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13th March 2008

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Feedback on 2008 Grid Planning Assumptions (GPAs)

Thank you for providing us with the opportunity to provide the Commission with feedback and comments on the proposed GPAs. As these GPAs have the potential to have a significant impact on the assessment of potential new transmission projects it is important that they reflect realistic scenarios. The need for new transmission investment to enable the increased uptake of renewable energy represents an important component of the government's New Zealand Energy Strategy.

Scope of feedback

NZWEA's feedback relates only to the draft generation scenarios. We have not reviewed the various demand forecasts and modelling.

Weighting of scenarios

It is clear from recent announcements (i.e. 90% target in the NZES, proposed Emissions Trading Scheme) that it is Government policy to support and increase the uptake of renewable generation The opposition National Party also supports the use of emissions trading and has also proposed a target for emission reductions of 50% by 2050. Accordingly the "high gas discovery" scenario, that shows emissions nearly tripling by 2040, appears entirely inconsistent with the energy and climate change policies that can be expected under any government (over the coming years at least). This scenario should therefore be accorded a much lower weighting than the other scenarios in its application in the GIT.

This scenario also shows a long term carbon price of NZ$20 per tonne. This appears to be well below any of the wide range of reputable forecasts that exist. For example recent Government presentations discussing the ETS show forecasts ranging between US$25 and US$60 per tonne at 2030[1]. This further reinforces the probability that this scenario has only a very small chance of occurring. It should receive a low weighting accordingly.

The outcomes of the other four scenarios all seem to be the more likely result of increased renewables uptake. They contain a range of reasonable considerations for factors that might influence the level of renewables uptake, such as options for the

[1] For example see the presentation from the Minister of Energy's presentation to the NZ Petroleum Conference on 11 March, available at:
http://www.beehive.govt.nz/speech/petroleum+and+new+zealand+energy+strategy

timing and extent of the phase-out of Huntly, possible gas supply limitations, increased demand response, etc.

It could be argued that a scenario that aligns with the Government's target of 90% renewables by 2025 is the most likely development path based on the actual policy environment today and that such a scenario should then be given the highest weighting. However it is unclear whether the Government's target considers the use of coal with CCS to be "renewable" (as your paragraph 62 suggests you have assumed) or envisages the shutdown of Tiwai by 2020. It might be appropriate for these assumptions to be confirmed with the MED (as the agency that has developed that target).

Gas price forecasts

Figure 3 of the consultation document shows the assumed gas prices used in the draft scenarios. These suggest gas prices (excluding any carbon charge and, we assume from the text, transport costs north of Huntly) of around $5.50-$5.75 per GJ today rising to between about $8 per GJ ("high gas") and $13 per GJ ("sustainable") by 2025. The price forecast in 2010 is around $6.50 per GJ.

We note that in the presentation of their most recent half year results, Contact Energy forecast delivered gas prices of around $8.75 per GJ for their 2010-2011 financial year.[2] If this is the view of one of the country's largest consumers of natural gas this would seem to suggest that the gas price path used in the modelling should be subject to further review and discussion. The presentation showed existing gas prices consistent with those used in the GPAs.

Selection of large amounts of diesel peaking plant

We note that in all 5 scenarios the modelling has selected significant quantities of new OCGT diesel peaking plant. The 2025 forecasts show that between 600 MW and 1200 MW of diesel plant might be required. This is in addition to the selection of some (but a much smaller quantity of) open cycle gas turbines and load curtailment that will presumably be providing similar "fast response" generation. While it is pleasing to see recognition that peaking plant is likely to be required regardless of whether the generation portfolio is highly renewable or "high gas", the quantity of peaking plant selected and the fuel selection was unexpected.

Table 3 shows the assumed LRMCs of various thermal generation technologies. These show a higher LRMC for diesel peaking than it does for gas. It therefore seems unusual that the model has selected significantly more diesel plant than it has gas. The risks around fuel supply and price, given the requirement to import diesel and its exposure to international pricing volatility, would also seem to point more towards gas or demand response as a more suitable option.

In Appendix 4 the 'energy stackplots' appear to show that the diesel peaking plants are expected to contribute barely any (if any) GWh of generation, even for the scenario when 1200 MW of peaking capacity is expected to be installed. It is difficult to understand the circumstances under which such a large investment in peaking capacity can be justified for what would appear to be very rare circumstances when it is required (and especially a scenario where 1200 MW of capacity might be needed).

The price at which demand response activities would be undertaken does not appear to be stated in the discussion document, but it might be expected that this would be somewhat less than the $500-$600 per MWh required to justify such extensive peaking plant investment. Our understanding of the demand side participation trials

[2] http://www.contactenergy.co.nz/web/pdf/financial/2008_hy_media_investor_presentation.pdf

that have been undertaken in the South Island is that these have shown that useful demand response can be made available. This would then seem to suggest that at least some demand response will be available at lower prices than the suggested peaking plant costs.

The 155 MW, diesel OCGT at Whirinaki has been designated to provide reserve generation since 2005 but has seen limited use. The Electricity Commission has also seen no need to purchase further reserves in its most recent assessments. It is therefore difficult to understand why most scenarios then show an increase in peaking capacity of around 200 MW in 2009.

In summary, the amount of peaking plant required appears to be excessive and the apparent preference for the use of diesel over gas in the modelling outcomes should be investigated.

Inconsistent outcomes

In the “sustainable” path Meridian’s Project Hayes (a consented, albeit appealed wind farm project) does not make it into the build schedule shown in Appendix 1. However in the “SI Surplus” scenario a first stage is built in 2011 followed by a second in 2013. A similar situation occurs with TrustPower’s Mahinerangi project (built in 2037 in MDS1, but 2013 in MDS2). It is unclear to us why these two scenarios should show such dramatically different outcomes. It cannot be the carbon price difference ($50/t in MDS1 versus $40/t in MDS2) as the projects are built earlier in the lower priced scenario. The only other material difference that we can see between these two scenarios from the information that has been presented is the treatment of the fate of HVDC pole 1. However as this pole is assumed to be replaced in 2012 in both cases this would seem unlikely to be a reason why a generation investment decision might be made in 2035 rather than 2010 (especially as in one set of outcomes the generation investment proceeds before the pole replacement).

Similarly it is hard to understand how the Motorimu wind farm in the Manawatu would be built 10 years earlier in the “SI surplus” scenario (2010) than in the “sustainable path” scenario (2020).

These apparent inconsistencies make it difficult to understand the main drivers behind the various scenarios that are dictating the generation build schedules that have been presented.

Possible data errors

MDS5, the “high gas discovery” scenario, does not show the Te Rere Hau wind farm in its build schedule, despite this project already being under construction. It appears in 2009 in all other scenarios.

In paragraph 42 of the consultation document it is suggested that in the period to 2012 that the HVDC could remain as a monopole in MDS2 or could return to full service in MDS5. However in Table 2 the opposite “fates” are indicated (i.e. Pole 1 fully available in MDS2 and totally unavailable in MDS5). We imagine that this does not have a great effect on the outcomes (as generation investment decisions will presumably be made with the knowledge that a new pole will be in place from 2012 regardless) but it would be worthwhile clarifying which “fate” applies to which scenario.

Further developments

We note that you intend to further develop these models with inputs from the Transmission to Enable Renewables (TTER) project. That project has, from the wind energy perspective at least, only presented preliminary information to date and its final outputs have not been subject to review or comment by the industry. We have suggested in a separate letter to the Commission that the outputs of that project should be reviewed with industry participants before it is used for further analysis.

We also note that further modelling is anticipated with respect to co-optimisation of generation and transmission. This would seem to also appear to have some close links to the TTER project.

We wonder whether the high levels of peaking plant generation being calculated relate to what is possibly a necessarily 'coarse' treatment of the reserve requirements for wind generation. Accordingly we agree that it is important that you further model the impacts of wind variability (i.e. peak demand and low wind output) and the treatment of constraints on variable wind generation. Similarly, perhaps it is also the treatment of wind's variability that is creating the high "statistical wholesale price projection" for the 'sustainable path' scenario that is discussed in figure 6 and paragraph 80 (i.e. the suggestion that not enough generation build may have been included). The generation profile that is being used for each wind project will presumably influence the effective capacity credit for all of the wind projects that have been incorporated. We recognise that attempting to build variable wind outputs into the model (on top of other variables such as demand) is likely to be a complex and difficult exercise.

Accordingly NZWEA would welcome the opportunity to discuss the treatment of wind energy in the modelling with the Commission in order to better understand the implications for the various scenarios and to see if it might be able to assist with the provision of additional information to assist with the modelling process.

It is also not clear to us if and how any costs for ancillary services (i.e. frequency keeping) have been built into this modelling.

We hope these comments are of value to the Commission as they develop the GPAs. We would be happy to meet with the Commission to discuss them further.

Yours faithfully

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