Mr Rainer Korte
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Lodged online via consultation@electranet.com.au

Thursday 25/01/2018

Dear Mr Korte,

RE: Eyre Peninsula Electricity Supply Options Project Specification Consultation Report

ENGIE appreciates the opportunity to comment on ElectraNet's Project Assessment Draft Report (PADR) for Eyre Peninsula electricity supply options.

ENGIE is a global energy operator in the businesses of electricity, natural gas and energy services.

ENGIE also has generating assets at Port Lincoln and, like ElectraNet, is keen to ensure that whichever option is eventually selected, it is in the best interests of consumers.

ENGIE wishes to complement ElectraNet on the comprehensive modelling and analysis of a wide range of network augmentation options.

ENGIE acknowledges and appreciates ElectraNets open and helpful approach when seeking additional information regarding the modelling methodology and assumptions.

1 Modelling methodology

In general, the least cost model is more representative of a central planner, or a single owner optimising their supply portfolio, rather than a competitive electricity market. Corresponding modelling results will typically deliver higher generation from low cost (merit order) plant when compared to half hourly market based modelling or actual electricity market outcomes. In a competitive market, generators need to achieve revenue adequacy to meet both variable and fixed costs for their assets for sustained operation. Specifically, they are not driven to minimise overall system costs (unless there was a single owner of all generators). Such a variation will also distort the calculated costs and benefits.

1.1 Wind and solar profiles

In ENGIEs experience, and recently reconfirmed by ACIL Allen, the correlation of wind and solar output affects the level of investment within regions.

The Houston Kemp (HK) modelling uses 15 sample days and 6 periods of demand on each day to represent a calendar year. From the information provided it is unclear how effectively wind and solar modelling correlates to actual generation of similar plant and to what accuracy network constraints are captured in the modelling (some of these will be a function of system conditions).

The very high levels of wind in Tasmania and South Australia and high levels of solar generation later in the projection suggests that the correlation of output has not been adequately dealt with in the modelling.

The desire to simplify the model formulation to facilitate faster solution times is understandable.

However, the load block representation introduces a number of major issues as follows:

- The load blocks used are coarse and don’t represent specific conditions in the system (e.g. top 10% of demand days are represented by 5 days intended a wide range of operating conditions). This makes this approach difficult/impossible to benchmark against real world outcomes/events.
- The severe averaging of system conditions to construct a load block filters out volatility. Arbitrary adjustments to modelling parameters to re-introduce volatility introduce yet new and unquantifiable uncertainties.
- The correlation between demand, wind generation, solar generation and location specific relationship is all but lost in the averaging process (i.e. average correlation will be vastly different to a time series based correlation).

Without benchmarking the load block model against a time series market model, it is impossible to demonstrate that the load block model is “fit for purpose” when quantifying the costs and benefits of transmission augmentations.

2 Input assumptions

2.1 Demand

ENGIE understands that HK has used the ESOO updated energy and maximum demand forecasts in their modelling. These are set out on the Demand tab in the assumptions workbook provided by HK.

ENGIE sought input from ACIL Allen to review the assumptions book. ACIL Allen confirmed that the data in the assumptions workbook is consistent with the data provided by AEMO for the September ESOO and provided the following context and critique of the inputs used in the modelling and the following insights.

The demand data is operational demand and is on a “sent out basis”. Therefore to convert to “as generated demand” (including generator auxiliaries), the demands need to be grossed up for auxiliaries. HK provides the auxiliary factors that they used and assumed auxiliary factors adds around 4.6 per cent per annum to the ESOO operational demand – see Table 1.

The definition of “operational demand” is that it includes transmission and distribution losses. Therefore, to convert to “total scheduled as generated dispatch”, auxiliaries need to be added as discussed in the previous paragraph. However, there are a number of significant non-scheduled grid based generators that provide support to operational demand. These are separate to the small non-scheduled generators that AEMO net off demand to get operational demand. ACIL Allen estimates these generators to be approximately 3,700 GWh per annum. This needs to be subtracted from operational demand to determine the demand to be met by scheduled generation – (see Table 1 for details).

Comparison between demand and dispatch data is also made. When compared with the “Core Dispatch” data provided by HK, the “Core Dispatch” in GWh is around 4.7 per cent in 2018 above the “As Generated” calculated demand using the HK Auxiliary factors. This rises to around 6.7 per cent in 2028 gradually falling to around 2.1 per cent by 2037. When the significant non-scheduled generation is accounted for, the difference initially is 6.8 per cent rising to 8.8 per cent in 2028 before falling to 4.1 per cent in 2037.

It is possible that HK has included the significant non-scheduled generation explicitly in the modelling such that it shows up in the Core Dispatch data. This would be expected to show up as wind, biomass and gas fired dispatch. However, on inspecting the Core Dispatch data, there appears to be little evidence that this is the case. For example, biomass is not included as a category of generators dispatched.

This leads us to conclude that HK have significantly overestimated the demand to be dispatched. We are not able to state how this error occurred, but it is likely to have happened in the process of translating NEM operational demand to scheduled demand. In ENGIE and ACIL Allen’s view, the apparent large errors in demand would lead to the conclusion that the analysis cannot be relied upon for determining market benefits, especially as they have a dependence on dispatch savings and capital investment savings.

In discussions between ElectraNet, HK, ENGIE and ACIL Allen, HK indicated that the most important factor was the ranking of projects. In a sense, this is true because the default option, Option 1, is to continue existing arrangements involving some line replacement works and continuing network support arrangements. However, ENEGIE and ACIL Allen takes the view that not only should the option that is chosen be the best ranked option but it must also have positive net benefits.

The large errors in demand raise significant questions with respect to the current ranking of options, and whether options that are currently assessed as having positive benefits would continue to have positive benefits using the corrected demand inputs.

TABLE 1 DEMAND ASSUMPTIONS AND DIFFERENCES

Year	ESOO Op - Demand Neutral scenario (GWh)	As Generated – Neutral + HK Aux (GWh)	HK - CORE Dispatch Option 1 (GWh)	Difference Core Dispatch and as Generated (GWh)	Difference Core Dispatch and as Generated (%)	Approx Sig Non-sched generation adjustment (GWh)	As generated less Sig Non-sched (GWh)	Difference Core Dispatch and as Generated less Sig Non-sched (GWh)**	Difference Core Dispatch and ESOO + Sig Non-sched (%)
2018	185,746	194,216	203,418	9,203	4.74%	3,700	190,516	12,903	6.77%
2019	183,815	192,202	201,227	9,025	4.70%	3,700	188,502	12,725	6.75%
2020	183,486	191,855	200,473	8,619	4.49%	3,700	188,155	12,319	6.55%
2021	183,260	191,623	200,378	8,755	4.57%	3,700	187,923	12,455	6.63%
2022	181,713	190,019	199,651	9,632	5.07%	3,700	186,319	13,332	7.16%
2023	180,785	189,052	199,055	10,002	5.29%	3,700	185,352	13,702	7.39%
2024	179,779	188,000	198,759	10,759	5.72%	3,700	184,300	14,459	7.85%
2025	178,945	187,123	198,871	11,748	6.28%	3,700	183,423	15,448	8.42%
2026	180,848	189,132	201,519	12,387	6.55%	3,700	185,432	16,087	8.68%
2027	181,454	189,765	202,218	12,453	6.56%	3,700	186,065	16,153	8.68%
2028	181,706	190,025	202,720	12,695	6.68%	3,700	186,325	16,395	8.80%
2029	181,412	189,717	201,723	12,006	6.33%	3,700	186,017	15,706	8.44%
2030	180,945	189,229	201,501	12,272	6.49%	3,700	185,529	15,972	8.61%
2031	180,813	189,098	200,713	11,615	6.14%	3,700	185,398	15,315	8.26%
2032	181,009	189,305	199,338	10,032	5.30%	3,700	185,605	13,732	7.40%
2033	181,105	189,403	197,686	8,283	4.37%	3,700	185,703	11,983	6.45%
2034	181,785	190,113	196,649	6,536	3.44%	3,700	186,413	10,236	5.49%
2035	182,452	190,811	196,188	5,377	2.82%	3,700	187,111	9,077	4.85%
2036	183,342	191,743	196,281	4,538	2.37%	3,700	188,043	8,238	4.38%
2037	183,902	192,331	196,406	4,075	2.12%	3,700	188,631	7,775	4.12%

NOTE: ** CALCULATED AS (CORE DISPATCH LESS AS GENERATED PLUS SIG NON-SCHED)/(AS GENERATED LESS SIG NON-SCHED)
SOURCE: AEMO, HOUSTON KEMP AND ACIL ALLEN

2.2 Technology costs and learning curve

HK uses the 2016 NTNDP assumptions published in December 2016. Capital costs were based on the 2015 Australian Power Generation and Technology Report (APGTR) that was published in August 2016. The process of finalising and approving the APGTR is such that the data is only valid to November 2015, is more than two years old, and misses the more recent technological developments. The capital costs for key plant including renewable plant are much higher than estimates that are more recent and delivered projects.

Solar PV single axis tracking (SAT) (the most likely technology investment) capital costs start in 2018 at around $2,200/kW and fall to around 1,200/kW by 2030 and around $800/kW in 2037.

Wind starts at around 2,600/kW in 2018 and falls to around $2,000/kW by 2030 and stabilises at around that level through 2037. These costs are well above the market rates that are being transacted in the market today.

ACIL Allen tests its capital cost assumptions regularly with debt and equity investors involved in actual projects.

ACIL Allens wind capital costs are around $2,200/kW in 2018 falling to around $1,650/kW by 2030, and $1,500 by 2037.

Similarly, ACIL Allen solar PV SAT capital costs start at around $1,700/kW in 2018 and fall to around $1,150 by 2030 and $1,000/kW by 2037 – much lower in the front end but higher in the back end.

ACIL Allen has significantly lower capital costs for CCGT and OCGT as well.

<u>These differences are likely to be material in the analysis as deferred capital or reduced investment in capacity will have less benefit</u>.

The impact on the modelling is that there is a cost <u>bias from solar PV towards wind</u>, which causes wind capacity to be overstated.

<u>Additionally, the magnitude of savings in moving from PV to wind and from lower capacity factor wind to higher capacity wind is thus overstated</u>.

2.3 Carbon emission reduction policies (state and federal)

2.3.1 Federal emission reduction target

The emissions targets appear incorrect for both the 28% and 45% targets. The emissions target should be set as a budget for 2021 to 2030.

The budget should be around 1,200 Mt for the 28 per cent case but HK's budget is 1,457 Mt. The 45% case is 1,309 Mt – which is also above the 1,200 Mt budget for the 28% case.

<u>Any errors in the carbon constraints render any modelled results unreliable.</u>

2.3.2 VRET

Victorian renewable energy target (VRET) is not implemented beyond what is already covered by the federal RET to 2020. The current policy includes a VRET target of 40% by 2025 and the generation is to be located in Victoria.

Therefore shifting renewable projects from Victoria to the Eyre Peninsula will not be feasible under this scheme.

The VRET policy needs to be included in the assessment of benefits for the transmission augmentation, and be also included in the reference case (Option1).

2.4 Technology build limits

HK use annual build limits on wind and total limits on zones. The annual build limits appear to be very low and considering the type of modelling used, total zone limits would appear unnecessary, as it is a constrained marginal cost optimisation.

Annual build limits that are too low could be favouring the line upgrade by limiting benefits from commitment to wind generators in other regions/zones.

The total wind build limits appear implausible and could be affecting the results. For example, Victoria appears limited to a total of 3,000 MW and Queensland to 1,500 MW while NSW/ACT is 5,000 MW.

2.5 SA Security constraint

It is not clear whether the energy security target has been modelled. It is our view that on balance it will be indefinitely deferred and ideally so should not form part of the modelling.

Alternatively, sensitivity analysis without the security constraint must be included in the analysis of options.

3 Scenarios

HK assumes a carbon constraint but does not differentiate policy outcomes. Different policies have different levels of economic and abatement efficiency.

Also some policies have other aspects that are not modelled, such as the NEG with its reliability obligation. It is questionable whether SA would meet a likely reliability obligation under the projections provided by HK.

While it is unreasonable to ask proponents to continually update RIT-T modelling for changes in the market, the changes since the assumptions used by HK are substantial and should not be ignored.

We recommend additional scenarios covering the NEG, Snowy Hydro 2.0 and the effect of a VRET/QRET (or both) should be included in the study. The 28% and 45% scenarios are not good approximations as they assume efficient greenhouse gas abatement, whereas the above scenarios will favour technologies and locations.

4 Network constraints and modelling methodology

4.1 Eyre Peninsula

Analysis of historical binding constraints on wind farm generation in the Eyre Peninsula area shows that constraints rarely bind as shown in the table below. This suggest that the removal of network constraints will not deliver meaningful benefits from increased capacity factors of existing wind generators.

Year	Number of 5min intervals	% of time
1/01/2011	12	0.01%
1/01/2012	21	0.02%
1/01/2013	42	0.04%
1/01/2014	138	0.13%
1/01/2015	0	0.00%
1/01/2016	50	0.05%
1/01/2017	6	0.01%
1/01/2018	0	0.00%

4.2 Intra and interregional constraints

It is unclear how the constraint formulation was implemented in the modelling. To ensure that the claimed benefits are correct, the model must faithfully represent the network, generating patterns and system conditions (i.e. generating patterns and network conditions).

This does appear to have been achieved using the abridged methodology and a coarse demand model.

5 Model outputs - Unusual dispatch

The dispatch data provided by HK has some unusual characteristics compared with ACIL Allen's expectations based on modelling the NEM and on recent history. These unusual characteristics may in large part be linked to the apparent demand errors discussed above. The HK Core Dispatch Option 1, which we understand is based on the ESOO Neutral scenario, has an annual dispatch of 203,418 GWh, well above the ESOO implied annual As Generated annual consumption as discussed in the previous section. We acknowledge that the annual dispatch will include transmission losses on the interconnectors that are not included in the ESOO numbers. However, interconnector losses across the NEM would not be expected to exceed 1,000 GWh per annum and do not explain the large difference between the ESOO and the HK results.

ACIL Allen notes that the 2017 annual dispatch was 192 TWh, some 11.5 TWh less than HK's projected dispatch for 2018. The last time that NEM dispatch was around the same level was in 2011 prior to the closure of the Kurri Kurri and Pt Henry aluminium smelters in 2012 and 2014 respectively. Other factors that have affected demand since 2011 include closure of large segments of industry, lower household and business demand driven by energy efficiency and the installation of significant volumes of rooftop solar PV embedded in the distribution system.

5.1 SA Dispatch

Between FY 2011 and 2016, SA Dispatch averaged 11,300 GWh and the SA region imported a net 1,365 GWh per annum. In FY 2017 this fell to around 9,040 GWh with the closure of the Northern power station, an increase in net imports to 2,730 GWh.

HK projects 13,253 GWh of SA dispatch in FY 2017, around 2,000 GWh more than the period FY 2011 to 2016 and more than 4,000 GWh in 2017. HK projected SA dispatch averages 12,370 GWh between 2018 and 2030, around 1000 GWh above the 2011-2016 average and only falls below the 2011-2016 average in 2023.

HK projects 8,047 GWh of gas-fired dispatch in SA in 2018, rapidly falling to 5,431 GWh in 2020 and then gradually declining to 3,270 GWh in 2030 with further declines after that.

This compares with 5,579 GWh in FY 2017 and an average of 5,965 GWh over the period FY 2011-2016. This is despite the fact that gas prices are higher in FY 2018 than they were over the period 2011-2016 (noting the effect of Northern competing in SA over that period).

HK project wind dispatch in SA in FY 2018 of 5,206 GWh rising to 8,308 GWh by 2030 and stabilising after that. This compares with 3,462 GWh dispatched wind in 2017, some 2,000 GWh less than the FY 2018 HK projection. ACIL Allen modelling indicates that FY 2018 SA dispatched wind would be around 4,500 GWh (around 700 GWh less than HK) rising to around 5,400 GWh by 2030 (nearly 3,000 GWh less than HK).

The combination of these variations is likely to overestimate the market benefits attributed to the network upgrade options.

5.2 Black coal

HK projects black coal dispatch for 2018 to be 125 TWh. Under similar policy settings, ACIL Allen expects black coal dispatch in 2018 to around 111 TWh. Black coal plant dispatch in 2017was 107 TWh, 18 TWh less than the HK 2018 projection.

The last time that annual black coal dispatch reached the levels that HK project for 2018 was in 2009 when NEM wide dispatch reached 207 TWh.

This was prior to the major investment in large-scale renewable energy under the revised LRET scheme and falls in energy consumption (projected As Generated consumption in 2018, is around 15 TWh less than it was in 2009).

The black coal projection includes 71.2 TWh in NSW in 2018. In 2017 black coal equivalent dispatch was 56.3 TWh and ACIL Allen projects that 2018 black coal dispatch will be around 57.7 TWh, or 13.5 TWh less than the HK projection.

Queensland black coal projections are more consistent with around 50.8 TWh in 2017, 53 TWh projected by ACIL Allen and 53.8 TWh projected by HK.

Despite this implausible dispatch scenario, in Option 4B, the preferred option, HK projects additional wind dispatch from FY 2019 (~100 GWh), rising to an extra 1,150 GWh by FY 2024.

5.3 Brown coal

The HK brown coal projection for Victoria for 2018 is consistent with the ACIL Allen modelled view (35.8 versus 35.9 TWh). Actual brown coal in 2017 included Hazelwood for nine months. If this is removed, the 2017 remaining brown coal in 2017 As Generated was 35.8 TWh. HK maintain all brown coal in service (noting the closure of

Hazelwood in FY 2017) over the projection despite Yallourn being unlikely to continue beyond its current mine life in 2032 and may even close as early as 2025.

5.4 Hydro

The hydro dispatch appears very high at nearly 18 TWh per annum over the projection. Long term hydro energy ratings across the NEM are around 9 TWh for Hydro Tasmania, 4.3 TWh for Snowy, around 0.7 TWh for Queensland, around 1000 TWh for AGL's Victorian hydro assets – around 15 TWh per annum. The average NEM wide hydro dispatch over the period 2011 to 2017 was around 14.9 TWh.

5.5 Natural gas

Despite the very high volumes of gas dispatched in SA in 2018 in the HK modelling, the gas dispatch across the rest of the NEM appears implausibly low (probably in part because of the very high black coal dispatch). FY 2017 gas fired dispatch was 17,802 GWh (averaged 22,830 GWh over the period FY 2011-2016 but this included ramp gas prior to the start of LNG production). The HK modelling shows NEM gas fired dispatch in 2018 of 12,065 GWh, some 5,700 GWh less than that dispatched in 2017. Outside SA, gas dispatch in 2018 is projected to be 4,018 GWh compared with 12,223 GWh in 2017. This is projected to fall to 2,283 in 2019 before recovering to 7,644 GWh in 2020 and then remaining between 6,000 and 9,500 GWh for the rest of the projection.

Option 4B shows more gas in the years FY18,19 and 21 but less gas in years FY22 onwards – averaging around 89 GWh less gas over that period which is then claimed as a benefit for the project.

5.6 Wind and Solar

Option 4B facilitates an additional 300 GWh of wind in South Australia compared with Option 1 between FY 2021 and 2037, most likely facilitated by the Eyre Peninsula line upgrade.

South Australia has implausibly high volumes of new wind build in the HK projection – 1,130 MW by 2026.

The new build wind in Victoria is very low at 1,679 MW by 2026 – would expect to be at least 2,500 MW and much more with VRET.

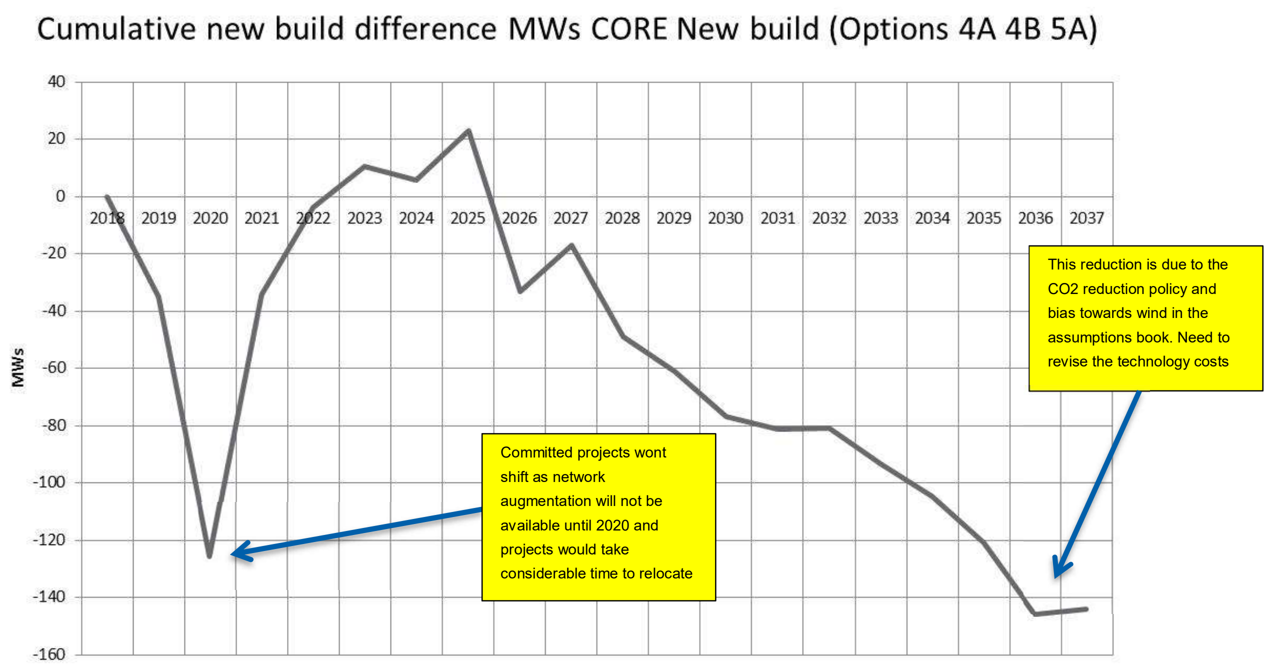
Tasmania appears to have an implausibly high level of new wind committed reaching 4,518 GWh by 2026 which is more than 1,000 MW of new build wind.

6 Movement in renewable projects capacity (model output)

Renewable energy projects needed to deliver the 2020 RET are incentivised to build as early as possible to maximise their creation of renewable energy certificates. Therefore it is considered highly unlikely that project proponents would delay construction of committed projects and await the construction of additional transmission on the Eyre Peninsula.

Modelling output shows the following movements in renewable generation.

The reduction in new capacity prior to 2022 is considered highly unlikely, and the additional build from 2026 to 2037 is considered to be a result of overestimated demand and technology costs bias towards wind.



7 Additional reliability benefits of Port Lincoln generators

The on-site generation at Port Lincoln provides a network support service. In addition, it also provides capability to meet the local load, including the provision of reserve generation in case of system black, or outages other than the transmission line to Port Lincoln. Thirdly, the Port Lincoln generators provide support the wider SA system reliability. In the options modelling it has been assumed that these additional benefits remain in place under all options considered.

However without a network support contract, or some form of capacity support/ reliability payment, this generation may not remain in place as a merchant generator.

Therefore the modelling of all options needs to consider the two possible outcomes as follows:

1) Port Lincoln generation is removed from service

Network support costs are reduced as claimed but the system becomes less reliable and the cost of unreliability will increase. The additional cost of increased unreliability must be included in the costing of all of the options with the exception of Option 1. This will result in market benefits being diminished as a consequence

2) Port Lincoln generation remains in service

The cost of generation remaining in service will need to be met by market participants (contracts and/or additional capacity/reliability payments). Therefore the cost saving claimed against the modelled options doesn't occur as customers will still need to meet these costs. This will result in market benefits being diminished by the same amount as the network support contract

Given the amount of regulatory and government interference in the SA region, there is a real risk of uncontracted generating assets being withdrawn from operation. The earlier withdrawal of a portion of PP capacity was a case in point.

It is therefore imperative that market and reliability benefits are tested for sensitivity of the removal of the Port Lincoln capacity.

8 Cost savings to mine on-site generation

The cost analysis assumes that all of the mining on-site generation is expensive distillate fired generation. However, it is also likely that mines could use some wind and/or solar generation to displace the conventional on-site generation (i.e. displace energy but not capacity). Meeting partial supply with renewables could also be implemented by contracting with a renewable energy project instead of investing in such generation directly. Mining projects could also be made self-sufficient, or less reliant on the network connection. By using a range of generating technologies some or all of the benefits of a lower cost connection would be captured by the mining project and would not represent a benefit of the transmission augmentation options.

The claimed benefits are circa $1,300,000,000 (ref fig 27 in the PADR), so there is a massive incentive for the mines to implement other alternatives possibly making the transmission options uneconomic.

In summary, while the work undertaken by ElectraNet is valuable, ENGIE has concerns there are some apparent large errors in input assumptions which raise very serious questions about the reliability of the modelling and modelled outcomes. Notwithstanding this, other input assumptions appear to bias the modelling with the potential to overestimate the resulting market benefits of the transmission augmentation options. There are a number of plausible policy related sensitivities that have not been tested and that should be included as additional equally plausible eventualities. And finally, the modelling approach has limited granularity and does not appear to be fit for purpose for the analysis that is required in this case.

ENGIE trusts this submission will assist ElectraNet in its assessment of transmission options and in quantifying potential benefits.

Should you wish to discuss our submission further, please contact David Hoch (Regulatory Strategy and Planning Manager) on 04 1734 3537.

Yours sincerely,

David Hoch
Regulatory Strategy and Planning Manager