Submissions on Draft Transmission Code

The following submissions on the Draft Transmission Code were received from members of th Working Group.

ORION

Orion New Zealand Limited (Orion) welcomes the opportunity to comment on the Transmission Code preliminary issue (dated 4 March 2009) released by Transpower.

In general Orion supports the proposals in the paper

1 In general we support the concept of a Transmission Code.

2 To increase understanding, the transmission code should better define the process of how the code is intended to interact with the existing EGR's (in particular the GRS). It is not clear from the current drafting whether the transmission code is effectively an extension of the rules and will become mandatory or not. That is, can the EC require Transpower to put forward solutions that are GRS compliant but not transmission code compliant? Or will Transpower insist on, or have the legal right to only put forward transmission code compliant solutions?

3 It is also not clear how widely the transmission code is to be applied. Is it intended for the code to apply to connection assets as well as interconnection assets? We recommend that connection assets should be treated differently to facilitate customer specific arrangements.

Special protections schemes (SPSs) – Application 2

4 As stated above we do not believe that the transmission code should be applied to connection assets. In the case of connection assets, SPS's can provide medium term solutions or even permanent alternatives to transmission investment. The Springston thermal overload protection scheme is an example of an effective SPS which carries no risk of cascade failure to the grid but would interrupt 60MW if it mal-operated. The low risk of this occurring is more than offset by the economic benefit of delayed or avoided transmission capacity.

Planned outages

5 We agree that it is critical to grid reliability that Transpower achieves an acceptable level of access to assets for routine/preventative maintenance.

6 We also agree that the transmission code planned outage criteria should **not** include a margin for project work. It is the role of Transpower planning to ensure that sufficient lead time is factored into any proposal to ensure that practical implementation can be achieved. The economic cost of bringing forward some transmission options to achieve this may make them unviable as a transmission option and this should be accepted as an outcome of economically efficient transmission planning.

7 We agree that in any given week there needs to be time for short outages to achieve emergency maintenance (e.g. failed insulator, hot spot alleviation, etc) and also further time is required on an annual basis to undertake programmed maintenance. However, more justification and/or detail is required to develop a defendable and robust planned outage regime. In particular, the following should be considered:

- What justification is there for a two day continuous outage every weekend? Transpower should justify the two day outage with an explanation of the type of work required to be undertaken during these unplanned outage windows. An alternative option worthy of further consideration may exclude Saturday mornings for the coldest (or highest load) weekends of the year.
- Further justification is required to demonstrate that a five day continuous outage is required for 70% of the year. The analysis demonstrated in Appendix B5.3 is over simplified and makes too many assumptions to be taken literally. Furthermore, the fact that London achieves more than 70% is not justification for NZ requiring the same. London may achieve 70%, but do they need it? – it may just be an outcome of the natural load duration curve. Transpower needs to undertake some region specific case studies (worst case scenarios) to demonstrate the quantity of outages required on an annual basis. In the case of London, they have more circuits, so they need greater access because at any given time it is more likely that one circuit will be required to be out for maintenance. Transpower should understand this relationship and produce a policy which reflects the wide ranging outage requirements. A one size fits all policy will not result in efficient outcomes. Perhaps a matrix approach is more appropriate? For example:

Number of transmissions circuits (lines and or transformers)	**% of year with 5 day continuous outage**
1	10%
2	20%
3	30%
4	40%
5	50%
6	60%
7	70%

- Is N-1 or N-1-G required for outage planning? Given that most outages will be planned, we consider that N-1 is sufficient. [010]

- What load forecast will be used for outage planning? (e.g. 10% or 50% probability of exceedance forecast). Who will produce the load forecast for weekends and every week of the year?
- What assumptions will be made about load management? Historic data does not include load management and most (perhaps all) distributors have been focussed on winter load management. The current TPM encourages this approach and so what incentives will be provided to encourage load management in the off season to achieve outages for maintenance?

Reactive compensation

8 Reactive compensation is a complex area of transmission planning and the transmission code attempts to simplify specific engineering applications into generic criteria. This is a challenge and although this may be useful to help assess the level of risk that is being taken or proposed to be taken with transmission investment proposals, it could lead to adverse results. Furthermore, there is significant uncertainty about the electrical characteristics of load connected to the grid and the level of embedded reactive compensation.

9 Given that the Transpower grid is relatively small with a low number of areas constrained by voltage, the uncertainty and complexity of a voltage constrained transmission grid should be addressed on a case by case basis. It is appropriate to take a conservative approach but this should be applied to the inputs of the reactive compensation study, not a generic transmission code.

Karen Frew, PowerCo

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Answer: Powerco supports the overall intent of the Transmission Code which brings greater certainty to investment using the well defined technical criteria. Transmission investment, and the technical aspects that form part of the decision making process, are highly complex and involve significant engineering judgement. Transpower's proposed Transmission Code lays a foundation for prudent investment in the electricity transmission system in terms of maintaining security of supply while allowing for necessary maintenance. Powerco believes Transpower have been through a thorough process of determining the criteria presented in this Code and support the results as presented in the Code.

In providing this support we caution that the 'voice of consumers' be heard in the mix during a decision making process. If there are grid exit points that currently have n security and don't meet the code requirements for outage planning there may be reasons for the existing levels that need to be considered in determining what, if any, investment is made. The price/quality trade off issues need to be well explained to consumers in order to help make informed decisions.

Finally Powerco also considers this document needs a regular review period in order to provide opportunity for industry review following its application. This will maintain the high level of confidence the industry has in the decisions made using this code.

Question: Please enter the characters you see below and click submit

Answer: mqFeO

A full set of results can be downloaded from the Forms Manager module in Notion.

Dr Mirmal Nair – Auckland University

It was very pleasing, for me personally, to see two of my research topic of interest prominently being paid attention to in the Transmission code document (1) Reactive Compensation and (2) SPS.

My group published a paper at the Australasian Universities Power Engineering Conference (AUPEC) in 2005 titled " Voltage COllapse Scenarios in the North Island of New Zealand Electricity Market". During our research we raised issue of choosing the appropriate mixture of dynamic and static var compensation; vulnerabilities of collapse due to WKM-OTA line or HEN-ALB line; etc. I have been closely following the reactive upgrades of TP since then. Was pleased to see an SVC commissioned at ALB and the one planned I think in Islington. Being active in academic research, it is very pleasing to see some of these topics being reflected in a Transmission planning document. I congratulate your team towards this effort.

One issue I find still of concern is the loss of discrimination of operational security visibility, specially from Voltage collapse following reactive compensation. I am sure that your SO will be really concerned with impacts of increasing reactive compensation (static+dynamic) towards their decreasign state estimator visibility.

On the issue of SPS, one of the issue I raised during the public meeting for the Warieki ring upgrade was one othe options raised by EC with regards to SPS as an option to upgrade, specially when they were focussing entirely on satisfying their economic criteria. Coming from a protection background, I am very concerned with using security operational tools as options for planning decision. Not that the protection is less smart, but more with the approximations we make before setting these devices. There are several instances when mal-tripping can cause serious operational damage (specially typical high hardware failure statistics). My group is currently looking at aspects of protection involving WAPS, IEC 61850, adpative protection and Voltage collapse monitoring relay etc. & The more I research into possibilities, the less confident I am about the efficacy of the general applicability of SPS. In short my experience suggest caution is needed before SPS is implemented.

I throughly enjoyed reading the document & have already passed it onto my research students. Really looking forward to reading about other stakeholder's response.

Rowan Maxwell Genesis Energy

In my view this is a good guideline.

(4.4) A comment should be included here to specify what the acceptable loading would be on the remaining equipment when the item of interest is taken out of service. (Or are these specified in the Grid Planning guidelines? The EGR definition of single credible contingency event is unlikely to cover a planned outage.)

(Figure 1) It is acknowledged that this curve is titled "dynamic ratio". However, this curve does not line up very well with the contents of clause 5.2. ie The curve should hit the horizontal axis at 40%. This not correct. The curve as drawn would suggest that a compensation factor of say 80% for example, (with a dynamic ratio of zero) would never be acceptable.

(5.6.1) Slight wording change suggestion: "....real time monitoring of static and dynamic reactive reserves". (5.6.2 as well)

(5.6.1) Also in the clause, "Sufficient....nose point of the PV curve for expected system states". The term "expected system states" should be defined. Eg n-1 or n-2.

Nenad Puljic - WEL

On page 27 in the reduced security paragraph Western Rd is not a grid exit point any more and has been finally decommissioned just before last Christmas. The new one is called Huntly.