Capital Power
Q3 2021 Results Conference Call
October 27th, 2021

Corporate Participants
Randy Mah
Director, Investor Relations

Brian Vaasjo
President and Chief Executive Officer

Sandra Haskins
Senior Vice President, Finance, and Chief Financial Officer

Conference Call Participants
Maurice Choy
RBC Capital Markets

Patrick Kenny
National Bank Financial

Robert Hope
Scotiabank

Mark Jarvi
CIBC Capital Markets

John Mould
TD Securities

Ben Pham
BMO Capital Markets

Andrew Kuske
Credit Suisse

Naji Baydoun
IA Capital Markets

Operator
Welcome to Capital Power's Third Quarter 2021 Results Conference Call. As a reminder, all participants are in listen-only mode and the conference call is being recorded today, October 27, 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 third quarter 2021 results which we released earlier this morning. Our third 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 up 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 third quarter 2021 MD&A.

With that, I will 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 with the highlights of the third quarter and comment on our 2021 outlook.

The third quarter results were generally in line with our expectations. The unplanned outage at the Genesee 2 facility will be longer than originally anticipated, with a return to service now expected at the end of November 2021. We continue to make progress on our seven renewable development projects that I'll comment on in greater detail later, but briefly, we're seeing cost pressures on our two Alberta solar projects. Also, the completion date for our three North Carolina projects have been extended due to delays in the interconnection process.

With our strong financial position, performance and our positive outlook, we are suspending our dividend reinvestment plan, or DRIP, effective with the fourth quarter 2021 dividend.
In the second quarter, we provided higher 2021 financial guidance, largely driven by the positive Alberta power outlook. That outlook has not changed, as the market continues to be robust. Despite the extended Genesee 2 outage, we continue to be on track to achieve annual financial results consistent with our revised higher guidance.

Turning to slide 5, as you may recall, Genesee 2 experienced a forced outage in mid-July that was caused by a generator failure, and the physical damage is covered by insurance. The unit is undergoing repairs to replace the generator, and as I mentioned, it's expected to return to operation at the end of next month. We continue to utilize our Clover Bar peaking facility to backstop Genesee 2 when it's appropriate. The loss of revenue qualifies for business interruption insurance after 60 days, and Sandra will cover the accounting impacts of the Genesee 2 outage in her comments.

I'll now turn the call over to Sandra.

Sandra Haskins
Thanks, Brian. I'll start with a review of the Alberta power market on slide 6.

We continue to see strong prices, with an average power price of $100 per megawatt hour in the third quarter due to hot temperatures, facility outages, and year-over-year weather-adjusted demand growth of approximately 4% in the third quarter. The strong average power price more than doubled the average price of $44 per megawatt hour in the third quarter of 2020. In the third quarter, our trading desk captured an average realized price of $75 per megawatt hour that was 27% higher than the $59 per megawatt hour a year ago. The market outlook for the balance of this year continues to be strong, with a $99 per megawatt hour forward price for the fourth quarter.

With the strengthening of the forward prices, we have increased our hedge positions for 2022 to 2024 since the second quarter. Our Alberta base load generation is now 67% hedged in 2022 at an average contract price in the mid-$60 per megawatt hour range. For 2023, we're 38% hedged at a contract price in the mid-$50 per [Mis-spoke, should be high-$50] megawatt hours, and for 2024, we're 21% hedged in the mid-$50 per megawatt hour. This compares to current forward prices of $91 per megawatt hour for 2022, $73 for 2023, and $62 in 2024. In addition to the base load assets, we have approximately 500 megawatts of gas peaking and wind facilities available to capture upside from higher power prices and price volatility in 2022.

On slide 7, I'll review our financial results for the third quarter. As Brian mentioned, financial results were in line with our expectations.

Consolidated revenues and other income were $377 million in the third quarter, down 17% from a year ago largely due to unrealized changes in fair value of commodity derivatives and emission credits. Excluding the mark-to-market impacts, consolidated revenues and other income were up 7% due to strong performance from the Alberta commercial facilities.

Adjusted EBITDA was $286 million in the third quarter, a slight increase of 1% compared to a year ago.

We generated $206 million in AFFO that was 7% lower than a year ago. The decrease in AFFO was due to the lower AFFO contributions from the U.S. contracted facilities and higher sustaining capex due to maintenance work performed for the Genesee 2 outage that was originally scheduled for the fourth quarter.

On slide 8, I'll discuss the accounting treatment of the Genesee 2 outage and associated insurance recovery.

Approximately $25 million of capital costs were incurred in the third quarter, of which $23 million net of $2 million deductible was accrued to be recovered through insurance. The net recovery is reflected in the third quarter income statement in the Gains on Disposal and Other Transactions line and not as an offset to the capital cost. In AFFO, we see the net impact of the $2 million deductible while there is no impact to adjusted EBITDA.

From an operational perspective, business interruption coverage is effective 60 days after the start of the outage, which would be as of mid-September. An accrual for business interruption was not recorded in the third quarter primarily as the final amount of the claim, which will take into consideration mitigation across the portfolio, will not be fully known until the unit returns to service.

Slide 9 shows our third quarter year-to-date performance.

Adjusted EBITDA of $830 million was up 13% compared to $735 million for the same period in 2020. The main driver for the increase was higher Alberta power prices where our realized power price was $75 per megawatt hour compared to $59 per 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 $456 million, up 5% compared to $436 million a year ago. Overall, we've seen strong year-to-date performance in our key financial metrics.

As Brian mentioned, we have suspended the DRIP due to our strong financial performance and outlook. We also accessed the capital markets this year, raising $288 million in equity and US$150 million in debt that we'll fund later this month. These successful financings have reduced our financing risk and the need for additional equity for current growth projects.

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

Brian Vaasjo
Thanks, Sandra. Turning to slide 10, I'll review our performance for the first nine months of the year compared to 2021 targets.

Year-to-date, the average facility availability was 90%. The extended Genesee 2 outage will impact our annual performance, and we expect to be below our 93% availability target at year end.

Sustaining capex was $99 million in the first nine months compared to the $80 million to $90 million annual target. We've exceeded the annual target largely due to the Genesee 2 outage and an unplanned rotor purchase at the Arlington facility during a planned outage in the second quarter, of which the latter will cause us to exceed our sustaining capex target for the full year.

After nine months, we reported $830 million in adjusted EBITDA. Based on our current outlook, we expect full-year results to be in line with the midpoint of the revised guidance of approximately $1.1 billion.

We generated $456 million of AFFO for this year, and expect full-year results to be modestly above the midpoint of the revised guidance range of $570 million to $620 million.

On slide 11, I'll provide a status update on our growth projects.

We continue to make progress on approximately $1.7 billion of growth projects under development. This includes developing and constructing seven renewable projects and the repowering of Genesee 1 and 2.

Our Whitla Wind 2 and 3 projects in Alberta are on budget and on schedule for commercial operations later this year.

The Strathmore and Enchant Solar Projects in Alberta are experiencing higher costs due to significant increase in transportation costs and higher costs from supply chain pressures. The revised project cost is estimated to be $57 million compared to $53 million budgeted for Strathmore

Solar, while the project cost for Enchant Solar is now $119 million compared to the $102 million budget.

We have three solar projects in North Carolina with an original commercial operations date of Q4 2022. However, due to delays in the interconnection process, commercial operation is now expected to be Q4 2023 or Q1 2024.

Construction on the repowering of Genesee 1 and 2 commenced in the third quarter. There are no changes to the budget or target operations date of late 2023 for Genesee 1 and 2024 for Genesee 2.

For our $500 million committed capital growth target, we continue to explore opportunities, with a potential growth announcement later this year.

To wrap up, I'll comment on other activities that we have going on as outlined on slide 12. COVID-19 continues to be well-managed, with no impact on our operations.

Our plans to build the world's largest commercial-scale production facility for carbon nanotubes at the Genesee Carbon Conversion Centre continues to be on a slower development path. We continue to work through the regulatory registration of our carbon nanotubes necessary for commercial operation.

For Island Generation, we continue to believe the facility is needed to ensure secure and reliable power supply for Vancouver Island and Metro Vancouver. We're currently negotiating on a medium-term agreement with BC Hydro before the current PPA expires in April of next year.

Finally, the CCS pre-feed study is nearing completion, and overall, the project looks increasingly promising. We plan on providing more details on our decarbonization strategies at our Investor Day.

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

Randy Mah
Okay. Thanks, Brian.

Before we take your questions, I would like to announce that we will be hosting our annual Investor Day event on the morning of December 2. We were hoping to hold a live event in Toronto, but it will be a virtual event again this year. More details on the event will be announced shortly, and we hope that you're able to join us virtually on December 2.

All right, Cherise, we can start taking the questions.

Operator
The first question comes from Maurice Choy with RBC Capital Markets. Please go ahead.

Maurice Choy
Thank you, and good morning.

My first question is on the repowering project. I just wanted to get some updated thoughts on this project. Obviously, you would have heard that one of your peers opted to suspend their project highlighting some of the potential regulatory and financial headwinds for new gas, including repowering. How would you characterize these risks, and what plans do you have should these risks materialize?

Brian Vaasjo
I guess maybe going to the essence of your question, when we look at the outlook in terms of regulatory stability, and in particular, where the 0.37 stringency is going, we've been reassured again by the Alberta government as—from direction from the Premier that the 0.37 will hold. The province is very confident in their equivalency from a federal perspective, and so don't really see that element changing.

In terms of our peers' decision to basically suspend moving forward with one project and shutting down two other facilities, we'd have to admit the shutting down of the other two facilities is actually a little bit in advance of what we thought when they'd actually be shut down, and in terms of advancing on a new facility, I think if you look back to when that facility was announced initially, what's happened since is that there's been the – and if you think of the stack in the Alberta market, it would have been one of the most efficient natural gas combined cycles in the province.

Since then, Genesee 1 and 2 repowering and there's been an additional announcement in Alberta, the Cascade Project, that's going ahead, so all of a sudden, there's 2,500 megawatts of capacity much, much more efficient that's been put in the queue, so that project not going forward was not a surprise to us whatsoever; didn't believe that – with those other results, that it would be economic even with our outlook, so not a big surprise, and again, in the face of constant reassurance from the Alberta Government that the 0.37 will hold, we continue to be positive.

Now, the second part of your question is what happens if it changed or what happens if there was a change in the 0.37? We actually, in our projections for the repowering of Genesee 1 and 2, we actually have it, after 2030, declining. At some point in time, it will reach zero, and it's fully within our economics that, over a reasonable period of time post 2030, that it will get there, so at worst, it's a timing difference. The shorter-term impact, of course, is that it will impact to a degree on power prices in the province given the dominance of natural gas generation, so the economics of Genesee 1 and 2 would continue to be very solid.

Maurice Choy
Thanks, and maybe just a follow-up to that, you set a few cost pressures for some of your Alberta solar projects. Any pressures or similar pressures to the $997 million budget for this project?

Brian Vaasjo
No. We are seeing some very, very modest cost pressures, but nothing that is moving the needle on the cost for the project.

Maurice Choy
Thanks, and just a final question on guidance. You've pointed to midpoint of EBITDA on a guidance range. You also highlighted that sustaining capex is slightly – likely to be above your $80 million to $90 million range, so despite this higher sustaining capex, AFFO's still expected to be not just at a midpoint, but modestly above that. What is causing this AFFO to go higher?

Sandra Haskins
There's a few things in there. We are seeing lower financing costs this year, so it's some of the below-the-line items, but just seeing strong performance in Alberta driving up the cash flow, so there are some timing differences in some below-the-line items that impact that differential, if you will.

Maurice Choy
Okay. Thank you very much.

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

Patrick Kenny
Thank you. Good morning. Brian, just a follow-up on the Genesee investment. Curious if there's any update on your carbon sequestration opportunity at the site, when you might have more clarity on the level of government support both provincially and federally, and when you think you might be in a position to sanction the opportunity.

Brian Vaasjo
Where we are in respect of the CCS opportunity is we continue to be pursuing it, and actually, with increasing bullishness. In terms of the development process, we're close to finishing our pre-feed study, and results there have been, on balance, positive; a slight increase in capital cost, but operating costs and the degree to which it needs power is declining, so on balance, the economics of the project are improving. And so then, of course, we moved to a feed study, which we expect to go through next year, and I would say the earliest that we would be sanctioning the project – and given that we would require government support and clear indication of government support before we would get into approving the project and moving forward, we would expect that to happen late next year or early in 2023. And in terms of the government activities, the Alberta government's moving forward on the hub concept and looking at different parties to provide carbon sequestration

hubs, and from what we've seen and the parties we've talked to, that's moving along quite well.

The other front is with the federal government, and discussions continue to go, from our perspective, well with the Canadian Infrastructure Bank, and bringing into play something like 45Q before the election was identified by the federal government as something that they would be doing, and so we are looking forward to hearing the next steps in terms of that development. They have been receiving comments from many parties as to what it should look like, but as we put all the pieces together, we continue to believe that CCS is definitely economic for Capital Power on the top of Genesee 1 and 2

Patrick Kenny
Great. Thanks for that colour, and then maybe also on C2CNT, do you still expect to have Board approval for the carbon conversion project by year end, and maybe just an update on how the technology continues to prove out here since the last update?

Brian Vaasjo
Given the timing opportunities for Board approval of that project, wouldn't see it happening before the end of this year. In terms of the development of the technology, the actual development of the technology continues to go very well. The testing of the carbon nanotubes as it relates to cement has been moving along, albeit slowly, very much in a positive direction. I'd characterize it that we're three-quarters or two-thirds of the way there.

The challenge that we've run into, and I think I've commented on it before, is that there's actually a very long regulatory process to actually get each and every carbon nanotube approved as a new material, which requires in-depth analysis and description of not only the process, but the mediums, for example, for distribution within a material, etc., so we have to be almost complete, say, for example, with our cement exploration and development, and then at that point, we start basically a minimum one-year process to get it approved, and we can clearly build a Genesee carbon conversion facility within that timeframe. So, until we have the precise product nailed down, it just is creating a delay for us in building the carbon conversion centre, so that's the general outline of what we're looking at and where we expect to be going with the project.

Patrick Kenny
Got it. That's helpful. Thanks, and then last one for me if I could, maybe for Sandra on the suspension of the DRIP, do you view this as being more of a sustained suspension in that even if you were to secure, say, the $500 million of committed capital projects for 2021 over the next couple of months, you wouldn't need to turn the DRIP back on at that point, or is this more of a temporary shut-off until you're able to secure a couple more developments?

Sandra Haskins
I view this more as a sustained turn-off of the DRIP Pat. So, when you look at the capital that we raised – the equity we raised this year, as well as the contributions that we'll receive from the DRIP, it does equate to the amount of equity that we indicated we would need for the $1.7 billion of projects that are currently under development, so we've achieved that. To the extent that we have growth, we're seeing strong cash flows, very strong credit metrics that we would be able to fund development. If there was an acquisition of any size that would need equity, we would probably look to approach the market with an offering for that, so go forward with a bit of a story with respect to it, so at this point in time, don't see the need for incremental funding or incremental equity in that regard, so see it as being a sustained turn-off of the DRIP.

Patrick Kenny
Okay, that's great. I'll jump back in the queue. Thank you.

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

Robert Hope
Hello, everyone.

Maybe just in terms of your outlook for the gas market and how you're managing that exposure, can you just remind us where you are in terms of gas procurement and how you're viewing the rise of gas pricing in terms of your operations for the rest of the year and into 2022?

Sandra Haskins
Yes. For the balance of this year, 2022, and even out into '23 and well into 2024, we have hedged a large portion of our gas, or substantially all of our gas, in the near term. Seeing a lot of volatility, as you've alluded to, and have taken that risk off the table by hedging that out materially, so looking at optimizing our fuel and the burn of coal as we optimize the mine plan as we wind down in 2023, so look to lock down those positions and close that exposure.

Robert Hope
All right. Thanks for that, and then just more prospective in nature, so we're seeing some cost pressures in terms of the renewable powers' development projects. When you're looking at that next phase of growth, whether it's that $500 million, how are you bidding into those projects just given the potential that you could see additional or sustained cost pressures?

Brian Vaasjo
As we look at various projects, that definitely weighs into it. Certainly, the greatest cost pressure that exists today is on solar. There isn't the same cost pressures associated with the wind business. There is some, but it's not a case—again, the solar production or production of solar panels and so on is largely Asian at this point in time, so it gets hit with both increasing commodity prices plus transportation costs, which are dramatically higher than they were previously.

So as we approach projects and consider the cycle time, are cautious on the solar side, and definitely consider where the costs are going, but I would say that what we see going on today – we're starting to see the curves going down, we're starting to see transportation costs inching down, we're starting to see some of the commodity costs or the forwards declining, so we are expecting this is a relatively short-term excursion in pricing and transportation costs, so depending on how far out a project procurement is, can have an impact on definitely how cautious we are around the bidding process.

Robert Hope
Excellent. Thank you.

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

Mark Jarvi
Thanks. Good morning, everyone. Maybe just going back to the Genesee repowering, can you just share anything in terms of how much of the costs have been locked in at this point?

Brian Vaasjo
A number doesn't come to mind, but we will be talking about it in-depth at investor day, so we'll be sure to comment on that element at – as well, unless you'd like us to follow up with a number.

Mark Jarvi
No. I've seen, at this point, some of the large lead items you've locked in. You've already spent $100 million in the quarter. Is it just ongoing labour costs and balance of plant, or I'm just curious of where you would maybe still have some exposure to variable costs or things that are not fully priced in yet.

Brian Vaasjo
Well, there'd still be definitely some material being procured, but definitely, the major elements have been procured and the cost for those have been established, so don't see a lot of forward cost pressures on those materials.

Mark Jarvi
Got it, and then coming back to the solar projects in Alberta with the cost increases, any comment in terms of – obviously, there'd be some return erosion, whether or not they're still meeting your hurdles, and whether or not they'd become active. Do you think about a sell-down strategy if you feel like the returns have been compromised a little bit?

Brian Vaasjo
As we go through projects and consider projects, we always have in mind the potential sell-down strategy associated with them, but when we look at those two projects, we had, in both of them, some headroom in terms of returns above our

hurdle rates. As they're developing now and where we expect them to come in from a cost perspective, they would be coming in, I'll say, modestly below our hurdles, but definitely above our WACC, so they're not – there isn't an erosion of shareholder value associated with those projects as they sit today.

Mark Jarvi
Got it. That's helpful, Brian, and then one more on Island Generation, just the commentary around the medium term, but also highlighting, I think, in the MD&A, the book value that you carry and some of the policy changes that BC Hydro is looking to in terms of phasing out gas-fired generation, is the assumption sort of now you could get a three, four-year contract, and at that point, Island probably has to be decommissioned and taken offline? Is that what you're trying to outline to us today here?

Brian Vaasjo
A lot of this depends on, obviously, where the BC Hydro goes and where things go generally in respect of power supply or capacity on Vancouver Island. We still are extremely convinced, and there's nothing that has been brought forward or anything that would suggest that our position is not correct in terms of needing Island Generation to support the capacity requirements of Vancouver Island. Our view, and this is actually supported in what's been produced by BC Hydro, they have no plans on increasing the capacity to the island or on the island until 2033, so that longer-term need is still there, so not much has changed in terms of our perspective.

The recent indications from the BC government about phasing out natural gas and so on and so forth, that's a position open for comment, and we think just as we go through the resource plan of BC Hydro, it'll become clear, and we're convinced that in the plans, they are expecting for there to be brownouts in BC on Vancouver Island because they don't have capacity, and that's not good planning and that's not apparent to the citizens that are on Vancouver Island, so we think that our position of having ultimately a 10-year contract, although there are different perspectives of the government that are coming out, we still think that good planning will ultimately prevail and there will be a 10-year contract.

Even with the latest indication from the BC government in terms of moving off natural gas in terms of power generation, that would provide for an eight-year contract, so we're still very optimistic on the back end. And certainly, what we're seeing in terms of the lack of reliability associated with these undersea lines, I think, is becoming extremely evident, and one of the things that's not well-known is the work that BC Hydro is doing on the lines is not increasing the capacity at all. It's just improving the reliability, so again, the need for additional capacity or the capacity of Island Generation continues to be the same as it always has.

Mark Jarvi
That's helpful context, Brian. Maybe just one quick follow-up on that, then. If the view is that the IRP or the updated IRP or final IRP will be filed by the end of this year, at that point would you be in a position, do you think, to come to the table and have an agreement, or would there be negotiations that would take this into mid 2022 before you'd actually have a resolution on Island Generation?

Brian Vaasjo
In terms of the medium-term contract, again, that ends up being a process of negotiation that will take into – may well take into next year. A lot of it just depends on how the negotiation goes, and I would say the discussions are positive, but they are infrequent right now, so again, we'll see how that develops. As you can appreciate, we're ready to move and negotiate at whatever pace. We're not setting that pace. When it comes to if there's any further extension – that won't be until the IRP is approved or modified by the BCUC, which isn't expected until probably at least a year from now, so that's where there might be, or that's where a further extension to be negotiated would commence happening.

Mark Jarvi
Got it. That's all I had. Thanks for taking my questions.

Operator

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

John Mould
Thanks. Good morning, everybody. Maybe just starting with the $500 million target for committed growth, we're 10 months into the year, and I know you know that you could have an announcement before year end. What has made it challenging to get closer to this target? Is it that you're holding really tight to your return targets? Is it opportunities have been, maybe, more competitive than you'd hoped? Have you seen some gas-fired deals that might make sense, but had some hesitation just given ESG considerations? Can you provide some colour on the growth targets?

Brian Vaasjo
John, we always sort of hold tight to our hurdle rates, we don't – and because we're coming into the end of the year and so on, we don't relax them. I think as we've always said, that's a target that's out there. If we hit it, tremendous. If we don't, that just means that we didn't see any opportunities that were right for Capital Power, and it's happened before where we have not hit the $500 million target, and from our perspective, that's fine. In the longer term, our average has been $700 million a year having set the $500 million target, so it averages out, and the last year was well over $1 billion—well, $1.7 billion almost in terms of achieving that $500 million target, so we're not fussed and we feel no pressure that actually we have to do something.

Now, in terms of what we've seen, we've been in second rounds on both renewables and on natural gas opportunities, so the market is there, but certainly, the traffic isn't. On the natural gas side, there's been, definitely, fewer opportunities than we've seen historically in a calendar year, and likewise, from a renewable M&A perspective, there's been fewer opportunities. And from a development perspective, we continue to be very active from that perspective, and actually, frankly, see where that'll be a lot of our growth coming from – in terms of the future is from actual development opportunities as opposed to M&A type opportunities. Just simply the way the market's developing and where we're able to create value is on the development side, especially from a wind perspective or a solar perspective, not on the M&A side.

John Mould
Okay, that's great. Thanks for that context, and then maybe just circling back to the Genesee repowering and CCUS plans, the federal government ran on net zero electricity by 2035, so if that moves ahead, that implies there most likely will need to be CCUS in place at Genesee for it to run beyond then, and you've pointed out the CCUS initiative at that project needs government support, so if that support isn't of the magnitude that you're hoping for, do you see a path to recovering some of those costs in the power market over the long term given the lack of any real technological alternative to gas absent some revolution in long-term storage or commercialized to small nuclear? How are you thinking about the repowering project overall in a case where the CCUS funding picture doesn't pan out the way you, and really, the industry overall in Alberta is hoping?

Brian Vaasjo
If you take CCUS off the table, the fact of the matter is technology's not here nor are the policies outside of Alberta here that would make it even possible – technically possible to eliminate natural gas by 2035. You've seen the recent work by the ISO in Ontario that's saying that being off natural gas by 2030 is just not in any way, shape, or form practical, and they're now being asked what might it look like, when might you be off natural gas? I think you'll find that that work will show – probably beyond 2035 is feasible in Ontario where natural gas is a much smaller component of the overall mix of energy. So, in Alberta, it's just not practical, and when you see government announcements on being even off coal by 2030, in Canada, through the equivalency agreements, there are exceptions to that.

There are going to be coal plants operating in Canada beyond 2030, so again, there's a practical element associated with any of these pronouncements, and there seems to have been good discussions not only in Alberta, but across Canada in terms of what's really a practical solution, aggressive solutions, moving forward from a carbon mitigation perspective, but what makes sense in each province is different, and thus far the federal government has respected that. Again, that's why there's the agreement for the TIER program in Alberta to stand and continue to be there, because it meets the federal objectives in a way that is different for Alberta and suits Alberta just like there are equivalency agreements in most of the other provinces.

John Mould
Okay. Thanks very much for all that context, and then just maybe one accounting clarification for Sandra on the Genesee 2 outage. Just as far as the business interruption insurance timing, I know you won't know what the final claim is until that returns to service. Are you expecting to be able to reflect that figure in your 2021 AFFO, or is it possible that that doesn't get resolved by the time you report your Q4 results?

Sandra Haskins
Our expectation is that we would be able to reflect it. From an accounting perspective, there has to be reasonable certainty around the amount, and if that's the case, then you can accrue all of that expected, or a portion of it. But at this point, we have confirmation from the insurers that it is a recoverable event, so that's the first step, and then the second part of that is just landing on the amount, and the complexity with that is just looking at modeling what your results would have been if there hadn't been an outage and compare that to what you actually achieved, and it does look at it from a portfolio perspective, so not just the loss from the asset, but to the extent other assets in your portfolio are able to pick up some of that offsetting benefit from having that outage, that comes into play. So it is a difficult modeling exercise, but we've already started that on our side, as has the insurers, so see that progressing quite well, so expectation is that when we get to the end of the year, we'll be in a position to accrue it similar to what we did with the property side this quarter.

John Mould
Okay, great. I'll leave it there. Thank you very much.

Operator
The next question comes from Ben Pham with BMO Capital Markets. Please go ahead.

Ben Pham
Hi. Good morning. I had a couple of follow-up questions. On a gas price, you mentioned you're hedged over the near term. I'm wondering, have you changed your gas price assumptions long term when you're modeling Gen 1 and 2 and your other facilities in the province?

Sandra Haskins
Yes, so when we're modeling out power prices and gas prices, we do continually update those as the fundamentals change, so similar to other third parties, we do see sustained higher natural gas prices over the next year or two before they start to come down, but do see that it is probably higher than it would have been at the beginning of the year even when you get out to the back end of the plan, but it's something we continually refresh in our modeling.

Ben Pham
Okay, and were you seeing $2 at one point in time in your models?

Sandra Haskins
At one point in time, yes, we would have been seeing natural gas in – just over $2, I think, coming into this year.

Ben Pham
Okay, and you would say, then, the way you project the gas, you tend to lean on third parties when you're doing that, I would assume?

Sandra Haskins
We do look at third party – multiple third-party forecasts, as well as coming up with our own internal view on that as well, yes, but primarily looking at forwards and other fundamental forecasts from third parties.

Ben Pham
Okay, and on some of the Alberta solar stuff, I know had a couple of questions from other folks. Now, on a project like Strathmore, you've spent a lot of capex on it already, but on something like Enchant, you've only spent about $6 million or so, but you've got the contract with Labatt. Can

you actually technically walk and shelve that project or is it pretty much too late given the contract?

Brian Vaasjo
Well, you definitely can walk. There are penalties associated with walking, and even without walking or even without those penalties, it would be a tough decision for us to shelve that project just simply – as I said, it's still above our WACC. It could be delayed. You could do other things to mitigate some of the cost exposure, but it still, in our mind, remains a viable project.

Ben Pham
Okay. All right. Okay. Thank you very much.

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

Andrew Kuske
Thanks. Good morning. The question really focuses on the power market in Alberta, and it's been probably coming up on 11 months since we've had the new market structure. Can you give us some colour on just how the dialogues have changed with counterparties existing, and then prospective on just their understanding of the market; maybe the things you were telling them a year ago which they were not so sure about? What has been the flavour from customers, and just the willingness to lock into contracts on a longer-term basis within the province, or to take more spot exposure?

Brian Vaasjo
Andrew, it's a very interesting dynamic, and the reason why it's an interesting dynamic is when you look at parties who have been in Alberta for a long time, really, what's new isn't what's going on today. This takes us back to the power market that existed before 2014 into 2015, so people who, again, were comfortable hedging out positions, and so on and so forth, and looking at supply/demand balance in the future and anticipating where power prices are going, this is back to normal as opposed to the last few years. So those people continue to look at hedging, and they continue to look at the forward market, but as well, again, their views as supply/demand.

As I think everyone knows, there's significant supply that's going to be coming into the market in the mid part of this decade, and so again, looking forward, they come up with their own expectations. New people in the market, people who are just recently looking for power supply in Alberta, I would say they're still – continue to be fairly hesitant seeing higher power prices, particularly in light of more recent, quite a bit lower power prices and trying to sort out a little bit more of what's going on, but those people who are experienced, again, do recognize this as a relatively simple market based on supply and demand economics, plus inputs such as things like natural gas price and increasing carbon tax.

Andrew Kuske
Okay. Thank you for that, and then maybe just on the carbon tax, and really, the credits market in general, and any insights you have or market flavour by jurisdiction would be appreciated, but just the desire for certain customers, or even yourselves, to effectively buy credits in the market or effectively engage in activities that are going to give you more offsets versus paying carbon taxes outright. I know it gets very technical on all of this, but any flavour you can provide would be helpful.

Brian Vaasjo
If you went back a couple of years, and talking about Alberta, in particular, there was a very active market; a lot of trading taking place, a lot of projects and developers who were looking for people to support longer-term carbon sales contracts. A lot of that has slowed down significantly just simply because there is a little bit more uncertainty, and there ends up being, if you take the posted price of carbon today versus what the market price is, there tends to be – and the discounted ranges from 10% to 25% depending on when trades may have taken place.

The market is, I would say, a little bit more uncertain now, and again, because of that, we're seeing a little less activity in terms of people developing carbon credits, but also in terms of people willing to necessarily buy them because they aren't at – nobody today is going to pay $120 for a carbon credit out a couple of years. That's just not sort of where people are feeling comfortable in terms of paying for carbon credit, so again, there's discounts in the market, and as time moves on and higher prices are being realized, I think you'll start seeing the market coming back and more and more activities associated with trying to find ways to produce carbon credits and capitalize on them.

Andrew Kuske
Okay. Thank you. That's very helpful.

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

Naji Baydoun
Hi. Good morning.

Just wanted to go back to a couple of points starting with the DRIP. I guess if you can give us just a bit more colour on why it made sense to suspend it not long after it was turned on. I guess the question is, is this really a reflection of a slowing development maybe relative to what you were able to source last year, or is it more that you expect maybe asset sales or other financing options to fill future funding needs?

Sandra Haskins
Yes. Thanks for that. If you go back to when we turned the DRIP on in the middle of 2020, at that point in time, we still weren't seeing the forward prices that we're seeing today. We were moving forward with a number of renewable projects, as well as repowering, so certainly wanted to be in a position where we were raising equity in advance of that spend in order to maintain our credit metrics. So, when you're looking at our FFO-to-debt with S&P, for example, there is a 17% threshold. There is a requirement to achieve that even if you are in a period of prolonged construction like repowering.

Historically, you may have seen a look-through period when you're in construction where they would allow you to go below your threshold and take a view as to what the impact of the construction would be, and that certainly is not the case that they look for, so we knew that maintaining our credit metrics was very important as we embarked on that construction, so when you were coming through the middle of last year still looking at power prices in Alberta for 2022 and '23 that are well below where we are today, it was prudent for us to include the DRIP to build up that equity, and we had discussed how else we would fund the equity side of those projects and opted to do an offering, and at the point that the DRIP is turned off, it'll raise approximately $80 million of funding as well with the $288 million offering. That's in the range of the amount of equity we felt that we needed, and with cash flows and internally-generated cash being much stronger than anticipated, we just don't have the need.

Our current FFO-to-debt is well above 20%, so we're maintaining a lot of cushion, so at this point, don't need any more equity for the growth that we have, and even have enough balance sheet strength that if we did do incremental funding, not seeing that we would need to access equity to be able to do that. So keeping the DRIP on was just being dilutive at this point, so there was just no reason to turn it on and has nothing to do with plans on asset sales or anything else. It's more the internally-generated cash flow that's so strong that takes away the need for us to maintain the DRIP.

Naji Baydoun
Okay, got it. That's great detail. Thank you, Sandra, and maybe just going back to Island Generation for a minute, I know, Brian, you said BC Hydro is not looking to build new capacity, but let's say the re-contracting discussions don't really go the way you want them to, or even if it's only a shorter-term contract, have you had any discussions with them about installing new generation capacity sooner to replace Island Generation?

Brian Vaasjo
The IRP is very clear that they're not looking at installing, whether it be batteries, and by the way, battery technology obviously can't replace the capability of Island Generation to run for six months. You can't possibly do that with a battery, so no, their plans are to just remove Island's capacity. I mean, they have some hopes around

reduced demand in the province – well, across the province, but conservation efforts on Vancouver Island, but on the other hand, they've got great expectations around electrification of vehicles and other things, so don't see the demand on Vancouver Island going down yet.

The capacity that they've needed historically, they are willing to abandon, and that's why I'm suggesting that in their detailed modeling, which hasn't seen the light of day yet, we would expect they fully are expecting to have increased outages on Vancouver Island when there are constraints or problems on the transmission system, and periods of high heat or extreme cold, or dry years from a hydro perspective, all create strains on Vancouver Island. We just don't get it. We just out-and-out don't understand how you'd be planning for a significant increase in outages, but in any event and there isn't – there's no indicated path in any way, shape, or form to replace Island Generation until 2033.

Naji Baydoun
Okay. Understood. It sounds like something has to give at some point one way or another, so we'll wait for more details on that in the next few months. Thanks.

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

Randy Mah
Okay. If there are no more questions, we'll conclude our conference call. Thank you again 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.