

**Capital Power
Investor Day Event
December 5, 2013**

RANDY MAH: Good morning everyone. My name is Randy Mah. I'm the Senior Manager of Investor Relations for Capital Power. Welcome to Capital Power's 5th Annual Investor Day event. This event is also being webcast so I'd like to welcome the listeners that are participating on the webcast.

Earlier this morning we issued a press release containing a number of announcements that included a joint venture agreement with ENMAX Corporation to develop, construct, and own, and to operate the Genesee 4 & 5 facilities. The completion of the 105-megawatt Port Dover and Nanticoke wind facility here in Ontario that began commercial operations on November 7th that was on schedule and under budget. And a construction update on the Shepard Energy Centre that's currently being built in Alberta, where the project is ahead of schedule and expected to be completed below Capital Power's budget. You will hear more details on these announcements in the presentations this morning.

Before we begin – next slide, please – before we begin, let me cover off the standard disclaimer regarding forward-looking information. Certain information in today's presentations and the responses to questions contain forward-looking information. The forward-looking information is provided to inform current shareholders and potential investors about managements' current expectations and plans relating to the future. Please 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.

I would now like to introduce Capital Power's management team and the following members that are here today. We have Brian Vaasjo, President and CEO; Bryan DeNeve, Senior Vice President Corporate Development and Commercial Services; Darcy Trufyn, Senior Vice President Operations, Engineering & Construction; and Stuart Lee, Senior Vice President Finance and CFO. The management team also consists of Kate Chisholm, Senior Vice President Legal & External Relations, and Todd Gilchrist, Senior Vice President Human Resources, Health, Safety & Environment.

So, in terms of the agenda, this year we have changed the presentation format of our Investor Day to a question and answer format. The questions that have been developed are what we perceive to be the top twelve top of mind questions from investors, as outlined here on the slide. In the first half of the morning we'll cover the first five questions and, at approximately 10:00, we'll have a 15-minute break and then, after the break, we'll cover the remaining seven questions off.

As we're covering quite a bit of material in the presentations this morning we'll hold the Question and Answer Session until the very end. And then we'll have lunch afterwards. So, to get us started...Brian?

BRIAN VAASJO: Thank you very much, Randy. And good morning and thank you very much for joining us this morning. As Randy mentioned, we've structured this morning's presentation to address the common questions that we believe are what the investors are asking us about on an ongoing basis.

The first question, of course, is: How and, of course, why has Capital Power's strategy evolved over the last little while? When we set out in 2009, Capital Power's strategy and underlying tactics were

consistent with the general expectations for what was going to be happening in the North American power markets. At a high level, our strategy has really not changed but our growth tactics and our expectations have due to some of the fundamental changes that have taken place in the North American merchant markets.

The companion set of position to our strategy and tactics are our mission, vision, and values, which have not changed. Our vision: to be recognized as North America – one of North America's most respected, reliable, and competitive power generators, continues to be the same. And embodied in that vision is our strategy: to be only in power generation and to have a North American footprint.

In 2009 the platform for our strategy was operational excellence. Good assets, good maintenance practices, and commodity management that optimized returns and leveled and smoothed those returns. Critical to our strategy is maintaining an investment-grade credit rating and an appropriate level of contracted cash flows in an environment of moderate risk, which supports access to capital and, of course, a growing dividend.

We also set a disciplined approach to growth to make sure that investments created long-term shareholder value. Disciplines around financial, fuel type, investment size, and geographic characteristics were set. We recognized that as market realities changed, some of our tactics might also need to change.

In 2009 North America was expected to move to a robust level of growth relatively quickly. Prior to, and during 2009, the public environmental momentum to close power plants in a relatively near-term was expected to continue. Although specific mechanics

at the time were uncertain, significant retirements were absolutely expected.

It was also expected that relatively stable, regulatory political policies and practices relating to power generation would continue. In fact, what has happened in the US has been a very weak economic recovery. The momentum to close power plants has weakened dramatically and the regulatory political environment has become both unstable and less favourable to independent power producers. This regulatory political uncertainty and what is evolving are fundamental changes to these markets. These changes adversely impact merchant assets and opportunities but much less so on contracted assets and opportunities. In fact, in some jurisdictions it's become more positive to invest in contracted facilities than it has before.

What has changed for the positive is the Alberta market. The Alberta market has been very strong and so is its outlook. The Canadian Federal Capital Stock Turnover Carbon Emission Regulations for coal plants gave certainty to the maximum dates that coal plants could operate to. This provides the market with significant investment opportunities and secures a very long economic future for Capital Power's coal plants. And we enjoy in Alberta an even more stable regulatory political environment situation than in 2009. The uncertainty relating to environmental regulations on emissions is all but cleared up, following very progressive Alberta environmental regulations.

And we have modified our growth strategy and tactics with these fundamental changes in outlook. In 2009 we were targeting merchant investments in California, much of the US East Coast and, of course, Alberta. Anticipating lots of opportunities, we were focused on the targeted merchant markets as

well as Ontario, BC, and the Desert Southwest, for contracted growth. By 2011 it was apparent that power industries' expectations were not being met. We recognized merchant investments in California did not have an appropriate risk reward balance for us. We also realized we had to broaden our footprint for contracted opportunities to maintain a strong base of contracted cash flow so we added the Pacific Northwest and Saskatchewan.

Through 2012 and 2013 we recognized that Alberta was a very good market, with even greater opportunities for Capital Power. The risk/reward balance in Alberta was much more favourable. At the same time, we came to the realization that none of the merchant markets outside of Alberta had an appropriate risk/reward profile for us. Our merchant focus is now solely in Alberta and that won't change. On the contracted side, we are comfortable pursuing opportunities where they arise in North America.

So with this backdrop, how has Capital Power evolved? We continue to demonstrate operational excellence with great availability and an excellent commodity management track record. Our fleet has changed dramatically; we have less than half the assets to manage, we have reduced the number of fuel types and the average age of our facilities has been effectively reduced. We are much more tightly focused.

Over the last two years, we've significantly reduced our costs and our risk. As Stuart will comment on, we have recently had our investment-grade credit rating confirmed. Our contracted cash flow base is growing significantly. Stuart will describe later that our contracted cash flow is expected to increase by over 60% between 2012 and 2015.

This slide highlights the changes to our assets over the past four years. A significant amount of change

that has moved us to a fleet of excellent assets in great markets – assets that represent a much higher average investment per facility with more than double the megawatts per facility and fewer fuel types. We have significantly high-graded our facilities and added excellent assets to that base. Today, we have the best fleet of assets in Alberta and with the Shepard facility it will make it even better.

On the contracted side, we have completed the Port Dover & Nanticoke Wind farm and we are about to start construction on the K2 Wind project here in Ontario. We are pursuing Genesee 4 & 5 and certainly today's announcement, relating to our partnership with ENMAX, moves that even closer to reality. As Bryan DeNeve will describe later, we're working hard to keep our pipeline full of contracted opportunities.

To directly answer the question, our major strategies have really not changed but our growth tactics have evolved in response to fundamental changes in the merchant power markets.

I'll now turn it over to Bryan DeNeve.

BRYAN DENEVE: Thanks, Brian. So, I'm going to be responding first to the question of: Why is Alberta's power market considered to be one of the most attractive in North America? So, just wanted to start out with a brief overview of the Alberta market. So, the Alberta market was fully deregulated on January 1st, 2001 and currently has 14,000 megawatts of installed capacity.

Alberta is one of two deregulated energy-only markets in North America. In other words, Alberta doesn't have a capacity market and it has a single clearing price that's done in real time on a post basis, of the hour. With no capacity market,

generators recover their costs through revenues earned from sales of electricity into the wholesale market, as well as sales of ancillary services to the Alberta electric system operator.

Because Alberta has a single clearing price, a robust wholesale market has developed, where generators are able to sell their output on a forward basis to manage their exposure. This is significantly different than the deregulated markets in the US where there's a capacity market – you actually have three prices. You have a day-ahead price, a balancing price, as well as a capacity payment price and part of our experience that it's a lot more difficult to manage commodity exposure hedging against three prices versus one.

So, what I would like to cover in more detail is the desirable characteristics of the Alberta market. And we really believe that it falls down – distills down to five key characteristics. The first is adequate price signals. The market is producing price signals that provide adequate return and recover the cost of new generation. A stable market design. As Brian mentioned, the stable environmental policy. A significant supply retirements and a lot more certainty around the timing of those retirements. And strong load growth.

So, in terms of price signals this graph illustrates the actual annual average pool price in the Alberta markets since deregulation. So you can see on the graph its range from a low of \$44 in 2002 to a high of \$90/MWh in 2008. And, for 2013, we're projecting a final settled price of \$81/MWh. If you average these prices over that period of time, it's \$66/MWh. And at current gas price levels the cost of new generation, or new builds, would be \$65 to \$70/MWh for combined cycle unit. So, that gives us comfort that historically, for the past thirteen years, the market

has provided price signals that have been adequate to fully cover the cost of new generation.

So when we look forward...or, sorry, let me back. Not looking forward yet. The other element is the stable market design has signaled addition of six gigawatts of new generation. So, on this graph, this shows on the bars the amount of capacity that has been brought online in the Alberta market over the first twelve years. 1,000—over 1,000 megawatts in 2001, and then we look at 2012 it's recent as 600 megawatts. Over those twelve years it's a total of 6,000 megawatts that's been brought on line, which is a 75% increase in installed capacity.

The other key point is the reserve margin, which is depicted by the line. You can see it is bounced between 15% and 25%. So, that reserve margin, that's consistent with what you would see in a reliable electricity market – or a regulated market – that you'd strive for reliability margin in that region. So we've seen supply being brought on in a timely manner in Alberta and a lot as a result of the price signals I spoke to just a minute ago.

So, in terms of the environmental policy, just to add a bit more detail to Brian's comments on stability of environmental policy, there's legislation in place in both the Federal and Provincial level that is creating this certainty. So, starting with the GHG emissions, we have the Capital Stock Turnover Regulations, which have been enacted by the Federal government. So that defines how long the existing coal plants can operate until they have to put in carbon capture technology – and that's fifty years.

But, on top of that, in Alberta we have the Specified Gas Emitters Regulation, which provides targets for intensity reductions and a price per tonne that payments need to be made for compliance if those 12% reductions aren't met. We expect that the

Specified Gas Emitters Regulation will be updated in 2015 and we expect we'll see the intensity target increase to 20% and the price per compliance increase to \$25.00 per tonne. However, Capital Power's well situated to actually benefit from that in the near to medium-term.

In terms of other emissions such as sulfur dioxide, NOx, mercury and particulate matter, those are covered under the Clean Air Strategic Alliance Regulations, which were enacted in Alberta in 2003. These regulations specify the time period in which generators will need to comply with the best available technology in meeting these emissions requirements and, currently, those target dates are 45 years, or the end of the PPA periods (Power Purchase Arrangement) in Alberta. And as I'll talk to you in the next slide, with—we believe that will have a dramatic effect on the actual timing of retirements of coal-fired units in the province.

So, here we have the solid line depicts the pace of retirements in accordance with the Capital Stock Turnover program. So this is where units, once they reach the age of fifty years, will have to put in carbon capture technology in order to physically get down to emission intensity equivalent to natural gas combined cycle. Under this you would see a pace where Sundance 1 & 2, Battle River 3, and H.R. Milner, would be retiring in the 2019/2020 period and then, towards the 2026 to 2029, you would see additional megawatts with Sundance 3 through 6, Battle River 4 & 5, and Keephills 1 & 2 retiring.

However, the dotted line represents a much early phasing of retirements. We believe this is our expectation of retirements in the Alberta market, which is largely driven by the CASA regulations. When – in terms of SO₂ reduction, for subcritical coal plants in the province, to meet the CASA

requirements will require significant capital investment in desulphurization equipment and, given the runway under the Capital Stock Turnover, it would be very difficult to justify those investments. Although there is a period that those requirements can be met through emission credits, those are very limited in Alberta. So as a result, when we apply that to the coal fleet in Alberta, we actually see a situation where almost 3,000 megawatts will be retiring in the 2020 period.

The retirement of the coal units in this pace, and the certainty around it is very important to investors in new generation such as Capital Power. When we look at the net supply requirements in the province due to demand growth and these retirements, we feel very comfortable that there will be a significant need around the 2020 period, which reduces the risk and on the timing of building new generation in the Alberta market.

The other element at play here is that, with the retirement of these assets, soon after the end of the power purchase arrangements you're going to see a lot of customers looking to hedge forward, or purchase on a forward basis, to meet their electricity requirements. So we see a growing need out in the market from customers that are looking to firm up their prices in this period and we expect that these prices will be in the range of \$75.00 to \$80.00/MWh, which is the cost of new generation at that time in the province.

So the other strong element in the Alberta market is the demand growth. And when we compare – when we look forward 2012 to 2020, we see a demand growth that's, on a cumulative basis, over 22%. And this is almost double the average demand growth over the same period that's projected for the balance of North America. What's interesting is we've just

recently hit a new peak in Alberta. So, 2 days ago we reached 11,100 megawatts peak demands in the province. This is a 9% increase over the last 2 years. So, when we look back in 2011, our peak was 10,200 megawatts and so it's 900 megawatts of growth of peak demand in two years, or 450 megawatts per year. That's equivalent to the size of the Genesee 3 or Keephills 3 generating units. This growth has significantly exceeded original expectations in that period of 3% per year.

So when you bring these elements together, both the supply retirements and the strong load growth, which we've done on this graph here – you can see that the need for new generation becomes very pronounced in the 2018 to 2020 period where we see the demand outstripping the installed capacity on the system. And, again, the bottom bars, which represent the coal-fired capacity, illustrates that the decline of those units, which will predominantly be met by...we expect...by natural gas-fired generation.

So, from a price perspective, when we look forward into 2014/2015 we're seeing forward prices in the, right now, currently, \$50 to \$55/MWh range. And that's largely a result of the return of the Sundance 1 & 2 units as well as the completion of the Shepard Generation facility. However, that's not unexpected. In the Alberta market, as we go through business cycles and new generation is added we expect to go through these low price periods followed by periods of price recovery. We've seen that over the first thirteen years in the market and expect that will continue as we look forward.

So, we look in the 2018 to 2020 period – as I mentioned the cost of a new plant in the province will be in the range of \$75 to \$80/MWh, and consistent with history we expect that electricity prices will rise to that level. And here we've also included the

sparks spread, which related to that. So it will be in the \$40 to \$50/MWh, which, again, is consistent with the cost of building a new combined cycle plant.

So, I think, just to summarize. When you look at the Alberta market and Capital Power's decision to renew our focus on that market, a big driver of it is the stable policy. And this has been confirmed by three independent studies. There was one done early on in deregulation by Tabor and Caramanis in 2003 but, more recently, the Brattle Group in 2011—in 2013.

And the stable policy design is a result of the strong commitment by the regulators in the province, as well as the Government of Alberta. And, it also is a result of just tweaks being done around the rules of the system but there hasn't been large subsidies for out of market generation that can have dramatic impact on the robustness of the price signals, like we've seen in some of the deregulated markets in the US.

So I'd like to turn now to the—the next question, which is: Why is Capital Power the preferred way to play the Alberta power market? So, what we've done here is, well walk through some of the salient characteristics that we believe positions us well in the Alberta market. But, as well, as—as you know we're also one of the most levered companies towards the Alberta market and the potential upside that we're going to see.

So the advantages, which I'll go through in a bit more detail shortly, would include: extensive construction expertise in the Alberta market, our ability to create incremental value from active commodity portfolio management, as well as create stability and earnings. A fleet of diversified assets in the province. A strong emissions exposure management team. A growing origination function,

and as Brian mentioned – a very young generation fleet relative to our peers.

So in terms of our project development and construction experience in Alberta, this graph depicts what we have accomplished historically. So, early on in the deregulation we started the construction of the Genesee 3 supercritical coal-fired facility, which was an \$800 million dollar capital cost project, and brought on close to 500 megawatts of supply. And the bars represent the cumulative supply that we've developed and built and also includes our working in conjunction with ENMAX on the Shepard facility.

So, through 2015 we'll be involved in developing and constructing over 2,200 megawatts of generation capacity in the Alberta market. And that's been across a wide range of fuel and technology types. So, Genesee 3 and Keephills 3 were supercritical coal-fired units. Clover Bar, a peaking aero derivative unit north—Northeast of Edmonton. The Halkirk Wind project and now the Shepard project where we're working in conjunction with ENMAX in the development of that. ENMAX is the lead on construction but we do have individuals that are part of that construction management team. The experience gained on Shepard will be very valuable for our—ourselves and ENMAX as we look forward to developing and completing the Genesee 4 & 5 project.

So, going to the second characteristic, is the commodity portfolio management. And you've seen this graph before; we've extended it for the 2013 experience. But when we look at, since the formation of Capital Power in the Alberta electricity market, for our base load generating facilities, we've captured 13% higher than the average pool price over the last four years. So when you translate that into an annual

revenue figure, it's equivalent to \$60 million dollars per year.

The other important aspect, though, of the commodity portfolio management – in addition to capturing higher prices in the Alberta market – is the stability that it provides. So, the light blue line shows the captured price and you can see it's much flatter than what the average settled price on a quarterly basis has been in the Alberta market. And if you pick out a—a couple of quarters and dig into them more deeply – if you looked at Q3 2010, our normalized earnings per share, which were \$0.55 in Q3 2010. If we had a passive strategy and just settled at the pool price our earnings per share would have been \$0.29, a reduction of 47%. So that's a magnitude of stability we get from the active portfolio management. We saw a similar situation in Q2 2012 where we had normalized earnings per share of \$0.07 but on a passive strategy it actually would have been a loss of \$0.14. So we view the—our commodity group in Alberta is—is absolutely critical to providing both value, additional value to the portfolio, as well as stability.

So, the next item I want to speak to is the generation fleet in Alberta and the advantages that it provides. So, just to refresh, our fleet in Alberta consists of the Genesee 1 & 2 subcritical coal units, which are under a power purchase arrangement to the Balancing Pool to 2020 at which point they revert back to us and will become merchant facilities. Those units have had very strong availability: 94% in 2012, 97% in 2011. The Joffre co-gen facility is a joint venture we have with Nova and Atco. That's a 475-megawatt cogeneration facility. There's about 100 megawatts of it is contracted base load to serve the needs at the Nova facility. The balance is sold on a merchant basis into the Alberta market and it does

contribute to our presence in the mid-market part of the supply curve.

We have the Keephills 3 and Genesee 3 supercritical coal units, which we've – as I mentioned – we've built in and led the construction on in Alberta. We operate the Genesee 3 facility; TransAlta operates the Keephills 3. These units, their GHG emissions are 20% less than the subcritical coal facilities and, actually, are among the few supercritical coal-fired plants in North America.

The Clover Bar Energy Centre, which is 240-megawatts of aero derivative peaking capacity, located just northeast of Edmonton, incorporates both the LM6000 technology but also the LMS100 technology, which is the most efficient peaking technology available in the market.

Moving on the Halkirk Wind, which is just recently completed – 100 megawatts. Halkirk's unique in the sense that 40 – 45% of its revenues are actually contracted out, selling recs into the California market. And, finally, the Shepard Energy Centre. Once it's completed in early 2015 will provide us with ownership of 400 megawatts of mid-merit, very efficient combined cycled capacity in the Alberta market.

So, when you look at the diversity of the supply, why is that critical in the Alberta market? Well, when if you break it down this bar here shows the percentage of the supply in Alberta and part of the supply curve that it fits in. So you look at the coal-fired, which is the base load generation in the province, and part of the co-gen, in addition to wind – which is really a price taker – you can see there that we, our ownership as a percentage in Alberta ranges from 20% on the coal side, 11% on the wind. But when you get to the mid-merit and peaking part of the supply curve, much less generation – we have

a much larger presence in that part of the supply curve, which is very important in terms of being able to manage our portfolio exposure and also in terms of units that are participating in the setting of price in the Alberta market.

The Clover Bar unit, in particular, is very important in terms of providing real time optionality in the Alberta market. So we find, in the last few years, 50% of the average pool price is actually formed in less than 10% of the hours, through price spikes of \$300/MWh or greater. In order to capture those price spikes in a very cost effective manner, peaking units fit very well. So we're able to ramp those units up to full load in under ten minutes, which allows us to capture those spikes. But then able to shut the units down in those off-peak periods where we see very low prices and avoid running at a loss. So that flexibility is absolutely critical. The other thing the Clover Bar units has done is they've provided a very valuable insurance policy for us on our base load units. So, we're able to cover an outage – Genesee 3 or Keephills 3 or one of the Sundance "C" PPAs units that we're the buyers of – we can cover the outages at one of those fully at one of our three peaking units at the Clover Bar plants.

So, I'd like to move on to managing environmental commodity exposure. So Capital Power's had a team in place since the start of deregulation that's been involved in sourcing CO₂ offset credits, which has been critical, of course, given our exposure with coal units in the province as well as natural gas-fired units. And we've been very active in the markets over the last fourteen years and have invested over \$100 million in sourcing low-cost GHG offsets and allowances. And we don't do this just in the Alberta market; we do it in California, we're involved in the US Northeast in procuring recs and we've

established ourselves as a significant player in the market.

And if I move to the next slide here you can see the value that this has produced for us as a company. So the top line, that shows the annual cost of complying with the Specified Gas Emitters Regulation in Alberta for our fleet of generating units. So, effectively, in 2015 we'll be seeing it'll cost us \$25 million to source the offsets that we need to comply with the Specified Gas Emitters Regulation. However, the portfolio we've acquired, when we look at the average cost of our offsets, which we'll be using for that compliance it's under...for example, in 2015 it's under \$15 million. So we're realizing the savings of \$12 to \$15 million dollars per year as a result of the procurement we've done on the GHG side.

The other thing I would note is that we do see the CO₂ offset cost does get reflected to some extent in the Alberta pool price. So being that it is a variable cost, we do see generators bid that in. So about half of this cost that you see here – compliance – does get reflected in the Alberta pool price and we've been able to mitigate the other half through prudent management in sourcing of CO₂ credits.

Another key element that Capital Power's developing is our origination function. So one of the things that we've seen happen in the Alberta market is reduction liquidity on the wholesale side. And that reduction is largely driven by the fact that we've seen a larger — a lot of the large banking institutions actually step back from wholesale commodity trading across North America. So, as a substitute for that, we recognized and are acting on the need to ramp up the origination side and ability to contract with end use customers. So this is an area we were involved in quite heavily at the front end of

deregulation and we're in the process now of actively bidding on our piece and being able to sell to end use customers, both in the large industrial segment but also the small, medium commercial segments. As we look forward, from the origination perspective, we would expect that about half our hedging of our portfolio in Alberta will actually come from retail contracts with end users.

So, the last element I want to speak to is the average age of our generation fleet in Alberta. And this is a very dramatic distinction when you look at the average age of Capital Power's coal-fired fleet, being 15 years in the province, compared to TransAlta and ATCO, which are 30 and 32 years, respectively. So, that is an advantage on a number of fronts. One is higher availability, less forced outages, less maintenance costs, but also the ability that these assets have a lot of runway left in their lives and being able to create value as we look past. In particular, once the PPA expires on Genesee 1 & 2 in 2020.

Ok, so I'll now turn it over to Darcy Trufyn.

DARCY TRUFYN: Good morning. So, what is Capital Power doing to drive long-term sustained operational excellence? For those that were here last year you may—will recall that I spoke about our plans to improve our operations' cost effectiveness and performance. This morning I will provide you an update.

Much has happened during the course of 2013. Capital Power and, previously EPCOR, have always had a reputation for strong operational performance, which is validated by our high availability. We are good at what we do and what we are now trying to do is get better. Our efforts on cost improvement are not at the expense of availability. In fact, just the opposite. We intend to improve our availability over

the next few years through our reliability program in parallel with our focus on cost improvements. Tools and processes like our computer-based maintenance program, root cause analysis, and management of change, have all been strengthened significantly this past year and we have already seen some of the benefits. Lastly, two facilities that have undergone major improvement over the past year are our two solid fuel facilities in North Carolina. And I will speak to those improvements later in my presentation.

Since last year we have achieved the 12% reduction on our total O&M spent from 2012 actual versus 2014 budget. All costs I discuss today are normalized to reflect our current fleet. That includes PD&N but excludes the New England assets.

Savings have been obtained from a combination of items including: reduced staffing and supply chain initiatives. We are just spending smarter. None of the cost improvements have negatively impacted our high maintenance standards nor our availability, either short-term or long-term. And spending smarter is not just about reducing costs. For example, in our coal mining operations we have spent funds to add computerized tools to our two drag lines. Drag lines are the heart of the mining operation and we believe these tools will help the operators become more productive, which, ultimately, means more—or, lower costs per tonne of coal as we go forward.

From a sustaining capital perspective, a 54% reduction in our spend. We have tightened our requirements by eliminating 'nice to have' projects, and focused our spend on projects that enhanced safety and improve our plant performance. We're also much more challenging on requests for capital. For example, we had three cooling towers of similar size that had some non-mechanical issues. Reviews

were done on—in the past using outside consultants and recommendations were made to replace all three cooling towers. The cost of replacement is about \$4.8 million and the work was planned for the 2014 sustaining capital budget. We did understand that there were certain things wrong with the existing cooling towers but none of these units – but these units were actually working quite well, mechanically. So we questioned the need for total replacement and, actually, brought in a contractor, an engineer, who actually specialized in this type of refurbishment and we worked with them. They did a review; we worked through a plan and through 2013 we, actually, repaired the three cooling towers at a total cost of about \$450,000 during three planned outage periods. So that's less than 1/10th the cost of the replacement. So that's just the type of savings we've been trying to achieve in sustaining capital.

Not all of our projects add to plant performance or to safety. Some are required for regulatory purposes but we still need to be cost prudent. We have one on the go right now that was originally planned for \$2 million dollars spend; currently we value engineered that project down to about \$600,000.

This slide shows the cumulative reduction of 20% in O&M and capital spend at our facilities. This excludes planned outage spend. Many of the changes were implemented in 2013, during the course of the year, so the number shown for 2013 are forecast actuals. As a result, 2014 does not show as steep an improvement over 2013 but what this really means is that for 2014 we have a high degree of certainty of achieving our budget as we are going into the year with most of the changes already implemented.

On fleet performance, the table at the bottom of the slide shows a couple of key performance metrics.

One is on safety. It's a statistic called TRIF, which stands for Total Recordable Injury Frequency and is based on a calculation of man-hours, recordable incidents divided by 200,000 man-hours. The numbers on TRIF are like a golf score; the lower the better. What the numbers don't reveal is that in 2011 Capital Power made a decision that we are responsible for the safety of all people who work on our plants and so, in 2011, we added our major outage contractors to our own statistics. And in 2012 we added all other contractors, including all the 'mom and pop' shops that work at our plants. As you can imagine, this brings into play several hundred contractors with a high variability of performance and skill. The fact that these hours and risks are now included in our numbers and that the TRIF has continued to improve, it's something that we are very proud of. And more work is planned in 2014 to improve our safety of all people within the Capital Power footprint.

In 2014, our availability target is 95% and includes two planned major outages at our Genesee facilities. So, as you can see, we've set the bar high on availability. Each of our plants has a reliability action plan and each plant is working on their actions. What reliability is ultimately intended to do is to move our outages from 'unplanned forced' to either 'planned' or 'maintenance' type such that our maintenance spend is actually proactive not reactive, which we believe will help lower our total spend as unplanned, forced outages are very expensive – both from a lost revenue perspective and also from a cost perspective. Because once you're down you will spend money and—and money really doesn't become an object to get the plant back running. So we're just trying to get out of those types of reactive spends.

As I previously noted, this year we beefed up our root cause analysis and management of change processes. On root cause analysis, RCA, we have critiqued in detail this past year approximately 35 RCAs, using the Senior Management team, that includes myself – to ensure that all root causes for each of those RCAs were identified and actioned properly. These 35 RCAs were then reviewed with all of our plant managers. The significance of this is that each of these 35 RCAs had key learnings that were applicable to the other plants and by implementing this methodical approach we believe we'll avoid re-occurrences of similar nature at our other facilities. As these types of improvement processes mature in the months and years to come we expect fewer incidences and higher availability, which all adds up to improved operations' bottom line.

I indicated last year that we had benchmarked each of our facilities using a couple of firms, one of which is Solomon. I wanted to briefly discuss our Genesee facilities. The numbers I'm referring to here are actually unplanned commercial availability and this just takes out the noise with—with planned outages. Genesee units 1 & 2, which are both over 20 years of age, continue to perform at a level very close to top quartile, as rated by Solomon. Genesee 3 has had a couple of technical issues related to design engineering or manufacturing conditions so availability hasn't been quite as good but in spite of these uncontrollable issues we are still operating at a level that puts us on G3 near the second quartile. I will also note that one of the advantages that we have under our JV with TransAlta with G3 and K3 is that with the two supercritical identical units, G3 has become the pioneer on O&M and learnings on G3 are transferred to K3 – which has helped K3 avoid some of the technical problems incurred at G3. And,

as a result, K3 has achieved excellent availability to date.

We had begun working on a reliability program for our Genesee boilers, that's in all three units. And in preparation for that, earlier this year we reviewed the history of all boiler tube leaks since COD for all three units. So we went back in time and just looked at every failure. An important observation is that we did not find any sustained deterioration trends. Leaks have occurred randomly, basically, since day 1. There has been no deterioration from aging. For 2014 we have budgeted unplanned availability for all three units at G3—or, at Genesee, that are in the first quartile. The availability for each three in the first quartile for all three units. And we believe that through the reliability program, our expectations are that all three units will move up into the first quartile of Solomon.

Much has happened at our Southport and Roxboro facilities through the course of 2013. These two plants had undergone conversions about three years ago, from expensive coal to a tri-fuels blend of coal, wood, and TDF – which is tire-derived fuel. Since the tri-fuel conversion, the plants have had issues maintaining consistency of feed and output. A major effort through 2013 was undertaken by Capital Power to address these problems and also to optimize the fuel blend. Coal is very expensive in that location versus wood and TDF. So, what we attempted to do through the course of the year is to wean ourselves even further of coal. And, so, we went through a number of tests, environmental tests, to ensure that we could run at a higher level of TDF and wood, and, actually, were able to achieve a 50/50 coal...or TDF and wood blend and actually eliminate the use of coal completely. Unfortunately with that, the TDF market is, actually...the supply/demand of TDF is quite precarious and our

moving up from 40% to 50% actually changes the cost structure quite a bit. So, right now we've throttled it down to around 40% TDF. But we're still hoping to improve that – but it's more of a commercial aspect. Actually, all the major technical issues we've resolved. We've got great consistency now. We've got great through put. And, really, it's now just better sourcing of our wood and TDF and so it's more of a commercial aspect, not a technical aspect. But, overall, we're very pleased with the results this past year.

So, back to the original question. I hope I've provided you with a good overview. With the work already done and—and with the work planned for the future we believe Capital Power is driving long term, sustainable operational excellence. Now I'll pass it over to Stuart.

STUART LEE: Thanks, Darcy. So I'll talk about has our financial strategy changed? So, just talking to our financial strategy I think the first place to start is really talking about the strength of our balance sheet metrics and I think we will see it's very consistent with our strategy of maintaining an investment-grade credit rating.

If you look at our overall debt to capitalization, we've targeted, as we've talked about in the past, 40% to 50%. If you look at our peers – typically in the 50 to 60% range. We've maintained very low leverage in the low to mid-30s. And, as we would expect, as projects like Shepard - \$800 million dollars worth of CAPEX – and others come on line in early 2015 our expectation is that we'll move back into that long-term target range of 40-50% going forward.

Looking at our balance sheet and, in further detail, looking at our credit facilities. With the recent proceeds from the New England sale it's restored our credit facilities in full. \$1.2 billion dollars in credit

facilities; \$1 billion dollars is available. The other \$200 million dollars is used in the form of letters of credit to support our commodity portfolio management business. In addition, we have \$300 million dollars in accordion feature associated with those facilities and the term on those facilities is five years.

Another important feature – if you look at the chart on the bottom – is looking at EPCOR's position at the IPO date. 72% with subsequent sell downs as well as primary offerings. Their position now is 19% and we would expect, over time, that that position will reduce further. And, certainly, I know investors have been worried in the past about overhang and I think we see the light at the end of the tunnel associated with that, with their percentage now down at 19%.

On the debt maturity side, if you look – well spread out maturities. About \$1.5 billion dollars in third party debt. No single year do we have any significant refinancing issues. Important bars in there are the EPCOR back-to-back debt in 2016 and 2018. As most people are probably aware when their interest became lower than 20% they have an ability to call that debt with one year's notice. Quite frankly, we would see that as a positive in the fact that we could reduce the cost associated with that debt as well as extend the term. So, as we look at our profile, certainly think that it's a very well spread out maturities consistent with the long asset lives that we have.

Turning to credit metrics – again, well onside credit metrics, both for DBRS and S&P. Starting with DBRS, above 20% FFO to debt as well as the four times EBITDA to interest - some of the financial metrics used in evaluating the criteria. And, I think one of the important things to note is the fact that

2014, obviously, we have \$800 million dollars of investment in Shepard that is not yet producing cash flow or EBITDA. As you scroll forward to 2015 those number rebound significantly; and as you move forward to 2016 and out, even more strongly. And, so one of the things I think DBRS is very good at is looking at cycles in heavy development spend and they certainly have in evaluating the credit and we're very comfortable and onside at triple B mid with a stable outlook.

For S&P most people will be aware of the fact that they've come up with new credit criteria that they've recently implemented. They reaffirmed our rating at Triple B- with a stable outlook. And, in fact, as we work through the methodology, our credit metrics under the new methodology actually, in our view, improved. They have two components in evaluating the core ratio. One is business risk. The other is financial risk. On the business risk we believe we rank satisfactory under their methodology. And under the financial risk, with our FFO to debt over 20%, we rank as significant. However, if you use some of the secondary measures, such as free cash flow over debt, it actually moves up to intermediate. So, from our perspective, well onside with their overall metrics. And, again, for the new methodology on the financial metrics: generally speaking, a five-year time horizon. Two years back, current year, and two years forward. And on liquidities, as I mentioned before, we have great liquidity coming to 2014/'15.

One of the really interesting questions I got asked last year at the investor meeting. That was on the back of the fact that the day we walked in everybody's Blackberry's were buzzing with the announcement of Loblaw's looking at a restructure and trying to unlock value to that. And one of the questions that got asked by one of the analysts, which I thought was very good, was: would it make

sense for you guys to take some of your contracted portfolio and look at a drop down to try to unlock some of the value? And, somewhat forward-looking in the fact that if you look at what happened in both the US and Canada this past year, is a couple of different IPPs have, in fact, set up yield-co structures where they drop long-term renewable contract assets down from their portfolio. And those have been done quite successfully.

And so, I think we've been asked the question, certainly: would you guys contemplate such a structure? And there is certainly pro's and con's to it as we have looked at it. Pro's have been unlocking value to shareholders and providing a cost competitive capital to pursue new opportunities. However, we'd also say there are some con's to the yield-co structure. One is the complexity it brings to both governance and structure. And, secondly, a recent Moody's report has cited the fact that they do expect eventual pressure on parent company credit ratings associated with some of those structures.

So, interesting enough we do have some pretty good experience with drop down structures. We had Capital Power Income LP that we divested in 2011, and it certainly provides us good context for some of the long-term challenges associated with that. And from our perspectives, as we've looked at that opportunity of a drop-down, we do think that the simplified story that we have coming out provides greater visibility on our contracted cash flow base and, certainly, it's one of the themes that you'll hear us talking about. And I'll be talking about it in the upcoming slides. And I believe that that contracted cash flow should provide a basis for multiple expansions as we move forward.

The other thing I think it's important to note is, we've talked this morning about the fact that we expect to

be a major player in the Alberta marketplace. And in order to finance that business, the merchant business, I think it's important from our perspective to maintain a capital structure that allows us to finance that growth in Alberta, which means we need contracted assets and, in our mind, an investment grade credit rating, in order to construct those projects. And that's why having this balanced portfolio makes sense. Key take away from us – we'll continue to monitor the yield-co structures and how they evolve in the marketplace but we believe that our current structure provides the appropriate long-term value for shareholders.

And speaking of contracted cash flow, I think this slide does a very good job of illustrating what's been achieved by the company in the development projects that we've undertaken over the last several years. If you look at the starting point, back in 2012, about \$225 million dollars in contracted cash flow. And as you scroll forward to 2015, that number moves up to \$375 million dollars – about a 66% increase in long-term contracted cash flow. And what's included in this chart as you move into 2013 is the additional of Quality Wind and the contracted portion of Halkirk. 2014 is the addition of PD&N and in 2015 the contracted portion of Shepard as well as K2.

Looking at our overall CAPEX program, you'll note 2013 has been very active, very heavy capital spend of over \$900 million dollars this year and I'll talk in the next slide about the sources of funding for that. And in 2014 you can see really just a much smaller CAPEX program. The results from the fact that we're finishing up most of the projects with the exception of K2 Wind, which will start significant build out in 2014. The numbers on K2 Wind are reflective of the fact that in the individual years, as effectively, our equity contribution, totaling about \$60 million dollars.

The balance of the \$291 million dollars in our portion of the project is expected to be financed through project-level debt.

Next slide. So, getting to sources and uses of cash, you'll note on FFO we've provided the mid-range of our expectations. So, for 2013, we provide the mid-range of our guidance at \$400 million dollars. We do expect that we'll be at the high end of our range so if you look at the overall net change in cash, which is slightly negative for 2013, expect that number to actually be slightly positive if we come in at the high end of our range.

Other financing sources were the Preferred share offering that we did earlier this year in March, as well as the proceeds from the New England sale of, in Canadian dollars, \$556 million dollars net. And that's funded our development projects, sustaining CAPEX, and dividends to both Common and Preferred shareholders.

For 2014, if you look at our FFO target, that fully funds all of our expected outflows. Funds dividends, sustaining CAPEX, as well as our development projects. So you see that from our perspective, fully funded coming in through 2014 - all of our lines available to us. No requirements to go to use the equity or debt markets in 2014.

And with that...I'll give it back to Randy.

RANDY MAH: So we are ahead of schedule so let's take a 20 minute break – come back at 10:00 and allow you to refresh your coffees.

BREAK

BRYAN DENEVE: Ok. I think we're going to get underway again. The next question, which I'll be speaking to, is what does a growth pipeline look like? So, I'm going to start with our bulls eye here

that we've used the last couple of years. But there's been some updates. So, as you recall, this kind of portrays our approach to ensuring that disciplined growth across markets. And, really, we use a series of screening criteria that take us from geography down to technology and then down to financial criteria that gets us into what we call the 'target zone'. But the other dimensions that are illustrated here is: merchant versus contracted and development versus acquisitions. So, as Stuart mentioned, the contracted/merchant mix is very critical and important in terms of maintaining our investment-grade credit rating but also being able to support our pursuit of merchant facilities and work in tandem. But, also, we've always looked at development and acquisition as both ways forward for growth within the company. However, as you can see we've—I've put in the projects that we've completed since formation of Capital Power. The bulk tend to be on the left hand side, so on the development side, which is just related to the fact that given our construction expertise and experience, also in success on the development side in finding those opportunities to acquire to move forward, and with the stakeholder relations side – that's where we've been very successful to date.

However, on the acquisitions side as Brian mentioned, those are still opportunities out there. We just don't expect, on the contracted side, there will be a lot of opportunities that will meet our target investment thresholds.

So, on the geography side, you saw that we've really narrowed the merchant side down to the Alberta market but, outside of Alberta, we've expanded the contracted footprint to cover all of North America.

On the technology side we're still focused on solar, wind, and natural gas. And natural gas, of course,

being both the combined cycle and peaking configurations. That hasn't changed. We certainly stay in the course and not looking at biomass or hydro or nuclear on a go-forward basis. And, this is the discipline around the technology is born out – not just by the opportunities we're pursuing but also in terms of how we reconfigured our portfolio through divestitures. So, the sale of CPILP assets to Atlantic Power was driven partly by the fact that it was made up of a lot of technologies that didn't fit this criteria. But, also, there's been other divestitures such as in BC, with Miller Creek and Brown Lake, where we sold those hydro assets because it didn't fit with our fuel mix that we're targeting.

Then on the financial side, that part hasn't changed. We're continuing to target our unlevered returns we've had in the past. Certainly on the contracted side, as I mentioned, typically that target is difficult to hit on a clean, long-term contracted asset but we have, of course, been successful on the development side.

So, in terms of, sort of, the distribution here, the CBEC and Keephills are fully merchant assets developed in the Alberta market but those have been balanced out by the K2 Wind—or, will be balanced out by K2 Wind and the recent completion of Port Dover & Nanticoke and Quality Wind project. And then the Halkirk, Shepard, and Genesee 4 & 5 projects are ones that, kind of fit in the middle. So we refer to those as 'hybrid projects', where they are a mix of merchant as well as contracted cash flow. In the case of Shepard, of course, that's in the form of a 20-year tolling arrangement for half of our share of the output from Shepard.

So, just looking at the footprint of the development opportunities, starting with the map here. This is just the location of our existing operating assets and then

if we scroll forward and add on the construction – assets under construction – you can see that, of course, includes the Shepard facility near Calgary and then the K2 Wind project, which I'll speak to further in a moment. So that's the footprint once we get those projects completed. But then when we look at the pipeline, which I show here as triangles, this gives a good illustration of the distribution and the locations where we're pursuing growth opportunities. And a lot of this is pursuing competitive sites, locations that are very cost effective in terms of required infrastructure, electrical interconnection, natural gas interconnection, availability of cooling water where applicable. But, also, those locations where we see either a combination of growth, load growth, or more importantly, retirements of existing assets. As well as a regulatory or market regime that's favourable to IPPs, creating opportunities as we look forward.

So, I'll touch on each of these, through each of the markets. But you can see they're kind of clustered. Continuing to look at the US Southwest. We see in the US Northeast there's going to be areas that will provide contracted opportunities. Ontario. And then, also, look at BC and Saskatchewan.

But, before I go to the contracted opportunities, I'll start with the Alberta outlook. So I won't spend a lot of time on the market opportunities – I think that was covered extensively earlier today. Just reiterate though that the need for supply in the 2018 – 2020 time frame. You know, in our comfort in that is driven largely by the certainty around coal-fired retirements shortly after 2020.

But in terms of the growth coupled with the retirements, there's going to be need there and, from the growth pipeline perspective, we see the completion of Shepard, which I'll speak to a bit more

in a moment, and also Genesee 4 & 5. But in this we expect that there will be opportunities in the Alberta market for Capital Power, potentially for some peaking expansion. That could be either developing a new site or potentially acquiring some peaking capacity. So, certainly, with the focus on merchant being in Alberta, that gives us some room to expand and grow even further beyond Shepard and Genesee, given the current holdings we have in the province.

So the Shepard Energy Centre...that partnership is going very well with ENMAX. And just to refresh on the commercial terms around that growth opportunity is there is a 20-year tolling agreement for 50% of our own capacity with ENMAX. But another important element to keep in mind is that we have an additional 25% of our share contracted for 2015, '16, and '17. And, on top of that, 100 megawatt CFD in 2015. So, as that plant is completed in early 2015, we're fully contracted for our share of the output for all of 2015 and 75% contracted for 2016 and '17 and then, beyond that, of course we'll be 50% contracted. Darcy'll speak a bit more on the construction side but from the commercial side it's, I think, the two companies are working very well together and that has really provided the platform for us to move forward on the Genesee 4 & 5 opportunity.

So Genesee 4 & 5, as announced today, is going to be a 50/50 joint venture with ENMAX. However, in this case we'll be the lead on construction but—but I expect they'll also have individuals participating on our construction teams, similar as the case with Shepard – only in reverse. And we'll be the operator of the facility, which makes sense because we're already operating Genesee 1, 2, and 3 on that site. You can see the rendering here, those—the buildings with the shorter stacks are Genesee 4 & 5.

They'll be located just to the east of the existing Genesee 3 unit. The space is there, very little site preparation needed to commence construction. The other big advantage of expanding on the Genesee site is the electrical interconnection and capacity in the switchyard. Also, from a gas supply side, fairly close proximity from that perspective. From the cooling side of things, the cooling pond has the capacity for these two new units. And, also, we see synergies, of course, from the operational side having those units located there.

In terms of timelines with the joint venture with ENMAX, we're well down the road in terms of negotiating definitive agreements. A lot of them will reflect or be similar to what we've done on Shepard. We expect those will be completed in the Q1 of 2014, next year.

In terms of the configuration of Genesee 4 & 5 it's a little bit different than Shepard, or we expect it will be different. At this time we are looking at two 1x1 configurations. So, really, what that means is a combustion turbine with a steam turbine as one train and we're going to build two of those. As opposed to Shepard, which is a 2x1 configuration. We feel the 1x1 configuration will be competitive with a 2x1. It'll give up a little bit in terms of efficiency on the heat rates side but we feel that offset by the benefit of having the flexibility and the timing of completing the two trains, depending on how things unfold in the Alberta market. But, also, being able to dispatch them completely separate as two units. So, a little bit, there's pro's and con's to both but in this case we feel most likely we'll go with this configuration. We're very close to completing our regulatory application to be submitted by the end of this year for environmental approvals, which we expect to receive towards the end of 2014.

One of the things we're doing with Genesee 4 & 5 is we're being very careful to approach development in a way that maintains optionality. So, we want to be able to be in a position to bring those units on as early as late 2017 or 2018, depending on what we see happen in the Alberta market. So, with some older coal-fired facilities, which, there may—there could be things happen or units that are retired sooner than we expect we'll be in a position to build these units and bring them on sooner if market conditions warrant that. However, because of the coal retirements we see, and the expiry in the PPAs at the end of 2020, that'll be the latest these units will be brought online, is the end of 2020. We don't see that they'd ever—be delayed for any reason beyond that point.

We have started our Open Houses. We had one last week. It went very well. Certainly in the Genesee region we have strong support in the community and you'll—you have a brochure that we included in the materials that gives you additional information on Genesee 4 & 5 that was used at the Open House.

So, I'll turn now just to the Canadian market from the contracted side, in the west. So, in British Columbia, a lot of discussion out there and a lot of activity around the LNG build out, although we expect LNG will use gas-derived technology so we don't see electricity—electrical plants being built for liquification. However, they will still create secondary demand growth in the province, which will, in our view, will create opportunities. So we're kind of looking at that market from two aspects. The first is from a natural gas perspective on the one hand. We—we anticipate a need for peaking capacity to serve the new LNG load or the compression on the pipeline system serving the LNG sites. Also, though, Site C, which is a pretty massive undertaking...and this is the long-term plan for BC. We do believe

there's a possibility that project, for a number of reasons, may not proceed and, as a result, could create quite a window for combined cycle units. And, so, we're in the process of securing what we believe is a very strong site in the south central part of the province to be positioned to serve that need.

The other thing is we do expect continued renewables to be brought on, maybe not quite the volume we saw in the last several years but certainly, I think, to meet the green mandate that the BC government has, we do see additional opportunities for wind. And we have two sites that which are positioned very well. One of them—the lead site is Klo Wind Project, which we have four years of wind data on. And so, certainly, we will be looking to leverage our experience and success on the Quality Wind project in the development of that.

So, moving down the coast, stopping in Washington State. Certainly the Pacific Northwest hasn't been an area that we've been too focused on over the last couple of years, however one of the interesting things is we do own the site next to Frederickson 1. So, it was always contemplated that a second plant would be built next to Frederickson 1...we call it 'Freddy 2', affectionately. So, Freddy 2 has the advantage of being able to utilize some of the common infrastructure with Frederickson 1, which is owned by Atlantic Power. We would see this being a joint venture, again, with Puget Sound – similar to Frederickson 1. In the latest resource plan from Puget Sound is the need for peaking capacity by 2017. So we see this as, certainly, one of those near-term opportunities, which will—we're working hard to develop.

Moving further south into the US Southwest. As you've heard previously we have been working sites down there. In California what we're seeing is a

continued push in increased in the renewable portfolio standard. They are going beyond the 33%. But also, they are starting to look at storage. But until storage does become commercially effective, we believe there's going to be a strong need for peaking natural gas supply in California. So, we do have a peaking site in San Diego we've been working on developing. That's been put on hold for a while. But, for the last year we do see some changes, politically, happening in San Diego that could facilitate us being able to move that forward. The other site we have in the US Southwest, more specifically the Desert Southwest is the Sun Valley site, which is about an hour west of Phoenix. That site is capable of supporting up to 300 megawatts of solar power as well as gas-fired generation. One of the things we're waiting for at the Sun Valley site was the green light from CAISO to move forward with the development of the Devers 2 line to connect it to the Delaney substation. A report was just recently released showing very positive cost benefit analysis around that line. We now feel very confident will be completed in 2019 time frame. And, with that line, it'll give Sun Valley, which is located right next to the Delaney substation, will have access to the Southern California market as well as Arizona power service area and the Salt River project service area. So being able to access most of Southern California and the Arizona markets.

Arizona is an area where, or a region where, again, we see the need for peaking gas supply in order to deal with the intermittency of the big solar/wind build out. And in addition to our Sun Valley site we are looking at locking in a site that's just near Glendale, north of Phoenix, that is also well situated to meet future RFP requirements and may see a need for new supply as early as the 2017/2018 time period.

So, moving from the West over to the East. Ontario – a lot happening. Certainly a long-term plan was just released out the last couple days. What we see there is new nuclear build doesn't look likely, especially given the cost and risk associated with it. But, also, we see some doubt, I think, in replacement strategies. So, in terms of Bruce and Darlington, which are going to be refurbished in the 2016 – 2020 period, what we read is if there's—if that continues to be difficult, especially on the Darlington side in terms of schedule and cost...that may open the opportunity for gas-fired generation sooner than anticipated. We also believe there's going to be need for peaking capacity to address some of the transmission constraints in the province. So, given that, we are working hard on look—sites, a couple of sites in Ontario, being able to secure to be able to be positioned in the Ontario market to meet the need on the peaking side and the medium term combined cycle.

The other thing, of course, in Ontario is it will be continuing with the procurement of wind and solar. I think it's about 300 megawatts in 2014 and 500 megawatts in 2015. That'll be an area we'll be looking at and we, as shown by PD&N and K2, we have a lot of experience developing wind in the province and we'll be looking to potentially participate in those RFPs.

So in terms of K2 Wind, which is a joint venture with Pattern and Samsung. That project continues. It's going along well. So, we received our environmental approval earlier this year. As all wind projects, it's going through an appeal process with Environment Review Tribunal and we expect a decision on that in our favour in early February 2014. We've also received approval from the Ontario Energy Board, granting leave to construct the transmission line and

transmission interconnection construction is already underway.

Pattern, who leads the financing side, is targeting close in March 2014. There is a risk that there will be an appeal of the ERT decision to the Divisional Court. That may delay financial close by up to three months but other than that, that's the only risk we see from a schedule perspective at this point in time.

Just to go back and clarify. On K2, I think Stuart mentioned we look—we anticipate that will be about a total investment from our perspective of close to \$300 million dollars. It's a 270-megawatt wind project, which we own one-third.

So when we go further south into the US, on the East Coast, one of the areas that we've been looking at and involved in, historically, and we believe there will be opportunities on a go forward basis, from a contracted perspective – is in the New York region. So, certainly, on Long Island. That's a market that is what I would call a bi-lateral market, where contracts are utilized to bring on new supply, just given the concentration of ownership. So we bid into an RFP there that they didn't fill the full need that's going to be needed on the island. So that'll be a region that we'll be looking at again in terms of looking at developing a site to compete for the next RFP that comes out in that region.

The other recent development is, in terms of transmission interconnection down through to Manhattan. The Energy Highway initiative is now underway, which is bolstering the transmission interconnection within the Hudson Valley. That's an area where we're looking at brand new green field sites that are close to gas/electrical infrastructure but, also, potentially sites that are partway through development where we can step in and—and bring those along and manage them. We expect, as you

look in the medium term, through the retirement of Generation and the question marks around Indian Point nuclear facility, that there'll be opportunities to build a combined cycle or peaking gas-fired generation in New York.

So, moving on to the renewable side. We have looked at renewables in, on the East Coast to some extent, however there's not a lot of opportunities to build large wind sites and the solar resources isn't as good as it is in California. So, we feel a lot of the RPS standard may be met...or, likely will have to be met through importing electricity from the north or from the west. To that end, we're spending time investigating opportunities in the Midwest, particularly the Kansas area, that are well situated to compete for RFPs to meet – not only renewable portfolio standards in that area but also we expect and anticipate being able to export that renewable energy to the East Coast.

So, that covers the pipeline and I'll turn it over, back, to Darcy for the status of projects under construction.

DARCY TRUFYN: Well, thank you, Bryan. So, what is the status of projects under construction? I think the thunder's been taken away here already but at Investor Day last year I did talk about Capital Power's strong development and in-house construction expertise and capabilities and how this has created a competitive advantage for Capital Power. This year, more success.

We were very pleased to advise earlier today that Port Dover & Nanticoke achieved commercial operations on November 7th, on schedule and significantly under budget. Port Dover is Capital Power's third major wind farm development that is brought into commercial operation over the past year. Each of the three wind farms had their own

unique challenges but the result has been the same on all three. Each were completed on time and significantly under budget.

For PD&N our challenges were all about schedule. It was how to maintain a— a COD in spite of such things as a six months delay due to an appeal of our REA (Renewable Energy Approval). So we did a bunch of different things – I think last year I spoke that we brought in a spare transformer from our Halkirk project and that really helped us maintain our schedule, gave us six months advantage. But we also did a bunch of other things. This picture shows us working at night with the cranes to get better utilization. But, another key thing that we did was how we commissioned the units and we did a lot of work without back feed power. So, kudos to all those involved.

Port Dover also achieved an excellent safety result with a TRIF of 1.19 and that consists of only two medical injuries and, most importantly, no lost time injuries. And while we had three different contractors at each of our three new wind farms, Vestas has been our OEM on all three and I do want to acknowledge here, publically, that Vestas worked very hard and close with our team and played a significant role assisting Capital Power to achieve COD on schedule.

On Shepard, Bryan DeNeve has already discussed the commercial aspects of the development. I'll focus on construction. The Shepard project is being led by ENMAX and Capital Power is providing construction assistance and oversight. Work on Shepard is proceeding very well and there are no major technical or commercial issues. Construction progress on the project is now over 75% complete and, overall, project status is 85% complete. Safety is also excellent on Shepard with a TRIF of 0.93.

From a cost perspective, Capital Power has reduced our forecast to complete by more than \$35 million dollars. And on schedule, the project has moved up to a COD in early 2015.

As this development is a JV with ENMAX, and Bryan's also touched on this but I'll emphasize this again...but real important aspect for Capital Power is our working relationship with our partner. This is the first time ENMAX and Capital Power have been in a JV together and I can say, from a Capital Power perspective we are very pleased with how well the two companies are working together. And I think today's announcement with G4 and G5 is testament to that.

One of the future major benefits that will come out of this project, however, are the joint venture learnings, both on construction today and tomorrow from operations. These learnings will be applied to our next project, G4 and G5, to help ensure that that project is also a success, both from a construction perspective and later on from an operations perspective. So, thank you and now over to Stuart.

STUART LEE: All right, thanks Darcy. So I guess following on Darcy's comments around construction, I guess, the next question to follow is: what are the financial impacts and, particularly, how do folks model some of the new assets that are coming into the portfolio? And I know that a lot of folks are starting to fill out their 2015 views on Capital Power and I think providing some of that guidance is helpful as you develop that.

So, looking at Shepard Energy Centre, I think, as Bryan DeNeve mentioned this morning, the way that contract is structured is it's 75% under long-term tolling arrangement, from 2015 to 2017, and then moves to 50% for the balance of the seventeen year term. So, when we look at our EBITDA

expectations...and, again, 2015 based approximately where forwards are—forwards are at about a \$50/MWh. Our expectations of EBITDA in the \$70 million dollars a year range. As we move out to 2018 and we start to see recovery in Alberta power prices and the contracted portion moves from 75% to 50%, expect to see that EBITDA number move up to about \$100 million dollars per annum.

And then, the bottom chart looks at the mix between contracted versus merchant EBITDA from the facility. And as you all note in 2015, 75% to 80% of the EBITDA is coming from the contracted portion. And as we move out to 2018, expect that that mix is about 60/40 merchant versus contracted. And that is reflective of the fact that we would expect higher returns on the merchant 50% portion, relative to risk.

On K2, we've modeled out the EBITDA guidance. As you'll see it's not a beginning of year start so you see full year performance starting in 2016. But in the range of \$25, moving up to high \$30 million dollars per year of EBITDA in 2016. Important to note that on K2 Wind, it is a partnership arrangement. It will be equity accounted for – we have one-third with Samsung and Pattern. And on an equity basis it's, basically, a one-line pickup in our financial statement, which would be an earnings number and investment number on the balance sheet. So, as you guys model that out, important that you model it on that basis.

And then, just looking at the bottom charts. Is looking at what the expected capture price is under the way the FIT program is structured. In 2015 the pricing is around \$149/MWh and escalates to a small extent with inflation going forward.

Next question is: What is Capital Power's cash flow outlook? Important component of, obviously, of our story is what does cash flow look like over the

upcoming years? And, maybe, talk a little bit about that. The chart that you see on your left hand side is the traditional discussion point that we've had where we've been targeting about a 50% contract versus merchant split. And you'll see, as we move into 2014, in fact we're above that – we're over 55% long-term contracted EBITDA, relative to our merchant, which is down to 45%. And that continues to improve to 2015.

As power prices start to recover in Alberta, we expect the merchant component of EBITDA will pick up and, therefore, gets back to about that 50/50 split around the 2017 time frame. And, one of the things in talking a about a 50/50 split is it's always sensitive to what happens in power prices. And, so, when we look at it internally, and certainly when we discuss it as an Executive team with our Board, the way we actually model it is—is the chart on the right, which looks at how does our contracted cash flow stack up against our fixed commitments? So when we look at G&A, O&M costs for the contracted plants and we look at sustaining CAPEX and we layer on any of our financing costs associated with our debt, how is that contracted cash flow in a position to cover all those fixed commitments? And, as you'll note in 2014, we're over 100% and as we move through the planned period, expect that moves up to 170%. So from a fixed income investor's point of view – very strong coverage, very strong security around contract—long term contracted cash flow to support that. And, not only from an equity holder's point of view, not only do you have that excess available but, also, the merchant assets that contribute to equity holders' returns.

Another way we look at our cash flow is looking at how it—how it splits out and how it gets effectively returned to shareholders in the forms of dividends or reinvested in the business. And you'll see, from this

chart... historically if you look at returns to shareholders in the form of dividends...35% to 40% is being returned in the form of dividends. The middle bar, the orange bar, relates to sustaining CAPEX. And, as Darcy talked to earlier today, what you see is a drive to—to really optimize our sustaining CAPEX and you see a reduction in the overall sustaining CAPEX associated with those efforts.

And then, the final bar is what's being reinvested in the business. And you see consistently 35% to 40% of our cash flow is being reinvested in the business, in projects like Shepard, in the wind projects that we've discussed earlier. And, so, a substantial amount of our cash flow is being reinvested for long-term growth. And, as an equity holder looking for support for the dividend, what we can tell you is – extremely well supported by cash flow. If you look at that growth CAPEX – always in a position to support the dividend. So, extremely well covered. The other thing I'd point out, too, is guidance is on cash taxes. We don't expect to be cash taxable until 2018. In fact, if we are successful in future renewable projects, like we're looking at in both Ontario and British Columbia, certainly expect that we'll be able to push that timeline out.

As folks look at building out their models for both Port Dover and K2, I think important as you guys look at that is to look at the accounting treatment. For Port Dover & Nanticoke, I think you'll be familiar with Capital Lease accounting – that's the way we account for Quality Wind; so, a very similar type of accounting treatment. And as I mentioned previously, for K2 it'll be an equity interest in a partnership so we'll be picking up our one-third, one line pick up in the financial statements. And, as previously commented on, we'll be using project debt financing associated with that.

Interesting article yesterday in The Globe, looking at peer group and commenting around cash flow versus price, or stock price. I'm looking at, effectively, what we refer to AFFO yield, which is adjusted funds from operations (FFO less sustaining CAPEX), and in this type of chart lower is better. Generally indicative of companies that have, where the market believes to have, very low risk and growing cash flow. And you'll see that we end up on the wrong side of this chart, on the right hand side and, in fact, third highest amongst the Canadian peers. The comments we'd make about that – one is, particularly for folks on the right hand side of this, I think, concerns about sustainability of cash flow going forward and whether or not folks are going to have issues with re-contracting. From our perspective, as we've talked about, if you look at our 2014 guidance cash flow expected to be fairly consistent. And then, on top of that, with our sustaining CAPEX coming down, in fact, AFFO is expected to be relatively constant. As you scroll forward to 2015, with Shepard coming online, K2 coming on line – in fact, cash flow improves and 2016 continues to improve, especially in the face of expected recovery in Alberta power prices.

So, while many people in the peer group may be looking at potential cliffs, our view is we're looking at the mountain and climbing up. So, coming at it from exactly the opposite side. So, when we look at our AFFO yield, we would expect, as people appreciate the story, understand that the contracted cash flow is coming online and the recovery in Alberta power prices. In fact, we should be on the other side of that line moving forward, as people better understand the story.

Next slide. So, moving to financial guidance. We are targeting 2014 FFO in the \$360 to \$400 million-dollar range, as previously discussed in a couple of

previous slides. One of the things I think when we came out in the IPO in 2009 – new company, complexity in our structure with CPILP, not a lot of asset-by-asset disclosure. So, we went above and beyond in trying to provide more detailed guidance in our financial disclosure to ensure that folks were effectively modeling this properly. As I think we've matured as a company, certainly our story has gotten simpler and I think our view is the analysts, overall, are doing a pretty good job and an effective job of modeling us. In fact, as we look at 2014 consensus estimates for cash flow and EPS – generally pretty well in line with our own internal forecasts. So, from our perspective...and we sat back and looked at peers and how they are disclosing, we were the only one in our sector that was providing EPS guidance. And, certainly, from our perspective, given the fact that folks are modeling us well, have decided to move forward, really focusing on FFO in our guidance—in our guidance provision.

Next slide. So I'll move to my final slide and my favourite question: What is Capital Power's view on dividends? One of the questions we get asked consistently at this Investor Day, and, again, standard response from us is: we don't have a formal policy around it. We don't have a fixed amount tied back to cash flow or earnings that provide an automatic, I guess, leverage, or an automatic level to move dividends based on movement on either cash flow or earnings. We do, however, obviously follow our cash flow and expect that our dividends would follow cash flow, subject, again, on a quarterly and annual basis to Board approval and review.

So if we look at our cash flow, and looking at contracted operating margin, again, the previous slide that we'd shown as how does that cover our

fixed obligations? And if you add dividends to that fixed obligations category, how does that stack up? And you'll see, as we move into 2015, we're over 100% meeting our fixed obligations plus dividends just from our contracted cash flow, and moving up to over 110% in 2017. And, again, if you look at the Canadian peer group in the high yield category, a lot of them are looking at payout ratios that hit that 100% on their total cash flow. We're in a position where we're looking at just our contracted cash flow in covering all those commitments, from contracted, merchant EBITDA and cash flow on top of that. And so, as we look at the outlook, for us, obviously we think we are extremely well positioned for dividend growth. And not only dividend growth in the near term, but on a consistent basis into the future.

And, so, with that I'll turn it back to Brian.

BRIAN VAASJO: Thank you, Stuart. Every year during our Investor Day we've shared with you what are our corporate priorities for the upcoming year. And, our practice is to lay them out in terms of the operating, growth and financial priorities and in each quarter we speak to those and speak to our progress against those priorities.

So, looking firstly at our operating performance priorities. Our operational targets first start off with availability, which, as we said earlier is 95%. Which is a very high target for our fleet and exceeds, both our target in 2013 but also our performance in 2013, as Darcy had described to you. We are looking for even greater availability, greater performance for our assets in 2014.

Also, as Darcy described the maintenance and capital targets of \$85 million and the plant maintenance and operating expenses of \$165 to \$185 million reflects, certainly, fewer assets but it also reflects improved cost performance. So those

are targets that we'll certainly be monitoring and updating you on, on a quarterly basis as to how we're achieving those targets.

Moving then to the growth priorities for next year. There are three projects that we expect to make very great progress on in 2014. The Shepard project will be completed in early 2015, with our portion of the costs being in the order of \$40 million dollars less than—than what was in our budget. We are continuing to pursue permitting Genesee 4 & 5 with a target of having approvals in hand during the first quarter of 2015. The K2 Wind project will commence construction in 2014 and the project financing will also be in place in 2014.

Turning to our one financial measure that Stuart was just describing to you – that core financial target for 2014 is funds from operations. As you look at 2013 versus 2014, they are relatively the same. And the reasons for that are, firstly: when you look at the power prices, they are essentially the same, as a forward curve going into 2013 and a forward curve going into 2014. The significant difference is that our hedged prices going into 2013 were in the order of mid-\$60 range whereas this year our hedge position price is in the mid-\$50/MW range. So a very significant difference there.

We've also redeployed the capital that was invested in the operating New England plants to support the Shepard project during construction and, therefore, not generating any cash flow. And, I think, as we described at the time, of moving forward with the Shepard project and also with the disposition of the New England plants, that there were going to be some cash flow implications but very short-term and, certainly, the positive implications of moving forward with the Shepard project is now, I think, pretty self evident. Offsetting these reductions in funds from

operations is the addition of Port Dover & Nanticoke Wind project as well as the cost optimization that we executed in 2013.

So that leads to our last question, and probably the most significant one for the morning, which is: Why invest in Capital Power? At the very basic level, you are investing in excellent assets and good markets. You would also be investing in a company that has proven operating, construction, and trading performance.

Over the last year we have reduced our risk, eliminated some activities that added volatility to our financial results, and significantly reduced the costs in the organization. Capital Power has the most efficient and competitive fleet of assets in Alberta and the Alberta demand growth surpasses all other markets, while being very stable from a regulatory and political standpoint.

The main take away from our presentation today is the very substantial growth in our contracted cash flow through 2014 and 2015, which supports dividend growth and our investment-grade credit rating. And the completion of the projects that give rise to this increase require no new Capital Power financings. In the longer-term, we have a number of solid projects in Alberta, like Genesee 4 & 5, as well as contracted opportunities elsewhere in North America, which will further contribute to growing dividends in the future.

Lastly, stock market dynamics should be favourable with the declining EPCOR overhang and the increasing market recognition of the value of contracted assets. I'll now turn it back over to Randy.

QUESTION AND ANSWER SESSION

RANDY MAH: Thanks, Brian. Before we start our Question and Answer session I'd like to ask you that

before asking your question if you could use the microphone for the benefit of people listening on the webcast. And, also to identify yourself as well. So, we're ready for questions.

Sara, we'll start on the left side here.

PAUL LECHEM: Thank you. Paul LECHEM, CIBC. I was wondering just on the comments made in the earlier part of the presentation around the CASA compliance costs and the expectation that'll push a lot more of the coal plants out of the market early. Can you give us some more insights into what those costs might be and what went into your assumptions or your thoughts about earlier retirements that might have otherwise have been by the federal government regulations?

BRYAN DENEVE: So, when we look at the cost of complying on the subcritical coal plants, you're looking at FGD technology on SO₂ and on the NO_x side, selective catalytic reduction on NO_x. And both of those combined you're probably looking at \$200 to \$300 million of capital costs that needs to be put in place on those facilities to meet those standards. As I mentioned, there is—there is a period of ten years that credits can be used to meet those targets. But, on the NO_x side there is quite a few credits in the Alberta market. On the SO₂ side – very limited amount. And, so, that dotted line in that timeline is...we've taken into account how much extension can be done based on the available emission credits and then as soon as that physical compliance is needed, that's where we just don't see it economic to put in that additional capital expenditure.

PAUL LECHEM: Ok. And then in terms of the cost to Capital Power for compliance for these standards?

BRYAN DENEVE: Yes. For Capital Power, when you look at our generation fleet and its age, we don't hit the 40-year point until quite a ways down the road. So, so for us, in terms of our Genesee 1 & 2 facilities we wouldn't be looking at that investment until, post—in the 2029 to 2030 timeframe. I would also mention on Genesee 3 and Keephills 3, because their supercritical technology, they already have equipment in place to reduce SO₂ and, I think there is a project underway, which Darcy can speak to, for us just to get to the threshold on Genesee 3.

PAUL LECHEM: Thanks, Bryan.

DARCY TRUFYN: So, yeah. So—on, as Bryan said, on K3 it's actually, the plant's performing above and beyond so there's really nothing on K3 that needs to be done. On G3 we have a program in place right now and it's still early days, but we believe that we can make our emission requirements on SO₂ through a number of tweaks to the current facilities. So, these things are already included in our plan going forward in 2014 and 2'15. Again, it's early days but we see this as I said, as just more tweaking and not that we have to redo the back end of the plant.

PAUL LECHEM: All right, thank you.

BRIAN VAASJO: Maybe, in addition, in terms of Genesee 1 & 2, we actually possess the credits, although it doesn't show up on the balance sheet. We possess the credits to push it out anyways. Regardless of what changes we may make to those facilities in that time frame, we have the credits for them to realize their 50-year lives.

PAUL LECHEM: Ok. I guess, one last question if I can, on Genesee 4 & 5. You say you expect to have some announcements around contracts by Q1. Just wondering, are those primarily around the

contributions to the construction costs or do you hope to have some comments also at that time to balance any contracting to the power outputs in that over the balance of the...once the plant goes into operation?

BRYAN DENEVE: So, when I spoke to the definitive agreements, yeah, I was referring to the full suite of agreements. So, on Shepard we have a joint venture agreement in place. We have a number of other elements in terms of the off take agreement on Shepard, as well as how we're going to be doing the dispatch, dispatch protocol, providing real time settlement, and operations services – which we'll be doing on behalf of Shepard. So, I was referring to...yeah, that full suite. Certainly one of the elements under negotiation is where ENMAX will purchase power from the Capital Power portfolio, post-2020. That won't be tied, specifically, to G4 and G5 but it will be purchased from our portfolio and that is one of the elements that will be firmed up in Q1.

RANDY MAH: Next question.

ANDREW KUSKE: Andrew Kuske, Credit Suisse. I guess this is open to anybody who wants to answer it, but is there a good comparing contrast between your initial relationship and your ongoing relationship with ENMAX that you're having right now on Shepard, and then G 4 & 5? And, if you're comparing contrasts, that said, the experiences you had with TransAlta on K3 and G3? And what were the lessons learned in those two situations and what are you learning right now?

BRIAN VAASJO: So, maybe from a very high level. One of the things that we have been very pleased with – and I'll go back to the relationship with TransAlta – is that, we've made, obviously, we compete in the marketplace and actually compete

pretty vigorously. A number of issues that come up in the market, policy discussions and so on, we're on opposite ends of the issues. But we have found that that, in no way, has any implications on our operating discussions on the operations of Genesee 3 and of Keephills 3; a very, very solid relationship from that perspective. And, likewise, we expect and have seen very similar circumstances with ENMAX. There are issues from time to time that we have been, and we will be, having differing views from a policy perspective. But, certainly, what we've seen thus far is those have absolutely no influence whatsoever on the proper construction of the Shepard facility. And we expect that kind of relationship will prevail.

The agreements that are in place, again, for going forward with Shepard are structured the same as the agreements we have in place for Genesee 3 and Keephills 3 and that seems to be a very, very, very good effective balance of governance and keeping them at sort of the operational level. And, very, very positive aspects we're seeing on almost a daily basis in terms of our relationship with G3 and K3.

The other thing that really is nice with the development of Genesee 4 & 5 is that we are in a position where we will be operating one facility and they'll be operating one facility. So again, a very, very balanced and it drives for a very, very balanced relationship on a go-forward basis.

So, our outlook for a relationship with ENMAX for Shepard and for Genesee 4 & 5 will be as good, and potentially even better than the great relationship we have with TransAlta right now on Genesee 3 and Keephills 3.

ANDREW KUSKE: And then, then, I guess, just from a broader standpoint. You've been very aggressive in taking the charge and leading the

charge in natural gas project developments in the province for the longer-term perspective. Do you foresee, really, a natural roll off of PPA holders at this stage in time just morphing into contracts on facilities like G4, G5, Shepard, and other facilities that will come in the future? And, so, the market really remains kind of as it is today? Or does the market start to morph into partly contracted and then a broader set of merchants?

BRYAN DENEVE: Certainly we're experiencing this as we speak today, so there's a lot of—the amount of activity and interest in, from the end-use and from large industrials and medium commercial, post-2020. Those discussions are increasing and, certainly, we're seeing our piece for 10-year off takes and now go beyond the end of the PPA period. So, I think, the short answer is that: yeah, it'll look a lot like it is today and we expect the percentage of end users have locked in their electricity prices for risk tolerance, or strategic reasons, will remain the same post-2020. And, exactly as you mentioned, we'll see the roll off of the PPAs and those will be replaced by commercial contracts and negotiated off new builds.

RANDY MAH: All right, next question?

BEN PHAM: Hi, Ben Pham from BMO Capital Markets. Just on the development opportunities in Ontario on the natural gas side. I understand that the long term energy plan highlights that they didn't need any natural gas facilities for the foreseeable future and you highlighted a couple of opportunities here so can you reconcile that for us?

BRYAN DENEVE: Yes, so when we look at the—the long-term energy plan that has come out in—there's just a couple of things, I think, we see when we look at it. The first one is there's very high level and we do believe there's going to need be specific

opportunities for natural gas to support transmission congestion. So, certainly, building a peaking generation is a substitute for transmission build out. So, we do believe that, not for supply/demand reasons, but for transmission congestion reasons there will be some peaking opportunities.

When you look at the broader supply/demand balance we see in that plan a heavy reliance on energy efficiency and—and conservation to meet the requirements. Certainly there's a lot of benefit to that. We've seen that approach being taken in a number of jurisdictions but, generally, typically fall quite short of—of what's projected. So, in that regard we, to extend the penetration on the energy efficiency side doesn't reach the levels that being projected, that's going to have to be filled by natural gas.

The other thing we see there is a commentary around the cost of refurbishing the nuclear plants. So, when you look at the Bruce experience and, I believe it was also on the...if I get this right, on the Pickering side...the cost of the refurbishment came in well above budget and took a lot longer than anticipated. And, when you read the long-term energy plan you see signals there that if that's experienced on the next round, on Darlington in 2016, that they may not stay the course in refurbishing Darlington fully. So then, in 2020 you've got Pickering retiring, questions around Darlington...so, as a result, for your base load needs it's going to have to be combined cycled gas-fired generation.

BEN PHAM: Ok, and then, on one of your slides what's the potential...I wouldn't say potential but thoughts on spin off of your contracted assets. You mentioned that your expectation of higher contracted cash flow as you gain a higher multiple in the

marketplace. So, just curious, if the market doesn't agree with that and you do reach a point, some future point in time, and you do want to spin off contracted assets – do you feel that you have the bandwidth to even do that? Because a lot of yield co's that have come out have about 1,000 megawatts of capacity with pretty meaningful inventory drop down opportunities.

STUART LEE: So, Ben, don't want to sit here and, kind of, speculate today. Again, from our perspective, looking at driving long-term shareholder value we think it's important to have a balance, particularly given the fact that we look to build out our merchant portfolio in Alberta and finance that. If several years from now we're sitting here and having this discussion around the fact that there's still this disconnect in value between contracted assets and a hybrid platform like our own, I think it becomes, probably, something that we'll look at more seriously. But, at this point in time I think our view is that our strategy will be successful in the long term.

ROBERT KWAN: Robert Kwan, RBC. Just thought I'd come back to CASA here. Is this an absolute emissions-based standard or is this an intensity-based standard?

BRYAN DENEVE: It's on—it's on the SO₂ and NO_x – it's an emissions intensity standard.

ROBERT KWAN: Ok, so there's no ability for plants to, say, ramp down in the off peak and shut down in the off season?

BRYAN DENEVE: No.

ROBERT KWAN: Ok. Can you talk about...do you have, I think you've got an inventory of some credit already built. Can you talk about what you've got and how do we think about the value of them?

BRYAN DENEVE: So, I think as Brian mentioned we have an inventory of SO₂ and NO_x credits. And, certainly, under CASA the SO₂ credits – once you hit the 40-year life or the end of the PPA you're allowed to use those emission credits for up to ten years. So, as Brian mentioned, when you look at Genesee 1 & 2, those plants, as they reach that 40-year period, we'll be able to look at extending with the emission credits for a period of time.

Certainly, when we look at those SO₂ credits, there's also going to be potential opportunities to monetize that value sooner. And that's something we're watching closely and have been in discussion with some market participants around crystallizing the value of those credits earlier. Because, certainly, being able to extend the life of a plant in 2020, 2021 is worth a lot more than waiting for G1, G2.

On the GHG side, as you saw the graph there where we have the portfolio of GHG credits on the Specified Gas Emitters Regulation. Certainly, that allows us to meet our compliance requirements at much lower cost than if we paid into the fund. And that was running, probably, in the \$10 to \$12 million range. And I think you could expect that that value is there for a period of four to five years, based on the volume of credits that we have.

Now, we also have other credits in our inventory. We have credit – REGI credits in the US Northeast. Part of that inventory went with the sale to Emera but we still hold an inventory there. And, certainly, we also hold an inventory in the WCI system around California.

ROBERT KWAN: So, you gave the numbers around GHG. If you were to take a mark today on those other three buckets, roughly speaking?

BRYAN DENEVE: I'd have to get back to you on that.

ROBERT KWAN: And then, maybe, lastly on this topic. How much is your view on how CASA may be implemented drive your timing decision on G4 and G5? Is that really the difference between the 2018 date versus...do you have it in acceleration and then, if it doesn't play out the way you think it's going to, that it will be the 2020 date?

BRYAN DENEVE: So, if...the 2020 date is driven by a couple of factors. So, one is that's when the PPAs expire that ENMAX holds. So, to back their retail portfolio, that timing works very well from their perspective. So, certainly, they hold the PPA on Keephills 1 & 2, and Genesee 4 & 5, their share of it. We would be replacing that power.

The load growth in the prov...all of it depends. We have strong load growth; we have what competitors are going to do in terms of builds. When you take that all together, with our view on CASA, the need in 2020 – there's going to be a need for not only Genesee 4 & 5 but probably two other plants of that size. If, for whatever reason, there's some of those plants actually go longer than we anticipate they will be...it depends what happens in terms of what competitors are doing and building.

We believe with Genesee 4 & 5 we're now in a leadership position in terms of developing new combined cycle generation in the province. And we're on track to build towards that. So we see it very unlikely that, again, that we would see that operational date going any later than 2020. We're committed to it because of the need of our partner.

So, the element in terms of it accelerating to 2018? That really turns on...not CASA but more the health of the fleet in the Alberta market and are we going to

see some large, long-term forced outages of some of the existing assets, similar to what we saw happen with Sundance 1 & 2 in the market. In the extent that comes to pass, we'll be in a position to accelerate the commission date on Genesee 4 & 5 and take advantage of that. And, ENMAX is on the same page with us. So even though there's absolute needs in 2020, they certainly are aligned with us in terms of accelerating the COD if the market conditions justify that.

RANDY MAH: There's a question up front here.

LINDA EZERGAILIS: Linda Ezergailis with TD Securities. As your PPAs expire and as you bring on more capacity and different types of your fuel mix shifts a little bit, how do you think of appropriate management of counterparty risk, merchant risk, and how your trading capabilities might shift over time?

BRYAN DENEVE: So I think one of the things that we're doing is a shift is we are getting into position to be able to do more with end users. So, we see that as not only a way that we're going to hedge, 18- to 24-months out in advance. Certainly we're doing now a lot of shorter-term contracts. But the end user market also provides much more access to longer-term contracts. So we're seeing requests coming out from industrial customers in that 5- to 10-year time range, so that's a market where it allows us to be able to lock in prices much farther in advance than just relying on the wholesale market where liquidity has typically been limited to the 1- to 3-year period.

In terms of our trading shop we've made adjustments there, given the fact that we no longer trade in the East, no longer trading in the North—natural gas on the North American basis. That's allowed us to realize a lot of savings and right sizing on the trading side. I believe our capabilities and individuals there, we're at the right size to carry us

through 2020 and be able to manage the portfolio just like we are today.

One of the things I didn't mention earlier, which is important to note is we've had tremendous stability in our individuals on the Alberta desk. The individual that now leads the Alberta desk has been with us right from the start of deregulation, so he's been there and had experience through the last thirteen years and the majority of our key traders have a similar length of experience, in the 10- to 12-years range. So, it's important to us to keep that talent as we move forward.

STUART LEE: And just on the counterparty risk question, Linda. A function that reports up to my area. And, again, I think a long history of looking at that in a very effective track record, on counterparty risk. If you go back, even prior to the EPCOR days, when we had one of the largest retail loads and one of the largest industrial and wholesale loads, with we were effectively selling into – we had very low credit losses, extremely low because we have a very active counterparty risk group. I've got six folks that report up to that group who manage that very effectively.

RANDY MAH: Next question, please?

ROBERT KWAN: Sorry, I think this one's back for Bryan here. You talked about on terms of what pricing you need for the gas plants, \$65 to \$70 in the Alberta market. Just wondering if you can tell us what the underlying gas prices assumption is and what return you think that would generate?

BRYAN DENEVE: Yes, so, that \$65 to \$70 that was based on current gas prices in Alberta. So, right now it's around \$3.50 a GJ, maybe a little less than that. And, certainly, when we look forward we see increase, modest increases in gas as we move

forward and so in the 2020 time range, when I mentioned \$75 to \$80, that increase is really just our expected rise in gas price multiplied by combined cycled heat rate.

ROBERT KWAN: And the expected return at that price?

BRYAN DENEVE: Oh, right. So, we look at that price will be sufficient to meet what we believe is a reasonable expectation of a return in a deregulated market such as Alberta, so in the region of 11% unlevered return.

ROBERT KWAN: After tax?

BRYAN DENEVE: Yes.

ROBERT KWAN: Actually, just one more related to that. In terms of that price, is that assuming a full out run rate, i.e. including—inclusive of off take losses or is that some sort of cycle price?

BRYAN DENEVE: Yeah, that would be...in order to make it comparable to average 7x24 prices, that's basically an assumption that is running base load. Certainly, if it's running at a 75% capacity factor, mainly in the peak periods, a little bit of off-peak generation, the capture price will be higher than that.

ROBERT KWAN: That's good. Thank you.

JUAN PLESSIS: Juan Plessis, Canaccord Genuity. I think, as a follow-up to one of Linda's questions. Can you talk a little bit about your approach to hedging the Alberta commercial portfolio? Are you looking to hedge a higher proportion, One, two, and three years out? More than you have in the past?

BRYAN DENEVE: So, when we look at that term, one to three years out, it depends year to year. Certainly, when we looked at 2014 and we were making hedging decisions we're coming into 2014

with a much higher hedge percentage than we did in 2013. And, some of that turns on our view of fundamental prices versus what forward prices are in the market. So, in 2014 we saw opportunities there in the forward market that we felt were added value relative to our view on fundamentals, and that's why we have a higher percentage. Of course, we do have corporate risk limits in place that provide guidance in terms of how much exposure we can carry into each year. So we always make sure, obviously, that we are within those limits but part of it is our market view.

As I mentioned earlier, though, we do see as origination function grows in size and number of transactions, that will provide an avenue for us to lock in a portion of the portfolio much further in advance than, perhaps, we have over the last few years.

JEREMY ROSENFELD: Jeremy Rosenfield with Desjardins. Couple questions: one just on the capital cost reductions for the plants that are under construction right now. Are there any things that you can do to try to reduce capital costs for Genesee 4 & 5, some takeaways that you've learned from, construction on Shepard that might help you with the construction of the larger plant, going forward?

DARCY TRUFYN: The short answer is: yes. So, we have high expectations for G4 and G5 that we will—to make them cost, more cost effective. One of the things I indicated in previous Investor Days is that we do have in-house capability that we don't think others have. One of which is an estimating department. And so we do break down our costs and our scope into great detail and we think this will lead to lower costs per megawatt. So, it's early days yet but the answer: yeah, we think we will do very well on G4 and G5, plus we have some infrastructure

Bryan spoke about that really gives us some advantages that, candidly, Shepard is a green field site, involves massive amount of earth works and infrastructure, which we have at Genesee. So, yeah, big positives from a dollar perspective.

ANDREW KUSKE: Andrew Kuske, Credit Suisse. So, I guess over the last year in particular and probably in a more accelerated fashion in the last four to six months, there's been an accelerated de-risking of the company with just some of the actions you've taken and refocusing and repositioning. So, just as we look ahead, and this was touched upon a little bit by Brian and also by Stuart, should we think about Capital Power as, really, a dividend grower over a period of time with some commodity upside exposure and there's, obviously, downside exposure? But you get this benefit of firm, contracted profile that's enhancing over a period of time, with this commodity edge to it with the goal of just growing dividends consistently over a period of time. Is that the positioning where you really want to go?

BRIAN VAASJO: I think if you go back to our...even our initial positioning. We've always talked about having a firm base of contracted cash flow and the upside of merchant markets. Now the upside of, just, the Alberta market, which I think is another way of stating what you just described. Our intention has always been to be a dividend growing company. That's the capital market that we're in; that's where our competitors are, for capital. So that's always been the intention. The issue has been, as we've talked about in the past, you've got a declining profile of power prices and you have—and, but we've been able to offset that with significant growth on the contracted cash flow side. I think as Stuart, basically, described we're probably getting into a position where some of our expectations are going to be realized and we certainly are in a much better

position today to go back to some of our very original statements about having that base. Having an ongoing, growing dividend, and certainly some significant upside associated with the merchant market, in particular in Alberta.

ANDREW KUSKE: So I guess, arguably, versus the past years you've just got a bigger, stronger foundation of cash flow to work with on a go-forward basis versus the past few years.

BRIAN VAASJO: That is correct. I mean, it is—again, I think, as you all know, you can't base a significant amount of your foundation of dividend on commodity prices. It's got to be very, very firm cash flow and I think as you look at our financial projections...and, again, those projections are firm at this point. You can start talking about things like growing dividends and long-term sustainability of dividends under that kind of a profile, where it's historically it just hasn't been I'll call it as comfortable taking those kinds of actions.

JEREMY ROSENFELD: Jeremy Rosenfeld, again, from Desjardins. You've talked a little bit about valuation, actually a lot, and something that you've raised in previous Investor Days. Can you just talk about, maybe, the pro's and con's about potentially doing something like a share buyback instead of increasing the dividend? And, what would potentially propel you to do that type of thing?

STUART LEE: So, Jeremy, one of the things we've looked at is if you look at since the time of the IPO, \$1 billion dollars spent on Keephills 3, \$1.4 billion on wind construction assets. We now have \$820 million dollars being invested in Shepard. So, a view that we're heavily investing back in the business and not trying to extract that capital back out to buy back shares. As we get to this heavy development period, as we look at different opportunities, I think we

demonstrated in the fact that when we looked at the financing for Shepard, we looked at recycling assets. And one of the things that we'll look at for future investments is one of the contrasts you have to look at is are we better off reinvesting our business through a share buyback versus a new asset? And, clearly, we are in a position now as we are moving forward where our CAPEX spending is coming down, is we'll be looking at those alternatives every time we look at a new investment for an asset – is: does that meet the hurdle of where we could reinvest by buying back shares? So, that remains an option that we continue to look at, particularly now that we're getting to the high development CAPEX spending. And a great question.

RANDY MAH: Any further questions? Back to Andrew.

ANDREW KUSKE: Andrew Kuske, Credit Suisse. I guess this question is for Darcy. And when you just look back on the experiences that Alberta's had with just building projects and labour productivity and just the labour squeezes that have happened. When you look ahead, and in particular, when you look at not just Shepard now but G4, G5 and then some of the activities that, in all likelihood, will happen on the West Coast with liquefaction plants. Just what's your level of confidence with labour availability, the productivity of that labour? And, I guess the productivity question the root of it is we've seen a good cycle of building happening of a variety of different things. So there's a better skilled labour force but there's some big elephants down the road that are going to consume a lot of that labour. So how do you, sort of, sort that out from your numbers and just your analysis looking ahead?

DARCY TRUFYIN: Yeah, ok. Well, lots there to respond to. So, one of the things with G4 & G5 that

we've tried to do, and you'll see by just the configuration – Bryan spoke about that. By going 1 on 1 times 2, what that does is it allows us, should we decide to build it in two stages, two phases. And that, we feel, is significant advantage from a construction perspective. Especially if we can time them such that we move crews over from one to the other. And what that does is, obviously, it cuts our peak almost in half, which then allows us to source labour much more effectively from the Edmonton market.

The Edmonton market is very, very large. We think a project of this size, if it's staged right, can be done cost effectively. We do have very good knowledge of what the Alberta productivity is. I think, not to pat ourselves but if you look at what we thought from doing our due diligence of what Shepard could achieve versus what it did achieve, I think we were spot on.

We were, the whole execution strategy on G4 & G5 is critical. We think that is an advantage that we will bring to the table and we will try to execute in a manner that makes it the most cost effective. Recognize your concerns and we have the same concerns. Getting out in front of others is also another strategy. Lots of different things to consider but those will all be factored into the equation when we do the math.

ANDREW KUSKE: And then, just as a follow up. How do you think about the total development costs within Alberta because of all of those dynamics versus elsewhere in North America where you don't have the same competing forces to the same degree?

DARCY TRUFYN: Yeah, yeah. And you look at the cost per megawatt of Shepard versus something south. It's not just labour. It's also things like winter

and the requirements for building in winter and also for protecting for winter. So those are all factored in but those are all, but as Bryan said, there's a price for power and new generation in Alberta and he's quoted a pretty good number. So that's all factored into it.

RANDY MAH: Any other questions? Ok, so if there are no more further questions I'll turn it over to Brian for closing comments.

BRIAN VAASJO: Well, thank you very much for joining us this morning. I hope that it's been helpful and informative for you, not only about Capital Power and where we're going but, you know, some of the broader questions about the North American power market, the Alberta power market, and some of those things that, given your space in general, may be of significant interest to you.

As you know, we're out, basically, quarterly speaking to investors. We generally attend every conference we're invited to. So, we're out there a lot but if you would like to, if you have a couple of questions or if you'd like to see us certainly contact Randy and we'll try to arrange something to provide you whatever insight you're looking for. And, certainly, always an open invitation to come and see our facilities in Alberta, although I think today it's -22, which is not so good for visiting but is great for power prices.

On that note...thank you very much for, again, joining us this morning and certainly for your interest in Capital Power. Thank you.