TransAlta Corporation

Third Quarter 2019 Results Conference Call

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PRESENTATION

Operator

Ladies and gentlemen, thank you for standing by, and welcome to TransAlta Corporation Third Quarter 2019 Results Conference Call. At this time, all participants are in a listen-only mode.

After the speakers' presentations, there will be a question-and-answer session. To ask a question during the session, you will need to press *, 1 on your telephone.

Please be advised that today's conference is being recorded. If you require any further assistance, please press *, 0.

I would now like to hand the conference over to your speaker today, Chiara Valentini, Manager, Investor Relations. Thank you. Please go ahead.

Chiara Valentini — Manager, Investor Relations, TransAlta Corporation

Thank you, Chantal. Good morning everyone and welcome to TransAlta's Third Quarter 2019 Conference Call. With me today are Dawn Farrell, President and Chief Executive Officer; Todd Stack, Chief Financial Officer; John Kousinioris, Chief Operating Officer; and Brett Gellner, Chief Development Officer.

Today's call is webcast, and I invite those listening on the phone lines to view the supporting slides that are currently available on our website. A replay of the call will be available later today and the transcript will be posted to our website shortly thereafter.

As usual, all of the information provided during this conference call is subject to the forward-looking statements qualification set out here on Slide 2, detailed in our MD&A, and also incorporated in full for the purposes of today's call.

All amounts referenced during the call are in Canadian currency unless otherwise noted.

Non-IFRS terminology used, including comparable EBITDA, funds from operations, and free cash flow, are also reconciled in the MD&A for your reference.

On today's call, John and Todd will review the quarterly and year-to-date results and expectations for the remainder of the year. In addition, we'll provide commentary on our recent announcements and how these advance our Clean Energy Investment Plan and growth strategy that we outlined at our Investor Day back in September. After these prepared remarks, we will open the call for questions.

And with that, let me turn the call over to Dawn.

Dawn Farrell — President and Chief Executive Officer, TransAlta Corporation

Okay. Thanks, Chiara, and welcome everyone to the call today. We're pretty excited to be here announcing our third quarter results. We did have a strong third quarter and we're pleased with the results across all of our businesses. And of course, strength in the third quarter has given us strong performance year to date and it's increased our expectations of our annual performance.

Now overall, our operational and financial performance is tracking to deliver a strong year. Our Clean Energy Investment Plan and growth strategy is on track. And through the quarter, we hit key milestones, which I think has been very impressive in terms of what the team has done. And finally, we successfully concluded the final leg of our Sundance PPA arbitration and collected an additional onetime payment of $56 million from the balancing pool, which is great news because it has added to our cash flow for the year.

So I'm going to just start with a couple of overall comments on our financial performance, and of course, Todd will get into more of the detail.

We earned a total of 305 million of comparable EBITDA in the quarter due to strong performance at our Canadian and US coal businesses, our Energy Marketing segment, from the efforts and the work that's been done across the Company to reduce our OM&A costs, and of course because of the onetime PPA payment.

Now if you take out the onetime PPA payment, our EBITDA was flat for the quarter relative to last year. Now what's important here is that the Mississauga and Poplar Creek contract changes that occurred at the end of 2018 were expected to reduce our EBITDA in the quarter by approximately $30 million. So to be able to deliver flat year-over-year EBITDA with these changes shows that we've been able to increase performance in our remaining key business segments. We see this increased performance as sustainable for a number of reasons, and we'll talk with you about that through the call.

In total, we've now received 213 million from the balancing pool related to the termination of the Sundance PPAs. I'm especially proud of our team. They held a strong view that the mining assets were part of the PPA, and I believe that the final payout was a very principled decision.

Overall, our free cash flow results for the quarter are also trending ahead of 2018, and the results are … for the quarter were in the following areas. Now first of all, strong availability … we saw strong availability across the fleet, with some of the strongest availability results that we've seen. The entire fleet had availability of 95.2 percent for the quarter compared to a pretty high availability last year in 2018 of 93.7. This was due to fewer unplanned outage hours and fewer derates at both the Centralia and the Sundance units.

Now although the Alberta market saw weaker prices in Q3 relative to 2018, we continue to maintain high realized prices for our Alberta coal fleet, with an over 40 percent premium to the pool price. Our fuel and carbon costs per megawatt hour were lower due to the availability of—due to the ability of the Alberta coal units to co-fire with the Pioneer Pipeline gas, which did come on line four months ahead of plan, which was just excellent results by the team.

Overall, comparable gross margins at Canadian Coal have improved, primarily due to the benefits of co-firing. We expect to realize further co-firing benefits as we reach firm throughput of approximately 130 MMcf per day of natural gas commencing this month.

Centralia delivered a strong quarter despite lower pricing in the Pac Northwest due to their higher availability from fewer planned outages, and strong performance in Q3 enabled us to partially recover some of the loss that they experienced in the first quarter. And of course, we continue to deliver OM&A reductions as we transition the fleet. Year to day, we’re tracking to 7 percent reduced OM&A compared to last year.

As we look forward at the balance of 2019, we continue to expect strong performance from our businesses. Year-to-date results, combined with our forecast, provide us with the confidence to both revise and tighten the free cash flow range to 300 million to 340 million for the full year.

So let me turn now to talk about our strategy. Just before I talk more about the milestones we achieved, I do want to briefly comment on the TIER program that the Government of Alberta announced last week. In short and simply put, it was exactly what we expected. The carbon levy will remain at $30 a tonne, with a performance standard for our business which is at 0.37, which is best gas. This standard will be reviewed every five years.

We finally have clarity on the credits that we’ll receive across our extensive renewables fleet in Alberta. All of our Alberta wind and hydro assets will receive green credits for their generation based off the previously mentioned performance standard. We expect these credits to be worth approximately 30 million annually at the current carbon prices. The clarity on this policy and the renewable credits are yet another step in the right direction that support the strategy that we've laid out for you here in Alberta.

So let me now turn to our strategy. We are very pleased with the progress we made through the quarter on our Clean Energy Investment Plan. Last week, we moved forward with the acquisition of two 230-megawatt Siemens F class gas turbines and related equipment by buying the Kineticor business. TransAlta will redeploy these assets to its Sundance site as part of its strategy to repower Sundance Unit 5 to a highly efficient combined cycle unit by integrating these gas turbines into the existing steam turbines. The acquisition also results in the Company assuming a long-term non-unit contingent power arrangement starting in 2023 with Shell, a strong investment-grade company that is also committed to providing more and cleaner energy for Albertans. This advances our coal to gas conversion project by three to six months.

Our initial plans discussed at Investor Day included possible retiring options at both Sundance Unit 5 and Keephills Unit 1 for a combined cost of about $1 billion and total megawatts of 1,180. Changing the plan slightly and installing the two F class turbine together at Sun 5 will provide 730 megawatts of capacity earlier than expected at a cost of approximately $760 million. We like that this plan allows us to have more flexibility in dispatching with two units, and it gets us to the market with cleaner energy sooner. We do retain an option to repower Keephills 1 to a simple conversion in 2022 as an interim step. And as you all know, the carbon levy here in Alberta has a quick payback, which provides a clear incentive for us to really consider this decision. In the meantime, we'll also continue to permit Keephills 1 as a combined cycle and continue to execute the project to meet the financial targets that we outlined at Investor Day, as we move into a fully deregulated market.

For the remaining coal fleet, the boiler conversions are well underway. In early July, we issued final notice to proceed on our Sundance Unit 6 and are planning to complete the conversion of that unit in the second half of 2020. We have also—we have since also issued limited notice to proceed for the Keephills Unit 2 coal-to-gas boiler conversion.

Our on-site generation strategy—on our on-site generation strategy, we told you our Investor Day that we were expecting to potentially announce a project, which we did. We executed an agreement with SemCAMS Midstream to construct and operate a new cogeneration facility. Subject to the satisfaction of certain conditions, SemCAMS will purchase 50 percent of the plant at COD, and detailed construction activities have commenced and COD is targeted for mid-2021.

Our investments in renewable energy projects under construction are also progressing to plan. All the towers and turbines are now fully erect at both sites. Antrim and Big Level are on track to deliver COD by later this year in 2019. Windrise execution has also commenced. We were excited and actually surprised, but very excited to receive AUC approval for the Windrise project ahead schedule, providing further opportunity to optimize the construction costs and integration, and Windrise is targeted still for a 2021 COD date.

Turning to Slide 7. You can see how these growth projects will lift our future EBITDA. We expect to see the benefits of Big Level and Antrim later this year, and next year we'll start to see some of the benefits from Skookumchuck as it comes into service sometime midyear. By 2022, we expect to have approximately 60 million of EBITDA added to our run rate. And over the next three years, we will have commissioned six projects which required a capital investment of approximately 890 million.

So I'll now turn the call over to Todd to walk you through greater detail on our financial results in the quarter and year to date.

Todd Stack — Chief Financial Officer, TransAlta Corporation

Thank you, Dawn, and welcome to everyone on the call. Before I jump into the financial and operational results, I would like to start by reviewing the Alberta and Mid-C power price trends and what we're expecting for the remainder of the year.

In Alberta, power price during the quarter was weaker when compared to last year, primarily due to a cooler-than-normal summer in the province, which reduced the number of high load days. The average price in the third quarter was $47 a megawatt hour compared to $55 per megawatt hour in 2018.

Even with the lower average market price, our merchant coal assets performed well and we are able to realize a power price significantly higher than the average pool price. For the remainder of 2019, forward curve is in the $58 per megawatt hour range; however, we are highly hedged, with approximately 85 percent of our expected production in Alberta hedged for Q4. For the full year 2019, we expect power prices to average approximately $57.

As we look at 2020, the final year where our Alberta assets will be under their PPAs, the forward curve is around $55 per megawatt hour, which is supportive of our merchant fleet in the province.

The Mid-C price in the Pacific Northwest settled at US$28 per megawatt hour for the third quarter compared to $46 per megawatt hour in 2018. Pricing in 2019 represents a more normalized level, whereas 2018 was positively impacted by a very strong demand in the US West region. For the balance of 2019, production at our Centralia facility is about 85 percent hedged.

Slide 9 breaks down the performance of our Canadian coal fleet and helps highlight the benefits we are seeing from decisions made in 2018. While overall revenues and productions were lower in Q3 compared to 2018, comparable gross margin improved from 103 million to 106 million in 2019. On a per-megawatt-hour basis, gross margin in Q3 improved year over year by 13 percent.

Excluding the onetime 56 million PPA settlement received in Q3, comparable EBITDA increased by 6 million, from 73 million last year to 79 million in 2019. EBITDA margins increased by $5 per megawatt hour from $21 per megawatt hour to $26 per megawatt hour in 2019. This represents an approximate 24 percent improvement to EBITDA margins, driven by both higher realized price and lower fuel and carbon costs.

In Q3, our average realized price per megawatt hour was $67 versus the average coal price of 47. Higher realized prices are driven by ongoing hedging, revenue from ancillary services sales, and effectively dispatching our plants during high-priced periods.

We continue to see lower fuel carbon costs and purchase power due to the increase in coal firing during the quarter, where we benefited from additional gas provided from the Pioneer Pipeline. Co-firing not only lowers the costs associated with emissions, but due to the low AECO gas price, which averaged around $1 per GJ during the quarter, co-firing greatly reduced the input cost to generate the power. The firm contract in the Pioneer Pipeline began November 1st, which will further increase our ability to operate on gas.

For the nine months ended September 30th, the trend is similar. Excluding the PPA settlements, EBITDA at Canadian Coal increased from 184 million in 2018 to 208 million in 2019, a 13 percent increase. EBITDA margins improved from $17 a megawatt hour to $22 per megawatt hour, nearly a 30 percent improvement in margins.

Our overall results for the third quarter were strong and modestly above our expectations. Comparable EBITDA, excluding the PPA settlements, was similar compared to 2018, with free cash flow increasing by 20 million to 114 million in 2019 versus 94 million in 2018. This was a result of strong performance from our business and lower sustaining capital spend in the quarter. Keep in mind that these numbers include the loss of Mississauga and the Poplar Creek contract changes which previously provided about 30 million of EBITDA in the third quarter of 2018.

On Slide 10, we've bridged our year-to-date EBITDA and segment cash flows for 2019 versus 2018, and we've shown the impact of the contract changes to our results. Excluding the impact of these known contract changes, we delivered EBITDA and segment cash flows higher than last year and in line with our expectations for the three and nine months ended September 30th.

Similar to last year, our energy marketing team generated strong cash flows of $30 million in the third quarter. For the nine months ended September 30th, cash flows from the Energy Marketing business have delivered 51 million better than 2018. Energy Marketing continues to deliver strong cash flow, primarily due to the gain they experienced in the Pacific Northwest in Q1, as well as their ability to capitalize on high levels of volatility across North American power markets. The results come from real-time and day-ahead trading in the Western market and have a positive impact on cash in 2019, without increasing the overall risk profile of the Energy Marketing business segment.

In the Canadian Gas segment, excluding the impact of contract changes, EBITDA improved by $3 million in the quarter and $14 million for the nine months ended September 30th, when compared to 2018. The improvement was primarily due to lower OM&A compared to the prior year and lower fuel costs at Sarnia due to less steam demand from customer planned outages.

Our Hydro business delivered good results, generating EBITDA of 28 million in the quarter and 92 million for the nine months. When compared to last year, Hydro, for the third quarter of 2019 had higher generation due to higher water resources. However, total gross revenue decreased slightly due to unfavourable power and ancillary pricing in the quarter. After net payments relating to the Alberta Hydro

PPA, comparable EBITDA for the three and nine months ended September 30th was consistent with the same periods in 2018.

As described on Slide 9, Canadian Coal delivered significantly higher EBITDA in the third quarter and nine months versus 2018. However, this improvement was offset by lower results at US Coal due to the unplanned outage in Q1. Coal segment cash flows were also negatively impacted by the additional planned maintenance at Sundance Unit 4 and on Keephills Unit 1. There were no planned outages in 2018 in our Canadian Coal business.

On Slide 11, we're again showing the buildup of our hydro PPA EBITDA to help illustrate the upside of the Hydro assets once the PPA expires at the end of 2020. For the nine months ended September 30th, our hydro assets generated 92 million in EBITDA. However, they would have generated 202 million if the current PPA obligation payments did not exist.

Lastly, I'd like to provide updates on a few other points. As most of you would have seen from our press release this morning, we have revised our free cash flow outlook range upwards for the full year 2019. Our prior range of 270 million to 330 million has been shifted to the new range of 300 million to 340 million, based on the continuing strong performance from our business. I would note that the onetime PPA settlement of 56 million is not included in this outlook, but does represent additional cash available to us.

Liquidity was very strong in Q3, with 1.4 billion available on credit facilities and with 300 million of cash on hand. The cash balances are due to a combination of proceeds resulting from the PPA settlement, positive working capital balances through collateral, timing of capital spend, and proceeds from the investment by Brookfield. This liquidity has given us the flexibility to be opportunistic with our equipment acquisitions and funding of our coal-to-gas investments.

During the quarter, we returned 6 million of capital to shareholders through our share buyback program. Our repurchases in the quarter were well below plan, driven by an extended blackout period caused by our Q2 reporting cycle and the timing of our Investor Day. We expect to resume share purchases in Q4, and plan to continue to return up 250 million to common shareholders over the next three years through our NCIB.

In addition to our boiler conversion and repowering projects, we have four gas and renewable projects at various stages of development and construction. All of these projects—Windrise, Windcharger, Skookumchuck, and SemCAMS—have long-term contracts with strong counterparties and would fit well with RNW's existing asset base. We continue to assess these assets for dropdown.

And finally, at our Investor Day in September, we provided insight on a de-consolidated view of TransAlta for FFO and for debt to EBITDA. In this quarter's financial report, we provided additional disclosure on how these metrics are calculated. We will continue reporting these numbers in our financial disclosures going forward.

With that, I will now pass the call back to Dawn to provide a brief summary before questions.

Dawn Farrell

Great. Thanks, Todd. So I've got a short summary, a short wrap-up here. In summary, I'd like to conclude with my perspective on our execution plans and the advances we've made on our repowering. The acceleration of the combined cycle unit at Sundance Unit 5 is a great example of how having a focused and clear strategy allows us to take actions that enhance our plan and shareholder value by capitalizing on market opportunities as they present themselves.

The proceeds from the Brookfield investment done earlier this year provided funding flexibility, which was demonstrated by our opportunistic purchase of the equipment from Kineticor. We also see enormous value in having a long-term hedge with a creditworthy counterparty as an excellent addition to our portfolio. This enhances the financial flexibility of the Company, and we do believe that investors and creditors value a portfolio that has a portion of the cash flows locked in as these projects come onstream and into the market.

The Sundance 5 repowering is now larger than previously assumed, and so it does bring forward future cash flows. Keephills 1 is now more likely a candidate for a simple conversion in 2022 and it will still be permitted for a combined cycle unit in the mid 2020s. We showed you at Investor Day that simple boiler conversions have very short payback, and that'll be even shorter if the carbon levy escalates with the current expectations under the federal policy schedule.

We look forward to providing further feedback in late January in terms of our annual outlook and guidance. Overall, I'd like give many, many thanks to the TransAlta team and our employees. They worked extremely hard through the quarter. You see the results and you see all the milestones they achieved, and they are just moving everything ahead for this company. So thank you.

And with that, I'm going to turn it back over to Chiara.

Chiara Valentini

Thank you, Dawn. Chantal would you please open the call for questions from the analysts and media?

Q&A

Operator

As a reminder, to ask a question, you will need to press *, 1 on your telephone. To withdraw your question, press the # or hash key. Please stand by while we compile the Q&A roster.

Your first question comes from Rob Hope with Scotiabank. Your line is open.

Rob Hope — Scotiabank

Hello, everyone. Thanks for taking my questions. First question is on Canadian Coal, just wanted to dive a little bit further into the fuel and purchase power savings that you're getting there. Is there a way to quantify the benefit that you saw from Pioneer in Q3? And then as we look into Q4 into 2020, is it fair to assume that, absent moves in gas pricing, that we could see on a per-megawatt-hour basis similar fuel and purchase power costs moving forward?

Todd Stack

Yes. It's Todd here. I don't have a specific number for you, but the trend that you saw over the summer, I would say we're going to increase the volume significantly in 2020 over the amount of co-firing as that contract steps up to the full capacity of about 130 MMBtu per day. So we'll see more co-firing. We did see very attractive prices on gas over the course of the summer, which did help during that period. Over the course of the winter, we've actually procured a fair amount of our gas needs over the course of the winter, but as you know, pricing on gas shifts quite a bit between summer and winter profiles. So I think you'll continue to see definite savings trends from both the fuel cost, as well as the avoided emissions costs as we go into 2020.

Brett Gellner — Chief Development Officer, TransAlta Corporation

Yeah. And the only—it's Brett—I mean, just simply on a carbon basis, if you take a typical coal unit at $30, I think it's about 18 bucks a megawatt hour. And then when you're burning gas, I think you're closer to 6 bucks.

Todd Stack

That's right.

Brett Gellner

So a difference of about $12 per megawatt hour on—

Todd Stack

The gas—

Brett Gellner

—the gas portion. So if you think about burning kind of 139 TJ a day, in around that zone, just co-firing, that is the carbon saving multiplied. Convert that into a megawatt hour and you can get the savings.

Dawn Farrell

So, Rob, does that help?

Rob Hope

Yes, that's great. Thank you.

Dawn Farrell

Okay.

Rob Hope

And then more broadly speaking, we've seen you move forward with SemCAMS on a cogen. We've seen Suncor do one, as well as Pembina do a small cogen as well and speak about further cogens. How are you thinking about increasing behind-the-fence generation and how it would affect forward pricing and kind of the overall supply-demand mix in Alberta?

Dawn Farrell

Well, I mean we've seen, if you go back and you look at load growth in Alberta and you look at how it's been supplied, I mean it's a lot of load growth from 2000 until 2019 was supplied by a combination of investments that we made and the cogeneration. So as we look ahead, our models do incorporate a lot of cogeneration going forward as we set our forward prices and think about our investments. Just remember that 99.9 percent of what TransAlta is doing is replacing existing supply, and we've actually taken supply out of the market so—because we've shut down Sundance Units 1 and 2. So we don't—so as we look at our estimates of pricing, we incorporate in cogeneration. I mean, you can—sometimes it's half and half, sometimes it's of two-thirds/one-third in terms of how new growth is supplied. But you really have to look at where the developments are in the province, you have to look at who can add cogeneration, you have to assess that against the AESO's plan for growth and our plan for growth. But net-net, Alberta has been supplied significantly by cogen and it's a great way to supply the market here.

Rob Hope

All right. Thank you. I'll hop back in the queue.

Dawn Farrell

Great. Thanks, Rob.

Operator

Your next question comes from Robert Kwan with RBC Capital Markets. Your line is open.

Robert Kwan — RBC Capital Markets

Great. Thank you. Maybe I'll just kind of continue on the cogen side. I'm just wondering in your kind of detailed modeling and expectations, how much cogen do you think is—that will be developed is going to be meeting new demand, so associated with, as we've seen, with new industrial facilities versus cogen that we're seeing being built to meet existing demand, effectively taking them off the grid?

Dawn Farrell

Yeah. Robert, we see that as proprietary information, so we don't share that kind of detail with the market. I mean, if you—you can—I think EDC potentially has some good ideas there that you can look at that's public, but.

Brett Gellner

Yeah. And the—Robert, the AESO just published their long-range plan and I think it's a good source, because I think they try to predict what the mix will look like. But you'll see, they've got pretty good growth still projected and more combined cycle coming in to serve that growth.

Dawn Farrell

Yeah. Just broadly, if you want to think about the decision-making now, when I think about the last 20 years—I mean, I've been here the whole time—what I've noticed about the—cogen is an incremental capital decision by an oil and gas company, so you have to be a company that has significant cash flows that you have nothing to do with to want to allocate capital over there. We do find that people will start with pretty large, ambitious projects and then over time, they narrow down as they get closer. And they start with, I'm going to do it all myself; over time, they tend to go look for a partner in cogeneration. So when I'm doing the analysis or when we're doing the analysis with the team, we do a risk assessment of every project based on the actual underlying cash flow of the company. And I mean, all else being equal, most oil and gas companies would be putting their capital towards what they do best and the returns that they get out of their business, and it's a secondary impact. But that's been the trend the last 20 years. It could change in the future but that's how we look at it.

Robert Kwan

Got it. If I can just finish on the AESO's market power mitigation proceedings and just your thoughts. After looking at others' submissions, it seems like many were supportive of the current framework like you were, but there were also—I'm wondering if you can comment also specifically on a couple of submissions talking about dealing with single participants on a one-off or a case by case basis.

Dawn Farrell

How interesting, eh?

Robert Kwan

Go figure.

Dawn Farrell

I'll try not to say what I want to say on this. But I think at the end of the day, when I look—again, when I look back over the last 20 years, there have been situations where the buyers in the marketplace had significant market power and the Alberta market adjusted to that using their FIAC regulation and using the OBEG and a number of different ways to ensure that we had an efficient market through the whole—for the last 20 years. So my belief is that if you actually look at kind of the light touch here, we've already got in place all of what's necessary to ensure that participants don't engage in market power behaviours. We also have an obligation under FIAC to make sure that—we have a positive obligation to make sure that we're not doing anything that would express market power. So that's an important thing for TransAlta and we've got the value set in this company to adhere to that, as you know.

So I think—I don't know what to expect, you never know what regulators are going to do. But I do know this, that if people participate in market power behaviours here in the market, they will be investigated by the MSA number one, and number two, they will keep prices in a range that will bring on more supply. So I don't know why they would do that. And I think we've had 20 years of experience creating a competitive market with a robust spot market price, and so I have a lot of confidence that the market works today.

Robert Kwan

Okay. That's great colour. Thank you.

Operator

Your next question comes from Mark Jarvi with CIBC Capital Markets, your line is open.

Mark Jarvi — CIBC Capital Markets

Yeah. Hi, everyone. Maybe I just want to talk a little bit on the shift in the Sundance repowering. Two questions, I guess. One is, the CapEx per megawatt goes up. What are sort of the offsets to preserve the returns you guys talked about the Investor Day? And then any incremental views on what to do with Sundance 3 and 4?

Dawn Farrell

So I'm going to turn over to Brett.

Brett Gellner

Yeah, I mean, as Dawn mentioned, this really helps us to some extent advance the opportunity, so we see that as return-enhancing. But at the same time, remember, by getting a long-term contract here provides a lower-risk investment, too, for us and we think that's very positive. And so when you blend all that together, we see the return's still very attractive from a risk-adjusted basis. In terms of the other units, yeah, we're still—no change from what we communicated at Investor Day. We'll still evaluate those come into the new year, next year, and it's fundamentally really on the outlook for the market fundamentals. But also, as Dawn says, just the payback on some of these, as we said at Investor Day, is pretty high on simple conversions. So we'll take next year to evaluate that and keep you posted.

Dawn Farrell

Yeah, I'd say, Mark, a couple of things from my perspective. So having been in the business a long time, I tend to be a proponent of those workhorse-type machines that the F class are. They're excellent to operate, they're stable, and they have a—when you look at, when you look at the overall life of contract and you look at the maintenance costs to go along with those kinds of machines, they're typically lower than some of the newer machines that may have a slightly higher keep rate but are much more expensive to maintain. So that's one thing. Number two, remember, we have a portfolio, so we can actually do something like this and then do a different kind of configuration at a different plant. And when you blend everything together and you run the math, we get some benefits out of the diversification and we do get significant benefits out of having two machines on one steam turbine, so that allows us some dispatch capability as well.

I think the final thing is, if you look at the federal rules on carbon tax, for the province here to stay in compliance with the federal program, and of course, we just had an election here, we know what the federal program's going to look like. And the federal program goes from 30 to 40 to $50 by 2022, so getting on gas sooner and saving greenhouse gas reductions makes a huge difference. Overall, these machines are here, they're built, they're ready to go. That significantly reduces construction risk and execution risk. So we factored all of that into our decision-making.

Mark Jarvi

Okay. And then, is there any other sort of additional benefits of doing that transaction, buying those turbines, by essentially potentially getting those out of the hands of someone else who might have built more capacity in the market? Was that at all in the sort of motivation for that deal?

Dawn Farrell

Well, no, not really. I mean at the end of the day, we would only—we could only put a price in for those assets that would work in our portfolio. So at the end of the day, I don't know what they were planning on doing; I didn't really care. I just know that Brett and his team had a bit of a sense that this was a way to accelerate our program, and the Kineticor guys I think saw that as their best opportunity.

Mark Jarvi

Okay. And then we've seen some commentary and some deals around either merchant or corporate PPAs for wind or solar in Alberta. I know in the past you guys have indicated you didn't think merchant wind was great for just how you guys think about financing your business and funding growth. But what about the prospects of finding commercial industrial offtakes for renewables in Alberta? Is that something you guys see as increasingly something you can work towards?

Dawn Farrell

Yeah. Listen, we've had a team that's been talking to people quite a bit on that. We already have quite a bit of merchant wind; we don't need to add to our merchant wind portfolio. And as you saw from the tier, we now have some additional revenues coming in because of the carbon offsets that they provide. And we've got some of the best wind that there is, really, and we'll have Windrise coming on and all the rest of it. So my view is, the team talks to every industrial customer here. If there is opportunities to build for people, we would do it. We would encourage them not to build new and to use some of the existing because it does have a—it's good wind and it was built at a good time it's got a good cost structure. But net-net, we'll see. What I know is, if you build more wind in Alberta, you're going to need our coal-to-gas because the wind blows here all—pretty well at the same time and you need to back it up.

Mark Jarvi

And my last question is maybe around TransAlta Renewables and dropdowns, you talked about Skookumchuck and Windrise. Is there an optimal timing around you guys would think about a transaction or any sort of the factors that go into how you think about sequencing dropdowns to TransAlta Renewables?

Dawn Farrell

Well, if we told you that, we'd have to kill you. So there's always an optimal timing and you'll hear about it when everybody else does.

Mark Jarvi

Okay. Thanks.

Dawn Farrell

Okay. Thanks.

Operator

Your next question comes from Jeremy Rosenfield with Industrial Alliance. Your line is open.

Jeremy Rosenfield — Industrial Alliance Securities

I'll try not to ask any questions that'll get me killed. Just on—thoughts on the supply cushion. Brett, you referenced AESO publishing the update, and the supply cushion looks like in winter, it gets to be pretty tight, both this year and probably next year as well. So any thoughts on positioning the portfolio, looking forward for potential upside in trading revenue, and that type of thing?

Brett Gellner

Yeah, I mean, as always, winter would be just given the load increases that go on. So yeah, we just—I mean there's no—I don't think any change to what were—they have been doing. We'll position the fleet accordingly. We're really looking more long term on the investments. So, Todd, I don't know if you…

Dawn Farrell

Yeah. Maybe a way to think about it, Jeremy, is that Todd talked about, I think our hedge portfolio was at 85 percent—

Todd Stack

Pretty highly hedged for the—

Todd Stack

Yeah. Pretty highly hedged, but you'll see that it's not 100 percent hedged. And the reason, as you know, is in Alberta being short of supply when a whole bunch of coal plants decide to take a rest on a cold day, it's a disaster. So we tend to carry production into the year in order to be able to withstand that. The second thing is, because we now have our—our Sundance Units are merchant, so they pretty well sit there and wait for those days, and we have the ability to capture some of that when it does occur, if it does occur.

Now you also have to remember, it is Alberta, so we had I think the wettest summer probably ever, coldest summer we've ever seen. Everybody's expecting a really cold winter and you never know in Alberta, we could have the hottest winter ever. So anybody who thinks, I can tell you, I've looked at thousands of years of weather data, at least 1,000. I've looked for correlations all over the place and it's a random lock. So the supply cushion could be short under cold weather conditions and it could be fine if the weather tends to be mild. And nobody knows what the weather will be.

Jeremy Rosenfield

Okay. I'm hoping for wetter for skiing, but anyway. If we look at the same thing looking farther out. So if you think about the merchant portfolio in Alberta from a long-term perspective, maybe 2025 and outward, after you're through all your boiler conversions, after you're through repowering, is there a hard number or something somewhere where you want to get the portfolio in Alberta to so from a long-term basis so that you have some kind of a hedge position or long-term contracted position on a sustainable basis going forward?

Dawn Farrell

Yeah. Yeah, you're thinking about what we've got. You're thinking about the Shell contract, would we want more of those in our portfolio. Is that how you're—is that what you're—

Jeremy Rosenfield

Yeah. Correct.

Dawn Farrell

Yeah. Yeah, you know—so as you know, we're pretty conservative here and the management team tends to like long-term contracted assets even if they have slightly lower returns than merchant because that's our DNA, right? So I would say that we've still got a lot more work to do. I wouldn't really want to give you any sort of—I don't want to say something here that we'll go away and do some analysis on and then regret. But I would say, having some portion of our fleet contracted is going to be a—it's always going to be good. Especially, I really like to have a portion of something hedged when it's coming online because typically, when plants come online, it depresses the price a bit, so you kind of want to have some of that in there.

I think the other thing that we have to do, Jeremy, is there will be a lot of analysis on what Alberta looks like when there's more of—when our fleet is more on gas. Gas runs at a higher availability and tends to—it doesn't tend to have some of the same issues as Rankine cycle coal does, so we'll have much more operational flexibility when we get out there. So I think if we mix the operational flexibility with our desire to have some consistent cash flows in our portfolio so that we have—so that Todd'll be happy when he goes to finance bonds and we'll have lower rates on that, we'll be doing all that mix, and more to come on that. It'll take a bit of time to think that all through. But in general, if we could get other long-term contracts with large industrials that are creditworthy, you would see us trying to engage in those.

Jeremy Rosenfield

Okay. That's great. I appreciate that. That's it for me. Thanks.

Operator

Your next question comes from Patrick Kenny with National Bank. Your line is open.

Patrick Kenny — National Bank

Good morning. Yeah, just back on the Sun 5 PPA, I know you can't provide too much detail, but I was just curious in general how you think about IRR for high-quality PPAs in Alberta relative to building merchant. If you are going to be looking at potentially additional corporate offtake agreements, what would you say is the fair spread and hurdle rate between merchant and contracted?

Todd Stack

Yeah. I mean, it's a little tough to answer that because we do look at it truly from a portfolio and we'll always have a merchant component. For example, our hydro is a merchant to be able to capture those kind of peaks, but. And you've got to remember, the contract is not unit-contingent per se, even though you reference it signed to the specific unit. But yeah, I mean I would say generally, you're going to look at probably 300 basis—3 percent higher for merchant. But again, it's a bit dependent on the technology, the age, where it's situated, what market you're in. So that's just a broad rule of thumb.

Dawn Farrell

Yeah. I would say, take that 300 basis points as a bit of a midpoint and think about it this way. The longer the contract, the fewer the base—you might have—you might take even a bigger reduction. The more pass-through of cost, the more it's tied to actual heat rate of the machine, so there's a number of considerations there. But generally, you pick up stability in your cash flows, better financing cost, a whole bunch of things that you can plan around that kind of offset those reductions and returns.

Patrick Kenny

Okay. Thanks. That's helpful. And then you mentioned the lower gas prices this summer having a positive impact on co-firing margins, but I guess at the same time, it's reduced drilling activity in the central part of the province. So perhaps you could just provide a bit of an update on how you're thinking about ramping up volumes through Pioneer over the course of 2020, 2021, as well as just securing long-term supply through the other pipelines coming into Sundance and Keephills.

Brett Gellner

Yeah. So we're—again, no real change from what we communicated at Investor Day. We're targeting to get up to that 350, 400 a day eventually, once we're fully converted. We're well-positioned here over the next year or so, given the Tidewater Pipeline, plus we indicated we have incremental firm capacity in the existing line there. And so, yeah, it's just a matter of working with parties. The drilling activity always ebbs and flows, and we never saw the low, low prices being sustainable for the producers and that's not in our planning. So we do expect those to improve and drilling to be sufficient. And yeah, so we'll, as I said at Investor Day, we'll keep you updated as we progress in our plans.

Dawn Farrell

Yeah. And I think, Patrick, I mean, we are talking to a lot of gas guys, as you can imagine. Really, our volumes, even though it seems like a lot of gas to us, they're in the rounding area of what Alberta producers in terms of gas, so that's helpful. What we do know is that this curtailment, whatever they did with TransCanada this summer that alleviated some of the curtailment issue so that the guys could get their gas into storage has helped to increase prices and get them closer to what you're seeing today. Those kinds of prices were what we had in our models. Because remember, we're using gas and the offset is what we've got to pay on carbon. And so net-net, what we know from—we've got gas—we've had gas guys on our board and we've got John Dielwart on our board. But as you get into this current pricing regime that we're seeing, the guys get out their drills again so—because they become more profitable. So we're starting to see evidence of that.

Patrick Kenny

Okay. That's great. Thanks. And then, just lastly on the NCIB, stock is up nicely here this morning, but still a little bit lower than where you've been in the market buying this year. So I just wanted to confirm that, given the extra free cash flow here in 2019, that the NCIB is still attractive in your view from a capital allocation standpoint.

Todd Stack

No, you're absolutely right. It is an attractive price. And as I mentioned earlier in the call, we plan to be back in the market here in Q4, as soon as we're out of blackout.

Patrick Kenny

Okay. Great. Thanks, guys.

Dawn Farrell

Thank you.

Operator

Again, if you would like to ask a question, press *, 1 on your telephone.

Your next question comes from John Mould with TD Securities. Your line is open.

John Mould — TD Securities

Good morning. Maybe starting with the SemCAMS cogen project, it's shown as a potential dropdown to RNW in your deck. It's fully contracted on steam and I think half contracted on electricity. So does TransAlta Corp. potentially take on that merchant risk in a dropdown scenario? Or are you comfortable with the co-gen going to RNW with some level of merchant exposure?

Brett Gellner

Yeah. John, we've, as you can imagine, we've had some kind of early discussions with the board of TransAlta Renewables, so they understand the project and that there is a bit of a merchant component to it. And in general, we prefer fully contracted assets at the TransAlta Renewables level, but I wouldn't rule out the notion that having a modest bit in the context of the whole portfolio of merchant power being available to—being accepted by TransAlta Renewables, given TransAlta Corporation's ability to manage and dispatch that into the market is likely okay.

John Mould

Okay. And then just on the Shell PPA, I appreciate you don't want to detail individual contracts, but just more broadly speaking, what's the minimum contract length that you need to characterize an agreement as long-term?

Dawn Farrell

It should be, so I would say a medium-term contract is five years and anything longer than that is long term.

John Mould

Okay. Helpful. And then just lastly on the US Coal results in the quarter, I know in your remarks you pointed to strong unit availability. Can you just give a little more colour on what drove that big gross margin increase in the quarter?

Todd Stack

Sorry, I missed. Could you just repeat your question?

Dawn Farrell

US results in the quarter were much better than—

Todd Stack

Yeah. US results. So in last year, we had a lot more unplanned outages. And so even though prices were high last year, the plant wasn't available to take advantage of high prices. This year, we saw strong pricing in around the $30 level and the plant had great availability in the quarter and really was able to capture those prices.

Dawn Farrell

Yeah. I would say, if you look at Centralia and you look at our trading business, our trading business, we have a lot of real-time traders and they arbitrage, and they move power from the North to California. And this year has this volatility that's occurred because of all the renewables in the California market that have to be backed up has benefited both Centralia and the trading business, because they're chipping away every day, moving power all over the place. So that's been very helpful.

I think as you look ahead, we know that Unit 1 comes off at the end of 2020, and plus, you've got a bunch of coal plants coming off in that region that all have been supplying base load power that has been sort of a nice complement to the hydro in the Pacific Northwest. I just think that there is a lot more volatility coming forward as we look at those markets. So we're starting to see for the first time some actual uplift as a result of that.

Brett Gellner

Yeah. But John specific to Todd's point, the specific answer was, the amount of purchase power we had in Q3 of 2018 was significantly higher than it was in 2019. So we were able to—

Dawn Farrell

Yeah, we made it.

Brett Gellner

—supply a lot more. So we made it as opposed to having to buy it in the marketplace. And that was probably the biggest driver between the results quarter over quarter effectively, or on the comparative-quarter basis.

John Mould

Okay. Thanks for all that colour. Those are all my questions. Thanks very much.

Dawn Farrell

Thanks, John.

Operator

Your next question comes from Chris Varcoe with Calgary Herald. Your line is open.

Chris Varcoe — Calgary Herald

Hi. My apologies if this question's already been asked. But I'm curious, Dawn, if you could tell me what are your thoughts on the government's new tier program, and more specifically, how it's going to affect the Company going forward.

Dawn Farrell

Yeah, I mean I thought the tier program was well—first of all, it was expected and I think it's a good program kind of overall, because what it does is it in enables companies like ours to make decisions like the ones that we've been making. There's a price on carbon but there's also our performance standard. That performance standard is incredibly important for us in terms of our already existing renewables, investments and also important in terms of making our coal-to-gas transition. So it's a good program. I'm really hoping that it stays stable as we go forward in terms of the performance standard. And I think the world is moving towards carbon being priced and we're ahead of the game here and we need to get credit for that.

Chris Varcoe

Can I ask you, what do you expect the financial implications of it will be in 2020 versus 2018 or 2019? In other words, will you be paying more or less for the same under the program? And just to follow up on a completely different issue, can I ask you what your outlook is on the electricity pricing in Alberta in 2020?

Dawn Farrell

Yeah. So the—it is the same, because it was expected to be $30 and a 0.37 performance standard. So there's no—

Todd Stack

Which is the same standard in price that's currently in the market.

Dawn Farrell

Yeah. Same standard of price for the market; expected that. And then the current forward price for electricity in 2020 is around—

Todd Stack

In the 55 to $60—

Dawn Farrell

—$55, 55 to 60, which has been, Chris, if you look back over the last 20 years, on average, Alberta trades in that sort of $60—55 to $60 range. So it's a great price for consumers.

Chris Varcoe

Thank you.

Dawn Farrell

Thank you.

Operator

There are no further questions at this time. I will now turn the call back over to Chiara Valentini.

Chiara Valentini

Thank you, Chantal. Thank you, everyone. That concludes our call for today. If you have any further questions, please don't hesitate to reach out to the IR team here at TransAlta. Thank you.

Operator

This concludes today's conference call. You may now disconnect.