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IEGA
INDEPENDENT ELECTRICITY GENERATORS ASSOCIATION

9 October 2018

Submissions
Electricity Authority
P O Box 10041
Wellington 6143

By email: submissions@ea.govt.nz

Dear Electricity Authority Board Members,

RE: Consultation Paper – List of distributed generation eligible to receive ACOT, Upper South Island

The Independent Electricity Generators Association Incorporated (IEGA) welcomes the opportunity to submit on the Upper South Island (USI) eligible DG. [1]

On 30 January IEGA submitted on the Lower South Island draft list of eligible DG. The key points of that submission are still relevant.

IEGA is not submitting on the draft list of eligible DG for the Upper North Island – given that DG behind every GXP analysed is required for Transpower to achieve n-1 reliability.

Individual members have also made submissions which the IEGA support.

Voltage stability

The IEGA agrees with Kawatiri Energy that the Electricity Authority (Authority) is not in a position to decide about USI DG eligible to receive ACOT because Transpower has applied a test to assessing DG (n-1) that is not consistent with the grid reliability standards for non-core grid (which requires an economic investment test).

Managing voltage stability on the West Coast and Upper South Island is a stark example of the how the Authority does not have sufficient information to make a decision.

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[1] The Committee has signed off this submission on behalf of members.

Voltage stability on the West Coast and Upper South Island has been an issue highlighted by Transpower in both its 2015 and 2017 Transmission Planning Reports[2] analysis of the West Coast grid.

The Mitton report identifies the potential for voltage collapse on the 66kV for a circuit failure if one of the DGs that has been deemed necessary to maintain n-1 reliability is not in service.

Transpower's Transmission Planning Reports (both 2015 and 2017) also identify possible voltage instability on the West Coast 110kV and 66kV for certain bus faults, the outcome of which would be dependent on the contribution from local generation (among other factors).

Mitton has raised this issue of voltage stability but has not investigated it because it doesn't meet the brief provided by Transpower (necessary to meet n-1). However, the test given to Transpower for the DG assessments (detailed in the Code) was to assess if the Grid Reliability Standards (GSR) were met.

The GRS for non-core grid is not n-1 but economic reliability. Transpower's reason for not requiring a grid investment to fix the voltage problem is that the local customers have not asked for higher reliability. But not having the extra DG increases the risk of voltage collapse and is a reduction in reliability. To justify this Transpower must show that the increase in the expected value of lost load is less than the potential ACOT payments to the rest of the DG fleet to determine the least cost economic reliability investment. The Mitton analysis does not address this question.

The IEGA therefore submits that the Authority does not have the right information to be able to determine eligible DG in the USI region.

We note that DG’s contribution to managing voltage stability issues was a significant contributing factor for UNI DG to be identified as being required to meet n-1.

Upper South Island results are counter-intuitive

Transpower’s analysis reveals that DG behind only 4 of 18 GXPs in the Upper South Island (USI) is required for Transpower to meet its Grid Reliability Standards (although this translates to 68% of total DG in the USI on the basis of assumed contribution to GXP winter load).

This result for the USI appears counter-intuitive.

The Authority chose to implement the revised Code in the USI last because the USI region is widely recognised as being the most constrained part of the transmission grid. The Authority acknowledged this when it described the reason for phasing implementation in the December 2016 decision paper[3]:

[2] Transpower New Zealand Limited, 2017 Transmission Planning Report page 294 https://www.transpower.co.nz/sites/default/files/publications/resources/Transmission%20Planning%20Report%20Final.pdf

[3] https://www.ea.govt.nz/dmsdocument/21514-decision-paper-review-of-distributed-generation-pricing-principles Page 33

3.43 The phasing also recognises that:

(a) distributed generation located in the UNI region are more likely to deliver avoided transmission benefits than those in the LSI or LNI (but less likely than the USI)

(b) potential reliability risks in the UNI region are higher than in the LSI or LNI (but lower than in the USI).

Further, Transpower has focused its efforts to manage transmission constraints using its demand response programme in the South Canterbury region for some time.

Transpower's Transmission Planning Report includes a number of embedded generation plant in its transmission planning to achieve its required reliability standards that are not identified by Mitton as being required to meet the n-1 test it has used. It is important to note here that an n-1 test is not the same test as Transpower uses for its Grid Reliability Standards. IEGA query what the impact might be on Transpower's reliability performance if these generating plants do not perform as expected while planning the transmission grid following implementation of this decision on eligible DG.

Table 16-2: Forecast annual generation capacity (MW) at West Coast grid injection points to 2032 (existing and committed generation)

Grid injection point (location/ name if embedded)	Generation capacity (MW) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2032
Dobson (Arnold)	3	3	3	3	3	3	3	3	3	3	3	3
Hokitika (Amethyst)	7	7	7	7	7	7	7	7	7	7	7	7
Hokitika (McKays Creek)	1	1	1	1	1	1	1	1	1	1	1	1
Hokitika (Wahapo-Okarito Forks)	3	3	3	3	3	3	3	3	3	3	3	3
Kumara (Hokitika Diesel)	3	3	3	3	3	3	3	3	3	3	3	3
Kumara (Kumara and Dillmans)[1]	10	10	10	10	10	10	10	10	10	10	10	10
Robertson Street (Kawatiri Hydro)	4	4	4	4	4	4	4	4	4	4	4	4

1. Kumara and Dillmans share the same water resource and are offered into the market as a single 10 MW generator. Kumara does not have significant water storage but is expected to supply an average of 4 MW during summer peaks.

Further, the Authority stipulated an arbitrary period for the analysis of DG that contributes to the Grid Reliability Standards (GRS) – from 1 April 2017 to 31 March 2020. Mitton's analysis highlights that DG connected to a further four GXPs is required for Transpower to meet an n-1 test in Winter 2021 (or 85% of existing DG in the USI). In transmission planning terms this is a very short period of time after the end of the arbitrary period. IEGA queries the level of sensitivity of this analysis – for example, how much would demand have to change by over the period for these DG to be needed for Transpower to maintain n-1 reliability before the end of 2020?

Differing treatment of DG and transmission

The Authority's Code change created a bright line and froze existing DG in stone on the date of the announcement of the Code change – 6 December 2016. BUT there was no equivalent treatment to transmission investment or the transmission grid. Transpower / Mitton's analysis for the first transmission region – the Lower South Island – used the 2015 Transmission Planning Report. Subsequent analysis for the other regions has used the 2017 Transmission Planning Report – updated for new assumptions about both demand and supply. It appears likely that if the USI had been the first region to be assessed under the new Code the outcome would have been different. This is not a robust or credible outcome.

This approach to allow an ever adjusting transmission grid has enabled Transpower to assume its different projects progress and potentially crowd out existing DG as an alternative to transmission investment in the n-1 assessment.

For example, Transpower's proposal for a switching station at Orari proceeds. This has been included in the analysis of whether DG is required to meet the n-1 test. That is, existing DG is compared with a transmission grid relieved by investment in constraints at Orari when the detailed analysis of a long and short list of options is yet to be undertaken. Not surprisingly, the existing DG is found not to be needed to meet the n-1 test.

The analysis takes no account of whether existing DG is a lower cost option to relieve these transmission constraints. Orion Group raised this issue in its submission[4] on the Lower North Island draft DG list:

> 8 As we see it the fundamental problem here is the way the Authority changed the Code to achieve its objective of reducing ACOT payments. The Code requires (Schedule 6.4 clause 2A) reporting on eligibility in terms of DG that is "required" to meet the GRS, but this is not the basis on which transmission charges are set and applied, and nor is it a measureable 'cost' in any useful sense. It is also not the only way that DG might contribute to lower transmission costs, for example by helping to defer investment.

As discussed by other submitters the n-1 test used by Mitton to determine eligible DG is not the same as the Grid Reliability Standards in the Code. Further, a significant part of the USI transmission grid is non-core and therefore must be an economic reliability investment.

Upper South Island load management

The Authority will be aware that there is well established management of USI peak demand via co-ordination between Buller Electricity, Westpower, Network Tasman, Nelson Electricity, Marlborough Lines, Orion, MainPower, EA Networks and Alpine Energy.

DG that is no longer eligible to receive ACOT will no longer be incentivised to generate during periods of peak demand. This DG will therefore not be working in concert with the co-ordinated load management in the USI.

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[4] https://www.ea.govt.nz/dmsdocument/23711-orion page 2

Prices in the wholesale spot market will not be incentivising ineligible DG to generate during periods of peak demand as high spot prices reflect fuel expectations and usually occur during autumn while peak demand is in winter.

Pioneer Energy commissioned EnergyLink to analyse whether cessation of load shifting activities in the Orion network, and upper SI as a whole, would increase or reduce total spot purchase costs. This report is attached as Appendix 1.

Load shifting was 91 -114MW and the analysis revealed:

> Based on the total change in cost over the 11 days, the average increase was 1.6%, but with a range from -1.4% to +72.1% for Orion only when looking at individual days, and -2.4% to 87.2% when all of the upper SI load shifting is included. On the two days with double digit increases the change in the load profile, the increases in price during the day was in the hundreds of dollars for a small number of periods.

The results of this study give an indication of the potential negative impact on spot prices from USI DG no longer generating in peak demand periods.

The Authority has refused to take into account other benefits from DG – as specifically highlighted in both Transpower's[5] and Mitton's[6] reports. The impact on wholesale spot prices is another example which may have long term dis-benefits for consumers.

Conclusion

IEGA submits that before the list of eligible USI DG is finalised further analysis is required on:

- the value of lost load relative to ACOT payments to determine which is the least cost economic reliability investment for all DG connected to the non-core grid; and
- the sensitivity of the n-1 test for a change in demand forecasts given 13MW of additional DG is required for Transpower to be able to maintain n-1 reliability in winter 2021.

We note that uncertainty continues to prevail for owners of existing DG and potential investors in new DG. The Authority continues to talk about reviewing arrangements for DG again. This level of uncertainty is unprecedented. It is also disproportionate to the size of DG in the market as well as the scale of the business of our members. The Authority must be aware that this uncertainty is impacting the bankability of existing and new DG investments.

[5] Transpower New Zealand Limited, 'Distributed Generation to meet Grid Reliability Standards, Upper South Island' https://www.ea.govt.nz/dmsdocument/23946-appendix-b-transpower-report-distributed-generation-to-meet-grs-in-upper-south-island-25-may-2018 Page 4

[6] Mitton ElectroNet 'Upper South Island Distributed Generation Impact Study' https://www.ea.govt.nz/dmsdocument/23950-appendix-d-mitton-electronet-upper-south-island-distributed-generation-impact-study page 4

We would welcome the opportunity to discuss this submission with you.

Yours sincerely

Warren McNabb

Chair

Appendix 1: EnergyLink report 'Impact on Spot Prices from Cessation of Load-shifting'