Capital Power
Third Quarter 2018 Results Conference Call
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Corporate Participants

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Conference Call Participants

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Mark Jarvi
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Operator: Welcome to Capital Power's Third 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, October 29, 2018.

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

Randy Mah: Good morning, and thank you for joining us today to review Capital Power's third 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 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 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 the GAAP measures which are provided in the analysis of the Company's results from Management's perspective. Reconciliations of these non-GAAP financial measures can be found in our third quarter 2018 MD&A.

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

Brian Vaasjo: Thanks, Randy, and good morning. I'll start off by reviewing one of the highlights of the third quarter.

On September 6, we announced an agreement with Oaktree Capital Management to acquire the 580 megawatt contracted Arlington Valley gas facility in Arizona for US$300 million. The acquisition has the following strategic benefits: First, it provides immediate accretion, with a 5-year average accretion of $0.22 or 6% on AFFO per share and $0.03 or 2% to earnings per share.

Second, Arlington strengthens our contracted cash flow profile. The facility is contracted until 2025, with a high probability of re-contracting as confirmed through third party assessments. We are also pursuing additional contracts for the output generated in the non-summer toll months; third, Arlington is a key addition to our U.S. growth plans. It's a well-positioned asset in the attractive Desert Southwest power market; and finally, Arlington provides geographic diversification outside of our core market of Alberta.

Turning to Slide 5, the Arlington acquisition will initially be financed utilizing our credit facilities, followed by permanent debt financing to take place at a later date. Given our existing balance sheet capacity, there is no need to issue equity. We expect the closing of the acquisition to be completed before the end of this year. Overall, the acquisition is a low-risk, long-term cash generating investment which provides an important platform for further potential growth in the Desert Southwest.

Moving to Slide 6, I'll briefly touch on the Alberta power market and its positive outlook. In the third quarter 2018, the average spot price was $54 per megawatt hour, which is more than double the $25 per megawatt hour spot price in the third quarter of 2017. The forward prices for the remainder of 2018 and the full year 2019 to 2021 continue to reflect the positive dynamics in the market, with prices around $50 and above. Current demand growth of 3% to 4% in the Province has contributed to the upward trend for both winter and summer peak periods. As depicted in the Alberta peak demand chart, on August 10, a new record for summer peak demand of 11,169 megawatts was recorded. We continue to have a positive outlook for the Alberta power market, and with our diverse fleet of assets in the Province, we are well positioned to capture value.

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

Bryan DeNeve: Thanks, Brian. I'll start off by providing an update on our Alberta commercial portfolio positions, as shown in Slide 7. There have been only minor changes to our commercial hedging profile for 2019 to 2021 since the second quarter of 2018. For 2019, we are 55% hedged at an average contract price in the low $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 range. This compares to current average forward prices of $56 for 2019, $49 for 2020 and $48 for 2021. We continue to benefit from having nearly 500 megawatts of gas peaking and wind to capture the upside from low natural gas prices, higher power prices and price volatility.

Turning to Slide 8, in the third quarter, we had excellent operating performance, with average facility availability of 98%. This contributed to solid financial results in the quarter that exceeded Management's expectations.

We generated $156 million in adjusted funds from operations, which is the highest AFFO quarter since Q2 2015, when comparative information was first reported for AFFO. On a year-to-date basis, we have generated $317 million in AFFO, which accounts for 83% of the $380 million midpoint of the guidance range. Despite the strong year-to-date results, we are maintaining our guidance and continue to be on track to achieve full-year AFFO above the midpoint of our $360 million to $400 million annual guidance range. Our outlook for Q4 2018 will include the impacts from major planned outages at Genesee 3 and Decatur. We also expect sustaining CapEx will be higher compared to Q4 2017.

Slide 9 shows our third quarter financial performance compared to the third quarter of 2017. Revenues and other income were $389 million, up 12% year-over-year. Adjusted EBITDA, before unrealized changes in fair values, was $173 million, up 7% from the third quarter of 2017. The increase was primarily due to strong results in the Alberta contracted facility segment, from a higher rolling average pool price that benefited availability incentive and excess energy revenues. Normalized earnings of $0.35 per share were up 25% compared to $0.28 in the third quarter of 2017. As mentioned, we generated strong adjusted funds from operations of $156 million, which was up 16% year-over-year. AFFO on a per share basis was $1.52 compared to $1.30 in the third quarter of 2017.

Turning to Slide 10, which shows our year-to-date financial results compared to the same period in 2017. Revenues and other income were $1.1 billion, up 20% from 2017. Adjusted EBITDA, before unrealized changes in fair value, was $547 million, up 30%, primarily due to the assets acquired and developed in the second quarter of 2017. After nine months, we reported normalized earnings of $0.87 per share, which is similar to the $0.88 in 2017. Adjusted funds from operations of $317 million was 19% higher than the $267 million in 2017, and AFFO on a per share basis was $3.07, up 15% compared to $2.68 in the first nine months of 2017. Overall, year-to-date performance is reflecting double-digit increase in revenues, EBITDA, AFFO and AFFO per share.

I will now turn the call back to Brian.

Brian Vaasjo: Thanks, Bryan. I'll conclude our comments by providing a status update on our year-to-date progress versus our 2018 annual operational and financial targets, as shown on Slide 11. In the first nine months, average facility availability was 96%, slightly ahead of our 95% annual target, but we expect to be on track with our annual target. Our sustaining capital expenditures is currently $54 million and we expect full-year results will be slightly higher than the $85 million target. We reported $177 million in facility operating and maintenance expense versus the $230 million to $250 million annual target. We are on track to meet the full-year target. We generated $317 million in AFFO in the first nine months compared to the $360 million to $400 million annual target range. As Bryan mentioned, we continue to expect our 2018 AFFO to be above the midpoint of the range.

Slide 12 outlines our construction and development targets for 2018. We currently have two wind projects under construction. For New Frontier, we are on target for completing the project within its $182 billion budget and for a COD in December of this year. For Whitla Wind, the project received AUC approval in August and we've commenced physical construction of the project. The budget is $315 million to $325 million, with a COD expected in the fourth quarter of 2019.

On the development side, our goal is to execute contracts for the output of one to three wind projects. Earlier this year, we executed a contract for Cardinal Point Wind in Illinois, and we are targeting commercial operations in March of 2020. We have a strong pipeline of growth opportunities in both Canada and the U.S., and we continue to make progress in executing on our wind development opportunities to create value and strengthen our contracted cash flow profile.

I'll now turn the call back over to Randy.

Randy Mah: Okay, thanks Brian. Operator, we're ready for the Q&A session.

Operator: 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 are using a speakerphone, please pick up your handset before pressing any keys. To withdraw your question, please press star, then two. We will now pause for a moment as callers join the queue.

The first question comes from David Quezada with Raymond James. Please go ahead.

David Quezada: Thanks. Good morning, guys. My first question here, just on the upcoming midterm elections in the U.S., are there any specific jurisdictions that you're keeping an eye on, or any potential impact that you could foresee there?

Brian Vaasjo: Generally, we're watching, of course, the jurisdictions that that we have existing operations in, and we don't see that there'll be any—by state, any significant changes that will impact on the positioning of our facilities. Overall, of course, there is the differing trends in the U.S. towards some—the Republicans, on one hand, having certain approaches to dealing with emissions, etc., while the Democrats have sort of a perspective on the other side of the spectrum. So, there may be some broader implications on a national basis as opposed to simply on a state basis, but we are watching it quite closely.

David Quezada: Okay, that's helpful, thank you. I guess just to follow that up on the Alberta side with the election next year, any thoughts, or if you've had any discussions with the UCP, if they potentially come in power, and any changes that they might make to power market after that election?

Brian Vaasjo: So, our general expectation is that the—regardless of the outcome of the election, we don't anticipate that it'll have substantive changes to the Capital Power's operations in the Province.

David Quezada: Okay, fair enough, thanks. I'll get back in the queue.

Operator: The next question comes from Rob Hope with Scotiabank.

Robert Hope: Good morning, everyone. Maybe just in terms of the Alberta coal units, just given the continued softness in the market there, just want to get a sense of how much gas you've been able to put through your coal units, and whether there's been any change in your thinking on long-term gas supply to those units, as well as the conversion to gas ultimately?

Brian Vaasjo: So, I'll speak to the longer-term expectations around our evolution of coal to natural gas, and Bryan will speak to the shorter term, so what we did in the third quarter. So, on a broader basis, we continue to look at the right time to take various steps to move our coal plants to enable them to co-fire more and more natural gas. As you may recall, we had announced that we are supporting the large natural gas pipe coming to the facility. That was in an end of 2019. We've since updated that due to construction timing, and that's moved to early 2020, and again, we continue to look at the right time to make the next levels of investment.

The next significant one would be actually putting in the, I'd say the plumbing to fully accept that natural gas capacity to the units, and we're looking at appropriate timing around that. We generally haven't changed our perspective or our approach and are looking to optimally make those investments that lead to the greatest economics associated with the co-firing of natural gas to coal and then ultimately, at some point, converting the units fully to natural gas.

Bryan DeNeve: So, just in Q3 of 2018, we continue to see quite significant volatility in actual natural gas prices, number of days where the average price settled below $1.00 a GJ. During those periods, we're able to have natural gas comprise approximately 20% of our fuel input to our coal units, which, of course, we optimize when those opportunities present itself. We foresee those opportunities continuing to be there over the next year or two, just given where forward gas prices are.

Robert Hope: Okay. I appreciate the colour there. Then just taking a look at your 2018 guidance, just want to get a sense of what the moving parts are there. In the MD&A, you said that the quarter was above your expectations similar to Q2 and yet, we're still pointing towards the upper end of the guidance. Are we more towards the upper end of the guidance, or are you look—or are there other offsetting factors there?

Bryan DeNeve: We certainly are pushing more towards the upper end of the guidance. We are being mindful of the fact that one of the factors we have to keep in mind is Arlington will close at the end of November. Certainly the December, the revenue isn't that large in that facility given the toll was a summer toll, so we're taking that into account when we look forward to Q4. We're also mindful of the fact that we have a couple more outages in Q4. One has just wrapped up at Genesee 3 and we have one at Decatur, so those are also elements, but certainly, at a 30,000 foot level, we would see that moving further up towards the top end of the guidance—top end of the range, sorry.

Robert Hope: All right. Thank you.

Operator: The next question comes from Mark Jarvi with CIBC.

Mark Jarvi: Yes, good morning. I wanted to touch base on the Alberta contracted segment, and there was a more significant increase in Adjusted EBITDA, like plus $13 million year-over-year versus the increase in the revenue. Maybe you can just help us understand why you got a bit more of an uplift on the EBITDA just versus the revenue? I know availability incentives were strong, but maybe you can provide some more colour there.

Bryan DeNeve: Yes, I think one of the factors contributing to that is being able to take advantage of low natural gas prices, so certainly that's reducing our fuel cost and increasing the EBITDA relative to the revenue we're seeing.

Mark Jarvi: Would that be the primary factor, or is there anything else kind of impacting that segment?

Bryan DeNeve: Yes. The other factor we would see is just—is the availability of the units, so very strong availability means that we're getting higher availability incentive payments than what would be on an expected basis during the period.

Mark Jarvi: Okay. Then I'm just wondering if you guys can comment; you talked about closing of Arlington in November. When do you guys think of in place of the permanent financing the debt? You also do have some 2019 maturities, so just wondering what you guys are thinking in terms of accessing the debt markets and timing for that.

Bryan DeNeve: With the Arlington acquisition, we have moved forward our timeframe on going to the debt market, so very, very possible we'll be coming to market in Q4 of this year and looking for something anywhere from $250 million to $400 million in medium term notes.

Mark Jarvi: Okay, that's helpful. Then there was some article suggesting that you guys are either completed or close to wrapping up some tax equity for the New Frontier. Just wondering anything in terms of pricing for that relative to where you guys were the market a year ago, and when do you think the proceeds will come in from the tax equity for New Frontier?

Bryan DeNeve: Yes, so we would see the proceeds coming in shortly after commissioning of that facility, which continues on track for December of this year; and in terms of the agreement, the rate being provided to the tax equity provider is consistent with what we've seen at Bloom.

Mark Jarvi: Okay. That's it for me. Thank you.

Operator: The next question comes from Ben Pham with BMO Capital Markets.

Ben Pham: Okay, thanks. Good morning. A couple of questions on Arlington, and you mentioned potential new growth opportunities in the Desert Southwest, and is that—that thought process, is that around more M&A you're thinking in that region or organic? Then maybe you can touch a little bit on the re-contracting prospects. I know it's seven years from now, but maybe supply demand and potential buyers of the power at that time.

Brian Vaasjo: So, Ben, in respect of the opportunities for growth, it's both from an organic perspective. We certainly, with the land position that comes with it, certainly see potentially some opportunity from the solar perspective. It's a good resource. It's already part of the lands that we—that came with it. We are leasing for an operating solar facility that's there. In addition to that on the natural gas side, there continues to be some increasing demand in the area for responsive generation, which can potentially provide for some Brownfield opportunities.

In addition to that, from an M&A perspective, I mean—although we've been active looking in the market for a considerable period of time, and in fact we had a business development office in Phoenix for a couple of years, you certainly understand the market much better if you have assets there and you're looking at what's happening to prices and the dynamics on a day-to-day basis. So, certainly can provide, I'll say a better opportunity, and I'd say perhaps even a lower risk opportunity in respect of M&A activities.

Ben Pham: And the re-contracting side of things?

Brian Vaasjo: So, one of the things that—in respect of Arlington is, as the market has evolved, and particularly with renewables coming into the market quite significantly, different assets have been utilized in different ways, and obviously, with the nature of the contract that's there, what's happening is that the—you're seeing a significant summer peak, and the expectation is the appropriate economic approach to keeping cost down is to continue with that kind of activity of contracting summer peak from reliable natural gas facilities. When we went through the process and had third party advice, and of course, analyzed it ourselves, we saw that that actual approach is the appropriate approach and certainly should result in that facility being re-contracted, if not once, twice again. So, just see in the longer term that it's got a very, very high probability of being re-contracted based on where it is in the market today and continuation of providing that kind of energy to serve the summer peak.

Ben Pham: Okay. You don't see gas playing out the same way you're seeing California, where renewables ramping up while gas is still there but maybe not as strong as what some folks have been expecting?

Brian Vaasjo: No, we don't see that playing out the same.

Ben Pham: Okay. Then maybe one more, can I ask on the M&A side? I understand the angle on renewables. On the gas side, it seems like you've been looking at more in the five to seven-year contracted context and then look to re-contract later on. So I just—I want to clarify capacity payment market. Is that still merchant-like cash flows for you guys when you think about contracts?

Brian Vaasjo: So that, of course, depends on the term. So, if you're looking at, say, capacity payments in Alberta which are expected to be one year, we wouldn't be considering those as being contracted. In the Arlington case, we're looking at capacity payments that—or the term of a capacity arrangement for the non-summer period to be equivalent in length to what the contracts are today, and we would consider that long term.

Ben Pham: What about, like, New England or PJM for your capacity payment? Is that—that's still in the merchant bucket to your…

Brian Vaasjo: Yes, in all likelihood. We look at some of the rating agency considerations when they look at it, and they're typically—you need to be sort of in the five-year-ish range to be considering something contracted.

Ben Pham: All right. All right, thanks a lot, Brian. Thanks, everybody.

Operator: The next question comes from Andrew Kuske with Credit Suisse.

Andrew Kuske: Thank you, good morning. Question partly relates to Slide 12 in your deck, and just how you'd wind up the construction of really three major wind projects coming up over the next few years. How do you think about just your construction group, how many projects you can actually handle, and is this really a purposeful dovetailing that you've maxed out the capacity of the group, or is there more that could be done?

Brian Vaasjo: Actually, Andrew, it's worked out extremely well in terms of how these three projects have come together, because as you can see from the timing, they are spread out over time and that allows us to focus resources, particular resources such as procurement at, again, particular points in time and our construction capability. So, it actually has helped in terms of spreading our capacity out. We clearly would be able to take on one or two wind projects in the nearer term on top of these three.

Andrew Kuske: Okay, that's helpful. Then maybe just a little bit differently, if we look at Ontario, you've got a project, the North Dumfries project. It's an interesting load pocket. How do you think about the potential for that project, where are you in the process and what kind of framework are you looking for in the Province of Ontario?

Brian Vaasjo: So, we've got a number of natural gas opportunities. We've got, I'll call them Greenfield opportunities. We keep them on a low-cost basis available. We've got them in British Columbia, we've got them in Arizona, we've got them in Ontario, and those are basically expected—at some point in time, may become a contracted facility, depending on supply demand balance and whatever else happens in the jurisdiction. So, when we look specifically at Ontario, and certainly with the changing government and some of the policies, there may well be opportunities for further natural gas investment in Ontario in I would say the midterm as opposed to necessarily the immediate near term. So—and again, we'll keep opportunities alive, and again, depending on where things go politically and economically with the possibility of those projects moving forward.

Andrew Kuske: Okay, that's great. Thank you.

Operator: The next question comes from Patrick Kenny with National Bank Financial.

Patrick Kenny: Hey, guys. Now, with two pipelines being connected into Genesee, just wondering if you can comment on any volume commitments you might have on a combined basis in terms of what that might imply from a minimum co-firing percentage at Genesee post 2020.

Bryan DeNeve: So, I think Pat, we're upgrading the capacity to Genesee, but yes, to the extent that that larger pipe will be available early 2020, it does provide us the option to potentially increase co-firing, not only up to a higher percentage but potentially full conversion at the facility if the economics warrant it.

Patrick Kenny: Right. Is there any minimum co-firing percentage that we should assume, just given any underlying contracts for those two pipelines?

Bryan DeNeve: No. We'll have full optionality to go coal or gas.

Patrick Kenny: Okay, got it. Then just more in the near term here on the hedging policy, I mean now that you've added Arlington and you have some other contracted cash flows coming online organically, wondering if you feel a bit more comfortable leaving the Alberta baseload position a little more open going forward, or should we expect the current 55% hedged rate for 2019 to move up closer to fully hedged as you roll into next year, kind of similar to 2018 here?

Bryan DeNeve: Yes, a lot of it will depend on just the liquidity in the market for 2019 and where those forwards are trading at, Pat. Certainly, as we see forwards moving up towards $60, that, subject to liquidity, would result in us looking to decrease the amount of length in the Alberta market.

Patrick Kenny: Got it. Okay, and then, yes. Sorry, just the last question here, if I could. Just curious, what was the downtime at Clover Bar in the quarter? Was this planned, unplanned maintenance? Then maybe just an overall comment on your expected availability and utilization rates for the peaker plants through, say 2019?

Bryan DeNeve: So yes, we expect the utilization of CBEC will continue at similar levels through 2019 as what we've been seeing in 2018.

Patrick Kenny: Any comment on the downtime in Q3?

Bryan DeNeve: Oh, sorry, can you repeat that part of the question, Pat?

Patrick Kenny: I was just curious what was the downtime caused by, and I couldn't recall if it was planned or unplanned maintenance.

Bryan DeNeve: Yes, that was some unplanned maintenance in Q3 for CBEC. That has been fully addressed and we would expect strong availability from those units on a go-forward basis.

Patrick Kenny: Great. Thanks, Bryan.

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

Robert Kwan: Good morning. If I could just start with the quarter on Alberta Commercial, comparing to last year, both quarters were 100% hedged but you did have better prices and volumes, although I guess some higher carbon costs this quarter. Were there any other moving pieces, and can you characterize the proprietary trading desk performance this year versus last year?

Bryan DeNeve: So, in terms of the trading desk performance, there's a couple of elements moving here. When you look at our—Page 12 of our MD&A, we do have a portfolio optimization. You'll see in 2018, we had 21 million versus 96 million in the same quarter in 2017. That line can't be looked at in isolation in terms of the performance of the trading group. What'll happen is, as power prices have risen in Alberta, that shifts dollars from the optimization bucket to the asset buckets above. So, when we look at 2018, our overall capture dollar per megawatt hour for the Alberta portfolio has been higher than 2017, and we project it'll continue to go higher as we look forward to stronger pricing in the future. So, generally, our trading desk has performed at a similar level this year as it has in previous years.

Robert Kwan: Okay, and that's included for the quarter?

Bryan DeNeve: Yes.

Robert Kwan: Yes. If I can turn to some comments you made on the PPA, obviously the RAPP was a big part of the quarter, but you also talked about lower gas and the co-firing, and so I'm wondering, does the PPA set out that that full benefit flows to you and is not indexed, and then as well, do you also capture the change in law provision around carbon? Is that for you, or is that still just a pass through based on how much gas gets burned?

Bryan DeNeve: Yes, in terms of the carbon intensity, that, for the most part, is a benefit to the Balancing Pool as the buyer, although we do have an agreement to share some of the benefits of being able to optimize the heat rate at the facility, but for the most part, the GHG benefits due flow through to the Balancing Pool.

In terms of being able to utilize lower cost fuel with natural gas, that's predominately to our benefit. So, the energy payments that we receive under the PPA are all based on, as you know, formulas set in advance that basically reflect a coal-fired operation.

Robert Kwan: Got it, and maybe if I can just finish with Arlington. There was some talk earlier of just around elections, as well as things that are going on within the state. I'm just wondering, how did the ballot proposition 127 factor into your evaluation of both the acquisition but as well, the re-contracting potential?

Bryan DeNeve: So that proposition —which would move the state to a much higher renewable percentage, the potential impact of that was something we built in and it was a scenario we considered. At the end of the day, the way we see Arizona is the economics are driven primarily around solar renewables as opposed to other renewables such as wind. So, as you continue to bring on more and more solar, that certainly decreases the net demand during those hours but doesn't address, of course, the off-peak hours when the sun isn't shining. So, even with that very high penetration, with it coming in the form of renewables—or in the form of a solar, sorry, we still see a need for natural gas to firm up in the off-peak hours.

Robert Kwan: You like how Arlington sits, both location and, I guess, setup-wise versus other gas resources then in the state?

Bryan DeNeve: Yes. Certainly, Arlington has a very competitive heat rate, and a big part of our analysis was where it will sit in the supply curve, and we're very comfortable on its efficiency relative to other units in the state.

Robert Kwan: Okay. That's great. Thank you very much.

Operator: The next question comes from Jeremy Rosenfield with Industrial Alliance Securities.

Jeremy Rosenfield: Thanks. Just a couple of questions around the renewal RFPs. First on Saskatchewan, there was the results from the RFP last week. I'm wondering if you can just comment on that and where you sit in terms of a future Saskatchewan Wind RFP? Then also on the Alberta REP rounds two and three, which are close here, timelines and any expectations that you have there?

Brian Vaasjo: So, in terms of Saskatchewan, we didn't participate. We continually monitor Saskatchewan, and as opportunities come up, particularly around land positions, we do look at them but generally, we're not overly active in Saskatchewan.

In Alberta, just one of the elements of the REP process is that if you are involved in it, you can't talk about it, and that's—very, very strict rules around that, so—but could comment. Certainly expect, and I think it's no surprise, but we do expect that to be quite competitive, both two and three.

Jeremy Rosenfield: Okay. That's it for me. Thanks.

Operator: This concludes the question-and-answer session. I would like to turn the conference back over to Mr. Randy Mah for any closing remarks.

Randy Mah: Okay, thank you for joining us today. Please mark your calendars for our upcoming Annual Investor Day event, which will be held on December 6th in Toronto. More details on the event will be announced shortly. Thank you for your interest in Capital Power. Have a good day, everyone.