Canadian Utilities Limited (TSX: CU, CU.X) Third Quarter 2018 Results Conference Call Transcript

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Speakers:

Dennis DeChamplain – Senior Vice President and Chief Financial Officer

Myles Dougan – Senior Manager, Investor Relations

Conference Call Participants:

Linda Ezergailis TD Securities, Inc. **–** Managing Director

Jeff Zippel BMO Capital Markets (Canada) – Associate, Equity Research

Patrick Kenny National Bank Financial (Research) – Director, Equity Research

Mark Jarvi CIBC Capital Markets – Director, Institutional Equity Research

Robert Kwan RBC Capital Markets (Canada) – Managing Director

Andrew Kuske Credit Suisse Securities (Canada), Inc. – Research Analyst

Jeremy Rosenfield Industrial Alliance – Research Analyst

Operator:

This is the Conference Operator. Welcome to the Canadian Utilities Limited Third Quarter 2018 Results Conference Call and Webcast. As a reminder, all participants are in listen-only mode and the conference is being recorded. After the presentation, there will be an opportunity to ask questions. To join the question queue, you may press star, then one on your telephone keypad. Should you need assistance during the conference call, you may signal an Operator by pressing star and zero.

I would now like to turn the conference over to Mr. Myles Dougan, Senior Manager, Investor Relations. Please go ahead, Mr. Dougan.

Myles Dougan:

Thank you. Good morning, everyone. We're pleased you could join us for our third quarter 2018 conference call.

With me today are Senior Vice President and Chief Financial Officer, Dennis DeChamplain, Vice President and Controller, Anthony Maher, and Vice President, Finance and Risk, Katie Patrick. Dennis will begin today with some opening comments on our financial results and recent company developments. Following his prepared remarks, we will take questions from the investment community. Please note that a replay of the conference call and a transcript will be available on our website at canadianutilities.com and can be found in the Investor section under the heading Events & Presentations.

I'd like to remind you all that our remarks today will include forward-looking statements that are subject to important risks and uncertainties. For more information on these risks and uncertainties, please see reports filed by Canadian Utilities with the Canadian Securities Regulators, and finally, I'd also like to point out that during this presentation we may refer to certain non-GAAP measures, such as adjusted earnings, adjusted earnings per share, funds generated by operations and capital investment. These measures do not have any standardized meaning under IFRS, and as a result, they may not be comparable to similar measures presented in other entities, and now, I'll turn the call over to Dennis for his opening remarks.

Dennis DeChamplain:

Thanks, Myles, and good morning, everyone. Thanks very much for joining us today for our third quarter 2018 conference call.

Canadian Utilities recorded third quarter 2018 adjusted earnings of $132 million or $0.49 per share, which is $38 million or $0.14 per share higher than the third quarter of 2017. Higher earnings this quarter were mainly due to stronger performance in our electricity global business unit.

As you may remember, earlier this year the Alberta Balancing Pool gave notice that it would terminate the Battle River unit 5 Power Purchase Arrangement, or PPA. In order to do that, the Balancing Pool was required to pay Canadian Utilities the remaining net book value of the PPA. We received that one-time payment from the Balancing Pool this quarter and the net amount was included on our income statement, but was excluded from the calculation of our adjusted earnings.

In addition, the Battle River PPA included clauses for Canadian Utilities to earn incentive payments if we maintained plant availability above certain thresholds. We also book a profit margin on the O&M services that we provide at Battle River. The combined amount of $42 million for these profit margins and incentive payments was included in our income statement this quarter. We recognize these kind of payments in the normal course of business, and therefore we have included them in our adjusted earnings this quarter.

We also had higher earnings mainly due to improved Alberta power market pricing. The average power price in the third quarter of 2018 was about $55 per megawatt hour, or nearly $31 higher than the third quarter of 2017. This was mainly due to an increase in carbon prices, which is being included in the market power price. There was also some improvement in the supply/demand balance, with some other power producers retiring and mothballing some other of their coal fire generation in Alberta. We also had a nice warm summer, with warmer than average temperatures in July and August here in Alberta.

On the business development side in electricity, we have been busy developing plans for the conversion of our coal plants to run on natural gas. Earlier this year, we successfully completed a project to co-fire natural gas at Battle River unit 4, enabling the use of natural gas for 50% of the unit's 150 megawatt total generating capacity. In the next phase of this coal to gas initiative, a conversion project will allow co-firing of natural gas on Battle River unit 5 from 100% of its 385 megawatt capacity.

We expect to complete this BR unit 5 conversion project in late 2019. A full conversion of Battle River unit 4 and Battle River unit 3 is under analysis.

We're also committed to the conversion of our Sheerness plant to run on natural gas. Sheerness is under a PPA with the Alberta Balancing Pool until the end of 2020. After that, they'll be returned to us to operate as a merchant power plant. We are planning a full conversion of Sheerness from coal to natural gas. The conversion project is expected to be complete in advance of firm natural gas supply, which has been secured for the second quarter of 2022.

In Australia, we completed negotiations on a five-year extension to the power purchase agreement for the 180 megawatt Osborne power facility located near Adelaide. The original agreement for 180 megawatts of contracted capacity was scheduled to expire at the end of this year, and has now been extended to the end of 2023, so our electricity business had a pretty good third quarter this year, with strong earnings in the power business and good progress on the business development front.

In the pipelines and liquids business, we are proceeding with plans to build the Pembina Keephills pipeline. This project will be a 59 kilometer natural gas pipeline to support coal to gas conversion for power producers in the Genesee and surrounding area, about 80 kilometers southwest of Evanston, Alberta. The pipeline will supply natural gas to the Genesee Generating Station, and has the capacity to support the forecast demands of other power producers in the area that may be looking at coal to gas conversions.

On the earnings side, over the first nine months of 2018 our natural gas distribution business has reported comparatively lower adjusted earnings than the same period in 2017. This is mainly due to the impact of rate re-basing in the second generation of performance-based regulation, or PBR. We're seeing a similar earnings impact in our electric distribution utility. In 2018, we are driving to achieve financial returns on equity that are well above the 8.5% regulated rate. While our 2018 year-to-date financial results in these PBR utilities are comparatively lower than 2017, it has more to do with just how strong our financial returns were in 2017. These utilities continue to perform very well in 2018, and we're confident in our strategy to create long-term shareowner value, as we always have with these businesses.
Regarding our financial strength, in August Dominion Bond Rating Service affirmed its A rating and stable outlook for Canadian Utilities. In September, S&P affirmed its A- rating and stable outlook for

Canadian Utilities. Credit ratings are important to our financing costs and our ability to raise funds. We intend to maintain strong investment credit ratings to provide efficient and cost-effective access to funds required for our operations and for growth.

That does conclude my prepared remarks and I'll turn the call back over to Myles.

Myles Dougan:
Thank you, Dennis. We'll turn it over now to the Conference Coordinator for questions.

Operator:
Thank you. We will now begin the question-and-answer session. In the interest of time, we ask you to limit yourself to two questions. If you have additional questions, you are welcome to rejoin the queue. To join the question queue, you may press star, then one on your telephone keypad. You will hear a tone acknowledging your request. If you are using a speakerphone, please pick up your handset before pressing any keys. To withdraw your question, please press star, then two. Webcast participants are welcome to click on the Submit Question tab near the top of the webcast frame and type their question. The Canadian Utilities Investor Relations Team will follow up with you by email after the call.

Once again, anyone on the conference call who wishes to ask a question my press star, then one at this time.

Our first question comes from Linda Ezergailis from TD securities.

Linda Ezergailis:
Thank you. Good morning.

Dennis DeChamplain:
Good morning, Linda. How are you?

Linda Ezergailis:
I'm well. Thank you so much for hosting this conference call. I have some questions about your PBR re-opener. Can you just give us an update on how you're thinking this might unfold in terms of timing to

resolve Phase 1, and perhaps what that might mean for timing of Phase 2, and an update, perhaps, on the bookends of outcomes with maybe any sort of read through potentially to PBR 2.0?

Dennis DeChamplain:

Sure. Before we get to Phase 2 we have to see if the AUC allows it to move forward to—pass the Phase 1. We did file our submissions on the first phase, indicating that our higher earnings in 2017 were a direct result of our responses to the incentives that were baked into the plan and for us to implement efficiency improvements, which is exactly what we did. We're still in, I'm going to say a holding pattern for Phase 1. I think the process that the AUC ran has come to its conclusion a couple of weeks ago, and we're expecting further comment from the AUC, let's say imminently. Interveners have requested kind of a right for argument and reply argument on Phase 1, so if that does go ahead, that will likely play out until the end of this year, and then if it does go to Phase 2, it would likely get kicked off in 2019.

In terms of the bookends that you were talking about, the—if the—the biggest area would be around the going-in rates for O&M services, and under the existing going-in rates they've chosen—the framework was for all of the Alberta utilities to pick their lowest of the first four years. For ATCO Electric distribution, that was 2016. They were reopened for their—as a result of their 2017 performance, and their 2017 operating costs were similar to 2016, so if the AUC were to reopen into—reopen the going-in rates for PBR 2, we don't think that there would be much of an impact for electric distribution.

On the gas distribution side, their returns in 2017 were considerably higher than experienced in 2016, so if they were to move to, I'll call it, retroactive rate making, where they change the results of the PBR going-in rates, there would be, I'll call it—there's maybe about $40 million in lower costs that we incurred in 2017 compared to 2016 that they're—we may get arguments for that to be flowed through to PBR 2. I've always contended that there's been no evidence that the going-in rates for PBR 2 are not kind of just and reasonable. That would manifest itself through our utility returns in 2018, so let's see where we end up for our results in 2018, and if we reopen it on that case, then there would be time to revisit the going-in rates.

Linda Ezergailis:

You're optimistic that it won't get past Phase 1?

Dennis DeChamplain:

We're the only utility that tripped the reopener. So, for me, that indicates that there's no structural defect in the performance-based regulation 1.0 plans. So, we are confident that, in our position, that the regulatory principles will be upheld and we'll move on to the opening rates for PBR 2 as previously approved.

Linda Ezergailis:

Thank you. That's helpful context, and just as my follow-up, I'm wondering if you can give us some parameters around how your strategic review with your Alberta power business is unfolding in terms of—I'm assuming you've made progress since your investor day, and can you give us a sense of the bookends of timing of when it might resolve and what the main factors might—are that might inform your decision making, including potentially the merits of using proceeds to finance other initiatives?

Dennis DeChamplain:

Sure. In regards to timing, we would hope to kind of resolve this strategic review in, I'll call it, first quarter of 2019. The factors that would influence our decision would be kind of what price we may be offered for the assets, and in terms of what we would do with the proceeds. There's been no decision made yet. Canadian Utilities invests in regulated and long-term contracted assets, including the electricity sector, so we would be looking at continuing on our strategy for that, and we've also talked in the past about diversification away from Alberta. Right now we've got—of Canadian Utilities' $21 billion in balance sheet, $20 billion is in Alberta, so 95%, so if a transaction were to occur we would also consider that geographic diversification in our plans to what we may do with the cash, if there was a transaction, so there is no assurance that a transaction will result from this process.

Linda Ezergailis:

Would a special dividend be possible if there was no use of proceeds?

Dennis DeChamplain:

We would look at all of the financing options, whether it's dividends and other financing arrangements, definitely.

Linda Ezergailis:

Great. Thank you so much.

Dennis DeChamplain:

Thanks, Linda.

Operator:

Our next question comes from Jeff Zippel of BMO Capital Markets.

Jeff Zippel:

Good morning, everyone. Just in the package would note that the general tariff application for transmissions without pushback from—you thought it was in Q1 originally in 2019. Now it's Q2. You also mentioned an additional $13 million that would be related to 2018, so just want to confirm that that is a retroactive impact for only 2018, or does that include what the expected impact for Q1 2019 would be as well?

Dennis DeChamplain:

That would be the retroactive impact for 2018 that would be recorded in 2019, and then 2019 there will be a delay from the—for the Q1 2019 rates into subsequent quarters within 2019. I think we can reasonably expect a decision on that file in Q2 or Q3, depending on how the rest of the process plays out, so the $13 million amounts relate to 2018, will be recorded in 2019, and there may be a little bit of noise in Q1, Q2 2019 as those rates get finaled sometime in 2019.

Jeff Zippel:

Okay, perfect. Thank you, and then I guess, just also on the strategic review, so I was wondering just—kind of what we're seeing right now, it's a focus because of the current premium valuations you're seeing, and just to get your thoughts on—really, we're seeing a lot of that geared towards renewable assets. Do you think you'd still be able to get those premium valuations if you take your gas and coal-fired power assets to the market?

Dennis DeChamplain:

I don't think it's necessarily the valuations. I mean if we go back to our strategy, we built our power generation business off of long-term contracted assets. We built the plants that were backed with long-term PPAs. Over the years, as those long-term contracts and PPAs have rolled off, the percent of long-term contracted has gone down, and right now in our portfolio we're about 50/50 merchant versus contracted. Alberta is a fairly mature market, capacity markets coming in, good for incumbent generators, and we're just taking a look at those factors and decided it would be prudent for us to take a look on the options available, cycling cash on our balance sheet just like every other good corporate does.

Jeff Zippel:
Okay. That's very helpful. Thank you. That's all.

Dennis DeChamplain:
Thanks, Jeff.

Operator:
Our next question comes from Patrick Kenny of National Bank Financial.

Patrick Kenny:
Hi. Good morning, guys. Just at Battle River 5, I know power prices have been fairly strong so far in October, but wondering if you can confirm for us what the utilization rate has been so far in the first 25 days or so running the plant as merchant, and perhaps maybe give us a sense as to what power price you need to see going forward just to keep the plant online prior to gas conversion?

Dennis DeChamplain:
Good morning, Pat. I don't have the detailed stats on BR 5 in front of me. You can follow up with Myles afterwards, but with Q4 pricing, the forward curve, if it stays in that—the $50 range, our marginal cost is lower than that, so we can economically dispatch that plant, so depending on the forwards in all of the other markets—sorry, not the forwards—depending on all the other market factors that drive the pricing, will obviously indicate whether that plant's economical or not, but right now we've been seeing it in the money.

Patrick Kenny:

Okay. That's great, and then just on Battle River 3, I know you mentioned the life extension for the overall generating facility, but can you confirm for Battle River 3 the potential life extension of that plant under gas conversion?

Dennis DeChamplain:

Yes. We haven't made any decisions on whether converting—whether we do convert BR 3 to gas or not. If we don't convert, then we need to retire that unit at the end of 2019, so we'll take a look at the factors, the costs to convert it, if we can get below the emission intensity standards and make a call, hopefully kind of early 2019.

Patrick Kenny:

Okay. I'll stick to the rules here and jump back in the queue. Thanks.

Dennis DeChamplain:

Thanks, Pat.

Operator:

Our next question comes from Mark Jarvi of CIBC Capital Markets.

Mark Jarvi:

Good morning, everyone.

Dennis DeChamplain:

Good morning, Mark.

Mark Jarvi:

I wanted to go back to your prepared remarks. You guys talked about, obviously, year-over-year reduction with the distribution utilities and how 2017 was sort of a high watermark for those businesses. What do you think in terms of, now that you've had a few quarters under your belt under PBR 2.0, the timelines to realize efficiencies, and maybe not get back to 2017 levels, but get back to 2016 earning levels, and whether or not you have more confidence in the sort of earnings trajectory for the electric or the natural gas distribution utilities?

Dennis DeChamplain:

Yes. We won't be returning to those 2017 levels. I think gas distribution outperformed by some 700 basis points, and electricity in the 400s. I think 400 to 450. We do have plans in place. They are manifesting themselves in higher returns this year. We would look to—probably not to the 700 basis points, given that that took five years to accumulate in natural gas, but we would look to—in the two to three-year time period to be able to push up to some of those re-opener thresholds. And again, the re-opener thresholds is two years in a row at over 300 basis points, or one year at over 500 basis points, if we exceed those amounts.

Mark Jarvi:

Okay, and then in terms of how you're seeing both utilities set up right now, the electric and natural gas, which one do you feel you guys are making the both—best progress in terms of driving towards overearnings?

Dennis DeChamplain:

Well, I think I've said before, there's no such thing as overearnings, but both companies are making fantastic strides. On the gas side, we've done a integration between our transmission and distribution operations, so we've been able to streamline the costs in that business. On the electricity side, we're—they've made changes to the work processes to aggregate work to better and more efficiently and economically mobilize crews. We're seeing great success from that initiative as well. I think the tie would likely go to the gas distribution business in terms of being able to exceed the approved return by a larger amount.

Mark Jarvi:

Okay. That's helpful, and then just quickly, in terms of the business, and maybe regulatory environment in Australia, I'm just wondering how you guys formed your views about potentially deploying more capital in that country. Obviously, you talked about maybe wanting to diversify the cash flows in different regions.

Dennis DeChamplain:

Yes. We're going through our next access arrangement in Australia, which is similar to a five-year PBR deal here in Alberta, continuing downward pressures on the returns on equity in that market. So we would view that, but it wouldn't—may not necessarily just be regulated assets that we would look at in Australia; a combination of regulated and non-regulated assets. But no, as you're aware, and we've been on record saying that Australia is one of our target markets, along with Mexico, and South America, in order to expand. So when we talk about geographic diversification, we're definitely looking at opportunities in Australia.

Mark Jarvi:
Okay. Thanks for that, Dennis.

Dennis DeChamplain:
Thanks, Mark.

Operator:
Once again, if you have a question, please press star, then one. Our next question comes from Robert Kwan of RBC Capital Markets.

Robert Kwan:
Good morning. Maybe just starting with the quarter, can you just—on the merchant power side, do you have an estimate as to what the hedging drag was in the quarter? Is it as simple as that 358 megawatts and the difference between spot spark spread and your realized and—I guess, just looking forward, do you have what the hedge book profile looks like for Q4 and into 2019?

Dennis DeChamplain:
Yes. Good morning, Robert. Yes. For Q3, I mean you could say that's a drag, but it's kind of like the 20/20 hindsight from when we did place the hedges back, and they were in the money compared to where the market settled in 2013. Given the small market, we are not prepared to outline what our hedge book is in the next couple of quarters. We're kind of undergoing our strategic review right now, and we'll let those factors play out.

Robert Kwan:
Okay, and I guess maybe if I can just clean up on the other part of the strategic review, you're looking at the sale of the Barking land in the U.K. Can you just confirm that you do, with the consolidation

previously, that you hold 100% of this, and can you just talk about what at Zone 4—has it been rezoned to residential?

Dennis DeChamplain:

No, it hasn't been rezoned to residential, and yes, we do own 100% of it. We didn't go in owning 100% of Barking. It was around 25%, but in 2015 and 2016 consolidated the ownership of Barking Power Limited, so now we're 100% owner of that land.

Robert Kwan:

How far into the remediation are you on that and how much is left to go?

Dennis DeChamplain:

We haven't remediated any of that site.

Robert Kwan:

Okay. That's great. Thank you.

Dennis DeChamplain:

Thanks, Robert.

Operator:

Our next question comes from Andrew Kuske of Credit Suisse.

Andrew Kuske:

Thank you. Good morning. Just on Battle River 5, and just a little bit of clarity on the $25 million of O&M margin that was brought into the earnings in the quarter, was that exclusively for the quarter or was that also partly for prior quarters?

Dennis DeChamplain:

That includes prior quarters. It was a true-up. When we converted to IFRS 15, the new revenue standard at the beginning of this year. We split that contract into the capital component and O&M component, because we're obligated—our performance obligations were to provide O&M services, and that was revalued at that point in time back to the beginning of the contract compared to the cash that was received. The cash that we did receive was—I'm going to say front end loaded as the capacity payments reduce with the reduction in net book value, so the—that $25 million associated with the O&M is the contracted margins on that portion of the PPA compensation.

Andrew Kuske:
Is there a rough breakdown of what would be applicable to Q3 versus the prior periods?

Dennis DeChamplain:
The vast majority in prior periods.

Andrew Kuske:
Okay. Thank you, and then just on Barking, when you think about the monetization process there and surfacing value from the parcel of land, is there any kind of guidance on timeline, and then, ultimately, on a disposition? How do you tax efficiently repatriate the capital?

Dennis DeChamplain:
In terms of timeline, we are relatively short fuse on that one. We hope to conclude that this year. It may trip into next year because the timelines are tight and we are looking at tax strategies in order to minimize any leakage on repatriation of those funds.

Andrew Kuske:
Okay. Thank you.

Operator:
Once again, if you have a question, please press star, then one. Our next question is a follow-up from Patrick Kenny.

Patrick Kenny:
Just back on the Pembina Keephills pipeline, just wanted to confirm the commercial arrangement there. Is this a long-term take-or-pay contract, or is it the capital just simply rolling in to rate base, and also, is the initial capacity of 550 TJs a day—is that also the maximum capacity of the pipe, or can you ramp that up based on incremental demand from customers in the area?

Dennis DeChamplain:

Good morning, again. The investment is part of ATCO Pipelines' regulated rate base, so that will go into the transmission—gas transmission rate base. In terms of capacity and amping it up, Myles, do you have detail on that?

Myles Dougan:

I think that 550, Pat, includes additional capacity for expansion beyond the deliveries for Genesee Generating Station, so there's some expansion capacity there already in that system.

Patrick Kenny:

Okay, got it. Thanks for that, and then just lastly, wondering if there's any update on the Pemex cogen plant in Mexico?

Dennis DeChamplain:

No change in the status on that. We continue to work with Pemex to see if anything can be done. I think they're still proceeding with that refinery expansion. I said before that it's an economic project, and we've gone through a number of times re-justifying it with the Pemex various leadership changes, so we continue to work with them, but no real change in the status on that.

Patrick Kenny:

Okay, great. Thanks, Dennis. Thanks, Myles.

Dennis DeChamplain:

Thanks, Pat.

Myles Dougan:

Thank you, Pat.

Operator:

Our next question comes from Jeremy Rosenfield of Industrial Alliance Securities.

Jeremy Rosenfield:

Thanks. Good morning. I have a couple of questions. Just in terms of growth opportunities or utilization of capital going forward, do you think it makes more sense to be investing in additional regulated utility infrastructure assets maybe in new geographies, or is the risk-return profile more attractive in more contracted power, and I'm thinking here both outside of Alberta and not in Alberta.

Dennis DeChamplain:

Well, it's a risk and return question. The regulated utilities, stable, reliable, shouldn't be too volatile, although we are seeing volatility in PBR utilities. Long-term contracted is, I'll say, fantastic for us. If we can get a long-term contracted asset with a little bit of merchant exposure similar to how we built the power generation business back in the day, I think those are ideal. Or maybe a mix of regulated and non-regulated operations in any sort of target that we may be exploring. So on the pure regulated, we look at it, but we do look for the market upside where we can extract additional value from the investments.

Jeremy Rosenfield:

Okay, and does the U.S. market attract any attention at this point? Are there any pockets where you see value where it could be interesting to make investments there?

Dennis DeChamplain:

In the U.S. I think we're—it's—ATCO is looking in the U.S. for—with its investments. On the Canadian Utilities side for energy infrastructures, it's tough given the valuations and multiples down there now, so for strategic reasons we have, and we will continue to look at kind of maybe some of the smaller transactions, but we've said before that we're—it's unlikely that CU would go in to take on the size of an ITC or something like that.

Jeremy Rosenfield:

Okay, and maybe if I could just have one clean up question, with regard to the items related to the Battle River 5 termination, the O&M margin and the availability incentives, how much of the amount—I think it was highlighted at about $42 million all together, so $25 million, $10 million, and $7 million—how much of that was actually cash or flowing through the cash flow statement in Q3?

Dennis DeChamplain:

Well, I think there's a couple of things here. That $42 million is the cash that came in through the one-time payment. Okay, sorry. It's $25 million for the O&M, $10 million for the availability incentive, and the remaining $7 million was this quarter's availability, so the cash for all of that would have come in over the life of the contract. That $7 million was, I'll say this quarter's impact.

Jeremy Rosenfield:

Right. Okay, so that's what I was getting at. Okay, perfect. Thank you.

Dennis DeChamplain:

Thanks, Jeremy.

Operator:

This concludes the question-and-answer session. I'd like to turn the conference back over to Mr. Myles Dougan for any closing remarks.

Myles Dougan:

Thanks, and just one follow-up answer to a question there. Battle River 5 dispatched about 50% of its capacity since the turn back here as a merchant unit, so we just had one outstanding question there. Thank you, and thank you all for participating today. We appreciate your interest in Canadian Utilities, and we look forward to speaking with you again soon. Thanks so much. Bye for now.

Operator:

This concludes today's conference call. You may disconnect your lines. Thank you for participating and have a pleasant day.