Capital Power Corporation
Second Quarter 2018 Results Conference Call
July 30th, 2018

Corporate Participants

Randy Mah
Director, Investor Relations

Brian Vaasjo
President and Chief Executive Officer

Bryan DeNeve
Senior Vice President, Finance, and Chief Financial Officer

Conference Call Participants

David Quezada
Raymond James

Mark Jarvi
CIBC World Markets

Ben Pham
BMO Capital Markets

Andrew Kuske
Credit Suisse

Robert Kwan
RBC Capital Markets

Jeremy Rosenfield
Industrial Alliance Securities

Robert Hope
Scotia Capital

Patrick Kenny
National Bank Financial

OPERATOR: Welcome to Capital Power's Second 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, July 30, 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 second 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.

On the call this morning is 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 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 Second Quarter 2018 MD&A.

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

BRIAN VAASJO: Thanks, Randy, and good morning. We had a number of achievements in the second quarter, which are highlighted on this slide. This included a 7% increase to the dividend, which increased the annualized dividend from $1.67 to $1.79 per share. We executed a 12-year contract for 150-megawatt Cardinal Point wind project, which is expected to be operational in 2020. We added approximately 78 megawatts to our U.S. growth pipeline with the acquisition of the Green Hills wind project in Missouri. We acquired a 5% equity interest in C2CNT, a company that captures and transforms carbon dioxide into carbon nanotubes. Finally, we secured additional physical natural gas delivery capacity for the Genesee site. This allows for increased natural gas co-firing in 2019, and further natural gas conversion of the coal facility as early as 2020.

Turning to Slide 5, the chart illustrates our dividend history and guidance. This year's dividend increase represents our fifth consecutive annual increase of 7%. Our current dividend guidance includes an annual 7% dividend increase out to 2020. Further dividend growth is supported by generating approximately $200 million per year in discretionary cash flow, which supports $400 million to $500 million of annual growth CapEx per year. Also supporting the dividend is an AFFO payout ratio target of 45% to 55%.

Moving to Slide 6. In the second quarter, the average Alberta spot price was $56 per megawatt hour. This is clearly triple the $19 per megawatt hour in the second quarter of 2017. As you can see from the Alberta peak demand chart, there's an upward trend for both the winter and summer peak demand periods. The current demand growth of 3% to 4% resulted in a new summer peak demand record of 11,100 megawatts being set earlier this month. The Alberta power market has recovered and Capital Power has the best fleet of assets in the province to capture value.

Turning to Slide 7, with an update of the Alberta capacity market design, AESO has now finalized its proposed market design. The design is constructive and provides an equal opportunity for existing and new assets to earn a return on and of capital. The key design elements, such as participation, market mitigation and term length are reasonable, as expected. AESO's next step in the process is to seek additional consultation with stakeholders on the technical details and finalization of various design elements. AESO will then translate its design into market rules for submission to the AUC for approval. The final design is consistent with our view of a properly designed capacity market for Alberta and we are positioned under the market design to do very well.

Slide 8 summarizes the progress made on our renewables growth strategy. We currently have 450 megawatts under construction and advanced development from three contracted wind projects that we'll add to our fleet over the next two years. We have 245 megawatts of potential wind development opportunities to develop in Alberta's Renewable Electricity Program, and we have approximately 1,200 megawatts of potential wind development opportunities located throughout the U.S.

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

BRYAN DENEVE: Thanks, Brian. I'll review our second quarter financial performance starting on Slide 9. Overall, financial results in the second quarter exceeded our expectations. This includes generating $76 million in adjusted funds from operations and Adjusted EBITDA of $201 million.

In the second quarter, we renegotiated the Bloom Wind tax equity agreement. A change in law provision was triggered in the agreement due to the reduction in the U.S. federal corporate tax rate that was effective on January 1, 2018.

Under revised commercial terms, the Bloom Partnership claimed bonus tax depreciation in 2017 to capture a larger portion of the tax depreciation at the 35% federal income tax rate, versus the 21% rate that became effective January 1, 2018. This resulted in a one-time, non-cash increase to Adjusted EBITDA of $44 million.

Additional information for modeling Bloom Wind is shown on Slide 10. On the chart, we show the impact from the renegotiated tax equity agreement on EBITDA and pre-tax cash flow. The chart is intended to be illustrative and all other inputs, such as generation, production tax credits and foreign exchange rates, were held constant. Under the renegotiated tax equity agreement, and considering the reduction in the U.S. federal corporate tax rate, we have maintained our original expected returns from Bloom Wind.

Slide 11 shows our second quarter financial performance compared to the second quarter of 2017. Revenues and other income were $363 million, up 81% year-over-year. Adjusted EBITDA, before unrealized changes in fair values, was $201 million, up 61% from the second quarter of 2017. The increase was due to the amended Bloom Wind tax equity agreement, a greater contribution from the Alberta contracted facilities and a full quarter of contributions from Decatur Energy and Bloom Wind. Normalized earnings of $0.22 per share were down 19%, compared to $0.27 in the second quarter of 2017. As mentioned, we generated adjusted funds from operations of $76 million, which was 73% up year-over-year. AFFO on a per share basis was $0.74, compared to $0.45 in the second quarter of 2017.

Slide 12 shows the financial results for the first half of the year compared to 2017. Revenues and other income were $670 million, up 24% from 2017. Adjusted EBITDA, before unrealized changes in fair value, was $374 million, up 44% from the same period in 2017, primarily due to the amended Bloom Wind tax equity agreement and a full six months of contributions from Bloom Wind and additional assets acquired in 2017. Normalized earnings of $0.52 per share were down 15%, compared to $0.61 in 2017. Adjusted funds from operations of $161 million was 22% higher than the $132 million in 2017. AFFO on a per share basis was $1.55, up 14%, compared to $1.36 in the first six months of 2017.

Turning to Slide 13. Our commercial hedging profile for 2019 to 2021 at the end of the second quarter of 2018 is shown on this slide. The hedge percentages in all three years have increased slightly, compared to the percentages at the end of the first quarter of this year. For 2019, we are 49% hedged at an average contract price in the low-$50 per megawatt hour range; for 2020, we're 25% hedged at an average contract price in the low-$50 per megawatt hour range; and for 2021, we are 5% hedged at an average contract price in the mid-$50 per megawatt hour range. This compares to current average forward prices of $56 for 2019, $52 for 2020, and $48 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.

I will now turn the call back to Brian.

BRIAN VAASJO: Thanks, Bryan. The charts on Slide 14 show our six-month operational and financial performance compared to our 2018 annual targets. In the first half of the year, average facility availability was 95%, which is consistent with our 95% annual target. Our sustaining CapEx was $41 million, compared to the $85 million annual target. We reported $121 million in facility operating and maintenance expense versus the $230 million to $250 million annual target. We generated $161 million in adjusted funds from operations in the first six months, compared to the $360 million to $400 million annual target range. We continue to expect our 2018 AFFO to be above the midpoint of the range.

Slide 15 outlines our construction and development 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 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 wind development projects. As highlighted earlier, we've executed a contract for the Cardinal wind project. We have growth opportunities from the Alberta Renewable Electricity Program and from our 1,200 megawatts of potential wind development opportunities in the U.S.

I will now turn the call back to Randy.

RANDY MAH: Okay, thanks Brian. Operator, we're ready to start the question-and-answer session.

OPERATOR: Thank you. 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 pause for a moment as callers join the queue.

Our first question comes from David Quezada of Raymond James.

DAVID QUEZADA: Thanks. Good morning, guys. I guess my first question, just on the outlook for development of wind in the U.S., I'm wondering what your thoughts are on, I guess, contractor availability and any potential for there to be a little bit of congestion in development, just given the huge overall pipeline in the country, and when you think kind of an effective deadline will be for a go-forward on projects just given the 2020 deadline for completion?

BRIAN VAASJO: In response to your first question, we're not seeing much evidence of a shortage of either turbines or contractors in the U.S. or Canada to execute on projects. There continues to be a significant amount of capacity that's available to us. In terms of the deadline, or the completion by the end of 2020, a lot depends on the particulars of a project. Certainly, some of the smaller projects can certainly be done within a calendar year, from start to finish, especially in the U.S. where, as you go south, it's easier from a construction, i.e., no winter construction.

But, again, very much dependent on the particular project and where it is on permitting, etc. When we look across our projects, we see a number of projects that we could potentially move to actually starting construction or advanced development within 2019, for completion in 2020.

DAVID QUEZADA: Okay, great. Thank you, that was very helpful. My only other question, just on the increased capacity for natural gas delivery at Genesee, I notice in the release you said as early 2020 for potential conversion, and I'm wondering if you have any colour you can provide on your thoughts as to what will govern your decision on the timing for that.

BRIAN VAASJO: Our timing decision continues to be the same as it relates to the clarity around carbon pricing, as well as the outlook for natural gas. What we've been doing over the last couple of years is maximizing our optionality and shortening up the timeframe in which we can react. Obviously, one of the significant elements around that ability to react quickly is having natural gas to the site, and we've dealt with that, so to speak, long lead time item. In addition to that, and what's very significant to our outlook over the next few years, is the fact that that moves us to a position where we can co-fire more and more natural gas in the coal units, and as we move forward and through the back part of 2019 and into 2020, we expect to be co-firing and have the capacity to co-fire significantly greater than it is today.

So, there's a number of reasons to get significant volumes in natural gas to the site sooner rather than later, but it certainly does facilitate a timely decision around the conversion of natural gas of those coal units. We haven't changed our fundamental outlook from what we've had before. Until you see some significant increases in carbon prices, we don't see conversion to natural gas until at least 2020, or beyond.

DAVID QUEZADA: Okay, great. Thank you very much. That's all I had.

OPERATOR: Our next question comes from Mark Jarvi of CIBC World Markets.

MARK JARVI: Good morning. I wanted to touch on the hedging. I think it says in the disclosures that we were 93% hedged in the quarter, 87% overall for the year, and I think you were close to 100% in Q1. So, maybe just give us some context for Q3 and Q4? Did you position yourself to be quite open for the summer and the peak pricing?

BRYAN DENEVE: We've continued to manage our position for the balance of the year. I can't really get into specific percentages of hedging for those two quarters, but it would be in the ballpark of what you'd seen us going into the year.

MARK JARVI: Okay, and maybe you can just provide some context with the optimization revenue in the quarter and your realized pricing. Is that just all related to the hedging book or is there some other things that happened in terms of not being able to realize as high a price as what the market provided in the quarter?

BRYAN DENEVE: Yes. So, one of the things to look at is our capture price includes a number of elements. It would include the weighted average price of all the hedges we would have entered into for the quarter over the past two to three years, depending on the timing and when those hedges were entered into. Certainly, Q2 typically is a lower price quarter relative to the rest of the year, so you can expect that our portfolio that was locked in was locked in in prices more on the lower side. Then, on top of that, we would look at what did we realize with our peaking facilities in the small amount of length that we didn't hedge forward. So, all of that gets rolled together. Basically, the fact that our capture price came in below the settled price for the quarter primarily is just a reflection of the fact that we had some long-term hedges that we entered into a number of years ago.

MARK JARVI: Okay, and then I just wanted to move—there's a comment in the press release about you guys are—it says, "actively participates in competitive bidding opportunities to acquire contracted wind assets." I'm wondering if you can provide more context—I think that's a new comment—whether or not that includes operating assets, whether or not operating renewable assets are something you guys are pursuing right now.

BRIAN VAASJO: We continue to look across the broad spectrum of opportunities, whether they be natural gas or wind, and acquiring fully contracted operational assets on the renewables side, occasionally we see one where we think we may be able to bring some expertise or manage some risks around those operations, but, again, those are relatively few. What we do see a lot of now is an increasing number of opportunities to buy sites or acquire interest in sites that have a high potential for becoming fully contracted assets in the relatively near term.

MARK JARVI: Just following on that comment, maybe you can provide a bit of colour on the Green Hills project in terms of the stage it's at, how you guys came to get your hands on that project.

BRIAN VAASJO: There's a number of projects on actually both sides of the border that come to light. Probably, every quarter we're looking at 10 to a dozen of those sites, assessing their potential and their ability to actually come to fruition, again, in the relatively near term. As it relates to that specific project, we do expect that certainly it will come to fruition within the—be complete by the end of 2020. It does have a high potential for contracting and we are continuing—or we are going through and looking at this point in time in terms of actually marketing that project in Missouri and in surrounding areas.

MARK JARVI: Is it possible that you could get a contract before year end for that project?

BRIAN VAASJO: Yes, it is.

MARK JARVI: All right, I'll leave it there. Thank you, guys.

OPERATOR: Our next question comes from Ben Pham of BMO.

BEN PHAM: Thanks. Good morning. I had a question on the Alberta RFP for this year. Could you comment on the queue you're seeing in terms of potential bidders versus the first iteration?

BRIAN VAASJO: I don't believe, Ben, and I could be mistaken, I don't believe the queue has been identified at this point. You could correct me if I'm wrong, but I can say that we do expect that it will be highly competitive and probably not a lot different in terms of numbers than last year.

BEN PHAM: Okay, all right. Can I ask you—on the slide on the Bloom Wind EBITDA and cash flow movement. On the cash flow, it looks like the trend is modestly lower from before, so I'm just wondering why the returns aren't different. Is there a change in the denominator portion?

BRYAN DENEVE: Yes, where we make it up, Ben, which isn't shown on this graph, is the fact that after the flip in the contract period, we benefit from the lower corporate tax rate in the U.S.

BEN PHAM: Okay, all right. Can I follow up on the hedging question? It seems like it's—and maybe I wanted to clarify. If the realized price includes your peaking facilities, which seem to run very well, it suggests that your hedge price looks like it's probably more in the $45 range, and so if you're hedged high-$40s coming into the year, would you say that you're closer to the forward curve in the second half than maybe the high-$40s?

BRYAN DENEVE: Yes, as I mentioned earlier, Ben, Q2 typically is the lowest trading quarter in the forward market, so hedges we would have entered into for that quarter would typically be less than other quarters in the year.

BEN PHAM: Okay, all right. All right, guys, thanks a lot.

OPERTOR: Our next question comes from Andrew Kuske of Credit Suisse.

ANDREW KUSKE: Thank you. Good morning. I guess the question is for either of the Brians, really, on the issuer bid, and how do you think about the constraints on buying back stock versus other forms of capital return, like dividends, and then also just ongoing reinvestment in the business.

BRYAN DENEVE: We have two primary considerations when we look at purchasing back stock. The first is, of course, where our stock price is trading relative to our view of value of the corporation. At current levels we're trading at, we still believe we're undervalued. But, having said that, we also are very mindful of the growth pipeline that we have and how close we are to having new growth projects materialize. And one of the things we just want to be careful of is that we're not buying back stock and then, following on that, having to access the equity market and the costs associated with that.

So, that's the balance we try to maintain. So, really, our activity in buying back stock, a lot of it hinges on the status of our development portfolio.

ANDREW KUSKE: Then, maybe, just an extension on that, when you think about the development portfolio and you balance opportunities outside of Alberta versus those in Alberta, where you've obviously got a very big position as an incumbent, how do you think about the internal development capability within the province of Alberta and then just the demand that you're seeing, which is obviously robust, but how much of the demand in the near term has really been driven by weather versus sort of a normalized view of things?

BRYAN DENEVE: Your question is around weather driving demand growth in Alberta?

ANDREW KUSKE: Yes, on a near-term basis.

BRYAN DENEVE: Yes. So, when we speak to 3% to 4% demand growth on an annualized basis, that is weather normalized. Certainly, there's some periods where we've had some very hot weather that has exceeded historical norms and actually has pushed demand growth above 4%, but we've normalized that out and generally we're seeing in that 3% to 4% range.

ANDREW KUSKE: Then, finally, if I may, as it just relates to the last point, if you've got weather normalized 3% to 4% growth, but you had spikey weather behaviour that peaked power prices in the quarter, is that really what got the optimization offside in the quarter?

BRYAN DENEVE: Well, again, I don't think our optimization was offside on the quarter. When you look at our capture price of—I think it was around $51 a megawatt hour—it definitely was lower than where the settled price was for the quarter, but, again, you have to keep in mind that embedded in our capture price is a historical hedging that we've undertaken over the past two to three years, and Q2 typically, in a forward-based market, trades at the lowest price for the entire year. Q2 was really robust, it had high settled prices, we captured a lot of that with our peaking facilities, but we also came into the quarter with most of our baseload hedged, and it was hedged in mid- to high-$40s. That's why our capture price came in lower.

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

OPERATOR: Our next question comes from Robert Kwan of RBC Capital Markets.

ROBERT KWAN: Good morning. Maybe I can just start with guidance. There's no change in the statement, but you also noted that Q2 results exceeded your expectations, so are you expecting AFFO for 2018 to exceed the high end of the range at this point?

BRYAN DENEVE: Not at this point. Certainly, there's still some uncertainties out there as we roll through the balance of the year. We're not ready to make a statement that we'll be closer to the upper end of the range, but we're still very confident we'll exceed the midpoint at this stage.

ROBERT KWAN: Okay. So, directionally, coming out of last quarter, you were above midpoint and now you're just further above midpoint, but you're still within the range?

BRYAN DENEVE: Yes, that's correct.

ROBERT KWAN: Okay. Just on the Genesee gas capacity side of things, is it your own pipe or have you contracted for firm service on NGTL?

BRIAN VAASJO: So, I guess to be clear, what's happening is there is a large pipe that will be built to our station gate by 2019, and there is some portion of that, as you scroll forward in time, that we have committed to, and I'll say generally a reasonably modest commitment, but it has brought a significant amount of natural gas to our station gate.

ROBERT KWAN: Sorry, is it a transmission pipe, is it an LDC pipe, or is it a third-party new pipe coming in?

BRIAN VAASJO: It's NGTL.

ROBERT KWAN: Okay. So, you've got—I assume you've got firm service, although you'd be subject to any rationing back that NGTL may have.

BRIAN VAASJO: Yes.

ROBERT KWAN: Okay. Maybe just to finish, a small question. Looking at the segments, Ontario and B.C. contracted. It looks like in the disclosure revenues from the disclosed plants are up a few million dollars, York is up a couple million, but the segment is down a million. Now, I don't know if it's K2, because it looks like those revenues were down $3 million, although the generation was up. So, I'm just wondering if you can give some extra colour as to what happened in the segment.

BRYAN DENEVE: In terms of Q2, for the B.C./Ontario contracted segment, we did have the—the York facility did not come in at expectations for the quarter on an EBITDA basis, so that would be the primary driver.

ROBERT KWAN: Okay, but York was still $2 million higher year-over-year.

BRYAN DENEVE: Right. I'm pretty sure we didn't close York in the first quarter, I think it was partway into Q2 of 2017.

ROBERT KWAN: Understood. Just, it looks like all of your revenue drivers are up, with the exception of K2, yet the segment was down, so were there some unusual costs in the quarter, and then, even just as a kind of follow-on, why was K2 revenue down $3 million, yet generation was higher year-over-year?

BRYAN DENEVE: We'll have to get back to you on that question.

ROBERT KWAN: Okay. Thank you.

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

JEREMY ROSENFIELD: Good morning. Just a couple of questions. The Green Hills development project, is the ideal agreement a long-term contract or is there an opportunity for a hedge, and what's the market maybe for RECs, also, in that area? Can you provide any colour?

BRIAN VAASJO: As we're looking at it, although there's opportunities for RECs, I'd say, broadly speaking, our primary driver is both our ability to tap the market from a hedge perspective, but there's also a number of utility and co-op opportunities in the area, so we're looking at a broad array of opportunities in relatively short order.

JEREMY ROSENFIELD: Okay, and you mentioned that it's close to an existing sub-station, so that implies that there's not a significant risk or a need for transmission infrastructure. I know there's a major transmission line, a project that's a little bit controversial, running through, I think a little bit southern, the southern part of Missouri, but it's not related to that one at all.

BRIAN VAASJO: That's correct.

JEREMY ROSENFIELD: Okay, good. Recently, one of your competitors, obviously, TransAlta, completed off-coal financing. I'm just wondering if there's any attractiveness for Capital Power to do something similar in order to actualize the future payments from the government.

BRYAN DENEVE: There's a number of considerations that go into that. One element is where that transaction was rated wasn't that strong, in our view, so that the lift we would get in terms of beneficial rates isn't as great as we thought it would be. We also have some tax considerations, from our perspective, that we're keeping in mind. So, I think, at the end of the day, it's not something that's high on our priority list, and, particularly, it would be something we would take a much closer look at if we had a need for a lot of cash at any point in time.

JEREMY ROSENFIELD: Great, okay, and maybe just a final commentary on a difficult subject. Obviously, in Ontario, there were some directives issued by the government recently in relation to projects that were pre-operating, so not impacting your assets specifically, but I'm wondering if you have looked at the value of those assets and if you are bracing yourself, or potentially in discussions with the government over the actual operations.

BRIAN VAASJO: As we've looked at it, we're not seeing any narrative—and, in fact, narrative to the contrary—around actually doing something with operating assets. There's quite a bit of difference between cancelling projects and providing some level of compensation to projects that haven't started versus that are in actual operation. That's a significant step for any government to take in terms of the whole issues of sanctity of contracts, and so on. I think any developer is always exposed to the potential of a contract being cancelled before realization, whether that be—it's happened in British Columbia, it's happened in Ontario before, it'll continue to be happening, and it happens in other countries, so that, I think, is—I'll call it a risk that developers take. To actually change existing, or eliminate existing contracts, again, is a very dramatic step for a government to take. So, we don't expect that to happen in Ontario, and certainly the narrative and the advice we've received is that's something that's not on the table.

JEREMY ROSENFIELD: Okay, that's good to hear. All right, that's it for me. Thank you.

OPERATOR: Our next question comes from Rob Hope of Scotia Capital.

ROBERT HOPE: Good morning, everyone. Along the same theme, in terms of Ontario, when you're looking at the market renewal that the AESO is going to put forward, can you give us some thoughts on how you think that will play out and whether or not that could be a headwind or tailwind for your assets there?

BRIAN VAASJO: Well, certainly, philosophically, we see the development of any market as being positive when you look at assets, and even though our assets in Ontario, the contracts are up well down the road, we see market development as fundamentally being a very positive element. The wind farms, of course, is our one issue, but when you look at the natural gas facilities, both of our facilities are situated to be very important from a transmission perspective and a grid security perspective. So, we see them as being a little bit different in terms of being very valuable, again, from, obviously, the energy generation from time to time, but more from a transmission perspective. From a developed market perspective, they would have both of those attributes of value and would be very positive for us.

ROBERT HOPE: All right, thank you for that. Then, just moving down south of the border, you touched on this a little bit before, but the changes to the tax equity market that we've seen year-to-date, has that potentially cooled your expectations for wind farms moving forward? It wouldn't appear so, but could you add some colour on the cost of tax equity there?

BRIAN VAASJO: We continue to look at projects. In particular, we're currently looking at, obviously, Cardinal Wind, but New Frontier, as well, and with New Frontier, we've had positive reception. We continue to work on tax equity arrangements. We haven't seen a significant change in terms of the kinds of yields that we could expect. In fact, New Frontier continues to be in the zone of yield that we were expecting even prior to the changes in tax laws in the U.S. So, it continues to be a market that's open to us and open for development.

ROBERT HOPE: Thank you. I'll jump back in queue.

OPERATOR: Once again, if you have a question, please press star, then one. Our next question comes from Patrick Kenny of National Bank Financial.

PATRICK KENNY: Yes, good morning, guys. Just back on potentially converting the Genesee units in a couple of years, obviously, carbon prices and gas prices are key drivers, but also wondering how the coal mine reclamation costs might factor into your decision there, and I'm just wondering if converting G1 and 2, but say leaving G3 on coal, might allow you to push that full decommissioning liability out to 2030, and if that's a factor in your decision to leave at least one unit on coal for a while beyond 2020.

BRIAN VAASJO: In terms of—kind of taking that question piece by piece—one of the things that when you look at the Genesee facility, and I think you look at any grouping of facilities that utilize a mine, it's actually economically challenging to leave, say, one unit on coal, the reason being is that a lot of your fixed costs remain relatively the same and yet you have basically a significant change to your denominator. So, that makes it somewhat challenging, again, to leave one unit in coal and convert two units to natural gas.

In terms of any changes in terms of our outlook and what we might do, one of the things that bringing in more and more natural gas does is, when you think of an arbitrage case or being able to arbitrage natural gas more and more, which certainly with bringing the natural gas capacity to the plant. What it actually does is it enhances the staying on coal case, because you're able to utilize, again, greater portions of natural gas, which reduces the differentiation between the two cases. So, as we continue to look forward, continue to see a lot of optionality around what we're able to do on the site, and to optimize our ability to utilize coal and natural gas.

In relation to the cost of reclamation, we've stayed relatively tight in terms of how much we have to reclaim relative to how much of the pit is open today. It's basically one mine, we're mining in two areas, but, again, it's a relatively tight cost, and the cost of reclamation, especially spread over a number of years, which is the nature of reclamation, we don't see as having a very dramatic impact on cash flow, so it doesn't enter into our considerations of converting to natural gas.

PATRICK KENNY: All right, that's great colour, thanks, Brian. Then, just lastly, on the credit rating, now that power pricing has recovered and the final CMD looks to be constructive, are you having any discussions with S&P or DBRS on what else might be outstanding to perhaps achieve a one-notch upgrade to BBB-mid, or is that on the radar at all over the next year or so?

BRYAN DENEVE: S&P and DBRS are certainly assessing the new market design and coming to conclusions around what that means. We expect we'll see something from them, potentially, in the near future. For us, we're not really working towards a one-notch upgrade. We feel BBB-low is the right place for us. We certainly maintain our credit metrics in a way that provides cushion to the thresholds that the rating agencies have to maintain BBB-low, so certainly we're not riding right on the edge, but we're not looking to improve those credit metrics to the point of a one-notch upgrade, so I think the expectation is more that we'll maintain that as we move forward.

PATRICK KENNY: All right, that's great. Thanks very much, guys.

OPERATOR: Once again, if you have a question, please press star, then one.

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

RANDY MAH: If there are no more questions, we'll conclude our conference call. Thank you again 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.