AltaGas

Q4 2011 Earnings Call

Company Participants

- David W. Cornhill, Chairman and Chief Executive Officer
- Debbie Stein, Senior Vice President Finance and Chief Financial Officer
- Randy Toone, President Gas
- David Harris, President Power
- Julie Puddell, Team leader Investor Relations

Operator

Good morning, ladies and gentlemen and welcome to the AltaGas Ltd. 2011 Fourth Quarter and Year End Conference Call and webcast. I would now like to turn the meeting over to Julie Puddell, Team Leader, Investor Relations. Please go ahead Puddell.

Julie Puddell

Thank you. Good morning everyone. Welcome to AltaGas' fourth quarter 2011 and year-end conference call. Speaking today are David Cornhill, Chairman and Chief Executive Officer; Debbie Stein, Senior Vice-President Finance and Chief Financial Officer; David Harris, President, Power; and Randy Toone, President, Gas. After some formal comments this morning we will have a question and answer session.

Before we begin I'd like to remind you that certain information presented today may include forward-looking statements. Such statements reflect the Corporation's current expectations, estimates, projections, and assumptions. These forward-looking statements are not guarantees of future performance and they are subject to certain risks which could cause actual performance and financial results to vary materially from those contemplated in the forward-looking statements. For additional information on these risks, please take a look at our annual information form under the heading "Risk Factors".

I'll now turn the call over to David Cornhill.

David W. Cornhill

Thank you, Julie. Good morning, everyone. 2011 was a great year. All our businesses performed well and we made good progress on our major projects. We continue to execute our business strategy of optimizing our assets and growing through acquisition and development of energy infrastructure in all three of our businesses.

In the Gas business, we began almost $500 million of construction - to add the Gordondale plant and expand and optimize current facilities such as Harmattan, Blair Creek and the Bantry/Princess complex.

In Power, we made great progress on the Forrest Kerr Construction and signed the EPA and IBA for Mclymont and Volcano. We completed the acquisition of interests in two biomass power plants and a wind project in United States.

We have been very busy in our Utility business closing the acquisition of PNG and announcing the SEMCO acquisition. The SEMCO acquisition gives us critical mass in our Utility business with over $1 billion in rate base and over 500,000 customers. The SEMCO acquisition moves our EBITDA growth time-line up by two years as these assets are expected to add similar EBITDA in 2013 as the Northwest projects in 2015. This transaction is expected to be 10 percent accretive per share in earnings, and cash flow, and expected to add approximately $130 million in EBITDA in the first full year of operation.

Getting back to 2011 results, we reported normalize net income of 102.1 million compared to a 101.7 million in 2010. In the fourth quarter 2011 normalize net income applicable to common shares was 29.7 million compared to 25.9 million in the same quarter 2010. All three businesses delivered stronger results in 2011 driven by higher volumes at extraction facilities, strong frac spreads, higher power generation from our wind and gas-fired power generation portfolio as well as the addition of PNG in the fourth quarter 2011. Results were stronger despite turnarounds in our two largest extraction facilities during the third and fourth quarter.

Before I pass the call to Debbie, I am going to talk a bit more about the acquisitions we completed and announced recently. In December, we close the acquisition of Pacific Northern Gas, which increased our rate base by more than 50 percent and our customer base by more than 65 percent. PNG is a greater addition to our Utility division and positions us well to take advantage of LNG and CNG opportunities and capitalize on the need for infrastructure as those activities materialized. We have also expanded our renewable power generation in the United States with interests in two biomass facilities and the partnership in the Colorado wind farm, expected to be operational by the end of 2012. Each of these assets has a long-term PPA in place providing stable long term cash flow for our shareholders.

On February 1st, we announced the acquisition of SEMCO Holding Corporation. We see it sitting well with our strategy of growing all our businesses, adding geographic diversity and increasing stable, sustainable cash flow. In 2013, the first full year of operation of SEMCO, we expect approximately two thirds of our cash flow to be generated from long-term contracted or regulated assets. The market has been very supportive of the transaction with about 14 million subscription receipts purchased including the over allotment by the syndicate. The rating agencies reiterated this as a credit positive event. I'm happy to report the FTC has granted our application for early termination of the waiting period under the Hart Scott Rodino Act so from the U.S. antitrust law perspective we are cleared to close the transaction. In mid-February we filed our applications for approval of the transactions with the Michigan Public Service Commission and regulatory commission of Alaska.

To date, that process has being going well and we expect the acquisitions to close in the third quarter of this year. I'll now pass it on to Debbie.

Debbie Stein

Thank you David. Good morning everyone. As David mentioned we had an excellent year with a busy fourth quarter and we are pleased to present stronger financial results from of our each businesses compared to 2010.

Normalized net income for 2011 was $102.1 million or $1.21 per share compared to $101.7 million or $1.25 per share for 2010. In 2011, AltaGas recorded income taxes as a corporation for a full year, compared to six months in 2010, with higher future taxes of $16.7 million or $0.20 per share. In fourth quarter 2011 normalized net income was $29.7 million or $0.34 per share compared to $25.9 million or $0.31 per share in the same quarter 2010.

We have normalized for the impact of mark-to-market accounting and transaction costs related to our recent acquisitions. On a cash flow basis results were also stronger. Normalized EBITDA for 2011 increased 13 percent to $282.2 million from $249.6 million in 2010. Normalized funds from operations increased 16 percent to $225.7 million, or $2.69 per share for 2011, compared to $195 million, or $2.39 in 2010. In 2011, AltaGas declared dividends to common shareholders of approximately 49 percent of normalized funds from operations. AltaGas reported a 19 percent increase in normalized earnings from our Gas, Power and Utility businesses for both the full year and fourth quarter 2011 compared to the same period in 2010. The Gas business performed well despite two major schedule turnarounds that had almost a $12 million impact to operating income in the year.

Operating income was $104.9 million compared to $86.9 million in 2010. The increase was driven by higher frac spreads, higher extraction volumes, higher fees from extraction volumes, contributions of new and expanded gas processing, the sale of the Groundbirch facility and the settlement of the take-or-pay contract. These increases were partially offset by lower daily contract quantities on the Suffield system and lower storage margin and lower volumes at some of the field processing facility produces or impacted by low gas prices. In 2011, 70 percent of volume exposed to frac spreads, which hedged at an average price of $27.80 per barrel compared to approximately 60% and at $21.62 per barrel in 2010. In 2012, 13% of our total extraction volumes are estimated to exposed to frac spreads. For 2012 approximately 75 percent of the exposure is hedged at an average price of $35 per barrel, and 2013 we are one-third hedged at $35 per barrel.

The Power segment reported operating income for 2011 of $86.0 million or 15 percent increase compared to $74.7 million in 2010. Operating income increased primarily as the result of higher generation from the Harmattan Cogen facility, higher run time at the GAAP higher peaking plants and higher generation from Bear Mountain. We had higher G&A including transaction cost and amortization resulting from the recent growth. In 2011, AltaGas's Alberta power generation was approximately 62 percent hedged at $70 per megawatt-hour compared to 63% hedged a $64.50 megawatt-hour in 2010. In 2012, we are approximately 60% hedged on an average price $70 per megawatt-hour.

For first quarter 2012, we have hedged approximately 75 percent at an average price of $80 per megawatt-hour with the second to fourth quarters hedged approximately 56 percent at an average price of $65 per megawatt-hour. For 2013, we are currently one-third hedged at approximately $70 per megawatt-hour.

The Utility segment reported higher operating income of $24.4 million in 2011, compared to $23.4 million in 2010. The increase was mainly due to growth in rate base of 13 percent and 23 percent at AUI and Heritage Gas respectively and the addition of PNG. Results were partially offset by transaction cost related to the acquisition of PNG, a higher depletion rate related to the Ikhil assets and higher operating and corporate administrative expenses.

Interest expense for 2011 was $52.7 million compared to $48.8 million in 2010.The increase was due to a higher average borrowing rate of 6.2 percent compared to 5.4 percent in 2010 and a higher average debt balance of $1.032 billion up from $0.988 billion in 2010.

Capitalized interest in 2011 was $11 million compared to $4.4 million, and in 2012 is expected to be in the range of $25 million to $30 million based on our current estimates of current timing of estimated CapEx.

We've been very busy with financing activities this past quarter and so far in 2012. In fourth quarter we issued a $144 million of common equity, $200 million senior unsecured medium term loan and filed a $2 billion base shell prospectus. At the end of the year we had approximately $848 million available on our credit facilities and our debt to total capitalization was 49.3 percent at the end of the year. In February, in support of the SEMCO transaction, we issued approximately $400 million in subscription receipts and obtained the commitment for a new $300 million U.S. credit facility. On March 2 we amended and extended our $600 and $700 million existing credit facilities to a new maturity date of May 2016, and closed the new U.S. $300 million credit facility, which expires on March 2, 2013.

After the announcement of the SEMCO transaction, both DBRS and S&P reaffirmed our BBB credit rating with stable trends.

As previously disclosed the acquisition of SEMCO will be funded through the net proceeds of the subscription receipts offering together with draws from the combination of our existing credit facilities and the new credit facility and the proceeds of future debt and preferred share financing. We will continue to prudently finance our existing capital program and the SEMCO transaction in a manner which is consistent with our investment rate credit rating. In connection with the SEMCO transaction, we are monitoring foreign exchange markets and as the regulatory approval process progresses, we will evaluate our foreign exchange management options, which may include a combination of natural hedging and the sourcing of a portion of the cash to close in U.S. dollars and other common financial products.

Our 2012 capital program is approximately $1.5 billion allocated approximately 20% for gas, 25% for power and 55% for utilities. The majority of the committed capital includes planned spending for SEMCO and northwest projects, completion of co-stream and Gordondale as well as the growth in rate base at the utilities in Alberta, Nova Scotia, British Colombia and various smaller projects in the gas business. We are well positioned to fund our current planned spending through internally generated cash flow, our dividend reinvestment plans, our available credit on bank lines and continued strong access to the capital market that we have just discussed.

Our expected tax rate in 2011 was 17 percent mainly due to an adjustment to our future tax liability in the second quarter. In 2012, we expect the effective tax rate to be closer to the statutory rate. In fourth quarter our maintenance CapEx was $3.2 million and for the year was $5.5 million.

Before I pass the call on to Randy, I would like to remind you that this is a last quarter we report under Canadian GAAP. Beginning in the first quarter of 2012 we will be reporting under U.S. GAAP; while there are impacts to our financial reports the changes affecting us are not expected to materially impact our financial results or our debt metrics and we expect to file our annual disclosure on or about March 12.

I'll turn the call over now to Randy.

Randy Toone

Thank you Debbie, 2011 was a very exciting year for the Harmattan Complex, with the Co-stream project forging ahead and increased raw gas is being processed. We added 15 mmcf/d of new raw gas volumes in to Harmattan in mid-2011 as customers benefited from our deep-cut capabilities with some capturing up to 150 Bbl/mmcf of NGL. We continue to explore options to increase our raw gas capacity as producers in the area are very active with the emergence of liquids rich gas at the Mannville Gas Condensate play. Harmattan's deep-cut facilities and access to NGL markets make it very attractive to producers.

The Co-stream Project is near completion with 95 percent of the pipelines completed at year end. We recently completed pressure testing of the 24 inch diameter gas pipeline and construction of the last 600 meters of the pipeline should be complete in March. The 4 inch NGL pipeline has been tied into the plant and is in the process of being tied into the NGL shipping terminal in Didsbury. Plant construction is progressing with the new inlet and refrigeration compressors installed and the mechanical construction is 35 percent complete. Project timeline is delayed slightly due to the additional NEB application process that we did not anticipate - this approval has now been obtained. The projects costs are expected to be slightly over the budgeted cost of a $130 million plus 20 percent contingency. Costs have increased as a result of higher engineering costs, rock formations along the pipeline right of away and higher in plant construction costs. AltaGas has experienced the impact of labor and engineering shortages that has managed to mitigate some of the increases. Based on the contractual arrangements in place, impact of the increased cost is somewhat mitigated and the current estimates of annualized EBITDA is slightly higher than $25 million. We expect the gas to flow in Q2.

An independent study has suggested that raw gas production from the Montney region is expected to grow to 5.2 BCF by 2020, more than double the current production today. We are working on a number of projects that will capitalize on the strategic location of our assets already serving the Montney region.

The younger extraction plant, the only straddle plant in BC, is now able to process 650 million cubic feet per day and it is operating close to capacity we have been investigating further increases of capacity up to 680 million cubic feet per day and potentially reaching the full license capacity for 750 million cubic feet per day while maintaining high NGL recoveries. The 40 Km

Septimus pipeline was completed at the end of last year which provided another gas supplier area from the liquid rich Montney play into Younger.

The Gordondale deep-cut gas processing facility expecting we are expecting to be in service late 2012 will provide very high liquid recoveries to producers in the Montney area. The gas plant site preparation is complete and equipment placement has commenced. The inlet and sales compressors have arrived on site, 4 of 15 pipe rack modules and 8 of 10 NGL storage vessels have been installed to date. Completion of the gas gathering, field gas and sales gas construction is scheduled to be at the end of this month along with all engineering work.

Another facility benefiting from the Montney gas play is our Blair creek facility. In Q4, we completed our initial expansion of 8 Mmcf/d, the second phase of extension is underway and will add another 50 Mmcf/d of capacity bringing the total capacity of the facility to 82 Mmcf/d. The expected expansion will be online in Q2 of 2012. The expansion is contractually supported by three active producers in the area.

High producer activity in the Notikewin gas formation and Cardium oil formation is expected to result in increased volumes to our Alder flats facility and we continued to discuss possible expansions at that site. Our Princess/Bantry facilities have seen increased throughput from our debottlenecking activities and diverting some gas to our Princess plants in Q4 2011 in order to increase utilization of Bantry. We see high levels of drilling from the Pekisko oil formation and given the bullish trend on oil prices, we expect to see increased drilling and processing opportunities for the associated solution gas around the Bantry/Princess complex.

A number of our assets are also well positioned to capitalize on the emerging liquids-rich Duvernay play and we continue to look for opportunities to serve producers in this area.

David Harris will now give you an update on the power projects.

David Harris

Thank you, Randy and good morning. Our power business has seen growth this past year with a recent acquisition of Decker Energy International and half interest in the Busch wind farm. We added 35 megawatts of operating biomass generation and 15 megawatts of wind energy that is due to come online later this year. These investments provide AltaGas with low risk entry in the U.S. market and contracted assets and position us for future growth within North America. We continue to diversify the fuel source to generate electricity and by 2016 about two thirds of our electricity generation will be produced by clean power sources. Much of our intention has been focused on our $1 billion Northwest hydro projects which will add 277 megawatts to the BC grid by 2015, with Forrest Kerr starting in mid-2014 and McLymont and Volcano Creek in late 2015.

I'll first give you an update on where we are with these projects and then discuss some of the smaller projects we are constructing.

At Forrest Kerr tunneling has gone extremely well with six of the eight tunnels associated with the project being complete. This equates to over 50 percent of the total tunneling required for the project. The only significant tunneling that remains is the power tunnel and completion of the powerhouse cavern. The powerhouse cavern is scheduled to be completed by the second quarter of this year with the power tunnel schedule to be completed in early 2013. Rock formations have remained consistent with geotech analysis and we have not encountered any abnormal rock formations. At the end of 2011, 86 percent of the costs of Forrest Kerr were fixed slightly below our target of 88%. This was due to timing changes on a few contracts creating an opportunity for us to lower cost across all three of the NorthWest projects.

We have completed procurement of the powerhouse crane, intake gates and trash rack/stop logs. The Sluiceway and coffer dam lock block installation is moving ahead as planned with Phase 1 on track to be completed in early April.

The McLymont Creek Project is in the BC Environmental Assessment process and we are expecting to receive the Environmental Assessment Certificate later this spring. Being less than 50 MWs, the Volcano Creek Project is in the initial stages of the BC Clean Energy Development Plan process. It is expected that the formal application under this process will be submitted in Q2 of this year. Detailed engineering has commenced on McLymont and Volcano and is on track to be complete prior to commencement of construction. We are currently in discussion with suppliers for long lead items on both projects. BC Hydro has commenced tree clearing activities on the upper and lower sections of the NTL.

The second Cogeneration unit at Harmattan is near completion and is anticipated to be in commercial operation in the second quarter of this year.

Two gas-fired peakers totaling 3.4MWs being constructed at our Gordondale plant are well into construction and are on track to go into commercial operation by the third quarter of this year.

I'll now pass the call off to David for closing remarks.

David W. Cornhill

Thank you, David. I would like to wrap up the call today with our outlook of 2012. 2012 is a big year for us. We expect to bring about $0.5 billion worth of gas projects online that will generate about $70 million of annualized EBITDA. The new power projects are expected to add another $10 million in EBITDA, and of course the full year contribution of PNG and SEMCO for the fourth quarter are also expected to increase earnings this year.

Our gas assets in operation today are expected to deliver strong results as we expect higher throughput and no major turnarounds which is expected to offset the impact of lower natural gas prices. AUI and Heritage continues to increase rate base approximately 15 percent. At today's forward prices in Alberta, we would expect power to be slightly lower than last year. Our new assets and current assets will deliver strong earnings in cash flow, with growing stable earnings and cash flow we are in good position to provide shareholder value. As I've said in the past we expect to see modest dividend growth until Forrest Kerr comes into service in 2014 and more aggressive dividend growth thereafter. We have moved up our cash flow profile by two years with the addition of SEMCO putting us in a strong position to continue to deliver dividend growth while maintaining a strong balance sheet.

That concludes my prepared remarks. I will now turn the call over to Julie.

Julie Puddell

Thank you. I'll now turn the call back to you Donna for the Q&A

Questions and Answers

Operator

And the first question is from Linda Ezergaillis from TD Securities. Please go ahead.

Linda Ezergaillis

Thank you. Congratulations on a strong quarter and a strong year. I do have a question with respect to the cost in your Power business and wondering what an appropriate run rate might be for the non-natural gas fuel costs in that segment. In the fourth quarter there was higher G&A costs, as well as PPA costs - I'm just wondering if we should use Q4 as a bit of a run rate or if the full year 2011 would be more representative of what we might expect for 2012?

David Harris

No you would use the full 2011. Q4 was off slightly because of G&A cost associated with actually closing the Decker transaction.

Linda Ezergaillis

Okay. That's helpful. And with respect to the inflationary pressures at Harmattan would you characterize them as being in the millions or 10 million plus? Just trying to see what sort of the book ends are possible given that we are so late in the construction process.

David Cornhill

I would say in the millions where we see it right now and we have contracts to mitigate for the financial impact to us on that.

Linda Ezergaillis

Okay, that's helpful. And with respect to Gordondale I realize it's early for that. But would you expect the magnitude of any sort of inflationary rate pressure to be in the millions or could that potentially be higher.

David Cornhill

It’s in early stages. We're still seeing ourselves tracking pretty close – there are some scope changes that will be recovered in fees. But we've been able to reduce a lot of the exposure because we've done module construction. Right now, I would say it's minimal at this point but we're not far enough along on the actual construction productivity in the field to give you a better answer than that.

Linda Ezergaillis

Great thank you.

Operator

Thank you. The next question is from Robert Catellier from Macquarie. Please go ahead.

Robert Catellier

Thank you. Just following up on the cost creep question. With Gordondale are there any contractual mitigants other than the scope changes that you mentioned? In other words, if cost increased beyond scope changes, does the contract respond with some protection?

Randy Toone

The contract does have some protection.

Robert Catellier

With the cost creep you’re’re seeing, Is there any worry that that might get into the Northwest projects, I know there’s a good amount of contractually fixed cost at Forrest Kerr, but the other two projects really haven't started at this point?

David Harris

No, Robert, for the couple of different reasons. One, we have not seen the industrial mining and commercial growth in the area. So, labour rates are staying down with respect to Mclymont and Volcano and engineering will be 100% complete before we go to the field. We're 100% complete on engineering now at Forrest Kerr - and then with respect to Forrest Kerr - the primary driver on cost is really excavation and we're 50 percent (plus) on the excavation. We've got a very good handle on what the rock formations look like and we're actually trending below the spend curve, because we've seen favorable rock and where we initially factored maybe running into percentages of rock that's not necessarily used to deal with. So, we're very confident with respect to projections and on-schedule and on costs for Forrest Kerr and Mclymont and Volcano.

Robert Catellier

Fantastic and is there a way to quantify the potential upside either to EBITDA, or ROE from incentive regulation at AUI.

David Cornhill

I would say not at this time, regulator has some defined rules.

Robert Catellier

Okay. And then finally with the SEMCO acquisition, obviously there is a good amount of accretion there and as you alluded to, brought the EBITDA basically 2 years forward an amount somewhat equal to the Northwest projects, yet you're still guiding to your current dividend outlook despite the significant change. I'm wondering if you could provide a little bit of clarity on the reasoning there, and as a separate item - now that the utilities form a larger part of the organization how should we look and analyze your payout ratio and what we might expect on the future. Would you still guide us to a percentage of funds from operations or should it be a mixed approach using the net earnings from the utility and funds from operations for the balance of the organization?

David Cornhill

I will answer the last question first. We are still focused on both net income and funds from operations combined and we think that gives you the best overall metrics to make that decision. So I wouldn't - we look at the company as whole not as parts or sum of parts. With respect to dividend - clearly that does bring our cash flow profile and EBITDA profile up two years. It does strengthen our credit metrics as you've seen with the bond rating and so it gives us more comfort with respect to dividend increases. But we will maintain a strong balance sheet and we do still have substantial spending in 2013. And clearly, we are not planning to raise any more common equity to build out all the Northwest projects so we'll balance that with dividend increases.

Robert Catellier

Okay, thank you very much.

Operator

Thank you. The next question is from Matthew Akman from ScotiaBank. Please go ahead.

Matthew Akman

Thank you very much. David I wanted to ask a couple of questions on SEMCO, it was obviously a very big deal and I guess our first opportunity to really get at your strategic thinking. Is this move strategically towards more fee based and less commodity sensitive business? Or is this a move for AltaGas towards regulated distribution utility in particular? How would you describe your strategic direction on this deal?

David Cornhill

We've been pretty clear on our strategy with respect to growing all three businesses and reducing the commodity exposure. I think, as you pointed out, our success with the PPA acquisition increased our commodity exposure and we're expecting that to be down by 2015 to less than or around 15 percent of total EBITDA. Probably in 2013 about 18 percent I think; I may be off slightly. So we just see it's a natural part of our business - I wouldn't say that you would see us growing our business only on regulated utilities. In our portfolio of gas, we see good access to gas opportunities, LNG opportunities, as well as a number of very interesting power opportunities so we see a balanced approach. The two acquisitions were somewhat just when they became available to us. I wouldn’t read a huge trend into that by saying that we'll only be looking at regulated utilities.

Matthew Akman

Okay. As a follow-up David obviously the businesses are very stable and there is an attractiveness there but normally when you've done deals they tend to have a bigger strategic growth purpose behind them. Can you talk a little bit maybe about what you see long-term for these assets and what you see in terms of longer term value there and boosting the growth profile of AltaGas?

David W. Cornhill

Well on the first, we think that investments in the U.S. are attractive for Canadian companies. We are bullish on the U.S. The Michigan assets are more mature, but Michigan has gone through a decade of hard times and I would suggest that we are at the beginning of seeing significant growth in Michigan. We're seeing that on the industrial side, the state government has over $1 billion surplus this year, very supportive for capital growth. And so we see Michigan as an attractive place to do business and we're are seeing load growth in SEMCO - But clearly I think we averaged about 2 percent growth or just under 2 percent for the last decade - which isn't bad when you think about the decade that Michigan had to deal with in that utility.

So, we see growth in Michigan, Alaska we see a lot of opportunity; its resource rich, we see opportunity to expand natural gas delivery to other areas or support industrial development there - we have seen that. We see additional opportunities with respect to CNG and LNG; we believe that Northslope gas will be coming south, providing investment opportunity there. There are storage opportunities, there is drilling in the Cook Inlet, which we could provide pipeline transportation of growth as well as some field gathering process. And so there is a lot of opportunity for growth in Alaska. Alaska is the energy producing area and we think that it fits very well with us.

Matthew Akman

Okay. Thanks. If I can just ask one more financial follow up on the subject. This might be for Debbie. Debbie, you talked about maintenance CapEx a little bit and normally AltaGas has in the past. How will the addition of big regulated utility change, how you think about maintenance CapEx? Companies that have big regulated utility positions like Enbridge generally talk about maintenance CapEx in terms of the depreciation on regulated utility which obviously is a much bigger number than the maintenance CapEx AltaGas has traditionally talked about. Or is maintenance CapEx something that you're not going to focus on as much as anymore for looking at free cash and payout.

Debbie Stein

Yeah to answer your last question, the answer would be that's how we would look at it. Any CapEx that is spent in our regulated businesses is going to rate base for the most part. So we consider that growth capital as supposed to maintenance capital. And that would be our protocol going forward.

Matthew Akman

Okay. So, excluding depreciation?

Debbie Stein

Including depreciation.

Matthew Akman

Okay. Okay, thanks very much for my questions.

Operator

Thank you. The next question is from Robert Kwan from RBC Capital Markets. Please go ahead.

Robert Kwan

Good morning. First question here is on Harmattan Co-stream. Randy you mentioned that you expect gas to flow in the second quarter and I'm just wondering you give an update on some of the challenges there, but also are you expecting it to flow in Q2 based on the timing of any of the challenges in getting resolution there or is it something where you'll just put the deep-cut into service and put the lean gas back on the NGTL.

Randy Toone

No, we expect the gas flow in Q2 it has nothing to do with regulatory delay it's just the NEB application that TransCanada would delay us a little bit. We had also seen some delays in equipment but we still feel strongly that gas will flow in Q2.

Robert Kwan

Okay. On the full Co-stream into the foothills line?

Randy Toone

Yes.

Robert Kwan

Okay. Just second turning to Empress can you just give an update on some of the activities to attract gas and your volume expectations and what you are seeing on extraction premiums.

Randy Toone

We've seen higher extraction premiums at Empress over the last two years but the energy service business and our downstream customers we are actually at full capacity at Empress till the end of the year and we have a good lock on next year so we've been successful but it's costing more money for sure.

Robert Kwan

Okay. And sorry, is it costing more money, you mentioned over a 2 year period, is it costing more money 2012 versus the 2011?

Randy Toone

No, it’s about the same.

Robert Kwan

Okay. The last question I've got is you had mentioned on AUI regulatory lag and I just I wanted to make sure I'm understanding that now. Are you okay kind of how your booking it versus GAAP and that you are just behind on cash?

Debbie Stein

That's a fair way to look at it Robert.

Robert Kwan

Okay and what is the deferral amount?

Debbie Stein

Probably about $9 million.

Robert Kwan

Okay. That's great thanks very much.

Debbie Stein

Thank you.

Operator

And the next question is from Steven Paget from First Energy. Please go ahead.

Steven Paget

Good morning and thank you. Looking back to this time last year and what your outlook was then, could you comment on which of your three divisions has most outperformed your expectations?

David Cornhill

I would say our power and gas businesses have exceeded in that order and part from our price perspective in Alberta and with respect to volumes on the gas side. So both of those have exceeded our expectation; clearly the wind power generation on our gas Cogen has performed at a higher level and more contribution as well.

Steven Paget

Thank you. You are extracting a significant amount of liquids at Harmattan, at Empress and will be Gordondale. Is there any way you might be looking at touching the liquids barrels more often in order to generate increased EBITDA?

David Cornhill

No. We are a toll processor; we think our selling point is we give liquids back to the producer. We work with the producers to maximize value there. So we don't see that as the place that we have any expertise or want to move down.

Steven Paget

Thank you. Those are my questions.

Operator

And there are no further questions registered at this time. I'd like to turn the meeting back over to Julie Puddell.

Julie Puddell

Thank you and thank you very much for joining us. If you have any questions, please feel free to contact me. Have a great day. Good bye.

Operator

Thank you. The conference has now ended. Please disconnect your lines at this time. And thank you for your participation.