Project EnergyConnect – Stakeholder Webinar #2 – 9 October 2020

On 9 October 2020 ElectraNet and TransGrid held a further stakeholder webinar to present the results of ElectraNet's updated cost benefit analysis for Project EnergyConnect and provide an overview of the ElectraNet and TransGrid Contingent Project Applications for the project.

An opportunity for questions was provided before and during the session, the majority of which were responded to in the time available during the webinar.

The following provides a full record of the issues raised by stakeholders at the webinar and responses to the issues raised.

Issue	Response
Gas price forecasts	
Why was no sensitivity case on claimed gas prices prepared, particularly given the latest forecast costs?	We have aligned our updated Cost Benefit Analysis (CBA) inputs, including gas prices, with the 2020 Integrated System Plan (ISP) forecasts. The gas price forecasts were adopted by AEMO based on independent advice and after consultation with stakeholders. We have verified these forecasts through updated forecasts prepared independently by EnergyQuest. We have released a summary of this report, while the full version of this report, which contains commercially sensitive information, has been reviewed by the AER. A thorough analysis of sensitivities would also require consideration of the full range of scenarios considered in the ISP, which has not been possible in the timeframe available and is beyond the scope of the updated CBA. For the scenario considered, indicative results suggest the long-term gas price forecast would need to fall well below current forecasts before net benefits were no longer positive, while gas prices would have to fall even lower under a weighted average scenario before this was the case.
Why weren't the latest updated gas price forecasts provided to the AER to allow them to consider them in relation to the updated CBA?	As noted above, we have aligned our gas price forecasts with the 2020 ISP. A full copy of the EnergyQuest report with updated independent forecasts used to verify the ISP forecasts was provided to the AER.
What would the impact of lower gas prices have on the net benefits calculated? Can you give some indication (e.g. -$1/GJ is a $30m reduction in benefits?).	As noted above, a thorough analysis of sensitivities would need to consider the full range of scenarios identified in the ISP. Indicative analysis suggests the gas price forecast would need to fall well below current estimates before net benefits were no longer positive under the scenario considered, while gas prices would have to fall even lower under a weighted average scenario.
The gas costs were prepared well before the impact of COVID	The updated gas price forecasts prepared by EnergyQuest take into account the latest information, and show a longer-term outlook that remains closely aligned with the forecasts adopted in the 2020 ISP.

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The most recent gas price forecasts established by AEMO for 2022 ISP have gas prices much lower than the 2020 ISP	AEMO will soon be commencing consultation on future planning assumptions as part of the 'Inputs Assumptions Scenarios Report' that will underpin the 2022 ISP. Gas price forecasts for the 2021 GSOO are under development and are expected to be the gas prices used in the 2022 ISP. However, these forecasts are not yet settled. AEMO's latest gas price forecasts were provided by Core Energy and Resources in December 2019, which provided two central forecasts (an upper and a lower). The 2020 ISP forecasts which ElectraNet adopted in the updated CBA and independent review by EnergyQuest remain within this range. This remains the most up to date information available.
AEMO's revised gas price forecasts are sub $9/GJ and do not include Narrabri	As discussed above, AEMO has not settled on the inputs for the 2022 ISP including the status of the Narrabri gas project in NSW.
Do you think it's prudent to rerun with the 2022 ISP gas price assumptions?	As discussed above, AEMO has not settled on the inputs for the 2022 ISP, and the forecasts applied remain the most up to date information available.
Updated cost benefit assessment	
What are the main sources of increased benefits for consumers from the updated CBA?	The largest contributor to market benefits based on the scenario assessed in the updated CBA is avoided generation fuel costs (64%) as more efficient supply sources are dispatched, followed by avoided storage build costs (14%) and avoided generator fixed costs (11%) as more efficient patterns of generation development and operation result. A full breakdown of the benefit categories is provided in Table 4 of the CBA report.
I am not sure how one can claim that there hasn't been a Material Change in Circumstances with a $900 million increase in capex? In our company we would go back to the drawing board.	A material change of circumstances is defined by the Rules (clause 5.16.4(z3)) to have occurred if the preferred option identified in a RIT-T no longer remains the preferred option. While both costs and benefits have moved materially, the outcome of the RIT-T has been found to remain unchanged through the updated CBA.
All you need is a 6% cost over-run and there is no net market benefit. This is too marginal and high risk. There is a need to go back and look at the capex again.	The CBA is focused on one particular scenario, which continues to demonstrate positive net market benefits up to a breakeven capital cost of $2.7bn, which would equate to a further cost increase of 11%. The AER has accepted the outcomes of the updated CBA on this basis. A full reassessment under the RIT-T would require a weighted scenario approach expected to show increased benefits under the majority of scenarios considered in the ISP. Both TransGrid and ElectraNet have adopted a rigorous competitive process to maintain downward pressure on project costs, based on a fixed price EPC approach applying established procurement methodologies. The project is considered relatively low complexity, with a manageable number of landowners and range of identified risks, providing a high degree of confidence in the final cost estimate.

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Issue	Response
Who is accountable if the project benefits are not realised? Consumers are responsible if the benefits fail to actually materialise, while NSP's continue to receive their regulated return.	A decision on any network or infrastructure project relies on the best available information at the time. The ISP, RIT-T, updated CBA and various separate pieces of independent analysis undertaken over the last four years consistently show that Project EnergyConnect remains the preferred option and delivers positive net market benefits. Based on all the information available this remains a 'low regrets' project that forms an essential part of the roadmap for the transition of the power system, and remains subject to the governance processes applying to regulated network investments and final approval of efficient costs by the AER.
You mention the ISP in relation to EnergyConnect, I believe it was costed at $1.99b in the 2020 ISP. Do you think this inconsistency presents any issues?	The updated CBA is based on the finalised cost estimate for the delivery of the project, being $2.43bn, and continues to show Project EnergyConnect remains the preferred option and delivers positive net benefits.
Line route	
A change since the PACR is building Dinawan substation. Presumably this comes at a cost - what benefits does it drive that justify this change?	It is marginally cheaper to go down this path. Bypassing Darlington Point involves a shorter line route and is less complex. While this also requires a new greenfield switching station at Dinawan, this is more than offset by the complex brownfield expansion of Darlington Point substation that is avoided given this is a constrained site.
Is the substation required for the changed line route?	A new switching station is required at Dinawan to allow for reactive plant due to the line distance involved between Wagga Wagga and Buronga.
What connections are proposed for PEC in NSW? TransGrid's Annual Planning Report is quite vague.	The line will connect Buronga to Dinawan to Wagga Wagga. Should generation or load developments occur over time, new connections will be accommodated at these or other suitable locations on the network at that point in time. The current scope of Project EnergyConnect remains limited to that required to deliver on the requirements of the project.
Why doesn't TransGrid coordinate PEC with VNI West - PEC has a new double circuit line from Dinawan to Wagga while VNI West has a double circuit 500kV line from Dinawan to Wagga. It doesn't seem to make sense.	The potential benefits of this coordination have been considered in the updated CBA. However, while the future timing of VNI West remains highly uncertain, the present scope and cost of Project EnergyConnect remains limited to that required to deliver on the requirements of the project and does not include 500kV capability from Dinawan to Wagga Wagga.
Why does the project not go via Darlington Point anymore? A second line is planned from Darlington Point to Wagga anyway but the cost of this has not been included in PEC.	The present scope and cost of Project EnergyConnect remains limited to that required to deliver on the requirements of the project. Addressing network constraints in South Western NSW was not one of these requirements. TransGrid has initiated a separate RIT-T process to address these constraints, which involves potential augmentation options from Darlington Point[1].

[1] TransGrid, *Improving stability in South-Western NSW: RIT-T – Project Specification Consultation Report*, 31 July 2020, available at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Stabilising%20SW%20NSW.pdf.

Issue	Response
Why does the project not utilise the Balranald substation?	Balranald was not considered a suitable site for several reasons including requiring additional 330/220kV transformers at Balranald, requiring additional reactors at Wagga Wagga due to the length of the Balranald to Wagga Wagga line and land use constraints due to developments adjacent to Balranald substation.
Nothing in the rules prevents PEC being built at 500 kV double circuit instead of 330 kV double circuit from Dinawan to Wagga, or build 500kV but operate 330kV. This should be a relatively low additional cost but would save money on VNI West if it hooked in to Dinawan.	We agree. However, as noted above, the potential benefits of this coordination have been considered in the updated CBA. However, while the future timing of VNI West remains highly uncertain, the present scope and cost of Project EnergyConnect remains limited to that required to deliver on the requirements of the project and does not include 500kV capability from Dinawan to Wagga Wagga.
Customer price impacts	
Do the prices include the increase in prices from PEC?	Yes, the indicative reductions for residential and other customers presented in the analysis from ACIL Allen and FTI are net of the expected annual costs of PEC.
How does a less than 10-year simple payback period reconcile against the cost of $2.4bn and a net benefit of $148m?	The updated CBA and customer price impact analysis are answering different questions. The updated CBA based on ElectraNet’s approved methodology shows a positive net <u>market benefit</u> of $148m on the particular scenario considered. As required under the RIT-T, this excludes the impact of wealth transfers between parties (for example price reductions to customers). The customer price impact analysis by ACIL Allen and FTI based on an equivalent set of assumptions shows significant <u>customer benefits</u> in the form of price reductions which are expected flow from reduced wholesale energy prices, more than offsetting the expected increase in network costs.
Is this saving based on SA consumers only paying the ElectraNet share of PEC or also paying part of the share of TransGrid's costs as an inter-regional charge?	The customer price impact analysis assumes that costs are recovered geographically, as required under the Rules, and does not attempt to predict the future flow of payments between regions that may result under the present inter-regional TUOS arrangements. These payment flows are relatively small and can be expected to vary over time based on net annual flows and network usage but will not impact on the total price benefits to be gained by NSW and SA customers.
Where is the equivalent analysis from ACIL on NSW?	TransGrid has commissioned FTI to undertake price impact modelling for NSW customers as presented in the Webinar, and published with its Contingent Project Application to the AER.
How can the independent analysis be truly independent if it uses the same input assumptions. Where is the true independence?	The customer price impact analysis by ACIL Allen was undertaken applying its own market models, its own modelling methodology and independently chosen inputs and assumptions. As these inputs and assumptions are based on the latest information, they align broadly with those adopted in the ISP, but are not identical. They remain comparable with those in the ISP and the updated CBA.

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TransGrid Rule change	
What happens if TransGrid's rule change request is not approved?	The Rule change relates to the timing of revenue recovery required to enable the efficient financing of the project, while maintaining an acceptable credit rating. Should the Rule not be approved, this would need to be assessed in considering a final investment decision on the project but would be expected to have negative impacts.
On the question of financeability - What impact will the rule change request have to consumers if successful?	TransGrid’s Rule change proposal identifies an expected annual impact of $3 per average residential customer in the current regulatory period. The overall revenue to be recovered over the life of the asset would remain the same in present value terms.
Project costs	
Is the cost for the special protection scheme an annual or total cost	The upfront capital cost of the Special Protection Scheme (SPS) has been forecast at $19m while the ongoing operating expenditure requirement for the delivery of the South Australian component of PEC has been forecast at $0.4m pa, the majority of which relates to the specialist engineering resources required to manage and maintain the SPS.
Costs are based on $17-18 yet we are now in 2020/21 so they need to be inflated by escalation to make them current.	Expenditure forecasts are required to be presented by ElectraNet and TransGrid in real terms in $2017-18 for revenue related applications in the current regulatory period. These costs are also presented in real terms in $2018-19 for consistency with the updated CBA and original RIT-T assessment. The AER’s Post Tax Revenue Model (PTRM) applies inflation to these figures to account for CPI in calculating the net revenue requirements to deliver the project.
Can you provide a variance analysis reconciling the PACR CPA for the NSW leg.	TransGrid has had an independent review of capex forecasts undertaken by GHD which includes a detailed review of price developments from the time of the PACR to the CPA. This information has been published with TransGrid’s CPA.
Risk	
Is the 5% for risk included in the contractor costs or is it a contingency included by ElectraNet? If the risk cost is included in the contractor cost, then this is a cost consumers will have to wear.	The risk allowance only covers risks not included in contractor costs and covers risks outside the control of ElectraNet that can still be expected to impact on the final delivered costs of the project. We have excluded risks that are under the control of ElectraNet, or contractors or that we can insure for.
So how can consumers properly evaluate a project at the PACR level when the capex estimate does not include risk?	Project risk allowances have not been included in RIT-T assessments to date, the focus of which is on the relative costs and benefits of alternative options rather than the absolute cost of each option. However, there is an argument for including a risk allowance in future RIT-T assessments for completeness.

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So a lot of risk has been passed to the contractors - which means consumers are bearing this; I take no comfort in TransGrid saying they have had 'success' in transferring risk to contractors - why should that be considered 'success' for consumers who pick up the cost of that in the higher capex?	The transfer of risk to contractors is a process of allocating risk to the party best placed to mitigate the risk and respond should it eventuate. The competitive tension of the tender process is the counterweight to balance risk allowance with price certainty. This does not automatically lead to higher capex, but does provide greater project certainty overall and is in the interest of consumers.
That is what project contingency is about. If you go over the contingency ElectraNet should bear the overrun cost.	The risk allowance has been assessed on a probabilistic basis, based on a 50% probability of exceedance outcome. This means ElectraNet remains exposed to any cost impacts that exceed this allowance, with a 50% likelihood.
Consumers can still bear overrun risk due to the networks simply delaying other non PEC capex to the next period given they have an approved total capex budget	Under the current regulatory framework, TNSPs are allocated a capital allowance considered efficient and prudent to manage their networks. A number of levers exist to managing capital over-runs on any individual project, including delays in other non-PEC augmentation expenditure, which acts to minimise price impacts on customers. This is managed under the oversight of the AER.
System security & resilience	
What happens if you don't get approval in 2021 from the Reliability Panel on the application for a protected event?	PEC is not dependent on any protected event declaration. The proposed SPS is inherent in the design of PEC to cater for the non-credible loss of either the Heywood or PEC interconnectors. The transfer capability across both interconnectors has been determined on this basis and the market benefits have been modelled accordingly.
Timeframes	
Could you please take us through the next steps on the project and any associated time frames?	The next step involves consultation by the AER on the Contingent Project Applications of ElectraNet and TransGrid to determine the efficient cost to deliver the project. This represents the final regulatory approval step required under the Rules and is expected to lead to a final decision by end 2020.
Can the slides be distributed to all attendees and can we also have formal responses to all the questions asked in chat?	The slides have been issued to webinar attendees together with this full record of questions and responses.

Further information is available in the CBA report available on our website, and ACIL Allen report and Contingent Project Application available on the AER website.

15 October 2020