**Capital Power**
**2017 Investor Day**
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**Brian Vaasjo**
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**Tony Scozzafava**
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**Jeremy Rosenfield**
Industrial Alliance Securities

**Robert Hope**
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**Robert Kwan**
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**Randy Mah**

Good morning everyone. My name is Randy Mah. I'm the Senior Manager of Investor Relations. Welcome to Capital Power's ninth annual Investor Day event here in Toronto. This event is being webcast, so I would like to welcome the people listening and joining us on the webcast.

The theme of this year's Investor Day is Driving to a Sustainable Future. Earlier today, we issued a news release that highlighted some key points that will be discussed this morning, including our financial and operating results for 2018.

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.

With that out of the way, let me introduce Capital Power's management team that will be presenting today. We have Brian Vaasjo, President and CEO; Bryan DeNeve, Senior Vice President, Finance and CFO. Unfortunately, due to unforeseen circumstances, Bryan is unable to join us today. Tony Scozzafava, our VP, Taxation and Treasury, will be filling in for Bryan. Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction; and Mark Zimmerman, Senior VP, Corporate Development and Commercial Services. The Management Team also consists of Kate Chisholm, Senior Vice President, Legal and External Relations; and Jacquie Pylypiuk, Vice President, HR.

This is the agenda for this morning. We'll start with presentations by Brian, Mark, Darcy, and then we'll take a mid-morning break. We'll conclude with Tony's CFO presentation and a summary by Brian. After the presentation, we will respond to your questions and then hopefully you can join us for the buffet lunch afterwards.With that out of the way, I'll turn it over to Brian.

**Brian Vaasjo**
Thank you. Good morning and welcome. And just to add a little color in terms of Bryan DeNeve not being here, actually he made the trip, but as you know, for us westerners, Toronto is not necessarily the healthiest place to be, so he's actually suffering in his hotel room right now. In any event, as you'll see, Tony can very much fill in for Bryan without a hiccup.

Firstly, before we jump into the formal presentation this morning, I thought I'd spend a few minutes providing some context around what we've been doing and also why the theme, Driving to a Sustainable Future has actually some substance behind it.

I'll start by sharing with you some of Management's strategic thinking and the discussions we've had with our Board. It starts with a view that decarbonization is the force behind everything in the power generation business. Through quickly evolving new technology, through to substantial changes in government policy, and ultimately, the major risks and opportunities in the power generation sector.

On the one hand, decarbonization results in carbon taxes and truncation of coal facilities lives. On the other hand, for power generation in Canada needed to eventually heat all of our homes and power electric vehicles, it's expected to double or triple over the next 30 years. Annual investment in the power generation business is expected to almost double in the short term of what it's been historically. But the pace, the targets, the actions, and ultimately the politics around decarbonization, have a high degree of uncertainty. In the United States, you see a federal drive against decarbonization initiatives, while at the same time, states, municipalities and industries have a strengthening resolve to pursue decarbonization. So how do we protect existing investments and make future investments given this uncertainty?

The answer is twofold. First, for new investments, focus on power generation assets that are resilient to several decarbonization scenarios. We developed a number of scenarios that range from accelerating decarbonization to halting it immediately. We've also developed scenarios that have significant technological disruption on both sides of the meter. When we tested investment strategies against these scenarios, we did it in the short, medium and longer term. We concluded wind generation has both a robust growth potential and is resilient against virtually all scenarios, overall three different time periods.

Likewise, natural gas has a very good future, but as a transition fuel. However, the timeframe for transition varies. In Canada, we see natural gas investments being safe for the next 30 years or so, evidenced by the recent confirmation by Alberta's Energy Minister and the recently released long-term energy plan here in Ontario. In the U.S., we see in most regions, that transition period being extended by at least 10 years, if not 30 years.

The contracted investments we've made over the last two years fit precisely within this strategic thinking, and going forward, it's consistent with a three to five wind farms we'll have underway next year, and the natural gas opportunities we continue to look at. It's also consistent with a pipeline of development opportunities we keep generating.

Secondly, in response to decarbonization, we need to protect the value of our existing assets. In particular, we need to manage our coal assets through this decarbonization. The truncation of our ability to burn coal at 2030 and the announced carbon tax in the Alberta Climate Leadership Plan are our two decarbonization challenges. We've worked hard to blunt the impact of those actions.

Immediately after the announcement of the Alberta Climate Leadership Plan, we shared with you our book value approach, which ultimately was what we're able to negotiate into coal compensation, which we believe was ultimately fair. We've also been accumulating a portfolio of carbon credits— the largest in Alberta—other than, of course, the Alberta government. The credits we own are hedged against our carbon liability.

In addition to that, last year at our Investor Day, Darcy talked about GPS, or Genesee Performance Standard, a program to reduce the carbon footprint of our coal assets. Today, he'll tell you about the progress we've made and the $28 million investment we've committed to in changing our turbine rotors on Genesee 1 and 2. We are now confident that by 2020, we'll reduce our carbon footprint by more than 10%. Reducing the risk as much as practical is ultimately better than hedging itself.

Likewise, we've been working on biofuel coal firing, which in time may reduce our carbon risk by an equivalent amount to GPS.

The ultimate mitigation to our carbon risk is to convert our coal plants to natural gas. Don't take not making an announcement today on which year as indecisiveness. We've analyzed this at length and understand it very well. We may not decide ultimately until 2020. Information is not available today to make a fully prudent decision. In the meantime, we are getting ready. Last year, we told you that our reaction time from decision to completion was in the order of 12 to 18 months. Now we are targeting nine months in terms of our reaction time. We're also looking at innovative staging approaches using existing outages and different configurations. When the time to converge comes, we'll be there. We won't be early, and we won't be late.

So why the theme Driving to a Sustainable Future? Well, we have the momentum and we're certainly seizing the opportunities that are available to us given our competencies and competitive positioning. Three to five of the wind farm sites that you see on this map in white, will have contracts and moving to blue by the end of next year. If we are fortunate, we may find contracted natural gas plants that fit our criteria as well. At the same time, we continue to aggressively reduce carbon emissions and our risk. This enhances our leverage to the Alberta upside.

Underlying all of these activities is the financial strength that supports asset and dividend growth. In more precise terms, our strategy is to provide investors with a strong total return. For fixed income, the stability of maintaining credit ratings. For shareholders with a robust total shareholder return, we're viewing a minimum average annual AFFO per share growth of 7% as reasonable. And just to note, we have achieved an average of almost 10% from 2014 through 2018.

Important is a substantial upside to Alberta market and maintaining that upside. Critical to the value proposition is a reduction in business risk, which we expect to reduce, and ultimately, to drive down our dividend yield.

From growth perspective, building and acquiring contracted assets in North America is key. Underlying that is growing our pipeline of opportunities. A natural result of our growth activities is the diversification of our geographic and fuel risk. For existing assets, continuing building on outstanding operations, but also reducing our GHG and risk. Darcy will speak to completion of our five-year program of increasing availability while reducing costs and risks. He'll also speak to management of carbon costs, including the GPS project. Tony will comment on optimizing carbon credits, and for conversion, coal and natural gas plants, we anticipate making a near-term decision in and around 2020. Carbon and natural gas pricing remain major factors in this decision. Although the carbon tax impact is notionally pretty straight forward, the sensitivity in the natural gas prices is not that clear and is very significant. For example, $1 per GJ natural gas price change is equivalent to the impact of a $30 per tonne change in carbon tax. As Darcy will describe, maximizing optionality of timing and fuel source is key to that decision.

I'd like now to turn to 2017, another year of excellent operations. Operating performance targets for our plants are in line. Progress on reducing our carbon footprint has been very significant. We've experienced an excellent realized Alberta power price. A tremendous year of contracted growth and diversification in particular. We acquired five thermal plants and advanced our renewable portfolio.

2017 continued to enhance our financial strength. We raised $1 billion to finance our growth. In 2017, this AFFO growth from new contracted assets supported annual dividend growth guidance out to 2020 of 7% a year.

Looking more specifically at contracted growth, we added 1,300 megawatts of capacity which consisted of three natural gas plants and two waste heat facilities. I'm pleased to note all are expected to meet or beat the acquisition business case.

We also completed Bloom Wind early and under budget. We recently announced the New Frontier wind project, a 99-megawatt project in North Dakota, to be completed by December of 2018. We also expect to secure two to four additional wind farm developments by the end of 2018. An added benefit of the recent acquisitions and completion of Bloom Wind has been geographic diversification. Alberta moves from 73% in 2016 to a contribution to EBITDA of 56% in 2018. As Mark will illustrate, the Alberta position will be down to almost 50% by 2020.

Important for 2018, Mark will describe the uncertainty for Capital Power in the Alberta market is declining rapidly. Yesterday's announcements clarified the Alberta carbon regime and OBA for natural gas, which Tony will speak to.

The last major piece is the Alberta capacity market design. Capital Power is very much engaged in this process. It's on track, tracked for first auction in 2019, for delivery in mid-2021. This schedule will require clarity of major market parameters by mid-2018.

Turning to our outlook for 2017, operating and financial results meet or exceed targets. In 2018, approximately a 5% growth in AFFO reflecting generally annualized growth, which has been offset by a carbon tax. We expect to secure 350 to 600 megawatts of contracted renewable developments.

For the longer term, we are providing information today on Genesee optionality, confirming 7% annual dividend guidance to 2020. We see numerous growth opportunities in Canada and the U.S., and as a result, increased geographic and fuel diversity. This all leads to solid contracted growth, while at the same time, reducing business risk. The combination of these should result in a yield improvement for shareholders, which Tony will provide some color on in his presentation.

I'll now turn the podium over to Mark.

**Mark Zimmerman**
Thanks, Brian, and I'd also like to welcome everyone. Thank you for your interest and time with us this morning.

Now that Brian's kind of gone through and given his views on the strategic overview of the environment we see on, I'd like to add to those observations on those contracted growth and reduced business risks. Specifically, tactically how are we going to do that?

To paraphrase, there is no one silver bullet available to us here. Cash flow growth for us is going to come from multiple sources and we need to be pulling on all levers at our disposal to do that. We've got a great fleet of assets, over 4,500 megawatts across multiple fuel sources and across multiple jurisdictions, and we need to continue to optimize those assets. We need to be ready and to capitalize on the transition to a capacity market, and as both Darcy and I will run through, we do think that we've got a real competitive advantage with one of the youngest fleets in Alberta, and some of the lowest variable costs which we'll transition to gas-fired opportunities as well.

Along with that, we look to continue with our great performance in optimizing the commodity exposure, both power and fuel. We've got certain amount of combined excess generation in Alberta that we've got a team that manages and creates great value for us, and as I'll illustrate, has resulted in a great captured price relative to spot over the last number of years, and all of that is before even considering how we're going to generate some good growth from capital redeployment. That capital is going to be allocated to numerous development opportunities that are available to us, and as well, we've seen some great acquisition opportunities; we were able to capitalize on the last year, and we expect that activity is going to continue going forward.

But before highlighting each of those levers and the specific steps we're going to take, perhaps a quick recap on the context that we see out there right now in the business environment.

Starting with Alberta, there was much uncertainty two years ago. At the beginning of 2015, we were quite bullish on the Alberta market. The all-energy market, demand load growth was great, Oil Sands was really booming and Alberta was really leading some good growth. We brought the Shepard plant online and we were starting to develop our plans on doing a similar sort of build on Genesee 4 and 5. However, a series of events have occurred, that oil price really softened, really impacting that load growth; a change in government brought a change in policy and our Climate Leadership Plan and the carbon tax and a change in market. Really, because of those events, really reinforcing with us over the last few years, our need to ensure that we're both flexible and adaptable to some of these changing conditions.

But since that time, clarity is coming. Oil prices bottomed out, have started to recover. Coal phase-out agreements have been reached. As Brian mentioned, the market transition is underway. The PPAs have been turned back to the Balancing Pool and now we're even seeing those assets being returned to the natural owners, if you will, the operators of those plants, and as we have seen by TransAlta yesterday, we're starting to see appropriate market actions being taken in respect to those plants as conversions, retirements, and mothballing are all starting to be planned and highlighted. So today, things are definitely improving.

The wind build has kicked off, capacity market rules are becoming clearer; options for the coal plants are being pursued. In short, we're starting to have a great environment in which we think we're very well positioned for continued Alberta success.

We've got great assets. They're industrial scale generations that generate great economies of scale with existing infrastructure and a workforce in place that we can capitalize on. In essence, we expect to realize substantial Alberta upside as we move forward.

But our footprint is growing. We now have a meaningful position in Ontario with over a billion dollars invested and we expect that to grow. While short-term fundamentals, supply and demand, are weak, we do see turning a corner come 2020 on the back of nuclear refurbishments, and in 2022, those nuclear refurbishments coupled with expiring gas contracts and the prospect of electrification-driven demand growth can create a real potential bullish long-term outlook for Ontario. In short, as Brian mentioned, highlighted in the long-term energy plan, a supply shortage by the early 2020s leads to a positive outlook for a flexible gas unit generation as well as the potential for new gas, and we feel we've got some assets now that can respond in that sort of environment.

Until 2020, our cash flow was well covered with contracts, and I'd also point out, as key both major political parties see an ongoing need for clean, efficient gas. As highlighted by Glen Thibeault recently, dispatchable gas-fired generation will continue to play an important role in the Ontario electric marketplace. Quick ramping and dispatchable peaking resources are going to ensure the system can remain strong and balanced.

Finally, for the U.S., we are really struggling with everything that is going on there to come up with one chart to encapsulate it all. What we landed upon is really as we look longer term, where we see the generation stack moving to and how we want to position ourself in it. Currently, right now, as many of you know, U.S. is absolutely dominated by coal generation, but there has been a real growth in wind, and natural gas has really established itself for the last couple of decades.

As we move forward to 2030, we see that wind continuing to expand materially, and we feel we can participate in that in a meaningful way. But we would also like to point out that natural gas remains a very prominent part of that stack going forward and really will be that bridge fuel to a cleaner and sustainable environment.

By the time we get to 2040 and 2050, as you can see, the wind amount increases dramatically, and by some estimates that we pulled this information from, see that being as high as 30% to 40% of the stack overall. So, a meaningful amount of capital needs to be deployed over the next number of years in order to achieve that goal.

So in short, long-term significant growth. However, in the shorter term, fundamentals are flat. We do have, in certain situations, more supply than demand, but as we've also stated in Ontario, as that demand growth continues and with the potential for electrification of electric vehicles, transportation, that could grow substantially; there could be a real surge in demand going forward.

There is political whipsaws underway. We've had Obama's policies, now we have Trump's policies, and we're not sure which policies there will be in 2020, but I'm sure it will be interesting and exciting. The market will continue to evolve and it's going to be refined, and again, reinforces our need to ensure that we remain adaptable and flexible as we move forward.

Within that context, let's start with Alberta revenues as we start going through our existing assets and our existing competencies. Since mid-2015, excess supply and low load growth has created a very low spot price and this was further exasperated by the PPAs being turned back to the Balancing Pool and then they were being dispatched at variable costs, driving to a very low spot price. Active management by our commodity portfolio management group has consistently realized the higher capture price relative to that spot price, and they do this through multiple actions: originations, strategic biddings, short coverings with some of our peakers, et cetera. They also actively manage the fuel supply costs in our environmental books. This comes from a very detailed market knowledge, market knowledge that overall is going to set us well for the transition to a capacity market because many of these same dynamics exist in that environment as well. Overall, we'll continue to effectively manage this exposure, reduce volatility and create incremental value for us.

Now we all know the energy market is going to change with the current government and perhaps it is best to revert back to what their objectives were for doing this. First off, system reliability. As a lot of renewables come on, there is a need to ensure that you have the backup generation available in order to ensure that the system remains reliable and robust. Secondly, to provide investor confidence by ensuring that all assets are being treated fairly both old and new, and avoiding any sort of generation ghetto that we've seen in other jurisdictions. Finally, to provide the investment signals, price signals in order to attract new capital to the province as part of this build that's going to be required.

As Brian mentioned, design and consultation is underway, first auction is expected to be in 2019, first delivery in 2021. We have also previously communicated, we expect the combination of the capacity and the energy pricing to provide similar overall revenue to what we would have realized in the current all-energy market framework, and we believe, when implemented properly, we should continue to prosper as we have a young, diversified and efficient set of assets in Alberta. In other words, and I'm sure as Darcy will run through, we have some of the best-performing assets, we have some of the best-performing market trading capabilities, and we expect that will continue as we transition to a capacity market. We are fully engaged in the transition process.

In our more immediate future, forward markets has also started to improve. This graph illustrates the price change for the forward 2018 market on a monthly basis, and taking a look at those contract terms on three dates throughout the year, and as we've seen from yesterday, there was a further $3 price increase for 2018. There's been a number of events that have transpired; they're all on the slide, I won't go through them. But the key is as they are being resolved we see the market become more constructive in terms of pricing going forward. A year ago at this time, we were seeing 2018 pricing being in the high-$30s. Today, we sit in the mid-$50s, a significant improvement and a significant value implication for our fleet.

In addition to the resolution of many issues, we've also seen load growth has started to return to Alberta. On a rolling 12-month basis, the load growth had fallen dramatically when the decline in oil prices occurred, as I previously mentioned. But as the producers have adjusted their plans, the load-growth bottom out has started to recover. Over the last year, Alberta has bounced back to from the lows experienced in 2016 in terms of growth. However, there is probably an element of this is that is perhaps a more of a dead cat bounce. We would expect a more normalized 1% to 2% growth going forward.

We also see significant improvement in spark spreads over the last year, creating great potential value for our gas interests as we do see this trend continuing. This graph illustrates how the per-unit margin has improved, and for illustrative purposes, the spark spreads that we've calculated here assume a heat rate of eight.

The rise through 2017 has been a combination of strengthening Alberta prices, but also just as important a softening of AECO prices, and this is all before considering the impact of the carbon tax that will be layered on and partially flowed through to the prices we move forward in 2018.

In other words, as we see this very strong spark spread, we do see higher margins associated with the gas fleet going forward and we have been able to take advantage of this. Which leads the obvious question of what this means for our non-gas facilities in the province. We still believe that our legacy assets are very well positioned in this environment, and to demonstrate that, we'll go through a series of dispatch curves to try and to highlight how we see the movement occurring.

This curve shows for 2017, that much of the existing coal fleet still remains low in the stack and is dispatched on a baseload basis. Taking into account the variable unit cost and the current carbon tax, it still has an advantage over gas-fired at a more normalized gas price. As illustrated here, our Genesee plant has some of the lowest costs and lowest emission efficiencies that are high. We lead that coal sector today.

And as one would expect from one of the youngest and supercritical plants, that is why we have that thing built for the low cost and high efficiency.

Similar story emerges for Shepard. It's one of the best combined-cycle plants in the province, and Clover Bar one of the best peakers. In all cases, as we see the stack coal followed by combined cycle followed by a peaker, we are leading the pack in those categories.

If we then move to a typical 2018 dispatch curve, where you then have a $30 carbon tax coming into play, that overall categories begin to shift. First, with the strong heat rate and low emission gas operations, we'll see our Shepard plant move ahead of the stack, relative to coal, just given where its overall variable costs are. However, as noted in here, coal will still play a very important role. It will still be in front of peakers and other forms of less efficient generation and higher cost generation.

Then if we move to next slide with a $50 carbon tax provision in the federal program, we'll see even some further movements. One of the interesting dynamics where we will start to see peakers start to become competitive with some of the older, less efficient coal, just given that spark spread and the higher variable cost associated with the coal operations. But that being said, the point of conversion of all coal plants to gas, it will all be relevant and they will all move together, so that whole section will slide. In other words, similar performance whether in coal or in gas.

We look at this being quite positive. Again, young efficient set of assets, very well positioned in the stack today, very well positioned in the stack as we move into the future. And secondly, as Darcy will go through in some detail, we have numerous options at our disposal to enhance value and we will make the call on those options when appropriate, as Brian has already highlighted.

So with that -- oh, sorry, I was one slide ahead of you on that. So with that Alberta background, what are we doing? Mentioned optimize the existing assets; let's look at we're doing with respect to those both in Alberta and across.

First, we mentioned Genesee. Coal-to-gas conversion longer term, once clarity is received in the environment. The key for us in the interim is let's preserve that low-cost option and do what we need to do in order to make sense and it's available when called upon. As Brian had mentioned, we are investigating biomass as well, and coal firing at Genesee as a way of reducing the coal emissions and providing some more environmentally friendly generation potential.

The final one is coal firing, which is actually a very interesting opportunity for us. Even before the implementation of the $30 carbon tax next year, we've had situations this year when the gas price has fallen to a point where it actually makes sense for us to burn more gas and reduce the level of coal that we're burning. As evidenced by the previous slide, with the spark spread, it became very, very supportive. Plus, with the emission savings that is attached to that, margins become very more favorable for us as we move forward. So given that we've been able to produce some good margin coming out of that strategy, knowing that we're going to have a higher carbon tax going forward, we're looking at options available to us to enhance that opportunity and allow us to further pursue that as we look to the future and how the gas price may unfold. As a side note, there is a lot of trapped gas in the WCSB, and at times pricing is very attractive for us.

In addition to optimizing on the gas at Genesee, we also have those options available to us, both at Clover Bar and Shepard. Low gas price environment and the corresponding spark spreads can provide very attractive opportunities for us going forward.

That's Alberta. We look to apply some of these skills elsewhere across our fleet as well. In Ontario, now that we have a great set of assets and needs for gas supply and transportation, we're looking at ways to optimize access to that and reduce costs.

Across our fleet, we're also looking to continue with recontracting discussions at some of our facilities that have nearer-term expiries, specifically Island Generation and Decatur, and we'll continue to pursue those opportunities.

Then with the wind fleet, we are starting to find very interesting opportunities arise as well as we try to optimize revenue from those facilities, specifically dispatch and day-ahead dispatch as we look to gain some critical mass and scale, we are seeing opportunities arise. We're able to capture discrepancies between day-ahead pricing and where we see things at and we've been able to capitalize and produce additional margin, plus managing the PTCs and existing eligibility on many of the U.S. wind sites. Of course, some questions will arise in respect to that in terms of some of the U.S. tax changes and Tony will kind of run through some of that as well.

So, that's kind our assets and how we look to optimize them and what we look to do to manage across the portfolio. Perhaps I'll now I'll move to what we're going to do in terms of where we're looking at to deploy capital going forward.

Starting with Canada, as you can probably imagine, short-term development focus is Alberta. We have sites and we expect to enhance those sites moving forward with a potential consolidation of some of the junior developers that are out there. With five gigawatts of renewable build, there is going also be a need for gas-fired capability for system reliability overall as we move forward.

In the medium to long term, other opportunities also arise for us. In BC, depending upon the outcome of Site C, we do have two wind sites and a gas site that we can move forward with if conditions warrant. Next door in Saskatchewan, the government has offered—has a 50% renewable target, which we are monitoring and will participate in should it become attractive enough for us to do so. In Ontario, as already kind of mentioned, between the nuclear retirements, market renewal as highlighted in the recently released long-term energy plan, we also have three sites that options exist for. To summarize in Ontario, over 500 megawatts of generation, a five-year life with them right now, so a very young set of assets with around 15 years of remaining PPA life. Just a couple of comments on the government's long-term energy plan and some of the outcome of that. While we've reaffirmed the commitment to the Clean Climate Action Plan to reduce GHG emissions, we don't see it as posing an immediate threat for us as all of our PPAs that we have in place do have change in law provisions. That is intended to preserve the underlying economics. The ISO’s change in the market renewal process is anticipated to be implemented well before the expiration of the PPAs, which is also positive for existing generation to have value at the end of the PPA term as there will be recontracting opportunities and incremental capacity options. There has also been the identified need for 2000 megawatts of incremental capacity by the mid-2020s, and that creates potential expansion opportunities for us, both at the York Energy Centre as well as two other sites that we have available positioned in great locations. Wind assets through OEM bolt-on technologies could become available as well as we look out into the future.

With that sort of background, let's do a bit deeper of a dive into Alberta. What you see in front of you, perhaps I'll describe the map a little bit. The map that is up there is attempting to highlight what the wind resource looks like in Alberta. The yellow and the orange being very high and constant wind, and so a great resource for the development opportunities, and that is overlaid with the major transmission grid in Alberta, trying to highlight where that takeaway capacity is, and hence, where are our assets are relative to that. As you can see, Southern Alberta and East Central Alberta are probably the most desirable locations for the resource. As it relates to transmission, there is pockets within Alberta that have excess transmission available, so become very conducive to wind development. The two that we are actively working on currently, first Whitla 1 and 2, we've mentioned that before. That was an opportunity that we were able to acquire that had a lot of existing data associated with it that we were able to capitalize on and really advance our plans in a much more accelerated fashion. A 300-megawatt facility in Southern Alberta kind of in between Medicine Hat and Calgary. Great location, huge capacity factor, i.e., you can capture a lot of wind. Very economic opportunity and significant available transmission that's been built around that in anticipation of builds historically and with the great proximity to interconnect. The other is Halkirk 2, a 148-megawatt site which is right next door to our existing Halkirk facility. It also has a good wind resource and a great capacity factor. It also has available transmission. It also has the added advantage of much of the wind in Alberta that has been developed in the past is in Southern Alberta. In an all-energy market, when that occurs, when the wind blows, it blows for everybody; having that geographic diversity can be helpful in that it can provide a counterbalance to that wind, when it isn't blowing in Southern Alberta, but it is in the Central part.

Then the final point is the junior portfolios I have up here. What I'd highlight is, our intent is not to hire an army of land men and go out and try and develop new sites in Alberta as there's already been a lot of work. It's been recognized Alberta's got a great wind resource historically, and you can see that when you look what's in the queue with the AUC and the AESO currently.  There’s over 8,600 megawatts of wind developments that are in varying stages of applications, and of that a third is owned by a number of junior developers. We do see an opportunity as things kind of flush out as we see what the rules are going to look like going forward, and as we've already had a numerous discussions, these developers are looking to develop these things, monetize them and move on. Once clarity comes out, we do see opportunity to have discussions with those developers that we see great potential with that are in these locations that we see good potential, to have those discussions and there will be consolidation that will unfold in this environment.

I'd also mentioned in respect of Alberta gas—and we don't want to forget that. With 5,000 megawatts of wind ultimately being developed, when that wind isn't blowing, you need something to backup all of that generation and right now, the most economic, the most logical is natural gas in order to provide that reliability. We view ourselves as actually having three very attractive sites in respect of that. They're all attached to existing assets that we have: Genesee, Clover Bar and Shepard. Specifically, Genesee, we've already talked about coal-to-gas conversion around the existing generation, but there is also opportunity to put new generation, whether it's combined cycle or peakers, on that facility; the land base is there. We have the water, we have the transmission infrastructure, we have the workforce, so there is some real competitive advantages in terms of expansion that we could see.

Similarly, that's case that we see at Shepard and at Clover Bar. Clover Bar also has gas availability attached to so it significantly reduces the turnaround time of any sort of development that we might want to put there in that we can connect fairly quickly. Shepard, very close to Calgary and a huge load pocket, could be very advantageous as well and having all that infrastructure I previously spoke to.

Last but not least in Alberta, I don't want to be remiss and not mention our strategic relationship that we recently announced with the Siksika Nation. Development agreements are in place with the Nation. They are the second largest reserve in Alberta and in Canada. It's a very large land mass that is there, and there is significant wind and solar resource that resonates in that area. The infrastructure in place, the transmission infrastructure is in place, and as illustrated by some of the existing developments around the Nation, that's evidence of the strength of the resource that we see there.

There is the 300-megawatt Black Spring Ridge development and another 100, or just under 100 megawatts that IKEA has developed at Wintering Hills, and there is the first solar development that's gone in just north of Brooks, 15 megawatts. Very attractive resource. We're currently very excited about that and we're looking at proceeding by installing MET towers to start gathering the data and start refining our thoughts on how best we can develop that opportunity going forward. Plus with the added advantage of some social consideration given our partners that we would have in this operation.

I should mention, we have expressed interest to the Alberta government. They have a solar renewable program that they're looking to bring an RFP out, and to the extent we were to move forward with that it would be in respect of the Siksika joint venture that we have.

So moving beyond Canada. You've seen us take a number of steps into the U.S. recently and perhaps, I'll just provide some color around strategically, how we look at different jurisdictions in the U.S. and where our focus would be. First off, probably for both gas and wind—and I should note, this prominently is focusing on wind development in terms of the color scheme on the states, but I'll speak to gas as well as I walk through this line. First off, the A circle is probably the most exciting area for us, for both wind and gas, and it's really for a number of reasons.

First, for wind, that's probably where you see some of the strongest wind resource in the U.S. is along the center part of the continent and we've seen that both with Bloom and some of the other developments that we're chasing out there. Incredible wind speeds, incredible capture factors, very economic. But also, as the jurisdictions that we see, whether it's RPS standards or whether we see the ability for bilateral contracting, it has those commercial environments that are attractive to us. So a lot of our focus will be in that middle part of the continent in the lower 48. That's also where we see good opportunity on the gas side.

As it relates to the B circle, that's an area where the wind resource is good, not as great as the middle part, but we do see a lot more RPS standards, we do see a lot more opportunity for our counterparty contracting, so we do see some great business environment for us to advance some of our development plans going forward.

Similarly, as we look to the C circle, that's an area in the northwest of the United States, where again, not a bad wind resource, but a number of utilities that do have the potential to secure supply through RFPs looking to procure, not self-builds but to diversify the market in those areas. So we see it as a potential area for us to focus on.

The D area is kind of in a low potential for wind, there's not a lot of a wind resource, but I would highlight it is an interesting area for us on the gas generation side. The reason I say that is really twofold. As we've seen the situation in Alberta with low gas prices, and given abundant supply, we see that situation there as well. It's connected to two very large hubs or basins where there is a lot of gas, there's a lot of transmission infrastructure, there is a lot of capability for very attractive gas pricing in that area, but it is also an area with a lot of current coal generation, which, if this gas environment persists, that conversion, our new gas can be quite competitive with old coal, and so it's an area we think we really need to keep our eyes on. And indeed, it's an area that we've recently transacted on, given we see fundamentals being strong as we go forward in there.

The other point I'd like to make, Brian had mentioned, just as it relates to the wind opportunities. We see two to four opportunities coming forward next year. We would also see probably as a run rate our targets would be two wind opportunities being developed on a go-forward basis per annum.

Next slide that we have here, we're already well positioned given that outline that I kind of ran through between the resource and the markets with the Element portfolio that we acquired a number of years ago. We've announced New Frontier. It's just under 100 megawatts of opportunity, again great wind speed in the MISO, and we have executed contract in-hand and the engineering is well underway, and we're going to start breaking grounds here soon. Darcy, I believe will be covering that.

Also, I'd like to highlight Cardinal Point. That's another development opportunity that we're quite bullish on and don't be surprised if we're able to advance things enough, that might be the next one in next few months that we may be in a position to announce here as well.

In addition, as we look at this, there is a number of other sites. I won't go through each of them individually, but they're well positioned given that overview of where we want to focus our efforts, and I think we have good potential to translate many of those into executable opportunities as we move down the road here.

Now let's move to tactically what we're doing. As I think I mentioned, execution has commenced of some of this over the last year. On the development side, we completed Bloom on time and under budget and probably ahead of time actually and under budget, and we've announced New Frontier. We've commercially got to the arrangements we needed. We're running through the development. We're ready to advance on that front, and as many of you know, we've also been successful on a couple of our M&A opportunities. I should note, we've been active in the deal flow over the last couple of years. We've been successful on two, but that comes after considering a multitude of opportunities. It's been quite robust, and as I'll point out, we do expect that to continue.

In Ontario, we enhanced our footprint with great positioned assets, solid commercial operations and brownfield potential that I've already kind of highlighted. And Decatur, established our presence in a market with low-cost gas and significant coal generation, so we think there's good prospect for good solid life on that. In all cases, with these acquisitions, we absolutely still expect to meet or exceed our investment business cases as we move forward.

I should also note, diligence was conducted by Capital Power employees. A lot of them really stepped up to the plate and put in a lot of effort over the last year. Where that gives me comfort is it's ensuring commitment by the organization to realizing on those projected economics; everybody's got a stake in the game here. And to that end, given this volume, I should note we've marginally increased our internal resources as we do see this level of activity continuing.

To that point, on that level of activity, on the wind acquisition front, many assets continue to change hands both from infrastructure funds and developers. As many of you are aware, infrastructure funds, they're monetizing as they look for liquidity events in connection with their limited lives and they look to turn these things over, and similarly, as I already mentioned, in Alberta small developers continue to take things to a certain stage and then look to liquidate to recycle their capital, and that's a great entry point for us to pick up on and then move forward on the development.

Once acquired, we do see continued opportunity in respect of optimization efforts, when combined with our existing fleet. As that critical mass grows I think that gives us more options and more economies of scale.

I should note when we look to acquire, we do find that we remain uncompetitive with young, new tax equity investments as the pricing on many of those opportunities are robust and very thin. However, we do see that as it gets to older assets or fleets that are past their flip dates, that are post-PTC eligibility but still with a decent contract life remaining, those are instances where it's less desirable for some of those competitors out there that are more financially oriented, could provide great opportunity for us and so that is the sort of response that we will consider. That goes both for Alberta and in the U.S.

Similar story exists on the gas side. We also see monetizations continuing to occur both with funds for the same reasons, but also other strategics that are, shall we say rebalancing or re-addressing their own unique needs, whether it be balance sheet or other requirements on their front. So, we see the level of activity continuing.

While there has been a lot of merchant opportunities arising and that's very, very attractive multiples, our real push is to make sure that we're ensuring the visibility that we need and while we'll not out rightly dismiss any component of merchant, our focus is still highly contracted and may come with small parts of merchants that we can manage, but the focus is contracted, and it's with those that we see that we can be competitive as we move forward as illustrated by this year’s acquisitions.

Between these taxable executions, as Brian started to point out, we're seeing diversification. He mentioned geographic on fuel. We've gone from 40% of our fleet being wind and gas to now just under 60% of Adjusted EBITDA, and if we repeat the performance of the last year over the next few years, we see that changing in to 2/3 gas and wind by 2020.

Similar story exists on the contracted side. We've migrated from 2/3 of our revenue stream—pardon me, our EBITDA stream being contracted back in 2015. We've achieved 80% this year with those acquisitions. Given that same pace, we would expect that we'll be able to maintain that. What's key about that is, that's in the face of a rising price environment in Alberta where we will see a rising EBITDA contribution in Alberta, but given our acquisitions, we expect we'll still be able to maintain over 4/5 of our results being visible and contracted.

Finally, as Brian pointed out, a similar story, 75% of our results in '15 Adjusted EBITDA were coming from Alberta. As we sit here today, that number has been reduced to 60%, and as we move forward, frankly, we're looking at 50% of our EBITDA coming from Alberta versus other jurisdictions in our fleet.

What does all this mean? We see a migration of our portfolio, and specifically, risk is decreasing through fuel diversification and geographic diversification and visibility is increasing through greater contracted cash flows.

So in summary, if there's one thing I really want you to take away from today's presentation is that we're truly excited about our future prospects. I hope that you are too. There is no doubt the Alberta outlook is improving, and let me be clear, we are very well positioned to capitalize on those opportunities right in our own backyard. As we've shown in the past and will continue to show, we feel we have a real market leader position in Alberta, but we're not stopping there. We see considerable opportunity, perhaps more than ever, to continue to grow our cash flow throughout North America.

We are actively exploring opportunities to expand within Canada and U.S. Our pipeline of wind development projects is top-notch and we expect to translate that into results in the near term. We'll continue to work to refill that pipeline, and the M&A activity is robust and we'll continue to leave no stone unturned.

We will remain disciplined in our approach. In short, we've identified the levers to pull and which we intend on fully utilizing. Maximize our portfolio in Alberta creating significant value; be well positioned for the transition to the capacity market; optimize our commodity exposure across our whole young, diversified and efficient fleet; add to our fleet by executing on these various development projects, both on-time and on-budget; and finally, continuing to acquire high quality assets that meet our investment criteria. I think there's a lot to look forward to and we're excited.

So with that, why don't I turn it over to Darcy to give you the specifics on how we're going to technically do this.

**Darcy Trufyn**

Well, thank you, Mark, and good morning. So my presentation today covers operations and development, both areas where we strongly believe that we have demonstrated excellence.

Capital Power has now completed our fifth and final year of improving plant performance and availability through our formal reliability program and driving optimization through our asset management plans. We have been successful at getting more production out of our units while spending less money. We manage our plants proactively as it is much more cost effective to deal with issues before they become forced outages. Our objective now is to sustain this high availability and target additional improvements on an opportunistic basis.

This year our availability, as Brian noted and I'll just give a little bit more color to it, we are tracking to budget with our own operated fleet running at 96% and the combined total assets at 95%, and that is, 95% was our budget, and while we have become very cost effective, we have, and will continue to do the right thing to ensure we do not put our assets at risk.

A good reflection of our reduced operating risk profile is that our insurers view us favorably with, again, we renewed our premium this year, and secured very, very low premiums. So much lower than they were five years ago and with very good coverage. So these people know plants and they view us very favorably.

A productive plant is actually also a safe plant. For the past two years, we've been awarded with Canadian Electrical Association's Gold Medal for Safety and we are tracking, again, this year to win the same level of award. When the Climate Leadership Program was announced in Alberta two years ago, we started work immediately on our Genesee Performance Standard, or GPS as we refer to it, which is a focused and prioritized five-year program to reduce carbon emissions from our coal fleet.

Now this slide shows the availability journey that we've been on over the past five years with the CP-operated fleet. The sawtooth that you see is really just because of the uneven planned annual outages. But you can see the improvement trend and it's evident there now we are sustaining an approximate 2.5% improvement on availability from where we started five years ago. This higher availability, obviously provides greater revenue on our contracted assets, and in Alberta, high availability and good start reliability has been of major benefit in the energy-only market. We can take positions knowing our units will respond when dispatched. This high availability, we also believe, will be equally beneficial in a new capacity market.

This slide shows our combined controllable O&M costs and our sustaining capital costs. They're combined together and they're measured against our kilowatts of Capital Power's operated fleet, and you can see the trend there as well. Now these are in real dollars, they haven't been adjusted. Real dollars per year of spend.

The planned outages I did pull out of these numbers because they are quite erratic, but what is included in these numbers are maintenance and forced outage costs and I think you can draw some conclusions from this. We obviously have been successful in not only lowering our cost per KW, but we are able now to maintain that cost and through continued optimization, actually we're offsetting inflation. This slide also demonstrates that our reduced O&M spend has not detrimentally affected the assets. You can see that there's just no extra spends for forced or maintenance outages. We actually have developed a very, very steady state in our operation fleet.

Now, I'll move on to Bloom. You've heard some things from Mark and from Brian; I'll just add a little bit more color to it without getting into too much my detail, but it really was another very, very successful development for Capital Power. On new developments like we said, we've come to these, and I know most of you have year in, year out, I talk about this all the time, but we are very much involved with our builds. We have a project team assigned to every project and that really helps to ensure that we keep the project on track, that we deal with issues as they're issues, before they become problems. We deal with things fairly and then we get what we paid for our facilities. Now Bloom did have, actually I thought, a very aggressive 11-month schedule given the location and the fact that there are some naturally tough weather conditions there, but through the good work of our entire team, the contractors, the engineering, everyone involved, we were actually able to achieve completion in 10 months, which I think is really impressive. Ten months does drive value. That really does help keep the cost down and set new objectives for us for future.

Now, Bloom did utilize—this is the first project that we went on with the larger Vestas 3.3-megawatt units. We learned a lot there, and that's great because as you'll see in the next slide, New Frontier has the same, similar units. I guess, the last point I want to make on this slide is that this Bloom project, it's a clear demonstration that geography is not a limit for Capital Power. We can build in any of those locations across North America, very successfully We're really confident on our construction capability.

New Frontier, it is our next wind development. You've heard Mark talk about it, and Brian, and it is scheduled for a December COD 2018. We are very, very confident that this will be another successful Capital Power development. The turbines, as I mentioned, these ones are slightly tuned up but they're 3.45 megawatts Vestas units. We've learned a lot from Bloom, some really good things and we'll apply those learnings to New Frontier. The blades on this one are actually 62 meters in length and the towers are 87 meters high and the wind capacity factor here we're expecting to get something in the plus 45% range.

Now, Brian and Mark both talked about us forecasting or announcing today two to four wind farms by the end of next year. I'm going to give you some color as to why we're so confident about that from my perspective.

On the development side, you know since the inception, we have—Capital Power, we have repeatedly demonstrated that we can build on time and on budget, and while opportunities for new wind developments remain and there are many opportunities, it is an extremely competitive environment, so being good at wind isn't good enough; you have to be better. So to be better, we took a very focused and methodical approach here over the last five years. We've worked very, very hard, but we have continued to drive down our cost structure. We've standardized our systems, our tools and our processes, both from an operations and construction process, and this ensures our plants are built to our standards and that we operate to the same parameters across the fleet, but what most importantly it is, it means that we know what we want and we can deal with that upfront with the contractors and engineers. We establish certainty with our scope and that is key for cost. Absolutely key. We also have in-house very good and just a strong, excellent expertise in engineering and process, and it really does matter. An example of that on Bloom, when we first got started, we had a serious problem on engineering and interpretation and because we had the internal expert, we were able to push back. That saved us millions of dollars and saved us actually probably a couple of months in schedule. You need to have that kind of talent in-house because if you rely on others they sometimes let you down.

Now the other, I think, key for me for driving our cost structure is that we do have in-house estimating capability. We know with a higher degree of confidence what our costs are and we have the knowledge in-house. We are also then therefore, because we know our cost, we are able to drive those costs down. As an industry, we've seen a major reduction—all of you know this that wind industry has become—the pricing on wind, costs per megawatt hour have come down dramatically over the last few years. What I can say from a Capital Power perspective, and I'm not going to give any secrets away, but for every dollar that we've seen from the industry, I believe that we've—and I have numbers to prove that—that we've actually seen internally about half of that in addition coming from our own cost savings. I think the net result of all of that is that we really believe that we've become a low-cost wind developer, and as Brian noted in his opening comments, because of all of this we are very confident that we will obtain two to four wind projects in the next year.

Now from an ops and maintenance perspective, we are also looking for ways and means to drive improvement, especially with wind and with the availability in capacity factors. We're looking at a variety of things and I know we're not the only one, but we are pushing. We're looking for things such as hardware and software modifications, we're looking at aerodynamic modifications. We've looked at and have revised commercial terms that create better alignment between ourselves and our service providers so that they really understand what are the things that we need as the owner.

We have also pushed and revised maintenance programs to ensure that we maximize the up time on our units.

Now with that growing fleet, and Mark touched on that also, we have begun to see some real benefits. Just as an example, I thought I'd just comment about our spares. Now, it is an infrequent occurrence, but blades do get damaged and when a blade is seriously damaged, it can result in actually many months of downtime for that unit, and that's obviously affecting availability. What we've done at Capital Power, over time, we've built up a variety of spares of blades and we're able to move those spares across North America when a problem arises, and we can therefore, minimize downtime and that has really been a savings, been a major savings for the company. We continue to maintain and expand our sets of spares for those very reasons.

Lastly, as we continue to grow our fleet, we are creating this critical mass. From an operations perspective, that critical mass not only comes with benefit of all these machines and locations and what we can do with that, but it's also that expertise that comes as we grow and develop special expertise internally that really does drive value, and so I believe that going forward, we're going to see further optimization that will really be material with our wind farms.

Now you've heard about the asset, so here’s a little bit more detail. But my detail, I just want to provide is more from an operations perspective on the assets that were acquired and developed last year. It was a very, very busy year. We actually -- I'm an engineer, so I'll say it's 1,270 megawatts—it's not approximately 1500. It's 1270, and so there was a lot of activity in operations integrating these assets, plus each of these assets actually had planned outages this year, so that gave us really good eyes into the plants. There's always some concern when you're going through due diligence that you're not necessarily seeing everything. Well we were able to, through those outages, do some additional inspection. So we really got a good look at it and it gave us a great deal of comfort. That I'll mention on the next page, but here I just make a few comments from an operations perspective on our units.

Now the three major plants, they all have equipment that we're very, very familiar with. The three units at Decatur are using Siemens 5000F class, and we have experience with these units as we have two of them at our Joffre JV plant. York also have two of these 5000F class units, albeit of a newer vintage, but that knowledge really helps us. So building up a critical mass of similar units is really beneficial from an operations perspective. At East Windsor, we have two GE LM6000s, and again, we have experience with this machine from our CBEC facility. Again, we have a relationship with the OEM. We have good knowledge internally of how that machine performs.

So, whether it's buying power, whether it's spares, whether it's sharing of maintenance practices or internal engineering and expertise, all of these things we believe that Operations will be able to add further value with the larger thermal fleet.

Specifically on the assets, I just wanted to reiterate what you've heard, but again, mine is in the context of Operations. I am very, very pleased that following the integration and the completion of the planned outages, I can sit here or stand here and say that everything that we did and saw, it meets or exceeds our expectations from due diligence. All the assets have been, the major assets have been well maintained and there have been no unpleasant surprises.

Now, while these assets are well run, we do believe there are good opportunities at these facilities from an Operations perspective to add further value, in addition to what I just previously mentioned.

Just as an example, we have internal engineering and operating knowledge and we have quality control processes that we believe mitigates risk and really does ultimately add value, and by being proactive in addressing issues before they become problems. As an example, in Decatur, through that outage, one of the things we saw as they didn't have an inspection program for certain piping. That is stuff that we're very, very familiar with. We know it can lead to serious problem, so we introduced a new inspection program there, and we did. We looked at some of the worst joints and locations and we did find one small issue but we were able to fix it and fix it at very minor cost, but that's the benefit of actually having a program like that. You can address something, fix it before it becomes a real problem. Something like that that we found, if had it not been detected and left for years later, it would have become a very serious problem, and a very costly one.

Now I'd like to just speak more and add more color about Genesee. And specifically, G1, G2 and G3. Now these units have consistently outperformed all other coal units in Alberta, averaging actually 96.3% availability over the past three years. But you can go back in time, they've been high performers, but that 96.3% on coal — there's a fellow here from GE, Brad, he said, "That's world-class, Darcy," and it is world-class, so I'm going to hold you to that. We like that. But that really just reflects on the proactive maintenance that we have in place that ensures that this excellent performance standard is maintained and sustained.

As we switch to the new market, the new capacity market and then transition from coal to gas, I really want everyone to understand that the advantages we have today, they will continue on as we go into gas.

Now, as Brian noted, we've implemented a very aggressive carbon reduction program called GPS, and I'm going to talk about that in the upcoming slides. I'm also going to talk more about the transition from coal to gas, but the key message there is that we see that happening in phases, in the transition, all for the benefit of maximizing our asset value.

Now, on GPS, approximately two years ago, in response to the Climate Leadership Program, we embarked on the multiyear carbon reduction program for our coal fleet. Now we spent the whole year reviewing our equipment, reviewing what the design conditions were. We went back to the original drawings, the original design specs, and tried to understand how are these units running today versus what they were designed for and then started working on so what can we do to bring them back to design, and even—then after, bring them up beyond design. Through that process, we ultimately landed on some targets, some objectives and they're still stretched, but the average for the units is 11% improvement, that's 11% reduction in carbon intensity.

To put that in perspective, so when we finished GPS and the numbers—I think the numbers you saw in your stack there didn't include GPS, I think that's just today, so we're going to change in that merit curve. Upon completion of GPS, the carbon intensity on G1 and G2 when we finish, will be at the same level as the carbon intensity—so that's subcritical. We're actually going to get it to supercritical level, so where supercritical is today. That's pretty darn impressive, so we're really, really driving our performance on the subcritical.

So this bar here, for those who were here last year, you can go back, you can check, the first bars in each year, those are the numbers I showed last year on a graph. They're the same numbers and that just shows you the buildup. The blue is the savings in carbon intensity, and the orange is the savings from fuel efficiency, from improved heat rate and less coal. So what I've done here is I've showed you what we had set out as our measuring stick last year. This year, with all the refinements, with all the good work that's been done, all the extra engineering work, we're now projecting the new bars, and you can see that we're showing a higher recovery in early years. The big difference you'll see in 2017—it's minor—but the amount of coal that does take a little while to get those variable costs, if you're just reducing the coal by a few x tonnes, it doesn't drive value yet, but we see that coal value coming. But all that aside, the key takeaway here is that we are still forecasting on annual savings when we hit 2021 of $35 million a year through our GPS program. That's substantial value and that is substantial risk mitigation.

Now this slide—I don't have too many fancy slides. This is one of my fancy slides. Mark has all the good slides, but this slide is a pictorial of GPS. It really shows the elements. It's a generic layout of the coal plant but it shows you the different areas that we're working on.

Now, firstly, on the coal side, we've worked actually over the last several years to improve our coal quality and to drive the coal costs down, but coal quality for carbon intensity, carbon reduction is huge. It's hugely important. The analogy I'd use is if you're driving a Ford Focus, probably not good to put diesel in it, and it's probably not—well, diesel is probably a bad one—but premium gas, you don't need to premium gas in a Ford Focus. So higher carbon content in coal is just as bad as lower carbon. You need to deliver carbon at the right level all the time, and so that's what we're focused on. We've really worked hard at making sure that we're delivering high-quality coal to our plant. So, that's one key area of GPS, but then you move on.

On the boiler side, we are doing a number of things. I'm not going to go through detail because obviously some of those things we believe are competitive advantages. But we are doing a number of things to improve our combustion in all our units and we're also adding smart technology.

We will be improving and have been working on improving airflows and are adding real-time monitoring, so we really do understand on an instantaneous basis how the units are running. We never used to worry about this. We didn't have real-time monitoring, because it wasn't—carbon wasn't a problem but today it is and so we need eyes and ears. Operations needs to understand instantaneously what's happening with the units.

Balance of plant, we're doing a number of things also. I think the key point here is we're looking at ways to reduce our parasitic because obviously, the less power we consume internally, that mean that you're getting higher net power out which de facto means improved efficiency.

Finally, the sort of one of the key changes, especially for G1 and G2 are the improvements we're making on the steam turbine side, which we announced today. But if you flip the slide over, just a little pictorial again. Unfortunately, we didn't use GE's diagram. It wasn't as good as this one. This is just a shot of a steam turbine, and so what we're doing here is—this is the LP rotor, low pressure rotor, and what we are doing, we've been working on this for about two years—actually almost since the Climate Leadership—on what can we do with these units? How can we improve the efficiency of these two subcritical units? We saw that there was a real opportunity on the LP side to capture more steam, and so we've been working on it. It took a lot of iterative work with the OEMs. Ultimately, we settled on GE and then worked with them for a long time to come up with the right mix. We ended up with a rotor that has a 40-inch blades and we're very excited about it, and I know GE is also. We're very confident that this is going to add huge value to the plant. The key here, a key takeaway for you is that value will continue on even when the units are switched to gas. This an improvement that will see payback, whether it's coal or whether it's gas.

Now just to quote GE—and they're obviously a major player, a global player. I think they view us as people that really have stepped out and taken on this carbon challenge, and as the quote says, they view us as a world leader in things that we're doing at Genesee.

Now on coal-to-gas, we continue to move forward. As I previously noted and again, I'll repeat that, regardless of whether these units stay on coal or are converted to gas, all the performance advantages that come with our coal units will be transferred to gas. This means, obviously the age of the units, their high availability, their excellent maintained condition, their competitive heat rates and improved heat rates, all of this transfers to gas when we convert them.

However—and we're not stuck on this, but we are actually—we do have huge advantage on coal that others don't have. We have a very good quality of coal and we have a very, very low-cost structure, so we have these advantages. Now when you couple that with GPS, it does make coal favorable for a period, but obviously, it depends on these other variables, the carbon tax and price of natural gas, et cetera, but we do have advantages that others don't.

We are flexible in the conversion and it is our intent to maximize asset value through a transition rather than just a straight conversion. We see this happening in the transition. Brian mentioned that we're targeting—we've already been working on this and we see that the overall scope of work we've able to pull that down to nine months and the outage time, however, is still two months for each of the units. But we are believing that—and we are still working on it—but we are believing that as we go through and work through more details, we'll start incorporating changes to our units through planned outages, and through that process I'm hoping that we can shrink the outage duration such that it may get to where we can actually do the change-out during a normal outage duration that we have for our units. But that's work yet to come.

What we wanted to do here, just to add a little bit more color, because I don't think people necessarily know, but we do have today, gas-firing capability or capacity at Genesee and we have been firing gas when the spot prices are such that we can't turn it down. So, we have been running this past year at times, opportunistically, at up to 250 megawatts. So if you just take that is—that is our max, if we can get the gas, but 1,250 megawatts is what the system designed for. Sorry, 250 is what we can fire up today, and have been, so 250 as compared to our total output of approximately 1,250 megawatts, so that's about a fifth of our capacity we can currently fire on gas if the gas is available. But we are working on, as I said, to make improvements. For this upcoming outage on G2 here in spring of 2018, we're going to add some things to the outage, some provisions, again, looking at ways to de-bottleneck the gas such that over time we can continue to increase our optionality and gas firing capability. Last point here, we are on track to bring significant new gas to the site in 2020.

Now on biomass, we have done a considerable amount of work over the last couple of years in research and have successfully had several test firings of a variety of products and we are very confident that we can co-fire biomass with coal. We are also confident we can co-fire biomass with gas. So this does intrigue us as, obviously, biomass, it has a very tremendous sort of positive effect on carbon emissions, and so we are interested in looking at ways and means to continue to reduce our carbon. So, biomass is favorable and we know we can do it.

The problem is to make it cost-effective it does require support from either the governments or from industry as there are considerable extra costs in transportation and material handling of a new fuel source, but there is something there and this is something we'll continue to work on.

In summary, we continue to optimize our assets from a costs and availability perspective. The assets that we acquired in 2017 meet or exceed all of our expectations from a physical condition perspective. On the development of new wind farms, we have become a low-cost wind developer and we believe this position us extremely well going forward. We are and have made excellent progress in our carbon reduction program and this will result in annual savings to the Company of $35 million by the year 2021. On coal-to-gas, Capital Power is well positioned already and we are very flexible in our transition as the markets evolve.

With that, I thank you.

**Tony Scozzafava**
For those of you who haven't met me, I'm Tony Scozzafava. I'm Vice President, Tax and Treasury with Capital Power. As those of you who do know me know that tax is my area of focus in the past, and so I thought I'd use the next four hours to go through U.S. tax reform.

No, what I'll really do is I'm going to provide you an overview of Capital Power's financial strategy, how the strategy has performed well historically and why it continues to be sustainable moving forward as we grow, as you've heard from Brian, Mark and Darcy with some of the plans, whether it's development plans, whether it's acquisition of gas and wind in North America. I think the system that we've used and the platform that we've used for a financial strategy has been quite successful, particularly given the fact that there has been a lot of turbulence, in Alberta particularly, and we've been able to manage through it quite successfully.

Firstly, the financial strategy is premised on four key components. The first one is the 7% annual dividend growth backed by an increasing percentage of cash flow under long term contract, and an AFFO payout of 45% to 55%. We made significant progress on this particular item in 2017 by adding the assets that we did. It enables us to continue to look forward as we move into 2018. Strategy is also premised on maintaining an investment grade credit rating. The BBB- and BBB low ratings that we have enable us to have a trade-off between achieving the optimal amount of leverage and having competitive cost to capital as we compete for assets.

The final thing that it also does is that it enables us to support the stability of the dividend. So by having that investment grade credit rating, we're able to compete for these assets and at the same time enable us to pay the dividend and fund the assets without being worried about the fact that the dividend has to be paid out as well. It ends up being a perfect balance in terms of how we run our financial balance sheet.

The other thing that I spend a bunch of time on is managing the financing risk. That would include the laddering of our debt maturities, which we spend some time on to make sure that we don't have too many refinancings in one year and that the maturities ultimately are aligned with the long term life of our assets that we own, develop and ultimately operate. The other thing that we do is making sure that the cost of that financing is reasonable. We need to be competitive with not only our peers in Alberta, we need to be competitive with financials in North America, hedge funds, investment funds on an ongoing basis, and in order to be successful, we need to make sure that cost is fair and can enable us to execute on our growth.

In terms of other things, we don't want to be speculating on things like foreign exchange. So we make sure that when we're doing our acquisitions, when we're looking at constructing a facility, we hedge our risk as it relates to particularly FX. We'll hedge our interest rate where it becomes material but we also will manage that within a certain realm of reasonableness to take advantage of spots in the curve, and particularly in this low interest rate environment, we've been very successful to keep a portion of our interest rate floating.

Finally, as again you can tell from the assets that we've been able to acquire this year, we try to diversify and maintain a strong portfolio of creditworthy parties as counterparties. So the ones that we've added this year, particularly in Ontario area as well as in the U.S., tend to be very strong credit counterparties. I think that's important going forward, particularly if you're looking at contracts that are 10-plus years or you have expectations of renewing these same individuals or counterparties in those markets; you want to make sure that they're going to be there when you go to recontract, and 10 years from now, if the contract goes that far or longer that they're going to be in the same credit state that they are today.

Finally on this slide, disciplined growth. While growth is important and the investments that we make are looked at very seriously, they need to support not only the 7% annual growth and cash flow per share, they also need to meet our other return expectations. We've continued to maintain that we would be disciplined in how we approach growth. We not only consider the regions that it comes from, we consider all of these other factors that I've described you including the counterparties, the technology, and ultimately, whether it meets all of our return expectations, including whether or not there is AFFO growth resulting from the acquisitions.

Capital Power has increased its dividend by an average of 7% since 2013, four increases in a row, and we are reiterating our guidance for an expected 7% annual dividend increase through 2020, while maintaining an annual AFFO payout ratio below 55%. Capital Power will likely present its dividend guidance for beyond 2020 after the completion of the first capacity auction in 2019.

Based on the actual financial results that Brian walked you through at the beginning of the presentation, through the end of November we remain on track to achieve the midpoint of our 2017 revised AFFO guidance. So, you can see from the picture we expect to be right in the middle of that second bar.

In terms of 2018, I'll elaborate a bit on more what Brian described earlier in his presentation. There are four major drivers affecting our 2018 AFFO expectations. Firstly, 2018 will be the first full year of AFFO for the Veresen and Decatur acquisitions and the completion of the Bloom Wind development, which is increasing AFFO by approximately $41 million or 11% on a full year basis. The second is the higher gross margins in Alberta due to increasing electricity prices coupled with decreasing natural gas prices, which is increasing AFFO by $38 million, which is the second piece of the chart in blue. The third driver is higher maintenance and sustaining capital costs of $83 million, which is approximately $21 million higher than it was in 2017, and this number is likely more representative of our long-term run on sustaining capex. Finally, there is of course the higher compliance costs due to the new Alberta carbon tax which has two components. The first is a requirement for large emitters in the electricity industry to meet the best-in-class standard, which increases our compliance costs by approximately $23 million. The second is a cap on the amount of emission credits that can be utilized in a given year, which is expected to increase compliance costs by $21 million in 2018, but ultimately, it will be offset by cheaper credits being available in 2021. So, ultimately, the second item is really just a timing item because of the rules that were finalized and announced yesterday.

Based on the 2018 AFFO guidance, Capital Power has grown AFFO by an average of 10% per year with an AFFO payout ratio of 46%.

This chart I'll spend a few minutes on and outline an example that we think is a very realistic example in terms of where we move forward. On the previous slide, we had approximately—you can see from the bars if you remember from the last slide—approximately $200 million of discretionary cash flow per year. We feel that we can take the $200 million and leverage it at a 50% ratio to ultimately do an acquisition or deploy in terms of developments, $400 million of growth investment. If you apply a 10 multiple to the investment, we feel we can generate $29 million of incremental AFFO without even accessing capital markets, which would result in an 8% growth rate in our AFFO. So the 29 is taking the 10 multiple and subtracting from it an average run rate for capex, incremental capex on the new assets and also taking into account debt financing in terms of the debt portion of the $400 million of growth.

Further growth in AFFO can also be achieved simply by optimizing our assets, as Darcy and Mark have contemplated, and doing additional accretive investments beyond the $400 million if opportunities arise.

The only retirement that we would expect to have in the next 20 years are our biomass facilities in North Carolina, which account for less than 3% of our cash flow. So essentially, we feel that this is all incremental because there's very little cash flow falling off from assets retiring between now and 2030.

In terms of the AFFO per share, which is an important number, of course, to investors, average growth in AFFO per share of 10% over the past four years remain supportive of our dividend growth strategy. This was reinforced, of course, by the acquisitions that we did in 2017 and the bringing to service of Bloom in the same year.

The other key element of Capital Power's dividend growth story is the improvement in the quality of cash flow backing the dividend. This chart depicts the EBITDA that's been coming from the contracted portion of our cash flow, and as you can see, there has been a 113% increase since 2014. It hasn't been only on one project; you can see it's been in the workings of a number of projects. Some of them have been developments, some of them have been in gas, some of them have been in renewables, so we continue to diversify that portfolio. The key common element is that it's strong contracted cash flow. Commencing in 2014, we began on this road of growing the assets under long-term contracts, which served a dual purpose of increasing AFFO but also improving the quality of that AFFO which is important going forward.

Between 2014 and '18, contracted EBITDA will have grown by an average of 21% per year. This has been accomplished primarily through the development that I described of the Shepard facility, which 50% of is contracted to ENMAX, and then the acquisitions and other development that we've done this year and years earlier.

In terms of our merchant contract mix, you can see from this picture that we go from 58% to 82% as our 2018 target. The EBITDA has been growing because of the events and the progress that we have made on executing on our growth and we feel that this has been an important part of us to continue to tell the story that Brian has told going forward by adding the two to four wind facilities in the next number of years. With this base, we can not only fund those assets going forward, we can finance them and continue to move towards maintaining a high level of contracted cash flow in the years beyond 2018, including after the roll-off of the G1 and G2 PPAs.

This is a slide that I think many of you are familiar with, the next one. It's a slide that I'm fond of because it demonstrates that we're able to cover essentially all of our financial obligations, including the dividends, including the growth that we've indicated that we would like to have through 2020 without relying on any merchant part of the pricing. So, irrespective of our open positions through 2020, we can cover all of those obligations and dividends, which is important, again, in terms of having that financial flexibility that commits to the development that we want to carry out and commit to having the growth that we want to have in our business. It enables us, basically, to have that platform and not have to focus on other things such as deleveraging or divesting of assets that potentially aren't strategic. We can do all of this because of what you see in front of you.

Then, as upside on this picture, to the extent that we have Alberta power prices on our open positions outperforming what we see today, which we've already started to see this week and we've seen in the weeks prior to today, that's just upside. So you can see from the gray line just from moving from that to, let's say, the $40 and the higher numbers, the forwards and above that, there's significant upside which enables that cash then to be redeployed for additional growth, which is over and above what we've described to you today.

The next slide is based on the new information that came out yesterday, so the Carbon Competitive Incentives Regulation that was finalized and released yesterday. So the new carbon regulation for large emitters will take effect January 1, 2018. The first component of the new regulation is expected to increase the percentage of compliance for coal-fired units from 20% to approximately 60%, which reflects the best-in-class natural gas standard. Capital Power has a substantial inventory of GHG offset credits that have been procured over the past number of years, economically, and which we will continue to mitigate, we use to mitigate the impact of this compliance. The government has also announced a cap on the amount of GHG offsets that can be utilized in a given year as I described to you in the 2018 guidance. This will reduce the cash flow in 2018 by 19 to 21. If you recall, I think we had 21 in the guidance and so there's a range actually that keeps moving around a bit but it's somewhere between 19 and 21 I think is what our expectation is in terms of what that impact would be in 2018. As I said earlier, that impact then would be offset as we move closer to 2021 by having additional credits available then.

This chart is also one that I like because at the very bottom of the line, you can see notwithstanding all of the things that we have going on in terms of development, we don't need to actually add any borrowings other than a very small amount that potentially is on our credit facilities. Given the level of operations and cash flow from operations that we're expecting, we would expect to fund the January debt maturity, which is about $160 million, as well as the New Frontier cost net of the tax equity financing, essentially off of our balance sheet, which is again an enviable position to be as an IPP.

To the extent that additional growth materializes, we would have almost full use or availability of our credit facilities next year, as well as we would expect to have strong access to capital markets as required for those opportunities.

Another slide that I think many of you are familiar with, so in terms of our Alberta commercial portfolio position, it provides you an update as to the position at the end of November. As you can tell, in 2018, we're substantially hedged, we're 81% hedged. Actually, I want to note that the reduction in the 2018 hedge value since the beginning of Q4, when we last reported, from 86% or roughly 86% to 81% in November is due to our team, our CPM team, adding length over the last couple of months. The team saw some significant value in October when the forward prices for 2018 dipped below $44. Prices have subsequently recovered, approximately 9%, supporting the expectation that they had. Reduction in hedge position can be viewed as a positive from a portfolio perspective because this additional length exposed us to additional length in 2018 that has enabled us to be in the money on that. The end of November, the average sold forward hedge price for 2018 is approximately $47 and forward prices have now exceeded that level.

In addition to the 700 megawatt baseload position that I've described you here, we also have 530 megawatt of non-baseload power at Joffre, Clover Bar and Halkirk, which can take advantage of these rising power prices.

The sensitivity for your modeling purposes of a $5 per megawatt hour price movement is $10 million, $23 million and $27 million for each of 2018, 2019 and '20, respectively.

As I mentioned earlier, our credit ratings are BBB low with DBRS and BBB- with S&P. These debt ratios we feel, again, accommodate the business model that we have, and as you can see from the chart, we also think that we have low leverage. We have additional room to carry out our growth expectations and, notwithstanding, you can see the leverage moved up a little bit since 2016 to finance the acquisitions and the growth that we've done, we still feel that we have a little leverage.

We also continue to believe that we have strong liquidity. We have approximately $1 billion of liquidity just on our credit facilities and we would be able to use this to fund construction or carry out any of the other growth that we have in our plans. The bottom line is that we maintain that we have a very strong balance sheet that facilitates the growth that Brian described to you earlier today.

This slide highlights the credit metrics. Again, we have some room within those credit metrics. We're well within, particularly, on a couple of them, but even with the other ones where we have flexibility, as I described before to you, to carry on the growth and still stay within the limits of those credit metrics.

2017 was a very busy year, not only in terms of growth but in terms of the financing, and it was good for us. We had not been in the market or very active in the market before 2017, but this chart depicts that not only were we active in the market, we were able to execute on a diversified form of capital. We were out in the market doing tax equity for Bloom with the counterparties that we normally are not carrying out a lot of business with, but we were able to get very receptive responses from the tax equity community in the U.S. and continue to see strong demand from U.S. tax equity market and at competitive rates, actually increasingly competitive rates.

In terms of the share market, we were out there doing common shares and preferred shares, and again, have had a great deal of success in terms of the reception that we’ve received in terms of both of those offerings. Finally, on the debt side, we were out and did $450 million seven-year tenure paper, which $450 million was, I believe, the largest one that we've ever done, and goes to the point that there was a lot of interest in our paper, notwithstanding the dynamics of the Alberta market and interest rate environments, which seem to be moving around in a variety of different directions. It was, in our view, a very successful point in terms of going to the markets and getting the reception that we did on the debt piece of financing that we did. We can continue to expect to see this sort of receptivity in capital markets, so we would expect that going forward, as we need to finance the growth that we may need to do that we would have this access to capital markets.

On this slide, I alluded to the laddering. We continue to have very good laddering. We targeted particularly with the recent debt financing to get somewhere in the gap that you see in there between '22 and 2026 and we're very successful to getting it right towards the end of that gap and at the same time achieving very cost-competitive rates in terms of that interest. You’ve got to remember that I think from our perspective we continue to be in a very low rate interest rate environment, so we were anxious not only to finance but to take advantage of the fact that we are in that environment and wanted to get as much of that financing done as possible given the circumstances.

As I call it the sausage-making—my American friends will understand, the sausage-making slide. I'll give you an update on this and it's obviously moving very quickly. There's two versions of the tax reform. There's the House version, which was released after much to-do and that was issued on November 2. The Senate released their own version. While the two versions have some similarities, they also have a number of differences. The House and Senate now have ultimately approved their respective bills and where we're at today is that they now need to reconcile their versions before President Trump can sign them, so they have to deal with that and that's the sausage-making. They have to actually iron out the details and turn it into something that can become law, ultimately.

In terms of highlights, there are a number of changes, including a reduction in corporate tax rates. In terms of corporate tax rates, the rate right now is roughly 35% and the proposals are consistent in the fact that it would go to 20%; the House version would start in 2020, sorry, 2018 and the Senate version in 2019, one year later. It's our expectation that ultimately, it will be the Senate version that is going to have more weight in all of these aspects because that's the version that will have to be the starting point for reconciliation. Also, there was a reason for the deferral and it's obviously to make sure that they got within their $1.5 trillion spending limit. I think there's a common belief that with the other item that I'm going to describe, which is the immediate expensing, there was really no need to start as early with the rate reduction as 2018.

There are some murmurs in the street as to whether the 20% will stick. I think there's a view that possibly it'll go up to as high as 22% to deal with some of the other reconciliation items that need to be dealt with, but I think we remain confident that it will probably end up somewhere between the 20% and 22%, and will ultimately be the tax rate. In terms of when it starts, whether it's '18 or '19, likely '19, but that's where we think it will end up.

I also mentioned that there's immediate expensing of qualified properties. So currently, you can immediately expense up to about 50%, a 50% rate. That would increase it for a period of time up to 100%. That’s also a positive for our industry, assuming that the property would be qualified property. That all hasn't been outlined in terms of real legislation yet so that would be something that we would be looking at the final legislation to determine.

In terms of other points, there are limitations in interest deductibility. There's a rule that applies to all U.S. corporations and there's an additional rule that applies to U.S. corporations that are members of an international group. Both of those would ultimately result in potential limitations in the ability to deduct interest. We have reviewed those rules. We don't think that either of those rules would be catastrophic. They would ultimately result in potentially some interest expense not being denied. But particularly, with the domestic rule, it would apply to everyone, and so I think from that perspective it would create a level playing field.

Then finally, the House version contains something that the House characterized as codification of the PTC guidance that currently existed around continuous construction. Many of us in the tax arena would disagree with that characterization, and I think many would agree that if those rules as drafted came in, it could be adverse to the PTC—continuation of PTCs being a way that you do renewable energy. Having said that, we don't think those rules are going to make it. We think they are not—first of all, not in the Senate version. We think there'd be enough resistance amongst the green state folks and the lobbyists to not have those in there, so we don't expect to see those rules come into effect. The Senate version did not have those rules, however, it has a couple of other rules that skin a cat differently in terms of other things. There's the base erosion anti-avoidance rules that are included in there, which potentially have the impact of reducing the tax equity market and it's because of how they work, and effectively, how they would work as they would force tax equity partners to potentially have a recapture of the PTCs if they were involved in PTC deals.

Based on our discussions with the tax equity community, the consensus is that those rules will likely be workable. There were some last-minute adjustments made over the weekend that made changes to how those amounts would be calculated for purposes of the BEAT, as it's referred to tax, particularly including derivatives or allowing derivatives between affiliates in the banking industry and that banking industry is the primary supply of tax equity. That would enable that market to continue to exist. So we continue to be optimistic that those rules, they may continue to become law, but they'll end up in a form that won't ultimately kill the tax equity market and would mean that we can move forward with our tax equity and renewable progress.

The other rule that was included in the Senate version, which was supposed to get repealed by all versions and then ultimately came back in as Mitch McConnell decided that he needed some extra money for the Senate version, so that the AMT reappeared and that rule could also be harmful to PTCs, again, in terms of how it's calculated and whether or not you're allowed to use the PTCs for the full 10 years against the AMT, that's the issue with that one. We'd expect that that rule is going to either come out entirely again, because President Trump had always indicated that the code will be simplified and those rules would come out or ultimately get changed so that they actually make sense. They currently don't make sense as they're written because the AMT rate is the same as the reduced regular corporate tax rate and it's never intended to be the same rate because the AMT base ultimately is always going to be broader. So you have the same rate, you're always going to be paying AMT. I think it was the last-minute thing that wasn't thought out well and it'll ultimately get changed or pulled out entirely, and that's possibly how they deal with the—how they pay for that is deferring their increasing slightly the regular corporate tax rate to manage the spending shortfall that they're looking at.

In terms of where we go forward, nothing has changed in terms of New Frontier. We continue to drive forward, construction continues to move forward. We have been very active in terms of engaging with tax equity on that project and we have a competitive process that's going on, where we have a number of folks that continue to be interested in pursuing that. Of course, we've paced ourselves so that we can wait out these final rules to be done, but we remain optimistic that they're going to end up in a place where we can secure that tax equity and continue to have New Frontier developed by the end of 2018 and financed with tax equity.

In terms of broader tax guidance, in the U.S., we would expect to continue to not be taxable in U.S. until the latter part of next decade. That would extend with anything with tax reforms. So the interest limitations that I described to you, there are other limitations on NOL utilization. As many of you know, we're using NOLs currently in the U.S. and we continue to expect to use those. There are some limitations included in there, but not withstanding those proposed limitations, we would expect this to continue to be the same. There are some state taxes that we don't have NOLs in some of those states, in which case that we have to pay either the state tax or some form of minimum tax. They all add up collectively to about $1 million a year, but other than that, we wouldn't expect the guidance to change from what we've provided to you in the past in terms of the U.S.

In terms of Canada, the situation continues to be quite dynamic. We would expect to have actual cash payments probably payable by about 2021, so that would mean that you'd actually see cash taxes on the balance sheet in 2020, but because we don't have an installment base in Canada, you wouldn't actually have to pay those until the following year. So in terms of timing, it would be a year later but you'd have them on your balance sheet at the end of 2020.

I say it'd be dynamic because if we are successful in developing some of the projects that we've described to you today, particularly the ones in Canada, that would add to our tax shelter. We'd end up with wind expenditures, likely in Alberta, that would result in significant expenditures that would be fast write-offs and push that number out, ultimately, by at least a couple of years and it could be further depending on how many of these we are able to do in the next number of years. So in terms of cash tax in Canada, it's less than $1 million if you exclude the Part VI tax. Of course, the Part VI tax we characterize separately, which we've indicated is expected to be about $16 million to $20 million a year based on the preferred share float that we have currently.

This chart, I think many of you have been interested in the profile of the wind projects. The EBITDA tends to be a number that doesn't align necessarily initially with the cash flow profile that we get out of the projects. The EBITDA would include, and the revenue for that matter, everything else from those projects, would include the tax attributes, so it essentially reflects 100% of the economics of the project. How these projects are structured though is that Capital Power ultimately gets the vast majority, if not almost entirely, all of the cash flow from the project. The tax equity investors hit their IRR, plus get their return on capital ultimately with the tax attributes. So that's all part of the gross economics, but we don't get the vast majority of those pieces. We get the cash. What you seen in the line is the cash and you can see as you get closer to the PTC line and the MACRS for instance, being used, the depreciation being used, you have some steepness forming in the curve and then once the contract comes up, we'd expect that recontracting prices because the PTCs aren't around and people continue to have to procure the renewables because the RPS standards or otherwise, but prices are going to go up and you're going to see that curve continue to move up. The EBITDA line, and ultimately the cash flow line, start to align once the PTCs have gone away and the contracts start to expire.

Last couple of slides I think that we have here on this topic. The last one is one that covers the yields of our peers relative to our own yield in terms of our common shares, and Capital Power continues to trade at a material discount relative to most of its peers, both from a dividend yield and an AFFO yield perspective, despite having over 80% of its cash flow under long-term contract and having substantially lower payout ratio than you'd expect. Although we should trade at a discount to our peer average, our expectations are that the dividend yield should migrate towards the 5% to 6% range as some of the uncertainty in the market dissipates and we're able to execute on the plans that we've been in progress of doing.

Also on an EV over EBITDA basis, which is how I like to look at valuations, you can also tell that you have a similar dynamic. The Capital Power trades at a discount to the average Canadian IPPs particularly, and also of course, the rest of the space including the pipeline and utilities, despite our successful execution on the strategy with long-term contracted cash flows. We would like to see and we think this number will gradually migrate as some of the uncertainty dissipates again.

To conclude, on the financial sections, the key takeaways is that Capital Power offers a growing dividend supported by our AFFO growth execution. The financial obligations and dividends are covered by the contracted cash flow. Our financial capacity is strong and able to fund growth and remains there in the years coming forward.

In addition to the hedges that we have in terms of our position, we have the ability to capture the upside that we started to see and we expect to continue to see as things unfold in Alberta and get some of the volatility on the upside on those assets including the wind in Alberta.

The share price growth expected to be driven by 7% dividend growth and the yield compression as Alberta uncertainty subsides. I'll turn it over to Brian to conclude. Thank you.

**Brian Vaasjo**
Thanks, Tony. As you may recall, every year when we do Investor Day, we identify those priorities and those metrics to which we target, in 2018 in this case, and we'll report on these in the progress towards these every quarter as we announce our quarterly results.

For operations, from an operating perspective, we see a 95% planned availability, which is in line with what we've had historically and does reflect more outage activity in 2018 than we had in 2017. We have maintenance capital at $85 million, which includes the maintenance on our new facilities and plant O&M of $230 million to $250 million.

Turning to our development and construction targets, firstly, the completion of New Frontier on time and on budget. Committed capital of $500 million for contracted opportunities, and we expect, as we've said a number of times this morning, to have two to four additional wind farms to been in progress by the end of 2018. Why we use the words “in progress”, because it can mean different things depending on that particular project, but this essentially means is that we are going for it. So for example, it could be that we've signed an offtake agreement and I would say probably in all cases, you can see it as it being that we have signed offtake agreements and are moving forward with the project.

In terms of our financial target, our primary target is Adjusted funds from operations, which is set at between $360 million to $400 million.

When we look at the key assumptions, the one that's attracting most attention right now is that we've used forwards, as has been our practice, and we see that at the time it was at $49 megawatt hour. Now there's been some recent movement, since yesterday actually, in terms of forward curves, they moved up about $3.50, and as Tony pointed out in the sensitivity—and so if one chooses to adjust our outlook on Capital Power—you'd move $10 million for every $5 in Alberta spot price at this point in time. That sort of gives you that sensitivity.

Tony did describe where we are in terms of our 2018 power portfolio and the fact that we're at 80% today. This target does exclude any impact of the $500 million committed capital growth target, but it does include, just to be clear, the impact of the carbon credit utilization constraints announced yesterday, so from a carbon perspective, it does reflect our current guidance.

So then in conclusion, we continue to see Capital Power as an attractive investment opportunity, especially in the context of strategies that are driving to a sustainable future. For 2017, we expect to meet or exceed our targets and we've had an excellent year for growth.

In 2018, we also see a very strong operating year. Our portfolio in Alberta is positioned extremely well to enjoy the upside of Alberta power prices. We discussed this morning our efforts to maximize the operational optionality and flexibility around our coal plants. We are reducing both our carbon risk and our market risk.

When we look specifically at growth, we expect to secure two to four contracted wind developments by the end of 2018. We have a robust pipeline of future development opportunities. We are reducing risk through GPS and carbon credit inventory. Growth is driving geographic and fuel source diversification, such as Alberta has moved from three-quarters of our EBITDA to one-half.

The combination of reducing risk through diversification and actual reduction in business risk, strong cash flows from growth that increases our overall contracted portion of our portfolio, all contribute to what we see as pressures to reduce the yields, and of course, increase share price. This is, of course, complemented by the confirmation of our 7% per year dividend growth guidance through 2020.

Thank you and we'll now open it for question and answers.

**Q&A**

**Randy Mah**
Okay, thanks Brian. Before we start our question and answer session, if you can use the microphone to ask your question and also to identify yourself before asking your question as well. Okay any questions? Right at the front here.

**Jeremy Rosenfield**
Thanks. Maybe I'll just start with a question on the overall hedging strategy. As you look forward maybe beyond 2018, do you expect to see more upside in the market in 2019, 2020 and even in the ‘21 and longer period? Do you expect to see more volatility and maybe does that make you want to have more of a long position in the market as you move forward than you might have had in the past? Just your thoughts on that longer-term outlook?

**Mark Zimmerman**
So I might respond this way, I guess, first off, much of our program is driven by fundamental view that we'll have relative to where we see the forward markets, and to the extent there's a disconnect will dictate whether we want to get longer or shorter as a general rule. But we are also very cognizant around the total overall exposure relative to that spread between our own forecast and the forwards. There will always be an appetite to lock in a certain level of the capacity we have to reduce that risk, but once we get to a point where it's manageable, if we do see opportunities where that disconnect between fundamentals and the forwards are, we will take steps. They typically don't result in large, large movements. I think as Tony kind of went through already, between the end of the third quarter, we are 86% hedged. We are now at 81% and that was just more with that deep knowledge, seeing a bit of a disconnect being a reflection in the forward curve versus our understanding, hence why we took a bit more length to it.

As a general proposition going out longer, we do see the supply overhang being managed through, both between some product coming out of the stack, whether it has been mothballed or permanently reduced. We do see that there are some real advantages to some other gas-fired generation coming in. That being said, we tend to see the forward gas prices improving over the long term and that will drive the power price itself, and we do see a return to normalization at the sort of levels that we've seen historically. So, we are bullish.

**Brian Vaasjo**
So maybe just to add a couple of comments on that. So in response to your question around volatility, certainly seeing assets back in owners' hands will significantly increase volatility. I think that's been a proposition that has been out there for the last two years that once that happens, we'll return to higher volatility and higher power prices to a degree. Of course, we see that happening going forward and we do expect that with what's happening and with what you've seen or heard in terms of TransAlta's actions yesterday, we definitely would expect to see, just even in the short term, an increase in the volatility in power prices in the province.

Adding a little bit to what Mark has said about us taking a fundamental view, it wasn't too long ago that we would walk into years with just 50% hedged based on our basic fundamental view as to where power prices will settle and where they are in terms of the forward curves. So, we definitely take a very active position and view on power prices, and the degree to which we're hedged reflects that view.

**Randy Mah**
Next question.

**Robert Hope**
Thank you. Robert Hope, Scotiabank. Just taking a look at the carbon pricing in Alberta and the dispatch curves that you presented, we see a good amount of your gas facilities moving to the left and more favorably on the dispatch curve, especially at $50 carbon pricing. How do you view the sensitivity of carbon pricing in your business longer term?

**Mark Zimmerman**
Longer-term beyond 2021?

**Robert Hope**
Or even in the interim, as well.

**Mark Zimmerman**
So I think it's—I'll rely on Brian here a bit as well given some of the active discussions he's been in. But I think, obviously, we got two policies that are out there. We got a provincial mandate go up to 30 bucks. You've got a federal announcement ultimately wanting to go up to 50 bucks. That's the band within which we take a look at the parameters of what we may see over that period of time; it's somewhere in between there. But we would expect that at this point we see little retraction from that position. I guess I would say don't see it going back down to zero as we move forward, especially with the federal overhang that is out there.

Beyond that, there can always be some additional pressure for carbon tax to continue to increase. It can be a good source of revenue for different governments in terms of what they want to try and influence. We haven't modeled a doubling or tripling at this point because we see the conversion happening in the fleets, but that's not to say that we may see some upward pressure, but I don't see it popping around a lot. I don't know Brian if you want to …

**Brian Vaasjo**
I think you're seeing the reactions that you'd expect. The detailed modeling that Mark described on the three charts shows you on a dispatch basis what the reactions are. But what it doesn't fully get into is the reaction in terms of if you take coal plants and convert them to natural gas. When that happens—and certainly TransAlta has made their announcements and we've said that when the economics are appropriate, you'll see us do the same—what it'll end up doing to those curves is probably not a lot, because where coal sits is pretty much in the zone where converted natural gas will sit in

terms of the overall supply stack. In the same parameters if you add, significant natural gas new generation, you'll end up seeing older coal plants fall off. That's just the reality of the market. So what you see is the dispatch and certainly carbon tax has a significant impact on those parameters as does the level of natural gas price, so that can cause movement along those curves. Generally doesn't have an impact on the positioning of those curves as long as they're moving in tandem.

**Robert Hope**
Great, thank you. Then just one additional question. South of the border, the ongoing tax reform, does that potentially put a risk in that two to four wind farm target that you are targeting for 2018?

**Brian Vaasjo**
So certainly part of that target assumes something similar to status quo. I mean to be clear and where we have got some significant confidence, if it weren't for tax reform, the prospect of it sort of stopping us, we would have already announced another project in the U.S. So it does have an implication. Now having said that, as Tony said, as they're making sausage, there are different kinds of implications. We believe at the end of the day, it'll end up being pretty close to status quo. May impact a little bit on the appetite from the number of players who are willing to play. Having said that, as Tony also indicated, the competition i.e. a significant growth in people with parties that want to participate in that market, the yield has been going down very significantly. So we'd see maybe to the extent that some of these rules may knock out, some of the potential ITC players or tax equity players what it'll do, it might do is just move yields back up a little bit. So we, at this point, don't see that as a significant risk. I mean that's evidenced by us continuing to move forward on New Frontier.

**Randy Mah**
Okay. Next question.

**Robert Kwan**
Robert Kwan, RBC. Just a couple of questions, first starting on M&A. You've talked about building your internal capabilities and you showed a number of the transaction values going forward. When you look at some of the pie charts that you also put out there through 2020 and given that you're targeting kind of, call it, greenfield or internal builds of contracted wind, gas percentage goes up quite a bit and the U.S. goes out quite a bit, yet also the contracted percentage stays about the same. Is that implying, given you have no gas builds on the go, a gas acquisition in the U.S. with a bit of a merchant component?

**Mark Zimmerman**
I might characterize that for the assumptions, yes, but in terms of the geography, it could be U.S. or Canada gas acquisition. I might paraphrase some of Brian's opening comments. Definitely see good opportunity for greenfield/brownfield wind development. On the gas side of the equation, probably see that more as acquiring mid-life gas assets that would be immediately accretive to us, et cetera. The issue of new gas builds, absolutely keep on the radar screen, but we'll also need to get that further comfort around the business environment that's out there, the sort of market conditions that would be at play and the sort of counterparty approaches we might have. Any sort of gas build with that sort of conditions probably wouldn't come into service until after that forecast period that we articulated.So, the U.S., Canada could change because there may be other contracted gas opportunities in Canada that we may pursue on the M&A front.

**Robert Kwan**
So if I can just maybe follow on that. So if you're looking at mid-life gas acquisitions, potentially, and the accretion, the arithmetic on that, how do you weigh that off though against, in general, the market attaching lower valuation multiples for those types of assets?

**Mark Zimmerman**
Absolutely agree as it relates to the contracted period and then we would give those assets, and you absolutely see that on fully merchant plants, the sort of low multiples that they're transacting at. As we are running through our calculus, if you will, around the returns, we're looking at for those opportunities, we are conscientiously addressing these sort of hurdle rates that we're ascribing in terms of those investments and what we're willing to put to work, and do absolutely take into consideration the sort of not only short-term but longer-term accretion that we could get under a deemed capital structure to ensure that we're showing that spread.

We haven't fully gone to a greenfield/brownfield development and because there's also a lag or a lead time associated with that as well. As I've mentioned, I think we need to pull on all levers here, put some capital at work for some immediate results but also capital to work for mid term and longer term sort of results.

**Brian Vaasjo**
Robert, maybe if I could just add two things. Just one element of your first question, I want to be absolutely clear on is you were maybe suggesting in your question that we were acquiring merchant, we're not. There is no merchant acquisition in there whatsoever. Now, that's not to say, and just to be clear, if you acquire a merchant [misspoken, intended to say "contract"] gas asset or a wind, you may have 10% of it merchant or there might be some small component, but we are only building or buying merchant assets [misspoken, intended to say "contract"].

**Mark Zimmerman**
Contract.

**Brian Vaasjo**
Contract. The other thing that I wanted to comment on, and this has been a little bit of a question around Decatur and when you talk about market recognition and so on in terms of natural gas assets. On Decatur, and as we've said, I think I probably said 100 times so far, but that asset as a contract that terminates in 2022, we've got extremely high confidence that, that will be recontracted, or if it was just 22 years and even a 50-50 chance, we would not have bought that asset. When you look at valuations in the market, I think as mid-life moves in the 10-year zone, et cetera, you start seeing good multiples and better value. If you're talking about a three-year stub or a four-year stub, that's where you start seeing very serious discounts in the market. We don't intend on acquiring assets. In fact, we won't be acquiring assets where we see that it will only have a four-year contract period, for example. It has to be beyond that for us to pull the trigger.

**Robert Kwan**
Got it. If I can finish on the dividends. There was a statement that you were not anticipating extending the guidance past 2020 until you see what the first auction looks like. Is there that much variability as you look at potential framework, either both to the upside or on the downside, around what you expect capacity pricing to shake out at? I guess as part of that, do you have any comments on the third iteration of SAM that came out yesterday?

**Brian Vaasjo**
Two things on that. We're on a track of a 7% guidance on dividends, and so when you look at that general time period, so you're looking at an auction in 2019 or building up our anticipation of an auction in 2019, we've said consistently that we will base our dividends, our dividend growth, on new growth and particularly contracted growth as we go forward. Certainly, when it comes to a decision, let me put it this way—I don't think, especially when you see the kinds of development or the level of development we expect to be happening, the wind farms we're talking about in 2018, and Mark commented that we expect to do a couple

more in 2019, and I think that's—although Mark will shoot me—I think that's a minimum.

The fact of the matter is, we're going to have a significant amount of growth in the bag. I think where a lot of the thought around waiting and seeing where that is, is whether there's maybe more of an adjustment to the 7%, which could be up, could be down, but looking at longer term, what that dividend guidance might be going beyond that, we don't see any reason why we would provide any guidance before that point, and so I think we could give firmer and probably more fine-tune guidance at that point in time.

**Mark Zimmerman**
Both of your questions caused more work, Robert.

**Mark Jarvi**
Mark Jarvi from CIBC Capital Markets. I wanted to dig into the $500 million of capital you're expecting to spend. Maybe talk about the sources of that and your willingness to commit capital on projects in advance of having sort of guarantees and security on tax equity.

**Tony Scozzafava**
In terms of the $500 million, I think as I described, that would be over a period of time. You'd have your cash flow, your discretionary cash flow would deal with a large amount of that and to the extent that it's U.S. projects and you have tax equity on top of that. I think for the $500 million, we wouldn't expect to be out there raising equity. We would think that we can manage that just with our discretionary cash flow, credit facilities, and to the extent the tax equity is needed, we would be able to deal with it from that perspective.

**Mark Zimmerman**
Again, I might add to what Tony is saying as well, and maybe I'll just paint a bit of a picture around the environment that we're seeing out there as well. We do continue to see interest levels being expressed by various intermediaries, financial intermediaries to be the counterparties for the off-take on the wind, number one, and it seems to be more that there's a really robust market for those sort of entities that are looking for those green attributes and are looking to buy wind. It doesn't necessarily have to be new wind. They just want the attributes from even existing wind. Then to Tony's point around the tax equity, even when all of this came out and then caused a pause, if you will, there seems to— and I'll defer to Tony—be very robust interest out there by a number of institutions around tax equity. The economics of it may be tweaked where it ultimately lands, but I think there's still a large interest level, comfort level in what we're seeing.

**Tony Scozzafava**
Yes, I can tell you from the process that we're in around New Frontier, nothing has stopped moving. I think what's clearly slowed down is funding. So I think I'm aware that there's probably a couple of fundings in the last month or something that have probably been deferred; they haven't been canceled, but it's just prudent. I think folks have said, "Well, what's the point? We might as well wait until we actually get real language as opposed to having to redo paper and spend a bunch of money on legal fees and everything else, right?" But I think, ultimately, the folks that we're talking to, whether it's the developers, whether it's the tax equity, they remained fully confident that the tax equity market will continue to move forward. We've got intelligence suggesting that the usual players will continue to be there. They did some substantial lobbying over the weekend to deal with some of the impediments around the base erosion rules and so I think they got where they needed to get to with those rules. From what I understand, the large guys are still going to be there. Some of them will be more impacted than others. Some of them will have less appetite. Having said all of that, we would expect the market's going to be there, and we've got a

number of projects, I think as Brian alluded to, even over and above New Frontier that we expect are going to be in the money and proceeding soon if we can get these rules finalized. President Trump has indicated—he may not have credibility on a number of other things, but I think he wants that tax bill by Christmas and to sign, and I would expect that you're going to see a tax bill that's going to get signed. If not by Christmas, pretty close to that. I think it's a top priority right now for everyone involved.

**Brian Vaasjo**
Just maybe to connect a couple of the dots in your question and the $500 million committed capital. We won't be committing any more capital in the U.S. beyond Frontier for wind projects until there's clarity, both in terms of the tax rules and in terms of there continuing to be a very robust market. I mean as evidenced by the fact that, again, just to repeat, we had a project that would have been announced by now that we stopped, and we said, "We'll just wait for clarity and make sure that there isn't something in the tax rules that ultimately creates a disconnect in the market." We won't be making that commitment again until there's absolute clarity in the marketplace.

**Mark Jarvi**
Okay, that's helpful. Going back to the slide that Tony showed on the profile, the cash profile of your tax equity projects, with a bigger step-up in the mid-2020s, just wondering what sort of assumptions on power prices would be baked into that forecast.

**Tony Scozzafava**
Yes. So I think, currently, what you're currently seeing in the market, it depends on which state it's in, but you're seeing around the $20 mark, and so that's only possible because you're getting the PTC. So the PTC is depending again on the state, whether or not there are state benefits available on top of the federal benefits. But it's accounting for at least half of the value of the project in terms of the economics, and so you have to see those numbers. We'd expect that those numbers would need to double roughly in order for RPS standards to continue to be met, for utilities to procure the power that they need. I can't imagine that you'd end up anything less than that for the system to work properly and operate as everyone would expect it would. And then those aren't—they're not inconsistent with what we see when we develop a project and we look at what the proposed PPA piece of it is.

They're not aggressive either is what I would say, right? I don't think for most of these projects, we're not assuming it's $70. We're assuming it's $40, $50, depending on the state, I guess.

**Andrew Kuske**
Andrew Kuske, Crédit Suisse. Maybe just on the two to four projects per year, the secured projects on the wind side, what's the biggest constraint? And maybe let's just put the tax equity issue to the side because that will get resolved in the near term and in one way or the other, I want to have clarity on that. So if you put that aside, what's the biggest constraint or the biggest variable on the two or four or more into the future?

**Mark Zimmerman**
Probably a couple of elements on that. Clarification around some of the RPS standards that are being driven out of different state legislatures and what's going to be available because there's PTC, ITC issue that's there and there's a tax equity, but there's also the environmental attributes that will factor into the pricing. We're always trying to dovetail that pricing with our economics, and there are certain levels before I'd want to move over or forward with. So you need those standards to come out. You need to have clarity on how the attributes are going to be treated. The counterparties that we're seeing more out there right now aren't your typical utilities handing out

the PPAs, but we are seeing more hedging and proxy revenue swaps coming out and that's what we're able to sign up counterparties on and for not bad terms; that's where the pricing is coming from. So there's a pricing signal in those different jurisdictions that is very much coming into play for us.

A final point for impediments is, once you get through all that and it is looking like it's a viable project, we've got projects in varying degrees of development. Some are permitted; we can move fast, provided there's the support. Others will need to take that additional step but don't see it as a huge hindrance provided all the other elements are in place for us.

**Brian Vaasjo**
Maybe the other thing, just to put a fine point on it, and certainly, I think Darcy went at length to describe how we believe we're very competitive, of course, at the end of the day, and we've historically made no secret that we intend on participating in the auctions in Alberta. Certainly, I'd say competition, whether it be in the U.S. wind or in Canadian opportunities is pretty significant. So I would say the one impediment is us not being competitive. I think by posting numbers like two to four is suggesting we think we'll be very competitive throughout North America in terms of securing new wind farm opportunities.

**Andrew Kuske**
So then maybe a follow-up. Given the Element portfolio, it's been very good for you since you bought it. You've managed to turn out quite a few things, and it looks like there's other things in the hopper. So the question really is, the 7% growth that you've talked about into the future, you may be able to do more than that, given the portfolio you've got, but do you just feel like that's the right place where you want to be and maybe where the market wants you to be as opposed to really pushing it a bit farther than that?

**Mark Zimmerman**
Yes. That's a reasonable assumption on growth that we should be able to deliver with a high confidence level. Pushing it beyond that would require additional things that we will look at we will be doing, but we wouldn't want to suggest that we can be swinging for the fancy chair every time we're up at bat, if you will.

**Andrew Kuske**
So then maybe the follow-up to that is the consequences. You're really high-grading your opportunities, and the two to four that you may deliver into the market are very good investment breed versus diluting down.

**Mark Zimmerman**
Yes.

**Brian Vaasjo**
I think it's important maybe to connect a couple of dots in terms of the $500 million committed capital, the 7% and the cash flow that we're generating and the opportunities that we see in front of us. If you take the example that Tony walked through, which was $400 million of capital, and if you think of committed capital year after year after year at $500 million, what that's telling you is that we can achieve 7% AFFO growth per share, year in and year out, if we're investing $500 million a year and we're not going to the equity market. So it's just they fit well in terms of being able to set a base level of growth.

Now, one of the things we don't want to do is to put out expectations based on an acquisition here or an acquisition there. And if you take two to four wind farms plus Frontier, and then a couple following in 2019, you sort of get a capital profile that just on wind development, we can probably spend that $500 million a year, go through all that development and not go to the equity markets and achieve a 7% growth. In the event that there are good accretive acquisition opportunities on top of that, then that starts moving you into a different level of growth. But what we don't want to do is talk about those things that, again, are quite speculative. We're confident in our ability to develop and move those wind farms forward. The M&A market, that's a different animal, and we don't want to base market expectations on us doing acquisitions.

**Randy Mah**
Okay, next question.

**Ben Pham**
Ben Pham, BMO Capital Markets. I wonder what your thoughts are with Keephills ENMAX implications and the power price and CPX and I'm also curious your thoughts on reserve margins with Sundance mothballing, demand 1% to 2%, how tight the supply cushion is now. Do you think that if Keephills or there's optimization of the portfolio, you're at a point now where every incremental megawatt, you see more of a parabolic move on power prices. A couple of years ago, Sundance A -- so that's a $20 move versus $3 to $4 yesterday. Is the Alberta market at a point now where you think you could see that?

**Mark Zimmerman**
So I wouldn't observe it. It absolutely is tightening up, and I think once that reserve margin is tightened up even more, you will see that migration of the curve. You will see improved pricing starting to manifest itself. And you will start to migrate back to the cost of new entry. I think that's probably more the cost of the new entry being probably a baseload gas sort of unit will tend to put a ceiling on the average price overall for a year, but the volatility within periods could very well increase on an hourly basis. So, I would agree with your observation, as these steps continue to take, it should be constructed for overall pricing, but part of that will be greater volatility on the hourly pricing, depending on which units are up and running or which ones are down.

**Ben Pham**
I guess if the Keephills gets decommissioned early then you'll see more of the move you saw yesterday, do you think, with reserve margins?

**Mark Zimmerman**
Yes. I would think so.

**Ben Pham**
Then second one on Decatur, you mentioned recontracting discussions. So that's starting quite a number of years earlier than 2022. Is that more early-stage discussion? Are you looking to extend the contract now and maybe some fine-tuning of the near term cash flow numbers?

**Mark Zimmerman**
Absolutely early-stage discussions. We've had the asset in our portfolio now for five months, and Darcy and his team have been doing a great job of familiarizing themselves, getting up and running, applying the best practices, and commercially, we're doing the same thing. We're not going to wait to initiate the discussions until later but start off right immediately, developing that relationship, but we would also expect it's not going to be an overnight sort of proposition. This is going to require an extended period of time and ensuring that we're coming up with a solution that meets the needs of the counterparties while also meeting the needs that we would have as an owner of that plant.

**Unidentified Analyst**
Hi. I was wondering if you could just balance, I guess, two different slides. You have one where you're assuming that you're acquiring assets at 10x EBITDA, and then you guys showed that you're undervalued at 7.5x. So, can you just explain why you're not reinvesting in your stock? Which is a higher rate of return.

**Mark Zimmerman**
So what I might observe on that acquiring things at 10x EBITDA, a lot of times, when we're looking at the cash flow profiles that we're

seeing in a number of these entities, you're not looking at a cash flow profile that is static on any one given year but rather can be variable over a period of time, and when you're looking at that 10x multiple on EBITDA, after you've tax effected and burdened it, when you're coming down to an AFFO sort of measure, we think we're buying things at something close to where our cost of capital is now, and that's before considering the improvements that we can bring into play around synergies and optimization as we grow out that fleet. But, I guess in addition, as Tony went through the math and Brian kind of reiterated, when you also think about the sources of capital that we have available and the available free cash flow as a starting point before going for incremental capital, that's also providing a big uplift for us in terms of value. We've got much cheaper capital that we can deploy on opportunities like that before having to go and look for incremental capital.

So net-net, upfront, first order of business, deploying that free capital; we deploy it towards opportunities like that. There's enough margin to support that 7% growth. Going further, incremental capital is expensive to us and probably sets the limit on what we're able to redeploy at, but that's before considering other things that we could do once that asset is in our portfolio, whether it's technically, commercially, financially or tax wise.

**Randy Mah**
Okay. I guess there's no further questions. I'll turn it over to Brian for closing comments.

**Brian Vaasjo**
Well, certainly appreciate your time and attention this morning, the folks here and the folks on the phone, in terms of listening to Chapter 9 of the Capital Power story. Certainly, we expect to be here next year and talking about how well the clarity has come to the Alberta market and the fact that we'll have a greater understanding as to what the new market will look like. Although as we've said over and over again, we're pretty confident that it'll still reflect fundamental economics in the way we're positioned, we're pretty indifferent to a lot of the details. We'll talk about a number of wind developments that are underway and certainly moving towards successful completion.

And hopefully, we'll be able to talk about some other initiatives that have taken place. As time passes and as there begins being greater and greater certainty around issues associated with the Alberta market, carbon pricing, long natural gas pricing, we'll be fine-tuning our view as to when we're going to convert our coal plants to natural gas. We'll also be sharing with you a more staged approach, in all likelihood, where we'll be identifying where we can create some significant short-term benefits and value associated with moving forward on, again, staged movements towards converting those facilities to natural gas. We're actually very bullish on what's going to happen through 2018 and what it will do for Capital Power and what it will do for our investors.

On that note, thanks again for joining us today and hope you and your families all have a very safe and happy holiday season. Thank you.