, as discussed last year, in cost management is minimizing our overburden stripping ratio through effective mine planning. The amount of overburden dirt to coal tons mined is referred as the stripping ratio.

The effect of successfully executing our revenue enhancement and cost control strategy is shown on slide 78. The continued margin improvement per ton sold is shown on the right hand legend, as you compare the green revenue line with the black expense line.

Slide 79 shows the forecast, future mine plans, and expected strip ratios on the right side for years 2013 and beyond. As you can see, as we move north in the mine, our stripping ratios do increase, however the margins that we expect from the PacifiCorp price reopener, and the fact that the utility affiliate pricing is cost-based, and we can pass through those costs, we plan to continue to be profitable as we move the mine towards the north.

In closing, slide 80 provides a bar graph comparison of BHC's mine mouth plant's coal sale price in orange on the left side, as compared to other regional coal plants in the middle, and natural gas prices on the far right. As you can see, our mine mouth operation is very competitive in terms of the overall price of fuel, and provides great value to our utility customers with the mine-mouth fuel supply.

Although growth opportunities are limited for the mine, we continue with a strategy that is expected to provide continued and stable profitability for the corporation, and low-cost fuel supply to our customers.

This concludes the coal mining business segment presentation. Thank you for your time.

Jerome Nichols: Thank you, Mark. So, we'll take just a few questions before we move on to oil and gas. So, if you have a question, David?

David Arcaro: Hi, thanks. David Arcaro, Sidoti. I wanted to clarify, on the power gen side, the distributed energy resources. Is that basically building rooftop solar for commercial and industrial customers, as I understand it?

Mark Lux: It could be any type of resources, micro-turbines are probably the most economical, nearing parity right now in terms of economics in some of the regions, but it could be renewable opportunities, as well, for demand shaving or other types of renewable services that are desired by those customers.

David Arcaro: And this would be customer-owned, basically?

Mark Lux: That's correct.

David Arcaro: I also had, let me see, one more question on the power gen. Have you, at this point, identified potential customers for additional megawatts, say municipalities with an old coal plant that you think might be retired, or PPAs that might be coming up for renewal? You know, opportunities there, maybe in terms of megawatts that you see on the horizon?

Mark Lux: As part of our business strategy, we continue, always, to look for those opportunities in the regions that we serve.

Matt Tucker: A couple questions on coal mining. On the Wyodak price reopener, can you just remind us how the new pricing terms compare to the prior terms? And then, similar question on the potential WyGen sale, if you could just reiterate how the pricing changes-- pricing terms have changed there?

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Mark Lux: Yes. Right now, we have two market-based contracts, basically. One of those is for the WyGen I coal. The other is to PacifiCorp.

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The first part of your question, on the PacifiCorp pricing, the good news is it's going to be a lot greater than what it is today. So, very profitable in terms of going forward in terms of that reset, and it escalates each year, based on commodity indices, so it's not a fixed price that just stops in 2014. It continues to escalate.

Matt: And then, I know the Wyodak plants are a lot older than the other plants at the mine, and believe EPA is asking for scrubbers to be installed for the next few years. I'm sure that they'll be some litigation around that, but any concern about PacifiCorp deciding to close the plant early?

Mark Lux: Yeah, PacifiCorp has coal supply agreements through 2023 for that power plant, and we have an operating agreement that has contractual requirements to continue to do investments to meet compliance requirements. So, the answer is, not at this time.

Matt: Thanks.

Tony Cleberg: I think you had another question, Matt (ph), on WyoGen I, and we disclosed that in the K last year, and we haven't updated it since. So, we gave all the mechanics in the K, so you can figure out where we're at. So, with that and our target date of December 15th, you should be able to do the calculation, and we'll update it again this year.

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Jerome Nichols: All right, Matt, one last question, and then we'll jump to oil and gas.

Matt Davis: Yeah, so you have the benefit from the reopener this year, the PacifiCorp, but then you said the stripping costs are going to be higher going forward. Should we think about coal as kind of just steady, like, contribution, from an earnings perspective as last year, just with those two offsets, or should we think about it a different way?

Tony Cleberg: I think that would be a reasonable assumption. We may get sort of a benefit early on, but the stripping ratio will go up, so it'll cost us more.

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Jerome Nichols: Very good. Thank you very much. So, next is oil and gas, and this will be John Benton, Vice President and General Manager of our Oil and Gas Group.

John Benton: Thank you, Jerome, and thank you all for coming today and making the trip out here. Looking forward to giving you a little update on our progress and our plans for the oil and gas division.

Briefly, on a summary of this, I just want to note that we did replace our reserves last year. We still have some production also coming out of the Williston Basin, a bit over 200 barrels of oil a day out of the Williston Basin, although if you look at this, we're still substantially gas-weighted, and that talks a bit to what we look forward to do, as far as some of our strategies overall on where we go with exploration.

I wanted to note on this and some of the production information here, we've been able to maintain our net production in the San Juan Basin. We've actually seen some improvement in the Williston Basin with the non-operated production on the oil side, also some optimization in our legacy oil asset in Wyoming has brought the oil production up there, and the Piceance, you can see some increase in production, particularly in the NGL side from the Whitaker Flats (ph) wells that we brought on this last year.

When you look at overall, our strategy is very consistent with what we had last year. We've included in the value services something that really has us engaged is working on the cost-of-service gas project for the utility company. It's something that we're pretty excited about, and it's got our folks pretty keen on going forward with that, and looking at that opportunity, because it's a benefit both to the oil and gas division, and to the utility division, as well.

This highlights a lot of things about execution of our programs. As you know, that's key to the profitable growth of our business, our E&P business, and since we're highly gas-weighted currently with our reserve base, we need to add to our inventory of oil exploration opportunities, and we're continuing to look at other opportunities.

We use this sort of as a reference slide. It provides some context to what our ongoing efforts are to quantify our Mancos gas resource. Some of the subsequent slides are going to go into a bit more detail of what our progress has been and what our plans are, as we move forward.

There's four key items that are identified in this slide for our Mancos objective. We'd like to know what's the size of the prize? How's the best way to recover it? Where are the sweet spots? And how much of it are we going to be able to recover?

Answering those questions brings us to profitable growth of our E&P division and creates some optionality for us. We've learned something with our program in the last year that we want to share a bit of that today. While I still have to say, we're still a bit like the blind man describing an elephant, because we got a lot more to learn about this resource.

You've seen this table before. We've made some adjustments to this, based on some of the results that we've had in the last year or so with the long lateral wells in the Piceance.

We also included a bit of an estimate here on what this resource would look like with increased density. You've not seen that before.

When you look at this, on the surface, it looks like we're just doubling down on our well spacing. We really wanted to give you a graphic image of what this looks like, overall, and we're going to move on to the next slide to provide that.

This slide sort of talks back to that question we had that says how much of this can we recover? The increased density is actually tied to the distance between the wells, if you sort of look down from the top, where we said 660 feet spacing between the individual wells, and in three dimensional space there's a significant amount of spacing in between each well bore.

We've got over 1,000 feet a section in the Mancos in the Piceance. Current technology for hydraulic fracturing, you can only contact about a third of that. So, notionally, if this resource is as big as we think it's going to be, much like the Bakken or the Niobrara in the DJ Basin, we're going to have to add some more layers of wells to be able to get at the overall resource.

In this particular diagram, we show about eight wells in this three-dimensional space.

Just some interesting things to note, that in the Denver-Julesburg Basin, which has a fairly thick Niobrara section, there are some operators that are piloting up to 32 wells in that same space that you see on that slide. So, there's a significant amount of learning yet to happen before we determine what's the optimum way to get at this resource and recover it.

One of the questions that come up, this is sort of why are you going to 10,000 feet? And I'll borrow an analogy from Mark Lux on this, is that when you think about the stripping ratio in a mine, where you have to strip off the overburden, much like that, the vertical section that we have to drill through is much like removing the overburden in a strip mine. And so we get more pay by removing less overburden by going to longer laterals for each well.

This slide talks a little bit about the size of the prize and where are the sweet spots. As you can see in here, we've sort of outlined where we think the liquids fairway lies, yet when you look at this as far as the actual wells that we have, we have these two wells, have this well and this well. That's all that we have currently on production.

So our program this year, the 2014 program, is going to drill wells up here in Homer Deep. The 2015 program is going to add some wells here over at Winter Flats, and again, more here in Whittaker Flats. So part of that is it's going to be this program helps us get better definition around where that liquids fairway may exist.

This is pretty much the same thing. It just gives you a broader idea about where that liquids fairway may exist, and it's sort of predicted where that may be. Just a comment, briefly, about who else is active out there. I'm sorry, Leslie. WPX is active right here in the Homer Deep area, just between the R and the D. And though we're not here, they're active up in here, and that's a deeper part of the basin.

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We showed a graphic like this last year for Whittaker Flats. These are our 2014 wells in Homer Deep. This is the first pad. One of the things we wanted to address with our horizontal drilling program this year was how do we address the drilling hazards that we encountered with our 2011 program? As you can see from this, we've been able to get out to 10,000-foot laterals. We were able to conquer our drilling hazards, and we did encounter some challenges getting casing out all the way to the end. But we hope that some of the learnings we're going to get from these wells will help us improve our ability to run casing out to more of a longer lateral length. But that's pretty substantial. These actually set some records for operators out here in the Piceance as far as lateral length.

We're pretty pleased with what we've seen for improvements in our drilling costs from 2011 to 2014. As you can see, our 2014 wells in Homer Deep were drilled and cased for about two-thirds of the cost of the 2011 wells, while they increased their total length by more than 50%. So that gets at that question about efficient recovery and how do we get at this resource and be efficient and cost effective in the recovery.

To put this in a different way, sort of the drillers look on the one side, the dollars per foot of case cost. The graphic pretty well tells the story about the reduction in cost we've seen on a cost-per-foot basis. What this represents is the cost per foot of cased lateral. So it's that for us. That's where the pay exists, is that the more that we can case in the lateral length is the more pay section that we can attack when we go ahead and complete the wells.

This is something we haven't shared before. I think the key takeaway here is that with the Whittaker Flats completion in 2013, that comes close to what we targeted for our development cost, which was between $1.20 and $1.50 per MCF. And we're right there. I think the one was around $1.35, and the other one's about $1.52, so that's sort of well within our development cost range. What that helps us is that we now, it gives us some line of sight to what this may be and that we can see economic development, being able to get to economic development in this project.

This is kind of an interesting slide in that it represents all the wells drilled in the Piceance with lateral lengths of greater than 7,000 feet. It's about six wells. When you think that this has a potential to be Marcellus size in resource, that's not a lot of data points. But what we like about this is you can see our two wells laying there with the Encana wells. They're all running about an 8 to 9 BCF type curve, with the exception of the one departure from the Encana well, which is above all the other averages. So as we develop this, we're hoping that we continue to fill this in or actually move the overall average up.

We've presented the type curve a couple of times. We wanted to show you this time where our wells look in this type curve. Remember, those wells averaged a little over 8,000-foot lateral. These are the Whittaker Flats wells from last year. They're well within the range of expectations for performance overall for the program.

We did put together a pricing slide. There's been some questions about sort of, "What do you get and what's your expected well head price?" We wanted to show this to you. As far as an effective well head price, you can see what the benefit is as the uplift you get for the NGLs coming out of Whittaker Flats. Homer Deep has got a bit of a challenge there on the price side, so we're looking at that, and it helps us with the drilling program this year, look at the overall cost to complete those wells and what the economics look like once we get those wells produced and online.

We put together a chart that shows the pre-tax rate of return for the Whittaker Flats area. Again, you can see that the 2013 two-well program is very encouraging for us in terms of where we are with the overall rate of return in finding and development costs. It definitely puts us on that path and says that we need to continue this program. We're pretty excited about it. It's very encouraging for us, and we're continuing to move forward with the appraisal program out here.

I wanted to add this briefly as a reference, and if you look back at the table we used in the San Juan Basin, I think an average of 6 BCF a well, this is the one well we did drill in the San Juan Basin. As you can see, it's headed on a path to get to at least very close to 7 BCF, if not exceed that over time. So good, encouraging results from us again there. I think the challenge for us out there is the economics aren't as good. The tax royalty structure is a little bit more restrictive, and we have some water issues as far as being able to get water out to that area to be able to continue with the drilling program, and we're still working on that.

A fairly short discussion on the oil strategy. It's not changed, remains unchanged. We talked about it the last time we presented. We participated in three plays in 2013. We've evaluated a number of plays this year and continue to look for it and using this same guideline. We're not going to stray from that, because we know that that has a better chance of being economic for us than, say, one-play wonders or something along that line.

Overall summary, we're very encouraged by the results we've seen in our Piceance. In terms of a great workplace, again, it's given us a very engaged workforce. We very much like that program. We want to continue the appraisal program. Being weighted to gas, obviously, we want to continue to develop additional oil opportunities for exploration. And finally, I think the cost-of-service gas project is something that we really look forward to working with Ivan and the rest of the Utilities Group on developing that and putting it into place.

Jerome Nichols: All right, thank you, John. So we'll open it up for questions for oil and gas.

Douglas Simmons: Okay, Douglas Simmons, Fidelity. So originally, I think you were going to give the results of the appraisal wells sort of the beginning of 2015. What's your estimate on when you'll give the results on the appraisal wells now? And also, maybe if you could also add what are the risks that that potentially could be delayed?

John Benton: And you're talking about the six-well program?

Douglas Simmons: For the Mancos, yes.

John Benton: For the Mancos? Well, as you recall, we had six wells this year and six wells next year. So we'll expect that as the wells get completed, we'll be able to release the results as they get completed. We're not sure on the completion timing. This time, as we're headed into the wintertime, there could be some weather delays. So I would hope to be able to release those as they get completed and go into production.

Douglas Simmons: Good. Do you think, is it fair to assume that throughout 2015, we may hear about the well results? Or do we need to wait until the end of 2015 before we hear the final say on what you, how you think the appraisal wells turned out?

John Benton: I think it would be fair to say that we would probably be releasing information during the course of 2015.

Douglas Simmons: And what might be the earliest time? Can you quantify the earliest that we might hear on some of those wells?

John Benton: Boy, that's a tough one. It depends on weather. I mean, we have two wells drilled and cased now. We're on the third well. We would expect to start hydraulic fracturing operations in November. So notionally, you would like to have at least 90 days of production before you could start releasing results, so probably some time towards the end of the first quarter or the early part of the second quarter.

Douglas Simmons: Okay, so we could still see results from the Mancos in the first quarter of 2015, potentially?

John Benton: That's a possibility, yes.

Douglas Simmons: And then can you also just talk to--I know that you've tried and are trying to quantify the Mancos. You've talked about 2.2 Ts of gas. Can you talk about why you continue to feel confident in that, if we haven't really seen the well results yet?

John Benton: Interesting question, in that if you do the math, it's based on what we see today. You can see there's been a bit of an adjustment. We have the two Whittaker Flats wells that are both going to be around 8.5 to 8.6 BCF each. So we make a resource estimate based on that. We'd like to say, "Well, has that changed your confidence level?" Well, it certainly has improved a little bit when we had very little information from just the Homer Deep and the Horseshoe Canyon well. But is that, when you look at sort of Marcellus-sized resource, does that say that I've de-risked the whole play? No. We do see the results from the WPX wells. You've seen the Encana wells up there.

But that's a hard thing to say, is to say how confident are you in the results? From what I've seen today, I like what I see, but it's still a fairly high level of risk, and it ties back to what the question was put about Ivan that says, "How do you put that in a cost-of-service gas asset?" You'd like to have substantially more information and more wells.

I think one way to look at that is that consistency, if we see the same results in our 2014 and 2015 program, if you see that consistent result, and those wells all sort of fitting that type curve, then you're going to have a much higher level of confidence at the end of that program, that 12-well program, than you would have today. If you see a variation in results, then you're going to have to go back to the drawing board, and you have to look at it and say it may take longer to define what it's going to be.

I'm not sure if that answers your questions.

Douglas Simmons: It's interesting, because it sounds like, then, as we get the well results, you won't necessarily know if it's not the resource potential that you believe, because it may take more time to really figure that out if some of them don't come in as you expect. Maybe you continue to drill before. So it's not that you won't know immediately if it's not meeting expectations, because you might just say a couple of these wells just aren't producing like we thought, and you'd drill more.

John Benton: That could very well be the case. I mean, you think about other places of resource--Haynesville, Marcellus--it's hard to say, "Well, I've drilled six wells out here, and I can tell you what the next 600 are going to look like." It's pretty difficult. I think if you asked anybody when the Marcellus was in its infancy, or the Haynesville, or even the Barnett Shale, if you'd asked that same question, you'd probably get--I don't mean to be evasive on the answer--but you'd get a very similar answer in terms of the range of potential outcomes relative to the few wells that you have completed.

Douglas Simmons: Thank you.

Matt Barnett: Just on the liquid nature of what you've seen so far, when you look at the math, it's interesting, but what percentage of that do you believe is liquid compared to what you found in the Whittaker? Are you expecting to see any liquids as you move up into the Homer Deep?

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John Benton: It makes a little bit, if you looked at that table that showed the pricing, we do get some liquids out of Homer Deep. It's not a significant amount. I don't, off the top of my head, I don't know the different liquid yields across there. And as I pointed out, we have very few penetrations into the reservoir. So if you look again at where we drew that fairway, we sort of drew it on the borderline of the existing Whittaker Flats wells. It shifts up more towards Homer Deep as we get more wells drilled. The wells we drill in 2015 are going to help us a lot. That's over there. If you look back, I think you'd want to flip back to that--there we go.

If you look at the wells, they say, I think WT on there, which we call the Wagon Track area. Those wells right now are mapped outside of what we see to be the liquids fairway. If they fall inside, then that whole line shifts up to the north and to the east.

Matt Barnett: When you've displayed this map before, David Emery has indicated it seems like it's around 60% NGL liquid, based on what you're getting at here. How much more is it if you move up and to the right?

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John Benton: I haven't done the math on that, I'm sorry. I'd say 60% would be a good number to stick with, since that's what we've talked about before.

Matt Tucker: Thanks. Matt Tucker again with KeyBanc. Could you talk about the decision to drill all six wells this year in Homer Deep? And would it make sense to drill three there, maybe three elsewhere, to kind of delineate a different part of the play? Is that a permitting issue?

John Benton: Some of it's related to permitting, some of it's related to spacing, so a lot of factors go into your decision about where you pick to drill. That was an area where we had an opportunity. We said we'd like to see what does it look like from pad-type drilling out on Homer Deep. We felt like that was important for us to drill a number of wells up there. We had a serious drilling hazard issue up there when we drilled that first Homer Deep well, so I wanted to be able to say, "I can go out there and drill six wells and do all six of them without having any problems." So that sort of helped drive that decision. And there were some permitting issues and a bit of infrastructure issues, particularly going all the way out to Winter Flats. We've got another line we have to lay out there.

Matt Tucker: Thanks. And then just follow-up on when we're going to hear some results in the pace of drilling. If we may not hear results from the first wells you drilled this year until 2015, should we assume we may not hear about some of the six wells next year until some time in 2016?

John Benton: That is certainly a possibility. Obviously, we want to--we're as incented as anyone else to try and get those wells drilled and completed online as quick as we can and get results out there and understand what it is to help us make a decision about where we go next with this project.

Matt Tucker: Thanks. And then I noticed in your prior presentations, you had mentioned a targeted well cost of $1.20 to $1.50 per net MCFE, and I believe in these materials, it's per gross MCFE. And I was curious about it being intentional, or why the change there?

John Benton: I can't speak to the per net one, but I know that it's on a per gross basis. That's what we've targeted, and if you look at the economics that we presented for Whittaker Flats, clearly that gets us into that 18% to 20% rate of return. So we just wanted to make sure that the numbers all went around this time, so we said we're going to tie it all to a gross number, because our net interest varies across the assets, so it's easier to tie it back to the gross number.

Matt Tucker: Thanks. And then one last one. Any of your oil and gas assets right now that you think would work well in a cost-of-service gas program?

John Benton: That's a good question. And when you look at where we are, and we actually talk about a little bit about sort of the life of a field or the life of an asset. And for the Piceance and Mancos, we're pretty early in that life. So in terms of, if you plot sort of life and production capacity and so on, we're at the high end of the risk scale and the low end of the production scale, so there's a high level of risk. So that asset probably is not going to fit.

The other assets on our vertical gas production, either in San Juan or here in the Piceance, they're more at the mature end. And as Ivan mentioned, if you want to have an asset, you'd like to have an asset you could put in there that would have some additional drilling opportunities. So they probably wouldn't necessarily be the most ideal asset that you would put in there.

They'll certainly get evaluated. As we continue to move forward, we'll continue to look at that, probably more on those assets as you move those in. And as Ivan said, we're not yet ready to say whether or not the Piceance will fit in there. But as we define it and we get a better understanding of it, it certainly could be one of those that you would move in to backfill as other assets in your cost-of-service gas program start to deplete and decline.

Jerome Nichols: Right. We want to cut questions off right now so we can get Tony in, and then leave us about 10 or 15 minutes at the end, and then we'll take additional questions at that time.

So the last section today is our financial strategy, and that will be with Tony Cleberg, our Executive Vice President and Chief Financial Officer.

Tony Cleberg: Well, welcome, and thank you for taking the time to learn more about Black Hills Corp. Many of you are very familiar with our business strategies and our financial strategies. But today what we've done so far is we've updated you on key things in our strategies that we feel are really important. You've heard about the actions that we are employing, and you've also heard about the priorities that we see to line up on these opportunities.

All of this impacts how we allocate capital. And as you know, it's important to align the financial strategies, including capital allocation, with your business strategies to achieve the results that benefit both the customers and the shareholders. By aligning strong, supportive financial strategies, we've achieved consistent, double-digit earnings growth over the last several years. We believe the strategies that have been presented today give us the opportunity to continue to deliver that kind of growth in the future.

If you look at our financial profile on Slide 14 (104), there are several key points here. The market data on the chart is as of September 19, but based on last Friday's stock price, our market cap is $2.2 billion, so our total capitalization enterprise value is $3.7 billion. Our valuation on an EBITDA multiple basis is 9.0. And as you know, our oil and gas segment, right today, is not contributing much EBITDA to the total corporation.

So if you compare just our utility and our utility-aligned businesses, you will see that the valuation on the EBITDA basis is dead average. I guess my belief, based on our historical performance and also the upsides that we have in the various growth objectives, I'm not sure that we should be average. But that is the way it is today.

On the right side of this slide, you'll see that we have $3.2 billion in assets in our utilities and a total of $4 billion. And you'll notice that 85% of our operating income is generated by our utilities. In addition, our coal mine and power generation, which directly support our utilities, make up a substantial portion of our non-regulated business. And this is supporting our strategy of being a utility-centered company.

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So with the profile, let's move to the financial strategy and describe how we're leveraging our assets and using our cash to grow our businesses. On Slide 105, if you look at our overriding goal here, we want to be in the top quartile of our peers for shareholder return for each three-year period. This is a challenging goal, because our peer group continues to outperform the UTY index by a substantial margin. But it is a goal that our top leadership are incentivized on. And although our earnings--so for the first two periods of the three periods that we have, we're tracking for that being in the top quartile of performance.

But as you look at 2014, even though year over year through June, our earnings were up 19% over the previous period, we're way behind our peers in terms of performance. But we believe that we've got over two years left to get this back into the first quartile. And what we talked about today from a growth perspective and the actions that we're taking, we believe that we have a really good chance of getting back there.

Now, if you look at the rest of these strategies, these are various strategic thrusts that we have, and they're about the same as last year. We've continued to make progress in all of these areas, growing rate base, receiving upgrades from BBB to BBB+ equivalent from two of the rating agencies.

And the other item I'm excited about is the continued development of our oil and gas business, both from the existing program to prove out the Mancos Shale, but also the cost-of-service gas approach.

If you think about oil and gas businesses, they have a much higher cost of capital than does utilities. This is driven by the price risk, by the exploration risk, and other factors. This requires a higher need for equity in that type of business. So if you're able to supply gas under a long-term contract on a cost-plus basis, you're probably not going to get the low cost of capital as low as a gas LDC. But you're going to be much closer to that than to an oil and gas business. So we really feel that this offers us an opportunity to earn superior returns while helping our customers get the volatility out of natural gas prices.

So let me move to Slide 106, which overviews our capital investment. If you compare where we expect to allocate capital over the next several years, and you look at it over the last five years, from a percentage standpoint, we're allocating about the same percentage to our utilities as we have spent in the last five years. And we're allocating more capital, because if you look at that average spend rate, we're up about 5% in the next three years, 2014 through 2016, compared to where we were in the last five years.

So this offers us good growth, and what we have done is we have, as I mentioned earlier, we've updated our second quarter forecast for capital spend, and we lowered our estimate for 2014 and increased our estimate for 2015 and 2016. If you look at 2015, it's more of a push from 2014 to 2015. But in 2016, that's an actual increase, and that's primarily because we just have more insight into capital opportunities as we get closer to the year. Thank you.

So in the next one, moving to Slide 108, you can see we've continued to outspend our DD&A rate over the last four years. A sub-goal that we've talked about in our oil and gas segment is the desire to be cash neutral in the 2016-2017 timeframe, and that is still an objective that we have. To accomplish this, we would consider a number of alternatives, including partnering to help fund the oil and gas segment investment needs.

Looking at Slide 109, our regulatory results, you can see that we've achieved--oh, one more slide. You can see that we've achieved reasonable results. We feel fortunate to have positive working relationships in all of our jurisdictions and believe that the results are fair. As you will note, our approved, authorized rate base is now $1.7 billion, which is $162 million more than when we met a year ago at this Analyst Day. Once we settle the South Dakota rate case, we expect to be at about $1.8 billion in rate base. And if you take a look at the compounded growth since 2010, that's almost 8% per year.

Slide 110 shows an estimated rate base at year end. One item that I have not seen discussed in the industry is the impact of the reversal of deferred income taxes in the out years. Although we are still depressing our rate base for net deferred tax liabilities, primarily as a result of the bonus depreciation, this is projected to start to reverse in about five years, when the net deferred tax liabilities decrease and it provides an increase to the rate base. As of the end of the second quarter, we had about $0.5 billion in deferred taxes, with most of that related to utilities.

Slide 111 overviews our pension strategy. Last year we spoke about our pension strategy, and some of you have asked the question about the impact of the new mortality tables for pension estimates. Well, we're not quite ready to give that estimate, but I thought it would be worthwhile to remind everyone what our pension strategy is.

By looking at what we implemented in 2012, we expect that the new mortality tables would impact us less than other industry players. That is, we implemented a soft freeze at the beginning of 2012, so only employees who are 45 years old and had 10 years of service would remain in our defined benefit pension plan. The rest of the employees moved to a defined contribution plan. In addition, we took a number of actions to achieve a more predictable, consistent pension expense which improves the recovery in our rates, and we implemented a glide path strategy to better match the asset classes to the liability needs. In other words, as our pension employees age, we are moving to more fixed income investments.

So how are we doing in funding? You can see that on Slide 112. And this slide compares our funding position compared to peers, and we are currently in the middle of the pack and have made good progress from 2012 to 2013 on our funding. That was primarily due to performance of the investment portfolio. We are careful on the contributions because there's nominal benefit once you reach 100% funding. So I think by taking actions early on the pension plan, we positioned ourselves to limit the exposure for large, unfunded pension liabilities and a volatile pension expense, which is influenced by year-end interest rates.

The next several slides show a number of financial metrics. On Slide 113, the left earnings chart shows our EBITDA. From 2009 to year-to-date June 2014, we've grown EBITDA at an annual compounded rate of 8.8%, and the growth rate out of our utilities was 9.2%. Our 2014 oil and gas EBITDA is about 53% of what it was in 2009, and that's primarily because we sold a portion of our Bakken assets here a few years ago.

On the right side of this chart, we show our return metrics. We've had a strong focus to get these metrics to more acceptable levels, and we are pleased with the progress that we've made. Year-to-date highlights have been positive. We've continued to make progress on various initiatives. The cold weather in the first quarter certainly helped our financial performance in the gas utilities.

Also, we've taken advantage of the low interest rate environment. Over the first six months, we had an improvement of $11 million in our interest expense for the same period in 2013. We also closed on selling the combustion turbine to the City of Gillette. This is a new approach for our non-regulated subsidiary, where we sell the asset but continue to operate and manage the energy resource, which provides an income stream without carrying the investment, so a real positive result there.

On the next couple of slides, we show the financing metrics. From the debt to cap standpoint, we feel we're in pretty good shape. Our credit metrics should continue to improve in the fourth quarter, with the in-service of Cheyenne Prairie Generating Station.

Looking at our credit ratings on Slide 115, we've been upgraded to an equivalent of BBB+ by two of the rating agencies in the last year, and we would hope that the other major rating agency would upgrade us. But as you know, it's much easier going down that it is coming back up, so a little bit slow there.

From a debt maturity standpoint, we don't have much debt. We have a $275 million term loan that will be coming due here. But other than that, we're in good shape and no debt due after that until 2020. So we feel good about the debt structure, and we feel good about the interest rates.

Dividend growth, we mentioned this before--44 years of consistent increases. The current yield as of last Friday was 3.2%. And this is a chart that we're very proud of. We've been achieving double-digit EPS growth, and it has allowed us to be in that first quartile of our peers of total shareholder return, and we've got it for a couple of the periods, and we're certainly working hard to get us to that third period, also.

And then just total cumulative shareholder returns--this shows our performance since the end of 2008. And as you can see, we've outperformed our peers, the S&P Utilities, and are in line with the S&P 500. However, as I mentioned, we've fallen off in the last three months, and we've lost ground. We are influenced by natural gas prices and interest rate sensitivity that the entire utility industry has. So we feel that we have to just work harder on cost, and we have to work harder on executing these growth opportunities that we've talked about today to continue delivering value, both for our customers and our shareholders. And we think these actions will get us back into that first quartile.

So thanks again for coming to hear about Black Hills, and we'll open it up for questions on my section or any of us.

Jerome Nichols: So any final questions, either on Tony's section or on anything that we've covered today? Chris?

Chris Turner: Hi. Chris Turner, JPMorgan. This is kind of for you, Tony, and maybe for Ivan as well. You alluded to the cap structure that might be authorized or allowed with the E&P rate basing. Could you give us a little bit more detail on what you're thinking there and preliminary discussions with regulators? And then also, overall your potential kind of willingness and need to do equity, given the E&P growth opportunities, even though there's a lot of questions that remain on how you're going to go about that?

Ivan Vancas: Well, Chris, the regulators certainly asked us what we were expecting in terms of a return, and indirectly, capital structure. I think that's driven by how we would look at the risk associated with a cost-of-service gas kind of program. You know, if you were to bookend it, on the one end, whatever expenses that you incur would be part of your cost-of-service gas formula, and whatever capital you invest, you would earn a return on. And that bookend has the customers paying for risk, but it's only paying for risk that's known or incurred.

The other end of the bookend would be for the shareholders to bear more of those risks, and I'm thinking like non-economic wells or in the event you would get a mechanical failure, as an example. But the shareholder would assume that risk, some or all, in which case we would expect a higher return and a different capital structure.

So how we work through that, I think, will determine where, between the utility bookend and an E&P bookend, we would fall. But as Tony said, the credit ratings agencies, as an example, even though it is very much a utility-like formula, wouldn't view that entity that we would create as strictly a utility, so it does bear some capital risk that a traditional utility would not have.

Tony Cleberg: So we would expect slightly higher returns than what we would earn on a gas LDC.

Ivan Vancas: Yes.

Tony Cleberg: But on the same token, we're not expecting--it all depends on how these agreements get finalized and how we get this model locked down, where we end up from a return expectation, because if we're--as Ivan said, if we're going to take on more risk, we have to get compensated. Our shareholders need to be compensated for that.

Ivan Vancas: And just as a follow-up, if you were to look at the companies that have implemented this successfully, you have bookend examples. Some receive a utility-like return and a recovery of costs; others get a much higher return and a much higher capital structure, but take on more of the risk.

Jerome Nichols: Mike?

Mike Worms: A question for John. In terms of Mancos development, is the infrastructure development going on in the Mancos in line currently with the production that is occurring in that area from Encana and Williams and some of the other players? Can you just kind of speak to is one ahead of the other at this point, or are we kind of matching infrastructure development with production?

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John Benton: So if you're referring to the infrastructure in terms of takeaway capacity in the overall Piceance?

Unidentified Participant: Yes.

John Benton: There's more than sufficient takeaway capacity now, because you've seen some decline in the production out of the Shallow Mesa Verde. The only company that's really active right now in Shallow Mesa Verde is WPX, so there is takeaway capacity between Williams Field Services and some of the other folks. And I think that the map that we put up there showed where our gas can go and how much of it is out there for takeaway capacity in the area. So I think we're in good shape there as that develops, to be able to get that gas to market.

Mike works: That's great. And then a question for Tony. As you go forward and potentially buy some additional gas fields, will that require any equity?

Nichols, Jerome 10/13/2014 12:44 PM
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Tony Cleberg: It depends. It depends on how big it is. Certainly, we haven't included the cost-of-service gas capital in our current capital estimates. So we'd have to take a look at that. This is--ideally, if we get this thing modeled correctly, I think the capital markets are very open, and I think the rating agencies will be very positive also.

Matt Barnett: Here's a question for John. In terms of the processing capability at Summit for the wells that are out there, when do you need to make a decision on expanding that? And does it align with the drill programs you've got now?

Nichols, Jerome 10/13/2014 12:45 PM
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John Benton: We're going to make it align with that drilling program that we have now. We currently have about 20 million cubic feet a day of processing capacity, so what we're going to do is continue to look at how we balance that with our well results. It's a bit of a balancing act, because it does take a while from once you make that commitment to expand it before it actually comes online. So we're doing the best we can to balance that with the wells as they come online.

Matt Barnett: When do you need to make an expansion decision?

Nichols, Jerome 10/13/2014 12:45 PM
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John Benton: At this point, I can't give you a specific date, because we want to see what these three wells that we're currently drilling, when they get completed, the next three that completed, probably some time after the first of the year, which is the next three Homer Deep wells. Let's say our first point where we're going to sit down and make an evaluation will probably be the second quarter of next year we'll make an evaluation. So do we need to accelerate that decision or can we slow it down a bit? So that probably doesn't give you the perfect answer, but I can't draw a line in the sand today and say, "This is when we make that decision on the expansion."

Matt Barnett: And then my second question is really a company-wide decision. I mean, you're very quickly becoming a confusing equity story, being a utility with an oil and gas operation that could have a value greater than the utility itself, yet you're also doing this cost-of-service plant, which creates a higher interdependency. So how are you going to explain that to the market, and how are you going to simplify the story as this moves along? Because, I mean, the last three months, your stock price has been down, and it's clearly relative to natural gas prices, which the market's clearly thinking of you as an oil and gas company in that sense.

Nichols, Jerome 10/13/2014 12:45 PM
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Tony Cleberg: I think one way we do that is in effect we make sure that the model that we build for cost-of-service gas is very similar to our coal mines and what we're doing there on a cost-plus basis, because I think our investors understand that. So that's one piece of it.

I think our strategy in our oil and gas business outside of cost-of-service gas hasn't really changed, from the standpoint that we want to develop our oil and gas business, but looking at cash flow and saying that we want to be cash neutral in that 2016-2017 timeframe, we will need somebody else to fund the capital if the Mancos is as successful as we think it might be.

Jerome Nichols: We'll take one more question, and then we're going to wrap it up.

Ivan: Let me, just a quick add to what Tony said. Cost-of-service gas is a utility program. There are two reasons why we're putting it in a non-regulated entity. One is there are certain tax efficiencies related to doing that. The second is we plan to have a long-term gas supply agreement or long-term hedge agreement between the utility and this entity that would flow through the purchased gas adjustment. So you've got contemporaneous recovery rather than dealing with regulatory lag. But it's really a utility program, and it expands the utility business.

Nichols, Jerome 10/13/2014 12:45 PM
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Jerome Nichols: One last question. Mike?

Mike Worms: Tony, I think the long-term objective is to limit non-regulated earnings to about 20% to 25% of the total. I'm just wondering if the Mancos development is such that it could potentially exceed that number by a significant amount. Is that strategy flexible, or is that a hard-core number and that you would then do other things to limit the non-regulated earnings coming through?

Nichols, Jerome 10/13/2014 12:46 PM
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Tony Cleberg: Well, it really gets back to sort of the cash flow question. If it's generating cash flow, positive cash flow, paying for its investments, we can continue to grow the oil and gas business. What we've talked about is we see a lot of room because it's producing no operating income today. Oil and gas, we could see producing 20% of our operating income. And we would probably keep it limited to that amount, because we've spent a long time trying to become utility-centered. We're excited about the cost-of-service gas, because it really does link all of our segments together from a strategy standpoint. And another reason just for cost-of-service gas, if you think about it, acquisitions going for two times rate base, and here we're talking about getting recovery and earning on every single dollar we put into it. It's a much better deal, and that's why we're excited.

Jerome Nichols: All right. That will be the end of our Q&A, so we're concluded for the day. I'm going to turn it over to Linn Evans for concluding remarks for our 2014 Analyst Day.

Linn Evans: My remarks will be extremely brief. I say thank you for being here, thank you for your time this afternoon, and we appreciate those who are on the webcast, and we look forward to our social event this evening. Thank you.