Capital Power
First Quarter 2019 Results Conference Call
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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

Robert Hope
Scotiabank

Patrick Kenny
National Bank Financial

Ben Pham
BMO Capital Markets

Andrew Kuske
Credit Suisse

Robert Kwan
RBC Capital Markets

Mark Jarvi
CIBC Capital Markets

Jeremy Rosenfield
Industrial Alliance Securities

John Mould
TD Securities

Operator

Welcome to Capital Power's First Quarter 2019 Results Conference Call. At this time, all participants are in a listen-only mode. Following the presentation, the conference call will be opened for questions. This call is being recorded today, April 29, 2019.

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 first quarter 2019 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 up 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 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 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 first quarter 2019 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'll start off by recapping the highlights from the first quarter.

One of the highlights was excellent operational performance. This included 98% to 100% availability from the Alberta, Ontario and BC facilities and an overall average availability of 96% for the fleet. With a high availability and recent growth from developed and acquired assets, we generated a record quarter of 5,782 gigawatt hours, which was up 15% compared to the first quarter of 2018. Bryan will talk about the financial performance shortly but based on our forecast for the remainder of the year, we expect AFFO to be in the upper end of our guidance range for 2019.

Another highlight in the quarter was the execution of a five-year heat rate call option agreement for Arlington Valley. This agreement is with an investment grade counterparty and covers the periods outside of the existing summer tolling agreements.

The counterparty has a right to call the plant in exchange for fixed monthly premiums plus reimbursement for fuel at an indexed price, variable O&M expenses, and start charges. The Adjusted EBITDA and AFFO during the non-summer period covered by this agreement are consistent with our expectations in the original guidance when the acquisition of Arlington was first announced in September of 2018.

Turning to Slide 5. On April 16, the United Conservative Party won a majority government in the Alberta provincial election. As outlined in the UCP's election platform, there are three important topics for Capital Power. The first one relates to carbon tax. At a high level, the UCP plans to implement a Technology Innovation and Emissions Reduction Framework for large emitters effective January 2020. The TIER Framework looks to be very similar to overall structure in the current CCIR. However, under the TIER Framework, the carbon tax compliance price is reduced from $30 to $20 a tonne, and the compliance obligations will be based on "good as best gas" performance standard.

Based on our initial assessments, the impact of the carbon tax reduction will not be fully known until all the elements of the policy, particularly performance standard, and emissions offset utilization rules are in place.

In the near term, we expect a modest impact on Adjusted EBITDA at the lower carbon compliance costs, which will be mitigated by lower power prices. As you are aware, the compliance obligations in 2020 for Genesee 1 and 2 remain with the Balancing Pool under the PPA. Also, the compliance costs through 2022 is substantially mitigated by our inventory of offset credits. In the longer term, we expect a greater Adjusted EBITDA uplift under the TIER Framework.

Moving to Slide 6, the UCP platform also commented to end costly subsidies for renewables after the third round of the Renewable Electricity Program is completed and move towards market-driven green power.

For Capital Power, we have experience and success with market driven renewables in the U.S. where we have found innovative ways in securing offtake agreements for our wind development projects. This experience plus our established construction and commodity and risk management expertise position us well for renewable investments in Alberta.

Finally, the UCP has committed to consult on whether Alberta should return to an energy-only market, and report back to Albertans within 90 days. For Capital Power, with our young, diverse fleet of assets, we are well positioned for success in a properly designed capacity market, or an energy-only market. We believe the AESO's CMD represents a workable framework if Alberta, believe that a capacity market is necessary. That said, we believe that the energy-only market has been successful in attracting timely investment and supported a reliable and competitive system for the benefits of Albertans, and that an energy-only market would continue to work and be successful.

We support the planned review of this issue and expect to participate fully. We are encouraged that the review has set a timeframe of 90 days. This will ensure this issue is addressed and direction provided in a timely manner and will support investor confidence.

Turning to Slide 7, I'll briefly touch on the Alberta power market. The average spot price of $69 per megawatt hour in the first quarter was the highest quarterly spot price in 2.5 years, and nearly double the $35 spot price a year ago. The high spot price in the quarter was due to a number of factors including unseasonably cold temperatures, higher gas prices, baseload facility outages, low wind generation and a high volume of power exports. As shown in the chart, current forward prices for the next few years are in the high $40 per megawatt hour range, due primarily to the lack of liquidity, but also due to carbon tax uncertainty and additional wind supply coming on.

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

Bryan DeNeve

Thanks, Brian. I'll start by reviewing our Q4 financial results on Slide 8. Overall, the first quarter financial results were in line with our expectations. This included generating strong AFFO of $117 million in the quarter, and Adjusted EBITDA of $202 million. The Company captured an average realized power price of $58 a megawatt hour compared to $47 a megawatt hour in the first quarter of 2018.

Slide 9 shows our first quarter financial performance compared to the first quarter of 2018. Revenues and other income were $397 million, up 27% year-over-year.

Adjusted EBITDA was $202 million, up 13% compared to the first quarter of 2018. The higher Adjusted EBITDA was driven by strong performance in our Alberta commercial and contracted facilities and was partially offset by weaker results in the Ontario and BC contracted facilities.

Normalized earnings of $0.29 per share was up slightly compared to $0.28 in the first quarter of 2018.

As mentioned, we generated AFFO of $117 million. That was up 38% year-over-year. AFFO on a per-share basis was $1.15 compared to $0.82 in the first quarter of 2018.

Overall, we had a strong year-over-year performance in all our key financial metrics.

Turning to Slide 10, I'll provide an update on our Alberta commercial portfolio positions.

For 2020, we are 24% hedged at an average contract price in the low-$50 per megawatt hour range. For 2021, we're 2% hedged at an average contract price in the low-$70 per megawatt hour range, and for 2022 we're also 2% hedged at an average contract price in the mid-$50 per megawatt range. This compares to current average forward prices of approximately $50 per megawatt hour for 2020 to 2022.

The low hedge percentage on the merchant position reflects our higher fundamental power price view compared to current forward prices.

I will now turn the call back to Brian.

Brian Vaasjo

Thanks, Bryan. I'll conclude our comments by comparing our first quarter performance against our 2019 annual targets. As shown on Slide 11, our average facility availability was 96% compared to the 95% annual target. Sustaining capital expenditures were $9 million in the first quarter and we continue to forecast $80 million to $90 million range for the full year.

We reported $202 million in Adjusted EBITDA versus the $800 million to $850 million target, and we generated $117 million in AFFO in the first quarter compared to the $460 million to $510 million target range. As mentioned earlier, we expect 2019 AFFO to be in the upper end of the range.

Slide 12 outlines our development and construction targets for 2019. We currently have two fully contracted wind projects under construction. This includes Whitla Wind in Alberta that has a $315 million to $325 million budget, with commercial operations targeted for the fourth quarter of this year. We also have our Cardinal Point Wind project under construction in Illinois. The budget is $289 million to $301 million, with a target to begin commercial operations in March of 2020. Once completed, these two wind projects will add 350 megawatts of long-term contracted generation to our fleet. We are also targeting $500 million of committed contracted growth capital in 2019.

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

Randy Mah

Thanks, Brian. Operator, we're ready to start the Q&A session.

Operator

Certainly. We will now begin the question-and-answer session. To join the question queue, you may press star, one on your telephone keypad. You will hear a tone acknowledging your request. If you're using a speakerphone, please pick up your handset before pressing any keys. To withdraw your question, please press star, two. We will pause for a moment as callers join the queue.

Our first question comes from Rob Hope with Scotiabank. Please go ahead.

Robert Hope

Good morning, everyone. Maybe just to start off on the 2019 outlook. Just in your commentary, you did mention that Q1 came in as expected. I just want to get a sense of what the moving factors are to bring it towards the upper end of the AFFO range and I would assume that potentially up to the upper end of the EBITDA range as well. Just wanted to get a sense of why Q1 was in line versus the upper end for the guidance.

Bryan DeNeve

Yes. For Q1, we did benefit, of course, from the higher power prices in Alberta on both our contracted Alberta assets, which do have a component to them where we benefit from higher prices under the PPAs, as well as with the Alberta commercial segment. That was partially offset by lower generation from some of our assets in the BC, Ontario portfolio and the U.S. portfolio.

However, when we look over the balance of the year, what we've seen happen is a strong power price performance in Q1 resulted in a lift in forward prices over the balance of 2019, which we were able to take advantage of from a trading perspective. We have locked in higher prices than we would have had when we provided guidance in December of last year.

Robert Hope

All right. That's very helpful. Then, as a follow up, just want to get some additional colour on how you think that the TIER Framework will impact your business, I guess, in 2020. Say, it's a modest impact, which implies uplift. Just want to get some moving parts there. I'm assuming better margin on coal and kind of your gas is probably down a little bit.

Brian Vaasjo

Well, as I commented, there's still a number of elements of the approach that we need to understand. For example, as you know, the existing regulations require that 30% of the commitment is fulfilled with cash as opposed to credits, so a lot of those details again will have an impact on whether it's positive or negative.

From a very high level, as you recall, we have a very extensive inventory of carbon credits, which are priced in about that $20 range, so to a large measure, whether it be up or down, we are somewhat immune to the impact of carbon price in the short term, other than, of course, the 30% that I referred to earlier.

As we look at the overall impact, we also see that as a result of carbon price moving to $20 next year, that that would have a modest downward pressure on power prices. Again, we need to understand the full details. I would say that at this point, our expectation is that for 2020 it would be potentially even very modestly negative. Certainly, we'd see 2021 moving to being neutral to potentially a little positive, but very significant positive implications in 2022.

Robert Hope

That's helpful. Thank you. I'll hop back in the queue.

Operator

Our next question is from Patrick Kenny with National Bank Financial. Please go ahead.

Patrick Kenny

Yes, good morning, guys. Just first on the Alberta market design, I know you mentioned you'll be working with the government over the coming months but wondering if you could just clarify what your preference or recommendation will be, from an operator's perspective. What some of the benefits might be from staying with the energy-only design? Or conversely, why transitioning to the capacity market is the way to go?

Brian Vaasjo

As we've said, historically, and maybe it's important to put this in a context. We have always been very positive on the energy-only market, and we're among the last ones standing supporting that moving forward. With the capacity market, our position has always been with a properly designed one and one that's got a reasonable stability associated with it, we'd be supportive of that as well.

With the prospect of moving to an energy-only market, again, we're very much more in favour of that. The other thing though that's evolved in terms of the capacity market, although what's currently on the table is well designed, there is a significant regulatory process between now and interim design and final design, which in our mind represents significant risk to incumbent investors in the Alberta market. Between the two factors, we are clearly in favour of the energy-only market but believe we would do well in both.

Patrick Kenny

Okay. That's great. Then maybe as a follow-on, assuming Alberta does stick with the energy-only design and with the carbon tax coming down to $20 a tonne, how do these dynamics all else equal impact the timing of your coal to gas conversions? In other words, are you more likely to convert to gas early or stay on coal for a longer period of time?

Brian Vaasjo

That tends to be a very dynamic question, as dynamic as the parameters moving around. I mean, the other thing that's happening as we're looking at it is it seems like natural gas prices are lower and will be lower for longer, which, again, somewhat supports the potential for increasing our level of ability to coal fire, and we continue to look at maintaining our optionality around our facilities. Again, we continue to look at advancing the coal firing and trying to optimize the situation without making a definitive decision one way or another.

In terms of timing, a lower carbon tax certainly does have the impact of potentially pushing out converting to natural gas. On the other hand, lower natural gas prices tend to kind of bring it forward. Again, it continues to be dynamic, and in the environment, in this kind of environment is the reason why we believe that maximizing our optionality, both on a current basis and a long-term basis, makes the most sense for investors.

Patrick Kenny

Okay. That's great, and then one last question, if I could, just with REP 4 and beyond expected to be canceled. Could you just give us your thoughts on whether or not merchant wind or solar is economically viable in Alberta? Or if the lower carbon tax going forward and hence lower renewable energy credits, along with, like you said, downward pressure on spot prices, might impair the economics for merchant renewables in the province?

Brian Vaasjo

Well, definitely, on a straight-up price perspective, we see that there is a gap between current power price expectations and the economics necessary to build a merchant wind, and even more remotely solar. On the other hand, there is a significant amount of activity in the province around industrial and commercial parties looking for renewable energy, although definitely not on a 20-year basis, on a much shorter basis. We might well see over the next year or two some projects moving forward based on commercial support as opposed to government support.

Patrick Kenny

Okay, that’s great. Appreciate your comments, Brian.

Operator

Our next question is from Ben Pham with BMO Capital Markets. Please go ahead.

Ben Pham

Okay, thanks. Good morning. I wanted to go back to the question around energy-only versus capacity markets. You mentioned that you do well in both scenarios, but would you say you're tilted more to the positive on energy versus capacity, just simply because of the volatility in the energy-only market and some of your peaking facilities that you have?

Brian Vaasjo

Absolutely, Ben. I mean, one of the things that we see in the capacity market as well is you still have the opportunity in a capacity market to utilize peakers, et cetera, et cetera, but you're quite right. In the energy-only market, the full use of the capability of our assets creates greater value for shareholders.

Ben Pham

Okay. Then on your Alberta commercial sensitivity to power prices, is it still $5 per megawatt hour drives about $16, 1-6, million in EBITDA?

Bryan DeNeve

Ben, I'd prefer to get back to you on that.

Ben Pham

Okay, all right. Okay. Then the only thing I wanted to check in is Gen 4 and 5, it's still on the project list, but is there anything to share there in terms of status? Should we be thinking about that, too, as you head out the next 12 to 24 months with market design changes?

Brian Vaasjo

Well, certainly, as we look at Genesee 4 and 5, one thing I can—just to be clear, it continues to be sitting on the shelf, and in the event that the province needs that magnitude of capacity, which can either come through growth or through what may happen with the coal fleet, it can be put in place and moved forward.

One of the things that's important—and this gets back to the energy-only market versus a capacity market. If you look at the process going forward, there wouldn't be any significant degree of certainty to be able to actually contract or bid an asset into the capacity market, in our view, until a minimum of 2022, which would mean the capacity couldn't be in place until 2025.

That regulatory process and risk that as I was referring to has a tail on it, and from our perspective makes it pretty difficult to invest in Alberta, at least until 2022 from a power perspective under the planned processes on the capacity market. Just thought I'd make that point that that definitely would put Genesee 4/5 on the sidelines until a 2022 decision.

Ben Pham

Okay. All right. Thanks, everybody.

Operator

Our next question comes from Andrew Kuske with Crédit Suisse. Please go ahead.

Andrew Kuske

Thank you. Good morning. I think the first question is for Bryan DeNeve, and it's just the dynamic on portfolio optimization in the quarter versus a year ago, where your $13 million revenues versus the $81 million. I'm just assuming that the market conditions that you saw, you really delivered on the commercial side because you got the $167 million. Obviously, part of that's price and volume, but could you just explain a bit of the dynamic that you saw from the trading book versus the fundamental performance of the equipment you've got?

Bryan DeNeve

Yes. As you know, Andrew, we have a number of hedges in place that we do one to two years in advance, so those hedges, we wiggle back to Q1 2018 where we had softer power prices. Those hedges would have been more in the money, so those dollars show up on the trading optimization line, and we have lower revenues at spot prices off our assets.

What happens in Q1 2019 is you would see a shift away from the trading line item to the actual spot price realized by the assets because those existing hedges are no longer as much in the money as they were a year ago. It's really just dollars shifting between line items that you're seeing. You can't look at that trading portfolio optimization line on its own as a pure indicator of how we're doing off the trading in terms of over and above what our guidance would be because it's reflecting the mark-to-market of those existing hedges.

Andrew Kuske

Okay. That's very helpful. Then, obviously in the quarter, you saw a lot of favourable market conditions and really good operational performance on your equipment really across the board by segment. Could you give us some colour on just the operational performance and what benefits you're seeing from predictive maintenance, and how happy are you with your equipment at this stage in time?

Bryan DeNeve

We're extremely happy with how the equipment and the fleet's performing from an availability perspective. As you saw, we continue to exceed our expectations on availability and have no reason to believe that won't continue as we move forward in the future.

Andrew Kuske

Okay. That's helpful. Then one final one. Could you maybe just give a little colour on Black Fork? I know it was noted in the corporate costs and just what happened there.

Bryan DeNeve

Yes. In terms of Black Fork, as we were moving forward to getting that development opportunity moving forward in a potential offtake agreement, we did reach a point where, from a development perspective, it looks less and less likely that that project would ultimately proceed. Because of that lower probability of it proceeding, we did write-off a portion of the costs associated with that asset. It's still possible we could use the site as a development site but, again, just given the lower probability from a wind perspective, we wrote off those costs.

Andrew Kuske

Okay. That's great. Thank you.

Operator

Our next question is from Robert Kwan with RBC. Please go ahead.

Robert Kwan

Good morning. Just coming back to the hedging, and I know that you dropped, or kind of policy is to drop the current year, but I'm just wondering if you look at your comment that you're able to take advantage of higher prices. Can you also just talk about did that materially increase the hedge volumes from that 78% level that you had going into the year?

Bryan DeNeve

That's correct. For the balance of the year, yes, yes.

Robert Kwan

Okay. Just turning to the U.S. segment and kind of digging in there, so you were up a few million dollars year-over-year, but the base business probably should have been roughly flat or should have been up that amount if you just take the FX tailwind. I'm just wondering. Can you quantify some of the drivers in the quarter? You added Arlington, recognizing that's highly seasonal, but you also added New Frontier? Arlington wasn't in the outage and Bloom Wind was down, but can you just kind of quantify all those factors and why results weren't higher?

Bryan DeNeve

Yes. With Arlington, the off-peak tolling arrangement we anticipated having in place in Q1, we didn't execute until effective April 1. It's now in place, and certainly, we're very happy with the agreement we have been able to optimize around that agreement. We didn't really see any lift, of course, from Arlington in Q1.

When we look at Decatur, Decatur wasn't dispatched as much as it typically is, and so that resulted in lower revenue from the offtake agreement. That's just vagaries of the market. We did see a downtick, but we expect that will recover as we go forward.

Then Bloom is primarily on—from an EBITDA perspective, the change in the tax equity agreement does result in us recognizing less EBITDA off the tax equity benefits than we did under the previous agreement. That's a headwind from an EBITDA perspective for the quarter.

Robert Kwan

Got it. Are you able just to quantify what, say, a normal would have looked like if you had Arlington in and Bloom, or I guess if Decatur's dispatch was higher?

Bryan DeNeve

Yes. If we had the tolling agreement in place for Arlington at the start of the year, that's probably about a $3 million delta. Decatur, the lower operation is about $4 million—and these are in Canadian dollars—and about $3 million from Bloom.

Robert Kwan

Okay. Perfect. Maybe just finishing up with Arlington and the new contract, it talks about fuel reimbursement at an indexed price. I'm just wondering if you can give some additional details around that and why the agreement wasn't just cost at the plant gate?

Bryan DeNeve

You're talking about the heat rate call option?

Robert Kwan

Yes.

Bryan DeNeve

Yes. Basically, it's a call option that the offtaker has to basically purchase power at a fixed heat rate, but it's determined in the contract; it's not based on the actual heat rate we see at the facility.

Robert Kwan

Right, so I'm just wondering is there a gap or a risk to you, given you're being reimbursed at an indexed price versus what's actually delivered to the plant gate?

Bryan DeNeve

Well, there is some risk, but it also provides an opportunity for us, to the extent we can optimize around that, and in fact, that's what we were able to do so far in April of this year.

Robert Kwan

Got it. Okay. Thank you very much.

Operator

Our next question comes from Mark Jarvi with CIBC. Please go ahead.

Mark Jarvi

Good morning. Just wanted to go back to the question around 2019 hedging. You talked about increasing the position, but maybe you can just talk about pricing. I think prior disclosure was mid-50s. Is it now pushing higher than that and close to the $60 level?

Bryan DeNeve

I don't have the number for the balance of the year, but certainly it is at higher prices than we would have reflected when we gave guidance in December.

Mark Jarvi

Okay.

Bryan DeNeve

I would say it's probably in the mid-50s for the balance of the year.

Mark Jarvi

Okay. Then going to Cardinal, I mean, one thing you guys have talked about in the past is internalizing some of the construction activity for the project. I think there was some headlines suggesting you guys did outsource this one to a third party for EPC. Just wondering what sort of dynamic is there about when you guys decided to bring that on. Or was it just refining a really attractive pricing in terms of third-party people available to construct the project?

Brian Vaasjo

Yes. That's reflective of the timing to properly go through the process. There was a competitive situation in terms of the contractors. The timing around that only reflects sort of a positive situation. There's really nothing associated with the timing of bringing on the contractor.

Mark Jarvi

Okay. Then maybe you can just provide more detail on the Decatur, the turbine upgrade, in terms of incremental, sort of, EBITDA contribution from that after you put that in place?

Bryan DeNeve

The Decatur upgrade, once it's completed for all three combustion turbines, we'd be looking at about 100 megawatts of incremental capacity that, ultimately, we would see playing out as additional revenue we would receive as we recontract that facility.

Mark Jarvi

But prior to recontracting, you don't expect any incremental uplift then?

Bryan DeNeve

Some, but not as much as what we'll realize once we recontract.

Mark Jarvi

Okay. All right, thanks.

Operator

Our next question is from Jeremy Rosenfield with Industrial Alliance Securities. Please go ahead.

Jeremy Rosenfield

Thanks. Just a question again on Arlington Valley and the offtake contract. The contract that you had signed, is this the agreement or the framework similar to what you had envisioned when you underwrote the acquisition of the asset originally?

Bryan DeNeve

The nature of the offtake agreement is different than we originally anticipated. As opposed to this being a tolling arrangement for the off-peak hours, it's now in the form of a heat rate call option, and in terms of the expected value that will be generated, it will be similar to what we expected under the tolling arrangement we had originally anticipated. It's a different form, but we expect it will get us to the same financial result.

Jeremy Rosenfield

Okay. I'm wondering in terms of the impact on the seasonality profile for EBITDA or AFFO from the facility, is there anything that may have changed with this contract versus what you had originally contemplated?

Bryan DeNeve

No. It would be roughly similar. It would be pretty similar.

Jeremy Rosenfield

Yes, essentially so it's still all summer peaking primarily?

Bryan DeNeve

Yes, yes.

Jeremy Rosenfield

Great. Okay. Then just with the sort of change in Black Fork, and maybe you can comment on the outlook for the U.S. sort of contracted renewable potential, and relative to your strategic sort of goals for new contracts and new wind assets in 2019, has anything changed there or you're still confident on one or two potentially new contracted wind assets this year?

Brian Vaasjo

Yes. As we sort of look forward, we continue to be optimistic that we'll be able to move forward on a renewable project this year.

Jeremy Rosenfield

Okay. Sorry. Did you had something to add?

Bryan DeNeve

Oh, no, no. I was just going to add to Brian's comment. We do have a number of other sites in the U.S. that we're continuing to move forward and develop. We never did anticipate that all those sites we have would ultimately move forward. Situations like Black Fork are not unexpected, but certainly, we view the other ones are good sites that will ultimately result in offtake agreements.

Jeremy Rosenfield

Okay. Maybe just one final question, just in terms of asset valuations, and I'm wondering if there is an opportunity or a desire on your part to monetize any of the assets as you bring them into service. For example, something like New Frontier. If there is or if there are parties that are willing to be acquirers of those assets at very good valuation levels, is that something that you are thinking of or may think of going forward?

Brian Vaasjo

I think whenever we look at capital requirements, et cetera, it's always an option to potentially dispose of an asset in terms of generating funds to carry on growth and refinance our business. What we find ourselves in a position though is that the opportunities that are in front of us and the ones that we're able to execute on pretty much balance against our growth aspirations. Another way of looking at it is we don't really have a surplus of projects. Certainly, if we found ourselves in that position, turning over projects would definitely be part of our overall strategy of optimizing our capital structure and financing options.

Jeremy Rosenfield

Okay, thanks. All right, that's it for me.

Operator

Once again, if you have a question, please press star, one. Our next question is from John Mould with TD Securities. Please go ahead.

John Mould

Good morning. Just want to start with the Whitla budget and just clarify that change. Your previous cost was, call it, $320 million, and it's now $337 million, but is the right way to think about that, that the actual delta is smaller than that $17 million because of the partial hedges that you had in place?

Bryan DeNeve

That's correct.

John Mould

Okay, great. Then maybe just coming back to the energy-only market structure. If Alberta does decide to stick with the energy-only market, are there any changes that you anticipate or think there might be a movement for in the current energy-only market, just given that there's only been a focus on the CMD over the couple years and some needed changes may have been put off? Or do you think it's just going to be steady as she goes?

Brian Vaasjo

I think there will definitely be some changes that are necessary, in particular because of the existence of the PPAs, and therefore, the market could count on stable generation and the reliability is certainly there.

When you move away from the PPA environment, there is a need for there to be other pricing mechanisms in the market around VAR support and other elements. You will see in terms of the ancillary services probably a broadening of the kinds of things that are priced. But other than that, we'd see the fundamental energy-only market should be working the same way as it is now. There is a need for additional tools for the AESO to have to guarantee reliability and stability in the market.

John Mould

Okay. I'll leave it there, and thanks very much.

Operator

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

Randy Mah

Okay. If that's it for questions, we will conclude our conference call. Thank you for joining us today and for your interest in Capital Power. Have a good day, everyone.

Operator

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