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P: Mathew Barnett;Jet Capital;Analyst

+++ presentation
Operator^ Good day, ladies and gentlemen. And welcome to the Black Hills Corporation 2013 fourth-quarter and full-year earnings conference call. My name is Esteban, and I will be your coordinator for today.

(Operator Instructions)

As a reminder, this conference is being recorded for replay purposes.

I would now like to turn the presentation over to Mr. Jerome Nichols, Director of Investor Relations of Black Hills Corporation. Please proceed, sir.

Jerome Nichols^ Thank you, Esteban.

Good morning, everyone, and welcome to the Black Hills Corporation 2013 fourth-quarter and full-year earnings call. With me today are David Emery, Chairman, President and Chief Executive Officer; and Tony Cleberg, Executive Vice President and Chief Financial Officer.

Before I turn over the call, I need to remind you that during the course of this call, some of the comments we make may contain forward-looking statements as defined by the Securities and Exchange Commission, and there are a number of uncertainties inherent in such comments. Although we believe that our expectations and beliefs are based on reasonable assumptions, actual results may differ materially.

We direct you to our earnings release, slide 2 of the Investor Presentation on our website, and our most recent Form 10-K and Form 10-Q filed with the Securities and Exchange Commission for a list of some of the factors that could cause future results to differ materially from our expectations.

I will now turn the call over to David Emery.

David Emery^ Thank you, Jerome. Good morning, everyone.

On slide 3 of the webcast presentation, for those of you who are following along, our format will be similar to prior quarters. I'll give an update on the quarter and the year from a highlight perspective. Tony

Cleberg will go through the financials, and then I'll talk about the forward-looking strategic overview.

Skipping to slide 5 -- fourth-quarter highlights. From a business environment perspective, we had colder weather in the quarter, both compared to last year and even compared to normal. While the cold weather certainly is good for our utility businesses, it does create some challenges in some of our other subsidiaries. For example, it slows down things like drilling and completion and connecting new wells in our oil and gas subsidiary, and things like that. But overall, a very positive impact of the weather for the quarter.

Highlights on the utilities side -- Black Hills Power, here, just a couple weeks ago, filed a request with the Wyoming Public Service Commission to increase our electric revenue in Wyoming from Wyoming customers, primarily related to the Cheyenne Prairie Generating Station. Black Hills Power also plans to file a case later this quarter with the South Dakota PUC. That case will also be related to the Cheyenne Prairie Generating Station.

In early January, Black Hills Power also received an accounting order from the South Dakota PUC, basically allowing restoration costs from a severe October blizzard that we had here in the Black Hills, to be classified as regulatory asset. That's until we apply for our next general rate case, at which we'll propose amortizing those costs.

Really, there's only several million dollars worth of incremental O&M there, and all of those have been recorded as a regulatory asset. We also have a few million in incremental capital from the storm. That, obviously, will also just be dealt with in our next general rate case -- which, as I said before, we're going to be filing here by the end of the quarter.

Cheyenne Light, in early December, filed a request with the Wyoming PSC, also related primarily to the Cheyenne Prairie Generating Station. But we also filed a small gas case for Cheyenne as well.

In Colorado, we received the Colorado PUC's initial written decision related to our electric resource plan there. That decision approved a settlement agreement for the construction of a 40-megawatt gas-fired turbine at our Pueblo Airport Generating Station. That decision is still appealable; we don't yet have the final written order. So until we do, it's not completely final. But we would plan on -- and have already, at least, commenced air permitting activities and some other things related to that facility.

Moving on to slide 6 -- a continuation of the highlights. During the quarter -- and actually, all year -- we continued our efforts to acquire small utilities, primarily municipals, near our existing service territories. And we were successful in doing several of those during the year, adding about 900 customers. And then, in January of this year, we announced a small gas LDC acquisition in northeastern Wyoming, adding another 400 customers. Not a huge needle mover, but great acquisitions, nonetheless. They're very easy to integrate and operate.

On the oil and gas side, we completed two horizontal Mancos Shale wells in the Piceance Basin. One of those wells was placed on production in late December, and the second well in late January. If you recall, those two wells were part of a transaction where, by drilling and completing them, we earned 20,000 acres of additional leasehold in the Piceance Basin. And that's been done.

Those wells are coming on a little slower than planned because Summit, who is our gas gatherer in the area, has not yet completed their new gas processing plant. And so we are a little rate-restricted there. But both wells are on and producing.

As a reminder, we do have a confidentiality agreement in place related to that transaction, which really restricts our ability to disclose, certainly, terms of the transaction itself and individual details on individual wells, including things like specific production rates and whatnot.

Moving on to the corporate side. Last week, our Board approved a dividend increase for the 44th consecutive year, increasing our quarterly dividend to $0.39 a share, which is an equivalent to an annual rate of $1.56. That's $0.04 above last year's number on an annual basis. And then last week, Moody's raised our corporate credit rating to Baa1, which is the second upgrade we received from Moody's in the past year.

On November 19, we completed our largest public debt offering. We issued $525 million of 4.25% 10-year notes. We used that to retire some higher-cost debt, settle some interest rates loss, and pay down our general corporate borrowing.

Moving onto slide 7. From a financial perspective for the quarter, we earned $0.70 a share, as adjusted, compared to $0.68 per share in the fourth quarter of 2012.

On slide 8, the full-year financial highlights. Our EPS, as adjusted, was $2.45, compared to $2.09 in 2012, which is a 17% growth rate, year over year. The $2.45 figure exceeds the top end of our previously-issued guidance, the top of which was $2.40, primarily as a result of a pretty cold late fourth quarter -- December, in particular.

Slide 9 provides a reconciliation of the fourth quarter of 2013 earnings from continuing operations, as adjusted, and reconciled that to the fourth quarter of 2013 results. Pretty minor variances between the entities. A little lesser performance in a couple of he businesses and a little stronger on the corporate side, primarily related to some of our financing activity.

On slide 10, the reconciliation of the full-year 2012 to full-year 2013 continuing operations as adjusted. Improvements in gas utilities, power generation, coal mining, and certainly on the corporate side related to the financing activities. And those were partially offset by slight declines in electric utilities and oil and gas.

Now I'll turn it over to Tony Cleberg, our Chief Financial Officer, for the financial update. Tony?

Tony Cleberg^ Thank you, Dave. Good morning.

As Dave described, we're very pleased with our fourth-quarter and our full-year performance. Compared to 2012, our earnings from continuing ops, as adjusted, grew [3]% for the quarter, and 17% for the full-year. You may recall, our Q4 earnings in 2012 improved 48% over the fourth quarter of 2011, so we were encouraged by another increase in this quarter.

For the full year, our earnings exceeded our upper end of the range. As Dave mentioned, that -- it was primarily driven by weather. And specifically -- more specifically -- a very cold December.

Moving to slide 12. We report GAAP earnings and reconcile to earnings as adjusted -- a non-GAAP measure. We do this each quarter to isolate special items and communicate earnings that better indicates our ongoing performance. This slide displays our last 5 quarters and the full-year.

During the fourth quarter of 2013, we had three special items. The first special item was a reduction of $0.01, for a mark-to-market gain on $250 million worth of de-designated interest rate swaps. For the full year, the 2013 gain on those same swaps was $0.44, compared to $0.03 in 2012. As we announced in December, we settled these de-designated swaps once we completed the $525 million worth of financing.

The next two special items relate to financing activity in the fourth quarter. We calculated the impact of these items as if the financing had been completed on December 31 -- so the settlement costs, negative carry, and interest savings during the quarter were netted to calculate the impact of these special items.

The first special financing item was an addition of $0.15 for the settlement of swaps on project debt, and the write-off of related deferred finance fees in our power generation segment. We paid off this debt prior to maturity, to capture and overall interest rate savings.

The second special item, of $0.13, relates to redeeming $250 million of 9% notes, which were due May of 2014. We paid a make-whole premium, and wrote off deferred finance fees. The early redemption had a slight projected economic benefit. But more importantly, it positions us to report a clearer picture of our recurring earnings in 2014 and thereafter.

So considering these special items, Q4's EPS, as adjusted from continuing ops, was $0.70, compared to $0.68 in 2012. Our full-year continuing operations was $2.45, compared to $2.09, an improvement of 17%.

Slide 13 displays our fourth-quarter revenue and operating income. Later, I'll discuss major differences between the years. But here, the main point is that 88% of our operating income came from our electric and gas utilities in the fourth quarter.

Our operating income, as adjusted, declined $3 million during the quarter compared to 2012, which resulted from higher expenses, partially offset by margins. The higher expenses were driven by increased employee costs, due to cash and stock incentives. We had a very good year.

Moving to the full year -- slide 14 -- revenue increased by $102 million, reflecting higher volumes and higher gas prices in our gas utilities. The better rates was slightly higher megawatts in our electric utilities. This was partially offset by lower production in our oil and gas segment.

Operating income, as adjusted, improved 4% compared to 2012, with increases in power generation, utilities, and coal mining. oil and gas declined by $5.6 million, due primarily to the sale of the Williston Basin assets in 2012.

Slide 15 displays our income statement for the fourth quarter and the full year. Some noteworthy changes includes increases in our operating expenses in 2013. Three factors accounted for almost all of the increase.

First, 2012 expenses were lower because of an aggressive cost containment initiative implemented to offset earnings shortfalls in 2012, which were caused by very mild weather in the first quarter. The second -- our variable compensation, which is aligned with shareholder interests, increased substantially in 2013, due to strong performance and stock price appreciation.

The last factor was a general increase of about 2 1/2%. So, we remain diligent in managing our overall cost structure. On later slides, I will discuss operating income in more detail.

Moving down to interest expense, you'll note a reduction, compared to 2012, of $3.6 million during the quarter. And $14.8 million for the full year. The reduced interest expense reflects lower rates and lower average outstanding debt in 2013, compared to 2012.

In the fourth quarter, we completed a number of financing transactions. After we issued $525 million in 10-year, 4 1/4% notes, we called the $250 million of 9% notes, which were due May 15, 2014. We paid off project debt related to non-regulated assets, and settled $250 million of de-designated swaps, for $64 million.

Going forward, these actions should result in a substantial interest savings. As you may recall, we used the proceeds from our Williston Basin sale to redeem $225 million of 6 1/2% notes in the fourth quarter of 2012. And paid a make-whole premium.

Continuing down the income statement, the effective income tax rate in the fourth quarter, compared to the prior year, was about the same -- at 37%. For the full year, both 2012 and 2013, we had an effective tax rate of 35%.

The last noteworthy item was our EBITDA. During the quarter, we produced $107 million of EBITDA, as adjusted, which is about flat compared to

2012. For the full year 2013, our EBITDA declined slightly to $399 million. Our oil and gas segment EBITDA declined by $22.4 million in 2013 -- primarily due to selling the Williston Basin assets in 2012. Improvements in other segments offset the oil and gas decline.

Discontinued operations relate to the divestiture of our energy marketing business in the first quarter of 2012. During the quarter, we recorded a charge for a final purchase price adjustment.

Moving to slide 16, we display our electric utility segment's revenue and operating income. The electric utility revenue increased in the fourth quarter by $10 million from 2012. This was driven by weather and rate increases, including riders. Megawatt usage increased 4% in Q4, compared to 2012.

Our operating income as adjusted declined by $4.8 million during the quarter compared to 2012. The decline reflects higher expenses, and 2012 included the receipt of $2.1 million of a construction bonus. The higher expenses were primarily for employee costs, vegetation management, and property taxes.

For the full year, revenue increased about $38 million, primarily due to pass-through purchase power costs and rate cases. Operating income was flat, with increased margins offset by increased expenses.

Moving to slide 17 -- gas utilities revenue increased $26 million in the fourth quarter, driven by 15% higher heating degree days and a 7% higher gas price. The operating income improved $2.5 million, or by 10%, in the fourth quarter, compared to 2012. Q4 retail and commercial dekatherms sold increased about 19% year over year. And the Q4 O&M expenses were slightly higher, primarily for employee costs, compared to 2012.

For the full year, the colder weather was primarily the driver of the $9.6 million improvement in operating income. As you may recall, 2012 had an extremely mild winter in our gas states. For our gas utilities, the heating degree days in 2013 were 9% higher than the normal 30-year average, while 2012 were 13% lower than the 30-year average. So, if you think about the weather impact for the combined Electric and Gas Utilities, it was a strong positive for both the quarter and the full year.

The next segment, power generation -- operating income had a slight decrease in Q4, primarily due to scheduled maintenance outages. For the full year, operating income improved $2.2 million, due to higher off-system sales margins. This segment performed slightly better than expected.

Moving to coal mining on slide 19. We saw operating income in Q4 decline by $600,000 from 2012. This was primarily driven by a power plant outage at our major customer. With the continued progress in reducing our mining costs and executing our revised mine plan, which lowered our stripping ratio in Q4 to [0.5], compared to [1.5] in 2012. For the full-year, the operating income improved by $3.2 million, compared to 2012. We have a price reopener with our major customer, and we should see better margins starting in Q3 of 2014 in this segment.

Slide 20 is our oil and gas. And here, we had a transitioning year after selling our largest oil-producing properties in the Williston Basin. Overall, fourth quarter production increased 11 1/2% from 2012, driven by an 8 1/2% increase in natural gas, and a 20% increase in oil.

From a pricing received standpoint, the oil decreased by 13%, and the natural gas price decreased by 20% in the quarter. From a cost perspective, our O&M expenses decreased by $500,000 compared to 2012. So we continue to see good cost management.

Depletion increased in Q4 by $1.3 million, compared to 2012. And this was really driven by higher production and higher depletion rate, due to the impact of having oil wells. Sequentially, our Q3 production declined -- or sequentially from Q3, our production declined by 2%, due primarily just because of normal declines in our gas wells, partially offset by a 6 1/2% increase in our oil production. With the recently completed Mancos wells, we expect production to increase in Q1, compared to the fourth quarter.

For the full year, production declined by 24%, driven by the sale of the Williston Basin assets. Prices received for oil increased by 7%, and natural gas declined by 19%. The depletion rate for 2013 was $1.83 per MMcfe, compared to $2.87 in 2012.

Slide 21 provides an estimated rate base at year end. For 2013, we were flat with 2012, at $1.7 billion. The capital additions, excluding Cheyenne Prairie, were offset by increases in depreciation and deferred income taxes. We expect Cheyenne Prairie Generation Station to be included in rate base October 1, 2014.

Moving to our capital structure on slide 22 -- this shows our current capitalization. At year-end, our net debt-to-capitalization ratio was 52.9%, an increase from 2012, yet low enough to fund our capital program. With the $525 million, 10-year note issuance in November, we now have over 90% of our debt as long-term.

As Dave mentioned, we were upgraded last week by Moody's to Baa1, which was the second upgrade in less than a year. Just as a reminder -- in 2013, we were upgraded to BBB flat with S&P and Fitch. And Fitch also has us on positive outlook.

In the press release, we reaffirmed our 2014 earnings guidance in the range of $2.50 to $2.70. This is for EPS, as adjusted, and excludes special items. There is a slide in the appendix that lists the primary assumptions regarding our 2014 earnings guidance that we made in November. Overall, we expect improvement in the operating income over 2013. And a notable reduction in our interest expense, which contributes to the improved EPS for 2014.

On slide 24 -- to conclude, we've achieved strong performance for both the fourth quarter and the full year. And we're really proud of our improving financial performance over the last five years. And we really look forward to the continuing growth in our utilities -- and capturing the value of the Mancos Shale properties.

With those comments, I will turn it back to Dave.

David Emery^ Thank you, Tony.

Moving on to slide 26, strategic objectives. Consistent with our prior quarters, we have five major strategic objectives, all of which are focused primarily on being an industry leader in everything we do. We want to be a leader in operational performance; earnings growth; earnings upside opportunities; and, certainly, our track record of 44 consecutive annual dividend increases.

We also plan to maintain our minimum BBB-equivalent unsecured credit rating. As you may recall, that was an objective, to achieve a BBB credit rating. And that's a goal we met this calendar year -- or last calendar year, 2013.

Slide 27 exhibits exceptional performance, relative to our peers, in safety, reliability, and several other utility efficiency measures.

On slide 28, you can see our superior plant availability and starting reliability. Slide also demonstrates that we have a very modern generation fleet -- it's very new -- and that our power plant construction safety record is great. Related to the power plant availability and starting reliability -- I mean, those are key from a customer perspective. And that we're able to better utilize our generation assets, which saves customers money in the long term.

Slide 29 illustrates our generation by fuel type and further demonstrates the ongoing modernization of our fleet as we continue to add new resources and have now retired -- or are in the process of retiring -- a couple of our older, both gas-fired and coal-fired plants.

Slide 30 -- related to earnings growth, Tony talked about our 5-year trend. We expect continued strong earnings growth, driven primarily by capital spending to meet customer needs in our utilities. And also to grow our non-regulated energy businesses. Capital spending is projected to be far in excess of depreciation.

Slide 31 provides a little more detail on historical and projected capital spending. And it's broken out there by business segment. For our electric utility, we actually break it out a little bit further for generation, transmission, and other.

Slide 32 is a subset of slide 31, providing a little more detail for select major utility projects, some of which even extend beyond the 2016 year, which is the final year that we disclose specific capital totals for the Corporation.

On slide 33, helping drive earnings growth -- strong earnings growth in the next couple years -- is our Cheyenne Prairie Generating Station. As

Tony said, you know, it's a $222 million,132-megawatt plant. And it's jointly owned by two of our subsidiaries -- Black Hills Power and Cheyenne Light. That project is on time, and on budget to be in service by October of this year.

Most of the contracts have been awarded, so we're pretty firm on our cost target there and feel real good about where we are at -- making excellent progress. And also, with a very good safety record. We've only had one safety incident to date on the site.

Slides 34 through slide 36 provide a regulatory update summary for our utilities. Most of these, I covered in the highlights, so I won't repeat them here. On slide 34, it does talk a little bit more about our plans at Black Hills Power to file our rate case in South Dakota, related primarily to that Cheyenne Prairie Generating Station. With the intent of those rates being effective with the plant in-service date in October.

On slide 35, near the top -- we talked about this last year, but we're continuing to evaluate the timing for Cheyenne Light to exercise its option to acquire the Wygen 1 coal-fired power plant. As we've stated previously, we intend to exercise that option when the impact will be neutral to Cheyenne's customers. We are continuing to evaluate the timing of that. This quarter, we've at least included some numbers that help you come to purchase price and current book value of the facility.

Skipping to slide 37, from a value upside perspective, we remain very focused on our oil and gas assets. We plan to prove up and capture the substantial value of our existing oil and gas properties. And also continue to pursue disciplined oil exploration projects, primarily in place with impactful reserve potential.

For 2014 -- our drilling program -- we intend to drill and complete up to 6 horizontal wells in the Mancos Shale and the Piceance Basin. And then continue our selective oil well exploration program as well.

Moving onto slide 38 -- as we've said previously, our oil and gas leases -- existing leases -- in the San Juan and Piceance Basins have net resource potential, to our interest, in excess of 2 trillion cubic feet of natural gas. It's noteworthy that we have not updated the tables on this slide to include results of the wells that we drilled in 2013, due primarily to the confidentiality agreement that I mentioned earlier.

We also have not included that additional 20,000 acres in this table, as far as potential, as well. We have earned the 20,000 acres, and they are part of our total. We just haven't updated the numbers to include those -- again, based on the confidentiality agreement we have in place.

On slide 39 -- also, as noted earlier, during the year, we met our goal of achieving the BBB equivalent or better credit rating from all three credit agencies. Very substantial step, as Tony said, based on the improvement in our financial condition over the last several years. We're pleased that all three rating agencies recognized our performance on the financial side.

In slide 40, as I already noted, we're very proud of our dividend track record, increasing our dividend -- annual dividend -- to shareholders for 44 consecutive years. One of the longest streaks in the utility industry, and one we're quite proud of.

On slide 41 -- this is our 2013 scorecard. And as you know, this is something we've been doing for several years. At the beginning of the year, we set out our goals and objectives for the year -- key strategic goals and objectives -- and then show you the progress that we made throughout the year. Slide 41 illustrates the great progress we made in 2013 towards our key objectives -- essentially accomplishing all of what we set out to do for the year.

And then, finally, slide 42 is the goals and objectives for 2014, which sets forth our plans for the year. And you'll be able to monitor our progress, quarter to quarter, as we go through the year.

That concludes our prepared remarks. We will be happy to open up the lines for questions if anyone has any.

+++ q-and-a
Operator^ (Operator Instructions)

It looks like our first question comes from Kevin Cole with Credit Suisse.

Kevin Cole^ Good morning.

David Emery^ Good morning, Kevin.

Kevin Cole^ I was just trying to reconcile the rate base slides -- slide 21. It looks like, in 2013, your rate base fell. And if I just compare that versus your slide 30, where you have the CapEx versus depreciation, your rate base should have increased. Is this rate base number just the summation of all prior approved rate bases? And not necessarily the hypothetical rate base that it should be today?

Tony Cleberg^ What we're trying to estimate, Kevin, is what our rate base is as of the end of 2013, on that slide. It certainly doesn't include all the capital expenditures on Cheyenne Prairie, and some of the things that still have to go into rate base from that standpoint. But we do have some movement on the deferred taxes.

As you know, with all utilities, we really enjoyed large deferred taxes on the -- because of the bonus depreciation. And so, we're getting some movement in that, which partially offsets some of the increase for the capital expenditures.

Kevin Cole^ Okay. And so, should we expect rate base to fall into 2014 or (multiple speakers)?

Tony Cleberg^ You should not.

Kevin Cole^ Or once you get Cheyenne Prairie in service, it should -- then you get the full true-up for Cheyenne Prairie?

Tony Cleberg^ Right. That's right.

Kevin Cole^ Okay.

Tony Cleberg^ So, as always, things get a little lumpy with [this function] (multiple speakers).

Kevin Cole^ Okay. And I guess, with E&P -- so, on the Summit project, what was the cause of the delay? And when is it expected to be up and going at full capacity?

David Emery^ Yes. They were originally planning on being on late last year. And weather and construction delays and other things related to their plant construction have delayed that. That facility is still not yet producing. We hope that it will be producing here -- literally -- any day. But it's restricting the wells' output on the two new wells we put on, because we don't have the take-away capacity without the plant.

So, we're producing the wells. We're cleaning them up after the frac and completion. But we're certainly not producing them at anywhere near full rate, right now, because the plant is not yet completed.

Kevin Cole^ The Summit project should be completed by the time you get your six other wells done this year?

David Emery^ I certainly hope it doesn't take that long. We won't start drilling until Spring. It certainly should be done -- really, should be done now -- hopefully, will be done at least this month, if not sooner.

Kevin Cole^ Okay. And then on the additional 20,000 acres that you earned, is there a requirement for you to have an active drilling program on that acreage to keep it?

David Emery^ There's some minimal requirements, Kevin, but nothing major.

Kevin Cole^ Okay. And then, I guess -- sorry -- last question then on slide 38. Is the 6 to 8 Bcf-per-well assumption still at the right number?

David Emery^ Well, based on a 4,000 to 5,000 foot lateral, it is. You know, we drilled these more recent wells with longer laterals. And, as I said, we can't disclose individual well results.

We can't provide an update, really, to that slide until we can publicly disclose the results of those reserves. But with longer laterals, you would typically expect higher reserve numbers per well.

Kevin Cole^ Can you remind me, then, when the confidentiality agreement ends? Or when your six wells you're going to drill -- outside of that confidentiality agreement -- will come online?

David Emery^ Well, the confidentiality agreement -- and I'm not 100% sure of this, Kevin -- but I believe it's at least six months from the date of first production on those wells. So, you know, you're looking at mid-year -- at a minimum -- for the CA. And it could be longer.

And then, the other wells -- basically, our intent would be to start drilling those in the Spring. Some of the areas, we've got wildlife restrictions and other things that preclude us from commencing drilling until April or May -- maybe even a little later than that. And then, that's somewhat weather dependent. If they have a really wet Spring, we'll probably wait until the mud goes away before we move in.

And then, it takes a month plus -- month and a half -- per well, to drill. And then several more weeks to complete. We would just plan on doing a pretty continuous -- pretty continuous activity.

But we will be drilling several wells from a single pad. So, when you do that, you drill for a few months, and then you move your drilling rig. And you complete all the wells at the same time. And so, you don't see production coming on one well at a time, which will delay production probably until, at least, mid- to late-third quarter before you see any new production, possibly later than that.

Kevin Cole^ Okay. That's helpful.

And then, sorry, one last question. Are you -- given you rolled forward the CapEx plan, do you still expect to be equity-free through this 2016 planning period?

Tony Cleberg^ Yes.

Kevin Cole^ Okay.

David Emery^ We'll make a statement to that effect in the 10-K that will come out here, soon.

Kevin Cole^ Thank you very much.

David Emery^ You bet. Thank you.

Operator^ Our next question comes from Eli Kraicer with Millennium.

Jeff Gildersleeve^ Hi, it's Jeff Gildersleeve. How are you?

David Emery^ Hello, Jeff. How are you?

Jeff Gildersleeve^ Good morning. Thanks.

I just wanted to look at slide 59 -- your guidance assumptions. For the commodity, you have NYMEX gas at $3.70, and well-head of $2.37. We've seen a lot of volatility, so I just wanted to get your perspective on those assumptions.

David Emery^ Yes. I mean, as Tony said, those are the assumptions we had when we put out our guidance on November 5. And we don't update those, typically, during the year, unless there's some major change.

Things are always moving one way or the other. We talked a little bit about, for example, the Summit plant being a little slower, and some of those. So, we don't typically update our guidance for price movements unless we see we've got actual earnings in -- related to that price increase -- then we do.

We hedge a fair amount of our gas and oil.

Jeff Gildersleeve^ Right.

David Emery^ And so, there's not a lot of incremental production, except new production that comes on, that is unhedged, typically. So, we end up hedging two-thirds number of our total production.

Jeff Gildersleeve^ Okay. Yes, because, I mean, I think the 2014 strip's like $4.60. And then, when you look at the -- your gas hubs out there, can you just remind us what hubs in the Piceance and San Juan that you're going into?

David Emery^ Well, in the San Juan, we're typically at San Juan. And then, depending on where the gas is in the northern Rockies, it's northwest Rockies, typically.

Jeff Gildersleeve^ Okay. Yes, because there's -- okay -- there's been a lot of spot volatility. As you said, you're hedged a lot, and the excess gas hasn't come on. But there's some pretty extreme prices out there now. You said you are at two-thirds hedged on your production?

Tony Cleberg^ Or more.

David Emery^ And we disclose our specific hedges, you know, in the K, Jeff.

Jeff Gildersleeve^ Right.

David Emery^ So, it's pretty easy to figure out the total hedged volume, when you see the K.

Jeff Gildersleeve^ Okay. But you wouldn't typically update your assumptions if they changed throughout the year, or --

David Emery^ No. Not unless -- if we were to raise guidance driven by, say, just pure price increase or something, we might change that assumption.

Jeff Gildersleeve^ Okay.

David Emery^ But typically, we leave our assumptions the same unless there's something that leads us to raise our guidance. And then we typically would revise at least a few of the assumptions.

Jeff Gildersleeve^ Right. Great. Thank you.

David Emery^ You bet. Thank you.

Jeff Gildersleeve^ Thank you very much.

Operator^ Our next question comes from Shelby Tucker with RBC Capital Markets.

Shelby Tucker^ Good morning. In your conversations with Commissioners, do you have any updates on the idea of rate basing natural gas reserves, similar to what you see in Utah?

David Emery^ No. That's something that we know others are doing. And certainly, it's something that we've at least contemplated, but haven't really had any substantive discussions -- certainly with Commissions related to that. It's something that's certainly intriguing to us -- with the natural gas holdings we have -- but we really haven't gone a whole lot further than that at this point, Shelby.

Shelby Tucker^ Great. Thanks.

David Emery^ You bet.

Operator^ (Operator Instructions)

Our next question comes from Mathew Barnett with Jet Capital.

Mathew Barnett^ Hi. Could you just remind us of the size of the gas processing plant with Summit? And whether or not that size is meant to satisfy the two wells being drilled, or the entire drilling program?

David Emery^ Well, it's not going to satisfy the entire drilling program. It will certainly help.

But the way that plant's designed is -- it's designed to be brought on in 20-million-cubic-feet-a-day increments. And so, they'll build it, basically, 20 million cubic feet of capacity at a time, based upon our request. And then the first phase is going to be 20 million a day, and that's the phase we're waiting for.

Mathew Barnett^ Great. Thank you very much.

David Emery^ You bet. Thank you.

Operator^ There are no more questions in queue. I would now like to turn the call back to David Emery. Please proceed.

David Emery^ All right, thank you. Well, thank you, everyone, for joining us this morning. We very much appreciate your time and your continued interest in Black Hills.

We're very excited about our performance in 2013, and expect good, continued growth going into 2014 as well. So, thank you. Have a great day and a good weekend.

Operator^ Thank you for your participation in today's conference. This concludes the presentation. You may now disconnect. Have a good day.