<table>
<tr><td>Date:
Thursday 27 February 2020</td><td>Start time:
1pm</td><td>Finish time:
4.15pm</td><td colspan="2">Venue:
Whittaker Room
Powerlink
33 Harold Street
Virginia QLD 4014</td><td>Meeting no:
16</td></tr>
<tr><td colspan="2">Facilitator: Gerard Reilly (Powerlink)</td><td colspan="4">Minutes: Nicole Maguire and Kiara Bowles (Powerlink)</td></tr>
<tr><td>Attendees:
Andrew Barger (Queensland Resources Council)
Kerry Connors (Energy Consumers Australia)
Georgina Davis (Queensland Farmers' Federation)
John Gardner (CSIRO)
Mark Grenning (Energy Users Association of Australia)
Robyn Robinson (Council on the Ageing)
Dan San Martin (Energy Queensland)

Powerlink panel members:
Jenny Harris
Daniel Anderson (proxy for Norike Ganhao)
Simon Taylor (proxy for Chris Evans)
Narelle Fortescue

Powerlink observers:
Dan Pollard</td><td colspan="3">Apologies:
Ian Christmas (Edify Energy)
Henry Gorniak (CS Energy)
Chris Hazzard (St Vincent de Paul Society)
David Hiette (BHP Billiton)
Sam Pocock (Energy Queensland)
Steve Straughan (Aurizon)</td><td colspan="2">Powerlink presenters:
Gerard Reilly
Roger Smith
Enrique Montiel
Mark Pozdena
Brian Atkin
Nicole Maguire
Matthew Myers
Ben Wu</td></tr>
<tr><td colspan="6">Attachments will include all documents provided to panel members at the meeting including:
PowerPoint presentation and pre-reading documents</td></tr>
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1. Welcome and introductions
- Gerard Reilly, General Manager Communications

2. Update on Regulatory Investment Test for Transmission (RIT-T) for replacement projects
- Roger Smith, Manager Network and Alternate Solutions

Summary:

- Current RIT-Ts in progress and update on timings.
- Several ‘minor’ and one ‘normal’ upcoming RIT-T consultations in accordance with the RIT-T Stakeholder Engagement Matrix.
- Detailed update on the RIT-T for expanding the transfer capacity on the Qld/NSW interconnector (QNI).

Comments (C), questions (Q) and Powerlink response (R)

Q. With secondary systems replacement projects, there’s limited opportunity for non-network solutions?

R. Yes, that’s correct. They’re relatively low in dollar value so on that basis we tend to classify these as ‘minor’ engagement projects, and also use the expedited RIT-T consultation process for these ones.

Q. How long is the Ross to Chalumbin line, which is identified as a future RIT-T consultation project?

R. There's about 530 towers along this line. I can't recall the exact length but it’s pretty long – over 200 kilometres. This will be classified as a ‘normal’ project in our RIT-T Stakeholder Engagement Matrix, mainly because of the value of the project work that we’ll be required to do here.

Q. You mentioned in the QNI Project Assessment Conclusions Report (PACR) that Option 1a was identified as the option that maximises the net benefit with a payback of about seven years i.e. the benefits outweigh the costs within seven years of completing the works. Is that a normal timeframe, seven years? Or is that quicker than normal?

R. That’s a fairly quick timeframe, given the long life of these assets.

Q. What is the total cost of this option?

R. $230 million.

Q. And how much of this is in Queensland? Very little?

R. Very little. In the region of around $90,000. That relates to protection changes in some of our substations. That’s really the limit of our works.

Q. What's the additional capacity for the QNI?

R. It depends on the conditions, but as a rule of thumb, about 150MW to 180MW in the southerly direction (which is of greatest interest).

Q. There’s been talk about installing batteries of a size that has never been installed in Australia before. That's the sort of technology we're talking about?

R. Yes, it is.

C. It's fair to say we've realised that there’s quite a lot we need to work through before we’re comfortable that it’s technically feasible. So should another application or need arise, where we could use a battery or a new technology, we're ready to go.

C. This will be discussed in more detail later on, but in the 2020 Draft Integrated System Plan (ISP), we’re talking about the medium term QNI upgrade. We fully expect these technologies to be considered as part of that consultation. And we are now planning for that next RIT-T consultation on the next stage of QNI upgrade.

Q. So the ISP was done on the basis of Option 2e? Is that the one that you're consulting on? Or are you consulting on all of the options?

R. The Australian Energy Market Operator (AEMO) considered a number of options in their economic assessment. Of these options, Option 2e was chosen as the preferred in the recommended development path. Obviously, when we do a RIT-T for the next stage upgrade of QNI we will also consider a broad range of options (perhaps some that weren’t even considered in the ISP). These options will also be assessed across all reasonable scenarios.

C. As our understanding improves of the virtual transmission line approach, then there may be additional viable options that we consider in the draft report or any responses and submissions we receive.

Q. In relation to where the costs came from in the Draft ISP – AEMO has said that Option 2e has a capital cost of between $1.04 billion and $1.925 billion. That's a big range. And as they told us yesterday, they used the midpoint of that. Were you aware of that?

R. I wasn't aware of that price range before the ISP came out, no, but I was aware of that option.

Q. When were you aware of what the range was and the fact they chose the midpoint?

R. After the ISP came out. I wasn't aware they chose the midpoint, but that's common practice.

C. To summarise, all the costings in the QNI upgrades are AEMO’s, and all the other ones to do with our network in Queensland are Powerlink’s.

3. AEMO's Integrated System Plan (ISP)

- Enrique Montiel, Senior Planning Engineer Network Limitation

Summary:

- AEMO's analysis approach regarding scenarios and scenario planning, and market modelling/optimisation.
- The results outlined in the 2020 Draft ISP.
- Highlights of Powerlink's submission on the 2020 Draft ISP.

Comments (C), questions (Q) and Powerlink response (R)

Q. What does AEMO mean by consumer-led?

R. It means the majority of investments occurring behind the meter, so in your home, putting rooftop PV or batteries in and using electric vehicles as well.

Q. You've got the big renewable energy zone up in North Queensland. When AEMO was doing the modelling, did they take account of the extra transmission expenditure required to get those renewables out of North Queensland?

R. Yes. There's a table towards the back of the ISP that has what they call 'existing spare capacity'. That number is derived by looking at how much capacity we can put in there before we trigger a material augmentation.

C. For Far North Queensland, this capacity would trigger a large augmentation by approximately 2040. And we see that the group three projects are triggered in the latter years, but what we do see in the earlier years is you only get enough generation in those zones to avoid that major build. So, before it actually builds that, it chooses to plant generation somewhere else. We see that up until the point where it can't build anything else without triggering an augmentation.

Q. We've looked at Table 4 a great deal, and it tells me that the net market benefits are about, at most, 2.5 per cent of the total system costs, without the projects. Then I look at EnergyConnect, which had the assumption of $1.5 billion in cost and the Australian Energy Regulator (AER) saying it's probably $2 billion – there's $500 million like that, off the $2.18 billion of combined benefits. And you've got QNI Medium, which is halfway between $1.1 and $2 billion. It just gets to me that the margin for change and the margin for that right-hand column going to zero or below is very small, and if the capital cost in accuracy of EnergyConnect is any guide, then those benefits are going to disappear pretty quickly.

R. Yes, I don't disagree with your point. Just to clarify, in terms of the costs that AEMO are using here – it's a 20-year study, and they annualise the costs, so because they're 50 or 40-year assets, the full cost isn't being captured in that $87 billion figure there. It's only the sum of these three projects, the total cost of them over the 20 years is $1.6 billion. And similarly, the benefits beyond 2040 are not being captured here.

Q. But the costs have already been incurred in the first 20 years. The benefits accrue over the life of the asset, so surely that's underestimating the costs?

C. Ok, now – sorry – all these layers of the onion of the ISP are peeling away. I would have thought they would have included the up-front capital costs, because that's paid for. Now, I know it's recovered over the life of the asset.

C. Yes, generally when you do this sort of analysis, where your analysis period is shorter than the whole life of the asset, you normally have a terminal value at the end.

C. Yes, but the assumption seems to be here that the terminal value of the benefits is the same as – or more than – the terminal value of the costs?

C. I suppose it is stopping the analysis after 20 years and extrapolating the benefits.

C. Normally, in my experience, you'd put the costs in and then you'd have a terminal value of benefits.

Q. As well as costs?

R. No, because if you do a net present value (NPV), you don't reflect how you recover the costs. You'd have the costs in the three years of construction, or whatever it was, and then you'd have the benefits accruing over the asset life, and if you cut it off at 20 years, you would then have a terminal value of benefits, and then a terminal value of operating costs, to maintain the asset from year 20 to the end of the asset's life.

C. Okay. My understanding is we also use the method with a terminal value for costs.

C. But that shouldn't include a component of capital cost, it should just be operation and maintenance (O&M).

C. You don't recover the full capital cost in the first year. The way we charge, I understand, is through a weighted average cost of capital.

C. Well, in my experience in the private sector, you didn't take account of how you recovered the capital in the economic analysis of the NPV value. You simply take your cash flows as when you actually incur them, and when you receive them, and you incur your capital in the front three years, you accrue benefits in the next 40 years. So if you're going to cut it off at 20 years, the only terminal value you'd have in that NPV analysis would be the terminal value of the benefits, plus a terminal value of the O&M, because you've incurred all the capital back here.

C. Okay. I don't believe that's how we do it but let's take this discussion offline.

Q. Are they underestimating or overestimating the uptake of rooftop solar PV?

R. They are underestimating, by a long way, we think, and both of these points go towards deferring QNI medium. If you had more rooftop PV, then potentially there's less need for interconnectors. If you have a cheaper option than the one that’s being recommended, then potentially this option might win over the other option, and if this option can be delivered much quicker than a transmission line, this removes the reason we have to do the Project Assessment Draft Report (PADR) straight away. That is if our need is 2026/27 and there is a faster delivered solution, then we could have another ISP before we have to make that investment decision.

Q. A question about the total systems costs. Does that include the cost of consumers purchasing devices behind meters?

R. I'm not 100 per cent sure on that. I mean, they certainly show the cost behind the new installations in all their prices, but I don't know if they've got that cost included in the total system cost. I think because it's common to both the base case and the option case, the market benefits wouldn't change, so potentially, it wasn't included in the total system cost.

C. We can get clarity on that for you.

C. I think that total system cost may not include absolutely everything, but they include those things that are important when you subtract one from the other.

Action:

- ***Powerlink to provide more context about the methodology used to assess benefits for long lived assets in economic analysis (e.g. ISP and RIT-Ts), i.e. the use of terminal values.***
- ***Powerlink to provide information on whether the ‘total system costs’ reported in the Draft ISP include the cost of customers purchasing behind the meter equipment.***

4. Non-network IT expenditure – Benefits Realisation Framework

- Mark Pozdena, General Manager Business IT & Brian Atkin, IT Strategy and Architecture Team Leader

Summary:

- Application of Customer Panel’s initial feedback from December 2019 Customer Panel meeting.
- Overview of the new framework now being used across the Business IT program – categories, criteria, scoring and project phases.

Comments (C), questions (Q) and Powerlink response (R)

Q. Some of the criteria in the framework could be perceived as being quite subjective. What are we doing to ensure that we are taking an objective approach to some of those criteria, and also to ensure that the various people who might be applying or assessing them are doing so on a consistent basis?

R. That's where the breakdown of these questions comes in. For each one of those criteria there is a very detailed assessment under each one of them, and you can't just casually assess them. We also apply a standardised governance model to determine if the organisation wants to go ahead and why.

Q. It sounds to me like there's been some really good work done here, but I do have some other initial thoughts. This sounds, from a high level perspective, very good, going forward, from 2020-21. Have we gone back to reassess what we've done in these past 2.5 years of this regulatory period?

R. Yes, we have, and this has formed why we've put these measures in where we have, and why we've weighted them because some of our investment was in relation to capability and efficiencies. But it’s about what does that actually mean? If we say for example there is a positive NPV 10 per cent higher than cost, then the clear return of investment needs to be absolutely transparent as to what that is. It can be cost avoidance. It can be about getting efficient time, but we have to recognise this in the way that we structure this, and how this applies to our new business cases and project delivery framework.

Taking a look back at what we've done previously has identified where there are some potential missteps that we have made, where we said we would get efficiencies. This framework has made it very crystal clear to track the outcomes from any expected efficiency measures. When we've applied this focus in the past, we haven’t been clearly or consistently tracking, monitoring or executing the realisation. So, yes, we have applied it across the portfolio. It's very much informing how we're building our submission for the next Revenue Determination.

Q. What is the order of magnitude where you have not delivered on savings that we thought we would deliver?

R. I would say there's probably three projects that stand out to me, where we have not. We've applied it across the particularly high-level investments, and some of the feedback we got was, don't go nuts if it's around a $100,000 investment – weight it. That's why that weighing of the NPV and counterfactuals, and using these very nicely defined guidelines, enables us to do that weighting.

It's not that some of those earlier projects necessarily went horribly wrong, it's been to do with the nature of the way that IT has engaged with the business. We now have that end-to-end view that if we're investing, we have to track outcomes. If things don’t stack up, we don't do it.

C. I think it is great work. I feel more comfortable in what information we can provide for our customers.

C. As customers, what we're looking for is a clear understanding and justification for information and communications technology (ICT) expenditure, which in the past has been pretty “loosey-goosey”. And if you now say we're going to do this, because we're going to save X dollars in opex, we want to see much more explicit qualification and quantification of that. And hopefully you’ll say you’ll be spending this amount in ICT and have a step-change down. So does it provide an opportunity for a step-change down in opex?

R. We are absolutely committed to applying this framework rigorously for the ICT component of our Revenue Proposal submission.

Action:

- ***Powerlink to provide more detail on the Benefits Realisation Framework.***

5. Update from Revenue Proposal Reference Group
- Georgina Davis, CEO, Queensland Farmers’ Federation & Matthew Myers, Manager Revenue Reset

Summary:

- Overview of 31 January and 27 February 2020 RPRG meetings, in relation to key topics including benchmarking, ISP and contingent projects, Business Narrative and Service Target Performance Incentive Scheme (STPIS).

Comments (C), questions (Q) and Powerlink response (R)

C. Thank you Georgina for putting in that extra time and reporting back to the wider group – delving into the detail and letting us get up to date with your thinking. That's really helpful for the rest of the group. Could I take some conclusions from your presentation? The first one about benchmarking. Are you telling us and the rest of your colleagues that the benchmarking doesn't look really good, but when you drill down, it's not too bad?

R. Yes, I feel the methodology is a little bit flawed.

C. Yes, I think so. As I understand it, they're engaging with Economic Insight, who are the main consultant for the AER on this, because it seems a peculiar issue in the methodology that potentially gives perverse results.

C. Okay, so the benchmarking doesn't look fantastic, but we're not sure the methodology is right anyway?

C. Correct.

C. And our approach is not to look good in the beauty parade, because underlying productivity might not be reflected in where you are benchmarked.

C. That's okay for the Powerlink people, but these are my colleagues advising me how we should react to that.

C. I think it's also partly a reflection of the progression of Transmission Network Service Provider (TNSP) benchmarking, which is still much earlier in the quality journey than Distribution Network Service Providers (DNSPs). I think it's important these issues are worked out as quickly as possible, because we like to rely on the benchmarking data as part of our advocacy.

C. Then you made mention of the ISP, and you raised concerns about the origin of the consumer costs?

C. Yes, the capital assumptions that were used.

C. And we had a conversation on that at this morning's RPRG meeting, but there's still a few question marks?

C. I think what we arrived at, hopefully, was that as they develop the Final ISP, Powerlink is going to ensure that the numbers used for those projects that Powerlink has an interest in, are as accurate as possible, and Powerlink is happy to stand behind them.

Q. So, that's the position for us?

R. Yes, and also that Powerlink has discussions with its colleagues.

C. We will definitely try to influence this where we can.

C. It's confusing because it's been represented to me that the estimates that the Australian Energy Market Operator (AEMO) have used in the Draft ISP were provided by the TNSPs. And that appears not to be the case, at least for some of the projects, and so we want to have a clear understanding that the numbers are robust and the TNSPs are happy with them when the Final ISP comes out.

C. Okay, thanks. And STPIS?

C. Everyone is encouraged to put in a supporting submission on Powerlink's Framework & Approach (F&A), calling for a STPIS review. Submissions are due by 20 March.

Q. Was there a review of STPIS quite recently?

R. A long time ago. In 2015, for transmission.

C. Powerlink also lodged a submission directly to the AER reiterating our request for a review of STPIS, following on from support indicated by our RPRG members.

Q. I'm not sure that we have a copy of Powerlink's STPIS submission?

R. We can send you a copy of this.

C. On the benchmarking discussion too, just to be clear, I don't think we're saying to disregard benchmarking completely. It's more the discussion about the outage component that we're going to keep talking about. We're also interested in what we can do to actually move the dial on benchmarking and how many of those elements have a benefit to customers, versus just changing things in terms of our practices. For instance, different ages of lines would move us. That has no effect on customer prices. It was more that discussion about checking in to see what kind of things the RPRG would like us to explore a bit more in that space. So, we're not saying to completely disregard AEMO's benchmarking results.

Action:

- ***Powerlink to send the Customer Panel a copy of Powerlink's submission to the AER calling for a STPIS review.***

6. Stakeholder Perception Survey, Energy Charter update and Business Narrative
- Nicole Maguire, Manager External Communications & Gerard Reilly

Summary:

- Overview of key results from online 'pulse' survey completed during 2019. Top three stakeholder issues identified: dealing with the energy system transition, transparency and stakeholder engagement, and price.
- Overview of the Energy Charter Independent Accountability Panel Report from December 2019, directions for 2019/20 Disclosures, and Better Together Initiatives.
- Discussion on latest version of the Business Narrative and feedback from the Panel.

Comments (C), questions (Q) and Powerlink response (R)

<u>Stakeholder Perception Survey</u>

Q. On the reputation slides outlining survey results, the landholder response seems quite low. Is there anything underlying that?

R. That's an interesting one. Normally we actually struggle to get landholders to participate. This time around, we actually got nine landholders involved, which is a big number for us. I would say that in some parts of state we've had some bad experiences with landholders, over the last few years. I think we're getting a lot better and more consistent in terms of how we work with our landholders, but I still think we've got some legacy issues. My initial thinking is that it's still probably a reflection of our previous views, but we are getting a lot better and more collaborative as we go along.

Q. Have we actually asked our customers what 'good' looks like in the energy transition space, and why they actually think that we're not doing as well as we possibly could?

R. I don't think we've ever actually put that direct question to them. It could be a very interesting one to do, though.

Q. So what does success look like, in that space? If we're doing a good job and helping our customers?

C. We had some pull-out quotes on this. Because we're a Government Owned Corporation, I think we need to step up and ensure that we are working with the Queensland Government, to be able to manage the energy transition as best as we can. I think everyone is being challenged, but depending on what customer area you're in, they're struggling with different parts of the transition. So, I'm not sure if there's one simple response to that.

Q. Have you got any thoughts on this from a Business Development perspective?

R. I agree with your comment, but it depends on what type of customer and segments you focus on. For example, for customers we're bringing onto the network, the issue of system strength, is massive. If you are a base-load coal-fired power station, if you're being overtaken by lower costs of generation, that's a massive issue. If you're a metals producer with a particularly sensitive input price to deliver the cost of energy, that's a whole different equation. Can we show leadership across a whole range of sections? I think that's the challenge, but it won't be the right answer for everyone, every time. That's not to say we shouldn't walk away from that, it's just a difficult space to work in.

In terms of the big stuff, for example, system strength, I would argue that we're actually leading edge in responding to the problem, how to integrate a massive amount of renewable energy into a grid that's not designed for that – and we're doing that. It's not pretty sometimes and some of our customers are unhappy with our answers, but the integrity of the whole system has to be maintained, so we've got this double edged sword.

C. I think it's going to be a bumpy ride for the next few years. I don't think in six months we're going to be saying we're through that transition and noting it was easy.

C. From an Energy Networks Australia perspective, we recently had our strategy session, where we had transmission, distribution, gas and electricity, and we all agreed that we need to put the integration of renewables front and centre on ENA's agenda, because it's also front and centre on ours.

<u>Energy Charter update</u>

C. In relation to 2019/20 Energy Charter Disclosure Statements, the main thing for me is that the next round of reports are much, much shorter - less than 10 pages.

C. Reflecting on the conversation we've just had regarding the IT Benefits Realisation Framework. That stands out to me as a good example of where we haven't done well at tracking the benefits realised for significant IT investments, which does then have a knock-on impact to customers. That we've worked with the Customer Panel to look at what would be a good way to realise those benefits, made changes to our approach, and have looped back to the group and are now implementing that framework. That is a very practical example we could potentially highlight in our next Disclosure.

C. In relation to the Better Together Initiatives, a good start would be to have a common engagement calendar.

C. Energy Consumers Australia tried to do that some time ago, but then the various organisations found it very difficult to keep up to date.

Action:

- ***Customer Panel to email Powerlink with any comments on the Business Narrative.***

7. Engagement approach for 2023-27 Revenue Determination process
- Matthew Myers & Gerard Reilly

Summary:

- Recap of Engagement Plan for the 2023-27 Revenue Determination process, in particular the engagement scope diagram, evaluation methods and opportunities for improvement, and proposed engagement timeline.

Comments (C), questions (Q) and Powerlink response (R)

Q. Why is capex IT not listed as a key engagement focus?

R. The topics we’ve highlighted are the ones that we've already started to engage on and we think there's going to be continued effort. With capex IT, the intent is to talk to the RPRG next month about that. I'm hopeful that what we will have in that space will be comfortable from the customer perspective. If that's not the case, then we'll certainly revisit that in more detail.

C. I agree we probably can’t do much with opex base year, that's a pretty standard AER methodology. Depreciation is standard. I don't think we need to do too much on depreciation, unless you're going to have an accelerated depreciation argument.

C. I think we will look into whether there are opportunities or any need for targeted accelerated depreciation on certain transmission lines. It won't be a wholesale sort of thing, but we will look at targeted opportunities, and if we have any of those, we will come to you to discuss them.

C. And price path – usually that's a discussion about whether you have it all in P0 (P-nought) or you have it over the time, and I think previously there has been consumer support for it all being in P0 (P-nought), but is that something you need to formally consult on again?

C. It's really an outcome of the process. I don't think it's essential to consult on this, but we'll talk about it anyway. Every time we develop an indicative forecast, you'll actually see what the price path will be.

C. I agree that it's not a big area of focus.

Q. So we might adjust that price path to be out of the focus area.

C. I'll be a bit forthright. Some feedback I'd appreciate is on pass throughs. In relation to the national planner.

Q. Is that caught by opex step changes?

R. No. Sorry – from my perspective, we do not want it – any of it – it's not our opex, it's a pass through.

Q. But it would be considered by the AER as a step change?

C. Well, our argument is no.

C. From today's RPRG discussion, we could put it up as it an opex increase but we did make a statement that ENA's position is that we treat it as a cost pass through, not a step change. So we just need to make sure, however we treat it, you're aware of it.

C. I can't see how we can treat it as opex, because we've got no control over it.

C. I'm confusing the terminology, because I assumed that a step change as a result of legislation, for example, is a pass through.

C. Yes, well, it affects us.

C. Our main concern is that if we're asking for more, you need to know about it. Then it's also incumbent upon us to tell you the way we got to the final Revenue Proposal and how we've treated those particular items.

C. So I would assume this would be a step change, and then the question is, how do you estimate what the dollars are? In this case, it's a pass through calculation of what AEMO gives you. In cybersecurity, it will not be a pass through, it'll be you coming to your own view about what the number is, but they're both step changes. Am I mixing it up?

C. My understanding is that from a cost pass through point of view, where current rules might say that a cost pass through applies to an item that is one per cent of maximum allowed revenue (MAR), included in a single Revenue Proposal and not over a period – our conversations at the moment are that these situations are to be treated in that way, rather than as an opex step change. There's also some differential treatment between an opex step change and a cost pass through in terms of what is included within our efficiency benefit sharing scheme (EBSS).

C. Yes I think we're all in furious agreement about it.

C. Maybe pass throughs is one that you want to be aware of. We'll be guided by our Customer Panel and please give us feedback, so we can raise this in the various forums that we attend, about the feedback on the pass through from AEMO's national transmission planning process.

C. It's that bit about an opex increase. We will engage with you on opex increases, how they're treated in terms of a step change or a pass through. The key point is that there are some opex increases that might occur that we need to consult with you on.

Q. Was the AER going to provide further information?

R. From today's RPRG meeting, the AER was going to bring us back some information on the treatment of cybersecurity costs.

C. The only one I'd probably flag is capex input and assumptions. That component of work, from my understanding, is more about material cost escalating, rather than specifically talking about capex projects as part of the replacement or augex expenditure. Does anyone have any other views as to what capex inputs and assumptions mean to them, and whether it should be included as an engagement opportunity?

R. I would suggest that the key inputs and assumptions for both capex and opex need to be a focus of engagement because they are two things which our Board must certify as having reasonable assumptions.

C. You'll have a lot of issues around how you evaluate that and whether or not it accords with the AER's evaluation methodology.

C. Yes, for example, in relation to opex, we'll have a look at how we develop our base, these are the step changes if we go forward with any of this, this is what they look like, this is the trend we're using and this is where we've got the number from. So that looks at the inputs and assumptions for opex. For capex, for example, we've used this out of the ISP, and they go to contingent projects, we've got these projects, bottom up or top down, and these are the escalated cost inputs and other things that we've used to come up with the ex-ante forecasts.

C. I think we'll have another look at this. Once we put out our preliminary forecasts and positions paper, our draft plan, in the middle of the year, based on what sort of reception we get might also give us some indication about the areas we might need to do some more focused engagement. So please be assured that we'll be looking – and re-looking – at this again.

C. Also, one of the issues that would normally come up in those bubbles to do with assumptions is treatment of cost allocation methodology, embedded in both the capex and opex inputs and assumptions.

C. At this stage, we do not plan on changing our cost allocation methodology, and we also do not plan on changing our capitalisation, subject to ring fencing guidelines.

Q. In relation to evaluating our engagement approach, we have quite a few KPIs there. Are they all meaningful to you as customers?

C. So our overarching objective centres on producing a Revenue Proposal that is broadly capable of acceptance. But we want to make sure we're not missing out on some other quantitative or qualitative measure along the way.

C. Reflecting on all the conversations I've had with various Customer Panel members through our Better Together Initiatives, the big thing we keep hearing about is the time and cost it takes to be involved in consultation activities. I'm wondering whether part of those informal debriefs and that conversation needs to be, do you feel that the time you're spending on this is valuable?

C. How are you planning to measure this? What's the mechanism of measuring whether stakeholders were satisfied with the engagement activities?

R. After key engagement activities that Powerlink does, we usually send around feedback forms. Also, in our Stakeholder Perception Survey we have some dedicated quantitative questions around the effectiveness of our engagement activities, and that also gives a quantitative score.

C. It could be part of your engagement plan, but one group of stakeholders that I would have thought would be useful for you is local councils, because they're the ones who are seeing constraints on investment that may be linked to a limited availability of supply. I also think it’s about providing people with genuinely useful information. Not just that they understand what you're saying, but that it’s helped them understand their consumption and how that fits into the broader system.

Q. If you’re asking your stakeholders for feedback, how do they separate out their responses to you on general Powerlink engagement from the Revenue Reset process?

R. Yes that can be a challenge as there is often an overlap with different components of our engagement activities like forums and Customer Panel meetings. It is difficult to say, just judge us on that particular conversation. Unless it's something like the RPRG, where it just has solely a Revenue Proposal focus, and you can actually just get specific insights on that. I think what we need to do more is get more qualitative and quantitative feedback from RPRG members, to see how we're going and how we can improve.

C. I know we've briefly talked about it before, but apart from engaging with the RPRG, what sort of engagement are you going to be doing around the state, to engage with your other stakeholders who you deal with every day, but specifically on the Revenue Reset?

R. We are conscious that even though we're transmission, and we have more of a niche engagement market, we've got to ensure that we don’t look back in January 2021 and we've only talked to 30 people about our Revenue Proposal, that's probably not a good outcome. We've got to make sure that we're actually having conversations beyond our Customer Panel. We’re not saying that we need to go through a full blown process to try and get 100,000 people to respond to a survey, but how do we make sure that we've got that right balance? That's why we are thinking of rolling out some sort of regional engagement forums, towards the end of the year, off the back of our position paper that we're going to put out in July.

C. One thing we need to be mindful of is that ‘deep dive’ language has been very loosely applied in general across all the engagement I’m involved in. For me, a deep dive is a very focused discussion on a focused topic that is complex. So it's not for example on capex, it’s just on one aspect of capex, which is somewhat problematic, and where the solutions may not be obvious.

Q. Is the intention of the regional engagement to tell those customers about the content of the Revenue Proposal? Or you're seeking feedback on aspects of it?

R. I think it's both. I think it's about letting people know where we're up to. We thought that it would probably be better to wait until we had more concrete documentation to share with them.

C. I think it’s going to be critical to make sure those regional forums are tailored to the concerns of the customers you're talking to and it’s not just a general conversation. You need to make it clear about what bits impacts them and their community.

C. I just want to give a shout out to what I think is one of the best tables and the first time I've ever seen it. The table on page 9 of your Engagement Plan about which bit fits into which part of the IAP2 spectrum.

C. I was going to make exactly the same comment.

Q. Is this a public document?

R. Yes, it's on our website.

C. I will send this to other parties that may learn something from it.

Action:

- ***Customer Panel to email Powerlink with any additional feedback on the Engagement Plan for the 2023-27 Revenue Determination process.***

8. Transmission pricing consultation update
- Ben Wu, Manager Pricing and Billing

Summary:

- Pricing consultation recap – rationale, engagement, pricing criteria, options and stakeholder feedback to date.
- Proposed way forward and timeframes for 2020 consultation opportunities.

Comments (C), questions (Q) and Powerlink response (R)

Q. It's easy for a directly connected customer to get direct benefits from effective transmission pricing, but what's the flow-on benefit of getting this right for indirect household customers?

R. As we all know, it's a big supply chain. Once transmission prices pass through to distributors and ultimately retailers, network charges are repackaged, and the real signal itself might be lost, but the overall intention here is that if we can signal more efficient use of our network, it can reduce our overall costs which will pass through down to customers.

Q. So there's a network utilisation benefit?

R. Yes, if it promotes more efficient use of the network, and to the extent those signals are passed down through to Distribution Network Service Providers (DNSPs), their larger users, and subsequently, ideally retailers pick up that signal, the whole network itself is being utilised more effectively, which results in overall lower costs.

Q. Did anyone have any particular views on the options or how they'd like to engage, going forward?

C. I think it's important there's a clear correlation between pricing and network stress – how it links to peak demand. If there's going to be a peak pricing proposal, then the access has to correspond to a peak in network demand.

C. That's particularly why the options that we're going forward with are emphasising the locational element, which is really identifying what stress points you are facing on your part of the network and how that flows through.

C. Given that my overall preference is that the sooner you move towards cost-reflective pricing the better, recognising that cost-reflective pricing can mean many different things to different people, I'm hoping that one of the reasons it's difficult for DNSPs is because they're 30 per cent of the bill. You're only 10 per cent of the bill.

C. Seven per cent, actually.

C. If we have a few more negative prices in the Queensland system, you're going to go up to 10 per cent, because the generation component will go down – but that's another story – and that suggests to me that you should be able to move quicker, because you're only a small part of the bill. Is that a reasonable perspective?

C. It's a tricky one. I can see where you're coming from, but we have to recognise that, whilst we may only be seven per cent of the end user’s bill, we've got to use the same arrangements for those customers as well as the ones directly connected to us. At which point, we might be 50 per cent or 60 per cent of their overall electricity bill, so any swift or significant arrangements in that space will have a direct impact on those customers, directly to us, which, ultimately will flow down through to the seven per cent that we get towards the end.

Q. One of the big issues for DNSPs is that they go out and do all this hard work, reduce their prices, but they're not sure the retailers will pass them on. They have all these inventive prices. How confident are you that your price initiatives are actually going to make it through? Obviously, they could go directly through to your direct connected customers, but for all other customers, how do you ensure that all your inventive pricing mechanisms get passed through?

R. I think it would be very wishful thinking that a direct transmission pricing signal would make its way down to your bill at home. We are working with Energy Queensland on this. While we might have our transmission pricing structures, how best can we look towards working together as an industry, towards passing these signals through? If we think about how transmission pricing signals only filter their way down currently to the very highest level of DNSP customers, they will see a direct transmission price through. What we're looking at is if we align our structures, as in kVA charging, have more direct locational based signals, can we pass these further and further down the chain? That's one aspect which we're exploring. The other one is working more collectively on the retailer/DNSP shuffle between what the DNSP offers and what the retailer ultimately picks up and passes through. That's a much bigger conversation.

C. There's some potential work for the Energy Charter.

C. Yes, I was just thinking that this is an area where the Energy Charter is creating conversations we haven't been having before. There could be something around how we try to get more consistent flow through of pricing signals throughout the supply chain.

C. I would also say we already have cost-reflective pricing, to a certain degree, and this is looking to see whether we can be more cost-reflective. I'm also mindful there are currently certain limitations and rules that may actually restrict the flow through that you might see as a directly connected customer, despite what we do.

10. Meeting closed 4.15pm