Capital Power
Second Quarter 2017 Financial Results Conference Call
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Conference Call Participants

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OPERATOR: Welcome to Capital Power's Second Quarter 2017 Financial Results Conference Call. At this time, all participants are in a listen-only mode. Following the presentation, the conference call will be opened up for questions. The call is being recorded today, July 26, 2017.

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

RANDY MAH: Good morning. Thank you for joining us today to review Capital Power's second quarter 2017 results which were announced earlier this morning. The financial results and the presentation slides 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 conclude with a question-and-answer session.

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 may 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 the Company's results from Management's perspectives. Reconciliations of these non-GAAP financial measures can be found in the Company's second quarter 2017 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. I will start off by reviewing some of the significant events that have taken place recently. On June 13, we completed the acquisition of the Decatur Energy Center for CAD$603 million. The Decatur facility is a 795-megawatt natural gas facility located in Decatur, Alabama that is fully contracted until December 2022. Based on its history and need for capacity in the region, we believe there is a very high probability of re-contracting after 2022.

The addition of Decatur is expected to be accretive to adjusted funds from operations by $0.18 per share in the first full year of operations. As part of the Veresen transaction, under which we previously acquired the two gas-fired Ontario plants in April, we have now completed the acquisition of the two waste heat generation facilities on June 1 totaling 10 megawatts for $8 million cash consideration, plus the assumption of $18 million of project-level debt. The facilities are Savona and 150 Mile House, which are in British Columbia. Both facilities are currently under 20-year EPAs that expire in 2028.

Turning to slide 5, another significant milestone for the Company is the completion of our first wind development project in the United States. Our Bloom Wind facility began commercial operations on June 1 and is located in Kansas. The construction of the 178-megawatt wind project was completed one month ahead of schedule, and construction costs came in below budget. Bloom has a 10-year fixed price contract, having 100% of its output with a subsidiary of Allianz SE, a worldwide insurance and asset management group.

Due to the U.S. tax attributes associated with the project, equity financing was provided by an affiliate of Goldman Sachs. We expect Bloom Wind to be the first of many U.S. wind development projects to reach completion.

Moving to slide 6, with the recent acquisitions of Veresen's thermal power business and Decatur Energy Center, in addition to the startup of the Bloom Wind, I'd like to illustrate how this has diversified our geographical profile throughout North America. The chart shows our geographical breakdown based on Adjusted EBITDA. At the end of 2016, 73% of Capital Power's Adjusted EBITDA originated from Alberta. This was followed by 13% in Ontario, 9% in B.C., and 5% in the U.S. With the addition of the six new facilities, you can see how we've achieved geographical diversification away from Alberta. In 2018, assuming there is no other changes in the current fleet, the expected Adjusted EBITDA from Alberta will be reduced from 73% to 52% and will largely shift to the U.S. where Adjusted EBITDA will increase from 5% to 22% of our new total.

Furthermore, the recent acquisition commissioning of Bloom Wind has materially increased the Company's contracted cash flows, as shown on slide 7. The chart shows the growth of our contracted Adjusted EBITDA from 2012 to 2017. As you can see, our contracted Adjusted EBITDA has increased 157% during this period, which translates into a 21% compound annual growth rate. For 2017, you can see the significant step up in contracted Adjusted EBITDA from the Bloom Wind project and the start of the annual off-coal compensation payments and contributions from the acquisitions.

Turn to slide 8, this growth in contracted Adjusted EBITDA provides the support for dividend growth. Based on Capital Power's outlook, we have announced a 7.1% increase in the quarterly dividend from $0.39 to $0.4175 effective with the third quarter dividend. We have also extended our 7% annual dividend guidance for an additional two years to the end of 2020. With the annual growth to the dividend, we expect the adjusted funds from operations payout ratio in 2017 to 2020 will be within a range of 45% to 55%. Overall, the Company is well-positioned to deliver on this consistent annual dividend growth.

On slides 9 and 10, I'd like to provide a brief update on the Alberta power market. First, with respect to the capacity market, the Government of Alberta's schedule for the transition of Alberta's energy-only market to a capacity market continues to be on track. The design is expected to be formalized in late 2018, early 2019. We expect that the first capacity auction to take place in 2019 for delivery in 2021. There are five working groups providing feedback on key design elements based on a straw model that is being iterated from 2017 to June in 2018. Capital Power is participating in four of the five working groups.

For coal-to-gas conversion, the decision on timing of converting our coal units to gas depends on numerous factors such as carbon and natural gas pricing, supply demand balance, regulatory framework for converted units, and the capacity market design. When the time comes to convert the Genesee facility to natural gas, it has many competitive advantages such as its young age, condition, availability, and heat rate that are maintained after gas fuel conversion, with the efficiency translating into higher dispatch. The estimated cost for a simple gas conversion on our units is between $25 million to $50 million per unit. We expect there will be significantly lower operating and maintenance costs after the conversion to natural gas.

Turning to slide 10, the Renewable Electricity Program, we have two proposed projects to bid in. Whitla Wind in southern Alberta has been bid into the first round and is <u>now competing in the third stage* of the process</u>. *[*__Correction__: Whitla Wind continues to make significant progress and if awarded a PPA, it can be in service in 2019. The AESO has closed the RFQ stage of its process, and indicated that it expects to open the RFP stage of its process on September 15, 2017.]* Halkirk 2 in east-central Alberta is well-positioned to participate in future procurement rounds. In July, we reached a partnership agreement with Siksika Resource Development Limited to develop new generation in Alberta. Under the agreement, Capital Power and Siksika will jointly develop power projects on the Siksika Nation reserve located 100 kilometres southeast of Calgary. The reserve is situated on 172,000 acres of land with excellent solar, wind, and natural gas project potential. This positions Capital Power very well for a number of future project developments.

As a leading developer of new power generation in Alberta over the past decade, Capital Power has the expertise and track record to build Alberta's next generation of renewable and baseload power generation.

Moving to slide 11 and the Q2 results, this slide compares the availability operating performance of our facilities for the second quarter of 2017 and for the first half of the year compared to the same periods a year ago. We had excellent operational performance in the second quarter with average availability of 94% which was higher than the 90% from a year earlier. In the first six months of the year, the average availability was 96% compared to 93% a year ago. The 94% availability in the second quarter reflects the major scheduled outage at Genesee 1, which had 70% availability. There were also other planned outages at Clover Bar Energy Center and Southport that reduced the availability for those facilities.

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

BRYAN DENEVE: Thanks, Brian. I'll start on slide 12 with a review of our second quarter financial performance. Overall, second quarter 2017 financial results were consistent with our expectations. This includes generating $47 million in adjusted funds from operations and normalized earnings per share of $0.27.

Alberta spot prices in the second quarter averaged $19 per megawatt hour compared to $15 per megawatt hour in the second quarter of 2016. Our trading desk performed well and captured 174% higher realized average price at $52 per megawatt hour on our Alberta commercial assets versus the spot price. Despite the strong trading performance this quarter, it was even stronger in second quarter of 2016 when the trading desk captured a 307% realized power price above the spot power price.

Slide 13 shows our second quarter financial performance compared to second quarter of 2016. Revenues and other income were $201 million, down 11% from the second quarter of 2016. Adjusted EBITDA before unrealized changes in fair values was $125 million, up 2% from the second quarter of 2016. Normalized earnings of $0.27 per share were down 10% compared to $0.30 in the second quarter of 2016.

As mentioned, we generated adjusted funds from operations of $47 million, which was down 41% on a year-over-year basis. The lower AFFO was due to higher costs in net financing expense, sustaining capex and preferred share dividends; as well as a lower realized power price and lower generation from the Southport facility.

Slide 14 shows the financial results on a year-to-date basis. Revenue and other income were $539 million, down 4% from 2016. Adjusted EBITDA before unrealized changes in fair value was $259 million, up 3% from the same period in 2016. Normalized earnings of $0.61 per share were down 3% compared to $0.63 in 2016. The lower AFFO in the first six months is due to higher net finance expense, sustaining capex, and preferred share dividends; as well as lower trading gains from portfolio optimization and lower generation from Southport.

On slide 15, I'll review the financial outlook for the remainder of 2017. The last half of the year will include full AFFO and the EBITDA contributions from the acquisitions of Veresen's thermal power business, Decatur Energy, and Bloom Wind. In the third quarter, AFFO will include the $52.4 million annual off-coal compensation payment from the Alberta Government.

Our updated commercial hedging profile for 2018 to 2020 is shown on this slide. For 2018, we are 66% hedged at an average contract price in the high $40 per megawatt hour range; for 2019 we're 45% hedged at an average contract price in the lower $50 megawatt hour range; and for 2020 we're 29% hedged at an average contracted price in the high $40 per megawatt hour range. If you compare 2018 to 2020 forward prices, from the first quarter you'll notice that forward prices have increased $6 to $7 per megawatt hour. This is due to higher-than-expected demand growth in Alberta, the retirement and mothballing of Sundance Units 1 and 2, and the balance Balancing Pool's plan to terminate all of the Sundance PPAs.

I'll conclude comments by reviewing our year-to-date performance versus our annual revised targets starting on slide 16. In the first half of the year, average availability was 96%, which is slightly ahead of our 95% target. Our sustaining capex in the first six months was $34 million compared to the $80 million revised annual target. We reported $104 million in operating and maintenance expenses in the first half of the year compared to the $215 million to $240 million target. We generated $138 million in adjusted funds from operations in the first six months. Taking into account the various items that I mentioned in the outlook for the remainder of the year, we are on track to reach the mid-point of the revised annual target range of $340 million to $385 million.

To conclude, slide 17 shows our growth targets for 2017. As Brian mentioned, we completed the construction of the Bloom project ahead of schedule and with construction costs below budget. Our other growth target includes the execution of contracts and the output of two new wind developments. We continue to make progress in our department pipeline in the U.S. and in Alberta. The Whitla Wind project has advanced to the <u>third stage* of the process</u> under a renewable electricity program, as previously mentioned. *[*__Correction__: Whitla Wind continues to make significant progress and if awarded a PPA, it can be in service in 2019. The AESO has closed the RFQ stage of its process, and indicated that it expects to open the RFP stage of its process on September 15, 2017.]*

I'll now turn the call back to Randy.

RANDY MAH: Thanks, Bryan. Operator, we're ready to start the question-and-answer session.

OPERATOR: Thank you. We will now begin the Q&A 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 pause for a moment as callers join the queue.

The first question is from Rob Hope of Scotiabank. Please go ahead.

ROBERT HOPE: Good morning, everyone, and thank you for the update on the Alberta power market. Just wanted to get your thoughts, just given that the United Conservative Party is polling well, being potentially led by Jason Kenney who is pro-coal and anti-carbon tax. I'm just wondering how do you account for this in your longer-term strategic planning for the business?

BRIAN VAASJO: So, what we've actually done as a company, is we've taken a look at a whole, I'll call it, array of longer-term outcomes as it relates to, I'll call it, de-carbonization. On that path, and these various scenarios range from accelerating what's here today to slowing down, to temporary stops. And what we've done is basically we've developed a strategy within the context of, I'll call it significant uncertainty, and picking those paths that make the most sense going forward.

As it relates specifically to Alberta, when we look at investments, certainly continuing to build renewables, and we expect that certainly with a change in Government there may be some changes, but, ultimately, renewable energy will be needed in Alberta and so therefore our efforts and the work that we're doing certainly will be utilized in the future.

The most fundamental and significant thing that's happening in the Alberta market and that's unaffected to a significant degree by Governments in the shorter-term, is the significant increase in demand that we're seeing in the province. That will have the greatest impact on both what happens from a development perspective and what happens in respect of the future of the Alberta power market.

Certainly, provincial carbon policy had some impact but, also you do have the impact in the overlay of the Federal positioning on it. So, we look at, the strategy and approaches in the long-term and specific political outcomes in the shorter-term. Again, we believe that the approaches that we're taking are resilient to whatever Governments come to pass.

ROBERT HOPE: All right. That's very helpful. Then, just kind of a similar question; just in terms of the working groups and the capacity market designs that have been put forward, are these largely as you would have anticipated before, or are there any sticking points that you're seeing right now?

BRIAN VAASJO: Well, it's certainly early days. We're not seeing any real sticking points. We think the overall process, although is definitely cumbersome by design, but the design is to engage a broad sector of interest in the power market. Going through iterations associated with, at different stages and different time frames, certainly provides for ensuring what is one of our biggest concerns, is that decisions are made in a vacuum and there's unintended consequences with other elements of the process. So, the way it's mapped out, we see that that minimizes the risk of that happening.

ROBERT HOPE: All right. That's helpful. Thank you.

OPERATOR: The next question is from Patrick Kenny of National Bank Financial. Please go ahead.

PATRICK KENNY: Good morning, guys. Just back to the bump in forward Alberta prices here in light of the Balancing Pool's plan to terminate the Sundance PPAs. Maybe you can talk about how you might be in a position from a trading perspective to take advantage of the Sundance supply potentially coming off here a couple of years earlier than expected; and does this impact your outlook for Genesee 1 and 2 at all just in terms of your decision to burn coal right up until 2029 versus compared to gas? Maybe also you can dovetail any comments on G4 and G5.

BRYAN DENEVE: So, in terms of the Sundance units going back to TransAlta, that certainly is a bullish catalyst for the market. We continue to hold length in 2018 and 2019, so certainly, as we manage our projections of pricing and look forward, that is a factor we're taking into account and, certainly, there's a lot more upside now with this than downside, in our view, in Alberta. So, as we continue to see upward movement in forward prices, we'll have the opportunity to increase our average hedge price as we take advantage of that.

The other thing on the PPA front, the Balancing Pool, in their release, made it clear that it also makes sense to potentially push back Battle River 5 and potentially Keephills 1 and 2. But, of course, those are still tied up in discussions between the Government and Enmax. We believe as that gets sorted through, we'll see the Balancing Pool take a similar position with those PPAs which will be a further catalyst for pricing in Alberta.

When it comes to coal-to-gas conversion, the higher pricing isn't really a driver in that decision. The biggest driver, as Brian mentioned earlier in his comments, is going to be where CO2 pricing lands and where natural gas pricing lands, and also some of the design elements in the capacity market. So, all of those are going to be factors in terms of the timing and when we do the conversion, and, of course, we'll be monitoring all those factors and that'll inform our decision on the timing.

At the end of the day, the lead time for the coal-to-gas conversion requires about 12 to 18 months to get the parts. Certainly, the downtime in the plant is at most a couple of months, so as we see factors change in the market, it's not a huge lead time for us to make those changes to the unit and take advantage of that conversion.

In terms of Genesee 4 and 5, the strong demand growth we're seeing in the province, coupled with—it'll be interesting to see as the owner gets back those units—as TransAlta gets back Sundance—and some of the decisions we may see them make over the next 12 to 18 months, that could affect our projected timing for Genesee 4 and 5. So, certainly we could still see that unit being needed in Alberta as early as 2021. We're in a position to move forward with that development, and it's a development project that we'll be looking to potentially bid into the capacity market in 2019.

PATRICK KENNY: Got it. That is great color. Thanks, Bryan. Then, in your disclosure here you mention the reduction in scope to the GPS project. Just wondering if we can get a bit more color on those changes; and if you can confirm from back in your Investor Day, you were talking about a $35 million annual savings on compliance costs, has that changed at all?

BRYAN DENEVE: No. The benefits in our projections of them hasn't changed. What has changed is there's some elements that, as we've gone underway, there's some pricing reductions actually we're experiencing that is reducing our projected capital expenditures necessary, which is a positive thing. The other factor that's happened is some of the bigger expenditures, upon further analysis, it doesn't make sense for us to make commitments on that until 2018 as opposed to 2017, so that's pushed out some of those capital expenditures. But, certainly, the scope of the benefits and emission reductions remain the same.

PATRICK KENNY: Got it. Thanks for that. I'll jump back into queue.

OPERATOR: The next question is from Ben Pham of BMO Capital Markets. Please go ahead.

BEN PHAM: Okay. Thanks, good morning. I had a question about your extension to dividend CAGR through to end of decade. If you look at Slide 7, you highlighted the contracted cash flows and that provides a pretty incredible picture to support that. I'm more curious, though, just as you thought about extending that guidance more to 2020 outlook and a lot of moving parts there that you've probably looked at and this Slide 7, a couple of those wedges start to roll over to the merchant side and you had some contract expiries as well to think about. If you can just walk us through that process a bit more, some of the puts and takes you looked at post 2020 and the range of payout ratios that you felt comfortable with when you extended the guidance?

BRYAN DENEVE: So, in terms of the extension through 2020, as you mentioned, Ben, we have a very good line of sight on how things will unfold financially, and we're very comfortable that with that guidance we provided, we'll be within that 45% to 55% payout ratio during that period. As we look beyond 2020, certainly there is some additional uncertainty, and one of them will be the implementation of the capacity market and what that'll mean for our merchant length in Alberta. We've done a lot of sensitivities on the capacity market and how that design could look, but generally, there's boundaries there and, effectively, the Government's commitment is that existing facilities will be treated fairly with new builds in the capacity markets. So, that will result in price signals that will support new builds and when we look specifically at Genesee 1 and 2, it rolls off of a PPA that's paying $40 a megawatt hour. We certainly will be responsible for carbon pricing on top of that, but with merchant pricing all-in in the $55 to $60 a megawatt hour range, we see stable margins off of Genesee 1 and 2 coming off of 2020.

So, that gives us comfort that as we roll into 2021 we'll remain within a payout ratio of 45% to 55% and when we look further beyond that, we do have re-contracting in terms of Island Generation in 2022, as well as Decatur. As we've mentioned previously, Decatur we're very comfortable in the prospects of re-contracting for that facility. And Island Generation, being that it's needed for supporting the grid on Vancouver Island, we also believe that'll be an asset that has a high probability of re-contracting. So, we don't see the re-contracting as an exposure relative to our ability to support the dividend beyond 2020.

BEN PHAM: Can I clarify Bryan, the capacity payments? Are you planning to treat that as contracted cash flows?

BRYAN DENEVE: There're still details to be worked out in terms of the term of the capacity payments in the capacity market. That's one of the areas under discussion. Generally, as we look forward, we wouldn't view those capacity payments in the same vein we would those under a long-term PPA. Having said that, to the extent there is three to five-year term on the capacity payments, that will provide more certainty and stability around cash flow, so certainly a positive.

BEN PHAM: Okay. My other question is, on the forward curve. You highlighted the $6 to $7 move and I'm just curious, you guys have been looking at the market for a long time now and do you think that move was warranted and how does that kind of compare to just the way you guys have hedged this year and in '18, '19, and '20?

BRYAN DENEVE: Well, one of the things that certainly you've seen this year is, although we've increased our hedge position in '18, '19, and '20, quarter-over-quarter it hasn't been dramatic. A large part of that is due to the fact that we felt forwards in Q1 were understated of the true value of power in those years. So, we took some select opportunities to lock in some additional length, but generally, where forwards are, is more in line with our expectations, and certainly now with the strong Alberta load growth and some of the decisions being made on older units, certainly we see a lot more upside than downside in the Alberta market. And we'll be looking to take advantage of that as we continue to hedge out our length in Alberta.

BEN PHAM: Okay. All right. Thanks, Bryan. Thanks, everybody.

OPERATOR: The next question is from Andrew Kuske of Credit Suisse. Please go ahead.

ANDREW KUSKE: Good morning. Really, the question is for either of the Brians, and really relates to the capacity market. So, when we've seen these transitions in the past from a competitive market or a regulated construct to a capacity market, it seems to favor the generators in, really the first iteration. I'm just wondering how you think about the market transition on a longer-term basis from where we are today to capacity market? Then, thinking about the long-term outlook that the AESO just put out, when a market possibly becomes more competitive and then obviously a skew of renewables that comes into it?

BRYAN DENEVE: Well, certainly there's a build-out of renewables, and as those renewables get built, it'll put some downward pressure on energy pricing. But looking forward, if we continue to see demand growth as we have, need for new capacity as early as 2021, you're going to see a combination of energy prices and capacity prices that are going to have to provide signals to incent new thermal generation to come online to maintain the reserve margin that AESO will be targeting.

So, at the end of the day, the all-in pricing, we are very comfortable that we'll see in the sort of $55 to $60 range, which is what'll be needed for new natural gas build in the province.

ANDREW KUSKE: Then, maybe just as a follow-up, when you think about your incumbent position right now in Alberta, do you view yourselves as having effectively the best of both worlds because you've been doing a lot of out-of-Alberta investment in the last little while, whether building new things or buying things, but you still have this ongoing optionality of just funneling capital back into the province if the price signals exist appropriately?

BRIAN VAASJO: Andrew, I think you've somewhat hit the nail on the head from our perspective, and definitely with this shift of cash flow coming from outside of Alberta and even within Alberta, the contracted cash flow around the Shepard facility, et cetera. We are finding ourselves to be in an excellent position of continuing to provide investors with the growth coming from the contracted cash flow side and providing them with, certainly some upside optionality around what may well happen in Alberta, not just from the pricing side and what may happen in the market, but in terms of assets that we hold and assets that we are positioned to develop. So, there's a tremendous amount of optionality, again, around the price side, but also around what can happen in terms of builds in the province.

So, certainly if the province moves to being a very positive environment from a constructive environment from both a pricing and a demand perspective, we can see significant opportunities for Capital Power in Alberta, both on the investment and, certainly, on the uplift in terms of financial results.

ANDREW KUSKE: Okay. That's great. Thank you.

OPERATOR: The next question is from Mark Jarvi of CIBC Capital Markets. Please go ahead.

MARK JARVI: Morning, guys. Question on the prospects for securing new contracts in the U.S.; just wondering what's sort of the gating items are that controls the process, whether or not you guys have a lot of control over the timelines, if it's sort of exclusive negotiations sort of like the Bloom contract or you're looking at more RFP opportunities?

BRIAN VAASJO: All of the above. We're extremely active on a number of projects, looking at both bilateral arrangements associated with more financial players that, again, ultimately end up providing power to somebody who is in need of power. And there continues to be RFPs associated with utilities or significant load requirements, such as you often hear about Microsoft and Walmart and others. So, there's an array of different opportunities that are available to renewable generators in the U.S.

In terms of gating, I mean, certainly there is formal RFP processes that we'll participate in, but there's also—and we have, in some cases, we're generating our own opportunities by offering the facilities and seeing what sort of interest there is out there on any of these fronts, and we've had some success from that perspective. So, we continue to be very bullish and certainly expect that, in the nearer term, that there'll be some positive announcements from us in respect of meeting our objective of two new contracts on the renewable side this year.

MARK JARVI: Okay. Then, going back to the capex, I mean, certainly the MD&A talks about maybe sustaining capex and Genesee performance standard spending being below the original target. Can you maybe quantify that or give us a better color how much lower than the initial target you might be?

BRYAN DENEVE: I think for 2017 our projections was about $10 million for GPS. I think our expectations are substantially lower because about half of that is being deferred into 2018, and again, that's because we determined that, from a timing perspective, relative to our planned outages, it didn't make sense to make those commitments in 2017 but rather 2018.

MARK JARVI: And spending on things outside of the GPS?

BRYAN DENEVE: We're more or less on target for the year.

MARK JARVI: Okay. Then, just circling back on your comments around the load growth, I mean, the AESO came out with their long-term forecast about a week ago. They're quite conservative looking at sub 1% sort of CAGR over the next several years. What is it—you think they're just being overly conservative or what gives you a bit more comfort that you guys see more constructive load growth than what they've just put out?

BRYAN DENEVE: Well, our comments have been driven primarily on the normalized demand growth we've seen over the last 10 months in Alberta, and in the first half of this year running at about 3.5%. Longer-term, we don't expect it's going to stay at 3.5%. It'll certainly start to temper as we roll into 2018, but we still see it being in the 1% to 2% range. And some of the examples we see out there are just loads that are looking to locate in the province and that we're seeing on the commercial side that we're in discussions with. So, a lot of our commentary is based on, obviously, on what we've seen actual demand growth has been over the last 10 months but also what we see happening in terms of new development.

MARK JARVI: Good. Thanks for taking my questions, guys.

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

ROBERT KWAN: Good morning. You talked about expecting a finalization or formalized capacity market in that late '18, early '19 timeframe. Just wondering though, do you expect to get a decent amount of granularity on some of the more technical aspects ahead of that such that you can make some decisions whether that's around coal-to-gas or G4, G5?

BRIAN VAASJO: So, the general theory in terms of the way this is moving forward, Robert, is the granularity will essentially be there by about the middle of next year and from '18 until '19 will be actually putting the regulations in place and enabling the auction process. So, we're very hopeful that there'll be a significant level of granularity available to us as we go through these processes. And kind of seeing the direction that discussions and policies are going, we're hopeful that there'll be some of the bigger picture issues will be somewhat resolved by the end of this year, and then as we go through the first half of next year, a fair amount of granularity will be resolved.

Now, there are some issues such as around auxiliary services and so on that, by decision, the AESO has pushed off onto later processes of determinations. So, again, we do expect that there'll be a significant amount of clarity that'll happen over the next calendar year.

ROBERT KWAN: Okay. When you look at some of the different things around coal-to-gas that you outlined, does that kind of mid-2018 granularity get you comfortable enough, if it kind of falls the way you think with respect to some of the other aspects, whether it's carbon and gas pricing or how you're going to be viewing supply/demand?

BRIAN VAASJO: So, we are expecting—I mean, to be kind of blunt, any reasonable capacity market would be supportive of continuing in coal or converting the units from coal to natural gas. It's more a case of if there's a bust in the process, then we might have an issue. But, again, any reasonable market, going forward, would support the conversion of our facilities at the appropriate time.

I think as Bryan identified, the major issues will be around natural gas pricing and around the cost of carbon or the realized cost of carbon that will be in place through the next decade.

ROBERT KWAN: Got it. Okay. I guess turning to the renewables call, can you just comment on the state of potential projects within this new partnership? Is there anything that's actually been scoped out or is it pretty much a blank slate at this point? Then, Whitla was bid in, but it sounds like Halkirk 2 was not, so I'm just wondering if there's some color there in terms of whether it was ready or was it a strategic decision to wait to see if you can get some location-based premiums going forward.

BRIAN VAASJO: So, it's actually the latter. Now, again, given Halkirk's positioning, I mean, its real positive attribute is around the fact that the cannibalization of price is much lower at Halkirk than it is in southern Alberta in a case like Whitla. Again, the first round of renewables are not going to incorporate the cannibalization; i.e., the Alberta Government is going to be paying that, and we would see it definitely makes sense going forward for them to either through zones or some other mechanism, recognize cannibalism and a project like Halkirk 2 will become much, much more competitive.

As it would stand just in straight up competition, I mean, we do expect a very significant amount of competition in this first round from a lot of very good wind resources. We don't think that Halkirk 2 would've been competitive.

ROBERT KWAN: Okay. Then, just the new partnership?

BRIAN VAASJO: In terms of the new partnership, so in terms of understanding the resource, the solar resource is available, exists today. And, certainly, we're looking at nearer-term opportunities around it. We will need probably two-plus years of wind data. It may be less depending on timing because there is—one of the things in regards to the Reserve is it borders on two wind farms today, one of them being the Enbridge Wind, the 300 megawatts that was the last significant wind farm built in the province. So, it has a good wind regime. It's a point of just understanding how good it is and the right placement and so on and so forth. So, that'll take a couple of years of study before we'd have anything, again, from the wind perspective. But from a solar perspective, we're in a good position to respond to opportunities that come forward.

ROBERT KWAN: That's great. If I can just finish, there was a comment earlier on Island Gen and the potential to re-contract that. I'm just wondering, is there generation at Island Gen right now that's now that's not showing up in the numbers around voltage support, or just given it's not really producing a whole lot, is there something you expect to change in the B.C. market as to why that's going to be needed then at that point?

BRYAN DENEVE: No. It runs very, very little and it's only operated, for the most part when it's needed to back up the transmission links to the mainland. But as far as its need in terms of providing that service, all our discussions with B.C. Hydro is that we'll continue as we look out in the future. So, we don't expect it'll ever have a high capacity factor. Again, it's there to—when they're doing maintenance on inner-ties with the Island or if there's significant issues with generation on the rest of the system.

ROBERT KWAN: Okay. That's great. Thank you.

OPERATOR: The next question is from Avery Haw of TD Securities. Please go ahead.

AVERY HAW: Hi. Good morning. Just with the recent move in the U.S. CAD FX rate, what are your thoughts on foreign exchange hedging given your recent diversification efforts into the U.S.?

BRYAN DENEVE: So, generally our approach has been to maintain a hedge position relative to the exchange rate with the U.S. So, we look at our projected cash flow margins from our

U.S. facilities and what our financial obligations are with some of our U.S. debt placement that we have, and we enter positions to basically neutralize our exposure. So effectively, for the most part, any of moves we're seeing in the currency is not something that either harms or benefits us.

AVERY HAW: Okay. Thanks for the color. Just moving on towards your power facilities in Alberta, just with all the potential changes in the market and the importance of portfolio bidding down the road, how important is operating control and your ability to dispatch power from a facility going forward? I guess specifically, if there are any ownership clauses at your jointly owned facilities that allow you to somehow gain control over dispatch at the assets that you currently don't have control over?

BRYAN DENEVE: Having dispatch control will be almost as important in the capacity market as the energy-only market. Certainly, you want to have that ability because you'll still be bidding into an energy market just like we do today, but also you'll be bidding into the capacity component of it. Don't expect the control over the ability to do that offering will change as we roll into the new market. I think, on our JVs, you're going to see everybody want to maintain the control they currently have, so I don't see much change on that front.

AVERY HAW: Okay. Thank you.

OPERATOR: As a reminder, it is star one to ask a question.

The next question is from Jeremy Rosenfield of Industrial Alliance Securities. Please go ahead.

JEREMY ROSENFIELD: Yes. Thanks. Just a couple of clean-up questions. First, on Shepard, it was a little bit low in the quarter and I was wondering if there's anything specific that had restricted its performance in Q2 here.

BRYAN DENEVE: No, there was nothing physical restricting the performance. We believe that was primarily due to dispatch strategy that our partner Enmax was exercising. But, of course, we don't know the details behind that, but just based on our observations in the market.

JEREMY ROSENFIELD: Okay. Then, another item related to the acquisitions, I think in the disclosure there was something related to the costs in Q2 and I was just curious if there's the expectation that some of the costs related to the acquisitions might drag into Q3 results at all.

BRYAN DENEVE: No, we don't expect that there are any. So, integration has been completed for all the facilities, and certainly any impact on G&A has been reflected in Q2 and I don't believe there's anything left that'll show up in Q3.

JEREMY ROSENFIELD: Okay. Perfect. Then, just more from a higher level, with the recent acquisition, just more strategically thinking, in terms of, I guess, deploying more dollars into contracted gas assets rather than the opportunities obviously in Alberta, you want to see how that develops. So if you look at that incremental dollar being deployed into Alberta versus into other markets, is it really going to continue to be situation-specific or you still want to try to find additional contracts in gas assets, let's say, in the U.S. market?

BRIAN VAASJO: So, I think as we've been commenting over the last couple of years, our focus and our priority is on generating contracted long-term cash flow, and, certainly, as we look at opportunities and we see more and more contracted natural gas opportunities, we'll continue to move on those as well as continue and we see—we'll have the ability to both do that and participate in the Alberta market in terms of builds. But our definite preference for where we put our dollars, assuming reasonable returns on both sides, would continue to be more on the contracted side than it would be on the merchant side in terms of preference.

JEREMY ROSENFIELD: Do you see a lot of assets, let's say, coming to market in terms of contracted gas assets that owners are either interested in selling or putting up for bids and that sort of thing?

BRIAN VAASJO: Yes. We continue to see, I'd say in the short- to medium-term, a continuation on that trend.

JEREMY ROSENFIELD: Okay. Good, that's it. Thanks.

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

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

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