AGL Energy Limited half-year results webcast

Thursday 13 February 2020

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Ms Kotsaris: Good morning everyone, this is Chris Kotsaris talking from the AGL Investor Relations team. Welcome to AGL's half year results presentation for the six months ended 31 December 2019. The agenda for this morning's presentation is as follows. Our CEO, Brett Redman, will shortly present an overview of our results and a business update; then be followed by our CFO, Damien Nicks, who'll present more detail on the results before handing back to Brett to comment on our outlook. At the end, we will open for questions. At that time, if you'd like to ask a question, please press star 1. I'll now hand over to Brett.

Mr Redman: Thanks Chris and good morning everyone. Our 2020 half year result reflects a disciplined approach to executing our strategy and operating the business amid increasing challenges. Profit is down year on year as per our guidance, but we are nonetheless tracking ahead of our expectations, we are making our portfolio more resilient and growing our customer base, while delivering disciplined cash and capital management outcomes. Underlying profit after tax was down 20% in the half, primarily due to the outage of Unit 2 at AGL Loy Yang, increased depreciation following record levels of investment in recent years and the impact of market headwinds relating to the wholesale energy prices and reduced gas volumes. We have declared an interim dividend of $0.47 per share, consistent with our policy of paying out 75% of underlying profit over the full year.

Throughout the period there have been many positives, evidence of how we are building a stronger, broader business amid ongoing uncertainty of our sector. Customers are responding positively to simpler pricing and the investments we've made to make it easier for them to do business with us. Energy customer accounts were up again in the period by 36,000 to more than 3.7 million. The acquisition of Southern Phone added another 160,000 broadband and mobile services and our reinvestment in large business electricity customers is also delivering growth. In Generation, our output was up 3% in the half, despite the Loy Yang outage, reflecting our efforts over the past 12 months to invest in plant availability and coal supply.

We're also expanding and modernising our energy portfolio. We announced two major grid scale battery deals in the half at Wandoan in Queensland last month and with Maoneng across New South Wales in October and we commissioned the first new gas capacity in the national electricity market for seven years at Barker Inlet in South Australia. We have refined our growth strategy to focus on connection, orchestration, trading and supply and generation. We have made targeted acquisitions in support of our strategy via Perth Energy and Southern Phone.

Our continued strong cash position, both from an underlying performance and capital discipline point of view, has enabled us to complete 51% of the share buy-back we announced in August 2019, while maintaining ample headroom to support investments in the business. We're announcing today that we expect underlying profit after tax for FY20 to be in the upper half of the $780 million to $860 million range to which we guided last August, while noting that headwinds remain as we look ahead to FY21.

I'll now cover our key metrics for safety, customers and people. These are trending in the right direction, but there is always still more to do. In safety, the total injury frequency rate for the half is marginally improved across employees and contractors at 3.5 per million hours worked, but it is still too high and requires continued focus and investment. For customer, net promoter score is substantially improved compared with recent years, although disappointingly the score did not improve over the past six months. Our objective remains to continue to improve and we're encouraged that our net promoter score surveyed against specific events and transactions, is positive and trending upward over time. There is no new data on engagement for our people, with the next enterprise-wide survey scheduled for the second half.

Now to the financial highlights of the result. Statutory profit was up 11.4% to $323 million, reflecting a lower negative fair value movement than in the prior corresponding period, due to the lower short-term forward electricity prices year on year. The reduction in underlying earnings was consistent with the guidance we gave at the 2019 full year result in August. There was a material impact from the Loy Yang outage, depreciation and market headwinds as I've already discussed. Despite resilience in the period, average wholesale electricity prices were still down, customer pricing has come down on average and gas volumes and margin are down in a tight operating environment. Consequently, underlying profit was down 19.6% to $432 million.

Cash result benefited from a strong underlying performance and a reversal of net margin calls in the period. The interim dividend declared is 15% lower than the prior corresponding period. This is a small reduction than for underlying profit, in part because of the benefit of the share buy-back reducing shares on issue. Return on equity was down 1.9 percentage points to 11.2%, reflecting lower earnings, again with some mitigation from the buy-back.

My next slide covers the Loy Yang outage in more detail. Having returned Unit 2 safely to full operation, we are now in a position to confirm the financial impact for this year and estimate the insurance proceeds that we expect in next year. To recap, after the initial generator failure in May, it became apparent following a full assessment that a full generator repair and stator rewind would be required which would take seven months. Although we completed the repair and rewind process largely on schedule in mid-December, following the initial return to service, we found cracking in one of the units two cold reheat headers, which meant we needed to undertake more boiler repairs before we could return the unit to full service. Final impact of the outage to our FY20 underlying profit after tax will be within the $80 million to $100 million range we provided in August.

The reason that the earnings impact was so large is that it has a low marginal cost as a result of supplying its own brown coal, so any loss of generation translates to significant loss of cash margin. We expect to receive the benefits of insurance claims in FY21 and expect the net benefit to be broadly consistent with the quantum of the FY20 impact. Looking ahead, the insurance market is becoming harder for ageing thermal coal assets. This means AGL will pay rising premiums at the same time as retaining greater risks through higher deductibles.

My next slide focuses on the resilient performance of the rest of our fleet. Total generation sold to the pool was up 3% to 21,793 gigawatt hours. Our increased availability and output enabled us to offset some of the extended cost of the Loy Yang outage. At the same time, wholesale electricity prices were stronger than we expected, albeit they were lower on average than the prior corresponding period. The biggest improvement in output was at our black coal plants, driven by our operating investment in plant availability and removing bottlenecks from the coal supply chain. The calendar year just ended was a record for coal deliveries to AGL Macquarie of more than 13 million tonnes, up by more than one million tonnes. This is a result of our major focus on working with train rail operators to improve the availability at our Antiene Unloader. More capacity gives us more opportunity to use lower cost contracted coal and reduce our use of more expensive spot coal. Elsewhere in the portfolio there was some reduction in hydro output following high generation last year and drought-related constraints. Generation from our wind assets was up as a result of output from Silverton and Coopers Gap.

I'll now turn to my CEO scorecard, which covers our strategic priorities of growth, transformation and social licence, as well as the operational goals, which I have already discussed. We presented our growth pathways of connection, orchestration, trading and supply and generation at the investor day last October. We have acquired Perth Energy and Southern Phone in support of this strategy. Our core energy customer base is now up more than 100,000 accounts over the past 18 months and is bolstered by the platform for multi-product retailing, which Southern Phone provides. This is one way we are transforming the business, building a broader customer base more resilient to a transitioning market, at the same time as we expand and further diversify our generation fleet and becoming a leader in both residential and grid scale battery projects.

In social licence, we are a founding member of the Energy Charter, reporting publicly on our ongoing commitments to improve affordability and service delivery for our customers. We have supported our people and communities through the recent bushfire crisis and we know that this is only heightened financial market and other stakeholder concerns in relation to climate change. So I am pleased with the progress we are making on delivering on our commitments to enhance reporting under the taskforce for climate-related financial disclosures framework. I continue to believe that developing new energy supply is the best way that we can support lower prices for customers over the long term and with the development of Coopers Gap, Silverton and Barker Inlet, we have delivered $1.6 billion of new plant.

Now let's focus on our growth strategy. Connection is primarily about exploring opportunities in mobile, broadband and the connected home as data and energy continue to converge. Our acquisition of Southern Phone has provided us a scalable platform on which to build a multi-product offering. Orchestration is primarily about the value we can create through a network of distributed energy assets. Our virtual power plant continues to expand. Trading and supply is about our DNA in trading energy in all its forms. Our proposed LNG jetty at Cribb Point is a key project in which we see enormous potential to make the gas market more dynamic, while our growing grid scale battery portfolio builds optionality into our electricity portfolio. Generation is about developing flexible, despatch-able assets that can support the ongoing transition of the grid to renewables. We're proud to have commissioned Barker Inlet. We have added the Kwinana Swift power station to the portfolio via the Perth Energy acquisition and we are progressing approvals for the Newcastle power Station. At the same time, we're continuing to invest in our core asset base to improve its flexibility and reliability and in November, we will reach the halfway point in the 100 megawatt upgrade of the Bayswater power station.

My next slide looks at the growth momentum we're seeing in our core energy customer base as we progress our journey to becoming a multi-product retailer. The chart to the left shows that we have achieved net growth of 102,000 customer accounts in the 18 months to 31 December 2019. Overall churn and market activity has reduced, with customer retentions down over the 18 month period reflecting higher levels of customer satisfaction. We have also seen a reduction in ombudsman complaints of 16%. Customer experience transformation program is delivering better service and customers are responding positively to simpler offers. We now have 750,000 customer accounts on our simple AGL's Essentials plan and call centre volumes are down 21% and we're staying focused on providing all customers with the best rate for them.

The chart to the right shows where more growth can come from. Our core energy customer base is increasing from a mature position and there are pockets of meaningful growth opportunity as we sell more services to more households in more places. Throughout our customer base there are considerable opportunities to provide more customers with services such as rooftop solar, batteries and demand response. Western Australian remains a growing market for us and of course there is data, with 160,000 services Southern Phone provides, giving us a platform for multi-product offers nationally.

Now let's turn to transformation and specifically our progress in batteries. As we said at the investor day, we are now at the dawn of the battery age and we are taking a leadership position at both grid and residential scale. This market is now at a tipping point, with the opportunity to leverage falling technology costs and government support for investment. The Wandoan South battery partnership announced last month with Vena energy, will be one of the largest battery projects in the country, complementing our energy position in Queensland through the Coopers Gap wind farm. WE announced in October our innovative derivative agreement with Maoneng, giving us a call on capacity at a fixed price at four 50 megawatt batteries throughout New South Wales. We're already operating the Dalrymple battery on the Yorke Peninsula in South Australia and we're progressing potential projects at Broken Hill and Liddell. Our virtual power plant residential and small business battery program now has more than 12,000 participants, a capacity of greater than 6 megawatts. Consumer interest is accelerating and we are responding, for example through the very competitive Tesla Powerwall offer we launched early this year.

Another way we are giving customers access to smarter energy solutions is via demand response. Today we are announcing we will expand our peak energy rewards program to other states before next summer, following successful trials in New South Wales and Victoria. The pilot program, with 8000 customers in New South Wales and the support of Arena, AEMO and the state government enabled customers to earn bill credits by reducing their energy usage at coordinated times of day. On average, participants saved 30% on their usage during peak events. The expansion is entirely AGL funded and follows the successful expansion into Victoria in December. There is no cost to customers for participating in the program.

Transformation is also about flexible generation supply. We were delighted late in January to accept full operational handover of the Barker Inlet power station adjacent to the AGL Torrens site near Adelaide. BIPS, as we call it, is a flexible 210 megawatt dual fuel gas peaking power station with fast start generation suited to an increasingly dynamic market. It assists in balancing the steep movements that can occur in wind and solar supply and its flexibility frees up gas for use in other parts of AGL's portfolio. The proposed mothballing enclosure of the four Torren A units will occur starting later this year through to September 2022. That is consistent with the deferral that we put in place last year to help offset the impact of the Loy Yang outage over summer.

In social licence, I want to acknowledge the efforts of our people in supporting our customers, communities and each other during the recent bushfire crisis. This response began at the start of the crisis last November. The AGL portfolio has performed strongly on extreme heat days that we experienced throughout that time. We have supported affected customers and the communities around our assets with prompt provision of targeted financial assistance. More than 173,000 of our customers have been directly affected by the fires and we have put in place targeted debt waivers, forgiven fees or paused billing for those affected. We've also given $150 credit for all volunteer firefighters. To date the billing measures we put in place amount to about $3 million in customer relief, with about a further $1 million committed through donations and work with our community partners ongoing. Many of our own employees' families and communities were affected because the main Southern Phone operations are run out of Moruya in New South Wales, although I am relieved to say none of our people were harmed and our assets have not been damaged.

I will close this section of the presentation with this slide showing the executive team that's now in place at AGL. When Markus Brokhof starts as Chief Operating Officer in April, combining leadership over our wholesale markets and group operation units in the integrated energy business, the team will be fully in place. It's a team with the breadth of skills, combining deep energy experience with broad customer, technology and finance expertise. I'm excited about what Markus is going to be able to achieve leading the new combined business and I'm encouraged by the way Christine is delivering growth and operational improvements in customer. Not only is the team, my team, now stable after a period of leadership change, it is ready to deliver with edge and I'm looking forward to what we can achieve.

I'll now hand over to Damien.

Mr Nicks: Thanks Brett and good morning everyone. I'll start by explaining the reconciliation of statutory profit to underlying profit in the half. Significant items in the period comprised of costs associated with the acquisition of Perth Energy in September 2019 and the partial impairment of our PARF investment, which reflects revised market pricing, marginal loss factors and generation assumptions for some of PARF's sites. The loss in the fair value of financial instruments of $92 million in the period compared with a loss of $251 million in the prior corresponding period, reflects movement in wholesale prices.

Now let's look at underlying profit across the group in more detail. The period-on-period $105 million reduction in profit reflects issues we flagged to the market back in August. The largest of these was the impact of the Loy Yang outage, which had a total portfolio impact consistent within the $80 million to $100 million range provided last August. The total negative movement in wholesale electricity gross margin of $50 million as shown here, reflects the offsetting benefit of our strong generation performance. The other large impact we forecast in August was higher depreciation. This was $80 million pre-tax in the half, reflecting recent investments such as customer experience transformation program and capital expenditure on major outages and life attainment activities on assets nearing their end of life. Noe that the first half impact makes up much of the pre-tax increase of the $100 million we forecast for the year. That step up in depreciation had already started to take effect in the second half of last year. Therefore the period-on-period change will be less in the second half of FY20 than the first half.

Nonetheless, full year depreciation may come in above the amount we forecast as a result of accelerated depreciation associated with unplanned capex on outages at both Loy Yang and Bayswater. Elsewhere the biggest movements were the decrease in gas margins due to lower volumes and lower eco market margins on lower LREC prices. The strong offsetting factors in the period were our consumer electricity gross margin, supported by stronger volumes and customer numbers, despite the introduction of default pricing. Operating costs were broadly flat, as savings in customer markets offset increased plant availability and digital capability spend. Net finance costs were down following the retirement of the hybrid notes in June 2019. Tax expense was down primarily because of lower profits.

I want to take a moment to talk about the second half, as our strong first half implies a lower result in the second six months of the year. Although we expect wholesale electricity margin to be higher in the second half now Loy Yang Unit 2 is back in service, we expect generation elsewhere in the fleet to pull back a little and we've experienced a number of small outages in recent weeks, combined with the impact of ongoing market price headwinds. In addition, we expect ongoing impacts in consumer electricity from customers moving to lower-rate products, as well as the timing impact of the accounting treatment of bad debts, which always weights to the second half. Finally, we expect ongoing pressure across the gas portfolio, as well as the usual seasonality impact from lower volumes in the second half.

Turning now to our electricity portfolio performance, pleasingly the 3% generation increase was coupled with increases in customer volume across all categories. Consumer volumes increased in line with our continued growth in average customer accounts, with weather impacts negligible to consumption. Large business saw increases in customer load in New South Wales and South Australia, a result of customer account growth following a renewed business development effort. Wholesale customer consumption was up slightly on aggregate. On the right hand side of the page you can see the wholesale electricity margin reflecting the Loy Yang outage and offsetting performance elsewhere. The increase in consumer margin reflected a lower transfer price because of lower wholesale prices. The group operations cost increase reflects the availability investment and depreciation trends I've previously discussed. There is enhanced disclosure in the portfolio margin reporting section of the operating and financial review on fuel and generation running costs as we flagged at the investor day last October. We'll continue to evolve these disclosures for the full year as part of our approach to integrated reporting.

The gas volume reduction is consistent with recent trends, with a continued decline in large business and wholesale customer volumes due to the loss of customers amid continued tight supply conditions. Lower consumption led to a reduction in consumer volumes, although customer accounts were up. Consumer margin was impacted by a combination of these lower volumes and customers switching to lower price products during the period, including the introduction of the gas safety net to reward loyal gas customers with lower rates. Wholesale and large business continue to experience a loss of customers as a result of tight supply conditions. Please note, for completeness we are now including gas production and storage earnings in our gas portfolio margin. These earnings improved due to a reduction in cost and increased gas sales at the Moranbah joint venture.

Looking at operating expenditure in more detail, last year's full year results we said we were going to have year-on-year savings and we are still on track for that, excluding the impact of newly acquired companies. At the half we are flat, excluding the impact of Perth Energy opex, meaning we are offsetting inflation. The savings are largely due to customer markets, the largest benefits being the non-recurrence of major debt forgiveness initiatives we undertook in the prior corresponding period. Lower market activity also meant lower variable costs, supported by the benefits of our investment in the customer experience transformation program.

Offsetting these savings, we had increased spend in group operations because of the Loy Yang outage and the continued deliberate investment in plant availability. We've also created the future business and technology unit, which is driving the delivery of innovation, long term business development, ongoing digital transformation and data analytics capability. This expenditure will be offset in margin growth in efficiency gains over time. Finally, we continue to see increases in insurance and regulatory costs reflecting our ageing thermal assets and the heightened regulatory environment. The net cash outcome of $1,135 million is a record for the first half, driven by strong underlying cash generation and working capital improvements.

The positive inflow from margin calls reflected the recent decreases in electricity prices, meaning we needed to keep a lower margin balance in relation to our net sole position in futures markets. The movement in other working capital also improved, reflecting reduced inventory growth at AGL Macquarie as a result of coal supply chain efforts and positive timing impacts between the periods relating to the purchase and surrender of green certificates. The tax cash flow of $5 million was net of tax instalments and a refund received for the prior year, as well as the utilisation of tax losses at Loy Yang. Cash conversion, excluding margin calls is close to 100%, consistent with a historical performance, as you can see on the graph to the right.

My next slide gives a good visual representation of capital management and our financial and funding position. We've now undertaken just over half of our announced share buy-back and we intend to complete in the second half, market conditions permitting. As a result, net borrowings have increased. We undertook our first sustainability link loan in September 2019 following the repayment of the hybrid in June last year. We maintain scope to invest in the existing business and new growth opportunities, while continuing to manage capital efficiently.

I will close my comments by providing an update on our plans for enhanced TCFD reporting. We committed last year to provide an analysis of at least one scenario in which the objectives of the Paris Agreement are met and global warming is kept to no more than 1.5 degrees above pre-industrial levels. This is one bookend of the scenarios we are modelling, the other being no change to current policy settings in Australia. Other scenarios we are modelling reflect other potential pathways to deliver meaningful emissions reduction. In all cases we will be extending our modelling further than before, at least to 2040 and using comparable, verifiable data from the IPCC and AEMO as starting points for our modelling, with KPMG assisting us as an independent adviser. The resilience of our business to the physical risks of climate change is also being considered in our scenario analysis and reporting.

I'll now hand back to Brett to wrap up.

Mr Redman: Thanks Damien. I will now wrap up by providing an update on our current views on the wholesale electricity and green certificate markets and on our fuel cost outlook. You'll recall that we spoke at our full year result in 2019 about how these market headwinds would affect our earnings in the short to medium term. I will start with the wholesale electricity market. Although down on average on the prior corresponding period, spot prices in fact proved reasonably resilient in the half and we were able to benefit from this because of our strong generation performance. However, there has been a sharp contraction in flat swap prices in recent weeks and as a result of lower pool prices in the first quarter of this calendar year to date.

The first quarter is often a volatile month for spot prices because of the emphasis on system availability over summer, so the current flat swap pricing may be slightly depressed compared with the three-year view. But, while that may mean some risks to the upside in the short term, the long-term trajectory remains for prices to continue to trend down as more supply comes on and demand remains flat. We expect over the next few years prices to trade in the $60 to $90 per megawatt hour range. In the green certificate market, although the large-scale renewable energy certificate price has been resilient over recent months, the forward outlook remains for further falls. We still expect certificates to maintain some value and we are watching the market closely in the context of demand for carbon offsets, which may create a conceptual floor for LREC prices.

Now I will turn to our fuel cost outlook and our revolving sourcing strategy for black coal and gas to mitigate impacts from maturing contracts and market price trends. As we have discussed, gas import costs were lower in the half because of lower volumes, meaning we sourced a greater proportion of gas from lower cost legacy contacts. While the cost of recontracting is lower at present than it has been for some time as a result of a fall in global gas prices, it is still materially higher than at a time when we struck these older contracts. As a result, the outlook for our gas sourcing costs continues to average up in coming years.

We continue to look at the most efficient ways to source gas to support the lowest possible prices for our customers and to increase competition in this market. We're progressing the proposed Cribb Point LNG import terminal, working through environmental approvals and expecting to reach a final investment decision during the 2021 financial year. When we do come to that decision, we do expect the timing of delivery of first gas and the overall costs of the project will have been impacted by the increasing complexity of the project since its first inception. Nonetheless, even with potentially later gas and higher costs, the economics of the project remain potentially very compelling.

Our average cost to black coal in the half just gone was greatly aided by the coal supply chain improvements I discussed earlier and I am confident the investments that we've made in logistics management over the past 18 months will continue to benefit AGL. Nonetheless, escalation will still occur on existing contracts and there are gradual step-downs in volume from the very cost competitive legacy contracts we acquired with Macquarie Generation in 2014. Of course black coal only services AGL Macquarie, not AGL Loy Yang, where we provide our own brown coal at a very low marginal cost.

So the market headwinds in our traditional business remain, but we are executing our strategy and operating the business in a disciplined way against these challenges. Building a broader based, more diverse business characterised by many relatively small initiatives, is all about growing our resilience in this transitioning world. If I reflect on our progress in recent months, we are now connected to more than 27% of Australian households and I am confident we will continue to expand the breadth, number and quality of our services. We've added broadband, mobile and battery offerings to our core electricity and gas services and this will enable us to provide more value to existing and new customers. Geographically we are more diverse than ever, with a meaningful presence in Western Australia, an increasingly physical presence in Queensland and a stronger regional presence to build on via Southern Phone.

Finally, as our traditional baseload generation fleet approaches the end of its life, we are developing a more modern, more distributed portfolio of nimbler, more dynamic energy supply using fast-start gas, batteries and other technologies. It remains an exciting time to be in the Australian energy industry and I am confident AGL, with its broadening customer base and asset portfolio, is extremely well placed to thrive. To close, the outlook reflects our solid performance relative to the known challenges. We expect underlying profit after tax for the full year to be in the upper half of our $780 million to $860 million range. This reflects the offsetting impact of our strong portfolio performance and customer growth on the impacts of the Loy Yang outage, depreciation and market headwinds that we expected. Those headwinds remain as we look into FY21, but our cash generation continues to be very strong, supporting our robust financial position and the anticipated completion of the share buy-back.

We will now take questions.

Ms Kotsaris: Thank you, Brett. A reminder to press star/one to ask a question and we also ask that you would please keep to one question at a time. You can re-queue if you have another question. Our first question comes from Tom Allen from UBS. Please go ahead Tom.

Question: Good morning all and congratulations on a solid first half result, obviously amid fairly tough market conditions. First question, can you please provide some further detail on the de-bottlenecking work undertaken to get better coal supply into the Mac-Gen assets and what work you've done to optimise the physical dispatch out of those Mac-Gen assets? I guess I'm interested in whether these new arrangements you describe with rail operators will continue and is the higher output from those assets over the first half the new run rate to expect going forward?

Mr Redman: Tom, we might - I'll get Doug Jackson, GM of Group Operations and we've got Richard Wrightson here too from Wholesale, as a collaborative effort, but I'll get Doug maybe to kick off the answer.

Mr Jackson: Sure, thanks Brett. Thanks for the question. Yeah, it was a lot of work done not only with the rail companies on improving the supply logistics, but there was maintenance strategy and operating strategies we put in place within the coal yard and the coal belt handling systems to improve not only availability and reliability, but through removing single contingency failures and just optimising the whole operation and maintenance of the coal yard and coal handling systems. Then Richard can comment on some of the work we did with the rail transport system.

Mr Wrightson: One of the major problems we had at Bayswater with (35:05) is actually getting the coal on the trains so it gets cancelled and if we cancel trains, we actually normally end up losing the (35:11) which is our lowest cost coals. So there is a real focus in making sure we could actively take all the trains that were coming in and get them to site and that allowed us to really improve both output at the Macquarie site and pick up generation, but really keep our lowest price coal coming into the portfolio by not cancelling trains through. So there's a bit of an effort between my team and Doug's team just to really work out the value of those investments and make sure the plant could take the coal when it arrived.

Question: Okay, I think that's clear, so that sounds like this should be a new run rate, I guess, on that physical output from those Macquarie assets going forward. So looking at your coal supply charts on slide 36 of your presentation, you're forecasting relatively flat Mac-Gen customer loads from FY21 to 2022 and I note that one of the units at Liddell will *close in March 2022. Are you saying that Bayswater will be able to ramp up output and offset that impact?*

Mr Wrightson: Just if you go to those forecasts and you look at the level of wind penetration, the issue that we have with the Liddell units is they're not very flexible. So they actually take a lot of, when they're on, baseload generation, so we run them and just run them at a flat rate. When we take a Liddell unit off, what that actually means is a lot of the Bayswater units are actually doing the offloading to actually make space for the Liddell units to run flat, so we reduce the amount of offloading off the Bayswaters through that period. It will be driven by the level of wind penetration to that market, so it's all subject to change depending how much renewables gets put into that market up until that date.

Ms Kotsaris: The next question comes from Ian Myles from Macquarie Group. Please go ahead Ian.

Question: Hi guys, congratulations on the results as well. Can you just talk about on the generation side Newcastle, when you'll need to make an FID decision and I think last time we spent lots of talk about hydro and I barely saw a word hydro in the presentation, it there a sort of an update where those plans are?

Mr Redman: Look they're good questions, Ian. I think in terms of Newcastle, I'm trying to remember what we've said in terms of timing of FID, but I think it's towards the back end of 2021, sorry, end of early 2021 I think it is that we'll be getting to an FID point there. We're actively out talking to potentially PC suppliers and looking at pricing for it, so that's a big area of focus. Look just to maybe pre-empt what might be a couple of questions, in this presentation we've rearranged it a little bit, just some of the growth pipeline things that we've been presenting for many years, so we just felt some of the slides were getting a little bit tired and we brought a few things into focus for this presentation, like the batteries work.

Pumped hydro remains a major focus for us. In the previous pipeline slides and presentations, it was always something that was going to take some years to develop. You may have seen the owners of the Kanmantoo site talk about some of the challenges that we've had there in trying to settle arrangements there. So I'm seeing that in the funnel of opportunities become a little more difficult in terms of bringing forward. On the other hand, I think Muswellbrook in New South Wales remains an excellent site for us to be looking at, but that one's more phased more for the mid-2020s. So pumped hydro in my mind, very much up there with batteries, but in a speed to execution sense, batteries represent something you can get to market much quicker than what hydro is because hydro is a much longer, more convoluted approvals process and business case preparation, versus a battery site simplistically you can get up and running quite quickly by comparison.

Question: Just on the battery side, you talked in the past about firming, cost of firming being $20 to $30 and I appreciate batteries are sort of complicated beasts, but in the signing of the PPAs that you're achieving, are you still expecting that that is the sort of price you're getting or are we seeing that decline?

Mr Redman: I think what I've found interesting with batteries is a year or two ago I talked a lot about I thought they'd be on balance sheet, I thought about them in relatively simplistic terms and that's somewhat reflected in what you're asking me there. The lived experience with the early battery projects are coming through are things like FCAS services are becoming a big part of the revenue and profit streams to make those grid scale projects work. So in these early days of the dawn of the battery age, some of the early projects are a much more complex bundle of revenue lines and profit streams to provide different market services as they get up and running. I think once we get a few years in and the cost of batteries comes down, the reliance upon government subsidy becomes a lot less and if you like, the first movers have picked up the things like the FCAS service benefit and the later movers are more focused on the time shifting of energy and the benefit that comes with it, we'll see it start to be more focused on that comparison to gas peaking, if you like. In a costing sense, though, I think that $20 to $30 is still not an unreasonable number to be thinking about. It'll narrow from there, but Damien, do you want to?

Mr Nicks: Just so we're clear, though, on the firming costs, that was a blended price, so if you can imagine renewables is going to be a lot cheaper and the firming cost is going to be a lot more expensive. It's not just a $25 price, per se, it's a bundled price.

Mr Redman: Yes, but the orders of magnitude are the same, the detail, though, is swirling around in a project-by-project sense as we're getting these things moving.

Question: *Thank you.*

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

Question: *Good morning guys, thanks very much for the preso and let me also congratulate you on the fine result. Can I just make sure that we understand how the $80 million to $100 million Loy Yang A's impact is reflected in these results? Does that include the little extra delay in January? Also, when we turn to the insurance recovery next year, which you said you're expecting to receive all of that, does that mean you're claiming the full $80 million to $100 million, or what I guess I'm estimating is a net impact of closer to $50 million, if that makes sense?*

Mr Nicks: Thanks Rob, I'll just briefly talk to it. The number we've given you is for the full impact for FY20, so it does include that small period in January, noting it wasn't big. When you think about from an insurance perspective, what we've said is the insurance will broadly offset that impact, noting that the outage went from the 2019 year into the 2020 year as well and obviously that's also going to be net of deductibles.

Question: *Okay, so does that mean that you're claiming the full $80 million to $100 million plus the little bit in FY19, or are you claiming the net impact, because you've obviously reduced that net impact through the extra generation at Mac-Gen.*

Mr Nicks: So just to be clear, so the impact of Loy Yang will be the overall impact when it was out of the market. We had offsetting generation for the rest of the fleet, so that's offsetting the result for the half. When we think about the insurance claim and just noting it is subject to ongoing commercial and sensitive matters with the insurers, that will be the claim on the outage for Loy Yang over the period of 2019 and 2020.

Question: *Yes, okay, all right, thanks Damien. Another question if I can, thanks for the extra colour on fuel procurement over the next few years and the coal charts are clear, can you remind us how much gas contracting you've got left to do?*

Mr Redman: I'm looking at Richard, but I think we as always will somewhat dodge that question because of commercial sensitivities. But Richard, do you want to give a more eloquent way of avoiding it?

Mr Wrightson: I'll more than happily dodge the question. We have been active in the market in buying gas to fill the gap. We've also left a little bit of spare room, given where the price is at.

So the portfolio just changes over time. I think the current fall in the gas prices is likely to sustain for a little while, given what's going on in the international markets; we will use that opportunity to pick up some more gas. But what we're trying to focus on is if we can source gas, where can we sell it to and how easily can we sell it. So we'll look at things like business customers and trying to push some more gas through the business customers and if the gas is at the right price, we'll pick up some for generation. We're not buying a fixed targeted volume because we can flex the portfolio around what gas is available and what price is both through our generation, through our business customer fleet. So in answer to your question, we've got adequate gas in the portfolio and we'll adjust our buying depending on market conditions.

Mr Redman: The build I'd sort of put on that answer to is, we've been talking about it for a little while now, what we're seeing in the gas market, I think, is a market trading much more like the electricity market nowadays. So while we have still some really nice significant legacy contracts that will go on for many years, so people have seen them from presentations in years past, the old QGC positions are still there and they're very competitively priced, those contracts. For the rest of the portfolio, you're seeing it more move to a bit like in the electricity market where it's more on a three-year horizon with a decline through that horizon and constantly layering in from different sources. The way we've been positioning our portfolio with a particular emphasis on storage, so WUGS is really starting to come, Iona is starting to really come into its own over the next year or two, we've got the Newcastle gas storage facility, other optionality like that. We're leaning in to storage and optionality that allows us to have a flexing rolling portfolio, so it will take time for gas price market change to roll through that portfolio, but it will be rolling through not dissimilar to what happens in the electricity world nowadays.

Question: *Okay, great, that's not a dodgy answer at all, thanks very much, that's very helpful. Just a final question I guess you've got a refreshed management team now all in place or coming into place, should we be anticipating any kind of re-segmentation of the accounts?*

Mr Nicks: So Rob, I'll answer that one. What you will expect for the end of June will be simply a summation, if you like, of group ops and wholesale, that's how we'll look at reporting 30 June, but you will still see the details of group ops and wholesale for 30 June.

Question: *Okay, great, thanks.*

Mr Redman: I'm not speaking too much for Damien, because I know this will come up a lot, I would think of it as just adding a new subtotal of wholesale and operations with the same amount of detail, rather than a rearrangement of detail, which I know creates issues for just keeping spreadsheets up to date.

Question: *Yeah, much appreciated, thanks very much.*

Ms Kotsaris: Thanks Rob. Our next question is from Pete Wilson from Credit Suisse. Please go ahead Pete.

Question: *Good morning. A comment on operating costs, if I could, so they're up 5% if you strip out pcp one-offs. I mean it's fair to say missing targets were set a few years ago and we're still not getting any benefit from the significant capital investment in digital and IT. So I'm just wondering whether we should all start reassessing our expectations for declining total operating costs in the next few years.*

Mr Nicks: I'll take that one, Peter. Look what we've said and continue to say, we will have year-on-year cost savings as you look forward to the end of this year. We are seeing the benefit of the work we did, particularly digitisation at CXT coming through in customer markets. Combined with that, because of the lower market activity and churn, you're starting to see that flow through the books. I think churn is down around about 15%, 16% and we are managing hundreds of millions of transactions per annum. So that digitisation is absolutely important as we continue to look forward and evolve our products and services. I would say that the money we spent on CXT and other systems upgrade is paying for itself and will continue to pay for it as we look forward.

Question: Okay and where shall we see that though, because I mean on the waterfall you've put in, on slide 22, the only negative cost is a reduction in market activity and then all the other ones are increases in cost, including investment in digital data and IT. Where are the savings in CXT in that waterfall?

Mr Nicks: Well I think much of them is coming through that reduction in market activity, we haven't broken that out any further, but that's where you're seeing it, because things like core volumes are down, I think, 19% in the call centre. That's one of the big ones and that piece therefore, because it's digitised, means we can start to really see that cost come out of the organisation.

Question: Isn't a fair chunk of that, though, just reduced market churn?

Mr Nicks: It's absolutely a combination of both, yes and we've always said that, market activity as it comes out, therefore our costs will also reduce at the same rate.

Question: Okay, so in FY21 we should still be expecting a reduction in total operating costs, should we?

Mr Nicks: In the customer markets business, yes that's right.

Question: The entire business?

Mr Nicks: We will be - well we're not going to comment into FY21. What I've always said is we will have year-on-year cost savings for this year, we'll provide guidance into the market when we get around to the August results.

Question: Okay, fine, thanks.

Ms Kotsaris: Thanks Pete. Our next question comes from Mark Busuttil from JP Morgan. Please go ahead, Mark.

Question: Good morning everybody. Just a question about the insurance claim and this might be a relatively simple question, but do you intend to include that in underlying earnings for whatever guidance you might provide for 2021, which would therefore mean if you unwind $80 million to $100 million in 2020 costs and add that amount into next year, so could be an uplift in the order of about $160 million to $200 million on underlying NPAT, everything else being flat?

Mr Redman: Look I'll pick that one up. In absolute isolation directionally that would be correct, in the sense that having Loy Yang 2 running for the full 12 months next year will clearly step up earnings and banking the insurance premium next year, which we will include in ordinary results because we'll be flagging it well in advance and it's really the recovery of a loss of operating profit over the last little while. But I just caution, as you're thinking about it, we also see the wider thematic of our business and the headwinds that we've been exploring in detail for some time now. So I just caution overemphasising one part of what will be a complex transition of numbers from this year to next year.

Question: *Yes, yes, got it. But it will be included in underlying, so we can make assessments of what we think what prices are going to do and margins are going to do and everything else, but in terms of being included in underlying, you will include it in underlying earnings?*

Mr Redman: Yes, that's right, so in a simple fashion, simple answer, when you do your waterfall from this year to next year, you should include in underlying an estimate of insurance recovery, subject to settling and recovering from the insurance company, but that's our expectation.

Question: *Okay. The other thing I just wanted to ask is we've seen a notable slowdown in the rollout of renewables, partly due to the marginal economics we've been reading all sorts of newspaper articles about these things struggling under the economic outcomes. Additionally, perhaps exacerbating these problems are the issues in terms of getting connections to the grid and MLFs and all sorts of stuff like that. I was just wondering in the context of the comments you made about wholesale prices continuing to be under pressure, do you think that there's going to be a continued rollout of renewables on the basis of those marginal economics?*

Mr Redman: I do. I think though, compared to what we might have forecast a couple of years ago for this moment coming, I think we're seeing a lot less renewable projects coming through, because I think the next, I will guess, couple of years, year, will be coloured by those that are looking to build renewables, trying to work out what the economics of connection will be. So that's sort of moving beyond the more usual discussion about what do you think price will do and how does your project stack up, to because of the struggle that all new renewables projects, including our own that we've been completing through the PARF in recent months, are struggling to get on and are struggling to maintain their forecast loss factors, their forecast MLFs, it's introducing a large amount of uncertainty into business cases when new projects are being proposed. That really weighs on projects, so only the really best projects then are sort of making it through, I suspect, investment committees in different organisations, whereas before the more average ones could get up because you were confident around the loss settings and risk factors.

Inevitably, less supply coming on must mean less downward pressure in the shorter term on pricing, but at the same time, what you're also seeing is the emergence of lower price gas into the market and I think that's going to have the same, if not greater impact on those forward price outlooks, because suddenly local LNG producers in particular are trying to work out what to do with gas and you're seeing more of it starting to be pushed towards gas fired generation. So I think the reduction in gas prices that are starting to emerge will have a balancing effect maybe compared to what a slower take up of renewables might have been doing in forward pricing.

Question: *Okay and maybe just one last, if I can just throw in another question, given what gas spot prices have done, would you not think to contract as much as possible at current prices?*

Mr Redman: There's always what you would like to do and what's available in the market. I use the electricity market as an analogy. There are moments in time when you look at the forward curve three years' out and think, wow, that's just moved 20 bucks, I think it's just over moved and it doesn't make a lot of sense, I want to go out and fill my boots at that price. The reality is there's not a lot of volume necessarily available. It's potentially the same thing in the gas market. The gas that we might need in the very short term to the extent there's a gap, we've got the spot markets as much as the contracting markets where we can fill that gap. Where we look at pricing two or three years' out and this is hypothetical, even if we think that we might like to fill up on what might look like cheaper prices, it doesn't mean producers are necessarily going to rush to offer those prices. There's often a question of liquidity in the forward price outlooks that you see and different participants in the market waiting for better days, whether that's up or down in price it depends on your viewpoint.

Question: *Okay, thanks so much.*

Ms Kotsaris: Thanks Mark. Our next question comes from James Nevin at RBC Capital Markets. Go ahead James.

Question: *Thank you, Chris. Just a quick question on your slide in there about Cribb Point and you're talking about the timing and cost is likely to be impacted by increased complexity and yeah, you don't have this knowledge around talking about the timing of when these things come on and the cost of them, before I think you talked about FY22 for Cribb Point and $250 million, I'm just wondering can you talk about what's changed there and is there an updated kind of timing and cost of that project?*

Mr Redman: I think the main thing there is it continues to, I guess, take longer than we might have expected 12, 18, more months ago, as we move through approvals processes and get all the underlying agreements and the like that we need in place to progress that project. We haven't recrystallised what we're seeing in time and cost at this moment, so we're not really at a position to provide a fresh forecast. The next milestone is in April/May where we put on public exhibition the environmental impact statement. That will be the crystallisation of the current phase of working with different government departments for approval. So once it goes on exhibition, it will go through a process of taking on board public comments and public hearings and then it will move into the final stage of both department and ministerial sign-off that loosely might take through to the end of the year. So I think until we - we see the next milestones as when we go through public exhibition and get a sense of where the project's sitting and then finally, when we get what I hope to see as approvals around the end of the year and any conditions that might come with those approvals. I think we are signalling that we are seeing a longer timeline than what we had seen in the past and inevitably that must weigh a little bit on cost. But we're not at a point yet to crystallise it.

I will say, though, I continue to think that this is a really good quality project and the reason I think that is the southern market, when you really bring it back to what the customers and markets need, the southern market needs more gas, unquestionably needs more gas and this project represents a good way of getting that gas to market. So I continue to believe that this is a project that will see the light of day, but it's a journey and it's a journey that's very respectful of the local community and what we need to do to get that project approved.

Question: *All right, thank you. If I could ask just one quick one, in relation to that operating cost and the waterfall, some of the increase in cost is the investment in digital and data and the product technology, so if we're already getting an uplift in D&A through the customer experience transformation and there's other uplift in the operating costs, just wondering what part of the business is that increase in costs coming through, that $12 million and the $5 million on that slide?*

Mr Nicks: Okay, so Damien here again, James. Look that is largely sitting in what we call the future business and technology area whereby we continue to put resources in there around the ongoing digitisation, product development, but also the analytics capability. So as I said earlier, we have hundreds of millions of transactions a year and that, for us, is where we think there is real value to go after. Ultimately the benefit will then flow through to, if you like, the customer markets and the group operations part of the business as we continue to work our way through the use of data and analytics.

Question: Thank you.

Ms Kotsaris: Thanks James. Our next question comes from Max Vickerson at Morgans Financial. Please go ahead, Max.

Question: Thank you. Just a quick question on the second half outages that were mentioned, I notice that the output from Bayswater seems to have been a bit low the last few weeks. Is that related to backing out or Liddell potentially being preferenced in terms output? I think Richard mentioned that before, or is that an ongoing mechanical issue?

Mr Redman: Look I think I know in the last week or two we've had a couple of outages at Bayswater and I think we had two or three units out at once in the last 24 hours. Look I would see that as more in the rucking ball of running our plants. There are moments in time when just normal outages, if I can put it in that way, of older plant can sometimes coincide and so we've just had, after a very good run in the first half, in the last few weeks we've had a couple more than normal outages that are relatively short term in nature coming through in that plant. Again, broadly the devil's always in the detail, I describe it as reasonably normal. By and large the group ops team have done a great job on the really big days in the market to sort of lean into those plants and nurse those units when we need to, to keep them available for when the market really needed it, which means right now there's quite a benign price in the market, weather's benign, prices well down, we're taking the opportunity to be a little extra cautious as we're seeing potential outages to just tidy a few things up.

Question: Okay thanks, that's it from me, thank you.

Ms Kotsaris: Our next question comes from Mark Samter at MST. Please go ahead, Mark.

Question: Thanks Chris, morning guys. Just a quick question on the gas business and obviously the stuff you're recontracting has obviously been recontracted materially higher price, if we put aside and acknowledge squeeze on that part of the gas business, I guess you contracted your two contracts with the Gippsland Basin JV last year pretty near the peak of the pricing cycle. Shall we think about the way prices are now, I mean theoretically that puts downward pressure on wholesale prices for FY21, shall we think about that being more of a negative and the ability for you to potentially buy some cheap gas on the market and push it into some of your contracts, I guess, i.e. since you signed those Gippsland Basin contracts, has your outlook for FY21 for the gas business got better or worse given what's happened to prices?

Mr Redman: Look I think we're possibly getting into an element of detail that we don't normally forecast. What I would say is a little bit like my comments earlier on about how the gas market has taken on a lot of similar characteristics to the electricity market. We're both purchasing in a rolling two or three-year sense, we're also selling in a rolling two or three-year sense. So we have C&I coming through on similar timelines and we're managing a portfolio where we had a couple of contracts picked up at the moment in time that you mentioned, but we have other longer-term ones that remain at lower cost and other sources of supply. But Richard, did you want to add?

Mr Wrightson: Just add to what Brett said, we've got a portfolio of gas on track, some of them more expensive, some of them cheaper, we pick them as we go, so we build up a portfolio and match it to where we sell. Fortunately we're not stuck with some major upstream production with very, very high costs associated with them, so we're in a fairly good position to flex the portfolio.

Question: Okay, thanks.

Ms Kotsaris: Our next question comes from Bruce Low at Bank of America Merrill Lynch. Please go ahead Bruce.

Question: Thanks Chris, hi guys. Just a quick one, with the change in wholesale prices, my understanding is that kind of gets reflected annually through tariff adjustments for residential customers. I remember back in 2017 when electricity prices took off, there was - I think AGL was talking about a delay for business customers of three years for that to flow right through to business tariffs. Is that still the way to look at it, with wholesale prices going the other way now, is that still the way we should look at business tariffs and how that gets passed through?

Mr Nicks: Bruce, look I'll take that one. I think when you think about our portfolio, what we were saying in the past was if you imagine business customers signing up from anywhere one to three-year deals, depending on which time of contract they're on, therefore every three years they're recontracting, so that's that position. Whereas consumer customers, we're recontracting their prices every year, as opposed to therefore wholesale prices which we used to say, well seven to 10-year time length. So that was a - that hasn't changed, depending on the length of the business customer contracts will depend how often they are recontracting, but I think that’s a reasonable assessment.

Mr Redman: I think the build on it, because this is the opposite in some ways to what we were talking about a couple of years ago as prices were rising. On slide 20 we give a breakup of where volumes come from and it's a good way to think about it, where - I'm just looking here optically, about a third or a little under a third of consumer sales, consumer sales pricing is reset once a year. Obviously that's caught up a little bit in DMO and VDO processes nowadays, but kind of reset once a year. Large business customers, large business customers typically contract two or three years, so that's where it takes two or three years to fully flush through any change. Wholesale customers, which are a large chunk there, they include things like the desals and the smelters, they're examples where they're very long-term contracts. It might have things like CPI-style adjusters and other adjusters in them, but they move very slowly compared to market move. I think that's still the same way as the wholesale market is starting to really settle down, the same way we described how to think about it going up is probably valid and how to think about it as it starts to settle.

Question: Okay, so just by prices being high, business customers will still - there's no real change to that two to three-year average kind of contract lens.

Mr Redman: No, so I don't know, Christine, if you wanted to add to that? No. So they're still typically contracting on that kind of horizon.

Question: Okay, sure and then just one last quick thing if I can, just in terms of the wholesale portfolio, I think you talked a bit about the availability of hedging, even if you wanted to *do it a little bit earlier, answering the other question, but was there any additional hedging from a wholesale perspective taken out, looking into FY21?*

Mr Redman: Look I would say we would never answer a question in detail on how we're hedging. I'd simply think about it as on the three-year horizon, as you get closer to now within the one year out, we typically are fairly highly hedged, we are managing risk. At the end of the three-year horizon, it tends to trail off quite a bit and in between is a never ending review, if you like, of the trading team about how to make sure we're managing risk on the way through.

Question: Cheers, no worries, thanks very much everyone.

Ms Kotsaris: Thanks Bruce. Our next question comes from Giles Parkinson at RenewEconomy. Please go ahead, Giles.

Question: Thank you very much for having me on, just a couple of questions. The battery project that you've identified at Broken Hill and Liddell, what's going to be the context of those? I mean judging by your earlier comments on the conference call, it seems to be basically about storage and arbitrage. Do you have any time factor on those?

Mr Redman: So I think what colours almost all new generation projects of all stripes at the minute is generally each project will have a unique story and it makes it a little harder to answer questions in a sweeping sense, so you tend to have to be a little bit project specific as to why they might get up. Broken Hill, that's an example of we've got a bunch of renewable generation at the end of a long skinny line out at Broken Hill that's struggling with loss factors to get on to the grid. So I see most likely a business case emerging there that will be partly stabilisation services and partly just time shifting energy into different parts of the day where currently there is a lot of renewable energy getting choked and if we can move some of it to different times of the day, we should see a business case emerge there.

Liddell is kind of at the opposite end of the grid, if you like, it's right in the middle of lots of transmission and lots of generation, so there, I suspect, while there will be some stabilisation that might be in its business case, I would speculate that we might see its business case lean more into time shifting and intra-day trading almost to make that one work. Broken Hill is probably more advanced because I think the market need is crisper and clearer, so I would be more hopeful of that one cracking through sooner rather than later. Liddell being much more in the centre, therefore the market need is lesser, may take a little longer to get the economics of that one working.

Question: Is there a timeframe, though, on the Liddell battery in the sense that you're closing down or plan to close down the last two units by 2023, so presumably it would be in place by then? While on the subject of Liddell, I wonder if you can offer any comment on the leaked report from the taskforce, which identified a $100 million a year cost to keep two units open?

Mr Redman: So on timing for a Liddell battery, I don't have a particularly exact date, because it's in an early stage, if you like, of assessment. I think as we go through Liddell closure, that will be part of the triggers in the business case to make it work. I'd like to see a battery project up there sooner rather than later, but I emphasise it's early days and some of the shifting sands that are going on in batteries right now is falling cost. If we suddenly see a step fall in cost in batteries, we'll be able to move quicker. If it takes a lot longer to see costs fall, it may be a little slower. But I don't want to directly couple it with Liddell closure simply because I'm hopeful of seeing it happen sooner rather than later and so we're leaning into the opportunity there.

On some of the recent press around Liddell, I don't want to particularly comment on some of the numbers and things that have been talked about in papers, all I'll say is we've been very up front with both the public and government about the age of Liddell and the challenges that we face operating that plant. We responded to requests from government and looked very, very hard at extending Liddell and as a result, we've extended it from 2022 to now 2023, so that gives the market another summer to prepare for change there. Longer term, we previously publicly talked about very large amounts that would be needed to spend to make that site safe and to deal with some deep operational issues that are around safety and around just continuing to allow it to operate, given it's a 50-year old plant and our belief that we're not seeing that as economic moving forward. So nothing has really changed in where we're seeing that plant sit. Even as we continue to engage very proactively, very collaboratively with both state and federal government in talking about where that site sits, answering questions that were asked, we have a policy of answering any questions the government asks of us, while at the same time just planning for transition on that site.

Question: *Okay, thank you. Look just one final clarification, sorry if I'm taking too much time, but just the proposed size for the Liddell battery, I can't quite remember what it was now, but do you know off the top of your head?*

Mr Redman: I think it's more generic, but on the site itself, I think simplistically I could see it being located on the greater Macquarie site. We've got a lot of land there and there's a lot of transmission lines obviously connecting into that site. So I'm not sure, I'm looking at Doug, I'm not sure we've actually roped off a particular plot on the site, but I would say on the Macquarie site. That will be the natural place for it, whereas the pumped hydro in that region, Muswellbrook is more driven by where are the mine voids that we can use to do pumped hydro, hence why it's a bit away from our Macquarie site at Muswellbrook.

Question: *Okay. I meant size, actually, not site, but anyway. Thank you very much.*

Ms Kotsaris: Cheers. Our last question comes from Rob Coe at Morgan Stanley. Please go ahead, Rob.

Question: *Thanks Chris, they let me have another one. So I just wanted to ask a question and I guess it's following on a bit from Bruce's question about how the repricing flows through the book. The draft DMO actually has an increased wholesale cost allowance across New South Wales and I know that you guys have actually lowered your internal transfer price, I'm just wondering if you can give us some colour on how we should be thinking about that DMO repricing impact through the book.*

Mr Nicks: So I think Rob you're talking about transfer price between the two previous halves, are you? Because I think transfer price, if you do the back calc, went from about $93 down to $90 between the two halves. When we look forward, the draft DMO is now out, so that will then form part of our pricing going forward for 1 July, so that work is still go to forward, if you like. So I think you're comparing transfer pricing from previous halves, we will then obviously then have to look at what our wholesale pricing is as we look forward.

Question: *Yes, okay, thanks Damien, appreciate it.*

Ms Kotsaris: Thank you Rob and thank you everyone for being on the call. We appreciate your interest and your time and we look forward to meeting many of you over the next few weeks. That ends our call now, bye.

Mr Redman: Thank you.

Mr Nicks: Thank you.

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