Capital Power
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RANDY MAH: Welcome to Capital Power's eighth annual Investor Day event here in Toronto. My name is Randy Mah. I'm the Senior Manager of Investor Relations. This event is being webcast so I'd like to welcome the listeners on the webcast participating today.

Earlier this morning we issued a news release outlining financial and operating targets for 2017, dividend guidance out to 2018 and implications from the coal phase-out compensation.

Before we begin, let me cover off the standard disclaimer regarding forward-looking information. Certain information in today's presentation and responses to questions contain forward-looking information. I ask that you refer to the forward-looking information disclaimer at the end of the presentation as well as our disclosure documents filed on SEDAR for further information on the material factors and risks that could cause actual results to differ.

Let me introduce Capital Power's Management team and the following people that are presenting today. We have Brian Vaasjo, President and CEO; Bryan DeNeve, Senior Vice President, Finance and CFO; Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction, and Mark Zimmerman, Senior Vice President, Commercial Development and Commercial Services. The management team also consists of Kate Chisholm, Senior Vice President, Legal and External Relations, and Jackie Pylypiuk, Vice President, Human Resources.

This is the agenda for this morning. We'll start with presentations by Brian, Darcy and Mark, and then we'll take a mid-morning break. After the break will conclude with the CFO presentation and a summary by Brian. After the presentation we'll take your questions so if you could hold all your questions until the end, and then hopefully you can join us for lunch afterwards. Okay, over to Brian.

BRIAN VAASJO: Thank you, Randy, and good morning. Thank you for joining us this morning for our Capital Power Annual Investor Day. This morning we're going to describe for you how Capital Power is executing on strategy. It's a strategy that's stayed relatively the same for the last couple of years. Operational excellence and a strong financial position enables contracted asset growth across North America and enables the growth potential that we're seeing in the evolving Alberta capacity market.

Capital Power's strengths remain the same: a growth oriented IPP with excellent assets, established in strength and in competencies and operations, development, construction and risk management, a balance sheet that enables growth, and as you can see on this map which shows Capital Power's existing operations and development sites that we have under control, we're targeting a very diverse portfolio of largely contracted assets that supports both the existing dividend and our growing dividend.

Before we talk about 2017, I want to briefly touch on 2016. Capital Power's assets continue to have excellent actual operating performance. We expect to meet all our costs and sustaining capex targets. We did the work to start reducing our carbon footprint from existing facilities and our trading activities have done very well in a very uncertain Alberta power market. This year we have taken a significant amount of risk out of our balance sheet and our financial strength has been enhanced by compensation payments that we will be receiving from the Alberta government, all supportive of further growth and a growing dividend.

We have made great strides from a growth perspective. The Bloom Wind project continues to do well, including recently securing a tax equity partner. We announced this morning securing one of the best wind sites in Alberta and we'll discuss the potential to further invest in the Genesee Mine. Although not discussed today we expect to announce over the next month or so another U.S. wind farm.

2016 is a pivotal year in the Alberta power market. Both the compensation issue related to the coal phase-out and the legal dispute related to Sundance C terminations have been resolved, and I'll speak to these in depth in a moment.

In November the government announced they were moving towards a competitive capacity market. On the environment front, the Canadian government has been overlaying policy considerations on top of the province's culminating in the First Ministers Meeting last week and it's actually a potential of that meeting is why decided to defer our Investor Day in case something came out on Friday that we needed to address with you today.

The coal phase-out agreement is straightforward and is available on SEDAR. Capital Power will be receiving 14 annual payments of $52.4 million starting next July. These payments total $734 million to be paid over the next 14 years. The formulation follows the net book value approach we've been advocating for the last year and a half. Under this agreement Capital Power is obligated to cease emitting coal-based emissions by December 31, 2030 and that is the only operational constraint that we have.

In addition to that, we need to spend a million dollars annually on development, on maintenance capital, on new projects within the province of Alberta to a cumulative total of about $70 million. We expect to meet that cumulative total within the next two years just through maintenance and normal expenditures.

We are also committed to maintain a significant Alberta presence which should be easily met. Later this morning Bryan will be describing the accounting and other implications of the stream of $52 million payments.

The PPA termination is also straightforward. In exchange for $39 million of which Capital Power will be funding or has funded $20 million, the Balancing Pool will assume the PPA obligations back to March of this year. Of significance is that that puts our two major issues with the government of Alberta behind us.

The announcement by the Alberta government that they are moving to a capacity market from an energy only market was a bit of a shock to many. We still believe the government objectives could be served by the energy only market but pursuing a well-designed capacity market would increase investor appeal. In the past our biggest concern about the move to any other market is the treatment of incumbents during the transition. The move to capacity market in a manner described by the Alberta government is the most positive and least risk to the incumbents from our perspective. Their commitment to fairness and equality of existing capacity is extremely positive, and again, it is very constructive from an incumbent perspective. As well, a capacity market in Alberta is expected to be supportive of coal generation and natural gas conversion.

On top of the Alberta regulatory activities, the federal push for more national response to climate change. Although there is a clear recognition that provinces may have different underlying regulations, what has been suggested federally has been generally positive. The proposed federal coal regulations are actually moot as the established provincial regulation is zero tonnes per gigawatt hour beyond 2030. However, the federal approach to natural gas conversion is enabling as it sets the standard at 550 tonnes per gigawatt hour for 15 years or 2045, whichever is earlier. Our units converted to natural gas fall well within that standard so we see definitely natural gas conversion extending the lives of our facilities through the 15 years.

As Bryan and Mark will touch on, this represents attractive economics for Capital Power. The development that took place last week at the First Ministers Conference is that the previous proposed increased in carbon price to $50 by 2022 is actually being replaced by a still undefined process where the federal government in conjunction with the provinces will set carbon prices for 2020 and beyond.

I would like now to highlight what you will hear during the balance of our presentations this morning. Darcy will speak to how we continue to make great strides on plant availability and cost. He and Bryan will comment on not only how we are viewing our carbon inventory but how we are working to actually reduce our carbon exposure. Mark will be addressing how we are maintaining our competitive position across a number of good contracted operations or opportunities in the United States. He'll comment on our favorable existing asset position in Alberta. In short, excellent assets and competencies in an energy-only market translate directly to great asset and competencies in a capacity market.

From a growth perspective, in addition to the Halkirk 2 site we will be adding Whitla, the proposed development we announced today. We will have 450 megawatts of shovel-ready projects to potentially bid into the first Alberta REP.

We also expect in the next few months to announce a strategic initiative that creates a substantial future pipeline for renewable development in the province of Alberta.

Bryan will comment on actions we've taken this year to increase our balance sheet strength and how we are positioned to fund future growth, all of which goes to increasing shareholder value and maintaining and growing our dividend.

I'll now turn it over to Darcy.

DARCY TRUFYN: Thank you, Brian, and good morning. Today I'll provide an update of our asset optimization and then I'll touch briefly on some of the things we're working on, both in operations and in construction.

Capital Power, we're in year five of our journey, improving performance and availability through our reliability program, and driving optimization through formal plans that we have for each of our units. At Capital Power we have been successful at getting much more production out of our units while spending less, and while we've become very cost effective, it's all about spending smarter. We have and will continue to do the right things to ensure we don't put ever our assets at risk.

On risk, we've done a variety of things; some of those things I've spoken about at past Investor Days, and I think this year a testament to how far we've come is because of our lower risk profile, our insurance premiums are actually substantially reduced this past year and it's because our insurers now view Capital Power as a very low-risk operator. As we've improved production, our safety and environmental performance has also improved, which clearly demonstrates that a productive plant is in fact a safe plant.

In response to the Climate Leadership Plan that has been announced by the government, we've implemented a very formal CO_2 reduction program for our coal fleet which we term the Genesee Performance Standard or GPS, and I'll provide details about GPS later in my presentation.

This slide shows our journey on availability of the CP operated assets since 2012. Now, the saw tooth is just because of irregular planned outages but there's definitely a trend of improvement. You can see from the slides that in 2012 our availability was at 93.5 and for 2017 we're budgeting actually for our own fleet a 96% availability, and those are substantial megawatts of production added to our company.

So on that, just this next slide shows the megawatt hour output improvements in that same period, and again, if you go back to 2012 when we were producing just over 8.9 million megawatts with our thermal fleet, that same fleet for our 2017 budget is actually at 9.6 million, so that's 700,000 extra megawatt hours which is substantial added EBITDA for the company.

From a solid fuel side, North Carolina we have two plants there. The journey has been very much the same and you can see here from the slide the improvements we've made and we're still pushing ourselves to get more out of those assets but it's the same story, more EBITDA coming out of our units.

On the renewable side, wind has become an increasingly bigger component of Capital Power's fleet and while we can't control Mother Nature we're doing everything we can to drive our capacity factors up and to improve our availability so that when the wind blows we are there ready to capture it. Again, this slide shows the journey, and again this is a little bit irregular but it is definitely trending upwards and we continue to push our availability on the wind assets.

From a cost perspective, the story is the same. These are normalized dollars. I'm an engineer so I look at it maybe different from an accountant but we are—you can see the journey. We continue to push down our costs. This is expressed in dollars per kW. You can use any metric. The journey is there. You can see that we're getting way more out of our assets and yet spending less, and you can see in 2016 where we budgeted and where we're targeted to finish, a substantial improvement even in just this past year.

Now, the low-hanging fruit has been picked. It's getting harder and harder to find cost savings but we continue to look for it. I mentioned earlier it's not about cost reductions; it's about spending smarter and a key part of that is that have become way more proactive in how we maintain and operate our units, and so we're finding ways to prevent excessive wear and breakage, which means that fewer breaks means fewer forced outages which means fewer dollars spent and the proof is right there.

From the capex side, this slide is sustaining capital for the Capital Power fleet, and so the numbers that Bryan will be talking about later in his presentation are all encompassing but I'm just here focusing on the CP operated. So there's two types of sustaining capital. There's the ongoing maintenance capital which primarily is the outages, the planned outages. I don't have a slide there but spending has been fairly consistent over the last numbers of years and we are working on that, but that is the spend to replace in-kind during outages to keep the plants going, and as I said that spending is pretty consistent. But on the sustaining part here that I show, this is the more what I would call the nice to have, and on this we really just cut it out of our spend, you can see from the numbers here.

What this is, is new projects, things that we would typically be adding to our existing plants, so at Capital Power on our fleet we really try to eliminate this type of spend. So unless it's actually going to add value and add production, or is a safety item, we just don't spend money any more and the numbers are reflected there.

Now, I did flag separately GPS. It's a significant cost component for 2017 in our budget and I'll speak specifically about GPS. GPS will have a business case to it and it's separate from normal sustaining capital, so we've broken it out separately and we'll talk about it separately today.

On the mining side, the Genesee, the journey has been very much the same. In parallel to our plant performance improvements, we've been working with our mining partner Westmoreland to drive the costs of our coal down and these two slides here capture very well the journey. So we've done a lot of things in terms of using some new tools and new mining methods that have helped improve our productivity of our equipment and the result is again you see the coal cost there and how they've improved since 2012, and that's real dollars when you look at the fact that we're mining over 5 million tonnes a year of coal.

In parallel to that, it's not that we're only mining at a better cost; it's the quality of the coal that we're mining that's gotten better and there's a 5% improvement shown in the heat value and that's just with the new mining techniques we're using. It means that we're delivering—that means less coal needs to be hauled to the plant and less coal into the plant means there's less ash and less wear and tear, so it has a whole knock-on effect in our operations, but we're very proud of these achievements and this is all about getting more from the assets.

From a HSE perspective the journey has been the same. You can see the trend in terms of improvements, both on a recordable incident and on an environmental perspective. Now at Capital Power, unlike many in our business, we actually include in our statistics all of our contractors and subcontractors. We do that because when you work on our sites or at our plants, we feel responsible for your safety. This past year we've actually gone just over two years now without a lost time with us, with all our employees and all our contractors and subcontractors, and we're really proud about that.

I just want to make a little comment because I think it reflects on our operations and specifically about the bird and bats mitigation. Bird and bat mortality is becoming increasingly more important with wind assets and we've just completed successfully at PDN and Halkirk our three-year program which was part of the permit, and how we did that, rather than just counting, we actually tuned down our units during specific times of the year and we did that to reduce the mortality. The net result is that we were well under the permit requirements, but it says to me, it reflects on how we operate. Rather than waiting for a problem, we were proactive in addressing it. It had a small impact on our output but really we think that that's the right thing to do.

On GPS, this slide is capturing the journey that we expect to go through over the next five years. Now, we've already started, and I actually talked about this last year at Investor Day about some of the changes we'd already started to make and those changes were primarily in terms of boiler tuning, in terms of tweaks in operation. CO_2 has never been a metric that we had to worry about until now as we go into the new Climate Leadership Plan. So, we've already started on that and started to make a number of operational changes, and we substantially improved our CO_2 performance over the last year and a half.

Now in this slide we don't show us capturing as much value and that's because on G1 and G2 the benefits really accrue to the Balancing Pool who own the PPA or hold the PPA on those units, but what we are showing here is that over the period of time from now to 2021—2021 is when we take over G1/G2 and then we'll get all the benefits then of our emission improvements. So you can see that we're ramping up to about $30 million of expected avoided costs for our fleet, coal fleet by 2021 and about $5 million in parallel of savings that will become an annual avoided cost. That will be funded or paid through a program that we think will cost around $30 million of changes. This is some hardware changes, software changes and other types of changes that we'll make to our fleet between now and then. So, we're very excited about this and I'll be reporting on this year-over-year on Investor Days.

I wanted to just briefly talk about new asset development. Since inception, we have successfully demonstrated that we can build plants on time and on budget, and Bloom is our latest project. It's our second U.S. wind development. It will be a success. Bloom I think confirms that Capital Power can really build anywhere successfully in North America.

Now, we are a very much hands-on builder. We are very prescriptive to our contractors and OEMs as to what we want, and we do that because we want to make sure that when we take over that plant that it's a plant that will be cost effective to run. We also have a group of people that we assign to the projects, probably more than some others, but we do that because we want to ensure that what we get, that what's built is what we paid for, and that we have people on the projects that can deal with issues before they become expensive problems.

We standardized our systems, our tools, our processes, both from an operations and a construction perspective, and this helps ensure that our plants are built to the same standards and that we operate to the same parameters across our entire fleet. We also have in-house estimating and front end development and an engineering capability that I believe personally it gives us the ability to really be cost, very competitive, cost competitive and find solutions. So on new builds and new opportunities we think that we're going to be extremely competitive and win more than our market share.

On Bloom, just a quick snapshot of Bloom. Bloom is 178 megawatt project in Kansas. It's 54 3.3 megawatt Vestas machines. This project is going extremely well. All the civil work is done. We're ahead of schedule. We're starting to receive towers as we speak and we're accelerating the construction, the erection of the turbines to early January. COD is planned for the end of June of 2017. I'd just say, here, this will be another successful Capital Power project.

Just a few words on coal to gas. Now, Mark has got much more on this from a commercial perspective. I just want to make a few technical comments about the coal to gas conversion opportunities. Really a key message that I want to deliver—you can read the slide here but the key message is that we have the youngest coal fleet in Alberta, the best conditioned units, the highest available units, the best heat rates of all the units in Alberta, and all those advantages—when the time comes that we want to convert, all those advantages will follow us to gas; we don't lose them. That's a really key point for you.

Now again, Mark will go through the commercial aspects of timing and that but I just wanted to leave that message with you. All the stuff that we've done over the years to make our units better, we'll capture that value even when we convert to gas.

In closing, we are executing to maximize asset value. We continue to drive optimization and now included in that optimization is a methodical approach to reducing our CO2 footprint and the advantages we have with our coal assets will follow the units as they are repurposed.

So, thank you and I'll now turn the podium over to Mark.

MARK ZIMMERMAN: Thank you, Darcy. I'd also like to extend my thanks to everyone for taking time out of your busy schedule to be here with us.

To recap, Brian has provided you guys with a strategic overview and Darcy has followed with a fiscal and operational snapshot of our business. I'd like to provide now a commercial development overview, set the stage for Bryan's summary of what our future will look like.

To begin with, we've got a very strategic footprint in the province of Alberta. We have low-cost, high-efficiency assets. We have the people to operate and optimize those assets, and it's those same people that we're able to leverage off of to support and grow our business.

I would observe the uncertainty that's overshadowed us in Alberta the last year is starting to clear up and it's leading to an improved business environment for us. As that business environment stabilizes, we are ready with a number of investment opportunities to exploit our incumbency advantage in the province.

In addition, we view the migration to a capacity market as something we can compete and win at as many of the energy market trading skills we have, and as Brian had pointed out, are equally applicable in a capacity market setting. That said, we do see the value in having a geographically and fuel diverse portfolio to provide the stability and visibility to our growing cash flows. So we'll continue in our efforts to secure investment opportunities elsewhere in North America. It is with this combination that we see sustaining and growing cash flow and increased shareholder value.

What does that mean to us and what our key focus areas are? First is the recognition of the unique position we have in the province and the value and opportunities it provides to us. It also means that we need to continue in our efforts to secure investments in other North American jurisdiction and ensure we continue in the development of a diversified investment portfolio.

Within that focus, we want to ensure we capitalize on the competencies we possess. Specifically, as an example of some of them, our construction capabilities and thermal, and renewable generation, as Darcy had reviewed. Our fuel management skills are a critical element in all our thermal generation. Our commercial skills in prospecting, contracting and optimizing is equally important, and our partnering and structuring skills to arrange and enhance joint ventures and partnerships to enhance our competitiveness is key. It is this focus and combination of competencies that will lead us to an improving cost of capital.

Let me start with the strategic footprint in Alberta. This map shows the main transmission routes in the province with an overlay of our existing assets, illustrating our incumbent, strategic position. We are strategically connected and thus require minimal incremental cost to connect additional supply. We have a highly trained workforce and we are one of the largest builders in Alberta over the last decade, demonstrating our ability to assemble and permit opportunities on time and budget. We have the trading skills to enhance our margin, skills which are portable to this new structure, and it is this footprint that gives us an advantage in gas generation development at the least consumer cost and the highest reliability.

We do have a shovel-ready new build in the form of G4 and G5. We and our partner continue to enjoy contractual flexibility and with the uncertainty arising over the last year we continue to push our final notice to proceed decision until more clarity in the market's design and the need emerges. When market conditions are conducive we are ready to ramp up and create one of the most cost and emission-efficient plants in the province.

In addition to the new build, opportunities also exist for the conversion of our coal-fired units which Darcy referenced and which I'll speak to in a moment.

Finally, we also have expansion peaking opportunities available within our Clover Bar Energy Centre facility should market conditions warrant. In short, in a market of 16.5 installed gigawatts of capacity we currently have around 15% of that fleet with a potential to grow further.

Now I mentioned our trading capabilities and I thought I would spend a brief moment on trading track record. As this chart illustrates, we have historically on average been able to realize better than the market spot price as a result of our activities. As you can see, more recently we have been experiencing very low spot pricing as daily volumes are being bid and dispatched at variable costs, however one month out forwards and beyond have remained robust.

Two key points are highlighted by this slide. One, we are well positioned to continue to generate enhanced value from managing our inherent long position, and two, the trading capabilities are portable to this new capacity market.

As we move forward, there is the expectation that the low spot price that we have now will not be sustained. As supply and demand come into balance, improving market fundamentals will emerge. The dashed blue line represents the current forward markets expectation of this, and while we have seen historically a directional correlation to gas prices to power prices, going forward we feel gas prices will recover less than power as other influences like carbon tax and the merit order will move to influence the power pricing on a forward basis. In short, the market is indicating that prices are due for a recovery.

This dynamic will assert itself regardless of which market structure is in existence. In other words, moving to a capacity market shouldn't change overall pricing fundamentals. As many of you know, Alberta will be implementing a capacity market structure. The current status is that the policy decision has been decided and the details now will be worked out over the next 24 months. The government has initiated consultation for implementation. The first auction is targeted to occur in 2019 for delivery in 2020/2021. The key to us is the promise that the existing generation will be treated fairly. As Alberta's Energy Minister Margaret McCuaig-Boyd recently stated, power companies have her word that the new market framework will continue to promote a level playing field.

So, with a level playing field like we had before, we will be competitive such that overall revenue should be similar to that which we would have enjoyed previously. It's just that now it will be provided in two components.

The mechanics are pretty straightforward, however with more certainty on the capital component. All generation capacity will bid in with the last bid in to meet the target setting the clearing price for everyone. Similarly on the energy side, those that receive capacity payments will need to offer in with the price being set by that marginal unit. The key will remain though specifically those with the lowest cost and best efficiency will generate the best margins.

To reinforce this point, I thought we'd share some analysis with you guys. The following chart illustrates a number of things. First off, the solid lines are representing the historical realized and spot prices that we've enjoyed over the last number of years. The dashed lines are the forwards and our expected realized price given our targeted hedged positions that Bryan will review shortly.

If we back-calculated what our assets would have realized from capacity and energy revenue in a PJM like capacity market, that represents the shaded area on the graph. If we project that going forward, a number of interesting observations emerge. First is the expectation that under either market scenario the total market price by 2021 will be similar in either market as the market fundamentals do return to balance. Secondly, there is a higher degree of stability in the capacity market than that which we enjoyed in an all-energy environment.

With respect to supply and demand fundamentals, a meaningful component of our current supply stack is the coal fleet. As we move into a world of higher carbon taxes, the merits of converting from coal to gas fired will come into play. The following graph is a simplified representation comparing coal-fired to converted gas-fired generation. The actual comparison will be more complex as it will be influenced by a number of additional considerations but for purposes of today's discussion is does give you a visual for the decision we'll be faced with.

The chart illustrates an indicative variable cost structure including variable operating costs, fuel and a carbon tax at a $30 level, and compares the cost of existing coal generation to a converted gas operation. A number of observations occur.

First, breakeven economics are close and we are almost indifferent between continuing to run coal or converting to gas. Second, the vintage of the units is very important as older subcritical are costlier and less efficient than newer subcritical and even more so than supercritical. This analysis will also be contingent on gas price and heat rates as can be seen by the large fuel component.

Finally, in a capacity market structure, the viability of generation will have to be in the context of a combined capacity energy price relative to the rest of the stack. In other words, a higher certainty of dispatch, the lower on the cost grid.

So, putting this all together. We put forward an indicative dispatch curve which will help to illustrate how the mechanics would work. Capacity and energy will be bid into market based upon the needs of the market. The current dispatch curve is the blue line on the lower right portion of the graph, illustrating that at current peak demand of 11.4 gigawatts, pricing is in the mid-$20 range. When a $30 carbon tax is applied, that dispatch curve will move up to the green line, plus gas and coal generation will switch places as illustrated by the wider ranges up front. As shown by the black square, our G1 plant will move from lower in the current dispatch curve to slightly higher when a carbon tax is applied. Equally as shown by the red circle, our Shephard plant will move from being quite high on the dispatch curve to much lower.

If we then take wind out of the stack, we would move to the purple dispatch line and it illustrates a very tight reserve margin emerging relative to the peak. So given the critical need for reliability in the system, a reserve margin will need to be applied and that is the dashed vertical black line, therefore new build signals and higher capacities will begin to materialize.

With that, I'd like to move to a discussion of Alberta renewables. First, to recap the situation, the policy has indicated a desire to move to 30% of the fleet being renewable generation by 2030. This represents about 5,000 megawatts of renewable electricity program. The Alberta System Operator will run the process. The first call will be for 400 megawatts for delivery in 2019. It will be under a 20-year contract and this first call will be awarded to the lowest cost alternative. The structure for subsequent auctions will evolve and may include stakeholder criteria as we move forward.

Of critical importance is the timing of the award being in Q4 of 2017 with delivery in 2019. This is a very tight turnaround which as a result will really only be available to those that have projects that are well advanced.

It's within this context to note that we are ready. As already highlighted, we have the demonstrated construction capabilities as evidenced by Tumbler Ridge and Halkirk, both projects that were able to be delivered on time and budget. We also have the trading skills to manage the overall portfolio. While I'll speak to our two most advanced projects Halkirk 2 and Whitla shortly, I would also like to point out that we're working on many other wind and solar opportunities within the province for future auctions. We are actively pursuing a number of new and existing sites that are well positioned in the best wind regimes and closest to the existing infrastructure, and that's what this map is attempting to illustrate is the wind resource that we would be looking at, central Alberta, southeast Alberta and the overlay of the transmission grid.

In addition, we are looking at different partnerships that would supply a significant pipeline of future development sites. As Brian had mentioned, we expect to announce a strategic development that will provide significant solar and wind capability for future development. I would also like to observe that as you will see in my comments on the U.S. efforts, we are increasingly becoming competitive in those markets and we expect that we can equally apply those learnings in Alberta.

The first opportunity I'd like to review is our Halkirk 2 option. This approximate 150 megawatt proposed project will be located north of Capital Power's existing Halkirk wind facility in east central Alberta. We're pursuing permitting and regulatory applications. Two meteorological towers were installed in early 2016 and environmental assessments and wind farm design are underway. The project is located about three kilometers away from a substation which has an estimated 450 megawatts of capacity. We have the local support and 18,000 acres have been secured. In summary, a project with a great wind resource in the high 30s capacity factor.

The second opportunity is our Whitla option. The project will be located southwest of the city of Medicine Hat in the 40 Mile County Alberta area. As announced in our press release, we have reached an agreement that allows us to leverage off of seven years of wind data. Our access to the data will give us a significant time advantage. Thirty-three thousand acres have been secured for this initial 300 megawatt opportunity that will be built in two phases. The project will use the latest technology in utility scale wind generation. We are pursuing permitting and regulatory applications and have filed an application for interconnection with AESO. The site is located approximately 8 kilometers away from a substation which is connected to the Southern Alberta Transmission Reinforcement Line, a line that is estimated to have 700 megawatts of capacity with very cheap expansion capability of up to 1,000 megawatts. The proposed site has a very attractive wind resource. It's expected to be in the high 40% capacity factor range. Finally, there's some real potential for future expansion.

Now I mentioned at the start that we remain focused beyond Alberta as well. We have been very active in many other opportunities and as you know this does not only mean greenfield but M&A as well. I would observe that buying or building generation infrastructure does remain a very competitive environment, however given the focus in the competencies I've previously reviewed, we believe we can compete while maintaining our investment discipline. We expect over the next couple of months that we'll be in a position to announce two moderately sized investments.

On a broader basis, we do see policy initiatives evolving, and given the recent U.S. federal election results there are some questions arising in respect of the level of federal support, but we would note many of the initiatives we are pursuing are more state-driven mandates than federal. In short, there's a lot of renewable initiatives that are out there and that we are prepared for.

For context, we're not just limiting ourselves to just one market. The initiatives we are pursuing cut across many markets in the U.S. On the installed 1,000 gigawatts of existing generation in the U.S., we are active in six of the 10 markets. The key for us is playing where we can be competitive. As evidenced by our Bloom opportunity in Kansas, our demonstrated capabilities of commercial contracting, stakeholder relations, permitting, supply chain and construction place us in a very attractive position.

Before reviewing some specific opportunities, I should also note that the nature of who the counterparties are has started to change. We are seeing an interesting emergence of a significant additional driver in the form of additional demand arising from commercial and industrial requirements. In short, many corporations are becoming greener with their load characteristics and as we have seen with Microsoft being a major subscriber for our Bloom capacity, we expect this trend will continue.

An example is Altenex as an aggregator is who we had used to assemble load and act as the intermediary counterparty for our Bloom project and we see this sort of arrangement continuing on many of our other developments as well.

I also mention the evolution of federal policy versus state. While there's been much discussion of potential declining federal support, as can be seen from this summary, the state level support for renewables continues to be significant. In short, it is clear the states are continuing with their plans. Many states are well established and continue to move forward in execution.

With this in mind and to maintain our competitiveness, we have taken steps to preserve the value of our production tax credit, or PTC. As many of you will recall as shown in the table, the PTC eligibility was set to ratchet down if not under construction by the year-end 2016. Put another way, projects must be under construction by the end of the year to qualify for the full tax credits. Plus, developers have four years from commencing construction to reaching COD in order to be presumed to have had a program of continuous construction. We believe our projects are fundamentally sound and will go ahead, so to enhance our competitiveness we have taken steps to maintain our PTC eligibility. To demonstrate that we have initiated construction, we have made a commitment for seven transformers as a way to demonstrate the start of construction and expect to utilize these within the four-year window.

So, Darcy has reviewed the status of Bloom. I thought I'd review some others in the queue that we're working on.

First out of the gate is Tisch Mills in Wisconsin which is part of the MISO. It's a roughly 100 megawatt investment opportunity for us; 12,000 acres have been secured. Tisch is well positioned for a RFP as it's one of a limited number of utility scale renewable projects in Wisconsin which they will seek out in order to meet their mandate of Wisconsin renewable portfolio standard requirements.

The second is New Frontier Wind in North Dakota, a 99 megawatt investment opportunity; 11,000 acres secured. It is already permitted and ready to go. It arose as a very strong wind resource in the MISO region where the utility transmission arrangements and the potential for bilateral contracts could enhance its competitiveness.

Another one is Black Fork Wind in Ohio. This could be anywhere from 100 to 200 megawatt investment for us; 24,000 acres have been secured. It is one of a handful of permitted Ohio projects that AEP might look to for its 500 megawatts of renewable requirement.

Cardinal Point Wind in Illinois, a 150 megawatt investment, 15,000 acres secured. Illinois has an RPS requirement that it has not procured much under and in addition the recently passed legislation in respect of Exelon has also included an additional 1,000 megawatts of renewable procurement required in the medium term.

So the foregoing was just a sample of some of the nearer term opportunities which may arise, and I should clarify that one of the two imminent projects that I had mentioned at the beginning would include one of these near-term wind opportunities. We continue to work on a number of additional options which may become viable in the medium to long term as evidenced by this table with some additional options. We also continue to look at other pure greenfield sites to assemble and we do remain active in the M&A space where the characteristics of the asset being monetized are consistent with our investment parameters; specifically, that they exceed our risk adjusted hurdle rates, are consistent with our articulated strategy and that will be supportive of dividend paying company.

So to recap, I hope I have left you with an appreciation for how we plan to invest and grow our cash flow. To reiterate the key observations I wanted to leave with you today, we have a very strategic footprint in the province of Alberta and are growing our presence elsewhere. We have the skills and the people to support and grow our business. The uncertainty that has overshadowed us for the last year is clearing up, and as this clears up we are ready with a number of investment opportunities. We view the migration to a capacity market as something we can compete in and win at, but we've also realized the value of a diversified portfolio in providing the stability and visibility to our growing cash flow so we'll continue in our efforts to secure investment opportunities in the rest of North America, so with this combination that we see sustained and growing cash flow for our investor base.

Thank you.

RANDY MAH: Okay. Thanks, Mark. It's 9:50 so we'll take a 10-minute break and come back at 10:00.

(COFFEE BREAK)

BRYAN DENEVE: Good morning. My name is Bryan DeNeve. This morning I'm going to touch on first of all a recap of our overall finance strategy at Capital Power, then get into a little bit of the accounting under the coal compensation, talk about 2016 guidance and then 2017 guidance, and then touch on an update around our GHG obligation status of our inventory of offsets, and then conclude with an overview of some of the financing initiatives that we've completed this year.

Moving to start with the finance strategy, there's really four pillars that Capital Power pursues, the first one being maintaining an investment grade credit rating. Certainly we see some IPPs in the U.S. that don't maintain investment grade. From our perspective, it does give us a lower cost of capital but also just as importantly access to the capital markets as we go through business cycles, so as you look at our strategy that Mark covered, entails a lot of longer term development projects that we need to finance over time.

The second component is on the dividend and certainly I'll talk about this in more detail but for us a key focus is maintaining a consistent growing dividend over time and we look for opportunities for projects that do sustain that or support that strategy.

In terms of managing financial risk, that primarily focuses around us putting in place medium term debt, but also includes our capacity to be able to manage foreign exchange risk, in particular given our U.S. operations. So we don't typically like to be speculating on the foreign exchange rate so we look on a net basis of our exposure and then take positions to manage that in the market.

Then finally, ensuring discipline around the growth. As Mark alluded to, we do have very well defined financial criteria that we apply to those growth opportunities, but we also look at those growth opportunities through the lens of ensuring that they won't compromise our ability to maintain our investment grade credit rating, but also that the profile of those projects in terms of cash flow is going to contribute to providing that base to support a growing dividend.

This chart I've shown in the past. Just to reiterate, our priorities for capital allocation: number one is to ensure the funds are going to maintain a sustained, growing dividend. Then of course our second priority beyond that is looking at growth opportunities in funding those as we move forward to support that underlying growth in the dividend.

Finally, if we do go through periods where we may not have the growth opportunities - we went through this about a year ago - that will be a point in time where we'll look at paying down existing debt or buying back shares as appropriate in the market.

Turning to the coal compensation, as Brian mentioned, under the agreement with the government we'll be receiving $52.4 million per year over the next 14 years and that will be received at the end of July of each year. When we look at that payment it will be recognized as Other Income and will be then forming part of our EBITDA and Adjusted EBITDA on our income statement.

In terms of net income or earnings per share, it will reflect the difference between the coal compensation and the higher depreciation expense that we're going to experience due to the fact that we will no longer be able to burn coal starting at the end of 2030.

What's interesting around this is as we've worked through in the discussions with the government and did internal work, it's become apparent to us that for our coal units at 2030 when we're no longer allowed to burn coal, we'll have an average remaining life of the equipment in those plants of about 15 years, so that would include the steam turbine, the generator and the boiler. So when we look at coal to gas conversion, one of the big benefits with our units is very little dollars will have to be put into the equipment that's downstream of the coal handling facilities. As a result, when we look at our depreciation expense, it's really the coal handling facilities and the mine capital equipment that has to be depreciated through 2030. As a result, we're expecting an increase in our depreciation expense in 2017 of about $27 million. That will leave a lift in net income of about $25 million which translates into about $0.19 per share on an EPS basis.

The final point I would like to make is through additional work we've done we don't expect impairment to our assets as a result of the 2030 date and that's after of course taking into consideration the level of the coal compensation but also the value that will remain in those units to operate beyond 2030. You take those two together, we don't anticipate seeing an impairment.

When you look at the nature of the cash flow from the provincial government, basically it's important to look at the underlying obligations in that agreement and those conditions basically fall into three buckets. The first one is we will no longer burn coal to produce electricity at the end of 2030. The second condition is we need to spend a minimum of $1 million each calendar year as investment in the Alberta market but with a total investment of $70 million by the end of the next 14 years. Those obligations will be fairly easy for us to meet. Our sustaining and maintenance capex on our units is about $65 million per year in Alberta so those obligations are ones that we don't anticipate—there'll be very low risk of us not meeting those obligations.

Then the third one is maintaining a significant presence in Alberta which of course we're doing now and don't foresee any changes in that.

What that leads us to is the prospect of potentially being able to securitize those cash flows given their low risk. We've had some initial discussions around potential securitization and it's possible that we may see a cost of capital associated with it in the 2.5% to 3.5% range. If you take that on a net present value basis of the $734 million, that translates into about $600 million in proceeds.

Now, of course for us the timing of doing a securitization will depend a lot on what's happening on the growth side. We do have further work to do in terms of understanding the interplay with some of our existing covenants but certainly it's an opportunity for us as an organization as we look forward.

One of the areas we're also looking at as we roll into 2017 is purchasing the remaining 50% interest in the Genesee Mine. Currently, we own 50% of the mine equipment and the current operator at the

Genesee Mine owns the other 50%. When we look at that, basically the structure of the arrangement is such that for the capital that the partner puts in we pay them basically a cost of service type payment for the coal which would include a return on capital investment as well as a depreciation expense. One of the things we're seeing happening of course as I mentioned earlier is that that equipment now is going to be amortized over to 2030 or depreciated over that period. So as a result we were expecting to see quite a lift in our coal cost expenses. By buying out the balance of the mine that will result in a substantial reduction in our coal costs in 2017 and we should see a lift of about $12 million in FFO.

The one other area I wanted to touch on quickly was just to provide some guidance from a modelling perspective around Bloom Wind. As Darcy mentioned, Bloom is on track to be completed in June of next year. Once that project is completed, at that point we will receive cash from the tax equity investor who is Goldman Sachs. We just closed that arrangement yesterday. So, Bloom's total capital cost is about CA$350 million. We'll be funding that up until completion of the facility. At that point we'll see an investment from Goldman Sachs of $235 million. The way we look at that from an accounting perspective is that's essentially debt that will be going onto our balance sheet and then that will get paid down as we recognize predominantly the tax benefits Goldman will be receiving through the production tax credits as well as the accelerated depreciation. So you'll see quite a gap, as this graph shows, between actual cash flow and EBITDA that will be flowing through our statements. That gap closes though by the time we get to the flip point when the tax benefits are fully realized by the tax investor.

Just want to touch briefly on our G&A expense. You'll recall last year we walked through in a bit of detail around steps we had taken as an organization to effectively right-size on the G&A expense. The result of that work is that when we go back from 2012 we're going to see our G&A expenses decrease by 8% as we look into 2017. So over that same period we've seen inflation running about a cumulative amount of 10%. So, 2015 was that period of time when we feel we did get the organization right-sized. We have the systems, operations in place that allowed us to streamline the operations and now we're seeing increases that are more commensurate with inflation as we go forward.

I'll just note the increase from 2015 to 2016, that was primarily driven by increase in business development spending, our out of scope management salaries we held constant over that period. As we look forward into 2017 we're expecting some wage escalation to increase about 2% the overall G&A expense.

So I'll turn now to our 2016 guidance. You'll recall that our guidance going into 2016 was a range of $380 million to $430 million of FFO. At the end of Q3 we were guiding that we were going to end up in the top end of that range. However, with the agreement and the settlement on Sundance C PPA, we have now made a payment of $20 million so that reduction in FFO means we'll probably come in or we expect to come in in the low end of the range for 2016.

As we look forward to 2017, you've seen this graph before. We've now added our targets for next year and the key message there is we're expecting continued strong cash flow generation. From an operations perspective we're expecting FFO to be more or less stable year-over-year, however we are seeing a lift of course from the coal compensation payment. So together that will result in approximately a 10% increase in our cash flow in 2017 relative to 2016.

When you look at the components of the allocation of that cash flow—and I'll get into a bit more detail on the next slide on this—but you'll notice that on the common dividend side it's about 35%, it's remained constant. What's happening there is we have built in a projection in our common dividend of 7% in 2017 but that is of course because we have the increase in overall cash flow, that percentage remains constant. There's a slight lift on the preferred share dividend and that was due to the placement of the $200 million earlier this year. Then when you look at the sustained and maintenance capex of 19%, that suggests quite an increase on sustaining and maintenance capital, however you want to keep in mind that there's $10 million in there for the Genesee Performance Standard program that Darcy referred to, so that's expected to produce benefits for us, particularly as we look forward into 2021.

This just shows the breakdown in more detail. So, sources of cash in 2017, the $440 million from funds from operations and compensation, and then the proceeds from the tax equity investor on Bloom with $235 million.

In terms of uses of that cash flow, common shares projected to be $155 million which includes a 7% increase; preferred shares of $30 million, so that includes about a $10 million increase as a result of the $200 million of preferred shares we raised earlier this year; the Genesee Performance Standards, we breakout separately on this table of $10 million and then our sustaining and maintenance capex of $75 million.

So net when you look at cash flow available for growth we're seeing about $385 million next year.

Our projected expenditures on growth is $320 million. That would include the completion of the Bloom Wind Project. It would include another wind development project that we expect to be underway next year; the purchase of the 50% interest in the Genesee Mine, and then also capital expenditures to continue to maintain the Genesee 4/5 project as a shovel-ready initiative.

One change we're making this year's guidance is we're going to switch to providing the guidance on adjusted funds from operations, and effectively the definition of the AFFO is consistent with what we see in the industry with the exception of the coal compensation which is a unique piece. We start out with our traditional funds from operations that we've defined in previous years. We add the coal compensation and then we subtract sustaining and maintenance capex and then subtract the preferred shares dividends. We're making the switch primarily because we feel the FFO will be the much stronger line of sight to the funds that are available to exclusively support the dividend, the common dividend, as well as what's available for capex expenditures.

What we've done here is we've cast 2014 through 2016 in terms of the FFO metric. So, 2014/2015 would be our actual AFFO, '16 would be based on our guidance we provided last year translated into a FFO number and 2017 would be our guidance around AFFO of $325 million.

Now, we've shown it broken down into the amounts that we see going to common dividend and the amount that will be discretionary cash flow that's available for growth investment. The payout ratio over those four years has been constant in around the 45%, 46% range. As we look forward to 2017, we're looking at a payout ratio in that ballpark. For us what's really important is that that payout ratio is substantially below where we see our peers which averages about 58% of AFFO.

So, just wanted to turn to some of the initiatives that Capital Power has completed in 2016 that has resulted in improving the strength of our balance sheet and improving our positioning to be able to fund growth on a go-forward basis.

The first initiative that was completed was in July of this year was extending our credit facilities by one year, so that's, you know, maintaining the five years was very important to us in terms of maintaining the liquidity. Through those discussions and extension, we also increased the credit facilities by $55 million through the next four years. We also have maintained an accordion feature which permits an additional $245 million to the credit facilities, if appropriate.

The second initiative that was completed was a private placement debt financing with Prudential. This work follows on a lot of good relationship building across Capital Power with Prudential in the market, and, effectively, is a 10-year unsecured senior note with a rate of 3.85% over 10 years. So, the cost of this debt relative to what was being quoted at the time in the Canadian bond market is very favourable, and has certainly led to a reduction in our overall cost to capital.

The other important point to note about this private placement is it's non-amortizing. The other thing is similar covenants associated with it as our credit facilities, as well as our other U.S. private placement we have in the U.S.

The third element that was completed as a follow-on to the private placement was preferred shares issuance. We felt the timing was right, following the completion of the private placement, to go into the preferred share market. We saw a lot of activity starting in the preferred share market and it was reopening, so we took advantage of that and we were able to place $200 million with yield of 6%. In terms of the yield that we achieved on that financing, part of that, we believe, was driven by the fact that we were able to achieve 3.85% on the 10-year debt placement.

So, as we look forward to financing growth opportunities in the pipeline that Mark spoke to, we're very well positioned in terms of the strength of our balance sheet. Most of our credit facilities are available to support development expenses or as a short-term financing vehicle. We also have $170 million of discretionary cash flow in 2017 that's left after we meet all our financial obligations. We're now in a position to also raise equity if the right opportunity presents itself. Certainly, the improvement in our share price—a year ago, we were sitting at around $16 per share, we're now getting close to $24—has, together, along with our lower cost of debt, has dramatically reduced our cost to capital and made us more competitive.

When you look at our 10-year spreads in Canada, we've seen a 150 basis-point reduction over the past year, a lot of that due to the certainty that's been gained in the market, but also I think by the demonstration of the private placement financing that was completed.

So, when we look at it from the credit agency side, the debt to total capitalization remains very low. For 2016, we're targeting that'll come in at approximately 34%, and of course very strong corporate liquidity measures with the credit facilities that are in place. We continue to remain investment grade credit rating by both S&P and DBRS.

One of the key metrics for us, when we look at the guidance that we're provided by DBRS and the S&P, is the cash flows to debt metric, and as you'll see from DBRS' metric, which kind of requires the threshold of 20%, we're well above that as we look at 2017, and similar, from the S&P perspective, with a minimum of 15%, we expect to be close to 20% this year and 20% next year. So, certainly we're in a position where we have a good cushion over that FFO to debt metric, which is critical, of course, to maintaining our investment grade rating, but also provides us flexibility as we look forward and look at different opportunities in the market.

This chart, you've seen over the last several years. Basically, the change made to it is we have the new private placement in there, coming due—maturing in 2026. We continue to have very well—very nicely spread out maturities on the debt side, so certainly that's something that fits with our objectives of minimizing our overall financing risk.

So, turning quickly to the compliance on the carbon side, I'll start with the Climate Leadership Plan in Alberta. The Climate Leadership Plan, Dr. Leach's report to the government that came out a year ago, provided recommendations on changes to the Specified Gas Emitters Regulation in Alberta. So, what was recommended was to move to a gas standard, in that you would be required to comply down to a best-in-gas standard on the coal units in Alberta.

So, effectively, we would see that best-in-gas standard as probably something similar to the CO2 intensity on our Shepard facility, around 0.37. Certainly, there's been some discussion and maybe that'll come in more about 0.4. Of course, for our coal plants, the intensity ranges from 0.9 to 1 tonne per megawatt hour, so that delta is one that we'll be obligated to comply to. We expect we'll have two ways to comply. The first is to have carbon offsets which have been approved, made-in-Alberta carbon offsets, or pay into the Carbon Tech Fund $30.

There's a process now underway that the government has started to iron out the details on this and we would expect in the first half of next year to have line of sight on this, but we still anticipate it'll look more or less consistent with what we saw in our report from Dr. Leach.

So, when we look at the impact of this change in the carbon tax, it's important to look at it from two periods. So, through the end of 2020, we have the obligation, from a compliance perspective, on Keephills 3 and Genesee 3. On Genesee 1 and 2, that compliance obligation rests with the Balancing Pool, which is effectively the PPA buyer.

So as Mark showed, once this new carbon tax is implemented, we're going to see the merit order change in Alberta. You're going to see this reflected as part of the variable costs of coal units bidding in, and we expect to see an increase in pool price of around $7 to $8 a megawatt hour in 2018, solely because of the higher compliance costs. So, when you look through to 2020, effectively, the increased cost to us, a lot of will be covered by higher pool prices as a result of the variable cost nature of those compliance obligations.

When we look beyond 2020, at that point we'll be then also assuming the obligation on Genesee 1 and 2, but I think what's important there is the focus and the good work that we're doing as an organization to physically reduce our emissions from our units under the GPS Program that Darcy spoke to you, and we anticipate that that will reduce our compliance costs by $35 million. Well, part of it will be a fuel, part of it will avoided CO2 costs, but, in total, a $35 million benefit in 2021.

The other element, though, to compliance in Alberta is going to be our carbon inventory of offsets. The first bar you see here is what our cost of compliance would be for our coal units in Alberta, assuming we didn't have any offsets. So, you see it increases dramatically, from $6 a megawatt hour in 2017 to $20 a megawatt hour in 2018. Again, that's just the fact that we now have to comply down to a best-in-gas standard.

So, last year, we walked through the other element to it, which was our inventory of offsets that Capital Power owns, and that second bar was what our cost of emissions would be as we utilize our inventory to meet those obligations, and it was interesting. When we got to 2019, unfortunately, our inventory would essentially be exhausted. Now, with pushing back Sundance C to the Balancing Pool, our inventory is going to last all the way through to the end of 2020. So what that has done is it has reduced our cost of compliance materially from what we anticipated last year because we no longer have the obligation of the Sundance C PPA.

One of the areas that, of course, we're tracking year-over-year—and we like seeing these bars with multiple colours on it, but I think it is a powerful representation of how much we've increased our contracted EBITDA as an organization to 2020, and of course, with the completion of the Bloom Wind Project next year, that'll continue that trend.

Switching to our hedging activities in Alberta, Mark gave you a flavour of how we've performed historically in the Alberta market. Just to provide a little bit more detail, as we look forward at the next three years—so in 2017, we've sold forward actually over a little over 100% of our baseload generation into the Alberta market at a contract price in the mid-$40 range. Average forward prices right now are trading at about $32 in Alberta. We've seen a little bit of a recovery in those forward prices, given the record demand we had in the last couple of weeks in Alberta due to the cold weather, so that was certainly a good sign, and one of the things we are seeing in the Alberta market is a return to positive demand growth over the last couple of months. So, certainly, from an electricity demand perspective, we've seen things turn the corner.

When we look forward to 2018 and 2019; in 2018, the percentage sold forward of 52%. Some of you recall this number hasn't changed a lot over the past six months and there's two things I'd like to comment on there.

The first one is, as we've gone through 2016, Shepard has been running more as a baseload unit as opposed to a mid-merit unit. A lot of that's given where natural gas prices are at. So, what we've done is now—we used to only include minimal stable generation as part of our baseload portfolio. Now, we include the entire output. So, what that does is it increases the size of the denominator and push down the percentage, which we have offset with additional hedges.

But, the other thing that we'll keep in mind is the forward price of $39, for us from a trading perspective, it's always based on us looking at our fundamental expectations for the year versus where the forwards are trading. Right now, that $39 price, from our perspective, is on the low side and we would expect some recovery there.

Another metric we track closely is our coverage by long-term contracted cash flow to our financial obligations. Just as a refresher here, in 2017, the bottom line is the percentage coverage of our long-term contracted cash flow, which would include all our assets outside Alberta that are our long-term PPAs, but also our 20-year contract, tolling arrangement, off of Shepard, as well as our 20-year contract on RECs off of Halkirk.

When we take that contracted cash flow and look at it, we compare it to our overall financial obligations, so preferred and common dividends, debt servicing, all our fixed O&M, all our maintenance and sustaining capex, so all of our financial obligations. We can see now in 2017, we're now heading into a period where we've got approximately 115% coverage, as opposed to before it was 95 to 100%, and that lift has come from the fact that we have $52.4 million of contracted cash flow now coming in the form of compensation payments. So, certainly, very much—very powerful in terms of supporting that contracted coverage.

Now, when we look forward, out to 2019, what that now means is that the margin we're making off of sales from our merchant facilities in the Alberta market over the next three years, that margin will be solely needed just to go towards growth. We won't need it to manage any of our financial obligations.

So, I'll just recap quickly in terms of the dividend growth story with Capital Power. So, in July, we announced our third increase in the dividend of 7%, so consecutive increases of 7% over three years. When we look at how 2017 and 2018 are shaping up—of course, it's subject to always maintaining a look at what's happening in the environment, what's happening with our operations, and subject to Board approval, but when we look at it, and the strengthening of that contracted coverage and what we see in terms of adjusted funds from operations, we don't see any reason why we wouldn't continue that dividend increase through 2018. Beyond 2019 is something we'll be looking at and assessing as we move forward, and part of that of course is going to be looking at those projects that Mark referred to actually crystalizing and taking shape to support the dividend strategy beyond 2018.

So, I'll wrap up with just a comparison to our peers. These two graphs are very instructive to the Capital Power story. The first one shows a breakdown of AFFO yield relative to our current share price. Basically, when you look at the AFFO we're projecting or giving guidance on for 2017, relative to the share price that's about a 16% yield; exceptionally strong, but also important to note is that the dividend yield at 6.8% is the second highest of our peers, again, suggesting very good value from that perspective. When we look at it on an AFFO payout ratio, we're sort of, as I mentioned, in the mid-40% range, which again is materially below what the average would be of our competitors, which is—or our peers, which is 58%. So, certainly very strong from a cash flow perspective, as we look forward.

So, with that, I'll turn it back to Brian to wrap things up.

BRIAN VAASJO: Thank you very much, Bryan. I will close out the formal part of our presentation this morning by identifying our 2017 targets.

As most of you know, we identify our annual targets during our Investor Day and report back on them every quarter as to the progress we're making towards those targets.

In terms of our operating priorities, our target for plant availability is 95%, and that's both Capital Power operated facilities and the facilities that we have an interest in that are operated by others. Our maintenance capital is $85 million. As Darcy mentioned and Bryan mentioned, this is higher in 2017, in large measure because of $10 million we're investing in the Genesee Performance Standards. Lastly, our target plant operating and maintenance expense is in the range of $195 million to $215 million.

In terms of our growth perspective for 2017, certainly deliver the Bloom Project on time and on budget, or hopefully earlier and under budget; execute two long-term PPAs for new contracted facilities, and again, those PPAs in support of new builds; continue to build development pipelines in Alberta and the United States.

Our key financial measure is adjusted funds from operations as Bryan has just described. Our range for 2017 is $305 million to $345 million, in comparison to our midpoint for this year of $320 million.

So, in terms of summarizing what you've heard this morning, in terms of 2016, our performance has very good, particularly under an Alberta power price environment that has not been constructive. We've resolved the outstanding issues with the Alberta Government on what we see as a very favourable basis. In 2017, despite the operating performance improvements that we've been talking about, our expectations, financially, is we'll end up similar to 2016. In 2017, we will more actively manage and mitigate our net carbon position, which I think over time, you'll see will be more and more significant to the Capital Power story and our bottom line. We'll continue to work with the Government of Alberta to define a capacity market that works very well for incumbents.

In the longer term, we are very well positioned in Alberta with our existing assets. Our plants are very competitive as coal units and will be competitive as natural gas units. A move to capacity markets improves the outlook for both our existing coal facilities and a transition to natural gas plants.

Genesee 4 and 5 continues to be the leading option for new baseload generation in Alberta as needed. And we have excellent short- and long-term renewable opportunities in Alberta, as announced this morning, and with further announcements you can expect over the next few months. In the U.S., we are making great strides in our competitiveness and an additional wind project should be announced within the next month or so.

These current and future growth initiatives are well supported by our financial strength and supports further dividend growth. In summary, we are executing well on virtually every aspect of our business.

Thank you very much and I'll now turn it over to Randy for questions.

RANDY MAH: Okay, thanks, Brian. For the benefit of the people listening on the webcast, if you can use the microphone when asking your question, and also identify yourself before asking the questions. Okay, we're ready to start.

BEN PHAM: Ben Pham, BMO Capital Markets. I'm just wondering, your dividend expectations for next year, if you did not receive compensation, would you have still reiterated your guidance, because it seems like your FFO is declining if you're excluding that compensation now?

BRYAN DENEVE: Yes, that's a really good question, Ben. If we take a look at what our payout ratio would have been without compensation, we would have still been below that average of our peers at 58%, so we would expect we would have still moved forward with the increase.

BEN PHAM: Okay. Then, you mentioned with REP in Alberta potential strategic partnerships. I was wondering what benefit do you think that would provide to you guys? Is it more cost to capital or access to sites that you don't already own?

MARK ZIMMERMAN: Probably a little bit of all of the above. Some of the individuals or entities that we're speaking with do have a collection of sites. Some are smaller and that could be helpful for us going forward in terms of capacity to build things. Some are more pure developers that would be looking for good construction expertise. So, it's a whole gamut that we're having these discussions with. Some of the more strategic ones are giving us the potential for larger access to larger land masses and very good wind resources that we find very attractive, so we're following up on those conversations as well.

ROB HOPE: Hi, Rob Hope, Scotiabank. I just want to know if you're in discussions with the Alberta Government regarding your carbon offset inventory and just to ensure that offsets under the SGER would still be valid under clean power plants?

BRIAN VAASJO: So, maybe I can answer that. The discussions that have taken place historically has been that the carbon offsets that have been accumulated and those carbon offsets that are on the books of many companies in Alberta will be recognized on a go-forward basis, without restriction. Now, that hasn't—there haven't been new discussions on that, that issue hasn't come up again, but we see no reason why they wouldn't continue to be fully valid carbon offsets.

The protocols on which they're generated continue to be valid protocols. One of the things that you can expect in Alberta, and across Canada, is a greater diligence in terms of defining what a carbon credit is, and under the—I'll call it more diligent criteria, the carbon credits we have would continue to be valid.

ROB HOPE: Great, thank you, and just as a follow-up, you mentioned that we're seeing positive demand growth once again in Alberta and that you're maintaining G4 and G5 as a shovel-ready project. In your view, when do you see the need for that new capacity entering the market there?

BRIAN VAASJO: I think as was illustrated on Mark's chart on where power costs are going and the convergence of both the capacity market and the energy-only market, that pretty much signals when there's a need for potentially new capacity in the market. Again, we'll have to also see how the capacity market timing and bidding process comes into play, because of course that's very significant, and certainly with the timing that's being identified, there really isn't an opportunity to bid and build, because we've only got sort of a one-year window.

So, again, there's a lot of details to be worked out over the next little while, but certainly if there is a demand for capacity in the market, the way in which the capacity market timing will evolve will certainly provide for an opportunity for a project like Genesee 4 to participate.

PAT KENNY: Hi, Pat Kenny, National Bank. Just on Page 67 here, looking at the AFFO chart, can you give us a sense how much of the cash flow has been trading contributions over the last few years, and I guess how should we think about your trading contributions post 2021, under a capacity market with less volatility? Maybe putting it another way, what's your expectation relative to your track record of achieving 13% above the spot?

BRYAN DENEVE: So, I'll start, and Mark may add to the response. When we look at 2016, we would have built in trading gains of approximately $15 million to $20 million. Now, one of the things to keep in mind is, of course, when we provide guidance, we take into account the value of our positions at that point in time, and so some of the strong performance that you've seen this year from the trading side was actually crystalized well in advance of 2016, but on a year-over-year basis, we look to add about $20 million from the trading.

I don't disagree that the reduced volatility will dampen some of the opportunity around that, but I think, as Mark pointed out, there's still going to be an opportunity to realize a good portion of that under the new market design.

MARK ZIMMERMAN: I might add, under a new market design, with the capacity market, there's really going to be two bidding strategies that are going to start panning out. There's going to be, of course, the capacity bid itself and how we want to position ourselves and what sort of margin will be created, and where we appear in the stack, and then there will be the ongoing daily bidding that will be required in terms of pricing energy itself. So, I still think there's going to be quite a value associated with that skill set that our guys possess, knowing the market and knowing where we need to bid in at.

PAT KENNY: Great, and maybe just one follow-up. Slide 25, on the GPS program there, can you give us a sense as to what your expectation is from an emissions standpoint? Where you expect your tonnes per megawatt hour to drive down to?

DARCY TRUFYN: I think the simplistic response is we're targeting, depending on the unit, between 10% and 11% reduction of CO2 emissions per unit. It's in that magnitude.

ANDREW KUSKE: Andrew Kuske, Credit Suisse. Since we're in the negotiation phase with the capacity markets, and really for the next few years, long before we go live, how do you think about what's best for Capital Power? What attributes of the capacity market business—when we think about capacity markets, there's all sorts of different market structures around the world. There's some similarities, but there's a lot of differences. So, what are the key things you will be negotiating for with the government?

BRIAN VAASJO: So, when you look at the capacity market versus an energy-only market, the real difference is that the actual revenue that's generated is in two components. One of the significant elements when we looked at going into any market—and as I commented earlier, we've been a strong advocate of the energy-only market historically, and the reason for that isn't that that's necessarily the best market for Capital Power and the way our business is. The reason for that is the road to whatever is a new market may—and in most cases, if you look at Ontario or if you look at California, and other markets that have evolved—has been horrendous for incumbents.

With the commitments that the Alberta Government has made, and as we see it, the introduction of an underlying capacity market has some significant benefits. Those benefits are around a more predictable cash flow, to a degree. I mean, it still is an merchant market. Still, the bulk of your revenues will be coming from the energy side.

The issue around volatility is quite interesting, because you end up with a bit of a different volatility, because you're also introducing at lot of renewables. So, overall, the magnitude of changes from year-to-year are not necessarily there, but certainly daily volatility will continue to be fairly strong.

So, the long and the short of it is, when we look at the evolution to a capacity market, if it's a level playing field, if existing generation is treated equally to new generation coming into the market, we think that's sufficient for Capital Power. Again, at the end of the trail, we believe that probably on balance, a capacity market is better for Capital Power, given the environmental directions of the province, than an energy-only market might have been.

ANDREW KUSKE: Then, maybe just to follow up on that, how do you think about the new market construct affecting you from an operational standpoint and how you position yourself operationally, and then just how the competitive behaviours may change? One classic example in the capacity markets is you wind up with antiquated equipment that just lives forever but never really runs that often

BRIAN VAASJO: Right. I mean, there's a lot of interesting dynamics that can unfold, and certainly, as you say—and we've seen it in other markets, where equipment that should have died didn't because there's enough in a capacity payment to keep doors open.

With a coal plant it's a little bit different because you have a significant amount of fixed costs. Unlike a gas facility where you have 500 megawatts and 25 employees, for a coal plant of the same size you've got hundreds of employees and significant maintenance. So, you'd expect the pressures for, as I say, around a coal plant to probably convert or to die a lot sooner under that kind of a market condition.

When you look forward to the elements of conversion, which is going to be the large issue in the Alberta market, is what plants convert. As Darcy, I think actually—I was going to say alluded to, but he didn't allude to it, he made the very strong point. If you have a very good coal plant, very efficient, relatively low maintenance, it will translate into the same kind of plant on a converted gas basis. It will be as efficient in the stack and what that drives us to is to say, we've been on a track of significantly improving the performance of our units, we'll continue to do the same, and one of the things that was maybe not brought out in terms of these improvements from a carbon perspective, is those are also improvements to the efficiency of the plant. Basically, it improves your heat rate. Those will apply to natural gas as well.

So not only do we see properly maintaining the plants and improving the plants excellent from a coal perspective, they will shine through as well when those plants are converted to natural gas. So our approach to plants is going to continue to be the same.

DAVID QUEZADA: Thanks. David Quezada from Raymond James. I'm just wondering on the coal to gas conversions if you can provide a little colour there, what the process is going to be like, capital costs, and then timelines of those projects.

DARCY TRUFYN: Yes. So, I think it's in the slides. I didn't talk about it but just a simple conversion would—I think we said for our units—and we don't envision much rebuild in our units, it's really just changing the burners, and so we're saying, for us, it's $25 million to $50 million, and the reason is that spread is really just on the NOX side, we're not sure of the NOX requirements. So, if it's a low NOX requirement, we'll be buying more expensive burners. But, it's a very simple conversion. We would estimate it would take something like 18 months or so, 16 months, and it would really entail probably just an outage of maybe two months' duration to actually make the switch. But, it's a very, very simple process to convert. That is just a simple conversion. There's other types of gas conversions, but we're not talking about that here today.

DAVID QUEZADA: Great, thanks, and would you be contemplating going ahead with that towards your 2030 timeline, or is there any potential to do that earlier?

DARCY TRUFYN: Yes, I think what Brian and Mark both spoke to is that with the price carbon, as we know it today, at $30, it just makes sense for us. Because of our high-efficiency fleet, coal fleet, it just makes total sense for us to continue to run on coal to 2030, and then do the conversion at 2030. Now, circumstances could change, the price of carbon could change, et cetera, but right now, that's our best guess moving forward and that's how we're planning.

DAVID QUEZADA: Great. Thank you.

MALE SPEAKER: Just a quick question on new gas. How are you thinking—I mean previously from an aggregate you were pretty optimistic on the new gas combined cycle. What are you thinking now versus renewables, let's say?

BRIAN VAASJO: So, speaking from an Alberta perspective, certainly, we think there's probably an expectation of the government, or desire of the government. It does make a tremendous amount of sense, if you end up in a situation where you have rapidly changing environmental regulations—and I think, as many of you have seen, some of the federal government scenarios on low carbon futures result in natural gas plants having, potentially, a relatively short life if you build one in, say, 2030. So, as we look at that, probably the lower risk for investors would probably be converting to natural gas.

Certainly, if you built a new natural gas plant, say in 2021 or 2022, there's definitely a lot of runway there to achieve the economics that you've gone in with. When it starts getting to 2030, that's when it's getting to be a little bit more dicey, from our perspective. So, we certainly see, in Alberta, new natural gas as a place early, but probably not later.

When you look at it from a North American perspective, there's still a need—and you're seeing a more definite switch towards peaking-type facilities and the less large generation that's taking place outside of, you know, the utilities, the major utilities. So don't see a lot of necessarily opportunity for large-scale natural gas generation, but again, there's still peaking plant opportunities throughout much of the U.S. markets.

DARCY TRUFYN: I'd just add one technical point to add to Brian's comments, and that's just with the simple gas conversion it doesn't give you the ramping capability that a new combined-cycle unit would give and so a lot will depend on what the market needs are as well, and that's why it still makes sense for us to have the G4 and G5 option available. Converting the coal units, just like I spoke to a few moments ago, it will have a better ramping capability, but it's still—quasi-baseload is its optimum, and a combined-cycle G4-type unit is much, much different in terms of its dispatch capability.

ROBERT KWAN: Robert Kwan, RBC. Just to follow on that question to start, have you done the calculations, as you look at G4 or G5, what net cone might look like for the Alberta market?

BRIAN VAASJO: Sorry, Robert, could you repeat that, please?

ROBERT KWAN: Just when you look at your G4 and G5 and the capacity as you go forward have you looked at what the net cost of new entry might be with respect to how the capacity market might function going forward?

BRIAN VAASJO: Well I think, you know, as the charts were somewhat indicating, you end up almost indifferent as to whether you're in an energy-only market or a capacity market, in terms of the signal of when you need new generation. The projections that we predict here are somewhat indicating in the 2021 timeframe, 2022.

Essentially, as you bid into a capacity market, say, with something like a Genesee 4 or 5, what you'd be doing is looking at the revenue that you would expect to be getting from the energy side, and then, out of your total requirement, which is, generally speaking, the $60/65 range, you would then layer in or establish what you'd need as a capacity payment for whatever that time period is, whether it's three years or four years or five years, whatever the duration of the capacity call is.

So, the decision is still largely hinged on what makes sense in the marketplace, as to whether or not you would invest. Again, if the government felt that there was a strong need for new capacity in, say, 2021 or 2022, they'd be signaling that and we'd be participating in whatever that process would be. But, we do see that there is a need for additional capacity some time in the early part of the next decade and would expect Genesee 4 to be definitely a front-running candidate for that.

ROBERT KWAN: As you think about the capacity market going forward, not having the rules yet, you're pursuing a number of wind projects at this point. Do you have any concerns about bumping up against any seller side mitigation in the capacity market?

BRIAN VAASJO: Not really, because what's happening is we had been—again, assuming an energy-only market—had been promoting a REC approach. The way the government is going is it'll be essential a CFD approach, or potentially they'll—your revenue will be guaranteed. There are some changes that may be taking place in the transmission side of the business that we'll be keeping an eye on, but those changes, we would expect that they'd probably, if any, the impact on the economics of any renewables would likely be covered by things like changes in law provisions.

So, basically, signing—participating in a REC process in Alberta, we see as the same as participating in BC or Ontario, and so on. Generally speaking, you're guaranteed the revenue. Again, there'll be things over time that have to be dealt with around the edges, but there won't be anything fundamentally at risk going into—at least as we expect—going into the first REC process in Alberta.

ROBERT KWAN: Okay, and if I can just ask one last question. You're projecting an AFFO yield in the 15% range. It sounds like as you go forward that your seeing stability and growth in the AFFO. So, I'm just wondering have you given thought—unless you've got these development projects with an AFFO yield greater than 15%—allocating capital to invest in your existing stock.

BRYAN DENEVE: Maybe, Robert, you could sort of expand—you mean in terms of share buybacks?

ROBERT KWAN: Yes. So, if your shares are at the 15% AFFO yield, unless your new projects are greater than that.

BRYAN DENEVE: Well, I think there's—one of the other elements that's at play is we do want to increase that mix of contracted cash flow, and certainly that comes from investment in the types of projects that Mark described. So, certainly, we're in a transition where we're reducing the merchant cash flow. The higher percentage of contracted typically has to come from the growth side.

ROBERT KWAN: Thank you.

ROB CATELLIER: Rob Catellier, CIBC. I wondered if you could go back to your comments about diversification and partnering. Is the partnering comment really to do with new projects in Alberta or is there a legitimate chance to sell down some of your position in Alberta and use that as a way of diversifying?

MARK ZIMMERMAN: So, the way we're looking at it right now is not so much as a source of raising capital but rather relationships that allow us to deploy additional capital, and if these partnerships can give us access to more sites, give us risk-sharing capabilities, or give us other strategic advantages where we can combine our competencies with a partner's competencies, it's those sorts of thing to improve the overall approach and improve our competitiveness. Improve our probability of success, is really what we're trying to do. At this juncture, it's not going to be looking to monetize a selection of our assets into a joint venture. It's more about deploying capital, not raising it.

ROBERT CATELLIER: You've chosen to safe harbour some projects and PTCs for the use of transformers; we've seen this approach usually through turbines. Can you elaborate a little bit on that choice and how many megawatts have been safe harboured and what's the related capital project—project capital?

MARK ZIMMERMAN: So, at a very high level—I guess a series of questions there. One, the choice of transformers was because of some specific language in the Code had identified the commitment to transformers would qualify us to start our construction; hence, that led to the selection of that. We chose seven transformers as they relate to many of the sites that I reviewed earlier today, and those transformers have the capacity that is applicable to those sites. I guess the view would be, over the next four years, we are very bullish that all of those sites will go forward in one form or another, so that equipment will be absolutely required. The use of trying to safe harbour with turbines, frankly, it was probably just more of a larger capital outlay than the transformer selection that we've made.

DARCY TRUFYN: So, I'd just add a couple of things, specifics. This is about US$10 million type allocation to purchase, and just on the megawatts, it's in that 800 to maybe 1,000 megawatts of potential. So, we think that's a very good bet for us and we're very confident that we can compete on those sites.

BRIAN VAASJO: I think the other thing to point out, you know, we've in the position before of having turbines that have flexibility as to where they get placed, and contractual arrangements around how prices get lowered with greater turbine use, et cetera. When you look at those arrangements, you're basically putting in a pin in your technology and a pin in a number of other different parameters, that, in our view, as time moves forward over the next four years, we'll be in a much better position and we'll get a much better cost response and performance response from contractors and from turbine manufacturers, as we have real projects and as we have—I'll call it a larger portfolio of projects to be under construction.

So, we think you're not going to save a whole bunch or you're not going to gain any cost advantage around transformers, but you can create a significant cost advantage for yourself by negotiating for turbines later in the process. So putting capital dollars aside, we think this probably leads to longer-term, lower cost of projects.

ROB CATELLIER: My final question has to do with the Balancing Pool. Any idea what they might do with the PPAs?

BRIAN VAASJO: I think at this point—I mean, we, of course, hear lots of different rumours and lots of things going on, and I would say that right now it's pretty uncertain, it's quite uncertain as to what the Balancing Pool is going to do. They're positioning themselves to do a whole range of different things, so, again, uncertain, and hopefully we'll see some clarity around that within the first quarter of next year.

DOMINIQUE BARKER: Hi. Just the U.S. dollar private placement, has that been swapped back?

BRYAN DENEVE: Sorry, could you repeat the question?

DOMINIQUE BARKER: The U.S. dollar private placement that you spoke about, first of all, the $160 million, is that U.S. dollar or Canadian dollar?

BRYAN DENEVE: That would be Canadian dollars.

DOMINIQUE BARKER: So, has it been swapped back?

BRYAN DENEVE: No, the deal was done in Canadian dollars.

DOMINIQUE BARKER: Okay, but the 3.85 is your Canadian dollar debt.

BRYAN DENEVE: Yes.

DOMINIQUE BARKER: Is it was originally U.S. dollar debt?

BRYAN DENEVE: No. Actually, it was placed there—it's being lended as Canadian dollars.

DOMINIQUE BARKER: Okay. Then, you have about a billion of liquidity, of additional liquidity. Has that been the kind of normal for the last—since you've existed? I'm just wondering why it's so high.

BRYAN DENEVE: Well, actually, it was higher and one of the things we did about a year is, when we did the previous extensions, we actually reduced it from about $1.3 billion down to $1 billion, and the size of it really is just gauging, you know, how much we're going to have under development, in terms we need that access to short-term financing, and at $1.3 billion, we felt that was a bit higher than we needed, so in order to reduce the costs we reduced it to $1 billion.

ANDREW KUSKE: Andrew Kuske, Credit Suisse. Just back on market design and market structure, so for the next—I think it's for four years, the government's capped retail at 6.8. We've seen that strategy in other jurisdictions around the world and some of it didn't work out so well and some of it worked out okay. Could you just maybe give us your thoughts on what that means from a power generation standpoint? Have they thought out all the options or is this really just a political action to lessen the volatility, on at least a barely perceptual basis, but also maybe a real basis for retail.

BRIAN VAASJO: You know, maybe to answer that from—so not to comment on the political side of it, but when you look at what the actual impact is—you know, they've established a cap with a view of subsidizing amounts around that, as opposed to putting, per se, an absolute cap, and what that does is that impacts on the retail side, but it doesn't impact on the wholesale side.

So, again, it can impact on the appetite for people to be taking contracts and it would be that kind of increased contract length in the marketplace, but other than that sort of secondary impact, it should not have any impact on the spot price of power in the province.

ANDREW KUSKE: Then maybe just to follow up, what kind of inbounds have you had from industrials since we've had greater clarity in the last month or so? Has there been any change in activity level and the dialogue?

MARK ZIMMERMAN: Not significantly. I mean, our guys continue to be very active in those relationships. Those that want to hedge, we continue to have those discussions and look to secure longer-term arrangements. There are some, with the spot price where it's at, have been comfortable taking more exposure in the near term. We would expect, as prices start to recover, we'll probably see that activity come back at us, those that are trying to minimize their costs going forward, but the activity level has been similar to what we've seen for the last little while.

LINDA EZERGAILIS: Maybe this a broader macro question, but with respect to the Balancing Pool, how do you see their mandate evolving, if at all—and I guess this is all part of the mix—and what part of criteria, beyond just your cost to consumers and taxpayers, do you think they'll consider when they weigh on the merits of holding onto PPAs versus cancelling them outright?

BRIAN VAASJO: There's obviously been some changing legislation and enablement, and so on, around the Balancing Pool. I think, ultimately, what would end up happening is they will be enabled to do whatever essentially they're directed by the government. That decision as to whether to hold onto the PPAs or which ones to move on, or to push back to the owners and so on. Certainly the Balancing Pool, I would expect would have a view and there'd be some discussions, but, ultimately, I would suspect that it is a government response, and whatever is necessary to do that would end up—the government would ensure the enablement of it.

LINDA EZERGAILIS: Just as a follow-up, do you think that they would kind of look at various cost considerations primarily, or do you think there'd be some kind of equitable allocation, maybe, of cancellations across various players, or …

BRIAN VAASJO: Well, the basic fundamentals continue to be the same. Some of those plants, given the PPA structure, it makes sense for them for the lowest cost resolution for—I'll call it Albertans—is to push them back to the plant owners. Others, it makes no sense. Like, for example, Genesee 1 and 2, the cost to put the PPA—or put those plants back to us is huge because it is based on net book value. So, you know, don't see that the government would be taking actions that would significantly increase the cost to Albertans.

One of the things, where the PPAs are today and is a little bit lost in the narrative is the fact that the Balancing Pool holding them and dispatching them the way they are, or the way they're being dispatched, results in lower power prices in the province, so there's tremendous benefits to consumers, but, again, that gets lost in the narrative and people are looking at pennies as opposed to the dollars that are there. I'm not so sure whether the government may, you know, recognize—and they do know it, but recognize that benefit and they hold onto them for longer than they otherwise might have, just from a purely pure perspective of the Balancing Pool decision. So there's a lot at play in what might evolve there.

RANDY MAH: Any other questions? One in the back.

MALE SPEAKER: Thank you. Can you just talk about your appetite to raise equity? Just thinking in terms of as you diversify into more contracted production, do you see your cost of capital at your 16% AFFO yield, and should we expect that some dilution there as you diversify?

BRYAN DENEVE: Certainly, there's a lot of head room we have in terms of our discretionary cash flow right now to support growth capex. As you saw in the charts, we're looking at $320 million in 2017, without having to go to the capital markets. So, certainly those investments will be, by definition, accretive.

When we look at opportunities that are bigger and may require us to access the equity market, we certainly would—we're going to be very mindful of the implications from an accretion or dilution perspective, and those are some of the metrics that we look at, but at this point in time, we wouldn't expect that that growth will be so rapid as to—we would be causing dilution by a lot of access in the equity markets multiple times.

PAT KENNY: Just back to your pipeline of growth opportunities for both wind and solar in Alberta—I know more details are still to come here, but can you just give us a sense, maybe, as a rough ballpark number, of potential megawatts, outside of Halkirk 2, and Whitla, as well, just on the wind side, and on solar, as well?

MARK ZIMMERMAN: So, as a rough ballpark, if you will, when I think about Halkirk and Whitla right now, combined, that's about 450 megawatts. We do know that the overall renewable build over the next 15 is targeted at 5,000 megawatts. To the extent we can be in a position to be targeting a series of those over the next three/four years, 150 megawatts in size so that we can participate in each, that would be preferable, but we of course have to balance that with the cost of maintaining those options, the cost to carry, and the nature of the arrangements that we're getting into.

I think as Bryan probably pointed out as well, we're continuing to be very cognizant of how the market is going to unfold and what these auctions are going to look like. That'll also inform how aggressive or not we want to be in securing additional sites to bid into this marketplace. But directionally, I would think if we can get to 500 to 1,000 megawatts of options for us that would be preferable, again, depending upon the cost.

PAT KENNY: Thanks, and maybe just for Brian, as you perceive these opportunities, would you—are you going to continue to go it alone or would you consider bringing in a financial partner with perhaps a lower cost to capital?

BRIAN VAASJO: Certainly, we have to look at how competitive are we going to be in the landscape, and certainly, with what the first couple renewable opportunities are going to look like in Alberta, being essentially your revenue is guaranteed, that'll attract a lot of players with relatively low cost of capital. Our approach to that, obviously, is to be very effective in terms of keeping our costs associated with the wind turbines, et cetera, to be quite low. In addition to that, execution on the construction side.

But, a real key—and we've talked about this a couple years ago—is the value of a site. The value of the sites today in Alberta are associated with—you need to essentially be able to just plug them in without any transmission—additional transmission costs, and both Whitla and Halkirk are in that vein. On top of that, it's going to be, again, really low cost and ready to construct. So, that eliminates in the first couple rounds probably a fair amount of potential going forward.

One of the things that's going to happen—so, in terms of partnering, we will seriously look at how competitive we think we are and if we believe that our cost to capital may not be competitive, we would look to partner to ensure that the projects are competitive. So, I think that goes without saying, and Mark was commenting about our willingness to bid with others and participate with others that bring significant value.

One of the other things, and maybe a little bit more squishy going forward, but represents definitely a perspective around partnerships, is that there's going to be, as time passes—and this may be sooner rather than later—the Alberta Government will start including consideration of local benefits, local partners, First Nations' participation in those, so we would absolutely expect that in time we will have those kinds of relationships and partnerships as part of the bid on any renewable project. So, you'll see in Alberta—and I think you're seeing it everywhere—an increasing need for broader participation and we are definitely going to be responding to that.

DOMINIQUE BARKER: I think Alberta hit a new peak last week. Can you just talk about whether that's a change in shift? What's happening behind-the-fence? Are they drawing more from the grid or is that true demand? Can you just talk about that generally?

BRYAN DENEVE: Yes. So, that would be true demand in the Alberta market. There hasn't really been much change in terms of behind-the-fence generation and the magnitude of it. So, I think our record previously was about 11,200 and we hit 11,440.

RANDY MAH: Any other questions? If not, I'll turn it over to Brian for closing comments.

BRIAN VAASJO: Well, thank you very much for your interest in Capital Power and for joining us this morning.

We certainly continue to be in a bit of a world that's evolving, particularly in the Alberta market, and in contrast to where we were last year where we were talking about a lot of things that we hoped would evolve and the issues of compensation, certainly, the PPA issue was starting to bubble a little bit, but certainly didn't take on the stature that it did through 2016. But as we look forward, we're seeing increasing clarity in the Alberta market. We're seeing an Alberta market that is definitely positive from a Capital Power perspective, both in terms of what we can do with our existing assets—and maybe just on that point, and maybe to tease you a little bit, we're hoping that by the time we're talking to you next year—you can simply convert to natural gas, but there's a lot more to an overall strategy and how you'd approach it and other elements that you can bring to that, that, again, next year, we hope to be able to talk to you about in a little bit more depth.

But, you can see that there's a continuing strong focus and although we've had this focus, definitely last year, an increasing visibility of our focus on developing projects, particularly renewable projects in Alberta, and certainly in the U.S. So, our outlook has changed in terms of certainty and from our perspective has increased, and uncertainty, by definition, has decreased, but you're seeing the organization continue to do what it's been doing; again, in some respects, with a little bit of a different focus but applying the same competencies, the same approaches to increasing our business and moving forward from a financially responsible perspective.

So, again, hopefully next year we'll have some additional, exciting news for you, and approaches and conversations around the evolving market and what it's meaning to us and what some of the actions are that we're going to be taking, and would invite you all at any point—and, again, there's going to be a lot of noise and a lot of news, and a lot of people creating news that isn't news, and so on and so forth, in our market, in our Alberta market over the next year or so, but I'd invite you to call us at any time for our take on it and our perspective on it. You can certainly expect us to be very involved in the discussions and looking for fundamentally good strong markets to prevail, and once again, that are very constructive from an incumbent perspective.

So, again, thank you very much for joining us this morning, and to all of you, have a very happy and safe holiday season. Thank you.