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Dear Paul

Capital Expenditure Input Methodology (Transpower) discussion paper

Thank you for the opportunity to comment on your discussion paper *Capital Expenditure Input Methodology (Transpower)*, December 2010.

Wider context

Before commenting on the Commission's specific proposals, I would like to set the wider regulatory context. Our view is that, in collaboration with the Commission, we should be moving gradually toward a regime that minimises the need for the Commission to regulate individual investment decisions and instead use effective (financial) incentives to ensure that Transpower spends capital in a manner that meets the needs of all stakeholders in the national grid – and accords with the Purpose Statement. The Australian regulatory arrangements for transmission, including transmission investment, represent an appropriate model.

To evolve toward that regime, we should be seeking to reduce gradually the number of large projects requiring individual approval and increase the envelope of ex ante approved capital within which Transpower can operate between regulatory "resets".

Ex ante capex threshold

The ex ante capex threshold applied in RCP1 ($5million) is too low. In support of the broader objective set out above, this threshold should increase over time. As a pragmatic step, we propose increasing the threshold to $40 million as soon as practicable. This would mean that all but a handful of Transpower's largest and more complex grid upgrades would be excluded from the ex ante revenue allowance. In RCP2 and RCP3, consideration should be give to raising the threshold further.

The nature of the regulatory oversight for larger, individual, projects itself requires careful consideration. The danger is in creating the potential for the regulator to become, de facto, the transmission planner. The Commission's use of the term "technical merit review" could be construed as an approach whereby the Commission develops and promotes its own technical solution rather than focusing on ensuring the necessary processes of analysis and consultation have been applied by Transpower: I am sure this was not the intention. Again, the Australian approach to regulation of large network investments is instructive.

Performance incentives

There may be a concern that raising the ex ante threshold will result in insufficient rigour being applied to the cost benefit evaluation of the projects below the threshold. This is unjustified. We would continue to apply a robust cost benefit test to all our investments and to consult on the outcome with our stakeholders as appropriate. At the end of the regulatory period, the Commission would confirm that the processes had been appropriately followed and could hold the powerful incentive of excluding any investment from the regulatory asset base that had not been subject to due process.

A higher threshold means that a larger proportion of our capex will be approved and "capped" before the start of the regulatory period. This effectively addresses concerns that the regulatory framework does not provide financial incentives for Transpower to achieve efficiencies or minimise project costs. In conjunction with the annual quality performance output measures and targets which will link to financial incentives from RCP2, we believe this provides an effective incentive arrangement.

It is more difficult to create effective incentives for individual projects, and this approach should be avoided. The Commission's tendency in this case is to seek to regulate more closely the delivery of the project spend against its approval criteria. This is an example of adding further, more intrusive regulation to address a more fundamental problem i.e. seeking regulatory control at an individual project level. In our view, the answer to this conundrum lies in moving away increasingly from project specific approvals and increasing the scope of the ex ante approach.

We understand the intuitive attraction of measures based on network health. However, such an approach is likely to be complex and difficult to implement in practice and is unproven both in New Zealand and overseas. In our view the Commission should focus on implementing an extended ex ante approval framework in RCP2 and RCP3 rather than the development of capital expenditure incentive measures based on disaggregated network outputs.

Application of a robust cost benefit test

We are also concerned about the Commission's view that capital expenditure approvals should be based on a net market benefits test only. We understand this is driven by the wording of Part 4 of the Commerce Act. Nevertheless, we believe that the benefits that accrue to New Zealand other than to consumers of transmission services must be taken into account. In addition, the test should be flexible enough to consider other difficult to quantify benefits (such as investor confidence, economic growth benefits and benefits to consumers from enhanced competition).

In Appendix 1 we expand on some of these points in response to the questions posed by the Commission in its discussion paper.

Conclusion

We support large parts of the proposed approach for the development of the Capital Expenditure Input Methodology. However, we do believe it is important for this work to take place insider the wider context of how the overall framework for transmission regulation will evolve over the next 10+ years.

We look forward to constructive interaction with the Commission on these issues.

Yours sincerely

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Patrick Strange
Chief Executive Officer

Appendix 1 – Transpower response to each of the questions raised by the Commission in the discussion paper

Commission question	Transpower response
5.2.5 **Scope of the Capex IM** The Commission is interested in stakeholders' views on the scope of the capital expenditure to be covered by the Capex IM	The Grid Reliability Standard (GRS), as recorded in the Electricity Industry Participation Code (Code), schedule 12.2, ties all of Transpower's economic reliability investments to the Capex IM including customer investments where the investments are funded through Customer Investment Contracts (CICs). We seek clarification of the Commerce Commission's assertion that "*Capital expenditure relating to NICs, where the other party has agreed to the terms and conditions of the NIC,……are excluded from the Capex IM."* Most customer investments are made on the non-core grid and under the GRS (Code schedule 12.2, clause 3(2)) and are 'economic reliability' investments**,** being "investments in the grid and transmission alternatives that would satisfy the test for an investment proposal applied by the Commerce Commission under Part 4 of the Commerce Act". In addition, the 'economic reliability' standard is currently evaluated using the Grid Investment Test (GIT), including the provision in the GIT for commensurate analysis, to reflect the lower-value and different nature of customer investments. When the Capital Expenditure IM is created, the economic test it prescribes will be used to evaluate CIC investments. Hence, it is not correct to say that capital expenditure relating to NICs is excluded from the Capex IM. We understand that the EGRs were developed in the manner they were to ensure protection for consumers from potential agency issues and we support that concept. A workable approach, which works for Transpower and our customers, has evolved over the last 2-3 years and to ensure it survives, we propose that the "commensurate analysis" provisions in the EGRs be carried over to the Commission's equivalent economic test.
5.4.11 **Expenditure objective** The Commission is interested in stakeholders' views on the content of the proposed expenditure criteria including whether the expenditure criteria are consistent with the other components of the proposed Capex IM	We support the same evaluation criterion for costs that is used in Australia (that is, the proposal **reasonably reflects** efficient costs of meeting capex objectives). These would be costs that seem reasonable given the level of certainty around information used for a forecast. 'Reasonableness' is a standard legal test. This evaluation criterion allows for a discussion about whether the costs of what is proposed 'reasonably reflect the efficient costs'. Section 54S requires that the IM contain "criteria that the Commission will use to evaluate capital expenditure proposals". The requirement supports the purpose of IMs to promote certainty for suppliers and consumers about the rules, requirements and processes applying to the regulation of (electricity services). However, we do not agree that there should be a new, explicit expenditure objective of "efficient costs" against which our capex proposals are evaluated, although an evaluation of costs is appropriate. The capex objectives are those provided for under the price-quality determination (e.g. replacement to maintain service level, refurbishment to extend economic life, etc); the expenditure objective (the end point) is not 'efficient costs', rather the 'efficiency' aspect relates to the means by which the investment objectives are met. In Australia, the rule (NER 6A.6.7 (c)) states (emphasis added): "The AER **must** accept the forecast of required capital expenditure of a Transmission Network Service Provider…if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period **reasonably** reflects: • The **efficient costs** of achieving the Capital Expenditure Objective

	• The **costs** that a prudent operator in the circumstances of the relevant TSNP would require to achieve the capex objectives • A **realistic expectation** of the demand forecast and cost inputs required to achieve the capital expenditure objectives." The Australian framework provides for reasonableness to apply to the assessment of the efficiency of costs, which recognises the fact that 'efficient costs' can never be fully known in advance. There may be ongoing information that reveals efficient production costs – e.g. based on service delivery of a repetitive nature – but dynamically efficient costs can never be known in advance, as these are affected by ongoing innovation and the timing of expenditure. An evaluation criterion that required 'efficient costs' without qualification would create an environment that encouraged legal challenges to capital expenditure approvals. The Rule goes on to list the other matters that the Australian Energy Regulator must have regard to in order to be satisfied with a proposal. We suggest the Commission give consideration to these broader evaluation criteria that extend beyond efficient costs.
5.4.16 **Integrated plan** The Commission is interested in stakeholders' views on the value of an integrated plan for development and maintenance of the grid to support Minor and Major capital expenditure and operating expenditure requirements, the content of such a plan, and the forecast period that should be covered.	A separate integrated plan is unnecessary, as Transpower's revenue reset submission provides this information and sets out an integrated expenditure plan for a five year regulatory period. Information to support a Grid Upgrade Proposal (GUP) should reference this plan. Transpower's annual compliance reporting, under the IPP framework is required, inter alia, to provide an annual update of performance against the plan forecasts – this will include highlighting any material changes to the plan.
5.5.11 **Ex ante approval of Major Capex** The Commission recognises that it would take time to move to an approach where a proportion of Major capital expenditure projects are approved prior to the regulatory period. It is interested in the views of submitters regarding the pros and cons of such an approach. It does not envisage that such an approach	Our view is that, in collaboration with the Commission, we should be moving gradually toward a regime that minimises the need for the Commission to regulate individual investment decisions and instead use effective (financial) incentives to ensure that we spend capital in a manner that meets the needs of all stakeholders in the national grid – and accords with the Purpose Statement. The Australian regulatory arrangements for transmission, including transmission investment, represent an appropriate model. To evolve toward that regime, we should be seeking to reduce the number of large projects requiring individual approval and increase the envelope of ex ante approved capital within which we can operate between regulatory "resets". The ex ante capex threshold applied in RCP1 ($5million) is too low. In support of the broader objective set out above, this threshold should increase over time. As a pragmatic step, we propose increasing the threshold to $40 million as soon as practicable. This would mean that all but a handful of Transpower's largest and more complex grid upgrades would be excluded from the ex ante revenue allowance. In RCP 2 and RCP3, consideration should be give to raising the threshold further. A move to a higher threshold would mean that a larger proportion of Transpower's revenue would be "approved and capped" before the start of

would be applied until at least RCP3.	the regulatory period which, as Australian experience indicates, would provide an appropriate level of incentive for efficient expenditure and ongoing improvements in service performance. An assessment of "outputs" delivered for any expenditure incurred during a regulatory period would be undertaken but at the end of the period and indirectly to inform revenue setting for the next regulatory period.
5.5.15 **Minor/Major Capex threshold** The Commission is interested in stakeholders' views regarding whether the current definition of Minor enhancement projects remains suitable in the longer term and what an appropriate enhancement threshold should be from RCP2 onwards. This could include any detriments or benefits from transitioning from the current five million dollar threshold to a higher threshold over time, what the transition period to a higher threshold could be, and/or whether there should be limits placed around substitutability within the Minor capital expenditure category if the threshold was raised above the current level.	Whilst we have previously supported an increase in the capex threshold to $20 million (as proposed by the 2009 revised Government Policy Statement), we believe a threshold of $40 million is more appropriate. This was our position in our submission to the draft Government Policy Statement two years ago: *Transpower's own view remains that an appropriate threshold for identifying works suitable for the proposed streamlined approval process is in the order of $40 – $50 million.* [1] An increase to the threshold would effectively achieve several of the benefits described by the Commission with respect to a move to an ex ante approval regime for Major capex (see 5.5.11). These include: • providing an incentive to adopt a more holistic approach to planning and improve the quality of our forecasts; • increasing regulatory efficiency by allowing an integrated approval of opex and Minor capex arising from our integrated plan; • allowing for greater price certainty by enabling a higher proportion of capex to be included in the forecast MAR. There may be a concern that raising the ex ante threshold would result in insufficient rigour being applied to the cost benefit evaluation of the projects below the threshold. This is unjustified. We would continue to apply a robust cost benefit test to all our investments and to consult on the outcome with our stakeholders as appropriate. Overall, the investigation process we would follow is the same as if we were following a commensurate process for those larger projects outside the threshold. At the end of the regulatory period, the Commission would confirm that the processes had been appropriately followed and could hold the powerful incentive of excluding any investment from the regulatory asset base that had not been subject to due process. Of the twenty GUPs approved to date, three were between $1.5 and $5 million, eight were between $5million and $40 million and nine were in excess of $40 million. Leaving the threshold at $5 million would involve a higher workload for the Commission's regulatory approval function and it is questionable whether this would provide any additional value to consumers, particularly given that our process would be the same for these projects in any case. We are also of the view that the continued use of "Major" and "Minor" in terms of categorising capex is somewhat misleading, and of no benefit, and would seek to change the terminology to reflect the fact that capex is either within the threshold, or outside the threshold.
5.6.33 **Capex incentive regime**	The Commission's substantial new proposal to develop a capital expenditure / performance outputs based incentive regime is, in our view, premature at this point in the development of the regulatory regime.

[1] http://www.transpower.co.nz/f1175,28006590/government-policy-statement-16-mar-09.pdf clause 19

The Commission is interested in stakeholders' views on the inclusion of an incentive regime for Minor and Major capital expenditure and the use of set deliverables (network output measures) as part of the Capex IM.	We understand the Commission's view to be that: • the regulatory framework currently provides limited financial incentives for Transpower to achieve efficiencies or minimise project costs; • there is limited assessment of delivered assets and costs versus approved assets and costs; • the direct links between the health of the network and network-wide investment are unclear. These concerns are already addressed by the following: • the Commission currently undertakes a detailed assessment of Transpower's forward looking capital and operating expenditure proposals (and the decision making processes that underpin these), including an independent review of the drivers for investment, the processes for considering appropriate engineering solutions, the basis of cost estimates, the outputs to be delivered and the deliverability of the overall programme; • annual quality performance output measures and targets are currently set (which will link to financial incentives from RCP2). Despite these being lagging indicators, they do 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 reasonable indirect measure of network quality. We understand the intuitive attraction of measures based on network health, but this approach is complex, difficult to implement in practice and unproven both in New Zealand and overseas. Where output based regulation has been considered, for example in the UK, it is underpinned by a mature regulatory framework and several years of planning and information capture. In our view the Commission should focus on implementing an extended ex ante approval framework in RCP2 and RCP3 rather than the development of capital expenditure incentive measures based on disaggregated network outputs. Great care and time will need to be taken when developing an appropriate incentive regime and the additional regulatory interventions needed to ensure that perverse incentives are mitigated. There is not adequate time between now and November 2011 to develop such a regime properly. We recommend that the existing incentive arrangements should be developed over time, considering and in light of the knowledge we gain from implementing the initial IM and evidence of effectiveness from other jurisdictions using similar incentives and interventions. We consider it would be impractical to implement such measures before RCP3. There is currently no provision for direct or fixed capex efficiency incentives built into the Australian regime. The incentives the Commission refers to in 4.2.11 relate to the ability of transmission service providers to retain, during the regulatory period, the difference between forecast and actual capex. This is not the case in New Zealand, since any difference between actual and forecast capex is fully returned to customers via the annual EV wash-up... Whilst we acknowledge that the UK, as a mature regulatory regime, uses capex incentives for transmission investments, it has taken six years to develop the network output measures that are intended to provided information that the regulator will use to assess the need for capex on replacement and refurbishment and to date there is no established evidence to confirm that the regime is effective. **Maximum Approval Cost** As stated in the discussion paper, Transpower currently uses a Maximum Approval Cost (MAC) approach in its funding requests for large capex. We do not see any good reason to deviate from this approach for the larger projects.

	The MAC approximates a P90 cost estimate and is effectively built up from an expected cost which comprises the estimated cost (P50) plus a scope allowance. 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 approximates a P90 cost and effectively allows tracking of all costs: those we can control and those we cannot. Project implementation budgets are set at the P50 figure. Should we find that we do exceed this MAC figure, we have, in the past had the ability to seek recovery of the overrun providing we provide sound reasoning to support this. This process requires full reporting of all costs against approved amounts and has been transparent and open to consultation. There has never been any guarantee that we can recover overrun costs. Whilst we have yet to commission the majority of the approved twenty grid upgrade projects, our current estimates of forecast end costs show that we are on track to exceed the approved amounts for two projects, which is what we would expect from a P90 approach. Lifting visibility of how our projects are tracking against approved costs will, we believe, provide adequate incentives to control those costs which we can control.
5.6.43 **Capex incentive regime** The Commission is interested in stakeholders' views on the appropriate incentives to apply to Transpower for Minor and Major capital expenditure including the appropriate cost categories, the incentives applying to those cost categories and the form of the EV account adjustment.	In our view, it is too early to comment specifically on the form that appropriate incentive measures might take and how they might be implemented. As noted above, we would welcome the opportunity to work with the Commission to investigate whether or not practicable and meaningful incentives relating to the condition and capacity of the network might be able to be successfully developed, but we consider it would be impractical to implement such measures before RCP3.
5.7.12 **Timeframes for Minor capex** The Commission is interested in stakeholders' views on the timeframes for Minor capital expenditure including what should happen if either party does	We are permitted to manage Minor capital expenditure within the threshold between years during each RCP. In practice, some projects will progress as planned and others will not. We contract out our capital work and we anticipate that underperformance by contractors will be managed via penalty provisions in contract terms.

not comply with the timeframes.	
5.7.23 **Minor capex assessment process** The Commission is interested in stakeholders' views on the Commission's proposals regarding the Minor capital expenditure process, assessment and information requirements.	The Commission's proposed approach, as described in the discussion paper, seems appropriate.
5.8.6 **Any other matters for Major capex IM** The Commission would be interested in any other issues that should be considered when developing and determining the (Major) Capex IM.	**Satisfying the economic test** To pass the GIT, an alternative needs to: • maximise expected net market benefit compared to alternatives, for a reliability investment; • maximise expected net market benefit compared to alternatives and be positive, for an economic investment; and • be robust to sensitivity analysis Transpower considers this approach to be sensible and recommends, subject to the comment below, that it also be reflected in the Capex IM. We note that the discussion document uses the term 'greater', and the 'proposed investment must…have **greater** expected net market benefits than the alternative options considered'. The relevant phrase in the GIT uses 'maximum', which implies that an exhaustive range of options needs to be considered. We seek clarification of the intent of this wording change. **Unquantified benefits** We have developed a list of unquantified benefits that we regularly consider as well the economic test. These include: • Option benefits (the extent to which alternatives have options to be changed if circumstances change in the future) • Consumer benefits (from enhanced competition) • Benefits of reduced disruption (to landowners and the public) • Diversity benefits (which add to the resilience of the grid) • Operational benefits (for future maintenance) The consideration of unquantified benefits has provided to be useful. to distinguish between alternatives and choose a preferred option when the outcome of the investment test is close... We strongly suggest the economic test allow for the inclusion of such unquantified or hard to quantify benefits. We also urge the Commission to broaden the nature of the test so that it can take account of the wider economic benefits that accrue from transmission investment. These include investor confidence benefits and economic growth benefits. This is discussed more fully below in

	response to 5.8.21. **Good Electricity Industry Practice** A separate area that concerned us, with respect to the Electricity Governance Rules (EGRs), was the consideration and role of Good Electricity Industry Practice (GEIP) in investment decision-making. GEIP is a term use to describe common industry practices that have derived over time from the application of expert judgement, 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 judgement. **Decision criteria** The decision criteria the Commission use to approve a proposal should include the result of the economic test, the application of unquantified benefits and a consideration of GEIP. **Sensitivity analysis** Sensitivity analysis is a key part of the economic justification because it establishes whether or not the preferred solution or proposal is robust over a reasonable range of the key variables. Our practice has been to derive a set of sensitivities tailored to each investment proposal, based on identifying the key variables and we recommend that the IM allow the same flexibility. The EGRs outlined the principal objective the application of sensitivity analysis and listed some variables which should be considered for analysis, but left the actual list open. We recommend the same approach for the IM, because, in our experience, the relevant sensitivities are very dependent on the investment proposal. **Commission's merit review** The nature of the regulatory oversight for larger, individual, projects itself requires careful consideration. The danger is the potential to create a situation where the regulator becomes, de facto, the transmission planner. The Commission's term of "technical merit review" could be construed as an approach whereby the Commission develops and promotes its own technical solution rather than focusing on ensuring the necessary processes of analysis and consultation have been applied by Transpower. Again, the Australian approach to regulation of large network investments is instructive. The process we use for developing a GUP includes extensive consultation with customers and other interested parties. There are opportunities for customers and interested parties to comment on the need, the assumptions (demand, generation, VoLL, etc), the long and short list to be considered and then, once the investigation is close to final, the outcome of the investigation and the proposal itself. The downsides of the Commission undertaking a technical merits review are first that it is duplication of effort, and hence an inefficient use of

	resources, but, more importantly, it risks recreating the blurring of responsibility for grid planning that we had with the Electricity Commission. This lack of role clarity between Transpower and its regulator has been discussed for some time and most recently cited in a Ministerial review discussion paper[2]: *"183. Under the current arrangements governing grid upgrade approvals there is a lack of clarity over who is responsible for grid planning (Transpower or the Electricity Commission), and at what level of detail. While it is important that transmission planning and upgrades are subject to the right disciplines, the balance of accountabilities and functions needs to be such that the regulatory process works smoothly and at minimum cost."* In our opinion, a process review would be more appropriate, whereby the Commission focuses on whether Transpower has consulted appropriately and taken feedback into account adequately, and considers the reasonableness of our application of the economic test.
5.8.9 **Ex ante approval of Major capex** As discussed in Section 5.5, the Commission considers that, over time, it may be desirable to move towards an ex ante approach to approval of a proportion of Major capital expenditure projects, while retaining project-specific approval. The Commission is interested in stakeholders' views on this matter.	See our response to 5.5.11.
5.8.21 **Scope of Major capex Assessment** The Commission is interested in stakeholders' views on the	The cost benefit test should allow for consideration of broader economic costs and benefits and not be restricted to a net market benefits test only. We understand the Commission's view is driven by the wording of Part 4 of the Commerce Act. Nevertheless, we believe that the benefits that accrue to New Zealand other than to consumers of transmission services must be taken into account. In addition, the test should be flexible enough to consider other unquantifiable or hard to quantify benefits (such investor confidence, economic growth benefits, consumer benefits that result from enhanced competition etc). While we do not necessarily disagree with the Commission's interpretation of the Part 4 Purpose definition of "consumer" and conclusion that a market benefit test should be applied to Transpower's large capex, we do not agree that this results in an appropriate decision-making framework

[2] See **http://www.med.govt.nz/upload/69725/volume1.pdf**

treatment of Major capital expenditure and the scope of any cost-benefit test used to assess Major capital expenditure under the Capex IM.	for investment in electricity transmission. Electricity transmission is essential infrastructure (as are roads, rail and communication networks) and provides substantial benefits to New Zealanders other than as consumers of transmission services – such benefits are not captured by a net market benefits test. Sound infrastructure is essential to economic development, our standard of living and social well-being. It is important not only to consumers of electricity, but to New Zealand as a whole – New Zealand Inc. Without a reliable supply of electricity, industry, manufacturers and investors in general will be wary about investing in New Zealand. Economic investment is critical to New Zealand's economic wellbeing and providing investor confidence is a key benefit that should be considered when assessing the economic rationale for transmission investment decisions. Wider economic benefits such as these do not accrue to consumers (as defined by the Commission) per se, but to New Zealanders in general. As such, they are not captured in a net market benefit test, but would be if we took a net national benefit approach (which sought to maximise net benefits to New Zealand Inc). We consider that application of such a net national benefit test would be more appropriate and would lead to more appropriate transmission investment decisions. A narrowly focussed market benefit test could lead to sub-optimal investment decisions for New Zealand Inc. In a similar vein, there may be occasions where it would be appropriate to consider private benefits that accrue to private investors, in our investment decisions. As an example, we are facing increasing pressure to use underground transmission solutions, rather than overhead solutions, in some urban areas. In general, undergrounding is much more expensive than overhead investment and, more often than not, undergrounding would not satisfy a net market benefit test. The benefits of undergrounding (visual amenity, etc) accrue to local residents, not to consumers and are not captured by a net market benefits test. We are finding, however, that local bodies are starting to express an interest in funding the cost difference between overhead and underground transmission solutions, on behalf of their residents. There are also instances where property developers are prepared to fund such cost differences. In our view, provided consumers (as defined by the Commission) are no worse off, we believe it would appropriate for the approval process to accommodate such situations. We suggest that the approval process should acknowledge the alternative which meets the requirements of the net market benefit test, but allow for the approval of a different alternative, possibly with the proviso that consumers are no worse off in terms of cost and transmission service relative to the alternative that passes the economic test.
5.8.39 **Dual or single investment proposal process** The Commission is interested in stakeholders' views on incorporating a single process and investment test for Major capital expenditure in the Capex IM, versus retaining separate processes for reliability and investment processes as per the EGRs.	We agree that there should be a single process for approval of investment proposals. We support the proposal for a process that puts the responsibility for consultation and presenting an economic evaluation and business case on to Transpower, such as the process used for economic investments in the EGRs.

5.8.55 **Use of multiple generation scenarios** The Commission is interested in stakeholders' views regarding the best approach to be taken to account for uncertainty about future development of the electricity sector, particularly in light of experience with the current probability-based) approach. While it has not come to a view on this point, later sections of this paper (such as the section on satisfying the investment test) where this decision is relevant are drafted as if a probability-weighted approach were taken.	Given the long life of our assets, we believe that a multiple market development scenario (MDS) approach is appropriate to enable a full economic assessment of options over a range of possible futures. A single scenario approach requires a view on what the most likely future will be for generation and demand development in New Zealand. This approach is flawed in as much as no one can predict the future. However, our experience with applying the GIT has shown that it is not always necessary, or practical, to be bound to a set number of scenarios. The GIT prescribed that 5 MDSs must be used. However, in several "reliability" GUPs, we have only needed to use one scenario, since it was prudent to assume that there would be no generation built, unless it was already committed. This approach was accepted by the Electricity Commission[3], but in order to comply with the Part F rules, we were required to assume the same scenario 5 times with an equal weighting of 20%. It would seem more sensible in the future to allow as many or as few scenarios in the economic analysis as seems sensible. We support the use of a probability weighted average approach to evaluating proposals under a range of MDSs since it provides for the option which gives the highest net market benefit over a range of scenarios without bias if the probability weightings are equal. We do not support the alternate method which selects the option that maximises net market benefits across the greatest number of scenarios, since we do not believe it will inform the analysis as much as taking a probability weighted approach. Some of our proposals consider a short list of eight or more options. By adopting the alternate approach, it would be very difficult to ascertain a clear winner in terms of outcomes, since many of the options could potentially have a positive net market benefit in the same number, but different, scenarios. It could also potentially provide bias in terms of favouring one scenario over another. We favour the method which provides a high degree of objectivity about future scenarios since nobody can predict the future with any degree of certainty. It should also be noted that, to date, in all the proposals which required extensive MDS modelling, we have presented the economic results of the preferred option under each individual MDS, as well as varying the probability weightings to test the sensitivity of the preferred option to different futures. This has proved to be informative and should be retained.
5.8.63 **Base case** The Commission is interested in stakeholders' views on whether it is preferable (and necessary) to codify a base case in the Capex IM, or to adopt a more output-focused requirement such as that set out above.	The wording in the EGRs describing the definition of a Base Case was unintentionally problematic, but the use of a Reference Case has proven a satisfactory work around. We found in practice that it did not particularly matter which alternative was used as the Reference Case. The short listing process ensured that all alternatives were credible and, since the Grid Investment Test effectively resulted in an economic ranking of the alternatives, the choice of Reference Case did not matter as the same alternative was always the most economic. However, we did converge on the following practice: Reliability investments – Reference Case was the least-cost alternative that delivered the GRS; Economic investments – Reference Case was a "do nothing" alternative.

[3] See Reasons for Decision set out in *Notice of Intention to Approve Transpower's North Island Grid Upgrade Proposal*, para. 6.3.22.

	These choices seemed to be most consistent with the intent of the EGR definition of Base Case. We do not feel strongly either way and would be happy if definitions similar to the above are codified into the IM, or the Commission's approach b) is used.
5.8.77 **Demand forecasts and generation scenarios** The Commission seeks the views of interested parties on the preparation of demand and generation forecasts including who should prepare these and the role they should play in the preparation and assessment of Major capital expenditure proposals.	These two sets of assumptions are key to the economic analysis. We strongly prefer that the IM reflect current practice, as this has evolved from the early days of the EGRs to a practice that both ourselves and the Electricity Commission considered appropriate. In summary: a) we should be required to base GUPs on independently derived demand forecasts and generation scenarios. This removes any doubts that the forecasts have been developed in a self-interested manner; b) the IM should allow us to submit GUPs on the basis of our own forecasts, but require that we justify any deviations from the independently derived demand forecasts and generation scenarios. Discussions are still under way about development of the independently derived demand forecasts, but it is possible that the Ministry of Economic Development (MED) will publish national (and perhaps regional) energy forecasts and that the EA will publish national (and perhaps regional and/or GXP) peak forecasts. Assuming this is the case, we will likely derive our own GXP forecasts (both energy and peak) by combining the MED and EA information with customer input. These forecasts will be published and consulted on as a part of our Annual Planning Report cycle and subsequently used to help produce GUPs. Similarly, discussion is still under way about the development of generation scenarios, but it is likely that the MED will publish generation drivers (e.g. gas prices and availability) and the EA will maintain a database of potential generation projects, reflecting independent technical assessments of future generation and up-to-date intelligence. We will use the EA's information, combined with its own intelligence, and the EA's GEM model, to derive generation scenarios specific to each investment investigation. We have found that the range of scenarios applicable to each investment investigation is quite specific to that investigation. As discussed in our response to 5.8.55, we therefore suggest not specifying the number of scenarios, but equally weighting the number used. The number of relevant scenarios varies between zero (when it is "certain" that no new generation will emerge, or new generation is not relevant) to e.g. 40-50 when there is a multitude of possibilities and all should be considered.
5.8.90 **Discount rate** The Commission is interested in stakeholders' views on the appropriate discount rate for assessing Major capital expenditure projects including the range that could be used when	The choice of an appropriate discount rate for the economic test is important, but controversial. Economists have written volumes on the rationale for choosing a discount rate, but there does not seem to be consensus on a single correct approach. For situations akin to our own, most of the controversy appears to centre on whether a commercial or social discount rate should be used and what risk premium should apply in establishing the discount rate. The GIT discount rate was set at 7% and given the GIT was a net market benefit test that seems appropriate. We have previously argued that the GIT should be a national cost-benefit test and that the appropriate discount rate would therefore be the social rate of time preference (approximately 4%). Our rationale is more fully explained in our response to 5.8.21, but relates to the belief that electricity transmission is infrastructure which provides broader benefits to a wider range of people than is recognised by a market benefits test. We consider that transmission investment decisions should be underpinned by a New Zealand Inc (i.e. national cost-benefit) analysis.

undertaking sensitivity analysis.	Ultimately, all our GIT analyses were undertaken using a 7% discount rate, with sensitivities undertaken at 4% and 10%. In practice, the discount rate itself would only have changed the proposal on one occasion. In that case the expected net benefit of the proposal and next best alternative were less than $1 million apart. Further sensitivity analysis, plus consideration of unquantified benefits, were undertaken to illustrate that the proposal was robust under most sensitivities and still preferred. However, to the extent that the IM may be confined to being a market benefit test, because of the requirements of Part 4 of the Commerce Act, the continued use of a 7% discount rate for the economic test seems appropriate. Please note that, as discussed above, sensitivity analysis using a +/- 3% discount rate, should also be undertaken to inform the final investment decision.
5.8.100 **VoLL and analysis period** The Commission is interested in stakeholders' views regarding its proposed approach to setting a discount rate, value of unserved energy, and calculation period to apply to the investment test.	We agree that the economic test should utilise the value or values of unserved energy determined by the Electricity Authority, but with a provision to allow us to propose alternate figures to be used in specific situations. The analysis period for any investigation should cover the full economic life of the proposal. However, some transmission assets have a 50+ year life and the uncertainties in trying to forecast over such a long time period mean the analysis for the latter years is meaningless. Also, cashflows that far out discount back to very little ($100 in year 50, discounted back at 7%, equates to $3.40 in current year dollars). As a result, we have previously considered 40 years to be the maximum timeframe we would analyse in detail. 20 years is a reasonable timeframe for analysis for many transmission assets, except perhaps where benefits increase significantly over time. The IM should allow for these situations by allowing aggregation of costs and benefits after 20 years into a terminal value. This approach was adopted with the Electricity Commission, which allowed the inclusion of a terminal value as the discounted sum of those costs and benefits. We typically do not attempt to determine a residual value for assets at the end of the analysis period, because of the difficulties associated with this and the material effect it can have on the decision, except where two alternatives are very close, but then consideration of other (unquantified) benefits would normally be a better way to distinguish between the alternatives. We also note that assets with lives shorter than 20 years should be evaluated over their lifetimes and not 20 years. The IM should allow for this as well.
5.8.134 **Phased or conditional approval of Major capex** The Commission is interested in stakeholders' views regarding the roles of Transpower and the Commission in the grid upgrade	We need regulatory capex approval of our investment proposals at a relatively early stage of the design process. There are two main drivers for this. The first driver relates to efficient use of time and resources. We can have up to eight or more shortlist options requiring assessment as part of the economic test. To compare the options on an even footing, they need to be costed to a similar degree of accuracy and it would be inefficient, in terms of time and money, to conduct detailed design on all options. Sensitivity analysis is used to ensure the choice of proposal is robust to the uncertainties inherent in the analysis because of the high level design. The second driver is the constraint that the Resource Management Act 1991 (RMA) process places upon us. For an average size project, the process of obtaining the various RMA approvals typically takes in the order of two years to fulfil, (longer for larger projects and where Environment Court appeals are involved). It is therefore necessary to commence consultation (to validate the environmental effects of various options), and obtain capex approvals in sufficient time before construction works are required to commence. Given the need to obtain approvals

processes, the approval criteria to be applied by the Commission and the approach for setting the timeframes for Major capital expenditure including what should happen if either party does not comply with the timeframes set.	before detailed design is completed, we rely on 'designations' under the RMA to provide appropriate design flexibility. The designation process enables two stages of approval, initial concept (with conditions) and a more detailed outline plan once further detailed design has been completed. Once we have lodged notice of intention to designate, section 185 of the RMA obliges Transpower to be prepared to compensate landowners where Transpower does not otherwise have suitable property rights. To allow for the cost uncertainty arising from the use of high level design costs, we have sought approval from the Electricity Commission for a Maximum Approval Cost (MAC), which is similar to the concept of a P90. This cost allows for key uncertainties in cost movements caused by factors such as scope, price, foreign exchange and inflation. Of the twenty projects we have had approved under Part F, there are currently only two (10%) which are forecast to exceed their respective approval cost. Similarly, approximately half are forecast to cost over the P50 level and half under. Consequently, we believe that the MAC approach works and should be adopted within the Capex IM. We recognise the need to raise the visibility of project tracking against costs and deliverables and believe that this in itself will provide a strong incentive to continue to control those costs that we are able to influence. The primary purpose of the Capex IM is to promote certainty. The introduction of phased and/or conditional approvals, even if only a financial approval has the potential to create uncertainty with regard to the option approval. This uncertainty could have a detrimental effect on both the demand and supply sides of the industry as well as our ability to move through the RMA process in a timely and cost efficient manner. Consequently, we strongly recommend that the Commission not pursue such approvals.
5.8.148 **Consultation for Major capex** The Commission is interested in stakeholders' views regarding an appropriate consultation regime for Major capital expenditure proposals.	We agree with the view that there should be provision for us to propose to the Commission that aspects of the first consultation be omitted or combined with another consultation in certain circumstances. We do not consider it appropriate for such circumstances to be prescribed, because we have found that they are unique to each case and prescription could unintentionally result in consultations being omitted when they are still relevant, or consultations being undertaken when they are not necessary. More general statements, similar to those in the EGRs which allow for commensurate GIT analysis, demand forecasts and generation scenarios to be altered, etc, but which require us to justify such changes to the Commission, have proved to provide the flexibility we need to undertake investigations efficiently. We note that the Australian framework, which mandates two consultation stages, does not have the regulator in an explicit approval role. Rather, it is left to other participants to interrogate the investment proposition and analytical conclusions, with the AER's role being in any ensuing dispute process. The lengthy, much prescribed initial consultation in Australia appears to be in response to insufficient previous consultation. We are not aware of any such shortcomings here and so are concerned that this level of prescription may lead to inefficiency. We recognise that the Commission has concerns around allowing appropriate time for transmission alternative providers to submit proposals. As far as we are aware this has not been an issue to date. Where the consideration of alternatives has progressed to a Request for Proposal stage, we have worked with proponents as required. More detail is described in our response to 5.8.159.
5.8.159 **Transmission alternatives** The Commission is interested in	We fully agree with the Commission that any process should continue to provide for consideration of transmission alternatives as part of the investigation and approvals process. It should be noted that we have a well established investment approval process which allows for the proponents of transmission alternatives to come forward and have their proposal considered alongside the transmission options. For all capex investments, we issue a Request for Information (RFI) for transmission alternatives at a very early stage. This is included in our first consultation, and goes along with the assumptions we will be using in the analysis (demand, etc) and the long list of options to be considered. It

stakeholders' views regarding the issues and options for identifying, proposing and considering transmission alternatives in the context of the process for Major capital expenditure proposals, and the extent to which a process for transmission alternatives should be prescribed in the Capex IM.	is distributed to a wide audience via our Grid New Zealand website and is not restricted to industry participants. The intent of this consultation step is to gather information on any options that we have not considered at the early stage, including any available alternatives. This consultation is usually open for three weeks, but if there are proponents of other options that require more time, we have extended the submission period – as was the case in the Upper North Island Reactive Support Investigation[4]. Following this initial consultation period, there is usually a period of between 3-12 months in which we refine the long list of options down to a short list to which we apply the economic test. Should a viable transmission alternative be mooted in response to the RFI, we then issue a Request for Proposal (RFP). This RFP would require the proponent to develop their proposal. We direct the Commerce Commission to the Upper North Reactive Support Investigation, which details how this process worked in an actual investigation. The RFP process took several months in that instance. Extending, or standardising the time for these consultations will result in lengthening the investigation and approvals process, often unnecessarily where there are no viable transmission alternatives. We submit that the process should require us to consider transmission alternatives, but leave the approach and consultation timeframes open. The process we use now has evolved through practice and we would expect it to continue evolving. The process includes flexible timing to allow proponents of transmission alternatives to develop their proposals following the initial consultation, where relevant. We request that the Commission note that we support the use of transmission alternatives and continue to seek ways to implement them. We dispute the assertion that we "may have relatively weak incentives to accept transmission alternatives". From a general business risk perspective, given the extremely heavy commitment of resources represented by our current build programme and the consequent pressure on our debt load, we have a very strong incentive to adopt non-network solutions where these are genuinely viable. In 2007, we trialled demand side participation in the Upper South Island[5] as well as funding an Upper South Island load controller to control load at peak times. We are currently seeking proponents of demand side initiatives to be implemented in the Upper North Island region by the end of this year as well as facilitating the implementation of a load controller in that region. We have also spent considerable time and resource developing a Grid Support Contract[6] that allows for the consideration of all forms of non-transmission options including large and small generation and both aggregated and distributed demand side participation (DSP).
5.8.168 **Grid Upgrade Plan content** The Commission is interested in stakeholders' views regarding the appropriate content of a grid upgrade proposal.	Grid Upgrade Plans (GUP) were required to contain: information on investment contracts, a comprehensive plan for asset management and operation of the grid and investment proposals. **Investment Contracts** The Code still provides for the EA, as owner of the GRS, to be notified of investment contracts. As these are not the purview of the Commission, we assume this information will not be required in large capex proposals to the Commission. **Comprehensive Plan for Asset Management and Operation** We believe the proposed Integrated Plan, which forms a part of our submission at the beginning of each new Regulatory Control Period,

[4] See http://www.gridnz.co.nz/f2504,36732578/p3-uni-dynamic-reactive-gup.pdf
[5] http://www.gridnewzealand.co.nz/f2246,34346588/dsp-trial-report-01-nov-08.pdf
[6] See http://www.gridnz.co.nz/gsc

	supersedes the comprehensive plan for asset management and operation of the grid. Whilst each Major capex proposal can include an explanation of where the proposal fits in the context of the most recent Integrated Plan, we assume the GUP requirement to submit such a plan will now be fulfilled by the Integrated Plan submitted at the beginning of each new Regulatory Control Period. **Investment proposal** We generally support the information requirements outlined in 5.8.167 but would like to clarify the following: a) what is meant by 'specification of outputs' – would this be the same project specification as required for a project for a Notice of Requirement under the RMA? e.g. one transformer, eighteen towers, duplex 'goat' conductor, etc? If this is the case then the requested plan for tracking and reporting against the approved 'outputs' would presumably require reasons for any deviations from the specification; b) the level of detail the Commission anticipates requiring in relation to: *"Approval amount for the proposed investment including justification of project costs on the basis of internal and external benchmarking and the procurement and tendering processes undertaken".*