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PRESENTATION

Operator

Good morning. My name is Mike (phon), and I will be your conference Operator today. At this time, I would like to welcome everyone to the Enerplus Corporation 2014 Third Quarter Results Conference Call.

All lines have been placed on mute to prevent any background noise. After the speakers' remarks, there will be a question-and-answer session. If you would like to ask a question during this time, press *, then the number 1 on your telephone keypad. If you would like to withdraw your question, press the # key.

I will now turn the call over to Jo-Anne Caza, Vice President, Corporate and Investor Relations. You may begin your conference.

Jo-Anne Caza — Vice President, Corporate & Investor Relations, Enerplus Corporation

Thank you, Operator, and good morning, everyone. Thanks for calling in.

Ian Dundas, our President and Chief Executive Officer, will be providing an overview of our third quarter results, which we released this morning. In addition, Ray Daniels, Senior Vice President of Operations, will also give some additional detail on our capital spending and operational performance in the quarter; Eric Le Dain, Senior Vice President of Corporate Development, Commercial, will be giving some colour on our marketing and hedging activity; and we also have Rob Waters, Senior Vice President and Chief Financial Officer, on the call with us today.

Our financials have been prepared in accordance with United States generally accepted accounting principles. All discussion of production volumes are on a gross company working interest basis, and all financial figures are in Canadian dollars unless otherwise specified.

Conversions of natural gas to barrels of oil equivalent are done on a 6:1 energy equivalent conversion ratio, which does not represent the current value equivalent.

The information we're discussing today contains forward-looking information. Listeners are asked to review our advisory on forward-looking information to better understand the risks and limitations of this type of information.

This advisory can be found at the end of our news release issued this morning and included within our MD&A and financial statements filed on SEDAR and EDGAR, and available on our website at www.enerplus.com

Following our discussion, we'll open up the phone lines and answer questions you may have, and we'll also have a replay of this call available later today on our website.

With that, I'll turn the call over to Ian.

Ian Dundas — President and Chief Executive Officer, Enerplus Corporation

Good morning, everyone, and thanks for joining us today. Our results released this morning demonstrate another quarter of consistent operational performance, execution of our noncore divestment strategy, and it highlights our strong financial position.

Daily production averaged 104,000 BOE a day, essentially unchanged from the second quarter, but nearly a 20 percent increase from the same period in 2013. This is despite the curtailment of 3,000 to 4,000 BOE a day of natural gas from the Marcellus caused by low natural gas prices and pipeline maintenance in the third quarter.

Crude oil and natural gas liquid volumes were up again this quarter, averaging 44,200 barrels per day. We continue to see strong performance from our Bakken/Three Forks activity in North Dakota. Natural gas volumes were flat quarter over quarter at approximately 360 million a day despite the curtailments.

Although commodity prices weakened in the third quarter, funds flow from operations was maintained quarter over quarter at $213 million, or $1.04 per share.

A drop in our cash share-based compensation expense, along with our hedging program, helped to keep funds flow flat quarter over quarter.

We continue to advance on our noncore divestment program through two transactions, one that closed September 30th, and the other, which closed in early November. We've sold approximately 3,100 BOE per day of nonoperated primarily natural gas production. In total, we've generated about $91 million in proceeds.

As we mentioned last quarter, we are redeploying a portion of these proceeds. As a result, we're increasing our capital spending for 2013 modestly by $30 million to $830 million. We plan to accelerate some of our 2015 capital program into the fourth quarter of 2014 to advance activity in both the Wilrich and North Dakota.

Our divestment activities have also served to improve the focus within our portfolio and further strengthened our balance sheet. We ended the quarter with debt to trailing 12-month funds flow ratio of 1.3 times.

Operating costs increased in the quarter to $10.67 per BOE due to production curtailments on our lower operating-cost Marcellus properties, along with seasonal well servicing, repairs, and maintenance. Curtailments will also have a modest impact on our annual operating cost guidance, which we are adjusting back to our original estimate for 2014 of $10.25 per BOE.

Cash G&A costs were flat quarter over quarter and continued to be in line with our expectations. Cash equity-based compensation costs are expected to decrease from $0.60 per BOE to $0.45 per BOE due to the drop in our share price.

I'll now pass the call over to Ray and Eric to provide some details on our operating activities and marketing.

Ray?

Ray Daniels — Senior Vice President, Operations, Enerplus Corporation

Thanks, Ian. As Ian mentioned, we delivered another solid quarter operationally with continued growth in liquids production. We invested a total of $208 million in development capital in the third quarter, drilling just over 19.3 net wells and bringing 17.3 net wells on stream.

The majority of our activity continued to be focused on oil projects, particularly in North Dakota, where we invested $96 million targeting both the Bakken and the Three Forks wells. We drilled 6.6 net wells with 5.6 net wells brought on stream.

We achieved another quarter of record production at Fort Berthold at about 22,400 barrels of oil equivalent per day, up almost 1,600 barrels of oil equivalent per day from our high in the second quarter.

Taking a look at our activity year to date, we continued to see very strong well performance. We've drilled a total of 19 wells with 13 wells brought on stream.

Our operated drilling activity has been focused in the central and northern half of our acreage. Overall, we're seeing higher initial production rates and shallower declines.

The 30-day initial production rates on our two-mile horizontal wells drilled in both the Bakken and Three Forks have averaged 1,725 barrels per day. This is about 20 percent above our highest tight well. We're also seeing shallower declines, as our 90-day initial production rates have averaged over 1,300 barrels a day, which is also about 20 percent higher than our high-end tight well.

These wells have been completed using about 1,000 pounds per foot of white sand with about 40 frac stages. Well costs year to date have trended about 5 percent higher than our budget due to the larger fracs, but the production increase of 20 percent more than offsets the additional cost and has driven further improvement in our capital efficiencies.

We have just fracked our largest pad to date, and commenced the flow-back process of the five wells. This pad includes two Bakken wells, two Three Forks first bench wells, and our second Three Fork second bench well. This will drive continued growth in fourth quarter. We currently have approximately eight operated wells awaiting completion.

While we have focused our drilling operations in the central and northern half of our acreage in 2014, we have participated in nonoperated wells in the southwest part of our lands. This includes a well offset in our operated lands that averaged over 1,800 barrels in the second month of its production; very encouraging results, given the acreage position we have in that area.

In total, our US oil assets in North Dakota and Montana produced nearly 28,000 barrels of oil equivalent per day during the quarter.

In Canada, we're currently running two rigs in the Brooks area of Alberta targeting the lower Manville, another light crude oil play. We've drilled six wells to date, and expect to have an additional 8 to 10 locations drilled by year-end.

We have four wells currently on stream, and early production performance has been positive. Based upon the results of our 2014 activity, we could see an additional 20 plus locations drilled in 2015.

Turning to the Marcellus. We continued with our drilling program in the quarter with 7.2 net wells drilled and 5.4 net wells brought on stream. We continued to see an improvement in capital efficiencies as a result of cost improvements and increased well productivity.

The continued evolution of well completions has been a principle driver behind these improvements. Over the past few years, we have seen horizontal well lengths increase from an average of 4,500 feet to roughly 5,500 feet as the planned length.

Frac spacing has also evolved, starting at 400 feet spacing originally with testing down to 150-foot spacing. We've also been testing the amount of sand with our fracs going from 1,000 pounds per foot up to 4,000 pounds per foot.

The net result of this has been a 30 percent increase in our IP30 rates and a 30 percent increase in our IP90 rates over the last two years. Using IP90, capital efficiencies have improved by 45 percent through the same period.

Lower realized prices, along with some pipeline maintenance activity, resulted in 3,000 to 4,000 barrels of oil equivalent per day of production on average being curtailed in the quarter. Despite this, production from the Marcellus was essentially unchanged from the second quarter, averaging 187 million cubic feet a day.

As a result of the lower regional natural gas prices, the pace of activity is slowing down, with our primary partner moving from a four-rig program to a two-rig program by early in the Yew Year. We expect capital spending in the fourth quarter to be lower than Q3 based on cost reductions, and this trend will continue more significantly in 2015 with the cost reduction and the slowing in activity.

Moving to the Duvernay. We drilled and completed two horizontal wells in the Willesden Green area this year.

Our first horizontal well was completed in the first quarter and brought on stream in late June, achieving a 30-day initial production rate of 535 barrels of oil equivalent per day of sales volumes. This included 2.24 million cubic feet of sales gas and 162 barrels of liquids, with over half of the liquids being condensate or C5+.

Our second horizontal well was completed in the second quarter and was brought on stream in early October. We have just now seen 30 days of continuous production, during which this well had an estimated 700 barrels of oil equivalent per day of sales volumes made up of 1.75 million cubic feet per day of sales gas and 410 barrels per day of liquids, approximately 85 percent of which was condensate.

Both wells have met our expectations on liquids content based upon our geotechnical analysis, with both in liquids-rich areas. Keeping in mind that these are very much exploratory wells, we are encouraged by the positive results we have achieved.

The costs of these wells were higher than we expected, particularly on the completions, not unlike what others have experienced in this deep over-pressured play. We see a number of opportunities to increase drilling and completion efficiencies going forward, particularly with multi-well pads.

With our drilling to date, we'll hold the core lands that we view as being most prospective for liquids-rich natural gas in the Duvernay, and we plan to continue—evaluate the performance of these two wells before determining our next steps.

Overall, we are very pleased with the results of our capital program to date in 2014. Based upon our revised guidance, we're poised to deliver above-average per share production growth of 13 percent year over year.

I will now turn the call to Eric, who'll give us an update on basis differentials, our price outlook, and our hedging program.

Eric Le Dain — Senior Vice President, Corporate Development, Commercial, Enerplus Corporation

Thank you, Ray. The natural gas supply and demand imbalance in the Marcellus region, of course, continued in Q3. The growth in supply from the Marcellus and the Utica continues to overwhelm takeaway capacity.

Scheduled pipeline maintenance during the quarter also added volatility to spot prices in the region, causing wide differentials to persist through the quarter. From September through December 2014, over 1.5 Bcf a day of transport capacity is being added to the Marcellus region. While maybe only 350 million of it directly ties to Northeast Pennsylvania production, the remainder will help to relieve pressure on key marketing points, such as Dominion South.

Our realized price differential to NYMEX for our Marcellus production was minus US $1.72 per Mcf in the quarter. Year to date we are at minus US $1.38 per Mcf compared to NYMEX.

During and subsequent to the quarter, we executed sales and precedent transport agreements for up to 80 million cubic feet a day priced at Transco non-New York that will fill in behind our existing sales agreements in the 2016 to 2018 time frame as those agreements roll off.

On the crude oil side, both WTI and Brent oil prices dropped sharply in the third quarter, and Canadian crude differentials weakened. The netbacks from rail to the east and Gulf Coast continued to define field prices in the Bakken.

Unfortunately, the start-up of the Pony Express Pipeline to Cushing was delayed. However, it is currently in service, and we expect it to help narrow differentials somewhat for the balance of the year.

Our realized Bakken differentials in the field saw little change over the second quarter, averaging US $14.72 per barrel below WTI. As you may recall, we had forecast a realized field differential for the year at US $13 per barrel below WTI. Year to date we are at 13.78 per barrel.

Despite the recent drop in crude oil prices, we continue to generate the majority of our funds flow from crude oil sales. For the remainder of 2014, we have approximately 64 percent of our forecasted net of royalties crude oil production swapped at prices just above US $95.

In the first half of 2015 we have swapped about 50 percent of our crude oil production net of royalties at an average price of US $93.58 a barrel, and for the second half of 2015 we have swapped about 25 percent at US $93.68 per barrel.

We also have added costless consumer collar financial contracts for 2015 that will enable us to participate in the upside on a portion of these volumes should prices rise above US $94 per barrel.

On the natural gas side, we added to our hedge book in the third quarter, and now have downside protection against NYMEX at around US $4.18 per Mcf on approximately 39 percent of our expected remaining 2014 net production after royalties, with an additional 10 percent hedged against AECO at CDN $4.25 per Mcf. So in aggregate, that's 49 percent hedged to the end of 2014. In 2015, we have approximately 28 percent of our natural gas volumes hedged net of royalties at US $4.24 per Mcf.

I'll now turn the call back to Ian.

Ian Dundas

Thanks, Eric. Based upon our production results to date, we are increasing the low end of our production guidance.

We now expect production to average between 102,000 and 104,000 BOE per day. We would expect to produce at the higher end of the range, but we are maintaining a relatively wide range to account for the potential for more curtailment in the Marcellus than we currently anticipate.

This also includes the sale of approximately 3,500 BOE a day of noncore production that we've discussed that has been completed to date in 2014. In total, we raised over $200 million in proceeds from the sale of noncore assets this year.

We also closed on our previously announced US $200 million senior unsecured notes offering and used the proceeds to pay down our credit facility. We now have almost our entire $1 billion credit facility available to us.

As Eric mentioned, we're also very well hedged, not only for the fourth quarter of 2014, but also going into 2015.

With the current volatility in the marketplace, we are assessing our plans for 2015. Directionally, we would expect modestly lower capital spending in 2015, with targeted production growth of 5 to 10 percent per share. However, we are still watching the market closely, and expect to release our 2015 guidance later this year.

Our financial position is very strong, and we have a conservative dividend policy. We will continue to invest with discipline in order to deliver affordable growth and a sustainable dividend going forward.

With that, I will turn the call over to the Operator, and we'll open it up for your questions.

Q&A

Operator

At this time, I would like to remind everyone in order to ask a question, press *, 1 on your telephone keypad. We will pause for a few moments to compile the Q&A roster.

The first question is from Greg Pardy with RBC Capital Markets.

Greg Pardy — RBC Capital Markets

Yeah. Thanks. Thanks. Good morning. I guess three questions for you, but maybe just to start. Ray, I've asked you this before is just in the Marcellus trying to get a feel for without short circuiting your 2015 guidance release, but moving down to a couple of rigs how many wells right now would you have completed, but not connected?

Ray Daniels

Sixteen, Greg.

Greg Pardy

Sixteen. Okay.

Ray Daniels

Sixteen, 1-6.

Greg Pardy

One-six; got it.

Ray Daniels

Yeah.

Greg Pardy

And then secondly, just with respect to Fort Berthold, could you lay out just generally what your fourth quarter and first quarter programs are going to look like? And is the plan now in place to move another rig into the Bakken early next year?

Ian Dundas

Greg, maybe I'll just take it at a high level for a moment…

Greg Pardy

Sure.

Ian Dundas

And go back to Ray relative to maybe some operational details there. At the highest level when we think about ‘15 versus ’14—because you're getting close to a guidance conversation here—we've said we expect modestly lower spend there. So what are the things that are moving?

We're going from four rigs to two in the Marcellus, so that frees up additional capital for sure. Strategically over the last several months we would have been talking about everything lining up to add a third rig in North Dakota with the caveat being what's going to happen to the price of oil? Well, price of oil moved to the downside, and so directionally I don't know that we are going to add a third rig any time soon in North Dakota.

We have some oil projects in Canada that we're looking at in Brooks that seem to be lining up pretty well. So I guess that's a bit of an open question for us.

The nonoperated activity in North Dakota is also continuing, as Ray talked about. That's actually accounted for a little bit of the additional spend in the back half of the year.

So when we look at all of that, I'd say it's less likely that there's a third rig coming any time soon down there with sort of a continued two-rig program and maybe a little more nonop than we were initially anticipating. Still going to drive good growth down there, and when you look at some of these well results to date it's pretty encouraging some of the productivity gains we're seeing.

Ray, is there anything else you'd add there?

Ray Daniels

No. Really I mean, I think, Greg, now with the five wells that was just completed on the Turtles/Butterflies pad, we have no more completions this year to do. I mentioned there will be eight wells still to be completed, so we've got plenty of work going into Q1 next year to get production off early.

Greg Pardy

No, that's very helpful. The last question is just on current taxes. There was a cash tax recovery in 3Q. Is the expectation that you'll have another cash—directionally have another cash tax recovery in 4Q? I know it's a modelling question, but it just seems to be standing out.

Rob Waters — Senior Vice President and Chief Financial Officer, Enerplus Corporation

Yeah. It's Rob Waters here, Greg. The way we account for taxes is that every quarter we forecast what that year looks like in terms of the income tax.

And so as you can appreciate, in the first two quarters when commodity prices were high we were anticipating more taxable income and more tax and booked that accordingly on a pro-rated basis. When we hit Q3 all of a sudden with the declining oil prices, that estimate of the full year of taxation has dropped, and that's where the recovery comes from. And the way that we're recording income taxes, we'd actually over accrued, as it were, in the first two quarters, just given where the year is now trailing out to be.

And so if these current oil prices persist, chances are we could get another recovery too, but it's not—we don't have a lot of income taxes in play, as you know, in our company. We're not really cash taxable in Canada, and in the US we've actually dropped our guidance in terms of income tax slightly to reflect the lower oil prices and lower taxable income that we're now expecting.

Greg Pardy

Okay. That's great. Thanks, all.

Operator

The next question is from Patrick Bryden with Scotiabank.

Ian Dundas

Hey, Patrick.

Operator

Patrick Bryden, your line is open.

Patrick Bryden — Scotiabank

Good morning. Can you hear me?

Ian Dundas

Yeah. We can.

Patrick Bryden

Sorry about that. Thank you. When you think about the dynamics at play in the Marcellus here and some of the shut-ins that may be happening with operators in the industry, as well as yourself, can you give us a sense for how that decision process is being made?

Ian Dundas

I guess I'll speak to our situation because people manage these things independently. So in our situation we have a few different operators. The single largest operator there is Chief. We have a good dialogue there, and we're very strategically aligned.

We anticipated the possibility of curtailment several months back, several quarters ago, and that was based on a view that when you looked at the build, the supply build, and then you looked at the transport build-out and that timetable and then you thought about summer pricing dynamics, you could see the potential for low prices in the summer. And Chief would have told us that in that dynamic, depending where those prices went, they might curtail production.

We tried to account for all of that, and I think we did a very good job doing it. I made a mistake, I think, by not maybe quite accounting for how much it could affect our operating costs.

And so we had to move our operating costs down a tiny—we moved them down a tiny bit and up a tiny bit, but on the production side I think we captured it really quite well.

So it's their decision, and we are very strategically aligned with how they've been going about doing it.

Patrick Bryden

Okay. And I know it's maybe hard to peg what the visibility is on that, but you're suggesting that might persist into Q4? Or would you think that kind of alleviates as we look ahead into the New Year?

Ian Dundas

So yeah, a lot can move in pieces, right? We have a pretty wide Q4 implied production level when you look at our 102,000 to 104,000 BOE a day.

We think probably we're towards the high end of that, and so that implies some curtailment, but not as much as we might have seen in the third quarter. But it implies some curtailment that sits there.

We could be wrong on that and, therefore, we think we need to keep that wide end of the range. Of late those pipe expansions have occurred as we anticipated and volumes—the prices are responding, and you can see that in the spot market. So we're comfortable with our guidance, but it does move around a little bit for sure.

I mean there is volatility that sits that, and I think it's what we've been saying for the last couple years: lots of gas in the area; pipes building out; weather is going to play a role; and so we will probably have this conversation every quarter for a while. And we're managing that; we're managing our guidance.

The big things that are at play here that are supportive; capital is slowing. You are seeing that slow. You're seeing it with our operator, you're seeing it with other operators, and the pipes are being built out. So I think it's all moving in the right direction, and we're managing it, I think, quite well.

Patrick Bryden

Okay. And I'm wondering if is it possible to get a bit more elaboration on the sales and transportation agreements as you look out in time? I think, Eric, you had touched on that in the 2016 to '18 time frame. Can we get a little more specifics on that?

Eric Le Dain

We can't in terms of the commercial sales agreement. We have signed precedent agreement with the Penn East Project, and the sales agreement's linked to pipelines that are in service in advance of that, in the 2015 to 2016, 2017 time frame.

Patrick Bryden

Okay. And did I hear you correctly, did you say 80 million cubic feet a day that is related to Transco NY?

Eric Le Dain

That's correct.

Patrick Bryden

Okay. And that would be a number that is net or…

Eric Le Dain

Pardon me, Transco Non-New York.

Patrick Bryden

Okay. And that is a net or gross number?

Eric Le Dain

That's our sales.

Patrick Bryden

It's net to Enerplus. Yeah.

Eric Le Dain

Yeah.

Patrick Bryden

Okay. And then on the Duvernay, just can you give a sense for you'd mentioned you want to evaluate performance and that you're pleased. But what would you be looking for as you evaluate well performance here? What specifically would push you one way or the other?

Ian Dundas

I think there's a couple of things, Pat. You look at that 15-8 well, which is the one that has the higher liquids content and it has the higher production, we're at day 31. So it's still early, of course. So time is going to be important to see how things stabilize and how they line up and give us more comfort on the reserve profile we're dealing with.

You've also got industry data coming that's important. We have a fairly large land position. In some areas we've got good control; in some areas we don't have a lot. If you actually looked at Willi Green generally, there's some areas where you have one well per township, so just more data is going to being helpful to that.

I think the other piece, though, is really understanding what's happening to costs in the area. Different producers are trying different completion approaches and they have different cost profiles, and so really understanding how all that lines up is going to be important for us.

Patrick Bryden

And on the cost side, I can appreciate if you want to beg off this question, but can you give us a sense for what that cost curve looks like as you start out and if you were to progress?

Ian Dundas

You'd have almost as much information as me on this. We have our own experiences, but we're levering as much on what other producers are doing who are running bigger programs and starting to think about pad drilling and those sorts of things. The companies who are spending more money are talking about the possibility of 10 to 13.

Some of that's going to—a lot of that's going to tie to the completion design that they actually have, and we haven't quite figured all that out at this red-hot minute. I think 10 to 15 is a good number to think about, but we don't have a lot of data on this point. And that's really what we're working on right now to understand that.

If you look at these well results, particularly that 15-8, and you think you're talking about well costs under $15 million, you can start to make it go around. If you think you can get them down to 10, it actually looks pretty interesting. Our type curve for what it's worth right now is still based on that 750,000 BOE of reserves, and in that northwest area that's got a shot at being half condensate or something along those lines. So that can line up pretty well in this pricing environment.

Patrick Bryden

Okay. Lastly and then I'll get out of the way, could we just maybe have a little bit more colour on Brooks in terms of running room in the Manville, the rates, and the cost? That kind of thing would be much appreciated.

Ray Daniels

Yeah. The cost, Pat, there are just under—they're 1.8 million to drill and complete IP30 just above 90 barrels a day, 94 barrels a day. And in terms of running room, we're looking at probably drilling somewhere between 50 and 70 in the full program. We've got another 8 to 10 this year, and as I said next year 20-plus, and it really, depending on the results, will depend what we end up drilling.

Patrick Bryden

Okay. And any comments on thickness or channels that might be more prospective? And the upside of what rates could do?

Ray Daniels

Well, there's a Glauc channel running through there as well, so we—and one of the wells that we brought on we hit virgin pressure, so we're looking at all of this stuff. And some of it feels as if it could be quite exciting, but we're still early in with the first six wells.

So we still have some learning to do, but certainly early indications are looking pretty good with, as I say, that virgin pressure well we're seeing somewhere between 50 and 80 percent oil cut, which is what you would expect to see first well in there, so that's good news.

Patrick Bryden

Okay. Appreciate that. Thank you.

Operator

Again, if you would like to ask a question, press *, 1.

The next question is from Kyle Preston with National Bank.

Kyle Preston — National Bank

Thank you, and good morning, guys. I think Patrick covered most of my questions on the Duvernay, but just one other question I had regarding your production mix in 2015. I realize your guidance isn't out yet, but obviously you had a lot of new gas brought on in 2014, but now it's the fact that you're laying down the rigs in the Marcellus. Should we expect to see a material change in your gas/oil mix there? Or will you just be sort of backfilling the Marcellus gas behind pipe gas you have there?

Ian Dundas

So we're talking at 5 to 10 percent growth. Oil will grow at the same kind of levels we have this year. The Marcellus would still probably expect decent growth.

When you look at the completion backlog that Ray talked about, you look at the profile, so I think as a round number to think about is similar kind of growth on the gas and the oil side. One of the things, we are actually kicking off a Wilrich program. It's not dramatically large, but it's in an area that we're pretty encouraged by, and so that could give decent contribution on the gas side as well.

So short answer, both gas and oil with, call it, three-quarters of the spend on the oil side.

Kyle Preston

Okay. Thanks. And as far as the basis diffs on Marcellus gas, I mean similar levels in 2015; I know Eric said there was some new capacity coming, but don't imagine that would have a big impact?

Ian Dundas

In Q3 we talked about $1.50 diff for the rest of this year and continuing into next year. That would have been the context of $4 NYMEX. It was wider in the quarter. It's tighter at the second. I think it's a good number to think about, and I can't say it enough: weather will influence it.

I think as we see 4.50 NYMEX, if that were to happen, the differential's probably a bit wider actually because there's a fair amount of gas here that is really, for all intents and purposes, disconnected from NYMEX right now.

Kyle Preston

Okay. Great. That's it for me. Thanks.

Ian Dundas

Thanks, Kyle.

Operator

There are no further questions at this time. I will turn the call back over to the presenters.

Ian Dundas

Well, thank you, everyone for dialling in today; nice to see a little bit of green in the market after the last summer.

Appreciate everyone's time, and hope everyone has a great rest of your day.

Thank you. Bye.

Operator

This concludes today's conference call. You may now disconnect.

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