Capital Power
Q2 2021 Results Conference Call
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Conference Call Participants

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Operator
Welcome to Capital Power's Second Quarter 2021 Results Conference Call.

As a reminder, the conference call is being recorded today, July 30, 2021.

I will now turn the call over to Mr. Randy Mah, the 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 2021 results, which we released earlier this morning. Our second quarter report 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 Sandra Haskins, Senior Vice President, Finance, 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 everyone 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 2.

In today's discussion, we will be referring to various non-GAAP financial measures as noted on Slide 3. These measures are not defined financial measures according to GAAP, and do not have standardized meanings prescribed by GAAP, and therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures are provided to complement the GAAP measures which are provided in the analysis of the Company's results from management's perspective. Reconciliations of these non-GAAP financial measures to their nearest GAAP measures can be found in our second quarter 2021 MD&A.

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

Brian Vaasjo
Thanks, Randy, and good morning. I'll start off with the highlights of the second quarter and comment on our 2021 outlook.

We delivered strong second quarter results that significantly exceeded our expectations, largely driven by our performance in Alberta where the Alberta power market continues to be robust with a positive outlook. Accordingly, we have updated our 2021 financial guidance, with ranges above the top end of our original targets for adjusted

EBITDA and AFFO, despite the impacts from the Genesee 2 forced outage that started in mid-July that I'll comment on shortly.

In line with our dividend growth guidance, we've announced an approximate 7% dividend increase that is effective with the third quarter 2021 dividend. We also continue to make solid progress on our approximately $1.7 billion in growth projects. As part of our goal to be net carbon neutral by 2050, we continue to advance our CO_2 reduction initiatives.

This includes carbon capture and storage at Genesee where there is significant government support, and the development is going very well. With the Genesee Carbon Conversion Centre, we continue to investigate the commercial opportunities for carbon nanotubes and board approval for the project facility is expected later this year.

Turning to Slide 5, Genesee 2 experienced a forced outage in mid-July caused by a generator failure. The outage is expected to last six weeks with return to operations anticipated in the third quarter of this year. We plan to utilize our Clover Bar peaking facility to partially mitigate the Genesee 2 impact. The three-week planned outage for Genesee scheduled for October will be advanced and completed during this outage.

Moving to Slide 6, this chart shows our solid track record of dividend growth with eight consecutive years of dividend increases, averaging 7% per year. As mentioned, we've increased the common share dividend by approximately 7% to $2.19 per year starting in the third quarter. We're also maintaining our dividend guidance for a 5% annual increase in 2022. As you can see, the AFFO payout ratio continues to track below our long-term payout target of 45% to 55%.

Turning to Slide 7, last month BC Hydro released its draft Integrated Resource Plan. In that draft IRP, it stated that BC Hydro is not currently intending to renew the long-term electricity purchase agreement for our Island Generation facility that expires in April of 2022. We are actively participating in the IRP review process, including retaining technical experts familiar with BC Hydro's utility resource planning and transmission systems operations to support the review of the draft IRP.

Comments are due at the end of this month, with the final IRP expected to be filed by the end of this year. We're also engaging with B.C. and local government officials and other stakeholders. We continue to believe Island Generation's dispatchable generation remains critical to the reliability of the B.C. system, particularly on Vancouver Island, as again shown by recent weather and system events. With the current transmission difficulties they're experiencing on Vancouver Island, Island Generation has been continuously dispatched since July 9.

I'll now turn the call over to Sandra.

Sandra Haskins
Thanks, Brian.

In the second quarter, we completed a successful equity offering of approximately 7.5 million common shares, including the over allotment that raised gross proceeds of $288 million. Following the closing on June 2, share price rebounded from the issued price of $38.45 and is currently trading approximately 9% above the issue price.

On the debt side, we executed a $150 million U.S. Dollar private placement of 12-year senior notes. The notes have a coupon rate of 3.24%, which with the inclusion of a forward starting swap settlement that was put in place for the issuance, equates to an effective interest rate closer to 2.5%. Twelve-year notes demonstrate investors' continued confidence in our long-term outlook. The transaction is scheduled to fund in late October to better align with the cash flow profile of our growth projects.

We've also had recent affirmations of our investment grade credit ratings and stable outlook by both S&P and DBRS. Earlier this month, we announced the closing of our inaugural $1 billion sustainability linked credit facilities, or SLC. This involved amending our existing credit facilities, including a 2-year extension to transition them into 5-year SLCs. Pricing is in line with our pre-COVID pricing grid. The SLCs are structured with one KPI tied to our CO_2 emission intensity reduction target of 65% by 2030, based on 2005 levels.

The agreements are structured such that borrowing costs increase or decrease based on annual performance against the target. These financings have reduced the financing risk of our capital program and the need for additional equity offering for current growth projects.

Turning to Slide 9, the Alberta power market continues to be very robust. Above average temperatures in June contributed to an average power price of $105 per megawatt hour in the second quarter that was 3.5 times higher than the $30 per megawatt hour in the second quarter of 2020. In the second quarter, our trading desk captured an average realized price of $75 per megawatt hour, or 42% higher than a year ago. Positive market outlook is reflected in forward prices of approximately $94 per megawatt hour for the last half of the year.

For our Alberta commercial portfolio, our baseload generation is 42% hedged in 2022 at an average contract price in the high-$50 per megawatt hour range. 2023 and ’24 were 30% and 15% hedged respectively at an average contract price in the mid-$50 per megawatt hour in both years. This compares to current forward prices of $72 per megawatt hour for 2022, and $61 for 2023, and $52 in 2024.

On Slide 10, I’ll review our financial results for the quarter. As Brian mentioned, financial results compared to budget significantly exceeded our expectations. Adjusted EBITDA was $241 million in the second quarter, up 11% from a year ago. The increase was due to higher Alberta power prices that resulted in a 28% increase in adjusted EBITDA for the Alberta commercial segment. However, this increase was partially offset by the impact of planned outages at our Decatur and Arlington facilities in the U.S., lower wind resource at most of our wind facilities, and a stronger Canadian Dollar.

Due to seasonality, the second quarter is generally the lowest quarter for AFFO. This year, we generated $91 million in the second quarter, down 6% from a year ago, as stronger plant performance was offset by $11 million of higher sustaining CapEx scheduled in Q2 2021, and the Milner line loss AFFO impact of $7 million in the quarter. AFFO per share of $0.83 was down 10% from the second quarter of 2020.

Slide 11 shows our performance for the first six months. Adjusted EBITDA of $544 million was up 21% compared to $451 million for the same period in 2020. The main driver for the increase was the higher Alberta power prices where our realized power price of $76 per megawatt hour compared to $58 a megawatt hour a year ago. Lower corporate expenses also contributed to the higher adjusted EBITDA, mainly due to the acceleration of coal compensation revenue.

AFFO was $250 million, up 16% compared to $250 million a year ago. Higher plant performance from strong Alberta results were partially mitigated by higher sustaining CapEx in the first six months of 2021 and $13 million in Milner line loss ruling impacts to AFFO. Overall, we’re seeing strong performance in our key financial metrics in the first half of the year.

I’ll now turn the call back to Brian.

Brian Vaasjo
Thanks, Sandra.

Turning to Slide 12, I’ll review our performance for the first half of the year compared to 2021 targets. In the first six months, average availability was 90%, including outages at our Decatur, Arlington, and Shepard facilities. As mentioned, Genesee 2 is currently offline with a forced outage; but it’s not expected to materially impact the 93% annual availability target, as Genesee 2 had a major planned outage scheduled in the fourth quarter that will no longer be required.

Sustaining CapEx was $47 million in the first half of the year compared to the $80 million to $90 million annual target. Based on our current outlook, we’ve increased our adjusted EBITDA and AFFO annual targets, largely due to the strength of the Alberta power market. Of note, the updated guidance range is higher than the top end of the original guidance ranges and reflects the estimated impacts from the Genesee 2 outage.

In the first six months, we reported $544 million in adjusted EBITDA compared to the revised annual target range of $1.09 billion to $1.14 billion. Lastly, we generated $250 million of AFFO compared to the revised $570 million to $620 million annual target range.

To wrap up, I'll cover our growth targets as highlighted on Slide 13. We continue to make progress on all of our renewable projects. This includes developing and constructing seven renewable projects on budget and on time for commercial operation, starting between the fourth quarter this year and the fourth quarter of 2022.

For the repowering of Genesee 1 and 2, all regulatory approvals have been received and construction is expected to begin in the third quarter of this year. Targeted operational dates are late 2023 for Genesee 1 and 2024 for Genesee 2.

With our major projects underway and the strength of our balance sheet from recent financings and our performance, we are positioned very well to pursue our $500 million committed capital target. This could be continuing to grow our renewable assets and/or acquiring midlife contracted natural gas assets.

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

Randy Mah
All right, thanks, Brian.

Anastasia, we're ready to take questions.

Operator
Certainly. We will now begin the question-and-answer session. The first question comes from Maurice Choy with RBC Capital Markets. Please go ahead.

Maurice Choy
Thank you and good morning.

Maybe I'll start off with a follow-up to one of the points you made in the prepared remarks. You discussed the Genesee Carbon Conversion Centre, as well as CCUS. More broadly, can you discuss what you need to see in order to commit to these two projects, specifically what is within your control and what isn't?

As well, if you could compare the returns from these projects that you expect versus the range of development assets that you currently have on the go. That would be great.

Brian Vaasjo
Okay. Thank you for the question.

In terms of the two projects, when we look at CCUS, and I'll start with that one, it continues to go well. What we need to see in terms of proceeding is, firstly, the government programs that we see and, you know, have not changed our view, nor has the government changed its view in terms of the kinds of support that would be available for this kind of a project. Obviously, that needs to come to fruition. And I would say, on those fronts, things continue to be quite positive.

Secondly, obviously, the technology needs to work itself out in terms of both cost and in terms of applicability. And we are looking at relatively stable technologies at this point, and so we don't see that that would necessarily be a difficulty. From the CCUS standpoint, we continue to see it being very positive and moving forward.

Now, depending on the types of government support that we're looking at, can have a significant impact on what we see as a hurdle rate. For example, if part of an overall package of support given to these kinds of projects is, say, a guarantee of carbon price for 10 years, then that certainly takes an element of risk out of the project. But having said that, when we look at what would be an appropriate hurdle rate for this kind of a project, we would start from a merchant perspective. That end of the spectrum and then adjust it depending on what we see as various kinds of support for the project. And in particular, the commodity risk associated with CO_2. That's the general framework for CCUS.

The other thing, sorry, in terms of CCUS that we would have to see is obviously the Alberta Government is pursuing a track of carbon hub and spokes associated with the pipeline access to what might be the spots to bury the carbon. That needs of course, to move along and to come to fruition. We certainly wouldn't want to get ahead of that development. We would like to see that move along very quickly and be in place from a number of different perspectives before we would move too quickly to commit our dollars to the CCUS facilities.

In regards to GC3, the design work continues to go very well and so we're not seeing that there's any technical issues associated with moving forward with it. What we continue to be evaluating and more or less finding – what are the different markets to be utilizing these carbon nanotubes in the short term and continue to explore that. Cement testing continues to be ongoing. In fact, there's a significant cement testing that is being kicked off as we speak. And so, we'll continue to be bullish from that perspective.

We need to see some significant commercial step forward in terms of people actually signing up for carbon nanotubes, or clear identification of a vibrant market that it can tap into before we actually start construction of GC3. Likewise, we look at that from probably a merchant plus hurdle rate, given that it is largely more speculative than a merchant market, so we'd be looking for some pretty robust long-term returns associated with that project.

I might also comment that just in terms of the way of looking at our development going forward. There is a fairly long process associated with getting carbon nanotubes and variations of carbon nanotubes approved from a both a Canadian and U.S. regulatory perspective, as a "new material". And that takes about 12 to say 15 months. And we're in a situation now that when we find the carbon nanotubes to start putting through this process, that gives us more than enough time to finish, polish up the design parameters associated with GC3 and to complete it so that we'll have regulatory approvals and completion of the project happening simultaneously.

Maurice Choy
Thanks. And to be clear, whilst you start at a merchant return level or a merchant plus, is the ideal end goal to have more than 50% or maybe even 70% contracted? Or are you happy to have it merchant and then back fill the contracted bits with other developments that you may go for?

Brian Vaasjo
Well, the nature of the market and this is the same with any sort of "material" is it's not typical for there to be long-term contracts associated with the supply of materials. It would be good to have long-term contracts, but we don't believe that that is practical. There may be shorter-term contracts for a year or two, or something of that nature, but we don't believe the nature of the market is such that long-term supply contracts would be available.

Maurice Choy
Thanks and my final question keeping the theme of contracted. Amidst your discussions with BC Hydro with regards to Island Generation, maybe more broadly, how do you view your current re-contracting profile? And more specifically, does it change your desire to acquire midlife natural gas generation assets?

Brian Vaasjo
Actually, no. And the reason is, as I indicated in the comments thus far, we see that that facility is definitely needed on Vancouver Island, and I would say the IRP that was put out by BC Hydro doesn't have the same level of diligence or analysis behind it that IRPs in previous years have had. It's very much, I would say, incomplete from that perspective and I think as their work is complete and as parties like ourselves have input, I think we will see a different answer, if not in the IRP itself when it's out in December, ultimately as it goes through process with BC Hydro, or BCUC. We definitely continue to believe that that facility will be re-contracted.

And when we look across the other re-contracting situations, and in the near term, the next one is Arlington, which comes up I think in 2024 or 2025. The outlook for that has been recently strengthened significantly and that's because we're seeing significantly high prices in the Arizona market. We're seeing supply constraints starting to evolve and the niche that we fill is particularly strained, so the outlook for re-contracting in Arlington Valley, which is the next one, is very, very strong.

When we look at what's the next series of re-contracts, which is at the end of this decade, 2029 in Ontario, the recent outlook that was published by the ISO shows that all three facilities will be very much needed as we go out the decade. There's a significant demand for generation, new generation in Ontario and even under scenarios where everything gets re-contracted there is still a very significant demand. And there are increasing constraints on the system, and our three facilities are on the right side of those constraints. They continue to be extremely well situated for being needed in the Ontario market. Our outlook for re-contracting existing assets is actually stronger now than it had been before.

When we look at new assets, obviously, we continue to have to scrutinize not only the current contracts and current circumstances, but definitely continue to ensure that anything that we bring forward has a very valuable market positioning, either physically or a particular niche that it fills, so. We continue to be very bullish on that market.

Maurice Choy
Great, thank you very much.

Operator
Your next question comes from Mark Jarvi with CIBC Capital Markets. Please go ahead.

Mark Jarvi
Yes, thanks. Good morning, everyone.

You mentioned, Brian, that budgets and timelines, everything for projects are going as planned. Can you just maybe give us a bit of a rundown in terms of exposure to some of these inflationary pressures we're all hearing about in terms of Genesee repowering and those other projects in terms of how much of the build costs are locked in and equipment costs are locked in at this point for those different projects?

Brian Vaasjo
It very much varies, obviously, by project. A lot of the repowering is locked in. I don't have a specific number in mind, but the general sourcing of it, materials and so on, is largely at risk from a G.E. perspective and Mitsubishi perspective, depending on the elements of the project that they're working on. I'd say, major components are covered from a cost perspective.

The other thing where the pressures are today, there's two components. One is the actual cost of material and supply/demand balance, but where we're seeing the major pressure on cost is on transportation. And the general perception is that, right now there has been a significant increase in terms of, a couple hundred percent in terms of transportation costs, but that will subside, and a lot of the deliveries associated with the Genesee repowering would be on the other side of that delivery. And a lot of that project is actually being sourced out of the United States, so don't really expect that element of pressure to impact on that project.

When we look at the renewable projects, the ones in Alberta, a lot of the backing per se was done prior to cost pressures. We do see some delivery cost pressures impacting on the Alberta projects. We think that those are manageable and expect that the impact would be relatively modest on the project. We don't see any costs going sort of out of control and continue to be pretty bullish on those.

When we look at the U.S. renewable projects, the contracting for those is still somewhat open. We do have some supply elements in place and as we move forward, we do expect that the particularly, again, as I mentioned earlier, the costs associated with transportation to be declining. Which is where we're seeing the greatest cost pressure in terms of the supply chain associated with our facilities.

Mark Jarvi
And then with those solar projects in the Carolinas, do you have some flex in terms of start date or COD, if you do kind of want to move away from some of these more transient effects that you're talking about?

Brian Vaasjo
Yes, we do. And we've been, even with the Alberta projects, within the construction schedule. We're able to move around some dates and change the way in which we're executing on the project to minimize the impact of some of these pressures.

Mark Jarvi

Got it. Now, let me come back to the Alberta market and talk about hedging and the forwards. Maybe just on the forwards, 2022 has come up nicely as of obviously this year. 2023 is starting to move up a little bit, but not nearly as much as 2022, and I guess the view would be that there's new supply coming. But when you look at your repowering work that's more late 2023, is your assumption that there's still a chance that '23 forwards have room to move higher when we think about supply/demand?

Sandra Haskins
Yes, I think, Mark, with respect to looking out as far as '23 and '24, there is less liquidity out there. And certainly, as we get closer to that date, you'll start to see more reflective forwards of where they will. You're correct with respect to increased supply during those periods of time, but we also expect higher carbon taxes as well. I do think there's upside to those years, but we won't see that until we get another year out or so, sort of similar to what you're seeing in 2022. It's starting to be more representative currently, but the other years need to see more liquidity before it will start to fully reflect where we would see it settling in those years.

Mark Jarvi
Okay, and then when you look at the 2022 hedge position, you've taken it up. The average price seems to have gone a little higher. Implies you're now starting to lock in some forwards in the $60 range at least. That's still below where the forwards are. Like would you still want to keep adding more forwards here into 2022, or like could you start to slow down here as you approach 50% hedging? Because, obviously, pricing is on the forward curve or north of $70 right now.

Sandra Haskins
Yes, as we've seen prices go up, it does inform our view as to incremental hedges. We would be very opportunistic in terms of adding positions at a price that we see being in line with where we think things will settle. We have locked in, you like to get hedges in place to protect the downside if you will. But certainly, our strategy has been to be less hedged and be very opportunistic at only hedging at prices that we think are more representative of forwards, so.

Mark Jarvi
If you didn't see more really good opportunities to lock in price, you'd still be comfortable if you ended this year at 50% hedged going into next year?

Sandra Haskins
Yeah absolutely. I think historically we've been somewhere between 50% to 100% hedged under the previous market dynamics and we're very comfortable to be less hedged in the current market environment. No expectation of having to increase that hedge position if we don't feel we're going to be seeing prices that are competitive.

Mark Jarvi
Got it. And then I just wanted to ask a question about the updated guidance in terms of the changes and the midpoints of the EBITDA and AFFO. If I take the new midpoints and what you've done year-to-date and kind of look between the cap date from EBITDA to AFFO, the cash outflows for the second half imply between the two midpoints about $226 million, and it was $294 million when you think of interest expense and pref dividends and whatnot in the first half.

It's sort of a $70 million lower sort of cash outflow between EBITDA and AFFO in the back half. Aside from maybe sort of lower interest expense and I guess the line loss not being there, what else would contribute to that? Or maybe it's just the ranges and using midpoints maybe not the most appropriate thing to do. Any sort of commentary around that sort of thinking between the below the EBITDA line cash expenses in the back half of the year?

Sandra Haskins
Yes, I think if you're looking at the difference between adjusted EBITDA and AFFO, is that correct?

Mark Jarvi
Yes, yes.

Sandra Haskins
So in Adjusted EBITDA, we have the coal compensation acceleration, and that's about $20 million a quarter of incremental year-over-year recognition. Where in AFFO it's still on a cash basis, which is $50 million a year and that's all in

Q3. There is some distortion in the timing, as well as the amount of that component. That's about the biggest difference between those two metrics.

Mark Jarvi
Yes, okay. That's helpful. Thanks for clarifying.

Sandra Haskins
And I guess, Mark, just the other thing too, is below the line is the impact of taxes as well. On EBITDA, to the extent that we're seeing higher plant performance, you're just seeing the margin there; where in AFFO, that's tax affected as well, so.

Mark Jarvi
Okay.

Sandra Haskins
That would be another difference between the two.

Operator
The next question comes from John Mould with TD Securities. Please go ahead.

John Mould
Yes, hi. Good morning, everybody.

On maybe just starting with the forced outage at Genesee 2, meaningful forced outages at Genesee in general are pretty unusual. And I know it's still ongoing and is reflected in your guidance, but I'm just wondering if there are any lessons learned there from the generator failure.

Brian Vaasjo
I'm sorry, John. I didn't catch the last part of the question.

John Mould
I'm just wondering, if there are any lessons learned from the failure of the generator there. Could this maybe have been mitigated if you hadn't had to defer. I think the outage was originally scheduled for 2020, but I think it was delayed for, COVID understandable reasons. Are there any takeaways from the outage there?

Brian Vaasjo
Actually, I mean, the way that things have come about, although obviously it's an outage. We've been very pleased with the way that we've been managing those assets. There's a major rewind expected that, even under normal course, continuing coal operations, existing facilities, there was a major rewind expected around the mid-decade this year, or this decade. There was an expectation that the rotor itself was going to be in need of major, major refit.

In expectation that, that's sort of signalling to you that you may be running into troubles even earlier than that, we actually have packages on site, "strategic spares" that will significantly reduce what would otherwise have been the outage experience with this kind of a failure. The combination of being able to be somewhat conservative in ensuring that we have those kinds of spare materials around such that when we have these kinds of failures. If this failure happened and we weren't well positioned, it could have been six months.

We're, again, very pleased with how we are positioned to deal with this kind of situation. It confirms the need to ensure that you have the right strategic spares, that you, when you're looking at major maintenance happening sometime in the future that, again, you should be prepared to move quickly and deal with it in a more timely manner than otherwise would have been the case.

John Mould
Okay, thanks. That's very helpful context. And then, maybe just moving to your development outlook. I'm just wondering if you can give us a bit of an update on, beyond the stuff that's in the construction pipeline, an update on your renewable power development activities in Canada, the U.S., and whether you're seeing interesting opportunities to either move forward with any new projects, or to increase the size of your potential U.S. development pipeline through additional early-stage acquisitions.

Brian Vaasjo
My answer to that is all of the above. We are seeing some positive developments from an Alberta and Canadian perspective, and see some opportunities moving forward. We also, on the U.S. side, have some opportunities that we

believe may come to fruition in the relatively near term.

But in addition to that, we are looking at opportunities to expand our pipelines on both sides of the border from a renewable perspective. And where we've been successful in the past is being aligned or acquiring, I'll call it smaller developers as one-off or series of developments. That continues to be fruitful in terms of some opportunities out there.

But we're also looking at the fundamental round of development of our own projects and we've been quite successful at that where we've undertaken it. We're looking at markets where it makes sense for us to actually, from a ground up, from securing the leases through to design and develop. Our pipeline will be getting built out from a number of different perspectives. But even with that—what we have today and what we're seeing, we continue to see some significant opportunities in the nearer term.

John Mould
Okay, thanks for that and then maybe just one follow-up question on Island. Appreciate you may not want to get too much into contract discussions and there's an active review process for the IRP. Have you had any follow-up from BC Hydro since the transmission issues and cable bulging problems started early in July that recognize the aspirations of the IRP just may not reflect the reality of the grid on Vancouver Island and its needs?

Brian Vaasjo
We've been, our discussions thus far have been with the government and the B.C. Government, largely because for logistical reasons and timings, we haven't had a good opportunity to directly discuss it with BC Hydro. But that is being scheduled and those discussions will take place, outside of the IRP process. We do have a number of questions, and we've informed BC Hydro these are the questions that we have and, just out and out don't understand their conclusion based on the facts. But again, we'll see where that gets to.

We don't believe that when you look at the IRP, we don't believe that that is their final version by any stretch of the imagination. We do believe that it is a work in progress, and recent information suggests that they still have work to do in terms of that assessment. We don't believe that we're talking to deaf ears. We do believe that there will be significant receptivity to having discussions around the re-contracting of the Island facility.

John Mould
Okay, I'll leave it there. Thank you for taking my questions.

Operator
The next question comes from Rob Hope with Scotiabank. Please go ahead.

Robert Hope
Yes, hello, everyone. Just kind of two follow-up questions. The first is that we have six months, or I guess seven months under the belt regarding the Alberta power market in the new world order. Has your view of how market participants will act or what the kind of long-run sustainable pricing is changed over the last six months?

Sandra Haskins
Yes, I think the environment that you're seeing now in 2021 is reflective of the market going forward in terms of the dynamics and setting price. I would temper that with, in 2021 what we've seen so far is some extreme weather, both in February and in June, which has driven prices above where I would say you would expect them to be longer run.

And wind availability is something that impacts on that volatility when you've got extreme weather. I think generally speaking, the dynamics are what you will see going forward. This is the supply/demand sort of fundamentals but artificially high, I would say for 2021 when you're looking at $105 per megawatt hour. But when you look at the forwards, going into next year, I think that's a little more representative of where you would expect it to be, given where the market tightness might be in any given year.

Robert Hope
Okay great. Then just taking a look at your 2021 guidance, what kind of range of power pricing are you assuming there, or is it kind of relatively centred around where the forward curve is?

Sandra Haskins
Yes, so it's based on both our position and the hedges we have in place, as well as our outlook for forwards for the balance of the year on our open position.

Robert Hope
Thank you.

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

Andrew Kuske
Thanks, good morning. And I guess the question really revolves around the Alberta power market and just your trading desk philosophy. Have things changed at all, or has it really been the same? And maybe I'll give the dichotomy of are you focused on capturing returns that are really acceptable to the capital you've put in the business, or is it really a focus on capturing close to market price?

Sandra Haskins
Yes, Andrew, I think it's a combination of both; when you look at where prices are, it's expected to be a return of and a return on capital for our investments in the market. But also in any given year that there is volatility depending on supply/demand dynamics. You're looking to optimize the price in a given year based on where you're seeing prices settle.

It's sort of a combination of both in terms of the strategy. You're always trying to realize the best price that you can and balancing that with volume as well. It's really two pieces of that strategy, if you will. In theory, the market dynamics are allowing for appropriate level of returns on investment.

Andrew Kuske
Okay, that's helpful and then maybe putting aside weather anomalies and other things. If you just looked maybe from last year to where we are now and the evolution of dispatch behaviour, are there any major surprises that have happened in the market versus how you thought it was going to pan out?

Sandra Haskins
No, I think it's generally in line. There was certainly some uncertainty around how it would unfold. There was sort of a range, if you will, of prices that you could expect. And so, you don't have a clear crystal ball. But directionally, I think it is lining up with what we would expect in terms of the market participants' behaviour and just the commercial being a much more rational market in terms of how assets are being dispatched.

Andrew Kuske
Okay, that's very helpful. Thank you.

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

Patrick Kenny
Thank you. Yes, good morning. Just on the natural gas price side of the equation, and I guess thinking about the upward bias narrative that's out there right now, not only into this winter, but perhaps longer term. Curious how you're thinking about mitigating your margin exposure there, especially once power prices eventually come back down to earth and the Genesee repowering comes online. Are you looking at strategic partnerships, investments, or long-term supply agreements that could lock in the natural gas cost side of the Alberta merchant margin equation? And if so, what might those structures look like?

Brian Vaasjo
Patrick, we have for a considerable period of time looked at, is there a strategic relationship out there in which we could access natural gas supply at let's say something other than market and then getting some security of market in return. And what we've found is that, generally speaking, the natural gas market isn't very reasonable. What they'd like you to do is, lock in a very high forecast price and guarantee them that kind of a cost. We haven't found the market that receptive.

Certainly in that environment it's very difficult to establish a mechanism that is responsive to power price. With increasing natural gas and, especially now when we'll be off coal, natural gas price will have a significant impact on the margin. As natural gas prices go up, that would be a variable cost for increasingly more and more generation in the province, and it would have an impact of increasing power prices as it goes up.

You're a little bit naturally hedged by the pricing mechanism in the marketplace for power. So your traditional wisdom is that unless you really have an ability to lock in both sides of natural gas price and the long-term price of power, you're probably better off to let it float with the price of the electricity prices that you're seeing.

We continue to look at those opportunities and where we can find somebody that has the right sensitivity and there's some value shared between, the power generation side and the natural gas side. In terms of sensitivity to where power prices go, it likely doesn't make sense to just lock in one side. Again, unless you're locking in a side and the other side is longer-term power price commitments.

Patrick Kenny
Thanks, Brian. Yes, appreciate all the colour and how you're thinking about that. And then maybe just back to the Island Generation situation or I guess, re-contracting process. Can you maybe just provide a bit more colour on how this experience has changed your approach in looking at other mid-merit acquisition opportunities, either in terms of recalibrating your hurdle rates, or perhaps taking certain jurisdictions right off the table?

Brian Vaasjo
It is, I mean, we're definitely going to be taking away some perspectives from this experience. Certainly, we've often with investors and with you folks have utilized Island Generation as this is the one that, this is the illustration of why something properly positioned makes a lot of sense.

And so again, big surprise to us. And when we look at these, again, in the longer term, we do have to consider that there can be just out-and-out mistakes made in terms of assessments of utilization and part of what's underlying some of the thinking in the IRP. Is it going to very, very substantial and pretty quick reduction of power utilization through conservation methods and so on and so forth, which, are still far away from regulatory approvals, etc.? There are things that can enter into the equation that are new or different.

It will probably broaden our perspective when we're looking at new natural gas acquisitions, considering, perhaps maybe some of the more outlier possibilities. I would say, the hurdle rate per se, again, may adjust depending on the particular risk profile you see in an area may in some future possible acquisition have an impact on hurdle rates. I think though where it will have probably more of an impact is on the breadth of our assessment.

Patrick Kenny
Got it. Okay. And then last one for me if I could, just I guess to finish off on a positive here but to follow-up on the new renewables' opportunity set. We're of course seeing big demand from pipeline companies and other infrastructure players looking to electrify their systems. I know they're running very competitive bidding processes. But just given your relationships with some of the larger players in Alberta, your development track record, how should we be thinking about the size of your backlog of opportunities today related to corporate PPAs, either wind, solar, or other relative to even say six months ago?

Brian Vaasjo
We continue to have a number of opportunities that we are pursuing and some, I'll say, are probably pretty close to fruition. Some of those to a degree are relationship based. But I would say, when you look at the very large PPAs that are out there, those tend not to be relationship based. There are certain advantages that we and other developers like us have, such as investment grade credit rating, track record of delivery.

There has been a number of PPAs in the Alberta market that have failed where. A commercial entity has signed up with an organization, and when the organization has got into the more detailed planning find that they can't move forward on the project. We've seen a handful of failed projects in the province.

The fact that when we say we're going to do something, we do it, is very helpful. There's a number of those kinds of elements that favour us and other substantive developers. But relationship, I'm not so sure in the larger ones whether they actually will make a difference. A lot of it is just what's the cost.

One of the other things though that does help us in the market is, we can bring a lot more to the table in terms of, people's load and being able to manage it. For example, we can provide both wind and solar combination right now. We can, we've got a lot of flexibility. We can actually round out somebody's overall power demands. There's a lot, again, that we can do that a number of different developers may not be able to do.

We can bring in RECs from other provinces because we've got quite a broad trading footprint. Whereas, a lot of the other developers don't. There's more tools we can bring to the table, depending on, what the specific requirements are of an off-taker. But they're pretty—they're getting increasingly sophisticated and it's becoming a very, very dynamic market. But again, we continue to be bullish in terms of our success in securing some PPAs.

Patrick Kenny
Excellent. Well, again, appreciate all the colour. Thanks, Brian.

Operator
The next question comes from Naji Baydoun with IA Capital Markets. Please go ahead.

Naji Baydoun
Hi, good morning. The first question is around, I guess, portfolio optimization and it's sort of related to the previous questions about Island Generation, or your gas assets more broadly. And you've talked in the past about potentially monetizing renewable assets if the right investment opportunities presented themselves. I guess the question is, would you ever consider monetizing some of your gas assets at the right price, of course, instead of renewable ones?

Brian Vaasjo
Certainly looking at assets and depending on how much capital that we're looking for and so no and so forth, there are certainly some of our natural gas assets that would be relatively easy to be monetized. Part of the challenge that we face is that when you monetize a renewable asset, long-term contracted asset, what you receive and the AFFO you give up have a particular relationship.

When you look at a natural gas asset, typically you're getting less proceeds for the same level of AFFO that you are giving up in terms of the sale. That's one of the things that comes into consideration. But absolutely we'd at reasonable pricing we'd consider selling natural gas assets as well.

Naji Baydoun
I understand the trade off that you're thinking about between immediate financial contributions versus a contracted profile and renewables profile and maybe diversification. Okay, that's helpful. Maybe just a couple questions for Sandra. Can you provide any colour on the sustainability linked credit facilities, on either the terms or the incentives versus the previous structure of those facilities?

Sandra Haskins
Yes, so most of the details around that aren't disclosed. What I can say is that it's plus or minus five basis points for our performance relative to the targets. And the targets are based on our emissions intensity and aligned with our trajectory to be 65% below our 2005 level by 2030. It is an annual target, so it's not where we are at the end of the five years. It is consistent with what most other SLCs you've seen out there. There are annual targets that need to be met in order to keep the pricing or to have it move downwards, or upwards in the case of not achieving that level of intensity.

One other element of that structure that I can share is just around the treatment of structural changes. To the extent that we acquire an asset that was already in operations, we would have that adjustment made to the intensity target; in that, when you look at it very holistically in terms of overall emissions. To the extent that asset was already in operations, it then impacts your targets. And likewise to your earlier question, if we were to divest of something that had an emissions profile, our targets would be adjusted to reflect that as well. There is that re-baselining component in the structure.

Naji Baydoun

Okay, got it. That's very interesting and very helpful colour. Just last question on the private placement of the U.S. notes. Do you see any other opportunities for similar favourable debt financings?

Sandra Haskins
Yes, I think it's been very favourable. The market has been favourable in both the U.S. private placement market and the Canadian market as well. At this point in time, don't see ourselves going to the market, absent any growth, but feel very confident that the market is there for us if we did have to raise capital.

Naji Baydoun
Okay, perfect. Thank you very much.

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

Randy Mah
Okay, if there are no more questions, we will conclude our conference call. Thanks again for joining us today and for your interest in Capital Power. Have a good long weekend everyone.

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