AGL Energy Limited

Full-year results webcast

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Chris Kotsaris: Good morning everyone and welcome to the webcast of AGL's 2019 Full Year Results. We're pleased you could join us. This is Chris Kotsaris speaking from the AGL investor relations team. And in a moment our managing director and CEO, Brett Redman will present today's key updates shortly before our CFO Damien Nicks goes into more depth on the financials. Brett will close out with the market update and outlook and we will then take questions. If you'd like to ask a question at that point, please press zero followed by one on your telephone keypad. To cancel your request, please press zero followed by two. I'll now hand over to Brett.

Brett Redman: Thanks Chris and good morning all. I'll begin by summarizing the result, some announcements we're making today and our market outlook. It was another strong result reflecting the resilience of our portfolio and customer base at a time of increasing headwinds. There is no question those headwinds are becoming stronger in the 2020 financial year, but we are investing in our customers, our energy portfolio and in growth and we are in robust financial shape, hence our ability to fund the share buyback we're announcing today. In the 2019 financial year underlying profit after tax was 1 billion and $40 million up 2% on 2018, primarily driven by our electricity business. This has enabled us to declare record dividends over the year of 119 cents per share, including today 64 cent final dividend. Annual dividends have increased by more than 50 cents per share since we introduced the new dividend policy in 2016. Our focus on fairness, simplicity and transparency for the customer continues. We are announcing today the extension to gas customers of our automatic loyalty discount for households and small businesses on standing offers. This follows the provision of the safety net to electricity standing offer customers in the 2019 financial year. We're seeing three new major generation projects come into production. The Silverton and Coopers Gap wind farms and the Barker Inlet gas fired power station and we have a further $2 billion of energy supply projects in development. We've also announced today the acquisition of Perth Energy, operator of the Kwinana Swift gas fired power station and Western Australia's third largest electricity retail of the business customers. And I'm delighted that we are seeing increasing customer numbers again off the back of the considerable investments we have made via the customer experience transformation program over the past three years.

Our guidance for the 2020 financial year is for underlying profit after tax to be in the range of $792 to $860 million, a material reduction on 2019. This is driven by three key factors, the impact of the extended outage of unit two at AGL Loy Yang that began in May; a step-up in depreciation expense following the high levels of investment we have been making; and the operating headwinds we communicated back in May. Those operating headwinds are lower prices for wholesale electricity and renewable energy certificates, increased costs for both coal and gas, and the impact of the introduction of default pricing for retail electricity. Nonetheless, our financial position remained strong and we have ample headroom, both to fund investment and a buyback of up to 5% of issued share capital over the next 12 months.

Let me now turn to the three key operational goals linked to the CEO scorecard we introduced at the half year results. We're encouraged by the improving feedback we are receiving from our customers and our people, but we're disappointed that our safety performance didn't improve in the period. The total injury frequency rate per million hours worked increased to 2.1 for employees and to 3.6 including contractors. While severity of injuries continues to lessen, we still want to see reduction in total frequency. Customer satisfaction as measured by net promoter score improved to negative 11.1 at the end of the period from negative 22.5 at the same time last year. There's still a lot to do on this front, but the trend is promising.

On the employee front, we took an additional engagement survey in May following the first in three years last September. The results show a steady improvement as we aim to return to and ultimately exceed employer standing.

This slide provides a brief summary of the financial results, the key driver of which was the performance of our wholesale electricity business. Similar to the half year, the strength of the wholesale electricity market impacted statutory profit as a result of the mark-to-market of hedging instruments. The 2% increase in underlying profit was consistent with our guidance. The strong performance in electricity offset the impact of customer affordability initiatives, a deliberate increase in plant operating expenditure and a decline in gas sales volumes to business customers. As forecast at the half year results, the second half was weaker than the first half. Our cash performance was also impacted by rising wholesale electricity prices in the period as a result of high margin calls. Dividends, as I've mentioned, have increased strongly in recent years and we're up 2 cents per share for the year. Return on equity was again strong at 12.5%.

My next slide recaps the growth strategy we set out at the half year. We introduced then three growth areas. One, optimize our existing portfolio for performance and value. Two - evolve and expand our core energy market offerings. And three, create new opportunities with connected customers. We have been active in all three areas. The Bayswater power station upgrade is underway, although the recent outage at AGL Loy Yang means the Loy Yang upgrade we announced in February will now start later than originally planned. Barker Inlet will be coming into operation over coming months while the power for wind projects are nearing completion. We're progressing our two pumped hydro options and the Crib Point LNG jetty proposal and as announced today we have expanded our footprint in Western Australia with the Perth Energy acquisition. We've recently launched our bring-your-own-battery initiative giving customers access to payments when they connect their batteries to our virtual power plant and we will soon launch a similar offer to new battery buyers. And of course we have been active in our exploration of how best to establish a presence in broadband. The takeover offer for Vocus earlier in the year was a result of considerable customer research into what customers want from AGL and how we could add value. We are confident AGL can continue to evolve as a multiproduct brand across energy, data and related products and services. The Perth energy acquisition is a strong strategic fit for AGL. The business is the third largest electricity retailer to business customers in Western Australia selling about 1,400 gigawatt hours of electricity a year as well as 1.1 petajoules of gas. It operates the 120 megawatt Kwinana Swift power station adding further flexible gas generation to the AGL portfolio, which we see is having increasing value in the WA market. More broadly, these acquisitions provide greater flexibility for our WA wholesale gas contracts and strengthens our competitive position in gas retail in the state where we now have 43,000 customers.

My next slide picks up on the continued investment we need to see in the national electricity market. We must not lose sight of the sheer scale of the opportunity as the industry transitions to more use of large scale renewables over the coming years. Bloomberg new energy finance forecasts $130 billion of grid scale and $70 billion of behind-the-meter investment is required in generation and storage between now and 2050. As this transition occurs, the first opportunity is in the flexibility of our existing thermal fleet. We are continuing to plan responsibly for the coming retirement of our oldest plants at Torrens Island in South Australia and Liddell in New South Wales as reflected in our announcement last Friday. But our remaining thermal fleet, Bayswater and Loy Yang A are among the NEM's youngest, highest quality and cheapest to run plants, so will be around the longest. That's why we are investing in making them more flexible and spending more on maintenance. Renewables will continue to penetrate, but renewables alone cannot fully replace capacity without firming to smooth out their inherent volatility. As the market transitions, AGL has an opportunity to play a key role as an enabler, transitioning our portfolio focus from energy to capacity assets. Flexibility and storage will be increasingly important in a market that requires more responsive assets. As we said at the half year, we're serious about storage and that means pumped hydro, more grid scale batteries and the continued expansion of our behind-the-meter orchestration and distributed energy capability and service offerings. We have a proud heritage as Australia's largest private developer of renewables. We now want to build on that heritage and become the biggest developer of the firming capacity that backs up that clean energy.

Our development pipeline now stands at $2 billion that excludes Silverton, Coopers Gap and Barkers Inlet, which are now at or near completion. Our attention is now on developing potential pumped hydro and gas firming products in New South Wales and South Australia and delivering our coal power station upgrades. The map on this slide has been updated since the last result to include the Kanmantoo pumped hydro option we have secured in South Australia. As announced in June, we have delayed the timing of our expected first gas from the Crib Point LNG import jetty as we work through environmental approvals.

This slide addresses some of the challenges and complexity of managing our fleet as it transitions over the coming years. The chart on the left shows generation sold to the pool in the 2019 financial year, which was at near record levels of approximately 44 terawatt hours. The continued running of AGL Torrens, a big year in hydro and the start of commissioning of new wind projects all contributed to this performance. The chart also shows how even when major planned or unplanned outages occur, a total output is generally quite consistent. We are managing our aging thermal fleet by investing significant amounts in it to maintain its performance. Total combined operating and capital expenditure was $1 billion in the 2019 financial year, the highest ever. We had some good outcomes such as the completion of a major overhaul of Bayswater unit one and the best reliability output at the Loy Yang mine in six years. Due to the age of the fleet there will always be outrages, planned and unplanned, which can result in lost profit as it will this year with the unit two outage at Loy Yang. This outage will extend seven months and require a full rewind of the generator so we'll have a profit impact at the upper end of our original forecast.

The unit has been out of service since 18th of May, 2019 following an electrical short internal to the generator which caused consequential damage to the stator and rotor components. The duration and cost of repair reflects the unique original technical design specifications of unit two and the extent of damage. We don't expect to recoup materially any costs via insurance until next financial year.

Now turning to our efforts in delivering simplicity, fairness and transparency for the customer and the extension of the safety net to gas customers. In the 2019 financial year, we delivered lower electricity tariffs across all states, put in place the safety net, ensuring all electricity standing offer customers got a discount after one year and put in place a $50 million support package for vulnerable customers. We also saw a strong uptake of the new AGL essential product which now has 300,000 customers. We have announced today that we will offer a safety net to residential and small business standing offer gas customers from 1 September. The measure will ensure these customers who have been with us for more than 12 months are automatically receiving a 5% discount without having to shop around. Today, 12% of our gas customers are still on the standing offer of which 145,000 have been with us more than one year and will benefit from this initiative. Before handing over to Damien, I would like to reflect on the performance over the year in the context of my priorities and operational goals. At the first half year results, my first to CEO, I introduced three strategic priorities; growth, transformation and social license and four operational goals with firm targets. The three strategic priorities will always overlap. Our ongoing development of new energy supply represents growth, investment as well as transformation of our portfolio and is integral to our social license as we invest in Australia for the long-term. Other achievements I've been particularly encouraged by in the social license area include the refresh of our purpose and values, which has been of immense importance to our workforce and the progress we are making on fairness, simplicity and transparency with customers. These priorities and goals are unchanged as we progress through FY 20, and we will continue to use them to guide our decision making, our remuneration objectives and to monitor our performance. I'll now hand over to Damien.

Damien Nicks: Thanks Brett and good morning all. I'll begin with a quick explanation of the reconciliation of Statutory Profit to Underlying Profit for the year. There've been no additional significant items since the half year results. There were gains on the sales of the National Assets and the development rights over the Yandin Wind Farm which were largely offset by the impairment when we closed our residential solar installation operations in September, 2018. The loss in the fair value of financial instruments of $139 million compared with a gain of $562 million in 2018 primarily reflects movements in wholesale electricity prices. Higher forward electricity prices at the end resulted in a negative fair value movement in AGL's net sold electricity derivatives. Underlying Profit after tax increased 2% to 1 billion and $40 million.

Now, let's look at Underlying Profit across the group in more detail. We find the most useful way to look at this waterfall is by the electricity and gas portfolios rather than by operating segment, as a portfolio view eliminating intercompany movements. The year-on-year increase in group profit was $22 million underpinned by the strong result in our electricity portfolio, which was up $83 million. This reflects a strong wholesale market and the flexibility of our fleet. Therefore, our focus on optimizing our assets for performance and value. There was an increase in revenue from large business and wholesale customers as a result of higher contract rates. Lower network rates and lower volumes resulted in lower network costs. The improved results in net portfolio management was largely because of increased surplus generation sold into the pool at higher spot prices. This more than offset reduced revenue from residential and small business customers, increased gas and black coal prices and the increased operating costs and depreciation of thermal plants. Our gas portfolio was marginally down year on year as we continue to experience the effects of increased wholesale gas prices and decreased large business customer volumes. The Other AGL section of this reconciliation was down $52 million year on year. We've highlighted the reclassification of certain fees, charges and recoveries to consumer gross margin in FY19. This was in order to improve consistency of revenue and cost allocation in a consumer business as we move to a single enterprise resource planning system. The impact on a segmental level was a reduction of operating costs and increase in consumer gross margin within customer markets, which we've normalized for opex reporting purposes. There was also a reduction in other margin and income due to the divestment of National Assets and Active Stream in the prior year. Net finance costs were down because of lower average borrowings.

Now, an update on operating expenditure. You recall at the half year we deliberately adjusted our focus to disciplined value driven spend in our plans to drive margin, mitigate risk and optimize for performance. The decision to increase expenditure in our plants was deliberate but measured. Nevertheless, we continue to drive operational cost improvements and business efficiencies. Costs were slightly down year on year and after taking inflation into account we managed to achieve ongoing business efficiency savings of $78 million, slightly higher than the $60 million forecast at the half year result. This included labour savings as a result of the Loy Yang transition and the reorganization programs from the prior year and efficiencies achieved through the customer experience transformation program. Offsetting these were increased cost related to our customer affordability initiatives and increased well expenditure at the Moranbah joint venture. As we look forward to FY20, we expect to deliver modest year-on-year cost reductions and we continue to focus on improving our plant performance and managing the reliability risk of our aging plants.

This slide shows how the investment in our customer base is delivering strong results. Market activity remains intense, but our key indicators are showing positive signs relative to the rest of the market. Although still elevated, churn has decreased and so have acquisitions and retentions compared with FY18. This is a sign of strengthening customer loyalty and as this trend continues, it ultimately means a reduction in cost. It's encouraging to see that our consumer accounts are growing increasing 66,000 over the past year, reversing the trend of the previous few years. The two states driving this increase are Victoria where we gained 38,000 customers and Western Australia where we gained 22,000. The customer experience transformation program has contributed to our improving metrics and is helping drive operational efficiencies. Total digital sales have increased 98% since FY17 and we're seeing encouraging outcomes in e-billing and reductions in call volumes. As we continue to drive digital adoption and enhance the customer experience, we expect further savings to materialize.

Let's look in more detail at our depreciation and amortization expense for the year and for the outlook for FY20. As a result of our significant capital investment over the past few years, our depreciation and amortization has been rising. The $57 million increase in FY19 was largely driven by increased investment we've been making to our thermal plants and the change in depreciation method used to our hydro assets. The increased from FY19 to FY20 again reflects the investment in thermal as well as the full year impact of amortization of our digital transformation projects and the beginning of the Barker Inlets power stations depreciation. The increase in FY20 of $100 million will have a downward impact on our after-tax profit of about $70 million.

This slide shows how we performed in the generation and sale of electricity during the year. Generation of 43.7 terawatt hours, were at a near record levels despite the outages during the period. This reflects a flexibility of our portfolio highlighted by the increased generation of the hydro assets. Residential and small business customer sales were not materially impacted by weather with a small decrease in volumes resulting from lower average consumption due to a change in customer mixed by state. There was an increase in customer numbers in Victoria where average consumption is typically lower than other states but decreases in New South Wales where average consumption is higher. Large business customer volumes were flat, which is an improvement on the decrease we saw at the half year resulting from some strong customer acquisitions and retentions. Wholesale customer volumes were marginally up from the existing customer base during the year.

I've already described the strong performance of the electricity portfolio. This slide shows margin at a segment level. Consumer margin was up due to a transfer price realignment from wholesale electricity and the reallocation of fees and charges, although as noted on the previous slide, volumes were down.

Large business margin was down due to a change in customer mix. However, there was an improvement on the first half results due to customer acquisitions. Eco markets improved due to higher generation from our hydro and other renewable assets and lower prices on market purchases. The group operations cost increase reflects the opex and the depreciation trends I've previously discussed.

The decrease in gas sales volumes continues to be driven by decline in large business volumes in a supply constrained market. Consumer volumes were also slightly down due to model weather in Victoria and change in customer mix. There was increase in customer numbers in Western Australia but a decrease in New South Wales. Wholesale customer consumption from existing contracts increased which more than offset a decrease in demand from AGL Torrens.

This slide shows that our gas margin has decreased. The impact of the decline in large business customers gross margin more than offset the increase in higher contracted rates to wholesale customers. The small decrease in consumer gross margin was driven by existing customers moving to lower priced products.

Turning to the cashflow, the trend we saw at the half year has continued with our otherwise strong result being impacted by the increase in margin calls. Similar to what we saw in FY17, this is due to the impact of higher wholesale forward electricity prices on our futures market positions. Because we manage our net long physical generation position through taking a net short contracting position, as prices rise our positions lose value. This means it's a negative mark-to-mark impact in statutory profit and a negative cash outflow for margin calls. Margin calls generally reversed through cash receipts as positions unwind and we expect to recoup the majority in FY20 and the balance in FY21. AGL is in effect a market maker in the electricity hedging market, which relies on the liquidity we provide. We've always and will continue to endeavour to provide that liquidity. Other working capital as an outflow compared with an inflow in FY18 due to an increase in renewable energy certificate purchases and in the coal stockpile at AGL Macquarie. Income taxes were up 104 million as AGL Loy Yang commenced paying income tax as of FY19. However, it continues to recoup tax losses.

Our capital expenditure of $939 million for the year was a record. The most significant portion was $382 million invested into our core thermal assets to support their ongoing operation. In addition, Barker Inlet power station is on track to be delivered in FY20 with the bulk of capital expenditure shown here in orange having been spent in FY19. As the dark purple indicates, FY19 was a significant year for systems development as we have largely completed the customer experience transformation and ERP upgrade programs. You can see that there is ongoing investment in our systems in future years. Overall, the outlook for lower capex reflects some of these major programs coming to completion. Although I note the FY21 and FY22 numbers do not include major projects yet to be approved. There are fewer plan major outages scheduled in FY21, hence the lower forecast for sustaining capex in that year.

I'd like to finish by talking about how we look at capital management. Our financial position is enabling us to return cash to shareholders through a buyback and still maintain scope to invest in existing business and in new growth. I will start by walking through the past year, how we generated cash, how we use cash and how that influenced our financial position and funding ability at the end of the year with strong operating cash inflows as I've already discussed and some minor divestments during the year. Our record levels of capital expenditure represented a significant cash outflow as did the redemption of the $650 million of hybrid notes. We maintained our dividend policy and paid the highest dividend in AGL's history. We ended the year with a very strong balance sheet and an increase in our funds from operations to net debt ratio to 45% and theoretical debt headroom of about $3 to $4 billion. As per our capital allocation principles, in the absence of these growth opportunities in the short term, we'll return excess liquidity back to shareholders. That is why today we're able to announce a buyback in FY20 of up to 5% of our shares, which is expected to be accretive to earnings per share. Growth continues to be a priority and we will still have ample headroom to fund opportunities as they arise. I'll now hand back to Brett.

Brett Redman: Thank you Damien. I'd like to finish today's presentation by commenting on current market conditions and the outlook for AGL. We've previously noted that we're expecting challenging conditions and mentioned the specific headwinds likely to impact our FY20 result. I'd like to spend time over the next few slides explaining these headwinds in more detail, including what we are doing about them. We are well placed to push through this challenging period and set AGL up for longterm success. Firstly, I'd like to cover the wholesale market and what we are seeing with forward electricity and renewable energy certificate prices. Electricity forward curves are in backwardation as new generation projects are coming online and demand growth stays low. LREC prices have dropped significantly since the end of last year and the forward curve suggests further reductions are coming. As AGL contracts for FY20 and FY21, any backwardation of curves means a year-on-year decrease in our wholesale electricity margins. Lower LREC prices means revenue received per certificate will decrease more than the cost to generate and any margin flowing through eco markets will reduce. We don't expect wholesale electricity prices to rise again to the levels of the past few years. The best way for AGL to prosper in the transitioning market is to invest in the flexibility of our portfolio so we capture value more effectively. This includes our existing thermal assets, new gas peakers and securing options for hydro and storage. AGL expects underlying demand for renewable development to continue to be strong regardless of any changes to current green schemes. We've shifted in recent years to short-term PPAs to help manage risk as wholesale prices fall.

Moving onto what we are experiencing with our sources of fuel, we have spoken many times before about the tightness of the gas market and the effect on supply and prices. AGL has benefited from long-term legacy supply contracts signed when gas was at a much lower price. These contracts are now maturing and need to be re-contracted at market prices. This compresses our gas portfolio margins and increases fuel costs for our gas generators. The tightness of supply has already resulted in a reduction in large business sales volumes. AGL’s strategy in wholesale gas remains to benefit customers by mitigating supply uncertainty and providing optionality. We're securing supply with the development of Crib Point and our gas storage positions increase our flexibility. We continue to re-contract where possible. Our investment in flexible gas peakers combined with Torrens A units progressively closing of the next few years means our gas demand for generation will reduce. Black coal prices have risen over the past few years. AGL Macquarie benefits from legacy coal contracts. While these contracts aren't maturing yet, they have stepped down in volume and any excess coal purchases to satisfy loaded market rates is well above this price. AGL continues to optimize its coal delivery process to maximize volumes it received under its legacy contracts. With AGL's ability to stockpile coal at AGL Macquaire, there's optionality around timing of entering into long-term contracts.

Now turning to retail, both the Default Market Offer and the Victorian Default Offer were implemented in July, 2019 representing a partial return to price regulation. Because AGL has been proactively implementing customer affordability measures, we were well placed when regulation came into effect. Nevertheless, there will still be an impact on customer gross margin in FY20 due to the reduction in standing offer prices. We anticipate more customers moving to competitive offers during the year, which will further compress margins.

Our customer base is strong and it continues to grow as we invest in it and develop new products, which should translate to reduce costs from increased customer loyalty over time. This customer base is a solid foundation for us as we continue to invest in distributed energy and explore multiproduct offerings with the connected customer.

I will close with a summary of our guidance for the 2020 financial year. The reduction in Underlying Profit after tax to between $790 million and $860 million has three key drivers. The Loy Yang unit two outage, depreciation and the operating headwinds I've discussed. We expect the impact of the Loy Yang outage to be between $80 million and $100 million after tax at the upper end of our initial estimate. The higher depreciation expense reflects record levels of investment and is expected to have an after-tax impact of about $70 million. The operating headwinds and wholesale electricity, renewable energy certificates and fuel costs are likely to endure with the LREC costs, particularly impactful in FY20. The share buyback will result in higher interest costs but is expected to be accretive to earnings per share. Guidance is subject to normal trading conditions and our usual disclaimer. To close, we're clearly now experiencing a change in conditions after a period of very strong performance driven by major investment decisions we made several years ago. During the last few years, we've delivered strong profits, material increase in dividends and we've today announced our second share buyback in three years. We're now facing a more challenging short-term earnings outlook. But as we look to the long-term opportunities that exist as our sector transforms, we should feel confident. We have a 3.7 million strong customer account base, which is growing again, churning less and telling us we're improving on what we deliver. We have the country's largest highest quality electricity generation portfolio and exciting development portfolio and deep and valuable intellectual property in energy trading. We're going to lean into the opportunities in our industry and we back ourselves to make the decisions that will drive the next phase of AGL's growth. Thank you for your time and we'll now open for questions.

Chris Kotsaris: Thank you, Brett. And for those listening to the live webcast, thank you for your patience. We just had some difficulties loading up the slides. A reminder that if you'd like to have some questions, please press 0 then 1 on your keypad. And if you'd like cancel your position in the queue, press 0 then 2. As we've got a lot of questions on the board, please limit your questions to one, and if you would like to do a follow-up, you can just re-queue. So our first question comes from Ian Miles at Macquarie. Please go ahead, Ian.

Ian Miles: Good morning, guys. You talked a little bit about the additional of flexible storage generation. Can you give us some timings of when it might be FID for some of those hydro.

Brett Redman: Yeah, I think this guide is within the slide we've put in there that shows the development pipeline. So was it in slide 10 which would typically sort of guided as to when we expect projects to occur. So some of the pumped hydro projects are little ways off. They are more in the feasibility study stage. The most immediate project is the Newcastle gas where actively advanced in getting EPC offers in on that. The approvals I think are pretty much done for the site. So by the end of this year, we should start to be in a position to look at that from an FID point of view.

In between those events, we'll continue to look at things like batteries and both at a high-end level and a good scale level but they'll bleed more into the next couple of years.

Ian Miles: Thank you.

Chris Kotsaris: Thanks Ian. Our next question comes from Rob Koh from Morgan Stanley. Please go ahead, Rob.

Rob Koh: Good morning, everyone. A bit of an echo on the line. I'm sorry, if I may sounding weird – weirder than usual. Can I ask a question about costs and I know that you inherited some targets and there's been many reports that you've brought McKinsey in. So I was just wondering if you can give us some colour on how we should be thinking about your cost initiatives over the next few years. And also I guess a bit of a specific question. On slide 17, which is the FY19 cost bridge, there's a one-off $42 million saving. I'm just wondering if you could tell us what that is, and I guess that's something that we should be putting back in for FY20?

Damien Nicks: Thanks Rob. This is Damien Nicks here. I'll take that question. Why don't I first talk about the one-off savings. The one-off savings – there's about three parts to that biz. The Active Stream, the National Assets divestments piece which is a one-off. What was also in there was included in the slides is that the reallocation of fees and charges as we've gone to one ERP, so they won't be there going forward. So we've quite deliberately taken them out to obviously not record that benefit.

And then if you think more broadly opex going forward, as we have talked to the market at the half year, we're absolutely focused on ensuring the focus on discipline spend on our plants so to maintain to both mitigate the risk of plant performance but also really step it up for performance going forward. So what you can expect going forward is modest year-on-year cost savings where we're focusing on delivery around obviously the CXT benefits and also the benefits coming out of our ERP transformations.

Rob Koh: Okay, great. Yeah, wish you well with that. I'll get back in the queue.

Chris Kotsaris: Thanks Rob. Our next call is from Pete Wilson at Credit Suisse. Pete, please go ahead.

Pete Wilson: Thanks Chris. I was hoping that you could give us a little bit more colour on the transfer price realignment between wholesale and customer and consumer. Was that electricity was it green and other costs and where we'd see it come through the line items?

Damien Nicks: Yeah sure, I'll take that one again. Look, that was largely in the second half of the year and primarily related by black and green cost with the significant movements in those prices in the second half. We made the – did that adjustment to half two. So that's why we always suggest look at the overall portfolio reporting that eliminates any of the intercompany or transfer price movements. But that was certainly something we did in the second half of H2.

Pete Wilson: Is there anything that methodology that you can share with us to help us understand it, or is it just completely arbitrary now on?

Damien Nicks: If you think what happened with LREC prices in the second half, if you think what happened with the black prices when we thought about Victorian pricing, that's what's driving that change.

Brett Redman: I think, Pete, what's important is no change in method but at the half way mark, a recognition that – particularly things like green prices had changed materially. And what was a reasonable transfer price under the same method at the beginning of the year at the half year needed to be tuned so that it remained consistent if you like rather than moved away from what we always do.

Pete Wilson: Okay. You say no change in method then the next was there is a change, so I'm not quite following the terminology[?].

Brett Redman: Pete, if you want, perhaps we'll come back to you separately on that one.

Pete Wilson: Okay, sure. Thank you.

Chris Kotsaris: Thanks Pete. Our next question comes from Dan Butcher at CLSA. Please go ahead, Dan.

Dan Butcher: Yeah, hi everyone. Just had a question on churn rates. Obviously [inaudible] couple of days ago was in the papers saying they had churn rates for half in some cases or that's still early days after the new VMO and DMO. Just wondering what you're seeing in terms of churn in Victoria over the last six months and the ex-Victoria in the last month or so? I know that you said you churn rates are down but you said the market's flat [inaudible] at this moment you can sort of flush that out a bit?

Brett Redman: I think, Dan, probably part of the answer is sort of distinguishing pre-30 June and post-30 June when the VMO/DMO came in. So pre-30 June, you can see – I guess, we published the full year numbers that the second half share I think was wildly different to the full year result. Post 30 June, there's definitely been a slow down in the market. So I think a lot of consumers are both taking some confidence in the DMO and DMO – VDO, sorry in DMO benchmarks mean that there's less of urgency for shopping around than they might have had before, whilst at the same time they're just absorbing what it all means.

But I think the safety nets that we did at the beginning of the – towards the beginning of the year in electricity, the safety nets actually that we're putting out today for gas and the VDO/DMO is meaning its allowing customers to feel more confident that they're on a reasonable deal and churn has probably backed off, I don't know, 1% or 2%, maybe 1% in the first month of this new year. So a little bit early days. Small reduction, not huge reduction.

Dan Butcher: All right, thanks a lot.

Chris Kotsaris: Thanks Dan. Our next question comes from Tom Allen at UBS. Tom, please go ahead.

Tom Allen: Thanks Chris. Good morning all. So it's clearly a difficult environment for management to source large attractive growth opportunities. You mentioned just now in response to Ian, I think it was, that by the end of the year you'll be getting closer to FID on Newcastle power station. Can you confirm that it's only the development approvals or are there other specific policy settings and/or access to a certain gas price? You need to commit capital to Newcastle. Are there any other investment in new firming generation?

Brett Redman: Newcastle, if you like, we've allocated the capital but we still need to make sure that the business case fully stacks up. So as we get towards the end of the year, we're going to be looking at what are the costs offered to us from EPC contractors, where do we sit in a gas book sense and then importantly where is market priced today and where do we see it heading. So like with any final investment decision, we will wait until the last moment to make sure we take account of all conditions and then make a final decision on that project once we have all the information in front of us.

Tom Allen: Okay, thanks.

Chris Kotsaris: Thanks Tom. Our next question comes from Mark Samter at MST Financial. Mark, please go ahead.

Mark Samter: Yeah, morning guys. So I'm desperately trying to resist [inaudible] the conference call. Just two question. Brett, you did – you kind of briefly touched on some of the FY21 headwinds that you faced. And please correct me where I'm wrong if I'm sure I am here. As a simple turn, it looks to me – I mean, clearly the pressures in gas did intensify as supply rolls off. But pretty much all the headwinds that you've highlighted in FY20, if anything on average intensified? Can you just give us a bit of a colour around obviously we got add back in the Loy Yang outage from this year. But ex-Loy Yang is there any reason to believe the headwinds in FY21 in dollar terms would be less than the headwinds year-on-year we're seeing in FY20?

Brett Redman: So Mark, the line was a bit shaky but I think the focus was on how do you think about FY21 in the context of what we're saying about FY20. We obviously don't project beyond the coming year in any kind of detailed sense but what we are seeing is a settling back of the market. So the big change in the last 12 months, particularly the last six months has been in green REC prices. That change by substantially happening during FY19. It's featuring quite strongly in the FY20 outlook.

We're also seeing or the forward market is pointing to declining electricity prices. Some of that's coming through in FY19, so appearing in FY20. But if that trend were to continue, then you would extrapolate what it might mean to our electricity margins further out. But it depends upon your view of the longer term electricity book but some of the effect is in there in FY20. If the market fell further, then clearly that would roll forward.

Mark Samter: And can we touch on [inaudible] too. I mean, obviously you stopped putting up the supply chart. There's not been much news supply added particularly when it gets delayed and how should we be thinking about that?

Brett Redman: Why don't I get Richard Wrightson, our EGM of Wholesale, just answer on our gas book.

Richard Wrightson: Hi Mark. As you know, we're working through a process of replacing the gas book. We obviously have contracts that come through and we noted a change in some of the cost base of the gas book going into next year. We're in the market for more gas. We manage those margins very tightly. The performance of the gas book has been very good in declining volumes and pushing the margins up. We will obviously be replacing gas and the book at higher cost than historically. That's obviously going to roll through any time. What will be important is how we monetise that gas since what works to market and how efficiently we can do that to see the overall impact on the wholesale gas book. But you're right to draw the conclusions as the older contracts drop off, we'll be replacing them and replacing with contracts that'd be at higher prices than they have been historically that was reflected in the forecast for this coming year.

Mark Samter: Thanks.

Chris Kotsaris: Thanks Mark. Our next call comes from James Byrne at Citigroup. James, please go ahead.

James Byrne: Hi. Thanks guys. Just wanted to ask about costs a little bit. I'm wondering whether there's any upside risk here to cost out particularly from retail in a partially regulated environment? You've said its early days but churns backing off. You're seeing price dispersion narrow which might exacerbate that? Are you seeing a reduction in discounts not only in electricity but gas as well? Just trying to see whether there's actually some upside here?

Brett Redman: James, I think the short answer is it's possible in the sense that we've allowed for a little bit of that in anticipating what the VMO and DMO – VDO and DMO, sorry, could do or should do into the market in the coming 12 months. As I said in answer to an earlier question, out of the gate, I think we're always seeing a drop of 1% in churn. So at that time a change you wouldn't expect a huge read through on opex. If you saw a material jump in churn, then I would say that's not necessarily factored into the opex outlook and there is always opportunity of activity levels drop to do more than just what we're building in here which is the benefits of all the structural changes that we've been doing post the CXT project that we ran and the PT3 project we ran where we're just coming off the back of having invested hundreds of millions of dollars - about $450m in total - in system development. We're factoring in the structural benefits of those changes. But activity level change a big shift is not necessarily in the outlook.

James Byrne: Got it. That's clear. Thank you.

Chris Kotsaris: Also from another James, James Nevin at RBC.

James Nevin: Thanks Chris. I just would like to ask about – so you talked about returning excess liquidity to shareholders, even with the buyback you still have ample headroom when talking through $3 billion to $4 billion of debt headroom. But when you look at kind of the capex kind of investment pipeline of activity, $2 billion that's quite long day for like hydro in FY25/26. Just wondering like is there at some stage where you kind of return to just some sort of like normalised targets kind of gearing levels that you look at? And is that tied to any – so as you're talking a bit more about, you know, moving into that broadband space, when you're going to finalise how you move into that area, if it's via an acquisition or whatever way, will that be a trigger for maybe some normalised level of debt?

Brett Redman: I think James, and I'll let Damien also comment, but I think what we're doing in capital management is in many ways continuing to roll forward on the principles we've talked about before, but it is a balancing act. On the one hand, we can see huge growth opportunities in the longer – in the longer term outlook for this market, including some of the things. And we obviously had a look at Vocus a little earlier on and that didn't go forward. But we can see both in emerging markets and in our traditional areas, the opportunity to invest sensibly on strategy, shareholders' money.

On the flipside, it is a choppy short term outlook, so that makes it harder, if you like, as we try and think about with confidence, what's the right next investment that we do. And so even though maybe some of those bigger things haven't come through quickly, you continue to see smaller things appear like the Perth Energy investment, the $100-odd-million there that we've announced today.

So we're continuing to navigate that middle path where we first run the business well. We manage our balance sheet around our credit metrics, so we continue to try and drive towards being a Moody's Baa2 credit writing, which gives you railway tracks for where the balance sheet gearing should sit. And within those railway tracks, we're clearly above or below, however you think about it, but we have excess liquidity compared to those railway tracks.

Today we reached a point or the board reached the point in the last couple of days that we felt that without an immediate, large acquisition, a large use of that cash, it was appropriate to return some of it to shareholders through the buyback. And we continue though to develop our growth opportunities going forward so that, you know, our priorities remain, you know, make the cash, see if we can invest it profitably for shareholders on strategy. And then if we find that we're not able to do that, then return it to shareholders as we're doing in the share buyback now.

James Nevin: Thanks.

Chris Kotsaris: Our next question comes from Baden Moore at Goldman Sachs. Please go ahead, Baden.

Baden Moore: Hi, Brett. I was just wondering if you could provide a bit more commentary on your outlook statements where you said the consumer margin compression is anticipated over the next 12 months to continue. I guess that means you'll still be cycling down on the consumer margin through FY 2021. I was wondering how long you thought it would take to re-price or find that rebased consumer margin?

Brett Redman: I think Baden, it's an ongoing thing and it's not trying to dodge the question, but the market environment I guess is relatively fluid, both around what state and federal governments are doing with things like VMO and sorry, VDO and DMO and also where competition is heading as well. I would say there's an immediate effect of the introduction of the VDO on DMO in the beginning of this new financial year, called in the order of low tens, low tens of millions. That's part of that outlook commentary that we're giving.

And then there remains something that is not an overwhelming amount, probably, you know, not overwhelmingly more than that, that affects lurking in the edges of as customers keep shopping for different deals. There are always some customers that are on higher, older pricing or lower discounting from years past that can potentially move to lower discounting or lower fixed rate products. But I see that more as a smaller rather than a huge effect into the future and it will flex up and down according to market conditions.

Baden Moore: Thanks. That's great.

Chris Kotsaris: Thanks, Baden. Our next question comes from Giles Parkinson at New Economy. Please go ahead, Giles.

Giles Parkinson: Good day. Yeah, thanks very much. I've just got a couple of questions. I – the conference call kind of broke up when you were talking about the New South Wales hydro project, so maybe just a little bit on that.

And secondly, I'm just wondering, your – your graph, it shows future developments. If we look at 6 to 12 months ago, there was a few grid scale batteries scattered around the place, one in Hunter Valley, one up in Queensland next to Coopers Gap, but I don't see them anymore. I was wondering if you can talk a little bit more about that, whether you don't quite see different technology measuring up or presenting the opportunities.

Brett Redman: No, happy to, Giles. And I think the way to think about it is at the Macquarie Conference presentation a couple of months ago, we had a slide headed with we're serious about storage, and that's unchanged. And so we're leaning heavily into a future that's going to need a lot of flexible generation. A big part of that is pumped hydro and a big part of that is battery.

So the pumped hydro projects, we're very positive about the projects in Muswellbrook in New South Wales and the one down in South Australia. We're kicking off all the feasibility work for it. And so you should see that as something which will take, you know, a while to get all the ducks in a row. But in my mind, it's less a question of if and more a question of when those projects emerge as the market needs them.

On the battery projects, I'm not sure if on this particular slide we included them in the past. I can recall it might have been the Macquarie presentation we had things like a potential Macquarie or even Liddell, I can't remember, but Macquarie site for a battery project. If it's not having it there, it's more oversight than conspiracy. Macquarie is a natural place for a grid scale battery installation. That's something we're continuing to look at. It's part of that broader battery thematics that we talk about that batteries are coming. It's a question of their economics, how quickly do the cost for batteries come down. As they come down, different sites will become more economic, then you'll see them kicking off. So that's a big part of our future. It will phase with cost.

Giles Parkinson: Thank you.

Chris Kotsaris: Thanks, Giles. Our next question comes from Dan Butcher at CLSA. Thanks again, Dan. Go ahead.

Dan Butcher: Sorry, I was on mute. I was wondering if I could sort of maybe ask, in terms of your new power stations you're looking at building and other investors as well, what sort of general capital do you expect for those sort of from a standalone point of view and sort of from a – how do you think about it sort of supporting your overall retail portfolio as well in terms of return to market from those? Given the [inaudible] returns on – especially on some renewables deals being done recently.

Brett Redman: So thanks, Dan. So again, just take the opportunity on the more immediate projects that we're looking at. You know, the next one is Newcastle Gas peaker. We're firmly committed to trying to make that project – our investment criteria is unchanged, so it remains at 12% hurdle rate.

Even where you see us engage in renewables projects, our piece of the pie, you know, depending on how we engage in those projects, is still to achieve that hurdle rate for AGL. Different participants in the market will seek different returns on capital or view things through different risk profiles, but from the way we're operating the business, we continue to seek that style or that level of return investment, so it continues to remain as part of the investment matra as we move forward.

Dan Butcher: All right. Great. Thanks.

Chris Kotsaris: Thanks Dan. Our next question comes from Mark Samter at MST Financials. Please go ahead, mark.

Mark Samter: Thanks, can you hear me on this line now? Or is it still –

Chris Kotsaris: Go ahead.

Mark Samter: Got it. Thank you. Just a quick question on, I mean I think it would be relatively easy for people if they could to dismiss the higher capex, that's not in our DNA – as the noncash, but obviously that was cash at one stage and you look at FY20 capex guidance, it's 100% higher than you would get for FY20 capex, a couple of years ago.

When we think about that vast increase level of capex spent on the business over the last couple of year, to increase – DNA and your earnings are still obviously declining pretty materially, how should we contextualise? Have you got the returns on this direct capex that you expected to? And therefore the conclusion of that should be underlying business? Has performed – yet we're still – or maybe some of the returns from recent capex being a bit more disappointing than you would have hoped?

Brett Redman: So Mark, I think there's sort of two parts to the question. Um, let me address the first part, which, I see coming up in one or two places, is I suppose, is our capex spend actually much higher than what we flagged in previous years' presentations.

The simplistic answer is yes, but the real answer is, no, in the sense that we don't forecast unapproved growth projects. And if you look at the growth, the forecast slide, sorry for capex that we've included in this pack in 25, we again show lower, purportedly lower capex in future years, but with a very clear statement, it doesn't include growth projects that, um, uh, that are yet to get past FID, are yet to be approved.

And you know, as I've said in actually in previous results presentations, I love the idea of coming back in the future and showing you a graph with a much higher capex spend if it's off the back of growth.

To answer the second question, broadly speaking or not broadly speaking, all of the growth projects that we've been doing when we go back and do post investment reviews, are comfortably holding their investment expectations so that sort of hurdle rate returns we're expecting are continuing.

So part of what you're seeing in that step up in depreciation, some of it is just investment in growth projects, which is great.

Some of it is where we've been investing in sustaining capex, which is about keeping old plant running. There has been some uptick in the last few years around that in the cash spend which is driving an uptick in the depreciation coming through. Again, it's deliberate decision at the beginning of my tenure as CEO to sort of lean into a bit more spend in opex and capex for sustaining purposes for those plants. And, and that is part of what's coming through in the depreciation number.

Mark Samter: Okay, perfect. Thank you.

Chris Kotsaris: Our next question is from Tom Allen at UBS. Please go ahead, Tom.

Tom Allen: Thanks, Chris. If management still believe in the convergence of energy and data, if that strategy hasn't changed, can you share what you learned from your short pursuit of Vocus that might influence any future interest in growing a data services business?

Brett Redman: Absolutely, Tom. And as always in these things, what breaks above the surface appears short, but what happens beneath the surface, I can assure that you that a long gestation process of thinking about the opportunity and how we go about it.

So we remain committed to the idea that data and energy is coming together and there are products and services emerging there that makes sense to our customers because that's what our customers are telling us.

We continue to look for opportunities. Vocus was clearly a very large nut, it was a reflection in part of, in the Australian market, if you strike out in a direction, sometimes it's hard to find opportunities because there's a small number of players and that can either push you to go to something larger than perhaps ideal, or maybe smaller than perhaps ideal.

Vocus has come and gone, we've emerged out the other side of that. I'm still comfortable with the strategy and the rationale of what we were doing there. It was price and value that effectively meant that that didn't work. So we are continuing to look at what are the products and services that our customers are telling us that they are looking for in this space. We're continuing to advance internally in how we bring that forward and in the coming months and years, you can see us continuing to lean into that space in a sensible, disciplined manner.

Tom Allen: Okay. That's helpful. If I can be taking it one step further, can you rule out any continued interest in a smaller subset of Vocus' asset?

Brett Redman: I think the best way is, so apart from, you know, the usual way to answer that, is we don't comment on M&A, is to say – a more nuanced answer is, we come out the other side of what we did with Vocus, feeling like, you know, the strategy was right and the thinking was right and the rationale was right, it was the price that was wrong.

So if you put that together, you would say, never say never on looking at subsets of assets and different assets that exist out there, simply because if you, if you weren't open to it, you'd be saying, my strategy was wrong, my rationale was wrong.'

So that means that never say never – re-prosecuting some of the things that were there. I would guide you to Vocus' comments, and I think that's the right place to direct these questions, their public statements around they're getting on with running their business for the benefit of their shareholders. And I respect that management team for it.

Tom Allen: Yeah. Okay. Thanks, Brett. I think that's a fairly clear through there. Thanks again.

Chris Kotsaris: And our last question comes from Rob Koh at Morgan Stanley, go ahead, please, Rob.

Rob Koh: Thanks, Chris. So I want to ask a question about LGCs and possibly also bring Perth Energy into the question. I guess you've highlighted a number of times the headwind from LGCs and in the past you, you suggested you weren't interested in a short surrender trade strategy.

It kind of looks from Infratil's accounts that Perth Energy actually made quite a bit of money from a LGC transaction, which may well have been a short surrender transaction. I just wondered if you could give us a sense if your strategy and thinking has changed on that front?

Brett Redman: Well, I'll let Richard answer, but let me say at a macro sense – the valuation of Perth Energy isn't a complicated, you know, mucking around with timing of LGC. So whatever they've done in the past is their business, not ours. On a future-looking basis, we think that's a really nice plant for the portfolio and a good kind of nut for the WA business. In terms of how we're just thinking about the LGC market generally, I'll get Richard to make some comments.

Richard Wrightson: Yes Rob, we have rolled out doing short sell strategies previously, shorts around the strategies, they have their own way of managing the book. We will look at their book once we own their book and look at the best way of optimising that, bit like Brett just referred to then, then we get real – anything in there particularly, but we will – we will have a strong preference of meeting our requirements in the year that they occur.

Rob Koh: Yup. Great. Thanks very much guys.

Chris Kotsaris: All right. Thanks, Rob. And thanks everyone for being on the call. This is the end of the webcast and we look forward to meeting with you over the coming week as we, uh, meet with some investors. Thanks again, and we'll meet again. Bye.