Capital Power
First Quarter 2018 Financial Results
Conference Call
April 30th, 2018

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OPERATOR: Welcome to Capital Power's First Quarter 2018 Results Conference Call. At this time, all participants are in listen-only mode. Following the presentation, the conference call will be opened for questions. This call is being recorded today, April 30, 2018.

I will now turn the call over to Mr. Randy Mah, Senior Manager, Investor Relations. Please go ahead.

RANDY MAH: Good morning, and thank you for joining us today to review Capital Power's First Quarter 2018 Results, which were released earlier this morning. The financial results and the presentation for this conference call are posted on our website at capitalpower.com.

Joining me on the call are Brian Vaasjo, President and CEO, and Bryan DeNeve, Senior Vice President and CFO. We will start the call with opening comments and then open the lines to take your questions.

Before we start, I would like to remind listeners that certain statements about future events made on this call are forward-looking in nature and are based on certain assumptions and analysis made by the Company. Actual results could differ materially from the Company's expectations due to various material risks and uncertainties associated with our business. Please refer to the Cautionary Statement on forward-looking information on Slide Number 2.

In today's presentation, we will be referring to various non-GAAP financial measures, as noted on Slide Number 3. These measures are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures are provided to complement GAAP measures in the analysis of Company's results from Management's perspective. Reconciliations of these non-GAAP financial measures can be found in our First Quarter 2018 MD&A.

I will now turn the call over to Brian Vaasjo for his remarks, starting on Slide Number 4.

BRIAN VAASJO: Thanks, Randy, and good morning. I'm pleased to announce we've executed a 12-year, fixed-price hedge agreement with an investment grade U.S. financial institution for our Cardinal Point wind project. Cardinal Point is a 150-megawatt project located in Illinois. The agreement is a revenue swap contract involving a fixed volume of generation for a fixed price per megawatt hour that covers 85% of the facility's output. The project has been secured by 15-year, fixed-price REC contracts with three Illinois utilities. These long-term contracts will strengthen our contracted cash flow profile and allow Cardinal Point to generate long-term predictable revenues that will allow us to secure tax equity financing. The capital cost for the Cardinal project is expected to be between $289 million and $301 million, and commercial operations are expected to begin in March 2020. Cardinal Point is our third wind development project in the U.S., as we continue to expand our growth in the U.S. renewables market.

Turning to Slide 5, our first quarter results reflected strong operations and solid financial performance. Our average facility availability was 96%, which included a major plant outage at Genesee 2. Our financial performance in the first quarter benefited from the assets acquired and developed in 2017, but was partially offset by higher carbon compliance costs, that Bryan will comment on shortly. In the first quarter, the average Alberta spot price was $35 per megawatt hour, which was the highest average quarterly power price in two-and-a-half years. Supporting the upward trend in power prices is demand growth and the impact of higher carbon costs, combined with coal plants coming off line. We expect even higher power prices for the remainder of 2018 and 2019, based on current average forward prices in the mid-$50 per megawatt hour range for these periods.

Turning to Slide 6, with an update on the Alberta power market design. Last week, the AESO released the second draft of the Comprehensive Market Design for the new capacity market. Overall, the design continues to be constructive, indicating that existing and future assets will have an equal opportunity to earn a return on and of capital. We have greater confidence that the Alberta Government's commitment to treat new and existing assets equitably will be honoured. The key design elements, such as participation, market mitigation and term length, remain reasonable, as expected. The AESO continues to be on track to finalize its proposed market design for July 2018. Draft 2 remains generally consistent with our view of a properly designed capacity market for Alberta and Capital Power is well positioned under this market design.

I'll now turn the call over to Bryan DeNeve.

BRYAN DENEVE: Thanks, Brian. I'll review our first quarter financial performance, starting on Slide 7. Overall, financial results in the first quarter were generally in line with our expectation. This includes generating $85 million in adjusted funds from operations and Adjusted EBITDA of $173 million.

Starting January 1, 2018, the higher carbon compliance cost came into effect in Alberta. This involves a $30 per tonne carbon tax on a more stringent output-based allocation set that increases the compliance target from 20% to approximately 60% for coal-fired generating units. In the first quarter, our gross GHG compliance cost was approximately $9 million higher than for the first quarter of 2017, prior to utilizing our existing inventory of offset credits.

When looking at our financial results in the first quarter year-over-year, there was a timing difference for the major planned outage at Genesee, which was completed one quarter earlier this year. The Genesee 2 plant outage was completed in the first quarter of 2018, compared to the Genesee 1 outage in the second quarter of 2017. Despite the Genesee 2 outage in the first quarter of 2018, revenues and Adjusted EBITDA for the Alberta contracted facilities segment were unchanged, compared to the first quarter of 2017. This is due to the receipt of lower net availability payments that were partially offset by higher PPA indices and higher power prices.

Turning to Slide 8, our commercial hedging profile for 2019 to 2021, as of the end of the first quarter of 2018, is shown on this slide. For 2019, we are 46% hedged at an average contract price in the lower $50 per megawatt hour range; for 2020, we're 22% hedged at an average contract price in the low $50 per megawatt hour range; and for 2021, we are 4% hedged at an average contract price in the mid-$50 per megawatt hour range. This compares to current average forward prices in the mid-$50 for 2019, low $50s for 2020, and mid-$40 for 2021. We continue to benefit from having nearly 500 megawatts of gas peaking and wind to capture upside from higher power prices and price volatility.

Slide 9 shows our first quarter financial performance compared to the first quarter of 2017. Revenues and other income were $307 million, down 9% year-over-year. Adjusted EBITDA, before unrealized changes in fair values, was $173 million, up 29% from the first quarter of 2017, primarily due to the acquisitions of the Veresen assets and Decatur Energy, in addition to Bloom Wind. Normalized earnings of $0.30 per share were down 12%, compared to $0.34 in the first quarter of 2017. As mentioned, we generated adjusted funds from operations of $85 million, which was down 3% year-over-year, primarily due to higher sustaining CapEx with the Genesee 2 plant outage. AFFO on a per share basis was $0.82, compared to $0.91 in the first quarter of 2017.

Turning to Slide 10, in February, we announced that we had reinstated our normal course issuer bid to purchase up to 9.3 million common shares, representing approximately 10% of the public float during a one-year period ending February 20, 2019. With our significant free cash flow, the NCIB provides us the flexibility to buy back stock when the shares are undervalued and considering the timing of growth CapEx. In the first quarter, we were active in buying back shares and bought back 713,000 shares at a cost of $17 million. We will continue to buy back shares under the NCIB if it is deemed to be the best use of capital.

I'll now turn the call back to Brian Vaasjo.

BRIAN VAASJO: Thanks, Bryan. The charts on Slide 11 show our first quarter operational and financial results versus the 2018 annual targets. In the first quarter, average facility availability was 96%, which is slightly higher than our 95%

target for 2018. Our sustaining CapEx in the first quarter was $21 million, compared to the $85 million target. We reported $61 million in facility operating and maintenance expense in the first quarter, versus the $230 million to $250 million target. Finally, we generated $85 million in adjusted funds from operations in the first quarter, compared to the $360 million to $400 million target range. There is no change to our AFFO guidance and we continue to expect our 2018 AFFO to be above the midpoint of the range.

Slide 12 shows our development and construction targets for 2018. We currently have two wind projects under construction. The construction goal for New Frontier is completing the project within a $182 million budget, with COD in December 2018. The other construction project is completing Whitla Wind within its $315 million to $325 million budget, with a COD in the fourth quarter of 2019. On the development side, our goal is to execute contracts for the output of one to three new wind developments. As highlighted earlier, we've executed a contract for the Cardinal Wind project. The other potential growth opportunities would come from rounds two and three of the Alberta Renewable Electricity Program and from continued growth from our U.S. development pipeline.

I'll now turn the call back to Randy.

RANDY MAH: Thanks, Brian. Claudia, we're ready to start the questions and answers.

OPERATOR: Yes, thank you. We will now begin the question-and-answer session. 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're using a speakerphone, please pick up your handset before pressing any keys. To withdraw your question, please press star, then two. We will pause for a moment as callers join the queue.

The first question comes from Robert Hope with Scotia Capital. Please go ahead.

ROBERT HOPE: Good morning, everyone, and congrats on the Cardinal Point contract. Then, just on that topic, I was hoping you could provide us with some return expectations, or how do you stack Cardinal Point versus your other U.S. wind projects. I'm just trying to get some understanding of the returns there.

BRYAN DENEVE: Yes. For Cardinal Point, our expectation is that it will generate a return on our investment around the 11% range, and that's consistent with what we're expecting on Bloom and New Frontier.

ROBERT HOPE: When we're looking at Cardinal Point and the tax equity component there, should we assume that it is going to be almost identical to New Frontier, where I guess you'll put tax equity once the project enters service, or around entering service, and that could contribute up to two-thirds of the capital?

BRYAN DENEVE: That's correct.

ROBERT HOPE: Then, just finally, have tax equity returns changed materially in 2018, so far? There was the expectation that returns could be impacted by U.S. tax reform.

BRYAN DENEVE: On the New Frontier project, we're in the process of putting in place an agreement with a tax equity provider. I can't comment on the details around returns, but what we're seeing is in line with our expectations. Now that we are moving forward with Cardinal Point, we'll be going to market and raising tax equity for that project, and we expect it may be 25 to 50 basis points higher than what we've seen historically, just given the reduced number of suppliers in the market, but that would be kind of our range of expectations from a tax equity provider's yield.

ROBERT HOPE: Thank you for the colour.

OPERATOR: Our next question comes from David Quezada with Raymond James. Please go ahead.

DAVID QUEZADA: Thanks. Good morning, guys. My first question, just on the Alberta market design, any changes between Draft 1 and Draft 2, and any kind of material negotiation points that you see happening prior to the final draft, the final copy?

BRIAN VAASJO: I guess the major points between Drafts 1 and 2 is that the government, or the AESO came out and they expressly confirmed that there will be an equal term length for both new and existing, i.e., one auction, which is very important to existing generators. They've come out with a more balanced penalty incentive structure, which we think is positive, obviously, in this environment. Then, there's also some greater flexibility addressing a number of parties' concerns around the UCAP. Generally speaking, 1 versus 2, 2 tends to definitely consider a lot of the input and tends to be definitely more constructive from our perspective. Given that even one as it stood was quite positive from our perspective, this just is an improvement over that.

As we look forward, I think the AESO has showed a definite element of listening and incorporating issues and resolving them as we go through the process. At this point, there doesn't seem to be too many really material issues that tend to be outstanding, or at least where we don't have a sense as to where the AESO may be going, so don't expect any surprises coming out of the final determinations.

DAVID QUEZADA: Okay, great, that's very helpful, thank you, and then my only other question, just on the U.S. wind, given that you've just executed the contract at Cardinal Point, can you just talk about how the demand is for power hedge off-takers, in general, in the U.S. right now?

BRIAN VAASJO: I think it continues to be much the same as it has over the last year or so. One of the things that is impacting is, of course, the price. Generally, prices are tending to be a little bit lower than maybe we've seen a year go, but there tends to continue to be an appetite for off-take agreements.

DAVID QUEZADA: Okay, great, thanks. I'll get back in the queue.

OPERATOR: The next question comes from Andrew Kuske with Credit Suisse. Please go ahead.

ANDREW KUSKE: Thank you. Good morning. I think the question is for Bryan DeNeve, and it's just looking at the Alberta commercial facilities segment in your reporting—the portfolio optimization revenues moved down quite a bit this quarter, and I guess that speaks to a few things, perhaps just the market environment you had, the contractual positions within Alberta in the quarter—if you could just give us a bit of colour on what happened in the quarter from a portfolio optimization versus the base business.

BRYAN DENEVE: Andrew, are you looking at a specific line in the financial statements?

ANDREW KUSKE: Yes, it's on Page 20 of the MD&A, and it's just the portfolio optimization, $81 million of revs in Q1 '18, versus $95 million, and then, obviously, the overall is $173 million versus $154 million, and it's really driving at what was the dynamic that played out there, is just you had more contracted positions on the base business, better pricing, and then that gave you less opportunities on the optimization side.

BRYAN DENEVE: Yes. There would be—as you know, there would be several factors involved there, but one of the things was in 2017, our portfolio optimization strategy was very successful in the first quarter of 2017, in terms of the position we took on the portfolio and how it played out. This year, we're not quite as aggressive, so you're going to see less coming through on that side.

ANDREW KUSKE: But, arguably, your base business is in better shape this year versus last year.

BRYAN DENEVE: That's correct, yes.

ANDREW KUSKE: Okay, that's very helpful, and then maybe a slightly different question. When you think about the opportunities you've had and the incremental wind farms you keep nailing down on a periodic basis, how much construction activity do you think you can reasonably manage in a given year? I know you've talked in the MD&A about sort of one to three contracts to try to secure in a given period of time, but how much do you think you can actually build at one point?

BRIAN VAASJO: We continue to have sort of capacity on all fronts, even with Cardinal Point, but maybe to sort of describe a little bit, when you look at the announcements that have been made, we've got—right now, we're in construction and expect to be finished by the end of the year in North Dakota. That involves a skill set and a number of people in the actual construction execution side. When you look at Whitla, we're in final preparation to get going on construction, finalizing plans. A lot of that activity will take place through the back end of this year and through 2019. When you look at Cardinal Point, it's actually pushed out a year beyond that. The staging of these three projects that we have actually very efficiently utilizes our resources and gives us a lot of incremental capacity to do more.

ANDREW KUSKE: Okay, that's great. Thank you.

OPERATOR: The next question comes from Mark Jarvi with CIBC World Markets. Please go ahead.

MARK JARVI: Good morning. I want to go to the commentary in the press release and MD&A about being at the upper—or above the midpoint of the AFFO guidance. Can you just reconcile that with moving the Genesee performance standard expenses, about $15 million, from the AFFO, whether or not, if those numbers were still in there, you'd still be above midpoint?

BRYAN DENEVE: The Genesee performance standard numbers was not taken out for the purposes of our original guidance. When we express that work, we expect to come in above the midpoint. The performance standard isn't included in either of those. It's apples to apples. If we were still taking off the Genesee performance standard, the guidance would be a bit lower, but we would still be projecting to be above the midpoint.

MARK JARVI: Okay, that's helpful. Then, there's some commentary that the O&M costs in the quarter tracked below your target, which is a positive. I'm just wondering what drove that, and in terms of profitability, looking forward the next couple of quarters, whether or not you think you can continue drive down O&M costs.

BRIAN VAASJO: Generally, the O&M costs variances that you see in the first quarter largely end up being timing differences. As we look through to the end of the year, we did experience slightly higher costs at Southport, but we do expect that, by the end of the year, we'll be on track to be within the ranges we identified.

MARK JARVI: Okay, and then I just want to move to the dividend. The last increase was around July last year, so I'm curious as to expectations of when you might come with an announcement, when does the Board review that, and sort of reconciling that with what's in the MD&A around expectations for dividends paid, it seems to sort of imply that the dividend increase would take effect in Q4, maybe you can comment on that.

BRIAN VAASJO: Well, as you indicated, it certainly is always up to Board discretion. Typically, we've either taken action in increasing dividends or changing dividend guidance around the July Board meeting. As it stands now, our guidance has not changed from as it had been previously. I guess there's no reason to expect anything different than what's been the historical pattern.

MARK JARVI: Okay, those are my questions. Thanks for that, guys.

OPERATOR: The next question comes from Patrick Kenny with National Bank Financial. Please go ahead.

PATRICK KENNY: Yes, good morning, guys. Now that we're a full month into the second quarter with Sundance being dialed back, I'm just wondering if we can get your assessment on how spot prices have reacted relative to your expectations prior to April 1, I guess both from an absolute and also a volatility perspective, and then maybe also just a quick update on whether or not you've put on any spark spread hedges for your peaker plants through 2018 and 2019, or if you're leaving this capacity open at this point.

BRYAN DENEVE: In terms of price volatility and what we're seeing in the market, certainly, we are seeing strategic bidding from the owners of the units that are no longer under power purchase arrangements. It's really too early to tell whether there's a sustained trend that it would be higher or lower than our expectations. We certainly saw some significant volatility earlier in the month of April and very close in some other hours of the month. As we move towards warmer temperatures in the province and de-rates due to ambient conditions, we expect we'll continue to see higher volatility as we move through the year.

I'm hesitant to comment on what we're doing from a spark spread perspective, Pat. Certainly, we look at managing our gas position in tandem with our electricity position, and that is one of the considerations we take into account, but at this point can't really specify where we are exactly on those two.

PATRICK KENNY: Fair enough, and you might be hesitant to comment on this one, too, but just any thoughts on the MSA complaint regarding mothballing, and I guess whether or not this is having any impact on forward prices at this point.

BRYAN DENEVE: We don't believe it's having an impact on forward prices at this point in time. When you look at the decisions around mothballing, those are business decisions that make sense from the owners' perspective, in terms of what those units can actually do in the market right now, and being able to run extended hours out of the money really hurts the economics. From our perspective, we don't see that as being—we don't see much risk in any changes around that rule having any adverse impact.

PATRICK KENNY: Okay, great, and lastly, Bryan, just on the NCIB, assuming you do lock up tax equity for two-thirds of Cardinal Point, can you just update us on how much dry powder you think you still have to buy back stock and still maintain your target credit ratios?

BRYAN DENEVE: Given the recovery in the Alberta market, higher prices we're seeing this year and 2019, that's materially increased our dry powder, so to speak. We have quite a bit of runway in terms of potentially being able to buy back shares and still being well within where we want to be and where the rating agencies expect us to be from a credit metric perspective.

PATRICK KENNY: Okay, those are my questions. Thank you.

OPERATOR: The next question is from Robert Kwan with RBC Capital Markets. Please go ahead.

ROBERT KWAN: Good morning. Maybe I can just follow up on that last question, having that runway to buy back shares. Does that include your targets on securing additional projects that would have spending either towards the end of this year and into next year?

BRIAN VAASJO: Robert, just in terms of the additional projects that we're looking at—and, again, just building on what I just commented on, on the ones that we have now are sort of tiered out—if we were successful on REP 2 or 3, the CODs for those are not expected until mid-2021, which would mean significant capital spend in 2020 and 2021. We wouldn't expect any new projects associated with the one to three target to have a material impact on cash requirements this year, and probably not a big requirement in '19, either.

ROBERT KWAN: Okay, and that includes the U.S. potential projects that you've scoped out in a lot more detail?

BRIAN VAASJO: Yes, we would expect those to probably, at this point in time, to have completion dates more in the 2020 timeframe as opposed to 2019, which again spreads our capital requirements out.

ROBERT KWAN: Got it. If I can come back to your thoughts on the Alberta capacity market framework. On the market power mitigation side of things, when you look at the capacity that you've got and what you expect to have going into the first auction, and what you think the rest of the market is going to look like in terms of the total, do you expect to be mitigated?

BRIAN VAASJO: The rules are in flux right now, but we would not expect that we would be in a position to be mitigated.

ROBERT KWAN: Okay. Based on at least what they've set out, that 10% threshold, you do not expect to be mitigated?

BRIAN VAASJO: That is correct.

ROBERT KWAN: Okay, and do you have any thoughts, as well, on the asymmetry for net buyer—or lack of net buyer mitigation?

BRIAN VAASJO: No, no, I think it's relatively straightforward and we think it's pretty balanced as it sits today.

ROBERT KWAN: Okay, and then maybe I can finish up for Alberta commercial just around the quarter. Can you just comment directionally how the trade desk performed and were there any material changes, either versus prior quarters or year-over-year, on carbon credit usage, or more specifically monetization of carbon credits in the first quarter?

BRYAN DENEVE: With the new rules that have been put in place, and, in particular, there's vintaging that's now in play, we did have some carbon credits that we believe we may not be able to utilize, so we hold those as part of carbon credits for trading, and so we're actively managing that as we move forward, but it's not a significant portion of our overall inventory of carbon credits.

ROBERT KWAN: Got it, but was there a somewhat material monetization in the quarter? I guess what I'm looking at, is there's a disclosure in Note 10 of the financials and there's not a comparable year-over-year, of $8 million of credit revenues.

BRYAN DENEVE: Yes.

ROBERT KWAN: Is that essentially the net revenue of excess credits that were monetized in the quarter?

BRYAN DENEVE: The majority of it would be, yes.

ROBERT KWAN: Okay, that's great, and do you expect actually something similar as we go forward through the rest of the year?

BRYAN DENEVE: No, the majority of the credits we had available have been monetized.

ROBERT KWAN: Okay, that's great. Thank you very much.

OPERATOR: The next question comes from Jeremy Rosenfield with Industrial Alliance Securities. Please go ahead.

JEREMY ROSENFIELD: Thank you, just a few questions. First, going back to Cardinal Point, I'm curious as to what assumptions you're using for pricing or for where you're going to sell the power following the 12-year hedge contract expiry.

BRYAN DENEVE: We look at beyond the hedge period. It's a market-by-market analysis we go through, but we look at the fact that there is going to be some need for replacement power, but also that renewables are still going to be playing a relevant role in those markets. We expect an increase, of course, in the off-take pricing, because you're not going to have the production tax credits available to push down that pricing, but we also take a measured view in terms of where we see the cost of renewables are going to be at that point in time, and we certainly are seeing the cost of production from wind and solar to continue to decline.

JEREMY ROSENFIELD: Okay. You've built in assumptions for market pricing, basically.

BRYAN DENEVE: That's correct.

JEREMY ROSENFIELD: If you were to compare, from a higher level, the investment returns that you can earn on an investment like Cardinal Point versus equity that you may deploy into Alberta wind opportunities that you might be bidding on in REP 2 and 3, what's maybe more attractive for you at the margin?

BRYAN DENEVE: Well, certainly, the way the off-take agreement is structured for Whitla 1 and what we see in REP 2 and 3, it's very much a low-risk off-take agreement, so we see more risk in developing in the U.S., but commensurate with that, we have higher expected returns. It's a risk-reward trade-off. The margins are higher in the U.S., but there's also more risk in terms of shorter term contracts. The way the contracts are structured are somewhat—leave us more exposure than the ones in Alberta do.

JEREMY ROSENFIELD: Okay, and if I could just ask one question on sustaining CapEx. I believe there's been a little bit of a bump in sustaining CapEx and mention of higher mine expenditures at K3, and I was just curious if this is a longer term trend or something that we can anticipate to continue going forward, or if there was something specific going on this year that hadn't been in previous years.

BRYAN DENEVE: In terms of production of coal at the Highvale mine, there are some expenditures associated with expanding the mine into a different area. Now, certainly, TransAlta is working through those numbers in detail. One of the factors at play here is the timing of their conversion of their units to natural gas. Don't expect those higher capital expenditures are something that we'll see on an ongoing basis as we move forward, it's more of a one-time item.

JEREMY ROSENFIELD: Okay, and then a similar type question for GPS on Genesee. The higher spending for this year, is it specific to this year, or is that something that you expect to continue, to spend higher amounts going forward?

BRYAN DENEVE: No, it would be more specific to this year, and a lot of it is related to procuring the new LP rotors for Genesee 1 and 2.

JEREMY ROSENFIELD: Okay. That's it for me, thank you.

OPERATOR: There are no further questions registered at this time. I would like to turn the conference back over to the Management for any closing remarks.

RANDY MAH: Thank you for joining us today and for your interest in Capital Power. Have a good day, everyone.

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