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Dear Paul

Capital Expenditure Input Methodology – Post Workshop Submission

Transpower appreciates the opportunity to make a submission on the issues discussed at the workshop on the Commission's Emerging View in relation to the specification of the Capital Expenditure IM (Input Methodology). We found the discussions at the workshop constructive and were encouraged that there seemed to be a broad consensus amongst interested parties on many aspects of the Commission's proposed arrangements.

As highlighted at the workshop, there are some aspects of the Commission's emerging thinking which cause us considerable concern; particularly the proposal to link new capex incentives to the delivery of asset health improvements, as a proxy for incentivising improvements in the quality of service experienced by consumers and users of the transmission network. The Commission's proposal necessarily leads the regulator down the path of ex post and intrusive regulation which runs contrary to objectives of the regime. This aspect was highlighted by Transpower's Deputy Chairman at the workshop. In our view, the approach could lead to an unacceptable blurring of the governance roles between the Commission and the Transpower Board.

Our concerns were mitigated, somewhat, by the Commission's comments at the workshop on the preliminary nature of their emerging thinking and the subsequent suggestion to Transpower that we propose an alternative mechanism that would satisfy the Commission's Part 4 obligations.

In the attached commentary paper we have outlined a proposal to extend and supplement our current network output measures and strengthen the associated financial incentive rates. Frankly, there is work to be done on the details of this: we do not have all the answers yet and will engage with customers and Commission staff to develop the approach further. However, this approach is much sounder in concept than using an intermediate, subjective proxy such as asset health

In the paper, we also expand on points raised at the workshop and respond to issues raised by Commissioners. Key points are:

- We agree with the emerging view that a financial incentive mechanism should be applied to the “minor” capital investment allowance, but consider it more difficult to create an effective incentive for individual “major” projects without creating perverse outcomes – hence, this should be avoided.
- As noted above, we have a strong objection to the proposal to link the “minor” capex incentive directly to “asset health” outputs.
- We consider that the linking of financial incentives to “outputs” should be to measurable network performance measures (customer focused outputs) that customers actually value – we have proposed a framework to strengthen the current incentives / measures in this area.
- We agree with the view that the IRIS scheme should be applied symmetrically from RCP2.
- We concur with the Commission’s view on the need for Transpower to lift its asset management capabilities during RCP1: this is fundamental to our own strategy and is a fundamental driver of our RCP1 revenue proposal.
- We agree with the emerging view that, during RCP1, we should report progress on commitments made to meet key asset management improvement milestones.
- We support the proposal to lift the Major / Minor capex threshold from \$5m to \$20m. However, we recommend that this threshold be transitional and that it should increase from RCP3 onwards.
- We agree with the view that “minor” envelope projects with a value >\$20m (irrespective of the project type) should be subject to an investment test and a commensurate level of consultation, applied by Transpower. We propose formal confirmation from the Transpower CEO to address any of the Commission’s process adherence concerns.
- We agree with most aspects of the Commission’s emerging view in relation to the scope and application of the Major capital expenditure investment test – we have commented on areas which require clarification and / or reinforcement.
- We do have a preference for a national cost/benefit test, but appreciate the current constraints placed on the Commission by the Act.
- In cases where expected financial net market benefits for alternatives are close, the Commission should explicitly allow for unquantified benefits to be considered when choosing between these alternatives.

The Commerce Act requires the Commission to make a determination on the final Capex IM by 1 November 2011. However, the Act allows the Minister, on written request from the Commission, to extend that deadline by up to three months (to 1 February 2012). Given the importance of the matters addressed by the Capex IM, and the time required to finalise and consult on the various policy positions and then ensure that these have been appropriately translated into the determination drafting, Transpower recommends that the Commission exercise its discretion now to request that the Minister grant allowed extension.

We look forward to a constructive interaction with the Commission on finalising the Capital Expenditure Input Methodology.

Yours sincerely

A handwritten signature in black ink that reads "Patrick Strange". The signature is written in a cursive style with a large initial 'P' and 'S'.

Patrick Strange
Chief Executive

Capex IM – post workshop commentary

Incentive Framework

We concur with the Commission's view that one of the objectives of the ex ante revenue envelope approach to price-quality regulation is to provide incentives for the regulated company to identify and achieve efficiencies, and, over time, to reveal the actual economic costs of its activities. We also concur that it is appropriate that incentives are in place to ensure that "efficient" expenditure is targeted to deliver network performance outputs and levels of service which are considered to be of most importance to transmission customers.

However, it is important to note that the actual choice and timing of transmission infrastructure investments (dynamic efficiency) is more important than the cost efficiency of their delivery (allocative efficiency). Thus, incentives put in place to drive efficiencies in expenditure can be value destroying if they place perverse incentives on the regulated company to amend its investment plans in a way that undermines the opportunity to achieve dynamic efficiencies.

Against this background, the following presents our view as to how the current IPP incentive mechanisms, which will be applied during RCP1, can be further strengthened from RCP2 onwards.

Capex incentive – Minor Capex Envelope

We agree with the Commission's emerging position that a financial incentive mechanism should be applied to the "minor" capital investment allowance by setting a marginal incentive rate at the outset of RCP2, which in effect would permit Transpower to retain a proportion of revenue associated with any out-performance of its forecast capital expenditure (that is, lesser expenditure) during the regulatory control period. To ensure a symmetrical approach, we agree that it is appropriate that a comparable proportion of any revenue associated with under-performance of forecast capital expenditure (i.e. over expenditure) should be a risk borne by Transpower's shareholder.

Transpower's actual performance and expenditure during an RCP will be taken into account by the Commission when setting the revenue envelope for the next regulatory control period, thereby providing an incentive on Transpower to ensure actual expenditure incurred during an RCP is justified and that any material deviations from a forecast plan are fully explained.

The Commission has proposed an initial fixed incentive rate of 33%, which we understand is aimed at aligning the capex incentive rate with that applying to opex under the incremental rolling incentive scheme. In the latter case, the incentive rate was lowered from the 100% incentive which applied under the Administrative Settlement to 33% under the IPP. We believe 33% is too low an incentive and we suggest that consideration be

given to setting the incentive at a 50:50 sharing rate for both opex and capex from RCP2 onwards (i.e. 50% Transpower / 50% customer).

Capex incentive – Individual “Major” projects

It is difficult to create effective, equivalent incentives for individual “major” capex projects, because of the perverse incentives they introduce. Major capex (as defined) is typically non-routine, new and has much higher levels of cost uncertainty (for example, contrast a typical transformer replacement with investments such as the North Island Grid Upgrade (NIGU) or North Auckland and Northland (NaAN) projects).

At the workshop, we outlined that perverse incentives could arise from the Commission’s emerging proposal to establish both a “Maximum Approved Cost” (MAC) at the time of a GUP submission followed by a separately approved “Target Cost” allowance at a later date, when final design and tender have been completed. The Commission’s proposal is that the incentive rate would be applied against the approved “Target Cost”.

Such an approach will incentivise Transpower to maximise the Target Cost so as to minimise its risks post contract award. This means loading all risks onto the contractor, whether or not that is appropriate, inevitably leading to higher contract prices and a suboptimal outcome for the customer. Transpower currently adopts a model of appropriate risk allocation between contractors and Transpower (i.e. place the risk with the party most able to mitigate it) and we firmly believe this to be the appropriate model to obtain best value across our investment programme. A simple example is land access for NIGU – the cost of this was forecast (and has proved) to be highly uncertain. If we were to place the risk on the contractor (who operates under relatively low margins and has little control over land access), the price they would place on it would be very high. Subsoil conditions for the 413 tower foundations are a similar example.

As stated at the workshop, Transpower currently uses a MAC approach in its funding requests for large capex. The MAC approximates a P90 cost estimate and is built up from an expected cost which comprises the estimated cost (P50). Additional allowances are added to the expected cost to allow for price variation, exchange rate variability, the cost of hedging the exchange rate, interest during construction and inflationary effects. The final approval amount allows tracking of all costs: those we can control and those we cannot.

Should we find that we do exceed the MAC figure, we have the ability to seek recovery of the overrun. This process requires full reporting of all costs against approved amounts and has been transparent and open to consultation. However, there is no guarantee that we can recover overrun costs. From a point of regulatory principle, the reliance on an ex post approval mechanism is not ideal, but we believe it is necessary and appropriate for the small number of major projects we perform, given their high levels of uncertainty.

Transpower only recovers revenue against the lesser of the approved (initial or amended) amount or expenditure actually incurred: however, the exposure to an ex post review (including consultation) of any expenditure in excess of MAC places an effective incentive on Transpower to minimise costs.

Of the twenty projects we have had approved under Part F, there are currently only two which are forecast to exceed their respective approved costs. Similarly, approximately half are forecast to cost over the P50 level and half under. We believe that the MAC approach is fit for purpose and should be adopted within the Capex IM.

We do recognise the need to raise the external visibility of project tracking against costs and deliverables and this will provide a further incentive to continue to control those costs that we are able to influence.

Finally, as noted at the workshop, we propose that, for “Major” projects, some form of project close-out reporting combined with formal CEO confirmation (if required by the Commission) of delivery against the intended scope should be considered as an appropriate level of assurance for the Commission.

Opex Incentive

We agree with the Commission’s emerging view that the incremental rolling incentive scheme (IRIS), which applies to operating expenditure, should be amended in order for it to apply symmetrically from RCP2 onwards. Under the current IRIS scheme only net gains are carried forward to adjust future revenue allowances and Transpower is not exposed, going forward, to incremental losses (net overspends).

Linking Capex incentives directly to “asset outputs”

Where our view diverges from that of the Commission is in relation to the proposal to link the capex “incentive” mechanism directly to measures of asset health, as a proxy for outputs. There are two issues with the proposal: (1) it presumes that there is a direct (and immediate) relationship between capital expenditure incurred and measurable improvements in asset health; and (2) asset health is not a directly observable outcome, requiring subjective assessment and judgement – meaning that any measure based on asset health must invariably require Commission assessment ex post, which is contrary to the objectives of the regime.

As we noted at the workshop, linking the incentive and allowed RCP revenue directly to asset health indices:

- inappropriately places the focus on the delivery of “intermediate” asset indicators rather than placing the incentive on the delivery of network performance outputs (customer focused outputs), which are what customers value;
- shifts the focus towards ex post regulation, which will blur the governance roles of the Commission and the Transpower Board by requiring the Commission to validate already committed expenditures and confirming or otherwise prior decisions made by the Transpower Board when determining whether or not asset improvement target have been achieved. Such an approach serves to undermine Transpower’s role as the grid planner. It is, we believe, accepted that Transpower must have the ultimate accountability for deciding what transmission investment should be made (and wear the consequences of decisions made under that accountability). Accountability

manifests itself most clearly when an inevitable element of judgment is applied in making investment decisions - and operationally, these judgments are made on a day by day basis as priorities inevitably change;

- assumes an overly simplistic relationship between a dollar spent and a unit reduction in measurable risk and fails to recognise the many variables that affect asset management planning and actual performance outcomes on the network;
- appears to be based on an assumption that Transpower will seek to maximise short-term gains at the expense of the long term service provided by the grid (i.e. to under-invest). Transpower's Board does have obligations to operate as profitably as any comparable private company, but it is wrong to suggest that Transpower's incentives are to maximise profits and returns at the expense of long-term investment and sustainability of the network. Rather, the Board's deliberations and decisions centre primarily on the long-term planning and development of the national grid. This is where most value is created for Transpower and the economy at large and where the Board focuses most of its attention;
- could lead to a perverse incentive on Transpower to spend mechanistically against what has been approved at the start of the RCP (the low risk approach), rather than appropriately optimising and substituting expenditure to address changes in risk as any prudent network operator should do.

We understand the objectives of the Commission in making this proposal, and it is appropriate that Transpower have incentives based on outputs. However, asset health metrics in this context are (incorrectly in our view) being applied as a proxy for actual network performance outputs (i.e. those experienced by customers). It is at the level of outturn network performance where the incentives should be applied.

We acknowledge the Commission's challenge for us to develop and propose an incentive mechanism that works at this level and links more directly to "customer service".

We have set out below a proposal which describes how the current network performance incentive framework that is to apply in RCP2 could be further strengthened and made more targeted to meet the Commission's stated objectives.

Network Performance – Outputs and Incentives

Annual quality performance output measures and targets are currently specified under the IPP (which will link to financial incentives from RCP2). Network quality indicators are generally lagging indicators of performance, but no more so than asset health indices. Further, they are sensitive to the level of investment (both medium and long term) and they properly focus Transpower on network performance outputs and the need to invest adequately in order to maintain performance quality over the longer term.

In our view, as performance indicators, they provide a direct measure of overall network quality as experienced by customers which aligns closely with the objectives of the Part 4 purpose as stated in s.52A (1)(b) "have incentives to improve efficiency and provide services at a quality that reflects consumer demands".

We acknowledge and agree that, over time, the financial exposure to Transpower would need to be materially greater than the 1 percent of revenue proposed for RCP2.

There are challenges to using them as performance measures: not least the inherent volatility of more aggregated measures such as total system minutes lost. However, we believe these can be addressed, in part by disaggregating the measures, for example by customer class, and by, as well, accounting for factors such as where customer choice has affected outcomes. These would make the incentive mechanism more targeted and the measures of more value to customers.

As an alternative output performance incentive framework to that proposed by the Commission, Transpower suggests that during the course of RCP1 we:

- review the current suite of aggregated measures: a) Total impact of interruptions; b) Loss of supply event frequency; c) HVAC circuit unavailability (unplanned); and d) HVDC bi-pole unavailability (unplanned), and consult on a range of alternatives or refinements which can be demonstrated to have direct relevance to customers and the overall security of the New Zealand grid;
- move away from establishing targets based solely on historical average performance and establish long term future targets (e.g. 20 years) – which equate to a view of the optimal level of service, i.e. where it may not be economic to make further improvements – such an approach should improve the link between future capital investment requirements and the economic level of future network performance;
- link the revised suite of measures to a materially higher incentive rate than is currently specified in the IPP.

The key is to ensure that the output measures are determinate, i.e. that they are clearly defined, able to be influenced by Transpower, and fall directly out of our performance and, as such, will not require ex post judgement to be applied by either Transpower or the Commission.

At the simplest level, the current performance measures could be simply disaggregated by customer or asset class to report at a sub-category level (e.g. major load centres, direct connects, critical / non critical circuits, line branch, transformer branch, etc) but, in addition to extended measures based on supply loss and duration statistics, we propose to explore alternative network performance output measures and to engage with customers with an open mind on practical options.

We also believe measures which assess the level of risk (versus actual outages) we expose customers to, may be relevant.

Proposed process

Given the lead time required to progress the above and to consult appropriately, we suggest that the Capex IM (to be finalised at the end of 2011) should specify the attributes

of the required incentive framework rather than lock in the detail of the measures and targets which will apply from RCP2.

We propose that we would then engage with customers (and the Commission) during the course of 2011/12 with a view to being in a position to propose a “dashboard” of revised measures (and associated targets) to the Commission as part of the RCP2 revenue submission – together with the proposed incentive rate and appropriate weightings for each measure.¹

Asset Management Improvements

We concur with the Commission’s view that there is a need for Transpower to lift its asset management capability and develop more robust site or asset specific metrics. In fact, this is a core element of our strategy, and was central to our RCP1 revenue submission.

At the workshop we presented our already established programme of work over the next three to five years to implement such improvements.

Asset Management Developments in RCP1

The Commission has acknowledged the positive steps being taken by Transpower to invest to improve its asset risk management processes and related reporting but is concerned that we implement the programme and deliver the capability improvements which we are targeting during the first regulatory period. We accept this, given the size and importance of the initiative.

Thus we agree with the Commission’s emerging view that, during RCP1, Transpower should report progress with the developments in its asset management capabilities against the milestones that have been outlined in its revenue reset proposal (February 2011). At the workshop we set out a summary of our asset management journey plan as follows:

Current Status

- Suite of strategic spare transformers procured
- Immediate plans in place to address high risk assets (e.g. single bank transformers)
- New Asset Management Policy developed
- Commitment made to enhance overall asset management processes and procedures in line with the principles of PAS55:2008 Asset Management
- New asset management strategies and plans developed for all major asset types (fleet strategies)
- Major enhancement of asset management information systems commencing this year
- Standard maintenance practices being reviewed and updated
- Asset risk management system project under way

¹ Transpower suggests that the Commission and the Electricity Authority, together with Transpower, also take the opportunity, during this period, to review the utility of continuing to report, annually, on detailed interconnection asset measures, which is a requirement under Subpart 6 (Interconnection asset services) of Part 12 of the Electricity Industry Participation Code 2010. In our view, these measures are of little benefit to customers as measures of network performance and are likely to be superseded by superior measures if the current IPP suite of network measures is improved as outlined above.

In two years

- Implement asset criticality and asset health frameworks to support and prioritise investment decision making
- Implement an asset risk management system
- Procure a replacement for our core asset maintenance management system
- Enhance our asset management system to achieve compliance with PAS55:2008

In five years

- New asset maintenance management system operational
- Implement advanced analytics capability for prioritised critical plant, leveraging off the new asset management system and targeted on-line condition monitoring
- Process of continuous improvement in asset health and criticality assessment in place
- Continuous improvement of asset management plans and works prioritisation in place based on robust risk, performance and economic assessment
- Review of routine maintenance activities using reliability centred maintenance techniques.

It is also important to note that overall network performance is not only influenced by asset health risk. An analysis of historical network performance “events” will show that human error, environmental factors, customer actions and asset design itself have all been contributing factors to network performance issues and our targeted improvements to address network performance over the longer term incorporates all of these factors which contribute to performance and not just those measuring the risk of asset failure.

Transpower will report annually to the Commission and the report will be made publicly available to ensure that customers and other stakeholders are equally informed on this initiative.

Level of the major / minor threshold

The Commission’s emerging view considers that a distinction should be made between projects included in the revenue envelope as part of an overall capex forecast (defined by the Commission currently as “Minor” projects) and those “Major” projects subject to more detailed scrutiny, approved under the GUP/GIT process and capped on an individual basis outside the envelope. We concur with this view.

As a transitional measure, the Commission proposes the threshold between “Major” and “Minor” projects for RCP2 be set at an individual project value of \$20m, and “Major” projects include only those categorised as grid enhancements (new grid asset investments where the primary driver for investment is capacity related). We believe this threshold is workable for RCP2, but recommend that this threshold be transitional and increase further from RCP3 onwards.

We disagree with the Commission proposing to have discretion to elect to require specified enhancement projects, within the value range \$5m to \$20m, to be removed from the “Minor” projects allowance and approved individually as if they were “Major” projects. We

acknowledge that, in exceptional circumstances, the Commission will always have discretion to disallow any particular project from Transpower's proposed "expenditure plan" when setting the "Minor" capital allowance (e.g. if there significant uncertainty around the need, timing, scope and/ or cost of a project). In such circumstances, the framework should allow for Transpower to decide whether or not to seek individual project approval, during an RCP, when any uncertainties have been resolved.

We agree with the Commission's emerging view that all "envelope" projects with a value greater than \$20m should be required to have a commensurate investment test applied by Transpower to confirm the proposed option, and a commensurate level of consultation applied, this being dependent on the nature of the investment in question²

However, the Commission has proposed a requirement for an independent review to be undertaken of all projects with a value greater than \$20m, to confirm that an appropriate investment test / consultation has been applied in each case. We suggest that a more sensible and pragmatic option would be for Transpower to provide the Commission with a summary, at the end of an RCP of all >\$20m projects which have been progressed during the regulatory period, together with formal confirmation from the Transpower CEO of the evaluation / consultation processes that have been applied in each case. This will provide equivalent and effective assurance, at greatly reduced cost.

We support the need for a cost/benefit approach for the evaluation of new investment (and major asset replacements) in the interconnected grid and that this should be applied by Transpower commensurately with its size and type, whether the project is above or below the "major" project threshold.

Equally, stakeholder consultation is important (and essential) to Transpower and this should not be eroded by the level at which the threshold is set. We will continue to consult on our investment proposals, as is the case currently, but can see considerable benefits, both to our customers and to Transpower, in our having the ability to determine the level of consultation for non-major projects. For example, we now consult periodically on proposed regional programmes of work and see value in aggregating smaller value projects of similar nature, and consulting on them as a single group.

Major Capital Expenditure Investment Test

Scope of Investment Test

At the workshop, Transpower highlighted the need for a national benefit test.

We note the Commission's position that it is constrained by legislation to allow for consideration of only market benefits in the investment approvals process.

² The term "envelope" in this context applies to the multi-year capital investment allowance approved by the Commission for all capex which does not meet the criteria for individual approval via the GUP process (enhancements with a value greater than \$20m).

In the majority of cases, the proposed market benefit test will adequately define the full range of costs and benefits (both quantified and unquantified) for each project alternative.

Allowing explicitly for the market test to consider unquantified costs and benefits associated with “options for future demand” would capture the potential for higher grid use (higher than in our demand forecasts) where an alternative provides greater certainty over future grid capacity and reliability.

Costs and Benefits

We agree with Commission’s view that a less prescriptive approach to the calculation of costs and benefits is preferred. Our experience with the Grid Investment Test was that suitable approaches for calculating costs and benefits were usually specific to each investment considered. Having particular approaches prescribed would have made some analyses difficult. Ultimately, the Commission can consider Transpower’s approach in detail once a proposal has been submitted.

In the preamble to the definitions of costs and benefits, we propose that a principle be included that all costs and benefits which may vary between alternatives should be included in the analysis.

The Commission’s definition of Cost currently reads:

“Cost means....and the following costs should be included....”.

We recommend this be amended to “Cost means....and includes....”.

The word “should” is unnecessary. The important thing is that any costs and benefits which differ between alternatives are included. This would also be consistent with the Input Methodology wording being less prescriptive.

We do not agree that interest during construction (IDC) should be included in the economic test analysis. There are two primary cost/benefit approaches in common use:

- a cashflow approach which reflects cash as it is incurred;
- a financial approach which reflects amortised payments as they are made.

The difference between the two is interest paid. IDC would be included in the latter, but not the former. One difficulty with the latter approach is that, to compare alternatives, one needs to know what the financial arrangements would be for each alternative. That is very difficult when assets have different operating lives. Consequently, we have always undertaken the Grid Investment Test analyses using the cash-flow approach which does not include IDC.

Operating and Maintenance Costs

The definition which states “operating, maintenance and.....over the operating life....”, should be amended to “operating, maintenance and.....over the calculation period or operating life whichever is shorter....”.

Although not explicitly discussed at the workshop, we presume the Commission will include a standard calculation period of 20 years (plus a residual value if appropriate) in the Investment Test. The operating life of transmission lines can be 80 years, but there would be little merit in undertaking an 80 year analysis. The present value of a constant cash-flow over 10, 20, 40 and 80 years (using a 7 per cent discount rate) is as follows:

Years	PV of cashflow
10	0.49
20	0.74
30	0.87
40	0.94
80	1.00

Hence, a 20 year analysis would capture 74% of the total operating costs for an asset with an 80 year life without incurring the difficulties of trying to forecast 80 years out. Our practice has been to use as long a calculation period as possible, up to a maximum of 40 years, as there is little point in forecasting generation and demand beyond 40 years.

The inclusion of “...or operating life whichever is shorter...” covers those analyses for assets with operating lives of less than 20 years.

Existing Generation

The definition which states “fuel costs of projects included in a scenario,” should be clarified to say “fuel costs of projects included in a scenario, including existing assets”. The term “project” commonly refers to committed and modelled projects, i.e. those not yet built, and does not include existing assets.

Exclusion of clause 27.9

The Grid Investment Test (GIT) clause 27.9, which refers to the benefit “subsidies or other benefits provided under or arising pursuant to all applicable laws, regulations and administrative determinations” should be included. This provision allowed for such things as subsidies for renewable generation (if they existed) to be taken into account. We think it is important that this provision be retained. We assume that any subsidies for renewable generation will aim to reflect uncontracted for benefits of such generation. . Consistent with our view that national costs and benefits should be recognised, we believe such benefits should be included in the test incorporated into the Input Methodology.

Inclusion of Good Electricity Industry Practice

The definition, “Clarifying that costs of the proposed investment or alternative projects must be consistent with relevant international design standards”, should be re-drafted. The reference to international standards is problematic. We design using New Zealand seismic standards, for instance, not international standards, and other aspects of our designs conform to New Zealand statutory requirements. Our recommendation would be to re-word as: “Clarifying that the proposed investment and alternative projects have been designed in accordance with Good Electricity Industry Practice (GEIP) and that their cost reflects the requirements of GEIP.”

GEIP is a term used to describe common industry practices that have derived over time from the application of expert judgment, but which may be difficult or impossible to justify using normal quantitative approaches. For instance, consideration of “black swan”, or high impact low probability events is extremely difficult if not impossible using traditional analysis.

The application of GEIP is critical to sound transmission design and must be reflected in investment decisions. We have attempted to capture such judgement issues in our Transmission Code of Practice, which is a live document and continues to be developed.

Consideration of GEIP should be accorded equal merit and consideration when making investment decisions and the Commission should have rules which allow it to approve proposals on the basis of the inclusion of such expert judgment.

Unquantified Benefits

The Commission’s suggestion regarding the inclusion of unquantified benefits in the Investment Test is an improvement on the GIT approach, but we think it should be expanded in the following manner:

- The Investment Test is initially applied quantitatively, using those costs and benefits defined in the test, to determine the expected net market benefit (ENMB) for all alternatives.
- A qualitative assessment is made of unquantified benefits.
- Where the unquantified benefits may change the investment test result, we attempt to quantify the benefit for each alternative. The quantified benefits are added to the initial ENMB results and may change the preferred alternative. Such quantifications are likely to be less accurate than those used for the initial ENMB, and would be weighted accordingly.
- In the event that the initial ENMB results are close and two or more alternatives are considered equivalent, the unquantified tick box qualitative results could be used to differentiate the ENMB between alternatives, without quantification.

It is important to recognise that the ENMB results have a large uncertainty associated with them. We commonly discuss the accuracy of the cost inputs to the EMNB results (which may be in the range of +/-10% to +/-30%), but not the accuracy of the benefit assessments. In reality, the accuracy of the benefits is almost always materially less than that of the costs because they rely on estimates (e.g. of demand) and mathematical models that rely on a range of input assumptions that are necessarily imprecise. Although we do not recommend prescribing when ENMB results should be considered equivalent, differences which are less than 10% of the capital cost estimates would generally be equivalent.

Overall, this approach is consistent with one where the investment test result is only one of the considerations taken into account when making an investment decision. We strongly advocate such an approach and this is discussed further under “Satisfying the Investment Test” below.

Investment Test Methodology

Use of Scenarios

We agree that the base input assumptions (demand forecasts and generation scenarios) to be considered in the Investment Test analysis should be derived independently from Transpower.

We also note, however, that it has been our experience when applying the GIT to date that it is often necessary to amend the base input assumptions for the investigation at hand (and this was confirmed as appropriate by the Electricity Commission). The main reason for this is that the base input assumptions are derived on a national basis and, while they may be appropriate from that perspective, they often need modifying to make sense in relation to a single GXP or region. Therefore, we recommend including the ability to vary input assumptions where necessary, provided such variations can be justified to the Commission.

With regard to generation scenarios, we agree that it is appropriate to use multiple scenarios, but the appropriate number will vary depending on the situation. Hence, we recommend not prescribing the number of scenarios that must apply to an investment proposal. In some cases, particularly for economic investments where the driver is to enable new generation, it may be appropriate to consider tens of scenarios, reflecting uncertainty around whether or not the new generation at question is likely to be built. In other cases, the investigation may be examining a grid enhancement where the presence or otherwise of new generation will have little or no effect. In such a case, it may be appropriate not to use alternative generation scenarios.

Base Case

We agree with the Commission that it is not necessary to determine a base case per se. Our practice to date has been to use the least cost alternative as a base case for reliability investments and a “do nothing” case as a base case for economic investments.

We agree with the Commission’s definition of alternative projects.

Satisfying the Investment Test

Subject to our comments above regarding unquantified benefits, we agree with the proposed criteria for satisfying the Investment Test. However, we do not agree that this should be the sole criterion when determining the preferred investment.

In our view, the investment decision itself should be made in a more holistic way than that specified by the GIT. We believe that the Investment Test result is important, but should not be the only possible determinant of the investment decision. Normal commercial investment decision-making practice would consider economic analysis along with other criteria (e.g. strategic factors and expert judgement), when arriving at a decision to invest or not and if to invest what investment to make. We believe such a broader decision-making framework is also appropriate for transmission investment decisions.

Where the proposed definition states:

“If these conditions are met, this potential investment has satisfied the Investment Test and becomes the proposed investment. The other potential investments that were considered are the alternative projects”,

we suggest deleting all text after “...satisfied the Investment Test...” so that it reads:

“If these conditions are met, this potential investment has satisfied the Investment Test”.

A list of decision-making criteria could be developed and included in the Input Methodology (IM), but we suggest that it is not necessary to be this specific. The only specificity required is that the Investment Test result must be reported. Other than that, the investment proposal should build a business case for investment and the Commission should be able to approve it accordingly.

Demand and Generation Forecasts

Whilst we agree that the base input assumptions (demand and generation forecasts) to the IM should be derived independently and that multiple generation scenarios should be developed, we do not believe the existing Statement of Opportunity (SoO) approach is appropriate.

The SoO approach developed generation scenarios based on deterministic predictions of what might happen in the future (i.e. a particular potential combination of future capital costs, fuel costs, etc) to justify a specific set of scenarios. We know it is not possible to predict the future, but by restricting ourselves to such predicted patterns of future events we are likely to be restricting ourselves to what we think might be credible today. Not considering other outcomes which may seem less credible today, but which may become feasible in the future, is unwise.

Our preferred approach would be to consider a range of futures to test the potential grid investment which test the efficacy of the investment independently of what we think might happen.

Transpower has a view on how suitable scenarios could be developed and we propose to engage with the Ministry of Economic Development on this.

Grid Upgrade Processes

Role of Transpower and Commission in applying Investment Test

We recommend that the Commission not undertake merits reviews of Transpower's investment proposals. This approach (adopted by the Electricity Commission in the discharging its investment approval role) undermines Transpower's accepted accountability for the grid planning function.

The process we use when developing an investment proposal, before submitting it to the Commission for approval, involves comprehensive consultation with consumers and stakeholders to ensure that consumer interests are fully considered. The Commission's role should be to verify whether we have followed due process and whether we have had regard to feedback received during the consultation.

Consultation Requirements

Although Transpower is not unhappy with the consultation requirements outlined in the Capex IM Discussion Paper, as they reflect our current practices, we would prefer that these not be prescribed in detail but rather key principles defined. Our consultation practices continue to evolve and improve to the benefit of both ourselves and stakeholders and flexibility is required to accommodate such improvements

Non-Transmission Alternatives

We support the development of non-transmission alternatives in circumstances where it is economic to progress these. Promotion of effective transmission alternatives (on both demand and supply sides) is a core element of our long term strategy, as defined in Transmission Tomorrow.

We therefore agree with the Commission's approach to ensuring that [non-]transmission alternatives are given due consideration. Transpower currently uses such an approach when considering transmission alternatives. We agree that they have an important role to play when economically justified and we will continue to evolve the transmission alternative framework. Currently, we are implementing an Electricity Commission approved project, the Upper North Island Demand Side Initiative. This project is aimed at developing a functional demand side participation product, which could be used to defer transmission investment in the upper North Island.

We would prefer that a minimum consultation period not be mandated for the request for information (RFI) part of the investigation process, because this unnecessarily slows down the development of investment proposals when transmission alternatives are not relevant.

It would be better to mandate a minimum period in the event that Transpower issues a RFI for transmission alternatives. At this point the RFI “sieve” has determined that transmission alternatives are feasible and this is where providers of transmission alternatives need time to develop their proposals.