RANDY MAH: Good morning everyone. Welcome to Capital Power's sixth annual Investor Day event. My name is Randy Mah. I'm the Senior Manager of Investor Relations. I'd also like to welcome those people listening on the webcast. So, from what I understand, Enbridge, of course, made the big announcement this morning so I know there will be a number of analysts that might have to pop in and out of the room to do follow-up calls. So, we have a break out room just on the other side of the registration desk so if you need to take a call or whatever, feel free to use that room just past the registration desk.

So, earlier this morning we issued a press release announcing construction plans for Genesee 4 and 5, and the acquisition of a portfolio of renewable development sites. You will hear more details about these announcements later this morning.

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

Let me now introduce Capital Power's Management team and the following people that are presenting today. We have Brian Vaasjo, President and CEO; Bryan DeNeve, Senior VP Corporate Development and Commercial Services; Darcy Trufyn, Senior Vice President Operations, Engineering, and Construction; and Stuart Lee, Senior Vice President Finance and CFO. We also have Todd Gilchrist, who is our Senior VP HR, Health, and, Safety, and Environment here at the front table. The management team also consists of Kate Chisholm, Senior Vice President Legal and External Relations.

So this is the agenda for this morning. We plan on going straight through, without any breaks, with all the presentations and we should end around 12:00, 12:15. So, depending where we end, we will either take a break and have everybody go out and grab their lunches and come back for the Q&A and then we'll do the Q&A during the lunch session, or else, if we finish a little bit earlier, we'll do the Q&A and then have lunch afterwards; so we'll just be flexible on that. Ok? With that, over to Brian.

BRIAN VAASJO: Thank you, Randy, and good morning and thank you all for joining us. This morning we did issue a news release that had a number of items on it, including our expectations for 2015. I won't go through them now, as they'll be discussed in context through the presentations this morning. You will see how they are contributing, though, to our theme today of delivering on our strategy.

Of course, the drive behind our strategy is preserving and growing shareholder value. Addressing existing operations by optimizing our existing assets, resources, and capital. Addressing growth by moving to actual construction of Genesee 4 and 5 in 2015, and the acquisition of a number of renewable sites that are prime for further development and construction; both directly on strategy and playing to our strengths of development and construction. Addressing how we positioned through the bottom of the Alberta power cycle is key to shareholder value and our outlook for 2015 and beyond. A key takeaway this morning is that our outlook for 2015 is what we have been expecting and talking to you about over the last few years. More importantly we've actually been getting ready for it.

We've taken actions such as accelerating our reliability program back in 2012 and working on programs over the last few years that resulted in substantial reductions in operating and maintenance and G&A costs, particularly in 2013. I am pleased to say we have realized and retained those savings. When we structured the commercial arrangements for Shepard Energy Centre, all of the incremental megawatts were fully hedged in 2015, 75% hedged in 2016 and 2017, and 50% hedged thereafter for the twenty-year term. Our commercial portfolio for 2015 is substantially hedged at prices that we expect are higher than what will develop in the stock market. We have been planning and have made decisions over the past few years based on this view of 2015. Our discussions over the last two years on the impact of growing contracted cash flow base, and our Board's decision in July to increase our dividend, incorporated that view of 2015. The development and shift into construction of Genesee 4 and 5 reflects the view of 2015 and beyond.

We have been using this diagram for the last year or so, which integrates our strategy, our priorities, and Capital Power's value proposition for shareholders. This demonstrates they are fully aligned.

Foundational to shareholder value, and our highest priority next to safety, is operational excellence. Darcy will speak to numerous activities in 2014 and 2015 that have increased our reliability, reduced our costs, and reduced our risks. We have and intend to continue to move the dial on all three. He will speak to restoring our North Carolina plants to capacity while at the same time increasing our fuel type flexibility. Darcy will also highlight increasing availability at Clover Bar, again, reducing expected costs and risks.

Stuart will speak to our strong financial position, despite the fact we are entering the low point in the cycle. Our cash flow is expected to increase from 2014 to 2015 by approximately 8%. Our balance sheet and credit metrics are expected to grow stronger through 2015, all of which contributes to a profile of consistent dividend increases beyond 2014.

Bryan will speak to trends in the North American power markets, relevant to contracted opportunities. In part, these trends are why the Element transaction is contributing to an exciting platform of opportunities for Capital Power. Opportunities that we can further develop and ultimately construct fully contracted renewable projects.

Bryan will also speak to the Alberta power market upside. He will discuss our 2015 hedging strategies that are appropriate for this period of low prices and low volatility. Bryan will also discuss supply and demand as it relates to the timing of Genesee 4 and 5. He will speak to our approach of starting to actually construct for 2018, with the ability to stretch out construction for later completions as market conditions warrant it. To be clear, we expected to be fully permitted this week. We will execute our power island procurement agreements by the end of the month, and literally have shovel in the ground by mid-year. He will also speak to why the configuration of power island for Genesee 4 and 5 is best suited for the Alberta market.

While Bryan will have touched on much of our future growth, Darcy will speak to how the Shepard project is coming in on budget and on time. He will also speak on the K2 Wind project, which is due to be complete in mid 2015. Darcy will also address the Genesee 4 and 5 construction strategy.

When the growth components are combined it continues to demonstrate a disciplined focus. We are only in the power generation business; we are only in the North American markets. Major investments in state-of-the-art natural gas facilities, like Shepard and

Genesee 4 and 5, fit well with our existing fleet. We have an excellent development platform for contracted assets outside of Alberta, and all of these activities focus on our proven competencies in development and construction of power generation facilities. In addition to our growth being right on strategy, so is our existing business.

The pursuit of higher lever of operational excellence, our strong and growing cash flow base driving increasing balance sheet strength and an increasing dividend profile, our commercial activities in Alberta continuing to focus on capturing that upside. We continue to have the best assets in the best market in North America. I'll now turn it over to Darcy.

DARCY TRUFYN: Well, thank you Brian. Good morning. Capital Power has always had a reputation of being an excellent operator. In 2012, after more than a year of benchmarking, we began implementing actions to optimize our assets, improving on an already high availability through our reliability program, and in concert with this undertaking a multi year program of cost improvement. At previous Investor Day sessions I've provided details on the elements of our reliability program, and our successes to date. Today you will hear the progress Operations is making through another year of optimization and our objectives for 2015 and beyond.

Our optimization program is based on four pillars: output, costs, risk mitigation, and safety and environment. With these four pillars in place, and with a plan for each to improve, we believe Capital Power has established a strong foundation to build on. On cost, this is not about cutting costs and risking our assets but rather to challenge ourselves on how to spend smarter. We found ways and means of getting more out of our maintenance dollars and, on the sustaining capital we have focused our spend on things that really matter, things that either improve our output or improve safety. On risks, we have taken and continue to take ways and means to reduce our operational risks and make Operations more predictable. And finally, on safety and environment, our commitment is to not harm our people and to be environmentally responsible.

When Capital Power publishes or discloses availability we talk about our fleet in its entirety, that's both operated and non-operated assets. My talk today is on Capital Power operated assets and my slides detail the Capital Power operated fleet. For our non-operated assets we work with our JV partners to help ensure the units are meeting our business targets. You can see from this graph our plan is based on Capital Power getting more from our assets. We expect to achieve 95% availability with our assets year-over-year, as a minimum. The dip in operations every second year is driven by the two major outages we have at G2 and G3, and from this graph you can see that for 2015 we're projecting a 96% availability for our assets, the CP assets. Overall, our availability with the entire fleet, including our JV, is going to be 94%.

This slide shows our controllable costs on O&M, and these are measured against our kilowatts of Capital Power's operated fleet. All cost have been normalized for 2014 dollars. Controllable costs are the costs that the plant can manage. Excluded from these costs would be insurance, taxes, and fuel. You can see we're trending in the right direction and are targeting additional improvements in 2015 in our budget. And just a footnote – our non-plant-controllable costs, we're still working as an organization to reduce, and fuel is a great example of that and I do have a slide later in my presentation that shows a significant improvement of our coal costs that feed our three Genesee plants.

Some of you may recall that I presented this slide last year and, at that time, we showed a 20% improvement between 2012 and 2014. Updating this slide and comparing it to the fleet of 2012, that same fleet is now showing at 24%. So, to just briefly explain, this blue bar here represents the fleet as it was in 2012 and that fleet, the same fleet exactly, is shown here; you can see the trend. The orange bar, portion of bar, is our sustained capital spend in 2012 and you can see there was a step-change in 2013. But the other thing you can see is that in, thereafter, we've been actually able to sustain, it wasn't just a one year thing; we actually had made a step-change in our spend on sustained capital. And then the light blue is the addition of new assets coming on with O&M, incrementally over these three years. You can—the sustaining capital, actually any of these—these are all the wind projects as we're bringing them on. But the sustaining capital for these wind…there are still some dollars but those dollars are embedded in the orange so it really hasn't changed our capital spend.

The other thing I'd just like to point out, in 2014 and 2015, and this is just a great example of spending smarter – included in the spend for sustaining capital was work that we did to be CASA compliant for January 1 of 2016 and—and that's at the G3 plant, our G3 plant. So that spend to improve the back end, to lower our SOX, S02 emissions; that's included in the spend. And when I say spending smarter, through that program our engineers actually found ways and means to improve our, we had some derate issues on G3 and those improvements with the S02 emissions, actually, have helped us improve our derates or lower our derates, which actually improve our effective availability.

So, on successful operations – on this slide, it implies predictability. And, to help us achieve that, we've been undertaking numerous actions, pro-active measures. Service agreements are in place at many of our facilities with the OEM's and these LTSA's, they provide cost certainty, IE: the failure risks, the wear and tear, the refurbishments; all of these things rest with the OEM. And on these LTSA's, we have commercial terms which help ensure that we maintain our high availability. On spares, we have invested significantly in spares and we continue to invest on spares. These investments are like, it's like an insurance policy for the plants.

On reliability, the intent is to become more proactive, we continue to be more proactive in our spend. When you have a forced outage, that's reactive spend and, not only that, it's the cost of the outage's lost revenues. So, when you add the two together, it's punitive. You can be so much more effective by being proactive in how you maintain that equipment. And no matter, though, how good we are, there are times we do have failures, or significant incidents, and when those happen we do have, what I think, is a very, very robust process of learning and we've incorporated that into everything we have at operations. So, any incidents we go through – any major incidents – a learning process and the learnings are applied, not just at that plant, but across fleet and I do believe that that is really helping make us a much better company.

Capital Power has made significant progress in safety and environment over the past few years. Management and all employees at Capital Power are committed to a zero incident objective for our people and our plants. The results in 2014 are industry leading. Aside from our objective of not wanting to have our employees get hurt, safe plants are, in fact, efficient, well-run plants, so there are also good economic reasons for making this a focus.

Now the next few slides, I'm just going to go through some of those four pillars I mentioned, detailing some of the improvements we've made year- over-year, and also to talk about some of the risk mitigation that we have embedded in our fleet. I grouped the plants by fuel type just to keep it quick and I've also left off safety, because safety is really repetitive from plant to plant. So, beginning with Genesee - on output, while availability overall at Genesee is improving, and I have a slide that shows you that, we did start to see some negative trends with one of our boilers in 2013 and leading into 2014, so we did a complete revamp of our boiler program, and it incorporated the changes into our 2014 outages for both G2 and G3. And it's early days yet but we've already seen on G2, which was done in the spring, an improvement on our availability since then with far fewer tube leaks.

And on the risk side, I've listed the complete — there is quite an investment there with rotors and with the big spare transformer, so we can backstop just about anything with minimum delays to operations, to our availability. But, pleased to say that with G3, this year we finally resolved our blade failure. Some of you may recall we had a failure just after G3 went into operation in 2008, and so we settled with Hitachi this year and part of the settlement includes a spare LP rotor, fully bladed. One of the reasons it took so long to reach that settlement is that we want to ensure that the failure that occurred was a one-off, that it wasn't systemic or design-related. And, once we confirmed that, we were able to then settle. But this year, as part of the G3 plant outage, we actually did take off the covers and inspected the rotor and the blades and we were very, very satisfied with what we saw; the blades were in pristine condition.

But having this bladed rotor, it's a huge advantage for our operations. We can take…if something ever does happen, and, later on, you're going to have to, as the blades wear out, we will have to go through a change out. But a change out, if you did one in situ, it would be about a 60-day outage with the blades, and that's if you have the blades. If you didn't have the blades it could be—you could be waiting for a year. But with the blades, bladed rotor, you can get the outage down into less than 30 days, which, basically, means if you can build it into a planned outage, a normal planned outage.

So this is about the Genesee, the benchmarking that we've done. And I'll just explain firstly that unplanned commercial availability, that's the bucket for everything outside of planned outages, so it includes forced outages, maintenance outages, and non-dispatched derates. Now this graph does show a directional improvement since 2011 and you may recall from the previous Investor Day presentations, we benchmarked our fleet using Solomon. We talked quite a bit about that and Solomon; they have well over 200 coal-fired units in their benchmarking data in North America. Our objective, when we benchmarked in 2012, was to get all our units to a first quartile by 2018. You can see from this, actually we intend to hit that in 2015, which is 3 years earlier, so quite an improvement with the fleet at Genesee. And this is really, this is the heart and soul of Capital Power. Oh and just a footnote on that one — we intend to actually in 2015 we want to benchmark again Genesee with Solomon, only to confirm our interpretations and understanding but also to see if there's any new benchmarking information we can get from Solomon.

So, over the past year, significant improvements have been made to our mining costs at Genesee, both in terms of O&M spend and in terms of capital spend. I do want to acknowledge that these improvements would not have materialized so quickly without the support and commitment of our mining partner and operator, Westmoreland Mines. You'll recall that Westmoreland bought Prairie earlier this year; that was the catalyst for us. So this result is—it resulted in significant reduction in our O&M spend going forward. We've reduced O&M by approximately 12% and approximately 25% reduction on our capital needs going forward, and that goes out ten years. So Capital Power will receive about 82% based on our ownership of Genesee; we'll receive about 82% of these benefits.

And, on the land purchase side, 2014 we actually completed our final, just about all of our land purchases that were required for the additional mine that incorporates G3. We now have 98%, basically, one property left to buy and that one we don't need until latter part of this decade and we have, sort of, an understanding with the owner, wants to stay there until we need it. So we, basically, bought all our land so that will mean that we won’t have to deploy capital going forward in 2015 and beyond. And, in fact, 2014 is our 25th anniversary of the mine. This was the first year in 2014 that we actually sold our first reclaimed land. This is land that was mined and restored and met all the government requirements for restoration. So we actually put it back, sold it back to the community. And we have a plan now that, going forward in 2015 and beyond, that every year we intend to dispose of some of our—either our reclaimed land or our surplus land.

Our Clover Bar facility, as most of you know, it's fundamental to supporting our position in Alberta. As I think some of you know we have experienced, over time, high costs operating our two LMS units. These are first generation units, they're single digit units, and so we did experience lower than expected hours between inspections that cost us, but, in addition, there was really high wear on the components. And so it has been costing us more in operating hour basis than we would have thought. But, in spite of all these issues, Capital Power has maintained very high availability and very high start reliability on these units. And one of the reasons for that is that we also have bought into a spare engine, a lease engine program with GE, so we can make a really quick swap out if something is wrong with the unit.

But on the newer generation LMS units, GE has developed much more durable components that—and components that are actually much more cost effective. So this last fall, we actually negotiated an arrangement with GE, in which there was some cost sharing, to upgrade our two units. And we actually did upgrade the two units over the year to include these much more durable components into the R elements – basically, bringing them up to what is new design today and that work has now been done. But as part of the arrangement with GE, we actually have established a LTSA going forward for those two units for the next twenty years, and that provides total predictability for us. We have an hourly operating cost with GE, and GE is now fully responsible for the repairs and the refurbishment of these two units, going forward, so there should be no more surprises, you can see that in our O&M spend.

Lastly, just a little comment here about Island, Island Generation. Since we've bought the Island plant it actually has, it's purpose on the Island has changed to where it's become a very low dispatch facility for BC Hydro but it does support, it's still a needed facility. It supports, it backs up the renewables and it provides grid stability for the Island. But, because it changed in terms of its demand for operations, we've revamped our operations accordingly. And with that, this past year you can see that there's been a 30% reduction in our O&M at Island.

And our wind farm place, we are now in excess of 435 megawatts and that doesn't include the 90 we're going to add next mid-year with K2. All of our facilities, all our wind facilities are covered by LTSA's with the OEM's. And, while it does certainly reduce our opportunities of finding ways to spend smarter, it does provide risk mitigation, huge risk mitigation on these plants. We have made, in spite of the LTSA's, there's still other areas to find ways and means to spend smarter and we have found a number of areas. And all those savings have been incorporated into those graphs I showed you earlier on the O&M spend. We do, however, continue to work with the OEM's, we believe we can still find ways and means to improve our availability and as well improve our capacity factors, so there's still some upside we think in these facilities.

Now last year I spoke at length on the improvements we made at our two North Carolina plants. The improvements continued through 2014 —those plants are running the way they should be so going forward, really, our focus is on mainly on finding ways to reduce our fuel fee costs; that's really the majority of work, the technical work that's been done. In addition, this past year we were successful in negotiating off-peak recs for the plant; they didn't exist in our PPA. Those are valued in excess of $1 million per annum. And, under the existing PPA we have for those two plants, 2015 marks the year that our recs actually increase by about $4 million a year for the combined plants.

So in summary, the foundations for operations optimization are the four pillars of Reliability, Cost, Risk Mitigation, and Safety Management. As we continue to focus on these four pillars and drive continuous improvements we will achieve our vision of being one of the most respected, reliable and competitive generators. Thank you and now I'll pass it over to Bryan DeNeve.

BRYAN DENEVE: Thanks, Darcy. So I'm going to start off with a presentation on the Alberta power market. And the areas I'm going to cover is, first of all just a brief overview of the Alberta power market, how our portfolio is well positioned in that market, and then I'm going to move on and provide some insight into our trading strategy in Q3, as well as on a go-forward basis, and an update, of course, of the Genesee 4 and 5 project.

So, in terms of the business development side in Alberta, we continue to focus on Alberta as one of those key markets and, as you heard these last couple years, we did refocus from the merchant perspective on Alberta. As part of that, of course, Shepard is very close to final completion and we'll be reaching COD in Q1 2015 – Darcy will be providing a bit more update on that facility. In terms of Genesee 4 and 5, which I'll speak to more detail in a moment, we're looking to start construction on that unit as early as May 2015. And we also have an increasing focus on large industrial customers and power solutions for those customers in Alberta. And this is both in terms of stand-alone generation for those customers as well as co-generation. And it's a good fit with our, the origination side of our business in terms of retail contracts with large industrial, commercial customers. And finally in Alberta, we do have the Halkirk Wind farm and we're looking at other potential renewable opportunities in the province, and we do believe solar may not be too far off in the future for Alberta.

So, just quickly in terms of the Alberta market design – it's competitive wholesale and retail energy market, with installed generation now of 16,000 megawatts. Alberta's a single zone, a single power price, established each hour on the incremental bid price, into the power pool. There is no capacity market so all revenue by generators is recovered through—through a single energy price. One of the beneficial features of the Alberta power market is, as supply/demand balance tightens, and when you do see forced outages, or hot weather spikes in demand, you also see a strong pricing on an hourly basis. And about 10% of the hours have prices greater that $100/MWh over the last four years. It's a well-functioned, stable market design; I'll touch on that in a bit more detail in a moment. It has experienced very strong load growth. We anticipate continued strong load growth but, of course, with the drop in oil prices that is an element that needs to be considered and I'll speak to that, and then go into a bit of detail on the legislated retirements in the province of coal fire units.

So, just in terms of historical pricing in the Alberta market, just to give a flavour of what it's looked like since it started deregulation in 2001 – the top graph illustrates the average daily power prices in the Alberta power market. And, as you can see, there's days where we've seen power price approaching $600/MWh, and that's where developers of generation look to recover a large portion of their investment in the capacity for new units. On the bottom graph, you'll see the average annual price in the Alberta power market, and, again, it does range quite dramatically. So we hit a low point in 2002 with $44/MWh, however we've also experienced prices, annual prices as high as $90/MWh in 2008. And, that range is driven by fluctuations in the supply/demand balance, which I'll get into in a bit more detail in a moment.

So this graph depicts the capacity additions in the Alberta market since deregulation, and as you can see it's over 7,000 megawatts. So, if you put that in conjunction with the size of the Alberta market before deregulation, that's approximately a 70 to 80% increase in capacity. So, almost half of the generating capacity in the Alberta market has been built and brought on line under the de-regulated market. The other thing that's interesting to note here is, with the orange line, that shows the reserve margin in the province. So the reserve margin is defined by total installed capacity, including the import capability into the province, relative to the peak demand in the province. And, as you can see, that reserve margin has fluctuated roughly between 25% to 35%. So, in the electricity market, you do need a healthy reserve margin for when there's planned outages on facilities, as Darcy was mentioning. Also, forced outages and those shocks you can have on the demand side through periods of very cold weather or hot weather in the province. And as that reserve margin shrinks, what will happen is you'll see more price spikes, healthier prices in the Alberta market, and that provides a signal for new capacity additions. And, as you can see when in 2003, after a large amount of capacity was added to the Alberta power market, and an increase, correspondingly in the reserve market, the market responds and you see less capacity additions the following year. And that's just a normal cycle in the competitive market.

One of the questions I think that comes up quite often is, what about the risk of overbuild in the Alberta market? Is there a risk that competitors are going to build new supply on top of each other? And, certainly we haven't seen that to date in the Alberta power market. Both the pace of new capacity additions, shown here historically, and the underlying prices in the market, have shown that we haven't seen an over-build that takes us above that 35% reserve margin range and into a 40% or 45% reserve margin. And, generally, that's because competitors in the Alberta market are very aware and watch very carefully on the pace of development and status of competing projects. And, as projects crystallize, get permitting, enter their procurement for equipment arrangements, get environmental approvals – that project becomes more real, and there's always an assessment of how economic those competitors projects are. And, certainly, as soon as a competitors' project, we feel, has a very high probability of moving ahead, that is built into our forecast, that is taken into account when we look at the timing of our supply additions. So that's a very dynamic process that goes on in the Alberta market.

So, but, the other thing that I think is interesting with the Alberta market is that, unlike in the past, there is additional dynamics on a go-forward basis, and that's expected coal unit retirements. So, as we look out over the next ten years in the Alberta market, the supply/demand balance is not only about load growth in the province but it's also about how and when coal units are going to be required or will retire in the province. And there's two fundamental drivers. The first driver, which is depicted by the blue line on this picture, is the Capital Stock Turnover (CST) regulations that the federal government has put in place. Now these regulations stipulate the point in time when existing coal fired units have to physically ensure their GHG emissions are equivalent to a natural gas combined cycle unit; so that's probably a 50-60% reduction in GHG emissions. So, when we look at those dates and, also, we're very familiar with the cost of technology to physically comply at a coal fire unit; it's prohibitively expensive. Work we've done in the past is carbon capture is north of $150/MWh, so we expect these dates; these coal units will retire by these dates.

Now the other element though that's at place, in place sorry, is the Clean Air Strategic Alliance (CASA) regulations. And these are provincial regulations, and Darcy alluded to them, which stipulate S02 emissions limits and NOX limits, based on best available technology that must be in place by dates outlined in the regulations. That affects all thermal units in the province. And, with Genesee 3, as Darcy mentioned, we didn't quite meet those limits on the S02 side. As a result, we have taken steps to improve the S02 reduction at Genesee 3 and we'll meet those requirements in 2015 and 2016.

When you look out in time, and units such as Sundance 1 and 2, Battle River 3, HR Milner – those units will have to meet those CASA requirements earlier than the Capital Stock Turnover. Now these aren't new regulations, these are not pending regulations; these are regulations that have been in place since 2003 in the province. So, depending on the status of existing thermal units in the province, how much life is left beyond the CASA date, what the physical condition of the unit is, and what the cost is of meeting those S02 reductions, we expect we'll see retirement of coal fired units much sooner than the Capital Stock Turnover, and that would be in accordance with the dotted line you see on this graph.

So how's this fit in when we look at need in the province, on a go forward basis? So this graph here, what it does is it pulls together the view on demand growth in Alberta, which is the red line, dotted line, for the forecast. This is based on the AESO’s forecast demand growth in the province in terms of what we'll see year-over-year. And then, plotted in addition to that, the demand is a supply in the province.

So I’ll just draw your attention to 2013. So, the bar there illustrates the installed capacity in the Alberta market relative to the demand; you'll see the supply is higher than the demand. That's the reserve margin I spoke to previously, which is probably around 32% in 2013. Then, as we scroll forward and look to this year, we have seen some small capacity additions in 2014. Of course we've seen some load growth, also, and those have been roughly offsetting each other. So 2014, we do see some expansion in the reserve margin, and then, in 2015 what happens, of course, is we have the Shepard facility being completed, that will be adding 800 megawatts to the Alberta system. And that's going to be when we'll see the widest or largest reserve margin that we've seen historically in the province. And this all ties back to the low prices we expect to see in 2015 and, as Brian mentioned, a lot of our positioning and what we've been doing is to prepare for this dip in market prices that we're going to see.

However, as you look beyond 2015, and this doesn't have any capacity additions beyond Shepard, so just holds the supply steady; you see it's kind of flat through 2017 and then it starts to drop off. And it's dropping off in accordance with our expectations of when coal units are going to retire in accordance with CASA and Capital Stock Turnover, predominantly CASA. And, at the same time we have that strong load growth in the province. And, by 2018, what you see is the reserve margin will have shrunk to well below what was there in 2013. So when we look at Genesee 4 and 5, we put together our view of the fundamentals in the Alberta market. We see a scenario where Genesee 4, the first unit, will potentially be required as early as 2018, but I will speak to some scenarios that could push that date out.

But, one of the most important things on this graph is that there's two dimensions. There's the load growth, the dotted line, which is driving need, but also the retirement of reduction in supply, which is driving the need for new supply in Alberta.

So, if we move to the next slide. This slide has now taken the previous graph, and what it's done is it's translating it into a reserve margin number. And again, I'll draw your attention to 2013 as our point where it's a 32% reserve margin that shrinks somewhat in 2014. And then 2015 we see a large increase, of course, with Shepard coming on. Then when we look at the forecast beyond that, the blue line is a base case from the AESO's proposed load growth in how the reserve margin shrinks. We saw that in the previous illustration. What we've done here is we've said, Ok, we have seen a drop off in oil prices, so we've taken that and looked at, what would that do to demand growth in the province of Alberta? And then we've projected what the reserve margin will look like under that scenario. And, basically, as you can see here, that low growth scenario will delay the need by two to three years. So, for us, what's important, as we looked at developing Genesee 4 & 5, is making sure that we have the flexibility with the development of that unit to be able to either meet the earlier date, in terms of what could transpire – 2018. Or, if needed, defer the first unit to 2020. We're not too concerned beyond 2020 because, again, because of the coal-fired retirements, there's going to be a need no matter what happens on the demand growth side.

I won't spend a lot of time on this graph, but this takes that reserve margin picture and then translates it into a price projection. So, again, as we see the reserve margin shrink in the province, need for new supply, that tightening is going to cause increasing number of price spikes and increases of overall electricity prices. And, as you can see, we project that prices will rise to that $70 to $75/MWh range in the 2018 to 2020 time frame. And, just for comparison, if you look at the Alberta market historically, through 2013 we've seen an average price of $66/MWh in the province. And, at current gas prices that's roughly equivalent to the cost of building new combined cycle supply. So, as we look forward, that $70 to $75 range, in terms of pricing, is consistent, again, with the cost of adding new supply in the province.

Now one point, I'd like to make just on this picture is there is an interesting situation for Capital Power in 2021. So what happens is that the power purchase arrangements in Alberta expire at the end of 2020. And Capital Power is in a unique situation where we're both a buyer of a power purchase arrangement as well as an owner under a power purchase arrangement. So, we bought the Sundance C PPA in

1999; that will expire at the end of 2020. That will result in a reduction of EBITDA due to that. But, on the other hand, what will happen is Genesee 1, 2 switches over from being a PPA to merchant capacity. And when we net—the net effect of those two, when we look at it, we project an increase in EBITDA of $150 to $200 million in 2021, as a result of the expiry of the PPA. So that's taking the net lift we'll have on Genesee 1, 2 and subtracting off the EBITDA we'll no longer have from the Sundance C PPA.

So, I think, another unique element to our Alberta portfolio is the fact that it's very diverse across what I would refer to as a supply curve in the province. So our capacity that we own and operate in the Alberta market covers all the way from base load and wind, with Genesee 1, 2 & 3, and Keephills 3 through to mid-merit, which would be Joffre Co-gen and the Shepard Energy Center, and then to peaking capacity with the Clover Bar Energy Center. And that mix and that diversity of the fleet is very beneficial for us being able to capture value price spikes in the province, but is also very helpful in terms of backing up various trading products that we offer into the market, whether in the wholesale market or to retail customers.

So, I'd like to switch now, just to talk a little bit about Capital Power's trading strategy, both in this year and through Q3 2014. And then a little bit about what we will see happening in 2015. So, I'm going to start with Q3. And Q3 was a very interesting quarter. So, through 2014 we had taken a view in many of the months that we've expected lower settled spot prices than where the forward market has been trading. And, as a result of that view, we did sell forward our base load supply as well as a portion of the Clover Bar supply, into the forward market. So, the question is, 'Well, how has that strategy played out?' Well, when we look at July, July was a month of extremes. So, in the month of July we saw very, very hot temperatures in the province, which not only results in high load, but also results in derates for some of those coal units that are constrained from the cooling side. So that was one factor – so, very, very hot temperatures resulted in high demand and a reduction in supply. The other factor we saw in July was there was a lot more forced outage rates than normally experienced in the Alberta market. And when you take those two factors together it effectively reduced the supply/demand balance in the month of July by 1200 megawatts. Typically what we see, due to forced outages and so on, is on average about a 500-megawatt reduction. So that 1200, what we saw in July, was actually the most extreme hit we have seen in supply/demand balance in the province of Alberta to date. So, what does that mean? Well, it resulted in some very significant price spikes. And you can see that as illustrated by the red line there.

What I've also shown on the graph is the forward prices. And the forward prices are the black dotted lines; those were the average forward prices trading 90 days in advance of the month. So, in Alberta, we trade forward our position; a lot of it's done many years in advance but part of it we fine tune our position as we come into the month. A lot of that will happen in the two to three months prompt or ahead of the month in question. And that's because there's a lot of trading around the regulated rate option at that time. So when we look at July, we actually sold forward our baseload position and then, as well, 150 megawatts of Clover Bar. And what happened is, because prices settled on average much higher than forward prices, it did result in a trading loss of $7 million for the month of July. But if you look at the next few months in Q3, in August and September where we didn't see those supply and demand shocks that we did in July, prices settled well below forward prices. And so we continue to sell forward supply capacity from Clover Bar for those months, and those generated strong gains for our trading portfolio.

Now the thing that's happened in conjunction with this is units that we own the dispatch rights to but don't operate - Keephills 3 and Sundance 5 and 6 - experienced a lot of forced outages and most of that was in July. So we had a compounding effect in July. We had losses on availability of units we owned, but also on the trading strategy in July. When you look at August and September the profit created by the trading strategy actually helped offset losses and outages at those units.

So, going to the next slide. This table just summarizes the impact of selling forward our gas-fired generation in the Alberta market, over and above our base load portfolio. And as I just walked through, in July we had sold forward 150 megawatts; the actual price in July settled at $123/MWh. The trading price 90 days prior was $59, so that 150 megawatts we traded for, we took a loss of $7 million. But if you look at the other months through the end of October, with the exception of February, that trading strategy where we've sold forward different levels of volume off of Clover Bar has resulted in a positive trading profit. And you look at the year through to the end of October; trading forward some of the Clover Bar capacity has generated $10 million of profit for Capital Power. So this, in our view, has been a successful strategy and one that was successfully executed through the first ten months, despite the fact there was a loss in July.

So that still leaves the question, of course, of, for the Alberta commercial portfolio of Capital Power, which does have a negative variance to budget through the end of Q3 2014. And when you break it down, the vast majority of that is much lower expected availability and significant derates on Keephills 3 and Sundance units. Now, with Keephills 3 we're joint owner on that facility, and, as Darcy mentioned, we work very closely with our partner in trying to improve the availability of that unit. And I can say that critical spares in—even as far as a gear box from Genesee 3, was transferred over to Keephills 3 to help bolster the availability of that unit. So the other thing that is happening is the learnings on Genesee 3, which was built five years sooner than Keephills 3 – a sister unit, super critical coal unit – we're working very closely with TransAlta in transferring learnings that we have off Genesee 3 to Keephills 3 to address the availability issues that we are seeing this year. So, when we look at the operating plants, you can see that generally there was a negative variance, primarily with Keephills and Sundance and that was primarily due to less output than anticipated from those units. The last two bars, the value of hedges, those were the hedges that were in place when we established our 2014 budget. And those hedges were entered into prices that are higher than settled price in the Alberta market, so they created a value of $13.7 million.

The last bar is around trading, which indicates a $7.7 million loss through Q3 of 2014. It's important, though, to look at what makes up the $7.7 million loss. We actually experienced $16 million gain in trading through the first three quarters, however our budget has a $24 million value creation target that's built in. So, unfortunately, through Q3 2014 we have fallen short of the target value we were going to create from trading, but it did trade $16 million through that period of time.

So, when we look forward to 2015, and a lot of you have seen this—this graph before, but in 2015 we've sold forward, and Brian alluded to this, 96% of our base load capacity. And those hedges are at an average price in the mid-$50 range, which is well above where we see current forward prices for 2015.

So we're very well positioned in terms of protecting against downside as we roll through 2015. And similar to 2014, if we see opportunities and it makes sense we may add to that forward position, or we may not – but it depends on what we see happening in the market place.

So, just to wrap up this area on the trading side. This is a graph we use every year, which really shows the realized price on the output from our units in the Alberta portfolio, what the averaged realized price has been, and compares it to the average settled spot price in the Alberta market. And, as you can see, since the start of 2010 we've realized average revenue 12% higher on a dollar per megawatt hour basis, than the average settled spot price. So that shows—that being able to outperform the hour settled price is due to gains we've been able to make in terms of optimizing and trading around the portfolio. Now the other thing that I think is important on that slide is just to also look at the orange line, which is our realized versus the settled spot, which is the blue line. So the other function, or value, from the forward trading is reducing earnings volatility. So the stability is created by the forward trading – you can see in terms of how flat the orange line is relative to the settled spot price.

Ok, so now I'd like to provide an update on Genesee 4 & 5. So, maybe, just go back one slide there. So, on this picture you can see a rendering of Genesee 4 & 5. And it will be right next to the Genesee 3 unit. And, as you can see here, it's two trains – each with a separate stack, so one on one configuration. And I'll get into in a moment about why that is beneficial for Capital Power in the Alberta power market.

So, Genesee 4 & 5 will be a 1,060-megawatt natural gas-fired combined cycle facility. It will be a two-train, one on one configuration. So, what that means is where Shepard is two combustion turbines and one large steam turbine, Genesee 4 & 5 will be a combustion turbine connected to a steam turbine and a generator as a single shaft. And then Genesee 5 will be a mirror image of that when it's built. So the unit will be built in two pieces, two separate trains. It will be located at the Genesee site, as I mentioned, and that generates a lot of brown field advantages.

In terms of status, we have received approval from the Alberta Utilities Commission and we expect to receive our final approval from Alberta Environment tomorrow. And the project is also being approved by the Capital Power Board of Directors. Construction, we see as commencing in Q2 2015, which provides us the ability to hit COD as early as 2018, depending on market conditions. And, as I mentioned earlier, depending on how we see things unfold in the Alberta market we'll have the flexibility to adjust the timing of the unit as appropriate. And one of the key elements with Genesee 4 & 5 is, because of the fact that it will be utilizing the latest combined cycle technology and work our construction engineering group has done in terms of low-cost configuration, as well as the site advantages of being built at Genesee, our projection is it will be 15% lower capital cost than any other combined cycle unit proposed in the province.

So the strategic fit for Genesee 4 & 5 – so there's a number of elements that we look at Genesee 4 & 5 that fit very well with Capital Power's objectives. So, one of the most critical ones, of course, is that 50% of our share of the plant will be under a long-term contract with ENMAX. So, similar to Shepard, when we look at this investment, this investment is going to be providing contracted cash flow that will be supporting that base of contracted cash flow we already have. But it will still have upside, of course, to the Alberta market with the 50% that will be merchant. Schedule optionality will be key with a two-train configuration. So, one of the things we are going to see happen in 2015 is when Shepard comes on line it's going to have quite a hit—quite an impact on Alberta pool prices because it is bringing on over 800 megawatts of supply. With Genesee 4 & 5, with ability to bring it on in stages one to two years apart, the impact on Alberta prices will be much less. So staging it works a lot better. The other thing is that, with staging it in two trains, it does allow us some flexibility between the two trains from a timing perspective. So, if we see some changes in the Alberta market we can hold off or delay somewhat when Genesee 5 will be brought on, relative to Genesee 4.

It'll be the lowest cost mid-merit gas-fired unit in the province and it will create a lot of dispatch flexibility, which is critical in this market, and I'll talk more about that in a moment. It allows us an opportunity to leverage our construction operational expertise – Darcy will speak more to that – but, certainly, our experience building in the Alberta market with Genesee 3, with Keephills 3, with Clover Bar, with Halkirk – all of that experience, and with Shepard, will be brought to bear on this unit. And we see a lot of the individuals that have been involved on the Shepard unit will move directly onto the Genesee 4 & 5 project. When we look at financial returns from Genesee 4 & 5, the after-tax IRR is expected to exceed 11% and will be accretive to earnings and cash flow. And, as I mentioned earlier, the fact that there will be an off-take agreement with ENMAX will increase our contract coverage, post 2020.

So, just to go into the technology and configuration a little bit deeper – the combined cycle technology, which has been selected and we will be executing the power supply agreement in the next couple weeks, will result in equipment that will have a 4% lower heat rate than the previous technology and also a much higher output than the previous generation, which has resulted in economies of scale and results in that lower capital cost. The single shaft layout – which is a single shaft running from the combustion turbine through to the steam turbine – simplifies the construction, lowers the cost of the construction, and also allows faster ramp up and down. It will actually have another thing from the engineering side, we've looked at, for the power island, is a clutch that will allow us to operate this unit in simple cycle mode if conditions warrant it. Also we will have duct firing, which will allow us to capture peak price spikes in the province, albeit at a higher heat rate, but we'll have that additional output through duct firing. So the two train, one on one configuration, as I mentioned earlier, allows for a phased construction and construction cost optimization. A lower minimum stable generation, because we can operate one train, shut down the other one, faster start up and ramp down, and higher availability since planned maintenance, in a lot of cases, will only affect one train as opposed to the entire facility.

So, in terms of the commercial structure, it's a 50/50 joint venture with ENMAX. Capital Power will lead and manage the development and construction of the facility. Capital Power will operate and maintain the facility which, of course, makes sense given its located on the Genesee site. And we do anticipate material savings on the O&M side by the fact that we can leverage the existing operational staff at Genesee. Each partner will have dispatch rights to 50% of the output and, as I mentioned earlier, in terms of our share of the output, half of that will be contracted back to ENMAX for a term of eight years with an option for it to be extended to ten years. So, I think I will turn it back to Darcy who will speak to construction.

DARCY TRUFYN: Thank you, Bryan. For construction, today I will provide a brief update on our two major projects that are currently under development. And then I will speak about our construction group and also give a little bit more color to the construction status of G4 and 5.

Shepard, as Bryan mentioned, is a two-on-one combined cycle unit. It's rated at 873-megawatt hours, that includes duct firing. This plant was built on a greenfield site in the southeast corner of Calgary. On this project, ENMAX is actually responsible for operations and construction. We, Capital Power, we joined the project when it was in development, when it was well under construction, however we did place a few people on the construction team. This project is well into commissioning, as noted, in fact steam blows have been completed and piping is now being fully restored. Of the 130 system packages required for commissioning, 90 are, in fact, complete and the remaining 40 are about 50% complete on average; so well near the end. We expect Shepard to achieve COD on schedule in February 2015, and finish on budget. And this is a huge accomplishment to the team given all the cost pressures of working in a heated Alberta construction environment.

The K2 project is a 270-megawatt wind farm being developed near Goderich, Ontario and that's adjacent to Capital Power's Kingsbridge 1 wind farm. K2, its process is a JV, with each of our partners having a 1/3 interest. Construction is also well underway, with approximately 55 of the 170 turbines now topped out and COD is expected to be reached mid-year 2015. The project is tracking to the budget that was established with our partners at time of FNTP, and our 1/3 portion is $310 million. On K2, I just want to point out that Capital Power, we actually do have our team on site, on behalf of the JV, overseeing construction. This is—it says something about Capital Power – we hear it consistently from construction engineering contractors, especially on wind projects, that "Capital Power, you are different than other developers." We take that as a compliment. We do want to be intimately involved with construction on our sites. We are a long-term investor, we operate our plants and want to make sure that they're built correctly and they're built – that we get basically what we paid for. But more importantly even is that we feel by being involved with our technical people onsite, being engaged with the project, that we can respond to engineering and construction, technical issues – we can respond very quickly while they're issues before they actually become very costly problems. For us, it just makes good economic sense to be there and we really believe this helps us keep our change orders, keep our cost down and under budget.

This slide shows, and you've seen, I think, this before but this slide shows that Capital Power's track record over the past ten years, in Alberta specifically. And, as you can see from the slide, Capital Power has proven that we can develop and construct successfully in Alberta. Not many developers, even in other industries, have this type of record of finishing projects on time and on schedule.

And this slide is just looking at it in a different way, and I believe you saw this slide before – we just updated it. We superimposed Genesee 4 & 5 on it and you can see that in power development we lead the pack. When you consider that the two largest developments are Shepard and the upcoming G4 & 5; when you layer those, it really does show that we have the experience, we know how to build in Alberta and be successful in that, because it is a challenging market it's quite different than anything in Canada—in the rest of Canada.

Bryan has given a lot of background on G4, G5 and I don't want to repeat it but I just want to re-emphasize – we have put a lot of thought into the front end of - this is where the project has really gone, this defines success – the front end. With our technical people, our engineering, our construction people, we have put a lot of thought into this project and so when he talks about the arrangements and all this, this is just the product of a lot of effort. But we believe that this thought, this effort, will give us and is giving us, real construction and operational advantages going forward.

We have, as been noted, we have completed the selection of the equipment, and Bryan mentioned this earlier, we intend to award this work power island later this month. We are now starting a very competitive process for the selection of our builder. And we believe the process we're taking is a little bit different but we believe this process will give us a very, very competitive EPC price, but, also, a very complete EPC price with few surprises. And we would expect to award that in late fall of 2015. And, as been noted, I'll just repeat it, but we'll start in late spring on preparations for the civil. We need to get going to do some work, there's some work that needs to be done in advance of G4 and 5, that is the extension of the cooling water inlet; we need to get that work in place.

So, over the past several years I've been coming – this is my fifth, I think, or whatever, in a row and I've been speaking about the competitive advantages that we created at Capital Power in construction and development. So I'm not going to go through that but I'm just going to make a few comments. We have assembled – we think we're different. We have a team of people, of skilled personnel that, they are our staff; we're not going out to hire people – not only in construction, but in engineering, and in pre-construction. Not many developers can say that in pre-construction areas, but we also have within our company a supporting cast. We have people in development and cross-functional areas that really do help as a combined unit, to develop these projects successfully.

We spend a lot of time and effort, we've always had this, actually for several years we've been looking to G4 and G5 but we spend a lot of time and effort working on our tools, our processes, our systems – getting all to that work. It's a lot of legwork, that…so we have all these tools. You just don't build projects without having tools or else you have to hire someone to do that. Well, we have these tools, we have the development tools to successfully project-manage projects. And now, we've got all this and we've also taken all the learnings of all the projects we've built, and including Shepherd, we've built that knowledge into how we're going to execute G4/G5. So we've got the management team, it's a proven team; we've got the management team in place. We have everything done and ready to be used, to be deployed, at G4/G5. So we are confident that this will be another successful development for Capital Power. Thank you and now I'll turn it over to Brian.

BRYAN DENEVE: Thanks Darcy. I'm going to switch now to the contract and growth pipeline within Capital Power and some of the recent events that have occurred – some it you've read about it in the press release earlier today. So I'm going to provide a very high level update on some of the trends we're seeing across North America and how that has lead to our strategy in approaching contracted opportunities, mostly in the US context. But before I turn to the US, I will start and provide a brief update from the Canadian perspective.

So, with British Columbia, as a lot of you know, there's actually two key elements there that will drive opportunities for independent power producers. So, the first one is the decision on Site C. And, even though Site C is probably, if a decision is made to move ahead with it, it's a good ten years out in terms of the lead time of construction, but that project will generate 5100 gigawatt hours per year and certainly will crowd out some opportunities on the independent power producer side.

But the other element that is moving, of course, is on the LNG side. It certainly has been moving in fits and starts but one positive sign we have seen is that there have been regulations put in place that require, or put GHG limitations for LNG facilities in term of their GHG emissions on site, and that has lead to a number of LNG proponents looking to buy off the grid from BC Hydro. And the three that are, so far, have been public with Fortis BC Tilbury plant, Shell Canada, Woodfibre LNG; the combined consumption of those is 3000 gigawatt hours per year just for those three, for ancillary loads on site. So, despite which way the Site C decision unfolds, we do think either way there'll be opportunity for independent power in the province. And to that end, we have spent time continuing to develop our Klo wind site in central BC as well as securing a location for combined cycle site near Kamloops, which we think fits very well into the grid in that province.

So I'll turn now to Saskatchewan. I think, probably, every IPP involved in western Canada speaks about the Saskatchewan RFP, which is just around the corner. We still believe it's just around the corner. You know, expect it in Q2/Q3 2015. This will be the size of the requirement as we understand it, will be smaller than one of the trains that we're looking at Genesee 4/5 so would result in likely or potentially different configuration, but as Darcy mentioned, we believe we have a very strong competitive advantage from the construction execution side that will make us competitive in that RFP process.

Turning now to Ontario. There is a long term plan that has been released by the government of Ontario which indicates refurbishment of the nuclear units, additional renewable generation, and is silent on gas-fired generation. We believe that's going to be a pretty tall order and when you look at refurbishment of nuclear facilities, the risk of cost overruns, schedule risk of doing that – we still firmly believe there is going to be a need for some peaking gas, or even some base load gas-fired generation in the province. We believe we're well positioned to compete for that with a peaking site located near North Dumfries and the combined cycled site located near the Nanticoke plant. Old Nanticoke plant. We've also qualified for the procurement this year on the renewable side. Certainly we don't have any particular project we're looking to bid in at this point, but, certainly, will look for if there's opportunities to partner, would look at doing that closely. So this just provides a map on the sites I've just spoken to.

So I'd like to turn to the US now. There's a number of dynamics, of course, we're seeing in the North American market in terms of future supply development. And we're seeing this through the falling costs of solar and what it means in terms of distributed solar, rooftop solar, which is becoming very predominate in the US southwest and is certainly becoming a major factor in terms of the need for new supply in that region. But we're also seeing the proposals that the EPA's put forth, in terms of clean power plan and what that will mean in terms of the requirements for various states to procure renewable energy, as well as what it'll mean for existing coal fired generation. So when we look at Capital Power's strengths in developing and executing wind production in Canada, we very much want to take that capability and leverage it in the US.

And where we started from, and this is being led by our commercial services team located in our Boston office. They started and looked at, in the US, where do we see the lowest capital costs for developing wind? And, as you can see, I know the words are probably hard to read there, but to the far left, that's the average installed capital cost for wind project located in the interior central area of the US. And that happens to be the lowest because, similar to Alberta, it's very low cost to build on the prairies. So, and based on our experience in building the Halkirk project in central Alberta, that is the lowest costs region to build. So, the interior of the US is very conducive to low cost wind from a construction perspective.

But then you add on, well what does the wind regime look like across the US? And, of course, through the central US, and as shown on the bottom graph, those are the areas, and the Great Lakes region, that have the strongest wind regimes in the United States. And with the latest technology a lot of those sites in the interior in the US will have capacity factors well about 50%. And that's critical because when you take a capacity factor above 50% with the latest wind technology, combine it with a low construction cost in those regions, low interconnection costs, you're looking at an all-in cost for wind in the $40 to $50/MWh range – and that is lower costs than new combined cycle generation. So, when you couple the wind regime, the low cost of construction, you've got renewables that are now, not only reach grid parity, but are probably lower cost than thermal alternatives. Now when you combine that with a production tax credit, which is currently in place, we see contracts as low as $23 to $30/MWh range.

So the other element that we looked at here was, so, where is the highest GHG intensity in the US? And it is through the Ohio valley just south of the Great Lakes down into southeastern US where there's a lot of coal-fire generation. And, as the EPA rules take effect and states determine how they're going to meet those GHG reductions, we see utilities-scale wind as being a key part of that solution. So the red circles on this map show the areas of GHG intensity. The green dots are the wind projects that we've acquired as part of the Element portfolio, and the yellow dots are the solar facilities —solar sites we've acquired as part of the Element portfolio. And the arrows—the yellow arrows that are going from the interior to that region with high GHG intensity – those are new transmission lines that are being permitted and will be constructed for the purpose of transmitting renewable energy from the central US to those regions with high GHG intensity. Now I'll just point out in the US southeast, of course, the wind regime isn't as good as you saw in the previous graph; it's more expensive to build. So, however, it does not have a bad solar resource so we do see solar as being an opportunity in that region.

So the next graph here just illustrates the renewable portfolio standards in place currently in the US. There's a lot of talk of these increasing in some states. We believe in order to comply with the EPA rules that we will see renewable portfolio standards potentially start to rise in the states that don't have them right now, and also increasing in some of those other regions. And what's interesting about the renewable portfolio standards is they do require load-serving entities to procure a certain percentage of the energy physically from renewable sources regardless of the cost. However, when you couple with that wind and in some locations, solar, being on grid parity, it's not going to be a big hit to consumers to meet those renewable portfolio standards.

So, as mentioned in the press release this morning, Capital Power has signed an agreement to acquire Element Power US for $69 million, which includes $52 million of project financing. The primary driver of that acquisition was to build a portfolio of development projects in those strategic locations in the US, which I just walked us through. So the portfolio will include ten wind development sites that are in various stages of development; some early, some late. It will also include six solar development sites; two of them are small but there's four that are of a size that we would see pursuing, and it includes one site located in North Carolina that does have a contract with Duke Energy and that is a project we would look to start construction on in 2015. The transaction is subject to FERC approval; we expect closing by the end of 2014.

So this table lines up those areas that we see as strategic from a renewable perspective and how the Element portfolio lines up with it. So, SPP, Ercot, in that region – two of the projects out of the Element portfolio fall into that region; 300-megawatt wind project in Missouri, 200-megawatts in Kansas. In the upper Midwest, there's a number of projects covering North Dakota, Illinois, Ohio, Iowa, Michigan and Wisconsin – again, very strong wind regimes and near the developed—the transmission expected to be developed to carry power from the central area to the east. And then three solar projects in the southeast.

So the other component of the Element portfolio is an existing wind project. The intent wasn't to, for this acquisition the driver wasn't the existing wind project but it did come with the portfolio. So it's a 50-megawatt project in Luna County, New Mexico. It has 28 Vesta V100s, 1.8-megawatt turbines – approximately half of our Quality Wind site in BC uses the V100 Vestas turbines. It reached COD in November 2011 and it's 100% contracted under a PPA with Tucson Electric Power through to 2031.

So, in addition to the Element portfolio, I did want to just speak to a couple other development sites we do have in the US. One of them is Bloom Wind. Bloom Wind is located in southwest Kansas, 180-megawatt project with wind speeds north of nine metres per second. It is adjacent to an existing substation and our interconnection approvals are pending. This project is virtually construction ready and we are looking closely at potentially partnering with companies that are PTC eligible. Currently, just given the strength of the resource at the Bloom site to move forward the project under production tax credit regime, or if we don't meet that window, and as we look forward, we believe Bloom Wind will be the most competitive wind project in the region to meet ongoing renewable portfolio standards.

The other one we've talked about over the past couple of years is the Sun Valley project in Phoenix. So that's a solar project one hour west of Phoenix. Development has been slower than we would have liked on this project and it's primarily being driven by the timing of the construction of the Delaney Colorado River transmission line. We have now reached a point where CAISO has approved the construction of that line and what that line will do is it will allow this site to access the southern California market. So, once that line's completed in 2019, we'll be well positioned to bid into renewable requirement of Southern Gas Electric or SCE in the future.

So I'll just wrap up just with an illustration of our development pipeline that's now assembled in the US. So, you can see through the interior up through the Great Lakes region that the wind sites that comprise of the Element portfolio also include, in Kansas, the Bloom Wind project. And then there are four additional wind sites that were under negotiation with an exclusive basis located in the Texas Panhandle and Oklahoma. And, again, it fits with that strategy of strong low-cost wind in the interior region of the United States. There's also the three solar projects from the Element portfolio in the US southeast. Sun Valley Solar, of course, is the sun in Arizona —there's sun down there. And, in the Pacific Northwest, I didn't touch on it but there is a wind project and the solar site that came with the Element portfolio, as well as we do have the Frederickson 2 gas-fired site, which is right adjacent to the existing Frederickson 1 facility that is one of the low-cost opportunities for new gas-fired generation in that region. So, with that I'll turn it over to Stuart.

STUART LEE: Thanks Brian. I appreciate everyone coming out this morning. I know there's been a lot of news in the market over the last 24 hours and a lot of folks busy scrambling to figure out exactly what that means. As I was mentioning to a couple of folks this morning, it feels a little bit like being in a scene from Caddy Shack. It's the one where you've got someone down, it's us I guess, polishing up your boat and getting ready for presentation and all of a sudden Rodney Dangerfield comes by in his yacht, screams by in his yacht and throws up a wake that's two feet higher than every other boat in the harbour, so it's interesting. It's interesting how you create $10 billion worth of value by taking a set of assets and moving around the org structure and going from a square to a circle to a triangle, but I guess pretty big news in the market today.

As I was traveling to this event I got an email from one of my colleagues and he'd forwarded on an article out of Forbes magazine, which I found quite interesting. And it was about a gentlemen by the name of Harold Hamm who is now the richest person in Oklahoma. And Mr. Hamm developed his wealth through a company called Continental Resources, which is one of the first companies to develop the Bakkan reserves in North Dakota back in the mid-1990s. And he's currently worth about, I think, $12 billion, which is a step down from $18 billion dollars a couple of months ago but still —still doing relatively well. Unfortunately for Mr. Hamm he's currently going though a divorce process and…he was married for 26 years and you would expect through that length of a marriage that a significant portion of his overall wealth would move over to his wife through that process, but, interestingly enough, the ruling came down recently where she was awarded $1 billion of his net wealth of $12 billion dollars. And I think people were surprised that she didn't end up with close to half of his overall wealth. And interesting, when the judge went through this process of assigning out that wealth from Mr. Hamm's estate, the judge made the decision that a significant portion of it wasn't directly attributed to his actions. It was really a lot of passive factors that lead to his wealth, including both the rise in oil prices as well as significant changes in drilling technology.

So as I was reading this on the plane and I started to reflect, and not so much about my own marriage, or jeez, how do you get a lawyer like Mr. Hamm but more around being in a commodity business where we have commodity exposure – how much of the value is related to passive factors and how much of it is deliberate based on decisions we make as a management team? And I think I'll try and talk to, in the upcoming slides, a view that we absolutely do have some commodity exposure. It has a big factor in our business but I think we've been very deliberate about how we positioned this portfolio and the decisions we've made around it and how that drives value. So, with that, maybe, I'll just jump right into the slides.

So starting off with Shepard, you'll see that we expect to add about just over $50 million to EBITDA in 2015. That steps up significantly in 2016 to about $70 million and that, again, is a reflection of the fact that we don't expect a full year in 2015 of production given that the timing of the COD. And then again a step up on 2017, which reflects our expectation around higher power prices as well as the fact that we expect higher dispatch from that facility in a more volatile market. Again, I think we've been very deliberate in how we've structured this arrangement on Shepard and the fact that we, knowing that power prices were likely going to hit a dip through 2015 to 2017, we contracted 75% of the output. And that'll drop to 50% in 2018, based on our expectations that the market recovers. And particularly, in 2015, in addition to the 75% contracted, we sold forward an additional 25% at fixed prices.

In addition to Shepard, if you look at the addition from K2 Wind we've provided guidance around that. Again, mid-year 2015 expected COD and expected to add about $20 million of cash distributions starting in 2016 on a full year. And, again, this is accounted for on an equity basis so I haven't included this on an operating margin or a cash flow basis; it's really on cash distributions, which is after any of the projects financing costs that will get expensed at the partnership level, and just our equity pick up and our distributions of cash. The one item that's not on here, that didn't get into the slides, was just around Macho Springs as folks look to model Macho Springs. And if you look at Macho Springs, as Bryan mentioned, there is a tax equity partner and, consistent with what you see with most tax equity partners, there's a flip structure in place so we end up with about 25% of the cash flow in the front couple of years. Expect that will slip likely in about the early 2017 period and, up front, we'd expect that still will generate about $9 million of EBITDA and about $1 million of cash flow back to us. When it flips we end up with 80% of the cash flow, which is expected in early 2017.

In addition to Shepard and K2, which, obviously, substantially add to our contracted cash flow in 2015 and 2016, what you see is a very methodical build out of our renewable portfolio and our long term contracted facilities since 2012. And, so, if you look at our long term contracted operating margin, it's moved from $225 million in 2012 up to $390 million in 2016. So, that's a 73% increase in long term contracted cash flow and, again, all that investment was done on a very deliberate basis, looking to provide that solid base of contracted cash flow into our portfolio. Next slide.

So the one slide in the deck that probably has the most interest is just around our guidance for 2015. And if you look at our FFO expectations, I've used a midpoint in the slide deck at $390 million. If you look at the expected uses of cash flow after dividends, development projects of $38 million, which would include a carry over at Shepard of about $15 million, new spending on G4/G5 of about $22, and then take off sustaining CAPEX, which is $64 million – again that's a drop from expectations coming in to this year of 2014 of $85, you end up with a net change—expected change in cash of about $162 million. And what I point out on this slide is the fact that we are at the low point of the cycle in the market and for a business to be kicking out that level of discretionary cash flow at the low part of the cycle, is extremely well leveraged to the upswing in the market. I think we're in very good shape with that level.

Another way that we look at that is we break down that cash flow, the expected FFO, into three different buckets. The light green, or dark green bars at the very top, look at what are we returning the shareholders in the form of dividends. And you'll see that historically we've been between about 34 to 42% of our cash flow is being returned to shareholders. The middle bar, I think, speaks to a lot of the great work that Darcy's team has done in taking sustaining CAPEX down. 17% expected through 2015 and, again, a very good trend. And then the final bar is, if you look at the bottom base, it's ranged between 34 and 46%, which is discretionary cash flow. And in 2015, close to $200 million of FFO that can be reinvested in growth projects and other capital allocations, which I'll speak to in another slide.

So, speaking about capital allocation, as we look at that free cash flow – again, a lot of the questions we get asked by investors, how do you really rank that, how do you prioritize your allocation of capital? And we stand back and look at our business; we look at really three different ways of allocating that capital. And I'd say the first priority is really around dividend growth. We have extremely good contracted cash flow and a base that is very supportive of continuing to grow that dividend. Secondly, looking at growth opportunities. In order to increase long term contracted cash flow and cash flow in general over time and be able to support a growing dividend, you need to continue to grow the business. And then third, looking at alternatives like debt reduction and share buy-back. And we recognize that there's different parts of the market cycle where we may not be as competitive on growth opportunities and we will be patient. We have specific hurdles in place that we look at on capital allocation and to the extent that we don't see opportunities to effectively meet those hurdle rates, and, particularly, if our share price is at a level that we think has a lot of intrinsic value in it, we will look at those options as well.

Just a quick update on our tax positions, because we do get a lot of questions around folks trying to model what the expectations are on cash taxes and, obviously, in the US we have significant NOLs available to us. Those have long dated expiries, 2027 to 2034. And, as we look at the development opportunities that Bryan has pointed out in the US, it certainly provides a good advantage around use of those NOLs. In Canada, we have about $3.5 billion worth of tax pools. We wouldn't expect to be cash taxable, certainly through the next three years, and even as we move in 2018 on a pretty minimal basis. So excellent structure in place with respect to our tax position.

One of the other areas in the company that I'd say we've been very deliberate is around our financial structuring. If you look at our balance sheet. And a lot of people would point out that, relative to the industry and peers, we're certainly under levered, relative to a lot of folks. And if you look at our long-term target debt to cap at 40 to 50%, it's just sitting and 33%. I think we would say we still have a lot of room to introduce additional leverage in the company. Part of that, us governing that level of additional leverage was a fact around just trying to manage credit ratings and ensure we're well on side and have lots of headroom. And, I think, as Bryan commented on — as you look out into 2015/16, even at the low part of the cycle, our credit metrics continue to improve and it gives us additional leverage to introduce into the capital structure in the next couple of years.

And talking to credit metrics, we've provided both DBRS as well as S&P expectations around their significant credit metrics. And you'll see, for 2015, we're well above the DBRS FFO to debt as well their EBITDA to adjusted interest. Likewise for S&P, expected to be well above their expectations of 15% FFO to debt in both '14 and '15, and lots of capacity on the adjusted debt to adjusted EBITDA on the far right side.

For debt maturity – well spread out, debt maturing profile. As you look at 2015, about $300 million that will come due and we're well positioned to roll that into a longer tenure in the Canadian market. Later, in 2015 – very manageable position. In addition, we have $1.2 billion worth of credit facilities with $1.1 billion currently available. This small portion is currently being used for LCs.

I think as folks have watched over the last several years, yield is a big focus of investors. Yesterday's announcement certainly was playing to that theme. When we look at our dividend yield at 4.9%, it's pretty consistent with where we see most of the industry peers – on average about 4.8%. I think what maybe differentiates us more is looking at our AFFO yield, which is adjusted funds from operations, which is effectively taking funds from operations and taking off sustaining CAPEX and looking at it over a share price. And what I'd comment, and again, we have great cash flow. This is based on 2015 consensus analyst estimates. 2015, we would argue, is the low part of our cycle. We still have lots of leverage to see that FFO move up. This isn't a situation where we're facing some sort of contracting risk and there's going to be a lot of cash flow that falls of. We're actually really positively leveraged to continue to achieve that growth in cash flow. And so, I think, from our perspective, still see a lot of value in the stock. Next slide.

As we look at our decision this past year on our dividend increase, one of the primary things that we looked at how is much contracted— long term contracted cash flow do we have to support all of our fixed obligations? And when I talk about fixed obligations I would include, not only G&A and O&M costs, sustaining CAPEX, but also our dividend requirements and our debt service costs. And, so, as you layer on all those different pieces of what we consider fixed obligations you'll see, as we move into 2015, with Shepard coming on line, K2 coming on line, we have over 100% coverage. Now there's a lot of folks in our space that effectively take all of their cash flow and look at coverage at 100% of their dividend. This is just our long-term contracted cash flow; it doesn't include any of the cash flow coming out of our merchant facilities. And you see over the next three years, we have very strong coverage on those fixed obligations, which, I think, great support for both the dividend as well as comfort for our fixed income investors. And this would include expectations around dividend increases through 2015 to 2017.

Kind of building on that theme, if you take the next slide on our merchant position. So the bottom part, the bottom line that you see on that is, effectively, the previous slide's contracted cash flow and all we've added on to that is the additional margin at a very low case, at $40/MWh in the Alberta market and the merchant EBITDA from that and then another sensitivity around $70 prices. And, as Bryan mentioned, historically that's kind of the level that we would have seen it in the Alberta marketplace so provides a good indication of the positive leverage to the Alberta marketplace as we start to see recovery in it. And the fact that there's great coverage for all of our obligations, including dividends, to both the contracted cash flow and through merchant.

And, from my perspective, when I talked a little bit at the beginning of my presentation about passive decisions and—versus being more discrete and deliberate around those decisions, I think this is the slide that really emphasizes that. We've been very deliberate in how we've built up that contracted cash flow base. We've been very deliberate as we looked at 2015 and the low part of the cycle, around hedging that position. And, at the same time, we haven't eliminated the opportunity to catch that mid to later value creation in the Alberta marketplace, which we view as the best power market in North America. And, so, I think we've structured this portfolio, I think, we would come to the conclusion we're not a passive management team in making those decisions and we've been very active in structuring this portfolio to take advantage of where we see the strengths.

So, just to wrap up, a core part of our strategy is around dividend growth. We continue to have one of the lowest payout ratios of Canadian IPPs. We're generating close to $200 million of free cash flow before growth CAPEX and that's the bottom of the market cycle. We have significant expansion of our contracted cash flow. And, really, the decision in 2014 was in the backdrop of an expectation of lower power prices going forward over the next year or two, and we weren't making the decisions on one and done, it was the expectation that we could consistently grow that dividend over time and really nothing's changed in our view around that ability. And I think we're extremely well positioned to deliver a dividend increase in 2015 that would be consistent with the amount of the increase in 2014. And, as always, that's subject to market conditions and economic outlook, our cash flow forecast, as well as Board approval at that time. And with that I'll turn it over to Brian.

BRIAN VAASJO: Thank you Stuart. Every year at this Investor Day we publish what are our key focus areas going into 2015 and this year is no different. As Darcy described, our availability target for 2015 is 94% inclusive of plant maintenance and assets that we don't operate. Our maintenance capital target is $65 million, significantly lower than prior years, while our plant operating and maintenance target range is $180 to $200 million.

Our growth priorities are K2 Wind with a major focus for us in 2015 being moving Genesee 4 and 5 from development to construction. When we look at the financial side, as Stuart described, our funds from operations are targeted in the range of $365 to $415 million. The mid point of the range represents an approximate 8% increase in cash flow over 2014. Generally attributable to lower power prices being offset by Shepard and K2 reaching COD.

So why invest or continue to hold Capital Power? In addition to it being in a zone of very good value today, there are a number of reasons, which combined, I think, are very compelling. A track record of and plan to continue to improve our existing business. We are moving to higher levels of operational excellence. We have the best fleet in the best market in North America and will be adding Genesee 4 and 5 to that fleet. We have significant existing contracted cash flow growth to support a growing dividend and are well-positioned to continue to grow that contracted cash flow base through development and construction of natural gas and renewal projects.

So, this morning we've provided you with a significant amount of detail in terms of both what we're doing but I think, more importantly why we're doing it. So we've had Darcy talking about what we're doing on the operations side and, as I said at the onset, that is absolutely our number one priority, is making sure we get the best out of our assets and then in the longer term they provide strong, stable cash flows. Bryan talked about some of the nuances of the Alberta market and how it is actually a market that is performing very well, somewhat predictable, and that where we see a continued great opportunities for us, particularly in Genesee 4 and 5. And when looking to the new opportunities that we see predominantly through the centre of the United States, we see that there are tremendous opportunities to grow our contracted cash flow base. And, of course, Stuart rounding things out, describing for you that at the lowest point, of what we see as the power cycle in Alberta, which impacts us the most, we are improving our balance sheet and we're improving our cash flow, which we think is a tremendous feat.

Now, the agenda says right now that we'll be closing and moving toward having a question and answer period, having gone out and got our lunch but if, in the event that those folks that have to go, I'm going to practice what I do when I speak to our staff. There's always questions that staff don't want to ask. So I ask myself the question and give the answer. In this case I know that you'll be asking the questions, so I'll ask them for you and give you the answers, and then well break for lunch and—and get into a Q&A session.

So the first one is on Element Power. And we've been talking to you and saying over the last two years that we're not generally competitive when it comes to buying contracted assets. And you'll look at Macho Springs and think, well how that did that happen? And is that a signal that we've changed our criteria and all of a sudden you can expect to see some significant acquisitions from a Capital Power perspective? And the answer to that is no. When we looked, and when you think about that opportunity, it's small. We actually wouldn't have pursued it ourselves if it was just a stand alone operating asset, because it is too small but it was a combination of it, and certainly what really drove our interest, was what we saw as a great group of development opportunities that were very sound and very, very well positioned. And when you think of the potential other purchasers out there, who would want to be buying a small asset and a lot of development opportunities? So it was a very, very, very narrow field and we've luckily prevailed. But, again, we didn't exercise any of our criteria other than size, to pursue that. So that's by no way an indication to you that you can start seeing acquisitions from us. That's one of the questions that I would've expected would have come up.

The other one is, now with this portfolio, and Stuart's gone through and described our cash flow situation going forward, which is very strong, but he's not showing that there's a lot of capital going into potential construction activities. Realistically, looking at our portfolio development opportunities, I would expect that over the next two to three years, two to three of those projects would be under way. You won't see all of a sudden we've got four projects going and we're stressing the balance sheet of the organization. That's just not in the cards, both from our perspective in terms of not wanting to take on that much, but from the perspective of the market itself. It's just those opportunities aren't that near term as a broad group, but, again, we do expect that a few of those opportunities will come to fruition and you'll start seeing some capital expenditures, potentially in 2015, but I don't think so, probably more like 2016 and moving out into the future.

And the last one is around Genesee 4 and 5 and are you saying, sort of a hell bent for leather drive to build those projects regardless of market circumstances. And I think Bryan's been very clear and it's been very ingrained in the way we've approached this. No, what we're doing is we've decided that we're going to pursue construction and deliver potentially a project in 2018, which is, sort of, the nearer point of when it might well be a requirement in the market. But it's the agreement behind it, is very structured to allow us to move the time frames up. So, again, we are on a track for building for 2018 and as market conditions dictate we'll be adjusting that time frame as we go forward.

So those, I think, are probably a couple of the key questions that may be on peoples' minds. Should we continue with questions, given the time? Yes, why don't—because we're actually doing quite well and having done most of your work already, I think we can, maybe, move forward to questions.

RANDY MAH: Actually, Brian just wait. Terry, can you set up mikes on the table here?

[PAUSE]

RANDY MAH: And just for the benefit of people listening on the webcast, before you ask your question can I ask that you identify yourself and your company name, as well. Ok? Any questions?

GLEN PICHANICK: Hi, Glen Pichanick, Lincluden Investment Management. There was a reference to the effective potential lower oil prices on the reserve margins, slide 37? Can you translate that to potential effect on either power prices in the future or sensitivity on your cash—effect on your cash flows? So, in other words, does your forecast for your cash flow, the low end of the range, does that incorporate, potentially, lower oil prices? Thank you.

STUART LEE: So again, just to comment on cash flow—the cash flow piece. We've given guidance on 2015 and, really, because a significant portion of the overall portfolio is hedged, a lower or higher oil price doesn't have a significant impact around our expected cash flow. As you move out further in to the forecast, if you saw sustained lower oil prices, clearly that would have an impact on overall demand growth in the province. And, I think, as Bryan mentioned, it likely pushes off recovery in the market a couple of years, as well as the requirement for new build. But, again, if you look at where forwards are at 2016, '17, '18 – currently in the Alberta marketplace we would see, our internal forecast would be a lot more bullish than where the forwards are at, based on just supply/demand fundamentals.

And there is a little bit of inertia within the Alberta market right now. Even in a low oil price environment, clearly that has an impact, particularly on some of the drilling activities. But, the oil sands projects themselves – there is a fair amount of inertia on the existing projects. It takes you out a year or two of, just, built in demand growth associated with that.

ROBERT KWAN (RBC Capital Markets): [indiscernible – microphone not working]

BRYAN DENEVE: So, certainly with Shepard coming on line we do expect that will put downward pressure on prices. Forwards are currently trading at $48 and we wouldn't be surprised to see some downward pressure from there. I think one of the things, though, that it is always important to keep in mind in the Alberta market, is there are a number of very old generating units on the system and as those facilities get older, you can see hiccups and forced outages of lengthy time periods. So, in terms of some significant upside in 2015, I think we'd have to see an availability of that.

ROBERT KWAN: I guess, as you roll forward here then, for G4 and G5 you've got an expected strengthening at the end of the decade at $75/MWh. How are you factoring or what do you think the transmission charge is going to be as you roll forward? And how that eats into the power price?

BRYAN DENEVE: In terms of how it eats into the power price?

ROBERT KWAN: Well, I guess there's a risk or expectation that transmission charges will rise pretty significantly as we roll forward here.

BRYAN DENEVE: So, certainly there is going to be an increase in transmission costs. That's going to flow through; the majority of the transmission costs in Alberta flow through to end users to customers. Line loss is an exception to that. That is going to drive some entities to build on-site, as we move forward. And, certainly, we're seeing some of that—and we're involved in that, from the origination side and working with some of those customers. That being said, the degree of on-site generation, we don't expect will be anywhere near, sort of, the magnitude of—in terms of what we're going to see with coal-fired retirements. So we don't see that as being a factor or pool prices towards the end of this decade.

ROBERT KWAN: And, Bryan, that's factored into the $75 expected price, all of that activity?

BRYAN DENEVE: Yes, yes. Absolutely.

ROBERT KWAN: Ok. If I can just ask one more, then I'll be done. If you look at your FFO guidance, you've got an 8% increase year-over-year. You're holding dividend, total dividends as a payout of FFO at 42%. I don't think, unless you're forecasting for preferred share issuance, is that fair then to say that you're basically telegraphing an 8% dividend increase in 2015?

STUART LEE: Yes, I think what we've tried to comment on, Robert, is the fact that we're looking for consistency in that growth and I think that the comment that we've provided is, again, subject to Board approval at that time and it will be based on the outlook for the business and market conditions but we are looking to provide that level of consistency.

ROBERT KWAN: Thanks Stuart.

BEN PHAM: Ben Pham, BMO Capital Markets. I just wanted to go back to slide 37 and Glen's question on the low growth scenario. Just wondering what's your quantification of load growth in that slide there? Is 2% low growth from your perspective?

BRYAN DENEVE: So, just trying to—so is this the slide here you're referring to?

BEN PHAM: Yes. I guess the base case that marked 3.5% type of context?

BRYAN DENEVE: Right. Yes, I think the load growth in the low case is probably somewhere to 1 to 1.5% per year. But again, what you're seeing is just quite a dramatic decline in reserve margin because of those expected retirements on the supply side.

BEN PHAM: And, Bryan, you had another slide where you seemed to be bullish on renewable energy in Alberta and particularly on solar and I'm seeing more wind projects being delayed more than moving quicker. Is that—can you talk a bit about that and is that renewable energy baked into this reserve margin expectation going forward?

BRYAN DENEVE: There would be some baked into the reserve margin expectations. In terms of the renewable side, which we think there's an opportunity in Alberta that's probably going to shift more towards solar, for a number of reasons. But, again, in terms of the magnitude relative to the load growth we're seeing we don't think it will be a big factor, in terms of the supply/demand balance. But we do believe it's an opportunity that we'll be pursuing and looking very closely at. And particularly how it links to some retail customers' expectations around renewable facilities.

BEN PHAM: And, maybe, lastly on the Genesee 4 and 5. You are budgeting for 11% returns. Can you provide us some CAPEX numbers around that?

BRYAN DENEVE: We would expect, I think, our share of the facility, Genesee 4 and 5, will be somewhere in the region of $870 million.

RANDY MAH: There is a question at the front here.

MATTHEW AKMAN: Hi, good morning. Sorry…Matthew Akman, Scotia Bank. Sorry, I missed part of this but I had a question about G4 and 5 and the timing of in-service. My question is just– why wouldn't you guys just say it's delayed to 2020, given that there's potentially some downside for you in bringing it on early? Not a lot of downside in bringing it on a couple of years late because all of your other assets benefit, especially because you're going to be more open on your overall portfolio. So it just feels like, especially given that we're in a depressed market and oil prices have gone down, that risk-reward it's better to just delay it. But, would be interested in your thoughts on that.

BRYAN DENEVE: So, certainly we want to monitor that closely and not get too far down the path that we can't delay if that is what the market is telling us. So, we don't need to make that decision yet but, as Brian mentioned, the contractual arrangements we're going to have on the power island side and the EPC side is going to allow us to shift the timing out two years with no penalty, in terms of doing that. And we have time yet to see how things develop in the Alberta market before we make that decision.

MATTHEW AKMAN: So, just to clarify – I might have missed this. But is there a lot of capital that you guys are spending in, you know, say the first year of construction? You're going to be starting construction this year; you're going to be tying up a lot of capital in this plant?

BRYAN DENEVE: No, not in the early years. As Darcy mentioned, we will be doing some early work on—on site to get ready. Certainly, there's some very long-lead time items, which is just a minimal, minimal capital spend on that. So the bulk of the capital spend isn't until we get into the 2016 and onward time period.

MATTHEW AKMAN: Sorry, to, sort of, continue on this, but, isn't there a risk that, you're signaling to the forward market at some point this is coming on? So, aren't you, sort of, de facto risking depressing the forward market versus just saying it's later and so then the forward market's going to lift, right?

BRYAN DENEVE: I think we can't assume that the need is going to be 2020. We see a number of moving parts in the market that could create a need for this facility by 2018. And, certainly, some of those factors that will drive a much higher need, or earlier need – was us being ready to have the plant online then, we'll see much higher returns than what I had shown there, of 11%.

MATTHEW AKMAN: Ok, thank you.

RANDY MAH: Any other questions?

[PAUSE]

RANDY MAH: Ok, I'll turn it over to Brian for closing comments.

BRIAN VAASJO: Thank you, Randy. And just really want to say, for those who aren't here with us today and those that are here in the room, thank you very, very much for your interest in Capital Power, your interest in continually following us and, most importantly, investing in us. And, as you know, we have a very active investor relations program and certainly go through Canada a couple of times a year and into the US, as well. And at any point in time that you'd like to speak to us and go into more detail on any of these factors, where the organization is going, please don't hesitate to contact Randy. And, again, very pleased to talk to you about Capital Power at any time. Thank you very much.

[APPLAUSE]

[END OF TRANSMISSION]